SUCCESSFUL FIELD APPLICATIONS OF CO_2 FOAM FRACTURING FLUIDS IN THE ARK-LA-TEX REGION

W. E. Warnock, Jr., Crystal Oil Company
and
P. C. Harris & D. S. King, Halliburton Services

ABSTRACT

The CO_2 foam fracturing fluid provides a gas drive to assist removal of the treating (load) fluids after the proppant has been placed in the formation, establishes permeability to gas within the formation volume that has been saturated by load fluids, and minimizes the actual water volume that is required to place a given volume of proppant in the formation. Due to the high density of the liquid CO_2 mixture, the CO_2 foam can be utilized on deep, high pressure formations without experiencing prohibitive wellhead treating pressures. The CO_2 also reacts with the water in the foam to form carbonic acid, so that the overall pH of the system is reduced (thus reducing the damaging effect of the fluids), and it lowers the surface tension of the load fluids so that they can be recovered more rapidly and efficiently. Field experience in the Ark-La-Tex area has demonstrated that the CO_2 foam system can be used successfully in low permeability oil and/or gas sands and carbonates, at depths ranging from 2900' to 14,000 ', reservoir temperatures of 120°F to 370°F, and reservoir pressures of 1000 psi to 13,200 psig. Treatment histories and pressure transient tests have demonstrated that many of these formations are sensitive to some fluids utilized in conventional gelled water fracture treatments. A comparison of CO_2 foam with several other stimulation methods demonstrates its overall success. In many instances the production results obtained with CO_2 foam fluid are superior to more conventional systems that have been used in the past.

INTRODUCTION

Hydraulic fracturing has been used to stimulate oil and gas producing wells since the late 1940's, and today it is considered a standard completion procedure on many wells that produce in the South Arkansas-North Louisiana-East Texas (Ark-La-Tex) region.[1] Technology associated with fracture treatments has advanced significantly, particularly during the last ten years. As the price of oil and gas has escalated, the application of many new fluids systems, proppants, etc., has become economically feasible, and many tight formations that were formerly bypassed as noncommercial are now producing significant reserve volumes.

Carbon dioxide has been added to fracturing fluids in various producing areas of the United States for many years. Usually up to 500 scf of CO_2 per barrel of fluid was added to assist in the post treatment clean-up operations. In the late 1970's CO_2 was initially utilized in Texas at concentrations of up to 50 percent of the total injected volumes because of the associated improved fluid loss efficiency and reduced total load water requirements.[2] Foam fracturing with 70 percent carbon dioxide as the internal phase of the fracturing fluid was attempted in the Ark-La-Tex region for the first time in early 1982, and the field results to date indicate that the system has distinct advantages over more conventional gelled water fracturing fluids and nitrogen foam fracturing fluids.

DESCRIPTION AND FRACTURE STIMULATION HISTORY, ARK-LA-TEX AREA

The South Arkansas, North Louisiana, and East Texas (Ark-La-Tex) tri-state area is shown in Figure 1. This area is characterized by sand or carbonate intervals with alternating shale sections from the surface to the Smackover zone at 10,000' to 11,800'. A typical penetration to Smackover depth (see Figure 2) will encounter over forty different sands that have produced commercially within the Ark-La-Tex region, and the existance of over five hundred fields demonstrates the fact that hydrocarbon sources, trapping mechanisms (usually structural anticlines and/or stratigraphy), and reservoir quality rock are present throughout this area. Commercial production was first developed in South Arkansas, North Louisiana and East Texas in 1921, 1922, and 1927, respectively.[3] However, the significant increase in gas prices that occurred in the late 1970's greatly accelerated the economic development of the tight Jurrassic zones (Cotton Valley, Haynesville, and Smackover) in numerous areas that had been identified years earlier.

Historically, low permeability gas sands in the Ark-La-Tex regions have been fracture treated to stimulate production. Initially, non-complexed water-based treatment fluids were used with some success. With the introduction of complexed gel systems in recent years, most operators took advantage of the improved proppant transport and greater stability of these systems. If load recovery was considered a problem, CO_2 was often commingled with complexed gels to aid clean-up. Recovery was further enhanced by using 70 quality nitrogen foams; however, increased wellhead treating pressures due to hydrostatic head loss made treatment of deeper zones prohibitive.

The Pettet Lime formation was primarily stimulated with acid treatments of varying volumes. Acids were often gelled or foamed with nitrogen for use in fracture acidizing to increase formation penetration. Fracture treatments utilizing proppants were seldom used in the Pettet.

With the introduction of CO_2 foams to the area, many of the qualities of the complexed gel systems (i.e., improved proppant transport and good stability) were combined with the improved load recovery of nitrogen foams. Successful CO_2 foam stimulation treatments were soon being completed in many tight gas zones as well as in the Pettet Lime formation.

The fields within the Ark-La-Tex region where the CO_2 foam fracture process has been utilized to date are shown on Figure 1, and the formations/zones that have been treated with this process are highlighted on the type log in Figure 2. Table I is a detailed summary of the reservoir characteristics for the zones that have been treated with the CO_2 foam. It is apparent from these data that the process has been tried in a wide variety of vastly different applications throughout the Ark-La-Tex region.

DESCRIPTION OF CARBON DIOXIDE FOAM FLUID PROPERTIES

The CO_2 based fluid used in the Ark-La-Tex region is a two-phase structured fluid having 70 percent liquid CO_2 as the internal phase and 30 percent aqueous liquid as the external phase. The aqueous phase contains the necessary viscosifying agents, surfactants and stabilizers appropriate for the temperature and type of formation being treated. Proppant is introduced to the fluid via the aqueous phase. CO_2 is pumped from the transport vessel(s) as a liquid and mixed with the aqueous phase prior to the wellhead, forming a two-phase fluid. The CO_2 will typically remain in the liquid state until reaching the bottom of the tubing. Once the fluid is heated sufficiently upon entering the formation the fluid becomes a foam.

Liquid CO_2 has a density greater than water at pressures above 5,000 psi.[4] The high density provides sufficient hydrostatic head to allow lower surface treating pressures than other gas assisted fluids. Therefore, treatments of deeper zones are practical with CO_2 based fluids.

The 70 quality CO_2 fluid has a two-phase structure similar to the nitrogen foams. The properties of viscosity[5] and resistance to fluid leakoff[6] have correspondingly been found to be very similar.

Application of the 70 quality CO_2 fluid to the hot Cotton Valley formation in Jackson Ph. required laboratory testing of the fluid stability.

Breakdown of two-phase structuring at high temperature would destroy most of the proppant transport and fluid loss control characteristics of the fluid. The 70 quality fluid was tested inside a stirring autoclave. The fluid showed excellent stability at 325°F at 3,000 psi. At 350°F, however, the fluid had good stability for only 18 minutes. In actual field usage, treatments in the Vernon field were successfully placed at bottom hole temperature of 370°F. Although some formation cooling would have occurred before the proppant laden fluid entered the formation, it is possible that the higher pressures encountered in the field (10,000 psig or greater) may have improved the fluid stability.

The ability to minimize the volume of water pumped into the formation while placing significant amounts of proppant is very important in successfully stimulating many zones in the Ark-La-Tex region. With 70 quality CO_2 fluid, the water burden placed on the potentially sensitive formation is only thirty percent of the total treatment volume. Since the CO_2 is partially soluble in the treatment water, as shown in Figure 4, most of the water will be removed following the treatment by solution gas drive. The excess CO_2 is also soluble in formation waters and in oil. This induced solution gas drive helps to establish an initial flow of the formation fluids toward the propped fracture system.

The dissolved CO_2 reduces viscosity of formation fluids, improving initial producibility. In addition, dissolved CO_2 lowers interfacial tension of load water to 18 to 25 dynes/cm,[4] thus reducing capillary pressures, so that less formation pressure is required to produce fluids. Such removal of blocking water helps to establish permeability within the fracture system in both gas and oil zones.

Indirect benefits of reducing water in the treating system include a corresponding decrease in the amount of chemical additives required to achieve desired fluid properties. This reduction helps to offset the cost of CO_2 as well as any additional cost associated with pumping a two-phase fluid. Typical CO_2 foams pumped down casing are approximately 10 percent higher in cost than conventional treatments. Tubing treatments are 30 to 40 percent more expensive due to significantly higher wellhead treating pressures.

Field experience has shown CO_2 foam to be very stable even under high temperature applications. CO_2 foams have been successfully placed at temperatures of 350 to 370°F with pump times greater than four hours.

The design volume has been pumped successfully on 96 percent of the 104 zones treated to date. On several occasions mechanical problems during the treatment have forced shutdowns with proppant laden foam in the wellbore for as long as thirty minutes, but no surface indication of proppant settling has been seen after pumping was resumed. These data indicate that the 70 quality CO_2 foam is a stable system that can be pumped under a wide variety of temperature and pressure conditions.

OPERATIONAL TECHNIQUE AND TYPICAL CARBON DIOXIDE FOAM FRACTURE TREATMENT DESIGN

CO_2 foam fracture treatment designs are based on the same parameters used to design any fracturing treatment (i.e., permeability, zone size, gross interval, etc.). Table 2 illustrates typical designs used to date in the four main producing areas.

FIELD OPERATIONS PROBLEMS USING CARBON DIOXIDE FOAM FLUIDS

There are several points which must be considered when a CO_2 foam treatment is to be attempted:

Conduit Geometry

As the conduit cross section decreases, friction pressure increases dramatically, making the wellhead pressure of jobs pumped down tubing much higher and more difficult to control than those pumped down casing. Casing treatments tend to show reductions in treating pressure as the proppant concentration and slurry density is increased. However, during tubing treatments the wellhead treating pressure typically rises as the proppant concentration is increased because the additional friction pressure associated with the higher injection rate is greater than the pressure reduction due to the increased hydrostatic head. Most jobs are therefore pumped down the casing unless the target zones are shallow (with minimal friction loss effect), or if the casing string is not capable of withstanding the required treating pressure.

CARBON DIOXIDE PUMPING CONSIDERATIONS

To insure that the CO_2 remains a liquid at the surface while it is pumped, the increase in temperature of the fluid must be controlled. Some factors affecting the temperature of CO_2 are the storage vessel pressure, ambient air temperature, discharge pressure, and pump plunger size. These factors become increasingly important as ambient temperature rises (particularly during the summer) and as injection pressure approaches 10,000 psig. If it is apparent that the increase in CO_2 temperature in a given system will be too great, then steps must be taken to relieve the problem by insulating suction lines, modifying pumps, or attempting to pump the job during cooler morning hours. Failure to consider these factors may cause vapor locking of the pumping system.

FLUID PUMPING CONSIDERATIONS

The fluid pumping system of a CO_2 foam is much the same as on any conventional treatment with the exception of the higher sand concentrations that occur in the blending and pumping equipment. A 70 quality CO_2 foam contains only 30 percent water phase and thus all proppant must be carried through the system in 30 percent of the fluid and at roughly 30 percent of the total rate. For example, to achieve an effective proppant concentration of 5 pounds per gallon of foam at bottom hole conditions, the fluid system would have to handle a proppant concentration of 16.67 pounds per gallon of fluid at the surface. Blending and pumping equipment may have to be modified to meet these conditions.

SAFETY CONSIDERATIONS

On any fracture treatment where compressible fluids are being pumped it is common procedure to secure all lines (low pressure and high pressure) to prevent them from becoming projectiles in the event of a hose rupture or line separation. In addition, on CO_2 foam treatments it is suggested that all personnel be equipped with portable breathing apparatus and that "lifelines" be installed to guide personnel off the location. These precautions are necessary if a high volume CO_2 leak should occur.

ARK LA TEX AREA CARBON DIOXIDE FOAM FRACTURE TREATMENT RESULTS

Through May 1, 1983, approximately 104 zones in 85 wells throughout the Ark-La-Tex area have been stimulated with CO_2 foam fracture treatments. The first CO_2 foam treatment in the region was in March of 1982 in the Cotton Valley zone at the Dorcheat Macedonia field (South Arkansas). The technique was gradually tried in various different applications where other more conventional treatments had been utilized previously. The CO_2 foam fracture treatment has been at least as good as any of the previous stimulation techniques in these areas. The clean-up time is always better with the CO_2 foam, so that production is realized more rapidly. In many cases the CO_2 treatment has improved the producing performance and/or the estimated ultimate recovery of the wells treated when compared to the offset completions that were stimulated with other techniques.

DORCHEAT MACEDONIA FIELD, COLUMBIA COUNTY, ARKANSAS

The series of multiple Cotton Valley sands at Dorcheat has produced from various wells since the field was discovered in the 1930's. However, the typical well was completed in the Cotton Valley zones that required only an acid stimulation treatment. Other intervals with lower permeability were routinely abandoned or bypassed. Those Cotton Valley members that had an indicated porosity of 10 to 15%, with a water saturation of greater than 45%, were largely unsuccessful even after acidizing and/or fracturing (they were characterized by a poor feed in and rapid decline). This experience prompted the conclusion that the numerous zones in the field that had those characteristics were too tight to produce commercially.

No conventional fracture treatments were attempted in the Dorcheat Macedonia Field after 1979 because of the previous lack of success. Beginning in late 1980, some nitrogen foam fracture jobs were tried at depths above 7700'. The depth at which the nitrogen foam could be utilized was limited by the high treating pressure associated with the low density fluid, and the treating rates had to be restricted so that only a small interval (generally 10' or less) could be fractured during each job. The expenses and mechanical problems associated with multistage nitrogen foam treatments were prohibitive, so it was difficult to fracture and commingle several tight sands within the same wellbore. As a result initial producing rates and economic rate of return continued to be marginal. In general, nitrogen foam treatments were thus utilized only on single zones above 7700' that had good net sand characteristics (i.e., 10 to 15' of acceptable porosity above 11 percent), which left approximately 1200' of gross interval below that depth (containing ten to twelve typically tight Cotton Valley sands) virtually untested.

The carbon dioxide foam fracture technique was first tried at Dorcheat in March of 1982. Unfortunately, due to the previous testing and production of shallow zones in the Dorcheat field, the casing string in most of the existing wells did not have pressure integrity. Thus any test in the deeper bypassed zones required that the CO_2 fracture treatment be pumped down the tubing. This procedure tends to restrict the treating rate and gross interval that can be fractured simultaneously, but due to the more dense CO_2 foam fluid it is still possible to stimulate individual Cotton Valley stringers down to the base of the section at 8900'. The best results using CO_2 foam fluid have been obtained in wells drilled more recently, because several of the deeper zones in those wells can all be treated together at a higher injection rate down casing.

The CO_2 foam fracture treatment process has been very successful in the Dorcheat Macedonia field, particularly in the numerous sands that were formerly bypassed as non-commercial due to their high indicated water saturations (greater than 45%) and poor previous performance.

The Willis D-1 well at Dorcheat is an example of a new completion where the CO_2 foam process was used in zones that would have been bypassed previously. The #D-1 was fractured over a 250' gross interval (86' net), which included six separate stringers with an average water saturation of 48% and a porosity of 13%. The well produced at an initial rate of 1160 Mcfg/D, 298 BOPD, 135 BWPD on a 16/64 choke with a flowing pressure of 1500 psig. It had declined to a rate of 130 BOPD with 500 Mcfg/D, 60 BWPD, and a pressure of 750 psig by the end of two months. However, the decline curve indicates an estimated ultimate recovery of 80 MBO with 310 MMcfg (i.e., a 50 percent per year decline) for these formerly "noncommercial" sands. Another example is the Paxton B-1 which came on in January 1983 at a rate of 870 Mcfg/D, 73 BOPD, 226 BWPD with a pressure of 1200 psig on a 16/64th choke. The well was still making 820 Mcfg/D with 66 BOPD and 150 BWPD by May of 1983, with an indicated ultimate recovery of 400 MMcfg with 32 MBO. The Paxton B-1 is producing from a single Cotton Valley member at 8750; that has a calculated porosity and water saturation of 13.5% and 55%, respectively.

It should be noted that these previously bypassed Cotton Valley zones do produce water with the hydrocarbons after being fractured, even though they have previously exhibited limited shows with little or no feed-in after being stimulated with conventional gels in offset completions. This implies that the formation within these stringers was being damaged by the fracture fluids during the previous conventional treatments, and/or that the fracture fluids combined with the connate water in the formation could not be adequately "unloaded" without the aid of the injected gas that is present in the foam system.

The success of the CO_2 foam fracture treatment at Dorcheat Macedonia has generated several additional drill well prospects within the field. The objective of these wells is to infill in areas where the previous completions did not produce these numerous tight sand stringers, and improve the recovery efficiency within those zones that were partially produced, but not adequately drained, due to the previous lack of stimulation.

Several zones that were partially drawndown due to offset drainage have been successfully treated at Dorcheat using a CO_2 foam fracture. Similar attempts with the nitrogen foam system were unsuccessful because the less soluble nitrogen tended to dissipate into the reservoir and leave the load fluids in place.

VERNON FIELD, JACKSON PARISH, LOUISIANA

This field is characterized by a relatively deep Cotton Valley section that consists of up to thirteen different tight sands located at a depth of 11,100' to 14,500'. The zones are all geopressured (.91 psig/ft of depth), and the reservoir temperature in the deepest members treated to date exceed 370°F (see Figure 3 - Vernon Field Cotton Valley Sand Series).

The first commercial completion ever made in the deeper Cotton Valley sands (i.e., below the Cadeville sand) at Vernon was in the lower Poole zone of the Davis Brothers A-1 well in February 1982. This 39' net interval was stimulated with a relatively small gelled water fracture treatment design for only 500' of half-length (60,000 gallons of total fluid, with 59,000 pounds of high strength proppant) because of the concern that the gel stability might be a problem under the temperature conditions that existed. The zone responded with an initial producing rate of 1500 Mcfg/D, 24 BWPD, with a flowing pressure of 7280 psig on a 6/64th choke. A pressure transient test was run approximately one week later to evaluate the sand and fracture characteristics (see Table 3, Pressure Transient Test Results Using Horner Analysis - Vernon Cotton Valley Zones).

Since the numerous sands within the Cotton Valley section at Vernon all have similar characteristics, the preferred completion procedure is to commingle the entire section in each wellbore in order to maximize initial deliverability and to allow the more efficient drainage of the individual members by producing them to a lower ultimate abandonment rate than would be possible if they were depleted individually. Also, the Cotton Valley sands are being developed on effective 160 acre spacing, and the experienced recoveries in this and other NGPA 107 tight formations in the area indicated a need for fracture half lengths of 1500' in order to adequately drain the development pattern.

Immediately after the pressure transient test in the Lower Poole sand of the Davis A-1, the zone was isolated and the next productive (Cotton Valley member, the Lower Stray Sand, was perforated and treated with a slightly larger conventional fracture treatment (110,000 gallons of total fluid, 122,000 pounds of proppant) designed for 1200' of half length. This second zone also responded favorably to the fracture treatment with an initial rate of 1950 Mcfg/D on a 10/64th choke, 75 BWPD, and a flowing pressure of 3000 psig. However, the decline in tubing pressure for the Lower Stray Zone was more pronounced than in the Lower Poole section, so a pressure transient test was run five days later to evaluate the new interval.

Table 3 details the Horner analysis results of the build-up test data on these first two completion intervals. It is apparent from the characteristics of the two tests that the second fracture treatment was less effective, even though it penetrated 700' farther into the tight Lower Stray sand than did the first treatment in the Lower Poole zone. In general, the stimulated Lower Stray sand in the Davis A-1 had a lower productivity index measured in terms of gas deliverability per foot of net pay, less indicated stimulation based upon the measured skin index, and a lower flow efficiency than the Lower Poole sand, even though the virgin Stray sand has a higher effective permeability to gas and better porosity and water saturation than the Poole interval. Conventional core samples were subsequently analyzed from offset wells in the Lower Stray section, and they indicated a regained permeability of 95 to 100 percent even after exposure to the same conventional fracture fluids. The results of these tests and the build-up analyses imply that the high capillary pressures associated with the low permeability Cotton Valley sands at Vernon probably cause the retention of the conventional gelled fluids along the fracture face, and the effective drawdown along the fracture is insufficient to displace these fluids from the pore spaces. The net effect of this problem would be to reduce the productivity of the formation nearest the well whenever it is exposed to additional fluid volumes. It appears likely that the additional wing length would not be beneficial because the effective drawdown farther from the wellbore would be even lower.

Due to the apparent "water block" of the pore space that occurred with the conventional gels, a CO_2 foam fracture treatment was subsequently tried in the Cotton Valley section at Vernon. As mentioned earlier, the laboratory stability tests had indicated possible degradation of the CO_2 foam whenever it reached temperatures in excess of 325°F. As a result the wing length, cooling pad volumes, CO_2 foam volumes, and pump times were gradually altered with each succeeding job until a 1500' foam fracture treatment was pumped in the lower Poole zone of the Davis E-1 well in December of 1982. This zone tested 1746 Mcfg/D, 11 BWPD, with a flowing pressure of 7300 psig on a 6/64th choke approximately 20 days after the treatment had been pumped. The subsequent pressure transient test analysis data are shown in Table 3. The data indicate that the 1500' CO_2 fracture treatment resulted in an improved productivity index per foot of pay with approximately the same skin factor and flow efficency as the substantially smaller treatment in the correlative Lower Poole member of the Davis A-1 wellbore. It is interesting to note that the volume of water pumped during the Davis E-1 treatment was only 50 percent greater (30,000 gallons) than the first Lower Poole treatment in the #A-1 well, even though the proppant volume pumped in the #E-1 was increased by five fold and its drainage penetration was approximately nine times greater.

Due to the relatively brief history of the Vernon field, the numerous different zones that are fractured and then commingled to make a final Cotton Valley completion, and the many different fluid types/volumes that have been pumped at Vernon to date, it is difficult to make a comparison of ultimate recoveries versus the type of treatment utilized. However, there have been occasions where a certain zone or group of zones has been produced long enough to establish a reasonable production trend. An attempt has been made to compare these data by calculating the indicated recovery per foot of pay, and as a percent of the original gas in place, as shown in Table 4. Since there is insufficient production history on any of the wells at Vernon to adequately establish their ultimate decline trend (exponential, hyperbolic, harmonic, etc.), the values shown in Table 4 are obviously estimates. However, the significant difference in the early performance of the zones stimulated with CO_2 foam fracture treatments has definitely improved the apparent ultimate recovery. It should be noted that the zones in Table 4 that were treated with CO_2 foam have a longer average half length than the conventionally treated intervals. This was possible due to the reduced water volumes in the CO_2 foam treatments. It is apparent that the longer fracture length should more efficiently drain a tight formation if the increased fluid volumes associated with the additional fracture length do not cause damage.

ARKANA FIELD, BOSSIER PH., LOUISIANA

The Haynesville sand series at Arkana, between the base of the Cotton Valley and the top of the Smackover, was first produced commercially in March of 1980, and the zone was rapidly developed with an additional thirty-eight penetrations (on nominal 160 acre spacing) by September of 1982. The typical Haynesville fracture treatment was designed for 1000 to 1500' of half length, and it was pumped down the casing string at rates of 40 BPM. The fracture fluid was a conventional gelled water with carbon dioxide added at a volume of 500 scf per barrel, which greatly aided the subsequent clean up of the fluids. These treatments were successful in stimulating the NGPA 107 tight Haynesville sands at Arkana, as evidenced by the data on several typical wells that is shown in Part 1 of Table 5. It should be noted that the average Haynesville completion is incapable of production prior to being fractured.

Although the earlier conventional gel fracture treatments at Arkana had been successful, the results using CO_2 foam fracture jobs in the tight Cotton Valley sands at Vernon encouraged the first CO_2 treatment attempt in the Haynesville in December of 1982. Part 2 of Table 5 details the initial production rates, and the stabilized rates after one month, for the first four CO_2 foam fracture treatments in the Haynesville. Although it is too early in the producing life of these wells to determine whether their ultimate recovery will be enhanced by the CO_2 fracture technique, it is apparent that the wells have initially performed significantly better than their nearest offsets, which were treated with conventional gelled water fluids. In fact, the indicated productivity is approximately three times greater (both initially and after 30 days) for wells treated with the CO_2 foam.

All of the wells shown in Table 5 penetrated a relatively comparable Haynesville section (in terms of net sand and structural position). Early production data definitely imply that the CO_2 foam fracture fluids cleaned up more rapidly and efficiently than conventional gel, so that any formation damage and/or water block of pore spaces is reduced.

The CO_2 foam fracture in the Haynesville section of the Barnett A-3 well (shown in Table 5) was the largest treatment of this type that has been pumped to date in the United States. It consisted of 480,000 gallons of foam, with 1,115,000 pounds of 20/40 sand and intermediate strength proppant, which was pumped at a rate of 50 BPM down the casing string at a treating pressure of 5800 psig. Approximately 1470 tons of CO_2 were injected as part of the foam, and the maximum effective proppant concentration was 5 pounds per gallon.

VARIOUS ADDITIONAL FIELD APPLICATIONS OF THE CARBON DIOXIDE FOAM TREATMENT

The Pettet interval within the Sligo formation is a relatively blanket limestone section that covers most of North/Northwest Louisiana and East Texas. The zone is generally characterized by erratic porosity development, with relatively good reserve potential whenever a reservoir with porosity and permeability is encountered. In the Caddo and Bossier Parishes of Northwest Louisiana, the zone is generally found at a depth between 5300' and 6500' and some wells within this region have produced in excess of 200 MBO (primary) over a period of more than 40 years, even though they came in at only 20 to 25 BOPD after an initial acid treatment. Typically the Pettet limestone throughout the Ark-La-Tex area has been initially stimulated with a hydrochloric base acid (100 to 1000 gallons per foot of interval) and the available core data indicate that a minimum permeability thickness of 40 md-ft has been required to obtain a commercial completion after acidizing.

The conventional core analysis from wells in four separate Pettet fields in Caddo and Bossier Parishes indicates that the limestone in this area is 95 percent soluble, with relatively few impurities to aid in the development of a good etching pattern whenever the typical HCl acid treatment is utilized. In addition, many of the Pettet intervals that have been encountered more recently in this area have had a low permeability thickness of less than 20 md-ft. Due to these reservoir characteristics, CO_2 foam fracture treatments were first tried in nine existing Pettet wells that had been previously acidized. The initial production response for these wells was an average 10.4 fold increase, with a sustained increase after 120 days that is four times greater than the rate prior to fracturing (from an average 7 BOPD to 28 BOPD per well). Based upon this response, a program was subsequently initiated to stimulate many of the new Pettet completions in Caddo and Bossier Parishes with CO_2 foam fracture treatments. The early results of this new completion method have been even more encouraging, with an average initial rate of 105 BOPD and a sustained build-up of 48 BOPD per well after four months of production. Even with the additional investment associated with these fracture treatments, the production response to date indicates that the payout on the average Pettet well will be improved from 29 months with the acid treatments to 15 months with CO_2 foams.

The CO_2 foam fracture system has also been utilized successfully in at least four other fields in the Ark-La-Tex area. These fields and the associated producing zones include Northeast Bethany (Cotton Valley), Greenwood Waskom (Hosston), Winnsboro (Travis Peak), and Shongaloo (Haynesville). The six CO_2 treatments that have been performed in the wells in these areas to date have not had sufficient production to adequately compare them to the zones that were treated with more conventional techniques. In addition not enough of the CO_2 foam treatments have been pumped in these areas to clearly establish an expected production response. However, all six of the wells have made commercial producers after being treated with the CO_2 foam, and in at least two cases the unstimulated zones had no shows or indicated production prior to being fractured.

The total of 104 CO_2 foam fracture treatments that have been performed on various zones in the Ark-La-Tex area through May 1, 1983, have yielded an initial production increase over prefracture rates of 7360 BOPD with 40 MMcfg/D, and a sustained production response of 3100 BOPD with 26 MMcfg/D. The average decline rate (after the initial flush production) during the first year for these inherently low permeability wells has been 30 to 50 percent, and the indicated payout of the stimulation investment on this particular group of wells was approximately three months.

CONCLUSIONS

1. The CO_2 foam fracture treatment process has been utilized successfully in numerous Cotton Valley sands of the Dorcheat Macedonia field (South Arkansas). These zones were formerly considered non-commercial because previous stimulation attempts in correlative members using conventional gelled fracturing fluids had been unsuccessful.

2. Pressure transient tests and production decline trends indicated poor stimulation results and limited recoveries in the deep Cotton Valley sands at Vernon (North Central Louisiana) after fracture treatments with conventional fluids. Correlative sands that were subsequently treated with the CO_2 foam fluids exhibited improved build-up test characteristics and estimated ultimate recoveries.

3. Although the former stimulation program in the Haynesville section at Arkana (Northwest Louisiana) was considered a success using conventional gelled water fluids with 500 scf/bbl of CO_2, improved results have been obtained using the CO_2 foam due to the more rapid and efficient clean-up of the load fluids.

4. CO_2 foam fracture treatments have been used successfully in both existing and new Pettet lime completions in Northwest Louisiana to improve

the initial production rates over those previously obtained with acid fractures and/or matrix acid treatments.

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Table 1
Typical Characteristics of Fields/Zones Where Carbon Dioxide Foam Treatments Have Been Used

Field;State	Zone (Type Rock)	Measured Depth-Ft.	Type Well	Porosity (Percent)	Water Saturation (Percent)	Gross/Net Thickness (Typical Zone-Ft.)	Est. Perm. (Md)	Reservoir Maximum Pressure (psig)	Reservoir Maximum Temp. (°F)
Arkana; Louisiana	Haynesville (Sandstone)	10546' - 10896'	Gas	8.8	38	165/65	.05	6320	260
Arkana Trend; Louisiana	Pettet (Limestone)	5392' - 6455'	Oil	14.9	43	57/17	3.80	2900	165
Dorcheat Macedonia; Arkansas	Cotton Valley (Sandstone)	6930' - 8867'	Oil	12.7	45	90/27	.10	4000	225
Greenwood Waskom; Louisiana	Hosston (Sandstone)	6420'	Gas	12.0	52	30/10	.10	3080	185
Mira; Louisiana	Woodbine (Sandstone)	2910'	Oil	19.0	35	20/6	5.00	1020	120
N.E. Bethany; Texas	Cotton Valley (Sandstone)	6340' - 8180'	Gas	10.9	45	53/20	.10	3760	205
Shongaloo; Louisiana	Haynesville (Sandstone)	10290'	Gas	21.0	35	25/6	10.00	3700	250
Vernon; Louisiana	Cotton Valley (Sandstone)	11626' - 14484'	Gas	11.1	48	100/40	.05	13200	370
Winnsboro; Texas	Travis Peak (Sandstone)	8500' - 9485'	Gas	9.7	28	92/43	.10	4370	220

Table 2
Typical Carbon Dioxide Foam Fracturing Designs in the Ark-La-Tex Area

Field (Formation)	Foam Vol. (gals)	Percent Pad	Rate (BPM)	Treating Pressure (PSI)	Total Prop (#)	Maximum Proppant Concentration (#/Gal)	1/2 Frac Length (Ft)	Pump Time (Hrs:Mins)
Dorcheat-Macedonia (Cotton Valley)	40,000	30	25	3750	80,000	4	500	0:50
Arkana Trend (Pettet)	20,000	30	20	2600	41,000	4	500	0:33
Arkana (Haynesville)	380,000	25	50	4800	925,000	5	1500	3:18
Vernon (C.V. - Lower Poole)	135,000	30	20	7800	225,000	4	1500	3:24

Table 3
Pressure Transient Test Results Using Horner Analysis, Vernon Cotton Valley Zones

Well	CV Zone Subsea Depth	Fracture Half Length	Type Treatment	K	h	ϕ	Sw	Productivity Index (Mcfg/D/psi-ft)	Skin	Flow Efficiency	Damage Ratio	Extrapolated Reservoir Pressure
Davis A-1	L. Poole 13,065'	500'	Conv. Gel	.10	39'	11%	50%	.0133	-4.2	2.62	.38	11,880 psig
Davis A-1	L. Stray 12,529'	1200'	Conv. Gel	.18	22'	14%	38%	.0121	-1.7	1.32	.76	11,426 psig
Davis E-1	L. Poole 12,764'	1500'	CO_2 Foam	.18	22'	16%	38%	.0284	-4.1	3.33	.30	11,624 psig

Table 4
Estimated Recoveries for Four Vernon Cotton Valley Completions

Well	CV Zone(s)	Fracture Half Length	Type Treatment	Estimated Ultimate Recovery	Recovery Per Net Foot	Recovery Efficiency Percent of Gas in Place
Davis A-1	L. Poole & L. Stray	500' 1200'	Conv. Gel Conv. Gel	975 MMcfg (Commingled)	16 MMcfg/ft	9.5%
Oxford #1	L. Poole L. Stray U. Stray	1050' 520' 520'	Conv. Gel Conv. Gel Conv. Gel	1011 MMcfg (Commingled)	12.5 MMcfg/ft	8.9%
Davis E-1	L. Poole	1500'	CO_2 Foam	2210 MMcfg	100 MMcfg/ft	63.7%
Emmons #1	L. Stray	980'	CO_2 Foam	1046 MMcfg	87 MMcfg/ft	46.5%

Table 5
Comparison of Producing Characteristics
Arkana Haynesville Wells

		Initial Production			Production after One Month			
Well Name	Fracture Half Length	Mcfd/ BOPD	Flowing Pressure	Choke	Mcfd/ BOPD	Flowing Pressure	Choke	Net Porosity Greater Than 8.5%
Part 1 - Conventional Gelled Fracture Fluids Treatments								
Barnett #2	950'	1939/239	2100 psi	15/64	1080/95	570 psi	28/64	26'
Barnett A-1	1020'	934/139	1047 psi	18/64	606/76	1050 psi	16/64	30'
Hamiter H-1-L	1490'	2550/157	2050 psi	18/64	1900/112	900 psi	24/64	38'
Willamette H-1	1580'	1264/222	1150 psi	20/64	1050/119	800 psi	20/64	48'
Part 2 - Carbon Dioxide Foam Fracture Fluids Treatments								
Barnett #3	1500'	3500/260	2496 psi	22/64	2400/125	1000 psi	29/64	36'
Barnett #A-3	1490'	3950/362	3300 psi	16/64	3100/320	3025 psi	16/64	48'
Foster B-1-L	1520'	4175/429	2450 psi	18/64	2350/145	1400 psi	18/64	30'
IPCO #K-1	1000'	4025/329	1575 psi	30/64	3366/225	1050 psi	28/64	48'

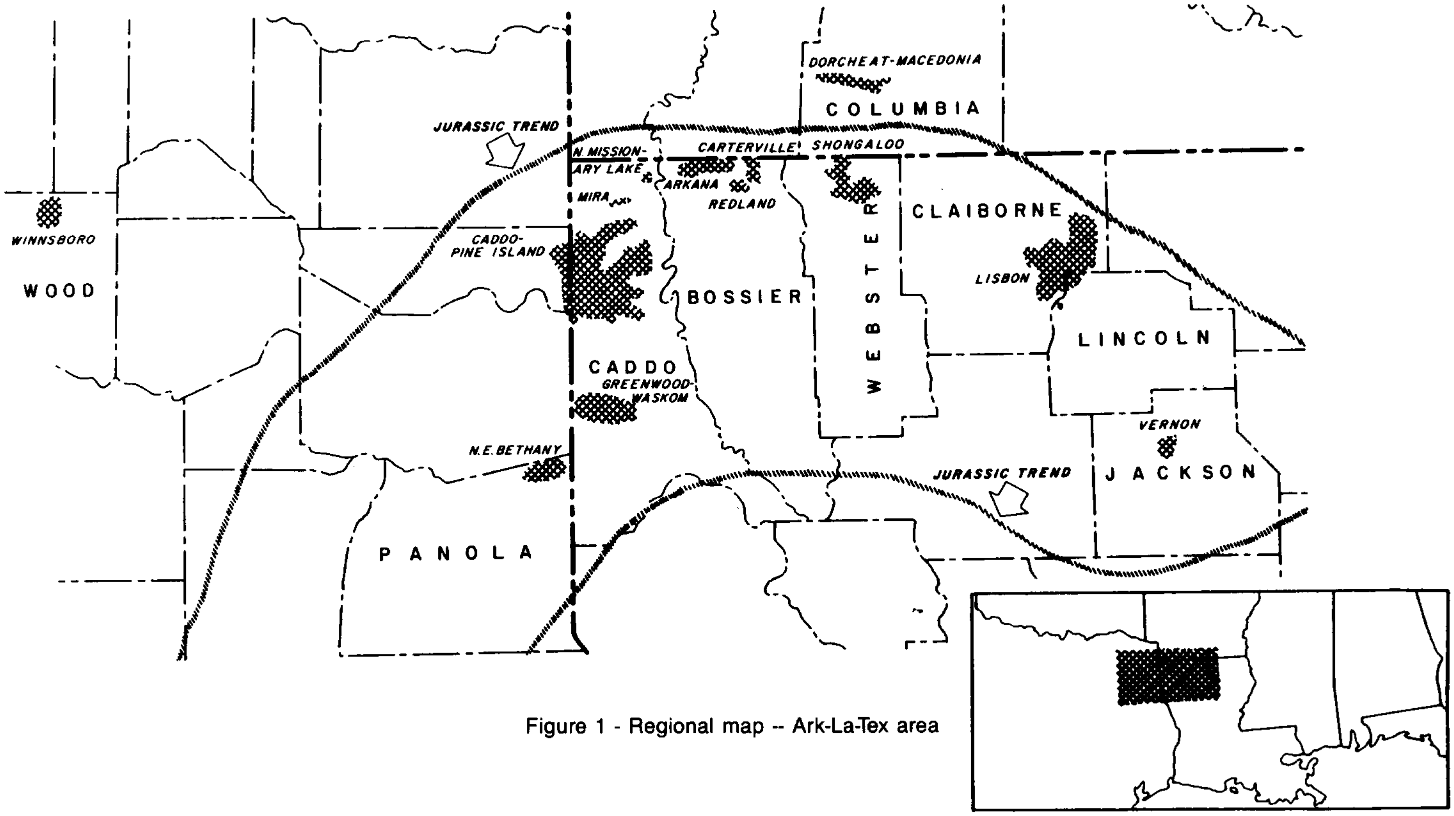

Figure 1 - Regional map -- Ark-La-Tex area

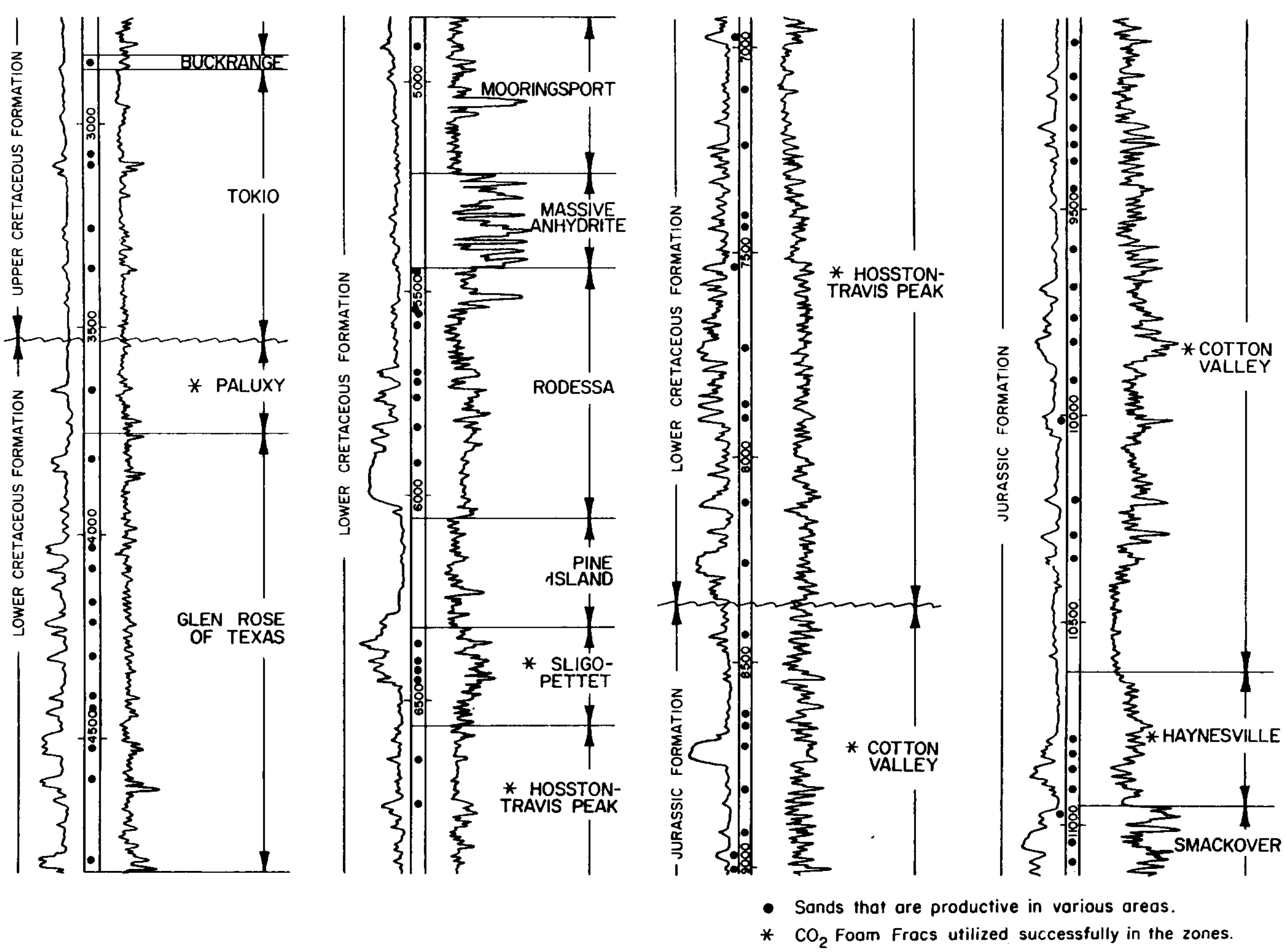

Figure 2 - Typical Ark-La-Tex penetration to Smackover depth

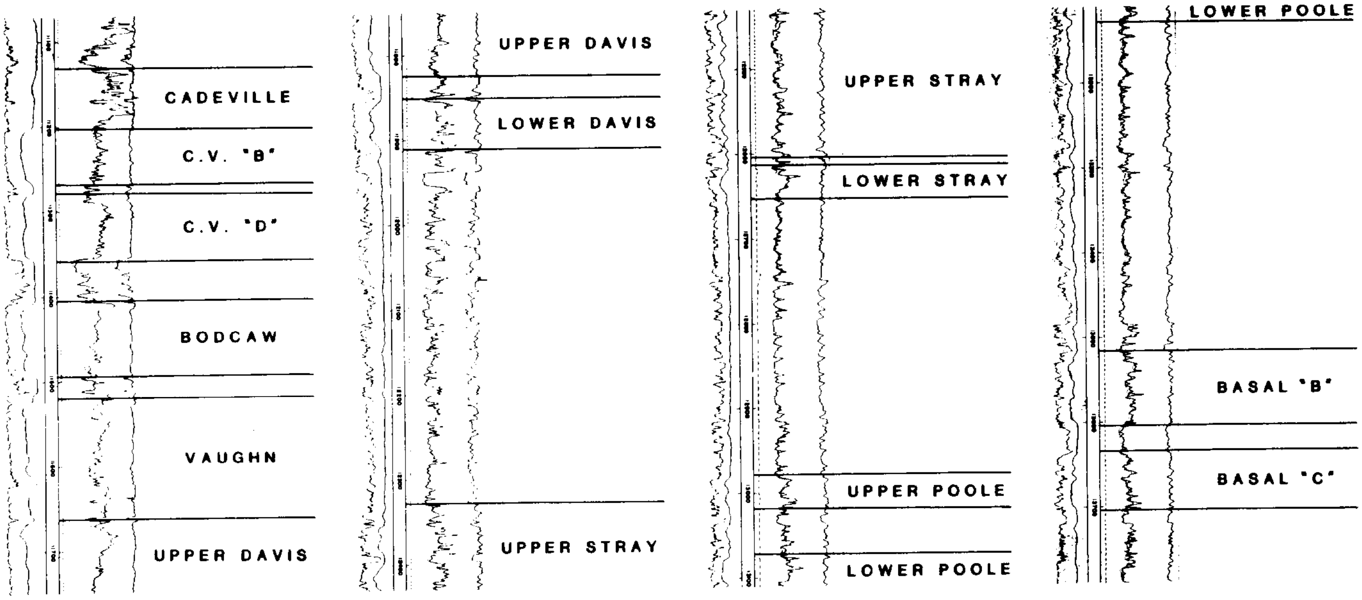

Figure 3 - Vernon field Cotton Valley Sand series Jackson Parish, Louisiana

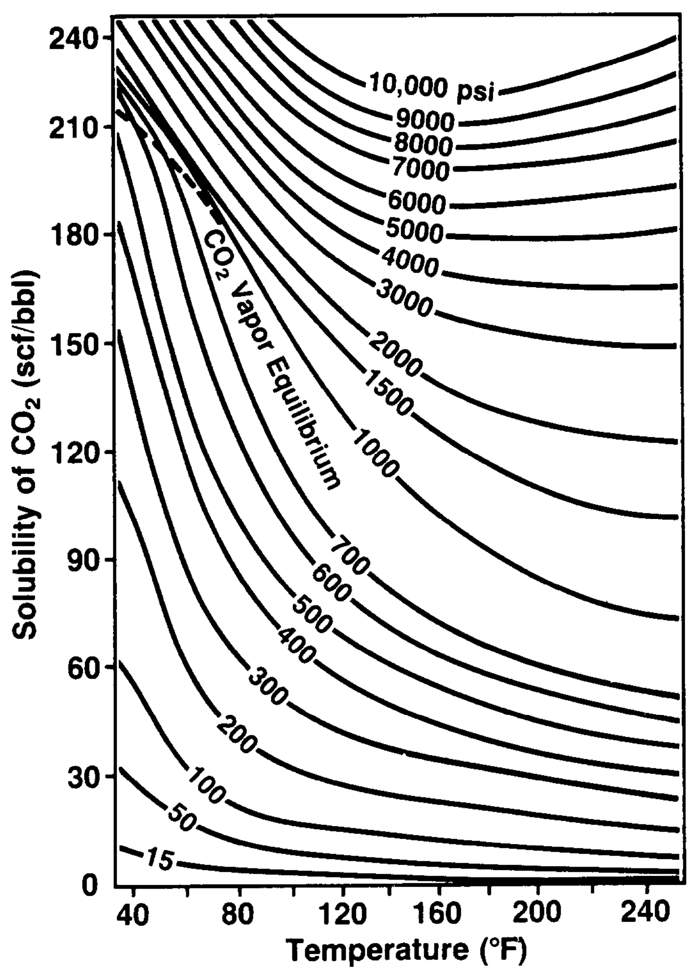

Figure 4 - Solubility of carbon dioxide in water