OPTIMIZED FRACTURE TREATMENT TECHNIQUES INCREASE WELL PRODUCTIVITY: A CASE STUDY ON RED FORK FORMATION WELLS IN OKLAHOMA

Robert M. Tjon-Joe-Pin and Harold D. Brannon
BJ Services Company USA
Patrick J. Handren
Oryx Energy Company

Abstract

A case study has been conducted on Red Fork formation wells with bottomhole temperatures ranging from 225°-250°F. The fracturing applications and techniques in this area had historically provided lower than expected post-treatment productivity and a rapid decline rate, suggesting that the fracture conductivity were less than optimum. Joint efforts of the operator and service company, utilizing state-of-the-art fluids, breakers, and design methodologies, were employed to optimize well productivity. The case histories of hydraulic fracturing treatments and subsequent production performance of five offset wells are analyzed and presented. Average incremental production rates were significantly improved through application of the new technologies, clearly demonstrating the effectiveness of the modifications.

Introduction

The study was conducted on Red Fork formation wells in the Strong City Field. The field is located in Roger Mills County, Oklahoma, approximately 20 miles north of Elk City. The wells, which are located in two adjacent sections, were drilled either as replacement wells or as increased density wells. The Red Fork formation has been described as a Pennsylvanian Age sequence of sands and shales with a gross thickness of 700-800 ft.

A representative type log for the Red Fork is shown in Figure 1. The interval depths were 12,500 ft to 13,200 ft in the study area. The sandstone formation contains small amounts of clay minerals such as chlorite, illite, kaolinite, and mixed layer. The study wells had permeabilities ranging from 0.01 to 0.19 millidarcies and porosities from 8 to 10%. Reservoir pressures ranged from 4,670 to 9,478 psi. The wide range of pressures was due to the effects of offset drainage on these increased density wells. The bottomhole static temperature of the production zones ranged from 225° to 250°F.

Hydraulic fracturing operations have been applied in the area as a means to stimulate the wells for many years with varying degrees of success. Fracturing fluid load recovery from these treatments was typically less than 25%. Foams generated with carbon dioxide were used in an effort to address the low fluid recoveries which were believed to be associated with water retention in the reservoir. Even with the energized, low pH fluids the recovery was still typically under 25%, suggesting that fracture conductivity was less than optimum. Premature screenouts were common when aggressive proppant schedules were attempted. Additional expenses were commonly incurred as a result of proppant flowback associated with extended shut-in times after stimulation.

The joint efforts of the operator and the service company technical teams were directed toward the improvement of well stimulation through the application of the cost-effective, advanced fracturing technologies. Ultimately, several recently introduced hydraulic fracturing technologies were combined to develop an integrated treatment design and application package to improve well production. Included among these were the use of state-of-the-art fracturing fluid and breaker technologies to improve proppant transport and maximize fracture conductivity, the introduction of higher foamer surfactant loadings to improve recovery in low bottomhole pressure wells, and the application of forced-closure techniques to control proppant flow-back.

Fracturing Fluid and Breaker Technology

Crosslinked fluid viscosity, fluid leakoff efficiency, and retained fracture conductivity were identified by treatment design analysis as being critical parameters in the productivity optimization process. Historically, the choice of breaker for high-temperature applications such as these has been oxidizers like ammonium, sodium and potassium persulfate. In many cases no breaker was added in order to allow placement of higher proppant concentrations. Recent studies have reported that proppant-pack conductivity damage is typically greater than 50% when fluids such as the conventional borate or titanate crosslinked systems with oxidative breakers are applied.[1] According to the 1989 Stim-Lab Proppant Consortium Report, the damage for these types of fluids without breaker is more on the order of 80 to 90%.[2] In the case of conventional oxidizers, the addition of highly reactive breakers is also known to rapidly degrade the fluid efficiency and proppant transport capabilities. Such competing phenomena can often limit the size of treatment, the proppant concentration which may be placed, and ultimately, the well productivity. The limitations of the conventional fluid and breaker technologies effectively precluded the execution of the advanced treatment designs to improve well productivity.

Organoborate crosslinked guar fracturing fluids were selected for these applications due to the superior proppant transport properties provided by the unique colloidal-crosslinked structure.[3] The colloidal-crosslink structures exhibit much stronger crosslink junctions and greater elasticity due to a greater number of bonds per junction than experienced with conventional mono-borate crosslinked fluids. High viscosities are an additional advantage provided by organoborate crosslinked fluids, often allowing fluids with reduced polymer loadings to successfully transport high proppant concentrations while maintaining sufficient fracture width to minimize proppant bridging.

Prior to the case study, breaker technology was sporadically applied in the Red Fork wells of the subject locale. Fluid viscosity for proppant placement was considered paramount to gel degradation and load recovery. The fracturing fluid formulation would often include gel stabilizers to ensure maximum viscosities at reservoir conditions, preventing the effective use of the oxidative breakers except in the final stages of the treatment where viscosity loss was of less concern. The tail-in breaker concentrations rarely exceeded loadings of 0.25 pounds per thousand gallons of gelled water. This proved to be deleterious to achieving optimized regained fracture conductivity.

Encapsulated oxidative breakers allowed for somewhat higher loadings through a greater percentage of the gelled fluid stages. There were, however, concerns with regard to early release of the oxidizing agent as a result of encapsulant breakage through the pumps and down the tubing. This concern coupled with the accelerated release and breaker reaction rates at elevated temperature prevented widespread use of this technology in high-temperature applications.

Polymer-Specific Enzyme Technology

Included among the state-of-the-art fluid technologies which ultimately showed to improve the well productivity most efficiently, was the use of "Guar-Linkage-Specific" enzymes.[4] As described in earlier studies, the guar polymer is most efficiently degraded by enzyme breakers. Enzymes are highly specialized proteins produced by cells of living organisms. Enzymes are true biological catalysts which promote specific reactions. The conformational structure of an enzyme is unchanged by the reaction it initiates and, therefore, it can theoretically "infinitely" promote this reaction. The limiting factor would be denaturization through damage of the tertiary structure of the enzyme molecule by chemical, thermal, or mechanical means.

The enzyme breakers historically used in this industry are non-specific enzyme mixtures which randomly hydrolyze polymers. These conventional enzymes are mixtures of hemicellulase, cellulase, amylase and pectinase in unspecified ratios. These enzymes are specific to react with guar, cellulose, starch and pectin polymers respectively. Each of these enzymes are hydrolases, and as such, are capable of some binding with any of the aforementioned polymers. Since each of these enzymes is reactive with the linkages found in only one type of polymer, only the enzyme which is specific to that polymer will promote a cleavage. The other enzymes, once bound, can neither react with nor release from the polymer, effectively blocking the "right enzyme" from cleaving the polymer. This phenomena, known as irreversible or competitive inhibition, results in the creation of polymeric fragments which are generally the molecular weight of the polymer strand to which it is attached, plus the enzyme itself. In the case of crosslinked fluids, the "combined molecular weight" could be many times higher than the original molecular weight of the linear polymer due to crosslinking of the residual fragments. The result of this is a partial degradation of the polymer into predominately short-chain to medium-chain length polysaccharides with minority concentrations of mono and di-saccharides. The crosslinkable short-chain and medium-chain polysaccharides are relatively insoluble and, therefore, may cause significant permeability damage.

The Guar-Linkage-Specific (GLS) enzyme complex consists of only two specific enzymes which are specific towards the linkages available between the sugar units of the guar polymer. The two key linkages for ultimate degradation of the guar polymer are the ß-1,4-glycosidic linkage between the mannose units of the polymer backbone and the α-1,6-glycosidic linkage between the mannose unit and the galactose unit which constitutes the substituent or the side chain.[5]

Laboratory Data

Flow loop rheology, proppant transport, and retained proppant-pack permeability testing were performed by an independent laboratory to validate the GLS enzyme breaker performance at high temperature. The procedures were typical of those utilized for testing by the industry consortiums for fracturing fluid performance evaluations.[6-8] All phases of testing for each fluid/temperature combination used the same GLS enzyme breaker concentration. The proppant transport was reported to be from good to perfect in each evaluation in which the GLS enzyme was applied.

The retained proppant-pack permeability results are summarized in Table 1. The data indicates that high retained conductivities were achieved when the GLS enzyme system was used. The effects of polymer derivatization, crosslinker type, fluid pH, and temperature were essentially neutralized by the GLS enzyme breaker with respect to retained proppant-pack permeability. The only real variable is the time necessary for the enzyme to affect complete degradation of the polymer. Test results are also provided for other fluid/breaker combinations used in these studies to illustrate the amount of damage that may be created during the actual fracturing treatments.[2] Analysis of this data supports that the Guar-Linkage-Specific enzyme breakers will inherently out perform the conventionally utilized breakers like oxidizers and the non-specific enzyme mixtures.

Field Case Histories

A comprehensive study of five wells in the Red Fork formation was conducted to evaluate the stimulation effectiveness and to guide further optimization. The wells, which were located in a two-section area, were drilled either as replacement wells or increased density wells on the sections, as shown in Figure 2. Individual case histories for the five wells are presented with details of the changes that were incorporated into the fracturing program. The pertinent well parameters are summarized in Table 2.

Well No. 1: The Govie Miller #2

The first treatment of the Govie Miller #2 was completed in December 1989 in the lower Red Fork interval, from 13,077 ft to 13,134 ft. The stimulation was performed using a titanate-crosslinked HPG system with 50 pptg polymer loading for the pad and 40 pptg loading for the proppant laden stages. The bottomhole temperature was 250°F. No breaker was incorporated into the fracturing fluid design. The proppant placed in the lower zone was 4,870 pounds per net foot of interval. The load recovery was 27% of the 2,400 barrels pumped. After five days, the recovery had fallen to less than 15 barrels of water per day (BWPD).

The upper interval of the Govie Miller #2 was stimulated in January 1990 using a conventional borate-crosslinked guar system with a persulfate breaker in the propped stages only. The maximum breaker loading was 1.0 pptg. The polymer loadings of the pad and proppant laden stages remained the same as for the lower interval. Several days prior to fracturing the well, a breakdown was done using floating ball sealers. None of the balls were recovered during the flow back period prior to fracturing the well. Proppant placement per net foot of interval was planned for 5,000 pounds. The well pressured out during the 2 ppg stage. The floating ball sealers were suspected as the cause of the premature job abort. This was confirmed during the flowback after the treatment when 59 of the 65 ball sealers were recovered in the tree. The five-day load recovery for this interval was 25% of 1,825 barrels. The well was not restimulated.

Well No. 2: The Merrick #2

The Merrick No. 2 was originally completed in the Red Fork in October 1988 and December 1989 using a conventional high-temperature, delayed-titanium crosslinked hydroxypropylguar (HPG). The polymer loadings for these treatments were 50 pounds per thousand gallons (pptg) in the pad fluid and 40 pptg in the proppant laden stages. The lower interval had a mid-perforation depth of 12,915 ft and a bottomhole temperature of 241°F. Proppant placement per net foot of interval was approximately 18,700 pounds. The upper interval had a mid-perforation depth of 12,660 ft and a bottomhole temperature of 236°F. The designed proppant placement was reduced to 5,000 pounds per net foot, but only 1,900 pounds of proppant were actually placed due to a premature screenout. The change in proppant per net foot of interval was based on the work published by Cornell in 1989.[9] Only a minimal amount of persulfate breaker (0.25 to 0.5 pptg) was used in the last proppant stages of either interval. The intervals were both flowed back after an overnight shut-in. After five days, the fluid recoveries from the lower and upper stimulations were 11% of 5,784 barrels and 33% of 2,836 barrels, respectively. After the well was completed in the Upper Red Fork, problems were encountered requiring a sidetrack reentry.

Once the well was sidetracked, both of the intervals were again fracture stimulated. These stimulations were done consecutively in April and May of 1991 using an organoborate-crosslinked guar system. The polymer loadings were reduced to 40 pptg for the pad fluid and 35 pptg for proppant laden stages due to the superior temperature-stable rheological properties provided by the new fluid. The perforated intervals and bottomhole temperatures were very similar since the sidetracked hole was displaced less than 200 ft from the original hole. The proppant placement per net foot of interval for the lower and upper intervals of the Red Fork were 8,000 pounds and 5,700 pounds, respectively. The treatment was pumped to completion, compared to the premature screenout experienced during the treatment of the original. No external breaker was incorporated into either of these treatments since the new organoborate system incorporates an internal breaker mechanism. The well was again shut in overnight to allow the polymer to break. The load recoveries from the upper and lower intervals were significantly improved as a result of using the new fluid system. The recoveries were 24% of 3,209 barrels and 56% of 3,400 barrels, respectively after five days. The recovery from the upper interval exceeded 90% after 10 days.

Well No. 3: The Govie-Miller #3

The lower and upper Red Fork intervals of the Govie Miller #3 were fracture stimulated with different borate fluid systems. The lower interval was treated in May 1991 with a conventional borate-crosslinked guar system. The polymer loading in both the pad and the proppant laden slurry was 40 pptg. A persulfate breaker was used with a maximum loading of 1.0 pptg in the final proppant stage. The proppant placed was 6,286 pounds per net foot with a maximum concentration of 5 ppg. The bottomhole temperature was 250°F. The "forced closure" flowback technique was used in an attempt to improve fluid recovery. The five-day load recovery was 29% of 3,781 barrels. No real improvement was seen, and load water recovery was down to 35 BWPD by the fifth day.

The upper interval was fractured in January 1992. Economic evaluation was performed using a production simulator coupled to a fracture design program. The net present value indicator was used to optimize the proppant placement. Based upon the simulator results, a stimulation treatment was designed to place about 2,100 pounds of proppant per net foot of interval. This was well below the range suggested by Cornell.[9] The pore pressure gradient for the well was 0.35 psi/ft. The organoborate-crosslinked guar was utilized with polymer loadings for the pad and proppant laden stages of 40 pptg and 35 pptg, respectively. An ammonium persulfate breaker loading of 1.0 pptg was used in the treatment. A foaming surfactant was added at 5 gpt to all the gelled fluid even though gas assist was not used. The reasoning for this modification was that the formation gas would foam the return fluid, lightening the gradient sufficiently to allow fracture cleanup to be achieved without swabbing. The treatment was pumped as designed with a maximum proppant concentration of 6 ppg. The well was flowed back immediately after the stimulation to enhance load recovery. The recovery after five days was 69% of 1,833 barrels, and exceeded 90% after 10 days.

Well No. 4: The Merrick #3

The Merrick #3 received a single treatment in June 1992. The gross perforated interval was from 12,582 ft to 13,109 ft. The single treatment was primarily due to the poor sand development in the lower Red Fork interval. Separate treatment of the lower interval could not be economically justified. There was evidence of depletion from offset wells as the bottomhole pressure was measured at 5,987 psi at 12,801 ft. The treatment was performed using a conventional borate-crosslinked guar system. The polymer loadings were 40 pptg for the pad fluid and 35 pptg for the proppant laden fluid. Based on gas recoveries from other neighboring Red Fork wells, an economic evaluation was run for different proppant loadings per net foot of interval. The economic-based proppant loading per net foot of interval was only 2,070 pounds. The pore pressure gradient was above the water gradient at 0.47 psi/ft. However, based upon the load recovery success achieved on the Govie Miller #3, a foaming surfactant was again added to all the gelled fluid at a loading of 6 gpt. Total load recovery was 27% of 1,192 barrels after three days. An aggressive persulfate breaker loading of 0.25 to 1.0 pptg was used for this treatment. Although an aggressive breaker schedule was used, viscous gel was recovered after flow of three times the tubular capacity in a seven-hour period.

Well No. 5: The Merrick #4

Both intervals of the Merrick #4 were treated with the organoborate-guar crosslinked fluid system. The pad and polymer loadings were 35 pptg and 30 pptg, respectively, for both treatments. The bottomhole temperature was just below 250°F. These jobs also included a polymer-specific enzyme breaker in all stages of treatment in an effort to further improve fracture conductivity. Both jobs also included a foaming surfactant loading of 4 gpt and used forced closure flowback procedures to maximize fluid recovery. The lower interval was fracture stimulated in January 1994 with a proppant loading of 1,833 pounds per net foot of interval. The designed loading rate was 2,075 pounds per net foot, but was not achieved because of an early job termination due to increasing wellhead pressure. The well was then shut in to prepare for treatment of the upper interval.

The upper interval of the Merrick #4 was stimulated in February 1994 with a designed proppant loading of 1,660 pounds per net foot of interval. The designed loading was not achieved due to a screenout in the 5 ppg stage. Consequently, the final proppant loading was only 736 pounds per net foot. Based on a bottomhole pressure of 4,670 psi at 12,550 ft recorded prior to the treatment, the well had some depletion from offset wells which may have caused excessive fluid leakoff. Load recovery from this interval was 40% after five days with rates of 20 BWPD after the fifth day.

Discussion of Results

The 12-month production histories of the subject wells after they were fracture stimulated are provided in Figure 3. Only seven months of production data was available for the Merrick #4. The same production curves normalized for the reservoir productive capacity (kh) and for the volume of proppant used to stimulate the well are shown in Figure 4. The Govie Miller #2 well was the only well treated with a titanate-crosslinked system. Although potentially coincidental, this was the poorest performing well. The borate-crosslinked systems, either conventional or organo-complexed, demonstrated a more favorable production response. The normalized production curves illustrate a dramatic difference for the one well that incorporated both the organoborate fluid system and the polymer-specific enzyme breaker. Since this is a small sampling with a single "optimized" case, more evidence is necessary to substantiate the validity of these findings.

As the optimization efforts progressed, well productivity was improved while the proppant volume per net foot of interval were reduced (Figure 5). This "contradictory" phenomena is believed to be due to the application of the improved fluid and breaker technologies to increase the retained fracture conductivity. Note that the well with the best productivity, the Merrick #4, had the least volume of proppant placed per net foot. This indicates that the proppant-pack placed in the Merrick #4 had the highest retained proppant-pack permeability.

A foaming surfactant was used in four of the fracture stimulations. In the two stimulations of reservoirs that had a pore pressure gradient less than a water gradient, there was significant increase in load water recovery. Both of these wells were also stimulated using an organo-borate crosslinked system. The two stimulations done in the reservoirs with a pore pressure above water gradient did not appear to benefit from the use of the surfactant. Thus, it may only be beneficial to incorporate the foaming surfactant in wells with a pore pressure gradient below 0.4 psi/ft.

Flowback of proppant from the fracture did not appear to be a significant problem in the wells studied. It was observed, however, that the conventional borate systems with the persulfate breakers did produce proppant for several tubing volumes. This was attributed to the fluid retaining higher than expected viscosity after several hours. After the viscosity had degraded sufficiently with exposure to reservoir temperature, no additional proppant was carried to the surface. This phenomena was not experienced with the organoborate-crosslinked systems. The only proppant carried to the surface with organoborate system was that left in the tubing as a result of screenout or slurry under-displacement. Because the proppant flowback was insignificant, resin-coated tail-ins were never considered necessary.

Conclusions

Case histories have been conducted on five fracture stimulated Red Fork wells to evaluate the effects of various fluid, breaker, and design methodologies on load recovery and well productivity.

The application of advanced chemical technologies provided for sufficient improvements in retained fracture conductivity to allow for significant reductions in the proppant volume placed per net foot of interval.

The wells treated with borate-crosslinked fluids were observed to perform significantly better than the well treated with a titanate-crosslinked fluid. The wells treated with organoborate-crosslinked fluids outperformed the wells treated with conventional borates. The well treated with an organoborate-crosslinked fluid and a guar-specific enzyme breaker provided the best performance even though the amount of proppant per net foot was the least of all wells evaluated.

Significant improvements in load recovery were observed with the addition of a foaming surfactant when pore pressures were less than 0.4 psi/ft. This is thought to be due to foaming of the return fluid with formation gas, reducing the gradient sufficiently to flow to the surface. The application of this technique was not observed to be beneficial when the pore pressure was above the water gradient.

The proppant flowback problems experienced in the early stages of load recovery when using conventional borate-crosslinked fluids were not observed in the treatments utilizing the organoborate-crosslinked systems.

Acknowledgement

The authors wish to express our appreciation to the management of the ORYX Energy Company and of BJ Services Company for their support and permission to publish this paper. We would also like to thank Doris Porter for her secretarial efforts to prepare the manuscript.

References

1. Brannon, H.D. and Pulsinelli, R.J.: "Breaker Concentrations Required to Improve the Permeability of Proppant-Packs Damaged by Concentrated Linear and Borate-Crosslinked Fracturing Fluids," paper SPE 20135 presented at the 1990 Permian Basin Oil and Gas Recovery Conference, Midland, Mar. 8-9.

2. Proppant Consortium Report: Fluids 1991.

3. Brannon, H.D. and Ault, M.G.: "New Delayed Borate-Crosslinked Fluid Provides Improved Fracture Conductivity in High-Temperature Applications," paper SPE 22838 presented at the 66th Annual Technical Conference and Exhibition, Dallas, Oct. 6-9, 1991.

4. Brannon, H.D and Tjon-Joe-Pin, R.M.: "Biotechnological Breakthrough Improves Performance of Moderate to High-Temperature Fracturing Applications," paper SPE 28513 presented at the 69th Annual Technical Conference and Exhibition, New Orleans, Sept. 25-28, 1994.

5. Tjon-Joe-Pin, R.M.: "Enzyme Breaker For Galactomannan Based Fracturing Fluids," U.S. Patent No. 5,201,370 (1993).

6. Report SL 3391A, Stim-Lab Inc, December, 1993.

7. Report SL 3331, 3331A, Stim-Lab Inc, August, 1993.

8. Penny, G.S.: "An Evaluation of the Effects of Environmental Conditions and Fracturing Fluids Upon the Long-Term Conductivity of Proppants," paper SPE 16900 presented at the 62nd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Houston, Oct. 2-5, 1988.

9. Cornell, F.L.: "Engineering Improvements for Red Fork Fracturing," paper SPE 18963 presented at the 1989 SPE Rocky Mountain Regional/Low Permeability Reservoir Symposium, Denver, March 6-8.

<u>SI Metric Conversion Factors</u>

acres x 4.046 873	E-01	=	ha
bbl x 1.589 873	E-01	=	m^3
ft x 3.048	E-01	=	m
ft^3 x 2.831 685	E-01	=	m^3
°F (°F-32)/1.8	=		°C
gal x 3.785 412	E-03	=	m^3
lbm x 4.535 924	E-01	=	kg
md x 9.869 233	E-04	=	micro m^2
psi x 6.894 757	E+00	=	kPa

Table 1

Frac Fluid	Breaker	Temperature	pH	% Retained Permeability (2% KCl)
Organo borate/guar	None	250°F	10.0	89%
Organo borate/guar	GLS-E	250°F	10.0	94%
Zr/CMHPG	None	250°F	9.5	21%
Zr/CMHPG	GLS-E	250°F	9.5	70%
Mono borate/GUAR	None	250°F	11.5	15%
Mono borate/GUAR	SP	250°F	11.5	11%
Titanate/HPG	None	250°F	6.5	N/A
Titanate/HPG	AP	250°F	6.5	36%

Table 2

Well & Fracture Parameters

Well	Perfs	Date	Phi (%)	Perm (md)	BHP (psi)	BHT (F)	Net/Gross (ft/ft)	FG (psi/ft)	Proppant (lbs)	Prop/Ft (lbs/net ft)	Pad Vol (M gals)
Merrick #2	12905-25	10/12/88	10		9478	240	18/50	0.85	336000	18667	93
	12613-707	12/4/89	9		4500	236	44/85	0.82	92000	1917	60
	12895-913	4/19/91	10	0.04	9410	240	18/50	0.85	144000	8000	60
	12612-704	5/17/91	10	0.15	4500	236	45/85	0.82	255000	5667	70
Merrick #3	12582-13019	6/10/92	10	0.15	5987	248	48/95	0.75	89000	2070	25
Merrick #4	12795-934	1/18/94	9	0.02	7800	230	36/75	0.85	66000	1833	25
	12555-688	2/18/94	9	0.15	4800	228	72/105	0.72	56000	736	25
Govie #2	13077-134	12/9/89	9	0.04	9369	254	23/70	0.91	112000	4870	36
	12870-13001	1/3/90	9	0.15	5000	251	44/80	0.87	50000	1136	40
Govie #3	12818-13053	5/16/91	10	0.1	7437	245	65/95	0.89	220000	6286	70
	12508-94	1/10/92	10	0.19	4670	240	59/120	0 78	122000	2068	35

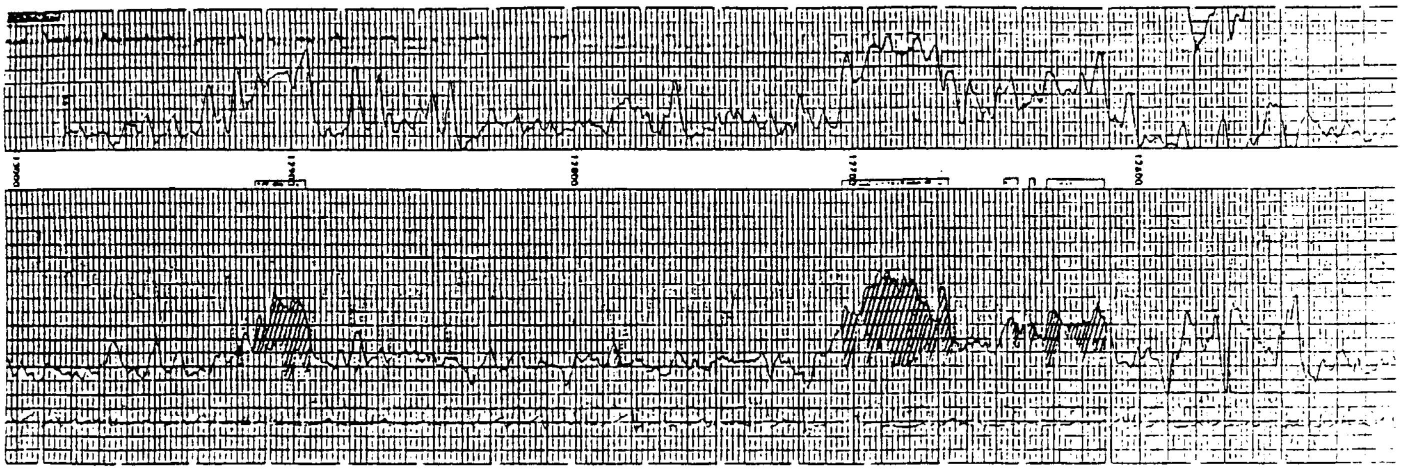

Figure 1 - Type Log

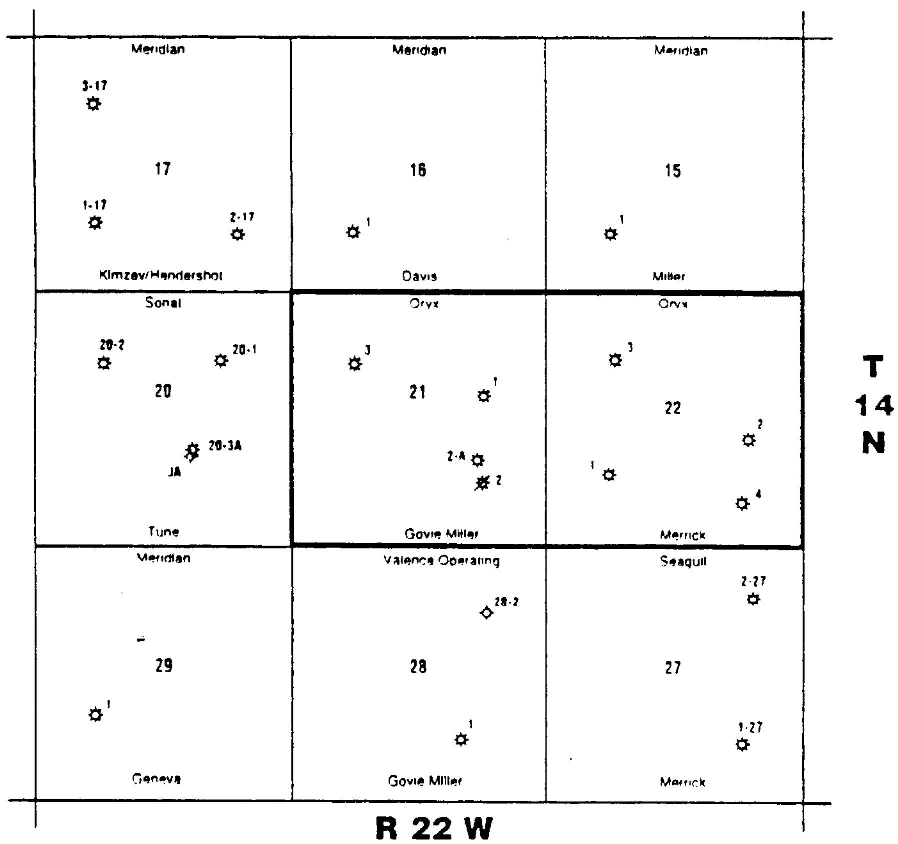

Figure 2 - Strong City Field

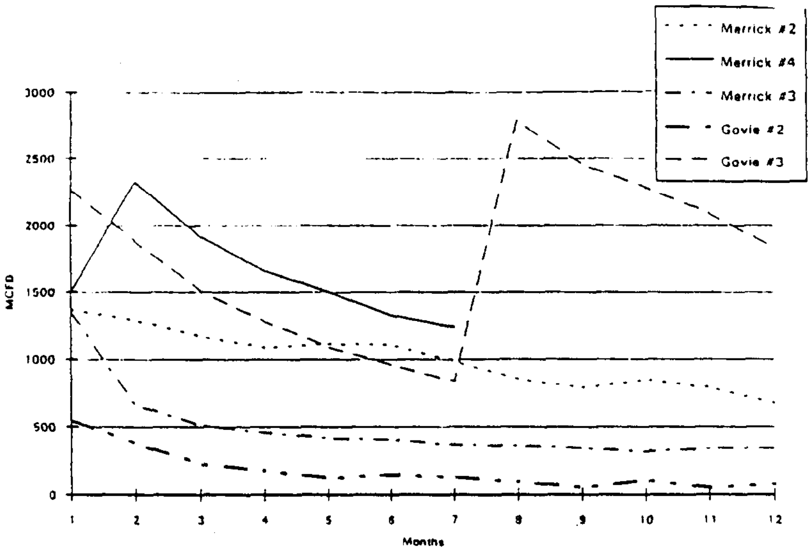

Figure 3 - Daily Average Production

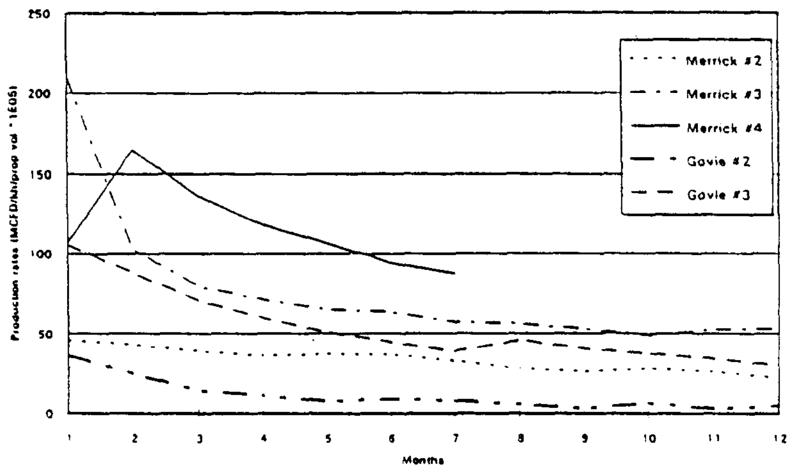

Figure 4 - Normalized Production Rates

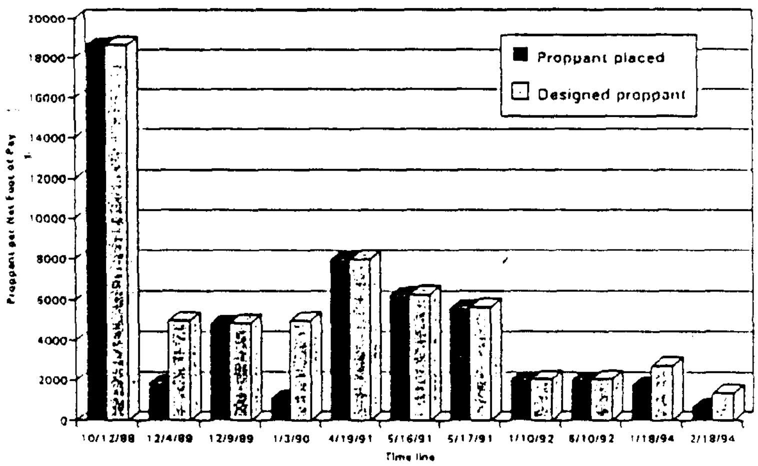

Figure 5 - Trend of Proppant Volumes