CANYON SAND STIMULATION TREATMENT COMPARISON AND OPTIMIZATION

Larry E. Lewis
Smith Energy Services

ABSTRACT

From its first development in the early 1960's an effort has been made to optimize a stimulation procedure for the Canyon Sand formation in Southwest Texas. Many attempts have been made to find a fluid system that would maximize stimulation results while minimizing treatment cost and formation damage. As a result, a variety of fluid systems have been pumped consisting of a wide range of both fluid and proppant volumes. This paper investigates historic stimulation practices over eight selected study areas. These procedures are then evaluated based on long-term production data in an attempt to identify an optimum treatment size, for each area, in terms of both fluid and proppant volume.

SCOPE OF STUDY

This study focuses on Crockett and Sutton counties. These counties were selected for several reasons. There has been a tremendous amount of development in these counties over the last twenty years, therefore a great deal of long-term data is available. These counties also are centrally located in a nine-county area where Canyon Sand development has been ongoing. This area is shown in Figure 1. There have been previous studies conducted in these counties which, when combined with this study, will provide a chronological analysis of the development of the Canyon Sand in Southwest Texas.

A total of eight separate areas were selected, four in each county, to be investigated in this study. Multiple areas were selected to minimize possible formation differences and their potential for unevenly influencing production values. The location and boundaries of the study areas are illustrated in Figure 2. Within the areas selected, data was analyzed for every well completed during the last fifteen years. A graphical distribution of the wells analyzed within each area can be found in Figure 3 at the end of this report. A total of 991 wells were completed by 76 different operators in the selected study areas during the chosen time frame. The large number of wells and the massive amount of data analyzed should allow valid conclusions to be determined from this study. Production decline data was used as a barometer for analyzing the success of historical treatments, as well as in selecting optimum treatment sizes to maximize production results and economic returns.

PURPOSE OF STUDY

The purpose of this study is twofold. The first phase is to investigate past stimulation practices and to pick an optimum treatment size in terms of both fluid and proppant volumes based on long-term production decline data. The results of this phase are published in this paper. The next phase will be to find a fluid system that will maximize stimulation results while minimizing treatment cost and formation damage. This second stage of the study will investigate the effect of additional treatment parameters including treatment rate, zone height, proppant concentration, and fluid additives for the control of clays, iron, and improving fluid recovery. The second stage was underway at the time this paper was published, and results will be published at a later date. The ultimate goal of both stages is to make a recommendation specifying an optimum treatment for the Canyon Sand formation in Crockett and Sutton counties based on the conclusions determined from this study.

FORMATION CHARACTERISTICS

The Canyon Sand of Crockett and Sutton counties is a Pennsylvanian-age sand and is found at depths from 4000 to 9000 feet. The sand is normally well-cemented, is medium to fine grained, and is often interbedded with shale. This formation essentially consists of everything below the Wolfcamp formation and above the Strawn formation. The Canyon interval is normally quite massive and is composed of many lenticular producing zones. The number of zones varies from area to area and from well to well in some areas. Average formation parameters include a porosity of 8-14 percent and a relatively low permeability of .01 to .2 md. Bottom hole pressures generally fall in the range of 1000-3000 psi and bottom hole temperatures vary with depth between 140-200 F. Fracture gradients will vary within the range of 0.7 to 1.0 psi per foot with some individual wells exhibiting gradients from 0.73 to 0.88 over a 200 foot interval. Average reservoir properties are listed in Table 1. Because of the drastic differences from zone to zone, most treatments are usually pumped in stages using various physical and mechanical methods to isolate separate intervals. Treatment rates also vary, with most falling in the range of 15-50 bpm depending on whether the treatment is pumped down tubing, casing, or tubing and annulus. The Canyon Sand also is known to contain both swelling and migratory clays, which need to be considered when planning a stimulation treatment. Early in its development, non-aqueous fluids were normally pumped to avoid water-clay contact and to minimize formation damage. It is now generally felt that the best stimulation fluid is aqueous-based because of its relatively low cost and high proppant transport capabilities. Clay sensitivities are generally handled through the use of a combination of pH control, use of energized fluids (thereby minimizing the water used), and a variety of additives designed to lower surface tension, improve load recovery, and prevent migration and swelling of clays. It is generally felt that the proppant placement ability of aqueous-based fluids supercedes formation damage considerations.

The majority of these Canyon Sand wells have gas-oil ratios which indicate essentially dry gas. Good wells will have a gas saturation as a percentage of total pore space of 60-90%. Fair to poor zones will be 45-60%. Some condensate is produced, which will normally be 50-60°API gravity. Some wells also produce a small amount of water. In general, the formation is more shallow to the north and produces oil and gas. To the south, the formation becomes deeper and produces dryer gas.

BACKGROUND AND HISTORICAL ACTIVITY

Throughout the 1960's and continuing through the 1970's and into the early 1980's, numerous fluid systems, additives, and proppant volumes were pumped into the Canyon Sand in Crockett and Sutton counties in an attempt to find the optimum treatment. Studies were often conducted which discussed the results of these treatments. At the time these studies were published, several different treatments showed encouraging results; however, only short-term production results were available. The most recently published study this author could find after a comprehensive literature search was from the early 1980's. Activity in the Canyon Sand formation in this area remained fairly consistent through 1984, with periods of peak activity occurring in 1974-75, 1977-78, and 1980. Table 2 contains a breakdown of all wells completed in the eight study areas during each of the fifteen years from 1973-1988 as well as an overall annual summary. All comments made in this paper refer to these eight areas, however results and conclusions can probably be applied to other areas within Crockett and Sutton counties as well as to the Canyon Sand formation in neighboring counties. As can be seen from Table 2, following the busy period of 1973-1984, the last four years reflect relatively low activity. This decrease in activity was due to a slowdown in the industry overall, as well as to the effect of decreasing gas prices.

As a result of the deregulation of gas prices and their relative stability compared to recent oil prices, there has been a renewed interest in development of gas reserves in general and in the Canyon Sand of Crockett and Sutton counties specifically. Many operators were active in this area in 1988 and have plans for increased activity in 1989 and into the early 1990's. Because of these plans for increased development and because of the unavailability of recent area stimulation-production studies, and because there is now long-term production data available for the wells completed throughout the 1970's, it was felt this would be an opportune time to analyze results of past stimulation treatments.

HISTORICAL STIMULATION PRACTICES

Initial Stimulation Practices (1960's)

Initial stimulation and completion procedures in the mid-to-late 1960's were poor, which led to many wells being termed uneconomical. These procedures have changed over the years to reflect improved technology in both areas. Stimulation practices have been altered to take advantage of improved fluids and fluid additives. As these developments have taken place and as more was learned about the formation itself, the success of stimulation treatments has been greatly enhanced.

A great variety of fracturing fluids have been used at one time or another to stimulate the Canyon Sand. One of the first fluids to be used was gelled oil. This system was an expensive fluid which was slow to clean up. Because of the poor economics associated with this fluid, gelled water became the predominant fluid in the late 1960's. Due to inadequate fluid loss control, larger jobs were pumped which increased fluid retention and clay control problems. High viscosity crosslinked fluids were introduced about 1969 but higher treatment costs, increased cleanup times, and questionable gel break times and quality led to the abandonment of this method.

Stimulation Practices (1970's)

In the early-to-mid 1970's several additional systems appeared on the scene, including alcoholic fracs, LPG-CO2 fracs and gelled weak acid systems. The alcohol and liquefied gas systems were excellent for formation damage control, but typical job sizes provided inadequate reservoir penetration. Increasing the job size to the volume required for adequate penetration proved to be more expensive than production economics would allow. The gelled weak acid system provided low pH and improved gel-breaking characteristics. It contained additives to prevent clay swelling, emulsions, and damage from iron. This system proved to be a viable and successful system, but was more expensive than gelled water treatments which had been improved since the 1960's. The additional cost associated with the acid system was primarily due to the additives included to prevent or reduce formation damage. Of primary concern was the potential damage caused by iron (siderite) which was released from the formation when acid was used.

In the early 1980's a crosslinked weak acid system was developed which had several advantages over the gelled weak acid system. Because it was crosslinked, it was capable of transporting proppant much better. As a result, smaller treatment volumes could be utilized to achieve the same productivity increases. The cost savings associated with smaller volumes made this system more competitive with the economics of a crosslinked water system, however, a crosslinked aqueous-based system was still more economical on a gallon-to-gallon basis and also simpler to pump. In addition, the crosslinked weak acid system presented a potential break problem due to the incomplete break sometimes associated with using a CMHEC gelling agent. As a result, crosslinked aqueous-based systems became the fluid of choice for most Canyon Sand operators. The crosslinked weak acid system did result in a number of successful completions, however, and is still used by some operators today.

Aqueous Stimulation Practices

The next step in the development of fracturing fluids was to disregard aqueous system induced formation damage and to pump gelled and gelled-crosslinked water systems, which were cheaper and less chemically complex. The theory behind this was that created fracture area was more important than formation damage considerations. Up until this time there had been an overriding concern for formation damage. At this time formation damage concerns were overruled by the necessity to successfully and economically place proppant a greater distance from the wellbore. This did not mean that damage considerations were ignored, as there was still considerable room for improvement in this regard. On a cost performance basis, however, aqueous-based systems became the fluid of choice.

Once formation damage control was no longer the primary factor in choosing a stimulation fluid, emphasis was placed on developing additives to be run in aqueous systems which would more successfully control formation damage. Clay control chemicals were needed to control swelling of clay particles and prevent their migration. A surfactant was also needed to reduce surface tension and give desirable wetting properties in the fracture. The goal for these additives was to reduce clean-up time, increase load recovery, and promote increased production.

Present Stimulation Practices

There are presently two primary fluid systems being used for stimulating the Canyon Sand. One system involves using gelled or gelled-crosslinked water in combination with varying percentages of carbon dioxide. The $CO2$ is used to reduce the amount of water which contacts the formation and is commonly used as 25 to 75 percent of the total treatment volume. The other system in use today is gelled-crosslinked water. These crosslinked systems are used at low, neutral, and high pH values. Both of these stimulation systems incorporate a number of additives to help reduce formation damage and increase fluid recovery. Standard treatment volumes are in the 1000-2000 gallons per foot of net pay or at a volume sufficient to reach 40-70% of the drainage radius. Some jobs involve pumping 3000-4000 gallons per foot of net pay. Typically recommended proppant volumes average 2-3 pounds per gallon of fluid. Most wells are treated in stages with an average number of three to five separate zones per well. Using these guidelines to establish treatment volumes results in an average fluid volume of 40,000-80,000 gallons per zone. Depending on the number of intervals treated per well, this will result in a frac volume of +/-200,000 to 400,000 gallons per well. The resultant average proppant volumes fall in the range of 100,000 to 200,000 pounds per zone and 400,000 to 1,000,000 pounds per well. The proppant mesh size used almost exclusively by most operators is 20-40, although some do tail-in with 12-20 depending on formation depths.

It is interesting to compare these current job sizes to the values used historically. The historical values are listed in Table 3 along with other historical stimulation parameters. The values found in Table 3 are the averages for 302 wells over the eight study areas. It is easily seen that the volumes which are presently being pumped are considerably higher than the historical average.

Gas Pricing Trends

To a certain extent historical completion activity parallels trends in gas pricing. Gas prices averaged 0.18/mcf in the late 1960's. By the early 1970's, prices had increased to $.40/mcf, partially as the result of higher interstate gas prices. In 1973, gas prices increased dramatically from $.40/mcf to $1.90/mcf with a corresponding increase in completion activity and gas collection facilities. Once completed, these facilities helped to maintain production levels even during periods of lower pricing. Gas prices continued to climb and reached a level of $2.40/mcf in 1978. Price levels were further bolstered in the early 1980's when the Federal Regulatory Energy Commission established the Canyon Sand formation in Crockett and Sutton, as well as four neighboring counties, as a tight gas sand. This designation qualified gas produced in these counties for the high cost incentive under the Federal Natural Gas Policy Act of 1978. Under this act, produced gas could be sold at a rate that was 200 percent of the rate for gas produced from new onshore wells. Gas prices fell in the mid 1980's as supply exceeded demand, but it is presently on the upswing. The average price of gas now stands at $1.65/mcf for production in Crockett and Sutton counties.

ANALYSIS OF PRODUCTION DECLINE DATA

Because of the variety of stimulation practices used over the years, it has been difficult to properly evaluate long-term production data. Usually, improvements were being made and stimulation systems were changed before long-term data became available on previous stimulation methods. Some production data analysis has been done and reported in the literature, but these reports normally dealt with only one or two methods and short term production data. As stimulation procedures changed, treatment and proppant volumes normally changed as well due to different fluid rheology values and treatment economics. In this paper, production data was analyzed to compare the effect of fluid and proppant volumes only.

The wells selected for production decline analysis are the same wells which were analyzed to determine average historical stimulation parameters. These wells were chosen with several factors in mind. Previous reports in the literature suggested that job size, both fluid and sand, directly affect long-term production. With this in mind, the average job size selected for analysis was generally larger than the average treatment pumped in each of the study areas over the fifteen-year study period. At the same time a wide range of job sizes was selected for each area so that production trends could be accurately identified. Unusually large or small treatments, when compared to the overall average, were left out of the analysis in an attempt to avoid any possible skew of the data which could result from their inclusion. A comparison of Tables 3 and 4 show the difference between the overall average treatment size determined for all wells for which completion information was available, and the average treatment size for which production data was analyzed.

Decline curves were generated for each well analyzed and two-year, five-year, and cumulative production values are listed in tabular form in Table 5 and graphically in Figures 4 through 7. Production decline curves were run using 100 mcf/month as the low end cutoff value. This value was arbitrarily chosen low to represent a value below the normal economic limit for any particular well. An interesting correlation is seen by comparing treatment volumes in Table 3 with production values in Table 5. It is generally believed that for tight gas sands, production values increase with increasing treatment size up to the economic limit for the treatment or up to a certain volume range. This increased volume for increased production correlation does not hold true for these study areas, however, as a comparison of Tables 3 and 5 show. In this case, area eight had the smallest average treatment volume (Table 3) but had the second largest average cumulative production value (Table 5). In addition, there were many instances in which wells in the same area with the same treatment volume had drastically different production values. In area eight, two wells completed by the same operator using the same treatment size and within one day of each other had cumulative production values of 1,645,500 mcf and 383,400 mcf respectively. These wells had TD values within 15 feet of each other and perforated intervals within 44 feet of being the same. They were, however, on different leases approximately three miles apart. As would be expected, this indicates that there are many other factors besides stimulation treatment volume which affect the ultimate cumulative production of a well. Some of these factors, such as formation characteristics, completion practices other than stimulation, treatment fluid systems and additives, and treatment techniques, will be the focus of the second stage of this study to be published at a later date.

Once production decline data was collected, plots were made correlating cumulative production against treatment fluid and proppant volumes. Data from each well analyzed was plotted and linear regression curve fitting techniques were utilized to identify production trends. Due to the wide range of points, correlation coefficients were quite low. However, best fit lines were determined for each area. Plots of these best fit lines can be found in Figures 8 through 25. These plots are standardized for fluid and proppant volumes for ranges from 0 to 150,000 gallons or pounds respectively, and over a production range corresponding to each area. Results for different areas vary, but some plots indicate that decreasing fluid and/or proppant volumes will result in increased production. This type of conclusion contradicts conventional philosophy of the proper way to stimulate a tight gas sand. There are many technical papers which document the fact that the best method of stimulating formations with low permeability is to obtain long fracture lengths. Lengths equal to 80-100% of the effective drainage radius are theoretically ideal but are normally uneconomical. The average treatment size historically pumped in the Canyon Sand, which is also the size analyzed in this study, is not large enough to result in this type of reservoir penetration. Therefore, results indicating excessive treatment sizes are not valid. Given this explanation to the contrary, there must be other reasons for these conflicting results.

There are a number of possible explanations for these results. They may indicate that there are substantial differences in formation characteristics from well to well due to the lenticular nature of the formation. The production data may also be related to the number of zones completed in a well. Original completions by many operators included fewer intervals than the number presently being completed in offset wells. The non-completion of potential pay zones in the original completion would have a significant impact on cumulative production. Properly interpreted, these results may demonstrate that formation damage due to stimulation fluids is critical. This would indicate that the best treatment fluid would be one which minimizes formation damage. Following this reasoning, one would conclude that individual fluid systems must be evaluated separately to determine an optimum fluid, before optimum fluid and proppant volumes can be identified.

Another explanation for these contradictory results might deal with the production data itself. The production numbers reported in this paper represent actual production, not potential production. They have not been adjusted for shut-in periods due to low gas price, allowable production quotas, transportation or end user restrictions, or individual well workovers. As such they represent conservative production values with actual potential values possibly much higher. The unknown effect of these conditions on production decline data could result in incorrect conclusions. This information was being compiled at the time this paper was published.

Another possible explanation deals with the reservoir itself. It is reasonable to assume that the earliest wells drilled in these areas were completed in locations which indicated the best potential. As additional wells were completed they would have been, of necessity, in less attractive areas and in a reservoir which was no longer virgin. With this in mind, the production data listed in Table 5 included a correlation with the average year of completion for all wells analyzed within each study area. A best fit plot was made of cumulative production versus average year of completion. The results of graphing this data can be seen in Figure 26. This plot would seem to indicate that the best wells were completed initially, since the more recent completions have smaller cumulative production totals. Since larger treatments overall (especially proppant volumes) have been used more recently, the smaller cumulative production would be associated with larger proppant volumes. This would help to explain the trend shown in Figures 17 through 25 indicating that more proppant will not result in higher production. However, the data in Figure 26 could also be explained by the necessity to limit production in the recent past due to allowable production quotas. Wells which were originally completed may have been able to produce at higher rates due to either greater demand or fewer wells to meet existing production quotas. This data could also be explained if reservoir depletion was occurring before offset wells were completed. This should not be a reason in this case, however, since wells are still on 80-acre and 160-acre spacings.

RECOMMENDED TREATMENT SIZE

Given the data discrepancies noted in the previous section of this paper, it is difficult to draw specific conclusions with regard to optimum treatment volumes. Ultimate cumulative recoveries are usually in direct proportion to initial production rates. This is illustrated in Table 5 by comparing two-year, five-year, and cumulative production data. The area with the highest two-year production has the highest five-year and cumulative production. This would seem to indicate that any economical method which could be used to increase initial production would ultimately increase cumulative production as well. Presumably this would include stimulation treatments, keeping in mind that recoverable reserves are the ultimate governing factor.

Without having determined a definitive range for an optimum treatment size, one is forced to rely on established theoretical procedures for treating tight gas sands and on experience in the area. The optimum treatment size should be one which provides the maximum proppant penetration within the economic limits of expected production. Using the average cumulative production numbers determined in this study to establish this economic limit should provide a conservative value. The treatment fluid utilized should contain additives designed to minimize formation damage.

Further examination of Figures 8 through 25, and especially Figures 16 and 25, indicates that larger fluid volumes result in higher production, whereas higher proppant volumes do not. This would imply that fluid volume is more important to a successful fracture stimulation treatment than is proppant volume. Since fluid volume correlates directly to fracture length and proppant volume correlates to fracture conductivity, one could conclude that fracture length is more critical than fracture conductivity. This conclusion is in line with accepted procedures for the proper method of stimulating tight (low permeability) reservoirs.

As a means of verifying the accuracy of this conclusion, several computer-generated designs were examined. A summary of these designs can be found in Exhibits A and B as well as Table 6. This data further establishes the accuracy of the conclusion that fracture length is more important than fracture conductivity for a successful stimulation treatment. One can see from examining this data that additional fluid volumes can have a dramatic increase on projected productivity while increased proppant volumes have only a minor effect.

If one was to select the optimum treatment volume for the conditions used in the design example, it would be 150,000 gallons of fluid and 260,000 pounds of proppant. This treatment size correlates closely to the values mentioned previously under present stimulation practices for gallons per net foot, pounds of proppant per gallon of fluid, and recommended length as a percentage of drainage radius. For the typical well analyzed, this treatment would be 1875 gallons per net foot, 1.73 pounds of proppant per gallon of fluid, with a propped fracture length equal to 79% of the drainage radius. This treatment would be selected based on projected productivity increase values only and might exceed production economics for a particular well. Selection of the 100,000 gallon/130,000 pound treatment would be the next logical choice of the sizes listed in Table 6. Selection of this treatment would result in 1250 gallons per net foot, 1.3 pounds of proppant per gallon of fluid, and a propped fracture length equal to 57% of the drainage radius.

In either case fluid volume, not proppant volume, is the key to selecting treatment size. With either treatment, the volumes fall within the ranges previously mentioned under present treatment practices with the exception of smaller proppant concentrations. At the present time, the recommended treatment size for wells on 80-acre spacing would be one which includes +/-1500 gallons per net foot of pay and +/-1.5 pounds of proppant per gallon of total fluid. Wells on 160-acre spacing would require treatment volumes approximately twice this size. Operators presently pumping treatments in this range appear to be near the optimum.

CONCLUSIONS

1. Fracturing the Canyon Sand formation with aqueous-based fluid systems appears to result in the best production on a cost performance basis.

2. On an economic basis, formation damage considerations cannot be the primary factor in the selection of a treatment fluid, but additional expenditures to minimize formation damage are justified when pumping aqueous-based frac fluids.

3. Clay stabilization, low surface tension, and iron control are important considerations for successful stimulation treatments.

4. Analysis of production decline data indicates that, in general, larger stimulation treatment fluid volumes result in higher production, however there are many other factors which also affect the success of any individual well completion.

5. Stimulation treatment volumes should be selected to provide maximum propped length within economic limitations.

6. Fluid volume is more critical than proppant volume for a successful stimulation treatment.

7. There may not be an "ultimate" fracturing system. There are several alternatives which will produce excellent results if properly utilized.

8. Much additional study is required to be able to definitively select an optimum treatment system as well as optimum treatment fluid and proppant volumes.

REFERENCES

1. Hurst, Robert E., "Designing Successful Gas Frac Treatments," Petroleum Engineer, July 1972, ppg. 69-76.

2. Byars, Carlos, "Persistence Pays off in Gas Hunt," The Oil and Gas Journal, September 4, 1972, ppg. 56-58.

3. Smith, C.F., "Gas Well Fracturing Using Gelled Non-Aqueous Fluids," SPE 4678, presented at the 48th meeting SPE-AIME, Las Vegas, Nevada, September 30-October 3, 1973.

4. Smith, C.F. and Murphy D.L., "Field Evaluation of Gas Well Stimulation Methods - Sutton County, Texas," SPE 4800, presented at the Permian Basin Oil Recovery Conference, Midland, Texas, March 11-12, 1974.

5. Weaver, Christopher R., "Efficient Operations Make 300 Mcfd Wells Profitable," World Oil, August 1, 1974, ppg. 45-47.

6. Long, Mike, "Hot Ozona-Sonora Play Still Expanding," The Oil and Gas Journal, June 14, 1976, ppg. 29-31.

7. Webster, Kale, "Current Completion Practices in Tight Reservoirs," SPE 6379, presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 10-11, 1977.

8. Anderson, Stephen W., "Developing the Southwest Ozona Field," Petroleum Engineer International, January 1978, ppg. 38-42.

9. Armendariz, Victor M. and Barringer, David K., "Use of Complex Weak Acid in Canyon Sand Stimulation," SPE 9706, presented at the Permian Basin Oil and Gas Recovery Symposium, Midland, Texas, March 12-13, 1981.

10. Foret, R.P., Diggons, W.F., and Grace, L.M., "A New Approach to Air-Hole Interpretation in the Canyon Sands of Central Texas," SPE/DOE 11619, presented at the 1983 SPE/DOE Symposium on Low Permeability, Denver, Colorado, March 14-16, 1983.

Table 1
Range of Average Reservoir Properties

Depth	4000 to 9000 feet
Permeability	.01 to 0.2 md
Porosity	8.0 to 14.0 percent
Bottom Hole Pressure	1000 to 3000 psi
Bottom Hole Temperature	140 to 200°F
Frac Gradient	0.7 to 1.0 psi/ft.
Young's Modulus of Elasticity	5.5 - 13E6
Poisson's Ratio	0.22 - 0.29
Acid Solubility:	
A. 15% HCl	3-70% (normally +/-15%)
B. Mud Acid	10-80% (normally +/-30%)
Clay Content (primarily illite and kaolinite)	0 - 10%
Iron Content (As siderite)	0 - 10%
Gross Zone Height	100 - 1000 feet
Net Zone Height	30 - 400 feet (normally +/-35% of gross height)
Gas Saturation	45 - 90%

Table 2
Number of Wells Completed During Year Indicated

YEAR	AREA 1	AREA 2	AREA 3	AREA 4	AREA 5	AREA 6	AREA 7	AREA 8	AVG	% OF TOT
1973	1	9	1	1	6	13	28	25	84	8.48
1974	2	4	2	7	22	10	22	25	94	9.49
1975	2	5	0	4	33	4	42	15	105	10.60
1976	4	8	10	1	8	1	1	4	37	3.73
1977	20	26	21	7	9	1	5	4	93	9.38
1978	22	12	8	22	4	13	7	2	90	9.08
1979	6	8	3	20	7	2	13	2	61	6.16
1980	6	2	10	53	9	3	9	1	93	9.38
1981	9	6	3	27	4	2	11	2	64	6.46
1982	12	3	3	10	22	8	19	8	85	8.58
1983	5	8	5	4	23	6	3	4	58	5.85
1984	4	5	0	7	26	1	19	1	63	6.36
1985	3	1	3	0	7	0	4	0	18	1.82
1986	1	0	0	0	2	0	0	0	3	0.30
1987	1	3	0	0	1	0	7	15	27	2.72
1988#	1	3	0	0	4	0	6	2	16	1.61
TOTAL	99	103	69	163	187	64	196	110	991@	100.00

\# Through June 1988

@ This figure represents the total of all wells completed in the indicated areas over the fifteen year period 1973 - 1988.

Table 3
Average Historical Stimulation Parameters

AREA	PERF. INTV. ft.	NET INTV. ft.@	FRAC VOL. gal.	FRAC VOL. gal/nt.ft.	PROP lbs.	PROP lbs./ net ft.	PROP lbs./ gal.
1	289	101	73,900	730	120,000	1190	1.62
2	228	80	72,200	900	96,700	1210	1.34
3	138	48	63,500	1320	111,800	2330	1.76
4	170	60	118,000	1970	286,000	4770	2.42
5	495	173	92,700	540	150,200	870	1.62
6	312	109	82,600	760	127,400	1170	1.54
7	770	270	75,400	280	78,400	290	1.04
8	310	109	59,900	550	95,000	870	1.59
Avg	339	119	79,800	670	133,200	1120	1.67

\# For all 302 wells for which production data was analyzed

@ Assumes net height is 35% of perforated height

Table 4
Average Historical Stimulation Parameters*

AREA	INTERVAL ft.	ACID VOLUME gal.	FRAC VOLUME gal.	PROPPANT lbs.	PROPPANT lbs/gal.
1	385	3500	79,500	108,000	1.36
2	240	2550	62,000	84,000	1.35
3	130	2550	60,500	105,500	1.74
4	205	2050	75,000	170,000	2.27
5	430	4350	66,000	109,000	1.65
6	305	2400	69,000	108,000	1.57
7	730	2200	60,000	70,000	1.17
8	245	1800	47,500	70,500	1.48
Average	334	2675	65,000	103,000	1.58

* For all 725 wells for which completion information was available.

Table 5
Production Decline Data (PDD)
(Production values listed are MCF)

AREA	TOTAL WELLS	PDD WELLS	% OF TOTAL	CC@	AVG. 2 YR PROD	AVG. 5 YR PROD	TOTAL CUMUL#	AVG YR OF COMP.
1	99	26	26.3	.68	95,000	160,300	211,500	82
2	103	35	34.0	.67	187,000	357,200	583,100	77
3	69	27	39.1	.58	291,500	542,600	916,100	78
4	163	37	22.7	.61	44,400	79,100	114,500	84
5	187	62	33.2	.53	122,200	205,700	276,600	80
6	64	31	48.4	.68	355,200	570,500	821,200	78
7	196	52	26.5	.62	249,000	433,900	704,300	78
8	110	32	29.1	.72	283,500	494,900	827,300	75
AVG.	--	--	--	.64	203,500	355,500	556,800	79
TOTAL	991	302	30.5	--	--	--	--	--

* Values in mcf (rounded to nearest 100)

@ CC = correlation coefficient

PDD taken to 100 mcf/month or 40 years

Table 6
Summary of Computer-Generated Design and Fracture Dimensions

FLUID VOLUME (gal)	PROPPANT VOLUME (lb)@	PROPPANT CONCENTRATION (lb/gal)	AVERAGE PROPPANT CONCENTRATION (lb/sq.ft)	AVERAGE FRACTURE CONDUCTIVITY (md-ft)	FRACTURE LENGTH (ft)	PROPPED LENGTH (ft)	AVERAGE WIDTH (in)	PERCENT OF DRAINAGE RADIUS #	PROJECTED PRODUCTIVITY INCREASE
50,000	130,000	2.60	0.99	1608	656	296	.401	31.7	6.04
100,000	130,000	1.30	0.59	884	887	535	.466	57.3	9.47
100,000	260,000	2.60	1.18	1983	919	507	.475	54.3	9.41
150,000	130,000	0.87	0.45	660	1154	648	.529	69.5	10.54
150,000	260,000	1.73	0.90	1435	1184	738	.535	79.1	11.75
150,000	390,000	2.60	1.34	2321	1214	669	.541	71.7	11.34

@ All designs used 20-40 Ottawa Sand

Based on 80 acre spacing

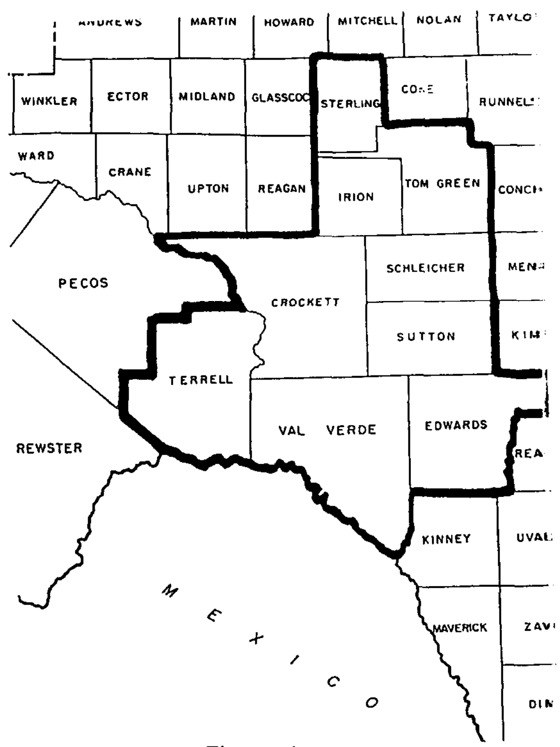

Figure 1

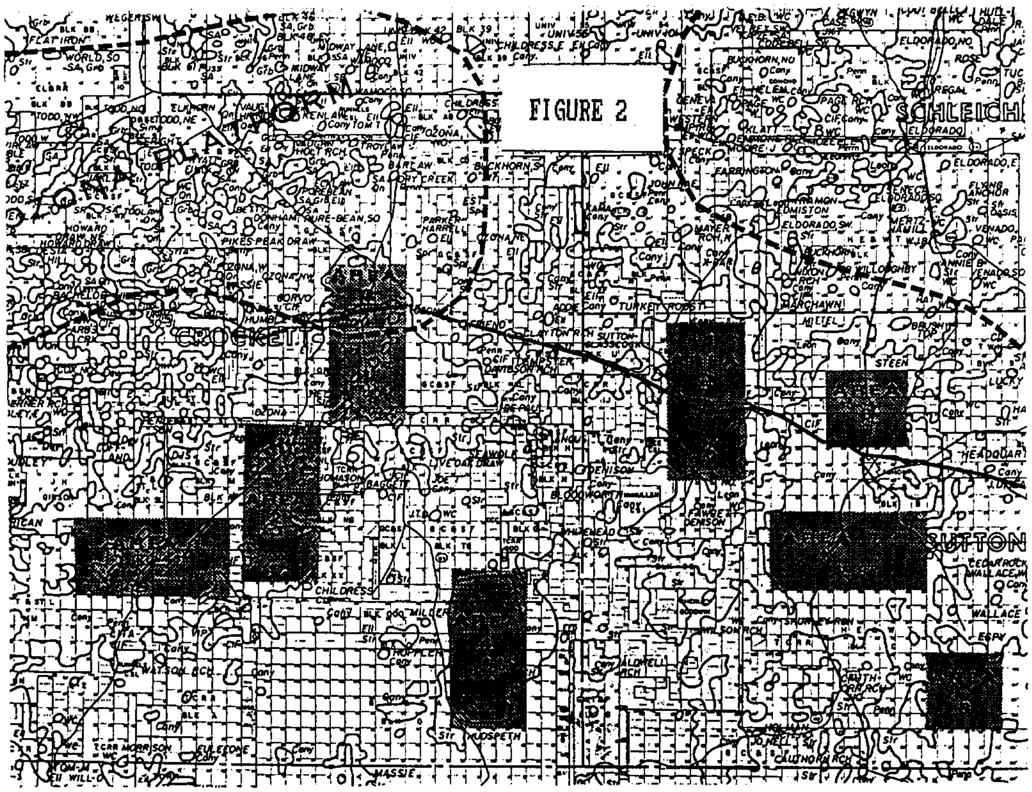

Figure 2

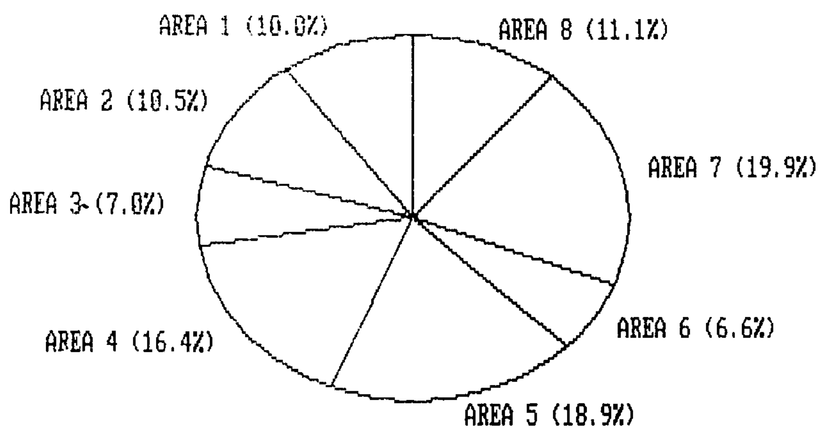

Figure 3 — Canyon Sand study —
total wells completed
1973 - 1988

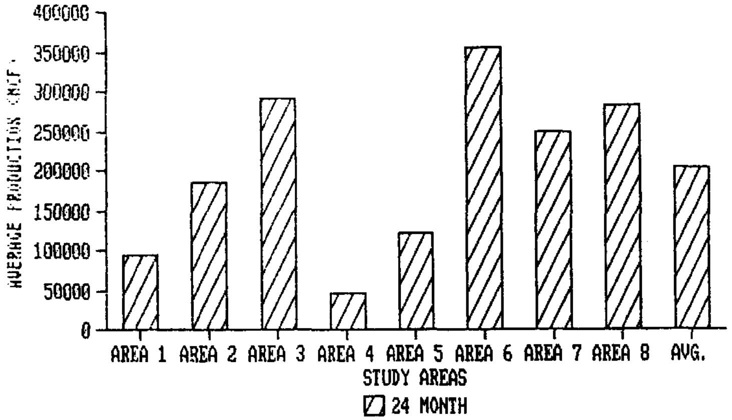

Figure 4 — Canyon Sand study — production decline data

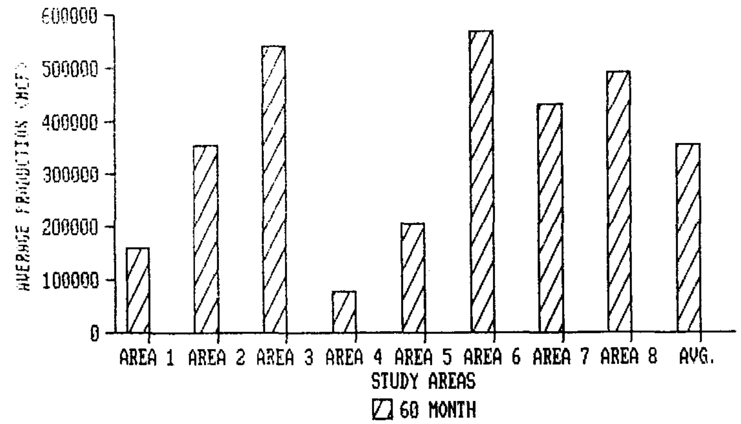

Figure 5 — Canyon Sand study — production decline data

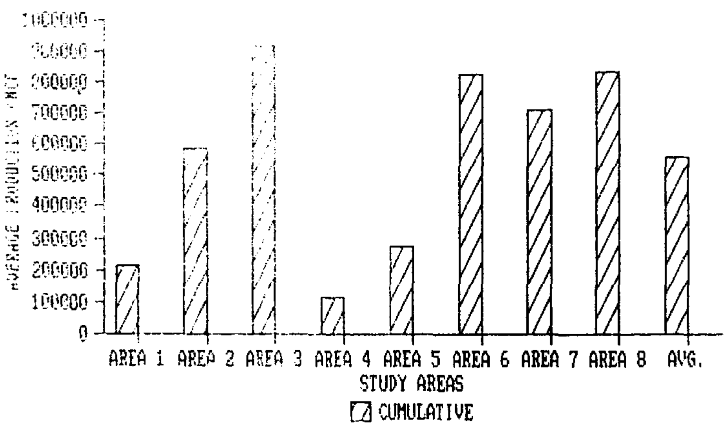

Figure 6 — Canyon Sand study — production decline data

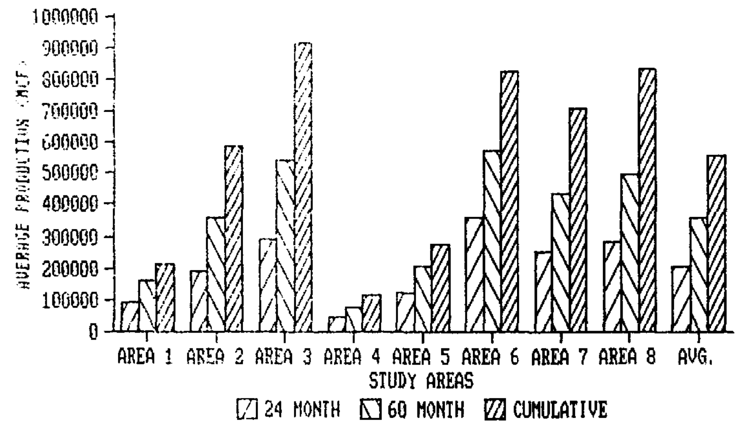

Figure 7 — Canyon Sand study — production decline data

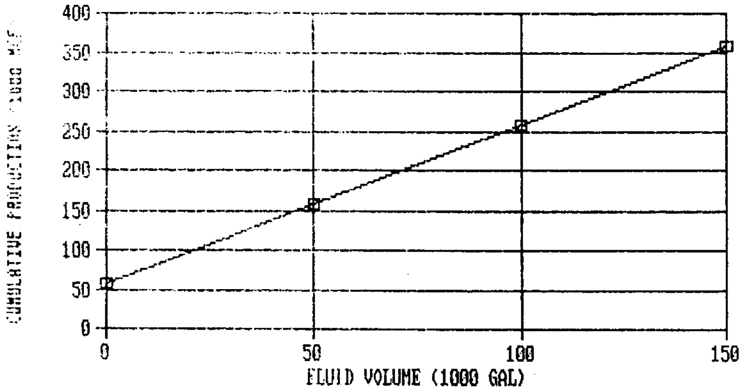

Figure 8 — Canyon Sand study
— Area 1—
optimum fluid volume

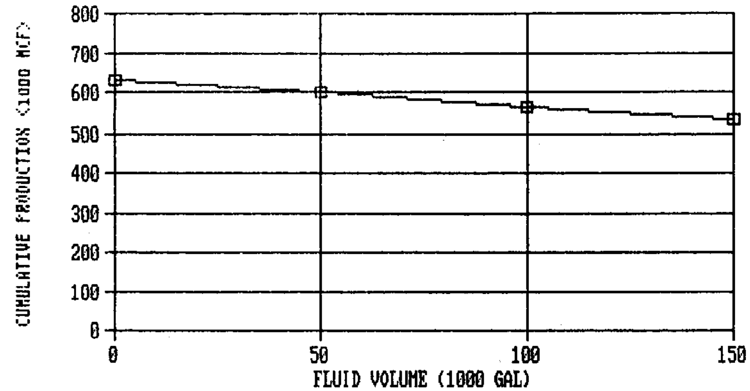

Figure 9 — Canyon Sand study
— Area 2 —
optimum fluid volume

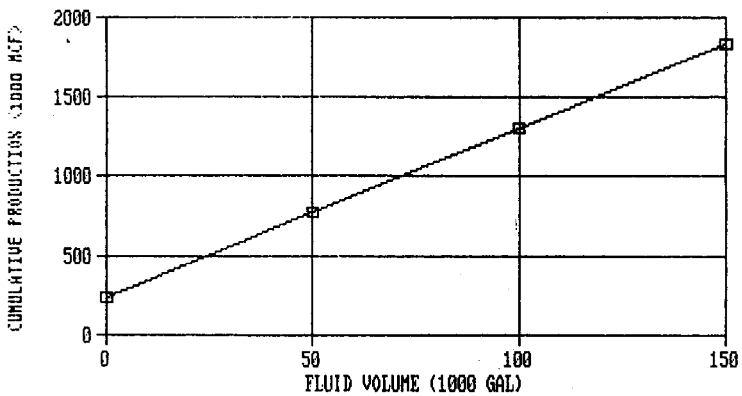

Figure 10 — Canyon Sand study
— Area 3 —
optimum fluid volume

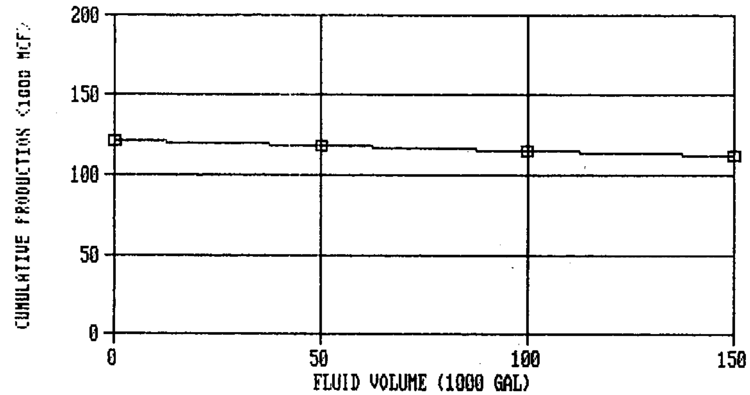

Figure 11 — Canyon Sand study
— Area 4 —
optimum fluid volume

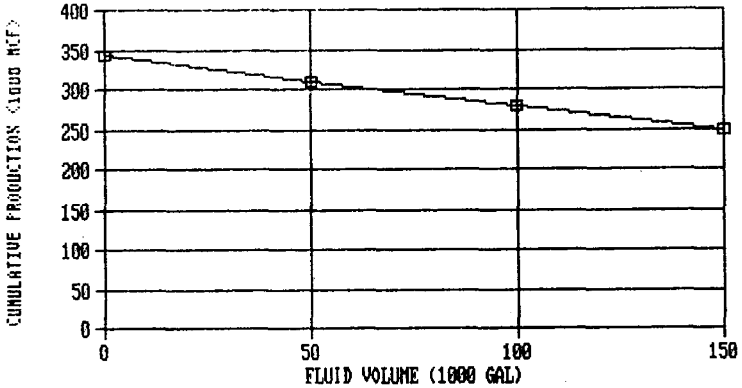

Figure 12 — Canyon Sand study
— Area 5 —
optimum fluid volume

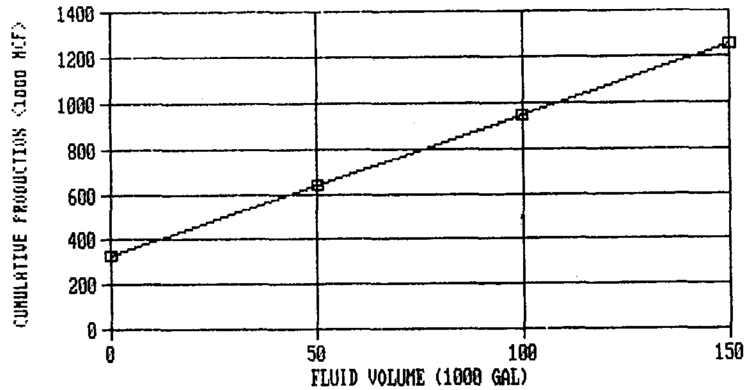

Figure 13 — Canyon Sand study
— Area 6 —
optimum fluid volume

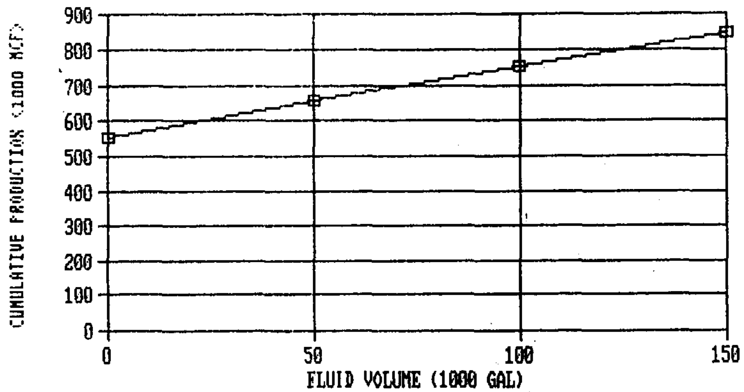

Figure 14 — Canyon Sand study
— Area 7 —
optimum fluid volume

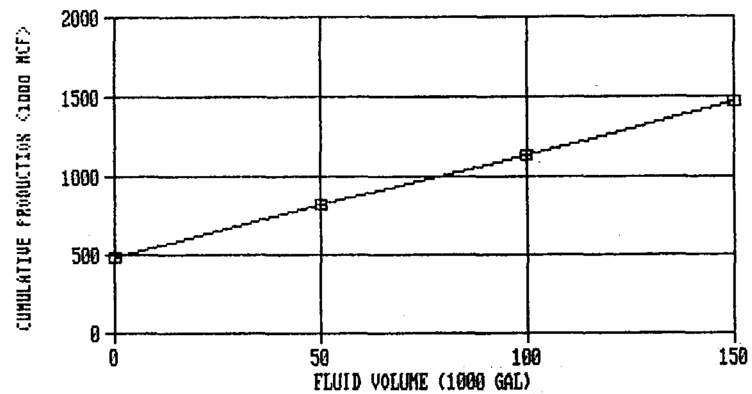

Figure 15 — Canyon Sand study
— Area 8 —
optimum fluid volume

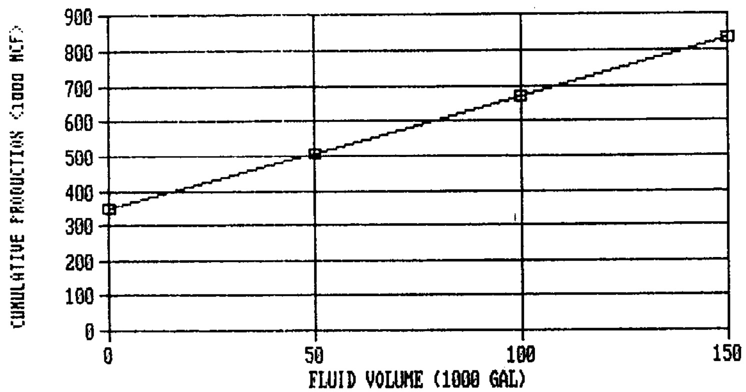

Figure 16 — Canyon Sand study
— average all areas —
optimum fluid volume

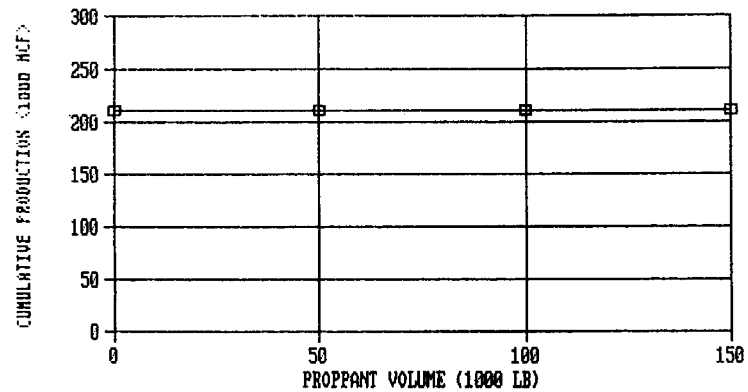

Figure 17 — Canyon Sand study
— Area 1 —
optimum proppant volume

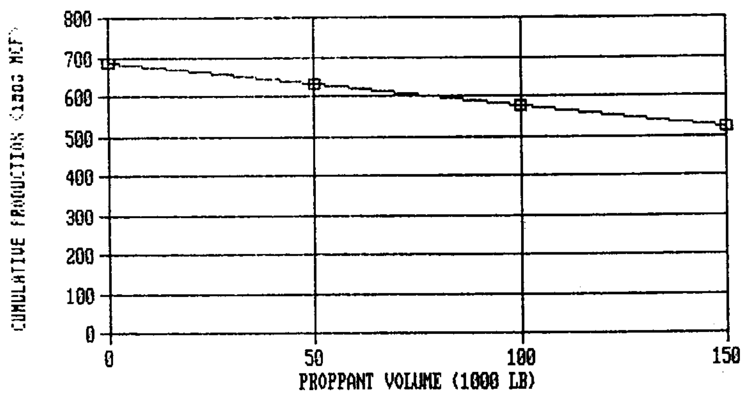

Figure 18 — Canyon Sand study
— Area 2 —
optimum proppant volume

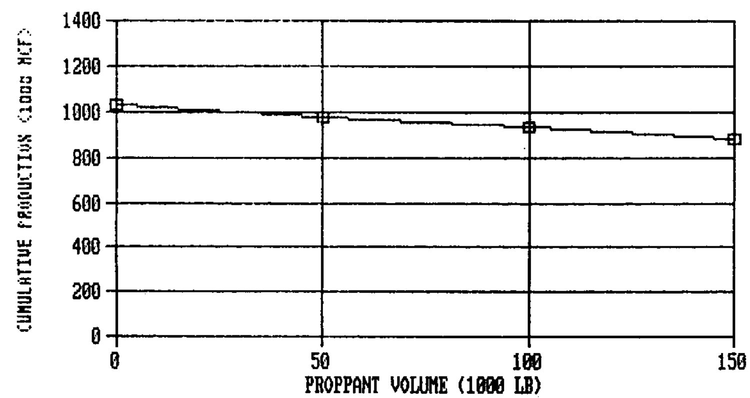

Figure 19 — Canyon Sand study
— Area 3 —
optimum proppant volume

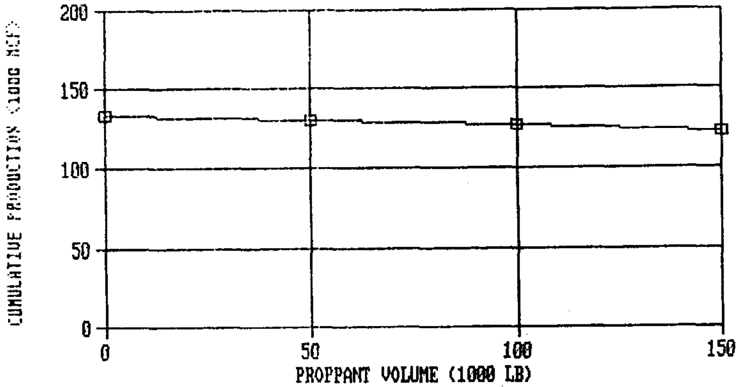

Figure 20 — Canyon Sand study
— Area 4 —
optimum proppant volume

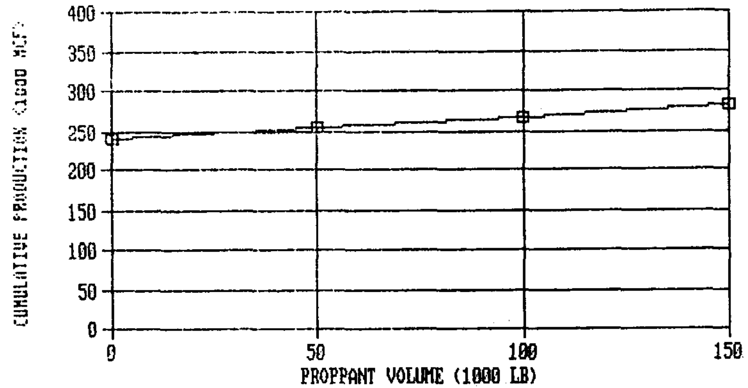

Figure 21 — Canyon Sand study
— Area 5 —
optimum proppant volume

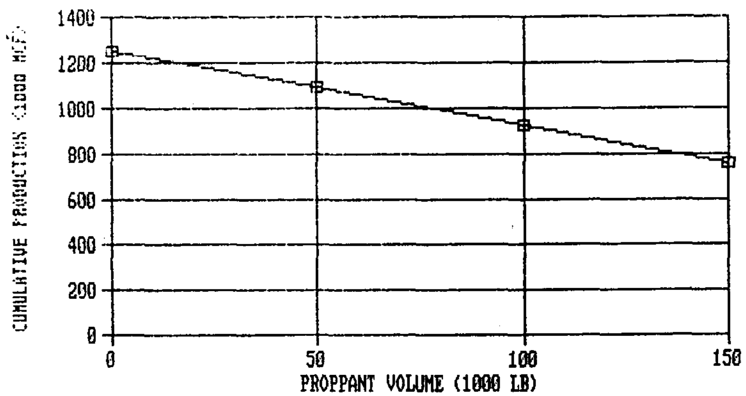

Figure 22 — Canyon Sand study
— Area 6 —
optimum proppant volume

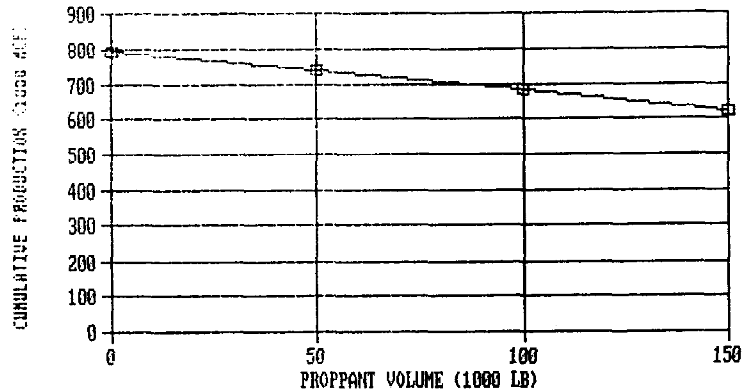

Figure 23 — Canyon Sand study
— Area 7 —
optimum proppant volume

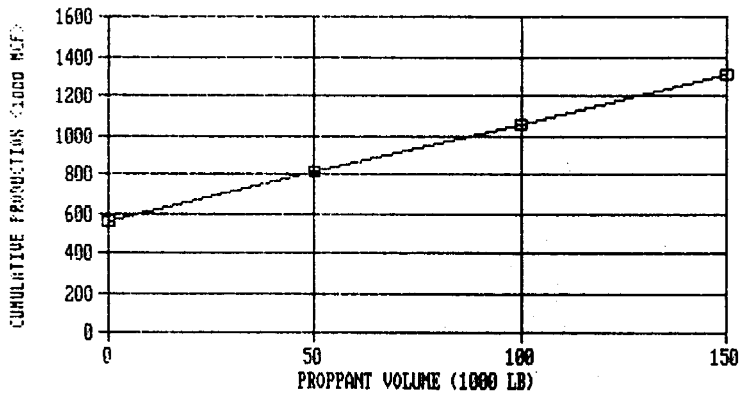

Figure 24 — Canyon Sand study
— Area 8 —
optimum proppant volume

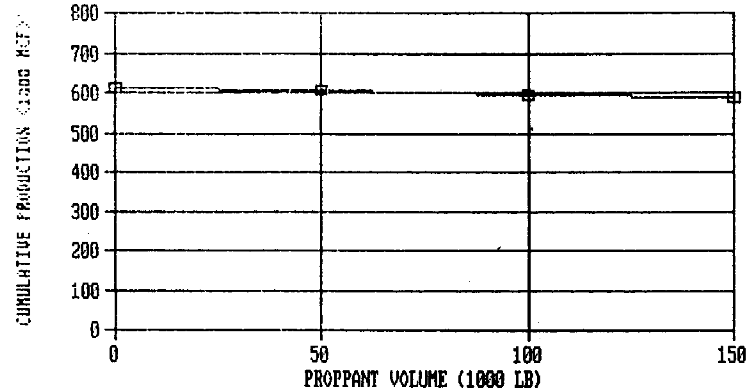

Figure 25 — Canyon Sand study
— average all areas —
optimum proppant volume

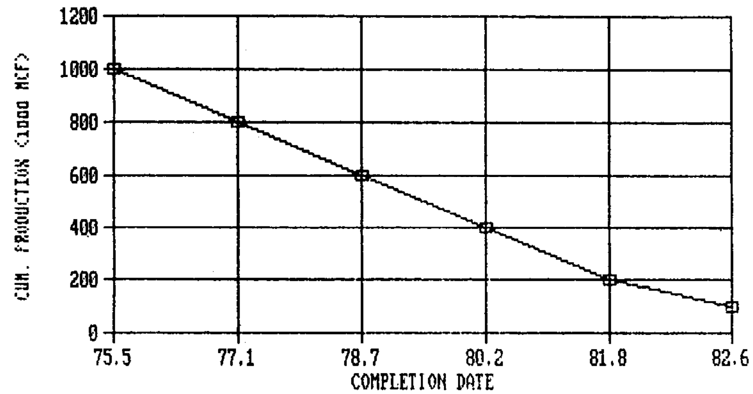

Figure 26 — Canyon Sand study —
cumulative production vs.
date of completion

EXHIBIT A

FRACDES : A Hydraulic Fracture Treatment Design Program for
Computing Created and Propped Fracture Dimensions

** Geertsma and DeKlerk's Linear Equations are Being Used

** Proppant Transport Calculation is Done

Company	NATURAL GAS OPERATOR
Well Name	TYPICAL
Location	CROCKETT OR SUTTON COUNTY
Formation	CANYON SAND
Treatment	150,000 GALLONS 40# GWX-9 WITH260,000 POUNDS 20-40 MESH OTTAWA SAND 35 BPM @ 4500 PSI DOWN 3 1/2" TUBIN

WELL COMPLETION DATA

Formation Depth (ft)	5550.
Packer Depth (ft)	5300.
Tubing I.D. (in)	.000
Tubing O.D. (in)	.000
Casing I.D. (in)	2.992
Wellbore Diameter (in)	5.000
Number of Perforations	18
Perforation Diameter (in)	.380

FORMATION DATA

Porosity (%)	10.0
Permeability (md)	.050
Res. Fluid Viscosity (cp)	.600
Res. Fluid Compressibility (1/psi)	.800E-04
Oil Specific Gravity	.000
Reservoir Temperature (deg F)	125.
Fluid Inj. Temp. at Surface (deg F)	70.
Low Temp. for Fluid Rheology (deg F)	100.
Well Spacing (ac)	80.
Reservoir Pressure (psi)	1600.
Young's Modulus (psi)	.55000E+07
Fracture Gradient (psi/ft)	.75
Poisson's Ratio	.220
Fluid Loss Height (ft)	80.0
Fracture Height (ft)	200.

EXHIBIT B
FRAC FLUID AND PROPPANT DATA

Time (hrs)	Temperature (F)	n'	k'
.7	100.	.490	.180
2.0	100.	.520	.120
.7	125.	.590	.063
2.0	125.	.620	.037

Frac. Fluid Gradient (psi/ft)	.440
Fluid Loss Coefficient (ft/sqrt(min))	.130E-02
Spurt Loss Coefficient (gal/sqft)	.100E-01
Input Fracture Permeability (md)	.000

TREATMENT PARAMETERS

Slurry Injection Rate (bpm)	35.0
Surface Treating Pressure (psi)	4508.
Pipe Friction (psi)	2385.
Perforation Friction (psi)	403.
Bottomhole Treating Pressure (psi)	4163.
Horsepower Requirements (hhp)	3866.
Closure Pressure on Proppant (psi)	3363.
Estimated Flowing BHP after Frac (psi)	800.