THE EFFECTIVENESS OF HYDRAULIC FRACTURING TREATMENTS IN THE DEVONIAN SHALE

by

Albert B. Yost II, Petroleum Engineer
Morgantown Energy Research Center
U.S. Department of Energy
Morgantown, WV

ABSTRACT

For more than 2-½ years, the Morgantown Energy Research Center's Eastern Gas Shales Project has actively pursued a program in stimulation technology to advance the state of the art for the Devonian Shale. This paper compares the effectiveness of 46 hydraulic fracturing treatments to conventional borehole shooting, using production history as a basis. The wells are compared on a regional basis to enhance the comparison. Included in the discussion are some of the most recent efforts under the Eastern Gas Shales Project to determine the effectiveness of cryogenic and foam fracturing techniques and the results to date.

INTRODUCTION

The productivity of Devonian Shale wells depends on several factors such as: 1) fracture porosity and permeability, 2) matrix porosity and permeability, 3) density and extent of these fracture systems, and 4) the amount of interconnection between the wellbore and the fracture system. These fractures provide the channels for gas migration to occur. The primary objective of hydraulic fracturing is to enhance the connection of the wellbore to a fracture system by creating highly permeable fracture/s having a large surface area.

Hydraulic fracturing of gas sands has been a commercially accepted practice for over 25 years. However, few hydraulic fracturing treatments were performed in the Devonian Shale. The use of gelled water hydraulic fracturing was not readily accepted for the Devonian Shale because operators were fearful of the damage water could have on the Shale. Part of this fear was overcome when it was determined that a 2% potassium chloride solution considerably reduced abnormal clay swelling caused by water base fracturing fluids. Chenevert determined that a 30-70 mixture of methanol and potassium chloride water reduced swelling of clays to a minimal level lower than the 2% potassium chloride water alone[5/]. To date, after demonstration that water damage can be controlled, over 150 wells have been stimulated by hydraulic fracturing in the Devonian Shale.

Selection of the interval/s for stimulation has been based on: 1) highest organic content, 2) gamma ray/sibilation and temperature logs indicating gas entry into the wellbore or possible gas migration near the wellbore in the fracture system, or 3) complete examination of a suite of logs and/or core material. Most of the wells addressed in this paper are wells perforated in the higher organic-rich intervals and/or intervals having gas shows by one of these techniques.

ANALYSIS OF VARIOUS STIMULATION TREATMENTS

The effectiveness of stimulation treatments can be analyzed in many ways; however, this analysis is based on comparison of actual production histories. This section compares gas production behavior over the first five to ten years of productive life and discusses the effectiveness of various hydraulic fracturing treatments and the indicated results.

The 13 wells used in this study were from the same area in West Virginia and had been hydraulically fractured, borehole shot, or considered as unstimulated natural flow. These hydraulic fracturing treatments include the use of mixed gas, gelled water, and gelled methanol-water. The mixed gases treatment consisted of a mixture of one-third liquid carbon dioxide, one-third liquified petroleum gas, and one-third methanol by volume. It contained no water. One well was considered to exhibit natural flow since only about one-third of the hydraulic treatment was completed and no additional gas production was apparent. Included in this study as a basis of comparison were wells that had been stimulated using both conventional and modified borehole shooting techniques.

A summary of the volume, rate, amount of sand, perforated interval, production before and after, and particular zone of completion for hydraulically fractured wells is provided in Table 1. The amount of proppant used varied from 5,000-50,000 pounds of 20/40 mesh sand. Also, the amount of perforated hieght and zones of completion varied in some cases and was similar in others. It should be understood that the gas was coming from a variety of zones within the Devonian Shale. This is pointed out in Table 2, which identifies the stimulated interval for each hydraulic fracturing treatment. Also, included in Table 2 are the open flows after stimulation and the amount of daily production after 4-½ years of production history.

The literature to date indicates that most gas production is from the so-called "Brown Shales"; however, temperature logs from wells in this study indicate that considerable gas production occurs in the upper and middle gray shales. In theory, because the gray shales tend to be highly fractured as compared to the Brown Shales in some areas, natural gas could have migrated from the Brown Shales into the gray shales, incorrectly indicating the gray shale to be the source of major gas production.

Table 3 compares the average daily production from each of the 13 stimulated wells covering about 4-½ years of production history. The wells in Table 3 are ranked according to the first years average daily production. Note the peculiar situation that exists between the third and fourth well in the table. An 80% gel shot treatment on the #3 well produced an open flow of 603 Mcf/Day and an average daily delivery rate during the first year of 83 Mcf/Day while a water fracturing treatment on the #4 well produced an open flow of 158 Mcf/Day and an average daily delivery rate during the first year of 76 Mcf/Day. While #3's open flow was approximately four times that of #4, the average daily production for the first year was essentially the same, only 10% better. The effectiveness of hydraulic fracturing becomes apparent in the second year of production history when the hydraulically fractured well (#4) became 20% better than the gelled borehole shot (#3). By the end of 4-½ years of production, the hydraulically fractured well was producing 50% more gas than the gelled borehole shot well.

Also, included in Table 1 was open flow measurements before and after stimulation for all thirteen wells. A plot of open flow after stimulation versus the average daily production in the second year of production history

(Figure 1) shows the effectiveness of water fracturing relative to borehole shooting. Both the water fractured and borehole shot wells tend to form individual clusters of points which distinguishes one group from the other, with the fraced wells clearly superior. Hydraulic fracturing with water produced over twice as much gas per day as the 80% gel shot treatments. Examination of Figure 1 also indicates that the use of the open flow measurements to determine the effectiveness of various stimulation techniques is not particularly reliable.

Table 3, arranged in order of decreasing average daily production over the first year is interesting in that three of the treatments failed to maintain their relative positions in the table over all five years of productive history. An inspection of all the average daily production values from the second year through the fifth year shows that each well maintained essentially the same relative position in the ranking. This type of behavior was extended to show that by using the average daily production during the second year of productive life, one could predict the 10 year cumulative production for any type treatment investigated. Figure 2 illustrates how second year average daily production can predict the 10 year cumulative production expected from a well.

A comparison of the various types of stumulation treatments is shown in Figure 3. Careful inspection of Figure 3 indicates no overlap of decline curve behavior occurs within the first five years. Both the mixed gases and natural flow wells exhibit the most impressive daily production. The effectiveness of hydraulic fracturing to connect to a major fracture system becomes obvious from observing the relative shape of the curves shown in Figure 3. After 4-½ years of production history, hydraulic fracturing with water produced an average of 42.4 MMCF of natural gas per well more than 80% gel shot treatments over the same period of time. A comparison of both annual and cumulative production from water fractured wells and 80% gel shot wells is shown in Table 4. Based on cumulative production after 5 years, water fractured wells, compared to 80% gel shot wells, gave 118% better results. At that point in time (5 years), the difference between water-fraced wells and shot wells was actually increasing. To say that this trend would continue, however, would be purely speculative.

ANALYSIS OF WATER FRAC VERSUS CONVENTIONAL BOREHOLE SHOOTING

A study was made to determine the effectiveness of water fracturing treatments compared to conventional borehole shot in the Devonian Shale. The wells were taken from the same region in the Eastern, Kentucky Gasfield peripheral region and were all connected to a low-pressure pipeline at some point during an eight year period. The data represents a total of 39 water fractured wells and 89 conventional borehole shot wells. Each well had production history from some portion of the eight year period.

Two types of comparisons were made on these wells. Case 1 presented in Figure 4 represents a comparison of water frac versus shooting for all wells within this set of 128 wells having a minimum of five years of production history. Results are shown in Figure 4 for 18 water fractured wells and 35 borehole shot wells meeting these conditions. It should be understood that this group of wells are some of the best wells in the entire data set and, therefore, represents a somewhat optimistic viewpoint. Results of this investigation show that gas production due to hydraulic fracturing could be as much as 53 MMCF higher than shot well production of gas after 5 years. It is obvious as shown in Figure 4 that hydraulic fracturing was highly effective.

A second comparison was made to include all wells to the extent production history was available. Thirty-nine fractured wells and 89 shot wells had been produced for at least one year while the number of wells in both categories decreases to 13 fractured wells and 20 shot wells, having 6 years of production history. Figure 5 indicated that the annual percent difference in production was getting larger, except during the sixth year. The reliability of the sixth year of production behavior is questionable, however, the number of data points for both the water frac and shot wells were greatly reduced between the fifth and sixth year. If one ignores the sixth year behavior of the average daily production, he concludes that the relationship between the two curves will be divergent in nature. Figure 5 also points out that the average incremental cumulative gas produced by the sixth year was 43 MMCF of natural gas. A summary of the production history for all wells in Figure 5 is provided in Table 7, where a comparison of both annual and cumulative production from Big Sandy peripheral wells are made.

CRYOGENIC AND FOAM FRACTURING

Basically, foam fracturing fluids used in the Devonian Shale consists of a water base liquid, a foaming agent, and nitrogen. Nitrogen constitutes 70% or more of the volume pumped and is brought to the location on pumping trucks. Because the pumping rates for the liquid is considerably less than the rate for a conventional water frac, the amount and size of the pumping equipment is reduced. Aside from this difference, the equipment used will be same as in a conventional frac job with the addition of both nitrogen and surfactant pumping equipment.

The cryogenic fracturing fluid used to treat the Devonian Shale under this project consists of a gelled water base fluid combined with liquid carbon dioxide. The volume of liquid carbon dioxide used has varied from 14 to 30 percent of the total fluid volume while the gelled water comprised the remaining fluid. Liquified carbon dioxide is brought to location in insulated tanks and is transferred as a liquid to a pumping unit which displaces the liquid to the injection head where it combines with the sand-laden gelled water to form a cryogenic fluid going down the casing string.

Figure 6 shows the most recent efforts under the Eastern Gas Shales Project to evaluate cryogenic and foam fracturing in the Devonian Shale. To date, nine conventional size foam fracturing treatments and nine cryogenic fracturing treatments have been completed. Tables 6 and 7 provide a summary of certain specific treatment parameters that were used. Typically, cryogenic fracturing treatments have been performed in the upper and middle Brown Shale sections with one being done in the Marcellus/Rhinestreet section. Conventional foam fracturing treatments have been performed in the upper and middle Brown Shale of the Appalachian Basin, the New Albany Shale of the Illinois Basin, and in the Antrim Shale of the Michigan Basin.

Results from the various foam and cryogenic treatments have been summarized in Figure 7 with open flow measurements ranging from MCF/D to 400 MCF/D. One well located approximately three miles from the Chester Field in Otsego County, Michigan, was stimulated using the foam fracturing techniques. The significant results of the treatment was that the foam fracturing treatment was able to stimulate gas production from this Shale nearly equivalent to the existing hydraulic fracturing production in the Chester Field a few miles away. Initial results indicated that after nine days, the well was producing 150 MCF/D through a 10/64 choke against a 190 psig tubing pressure. The Antrim Shale in this area has a significant amount of associated water production and this well was no exception as it had an average water influx rate of 44 bbl/day.

BENEFITS AND LIMITATIONS OF FOAM AND CRYOGENIC TREATMENTS

Limited production history exists to support a statistical data base that can be used to document the extention of the state of the art from the use of wellbore shooting and water fracturing to foam and cryogenic fracturing. To date, the primary benefit in the use of cryogenic fracturing treatments has been to provide a highly energized fluid which has the capability to transport large amounts of proppant to the tip of fracture and then produce this water base fluid out of the fracture into the wellbore in a short period of time. A comparison of the surface equipment proppant transport capabilities available in a cryogenic liquid system as compared to a foam system would indicate that as much as 3-4 times as much sand could be carried by the liquid-CO_2 system. It should be understood that the limitation of these proppant concentrations is purely mechanical[2/]. The sand-carrying characteristics and suspending capability of 75 quality foam are superior in nature to other fluid systems available[4/]. High quality foam in essence could carry more sand in suspension than the cryogenic system if the mechanical difficulties of transporting proppant prior to the generation of foam could be overcome.

Both the cryogenic and foam systems have their merits. The use of the cryogenic system is warranted by some unique physical and chemical qualities of CO_2. Injected under pressure as a fluid, CO_2 vaporizes at reservoir temperatures above 88.6°F and when surface pressure is released, treating fluids are forced from the formation. Carbonic acid is formed when water is saturated with CO_2. This acid has a pH of 3.3 to 3.7 and is relatively non-corrosive to casing and requires no inhibition[3/]. An important characteristic of CO_2 is the solubility of CO_2 in fresh water. Based in a 100°F reservoir, the solubility of CO_2 ranges between 152 and 191 scf/bbl. Due to the acidic nature of CO_2 in water, swelling of formations clays is greatly reduced.

Some of the benefits of using foam fracturing include: low friction loss, high viscosity in the fracture, negligible sand settling velocities, and a highly efficient fluid due to low fluid loss coefficients[1/]. Foam fracturing has reduced the amount of service rig time to swab and bail fracturing fluid from the wellbore and has also reduced water haulage and storage cost. These reduced costs should justify the additional $5,000 worth of cost associated with a conventional size 1200 bbl treatment. Foam fracturing cost are highly related to the nitrogen cost. The nitrogen requirements are directly related to the treating pressure and increase exponentially with pressure. Foam fracturing can play a major role in treating the Devonian Shale until the treating pressure expected exceeds 3000 psi where the incremental nitrogen costs begin to increase beyond what operators are willing to spend. Typical bottom hole treating pressures range from 900-2500 psi.

AFTER-FRAC CLEANUP ASPECTS

The after-frac cleanup aspects of both cryogenic fluid and foam systems has been subject to a great deal of study primarily because much of the industry believes that formation fracturing fluid retention could be a significant problem in the alteration of the well productivity over as much as 10 years[6/]. To date, no one has documented with substantial evidence the extent of the significance this factor possesses. At this time, no conclusion can be made as to the relative benefit of using one fluid system over another; however, as a result of some extensive field monitoring of after-frac cleanup behavior of both foam and cryogenic fracturing treatments, the following preliminary conclusions can be drawn: 1) fluid recovery from foam fracturing using approximately 300 bbl of water in the treatment has been between 22 and 75%. An exception to this was a single treatment performed in Otsego County, Michigan, in the Antrim Shale where 100% of the foam fracturing fluid was recovered; however, this formation had connate water present which was produced with the associated gas production and was not considered a factor in this particular case. From the limited number of treatments performed, fluid recovery has been better in the West Virginia wells than in the Kentucky wells. One of the West Virginia wells located in Mason County, West Virginia, recovered 75% of the N_2-water fluid within 30 hours after flowback commenced. 2) fluid recovery from cryogenic fracturing treatments have resulted in recovery of as much as 80% of the fluid within 3 days. The amount of total water in the fracturing fluid has ranged from 70-85% by volume; however, well cleanup is still necessary and requires a few days service rig time. The effectiveness of well cleanup from cryogenic and foam fracturing is still in the evaluation mode for the Devonian Shale.

CONCLUSIONS

Based on the stimualtion treatments analyzed in this paper, Devonian Shale wells taken producing from an area in West Virginia provide an average of 42.4 MMCF of additional gas over a four and one-half year period with water fracturing as compared to conventional borehole shooting. Devonian Shale wells in the Eastern Kentucky Gasfield peripheral region provided on the average 35.3 MMCF additional gas over a five year period with water fracturing as compared to conventional borehole shooting.

Hydraulic fracturing will continue to provide additional gas production even after the incremental completion costs are recovered.

Based on thirteen wells located in a particular area in West Virginia, the average daily production from any type of stimulation treatment can be used to predict the cumulative production after ten years with reasonable accuracy.

The foam and cryogenic fracturing treatments appear the best approach to improve the ffectiveness of the hydraulic fracturing technique.

Both the cryogenic and foam fracturing permit the investigation of water retention and after-frac cleanup aspects and may result in a better understanding of why hydraulically fractured wells produced more gas. Also, included is the examination of fracturing fluid efficiency to create the maximum surface area. The maximization of the surface area of expose will increase the likelihood of interconnecting the wellbore to a major fracture system to enhance gas production from the Devonian Shale.

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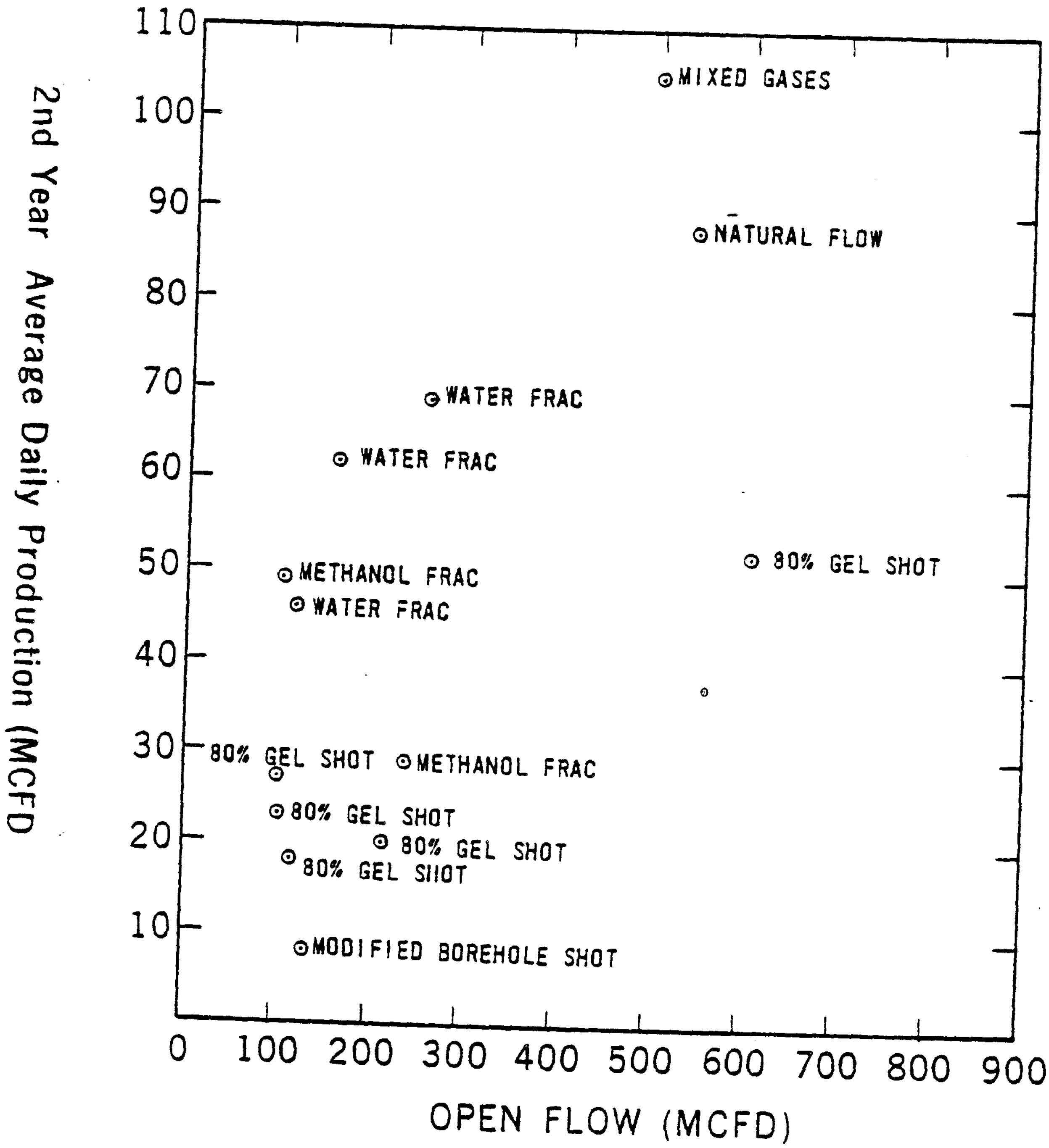


Fig. 1-Effectiveness Of Various Stimulation Treatments

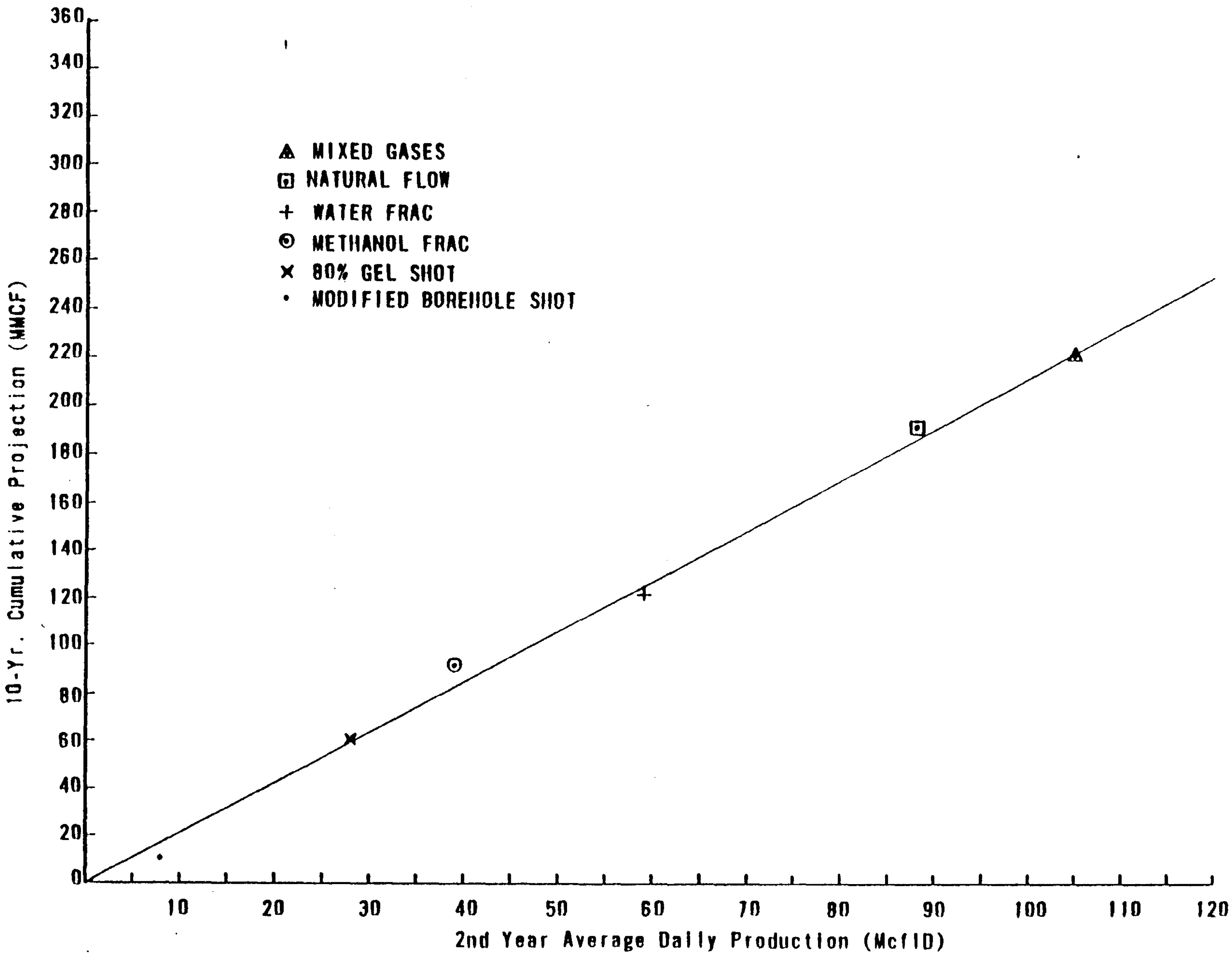


Fig. 2 PREDICTING WELL BEHAVIOR BASED ON 2nd YEAR AVERAGE DAILY PRODUCTION

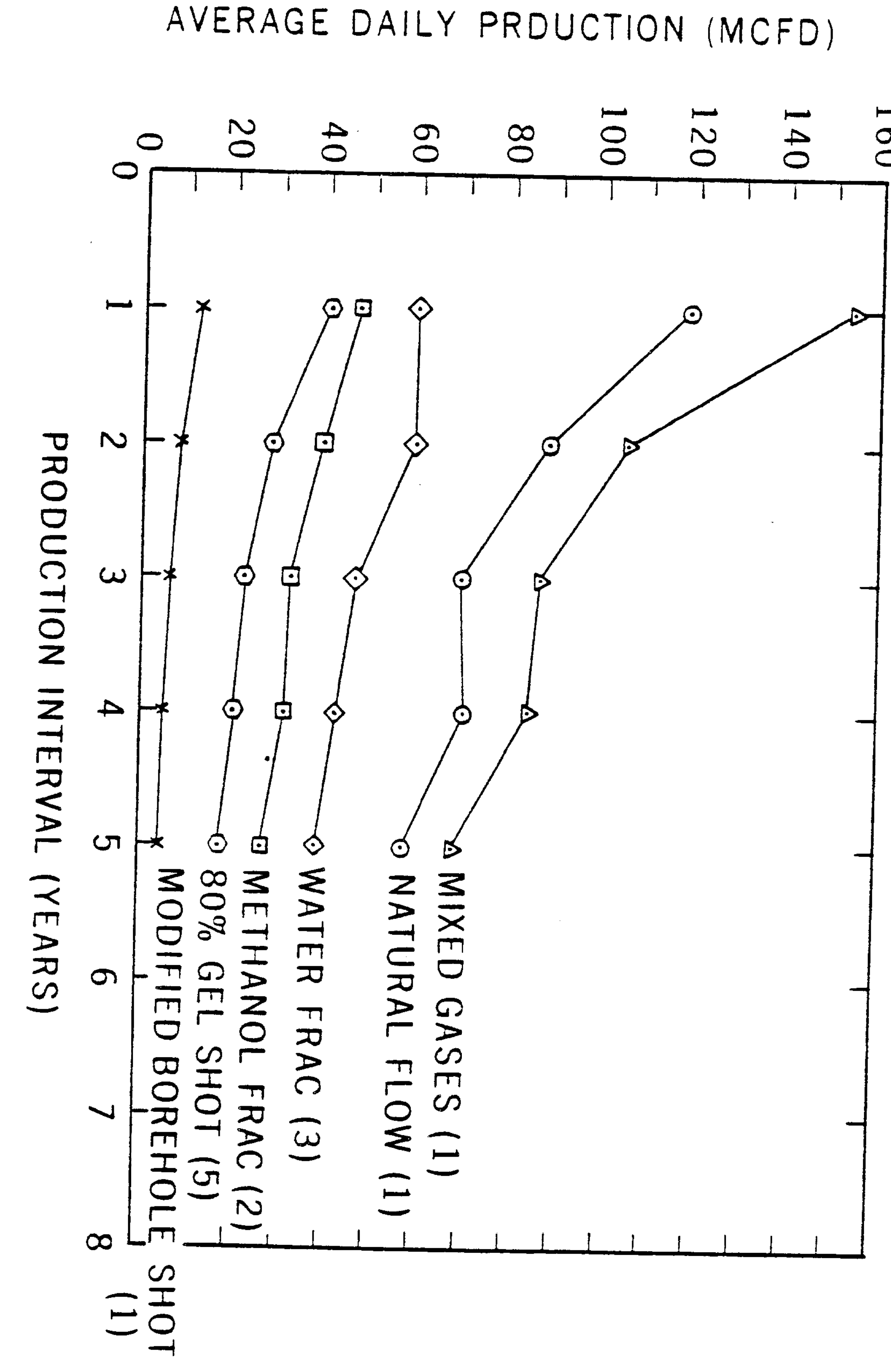


Fig.3-Comparison Of Various Types of Stimulation Treatments in the Devonian Shale

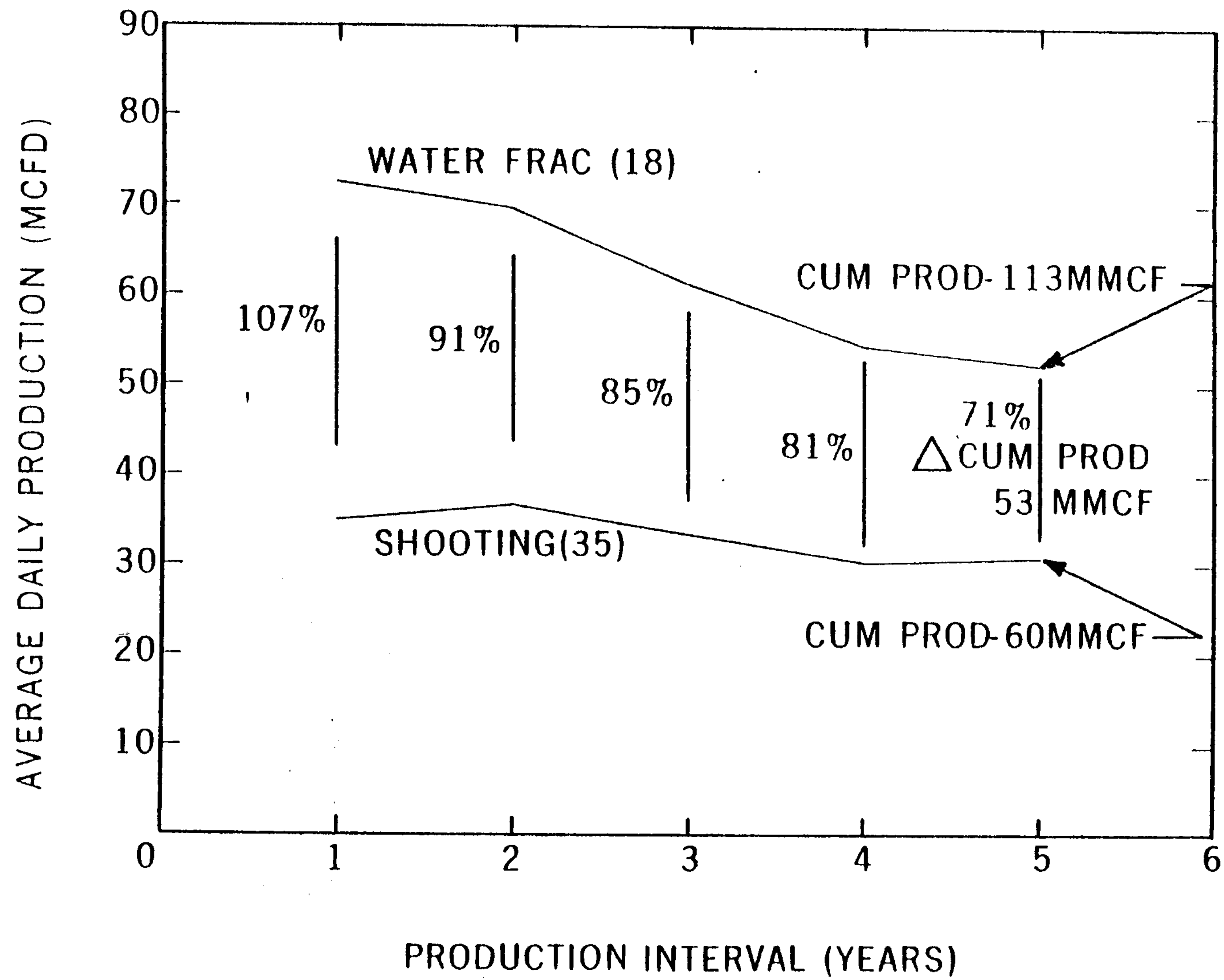


Fig.4-Comparison of Devonian Shale gas production from Eastern Ky Gas field peripheral using production from hydraulically fractured (1000 bbl H_2O) and shot wells having 5 complete years of production history/well.

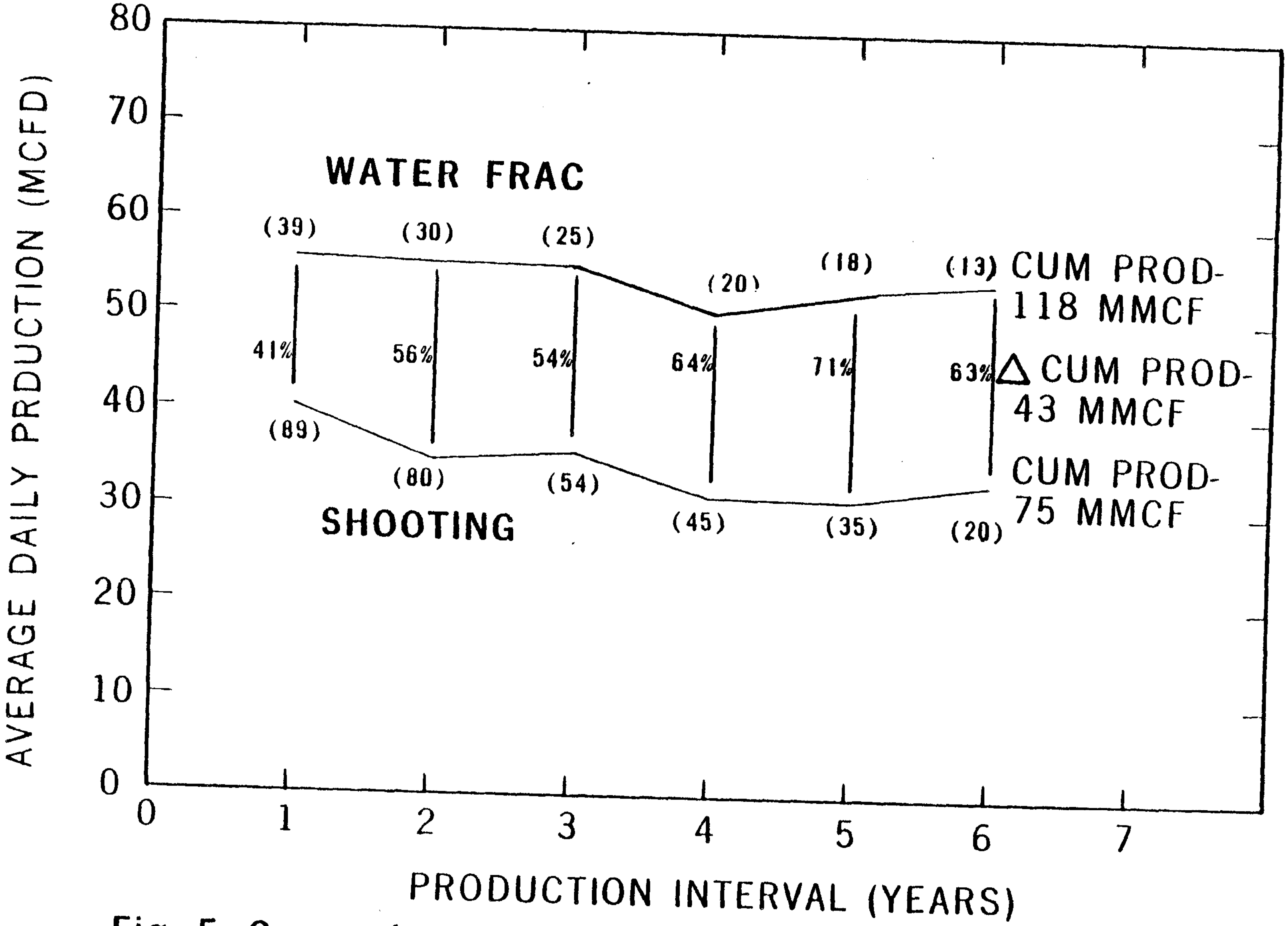
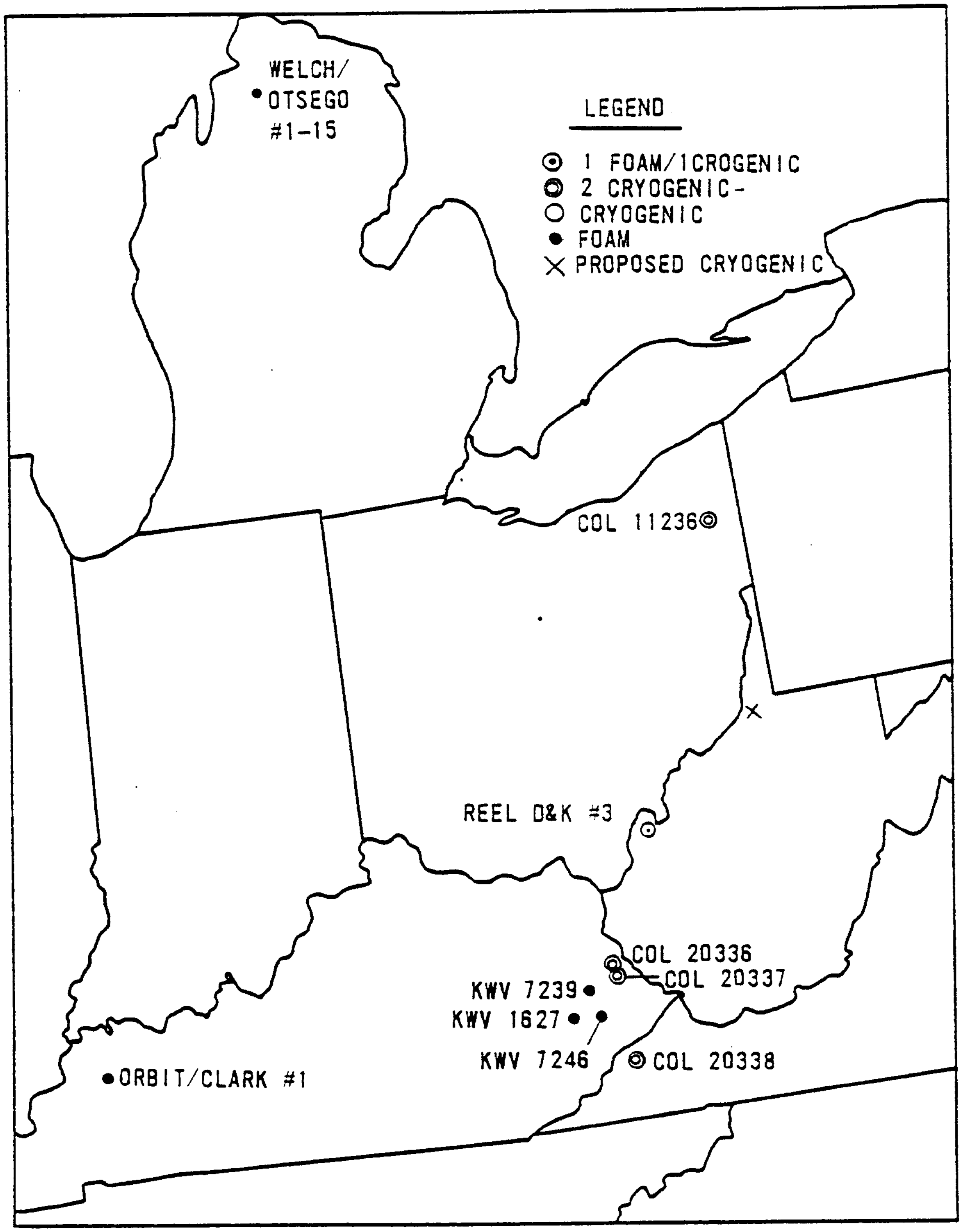


Fig. 5- Comparison of Devonian Shale gas production from fracturing and shooting in Eastern,Ky Gasfield peripheral using incomplete production history for all years

FIGURE 6 - LOCATION OF E.G.S.P. CONVENTIONAL FOAM AND CRYOGENIC TREATMENTS



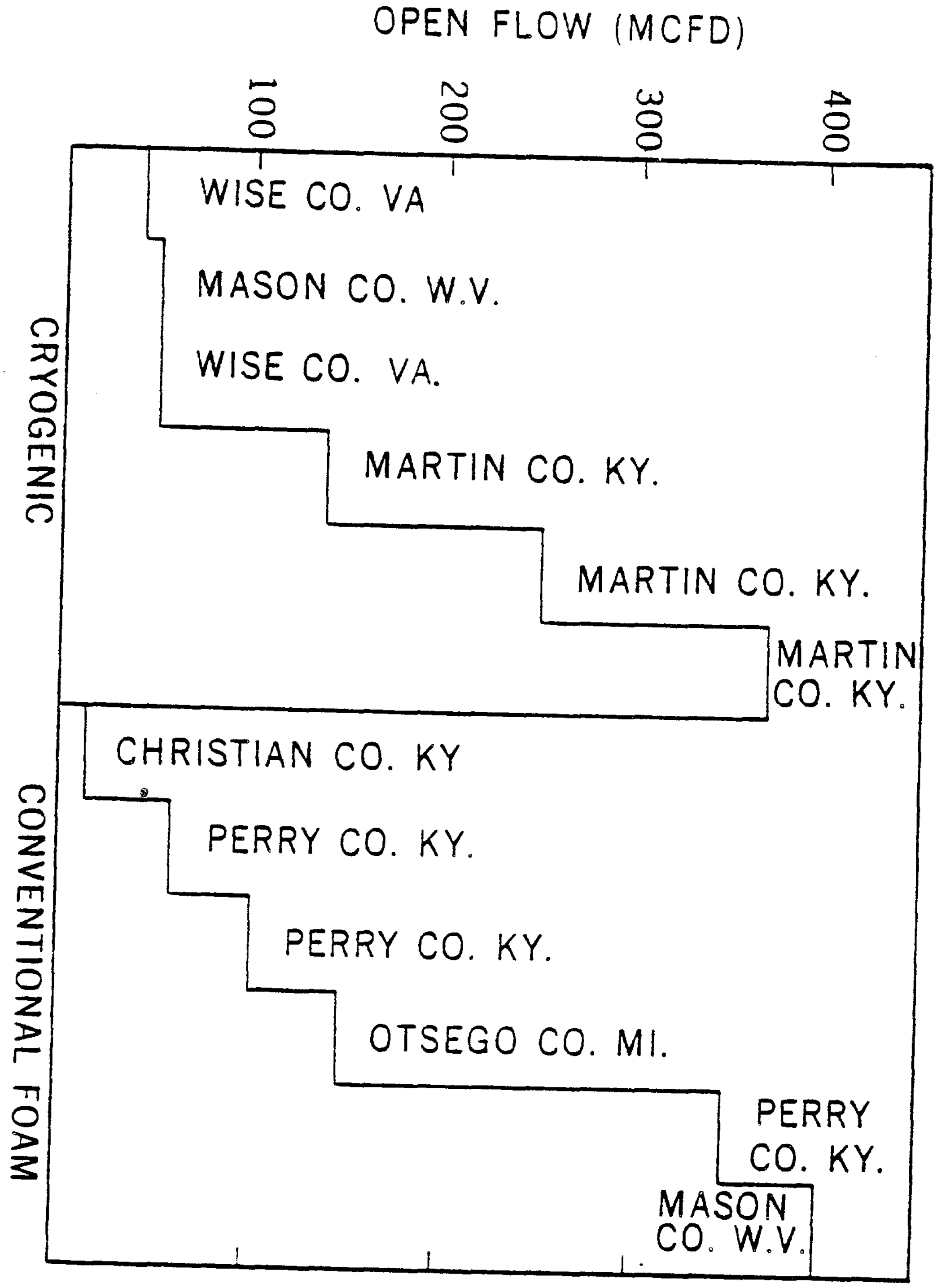


Fig.7-Summary of Various E.G.S.P. Fracturing Treatments

TABLE 1 - DEVONIAN SHALE FRACTURE TREATMENTS

TYPE OF TREATMENT	VOLUME OF RATE OF TREATMENT	AMOUNT & SIZE OF SAND	PERFORATED INTERVAL (feet)	HEIGHT OF TREATMENT TOP-BOTTOM PERFORATIONS (feet)	PRODUCTION MCF/DAY BEFORE	PRODUCTION MCF/DAY AFTER	RATIO	ZONES OF COMPLETION
NATURAL FLOW	502 BBLS 18 BPM	14,000 #20/40	4582 TO 4610 WITH 15 HOLES	28	539	539	1:1	ZONE #2
MIXED GASES	555 BBLS 30 BPM	5,000 #20/40	4030-4034 4260-4278 15 HOLES	248	55	492	1:9	ZONE #1
WATER-METHANOL	900 BBLS 50 BPM	52,500 #20/40	3784-3800 9H 3975-3980 3H 4238-4242 3H	458	42	239	1:5.7	ABOVE ZONE#1
WATER-METHANOL	700 BBLS 46.7 BPM	35,000 #20/40	4710-4724 8H 4860-4874 8H 5070-5084 8H	374	26	103	1:4	BETWEEN ZONES 1&2 AND ZONE 2
WATER FRAC	900 BBLS 40 BPM	37,500 #20/40	3532-3546 3570-3584 3627-3642	110	32	119	1:3.7	ABOVE ZONE #1
WATER FRAC	782 BBLS 54 BPM	42,000 #20/40	4712-4734 10H 4760-4794 15H	82	84	158	1:1.9	ZONE #1
WATER FRAC	840 BBLS 49.4 BPM	50,000 #20/40	4222-4228 4322-4326 4768-4782	561	10	253	1:25.3	BETWEEN ZONES 1&2

TABLE 2-DEVONIAN SHALE ZONES OF COMPLETION

REGION	FORMATION	TREATMENT TYPE						
		NATURAL FLOW	MIXED GASES	METHANOL FRAC	METHANOL FRAC	WATER FRAC	WATER FRAC	WATER FRAC
	1600 FEET OF MOSTLY GRAY SHALES AND SILT-STONES			[1]O.F.-239 * [2]A.D.P.-19		[1]O.F.-119 * [2]A.D.P.-32		
ZONE #1	320 FEET UPPER BROWN SHALES	[1]O.F.-492 * [2]A.D.P.-68					[1]O.F.-158 * A.D.P.-51	
	620 FEET UPPER BROWN SHALES				[1]O.F.-103 * [2]A.D.P.-34			[1]O.F.-253 * [2]A.D.P.-32
ZONE #2	340 FEET LOWER BROWN SHALES	[1]O.F.-539 * [2]A.D.P.-57						
	230 FEET GRAY SHALES							
ZONE #3	52 FEET MARCELLUS							

[1]O.F. - REPRESENTS OPEN FLOW AFTER STIMULATION, MCF

[2]A.D.P. - REPRESENTS AVERAGE DAILY PRODUCTION AFTER 4½ YEARS, MCFD.

* - REPRESENTS THE STIMULATED INTERVAL

TABLE 3 - WELL PRODUCTIVITY FOR VARIOUS STIMULATION TREATMENTS

Average Daily Production By Year

TREATMENT	I.O.F.	O.F.A.S.	1	2	3	4	5
MIXED GASES	55	492	154	105	86	84	68
NATURAL FLOW	539	539	118	88	69	70	57
80% GEL SHOT	5	603	83	52	38	35	29
WATER FRAC	84	158	76	62	56	56	51
METHANOL FRAC	26	103	59	49	40	39	34
WATER FRAC	115	119	56	46	34	35	32
WATER FRAC	10	253	45	69	50	37	32
80% GEL SHOT	0	103	36	27	21	20	17
METHANOL FRAC	40	239	35	29	24	23	19
80% GEL SHOT	5	103	34	23	18	16	14
80% GEL SHOT	5	215	26	20	20	18	16
80% GEL SHOT	5	119	23	18	14	13	10
MODIFIED BOREHOLE SHOT	26	133	12	8	6	5	4.5

COMPARISON OF FIVE-YEAR CUMULATIVE PRODUCTION

WEST VIRGINIA WELLS

Year	Fraced No. Wells	Fractured Mmcf	Shot No. Wells	Shot Mmcf	Increase Due To Frac Mmcf	Cum % Change
1(partial)	3	15.8	5	6.8	9.0	132
2	3	34.6	5	15.5	19.1	123
3	3	51.0	5	23.4	27.6	118
4	3	64.3	5	28.7	34.6	116
5	3	78.2	5	35.8	42.4	118

COMPARISON OF ANNUAL PRODUCTION - FIVE-YEAR

Year	Fraced No. Wells	Average Daily mcf/D	Fractured Mmcf	Shot No. Wells	Average Daily mcf/D	Shot Mmcf	Increase Due To Frac Mmcf	Increase Due To Frac mcf/D	Annual Prod. % Increase	Average Daily % Increase
1(partial)	3	59.0	15.8	5	40.4	6.8	9.0	18.4	132	46
2	3	59.0	18.8	5	28.0	8.7	10.1	31.0	116	111
3	3	46.7	16.4	5	22.2	7.3	5.8	24.5	108	110
4	3	42.7	13.3	5	20.4	6.3	7.0	22.3	111	109
5	3	38.3	13.9	5	17.2	6.1	7.6	21.1	128	123

TABLE 4 · COMPARISON OF ANNUAL AND CUMULATIVE PRODUCTION FROM W.V. WELLS

COMPARISION OF FIVE-YEAR CUMULATIVE PRODUCTION

ALL WELLS

BIG SANDY PERIPHERAL

YEAR	FRACTURED NO. WELLS	FRACTURED Mmcf	1965-1973 SHOT NO. WELLS	SHOT Mmcf	INCREASE DUE TO FRAC Mmcf	CUM. % CHANGE
1	39	20.5	89	14.6	5.9	40
2	30	40.4	80	27.3	13.1	48
3	25	60.4	54	40.3	20.1	50
4	20	79.0	45	51.6	27.4	53
5	18	98.1	35	62.8	35.3	56

COMPARISON OF ANNUAL PRODUCTION - 5 - YEARS

YEAR	NO. WELLS	FRACTURED Mmcf	1965-1973 SHOT NO. WELLS	SHOT Mmcf	INCREASE DUE TO FRAC Mmcf	ANNUAL % INCREASE
1	39	20.5	89	14.6	5.9	40
2	30	19.9	80	12.7	13.1	57
3	25	20.0	54	13.0	20.1	54
4	20	18.6	45	11.3	27.4	64
5	18	19.1	35	11.2	35.3	71

TABLE 5 - COMPARISON OF ANNUAL AND CUMULATIVE PRODUCTION FROM BIG SANDY PERIPHERAL WELLS.

CRYOGENIC FRACTURING

Stimulation Type	Formation Type	Vol (gal)	Sand (Lbs)	Rate (BPM)	Depth (Ft)	Perf Ht (Ft)	Production Before/ After	Cost ($$10^3$)	State/ County	Contractor Contractor	Well No	Date
Cryogenic	Middle Br Sh	98.000	185.000	30	5450-5480	30	0/50	56	Va/Wise	Columbia	20338	Sept. '77
..	Upper Br Sh	140.000	210.000	..	4890-4910	20	0/40	70	..	..	..	Nov. '77
..	Middle Br Sh	74.000	110.000	..	2988-3122	154	0/370	30	Ky/Martin	..	20336	Dec. '77
..	..	85.000	120.000	..	2666-2712	46	0/250	30	..	..	..	Jan. '78
..	Lower Br Sh	43.000	80.000	..	3526-3574	48	0/133	26	..	..	20337	Nov. '77
..	Middle Br Sh	45.000	..	32	3100-3250	150	Not Tested	30	..	..	..	Dec. '77
..	Rhinestreet	50.000	115.000	15	3345-3374	26	0/50	24	WV/Mason	Reel Energy	D&K #3	Mar. '78
..	Lower Br Sh	82.000	287.000	28	2410-2525	135	Not Tested	55	Oh/Trum	..	11236	May '78
..	Middle Br Sh	..	248.000	..	1915-2000	85	..	..	..	..	..	..
..	Marcellus						Scheduled		WV/Wetzel			July '78

TABLE 6 - SUMMARY OF E.G.S.P. CRYOGENIC FRACTURING TREATMENTS AS OF 5/15/78

FOAM FRACTURING

(CONVENTIONAL SIZE)

Stimulation Type	Formation Type	Vol (gal)	Sand (Lbs)	Rate (BPM)	Depth (Ft)	Perf Ht Ft	Production Before/ After	Cost ($10^3)	State/ County	Contractor	Well No.	Date
Foam	Br Gr Sh	40,000(4)	40,000(4)	30	2328-2875	350(4)	0/80	35.6	Ky/Perry	Ky-WV	7239	Nov. '75
"	Upper/Middle Br Sh	50,000	55,000	25	3174-80 3412-81	88	0/350	18.4	"	"	7246	Aug. '76
"	New Albany Sh	45,000	54,000	"	2186-2320	134	0/15	17.0	Ky/Christian	Orbit	Ray Clark #1	Nov. '76
"	Upper/Middle Br Sh	50,000	55,000	"	2560-2580. 2730-2790	• 80	0/103	15.7	Ky/Perry	Ky/WV	1627	Apr. '77
"	Antrim	40,000	50,000	"	1508-1580	72	0/150	17.6	Mi/Ostego	Welch	Ostego I-15	Dec. '77
"	Upper/Middle Br Sh	50,000	64,000	"	2735-2777 2928-3041	154	0/350	17.5	WV/Mason	Reel Energy	D&K #3	Apr. '78

TABLE 7-SUMMARY OF E.G.S.P. CONVENTIONAL FOAM TREATMENTS AS OF 5/15/78