FIELD STUDY AND STIMULATION APPROACH: RHODA WALKER (DELAWARE) FIELD, WARD COUNTY, TEXAS

TIM LOOMIS,
DAVID BARRINGER,
and VITHAL PAI
The Western Company of North America

ABSTRACT

The rapid development of the Rhoda Walker Field (51 new wells in 1977 and 31 wells in 1976) indicates the interest in the Delaware Mountain Group pays in the Delaware Basin. Hydraulic fracturing treatments are necessary to stimulate production to a commercial level. An efficient stimulation approach has been developed, with the aid of detailed computer design studies, to produce maximum productivity in a cost-effective manner.

INTRODUCTION

The Rhoda Walker Field is located 5 miles southwest of Pyote in Ward County, Texas (see Figures 1 and 2). From discovery in 1967 with the Sinclair Oil and Gas Company's Rhoda Walker Unit No. 1, the number of producing wells increased slowly to a total of 18 at the end of 1975. This total rose to 42 by the end of 1976, 84 by the end of 1977, and 103 by the end of the first quarter of 1978. Now there are more than 140 producing wells in the field. The growth corresponds with the increase in gas and oil prices. The principle operators are Clayton Williams, Jr., HNG Oil Company, Gulf, Exxon, Petroleum Corporation of Texas, Amoco, and Continental Oil Company.

The drilling is generally on 40-acre spacing. Production in the field is highly variable, but all the wells need hydraulic fracture stimulation to bring the production up to a commercial level. After treatment, the average well in the field produces 130 barrels of oil and 253 barrels of water per day and has a 6,991/1 GOR.* In the early stages of development a number of different fluid types and techniques were tried in an effort to maximize oil production and minimize water production. It became evident that there was little difference in the results of the various techniques and the key to

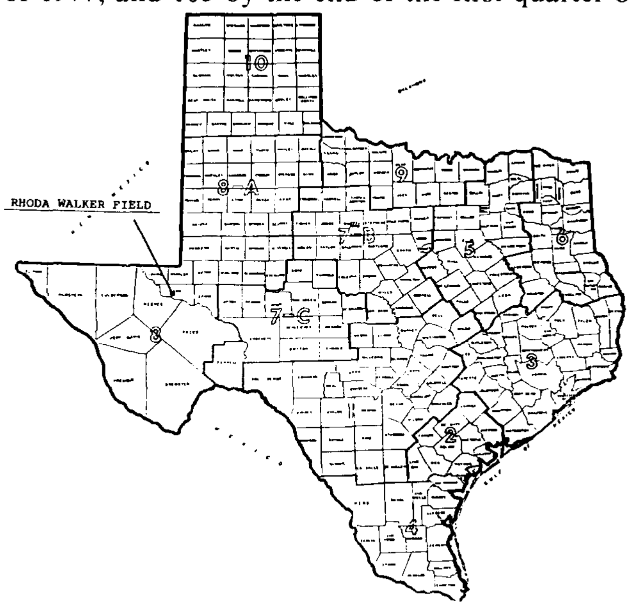


FIGURE 1

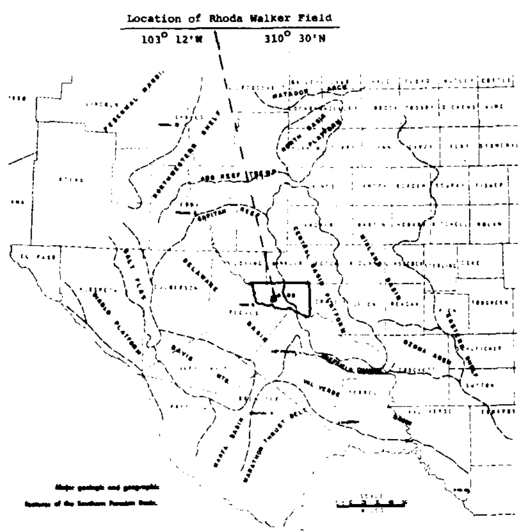


FIGURE 2

*A simple average of the wells listed in Table I

TABLE I RHODA WALKER FIELD DATA

Well Name*	TD*	Perforated Intervals*	Net Pay (ft.)*	Treatment Volumes & Type	IPP*	GOR* Ft.³/bbl.	BHT*	Frac Gradient (
Avary #5	6,800'	5,071 - 5,143'	52 (20, 32)	1,500 gal. 15% HCl 19,000 gal. XLW** 19,000 lb. 20-40 Sand				.579
		5,991 - 6,252'	100 (16, 6, 16, 44, 18)	1,500 gal. 15% HCl 49,500 gal. XLW 49,500 lb. 20-40 Sand	86 BOPD & 346 BWPD	15,116 / 1	116° F.	.561
Avary #9	6,800'	6,047 - 6,234'	55 (10, 15, 14, 16)	1,500 gal. 15% HCl 15,000 gal. XLW 15,000 lb. 20-40 Sand				.545
		5,100 - 5,133'	30 (8, 22)	1,000 gal. 15% HCl 8,000 gal. XLW 8,000 lb. 20-40 Sand	90 BOPD	2,222 / 1	118° F.	.569
Avary #11	6,800'	6,098 - 6,256'	46 (8, 16, 22)	2,000 gal. 15% HCl 35,000 gal. XLW 35,000 lb. 20-40 Sand				.529
		5,067 - 5,242'	74 (14, 8, 46, 6)	2,000 gal. 15% HCl 16,000 gal. XLW 16,000 lb. 20-40 Sand	35 BOPD & 99 BWPD	45,710 / 1	115° F.	.567
Avary #15	6,800'	6,079 - 6,293'	45 (8, 8, 10, 5, 12)	1,300 gal. 15% HCl 20,000 gal. XLW 20,000 lb. 20-40 Sand				.528
		5,069 - 5,147'	50 (16, 10, 14, 10)	1,400 gal. HCl 15,000 gal. XLW 15,000 lb. 20-40 Sand	109 BOPW & 250 BWPD	18,348 / 1	118° F.	.579
Avary #16	6,800'	6,530 - 6,670'	26 (8, 8, 10)	1,000 gal. 15% HCl 15,000 gal. XLW** 15,000 lb. 20-40 Sand				.508
		6,035 - 6,294'	94 (10, 24, 22, 20, 18)	1,500 gal. 15% HCl 55,000 gal. XLW 55,000 lb. 20-40 Sand	170 BOPW & 902 BWPD	588 / 1	118° F.	.587
Avary "123" #2	6,750'	6,049 - 6,122'	50 (6, 6, 38)	2,000 gal. 15% HCl 40,000 gal. XLW 32,000 lb. 20-40 Sand 10,000 lb. 10-20 Sand				.608
		6,237 - 6,293'	32 (8, 8, 6, 10)	1,500 gal. 15% HCl 30,000 gal. XLW 25,000 lb. 20-40 Sand 10,000 lb. 10-20 Sand				.596
		5,082 - 5,137'	15 (6, 9)	1,500 gal. HCl 40,000 gal. XLW 32,000 lb. 20-40 Sand 9,000 lb. 10-20 Sand	90 BOPD & 101 BWPD	200 / 1	108° F.	.628
Avary "123" #1	6,750'	6,212 - 6,330'		500 gal. 15% HCl 30,000 gal. XLW 24,000 lb. 20-40 Sand				.609
		6,212 - 6,250'		250 gal. 15% HCl 20,000 gal. XLW 16,000 lb. 20-40 Sand	75 BOPD & 90 BWPD	200 / 1	119° F.	.609
Avary B #1	6,800'	5,996 - 6,610'	113 (18, 6, 20, 12, 6, 22, 8, 6, 15)	2,000 gal. 15% HCl 35,000 gal. XLW ** 35,000 lb. 20-40 Sand				.529
Avary D #3	6,800'	5,955 - 6,332'	143 (45, 12, 18, 25, 16, 22, 5)	1,800 gal. 15% HCl 75,000 gal. XLW 75,000 lb. 20-40 Sand	260 BOPD	3,846 / 1	118° F.	.587
K. Avery #1	6,353'	6,023 - 6,223'		1,000 gal. 15% HCl 20,000 gal. XLW 4,000 lb. 100 Sand 22,000 lb. 20-40 Sand				.594
		5,058 - 5,144'		1,000 gal. 15% HCl 20,000 gal. XLW 4,000 lb. 100 Sand 22,000 lb. 20-40 Sand	102 BOPD & 40 BWPD	6,373 / 1	116° F.	.616
Dyer "135" #1	7,189'	6,292 - 6,393'	51 (16, 20, 15)	1,500 gal. HCl 30,000 gal. XLW 25,000 lb. 20-40 Sand 9,000 lb. 10-20 Sand				.558

TABLE I RHODA WALKER FIELD DATA (CONTINUED)

Well Name *	TD *	Perforated Intervals *	Net Pay (ft.)*	Treatment Volumes & Type	IPF *	GOR * Ft.^{3}/bbl.	BHT *	Frac Gradient (p
		6,594 - 6,686'	48 (28, 20)	1,500 gal. HCl 30,000 gal. XLW 25,000 lb. 20-40 Sand 9,000 lb. 10-20 Sand	435 BOPD	230 / 1	119° F.	.523
J. C. Gunn A #3	6,430'	6,038 - 6,328'	54 (16, 8, 14, 16)	3,000 gal. 15% HCl 50,000 gal. XLW 66,000 lb. 20-40 Sand	100 BOPD & 234 BWPD	19,500 / 1	109° F.	.591
J. C. Gunn A #4	6,800'	6,066 - 6,556'	52 (6, 8, 8, 12, 10, 8)	2,000 gal. 15% HCl 60,000 gal. XLW ** 79,500 lb. 20-40 Sand				.534
		5,080 - 5,140'	42 (12, 22, 8)	2,000 gal. 15% HCl 50,000 gal. XLW 66,000 lb. 20-40 Sand	75 BOPD & 191 BWPD	10,133 / 1	112° F.	.603
Gunther Unit #2	6,355'	6,038 - 6,225'		1,000 gal. 15% HCl 30,000 gal. XLW 46,500 lb. 20-40 Sand 13,500 lb. 100 Sand				.581
		5,067 - 5,236'		1,000 gal. 15% HCl 30,000 gal. XLW 13,500 lb. 100 Sand 46,500 lb. 20-40 Sand	81 BOPD & 40 BWPD	4,222 / 1	107° F.	.634
Kewanee "112" #1	6,650'	5,926 - 6,251'		2,000 gal. 15% HCl 60,000 gal. XLW 60,000 lb. 20-40 Sand				.550
		5,157 - 5,163'		1,000 gal. 15% HCl 17,500 gal. XLW 15,000 lb. 20-40 Sand	5 BOPD & 160 BWPD	200 / 1		.575
Middleton "124"C #3	6,700'	6,215 - 6,286'		1,000 gal. 15% HCl 27,000 gal. XLW 21,000 lb. 20-40 Sand	262 BOPD & 380 BWPD	1,527 / 1		.560
Middleton "124"C #8	6,700'	6,010 - 6,143'	50 (6, 2, 10, 32)	1,500 gal. 15% HCl 25,000 gal. XLW 27,500 lb. 20-40 Sand 7,500 lb. 10-20 Sand	10 BOPD & 290 BWPD	2,500 / 1	116° F.	.563
Monroe "116" #1	7,300'	6,153 - 6,393'	112 (20, 16, 6, 10, 26, 24, 10)	2,500 gal. 15% HCl 80,000 gal. XLW ** 66,000 lb. 20-40 Sand 25,000 lb. 10-20 Sand				.560
		6,543 - 6,710'	22 (12, 10)	1,500 gal. 15% HCl 10,000 gal. XLW 8,000 lb. 20-40 Sand 3,000 lb. 10-20 Sand	48 BOPD & 720 BWPD	1,666 / 1	119° F.	.527
Monroe "118" #A-4	6,667'	6,002 - 6,230'		3,500 gal. 15% HCl 87,000 gal. XLW 75,000 lb. 20-40 Sand				.564
		5,082 - 5,088'		500 gal. 15% HCl 14,000 gal. XLW 12,000 lb. 20-40 Sand	8 BOPD & 60 BWPD	1,875 / 1	115° F.	.635
Seale "D" #1	6,670'	6,240 - 6,243'	12	250 gal. 15% HCl 12,000 gal. XLW 10,000 lb. 20-40 Sand	14 BOPD & 85 BWPD	143 / 1	110° F.	.631
Thompson Est. #3	6,700'	5,993 - 6,296'	84 (6, 24, 28, 19, 12)	2,000 gal. 15% HCl 50,000 gal. XLW 66,000 lb. 20-40 Sand	145 BOPD & 145 BWPD	8,466 / 1	120° F.	.516
Thompson Est. #5	6,750'	5,991 - 6,252'	91 (24, 14, 15, 6, 6, 8, 8)	1,500 gal. 15% HCl 52,000 gal. XLW 52,000 lb. 20-40 Sand				.569
		5,080 - 5,143'	40 (24, 8, 8)	1,500 gal. 15% HCl 13,000 gal. XLW 13,000 lb. 20-40 Sand	195 BOPD & 400 BWPD	10,769 / 1	118° F.	.583
Thompson Est. #6	6,750'	5,990 - 6,291'	70 (10, 20, 14, 6, 6, 8, 6)	15,000 gal. HCl 40,000 gal. XLW ** 40,000 lb. 20-40 Sand				.560
		5,096 - 5,363'	67 (20, 8, 5, 8, 6, 20)	1,500 gal. 15% HCl 30,000 gal. XLW 30,000 lb. 20-40 Sand	450 BOPD & 271 BWPD	2,220 / 1	118° F.	.596

*Data taken from Petroleum Information Corporation completion cards

**XLW - cross-linked water based system

successful completions was a good cement job and selectivity in the zones perforated.[1] High water production is a characteristic of the field.

The authors have been involved with the stimulation of about 80 percent of the wells in the field and have developed, in conjunction with the operators, an efficient technique that has become the standard in the area. This paper primarily deals with the stimulation approach, but also serves as a catalog of the Rhoda Walker Field. Table 1 is a random sample of 22 wells selected for the study.

LITHOLOGY AND RESERVOIR CHARACTERISTICS

The Rhoda Walker Field production comes from the upper two formations, Cherry Canyon and Bell Canyon, of the three-member Delaware Mountain Group of Guadalupian Age. The entire group, Bell Canyon, Cherry Canyon, and Brushy Canyon, is in the order of 3,000 feet thick in this area. These formations represent surge channel and levee-overbank deposits of clastics and carbonates and they tend to occur normal to the Delaware Basin margins and extend well into the basin.[2,3] The best recent analogs to the Delaware Mountain Group are the depositional environment and mechanics occurring in the borderland basins at Southern California.

The stratigraphic form at the Bell and Cherry Canyon Formations is interbedded thinner carbonate intervals and thicker clastic units. The productive intervals in the Rhoda Walker Field are made up of very well sorted, fine-grained sandstone, siltstone and shale. Figures 3, 4, and 5 show typical gamma ray and acoustic logs of the producing intervals and Table 1 gives an indication of the number and thickness of zones.

Laboratory analyses of various core samples have been conducted. X-ray diffraction analysis indicates the presence of quartz, feldspar, and calcite, as well as chlorite and illite, as shown in Table 2. The rock is described as a fine-grained feldspathic sandstone with nonexpandable intersitial clays. Scanning Electron Micrographs (Figures 6-8) indicate that chlorite is the prevalent clay mineral present, and occurs in many pore spaces. Illite is also present in some quantity. These clay minerals tend to be dissolved and dislodged by aqueous solutions, and

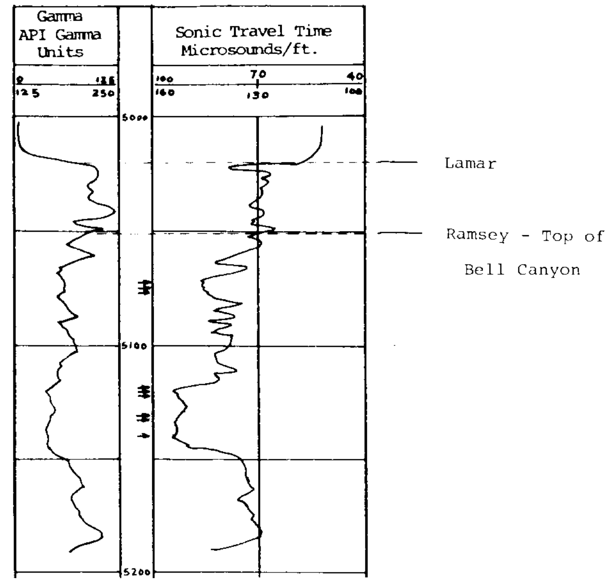


FIGURE 3

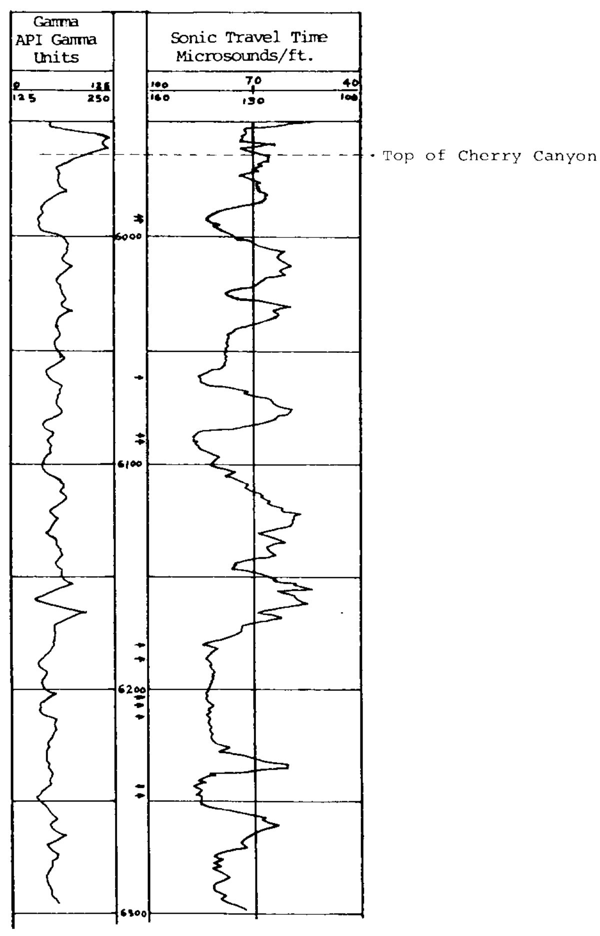


FIGURE 4

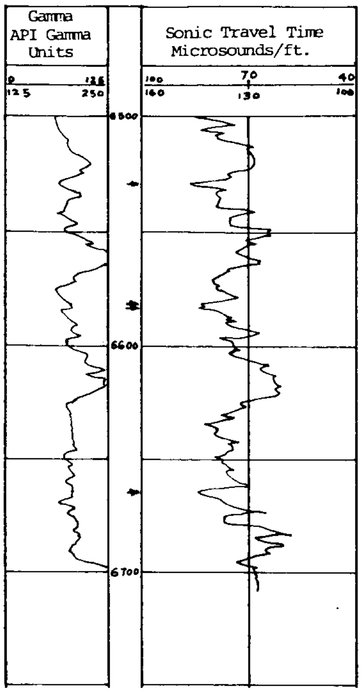


FIGURE 5

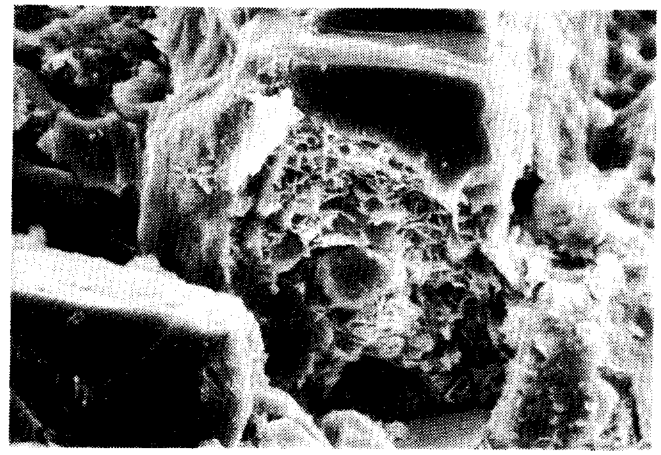


FIGURE 6 CHLORITE CLAY DEPOSIT CONSISTING OF THIN PLATELETS. FELDSPAR GRAIN PRESENT ABOVE CHLORITE. QUARTZ GRAIN PRESENT AT LOWER LEFT.

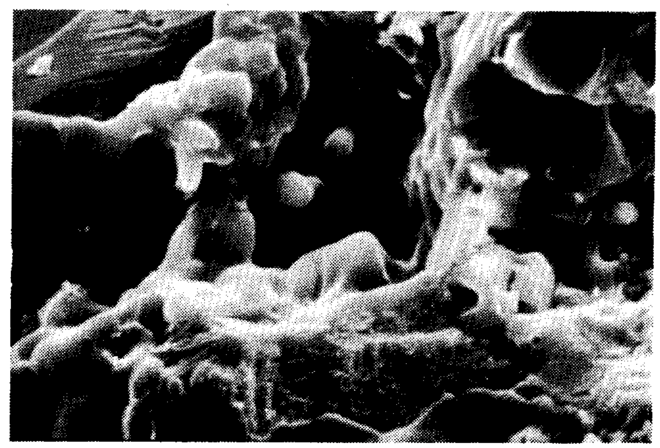


FIGURE 7—SMALL PORE BELIEVED TO BE SURROUNDED BY QUARTZ, FELDSPAR, AND CALCITE. ALL MINERALS PRESENT ARE POORLY SORTED.

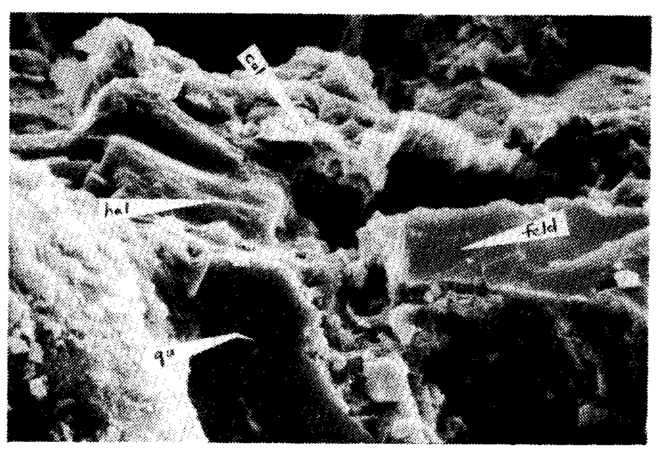


FIGURE 8—PORE SURROUNDED BY CALCITE, FELDSPAR, AND QUARTZ GRAINS AS INDICATED. HALITE (NaCl) DEPOSIT BELIEVED TO BE PRESENT AT LEFT OF PORE.

can be troublesome in the form of fines, which can cause plugging near the well bore. The use of potassium chloride brines and clay stabilizing chemicals should alleviate any associated problems.

The formation is approximately 25-percent soluble in hydrochloric acid and does contain about 1 to 1.5 percent soluble iron. Since the cementaceous material of the matrix appears to be calcareous in nature, the use of large acid volumes could cause the formation to become unconsolidated near the well bore. The presence of iron dictates a need for an iron-chelating agent.

Routine plug core and sidewall plug analysis from wells has shown that permeabilities above 5 md were the exception with most of the intervals falling in the 1 to 3 md range. Porosity values generally are 16 to 21 percent. High water saturations are characteristic and it appears that about 50 percent is the maximum for a potential productive zone. Imbibition tests have shown that the formation is water wet.[4]

A detailed analysis of fluid production was completed, and there appears to be very little pattern between production and position in the field. Contouring the top of the Cherry Canyon indicates that there is a general dip to the southeast, with a geologic high in the northwest corner of

TABLE 2 X-RAY DIFFRACTION ANALYSIS

Sample Identification	Mineral Percentages: Quartz	Feldspar	Calcite	Dolomite	Siderite	Anhydrite	Gypsum	Pyrite	Barite	Kaolinite	Illite	Chlorite	Montmorillonite	Mixed Layer Illite/Mont.	Mixed Layer Chlorite/Mont.	Total		15% HCl Solubility (%)	Soluble Iron Content (%)	
Sample Average	50	20	15								5	10				100		25.4	1.20	

Comments: The rock is a fine-grained, feldspathic sandstone with non-expandable interstitial clays.

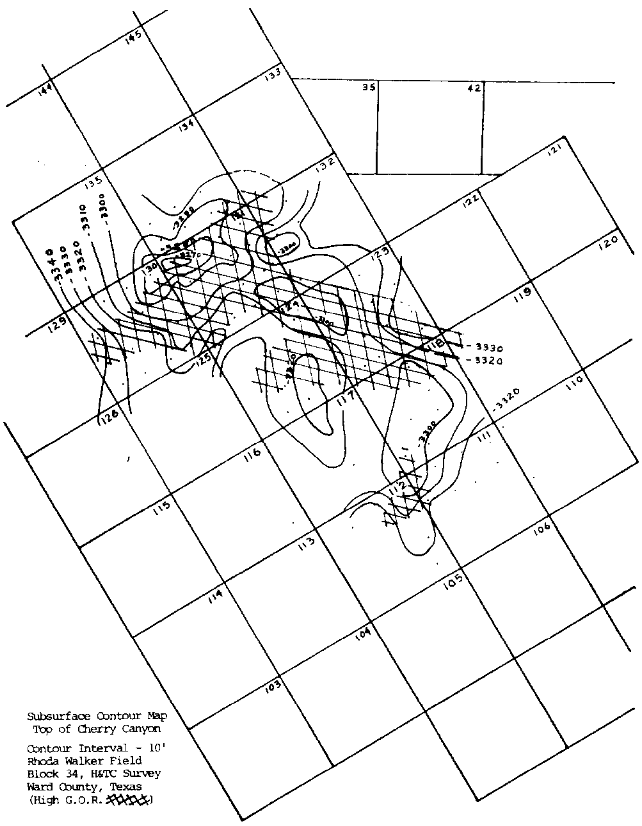


FIGURE 9

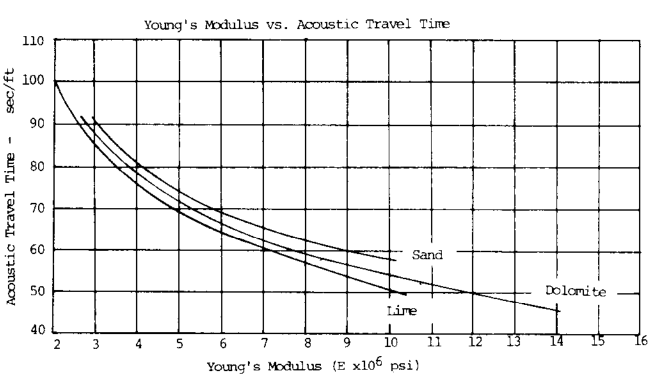


FIGURE 10

Section 131. Figure 9 shows the contour of the Cherry Canyon. The map also shows, in the shaded portion, the area of high G.O.R. (greater than 3000 cubic feet per barrel).

The average temperature gradient in the area is 0.64°F per 100 feet depth, taken from a surface temperature of 74°F. From the treatment of the wells, the average fracture gradient has been determined to be 0.60 psi/foot for the Bell Canyon and 0.56 psi/foot for the Cherry Canyon. These gradient values are well within the range of assuming a vertical fracture. The acoustic travel time gives a Young's Modulus of approximately 4.0 x 10^6 psi (Figure 10).

RESERVOIR FLUID CHARACTERISTICS

The fluid from the Rhoda Walker Field is very representative of other Delaware Basin pays in the Delaware Mountain Group. The produced water has high dissolved solids content, 9.7 to 9.8 pounds per gallon, and is corrosive due to its acidic nature. There has been no evidence of scaling but ion concentrations are such that calcium carbonate and calcium sulfate scales are a possibility. Table 3 is a composite water analysis from nine wells scattered throughout the field.

The oil phase taken from the field falls in the 36° to 47° API gravity range. There are slight paraffin components, but they have not proven to be a major problem.

TABLE 3 WATER ANALYSIS COMPOSITE OF 9 SAMPLES FROM THE WESTERN COMPANY SERVICE LABORATORY

Iron	Fair Trace
Sodium and Potassium	63,572 ppm
Calcium	27,022 ppm
Magnesium	3,294 ppm
Chloride	155,333 ppm
Bicarbonate	143 ppm
Sulfate	264 ppm
Hydrogen Sulfide	None
Density	1.173 @ 79° F.
Resistivity	0.047 @ 79° F.
pH	6.0

Table 4 is representative of the gas taken from the field. There are three pressure systems in the field: high pressure — greater than 850 psi; intermediate — 400 psi or more; low pressure — 40 to 50 psi. As would be expected, there is an increase in the heavier factions and BTU content as the producing pressure decreases. The H_2S content is variable, and some of the gas needs treatment prior to entering the pipeline.

Figure 11 gives a production decline curve of a typical Rhoda Walker well.

TREATMENT TECHNIQUE

Once the zone or zones of interest are selected, perforating and stimulation programs are generated. A majority of the wells were treated using a limited entry technique for each of the zones of interest. An injection rate of 2 BPM per perforation was adopted to achieve a differential pressure of approximately 400 psi.[5] Starting from the lowest productive zone, the pays were successively isolated, perforated, acidized, and fractured. The fracture fluid volume is determined from computer studies, as discussed under "Computer Aided Stimulation Design". Each zone was individually tested for production prior to completion in the next successive interval. Weighted brine (11 pounds per gallon) was used as flush to act as a "kill" fluid to facilitate running in with tubing for load recovery. An example completion procedure is listed in the following section.

The majority of the treatments performed in the Rhoda Walker Field during the late developmental stage have been water-base gels (more specifically, cross-linked guar gum systems). One operator in the southern portion of the field has pumped a gelled hydrocarbon system. The primary consideration for choosing a particular fluid system (assuming such properties as effective viscosity, sand transport capability, and friction reduction properties are relatively equal) lies in the compatibility of the fluid to the formation and to the reservoir fluids. Based on the above core studies, it was determined that a properly treated water-based system could indeed be utilized with minimum incompatibility problems.

TABLE 4 AVERAGE GAS CHROMATOGRAPH ANALYSIS FROM WOLF PETRO LAB, INC.

	High Pressure Mol. %	Intermediate Pressure Mol. %	Low Pressure Mol. %
CO_2	.18	.18	.15
N_2	5.70	7.00	2.69
Methane	82.16	77.47	65.05
Ethane	6.52	8.10	12.11
Propane	3.13	4.41	9.68
iso Butane	.52	.55	1.94
N-Butane	.95	1.26	4.56
iso-Pentane	.34	.30	1.23
N-Pentane	.29	.29	1.14
Hexanes	.23	.38	1.45
H_2S (gr)	2.76	.42	3.27
BTU (wet)	1092	1119	1432

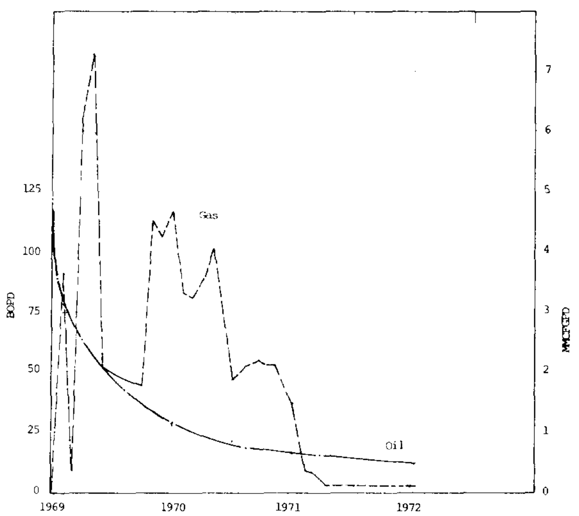


FIGURE 11 TYPICAL PRODUCTION DECLINE CURVE

SAMPLE TREATMENT PROCEDURE

1. Run in hole with tubing to base of the Lower Cherry Canyon.
2. Circulate hole with 2 percent KCl Water and spot double-inhibited hydrochloric acid across Lower Cherry Canyon interval.
3. Pull tubing, then perforate selectively with ±10 holes.
4. Run in hole with tubing and packer to ±50 feet above acid level.
5. Breakdown and acidize with 1,000 gal. 15 percent Acid (±100 gallons per perforation). Stage the acid with ball sealers and attempt to ball-out.
6. Flush with 2 percent KCl Water.
7. Pull tubing and packer.
8. Frac the Lower Cherry Canyon with sufficient fluid to attain a frac radius of ±530 feet at 20 BPM for limited entry.
9. Flush with weighted $CaCl_2$ water.

10. Shut-in overnight.
11. Run in hole with tubing and swab or flow back to recover load.
12. Test for production.
13. Run in hole with retrievable bridge plug and set above Lower Cherry Canyon perforations.
14. Complete Upper Cherry Canyon and/or Bell Canyon similar to the above procedure.
15. After sufficient test period, the various zones are then commingled and placed on rod pump where necessary.

TABLE 5 RESERVOIR PROPERTIES

Average Bottom Hole Temperature	118° F.
Frac Heights Considered	20', 30', 40' and 50'
Thermal Gradient	0.64° F./100 feet
Average Formation Permeability	3 md.
Average Formation Porosity	16%
Average Bottom Hole Pressure	2,500 psi
Average Acoustic Transit Time	81 μ sec./foot
Rock Young's Modulus	4.0×10^6 psi
Average Well Depth	6,800'
Reservoir Fluid Viscosity	2.8 cp
Reservoir Fluid Gravity	40° API
Average G.O.R.	7,000 SCF/bbl.
Average Frac Gradient	0.56 psi/foot
Drainage Radius	660'
Formation Permeability to Frac Fluid	1.8 md (estimated)

TABLE 6—FRAC FLUID PROPERTIES AT BOTTOM HOLE CONDITIONS

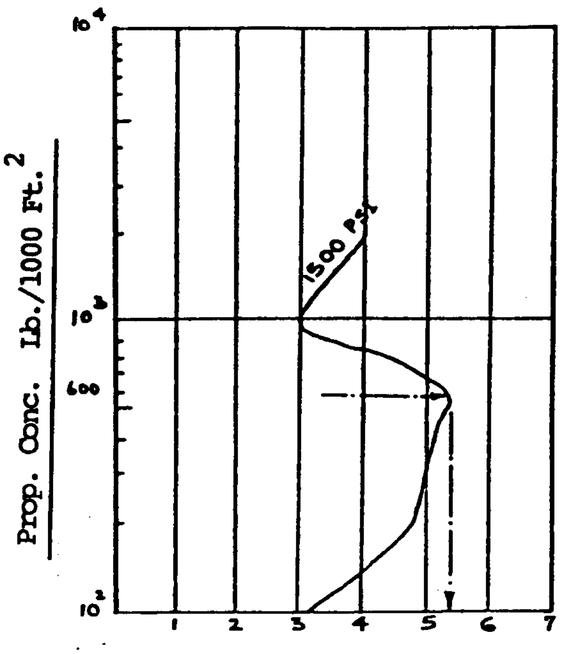
Fluid Leak-off Viscosity	1.0 cp.
Spurt Loss	0.0
n'	0.425
k'	$0.06\ lb_f \cdot sec.^{n'}/ft.^2$
Specific Gravity	1.02
Specific Heat	1.00 BTU/lb.f
Fluid Leak-off Coefficient C_{III}	0.003

COMPUTER AIDED STIMULATION DESIGN

A computerized study [6,7] was conducted to determine the fluid volumes required to optimize the productivity increase contrast (J/J_o). The fracture heights used for design purposes were varied from 20 to 50 feet. The proppant concentrations (Figure 12) were maintained at 5.3 darcy-feet, which is the maximum conductivity possible at an overburden pressure of 1,500 psi. From Figure 12 it can be seen that the proppant concentration required to achieve a conductivity of 5.3 darcy-feet is 600 pounds per 1,000 feet^2.

The following parameters were assumed for purposes of the study.

The results of the computer study are presented in Table 7 and plotted in Figure 14. Figure 15 shows productivity increase contrast as a function of penetration[6]. It can be seen from Figure 15 that L/r_e ratios in excess of 0.8 provide very little productivity increase contrast increase. The frac treatment, therefore, should be designed to provide a fracture length of 528 ft (0.8 x 600 ft drainage radius). The actual treatments by and large were designed to achieve a fracture length of 530 ft. From Figure 12,



Conductivity - Darcy - Ft.
20-40 Mesh Sand Conductivity

FIGURE 12

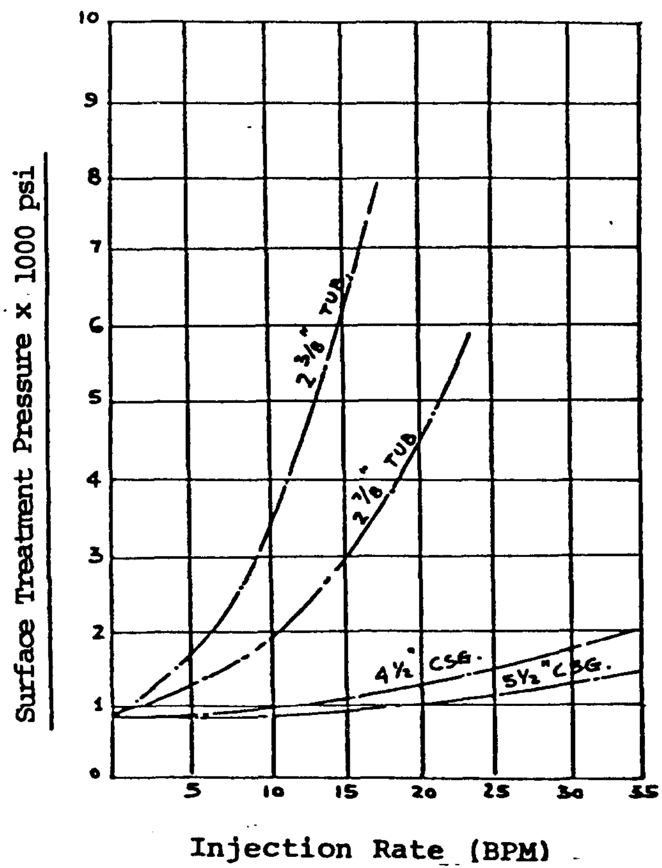
it can be seen that conductivity is mazimized at sand concentration of 600 pounds per 1,000 feet^2. The amount of sand to be pumped is calculated as follows.

Sand (lb.) = 2 H x L x sand concentration lb/ft^2

The amount of sand to be pumped in a 50 foot fracture is calculated as follows.

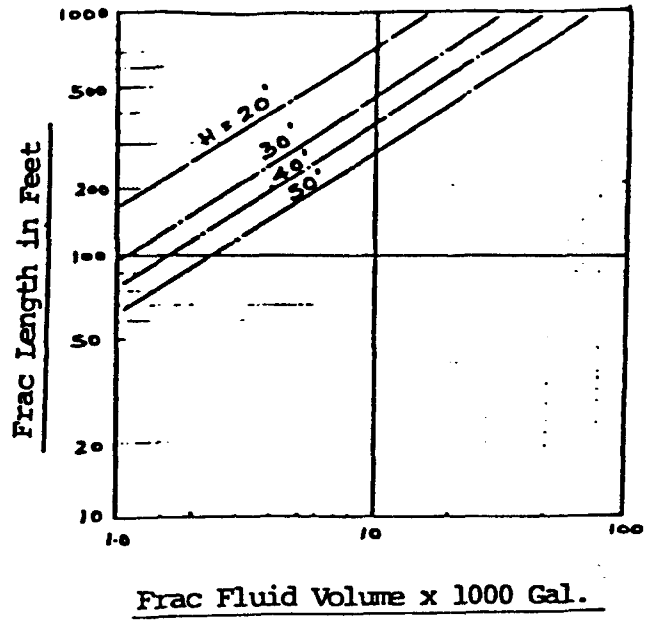
Sand (lb.) = 2 x 50 x 530 x .6 lb/ft^2
= 31,800 lb

All frac treatments should be designed using the above guidelines.



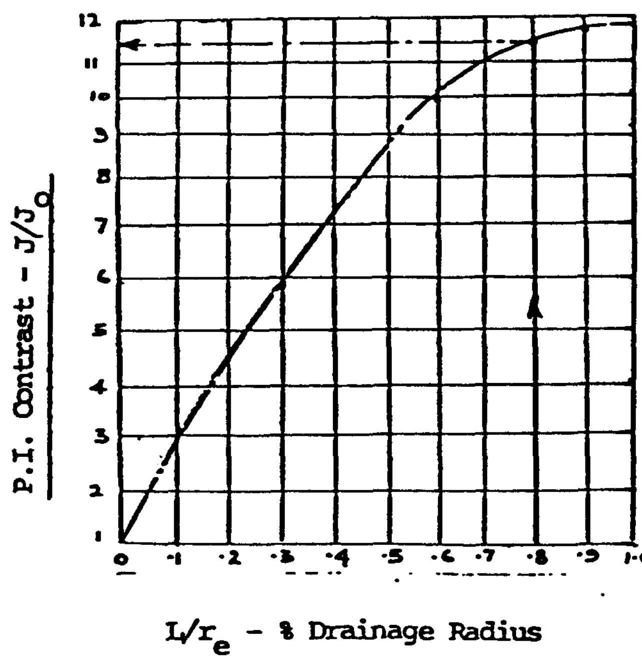
Cross-linked Gel Treatment Pressure

FIGURE 13



Volume versus Penetration

FIGURE 14



P.I. Contrast vs. Penetration

FIGURE 15

TABLE 7

Frac Height Feet	Fluid Volume Gallons	Frac Length Feet	Frac Width Inches	L/r_e	P.I. Contrast $\times 10^4$	J/J_o
20	800	132	.139	.2	2.12	4.3
20	1,420	198	.168	.3	2.12	5.8
20	2,150	264	.186	.4	2.12	7.2
20	4,000	396	.215	.6	2.12	9.9
20	6,400	528	.238	.8	2.12	11.4
20	7,700	594	.247	.9	2.12	11.9
30	1,600	132	.166	.2	2.12	4.3
30	3,000	198	.190	.3	2.12	5.8
30	4,500	264	.218	.4	2.12	7.2
30	8,200	396	.236	.6	2.12	9.9
30	12,800	528	.263	.8	2.12	11.4
30	14,400	594	.270	.9	2.12	11.9
40	1,900	132	.164	.2	2.12	4.3
40	3,320	198	.194	.3	2.12	5.8
40	5,900	264	.221	.4	2.12	7.2
40	11,400	396	.248	.6	2.12	9.9
40	18,000	528	.271	.8	2.12	11.4
40	21,900	594	.285	.9	2.12	11.9
50	3,100	132	.180	.2	2.12	4.3
50	5,800	196	.203	.3	2.12	5.8
50	9,000	264	.222	.4	2.12	7.2
50	17,000	396	.258	.6	2.12	9.9
50	26,500	528	.284	.8	2.12	11.4
50	32,000	594	.298	.9	2.12	11.9

SUMMARY

In summary, we have noted several things about the completion techniques of the Rhoda Walker Delaware Field.

1. The three zones in question (Upper and Lower Cherry Canyon and Bell Canyon) can be highly productive if sound drilling and completion practices are observed.
2. The various sands require hydraulic fracturing to establish production at commercial levels.
3. Properly treated, water-based fluids can be utilized as efficient, non-damaging fracturing fluids. This fact has been substantiated by core studies of the formation(s) in question.
4. With the aid of computer modeling, we can optimize fracture treatment size and hydraulic horsepower requirements to attain maximum productivity.

NOMENCLATURE

- H = Fracture Height, Ft.
- J = Productivity Index after Fracturing
- J_o = Productivity Index before Fracturing
- k = Formation Permeability to Reservoir Fluid, md.
- k_f = Proppant Pack Permeability to Reservoir Fluid, md.
- L = Frac Length from Well Bore, ft.
- r_e = Drainage Radius of the Well, ft.
- W = Propped Fracture Width, in.
- Wk_f = Conductivity of the Fracture, md.-in.

REFERENCES

1. Conversations with Bill Carisle (HNG) and Clint Atkins (Clayton Williams, Jr.)
2. Beck, Ray Hall: "Depositional Mechanics of the Cherry Canyon Formation (Lower Permian), Delaware Basin, Texas," Master's, Texas Tech University (1967).
3. Pitts, J.P.: "Surge Channels may still hold Rich Deposits of Hydrocarbons," *Drill Bit* (July 1978).
4. Jenkins, R.E.: "Characteristics of the Delaware Formation," *Journal of Petroleum Technology* (Dec. 1961).
5. "Engineered Limited Entry," a Western Company Publication.
6. Western Company Stimulation Program Library
7. Craft, B.C., and Holden, W.R., and Graves, E.D., Jr.: *Well Design Drilling and Production*, Prentice-Hall, Inc., Englewood Cliffs (1962) 483-533.