A COMPARISON OF MEASURED VERSUS PREDICTED MODEL FRACTURE HEIGHT IN THE SAN ANDRES FORMATION

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ABSTRACT

This paper presents a discussion of fracture height measured with gamma ray and temperature surveys and fracture height predicted with a real-time model during the pumping of a fracture treatment. The San Andres formation was fracture stimulated in six West Texas wells. Each treatment was pumped down the annulus with open ended tubing in the hole. The open ended tubing pressure was monitored to obtain direct measurement of bottomhole treating pressure. Throughout each treatment a real-time quasi 3D fracture model was run to predict fracture geometry. After each treatment, gamma ray surveys were run to determine fracture height. A temperature survey was also run in three of the wells. Excellent agreement was obtained between the post stimulation survey fracture height and the quasi 3D model predicted fracture height.

INTRODUCTION

Fracture stimulation of the San Andres formation is a normal completion practice. In this study, each well was perforated for limited entry stimulation. Thirteen to 15 holes were shot in each well over 120 to 200 foot intervals. The treatments were pumped at 30 BPM using a borate crosslinked hydroxypropyl guar system and oil soluble resin for matrix fluid loss control. A total of 100,000 to 180,000 pounds of 12/20 mesh frac sand was used to prop the fracture created by each treatment. After each treatment, a gamma ray survey was run to measure fracture height. A temperature survey was also run in three wells. Comparison of the post stimulation survey fracture height to the model predicted fracture height gave excellent agreement.

QUASI 3D MODEL

Description

The determination and interpretation of bottomhole treating pressure has become an important factor in the fracture stimulation of oil and gas wells. Qualitative analysis of fracture propagation by many authors has been performed by using the real-time net bottomhole treating pressure. A quantitative analysis of real-time net bottomhole treating pressure is accomplished with a real-time quasi 3D fracture model. The net bottomhole treating pressure is used to initiate an interative technique to solve for the unique solution of fracture height, width and length at selected time intervals during the treatment.

Input data for the model are fracturing fluid, n', K' and combined fluid loss coefficient, Cc. Formation properties required are Young's modulus and Poisson's ratio. The model can depict height growth equally

upward and downward or predominately upward or downward based on the ratio of confining stresses above and below the pay zone. For example, if the upper confining stress was 500 psi and the lower confining stress 1000 psi, the fracture height would be depicted as growing upward 2 feet and downward 1 foot for every 3 feet of height growth modeled.

Equipment

Data acquisition and signal conditioning is accomplished with a standard digital frac monitor. The monitor is a microprocessor based unit with built-in high speed mathematical capabilities to continuously monitor process signals and deliver smooth data display. A technical computer with expanded memory and a microfloppy disc drive are the center of the system to determine net bottomhole treating pressure. Averaging of real-time data and calculations required for net bottomhole treating pressure are performed. Data display is accomplished via two 19-inch high resolution color monitors, an eight-pen bed plotter and a thermal printer. The net bottomhole pressure plot is plotted real-time on the bed plotter.

The real-time quasi 3D fracture model is run on an IBM-compatible computer obtaining data from the technical computer or standard digital frac monitor. A math co-processor is installed in the computer to reduce solution time for fracture geometry. A 14-inch EGA monitor is used to display an interchangeable fracture geometry screen and net bottomhole pressure plot. The amount of fluid/slurry pumped, fracture geometry, and proppant concentration (lb/ft^2) in the fracture are graphically displayed on the fracture geometry screen. A text window displays the elapsed job time, surface treating pressure, injection rate, proppant concentration, net bottomhole treating pressure and model fracture height, width and length. The net bottomhole pressure plot contains a semi-log plot overlay of surface treating pressure, injection rate and proppant concentration.

A 12-inch amber monitor is used to display text information of fluid stages in the fracture, total fluid/slurry barrels and pounds of proppant pumped. Average surface treating pressure and rate are also displayed. A black and white printer tabulates the elapsed job time, geometry information and measured parameters each time the geometry is updated. A color printer can be used to plot the fracture geometry screen or net pressure screen during the treatment without interrupting collection of data. The color printer is also used to generate a summary report after the treatment.

DISCUSSION

General

Each of the six treatments were pumped down the annulus of 2.375 inch (1.995 inch I.D.) tubing and 5.5 inch (5.012 inch I.D.) casing. The tubing was filled with 2% KCl water before the treatment and a pressure transducer installed to monitor the open ended tubing pressure. A hydrostatic head pressure, from the midpoint of the perforations to the surface, was added to the pressure measured at the surface of the open ended tubing. The bottom of the open ended tubing was set about 100 feet above the top

perforation in each of the six treatments. The use of the open ended tubing enabled the real-time quasi 3D fracture model to incorporate accurate bottomhole treating pressure information into the geometry calculations.

Variable time intervals for updating the fracture geometry model can be selected by the operator. In this case, the model recalculated fracture geometry, fluid interfaces, proppant concentration in the fracture at 10 or 20 second intervals as selected by the operator prior to each treatment. The reservoir parameters of the San Andres formation for the six wells in this study are listed in Table I. The fracture treatment and fracturing fluid parameters for these treatments may be found in Table II.

Well Number 1

Figures 1 and 2 are the fracture geometry and net pressure plots from the real-time quasi 3D model. The model predicts a wellbore fracture height of 191 feet at completion of the treatment. The post treatment gamma ray survey, Figure 3, indicates a total fracture height of about 200 feet. Table III is a text output of the fluid interfaces, the stage and total barrels of slurry pumped and the pounds of proppant pumped.

Well Number 2

The fracture geometry and net bottomhole pressure plots are Figures 4 and 5. The post treatment gamma ray survey, Figure 6, indicates a fracture height of about 150 feet compared to 165 feet predicted by the model at the end of the treatment. Table IV provides the fluid and proppant summary and position of each fluid stage in the fracture.

Well Number 3

The post treatment temperature and gamma ray survey, Figure 9, indicates about 175 feet of fracture height. Figures 7 and 8 are the fracture geometry and net bottomhole pressure plots. The model predicted a fracture height of 192 feet at the end of the treatment. Table V contains the amount of fluid and proppant pumped on this treatment and position of each fluid stage in the fracture.

Well Number 4

The model predicted a fracture height of 173 feet at the end of the treatment as shown in Figures 10 and 11. The post treatment temperature and gamma ray survey, Figure 12, indicate a fracture height of about 180 feet. Table VI contains proppant and fluid quantities pumped during the treatment.

Well Number 5

The post treatment gamma ray survey, Figure 15, indicates a fracture height of about 180 feet. The quasi 3D model plots, Figures 13 and 14, predict a fracture height of 191 feet at the end of the treatment. Proppant and fluid information may be found in Table VII.

Well Number 6

The model predicted a fracture height of 182 feet at the end of the treatment as depicted in Figures 16 and 17. The post treatment gamma ray and temperature surveys, Figure 18, indicate a fracture height of about 180 feet. Table VIII contains information on total stage and total fluid and proppant pumped during the treatment.

CONCLUSIONS

1. The real-time quasi 3D model prediction of fracture height matched the fracture height obtained with post fracture treatment temperature and gamma ray surveys.

2. The real-time quasi 3D model based on net bottomhole treating pressure can be used to accurately predict fracture height while a treatment is being pumped.

ACKNOWLEDGEMENT

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2. Nolte, K. G. and Smith, M. B.: "Interpretation of Fracturing Pressures," J. Pet. Tech. (Sept., 1981) 1767-1775.

3. Mack, D. J. and Baumgartner, S. A.: "Friction Pressure of Foamed Stimulation Fluids Evaluated with an On-Site Computer," paper SPE 15631, presented at the 61st Annual Technical Conference and Exhibition, New Orleans, Oct. 5-8, 1986.

4. Baumgartner, S. A. and Mack, D. J.: "On-Site Computer Monitoring of Foamed Stimulation Fluids," paper SPE 17531, presented at the Rocky Mountain Regional Meeting, Casper, May 11-13, 1988.

Table I
San Andres Formation Reservoir Parameters

Depth, feet	2000-2300
Permeability to Reservoir Fluid, md	1.5
Porosity, percent	15
Reservoir Fluid	Oil
Reservoir fluid viscosity, cP	1.0
Reservoir Pressure, psi	800
Bottomhole Static Temperature, deg F	90-95
Bottomhole Fracture Pressure, psi	2000
Bottomhole Closure Pressure, psi	1150
Reservoir Fluid Compressibility, psi^{-1}	.0003
Young's Modulus	5.1-5.5 E6
Poisson's Ratio	.27

Table II
Treatment and Fracturing Fluid Parameters

Volume, gallons	27,000-40,000
Pump Rate, bbl/min	30
Polymer Loading, lb/1000 gal	30
Oil Soluble Resin, lb/1000 gal	25
n'	.30
K', lbf $sec^{n'}/ft^2$	.71
Cc, $ft/(min)^{\frac{1}{2}}$	.00076-.00085
12/20 sand, lb	104,000-177,000

Table III
Geometry, Fluid and Proppant Summary — Well No. 1

«««««««««««« THE WESTERN COMPANY OF NORTH AMERICA -- QUASI 3D MODEL »»»»»»»»»»»»
ELAPSED TIME = 43.90 min. AVE. STP. = 2048 psi. AVE. RATE = 27.6 bpm.
HEIGHT = 191 ft. WIDTH = 0.568 in. WING LENG = 321 ft.

STAGE no.	TIME min.	LENGTH ft.	START ft.	END ft.	EXPOSURE min.	PROP lb/sqft.	SLRY bbls.	PROP lbs.
1	12.22	95	227	321	40.6	0.00	336	100
2	19.48	55	172	227	28.8	1.29	203	27745
3	25.15	43	129	172	21.6	2.06	158	33307
4	32.60	60	69	129	15.9	2.37	203	51381
5	41.07	69	0	69	8.3	2.60	224	64220

NET PRESSURE = 1229 psi. NET PRESSURE SLOPE = -1.67
TOTAL SLURRY = 1160 bbls. TOTAL PROP = 177213 lbs.

Table IV
Geometry, Fluid and Proppant Summary — Well No. 2

«««««««««««« THE WESTERN COMPANY OF NORTH AMERICA -- QUASI 3D MODEL »»»»»»»»»»»»
ELAPSED TIME = 33.43 min. AVE. STP. = 1905 psi. AVE. RATE = 28.2 bpm.
HEIGHT = 165 ft. WIDTH = 0.505 in. WING LENG = 311 ft.

STAGE no.	TIME min.	LENGTH ft.	START ft.	END ft.	EXPOSURE min.	PROP lb/sqft.	SLRY bbls.	PROP lbs.
1	9.70	92	219	311	30.3	0.00	282	2110
2	14.20	46	173	219	21.1	1.08	131	16232
3	19.20	50	123	173	16.4	1.81	144	30326
4	25.87	71	52	123	11.4	2.15	189	49184
5	30.27	52	0	52	4.7	2.14	111	26872

NET PRESSURE = 1005 psi. NET PRESSURE SLOPE = 0.00
TOTAL SLURRY = 894 bbls. TOTAL PROP = 124981 lbs.

Table V
Geometry, Fluid and Proppant Summary — Well No. 3

«««««««««««« THE WESTERN COMPANY OF NORTH AMERICA -- QUASI 3D MODEL »»»»»»»»»»»»
ELAPSED TIME = 34.18 min. AVE. STP. = 1720 psi. AVE. RATE = 30.7 bpm.
HEIGHT = 192 ft. WIDTH = 0.537 in. WING LENG = 287 ft.

STAGE no.	TIME min.	LENGTH ft.	START ft.	END ft.	EXPOSURE min.	PROP lb/sqft.	SLRY bbls.	PROP lbs.
1	8.07	77	211	287	31.3	0.00	247	623
2	14.07	52	158	211	23.0	1.33	188	28109
3	19.07	45	113	158	17.0	1.95	156	33396
4	23.57	42	72	113	12.0	2.22	138	34955
5	31.60	72	0	72	7.5	2.62	243	70760

NET PRESSURE = 874 psi. NET PRESSURE SLOPE = -0.93
TOTAL SLURRY = 999 bbls. TOTAL PROP = 167976 lbs.

Table VI
Geometry, Fluid and Proppant Summary — Well No. 4

«««««««««««« THE WESTERN COMPANY OF NORTH AMERICA -- QUASI 3D MODEL »»»»»»»»»»»»
ELAPSED TIME = 26.73 min. AVE. STP. = 1934 psi. AVE. RATE = 30.1 bpm.
HEIGHT = 173 ft. WIDTH = 0.489 in. WING LENG = 261 ft.

STAGE no.	TIME min.	LENGTH ft.	START ft.	END ft.	EXPOSURE min.	PROP lb/sqft.	SLRY bbls.	PROP lbs.
1	6.40	69	192	261	24.1	0.00	198	329
2	9.07	27	165	192	17.7	1.14	83	10872
3	12.90	41	124	165	15.0	1.70	118	23527
4	18.40	61	63	124	11.2	2.03	163	40347
5	24.40	63	0	63	5.5	2.21	175	49047

NET PRESSURE = 1028 psi. NET PRESSURE SLOPE = -0.97
TOTAL SLURRY = 766 bbls. TOTAL PROP = 124123 lbs.

Table VII
Geometry, Fluid and Proppant Summary — Well No. 5

«««««««««««« THE WESTERN COMPANY OF NORTH AMERICA -- QUASI 3D MODEL »»»»»»»»»»»»
ELAPSED TIME = 31.20 min. AVE. STP. = 1816 psi. AVE. RATE = 29.7 bpm.
HEIGHT = 191 ft. WIDTH = 0.520 in. WING LENG = 269 ft.

STAGE no.	TIME min.	LENGTH ft.	START ft.	END ft.	EXPOSURE min.	PROP lb/sqft.	SLRY bbls.	PROP lbs.
1	7.70	69	200	269	29.1	0.00	226	142
2	13.37	49	151	200	21.8	0.84	174	18828
3	16.70	32	120	151	16.2	1.74	100	19632
4	22.53	54	66	120	12.7	2.19	171	42930
5	29.37	66	0	66	6.8	2.36	195	54860

NET PRESSURE = 1025 psi. NET PRESSURE SLOPE = 0.00
TOTAL SLURRY = 904 bbls. TOTAL PROP = 137862 lbs.

Table VIII
Geometry, Fluid and Proppant Summary — Well No. 6

«««««««««««« THE WESTERN COMPANY OF NORTH AMERICA -- QUASI 3D MODEL »»»»»»»»»»»»
ELAPSED TIME = 31.90 min. AVE. STP. = 1570 psi. AVE. RATE = 30.0 bpm.
HEIGHT = 182 ft. WIDTH = 0.518 in. WING LENG = 284 ft.

STAGE no.	TIME min.	LENGTH ft.	START ft.	END ft.	EXPOSURE min.	PROP lb/sqft.	SLRY bbls.	PROP lbs.
1	7.37	70	214	284	29.1	0.00	221	279
2	13.70	59	155	214	22.0	0.93	196	22099
3	17.37	36	119	155	15.7	1.68	111	21302
4	19.87	22	97	119	11.9	2.09	73	17738
5	29.03	97	0	97	9.5	1.29	281	42435

NET PRESSURE = 764 psi. NET PRESSURE SLOPE = -2.43
TOTAL SLURRY = 914 bbls. TOTAL PROP = 104249 lbs.

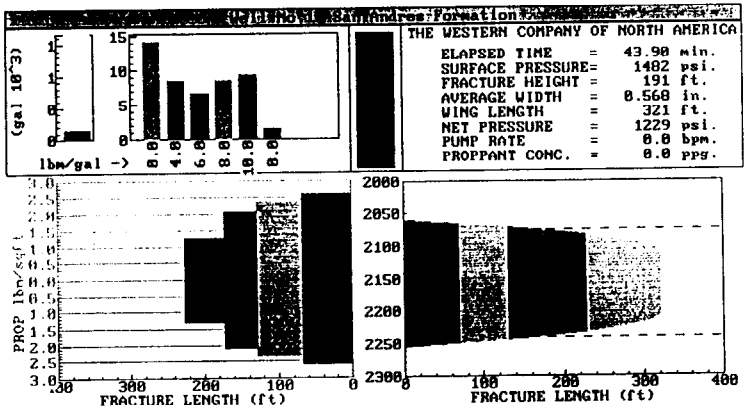

Figure 1 — Fracture geometry plot
(Well No. 1)

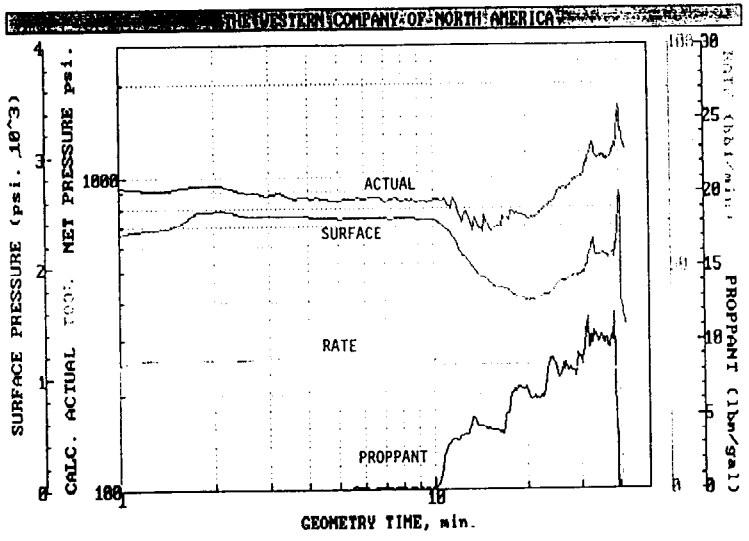

Figure 2 — Net bottomhole pressure plot
(Well No. 1)

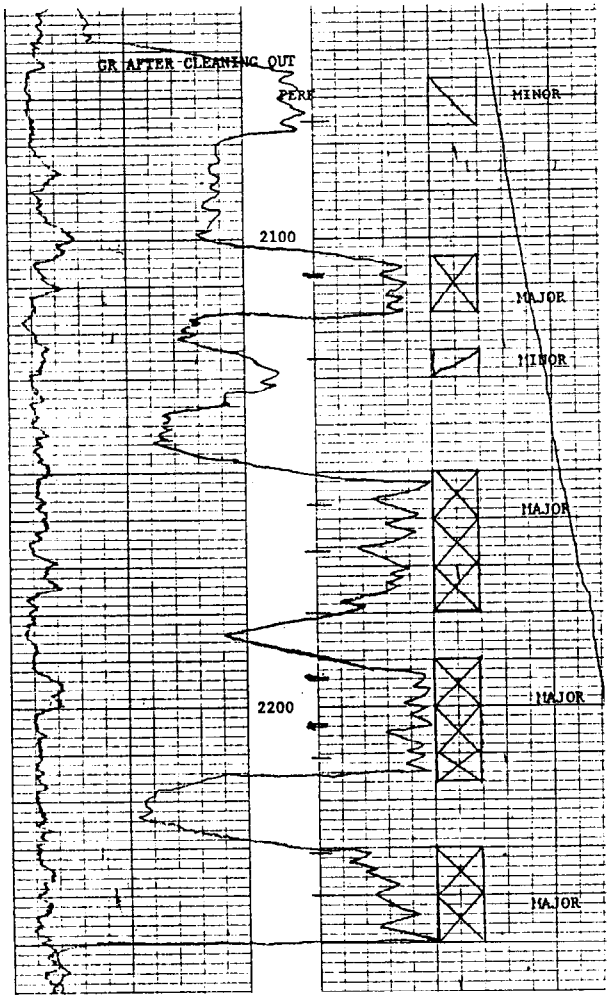

Figure 3 — Post treatment surveys
(Well No. 1)

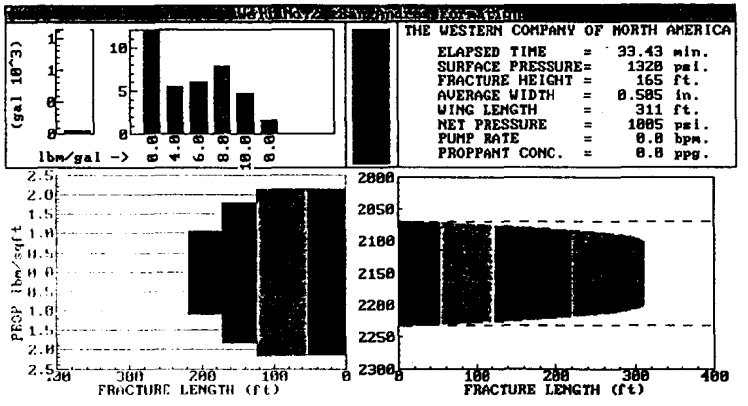

Figure 4 — Fracture geometry plot
(Well No. 2)

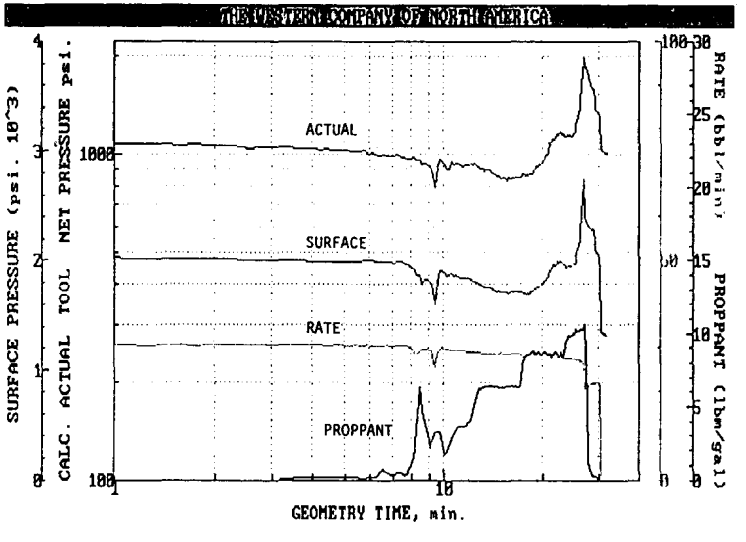

Figure 5 — Net bottomhole pressure plot
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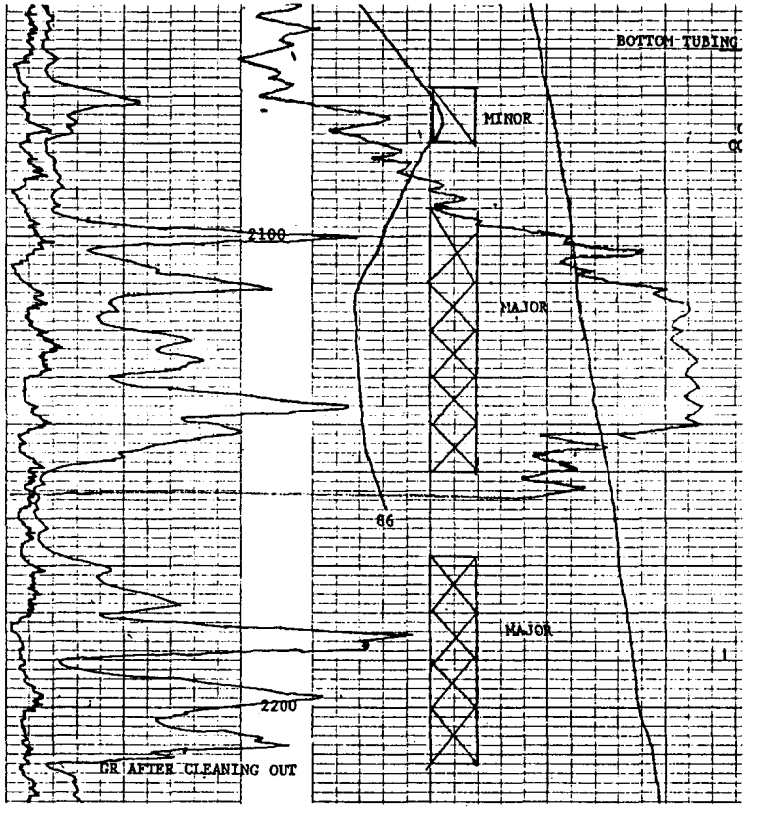

Figure 6 — Post treatment surveys
(Well No. 2)

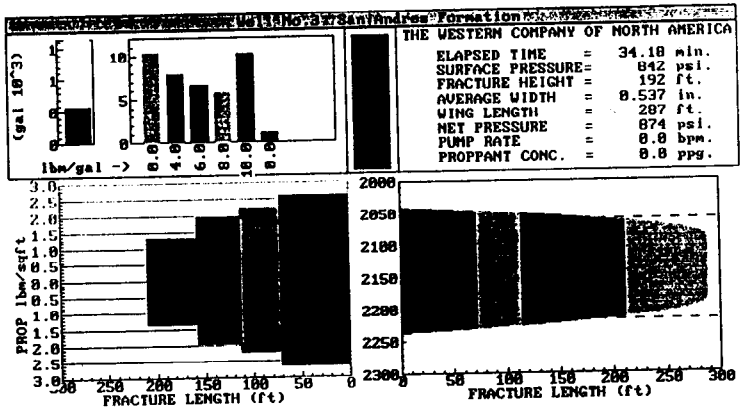

Figure 7 — Fracture geometry plot
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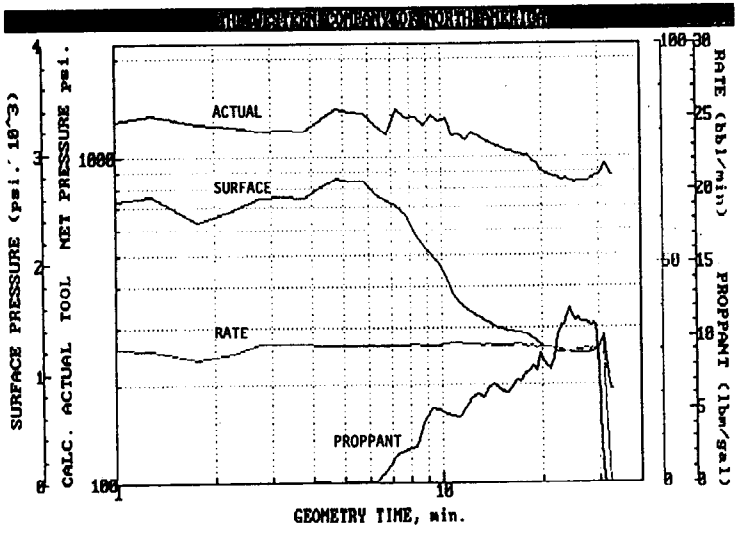

Figure 8 — Net bottomhole pressure plot
(Well No. 3)

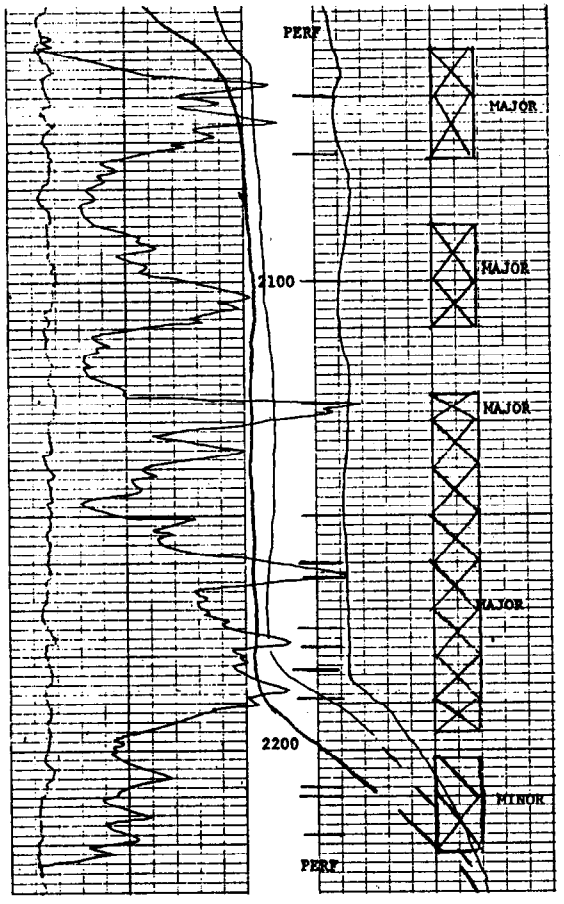

Figure 9 — Post treatment surveys
(Well No. 3)

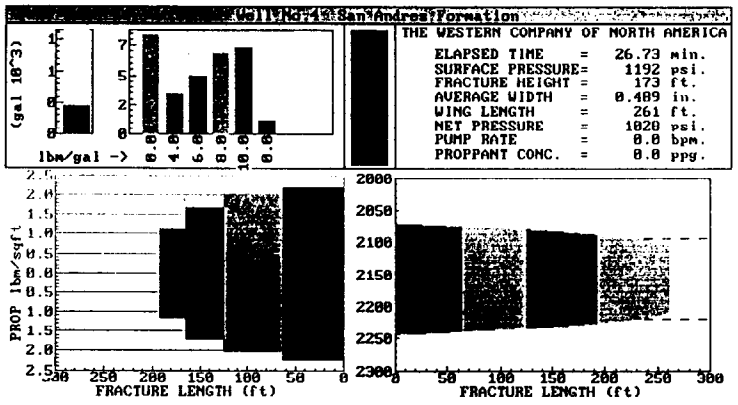

Figure 10 — Fracture geometry plot
(Well No. 4)

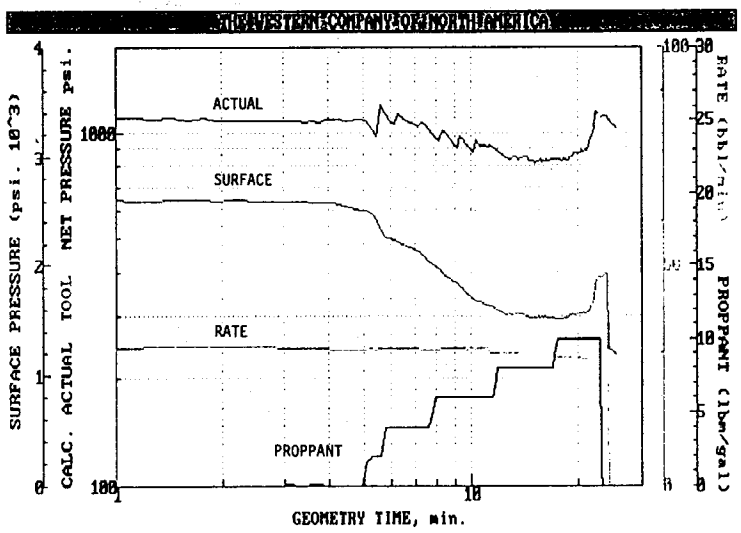

Figure 11 — Net bottomhole pressure plot
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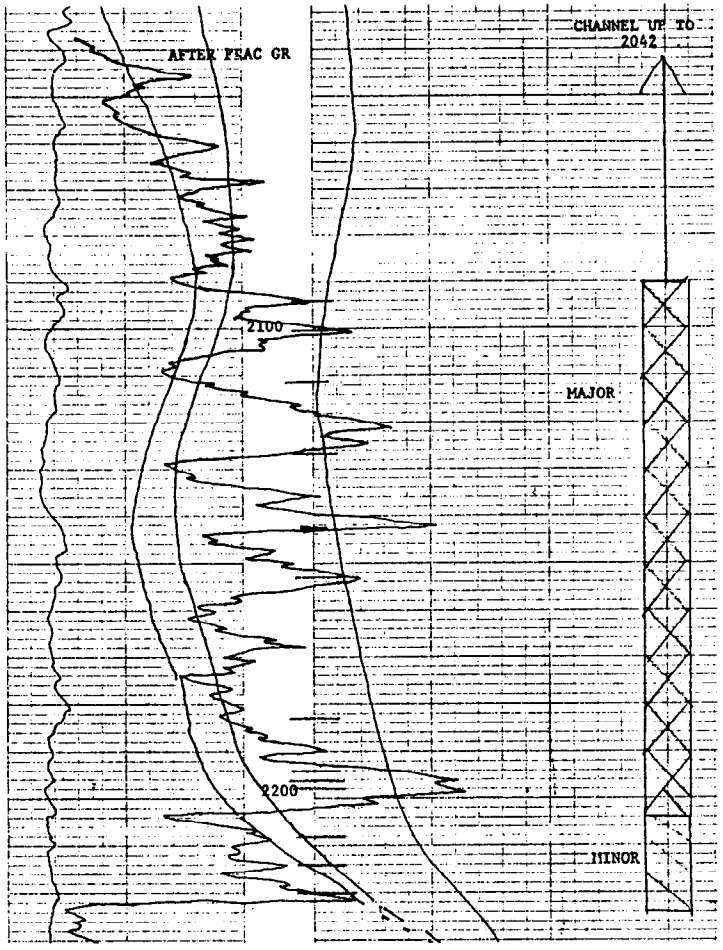

Figure 12 — Post treatment surveys
(Well No. 4)

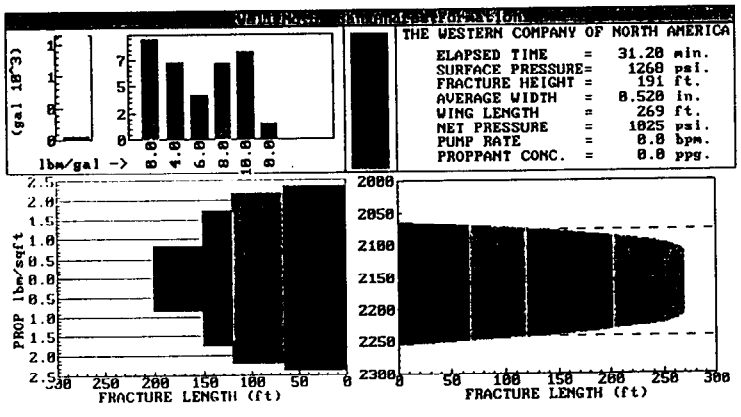

Figure 13 — Fracture geometry plot
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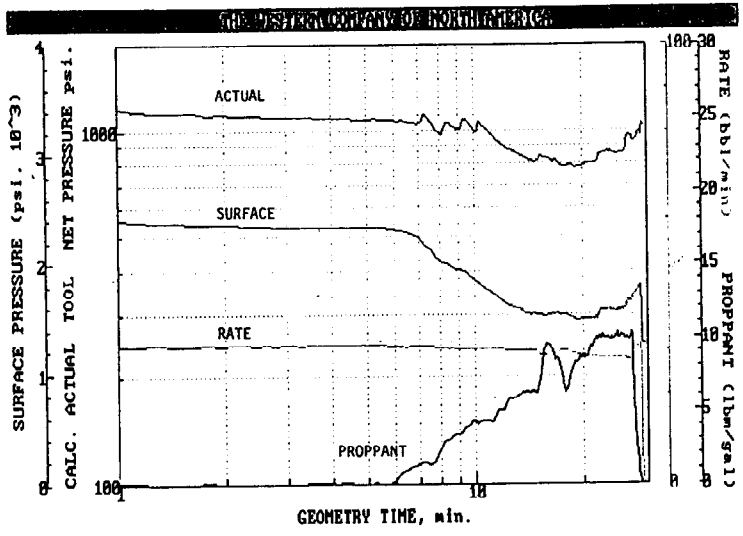

Figure 14 — Net bottomhole pressure plot
(Well No. 5)

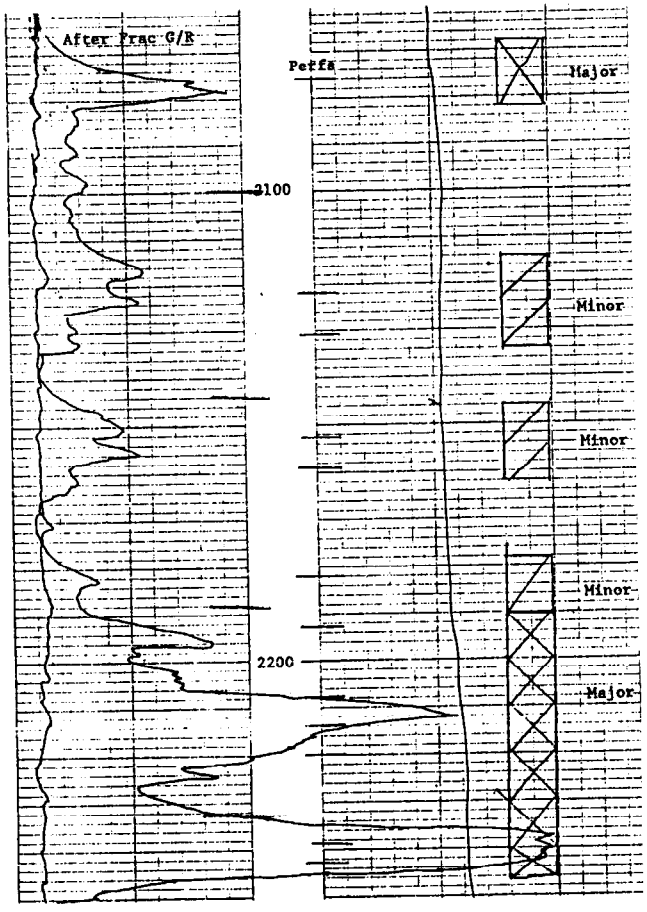

Figure 15 — Post treatment surveys
(Well No. 5)

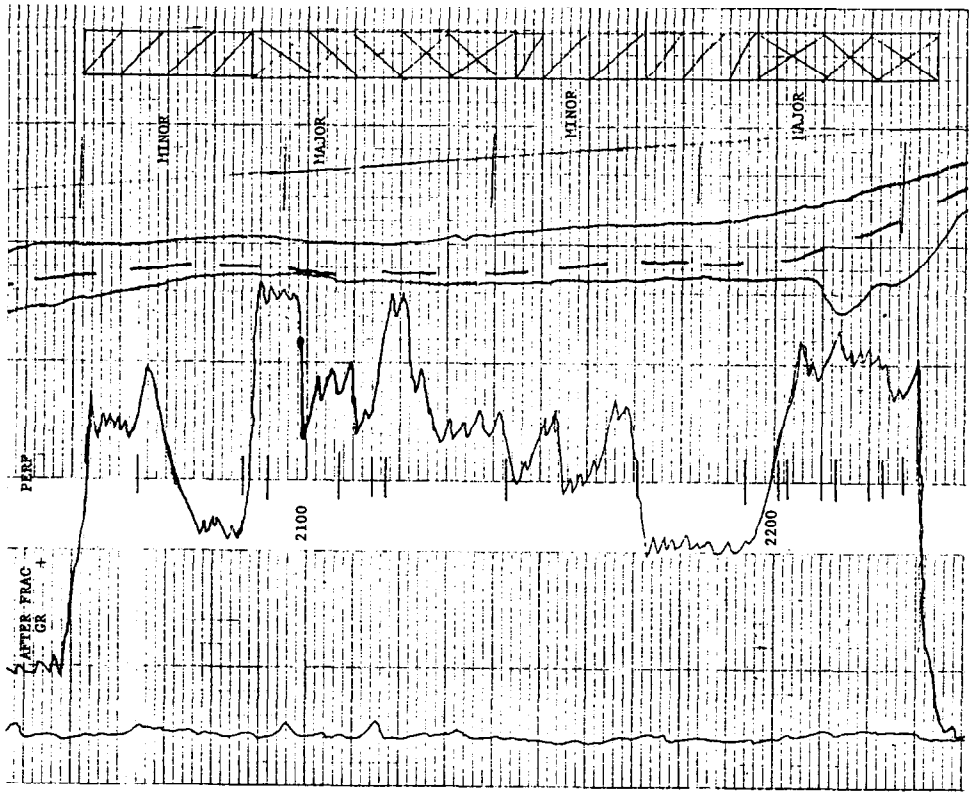

Figure 18 — Post treatment surveys
(Well No. 6)

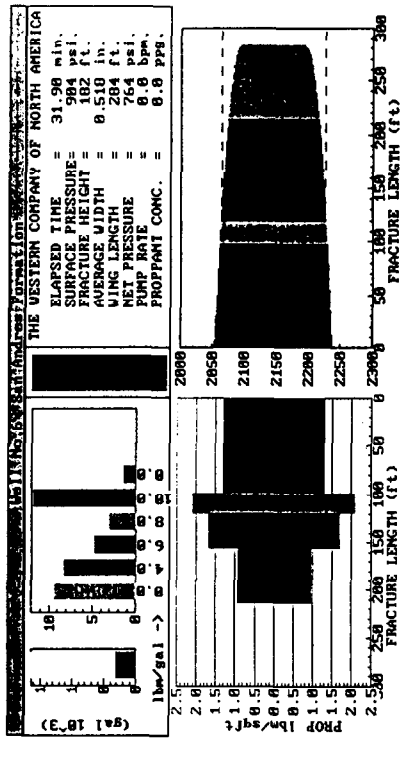

Figure 16 — Fracture geometry plot
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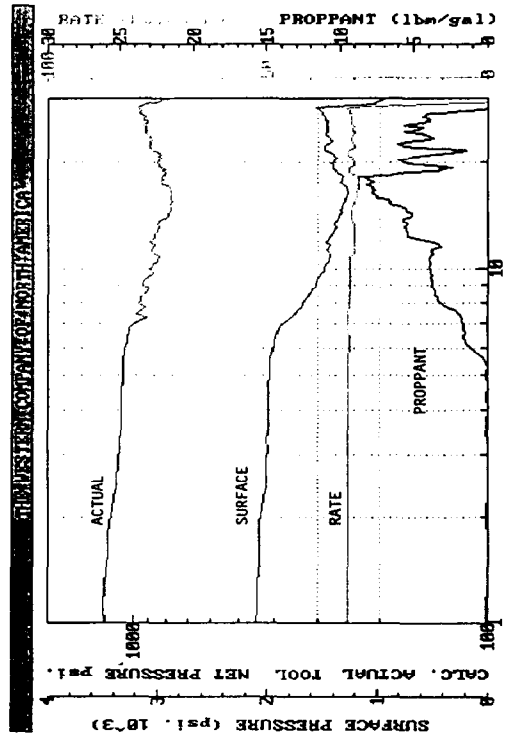

Figure 17 — Net bottomhole pressure plot
(Well No. 6)