FOSSIL

DOE/MC/22002-3042(Vol.1)
(DE92001117)

RECOVERY EFFICIENCY TEST PROJECT

Phase II Activity Report

Volume I

Final Report

By
W. K. Overbey, Jr.
S. P. Salamy
C. D. Locke

February 1989

Work Performed Under Contract No. AC21-85MC22002

For
U.S. Department of Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
The BDM Corporation
McLean, Virginia

DISCLAIMER

Printed in the United States of America, Office of Scientific and Technical Information, Oak Ridge, Tennessee

DOE/MC/22002--3042-Vol.1

DE92 001117

Recovery Efficiency Test Project
Phase II Activity Report
Volume I

Final Report

W.K. Overbey, Jr.
S.P. Salamy
C.D. Locke

Work Performed Under Contract No.: DE-AC21-85MC22002

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
The BDM Corporation
7915 Jones Branch Drive
McLean, Virginia 22102

February 1989

RET #1 PHASE II ACTIVITY REPORT
FINAL REPORT

TABLE OF CONTENTS

TABLE ON CONTENTS (continued)

TABLE OF CONTENTS (continued)

LIST OF FIGURES

FIGURE

FIGURE

LIST OF FIGURES (continued)

FIGURE

LIST OF FIGURES (continued)

FIGURE

LIST OF FIGURES (continued)

FIGURE

LIST OF FIGURES (continued)

FIGURE

FIGURE

LIST OF TABLES

TABLE NO.

LIST OF TABLES (continued)

TABLE NO.

RET #1 PHASE II ACTIVITY REPORT

FINAL REPORT

1.0 EXECUTIVE SUMMARY

The drilling of directional wells and even horizontal wells to augment oil and gas production goes back to at least 1944 in the Appalachian Basin. This is when a horizontal well was drilled from a 500-foot-deep shaft in the Franklin Heavy Oil Field in Venango County, Pennsylvania, to improve oil recovery. Several hundred feet of horizontal core was taken during the drilling operations in the Venango Sand.

The overall objective of this project was to test the increase in recovery efficiency of multiple hydraulic fractures induced in the gas-bearing Devonian shales from a wellbore deviated 60° to 90° from vertical in a particular azimuthal direction selected to enhance the hydraulic fracturing process.

1.1 Site Selection

A review of the potential geographical sites where a directional well could be drilled which would produce the best opportunity for successful completion of the Recovery Efficiency Test in the Devonian shales of the Appalachian Basin was conducted. An examination of various structural and tectonic elements of fourteen (14) different geographic areas was made in light of the site selection rationale and criteria developed for the project. These geographic areas (partitions) are shown in Figure 1.1.1.

The BDM Corporation recommended that final site selection studies be conducted in geographic partition WV-1 area which includes Cabell, Wayne and Lincoln Counties, West Virginia. This area is identified as the hatchured area in Figure 1.1.1 with the final ranking of the partitioned areas.

BDM recommended drilling the directional well at a site in Wayne County. The well site is shown with the projected well path trajectory in Figure 1.1.2. The bearing of the well path trajectory was S37°E, which is nearly normal to the principal stress direction for the area estimated to be N52°E based on correlation of structural and lineament trends.

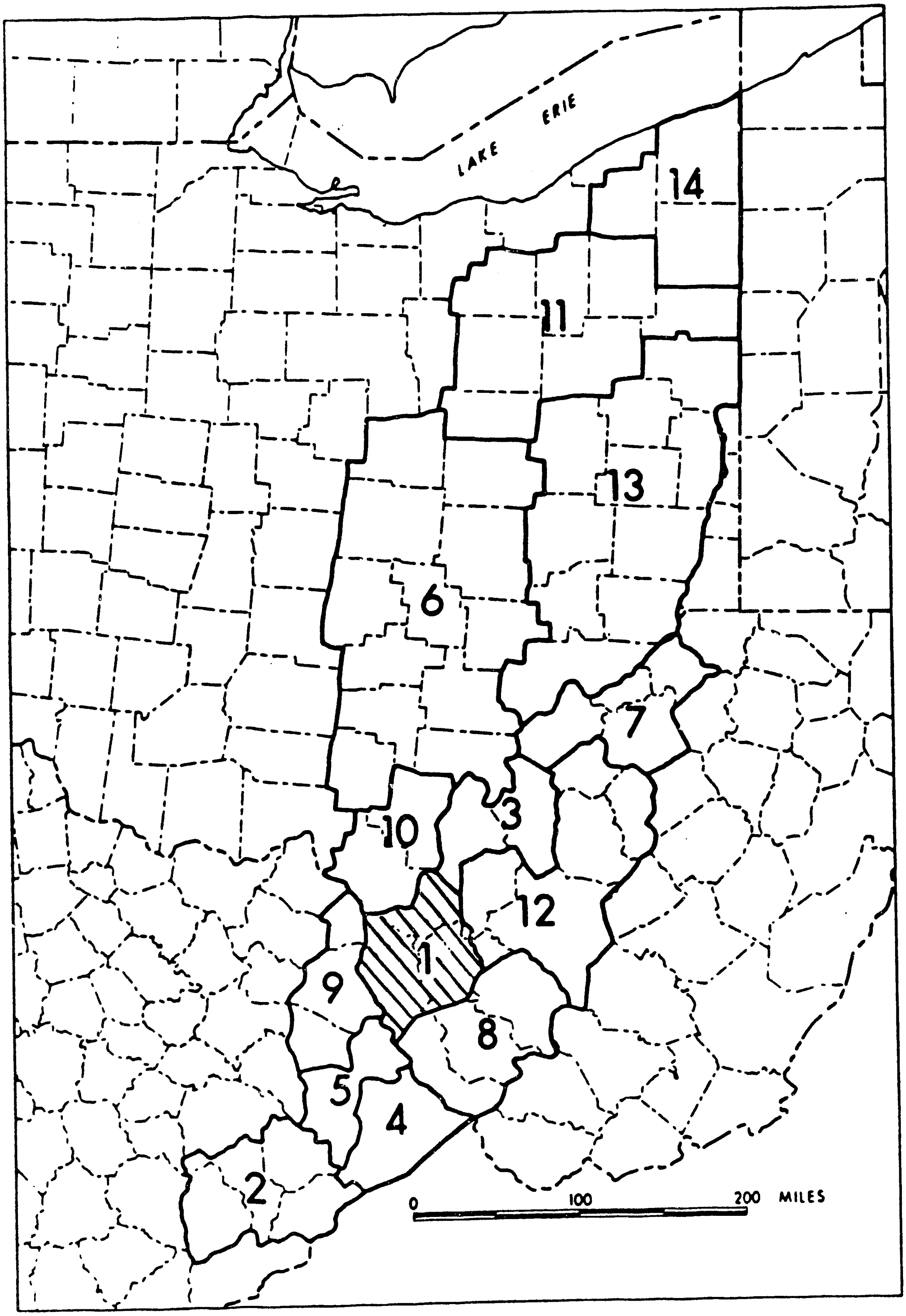


Figure 1.1.1: Location and Ranking of Partitioned Areas Accepted for Analysis

1.2 Drilling Operations

BDM reviewed the state-of-the-art literature relative to directional drilling and investigated a number of scenarios which could be used. These key elements as well as trajectory design, drag, hook load, rig size, risk factor, and cost determined the well design needed to accomplish the requirements set forth in the Statement of Work for the Recovery Efficiency Test Project.

Drilling operations were conducted at the selected site between October 21 and December 18, 1986. Total drilling days were 58 compared to the estimated 45 days to drill 2000 feet of horizontal wellbore. Figure 1.2.1 shows a plot of depth versus days for the actual and planned drilling program. The actual drilling program took 58 days to complete. The planned drilling time was 45 days.

The major difference in drilling time was consumed in the vertical portion of the hole. HLH Drilling Company drilled this portion of the hole on a footage contract basis. The estimated drilling time was three days and it actually took 15 days. The directional portion of the hole was planned at 42 days, but required 43 days. The angle building portion of the well took longer than expected because of the two sidetracks; however, the horizontal section went faster than expected because no motor corrections were required.

The primary objective of the drilling plan which was to drill and evaluate a 2000 foot horizontal wellbore was accomplished. The well had more than 2000 feet of wellbore with an inclination of more than 85° that could be tested and evaluated.

While drilling the surface hole at 161 feet, two bit shanks broke off of the 18-1/2 inch bit and could not be recovered. The contractor skidded the rig and began drilling a new well. The 16-inch surface casing was set at 650 feet in a 17-1/2 inch hole and cemented to the surface. On the first attempt, the 16-inch casing would not go in the hole. The 17-1/2 inch hole was reamed, then the casing went to bottom.

A 14-3/4 inch hole was drilled to 2113 feet without incident. The 11-3/4 inch casing was run and set at 2025 feet. The casing was cemented back to the surface. Directional drilling operations began at

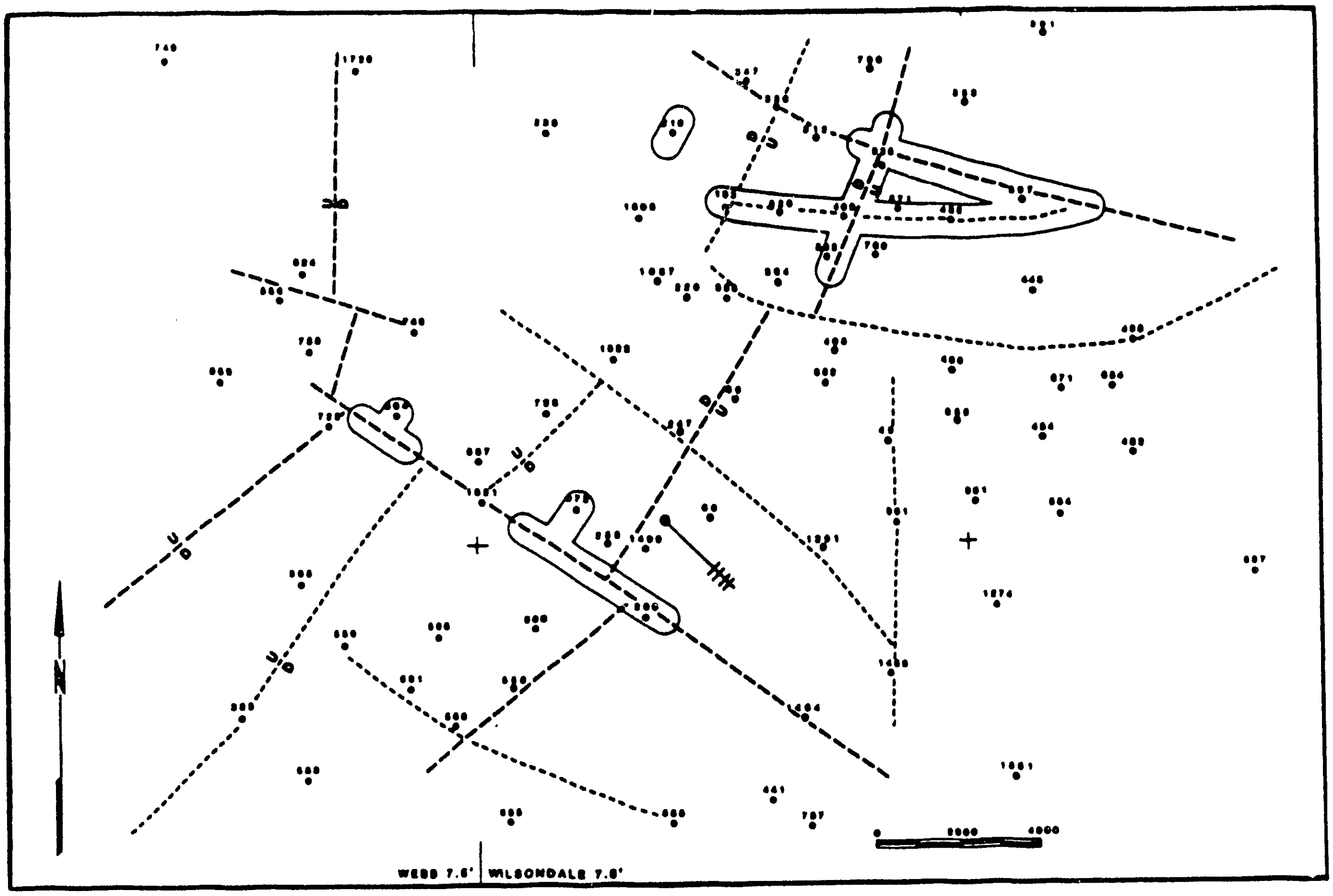


Figure 1.1.2: Location of Site Selected Relative to Fracture and Production Trends

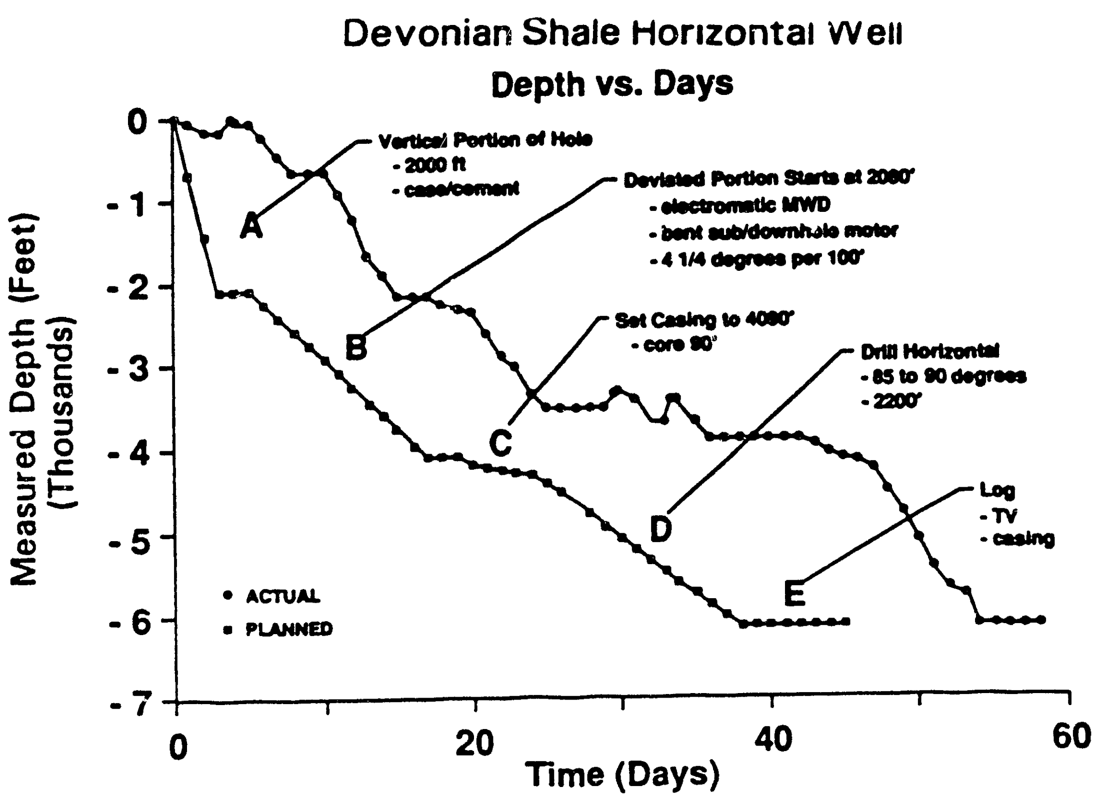


Figure 1.2.1: Comparison of Planned versus Actual Drilling Schedule for Devonian Shale Horizontal Well

2113 feet in the 10-5/8 inch hole. The highest inclination was 92° at a measured depth of 4043 feet. The entire angle building section was built using downhole motors as planned.

There were three major problems encountered in the 10-5/8 inch (angle building) hole. The first problem was caused by sticking the drill string, resulting in a subsequent sidetrack operation. While reaming the hole out at 3509 feet, the drill string became stuck in the hole. The drill string was backed off leaving two monel collars, two steel collars, and two reamers in the hole (Figure 1.2.2). The fish (lost tools) were jarred for more than eight hours with no significant movement when the jars failed. Jarring loads as much as 130,000 pounds over the string weight were observed.

The well was successfully sidetracked at 3239 feet and directionally drilled to 3666 feet. Because of problems in getting the motor oriented during the sidetrack, the inclination was behind schedule and the target could not be hit.

The well was sidetracked a second time at 3362 feet and drilled to 3827 feet. At this point, hole cleaning became a significant problem. The drill string had to be pumped in and out of the well. To alleviate the hole cleaning problem, the 8-5/8 inch casing was run and cemented at 3803 feet. The inclination at this point was 74°. The drilling plan called for setting the 8-5/8 inch casing at 85°.

The remainder of the well went very well. The angle was built from 74° to 92° with a 7-7/8 inch bit at a depth of 4043 feet. At this point coring operations were initiated. A total of 75 feet of core was obtained at an inclination of 92°. The core showed natural fractures and faulting in the interval. Core recovery was 50 percent on one run and 100 percent on two runs.

The remainder of the horizontal section was drilled with a rotary assembly and air as the circulating medium as planned. The assembly dropped inclination from 92° to approximately 87° at a total measured depth of 6020 feet. The wellbore stayed within the target interval in the Lower Huron shale. The bottom of the Lower Huron shale was at a vertical depth of 3450 feet. The maximum TVD reached by the wellbore was 3427 feet. Figures 1.2.3 and 1.2.4 show the planned versus actual wellbore paths.

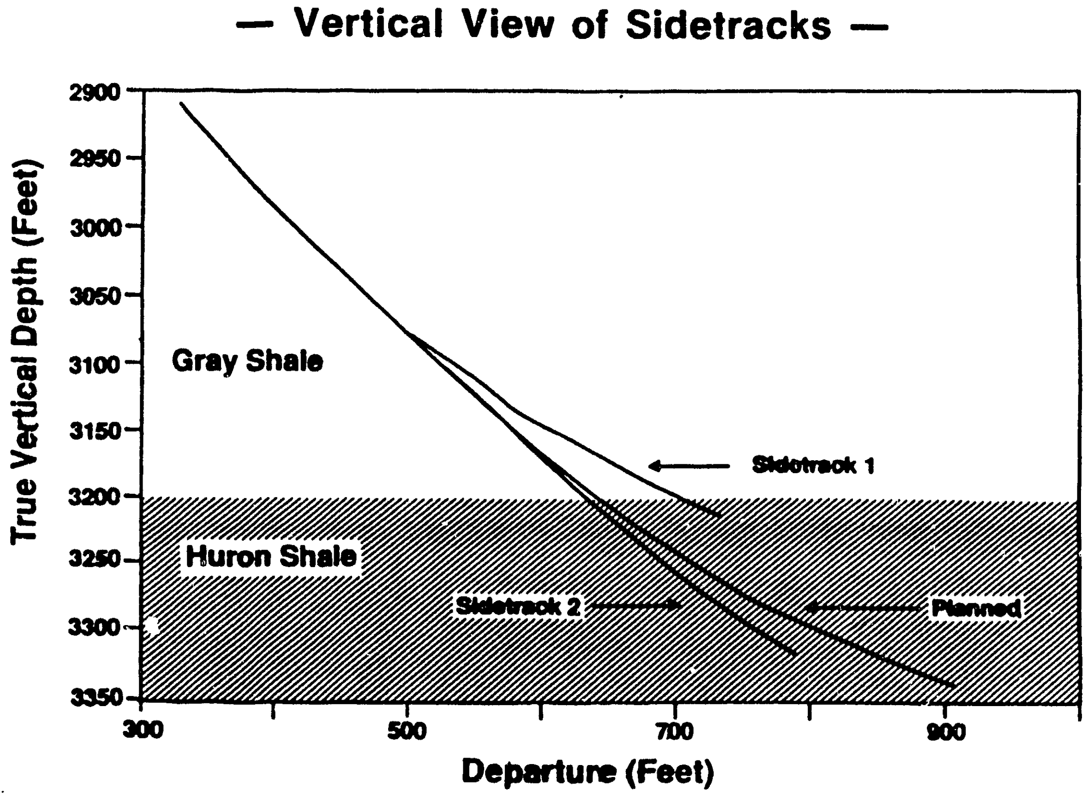


Figure 1.2.2: Elevation View of Sidetracks and Planned Trajectory Through the Lower Section of Inclined Hole

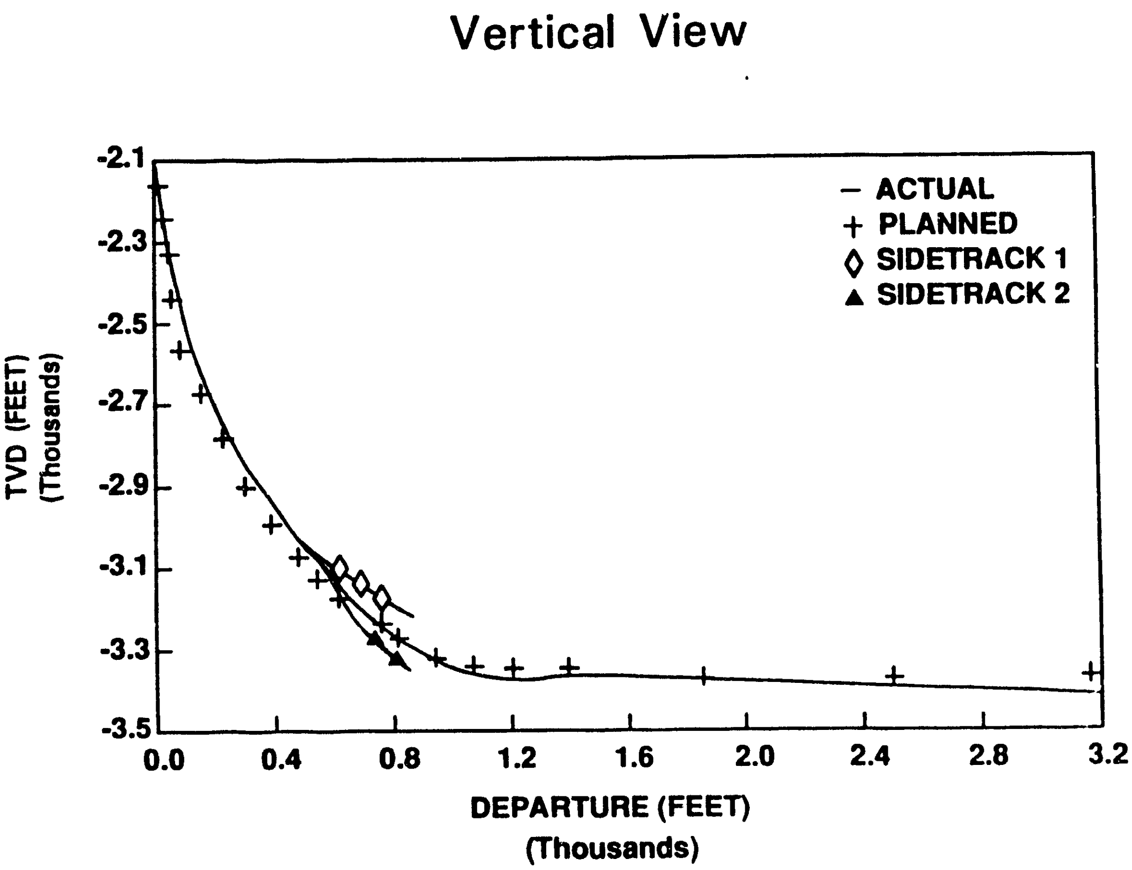


Figure 1.2.3: Elevation View of Inclined and Horizontal Section of RET #1 Well

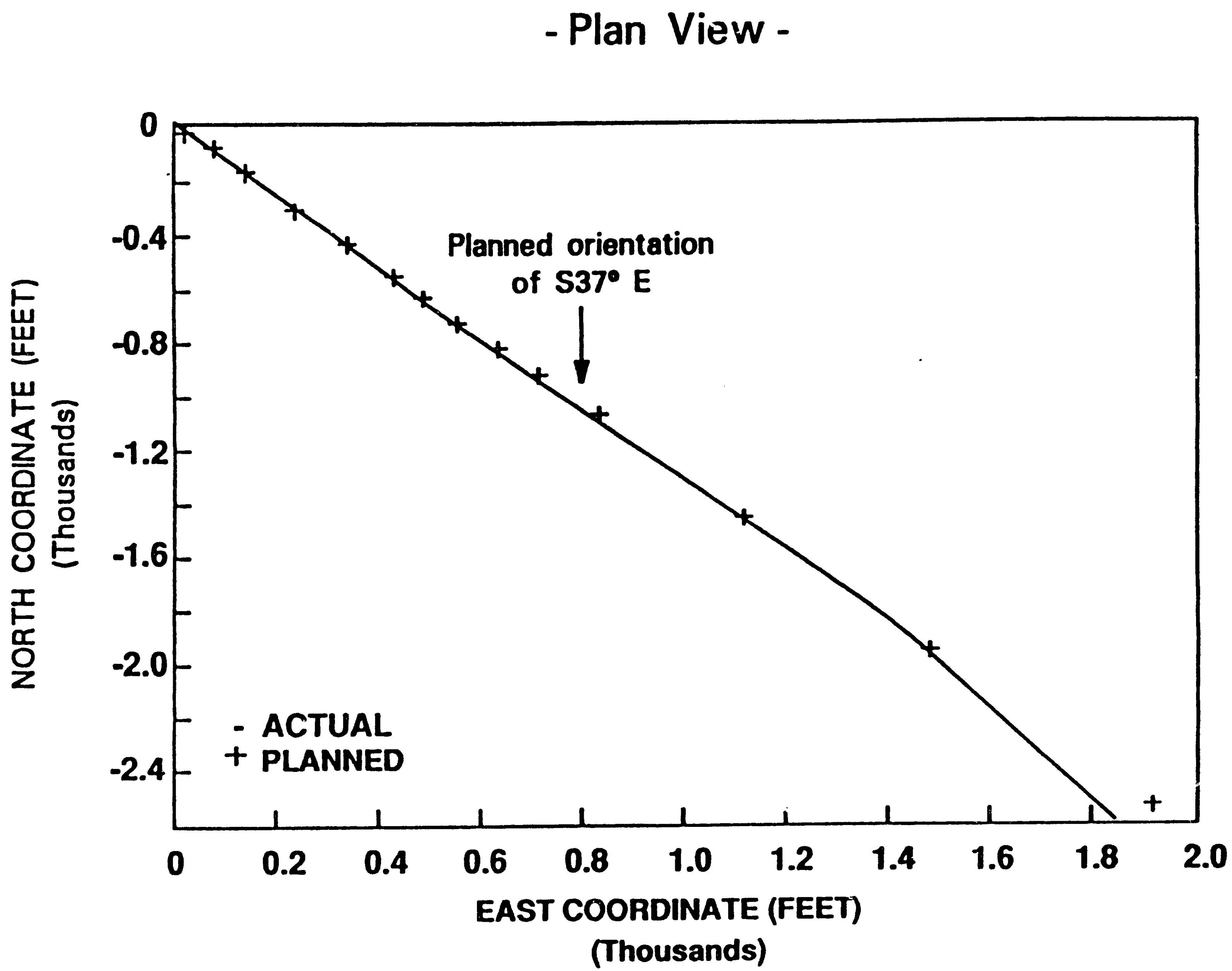


Figure 1.2.4: Plan View of Horizontal Displacement of RET #1 Well

The strategy selected by BDM, which was to use downhole motors to build the entire inclined portion of the well, was obviously the correct one. The major problem overcome during this part of the drilling operation was hole cleaning. Motor starting was another problem which was later addressed by picking up a double stand (62 feet) with each connection. BDM tried to determine potential detrimental effects of various chemicals used in the mist fluid, but was not successful. Evaluation of BDM data by Drilling Resources Development Corporation indicates that a higher fluid injection rate of 15 to 20 barrels per hour should have been more successful in hole cleaning than the 10-12 barrel per hour rate used by BDM. This probably would have been more successful in wetting the cuttings and preventing agglomeration of the cuttings to form mud balls which oculd not be removed from the wellbore.

Testing of the electromagnetic measurement while drilling system (EM-MWD) to provide tool face orientation, wellbore inclination and trajectory azimuth was disappointing. The tool worked reasonably well but needed additional hardening and software configuration to obtain required data in a timely fashion. Future development of horizontal drilling as an efficient and economic method of producing petroleum and natural gas depends largely upon reducing the time required to make these measurements.

The use of 3100 cf/m of air for the circulating medium with the rotating bottomhole assembly was very effective in removing cuttings during drilling of the horizontal section of the hole. The use of an on-site computer to examine the drilling tendencies of several BHA's allowed BDM engineers to select the best assembly for the operation. The assembly selected worked so well that a motor run to correct for dropping angle or walking was not required.

Chromatographic analysis of the air stream monitored while drilling the horizontal hole indicated 30 fractures were encountered which produced measurable volumes of natural gas (Figure 1.2.5). The largest of these had a calculated open flow of 2168 mcfpd. Examination of the borehole with a video camera revealed circular and eliptical features which were interpreted to be fractures since many of them were bleeding gas and condensate into the wellbore. The presence of condensate indicates two phase flow conditions may exist at different periods of time in the

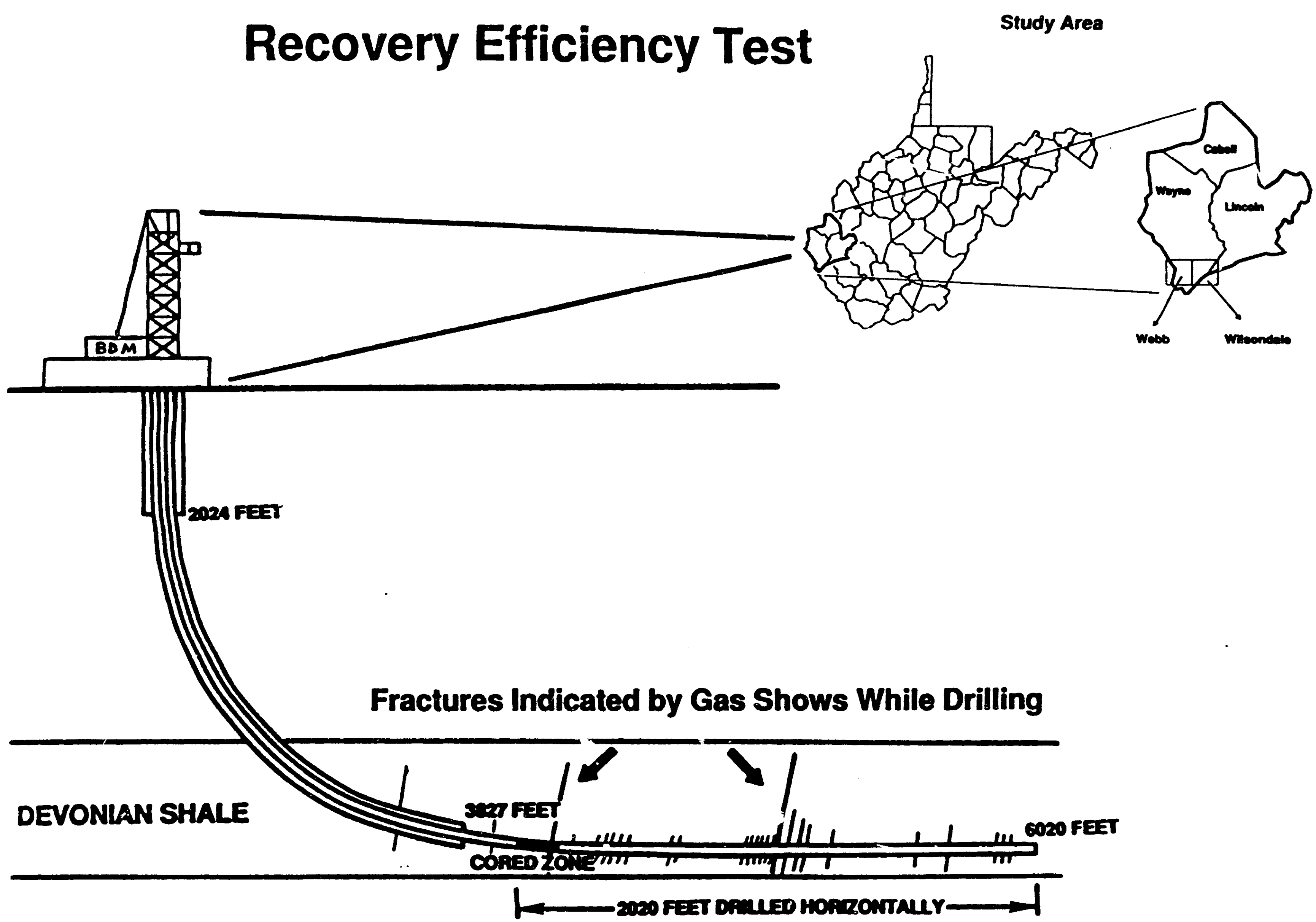


Figure 1.2.5: Schematic of Well Showing Location of Well and Location of Gas Shows and Fractures along Wellbore

life of a well or field. Some Devonian shale producers have suspected this was the case, but lacked proof to explain oddities in production.

1.3 Logging Operations

Upon completion of the 14-3/4 inch hole which was drilled to a depth of 2124 feet, a suite of shallow hole logs was run in the hole. The logs obtained included Gamma Ray, Neutron, Density, Dual Induction, Caliper, and Temperature.

After the decision was made to set the hole protection string at 3824 feet where the inclination was approximately 74 degrees, a second shallow hole logging suite was run; however, there was so much mud and cuttings in the wellbore that the logging tools could only fall to 3648 feet. After logging, 3803 feet of 8-5/8 inch casing was set and the balance of the well was drilled.

The 7-7/8 inch hole was logged with an open hole logging suite and a TV camera. A Dresser Atlas drill pipe conveyed logging system was used for both logs.

The first logging run was made with a Density, Gamma Ray, CValiper, and Dual Induction resistivity tools. The Density and Caliper tools did not function properly because the pad was on the low side of the hole and could not be deployed to contact the sidewall properly. After logging from 6020 feet to 4137 feet, the wet connect pulled loose from the logging tools. Dresser personnel speculated there was some rust scale from the pipe in the wet connect causing it not to seat properly. The wet connect was again made and the logging run completed.

The second logging run consisted of Temperature and Gamma Ray tools. The temperature was logged down while tripping in the hole. The correlation Gamma Ray tool failed, so the 8-5/8 inch casing seat was used for depth correlation.

A third logging run was made with a TV camera. The TV camera was attached to the drill string using a special housing and the wellbore observed (logged) going in the hole. This tool proved to be very useful in identifying the fractures in the wellbore. This is the first time a TV camera has been run using a drill pipe conveyed logging method and was very successful. The TV camera was invaluable in providing fracture identification and hole condition information. The most notable information observed was the production of liquid condensate from several of the fractures found in the wellbore.

1.4 Coring Operations

After the hole protection casing was set and the inclined portion of the drilling operations completed, operations to collect 90 feet of oriented core were initiated. The core barrel was modified externally to build angle (stabilizer was added) and the inner barrel was modified to allow core to slide into the aluminum inner barrels very easily.

There were no major difficulties encountered during coring operations. The modified core barrel worked very well, recovering 100 percent of the core cut on two of the three runs made. Examination of the core material revealed the presence of 15 natural fractures, 6 faults, and 59 coring-induced fractures. The natural fractures had a mean orientation of N37°E, 87°NW, while the faults (normal) had a mean orientation of N22°E, 56°NW (see Figure 1.4.1). Mean spacing between fractures was 8 feet. Chromatographic analysis of the air stream during coring indicated a major fracture had been encountered.

1.5 Completion and Well Testing Operations

The well was completed for production by installing 4-1/2 inch J-55, 10.5#/ft casing equipped with eight external casing packers, one cement packer, and 14 full-opening ported cement collars (see Figure 1.5.1). The position and measured depth of each casing string is shown on Figure 1.5.1.

After the casing was installed, the well was shut in for 9 days during which time the pressure built up to 135 psig. The well was open flow tested at the end of the build-up for a period of several days. Final open flow was determined to be 24 mcfpd (see Figure 1.5.2).

The external casing packers were then inflated with 1100 psi nitrogen pressure (see Figure 1.5.3), then pressure tested to see if they were holding. Seven of the 8 packers tested okay. Packer No. 2, separa-

Rose Diagram of Core Fractures

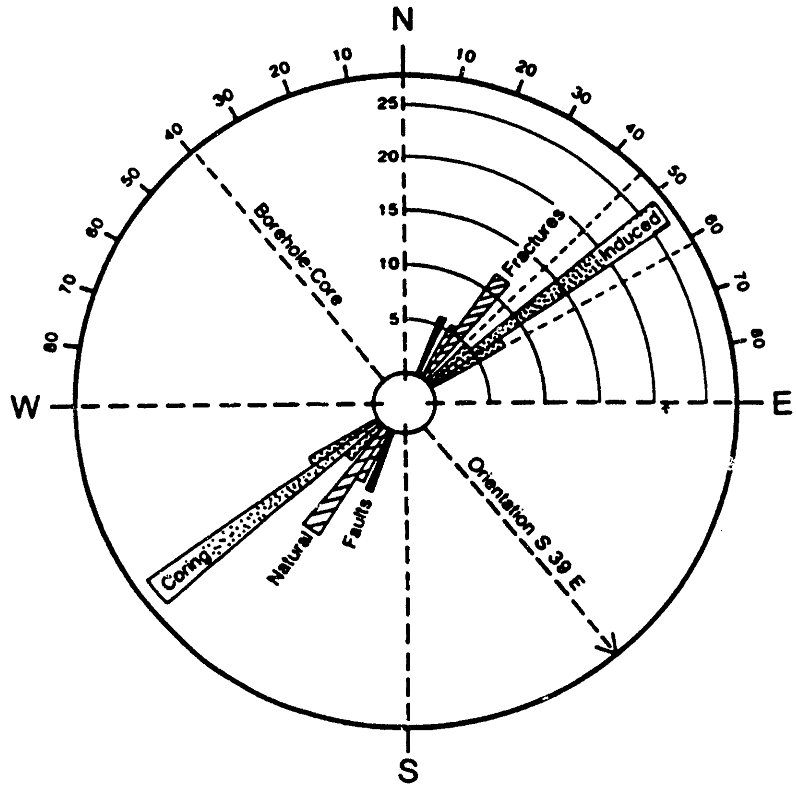


Figure 1.4.1: Rose Diagram of Core Fractures and Faults

Wellbore Schematic

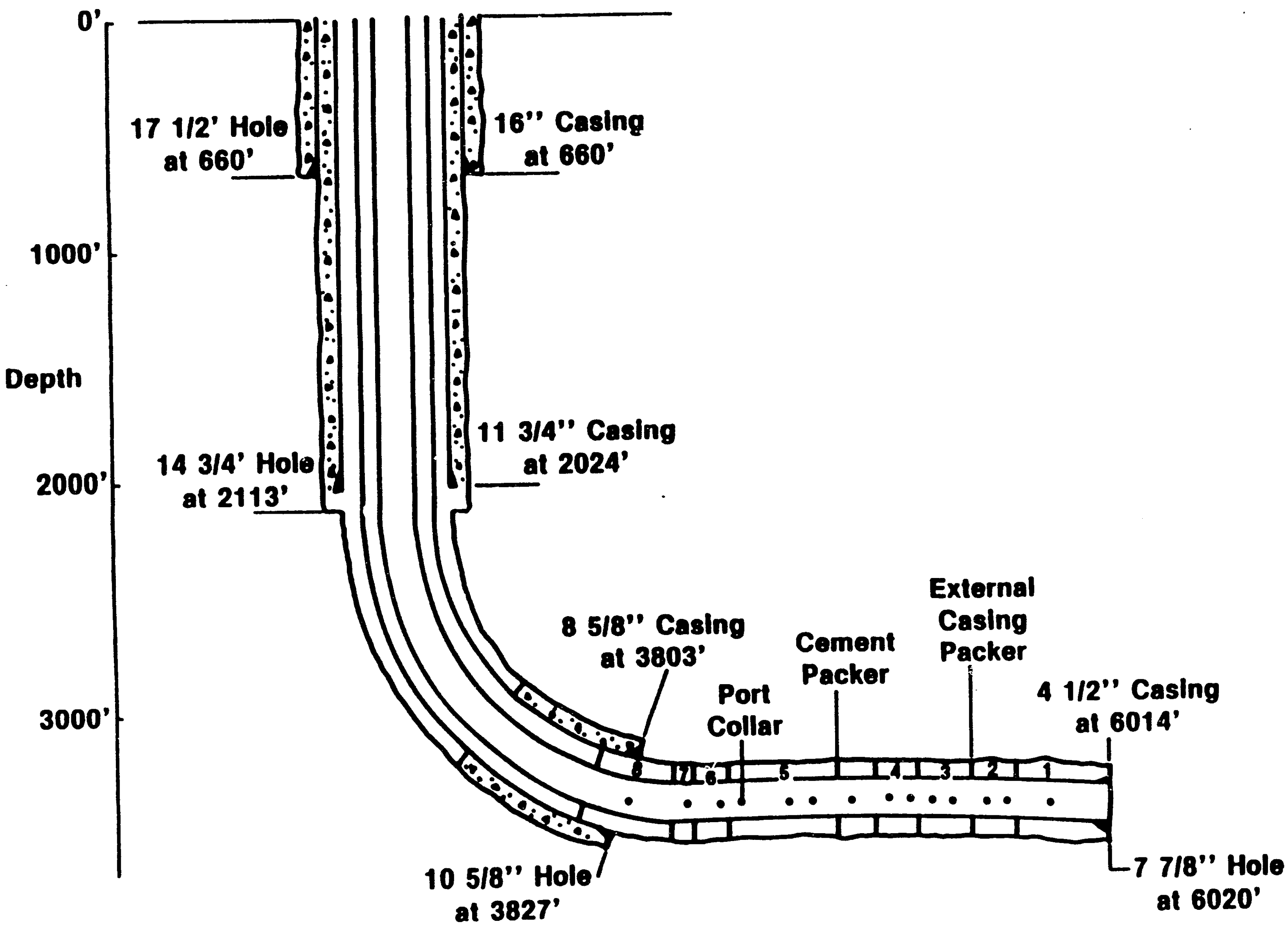


Figure 1.5.1: Schematic of RET #1 Completion Configuration

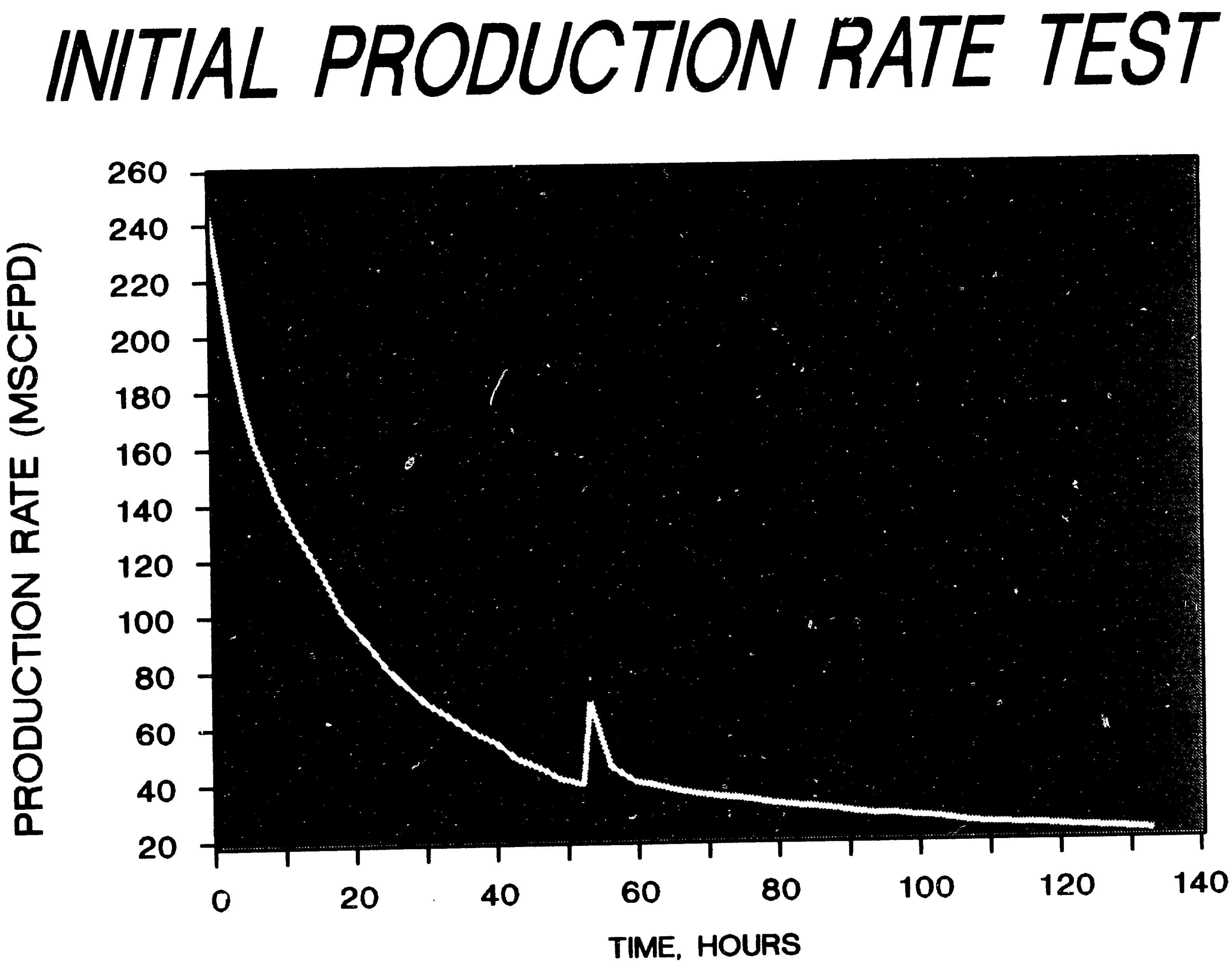


Figure 1.5.2: Initial Production Rate Test of RET #1 Well (January, 1987)

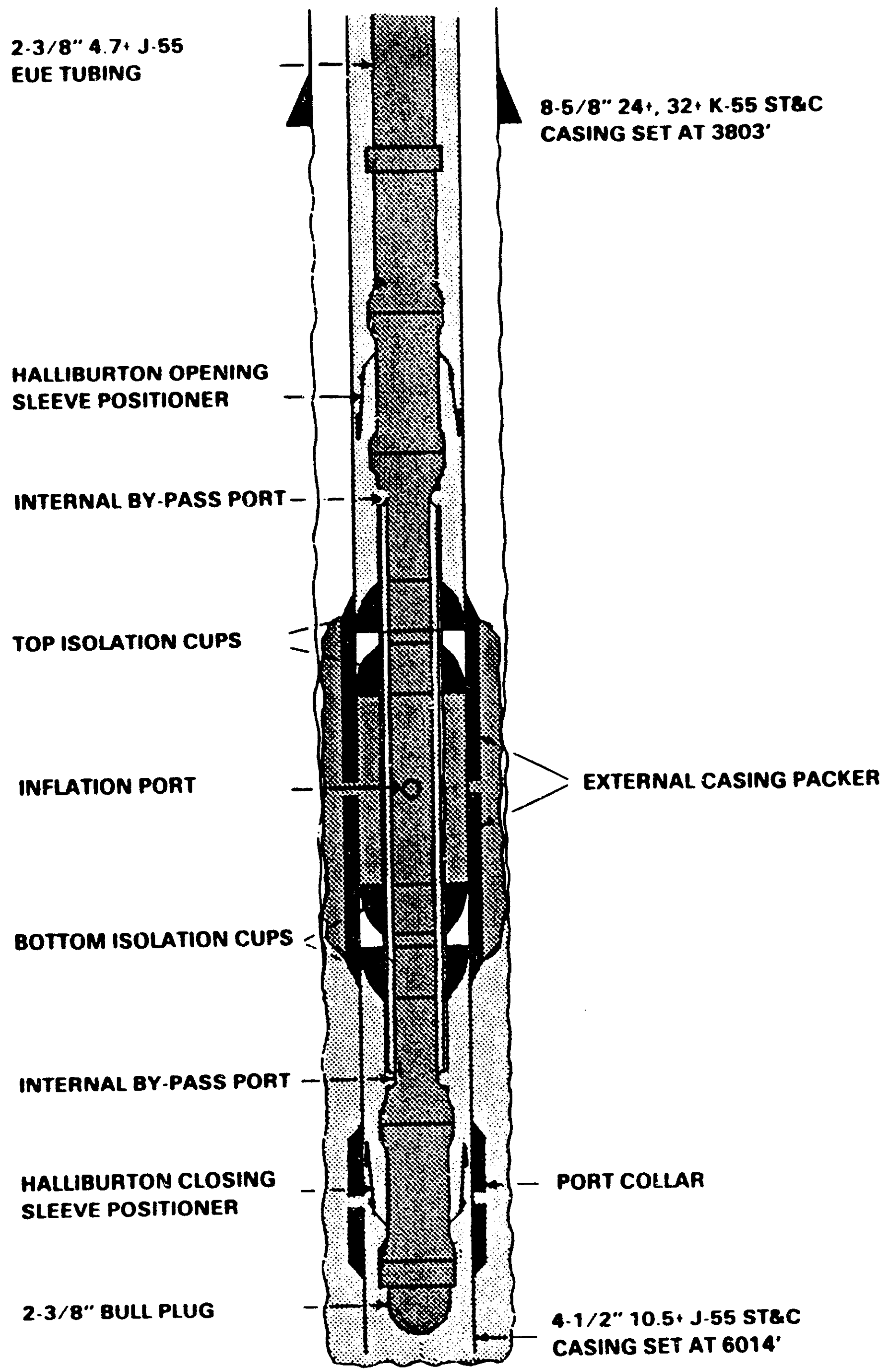


Figure 1.5.3: Configuration of Isolation Tool Assembly used to Inflate and Test External Casing Packers

ting Zones 2 and 3 would not hold 400 psi gas pressure, thus Zones 2 and 3 are considered a single zone. The isolation tool and opening and closing tool was then used to conduct individual zone pressure build-up and draw-down tests. Results of the tests are presented in Table 1.5.1. At the time of testing, the whole well had a calculated bulk permeability of 0.033 md and a Skin factor of -4.28.

1.6 Stimulation Operations

The objective of stimulation tests conducted on the well was to evaluate the effects of different combinations of fluids, volumes, rates, pressures, and proppants to improve the productivity of the natural horizontal well by inducing multiple fractures with possible multiple orientations along the wellbore.

A stimulation rationale (see Figure 1.6.1) was developed to conduct a series of tests that would lead to the development of an optimum stimulation for the well. Four preliminary stimulations were conducted on Zone 6 which had the fewest number of detected natural fractures in the wellbore. From this series of tests, closure pressure (or parting pressure) was determined to be 850 and 1050 psi. The lower pressure is postulated to be the closure pressure for a natural fracture, and the higher pressure for an induced fracture. The fracture gradient was calculated to be 0.25 psi/ft of depth for Zone 6. The ratio of minimum horizontal stress to vertical stress $(\frac{Vs}{Hmin})$ was calculated to be 0.22 for Zone 6.

The first of five full-scale stimulations on the horizontal well was conducted on Zone No. 1 with nitrogen gas fluid. The gas was injected at slow rates to inflate the natural fractures in the wellbore. Although no fracture diagnostics were used, BDMESC believes that at least 6 fractures located near the port collar were inflated. Initial open flow rate of 80 mcfpd declined rapidly so that the well was making the original rate after 20 days.

The second full-scale stimulation was also conducted in Zone 1 since it was felt that a better comparison of fluids would be more realistic and meaningful if all tests were conducted in the same zone. The second

TABLE 1.5.1

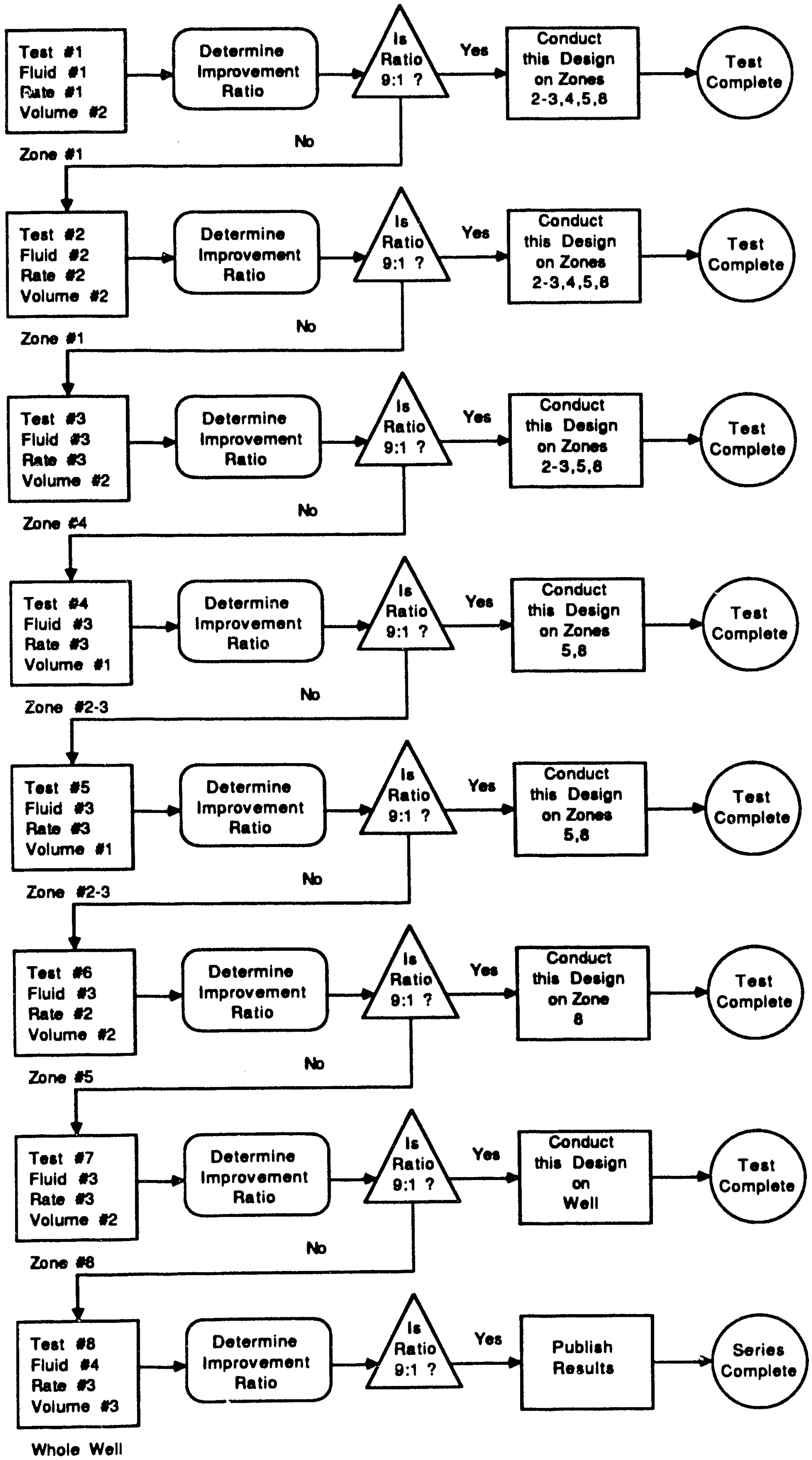
SUMMARY OF PRE-STIMULATION PRESSURE BUILD-UP AND DRAWDOWN TEST RESULTS
RET NO. 1 - WAYNE COUNTY, WEST VIRGINIA

ZONE	LENGTH	24-HOUR PRESSURE BUILD-UP	PERMEABILITY* (md)	FLOW RATE**
1	404'	54 psia	0.031	2.2 mcfpd
2-3	417'	75 psia	0.078	4.4 mcfpd
4	182'	68 psia	0.098	16.7 mcfpd
5	640'	73 psia	0.073	4.4 mcfpd
6	135'	74 psia	0.078	2.2 mcfpd
7	90'	74 psia	0.037	0
8	292'	83 psia	0.068	5.2 mcfpd
			TOTAL:	35.1 mcfpd

* Predicted by reservoir simulation model G3DFR.

** 24-Hour flow rate test after pressure build-up test.

RET #1 PROPOSED TEST SERIES STIMULATIONS TO IMPROVE RECOVERY EFFICIENCY



LEGEND

RATE

1. 5 bbl./min.
2. 25 bbl./min.
3. 40 bbl./min.

VOLUME

1. 2,000 reservoir bbls.
2. 4,000 reservoir bbls.
3. 6,000 reservoir bbls.

FLUID

1. N2
2. CO2
3. Foam (N2)
4. Foam (N2) & 2lb/gal sand

Figure 1.6.1: RET #1 Proposed Test Series Stimulations to Improve Recovery Efficiency

fluid was liquid CO_2, which is a cryogenic fluid, pumped at 0°F, and at pressures about 200 psi above closure pressure. The stimulation was conducted in two stages, pumped at two different rates, with considerable difference in the results (see Figure 1.6.2) in terms of the number of fractures inflated. More fractures were inflated at the higher injection rates. In addition, the production improvement ratio was higher with CO_2 when compared to nitrogen gas and nitrogen foam as fluids (see Table 1.6.1). Initial production was more than 250 mcfpd, however, after more than 50 days of production, the rate had declined again to the original rate of 2.2 mcfpd. BDMESC geologists and engineers interpreted this to mean that without proppant, the fractures opened up, simply closed with time.

This experience of losing production because of closing fractures led us to conclude that proppant was a necessary ingredient in the stimulation design. The third stimulation was a small volume nitrogen foam stimulation pumped in two stages (#1 pad; #2 proppant), but at the same rate of 10 bbls/minute. Two different radioactive tracers were used to determine where fractures were being propagated along the wellbore. Forty-six (46) fractures were opened and propagated. After clean-up, the zone was producing 15.5 times more gas than it was before stimulation.

The fourth stimulation was conducted in Zone 2-3 and 4 combined. After the results of Frac No. 3, it was felt that we needed to see if a large volume fracture over about the same length of wellbore would give a proportionate increase in production rate. The large volume fracture consisted of 4500 gallons of liquid CO_2 as a prepad, 44,000 gallons of pad and 90,000 gallons of 80-quality foam containing 250,000 pounds of sand (2.5 lbs/gal) all pumped at 50 gallons per minute downhole foam rate. There were some severe sand clean-up problems after this frac job. The improvement ratio of stimulated production to natural production was a disappointing 3.1 to 1. Zone 4 was the zone with a high natural show of 2.16 million scf of gas per day and was a major fault and fracture zone. Again, we proved that it is difficult to improve upon a good natural flow condition in a well.

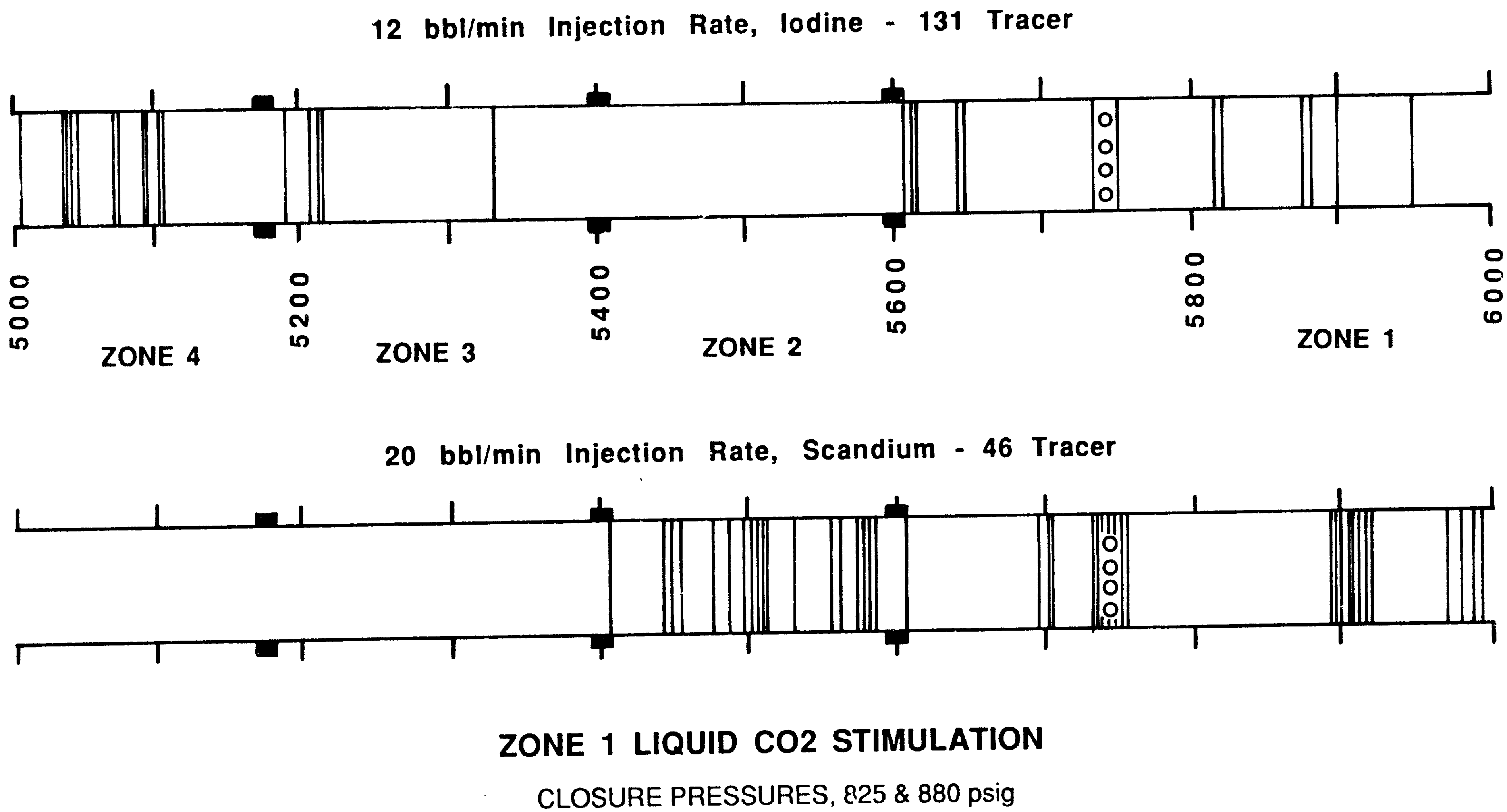


Figure 1.6.2: Schematic Diagram of Wellbore of Zones 1-4 Showing Location of Fractures Stimulated during the Liquid CO_2 Frac Job

TABLE 1.6.1

SUMMARY OF RESULTS OF STIMULATIONS TESTS
TO INJECT INTO OLD FRACTURES OR CREATE NEW ONES

TEST NUMBER	ZONE	NATURAL FRACTURES DETECTED	FRACTURES PUMPED INTO	PRODUCTION IMPROVEMENT
1	6	6	6*	4.1
2	6	6	6*	4.1
3	6	6	14	4.1
4	6	6	14	4.1
5	1	69	12**	5.0
6	1	69	27 (over 4 zones: 1,2,3,4)	25.0
7	1	69	67 (over 4 zones: 1,2,3,4)	25.0
8	1	69	17 (over 3 zones: 1,2,3)	15.5
9	1	69	69 (over 4 zones: 1,2,3,4)	15.5
10	2-3,4	72	No tracers	3.1
11	2-3,4	72	54 (over 3 zones: 2,3,4)	3.1
12	5,8	65	No tracers	6.0
13	5,8	65	No tracers	6.0

* Based on camera observation.

** Observed from Test 6.

The fifth and final fracture was a scaled-down version of frac job No. 4. We addressed almost twice as much borehole (930 feet) in Zones 5 and 8 versus 590 feet in Zones 2-3 and 4 during Frac No. 4, but pumped only 105,000 gallons of 85-quality foam and 150,000 lbs of sand at 50 barrels per minute rate. Sand cleanout problems were not as severe this time. Gas production improvement ratio for the combined zones was 6.1 to 1, which was an improvement over Frac job No. 4 in Zones 2-3 and 4, but not in the same class as Frac No. 3 with its 15.5 to 1 improvement ratio.

The stimulation program resulted in a net improvement ratio of 4.4 to 1. Final open flow production rate of the well was 155 mcfpd.

1.7 Fracture Diagnostics

To determine the success of BDMESC's attempts to induce multiple fractures in the open hole completion configuration, two different approaches were used to determine the geometry of induced fractures. The first technique was the inclusion of radioactive isotopes in the liquid phase of the fracturing fluid, or as radioactive beads included with the sand proppant material, to indicate the position outside of the casing where frac fluid and/or proppant was exiting the wellbore either through natural fractures previously identified or through induced fractures. The second technique was the emplacement of eight tilt meters in a circular configuration on the surface above the area of Zones 1, 2, 3 and 4. The tilt meters imbedded in sand in 8-inch diameter boreholes drilled 6 feet deep were installed to determine the orientation and lateral extent of the induced fractures by detecting movement of the surface of the earth created by the lateral displacement of the induced fractures.

Eight different tests had the benefit of fracture diagnostic techniques being conducted to provide data for analysis on the success of stimulation operations. The first fracture diagnostic tests conducted was in conjunction with the data frac series, a series of four tests designed to look at the effects of pumping rates and pressures with gaseous and foam type fluids. In addition, we wanted to be able to measure closure pressure and thus calculate fracture gradient and stress ratio for the Devonian shale formation at this location.

Since BDMESC had projected that the multiple natural fractures which existed in surface rocks and in the cores taken from the well could be inflated during stimulation operations, it was natural to assume that multiple closure pressures should be detected. It was postulated that slow injection rates would open up the natural fractures by allowing the frac fluid to penetrate the fracture creating a pressure wedge which would open the fracture a greater length and keep it propagating. It was further postulated that higher injection rates (and thus higher pressures) would overpower the formation and produce fractures before pressure adjustment could occur. The use of two different radioactive tracers in the liquid phase of the "data frac" test was designed to look at the number of fractures opened and propagated at low rates of 5 bbls/minute versus fractures opened and propagated at 12 bbls/minute. Radioactive scandium 46 ws used as the diagnostic material at the 5 bbl/minute injection rate and iodine 131 was used at the 12 bbl/minute rate, and the results as shown in Figure 1.7.1 supported the hypothesis in that twice as many fractures were indicated by the iodine as by the scandium.

The first full-scale stimulation conducted on Zone 1 was a nitrogen gas frac. A decision was made not to use radioactive tracers on this test since it would need to be a gas and the only gas tracer available had a half life of more than 100 days which did not make it practical to use. The well would have had to be shut-in without flowback for more than 200 days.

Stimulations 2, 3 and 4 were also traced with radioactive isotopes as shown in Table 1.7.1. Generally a tracer was used during the pad stage; a tracer was used during the proppant stage, and it was obvious from examination of the spectral gamma logs that the fractures being pumped into were often a different set of fractures from one stage to the next. Figure 1.7.2 is a synthesis of the data from the spectral gamma logs of all of the three stimulations which were conducted on Zone 1 using nitrogen gas, liquid CO_2 and nitrogen foam. For purposes of clarity, each stage

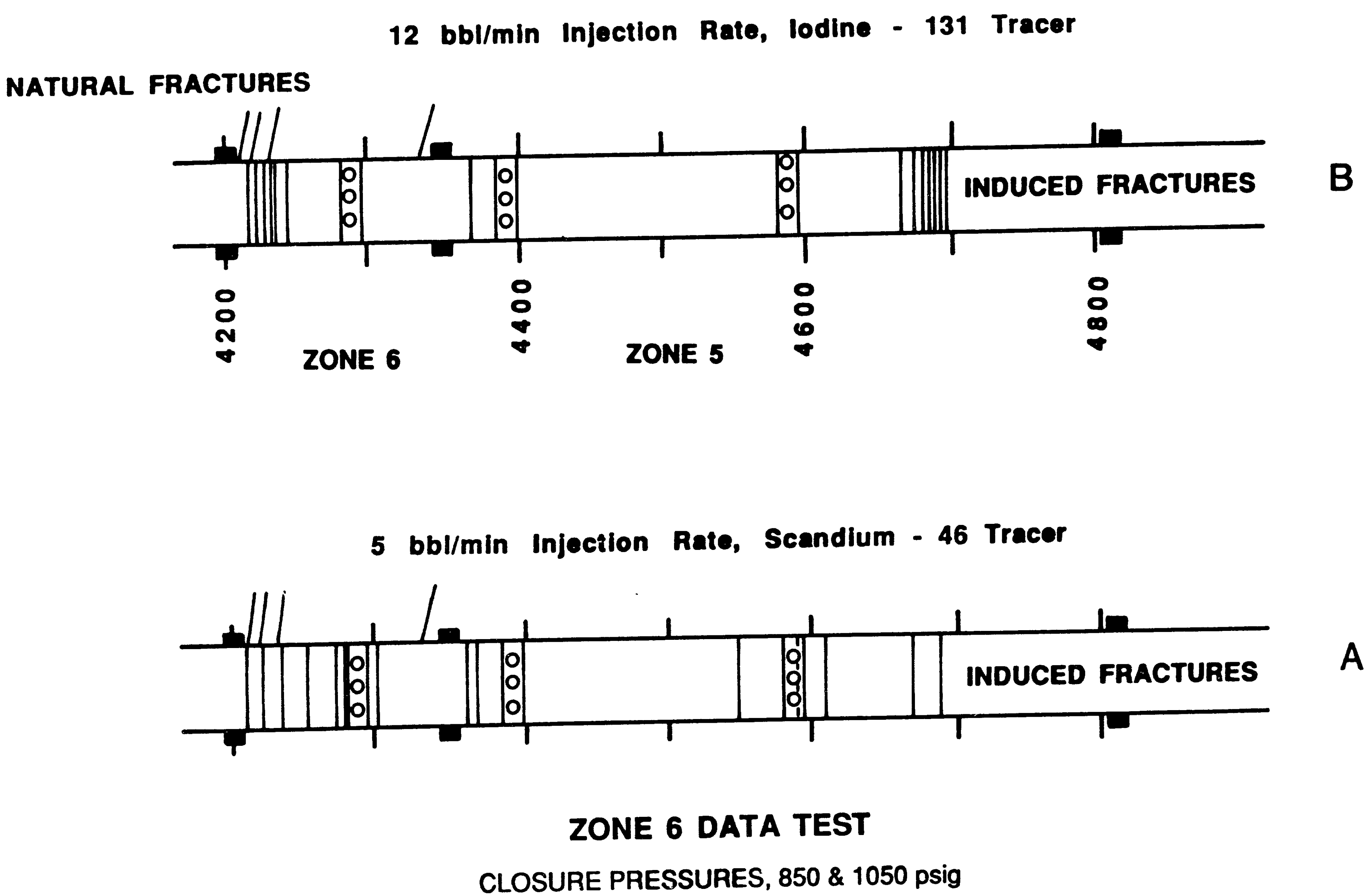


Figure 1.7.1: Schematic Diagram of Wellbore of Zones 5 & 6 Showing Location of Fractures Stimulated or Connecting to the Wellbore after the "Data Frac"

TABLE 1.7.1

SUMMARY OF STIMULATION TEST SERIES CONDUCTED ON RET #1 WELL

TEST NO.	ZONE	FLUID/PROPPANT	RATE	VOLUME	FRAC DIAGNOSTICS
1	6	N_2 (Gas)	5 BPM	37 MCF	None
2	6	N_2 (Gas)	15 BPM	212 MCF	None
3	6	N_2 Foam	5 BPM	100 BBLS	Scandium 46
4	6	N_2 Foam	12 BPM	300 BBLS	Iodine 131
5	1	N_2 (Gas)	8-16 BPM	1600 MCF	Tilt Meters
6	1	CO_2 (Liquid)	12 BPM	200 BBLS*	Iodine 131
7	1	CO_2 (Liquid)	20 BPM	400 BBLS*	Scandium 46
8	1	N_2 Foam-pad	10 BPM	166 BBLS	Antimony 124
9	1	N_2 Foam-proppant (20,000 lb, 20/40)	10 BPM	595 BBLS	Iridium 192
10	2-3, 4	N_2 Foam-pad	40 BPM	905 BBLS	None
11	2-3, 4	N_2 Foam-proppant (225,000 lb, 20/40)	30 BPM	2142 BBLS	Scandium 46
12	5 & 8	N_2 Foam-pad	25 BPM	530 BBLS	None
13	5 & 8	N_2 Foam (150,000 lb,20/40)	50 BPM	2500 BBLS	None

* Surface volume.

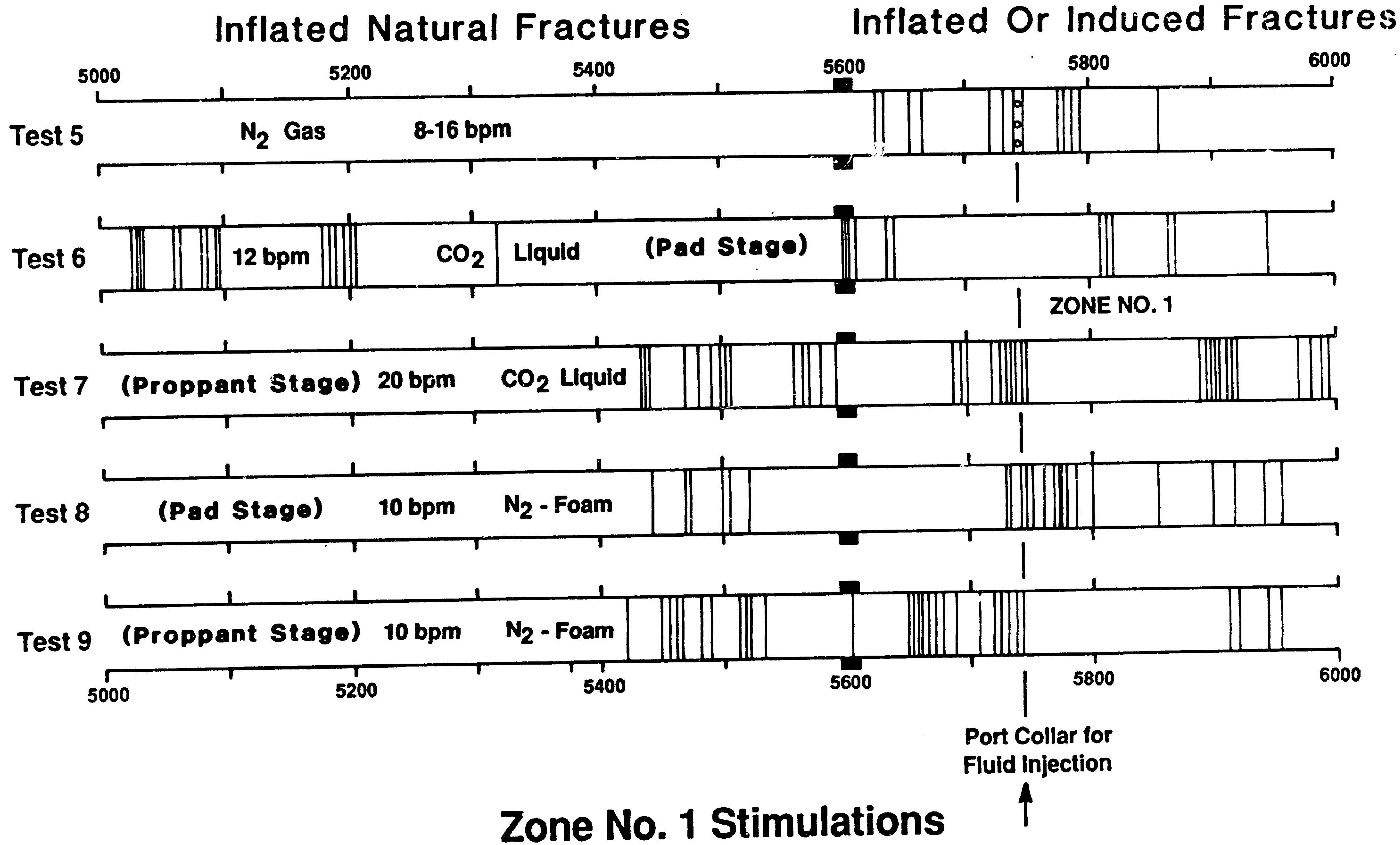


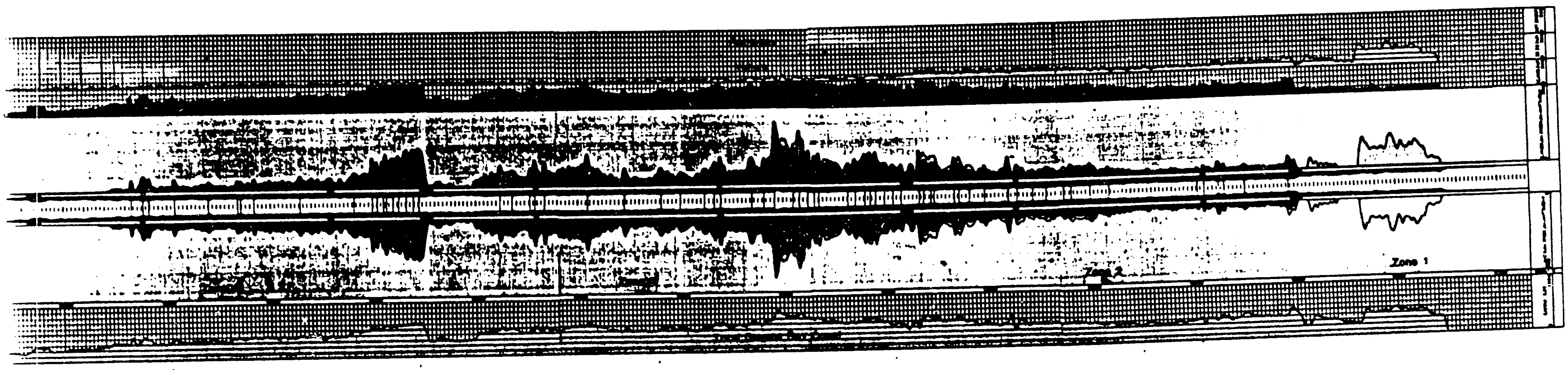
Figure 1.7.2: Schematic Diagram of Wellbore of Zones 1-4 Showing Locations of Fractures with Tracer Material from 3 Different Frac Jobs Composed of 5 Stages or Tests

was considered a separate test since it consisted of different volumes and rates (see Table 1.7.1) as compared to the second, or proppant, stage of the same stimulation. As seen in tests 6 and 7 (see Figure 1.7.2), the fractures indicated by the tracers were completely different in Zone 1, the zone being stimulated. In tests 7 and 8 which were pumped at the same rate, several of the same fractures were pumped into near the port collar and at 5900 feet. The rate of 10 barrels per minute is considered a low injection rate and therefore, many natural fractures were opened and propagated.

During the analysis of this test in which the rates remained the same but fractures still were induced or propagated in different sections of the borehole, we get the first indication that build-up of stresses in the natural fractures after some period of time (representing an unknown volume of frac fluid) triggered auto-selection of another area and set of natural fractures of lower stress state for continuation of the hydraulic fracturing processes. This was a significant finding of the studies conducted on Zone 1, along with the effects of slow versus fast injection rates.

The next step in the progression of studies was to examine the effects of considerably higher rates such as 40 barrels per minute versus 20 barrels per minute which had been used previously. Since Zones 2-3 and 4 had the same intensity of fracturing as Zone 1, these zones were the best candidate for the high-rate, high-volume test set forth in the rationale. For economic reasons, tracer was injected in the proppant stage only. Examination of the spectral gamma log (see Figure 1.7.3) revealed that 20 fractures had received significant amounts of tracer (proppant). An additional 34 fractures received enough fluid and proppant to be readily identifiable on the spectral gamma ray log.

Thus the use of radioactive isotopes with the injected stimulation fluid and proppants was a very successful method of determining how many fractures were propagated, in what order, and what part of the borehole they were opened in, and how the frac fluid traveling through a complex fracture system was able to make its way back to the wellbore at several points.



Fracture Diagnostic Spectral Gamma Log -Zones 2,3,&4

Figure 1.7.3: Reduced Section of Spectral Gamma Log used to Determine Location of Fractures Pumped into During Stimulation of Zones 2-3 and 4.

1.8 Well Test and Analysis

To determine the efficiency of the stimulations conducted on the horizontal well, it was necessary to conduct a series of pressure build-up and drawdown tests to collect information that could be analyzed and used to calculate flow capacity and project production.

Prior to any stimulation operations, a series of 24-hour pressure build-up and drawdown tests were conducted on each zone to get an idea of the flow capacity of each zone (see Figure 1.5.4 for a summary of results). Then a longer build-up and flow test was conducted on Zone 6 which was selected for a series of mini-frac tests to determine breakdown pressure, average treating pressure, and closure pressure for the Devonian shales at the location of the well. After the mini-frac tests and after the well had flowed several days to clean up nitrogen and CO_2 gas from the produced gas, a post-frac pressure build-up and drawdown test was conducted. Analysis of the data utilizing a history matching iterative technique where critical input values in a model (Gas Three Dimensional Fractured Reservoir Model - G3DFR) are changed until model results closely match the actual field test data (pressure build-up and/or drawdown, as shown in Figure 1.8.1). This procedure of clean-up flow, pressure build-up test, and flow test was followed after each test conducted.

The pressure build-up data were analyzed using type-curve matching, Horner's method, and a recently-developed technique known as the Rectangular Hyperbolic Method (RHM). Utilizing these procedures, values for average reservoir pressure (producing well area), formation flow capacity, and skin effect (wellbore damage) were estimated.

Early results of the 28-day pressure build-up test on the entire well indicated a permeability of 0.033 md and a skin factor of -4.28. The actual results show a 9.6 fold increase in flow capacity (0.033 md before frac versus 0.22 md after frac) as a result of the stimulation operations. In some cases, the skin factor is more positive than before stimulation. This could be a function of the completion (open hole type) and changes in flow regimes. Sand which may be produced from the fractures after initial clean-up operations could accumulate in the annular space between the 4-1/2 inch casing and the 7-7/8 inch wellbore, producing an impediment to flow, and then sand could also accumulate inside the 4-1/2 inch casing, also reducing flow.

Further studies have revealed that the average initial reservoir pressure in the vicinity of the RET #1 well was between 185-200 psia. A more accurate/detailed analysis determined the reservoir pressure at 192 psia with an effective fracture permeability of 0.082 md and a skin value equivalent to -2.87. We feel that these results reflect the actual performance of the reservoir, and hence were used to estimate the improvement ratios as shown in Table 1.8.1.

Test and analysis results indicate stimulation operations were successful in increasing the flow capacity of the well from 20 md-ft to 50 md-ft, which is an increase of 2.5 times the original values determined for the well. Absolute reservoir pressure in the near vicinity of the wellbore is estimated to be 192 psi (based on 28-day pressure build-up test).

Based upon results of the G3DFR model analysis of the field and input parameters from the horizontal well, BDM projects that the well should produce 420 mmcf of gas over the next 20 years (as shown in Figure 1.8.2).

TABLE 1.8.1

COMPARISON OF PRE- AND POST-FRAC TESTING RESULTS

FRAC NUMBER	ZONE(s)	PRE-FRAC PRESSURE (24 hr) BUILD-UP (psia)	PRE-FRAC PERMEABILITY K (md)	POST-FRAC PRESSURE (11 day) BUILD-UP (psia)	POST-FRAC PERMEABILITY K (md)	POST-FRAC SKIN VALUE	PRE-FRAC FLOW RATE (mcfpd)	POST-FRAC FLOW RATE (mcfpd)
0	All	119*	0.033	NA	0.20 ***	---	34.0	155.0
1	6	74	0.0792	199**	0.1835	---	2.20	9.0
2	1	54	0.0306	190**	0.0477	---	2.20	11.0
3	1	54	0.0306	158	0.0480	---	2.20	55.0
4	1	54	0.0306	173	0.090	-3.212	2.20	34.0
5	2-3 4	75 68	0.084	150	0.1505	-4.22	21.1	62.0
6	5 8	73 83	0.071	169	0.327	-0.881	9.6	50.0

* Data from 28-day build-up (169 psia bottomhole pressure recorded; 192 psia projected as absolute reservoir pressure.

** Slightly over-pressured by nitrogen.

*** Weighted average of individual test results.

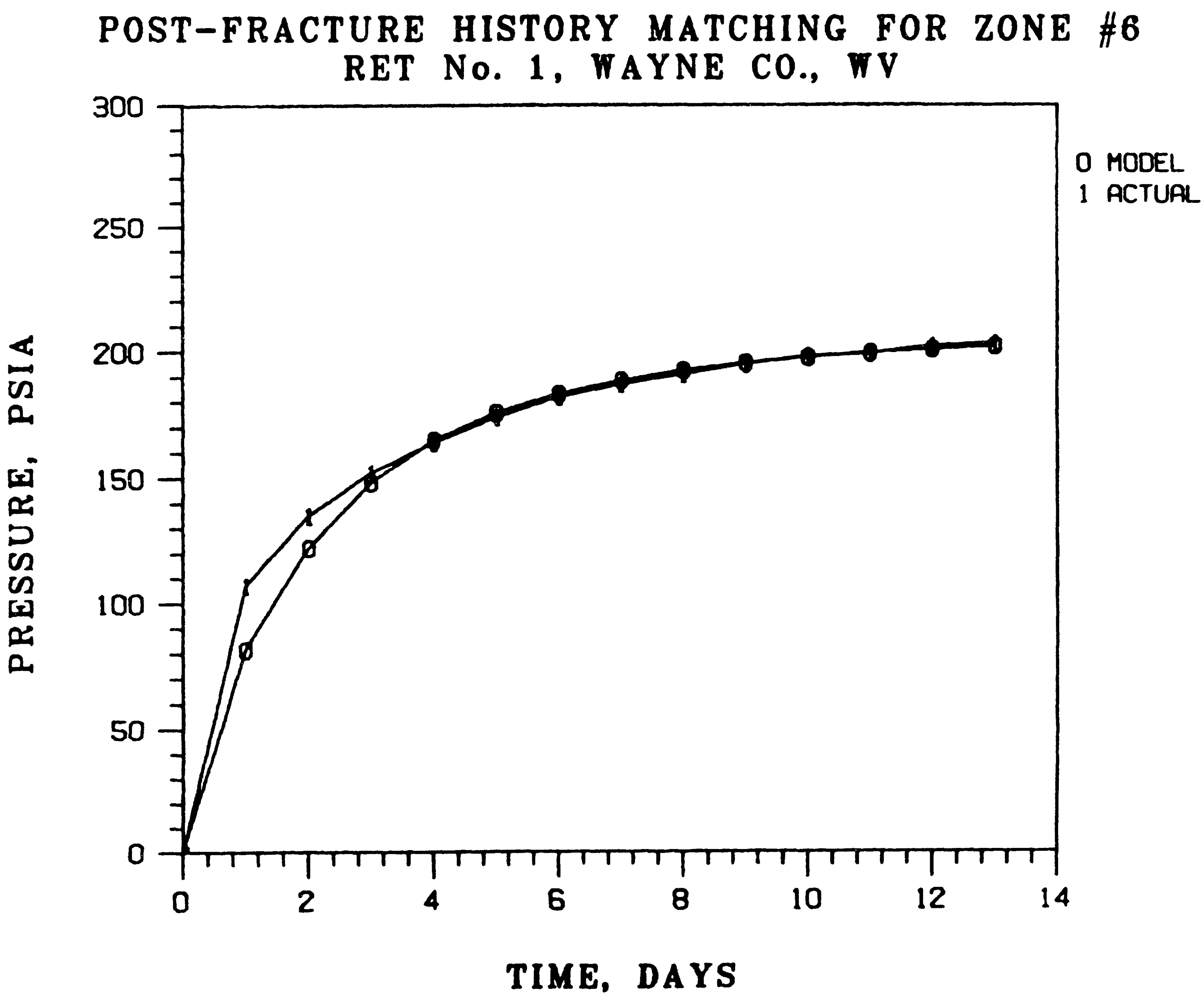


Figure 1.8.1: Post Frac History Matching for Zone #1 "Data Frac"

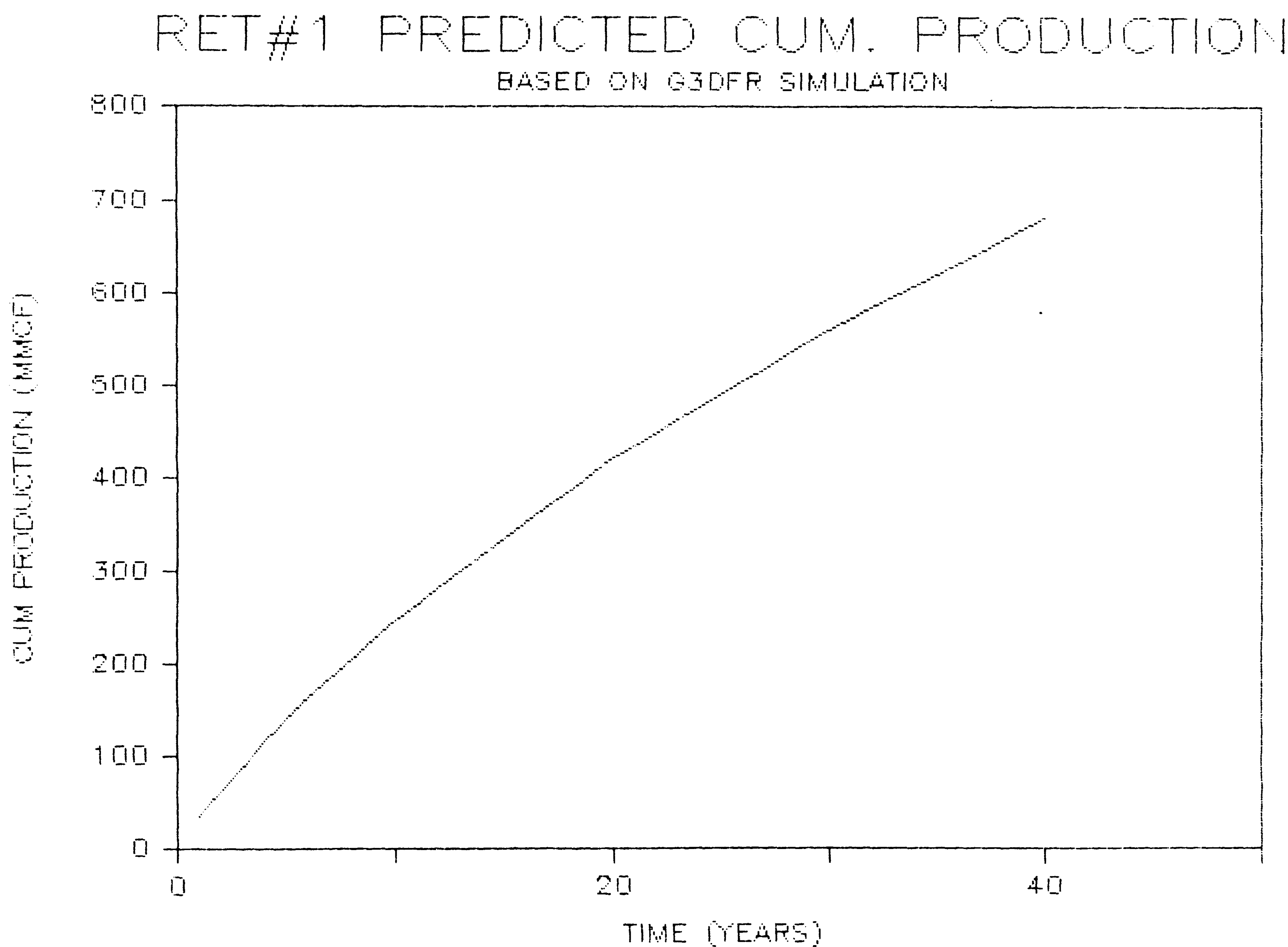


Figure 1.8.2: Cumulative Production Predicted by G3DFR Simulator Using Kf = 0.1 md, Rp = 182 psia, øf = .01, øm = .017, and IPR = 106 mcfpd

2.0 PHASE II ACTIVITIES OVERVIEW

2.1 Introduction

The purpose of Phase II operations of the Recovery Efficiency Test Project is to enhance the natural production of the well and evaluate the relative improvement as a function of the type of stimulation conducted. Another purpose is to compare the stimulated production performance of the horizontal well with vertical wells in the field.

2.2 Background and History of Previous Work

The U.S. Department of Interior, Bureau of Mines, Morgantown Energy Research Center initiated studies of fractured oil and gas reservoirs in the Appalachian region in 1964. Results of these early studies pointed out that the earth's natural fracture system played a major role in the flow of fluids from oil and gas reservoirs.

In 1976, the Energy Research and Development Administration's (ERDA) Morgantown Energy Research Laboratory (successor to the U.S. Bureau of Mines) initiated the Eastern Gas Shales Project. This Project was designed to characterized the Devonian-age shales in the east, determine the total gas resource in place. The U.S. Department of Energy (successor ERDA) has completed the tasks of resource characterization and presently pursues research directed to improving the efficiency of recovery of gas from the shales. The present project is a continuation of studies initiated in 1968. The first directional well test was drilled in September and October, 1972, in Harvey District, Mingo County, West Virginia, in a cooperative project with Columbia Gas. The well was targeted to reach an inclination of 60°, but only obtained a deviation of 42±. The second test was conducted in 1976 in cooperation with Consolidated Natural Gas (CNG) in Jackson County, West Virginia, and obtained an inclination of 52°. The third test was conducted in Meigs County, Ohio, in 1982. Again, the target inclination was 60°, but only 25° was obtained in this test.

The U.S. Department of Energy's Morgantown Energy Technology Center awarded The BDM Corporation a contract in September, 1985, to select an area within the productive areas of Devonian shale production; pick a specific site; prepare a specific drilling plan; drill, core, log, test, stimulate and evaluate the recovery efficiency of the well. The results of Phase I operations are presented in a separate report. This report covers all Phase II plans, operations, and results and analyses.

2.3 Objectives of Phase II Operations and Plans

The objectives considered for Phase II operations and plans were:

1) Develop a rationale for a systematic approach to designing stimulations for the well.

2) Conduct a series of stimulations designed to optimize the fluids, injection rates, proppant volumes and general approach to stimulating a horizontal well with similar geologic conditions.

3) Develop and test a method or methods for determining the geometry of stimualtion-induced fractures.

4) Conduct tests and analyze the results to determine the efficiency of stimulation operations.

The technical approach pursued in developing plans to accomplish these objectives was to:

1) Review the data needs for all objectives and obtain that data first.

2) Identify the operating geologic, geomechanical, and reservoir parameters that need additional clarification or definition.

3) Investigate existing models which could be used to plan or evaluate stimulation on the well and the reservoir.

4) Plan for analysis and verification of models and approaches.

2.3.1 Operational Plans for Phase II

The overall requirements for work to accomplish the Phase II objectives was defined by two tasks. The following is a brief description of the work plan for Phase II operations:

Task 1 - Well Stimulation and Fracture Diagnostics

Prepare plans, conduct stimulations, collect fracture diagnostics data, conduct well tests, analyze results.

Subtask 1 -- Prepare a preliminary well stimulation plan and fracture diagnostics plan.

Subtask 2 -- Conduct small-scale frac testing in a selected zone to aid in the overall job design.

Subtask 3 -- Prepare a detailed well stimulation design and procedures utilizing the information obtained in Subtask 2. Initially, only four of the seven zones were to be stimulated.

Subtask 4 -- Stimulate the four zones chosen in Subtask 3 using a combination of high and low rates with large and small volumes as determined from Subtask 3.

Subtask 5 -- Analyze the stimulation test data and fracture diagnostics data; prepare post-frac testing schedule.

Subtask 6 -- Conduct the post-frac testing of the selected intervals.

Subtask 7 -- Analyze the post-frac test information and compare it to pre-frac information. Make conclusions based upon these test results.

Task 2 - Prepare Final Report to be Submitted to the Department of Energy

Collect, collate, analyze, and report on the results of all operations during Phase II and summarize overall activities as a final report of the Recovery Efficiency Test Project.

2.3.2 Stimulation Objectives

The objective of the stimulation operations was to try to learn as much as possible about designing stimulations for a horizontal well which is completed as an open hole completion with direct access to more than 2213 feet of wellbore. The accepted proposal planned one mini frac to collect design data such as leakoff rates, breakdown pressure and closure pressure, and four conventional frac jobs. The results of these stimulations could be used to design an optimum frac job which could be applied to the balance of the untested well.

2.3.3 Fracture Diagnostics Objectives

The objective of fracture diagnostic operations was to determine the orientation, spatial distribution and geometry of hydraulically induced fractures. Since the well was being stimulated open hole; and because a number of natural fractures was known to exist; and BDM geologists predicted that these natural fractures could be inflated and propagated; then the fracture diagnostics tests could provide information that would help ascertain whether or not the objectives had been accomplished.

2.3.4 Well Test and Analysis

The objectives of well test and analysis operations was to collect data which could be used to determine how successful the stimulation jobs were. Analysis of the data would indicate any improvement in production capacity, wellbore damage, and determination of improvement ratio.

3.0 WELL STIMULATION

3.1 Rationale Development and Planning

The Recovery Efficiency Test well is located in the west-central plateau region of the Appalachian Basin (Figure 3.1.1). The rock strata generally exhibit low 1 to 1-1/2 degree dip southeast toward the center of the Basin. Faulting of the basement rocks during pre-Cambrian time produced a series of normal faults in the area, thus the area is considerably fractured and faulted and nearly stress relieved.

Since the area is in a state of tectonic relaxation, the investigators anticipated a low fracture pressure gradient for stimulations on the well. The authors further postulated that the multiple fracture orientations observed in wells in the area (Figure 3.1.2), in the wellbore (N37E, N48E, N57E, and N67E), and in core material are within a 15 degree angle with the principal stress orientation (N48-52E) and likely are good conduits for the flow of natural gas. Natural gas was observed flowing from fractures oriented both N37°E and N67°E on the video camera analysis. It seems logical that fractures which permit gas to flow into the wellbore can, in turn, be inflated and propagated during the hydraulic fracturing processes. One of the prime directives for this project was to evaluate the potential for enhancing natural production by inducing multiple hydraulic fractures; thus inflating natural fractures seems like an excellent way to induce multiple fractures.

3.1.1 Introduction and Background

The objective of stimulation research in the horizontal wellbore was to determine the recovery efficiency of the natural fracture system and the effects expected from hydraulically fracturing the well whenever multiple fractures would be induced. To determine the most effective wellbore stimulation under these conditions, it was necessary to use a systematic approach to examine the effects of various combinations of four factors, which were: (1) type of fluid (e.g., gas, liquid, foam);

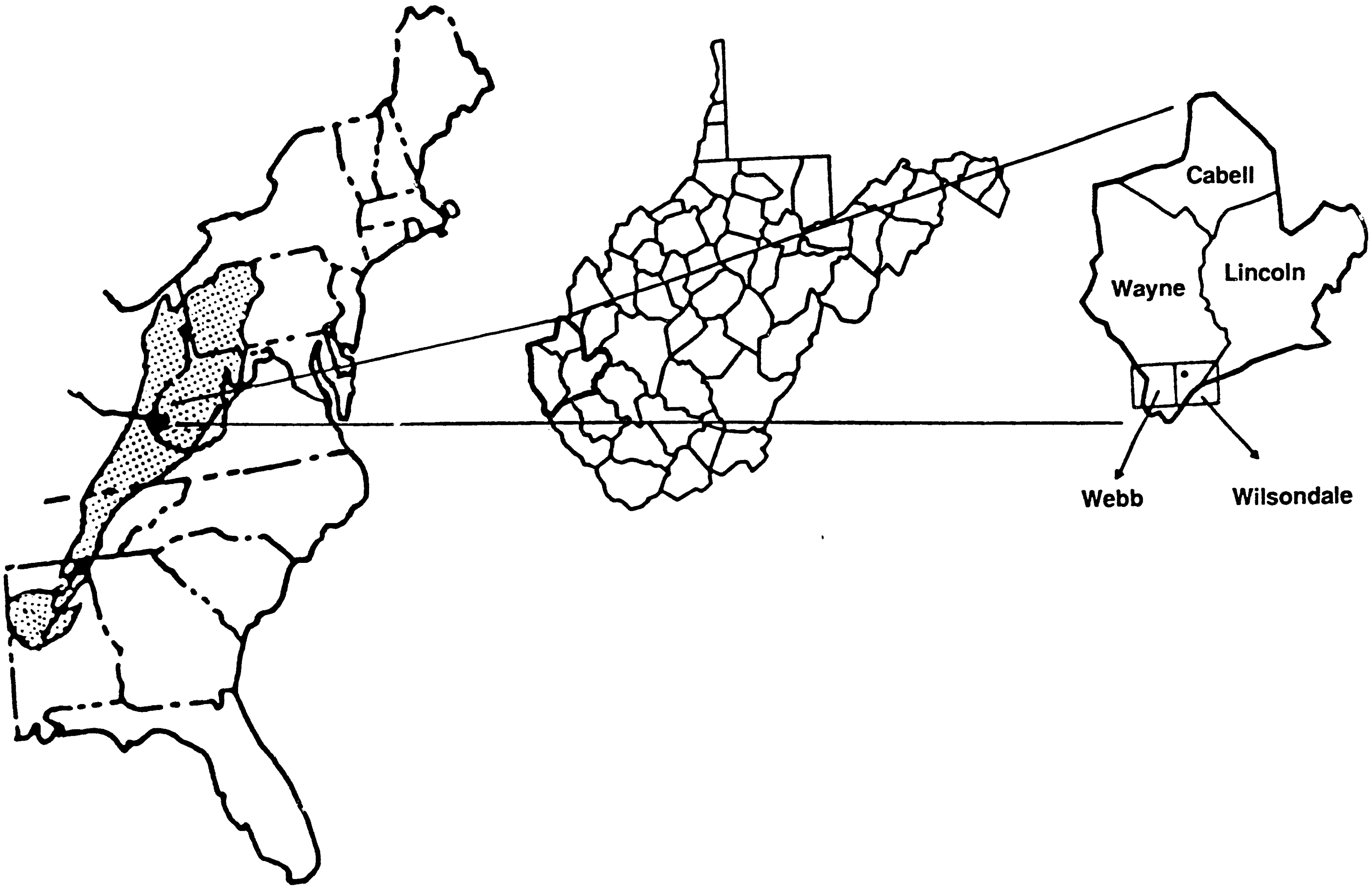


Figure 3.1.1: Location of the Project in the Appalachian Basin

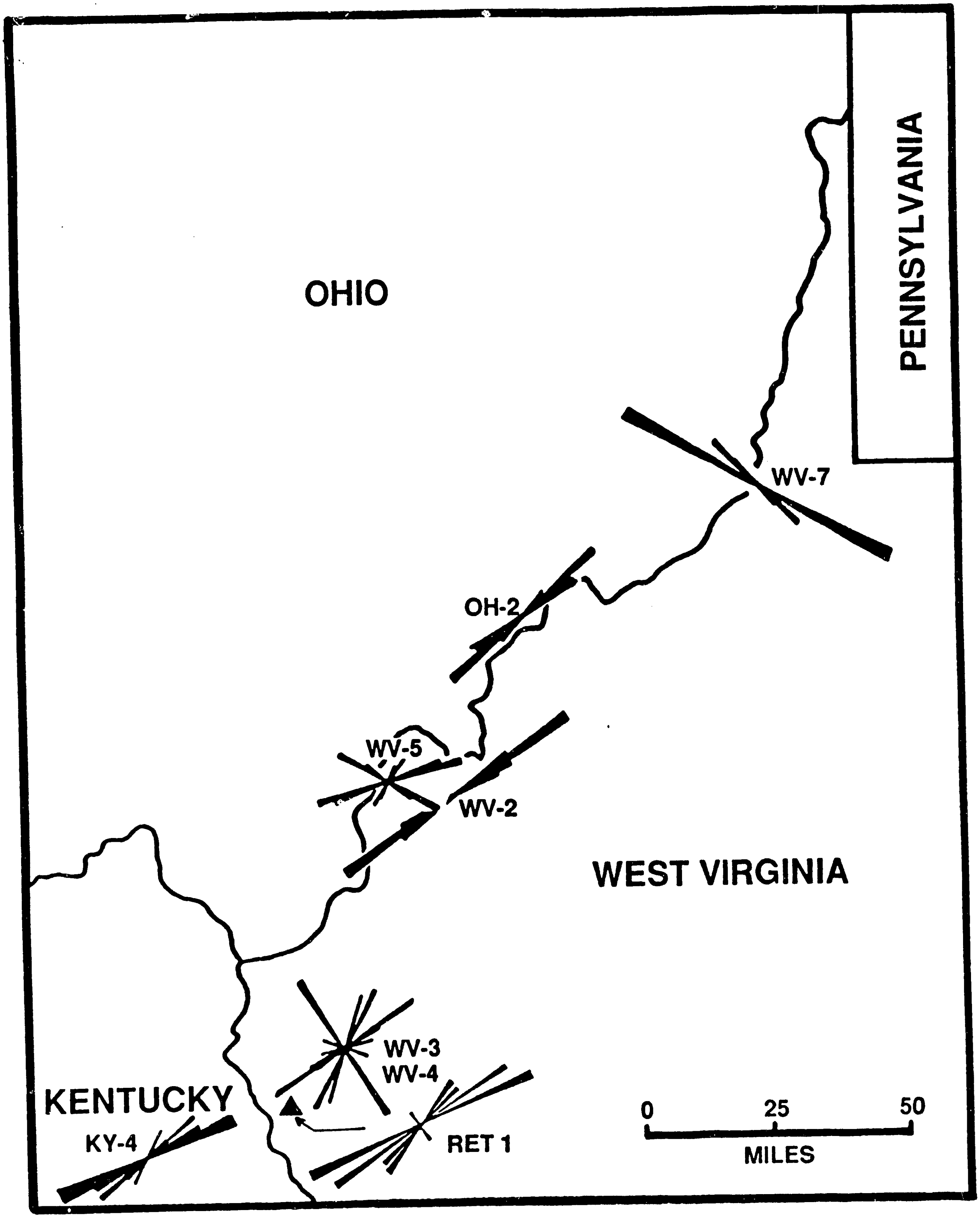


Figure 3.1.2: Location and Comparison of RET #1 Core Fractures with Orientation of Natural Fractures Measured in DOE Oriented Cores Obtained During the EGSP Resource Evaluation Studies

(2) fluid injection rate; (3) volume of fluid injected; and (4) bottomhole treating pressure. Following each stimulation, flow rate and build-up test data were used to determine permeability-thickness product and flow rate improvement ratio. Key stimulation issues identified were:

(1) the number of fractures that could be opened and propagated during a single hydraulic fracture pumping event;

(2) whether proppant would screen out easier in a horizontal well;

(3) understanding what determines which natural fractures are propagated;

(4) determining the best fracture diagnostic system to use in a horizontal well;

(5) understanding how to place proppants and the volumes required;

(6) understanding the need or value of pad volumes when treating multiple fractures at the same time.

The overall technical approach was to:

(1) induce multiple hydraulic fractures, both controlled and uncontrolled;

(2) determine how many and where fractures were induced in the borehole;

(3) evaulate hydraulic fracture design for a horizontal well in shale formation;

(4) establish need or lack of need for proppant in low stress ratio (minimum horizontal to vertical) areas.

Conceptual hydraulic fracture design had to consider the strong interaction between the natural fracture orientation of N37°E and N67°E and the predicted induced fracture trend of N52°E as shown in Figure 3.1.3. In addition, the consideration of other joint systems having nearly parallel orientations which would either act as leakoff areas or actually accept fracture fluid under propagating conditions. Each zone available for stimulation had numerous natural fractures which would accept fracturing fluid. The open hole type completion using external casing packers to isolate zones with different stimulation potential, such as

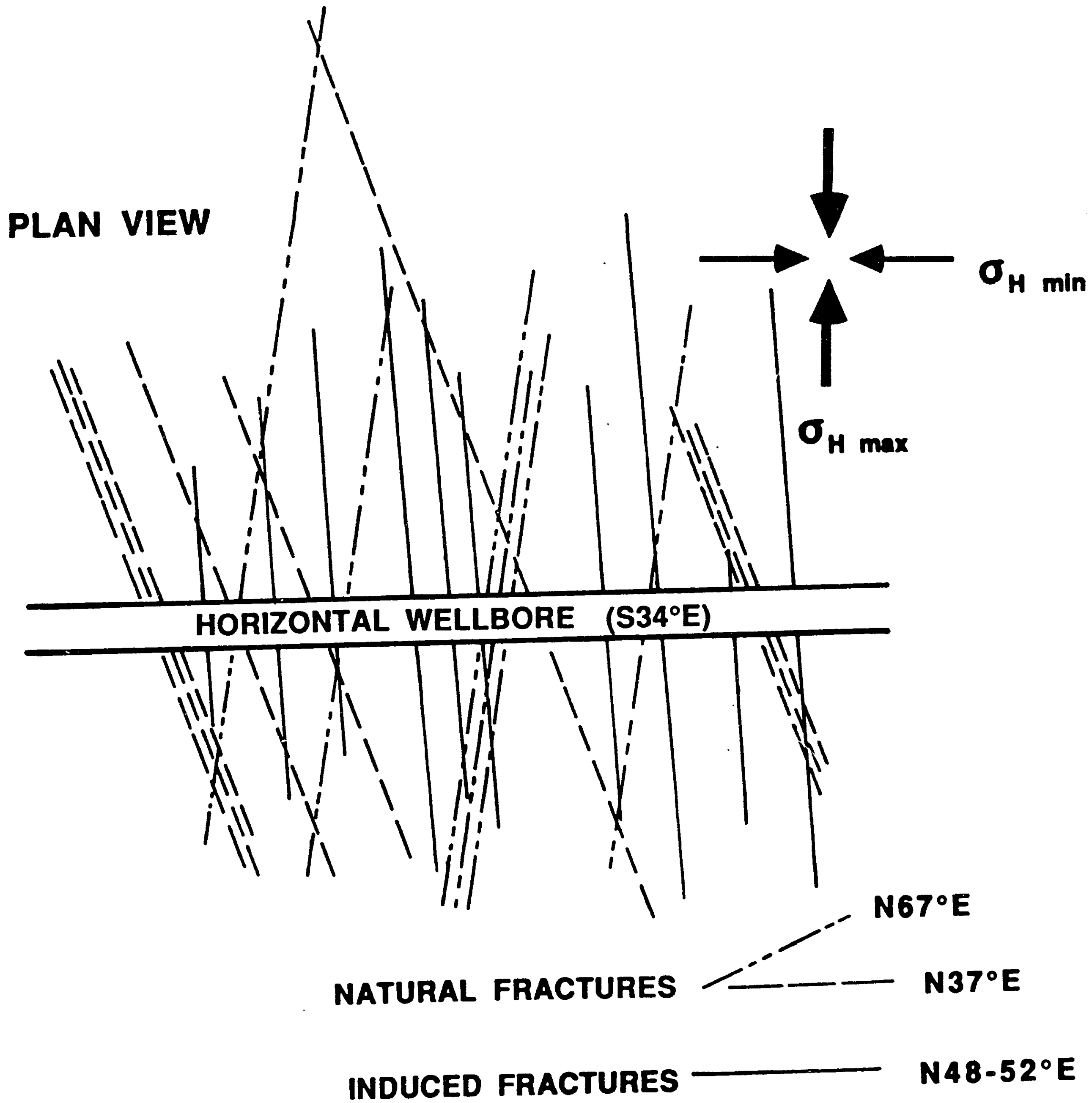


Figure 3.1.3: Schematic Diagram Presenting Orientation of Natural Fractures as Oriented by Borehole Camera Analysis and Orientation of Regional Stress Field Horizontal Components

the number of fractures present, is shown in Figure 3.1.4. Therefore, the need for acquiring injectivity information was warranted to observe whether multiple hydraulic fractures were propagated during a single pumping event as postulated in Figure 3.1.5.

3.1.2. Review of Pre-Stimulation Data

During Phase I, each individual zone in the well was tested to measure flow rates and to estimate permeability. A combination tool was used to open and close port collars as well as provide pack-off for zone isolation during pre-frac testing. Pre-frac flow rates from individual zones varied from 2 to 17 thousand cubic feet of gas per day (mcfd). Pressure build-up tests were conducted on seven zones with permeabilities ranging from .031 to .098 millidarcies (md). A summary of all pre-stimulation input data and reservoir characteristics is provided in Table 3.1.1 and 3.1.2 respectively.

3.1.3 Stimulation Rationale

The mechanical handling of fracturing fluids, proppants, and tracer materials along a 2000 foot horizontal wellbore offers a technical challenge relative to developing a systematic approach to conducting fracturing experiments in selected zones without causing any permanent damage to the wellbore that would prevent execution of remaining stimulations. The rationale used was to select the lowest productive zone(s) to conduct experiments in and subsequently, reserve the better zones for full-scale stimulation. As shown in Table 3.1.1, both Zone 6 and 1 were selected for testing. Zone 6 had very few fractures and was selected for the mini frac tests, while Zone 1 had many fractures and was selected for frac fluid testing. The overall stimulation rationale focused on the following considerations:

(1) Primary design was to propagate natural fractures with a slight difference in orientation from principal stress orientation.

(2) Injection at low rates allows fluid to select pre-existing natural fractures to be propagated.

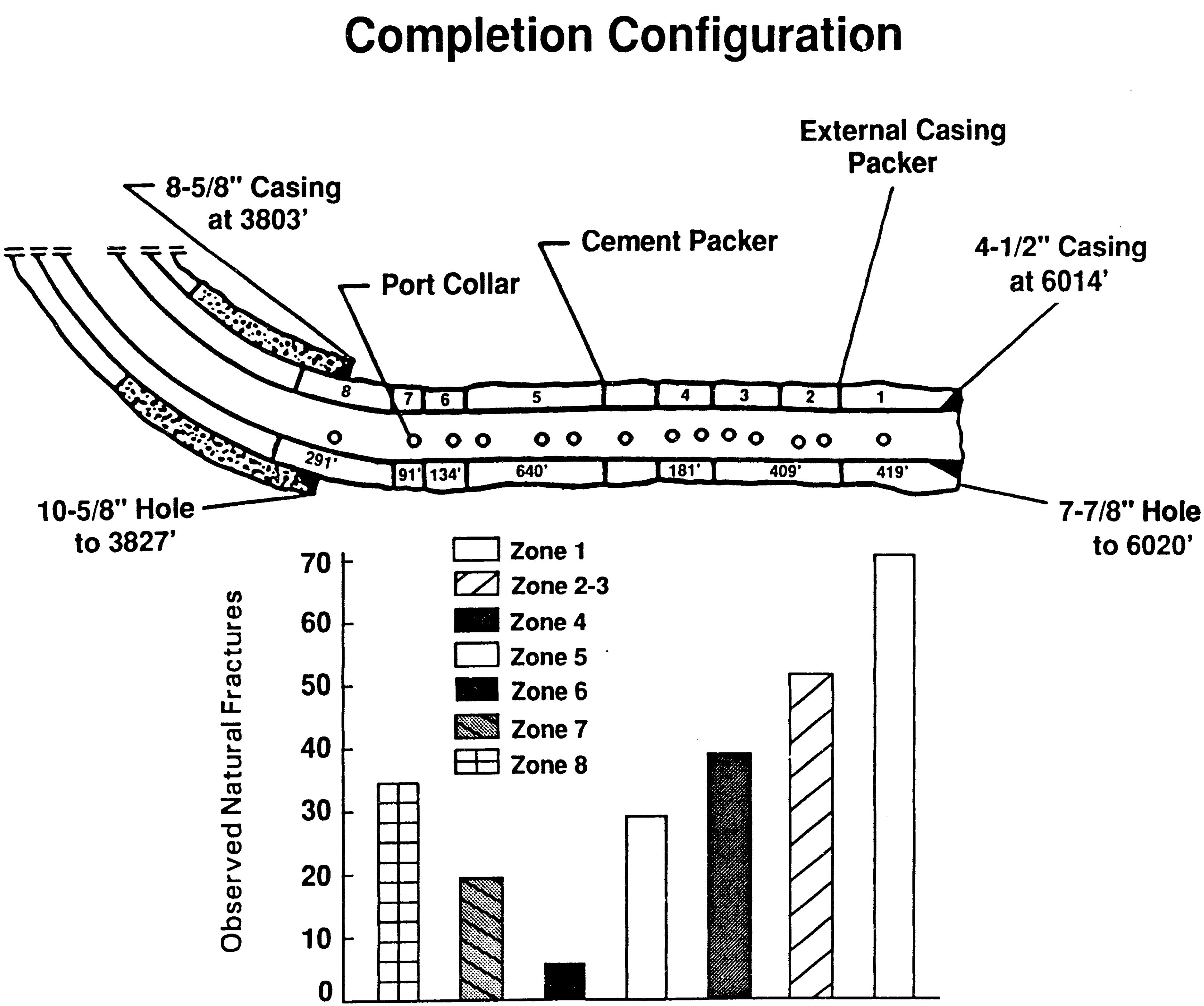


Figure 3.1.4: Schematic Diagram of Completion Configuration and Numbers of Observed Natural Fractures in Each Zone Showing Irregular Distribution Frequency

DIAGRAM OF MULTIPLY-ORIENTED MULTIPLY-INDUCED HYDRO-FRACTURES

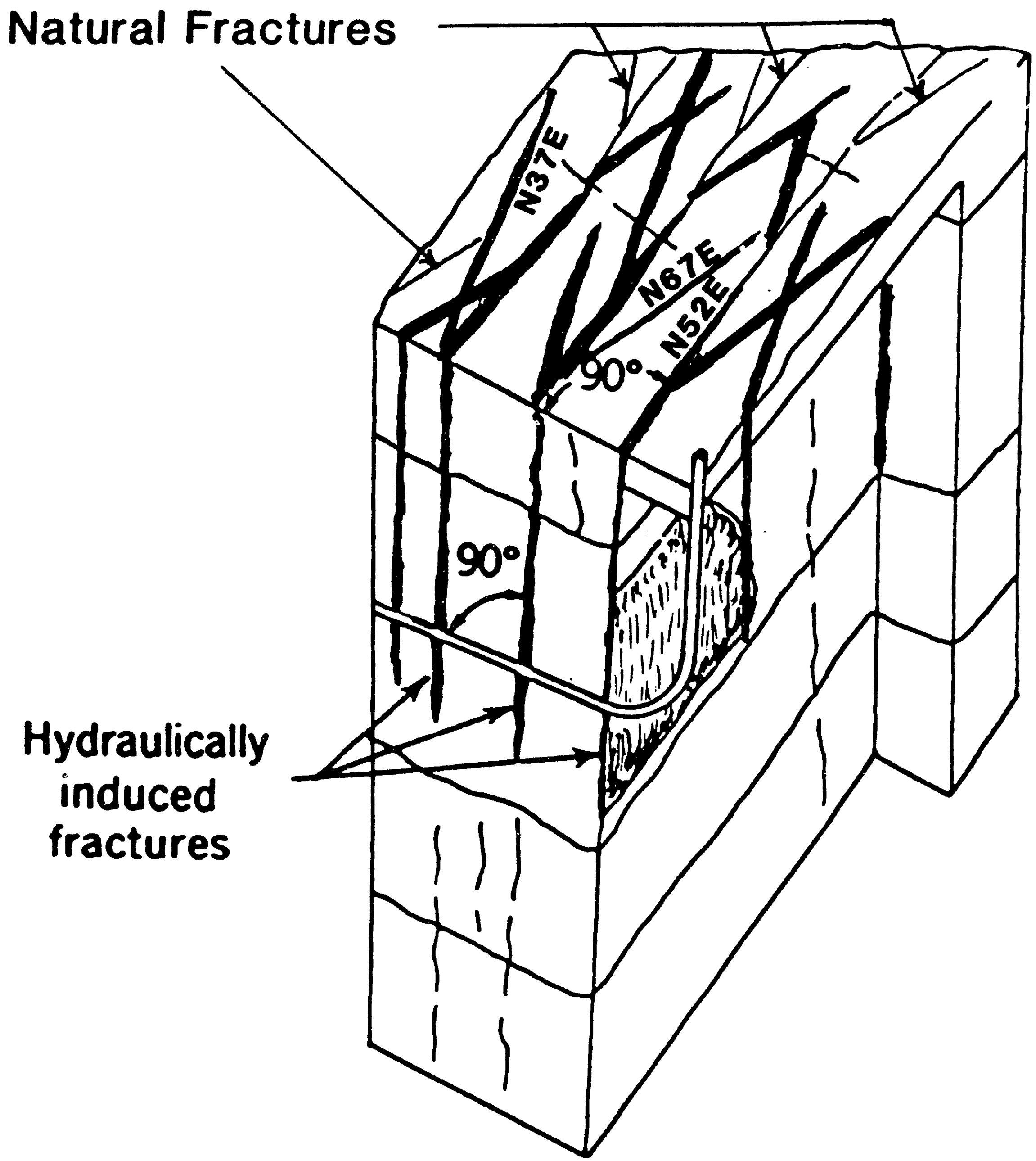


Figure 3.1.5: Three Dimensional perspective Diagram Showing Predicted Inflation of 2 Sets of Natural Fractures and 1 Direction of Induced Fractures

TABLE 3.1.1

PRE-STIMULATION INPUT DATA

ZONE	INTERVAL (md)	INTERVAL (TVD)	TVD	md	FLOW RATE (mcfd) (Pre-Frac)	PRESSURE BUILD-UP (24 hrs)
1	6014 - 5610	3426.7 - 3409.2	17.5	404	2.2	54
2-3	5602 - 5185	3408.8 - 3397.0	11.8	417	4.4	75
4	5176 - 4994	3396.8 - 3392.8	4.0	182	16.7	68
5	4986 - 4346	3392.7 - 3393.2	0.5	640	4.4	73
6	4337 - 4202	3393.5 - 3397.0	3.5	135	2.2	74
7	4194 - 4104	3397.2 - 3400.4	3.2	90	0.0	74
8	4095 - 3803	3400.7 - 3364.6	36.1	292	5.2	83
				2160[1]	35.1[2]	

[1] Excluding packers.

[2] Stabilized flow rate.

TABLE 3.1.2

RESERVOIR CHARACTERISTICS BY ZONE

ZONE	PERMEABILITY, md (SIMULATION)	AVERAGE FRAC SPACING, ft (TV CAMERA)	NO. OF FRACTURES (CAMERA)	MAJOR SHOWS >100 mcfd	MINOR SHOWS <100 mcfd	TOTAL GAS SHOWS (MAJOR + MINOR)
1	0.031	6.0	69	0	3	3
2-3	0.078	7.9	51	4	0	4
4	0.098	7.8	23	4	2	6
5	0.073	22.9	28	0	16	16
6	0.078	22.3	6	0	1	1
7	0.037	5.4	17	1	1	2
8	0.068	8.6	34	1	4	5
		11.6	228	10	27	37

(3) Injection at pressures which will keep the fracture(s) from growing out of zone.

(4) By starting off at low injection rates and not exceeding 200 psi above closure pressure with average BHTP, natural fractures would be propagated.

(5) By increasing injection rates, additional fractures would be induced which would likely create a network of interconnected fractures with orientations of N37°E, N52°E, and N67°E.

The initial frac design sequence was premised on treatment of Zone 6 with both N_2 and foam injection tests to verify fluid leakoff characteristics for low and high viscosity fluids. The initial flow diagram was developed to conduct pre-frac tests on Zone 6, followed by hydraulic fracturing experiments using straight N_2 and CO_2 in Zone 1, followed by N_2-foam without proppant on Zone 2-3 and 5 as shown in Figure 3.1.6.

3.2 Preliminary Studies - Data Frac

As previously discussed, Zone 6 was selected for data frac experiments to determine breakdown pressure, closure pressure, and leakoff characteristics. A computer-controlled data acquisition system was used to perform fluid injection tests.

3.2.1 Data Frac Design

The data frac-treatment procedure is described as follows:

(1) Pump straight N_2 downhole to load hole at 5 bbl/min (2500 scfm) to fill wellbore. (Wellbore storage calculated at 51,000 at 1600 psi.) Estimated time: 20.4 minutes.

(2) Pump Test No. 1 at 5 bbl/min rate for 15 minutes. (2500 scf x 15 minutes = 37,500 scf N_2.)

(3) Shut in for 37.5 minutes and watch leakoff.

(4) Pump Test No. 2 at 15 bbl/min rate for 15 minutes. (7500 scf N_2 x 15 minutes = 112,500 scf N_2.)

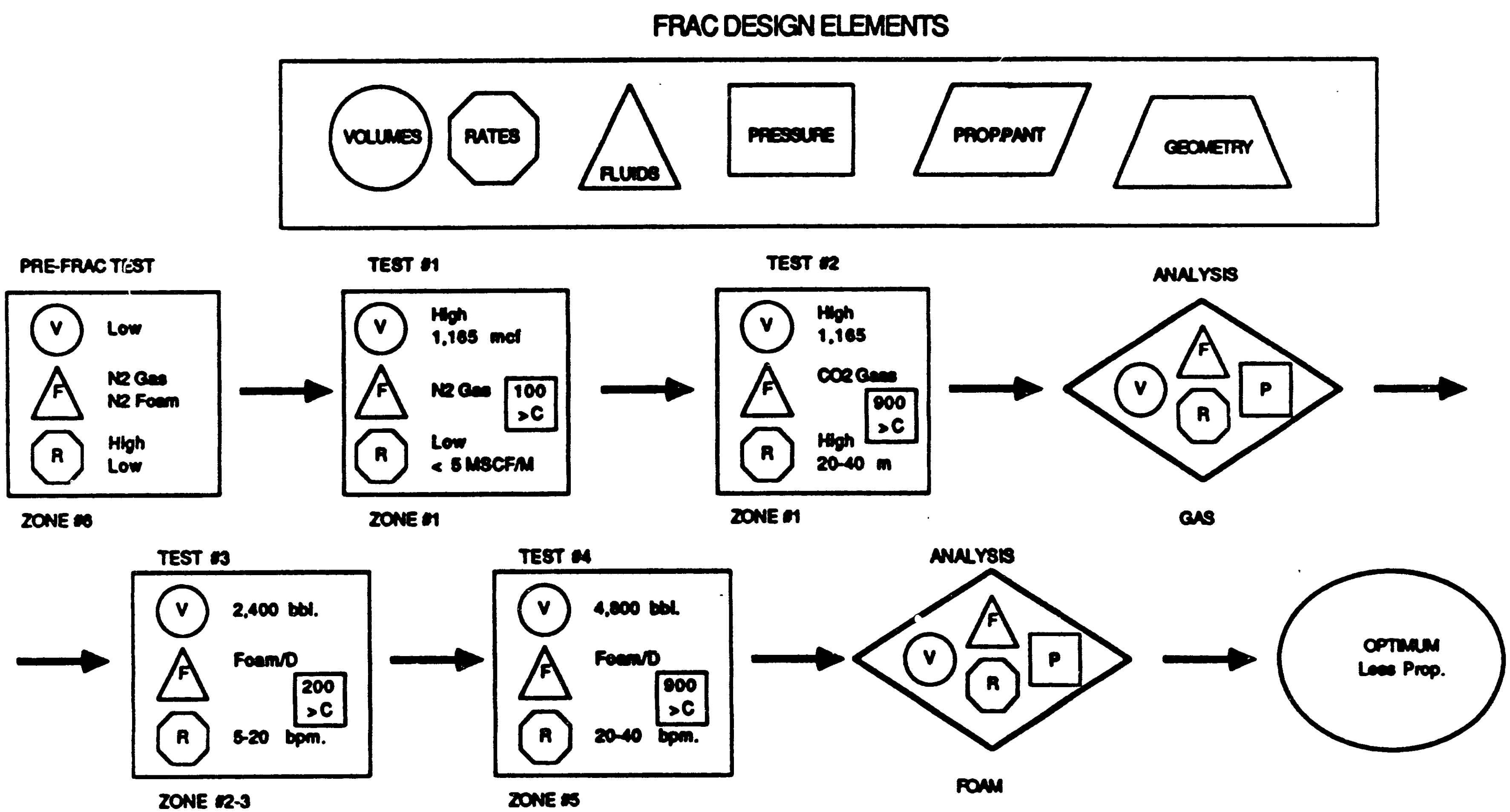


Figure 3.1.6: Schematic Diagram Illustrating Stimulation Test Series to Determine Optimum Frac Design

(5) Shut in for 37.5 minutes and watch leakoff.

(6) Pump 80 quality foam at 5 bbl/min for 20 minutes. (Tag with radioactive iodine.) (40,000 scf N_2)

(7) Shut in for 50 minutes to watch leakoff. Note ISIP calculated closure pressure.

(8) Pump 80 quality foam at 15 bbl/min for 20 minutes. (Tag with second RA liquid.) (120,000 scf N_2)

(9) Shut in for 50 minutes to watch leakoff. Note ISIP calculated closure pressure.

(10) Within 2.5. hours, replumb well for flowback.

3.2.2. Data Frac Testing

Approximately 25,000 scf of N_2 was used to load the hole to start the data frac activities in Zone 6.

Pump Test No. 1 was pumped for 15 minutes at an average rate of 2500 scfm of N_2, then shut-in for 15 minutes to watch leakoff rate. Leakoff rate was 6.6 psi per minute. A total of 37,500 scf N_2 was pumped into the formation.

Pump Test No. 2 was pumped for 15 minutes at a programmed rate of 7500 scfm of N_2; however, the rate meter was in error and injection rate is projected to be 10,000 scfm since the unit was running wide open. A total of 150,000 scf of N_2 was pumped into the formation. Leakoff rate was 8.4 psi per minute.

Pump Test No. 3 was pumped for 20 minutes at 5 bbl/min of 80 quality foam. Leakoff rate was 41.5 psi per minute after Test No. 3; 33,000 scfm of N_2 was pumped during this stage. Radioactive scandium was injected as a tracer for this test. A total of 100 bbls (4200 gallons) of foam was injected in the formation.

Test No. 4 was pumped for 16 minutes at 12 bbl/min of 80 quality foam. Leakoff rate was 4.7 psi per minute for the final stage; 69,200 scf of N_2 was pumped during this stage. Radioactive iodine was injected with the foam as a tracer for the final test. A total of 200 bbls of foam (8400 gallons) was injected in the formation. A pressure versus time plot is provided in Figure 3.2.1.

Four Stage Pre-Frac Test
(Zone 6)

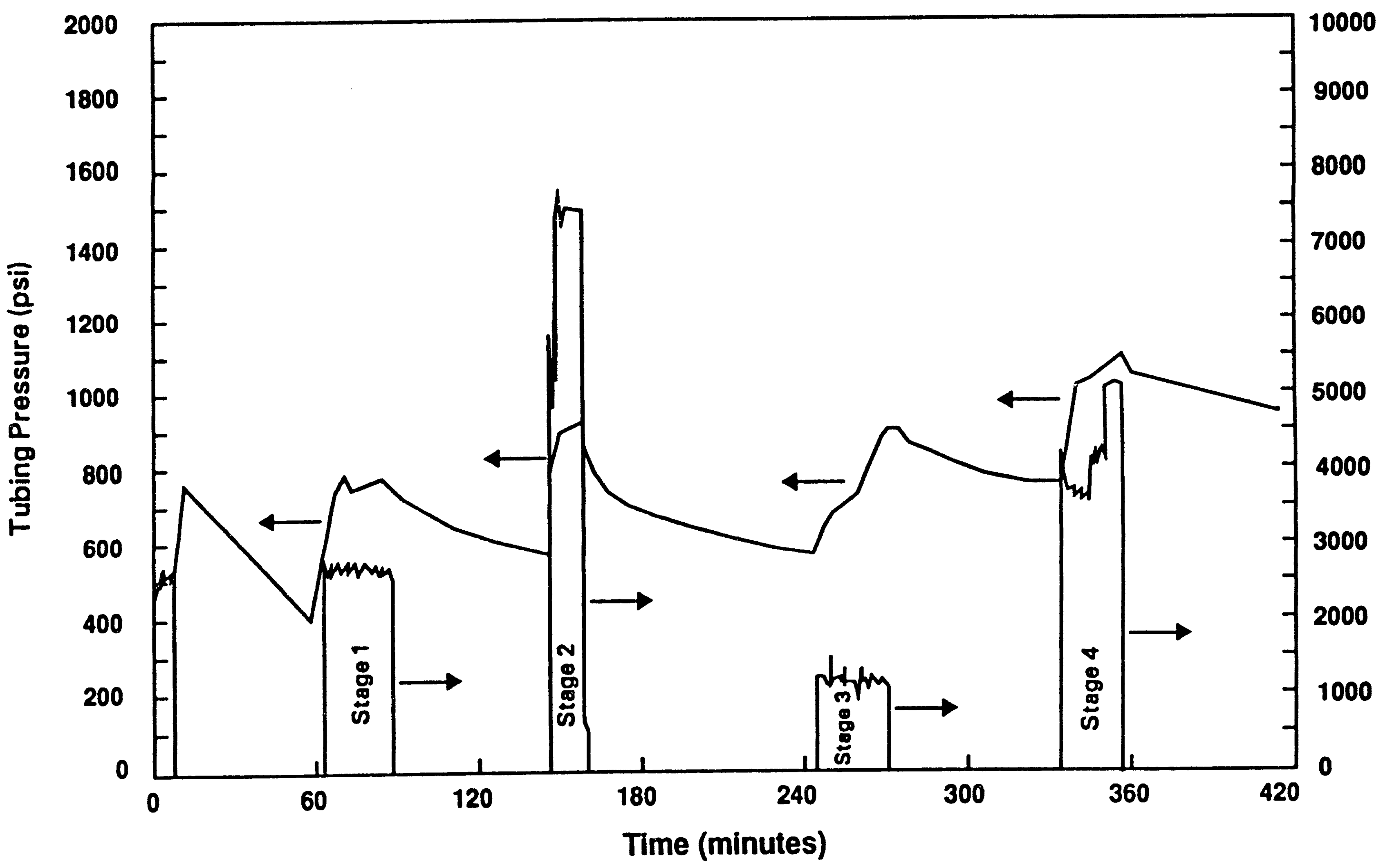


Figure 3.2.1: Plot of Tubing Pressure and Injection Rate versus Elapsed Time for Each Stage of the 4-Stage Pre-Frac Data Test

Following the four data frac experiments on Zone No. 6, a spectral gamma ray, casing collar, and temperature log was run into the well on coiled tubing through Zone 6 (see Figure 3.2.2). Evaluation of the tracer log indicates that the majority of the tracer material was located in the vicinity of the only mud log gas show in Zone 6. However, up to 13 fluid entry points were observed in Zone 6 on the tracer log (see Figure 3.2.3) as compared to 6 natural fractures observed on the downhole camera. Note the opening of natural fractures near the external casing packer at 4200 feet during injection at 5 bbls/min. Scandium-46 was the tracer used in this stage. Additional fractures were induced when the rate was increased to 12 bbl/minutes.

Results from the data fracs as shown in Table 3.2.1 indicate the following:

(1) two different closure pressure (850 and 1050 psi) were observed from the N_2 and N_2-foam injection test. One possible explanation was that different fractures were induced having near-adjacent angles in Zone No. 6;

(2) calculated fluid loss coefficients vried from 2.75 x 10^{-4} to 1.38 x 10^{-3} ft/min between N-2 foam;

(3) frac gradients ranged from .25 to .31 psi/ft; low frac gradients provide a formation stress environment where proppants may not be necessary;

(4) fracture diagnostics indicate that the differences in foam injection was not enough to alter the preferential fluid acceptance paths established by an initial injection rate of 5 barrels per minute; and

(5) fracture diagnostics showed four of six natural fractures were opened and propagated, plus nine additional fractures were generated which interconnected with Zone No. 5.

Following well logging, Zone 6 was produced and cleaned up over a 7-day flow period, and a 75 psi back pressure was applied to simulate flowing conditions. After 10 days of flowing, Zone 6 was flowing 14 thousand cubic feet of gas per day (mcfd) as compared to a pre-frac rate of 2 mcfd. After 3 days of simulated back pressure, the well's flow rate suddenly dropped to 9 mcfd as shown in Figure 3.2.4. A plausible

Tracer Log of Zone 6 Tests

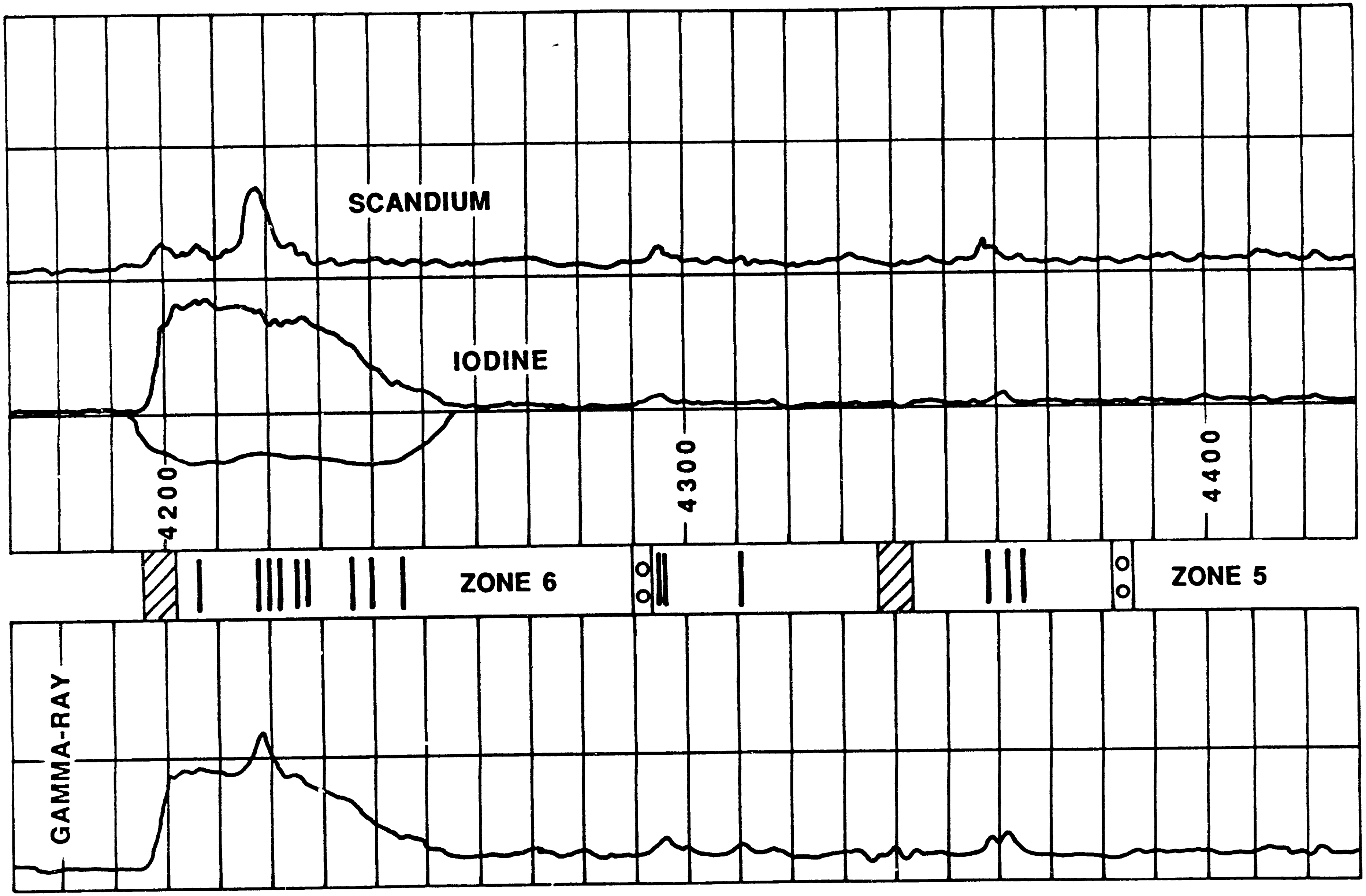


Figure 3.2.2: Tracer Log Response in Zone 6 and Showing Location Fracture Pumped Into and Induced During Data Frac Test

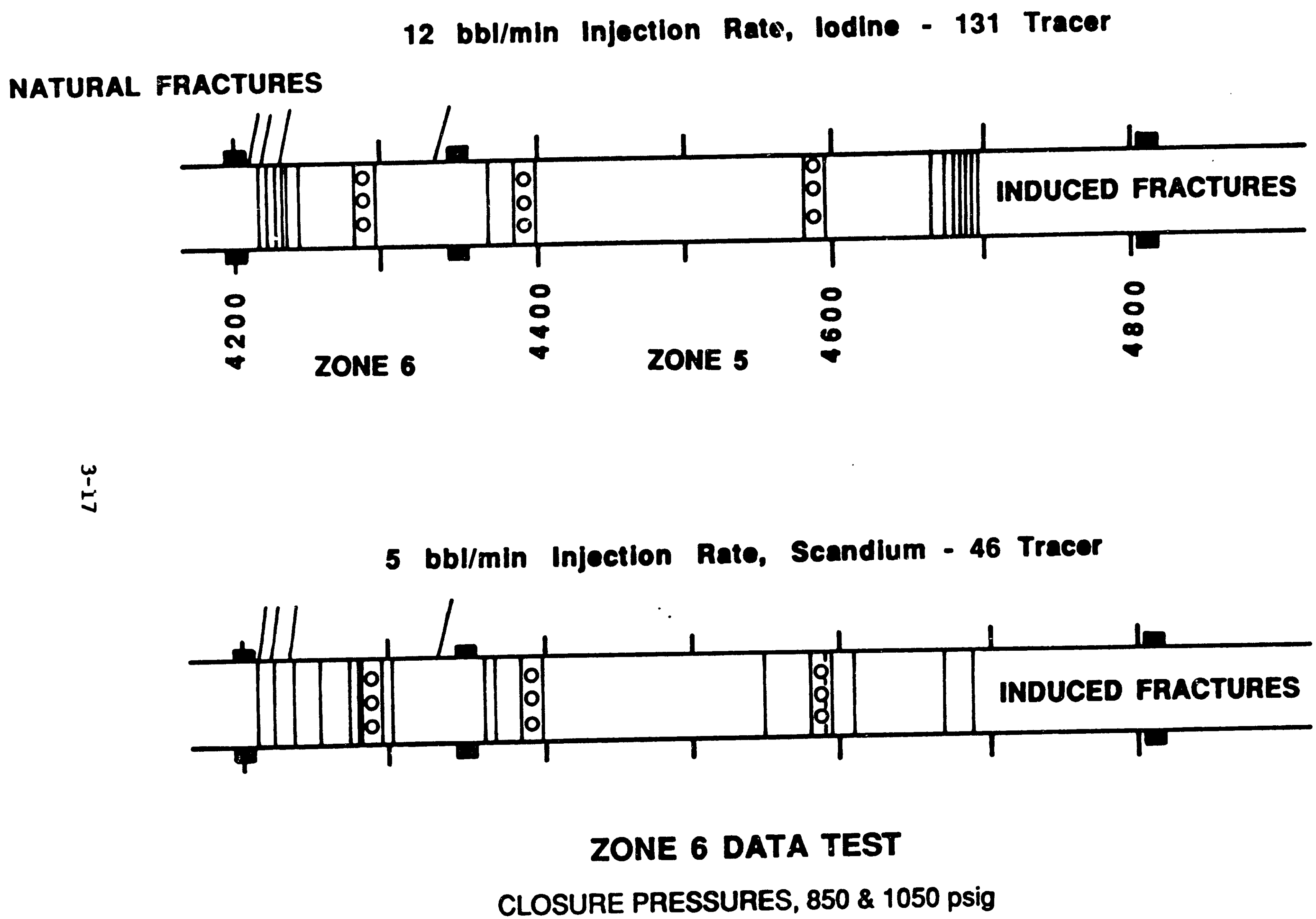


Figure 3.2.3: Schematic Diagram of Zones 5 and 6 Showing Location Fracture Pumped Into and Where Fracture Came Back to the Wellbore During Data Frac Test

TABLE 3.2.1

ZONE NO. 6 DATA FRAC RESULTS

TEST	NO. FRACTURES TAKING FLUID	CALCULATED FLUID LOSS COEFFICIENT (ft/min)	CLOSURE PRESSURE	FRACTURE GRADIENT
1 - N_2	5	7.90×10^4	850	.25
	10	5.95×10^4	850	.25
2 - N_2	5	1.38×10^3	850	.25
	10	6.70×10^4	850	.25
3 - 80-Q Foam	5	5.90×10^4	1050	.31
	10	4.70×10^4	1050	.31
4 - 80-Q Foam	4	3.75×10^4	Didn't Close	----
	8	2.75×10^4	Didn't Close	----

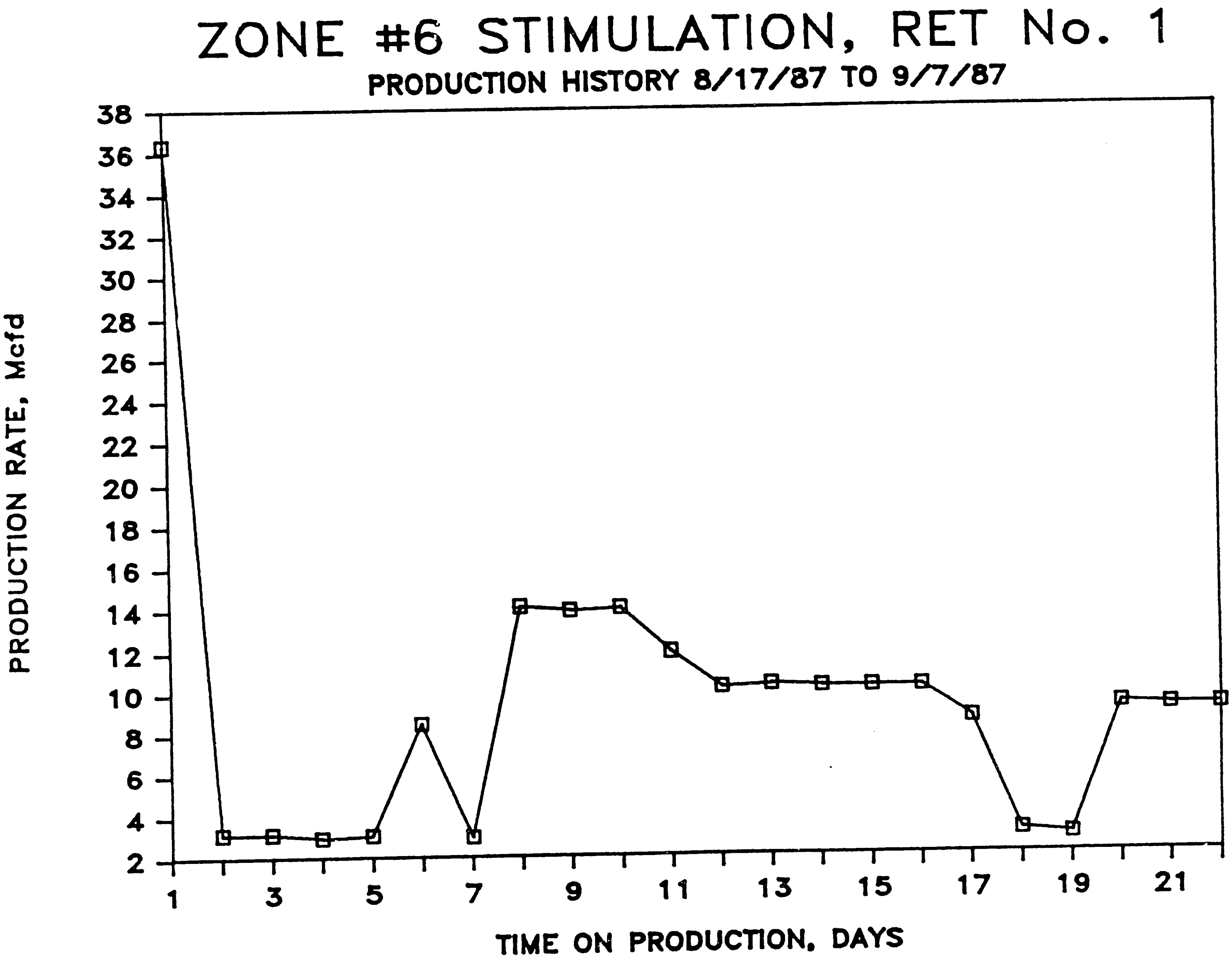


Figure 3.2.4: Production Rate versus Days on Production After Stimulation for Zone 6

explanation for this drop in rate was some of the induced fractures were closing off. Subsequently, 4 days later Zone 6 was opened to atmospheric conditions and production rate dropped to 3 mcfd; however, when the 75 psi back pressure was reestablished, Zone 6 began producing 9 mcfd, a 4.5-fold increase over baseline conditions. A plausible explanation for this type of flow behavior is that the natural gas liquids, observed in the fracture by the downhole video camera, restrict the gas flow under open flow conditions. Subsequently, the addition of back pressure improves the relative flow potential.

After flow rate testing, a 14-day build-up test was performed on Zone 6. Both the pre-frac and post-treatment build-up test for Zone 6 are shown in Figure 3.2.5. Results of the build-up test analysis was used to develop a history matching model using G3DFR to estimate permeability (Figure 3.2.6). Results indicate a permeability increase from .079 to .184 md, while the measured flow improvement ratio was 4.8:1.

After the data frac execution and evaluation, a logic diagram was developed for the remaining stimulations as shown in Figure 3.2.7. An overall improvement ratio of 9:1 was used as a goal of stimulation. If this improvement ratio was achieved, then all remaining stimulations would be performed in a similar manner and the tests were complete.

3.3 Stimulation #1, Zone #1 - Nitrogen Gas Frac

In keeping with the rationale of examining various fluids, volumes, and injection rates to arrive at an optimum stimulation design for Devonian shale horizontal wells, the first fluid to be tested was nondamaging, nonproppant-carrying nitrogen.

3.3.1 Stimulation Design

Examination of the results of studies of core material from two wells in Lincoln County, West Virginia, about 18 miles ENE from the RET #1 well indicated the minimum horizontal stress in the Rhinestreet

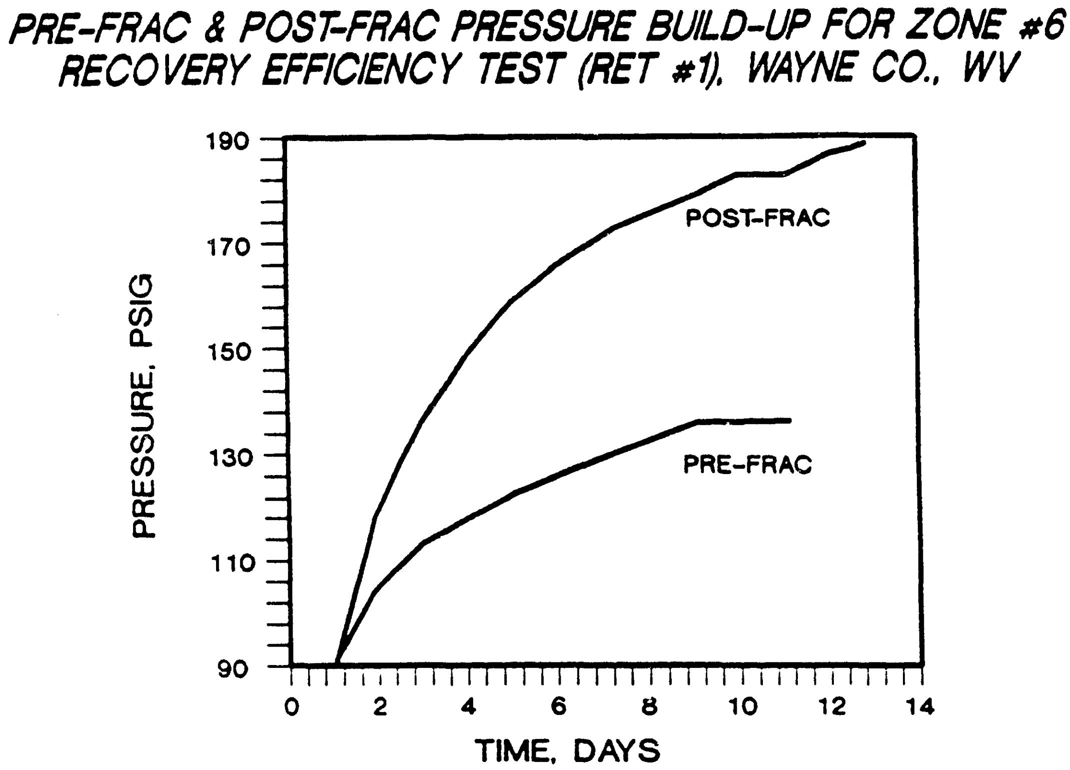


Figure 3.2.5: Comparison of Pre-Frac and Post-Frac Pressure Build-Up Curves for Zone 6 Data Frac Test

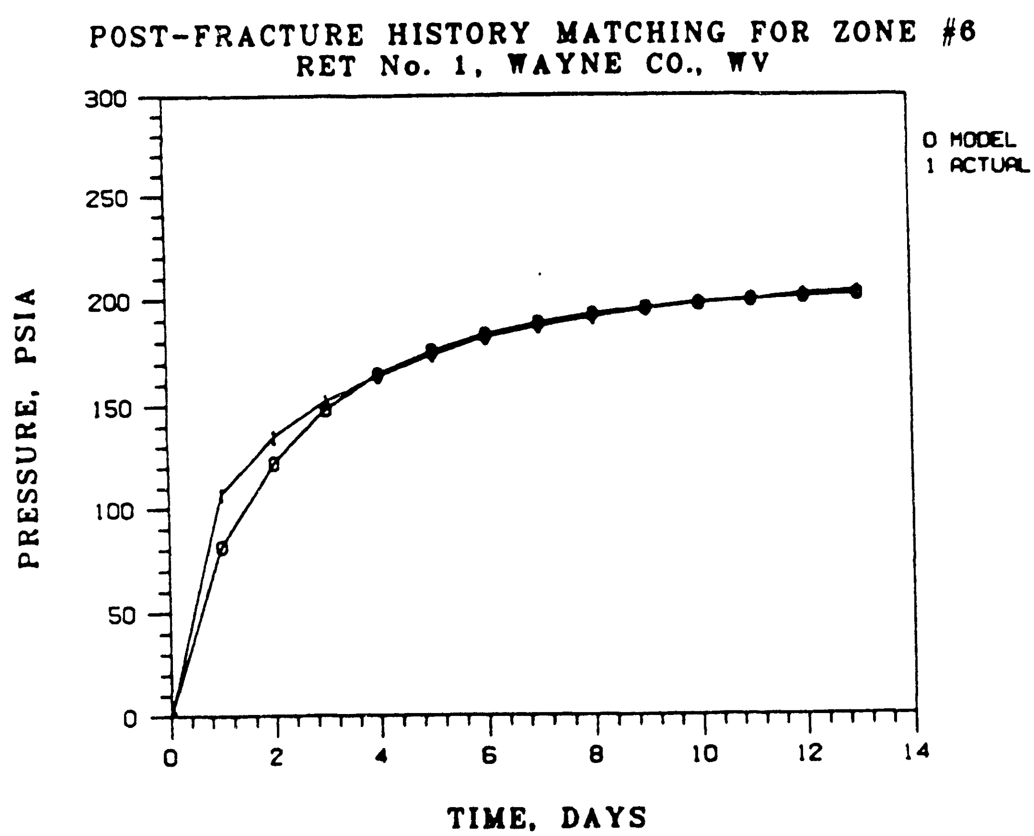


Figure 3.2.6: History Match of Pressure Build-up Curve for Post-Frac Test to Determine Permeability of Zone

REVISED SERIES OF TEST STIMULATIONS

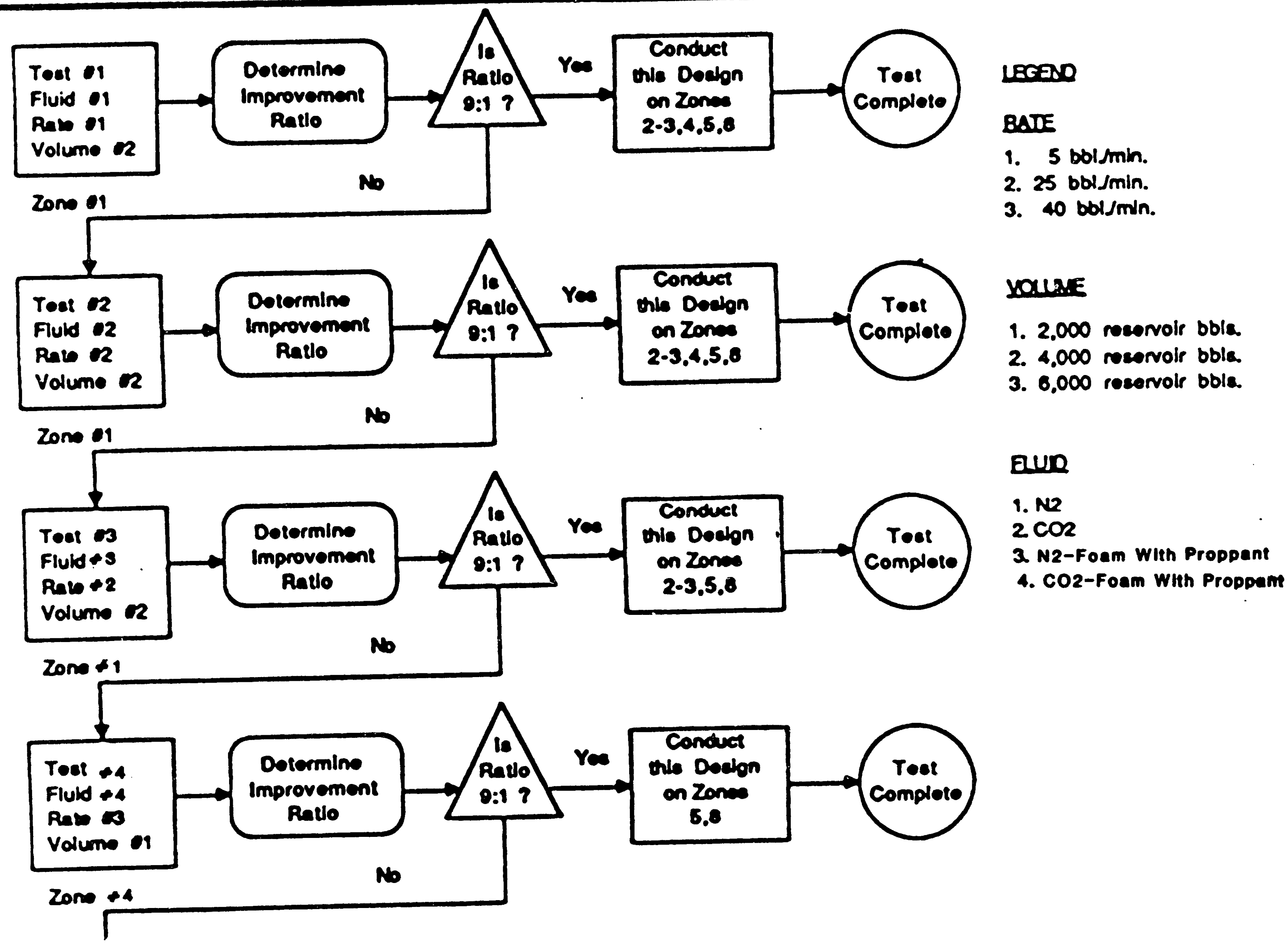


Figure 3.2.7: Schematic Diagram Illustrating Revised Series of Stimulations Including Tests with Proppants

shales was 1300 psi; that for the Huron shales was 800 psi (target formation); while that for the Ohio shales above the Huron shales was 1000 psi. This indicated that it would be easier to propagate a fracture vertically upwards than downwards.

Based on this information, a single plane hydraulic fracture model predicted a bottomhole treating pressure of 200 psi above propagation pressure would result in driving the fracture out of zone. Zone #1, the test zone, had 69 natural fractures identified by a borehole video log which gave some concern about how many fractures could be propagated simultaneously at various injection pressures and rates. One constraint was the fact that the external casing packers would not survive a differential pressure of 2300 psi, so injection pressures should remain below that level. Since BDM wanted to determine if natural fractures could be inflated and propagated by injecting at low pressures and rates, the first stimulation on the well (Test No. 1 on Figure 3.1.6) would be a high volume, low injection rate job. The objective in this design was to propagate multiple fractures simultaneously and try to keep fractures from going out of zone.

3.3.2 Wellbore Configuration

In order to collect as much real time data as possible about the stimulation in progress, a string of 2-3/8 inch EUE tubing was run in the hole to use as a static string to approximate bottomhole pressure at the surface. In addition, a battery-powered quartz-crystal pressure gauge was placed in the bottom of the tubing (see Figure 3.3.1) and 10 feet below the port collar where fluid would be accessing the formation. A pressure transducer was attached to the tubing and tied into an on-site computer van which provided plots of calculated bottomhole treating pressure, injection rate and delta P or differential pressure above fracture propagation pressure. Injection was through port collar #1 at 5746 feet.

3.3.3 Treatment Execution

The nitrogen stimulation treatment was conducted on the morning of September 23, 1987, by injecting down the annulus between the

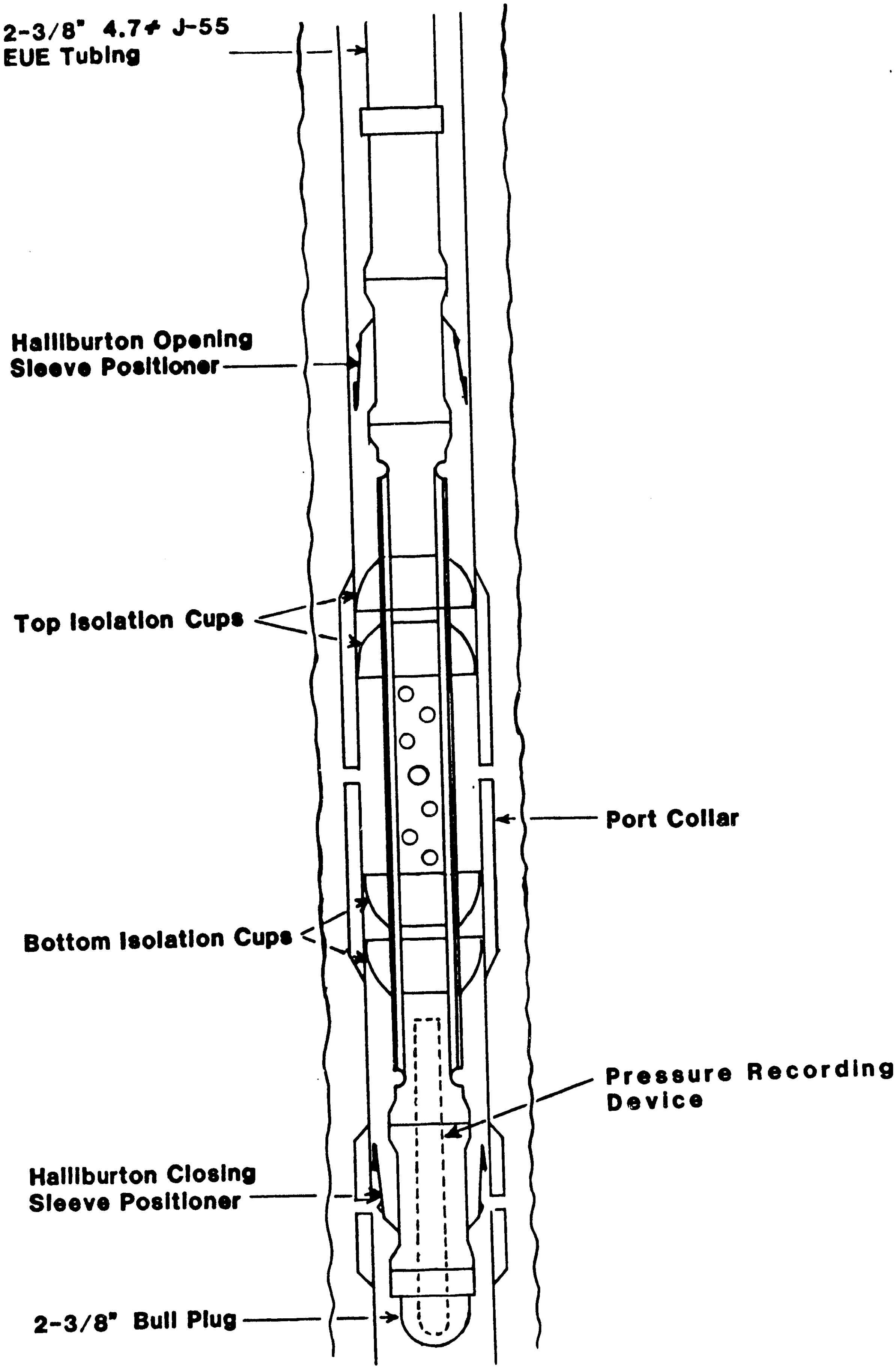


Figure 3.3.1: Schematic Diagram of Isolation Tool and Bottomhole Pressure Recording Device

4.5-inch casing and the 2.375-inch tubing. Injection started at 2000 standard cubic feet (scf) per minute and was to have progressed at incrementally increasing rates to 7500 scf/m. However, the calculated bottomhole treating pressure (BHTP) was above the design delta P (differential pressure) of 200 psi after reaching an injection rate of 3000 scfpm. The rate was slowed down and the incremental increases lowered. Erroneous nitrogen fluid rheology figures introduced about a 100 percent error in the calculated BHTP which prevented us from obtaining design rates. Although when multiple fractures are being propagated, the chances of exiting the target formation would seem to be somewhat reduced.

A total of 1,165,000 scf of nitrogen was injected during the frac job. Initial breakdown occurred at 770 psig. Instantaneous shut-in pressure was 863 psi. Average bottomhole treating pressure for the first half of the job was 840 psig and 865 psig for the second half. A plot of bottomhole treating pressure versus time is shown in Figure 3.3.2. The 770 psi breakdown pressure correlates with the first of three indicated closures. A plot of bottomhole pressure versus square foot of time also defines the pressures quite well.

The job took 5 hours to pump. Table 3.4 presents the different stages and the volumes injected. Pressure falloff was recorded for 35 minutes. The well was replumbed for flowback which was initiated 2 hours, 15 minutes after job completion. The well was initially opened up on a 1/8-inch choke to lower pressure below 550 psi, then the well was opened up and completely blown down overnight so that the pressure bomb could be removed and the bottomhole treating pressure retrieved.

TABLE 3-4

ACTUAL HIGH VOLUME/LOW RATE STIMULATION FOR ZONE NO. 1

VOL. STAGE	INJ. RATE (scf/min)	INJ. TIME (min)	CUM. TIME (min)	VOL. INJ. (mscf)	CUM. (mscf)
1	2,000	30	30	60	60
2	4,000	5	35	20	80
3	3,000	20	55	60	140
4	3,500	35	90	122	262
5	4,000	32	122	128	390
6	4,500	40	162	180	570
7	4,800	50	212	240	810
8	5,000	71	283	355	1165

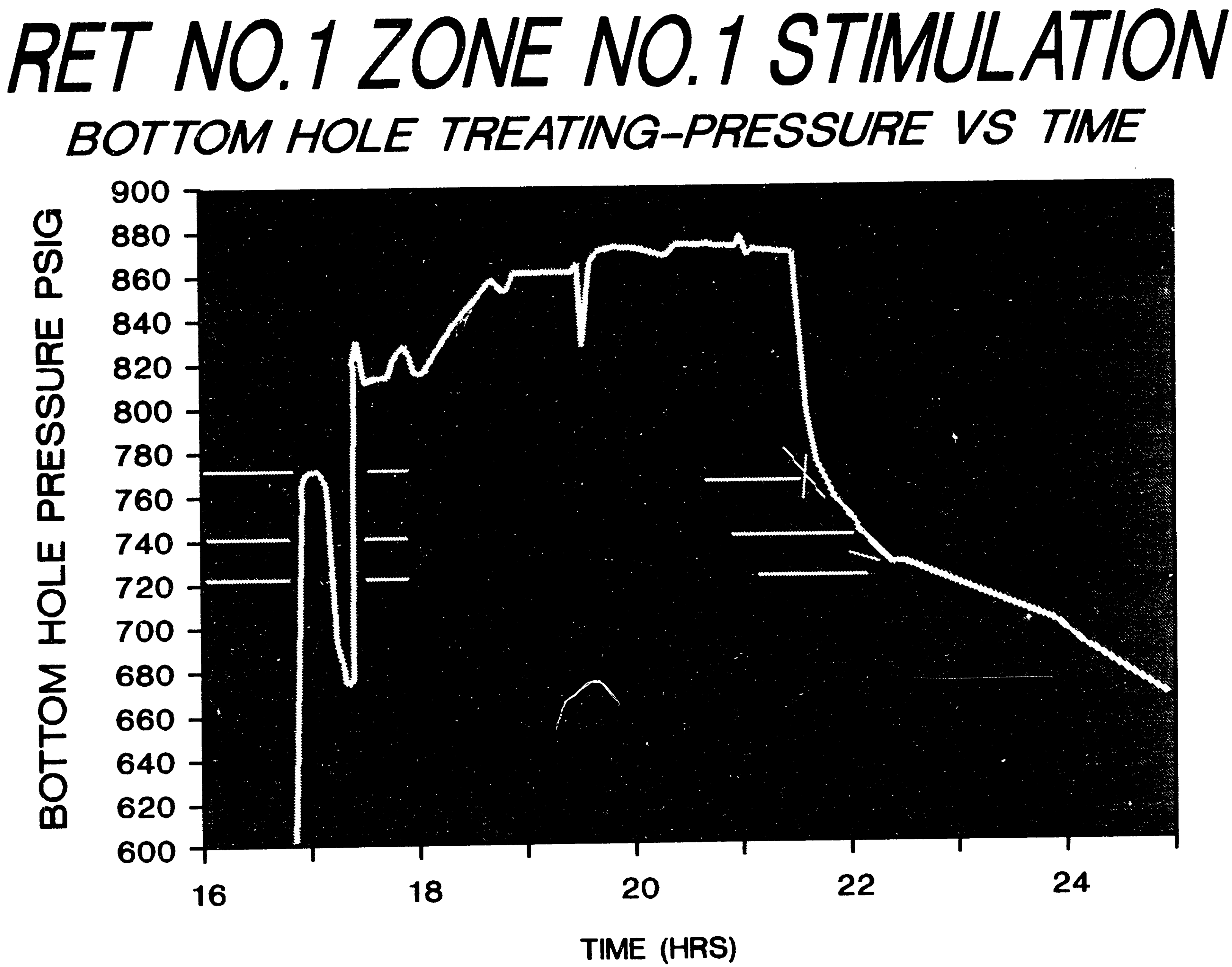


Figure 3.3.2: Plot of Bottomhole Pressure versus Time During Fracturing of Zone 1 Showing Multiple Fracture Closures

3.3.4 Fracture Diagnostics

The purpose of fracture diagnostics is to determine as accurately as possible the three-dimensional orientation of hydraulically induced fractures in the formation. In a conventional vertical well, if a hydraulic fracture is extended in a plane away from the wellbore, an array of tiltmeters can determine the orientation of the fracture (azimuthal) and radioactive tracers can indicate the height next to the wellbore that a fracture has been propped. Fluid volumes and rheology will allow calculation of the lateral extent and width of the fracture, thus giving an idea of the complete geometry of the fracture generated.

A horizontal well, and in particular, one that has been completed for openhole stimulation, presents an entirely different set of problems. A tiltmeter array must try to detect not one, but perhaps as many as 10 to 15 fractures; perhaps five of which are being propagated at any point in time. Radioactive tracers can pinpoint where the fractures exit the wellbore and come back to the wellbore, but they give no clue as to the height of a fracture being generated. To determine height, a second monitor well would have to be drilled perhaps as close as 200 feet to the horizontal well to be able to detect seismically the energy from fractures growing away and up from the wellbore.

BDM planned to use radioactive tracers and tiltmeters in its fracture diagnostics studies, but the results of the first test made during the stimulation of Zone #1 with nitrogen indicated that it would be impossible to complete those plans. The tiltmeters need to have good ground (bedrock) coupling to record tilts, which means burial about 20 feet deep normally. Because the RET #1 well is located in a state forest, permission could not be obtained to bring in rigs large enough to drill into solid bedrock. Hand-held drills were used to install the tiltmeters 5 to 6 feet deep. At this depth, the tiltmeters would not stabilize and were particularly susceptible to the forces produced from wind blowing on nearby trees. The location of tiltmeters for the test are shown in Figure 3.3.3. The tiltmeters were site-hardened for three weeks before the frac job was conducted on September 23. A calculated

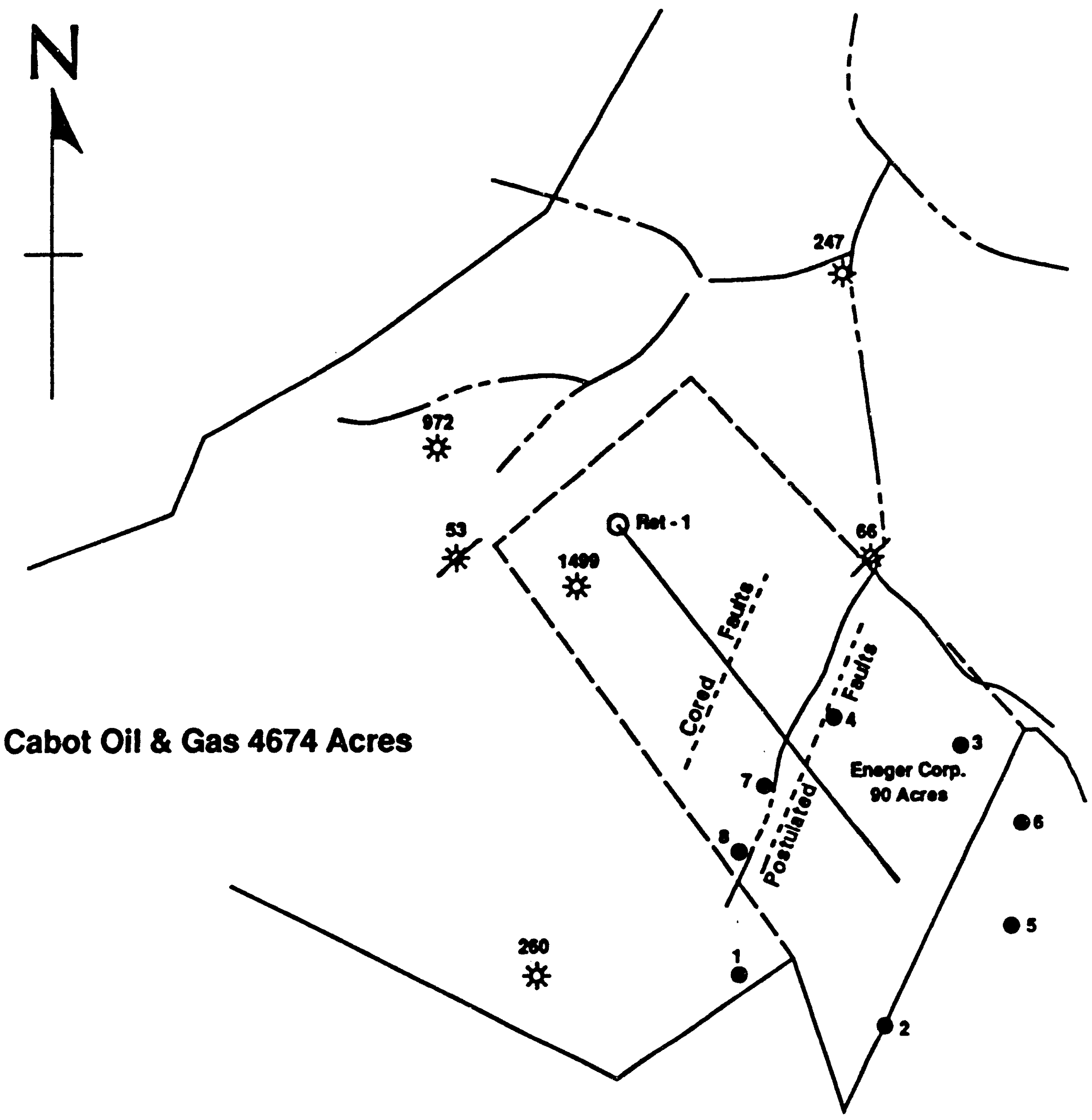


Figure 3.3.3: Map of Location of Tiltmeters for Recording Tilt During Fracture of Zone 1 by Nitrogen Gas

risk was taken in installing the meters at such a shallow depth, but Hunter Geophysics had obtained signals from frac jobs in California by imbedding the meters in a barrel of sand setting on the surface.

Examination of data after the frac revealed that no readable signals had been recorded. This was attributed to two possible causes:

(1) The pumping rate on the job was so low that only natural fractures were inflated and possibly no fractures induced.

(2) Signals from roots of nearby trees (20 feet) when the wind blew gave so many spurious signals tht any valid data may have been masked.

Since this frac job used nitrogen gas as the fracturing fluid, no radioactive tracer was used because of the high probability of having the gas tracer produced with the natural gas and having it escape to the atmosphere.

Examination of the BHTP versus time curve of Figure 3.3.3 indicates 5 separate events which might be interpreted as fractures opening and taking fluid. BDMESC estimates that a minimum of 5 fractures were opened and propagated during the frac job.

3.3.5 Well Test and Analysis

Following the stimulation, flowback of the RET #1 well was initiated. The well flowed back at a rate exceeding 350 mcfpd initially and declined rapidly (within 48 hours) to 55 mcfpd (see Figure 3.3.4). The well was then opened up and the tubing removed to recover the quartzpressure gauge (see Figure 3.3.2). Gas open flow rates were not measured during this period. On October 13, 1987, the well was shut-in for a 15 day post-fracture pressure build-up test. Pressure measurements were made with a quartz pressure/temperature transducer and recorded on a computer controlled data acquisition system backed up by a conventional chart recorder with an 8-day clock.

The flow data collected during the flowback period was subjected to a decline curve analysis for the 20-day period that data was available. As seen in Figure 3.3.5, the fit is not too good between

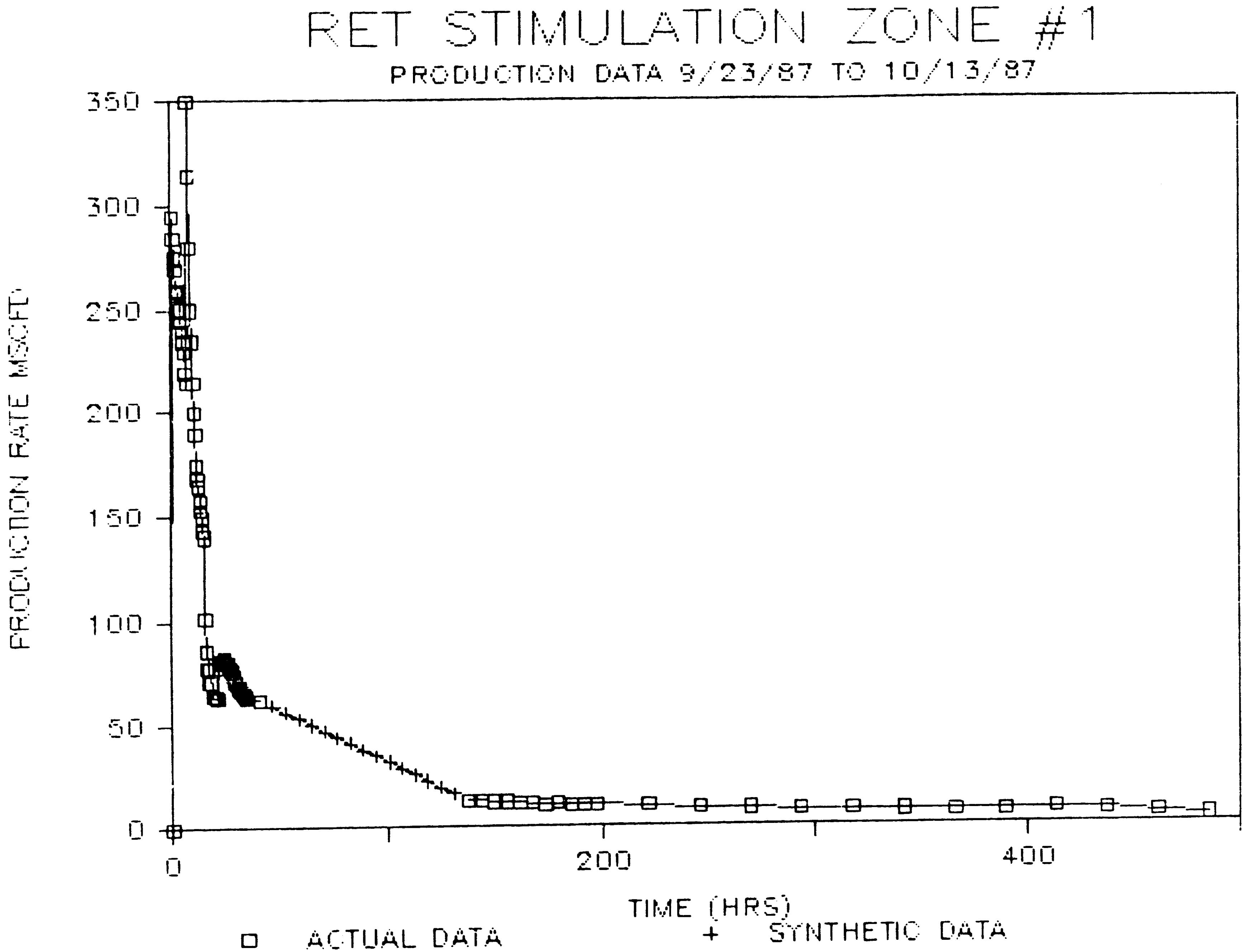


Figure 3.3.4: Plot of Production Rate versus Time after Nitrogen Frac of Zone 1

the actual data (labeled "field") and the exponential and hyperbolic curves shown during the period between the fourth and ninth days and the fourteenth and nineteenth days. A better fit is obtained if the first 5 days are ignored and the sixth through twentieth days is plotted as shown in Figure 3.3.6. The curves project the zone returning to baseline (original natural production) rate in 40 days when it actually returned in 20 days.

At the end of the 20-day flowback period, a pressure build-up test was initiated. Analysis of a gas sample taken at the time the shut-in period began showed the gas stream still contained 16 percent nitrogen. The results of the pressure build-up test are presented in Figure 3.3.7 and shows that the formation fracture system is still charged with nitrogen and presents a reservoir pressure about 63 psi higher than the maximum of 192 psi estimated as a result of the analysis of the 28-day pressure build-up test conducted before any stimulation or testing was performed on the well.

The collected pressure data for the Zone 1 nitrogen stimulation were analyzed and history-matched using the G3DFR model. Critical input parameters are changed in the iterative processes until the simulated data matches quite well with the actual field measured data as presented in Figure 3.3.8. The model critical parameters include:

- Zone length - 413 feet
- Reservoir Temperature - 93°F.
- Initial Reservoir Pressure - 540 psia
- Formation Thickness - 247 feet
- Matrix Porosity (Fraction) - 0.02
- Matrix Permeability - 0.00082 md
- Bulk Reservoir Permeability - 0.0477 permeability
- Bulk Fracture Porosity - 0.0009
- Permeability Anisotropy - 1:1

Table 3-5 is a summary of pre- and post-fracture pressure build-up test results.

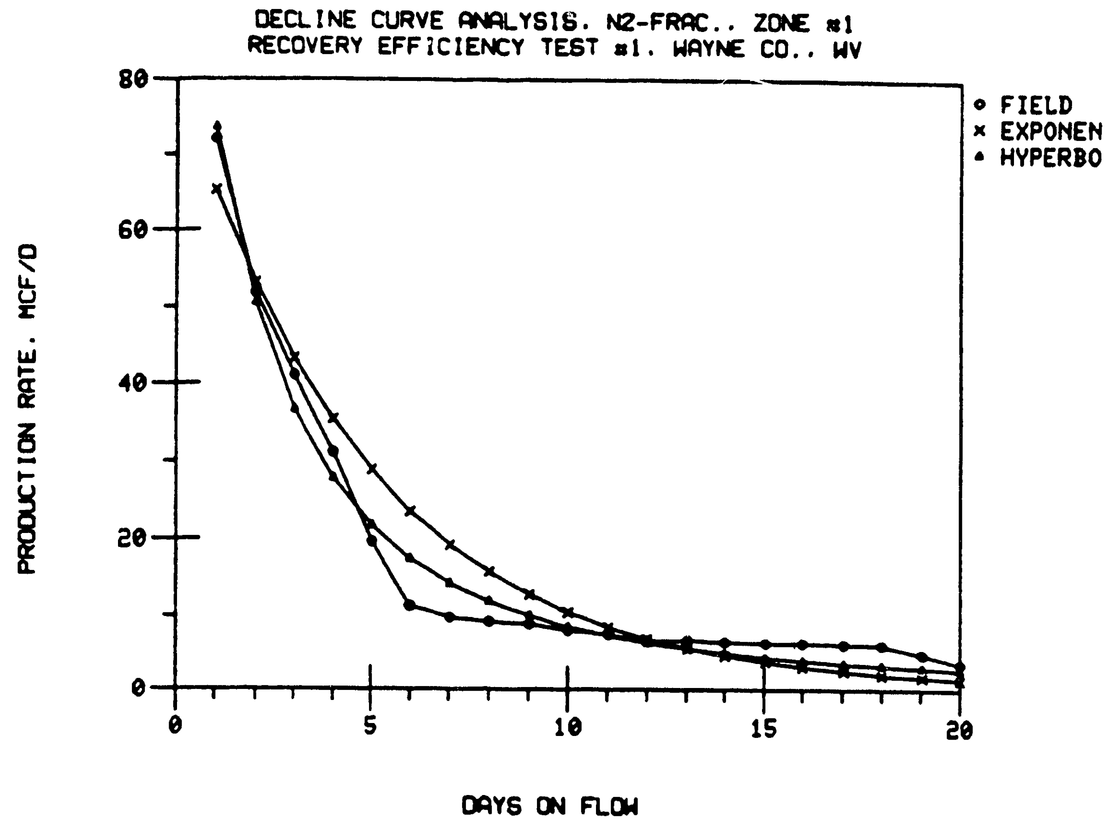


Figure 3.3.5: Decline Curve Analysis of Production Rate versus Time for Two Different Projection Curves For Zone 1 Nitrogen Frac

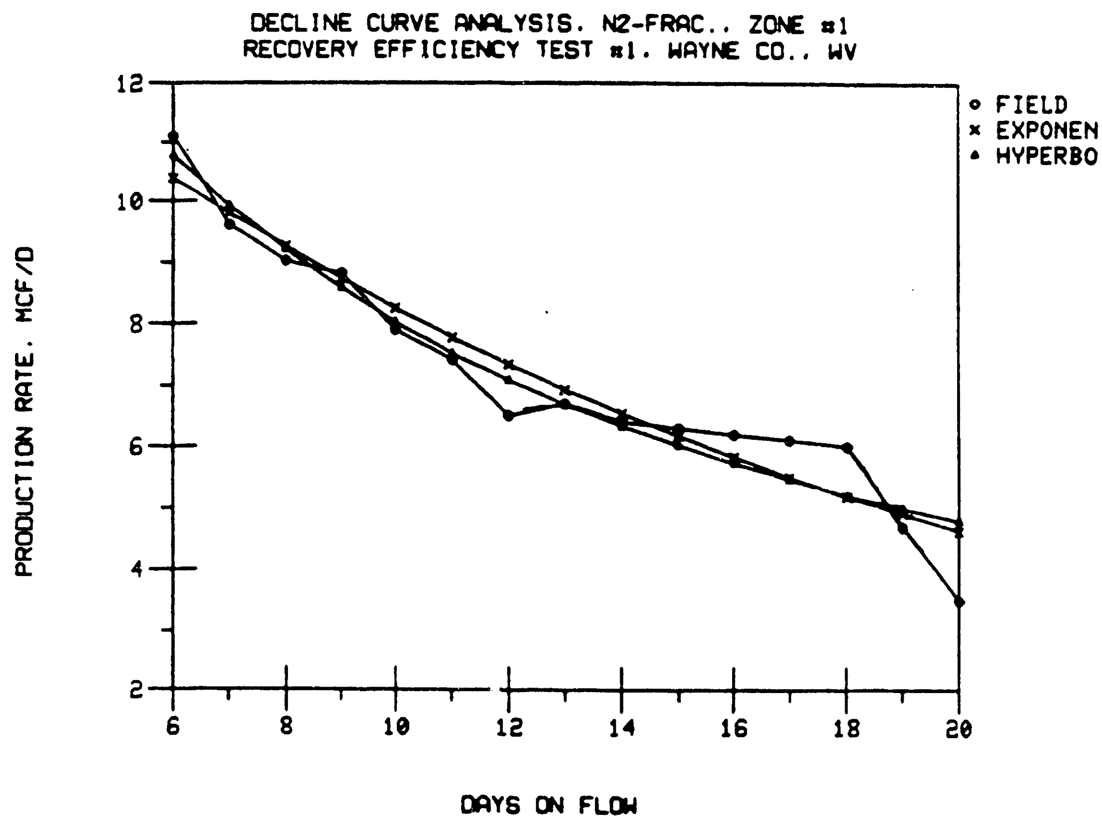


Figure 3.3.6: Decline Curve Analysis for Zone 1 Nitrogen Frac for Production Starting 6 Days After Initial Open Flow and Showing Sudden Closure of Last Fracture after 18 Days

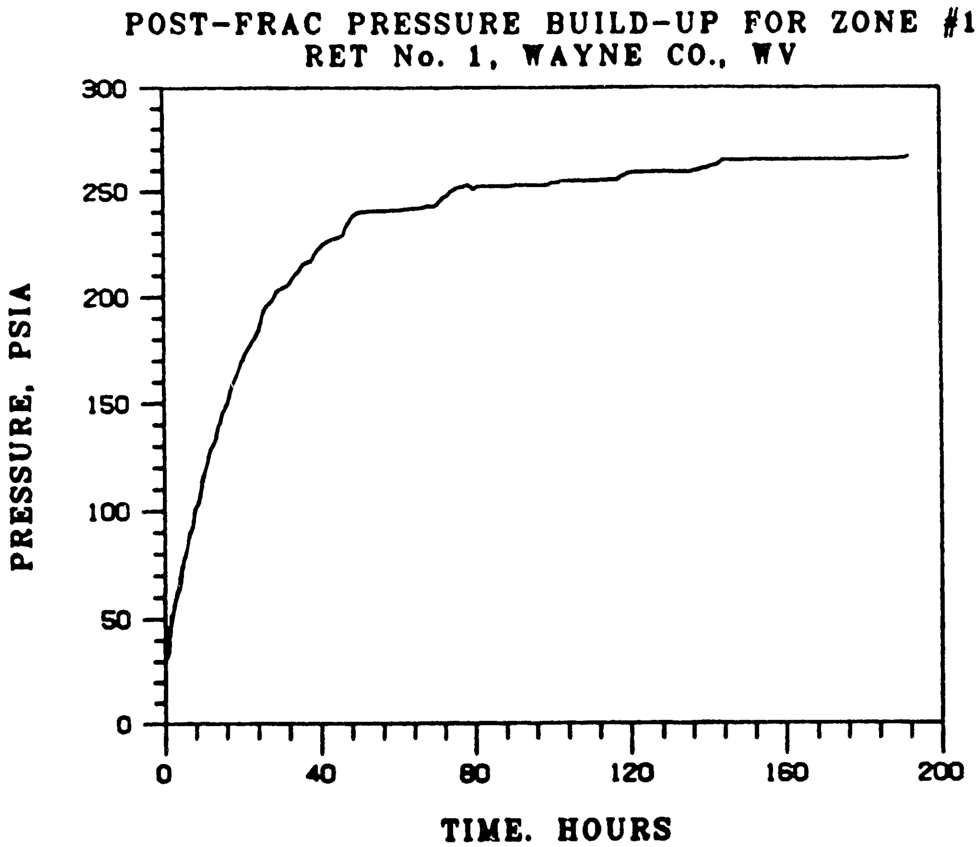


Figure 3.3.7: Post Fracture Pressure Build-up Curve for Zone 1 Nitrogen Frac

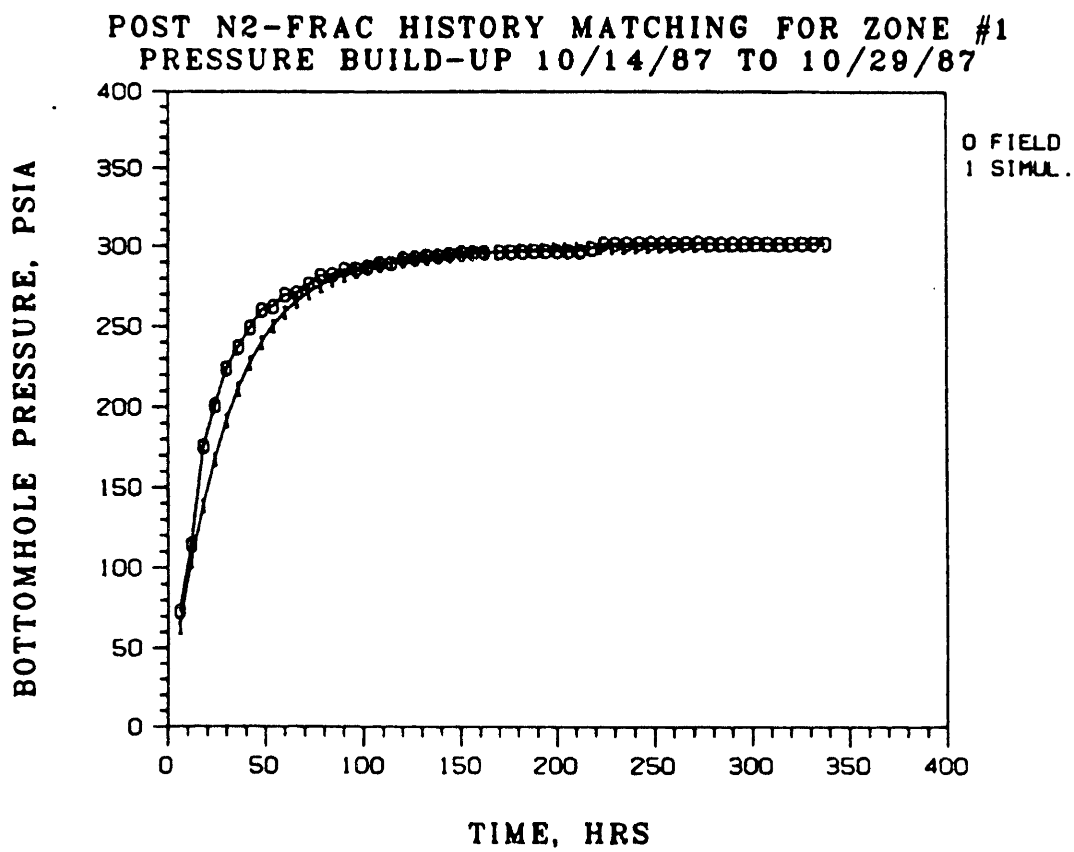


Figure 3.3.8: Post Nitrogen Frac History Match to Determine Permeability Improvement

TABLE 3.3.5

COMPARISON OF PRE- AND POST-STIMULATION
PRESSURE BUILD-UP TEST ANALYSIS

	PRE-STIMULATION	POST-STIMULATION
Permeability, md	0.0306	0.0477
Pressure, psia	192.0	295.0
Flow rate, mcf/d	2.20	10.78 (6 day)
Improvement Ratio		4.9

3.3.6 Discussion of Results

Table 3.6 presents a comparison of planned versus actual design parameters. The stimulation conducted was fairly close to the planned design.

TABLE 3.3.6

COMPARISON OF STIMULATION DESIGN PARAMETERS
STIMULATION TEST NO. 1
NITROGEN GAS; HIGH VOLUME; LOW RATE

PARAMETER	PLANNED	ACTUAL
Volume of N_2	4000*	3800*
Injection Rate (bbl/min)	7-25	7-16
Injection Rate (mscf/min)	2-7.5	2-5
Injection Pressure (psig)	200> closure	100> closure

* Reservoir barrels at average BHTP.

BDM believes it was successful in the attempt to inflate and propagate multiple natural fractures by injecting at a slow rate. The 5 pressure peaks followed by a fall-off we interpret to mean a separate fracture was opened and propagated. BDM further believes that three closure pressures were identified (Figure 3.3.2) and has speculated on a possible orientation for each set of fractures that closed.

BDM also concluded that a more effective stimulation would have resulted if a much higher injection rate had been used during Stages 7 and 8; for example, 10 to 12 mcf/min than that used. BDM could also see merit in testing a different flowback scheme for a nitrogen stimulation than the one used. BDM would recommend testing an uncontrolled or wide open flowback procedure with the following projected results:

(1) Nitrogen content of gas could be reduced faster, reducing the amount of time for diffusion to occur and reducing clean-up time.

(2) High initial flow rates might erode channels in the shale which would leave possibly more after frac permeability than when the fractures are opened up and slowly close again as occurred during the test.

BDM interprets the return to baseline production as evidence for the need of proppant in a stimulation even in a low-stress magnitude environment such as exists in the wellbore area. BDM also interprets the difference in closure pressure between Zone 6 (850 and 1050 psi) and Zone 1 (760, 740, and 720) to be related to differences in basic rock properties between the two intervals due to a vertical difference in strata of 29 feet, and to a reduction in stress levels as a function of the higher fracture density (1/6-foot in Zone 1 versus 1/22-foot in Zone 6). By the same anology, permeability anisotropy would also show a considerable difference between Zones 1, 2-3, 4, 7, and 8 which have close fracture spacing versus Zones 5 and 6 which have wider fracture spacing. BDM would speculate that Zones 5 and 6 would have an anisotropy of 20:1 while Zones 1, 2-3, 4, 7, and 8 would have an anisotropy of 4:1.

3.4 Stimulation No. 2, Zone 1 - Liquid CO2 Frac

The second stimulation, as dictated by the design rationale (see Figure 3.2.7), was to test twice the volume in reservoir barrels of nondamaging, nonproppant-carrying liquid CO_2 pumped at 2 to 5 times faster rates.

3.4.1 Stimulation Design

Stimulation No. 2 which was originally scheduled to be a 4000 reservoir barrel stimulation was reduced to 2700 barrels to reduce the cleanup time and to maintain costs within budget. The planned rates remained the same as intermediate rates (12 to 22 bbl/min). The overall design approach was to inject the pad volume at 12 bbl/min and the main frac at 22 bbl/min. The 12 bbl/min rate should allow opening and propagating of natural fractures. The model anticipated propagating five fractures simultaneously at rates of 2.4 bbl/min each. To be able to determine how many fractures were pumped into at the different rates, different radioactive isotopes were injected with the CO_2.

The design of maximum injection rate was controlled by wellhead equipment. The frac valve had a 3000 psig working pressure rating with a 6000 psig test rating. The surface pressure calculated at an injection rate of 22 bbl/min was 3046 psi, thus this rate became the practical maximum rate.

3.4.2 Wellhead and Wellbore Configuration

As with Stimulation No. 1, the second stimulation was pumped through the annular space between the 2-3/8-inch EUE tubing and the 4.5-inch J-55 casing and out through port collar #1 at a depth of 5746 feet. The 2-3/8-inch EUE tubing was again used as a static string to measure pressure; however, a bottomhole quartz pressure gauge was placed inside the tubing and pumped down to the bottom of the tubing with nitrogen. A lubricator was used at the surface as shown in Figure 3.4.1 of the surface wellhead equipment. By placing a quartz pressure gauge on wireline, real time bottomhole treating pressure data could be collected for monitoring the pressure on other equipment and making any necessary changes in the frac job based on the data.

3.4.3 Treatment Execution

On November 8, 1987, Zone No. 1 was stimulated through one port collar which had four 1-1/8-inch holes open to the formation behind the casing. The treatment proceeded as scheduled in Table 3.4.1.

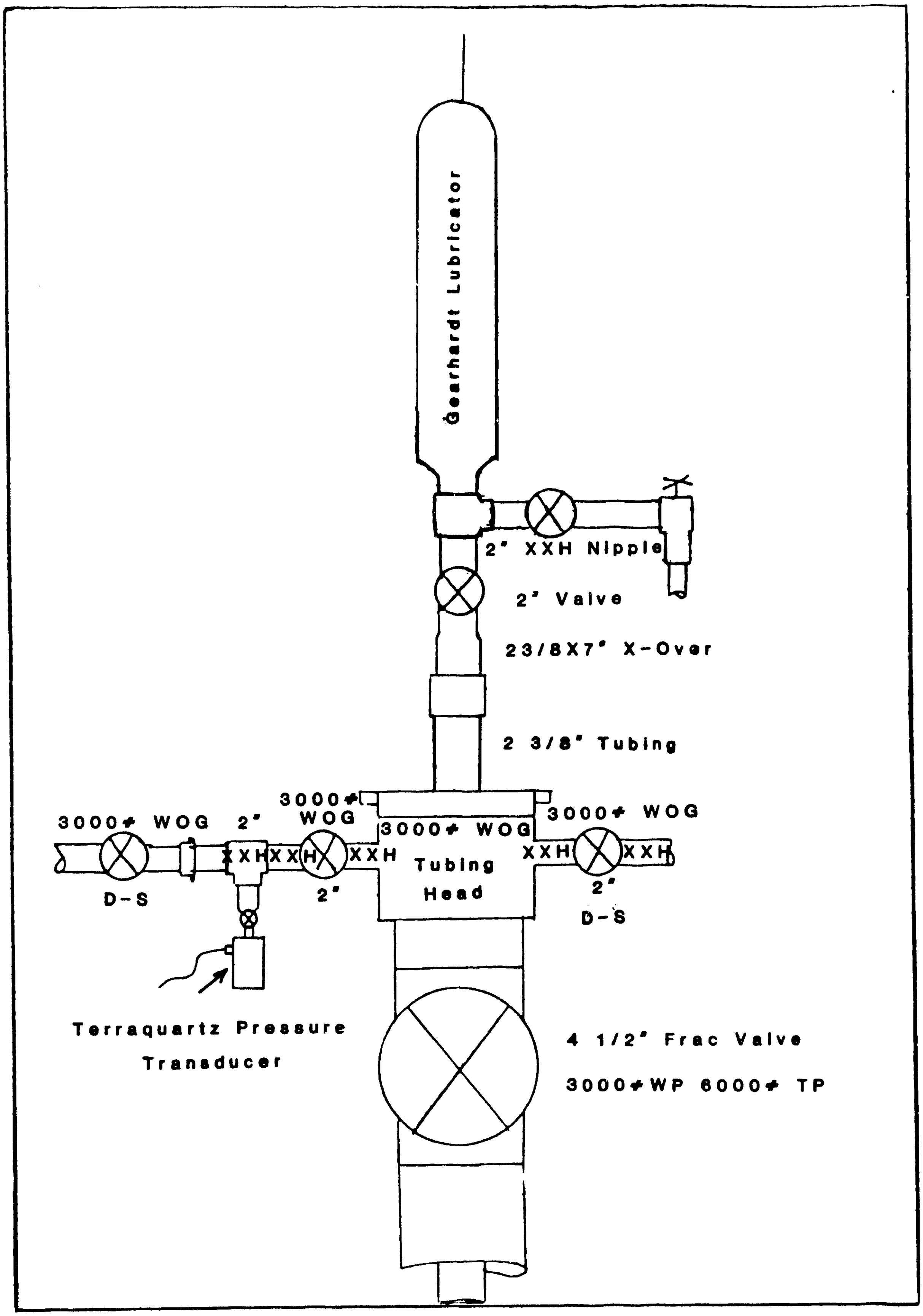


Figure 3.4.1: Schematic of Wellhead Configuration During Stimulation Treatment of Zone 1 with Liquid CO_2

TABLE 3.4.1

TREATMENT SCHEDULE FOR CO_2 STIMULATION

STAGE	RATE (bpm)	STAGE VOLUME	CUMULATIVE VOLUME	PUMPING TIME
1	12	200 bbl	200	17 minutes
2	22	400 bbl	600	18 minutes

Maximum surface treating pressure was 2642 psig while the maximum bottomhole treating pressure was 1181 psia when injection rate reached 20.7 bbls/min (see Figure 3.4.2). Instantaneous shut-in pressure was 958 psig based on the Gearhart bottomhole quartz pressure gauge. Fracture closure pressures can be detected at 860 psi, 820 psi, 790 psi, 750 psi, and 720 psi. The well was opened to flow back within five hours of completion of the frac job, and allowed to blow down completely. On November 9, flowing pressure was 180 psi and the estimated flow rate was 600 mcfpd. The bottomhole pressure gauge was removed from the tubing. Additional detail can be seen on the expanded scale of the plot of bottomhole treating pressure versus time as shown on Figure 3.4.3. Table 3.4.2 summarizes the fracture treatment data collected.

TABLE 3.4.2

MEASURED FRACTURE TREATMENT PARAMETERS

PARAMETER	STAGE 1 (12 bbl/min)	STAGE 2 (20 bbl/min)
Maximum surface pressure	528 psig	2642 psig
Maximum BHTP*	981 psig	1173 psig
Average surface pressure	400 psig	2550 psig
Average BHTP*	970 psig	1170 psig
Average friction pressure**	80 psig	215 psig
Fracture closure pressure	774 psig	820 psig
Instantaneous shut-in pressure		958 psig

* At point of measurement 4137', which is 1609' from perforations.

** 4-1/2" casing friction pressure from 4137' to 5746' plus perforation friction pressure as indicated by Quartz Pressure Gauge.

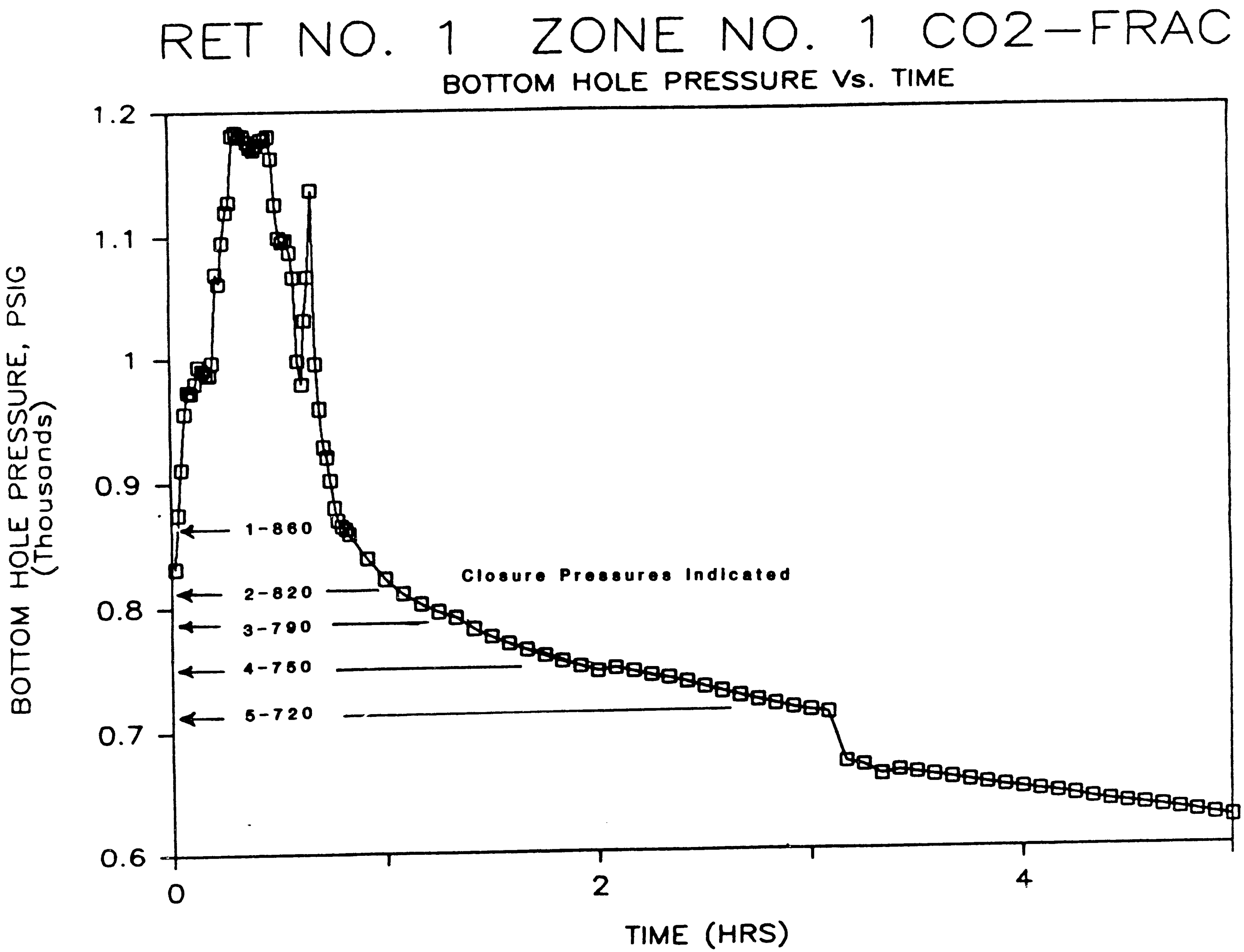


Figure 3.4.2: Plot of Bottomhole Pressure versus Time During and After Stimulation with Liquid CO_2

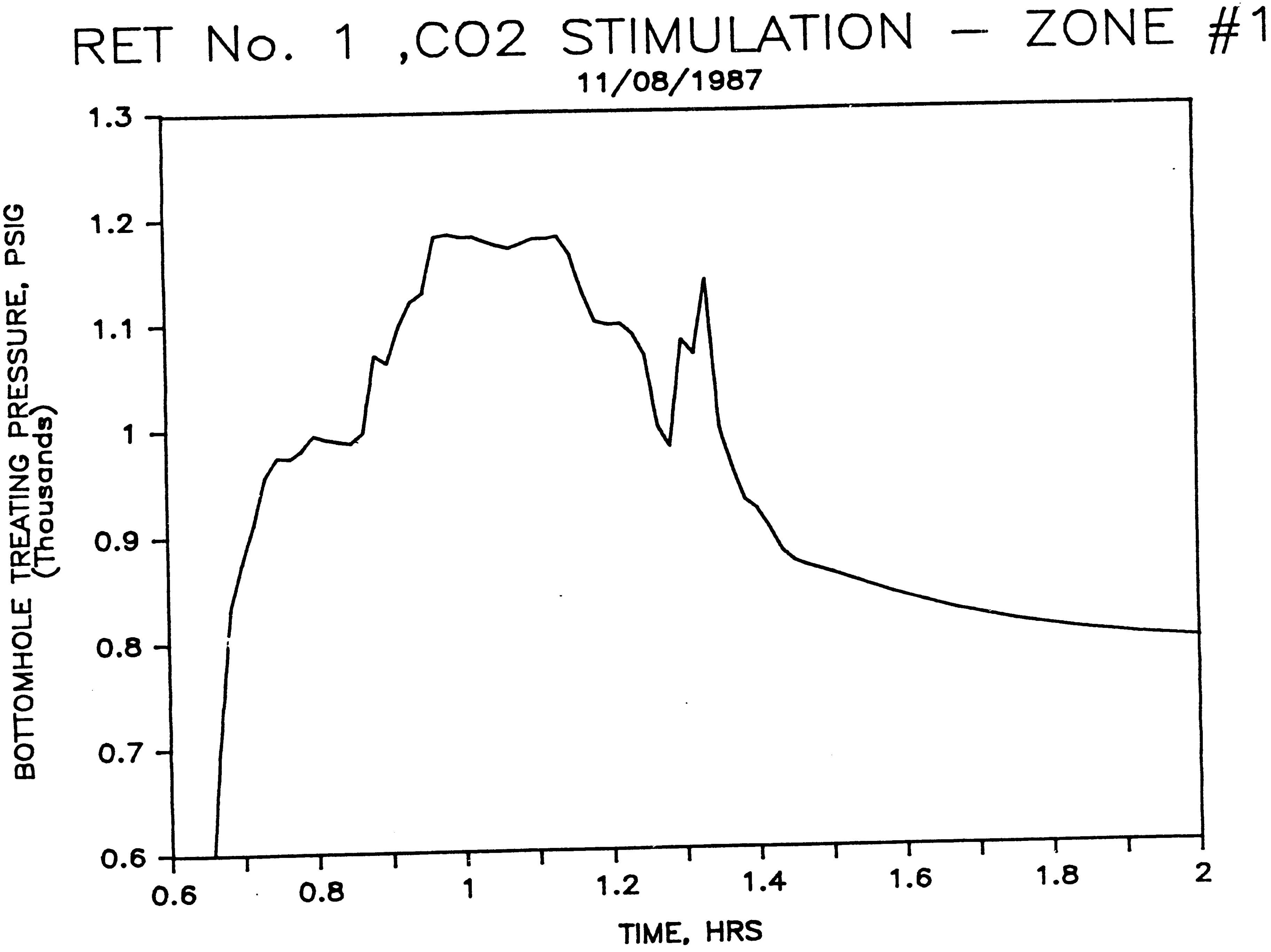


Figure 3.4.3: Expanded Plot of Bottomhole Pressure During CO_2 Frac to see Details of Pressures Recorded

3.4.4 Fracture Diagnostics

Two different radioactive isotopes were injected in a methanol solution with the liquid CO_2 to determine the number of fractures and where along the wellbore they were propagated.

During Stage 1, which consisted of 200 barrels of liquid CO_2, Iodine-131 was injected as a tracer. The average injection rate during this stage was 12 barrels per minute and the average bottomhole treating pressure was 980 psig.

During Stage 2, Scandium-46 was injected during the 400 barrel stage. Injection rate was 20 barrels per minute and the average bottomhole treating pressure was 1180 psig.

A 3-inch diameter spectral gamma tool was attached to 2-3/8-inch tubing and pushed into the wellbore to log the hole and locate fractures which took fluid. A special latching system and side-door sub was used with the tubing string to log the hole.

Difficulties occurred almost immediately after starting the logging operation, when the wireline was crushed by the tubing slips. Six thousand (6000) feet of wireline had to be cut off and the operation repeated. The logging operation was slow and cumbersome since only 30 feet could be logged at a time. An inconvenience was the saturation of the detector from sitting in one place for approximately 1 minute, 30 seconds, when tripping the tubing back out of the hole and logging. The fracture diagnostics clearly indicated that tracer material left the wellbore in Zone No. 1 and came back into it in Zones 2-3 and 4 via the inflated and propagated natural fracture system. Fifty-one (51) of 69 fractures contained tracer material.

3.4.5 Well Test and Analysis

After the last of the CO_2 was displaced with nitrogen, the well was shut-in to watch the pressure decline. To insure that all CO_2 injected had time to convert to gas, the flowback was delayed 5 hours. The well was blown down in 12 hours, and the tubing and bottomhole pressure device removed. Production monitoring was then initiated and recorded for 21 days. Production declined from 83 mcfd to 48 mcfd (see Figure 3.4.4) at which point a special series of tests were conducted on the well over a 3-day period. The objective of the testing was to obtain pressure data from Zones 2-3 and 4 to determine if Zone 1 was pressure-connected via the induced or natural fracture system with Zones 2-3 and 4. Figure 3.4.5 presents the bottomhole pressure measurements made during the test, while Figure 3.4.6 presents the wellhead data collected at the surface. All tests were made while Zone 1 was flowing out through the tubing. Of particular significance is the flat curve in Zone 4 recorded overnight (Figure 3.4.5) which reveals that Zone 1 and Zone 4 are definitely pressure-connected. Zones 1, 2, and 3 are all within 20 psi of each other.

After each zone underwent a one-hour pressure build-up, then the well was flowed for one hour from that zone to collect gas samples for analysis. The results of the sample analysis (see Figure 3.4.7) clearly show the presence of CO_2 from the recent stimulation in zones other than Zone 1 where it was injected. In addition, the presence of nitrogen in Zones 2, 3, and 4 when it was injected into Zones 1 and 6.

After this test was completed on December 5, 1987, Zones 2-3, 4, 5, 6, and 8 were produced through the casing annulus while the tubing produced Zone 1 (Figure 3.4.8). Producing both zones at the same time showed a definite effect on the production of gas from Zones 1 which had been tracking close to the dashed curve on Figure 3.4.4, but showed a rapid decline to about 2.2 mcfd although the decline curves in Figure 3.4.9 predicted production rate of 10 mcf after 56 days.

At this point (December 29, 1987), a 14-day pressure build-up test was started (see Figure 3.4.10). The build-up curve was again history-matched as it was previously (see Figure 3.4.11). Table 3.4.3 presents the results of the build-up test analysis for nitrogen and CO_2 stimulation of Zone 1.

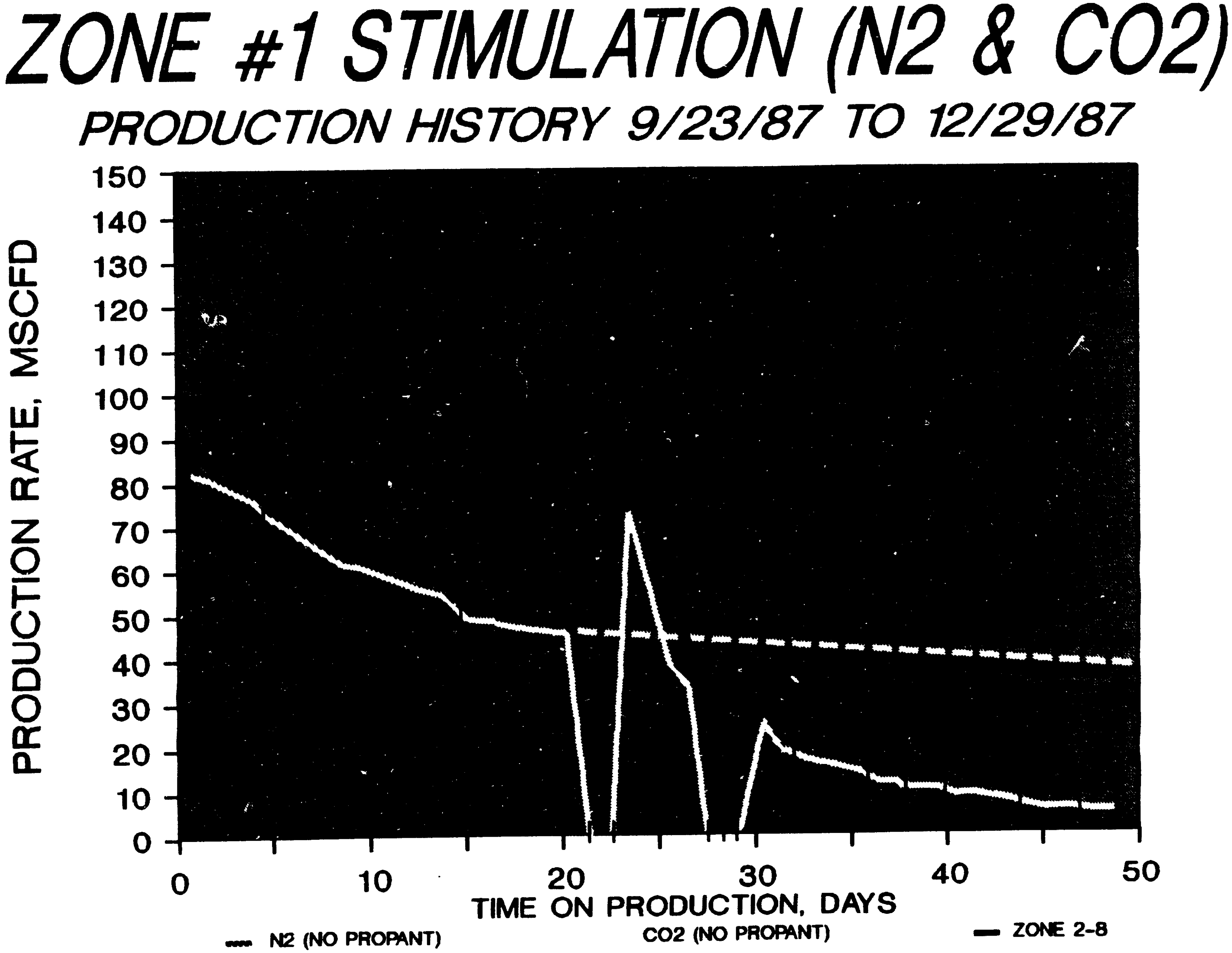


Figure 3.4.4: Production Decline Curve Comparison Between N_2 and CO_2 Stimulations

Geoservices Inc. Production

Client: BDM CORP.	Calibration Date 10/30/87
Well : BDM RET #1	Calibration Number JL#1
Field : WILSON DALE	Calibration Range 0-1000 ps
Date : 12/01/87	Calibration Temp. 50 C
Reader: DataView	Corrected Data CD=(M*UD)+I
Disk : BDM#1	M = .66357
DEMETER Pressure Guage #51	I = -343.729

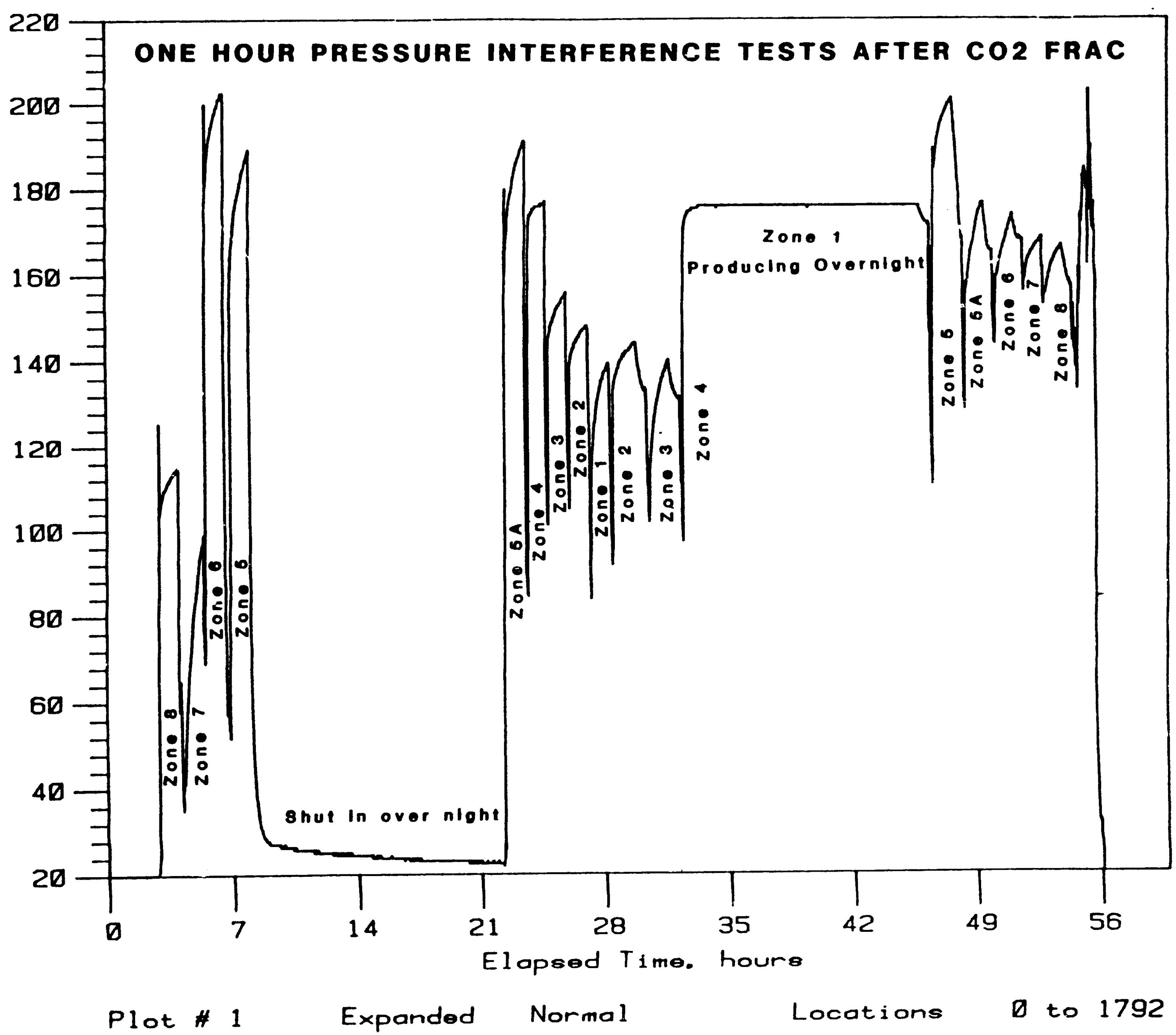


Figure 3.4.5: Bottomhole Pressure Recorded During Series of Individual Zone Pressure Build-up and Flow Tests while Zone 1 was Flowing to Detect Interference

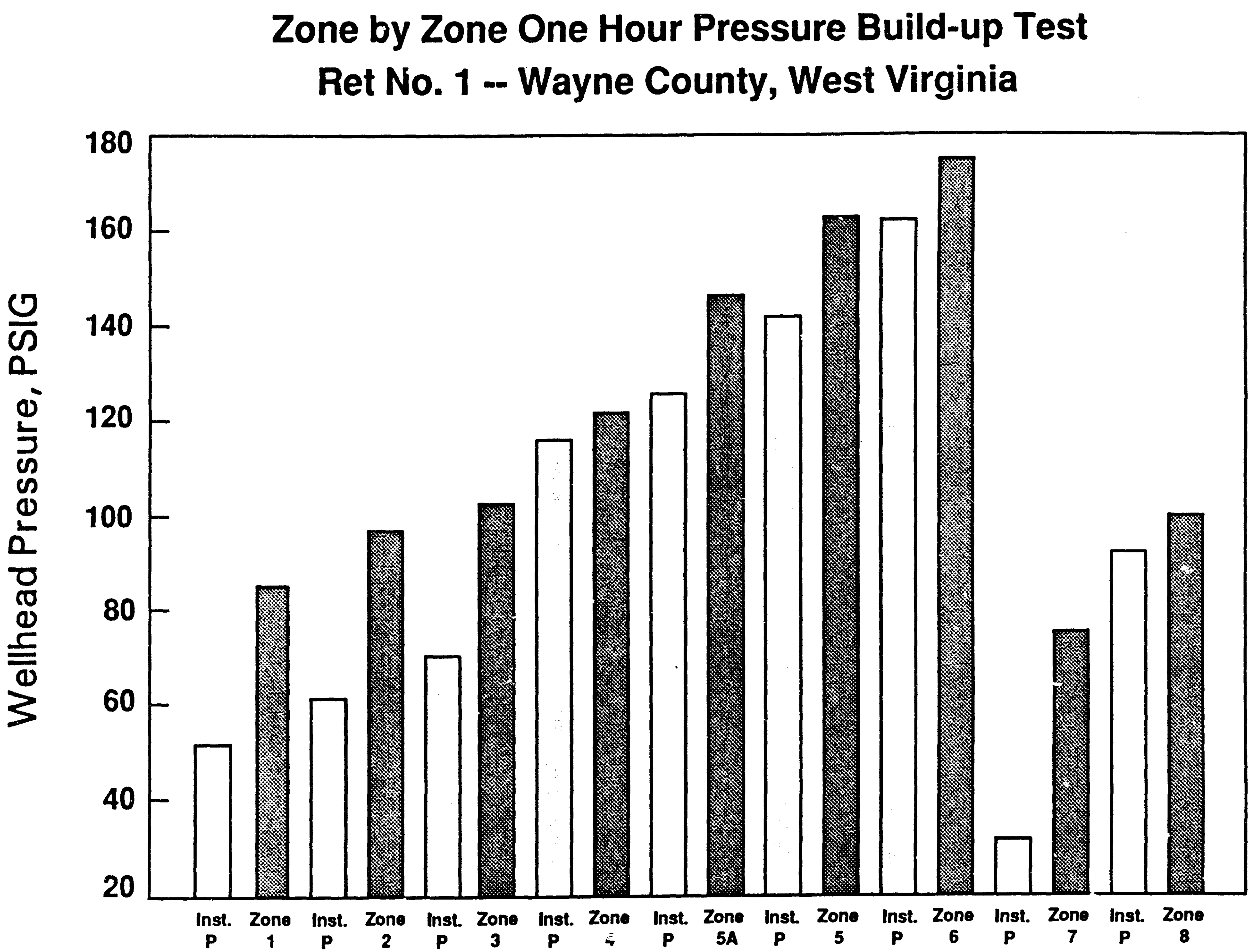
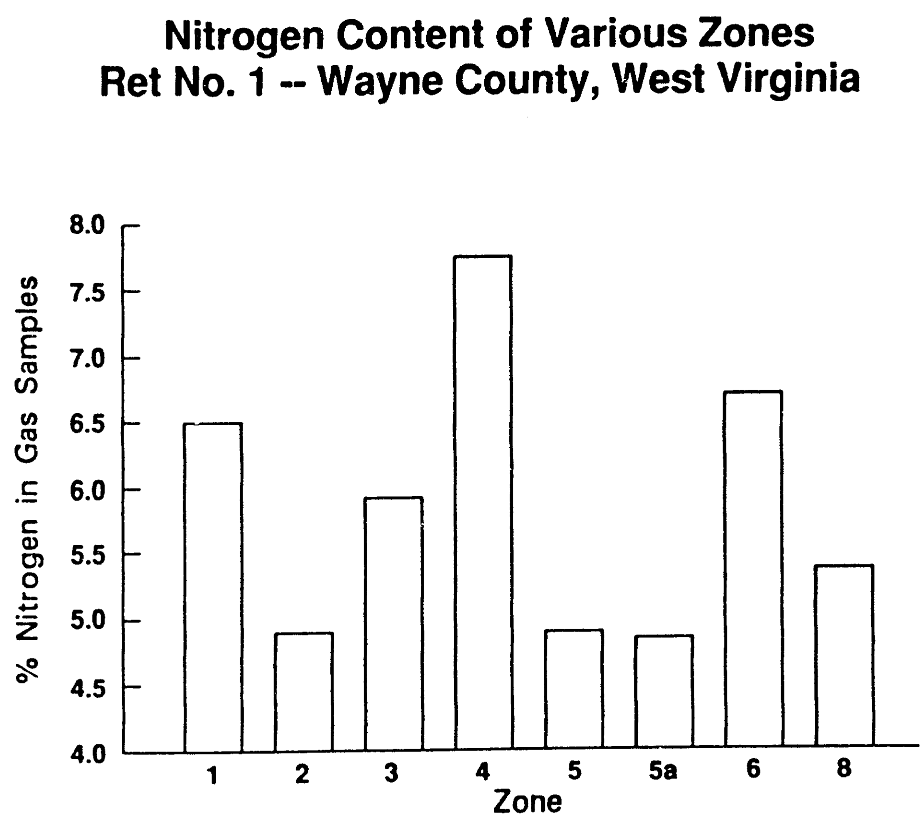


Figure 3.4.6: Plot of Zone-by-zone Wellhead Pressure Built Up During a Series of One-Hour Tests



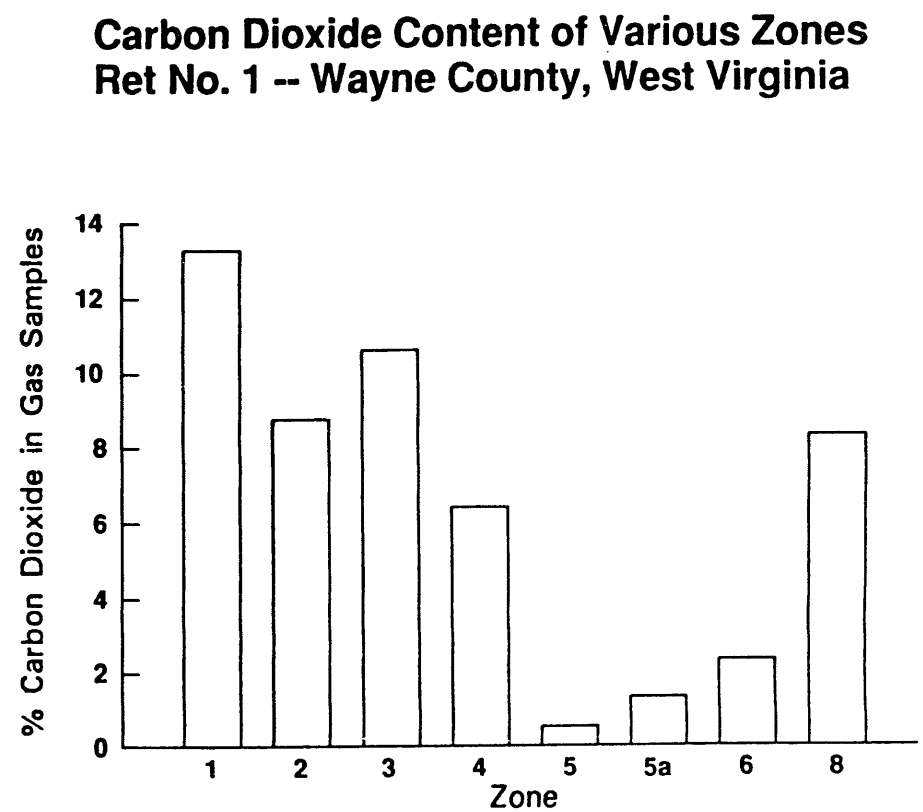


Figure 3.4.7: Presentation of Nitrogen and CO_2 Gas Content in the Natural Gas Samples Obtained from Each Zone During Pressure Interference Tests

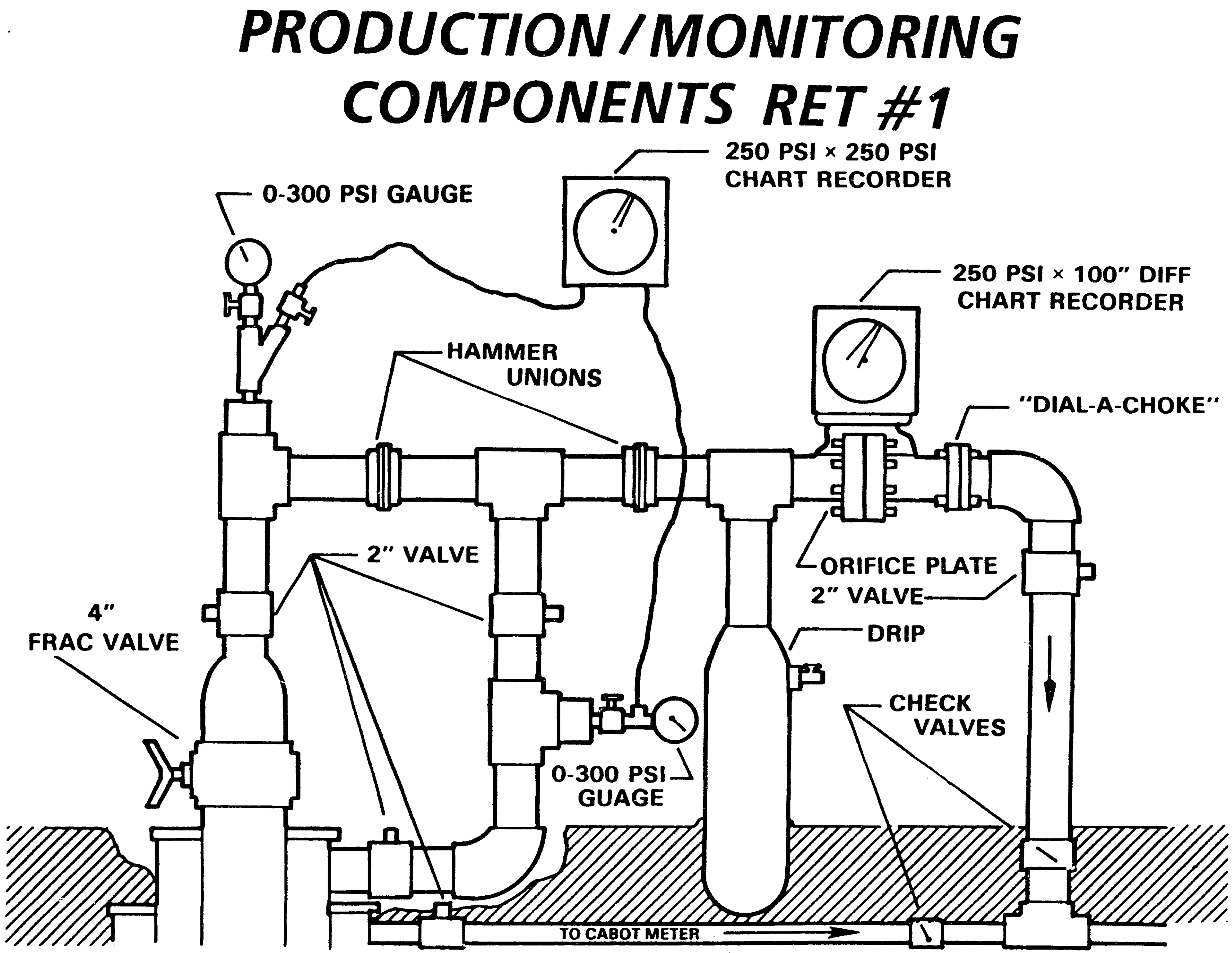


Figure 3.4.8: Wellhead Production and Monitoring Equipment Configuration Set Up to Record Pressures and Production Rates

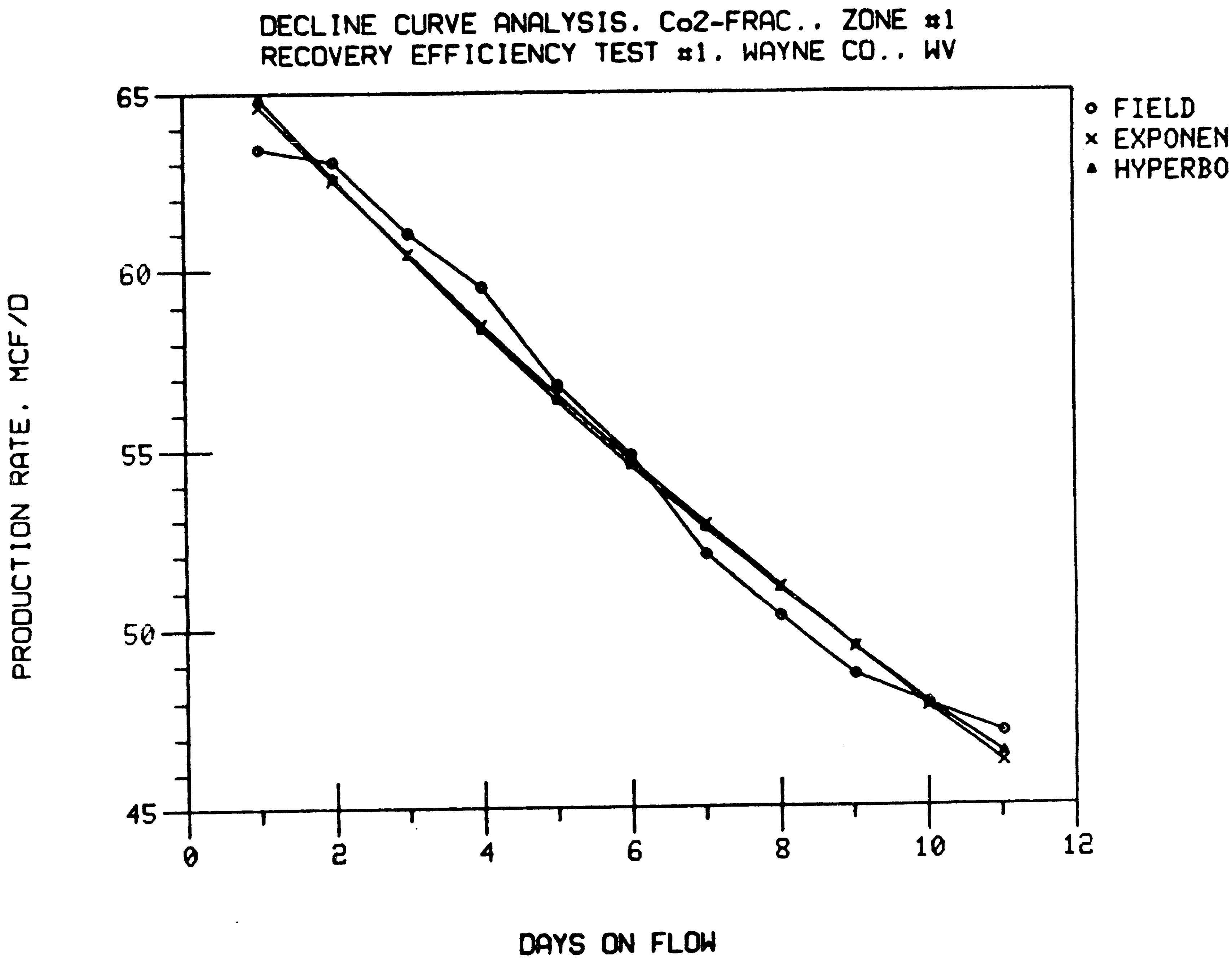


Figure 3.4.9: Decline Curve Analysis of Zone 1 after CO_2 Frac

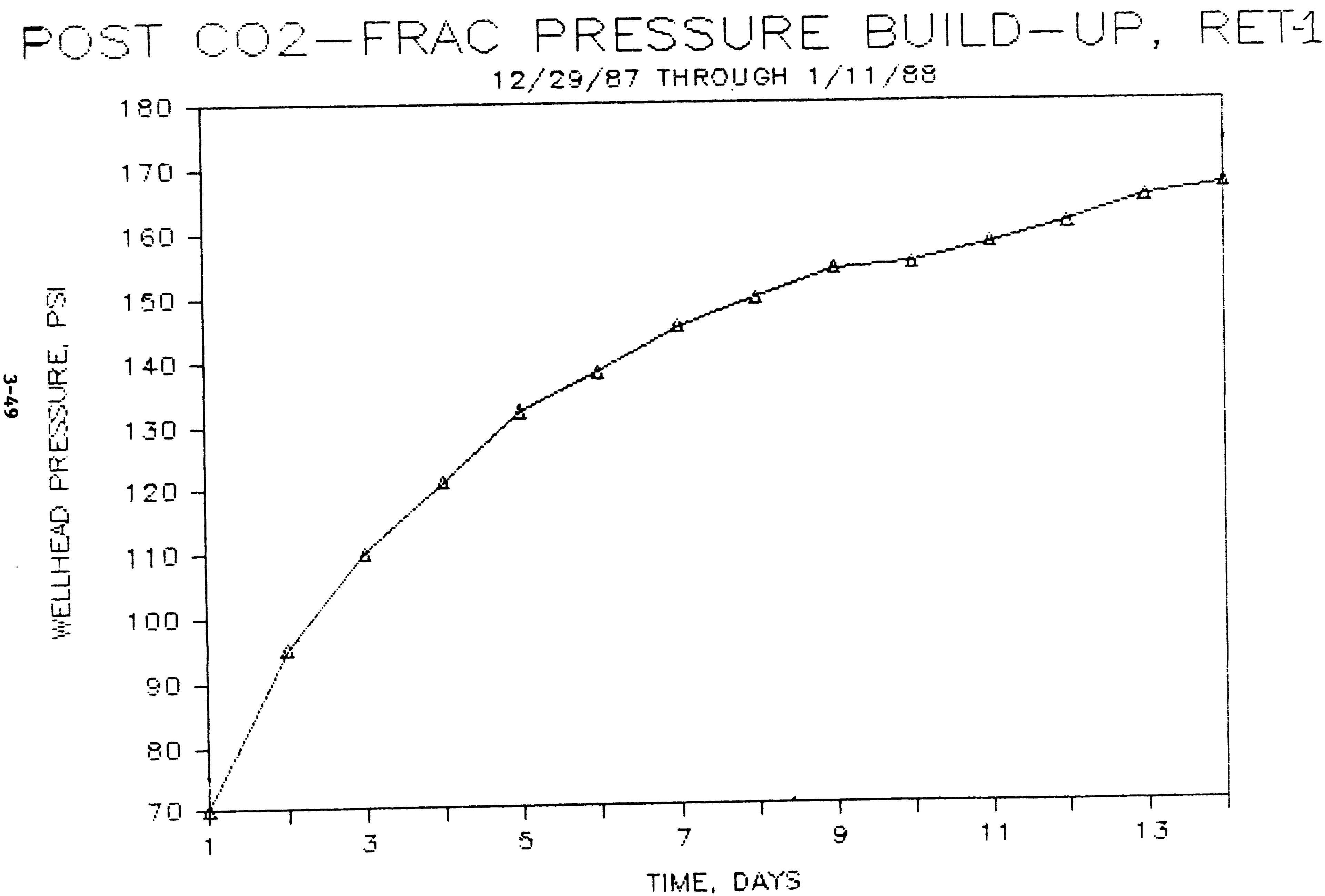


Figure 3.4.10: Post CO_2 Frac Pressure Build-up Curve

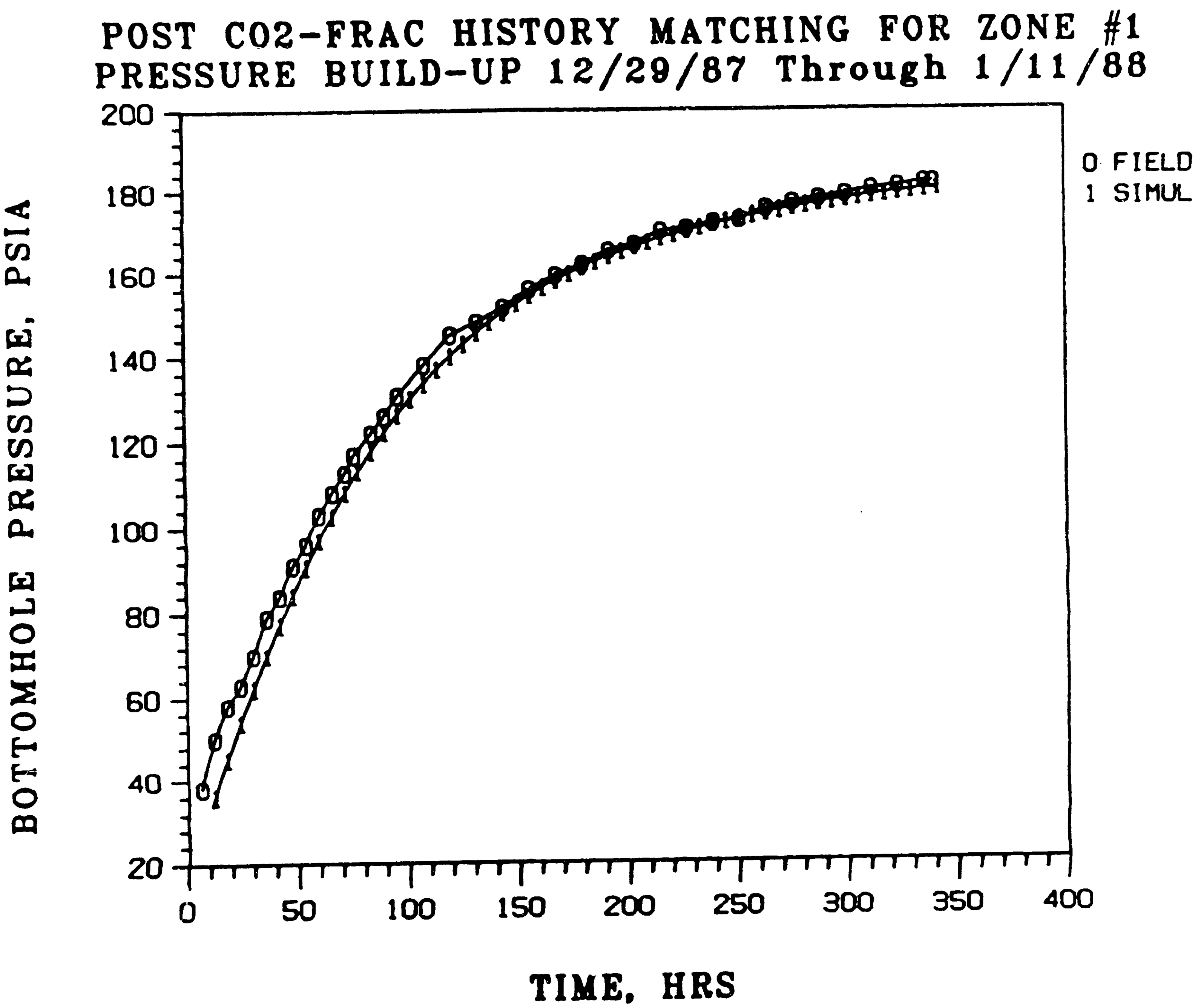


Figure 3.4.11: Post CO_2 History Match of Pressure Build-up Curve to Determine Permeability

TABLE 3.4.3

COMPARISON OF PRE- AND POST-STIMULATION PRESSURE BUILD-UP TEST ANALYSIS FOR NITROGEN AND CO_2 STIMULATION

NATURAL TEST	N_2 STIMULATION[1]	CO_2 STIMULATION[2]
0.031 md	0.0477 md	0.0485 md

1. Nitrogen frac 1,169,000 scf gas at 5000 scfm.
2. CO_2 frac 2,300,000 scf gas at 9000 and 14,200 scfm.

All permeabilities determined by history matching.

3.4.6 Discussion of Results

The stimulation was conducted without any major changes except for the volume of fluid injected. The volume was reduced from 4000 reservoir barrels to 2700 because of the low reservoir pressure and the length of time required for cleanup. The stimulation was successful in opening and propagating more than 67 out of 69 known fractures in Zone No. 1. The spectral gamma log of Zone 1 showed that fractures were initially opened and propagated in the interval 5730 - 5760 feet (see Figure 3.4.12) and then moved to the interval 5600 - 5690 feet. Finally, during Stage 1 or Test No. 6 (each different stage that was unique or could be labeled was given a test number) the last interval being injected into was 5840 to 5890 feet. The fractures in this zone also took some fluid and tracer from Stage 2 (Test No. 7) which was pumped at 20 bbl/min as opposed to 12 bbl/min for Stage 1. Stage 2 had 37 fractures pumped into in Zone 1, the target zone, as opposed to 16 during Stage 1.

CO_2 as a frac fluid seems to be very efficient in opening fractures. The decline back to original production rates within 52 days by both fluids is a strong indicator of the need for proppant material in a stimulation, even in areas which are nearly stress-relieved.

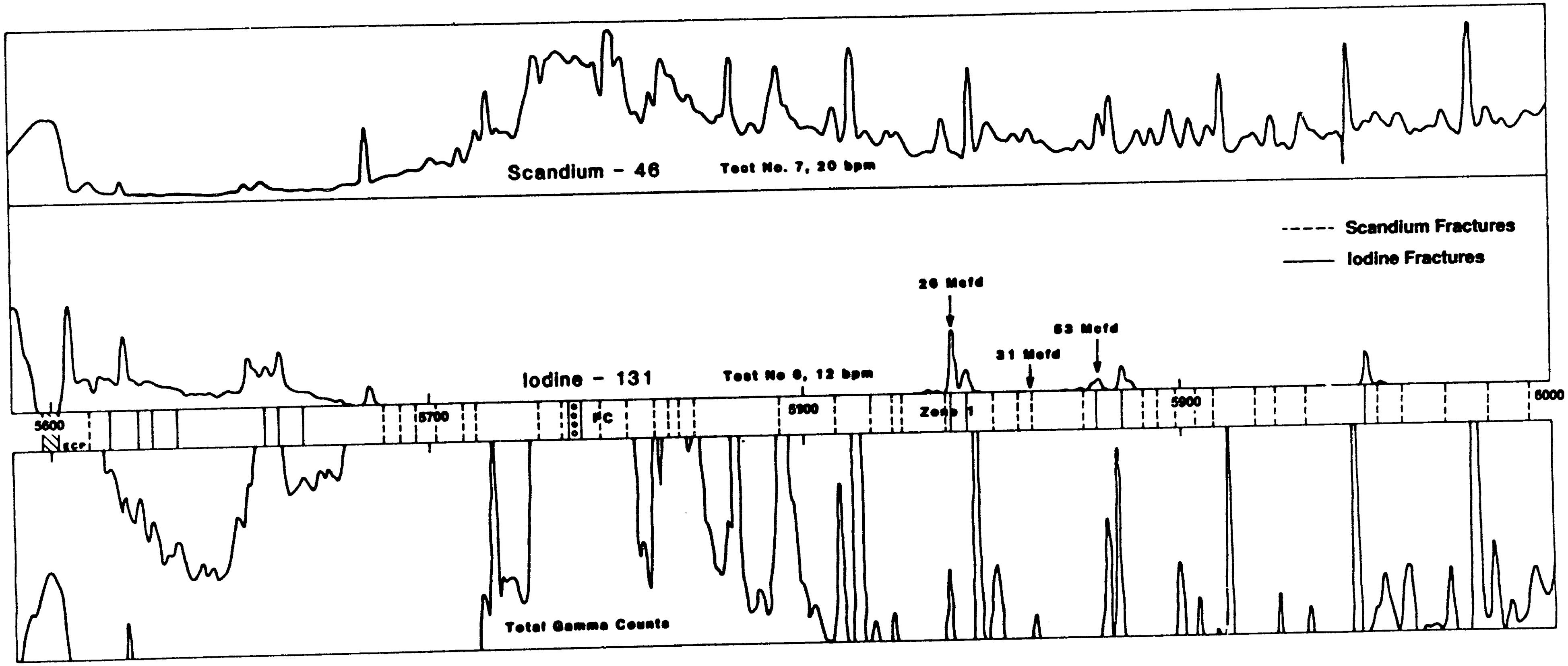


Figure 3.4.12: Log of Gamma Radiation from Radioactive Tracers to Determine Position of Fracture Pumped Into

The CO_2 stimulation was conducted at an injection rate which was 6.9 times the rate for the nitrogen stimulation, as presented in Table 3.4.4. Five times more fractures were propagated and the initial production rate was 5 times higher for the higher injection rate CO_2 stimulation, but the total volume injected was only 1.77 times the nitrogen frac volume. One might conclude that rate had more significant effects than volume on the resulting production.

Analysis and evaluation of the results of stimulation No. 2 strongly indicates that the original stimulation rationale needed to be revised to include proppants in the second stage.

3.5 Stimulation No. 3, Zone 1 - Nitrogen Foam/Proppant Frac

The third stimulation, which was originally planned to be a nonproppant bearing foam frac to be conducted in Zone 2-3, was revised. BDMESC engineers and geologists believed that more immediately-useful data could be obtained by conducting a third stimulation using the planned fluid, but including proppants to prevent decline of production rates, and by conducting the frac job in Zone No. 1 again to obtain direct comparison with the first two stimulations.

3.5.1 Stimulation Design

After the evaluation of the results of stimulations No. 1 and 2, and the long cleanup times required when using the original design volumes of gas, BDMESC engineers proposed to DOE to reduce the volume from 2000 reservoir barrels to 600 barrels. Also proposed and approved was a reduction in injection rate from 25 bbls/min to 10 bbl/min. The purpose in reducing the injection rate was to allow us to reinflate and prop fractures previously inflated and not to create any new ones, since our fracture diagnostics indicated 67 fractures had been pumped into during the first two frac jobs. In addition, the calculated friction pressure that would be generated by the 85-quality foam and sand would exceed the differential pressure limit of the external casing packers (2000 psi) and possibly produce a failure, so the injection rate was reduced to 10 bbl/min.

TABLE 3.4.4

COMPARISON OF RESULTS OF STIMULATION
SAME INTERVAL BY DIFFERENT FLUIDS

PARAMETER	NITROGEN	CO_2
Total volume in reservoir barrels injected (at 850 psi BHTP-N_2, 1050 psi CO_2)	3,832	2,770
Total volume in scf injected	1,165,000	2,063,000
Average injection rate in reservoir bbl/min	11.5	79
Average injection rate in scf/min	3,500	28,914
Max injection rate in bbls/min	17	102
Max injection rate in scf/min	5,000	37,413
Total number of fractures propagated	12	67
Pre-frac production rate	2.2	2.2
Post-frac production rate (at end of 6 days)	11 mcfpd	55 mcfpd
Post-frac production rate (at end of 20 days)	2.4 mcfpd	48 mcfpd
ISIP	776	958

Since this was to be the first frac job using sand, and two or more jobs would be conducted after this one, there was a need to prevent sand from being exposed to the sliding sleeve port collars. This could be accomplished by pumping the job through the 2-3/8-inch tubing and using a set of isolation cups on the string to keep the frac fluid from moving back up the hole.

To determine the difference between proppant bearing and non-proppant bearing fluid, it was decided to use two radioactive tracers. Iridium-192 and Antimony-124 were placed in the proppant and pad stages, respectively. Twenty (20) tons of liquid CO_2 were planned to be injected as a prepad to open up the fractures for the foam stage.

3.5.2 Wellhead and Wellbore Configuration

The third stimulation was pumped through the 2-3/8-inch tubing, while 1000 psi pressure was held on the annular space for a safety factor. The tubing had two sets of 4-inch rubber isolation cups placed in the string just above the bottom joint. One set faced downhole to prevent fluid from coming back uphole, and the other set faced uphole to contain the pressure between the casing and the tubing. The wellhead configuration was similar to that used during the second stimulation except there was no device for measuring bottomhole pressure. Surface pressure was measured by the service company transducer and recorded in the control truck.

3.5.3 Treatment Execution

On January 19, 1988, Zone No. 1 was stimulated for the third time by pumping down the 2-3/8-inch tubing and out the port collar at 5746 feet. Pumping of the job started at 12:20 p.m. and was completed at 2:02 p.m. The treatment proceeded according to the schedule shown in Table 3.5.1.

TABLE 3.5.1

TREATMENT SCHEDULE FOR NITROGEN FOAM/PROPPANT STIMULATION

STAGE	RATE (bpm)	VOLUME (bbl)	CUMULATIVE VOLUME (bbl)	SAND VOLUME (bbl)	PRESSURE (psig)	PUMP TIME (min)
1	3	119	119	0	240	40
2	10	167	286	0	1530	14
3	10	143	429	3000	1540	12
4	10	95	524	4000	1580	10
5	10	79	603	5000	1610	7
6	10	95	698	8000	1760	10
7	--	--	---	----	1560	N Flush

Maximum surface treating pressure was 1890 psig. The average treating pressure was 1540 psig. Bottomhole treating pressure was not measured, but was estimated to be 1150 psig. Instantaneous shut-in pressure was 1270 psig surface. Closure pressures were 770 and 730 psig as determined from examination of the plot of wellhead treating pressure versus time as shown on Figure 3.5.1. The well was opened up to flow back within 2 hours through a 1/8-inch choke. When the well was opened up, it was already well below the lowest closure pressure and a higher choke size used, but we were too conservative and worried about producing sand, and as a result, the well bridged off completely within 4 hours of being opened up. Arrangements had already been made to use a coiled tubing unit to clean out sand. Three hours of pumping nitrogen and running the coiled tubing in and out of the hole were required to clean the casing of sand. Nitrogen was pumped at an average rate of 1400 cfm with pump pressure reaching 3000 psig once or twice, but averaging about 2400 psig.

3.5.4 Fracture Diagnostics

Two different radioactive tracers were used during the stimulation. Antimony-124 was used in the liquid phase of the foam pad injected during Stage 2, and Iridium-192 pellets were injected with the proppant during Stages 3 through 6.

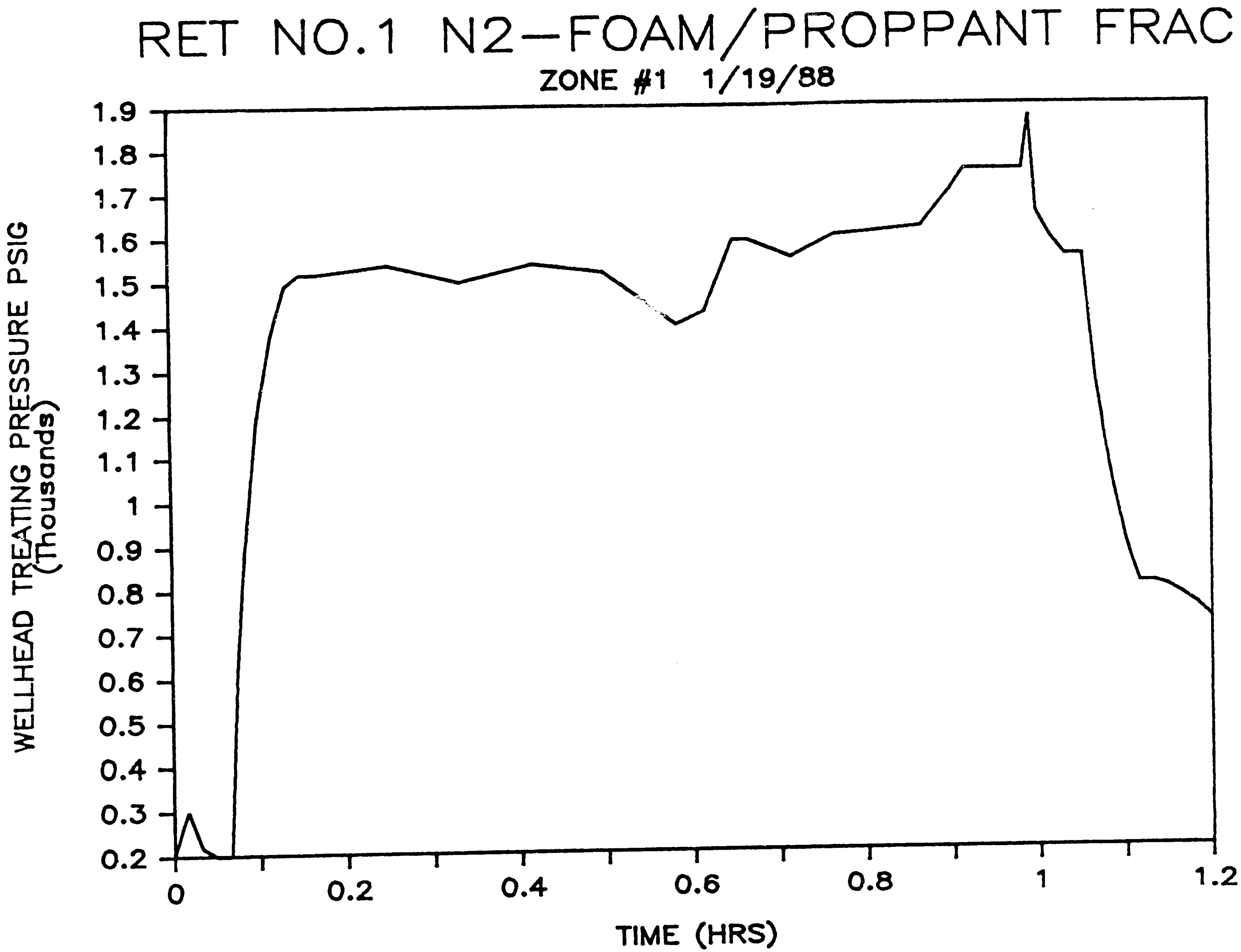


Figure 3.5.1: Plot of Well Treating Pressure versus Elapsed Time During Third Stimulation Conducted in Zone 1 (A Nitrogen Foam Frac with Proppant)

A 2-inch diameter spectral gamma tool was blown down to bottom inside the 2-3/8-inch tubing using nitrogen being injected at rates that started out at 700 cfm at an inclination of 47 degrees and increasing to 2000 cfm at 89 degrees. It took 3 hours, 28 minutes to put the tool out to 5980 feet, where logging in a conventional manner proceeded. The first run was made up to a measured depth of 3900 feet where the well was inclined at 75 degrees. A repeat run was made by blowing the tool back in the hole again; however, after the initial cautious experience was gained, the tool was blown back in only 15 minutes by using 2000 cfm nitrogen injection rate.

During Stage 2, the presence of tracer indicated that 17 fractures were pumped into in Zone 1, and 5 fractures in Zone 2. During Stages 3 through 6, tracer was detected in 69 fractures over Zones 1, 2-3, and 4. Significant amounts of material was detected in 20 of the fractures.

Other significant information was gleaned from examination of the tracer log as shown in Figure 3.5.2. The spectral gamma tool also picked up Scandium-46 which was the tracer used during the CO_2 frac job. What is easily noted is that 12 fractures were pumped into during both jobs in the interval between 5700 - 5800 feet. Also notable is that 6 new fractures were pumped into during the last 3 stages that had not been pumped into before. Thirty-five (35) of 69 fractures observed in Zone 1 were pumped into during the third stimulation.

3.5.5 Well Test and Analysis

The initial production of Zone 1 after the proppant-laden foam frac was not nearly at as high a rate as it was after the CO_2 frac. After the sand bridges were cleaned out and the tracer logs run, then the well was set up to record post-frac production rates. As shown in Figure 3.5.3, production was fairly stable for about 15 days before sand began to accumulate again, causing production to drop until eventually all production stopped and it was necessary to clean out the wellbore again. After clean-out was completed, production was higher than it had

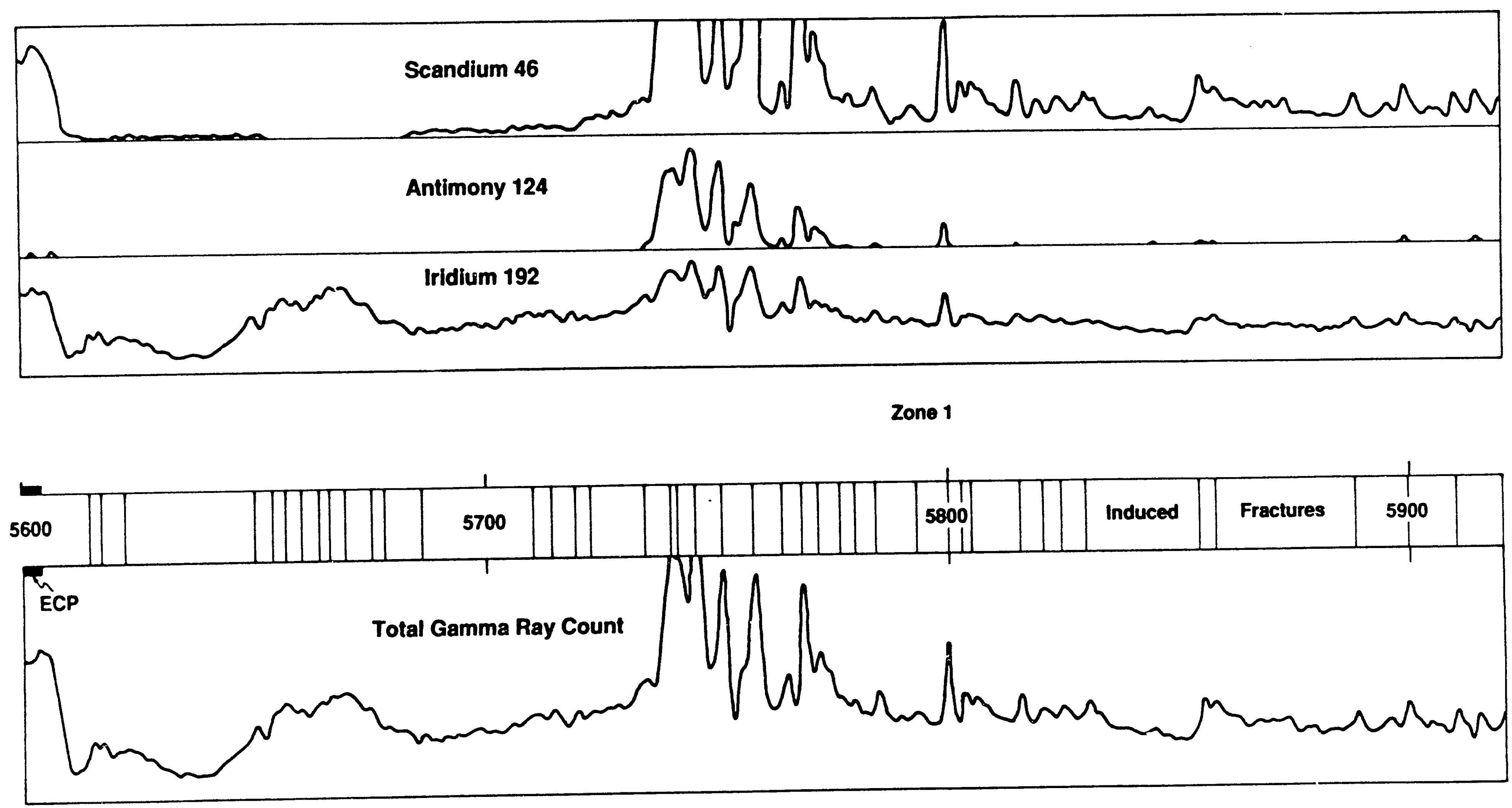


Figure 3.5.2: Log of Gamma Radiation from Different Tracers in Zone 1 After Third Frac to Show Location of Fractures Pumped Into

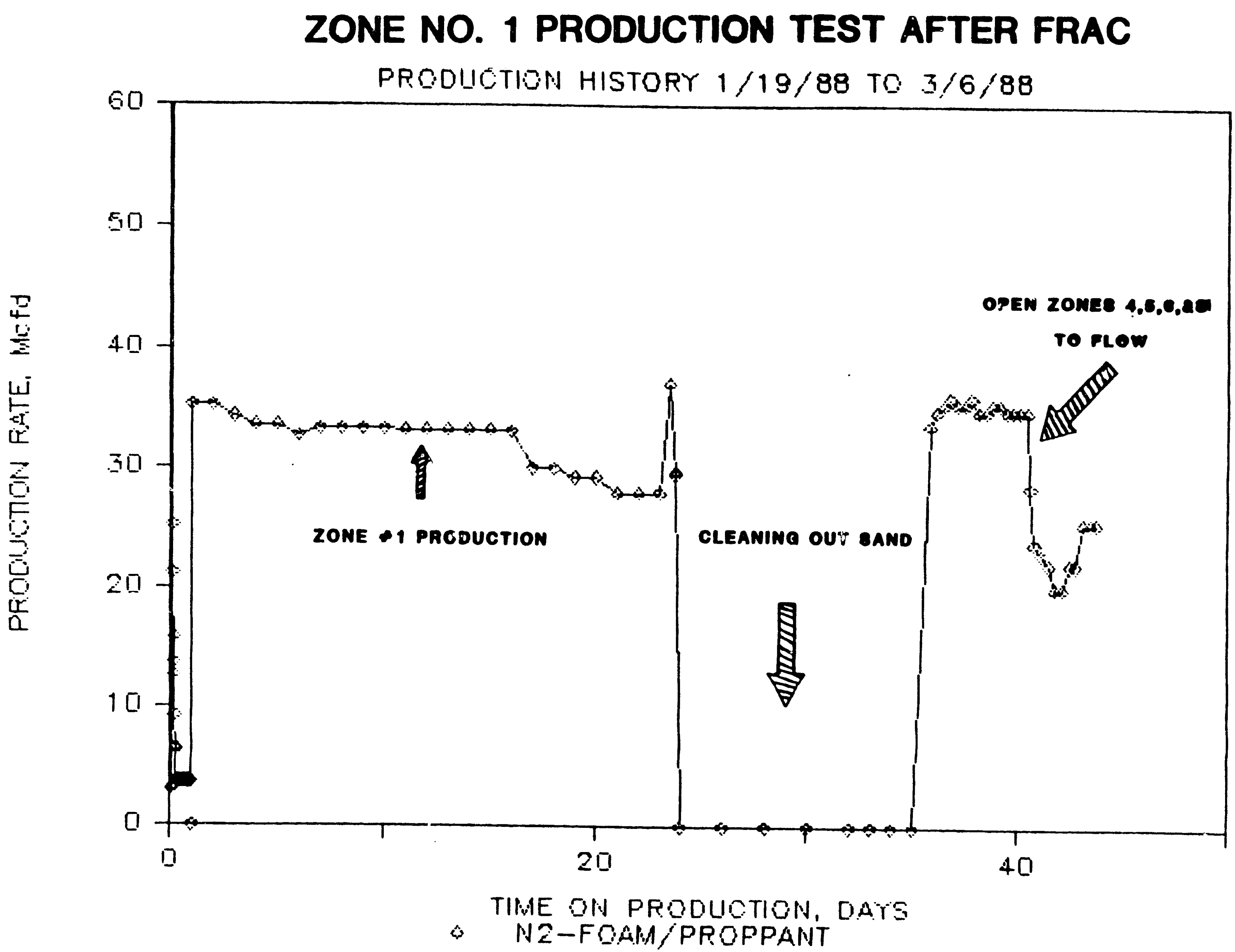


Figure 3.5.3: Production Rate versus Time on Production After Fracture with N_2 Foam and Proppant in Zone 1

been initially, and was fairly stable until Zones 4, 5, 6, and 8 were opened up to produce at the same time as Zone 1 to determine the amount of interference between the zones. Figure 3.5.4 illustrates the rapid falloff of production rate in Zone 1 when the rest of the well was shut in. A direct comparison of the production rate from both zones is shown in Figure 3.5.5. After about 10 days, both zones seemed to stabilize at about 28 mcfpd making the combined production rate about 56 mcfpd.

On March 13, 1988, a 14-day pressure build-up test was initiated and the results are presented in Figure 3.5.6. A build-up on the rest of the well is shown in Figure 3.5.7. This data was used to calculate permeability and skin effect in the following manner. A plot of pressure squared (P^2) versus the log of Horner's time ($\frac{tp + \quad t}{t}$) revealed a dual porosity system does indeed exist in the Devonian shales as illustrated in Figure 3.5.8.

Using the equation for the slope of aline ($m = \frac{Y-b}{x}$) , and substituting the values from Figure 3.5.8, we have:

$$m = \frac{33889 - 10000}{1.9379} = 12{,}327 \text{ P}^2/\text{log time.}$$

The slope for the mid region (m') was calculated in a similar fashion:

$$m' = \frac{28611 - 10000}{2.0966} = 6{,}492 \text{ P}^2/\text{log time.}$$

In examining the value for P^2 = 33,889, from the graph P = P^2 = 184 psia which is a value very close to the absolute values obtained in previous build-up curves and is reasonable. From the equation for flow capacity (1), we are able to substitute values and calculate K as follows:

$$Kh = \frac{1637 \; q_{avg} \; (\mu ZT)_{avg}}{mH} \qquad (1)$$

$$Kh = \frac{1637(29)(0.0107)(0.980)(553)}{12{,}327}$$

$$Kh = 22.3 \text{ md-ft}$$

$$K = \frac{22.3}{h} = \frac{22.3}{247} = 0.090 \text{ md}$$

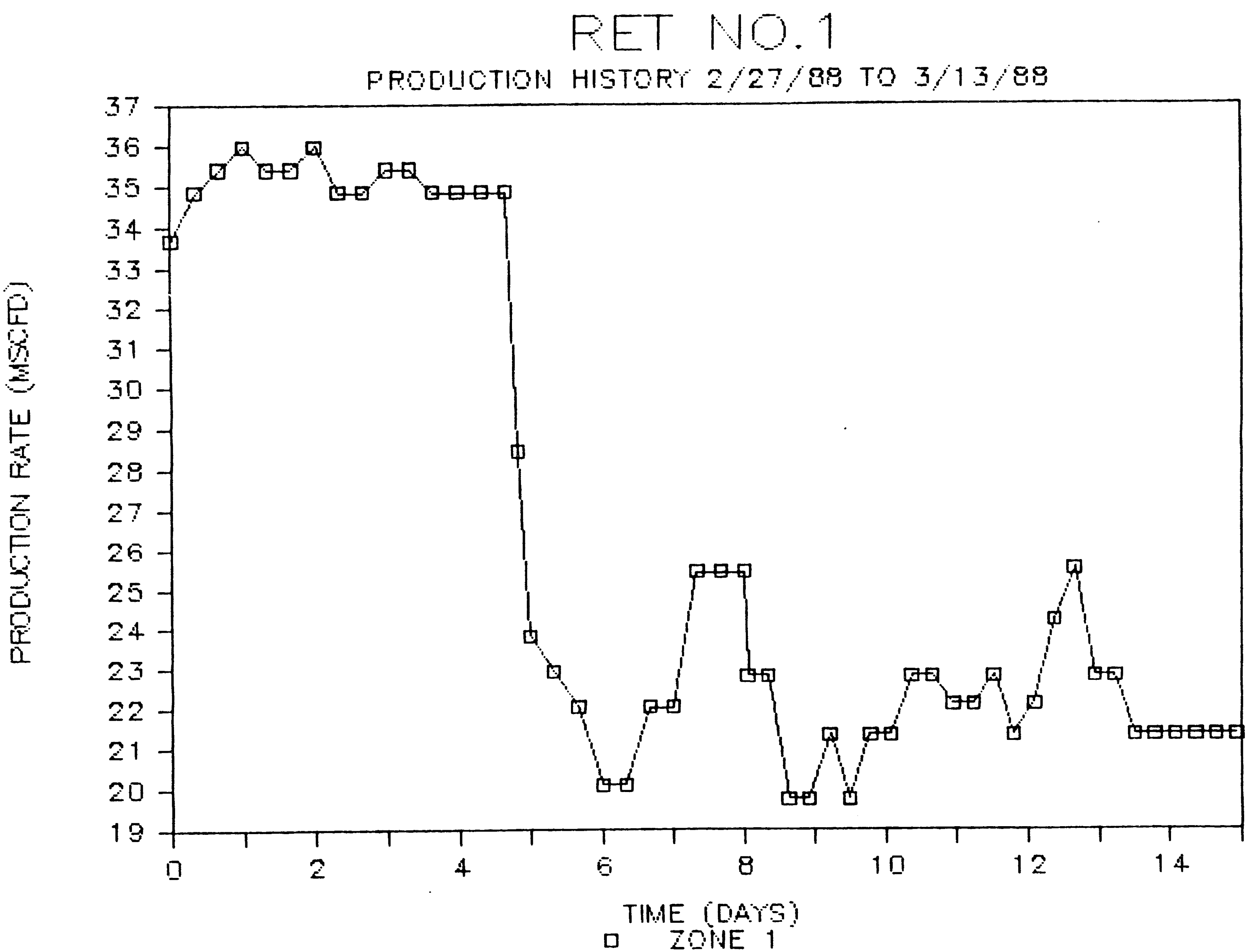


Figure 3.5.4: Production History Plot Starting 35 Days After Frac and After Cleanout of Sand from Wellbore and The Effects of Opening Up the Rest of the Well to Produce on the Fifth Day

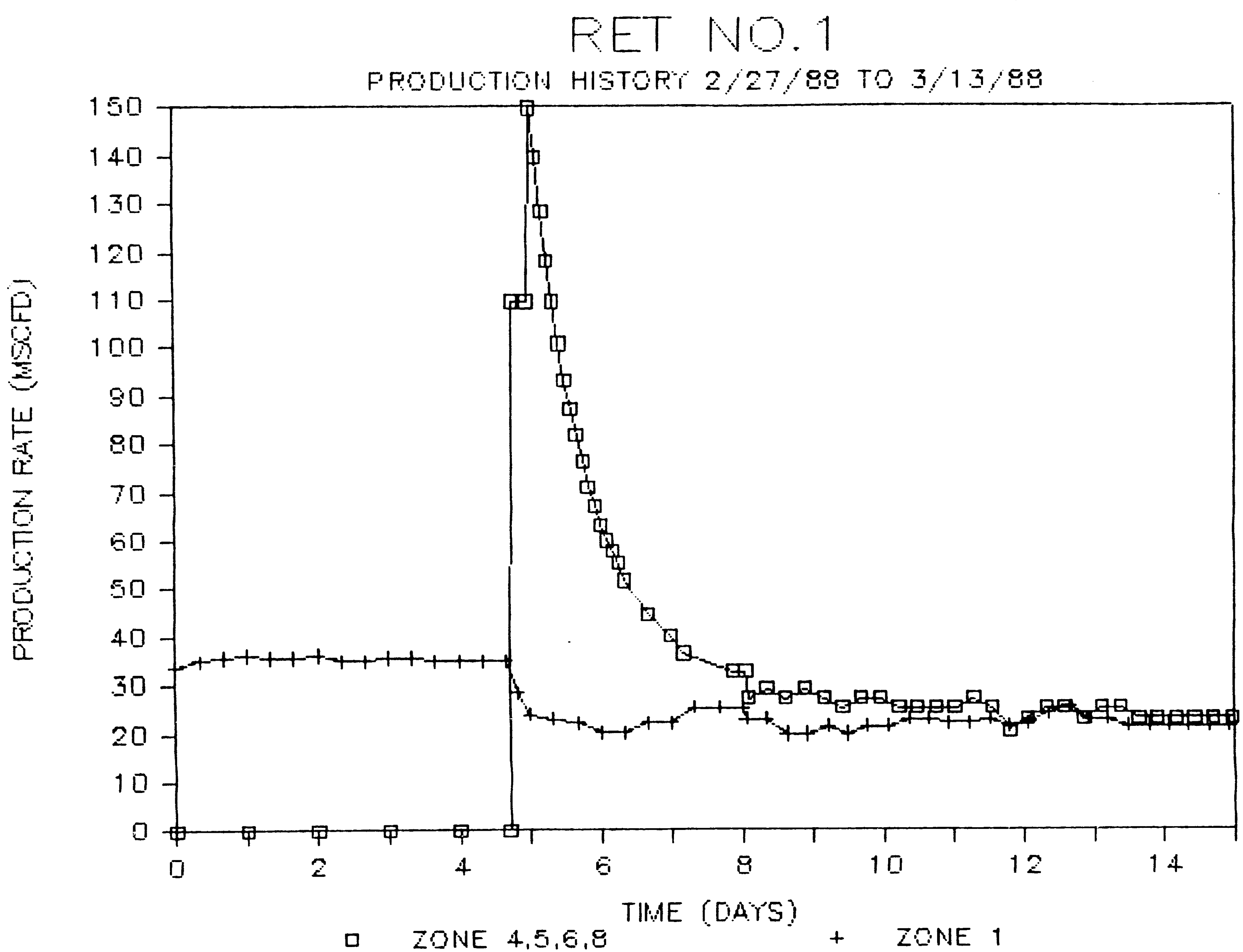


Figure 3.5.5: Plot of Zone 1 Production versus The Rest of the Well Showing Interference and Stabilization After 10 Days

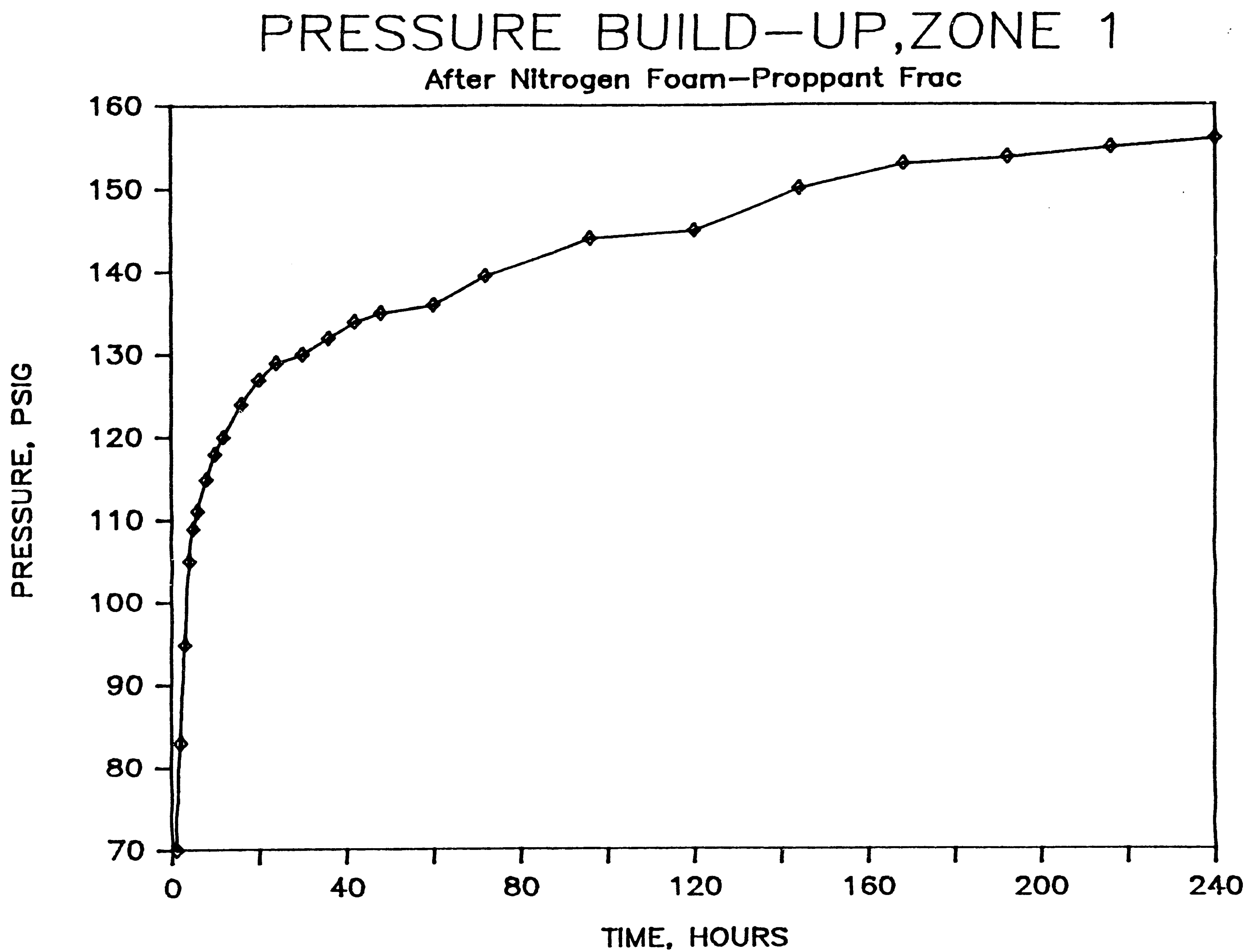


Figure 3.5.6: Pressure Build-up Curve After Gas has Cleaned up for Zone 1

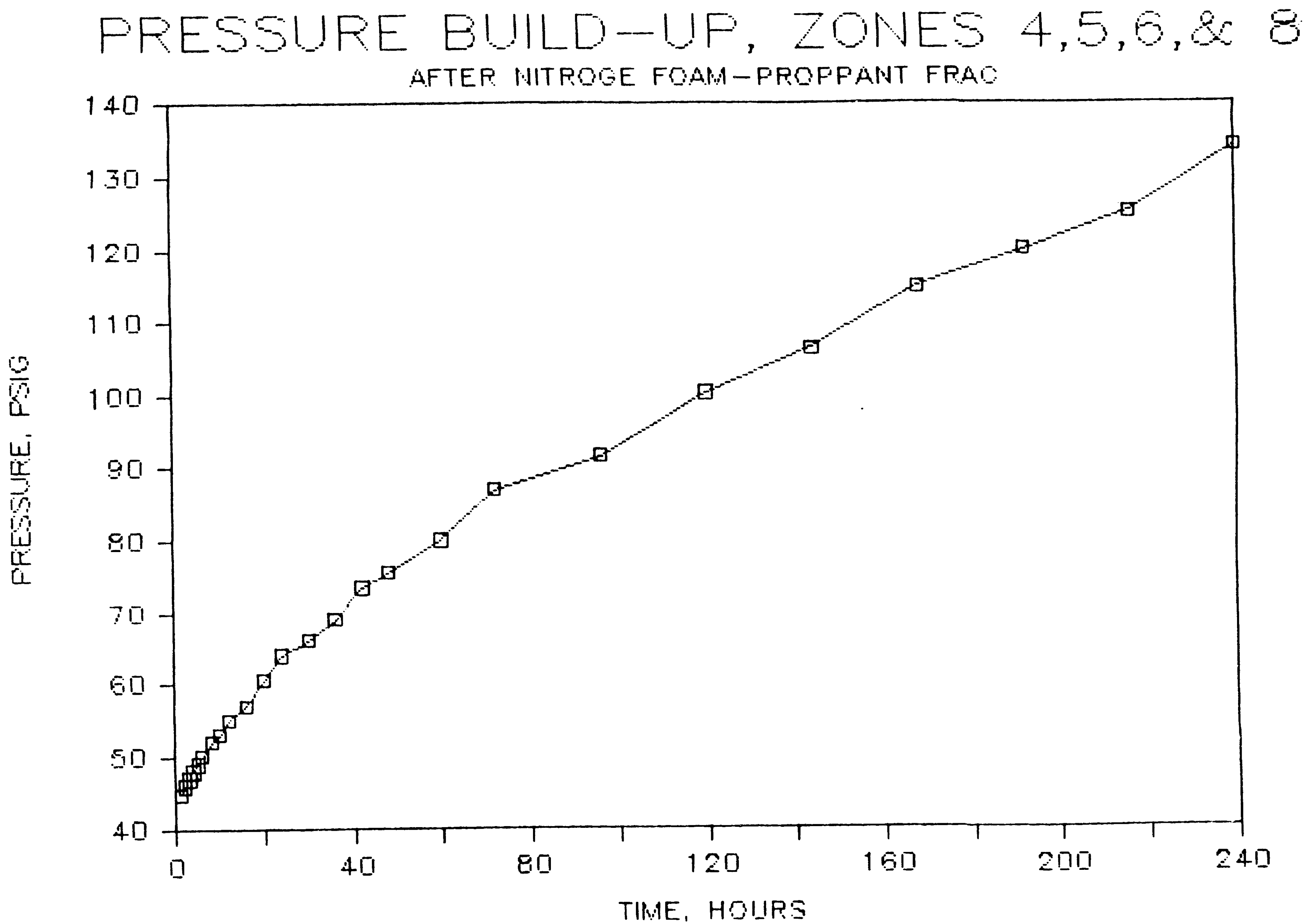


Figure 3.5.7: Pressure Build-up Curve for Balance of Well During the Same Build-up Period for Zone 1

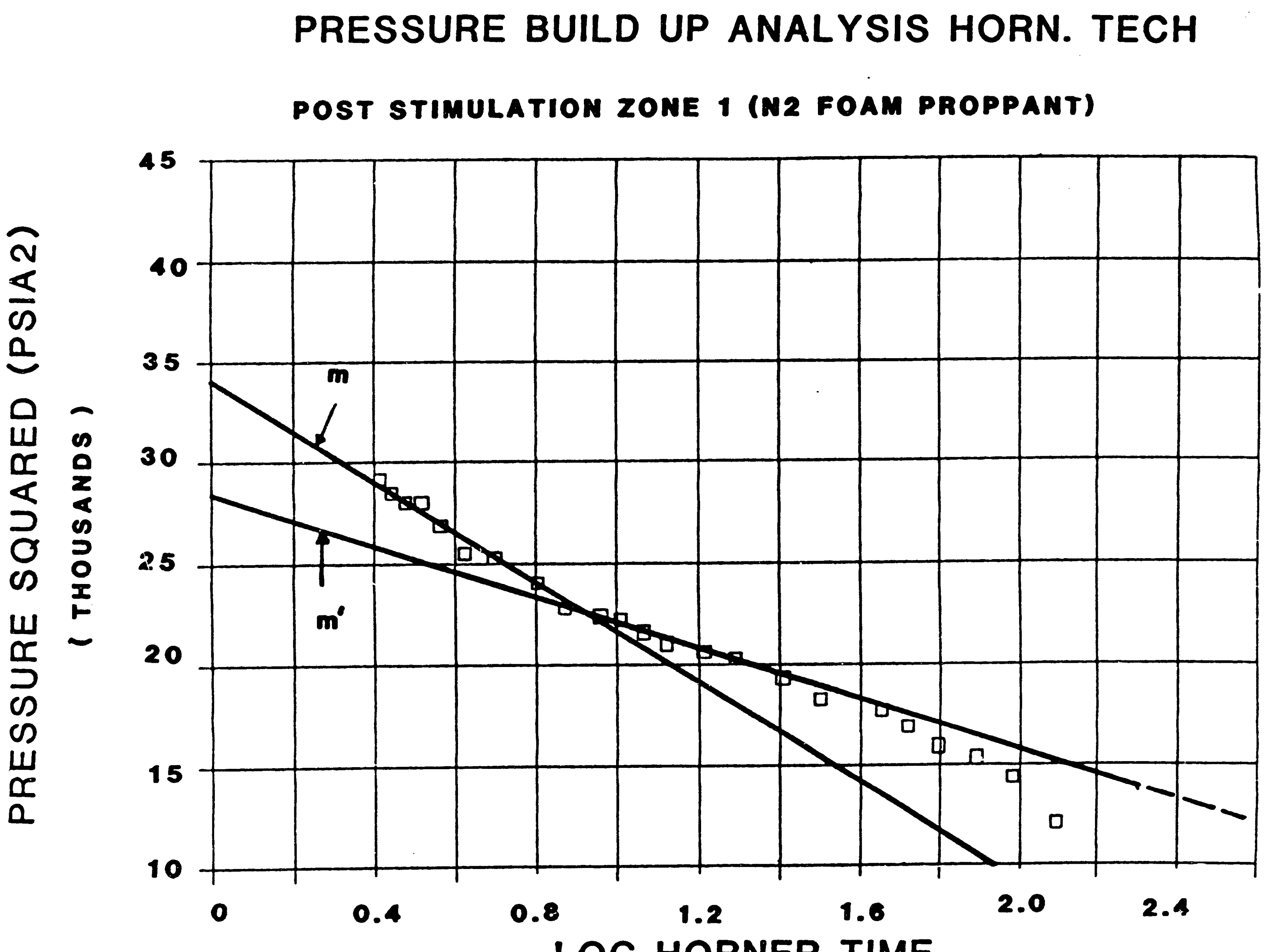


Figure 3.5.8: Pressure Build-up Analysis by Horner Technique Showing Determination of Two Different Slopes

where K = permeability in millidarcies

h = thickness of productive interval = 247 ft.

q = average flow rate = 29 mcfpd

μ = gas viscosity from gas analysis

Z = gas deviation factor from gas analysis

T = reservoir temperature in degrees = (460 + 93) = 553°R

mH = slope of Horner plot build-up data.

Skin factor for Zone 1 after stimulation with nitrogen foam and proppant was calculated as follows:

$$S = 1.151 \left[\frac{P^2\ 1\ hr - P^2\ wf}{m} - \log\left(\frac{K}{\phi\mu Ctrw^2}\right) + 3.23\right]$$

$$S = 1.151\ \frac{2018 - 7225}{12{,}327} - \log\left(\frac{0.090}{(.0173)(.0107)(.014)(.315)^2}\right) + 3.23$$

$$S = 1.151\ [-0.4224 - 5.598 + 3.23]$$

$$S = -3.212$$

Using G3DFR reservoir stimulator, a value of permeability equivalent to 0.33 md was estimated. We believe that the Horner technique calculated permeability value of 0.09 md is more accurate because all of the pressure build-up data is incorporated instead of only the last few points as with the G3DFR simulator.

3.5.6 Discussion of Results

The stimulation was conducted as planned without any major problems as shown in Table 3.5.2. The first horizontal well open-hole nitrogen foam frac carrying proppant was conducted at relatively low injection rates (10 bpm) to prevent the fractures being propagated from climbing out of zone. We cannot know conclusively, but it appears that several fractures (34 are estimated) were opened up in Zone 1 between

5710 feet and 5988 feet. During Stage 2, an estimated 29 fractures were opened and propagated. During Stages 3 through 6, additional fractures were opened and propagated between 5649 and 5680 feet which had not been previously opened. Considerable volumes of material exited Zone 1 in fractures that had been opened and propagated previously during frac jobs 2 and 3 and traveled some distance before encountering fractures which brought them back to the wellbore in Zones 2-3 and 4. These fractures were propped by the 20,000 pounds of 20/40 mesh sand carried by the 85 quality foam.

With 69 natural fractures available to take fluid, there was no problem with screenouts, although pressure would begin to build for a short period of time and then another group of fractures would begin to take fluid.

Although we have no direct evidence, viz-a-viz tracers logged in fracture systems, concerning the efficiency of CO_2, we consider the work done in frac job No. 3 as primie facie evidence that the fluid is very good at opening fractures.

The stabilized production at low rates over a period of time as shown in Figure 3.5.3 indicates that a good number of fractures were opened and propped with the proppant. The 6-day production rate improvement was the second best behind the CO_2 stimulation No. 3. The long range improvement ratio of 11.8:1 is the best conducted to date (see Table 3.5.3).

The results of well test and analyses clearly demonstrate that the use of even small amounts (20,000 lbs) of sand as a proppant in an area that is nearly stress relieved will improve overall production performance from the well by a factor of 3.

Based on the results obtained to this point, BDMESC concluded that the next logical step was to frac the well at high rates to determine if there would be significant numbers of additional fractures that would be opened and propped, or if the fractures that were being propagated would be propagated out of zone vertically. Our current fracture diagnostic system will not provide an answer, but perhaps some clues.

TABLE 3.5.2

COMPARISON OF PLANNED VERSUS ACTUAL DESIGN PARAMETERS
EXECUTED DURING FRAC JOB. NO. 4

STIMULATION TEST NO. 4
CO_2/NITROGEN-FOAM/PROPPANT - LOW VOLUME; LOW RATE

PARAMETER	PLANNED	ACTUAL
Volume of CO_2 (bbls)	120	119
Volume of Foam (bbls)	600	579
Volume of Sand (lbs)	20,000	20,000
Injection Rate (bbl/min)	10	10
Injection Pressure (psig)	2,000	1,550*

* Wellhead pressure (BHTP estimated - 1250 psig).

TABLE 3.5.3

COMPARISON OF PRODUCTION IMPROVEMENT AS A RESULT OF FRAC JOB NO. 4

FRAC	ZONE	PRODUCTION RATE PRE-FRAC	PRODUCTION RATE POST-FRAC 6th Day (mcfpd)	IMPROVEMENT RATIO (6 days)	IMPROVEMENT RATIO (20 days)	IMPROVEMENT RATIO (40 days)
N_2 foam	6	2.2 mcfpd	9 mcfpd	4.1	4.0	4.0*
N_2	1	2.2 mcfpd	11 mcfpd	5.0	1.1	1.1*
CO_2	1	2.2 mcfpd	55 mcfpd	25.0	22.0	4.5
N_2 foam/ proppant	1	2.2 mcfpd	34 mcfpd	15.5	13.6	11.8*

* Projected by decline curve.

BDMESC believes that the area being treated at any given time will probably be equivalent to that of only 5 to 8 fractures. Based on this, BDMESC believes that in an open hole situation, proppant should be introduced sooner than normal and the volume of true pad should be drastically reduced. In an effort to increase the number of fractures being propped, BDMESC recommended that the volume of sand injected be increased.

3.6 Stimulation No. 4 -- Zones 2-3 and 4 -- Nitrogen Foam/Proppant Frac

The fourth stimulation under the original project plan was to be the ideal stimulation for the well as indicated by the results from the first 3 stimulations. These results indicated that the best liquid would be CO_2, that proppants were necessary, and injection rates should be at least 20 barrels per minute. The stimulation was planned to be conducted on Zone 4 which is the most naturally productive zone in the well. Since the plans were changed to conduct unique stimulation tests in the same zone (No. 1), BDMESC felt it was necessary to double up on the zones to be able to adequately evaluate the results of stimulating the well. Zones 2-3 and 4 are very similar in that they both have fracture spacing of about 6 feet and were coupled together for the fourth stimulation.

3.6.1 Stimulation Design

The results of the three previous stimulations conducted in Zone 1 provided some very good results, which up until this time could only be speculated. The following conclusions derived from the first three tests:

(1) Injecting gases or liquids at slow rates allows selection of low dihedral angle natural fractures for propagation.

(2) Liquid CO_2 pumped at slow or moderate rates is an efficient fracture-generating fluid.

(3) Fractures opened up, but not propped, will close. Fractures close much faster when the internal pore pressure, or reservoir pressure, is low as compared to when the pressure is higher.

(4) Sufficient proppant must be placed in the generated fractures to keep propped fractures connected with the wellbore.

(5) In an openhole stimulation environment where there is considerable hole length and natural fractures to be propagated, the length of a propagated fracture is likely to be short, as new fractures open up and steal fluid from the propagating fracture.

Based on the above observations, BDMESC engineers and geologists reviewed this data with DOE and proposed a large volume stimulation to be pumped at rates higher than the natural flow capacity of the zone had demonstrated (2 flow of 2,165,000 scf during drilling). At an injection pressure of 850 psi, it would take more than 40 bbl/min to exceed the natural flow capacity of the zone, so a rate of 50 bbl/min was proposed. Since financial resources were limited, a reasonable volume of fluid and proppant was agreed upon, which was 140,000 gallons of 80-quality nitrogen foam and 225,000 pounds of sand. Even though evidence obtained to date indicated that CO_2 was the preferred fluid, it was believed that less risk, lower costs, and more direct comparison with the results obtained during stimulation #3 would result from using nitrogen, other than CO_2, during this job.

Thus, the revised strategy, which was to inject 6000 reservoir barrels of CO_2 foam into Zone #4 at 40 bbl/min was revised to inject 3300 reservoir barrels at 40 bbl/min of N_2 foam, carrying 2.5 pounds per gallon of 20/40 mesh sand, for a total volume of 225,000 pounds of sand. It was planned to use 200 barrels of liquid CO_2 to initiate the frac process because of its high efficiency in doing such.

3.6.2 Wellhead and Wellbore Configuration

Since a large volume of sand was going to be pumped into the well and there was a risk of getting a 2-3/8-inch tubing string sanded into the hole, BDMESC decided not to use the tubing to monitor bottomhole treating pressure as had been done before. To reduce cleanout costs, a retrievable bridge plug was set at 5645 feet, and port collars 2, 3, 4, 5 and 6 opened (see Figure 3.6.2.1). Port collar number 7, which is opposite the high productivity zone in the well, was kept closed to force the fluid to travel some distance to get to that zone and thus preserve more fluid for treating other less effective fractures in Zones 2 and 3.

The wellhead configuration was different since fluid was being pumped directly down the 4.5-inch casing. Service company heavy-duty (10,000 psi test) nipple and control valve was screwed into the top of the 3000 psig test Demco frac valve setting above the 8-5/8-inch casing head.

The retrievable bridge plug was a Baker #43A adapted with a #10 Model "J" hydrosetting tool and was put in place with the 2-3/8-inch tubing and set with 1000 psi nitrogen gas pressure. The unit was pressured to 5000 psi and sheared off the bridge plug releasing the tubing which was then tripped out of the hole.

3.6.3 Treatment Execution

On May 25, 1988, Zones 2-3 and 4 were stimulated by pumping down the 4.5-inch casing. Pumping of the job started at 9:53 a.m. and was completed at 11:43 a.m. The treatment proceeded as shown in Table 3.6.3.1.

Maximum surface treating pressure was 1490 psig. Average treating pressure was 1350 psig. Instantaneous shut-in pressure was 1150 psig. A total of 138,000 gallons of 80-quality foam was injected along with 225,000 pounds of 20/40 mesh sand. A total of 657 barrels of H_2O and methanol was injected into the formation during the job. Total nitrogen used was 1,061,151 scf.

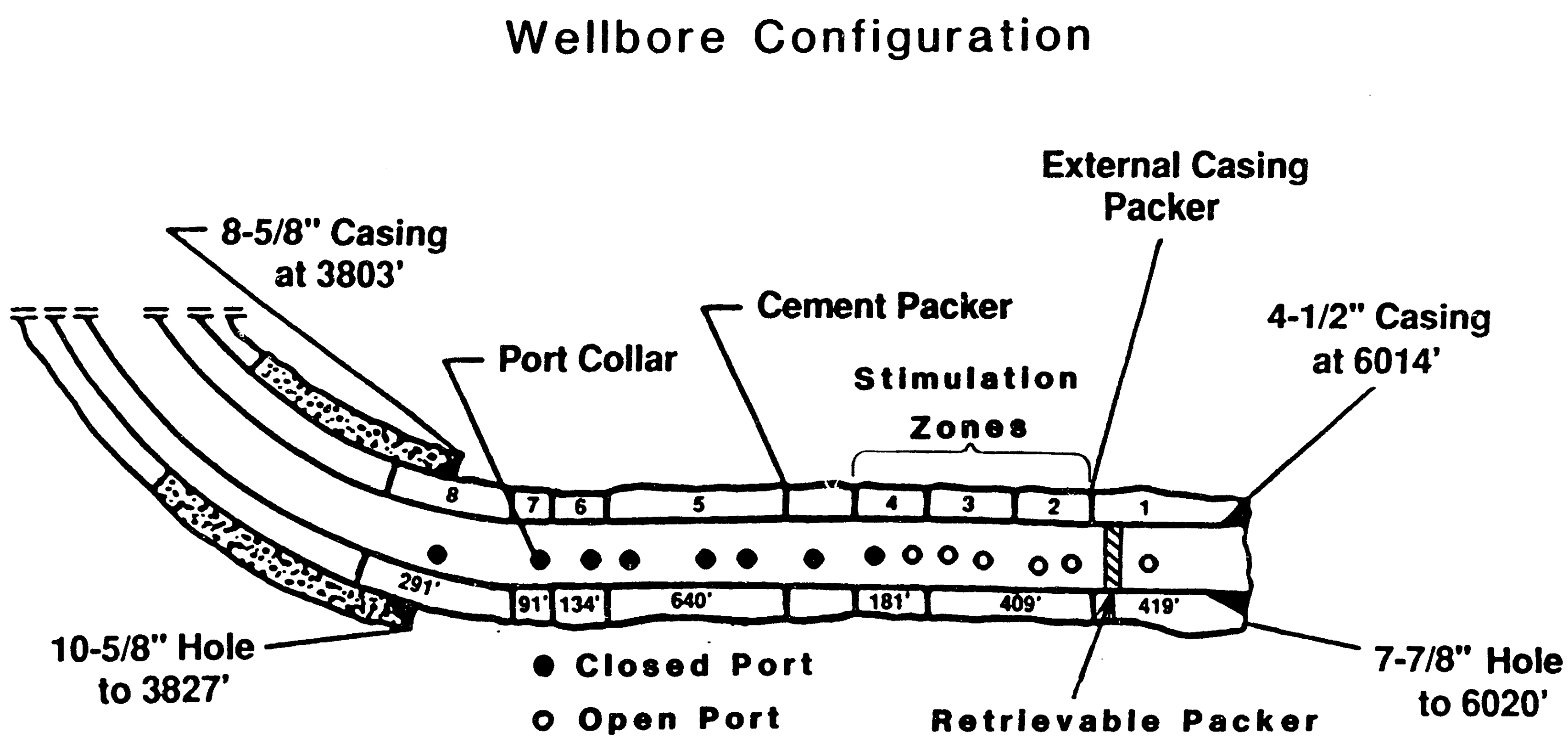


Figure 3.6.2.1: Wellbore Configuration During Stimulation of Zones 2-3 and 4

TABLE 3.6.3.1

TREATMENT SCHEDULE FOR STIMULATION NO. 4

STAGE	RATE (bpm)	VOLUME (bbl)	CUMULATIVE VOLUME (gallons)	SAND VOLUME (lbs)	PRESSURE (psig)	PUMP TIME (minutes)
1	15	119 (CO_2)	5,000	0	200	8
2	50	1,140	48,000	0	1350	22
3	40	119	53,000	2,500	1300	3
4	40	119	58,000	5,000	1350	3
5	40	119	63,000	7,500	1370	3
6	40	238	73,000	20,000	1390	6
7	30	238	83,000	25,000	1150	8
8	30	1,310	138,000	165,000	1200	44
9	8	29 N_2 flush				4

The treatment could not be completely executed as planned. Approximately 3 minutes after beginning Stage 7, a leak occurred in a nitrogen line which forced a reduction in the injection rate of 10 bpm from 40 to 30 bpm. Examination of the records of the frac job (Appendix E-2) shows some occasional difficulty with nitrogen rate and sand rate. The well was opened up to flow back within one hour. An estimated 160 barrels of fluid was recovered during the first 7 hours of flowback operations.

3.6.4 Fracture Diagnostics

Forty (40) millicurries of Scandium 46 was injected during Stages 3-8 as a liquid. Because of anticipated problems with well cleanout (sand0, the normal spectral gamma ray logging of the wellbore shortly after the frac job was completed was delayed until the cleanout operations would be conducted.

Cleanout operations to remove sand bridges in the casing was conducted on June 15, 16, and 17, 1988. On June 17, the spectral gamma ray log was run by pumping the 2-1/6-inch diameter Atlas Wireline tool down the 2-3/8-inch tubing with nitrogen (see details in Appendix E-1), and logging back out in a normal manner.

Examination of the log (see sample section in Figure 3.6.4.1) revealed that 54 of the 72 observed natural fractures in the three zones (2, 3, and 4) had been pumped into. Close examination of the section of spectral gamma log of Zone 4 shows that 3 fractures in the highly fractured (faulted ?) zone between 5040 and 5054 feet (located just to the right of the port collar marked PC) had received radioactive tracer during the January, 1988, stimulation of Zone No. 1 as indicated by the residual activity of Iridium 192.

A computer-processed "Prism" log of the data (Figure 3.6.4.2) shows where radioactive material is located either outside or inside of the casing and where relative amounts entered fractures at different points along the wellbore. Evaluation indicated 30 fractures received considerable material of the 54 indicated. Thirteen (13) of the 30 received twice as much material as the balance.

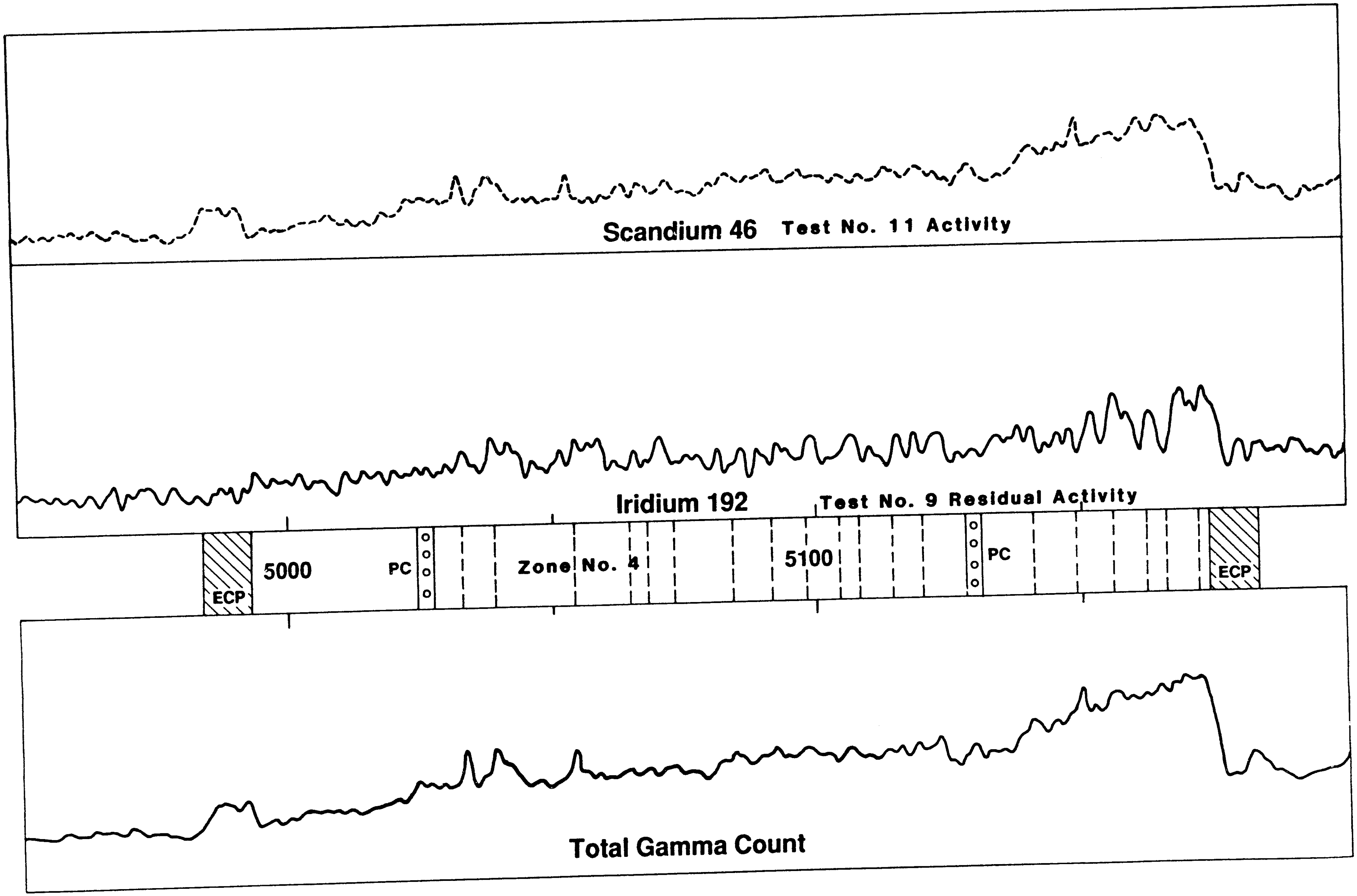


Figure 3.6.4.1: Section of Spectral Gamma Log Showing Residual Radiation from the Tracers Used During Stimulation No. 3 in January, 1988

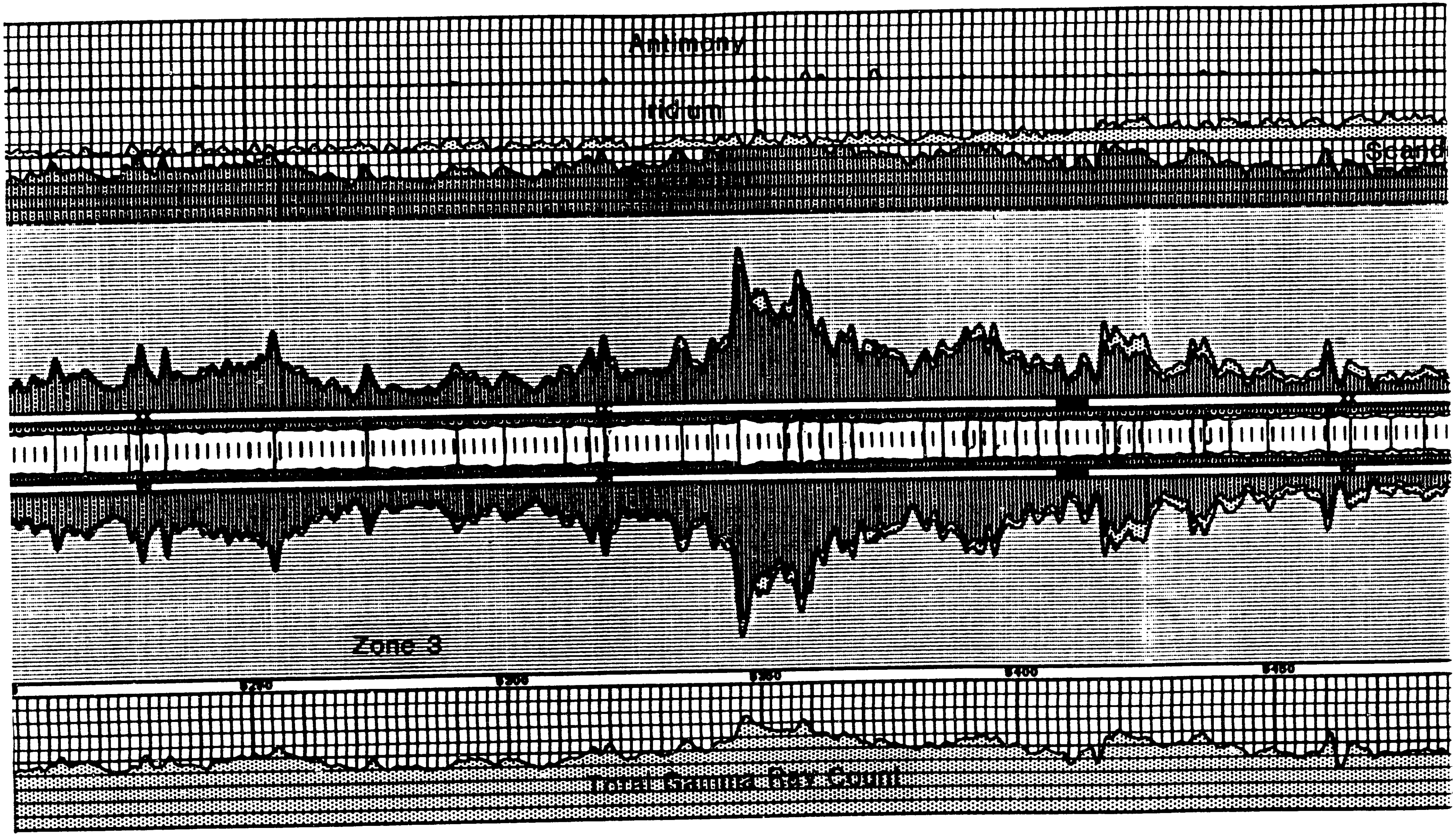


Figure 3.6.4.2: Portion of Computer-Generated "Prism" Log Made from Multispectral Gamma Log of the Borehole After Stimulation No. 4 in Zones 2-3 and 4

3.6.5 Well Test and Analysis

The initial production from combined Zones 2-3 and 4 after the large volume frac job was completed was fairly high. Eight hours after the flowback started, the well was flowing at a calculated (choke flow) rate of 1320 mcfpd. More than 1160 mcf of nitrogen gas was injected and charged the formation fracture system, but as this was produced back, the rate dropped very rapidly as shown in Figure 3.6.5.1. The well had declined to 202 mcfpd on the second day. The well dropped to a low of 46 mcfpd, then climbed to a stabilized rate of 62 mcfpd with the rest of the well shut-in. Production from the 19th to the 25th day was reduced by sand bridges in the casing which had to be cleaned out. Production climbed 8 mcfpd to 62 mcfpd after removal of the sand bridges. The well was flowed until nitrogen and CO_2 content was below 8% by weight, then the well was shut-in for a 10-day pressure build-up test.

Figure 3.6.5.2 is a plot of pressure squared versus the shut-in time (delta t) for the stimulated Zones 2-3 and 4.

From the plot of pressure squared (P^2) versus Horner Time (log $(\frac{tp + t}{t})$ as shown in Figure 3.6.5.3, the slope was calculated to be 15,879 $\frac{psia^2}{Log\ time}$. Using this data, the reservoir pressure, permeability, and skin factor was calculated as follows:

tp = flowing time = 35 days

q_{avg} = 62.2 mcfpd

T = formation temperature = 93°F = 533' R

μ_{avg} = gas viscosity = 0.0107 cp

Z_{avg} = gas deviation factor = 0.980

h = formation thickness = 247 feet (assuming the whole interval to be productive).

From Figure 3.6.5.3, the slope if 15879 psia²/log time period. Therefore, the formation permeability (k) is:

$$k = 1636.36\ q_{avg}\ T\mu_{avg}\ Z_{avg} = \frac{(1636.36)(62.2)(553)(.0107)(.980)}{} = 0.1505 \text{ md}$$

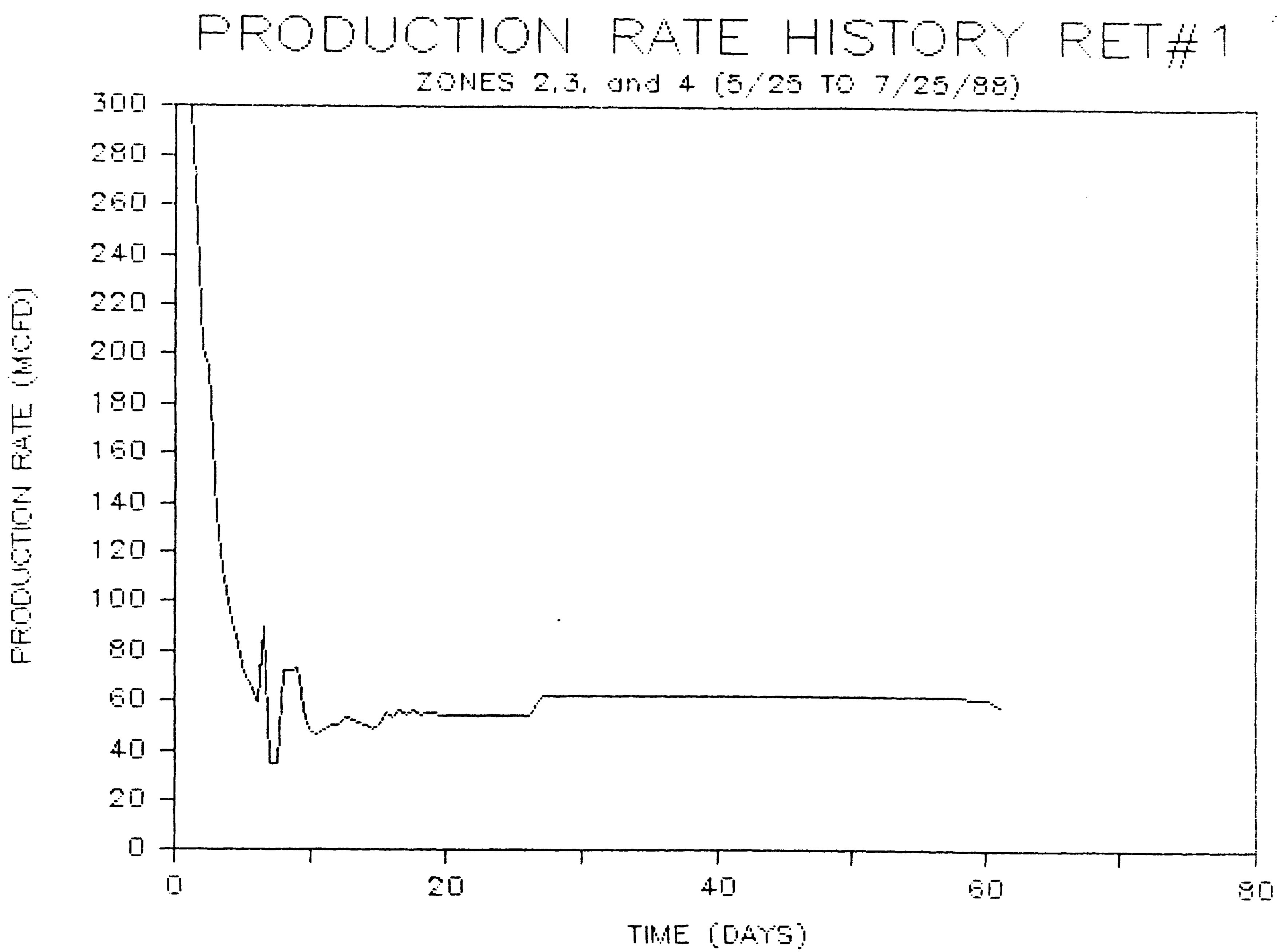


Figure 3.6.5.1: Production Rate History of Zones 2-3 and 4

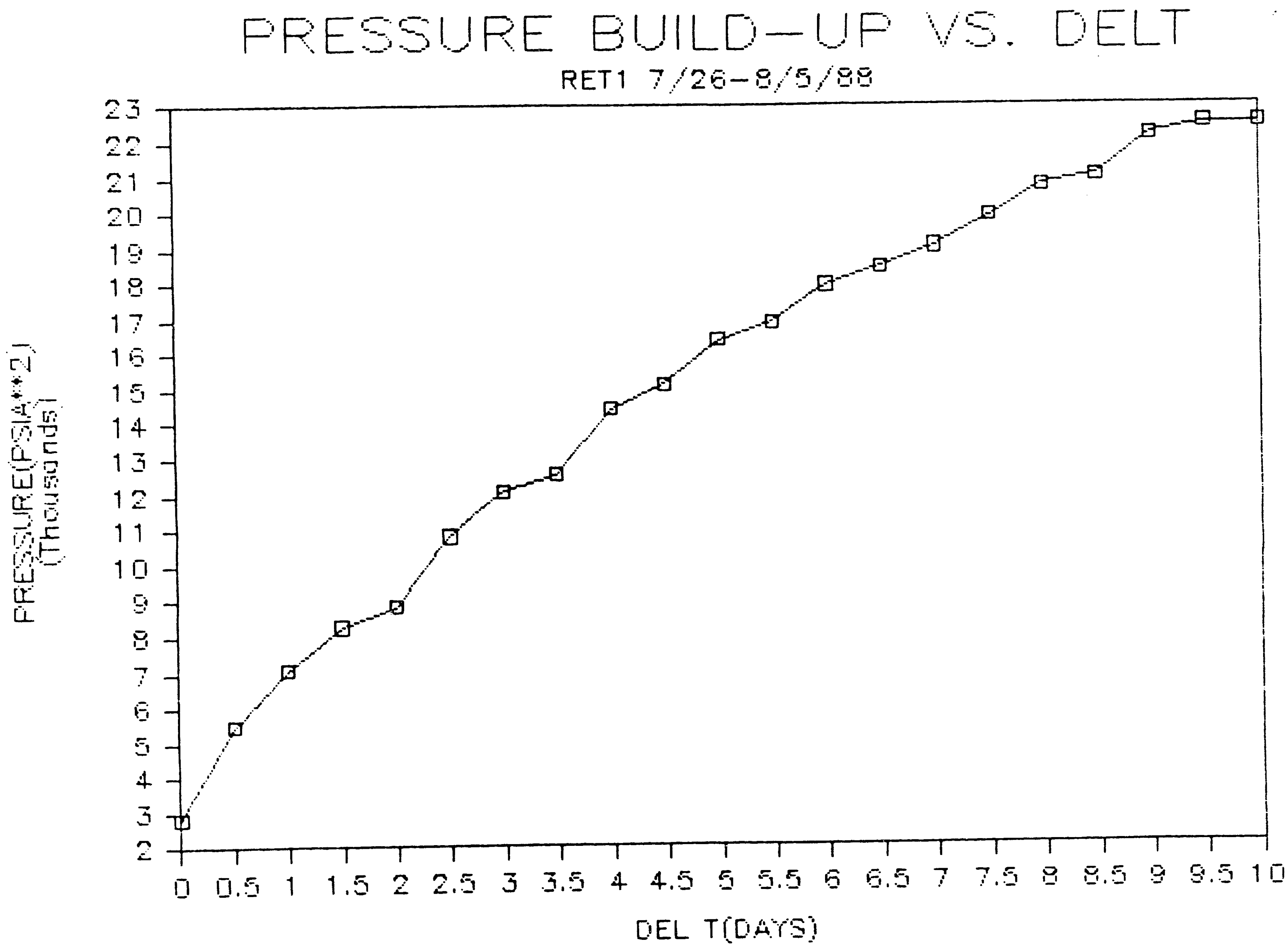


Figure 3.6.5.2: Plot of Pressure Squared versus Delta Time (Elapsed) for Zones 2-3 and 4

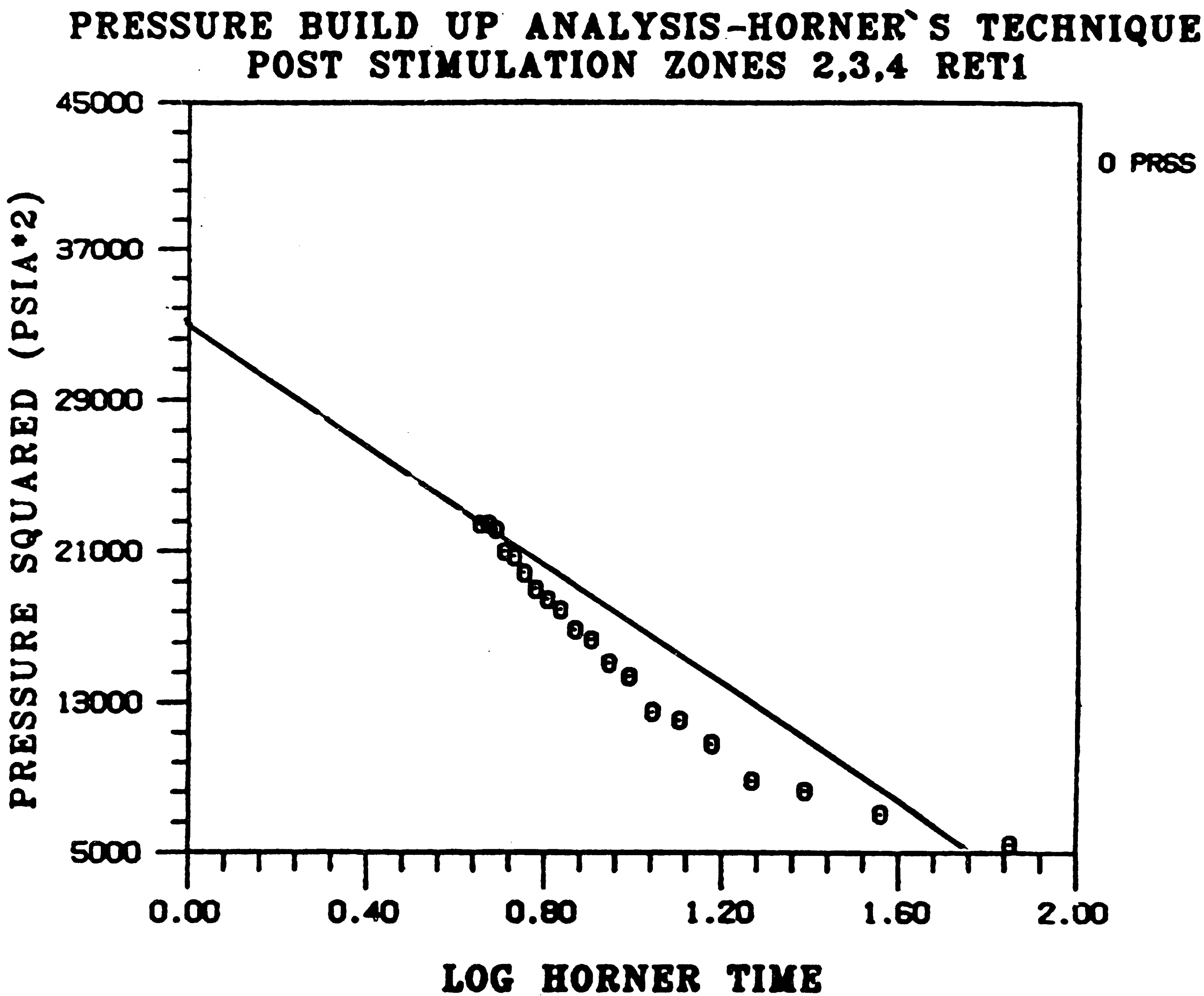


Figure 3.6.5.3: Pressure Build-up Analysis by Horner Technique

The "skin" factor is also computed from equation:

$$S = 1.151 \quad [(\frac{P^2 1hr - P^2 wf}{m}) - \text{Log} \frac{K}{\phi \mu C_t \ rw^2}) + 3.23 \ ]$$

where ϕ = porosity = 1.73 = 0.0173

C_t = C_g = 0.010 $psia^{-1}$

rw = 3.936 in = 0.328 ft.

P^2wf = $(53)^2$ = 2809 psia (actual flowing pressure before shut-in.

$P^2 1hr$ = -13,366 $psia^2$ (determined from the straight line in Figure 3.6.5.3).

Therefore,

$$S = 1.151 \ [\frac{-13366 - 2809}{29486.55} - \text{Log} \frac{.1505}{(.01)(.0107)(.0173)(.328)^2}) + 3.23 \ ]$$

$$= 1.151 \ (-1.0186 - 5.8784 + 3.23). \quad S = -4.22$$

Reservoir pressure is estimated by examining Figure 3.6.5.3 where:

$$\text{Log} \ (\frac{tp + \ t}{t}) = 0$$

where P^2 = 33077 $psia^2$ = 182 psia.

3.6.6 Discussion of Results

The stimulation was conducted as planned with the exception of the drop-in injection rate caused by a nitrogen leak during the last 3 stages. A comparison of planned versus actual results is presented in Table 3.6.6.1. The initial open flow rates were high, but they fell off rapidly to about 62 mcfpd, which is an increase of about 2.9 times the natural production of these 3 zones.

Since only one tracer was used, and that being in the proppant stage, it is difficult to say where the first and second stage material went except by indirect reasoning. The major flow capacity in the well is found between 5040' and 5054'; we would anticipate that fluid

TABLE 3.6.6.1

COMPARISON OF PLANNED VERSUS ACTUAL DESIGN PARAMETERS
EXECUTED DURING FRAC JOB. NO. 4

STIMULATION TEST NO. 4
CO_2/NITROGEN-FOAM/PROPPANT - HIGH VOLUME; HIGH RATE

PARAMETER	PLANNED	ACTUAL
Volume of CO_2 (bbls)	120	119
Volume of Foam (bbls)	3,285	3,295
Volume of Sand (lbs)	225,000	225,000
Injection Rate (bbl/min)	40	40-30
Injection Pressure (psig)	1,550	1,250*

* Wellhead pressure (BHTP estimated - 950 psig).

went into this zone initially when no proppant was being carried, then as that stage (48,000 gallons) was completed, the fracture system must have been loaded enough to change the local stresses enough to cause a shift to areas and fractures which presented lower resistance to flow into the natural fractures. Again, this suggests that with stimulation in an open hole environment, the amount of pad pumped should probably be reduced to 10 percent of the total volume.

It is difficult to know if a better result could have been obtained if even higher injection rates had been employed during the frac job. It is also possible that the same result could have been obtained by using one half the volume of fluid and sand to prop the many fractures known to exist in the well.

Production from the combined zones after stimulation, clean-up, production test, pressure build-up test, and production test declined approximately 30 percent over a period of 85 days (see Figure 3.6.6.1). This zone has exhibited the most stabilized production rate of all zones tested thus far. One reason could be that although we pumped into only Zones 2-3 and 4, they could now be interconnected with Zones 1 and possibly 5 and 6. it could also be that the large volume of proppant has propped several fractures that are providing sustained flow. The fracture network generated provides a reservoir that now somewhat resembles a porous sandstone.

The production improvement ratio for this fifth frac job presented in Table 3.6.6.2 does not show a high improvement when compared to the other stimulations, but the net result is definitely good in terms of gross production.

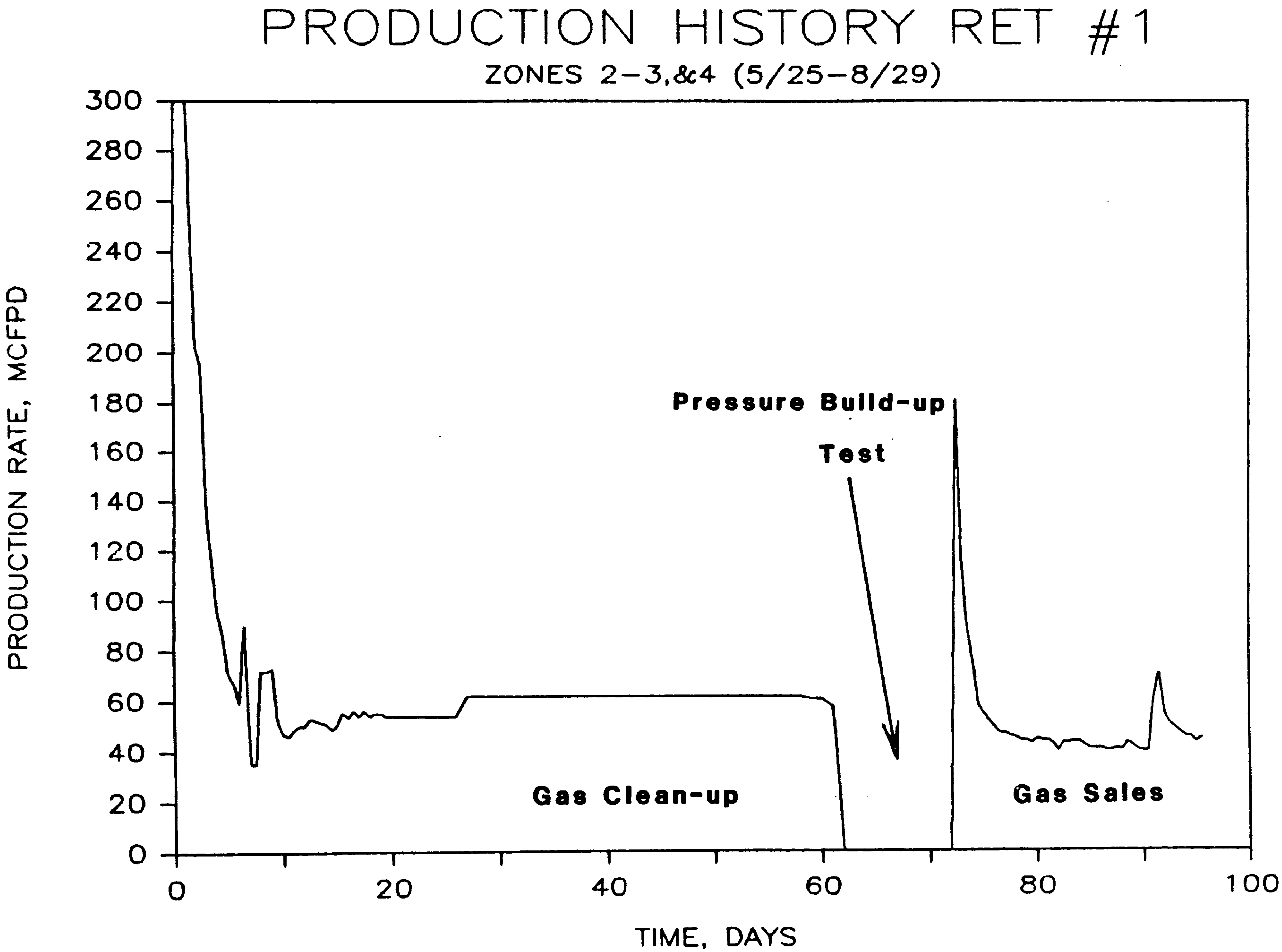


Figure 3.6.6.1: Production History of Zones 2-3 and 4 Over a Period of Three Months

TABLE 3.6.6.2

COMPARISON OF PRODUCTION IMPROVEMENT AS A RESULT OF FRAC JOB NO. 4

FRAC NO.	ZONE	PRODUCTION RATE PRE-FRAC	PRODUCTION RATE POST-FRAC 6th Day (mcfpd)	IMPROVEMENT RATIO (6 days)	IMPROVEMENT RATIO (20 days)	IMPROVEMENT RATIO (40 days)
0. N_2 foam (Test)	6	2.2 mcfpd	9 mcfpd	4.1	4.0	4.0*
1. N_2 gas	1	2.2 mcfpd	11 mcfpd	5.0	1.1	1.1*
2. CO_2 Liquid	1	2.2 mcfpd	55 mcfpd	25.0	22.0	4.5
3. N_2 foam/ proppant	1	2.2 mcfpd	34 mcfpd	15.5	13.6	11.8*
4. N_2 foam	2-3,4	21.1 mcfpd	75 mcfpd	3.6	2.6	2.9

* Projected by decline curve.

3.7 Stimulation No.5- Zones 5 and 8 - Nitrogen Foam/Proppant

The fifth and final stimulation of the well was planned to be the stimulation that was optimized through evaluation of all of the previous stimulations. As noted in Table 3.6.6.2, improvement ratio degraded with time. Since it normally takes 30 days to clean up the gas (reduce the CO_2 and N_2 weight percent) sufficiently to be able to sell it, the improvement ratio measurement point should probably be after 30 days of production. Based on this, stimulation No. 3 (frac No. 4 in Table 3.6.6.2) met and exceeded the 9:1 improvement ratio criteria established during the initial planning operations for Phase II activities. The fifth and final stimulation was to be an optimized version of frac job No. 3 which was a CO_2 pre-pad, nitrogen foam pad and foam with proppant main stage.

3.7.1 Stimulation Design

With the stimulation of Zones 2-3 and 4 during the fourth frac job, 1003 feet of the 2160 feet of bore which is accessible has been stimulated. To complete as much of the well as possible, BDMESC proposed and conducted stimulation on Zones 5 and 8 with a total borehole length of 932 feet. Zone 7, which is 90 feet long minimal flow capacity as indicated by pre-frac testing (see Table 3.1.1), was not included in the plans, as well as Zone 6 which had the abbreviated mini-frac test conducted on it, but resulted in an increase in production (Frac No. 0, Table 3.6.6.2).

In designing a stimulation for a conventional vertical wellbore, the height of the interval and the length and width of fracture desired are determined from logs, and it is then relatively easy to calculate the volume of fluid required to generate the fracture and the volume of sand required to prop it open to some desired width. In addressing the problem of creating a fracture, or in this case multiple fractures 100 feet high spaced every 40 feet along 932 feet of wellbore length and 0.25 inches wide, would require a minimum of 105,000 gallons of fluid and 325,000 pounds of sand. However, this cost exceeded funds available, so the sand volume was cut to 150,000 pounds.

So we designed a theoretical stimulation that would support development of 22 penny-shaped fractures 100 feet in diameter and 1/4-inch wide partially propped with sand. Obviously with a total of 60 natural fractures available for propagation over the 932 feet, it is difficult to project how the fluid will be distributed between the fractures.

BDMESC proposed and conducted the following stimulation as the final optimum stimulation on the RET #1 well:

(1) 9900 gallons of liquid CO_2 pumped at 12 bpm to initiate propagation of fractures in addition to those already known to exist.

(2) 23,333 gallons of 85-quality nitrogen foam pad to be pumped at 25 bpm to prepare multiple fractures for sand-laden foam.

(3) 82,891 gallons of foam carrying 150,000 pounds of sand pumped at 50 bpm to prop the fractures. Foam to be displaced to the last perforation to insure that sand is displaced out of the casing.

3.7.2 Wellhead and Wellbore Configuration

This frac job was similar to No. 4 and was also pumped down the 4.5-inch casing. Because of problems in retrieving the cast iron bridge plug which had a collapsed OD measurement of 3.66 inches where the casing ID was 3.99, BDMESC decided to use a rubber inflatable, retrievable bridge plug with a collapsed OD of 3.16 inches which would provide some additional safety margin relative to getting stuck with a few grains of sand inside the casing. The retrievable bridge plug was pushed into the wellbore on 2-3/8-inch tubing to 4950 feet near the external casing packer separating Zones 4 and 5, as shown in Figure 3.7.2.1, and set with a J type hydraulic setting tool. The packer was set by pumping nitrogen gas to a pressure of 5000 psi where the bridge plug was set and sheared off from the setting tool. The tubing was pulled out of the hole, leaving 5 ported collars open and two closed.

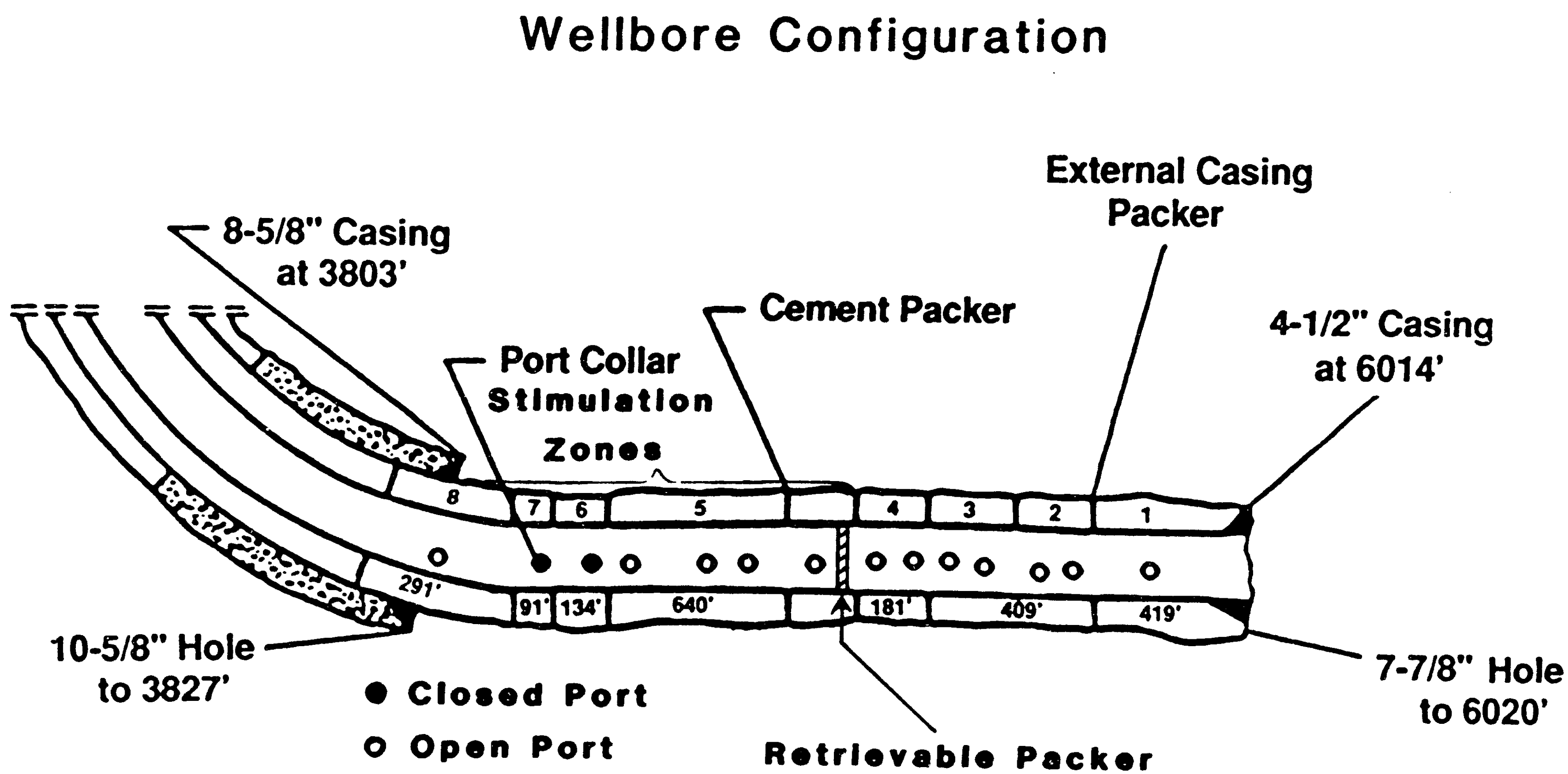


Figure 3.7.2.1: Wellbore Configuration During 5th and Final Stimulation of RET #1 Well

3.7.3 Treatment Execution

On August 31, 1988, Zones 5 and 8 were stimulated by pumping the planned frac job down the 4.5-inch casing. Pumping of the job began at 5:35 p.m. and was completed at 7:13 p.m. The treatment proceeded as presented in Table 3.7.3.1.

Maximum surface treating pressure recorded was 1530 psig; instantaneous shut-in pressure was 1280 psig. The planned treatment of 40 tons of CO_2, 105,000 gallons of 85-quality foam, and 150,000 pounds of 20/40 mesh sand was pumped without any major problems. A total of 376 barrels of water and methanol was injected into the formation during the treatment. Pressure versus time charts for the job are contained in Appendix F-3. Flowback was started within one hour; within 12 hours approximately 104 barrels of liquid or approximately 30 percent of the total injected had been recovered.

3.7.4 Fracture Diagnostics

Because of the shortage of funds available for this job, the planned fracture diagnostics studies were not conducted. This resulted in a savings of approximately $10,000 which was used in other aspects of the stimulation and recovery operations for the final stimulation.

TABLE 3.7.3.1

TREATMENT SCHEDULE FOR STIMULATION NO. 4

STAGE	RATE (bpm)	VOLUME (bbl)	CUMULATIVE VOLUME (gallons)	SAND VOLUME (lbs)	PRESSURE (psig)	PUMP TIME (minutes)
1	12	238 (CO_2)	10,000	0	200	22
2	25	1,140	22,333	0	1100	24
3	50	119	29,000	3,300	1300	3
4	50	119	42,333	13,400	1350	3
5	50	119	55,666	20,000	1370	7
6	50	238	69,000	26,600	1500	7
7	50	238	86,012	36,700	1550	8
8	50	1,310	105,000	50,000	1550	18
9	10	40 N_2 flush				4

3.7.5 Well Test and Analysis

The pressure build-up data were analyzed using type-curve matching, Horner's technique, and a newly-developed technique known as the Rectangular Hyperbolic Method (RHM). Values of average reservoir pressure, formation flow capacity, and Skin factor were estimated. After performing the frac job on Zones 5 and 8, the RET #1 well was producing from these two zones at an average flow rate of 50 mcfpd for a period of 20 days. On September 22, 1988, the well was shut in for a period of 13 days during which the reservoir pressure was monitored in Zones 5 and 8. Figure 3.7.5.1 shows the pressure build-up performance for Zones 5 and 8.

3.7.5.1 Analysis Using Three Different Methods

a) Type-Curve Matching: Due to the complexity of production from the Devonian Shale and the existence of a dual porosity system, a log-log plot of Δp^2, $(p^2_{ws}-p^2_{wf})$, and $d(\Delta p^2)$ (derivative of delta pressure squared) versus Effective Time (Δte) was generated;

where $\Delta t_e = \Delta t/(1+ \Delta t/t_p)$

Δt = shut-in time (days)

t_p = flowing time, 20 days

The use of pressure-squared approach instead of the pseudo pressure for gas reservoir analysis is proven to be valid for reservoir pressures less than 2000 psia. A Flopetrol Johnston/Schlumberger type-curve was used for infinite acting reservoir with double porosity behavior (pseudo steady state interporosity flow), wellbore storage, and Skin (Figure 3.7.5.2). The Δp^2 and $d(\Delta p^2)$ were matched on the curve $C_De^{2S} = 10^4$ simultaneously (Figure 3.7.5.3). Match points of pressure and time were established and values of permeability and Skin were estimated. The following is the computation procedure for determining the permeability and Skin values (Figures 3.7.5.2 and 3.7.5.3):

Pressure Match Point ($\Delta p^2 = 1000$, $p_D = 0.295$)

Time Match Point ($\Delta t_e = 1.0$, $t_D/C_D = 25$).

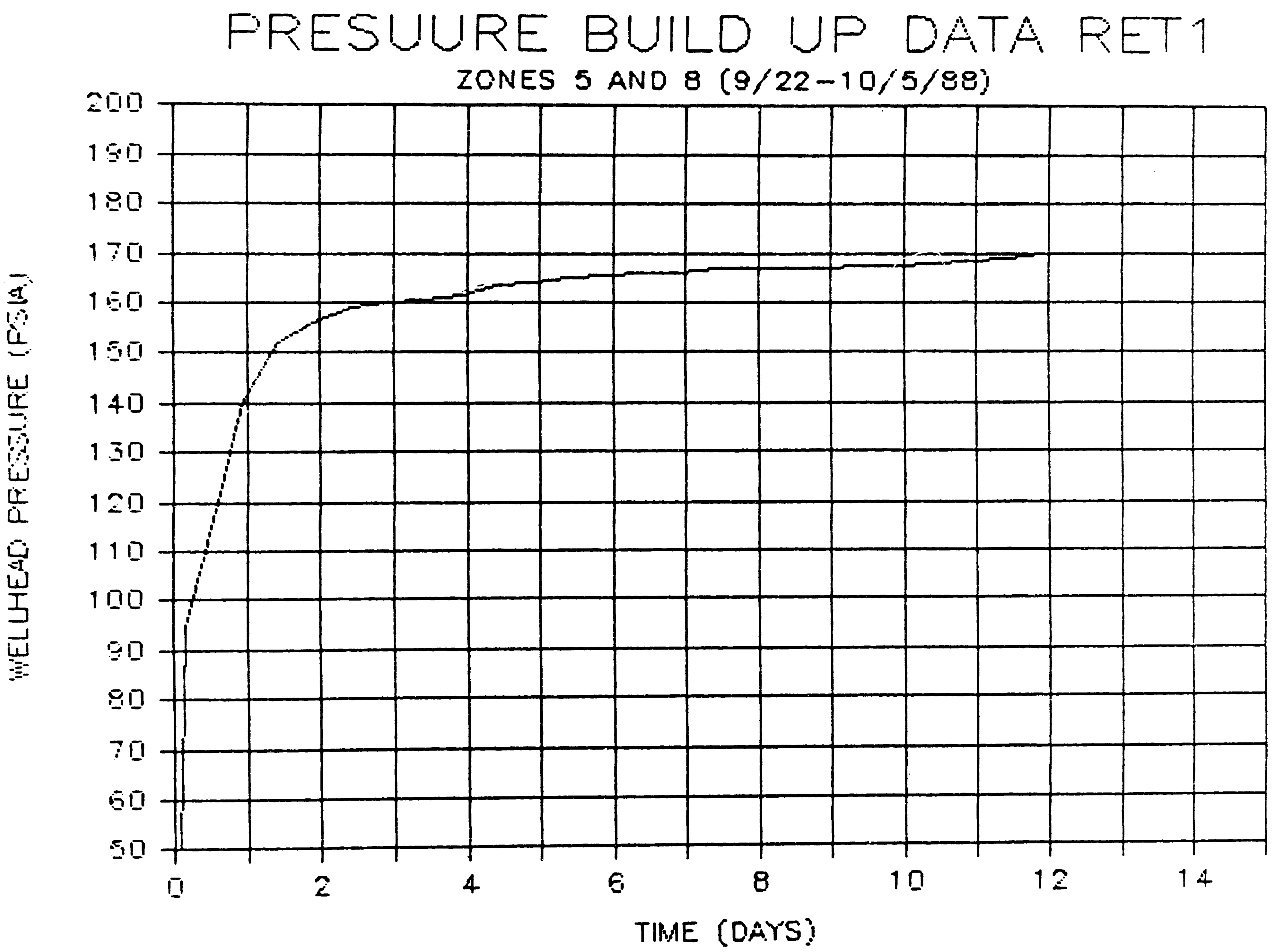


Figure 3.7.5.1: Pressure Build-up Data for Zones 5 and 8 After Well has Cleaned Up

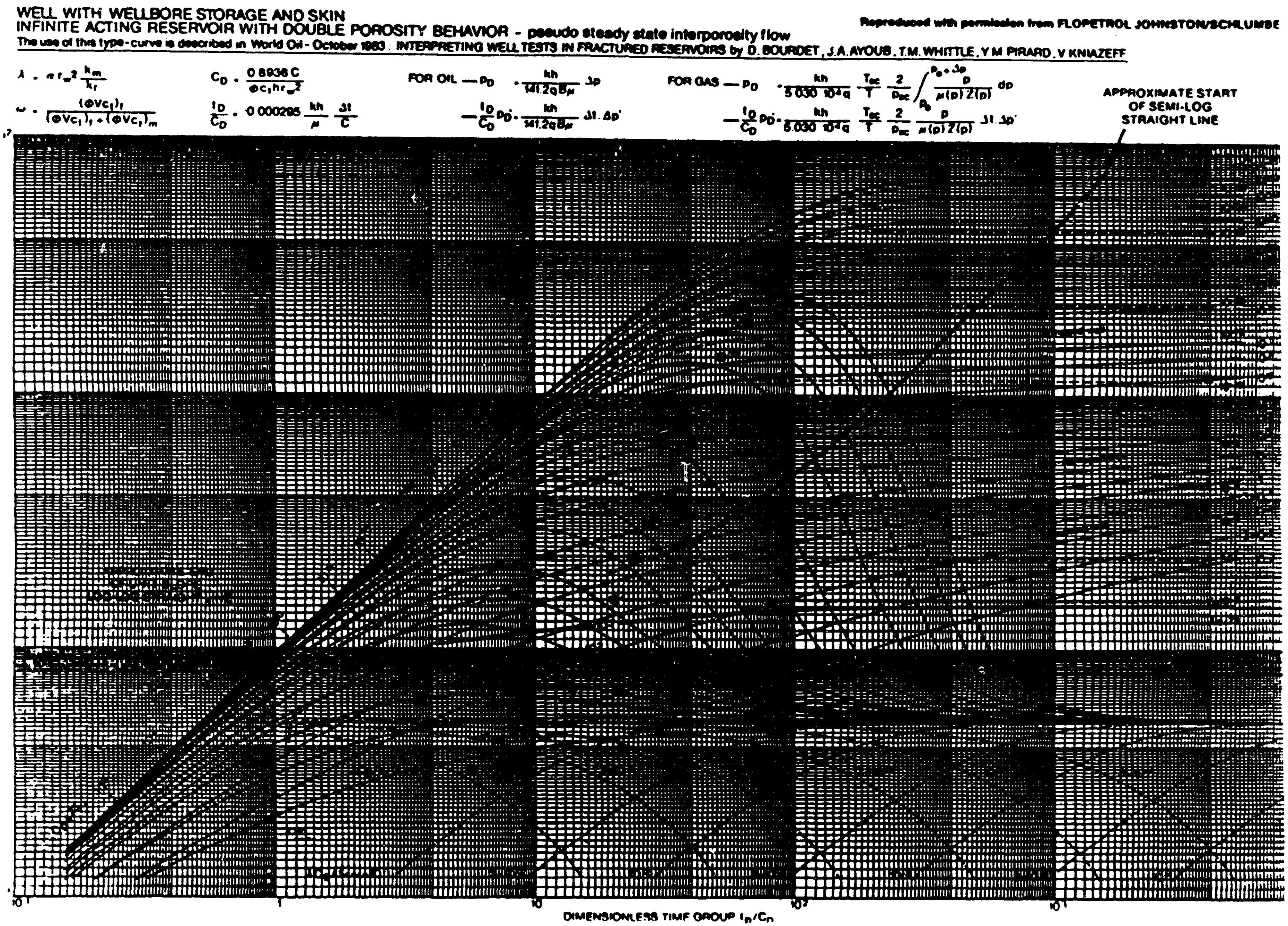


Figure 3.7.5.2: Curve plots for Dual Porosity Reservoir Used for Curve Matching to Determine Permeability

DELTA PRESSURE SQUARED AND ITS DERIVATIVE VERSUS TIME

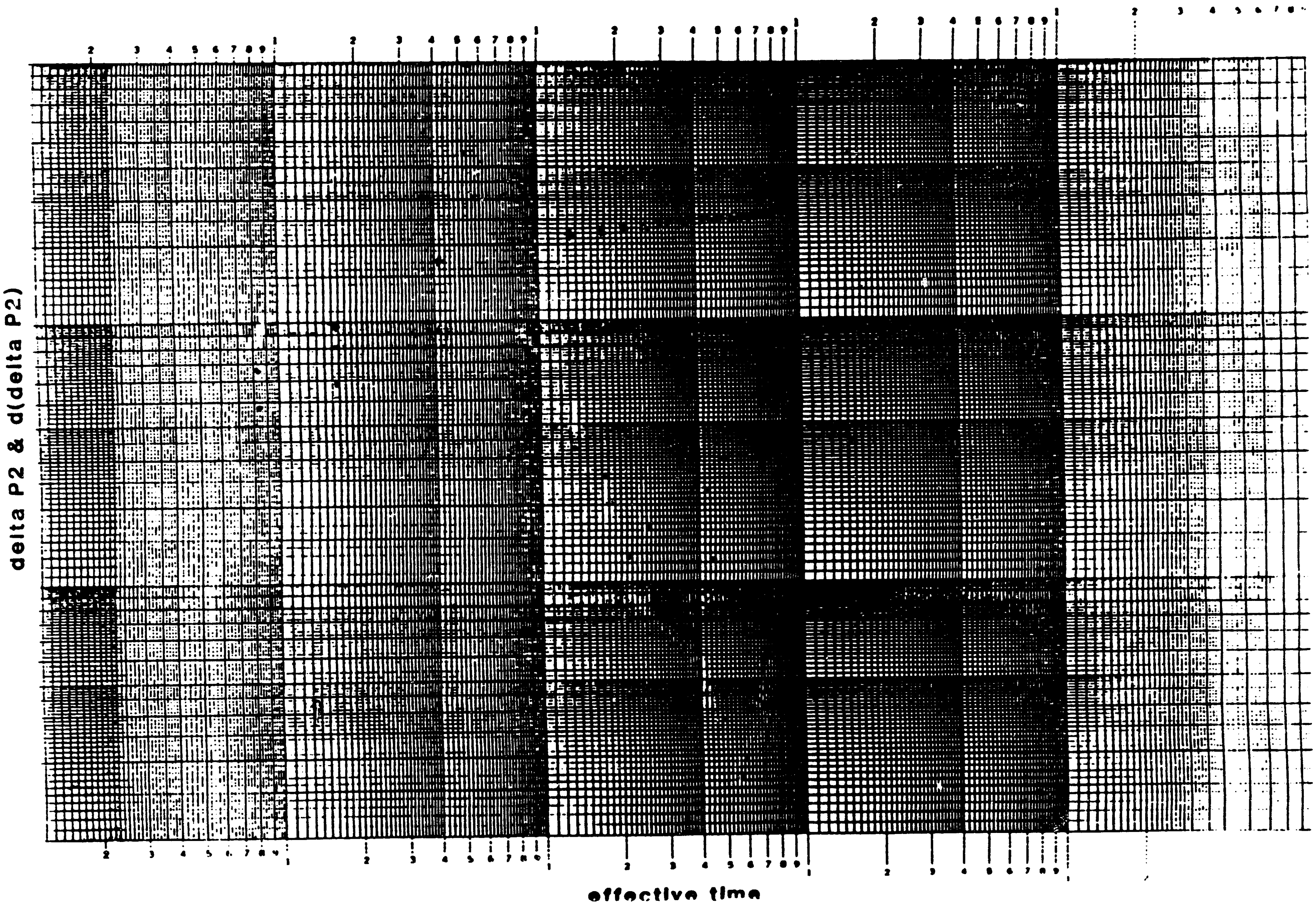


Figure 3.7.5.3: Plot of Delta Pressure Squared and Its Derivative versus. Time

Therefore, $k = 1422[(q_{avg}\ \mu_{avg}\ z_{avg}\ T)/h][p_D/\Delta p^2]_{MP}$ (1)

where
q_{avg} = average flow rate = 50 mcfpd
T = formation temperature = 93°F = 553°R
μ_{avg} = average gas viscosity = 0.0107 cp
z_{avg} = average gas deviation factor = 0.980
h = formation thickness = 247 ft (assuming the whole interval to be productive).

Using equation (1):

$$k = 1422\ [(50)(0.0107)(0.98)(553)/247]\ [(0.295/1000)] = 0.492 \text{ md}$$

In order to determine the Skin value (s), the value of C_D is computed using the time-match-point equation:

$$C_D = [0.0063288k/(\phi\mu C_t rw^2)][\Delta te/(t_D/C_D)_{MP}] \quad (2)$$

where
ϕ = porosity = 1.73% = 0.0173
C_t = total compressibility = 0.0100 psia^{-1}
rw = 3.936 inches = 0.328 ft.

Using equation (2) value of C_D is determined as follows:

$$C_D = [(0.0063288)(0.492)]/[(.01)(.0107)(.0173)(0.328)^2][1.0/25] = 625.4$$

The value of s is determined from the following equation:

$$s = 0.5\ \ln(C_De^{2s}/C_D) \quad (3)$$

$$s = 0.5\ \ln(10^4/625.4) = 1.386$$

Where C_{De} 25 is determined from the type curve (Figure 3.7.5.3). As indicated on the type-curve, the last 4-5 points on the ΔP^2 vs Δte curve falls within the semi-log straight line region. Therefore, these points could be used for the Horner's technique to estimate/predict values of permeability and Skin and establish a correlation of k and S based on both techniques.

b) <u>Horner's Technique</u>: Based on the previous analysis, and using the last 4-5 points that were determined to be in the semi-log/straight line region, a semi-log plot of P^2 versus Horner time (Horner time = (tp + Δt)/Δt) was generated (Figure 3.7.5.4). Utilizing Horner's technique, the following procedure was used to determine/estimate values of average reservoir pressure (P), formation flow capacity (kh), and Skin factor (s).

(1) Determine the flow capacity (kh) using the following equation:

$$kh = 1636.36\ (q_{avg}\ \mu_{avg}\ z_{avg}\ T)/m \qquad (4)$$

Where m is the slope of the straight-line determined from Figure 3.7.5.5;

$$m = -5878 \text{ psia}^2/\text{log time period.}$$

$$k = \frac{1636.36\ (50)\ (0.0107)\ (0.98)\ (553)}{(-5878)\ (247)} = 0.327 \text{ md}$$

2) Determine the average reservoir pressure (P) by determining the equation of the semi-log/straight line.

where $y = -5878\ x + b$

$y = p^2 = \text{psia}^2$

$x = \text{Log}\ (tp+\Delta t)/\Delta t$

$b = $ Y-intercept at $\text{Log}[(tp + \Delta t)/\Delta t = 1]$

Therefore,

$$p^2 = -5878\ \text{Log}[(tp + \Delta t)/\Delta t] + b \qquad (5)$$

represents the equation of the straight line in terms of pressure-squared and time.

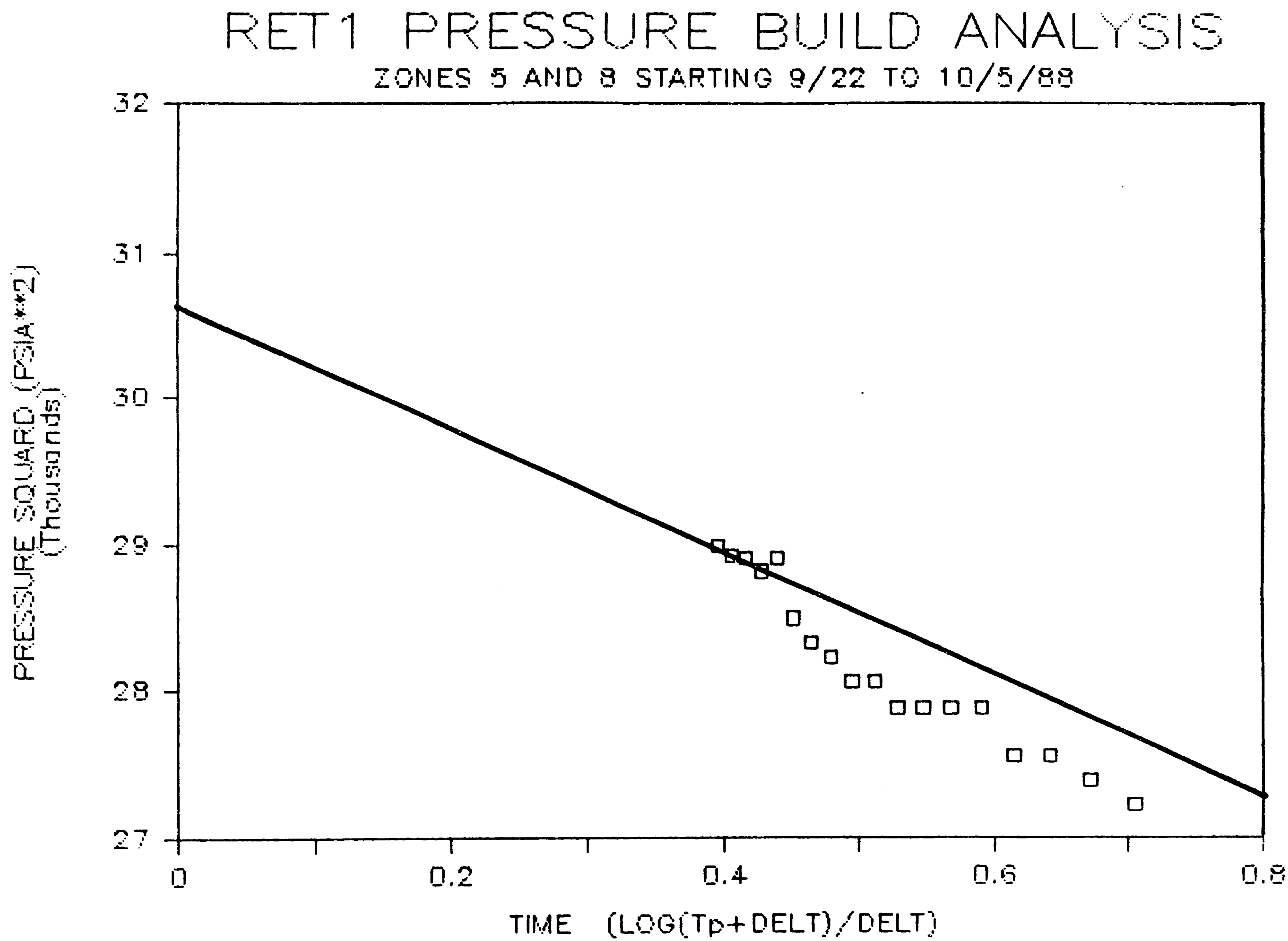


Figure 3.7.5.4: Pressure Build-up Analysis Using Horner Technique for Zones 5 and 8 After Final Frac Job

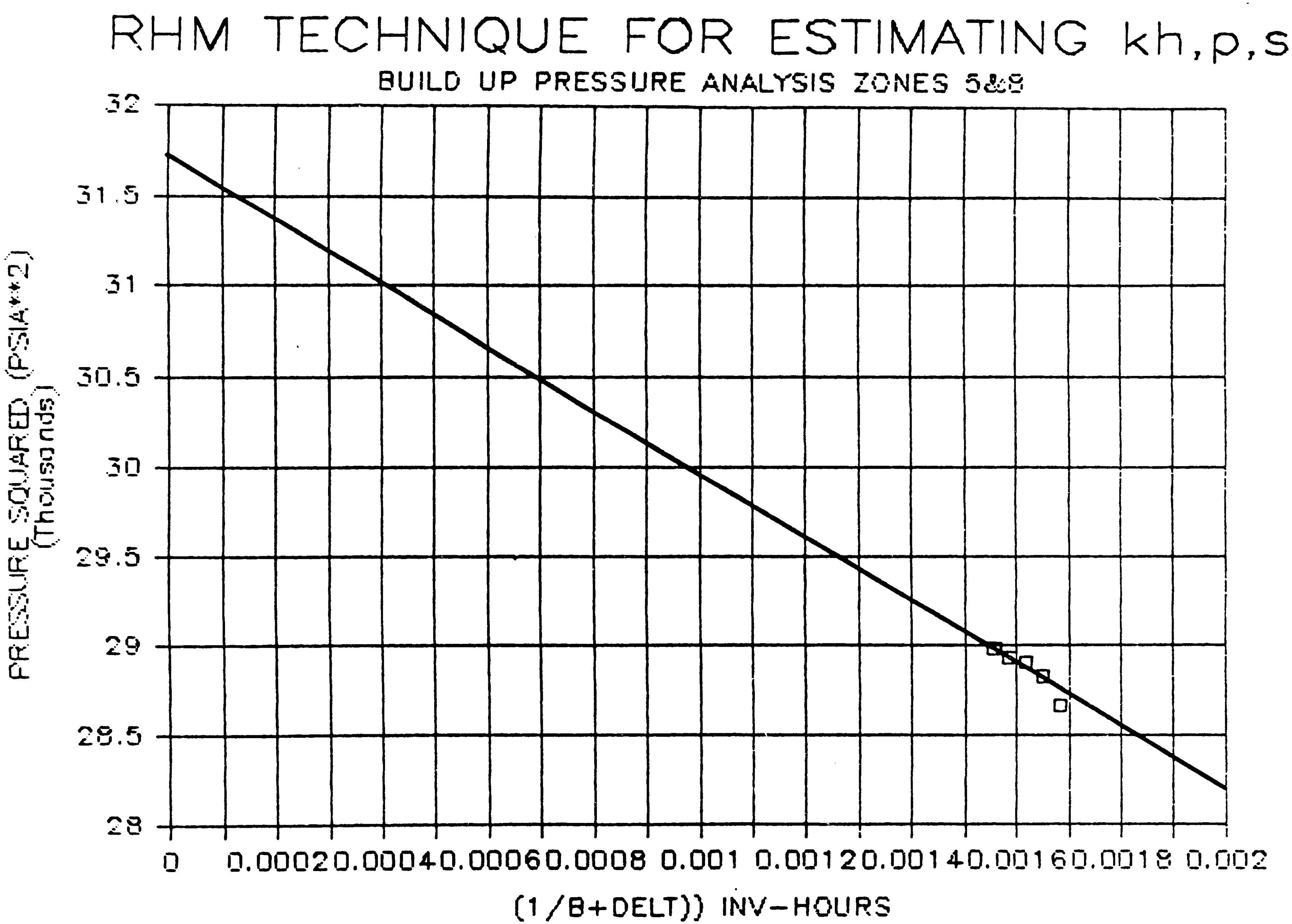


Figure 3.7.5.5: RHM Technique for Pressure Build-up Analysis of Zones 5 and 8

By selecting a pressure and a corresponding time value on the straight line, a value of b equivalent to p^2 is calculated, and hence equation (5) is written as follows:

$$p^2 = -5878 \log[(tp + \Delta t)/\Delta t] + 31323$$

Therefore, at $\log[(tp + \Delta t)/\Delta t = 1]$, $p^2 = p^2 = 31323$, hence $p = 177$ psia.

3) Determine Skin Factor (s) using the following equation:

$$s = 1.151\{[(p^2_{1\ hr} - p^2_{wf})/m] - \mathrm{Log}[k/(\phi \mu C_t r_w^2)] + 3.23\} \qquad (6)$$

where $p^2_{wf} = (50\ \text{psia})^2 = 2500\ \text{psia}^2$ (actual flowing pressure before shut-in).

$p^2_{1\ hr}$ is determined from equation 5 at t = 1 hr.

$$p^2_{1\ hr} = -5878\ \mathrm{Log}[(481 + 1)/1] + 31323 = 15557\ \text{psia}$$

$$s = 1.151\ \{[(15557-2500)/-5878] - \mathrm{Log}[0.327/(.01)(.0107)(.0173)(0.328)^2] + 3.23\}$$

$$= 1.151\ [\ 2.22 - 6.215 + 3.23\ ] = -0.881$$

c) <u>RHM Technique</u>: A newly-developed technique known as the Rectangular Hyperbolic Method (RHM) was utilized to estimate the various reservoir properties using the pressure build-up data that was used for the Horner plot. (Data points determined from the Log-Log plot falling within the semi-log straight-line region.

This technique enables one to determine P directly from the field data without prior knowledge of the drainage shape (Ref. 1 and 2).

The Horner's equation for a well shut-in after producing at a constant rate in an infinite-acting reservoir is written as:

$$p_{ws} = p_i - (m/2.303)\ \ln[(tp + \Delta t)/\Delta t] \qquad (7)$$

Equation (7) was modified and re-written as follows:

$$Pws = a + c/(b + \Delta t_e) \quad (8)$$

A linear regression can be performed for the variables Pws and $1/(b + \Delta te)$ to obtain optimal values of a, b, and c. Because equation (8) is a three constant equation, a trial-and-error procedure has to be employed by assuming values of b until a value of regression coefficient close to unity is obtained.

After determining the optimal correlation coefficient using the trial-and-error method, a straight line is plotted through these points and values of a and c are determined, where:

- a = Intercept = P = average reservoir pressure
- c = slope of the straight line
- m = slope of Horner's straight line = $162.6\ q\mu b/k$
- b = trial-and-error value

Equation (7) and (8) are modified (Ref. 1) and a value of kh is determined as follows:

$$kh = 282.39\ q\mu Bb/(-c) \quad (9)$$

Equation (9) is re-written for gas reservoirs as follows:

$$kh = 1423\ \mu zTbq_{avg}/(-c) \quad (10)$$

From Figure 3.7.5.5, $C = (28718.75 - 3178.75)/(0.0017 - 0) = -1,764,706$

where C is the slope of the straight line.

$kh = (1423)(0.017)(0.980)(553)(50)(320)/(-)(-1,764,706) = 74.82$ Ft-md

With $h = 247$ ft; then $k = 0.303$ md.

$a = p^2 = \text{intercept} = 31719\ \text{psia}^2$, or $p = 178$ psia.

3.7.5.2 Results

The following table summarizes the results of the pressure build-up analysis using the various techniques:

	TECHNIQUE	k (md)	P (psia)	s (skin)
1.	Type - Curve	0.492	------	1.386
2.	Horner	0.327	177	-0.881
3.	RHM	0.303	178	>0.00

The Horner and RHM techniques produced results which agree fairly closely.

3.7.5.3 Conclusions

A pre-stimulation pressure build-up analysis using the G3DFR reservoir simulator predicted an average permeability of 0.071 md for Zones 5 and 8. The results of the post-stimulation build-up analysis indicates an average improvement ratio of 5:1. Furthermore, a positive Skin value was calculated for Zones 5 and 8 indicating a slightly damaged well. Previous analysis did not calculate a pre-stimulation Skin value for Zones 5 and 8, however, a pre-stimulation Skin value of -2.87 was calculated for the entire wellbore when the well was shut in at the early stages of its life. A drop in the Skin to a more positive value could be attributed to:

(a) the sand problem that was encountered during the clean-up process, hence indicating damage in the wellbore;

(b) the decrease in the analyzed horizontal section of the wellbore from 2160 feet (all zones) pre-stimulation analysis, to 932 feet (Zones 5 and 8) post-stimulation analysis.

In addition, the accuracy of these results was tested using three different techniques as shown in the above table. Values of P using the RHM technique has an advantage over the conventional methods because knowledge of neither the well/reservoir configuration nor the boundary condition is required for a routine build-up analysis.

However, the conventional methods such as the Horner's technique, when correctly used, will provide superior results of kh and S values compared to the RHM technique. Therefore, values of K and S for Zones 5 and 8 are believed to be in the range of 0.300 md - 0.492 md and -0.881 - 1.386 respectively, whereas; the average reservoir pressure is calculated at 178 psia based on the RHM technique.

References

1. Hasan, A., Kabir, C. : "Pressure Build-up Analysis: A Simplified Approach, " JPT, January 1983, pp 178-188.

2. Mead, H.N.: "Using Finite-System Build-up Analysis to Investigate Fractured, Vug lar, Stimulated and Horizontal Wells," JPT, October 1988, pp 1361-1371.

3.7.6 Discussion of Results

The stimulation was conducted as planned. The 40 tons of liquid CO_2 pumped at 12 bpm as a pre-pad was pumped without problems. It was displaced from the casing with nitrogen before starting Stage 2 which was the primary pad stage. The pad was pumped at 25 bpm and the main stages with proppant were all pumped at 50 bpm without any problems. This seems to suggest that an open stimulation with 932 feet of borehole and 60 pre-existing fractures should run into very few problems in execution. It would seen that there should be very little chance or danger of screenout. Once the foam has been generated and is carrying the sand as long as pressure is maintained on the system, there would be very low risk of screening out, especially since the fracture gradient is 0.20.

Friction pressure was continually lower than calculated. Of course with twenty 1.125-inch diameter holes to pump through there would be very little per friction pressure, and the thin layer of ice that developed on the casing at the start of the job probably helped to reduce friction also.

A comparison of other planned versus actual parameters for stimulation No. 5, the final frac job on the well, is presented in Table 3.7.6.1.

Without conducting a second frac job in the same zone with a much larger volume of foam and proppant, it is very difficult to make projections on the success of this stimulation procedure. Until we can develop the ability to model multiple simultaneous propagating fractures from a horizontal wellbore, the best we can do is make a series of comparisons of the results conducted in the wells like this one and hope that we can properly evaluated the observed results.

The apparent results of stimulation No. 5 is presented in Figure 3.7.6.1 which shows the rapid decline over the first 3 days from rates in excess of 300 mcfpd to 83 mcfpd. The rates as projected seems to be fairly stabilized after 30 days at 56 mcfpd.

TABLE 3.7.6.1

COMPARISON OF PLANNED VERSUS ACTUAL DESIGN PARAMETERS
EXECUTED DURING FRAC JOB. NO. 5

STIMULATION TEST NO. 5
CO_2/NITROGEN-FOAM/PROPPANT - HIGH VOLUME; HIGH RATE

PARAMETER	PLANNED	ACTUAL
Volume of CO_2 (bbls)	224	220
Volume of Foam (bbls)	2,500	2,482
Volume of Sand (lbs)	150,000	150,000
Injection Rate (bbl/min)	50	50
Injection Pressure (psig)	1,550	1,250*

* Wellhead pressure (BHTP estimated - 950 psig).

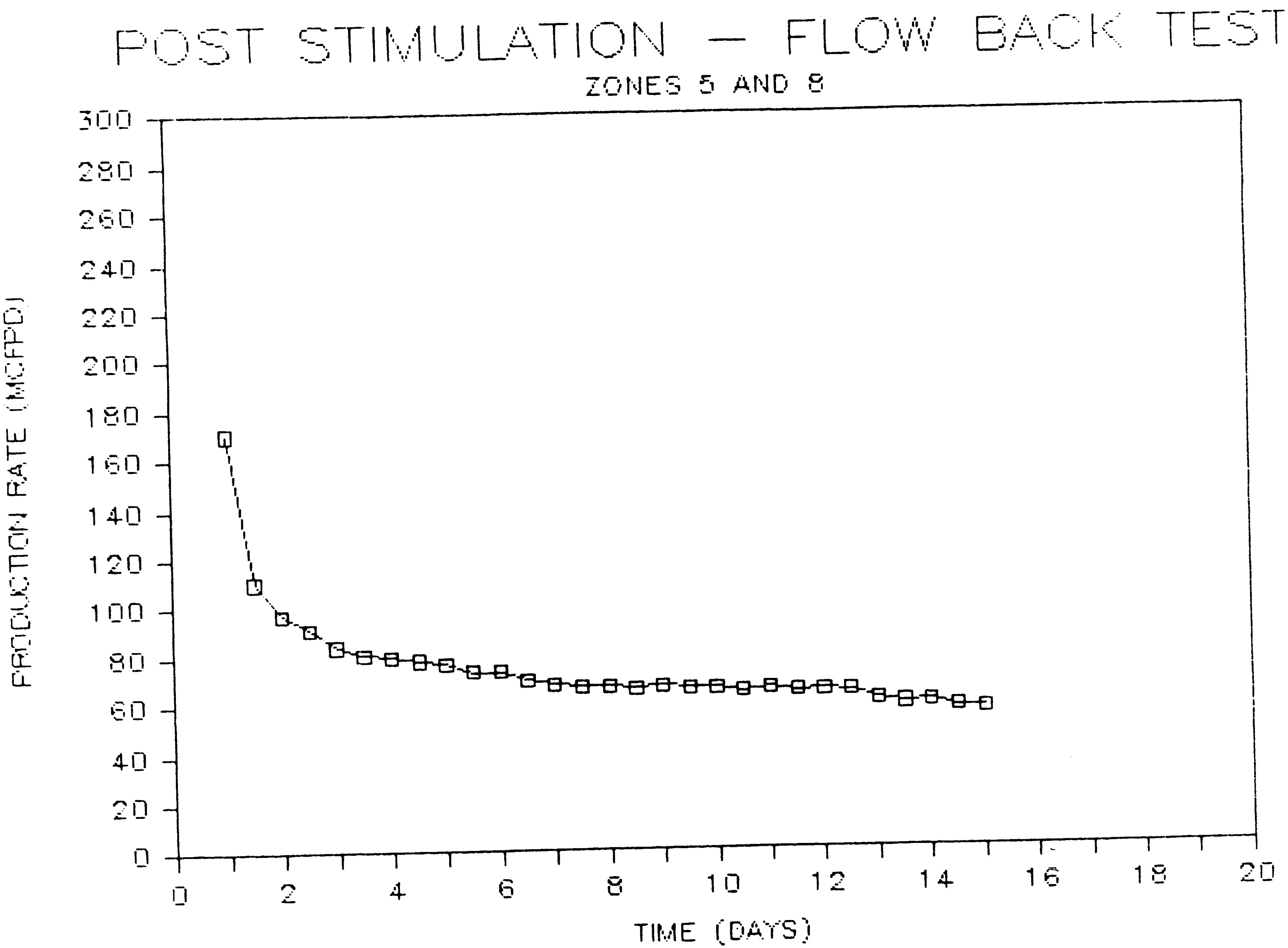


Figure 3.7.6.1: Plot of Production Rate versus Time After Stimulation of Zones 5 and 8

The improvement ratio as a result of the frac job is presented in Table 3.7.6.2. This stimulation did not reach the target 9:1 improvement ratio, but came closer than frac job No. 4. One interesting fact to note from Table 3.7.6.2 is that the post-frac flow rate on the sixth day is slightly higher (76 mcfpd versus 75 mcfpd) even though frac job No 5 is 25 percent smaller than frac job No. 4. Stimulation No. 5 had to address a 60 percent longer borehole with less fluid and proppant and was still more efficient. This could either be due to more beneficial effects from the 50 bpm injection rate during frac job No. 5 versus 30 bpm injection rate during frac job No. 4. In addition Zones 2-3 and 4 already had extensive fractures which bled off during the job and reduced fluid efficiency while there were fewer fractures available during frac job No. 5 to be opened and stored.

4.0 FRACTURE DIAGNOSTICS

To be able to determine the efficiency of the hydraulic fracturing processes in a horizontal wellbore, BDMESC conducted a series of tests utilizing two distinct and different methodologies. The primary purpose in conducting fracture diagnostics tests is to determine, if possible, the three dimensional geometry of the fractures induced during the fracturing processes.

4.1 Rationale and Planning

BDMESC originally proposed to use surface installed tiltmeters to provide information on the number and orientation of hydraulically induced fractures, but decided to supplement this data with dat on the location of induced fractures as they exited the wellbore as determined by the use of radioactive tracers added to the fluid and/or sand proppant. This technique would also tell us how many fractures were pumped into as well as where they were being pumped into.

BDMESC planned to place the eight to twelve tiltmeters in a circular array above the Zone 1 section of the wellbore, then use this array to monitor 2 or 3 frac jobs before having to move the array.

In using the radioactive tracers and the spectral gamma ray log to map the location of high intensity radioactivity zones representing exit points from the wellbore of the induced or extended natural fractures, BDMESC prioritized the use of 8 to 10 tracers based on half life and spectral energy levels. Short half life tracers were used during the early stimulation in which no proppants were used and well cleanout problems would not delay running of the spectral gamma ray log.

4.2 Tiltmeter

The tiltmeter used in this experiment was a very sensitive bubble level type instrument which is capable of measuring very minute changes in tilt of the surface associated with hydraulic fracturing. Diagrams illustrating the instrument is found in Figure 1 of Appendix G-1.

4.2.1 Installation of Tiltmeters

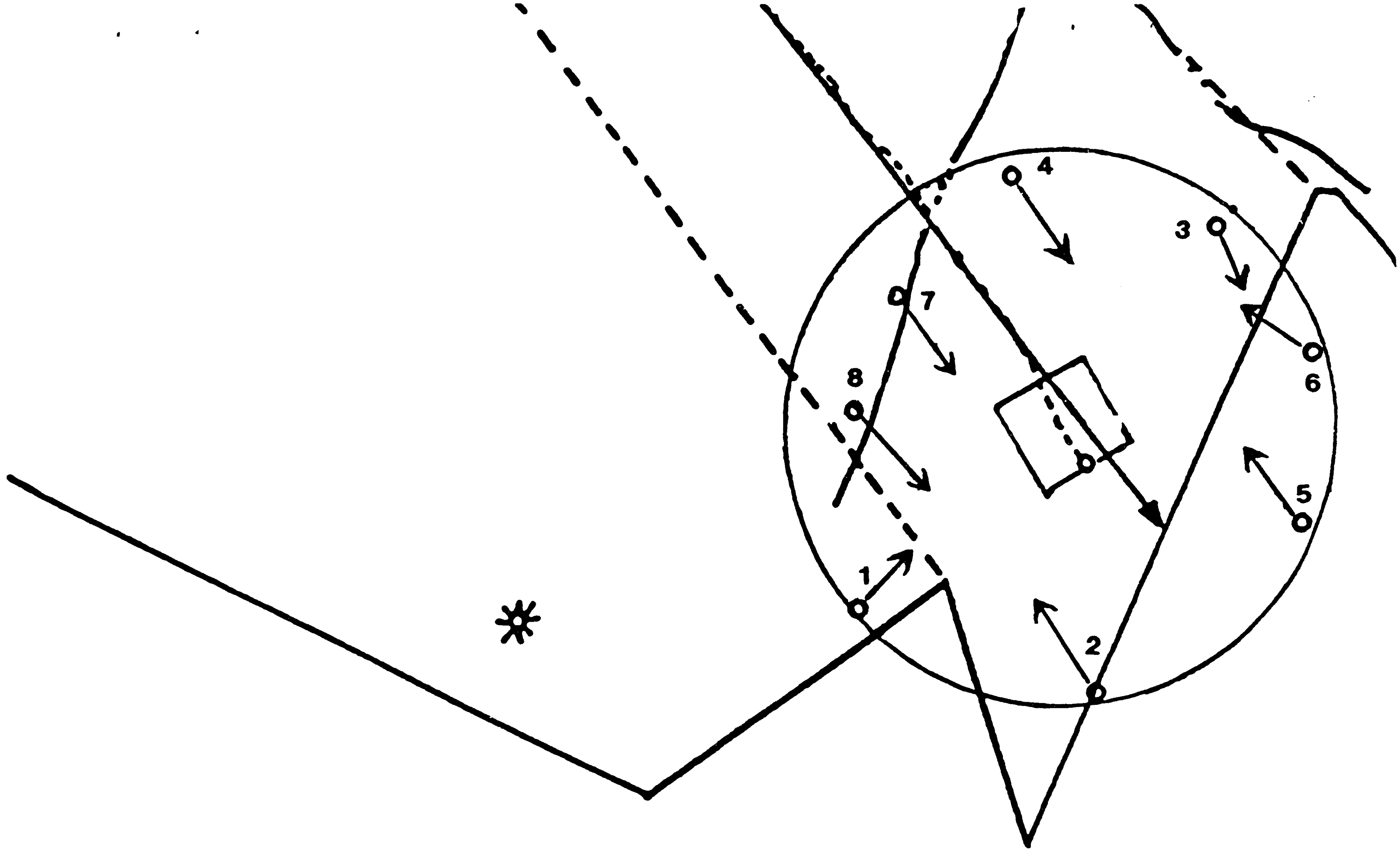
In an initial meeting with M.D. Wood of Hunter Geophysics, a typical installation of the tiltmeter required that they be buried in a sand-filled hole 8 inches in diameter and 20 feet deep. Because the well was drilled in Cabwaylingo State Forest, permission to bring a drilling rig large enough to drill a 20 foot deep 8-inch hole could not be obtained from the West Virginia Forest Service. Upon further consultation with Hunter Geophysics, they explained that signals might be obtained if the holes could be drilled as deep as 6 feet. It was desirable to have 12 tiltmeters emplaced, but because of the steep terrain, only 8 could be installed, as shown in Figure 4.2.1.1. The holes for the tiltmeters were drilled by a hand-held portable drill carried in on a 4 wheel drive ATV. It was difficult to find sites in the right position away from the wellbore which was located at least 20 feet away from the nearest tree.

4.2.2 Data Acquisition

The tiltmeters were installed over a two week period about 3 weeks prior to the first nitrogen stimulation conducted in Zone 1. Data was collected as shown in Figure 4.2.2.1 and was used to "calibrate the site"; that is, to determine what a typical signal looked like for each unit. Examination of the data indicated that signals were not stabilizing. A check of the instruments indicated that animals walking in the woods were being detected as well as movement of nearby trees which were being moved when the wind was blowing. We decided to go ahead and collect data during the frac job because there was potential for detecting data above the level of site signal. The vector arrows shown on Figure 4.2.1.1 were the configuration we anticipated seeing upon analysis of the data to be collected.

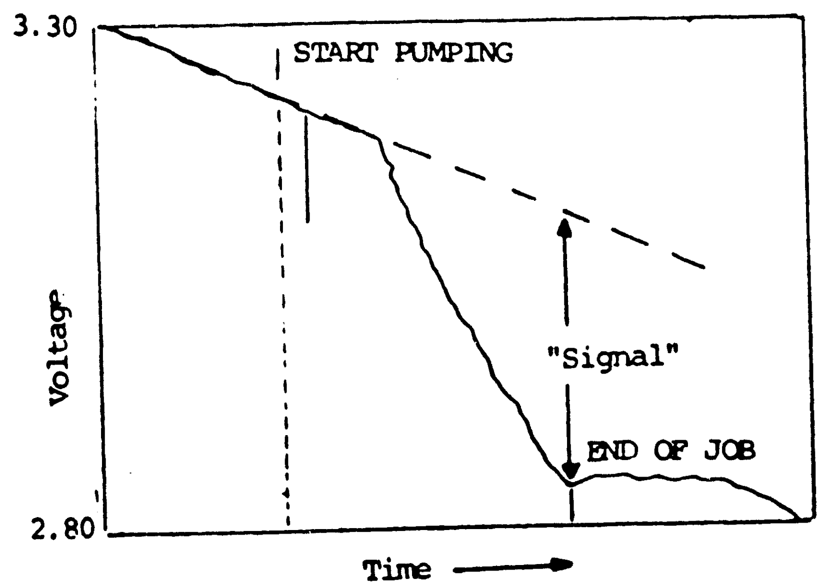
4.2.3 Results

No useful data was collected by the tiltmeters during the frac job. All of the data collected and the report prepared by Hunter Geophysics is contained in Appendix G-1. We determined that trees and

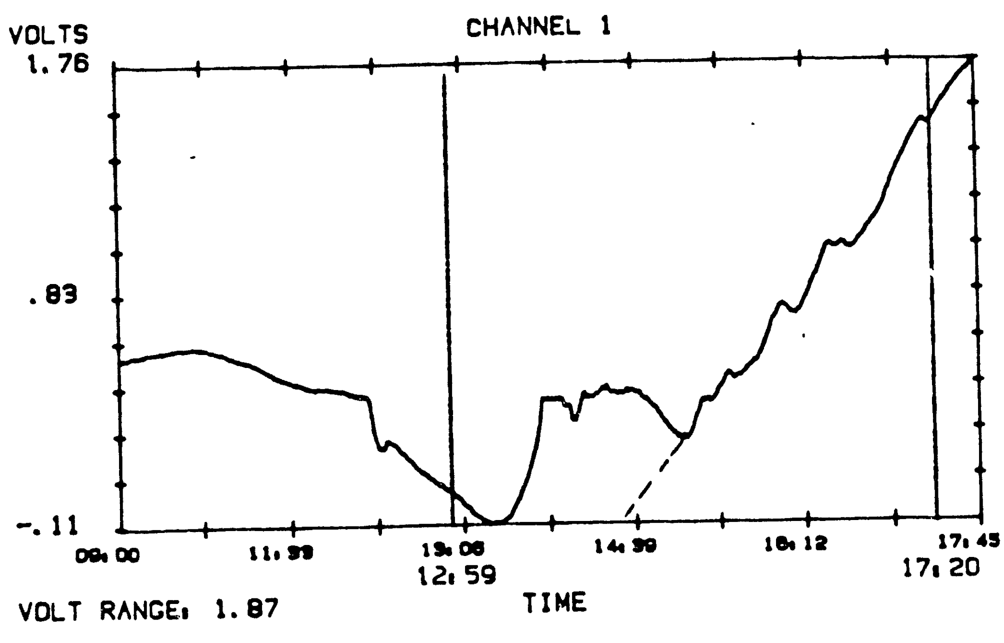


TILTMETER ARRAY FOR FRACTURE DIAGNOSTICS ON ZONE NO.1

Figure 4.2.1.1: Tiltmeter Array for Fracture Diagnostics Test on Zone 1 and Anticipated Tilt Vectors for a Single Fracture Created Within the Box Defining Zone 1



Typical Tilt Signal and Example of Picking Frac Related Tilt



Actual Signal Recorded Durring Frac Job

Figure 4.2.2.1: Illustration of Typical and Actual Signals Received During Stimulation of Zone 1 by Nitrogen Gas

other environmental noise would not allow us to collect useful data with the tiltmeters and thus decided not to attempt to collect data during the second and additional stimulations in order to save money.

4.3 Radioactive Tracers

Radioactive tracers were used to tag either the injected fluid or the sand proppants as beads in 6 of 13 stimulation tests conducted in the well. Four of the tests were data collection tests and were not of sufficient volume to be considered a frac job. Thus tracers were used in 5 full scale stages of frac jobs on the well. The results obtained from examination of the tracer logs were very enlightening regarding the stimulation processes.

4.3.1 Tracers Utilized

Four different radioactive tracers were utilized during the 7 tests staged over a period of one year. Iodine-31 with a short half life was first used with Scandium-46 in August of 1987 during the mini frac test. These two tracers were used in Zone 6. In November, 1987, they were used again; this time in Zone 1 to tag two different stages pumped at different injection rates. In January, 1988, two additional tracers, Antimony-124 and Iridium-192 were used in Zone 1 to tag 2 stages of the first foam frac with proppant. In May, 1988, Scandium-46 was again used to tag one stage during the stimulation in Zones 2-3 and 4. The tracers were injected with a chemical injection pump into the pumper. it was generally mixed with methanol as a carrier for injection. Table 1.7.1 is a summary of the stimulation test and the tracer used.

4.3.2 Spectral Gamma Logging Techniques

Three different methods of tool placement and logging were used to obtain the spectral gamma log of the wellbore to determine where the radioactive material had been injected. The first method used was emplacement with a coiled tubing unit. This method encountered considerable problems when running the tools. The tool was screwed into the end of the tubing without a swivel unit in place and the coiled tubing rotated about 3 turns when going in the hole and wrapped the wireline around it. We had intended to log the entire well, but could only push the tool package into a depth of 4900 feet the coiled tubing apparently buckled making it impossible to push it in any further. There was no problem in retrieving the tubing and wireline combination until we got to within 200 feet of the surface. At this point we reached a position where the wireline could not unwrap from the tubing and the tubing was kinked by the wireline and had to be cut and repaired. This method took about 6 hours to log 1000 feet of wellbore.

On the next spectral gamma logging job, the tool was attached to the 2-3/8-inch tubing and pushed into the casing and logged in the same manner as conventional logs using the "slant hole express". The method uses a side entry sub and wet connect system to power up the tool and run the logs. This method took 3 days to log since the well was logged 30 feet at a time as each tubing joint was pulled. A major problem occurred after the third jet had been pulled while logging out, the tubing slips set down on the wire line and kinked it breaking the electrical connection. Six thousand feet of wireline had to be pulled off of the truck and the line reheaded, then run the tools back in again. This method produced a log that was useable but the counters saturated every time we stopped for 48 seconds to unscrew a joint of tubing. This produced a strong radioactivity spike every 30 feet on the log.

The third technique used was the most satisfactory. A string of 2-3/8-inch tubing was run into the well with a bull plug and perforated sub on the end. A 2-1/16-inch diameter spectral gamma tool was then pumped down inside the tubing pulling the wireline behind it. The tool was pumped away to the end of the tubing using nitrogen gas. The tool could possibly have been pumped in with a 1000 cfm air compressor. Once the tool was blown all the way in to the hole or as far as the tubing was run into the hole, then the well was logged back out in a conventional manner. This method was used on the final two logging runs in the well.

4.3.3 Analytical Methods

The logging company provided field prints of the field recorded "SPECTRALOG" for initial examination and analysis. Generally within 60 days a computer generated "PRISM" log was provided which provided information about how much of the gamma ray response was coming from inside the casing and how much was attributed to material outside the casing and supposedly concentrated in fracture eminating from the wellbore. An example of this is shown in Figure 4.3.3.1. Also shown is the marking of the baseline response so that any response above that is considered significant. Fractures interpreted to have been pumped into from both traced stages are marked in the depth column in the center of the illustration. This logging operation was conducted with a coiled tubing unit placing the logging sonde in position in the horizontal hole and then retrieving it at normal logging speed.

Analytical methods had to be slightly modified for the second logging operation conducted after the liquid CO_2 frac job. The tool or sonde was attached to 2-3/8" tubing and after being pushed into the hole was pulled out 30 feet at a time producing the saturation spikes marked with an S on Figure 4.3.3.2. Baseline response is again marked on the log and gamma peaks not associated with saturation spikes or the position of known port collars or external casing packers (ECPs) are considered as identifying fractures eminating from the wellbore. Fractures identified by Iodine-131 are indicated by a solid line while those identified by Scandium-46 are indicated by a dashed line. Injection rate was 12 bpm when Iodine-131 was used and 20 bpm when Scandium-46 was used. A line which represented 3 times the baseline response was marked on the log and all peaks above this line which were not an artifact of the logging process were designated as major fractures which had received more radioactive tracer material than lower response curves.

On the third logging operation after the January 21, 1988, frac job the tool was blown into position for logging inside 2-3/8" tubing and then logged as in a conventional manner by pulling the wireline attached sonde at normal logging speeds.

Interpretation begins on Figure 4.3.3.3 as a baseline response is determine which is above the value determined to be material located inside the casing (January 21, 1988 PRISM log 5400' md reading in 700 API counts on Iridium Scale - Baseline is 800 API counts). The log is then examined to find peak responses at the highest levels at first because they stand out nicely. On the January 21, 1988, log made after the first proppant laden fracture (No. 3), major fractures were defined as those having a response at least 3 times the size of the base response (2400 or greater as compared to 800 API counts, as shown in Figure 4.3.3.4).

On this log it can easily be seen that the Scandium response is still visible from frac job No. 2 conducted in November, 1987. Many of the same fractures were pumped into again during the January 19, 1988, frac job. Nine major fractures were pumped into probably during all 3 frac jobs conducted on Zone 1. Five new major fractures were pumped into which had not been pumped into during any of the previous frac jobs (1 or 2).

On the last logging operation after fracing Zones 2-3 and 4 the sonde was again blown into the hole with nitrogen and the spectral gamma log obtained in a nearly normal manner. A section of the field print of the "SPECTRALOG" is shown in Figure 4.3.3.5. The baseline and major fracture lines are drawn and major peaks identified. When the lines are drawn locating the fractures on the depth column, it is easily noted that several fractures are fractures that were pumped into during the January frac job as indicated on the Iridium curve. New fractures are marked N, old fractures are marked O. The computer generated "PRISM" log for this frac job has a new, more easily interpreted format as shown in Figure 4.3.3.6. The response inside the casing is presented inside the normal depth column along with footage marks. The response for each tracer is coded with a pattern. The presentation is also shown in the previous manner at the top of the page while depth and total gamma count is presented at the bottom. This is a very useful presentation mode. For more detailed analysis, a table can be made for each fracture identified indicating depth, API gamma count for each tracer, and total gamma count.

In the future, methods may be devised to relate gamma signature to the volume of fluid that has been injected at a particular point in the wellbore allowing you to calculate length of fracture generated.

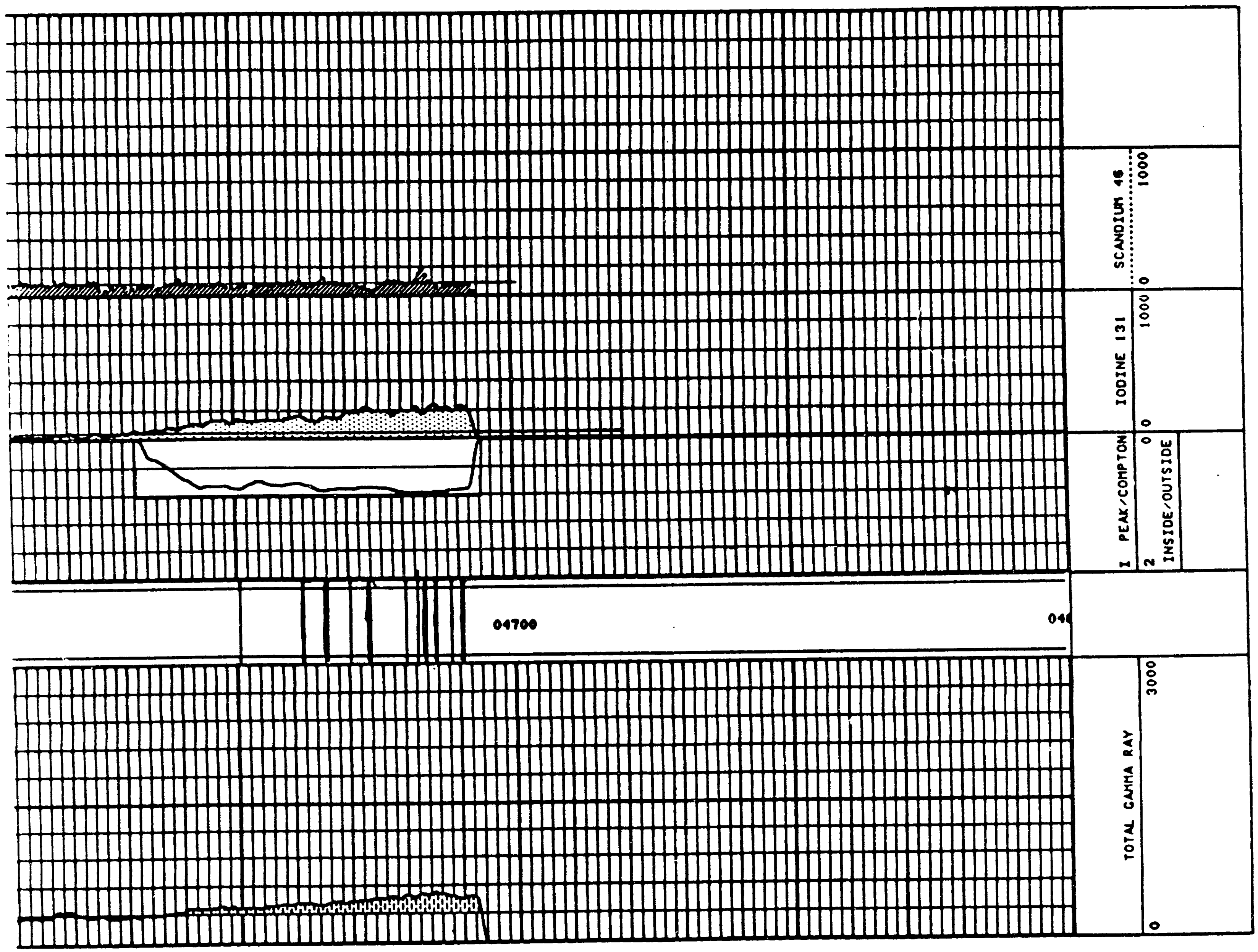


Figure 4.3.3.1: Tracer Log of Zone 5 Showing Fractures that Came Into Wellbore From Zone 6

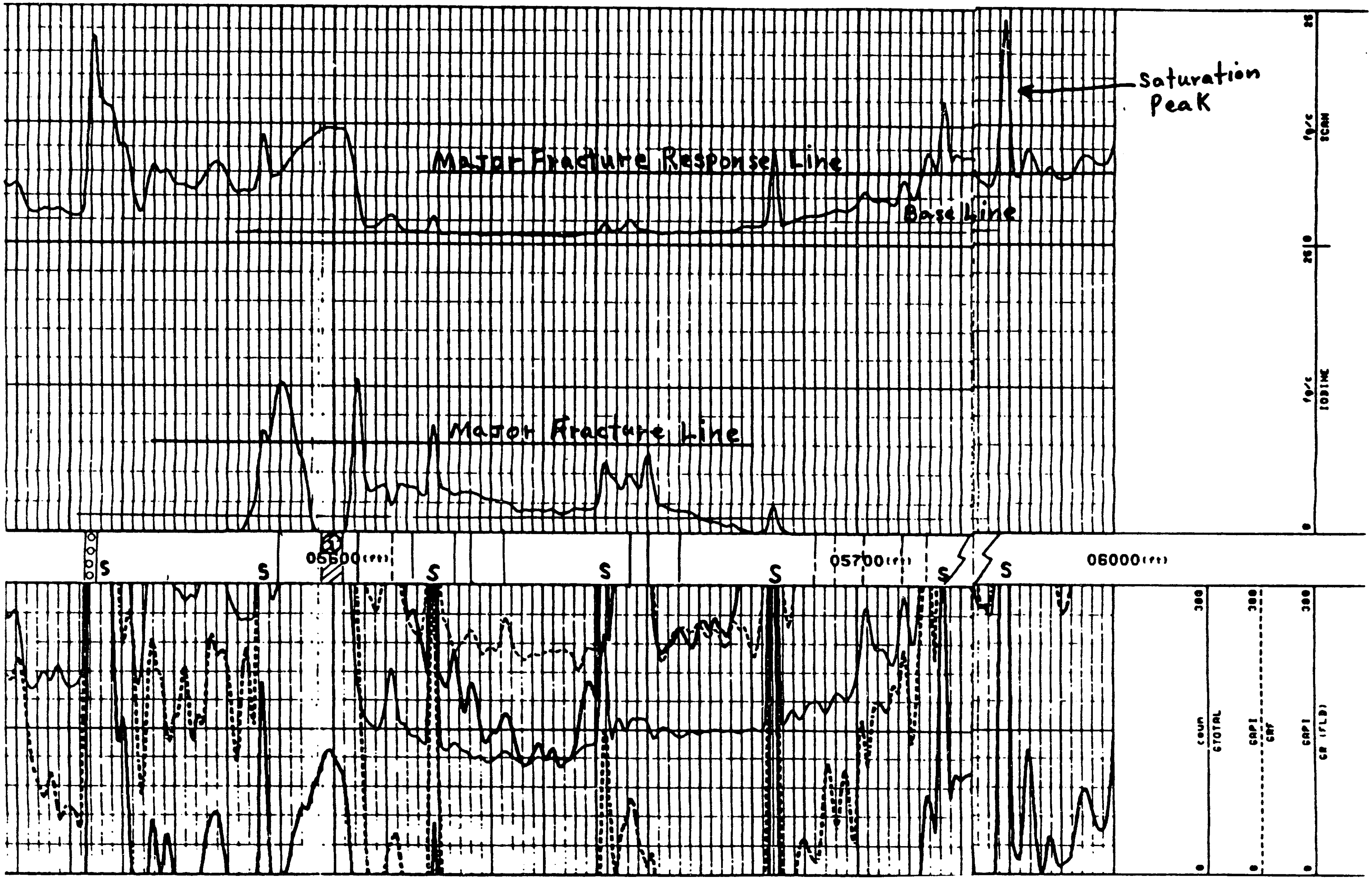


Figure 4.3.3.2: Tracer Log Showing Selection of Baseline and Major Fracture Response Line Developed for Analysis of Logs for Horizontal Wellbores

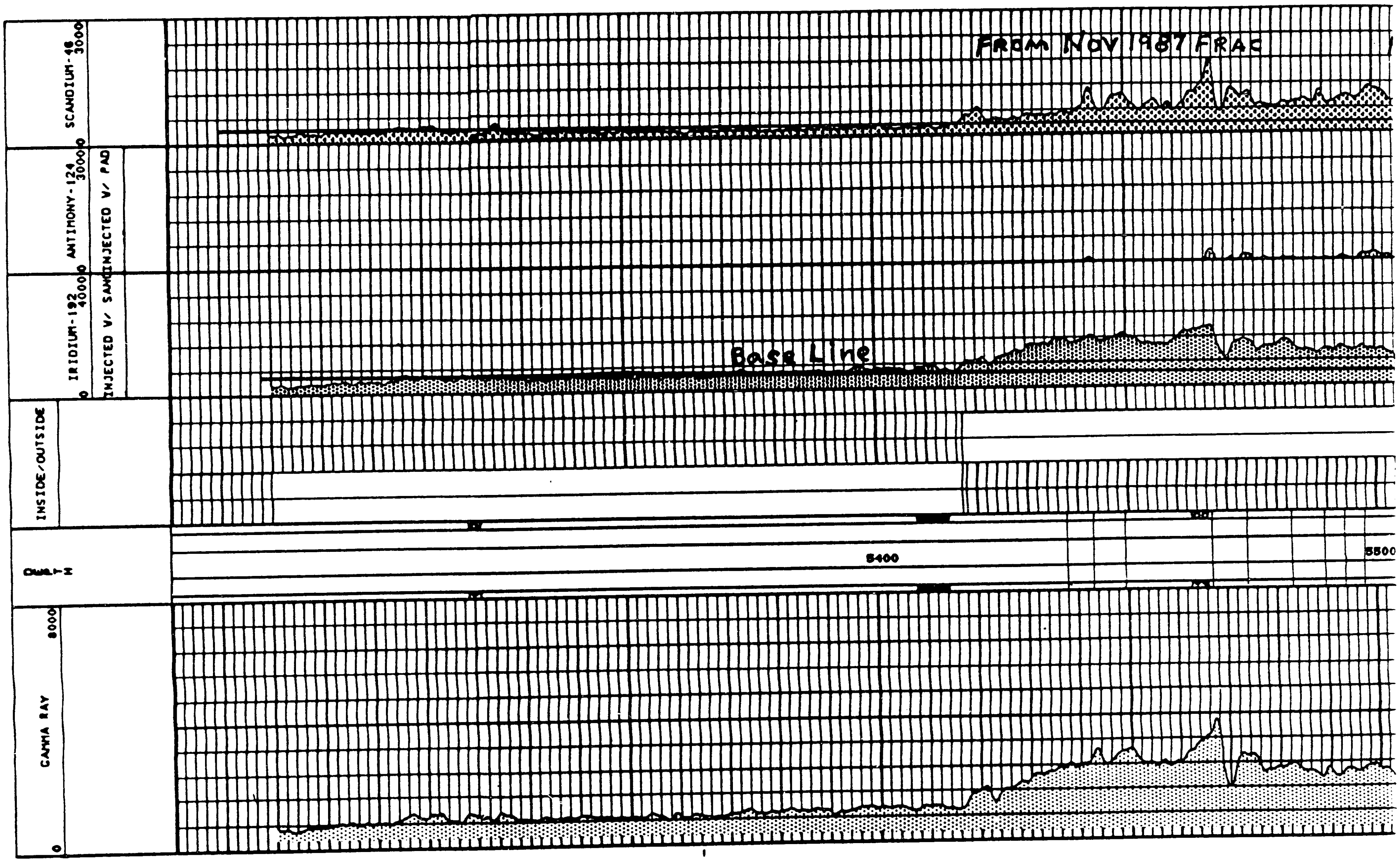


Figure 4.3.3.3: Tracer Log for Zone 1 Foam Frac Test Showing Selection of Baseline Response in Zone 3

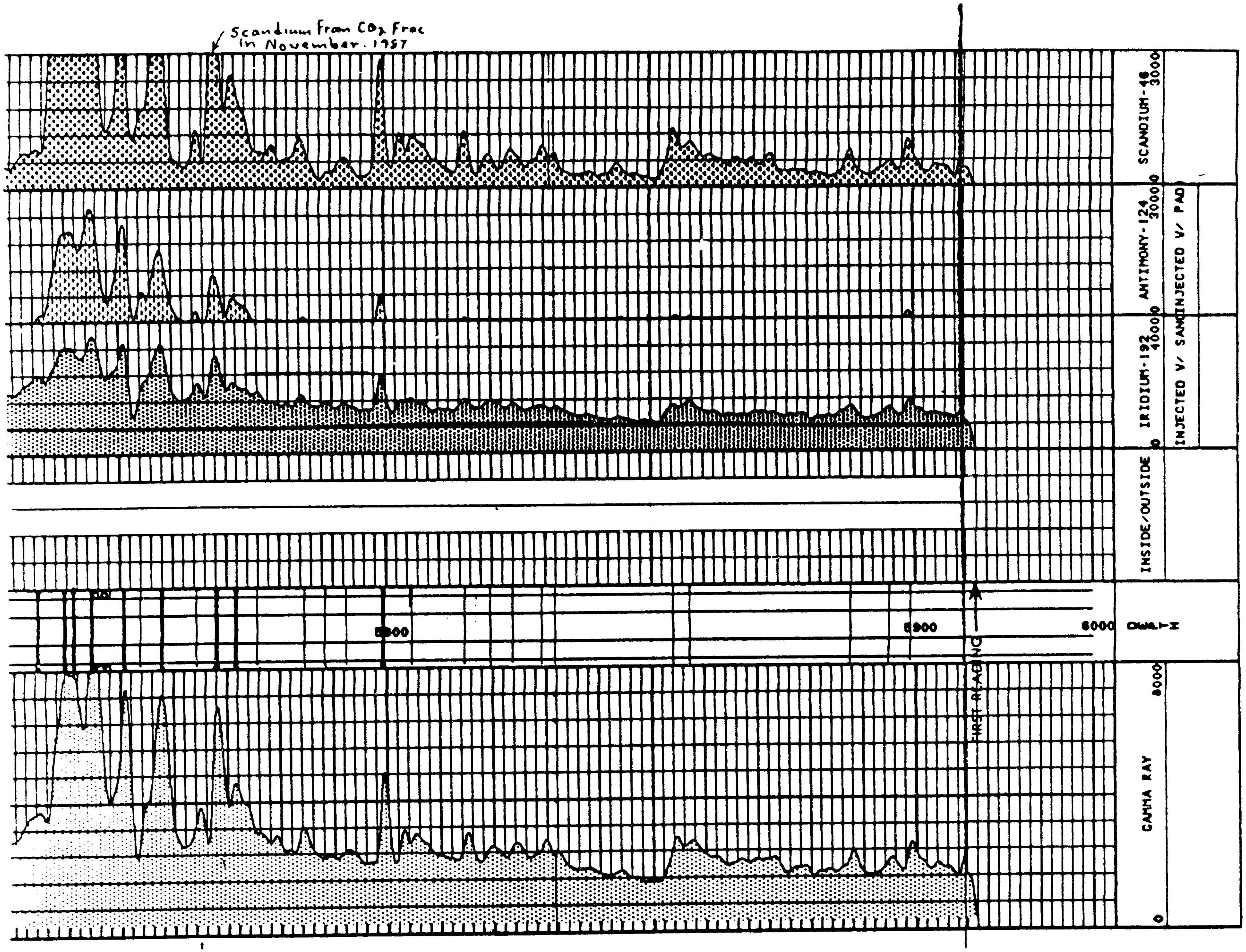


Figure 4.3.3.4: Tracer Log for Zone 1 Foam Frac Showing Baseline and Major Fracture Response Line in Zone 1

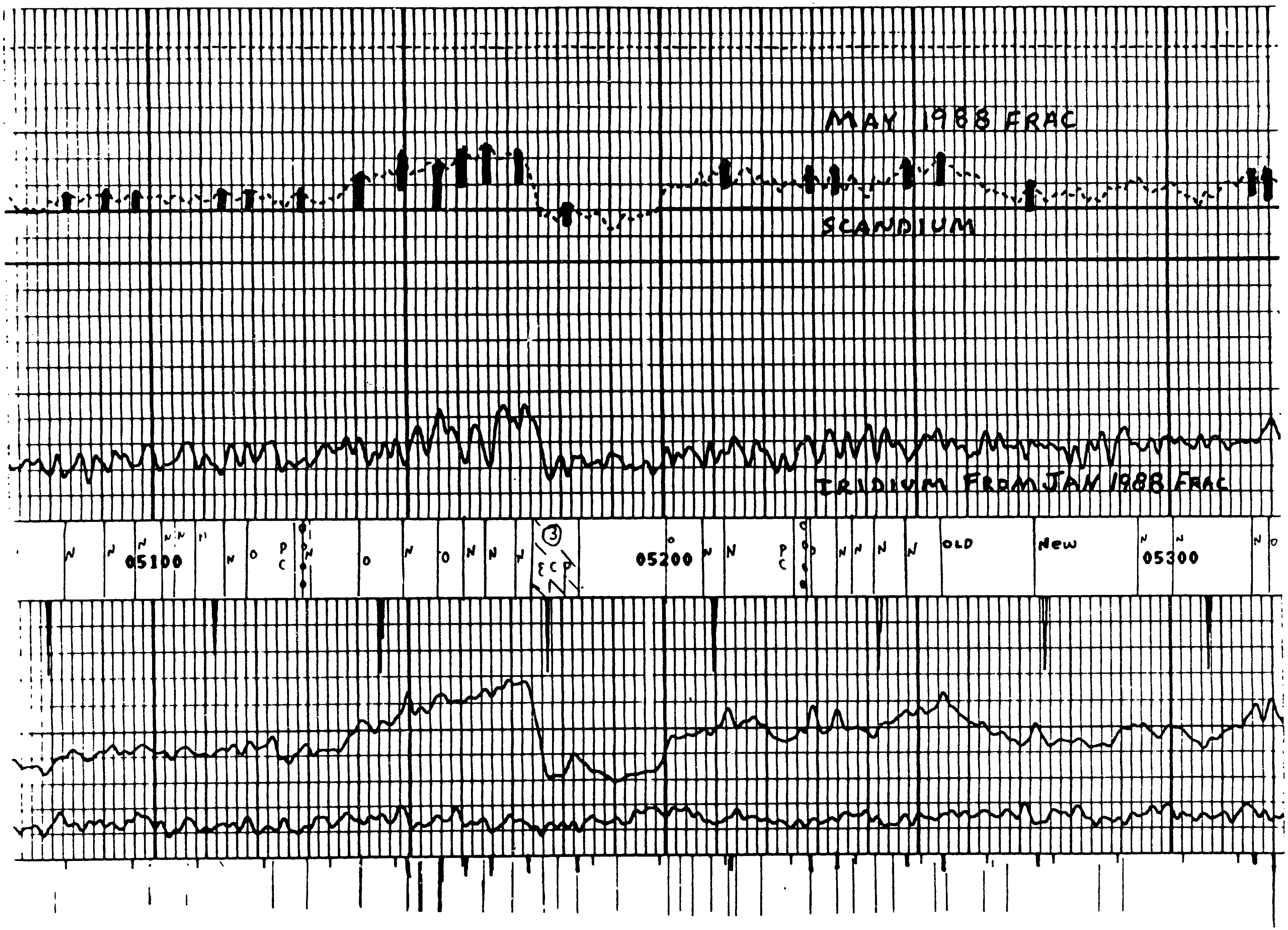


Figure 4.3.3.5: Field Print and Initial Selection of Major Fractures Pumped Into During Frac Job in Zones 2-3 and 4 in May, 1988

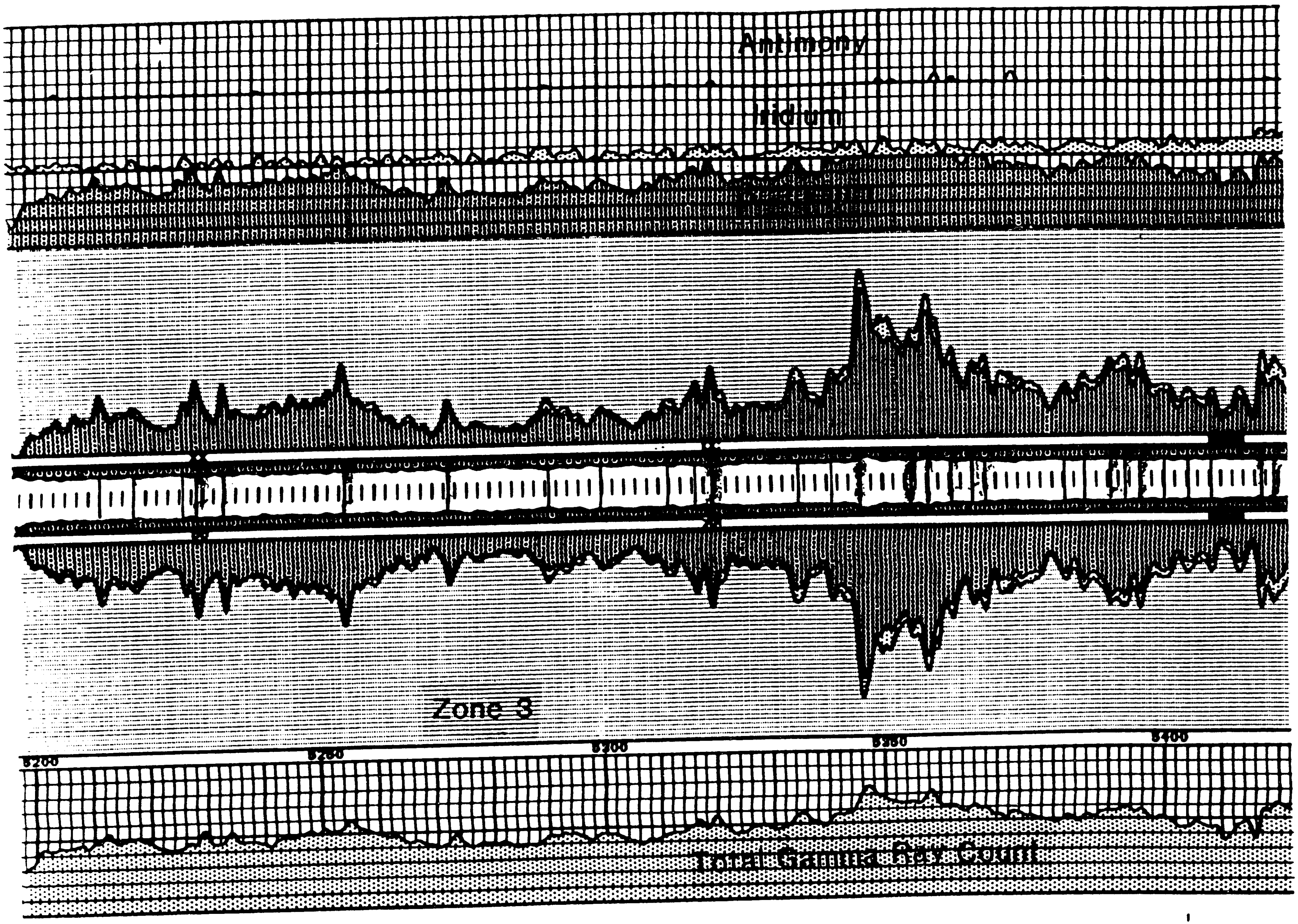


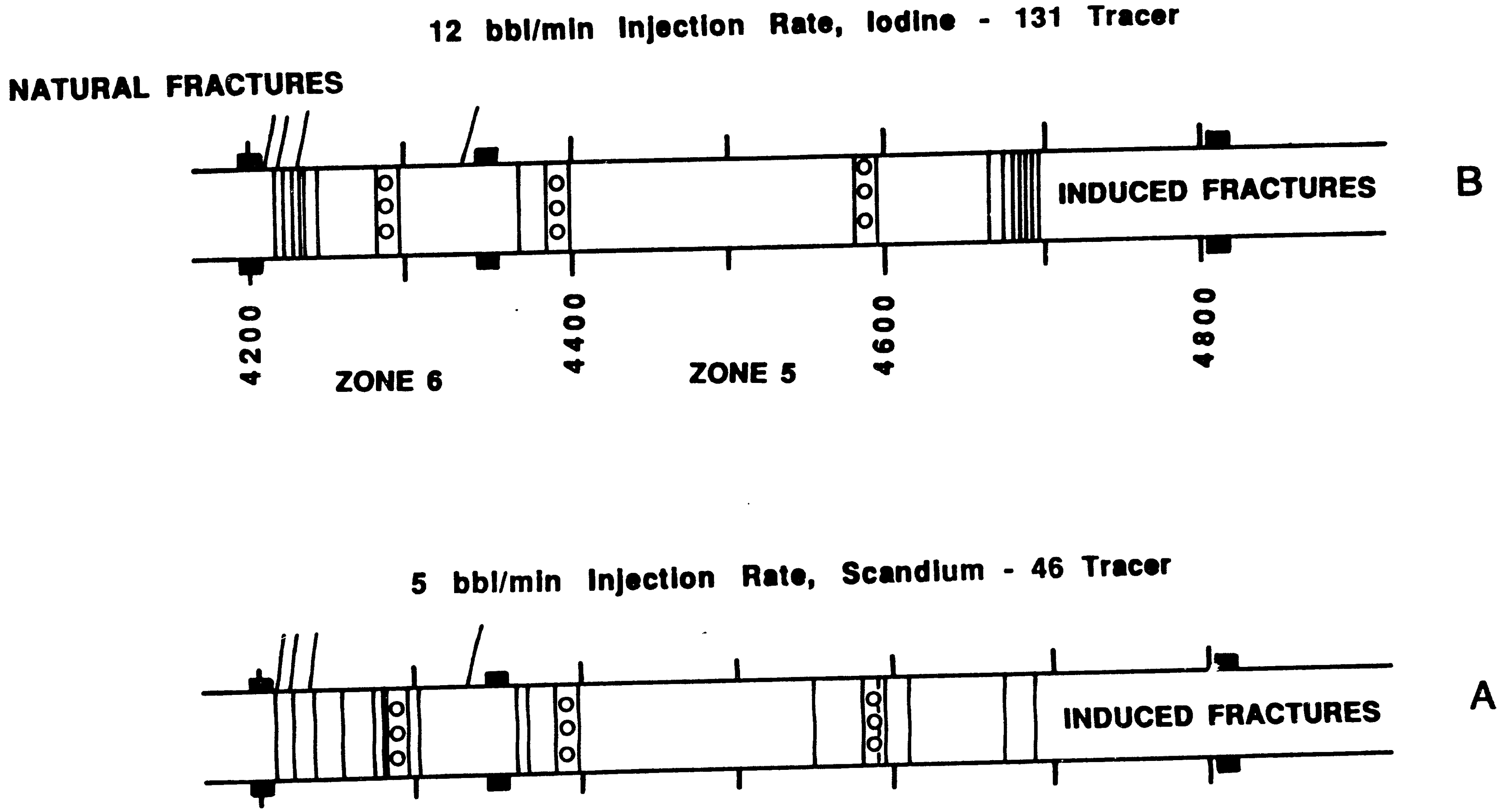
Figure 4.3.3.6: Computer-Generated Presentation of Same Tracer Log over Much of the Same Interval as Figure 4.3.3.5

4.3.4 Results of Analysis

The results of the analytical approach described was the mapping of a number of major and minor fractures pumped into during each stimulation. The results of analysis of the mini frac test conducted on Zone 6 are presented in Figure 4.3.4.1. The natural fractures mapped from videotape analysis are presented above the diagram with the orientation. The induced fractures are presented in each diagram and related to the injection rate. On first examination it would seem that our hypothesis that slow injection rates would propagate existing natural fractures while faster injection rates would result in new fractures being induced was demonstrated. On part A of the figure there is good correlation between the natural fractures existing and the fractures propagated. On part B, additional fractures were created close together in Zone 6 which travelled out of Zone 6 and came back to the wellbore in Zone 5 near the 4700 feet marker. Analysis of this log says fractures leave the wellbore and intercept other fractures with a different orientation and comes back to the wellbore.

Results of analysis of the second frac job conducted in Zone 1 again showed that the slow injection rate traced with Iodine-131 inflated natural fractures (see Figure 4.3.4.2). Examination of the log also revealed that the natural fractures came back to the wellbore in Zones 2-3 and 4 as shown by the Iodine-131 traces in Figures 4.3.4.3 through 4.3.4.5. When the injection rate was increased from 12 to 20 bpm fractures were generated in new areas of Zone 1 and came back to the wellbore in Zone 2 (see Figure 4.3.4.3 scandium fractures). Figure 4.3.4.6 is a compressed view of the wellbore showing where the fractures were generated as a function of injection rate and where they came back into the wellbore. The identification of several fracture zones which left Zone 1 and came back into Zones 2-3 and 4 precipitated a special series of pressure build-up and flow tests along with gas analyses which led to confirmation of the movement of gases between zones.

The third stimulation in Zone 1 was a foam frac carrying proppant but pumped at a moderate rate of 10 bpm which is just designed to open fractures and prop them with sand. Analysis of the location of fractures generated during each of the two stages pumped at the same rate



ZONE 6 DATA TEST

CLOSURE PRESSURES, 850 & 1050 psig

Figure 4.3.4.1: Diagramatic Illustration of Natural and Induced Fractures in Zones 5 and 6 for Zone 6 "Data Frac

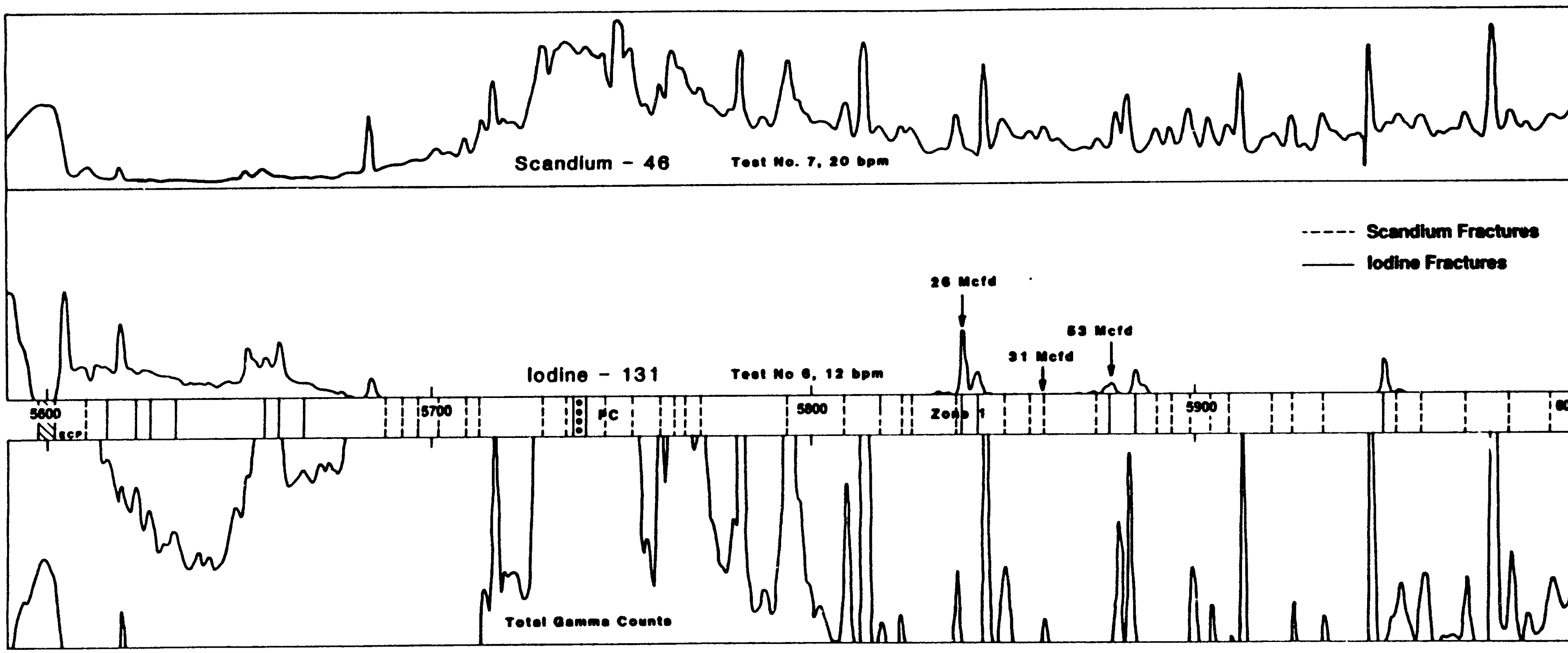


Figure 4.3.4.2: Tracer Log Showing Interpreted Fractures After CO_2 Frac and Location of Natural Gas Shows During Drilling Operations in Zone 1

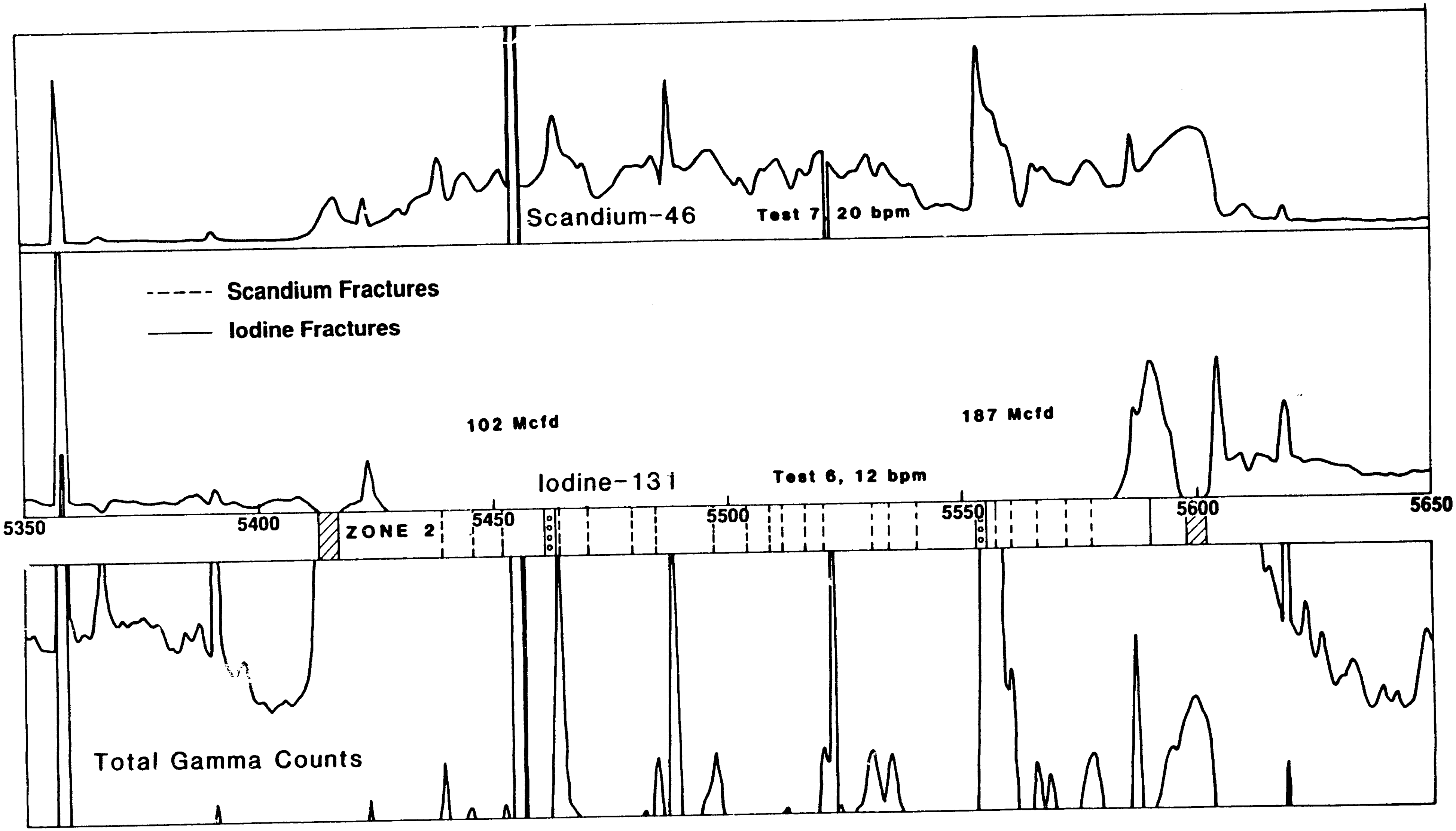


Figure 4.3.4.3: Tracer Log Showing Interpreted Fractures after CO_2 Frac and Location of Gas Shows During Drilling Operations in Zone 2

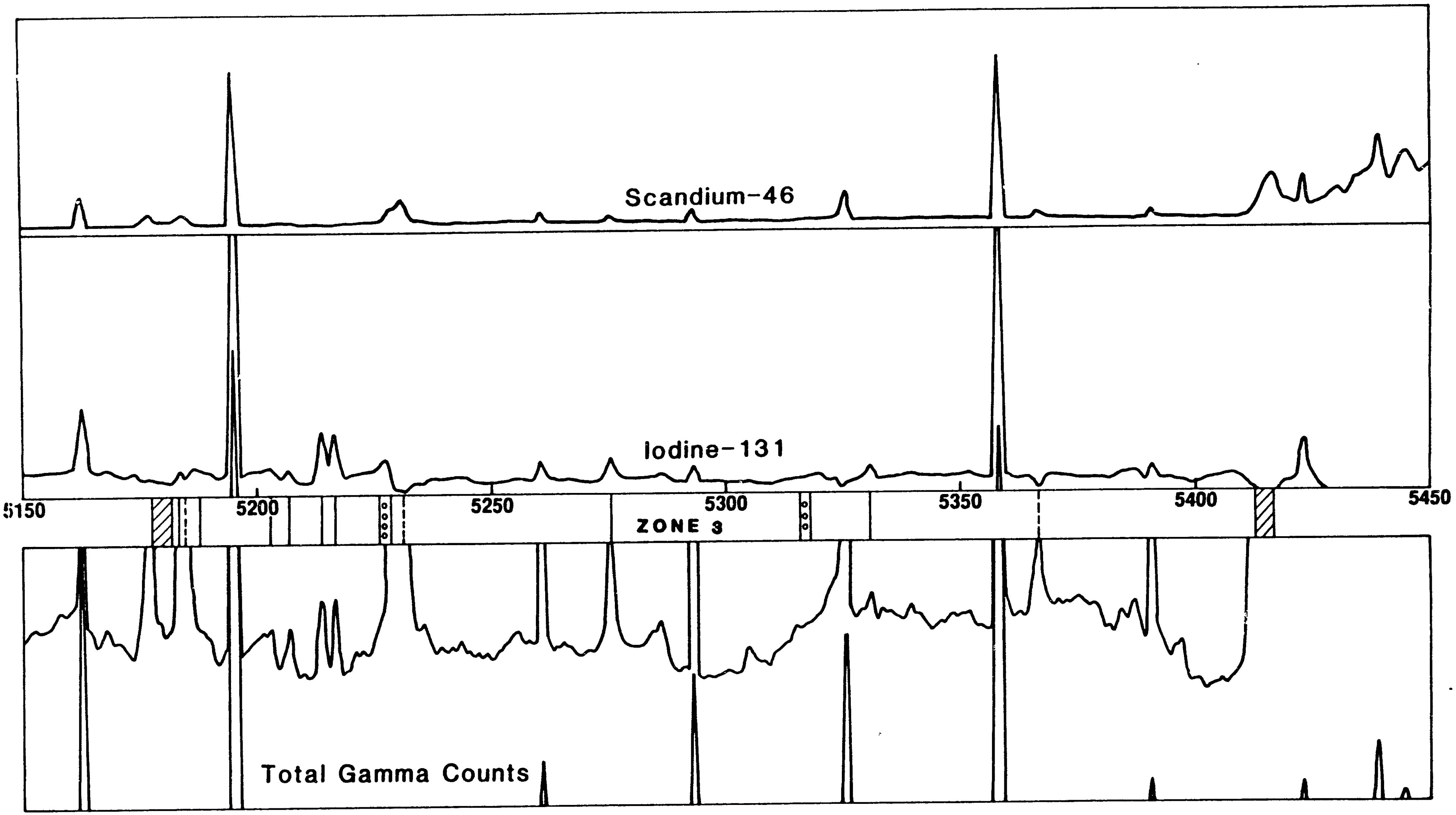


Figure 4.3.4.4: Tracer Log Showing Location of Interpreted Fractures in Zone 3 After Frac in Zone 1

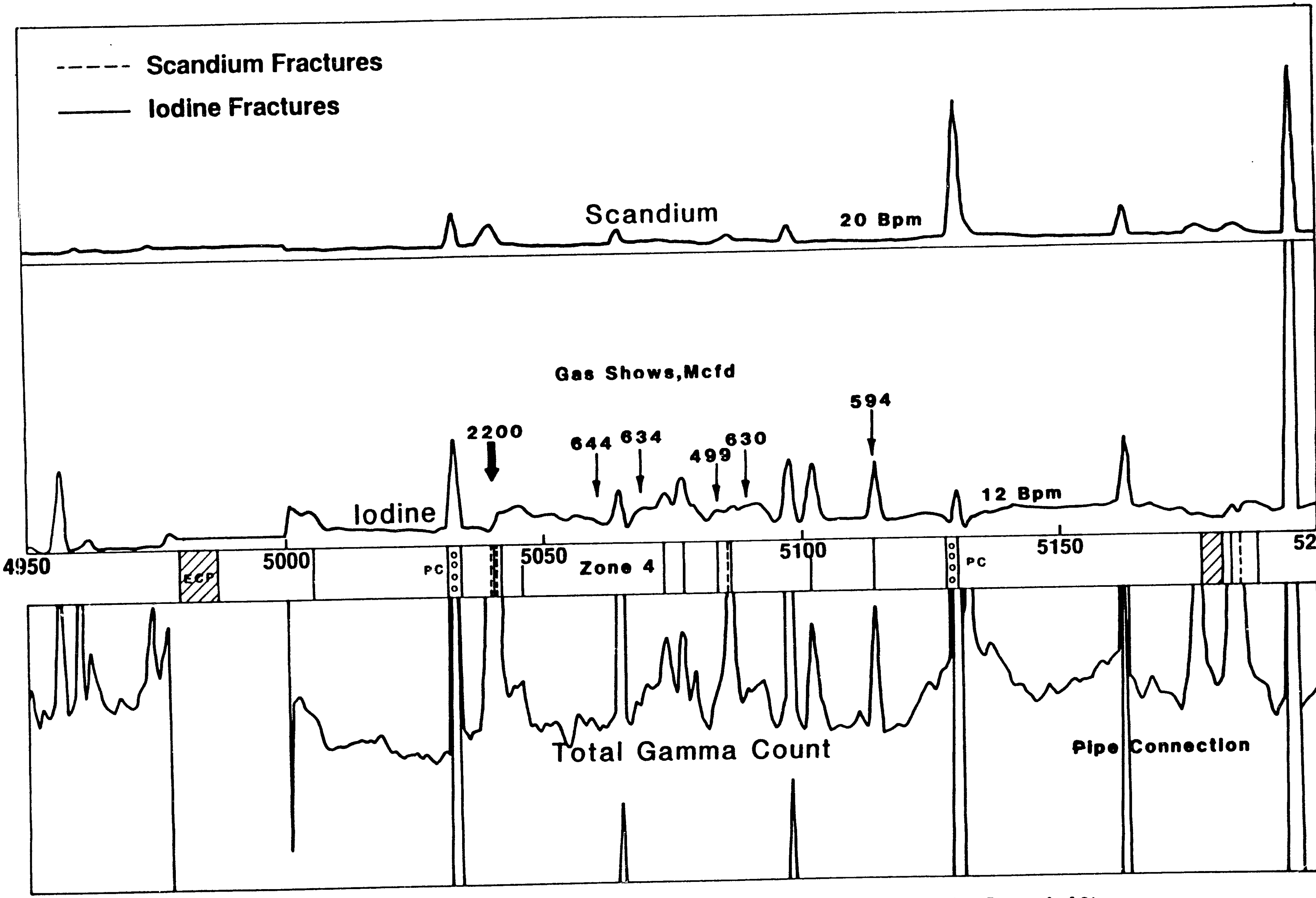


Figure 4.3.4.5: Tracer Log Showing Interpreted Fractures in Zone 4 After CO_2 Frac in Zone 1 and Location of Shows Noted During Drilling Operations

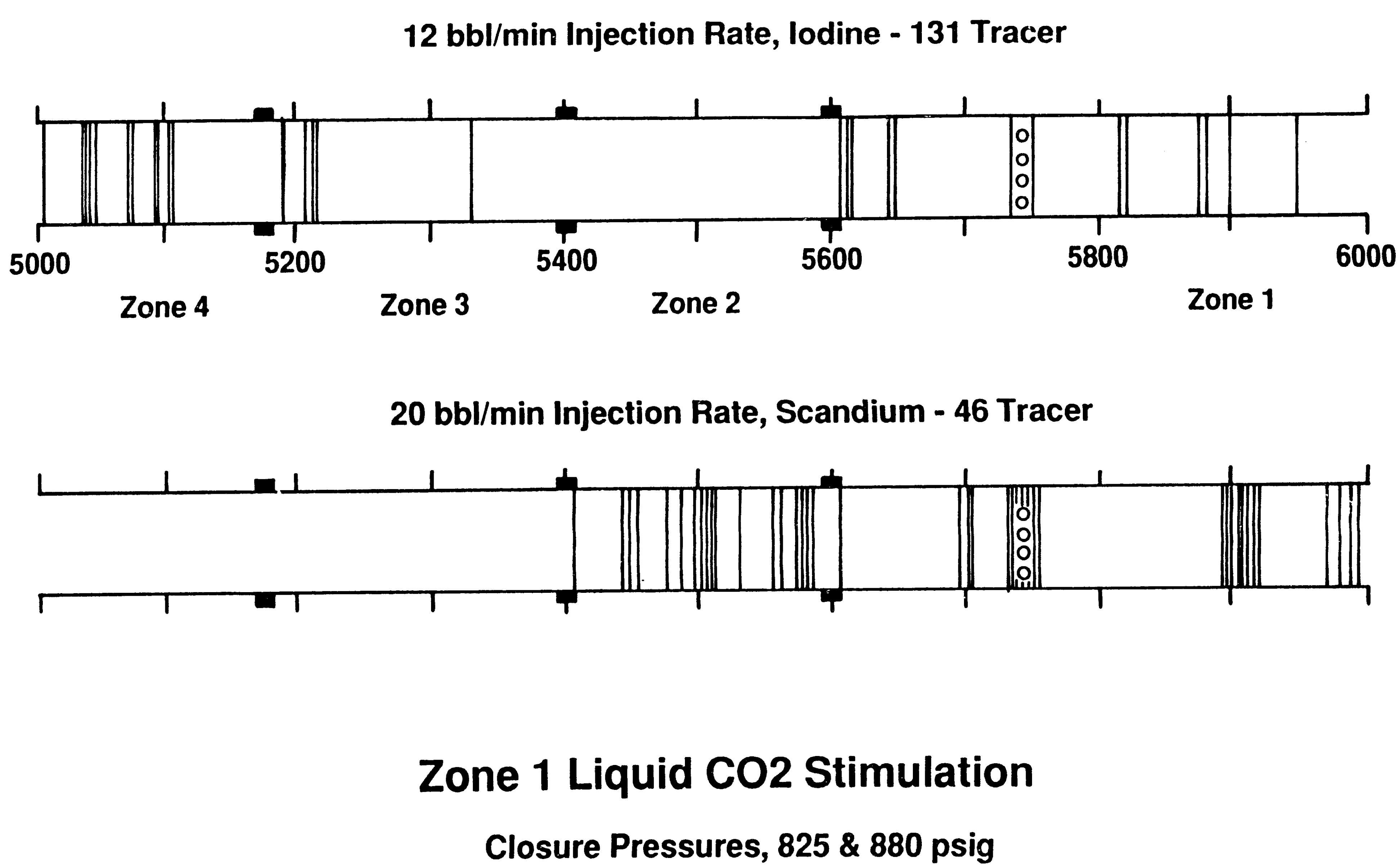


Figure 4.3.4.6: Diagramatic Illustration of Fractures Induced During Different Injection Rates of CO_2

(marked Test 8 and Test 9 on Figure 4.3.4.7) indicates that stress build-up from fluid injection forced the injection point to move down the wellbore to a point where stress was lower. A total of 69 fractures over 4 zones provided evidence that fractures had been opened and propped.

Analysis of all of the stimulations conducted on Zone 1 as shown in Figure 4.3.4.7 shows that some fractures were pumped into each time, but that a number of new fractures were opened up or propped open with each frac job that had not been addressed before. It also shows that a number of natural fractures were inflated which because of their orientation intercepted other fractures which brought the material back to the wellbore in zones other than the one it was pumped into.

Analysis of the data from the foam frac in Zones 2-3 and 4 for Zone 4 is shown in Figure 4.3.4.8. This shows the fractures that were induced and their relationship to the natural fractures that were mapped by video log analysis. Orientation of the fractures shows how the natural fractures can intercept one another to produce tracer in a zone in which it was not pumped directly. Frac No. 4 in Zones 2-3 and 4 was a large volume high rate frac which induced or pumped into 54 fractures over the 3 zones. The distribution of fractures pumped into is shown in Figure 4.3.4.9.

4.4 Significance cf Results

Analysis of the tracer logs for the stimulations monitored produced some very significant results. They clearly demonstrate that injecting fluids at slow rates will allow the fluids to select the easiest path of flow or the path of least resistance which quite often will be a natural fracture or fractures penetrating the wellbore. The analysis pointed up the role of stress buildup during inflation of a natural fracture and the subsequent autoselection of another area and set of fractures to inflate during a frac job. The analysis demonstrated that use of radioactive tracers injected as liquids and pellets can be very useful tools in developing data about the fracture system in a horizontal wellbore.

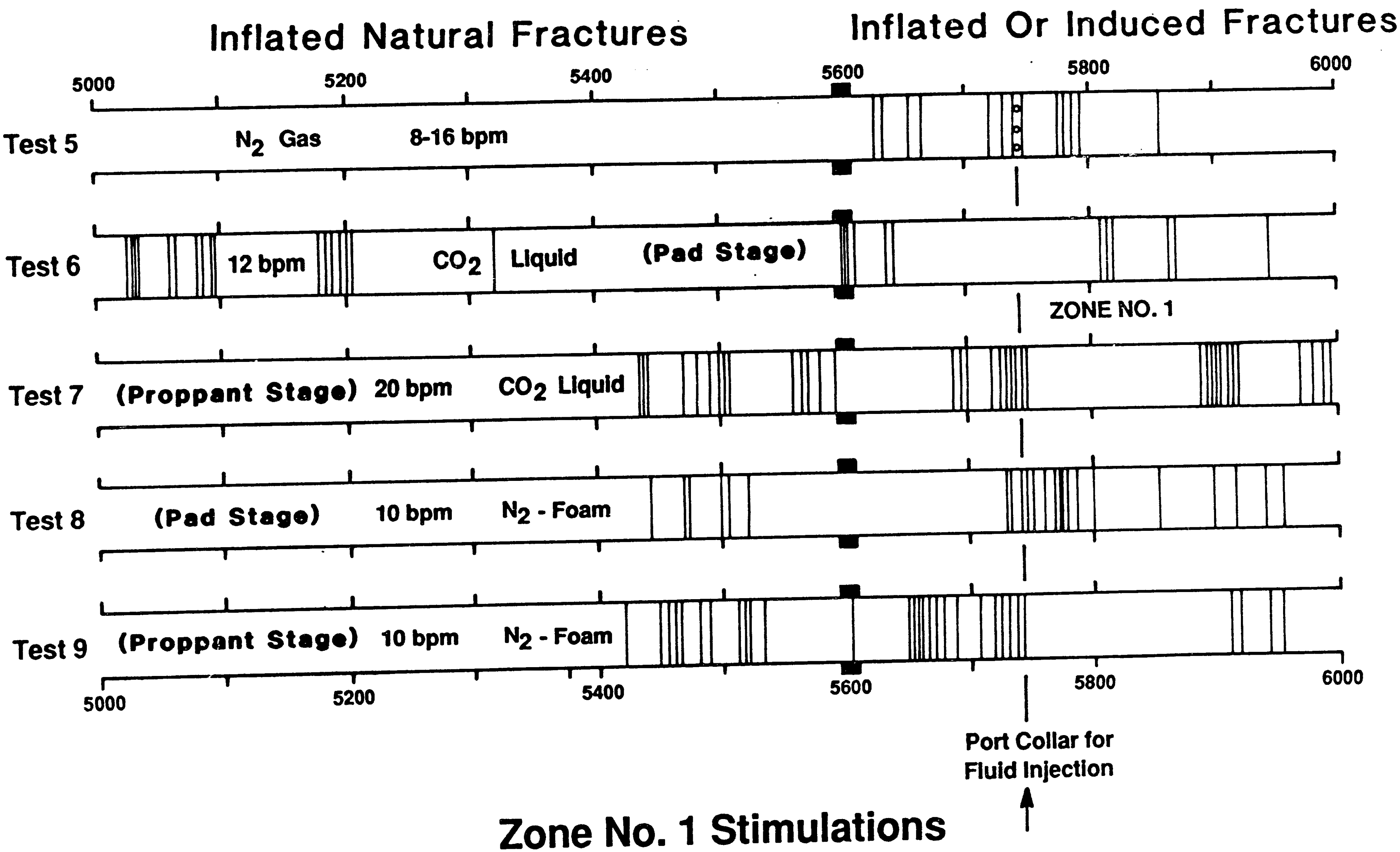
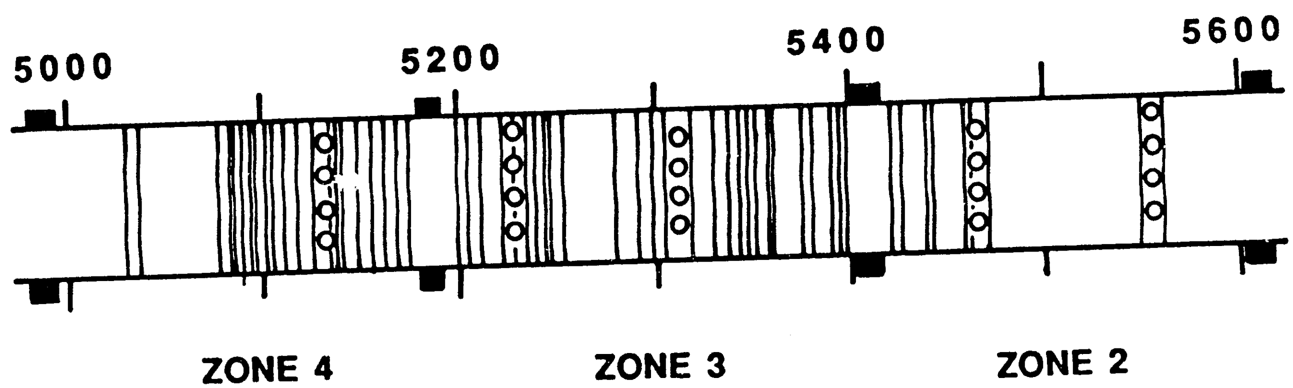


Figure 4.3.4.7: Summary Diagramatic Illustration of Fractures Created During Various Stimulations in Zone 1



TEST 11- LARGE VOLUME NITROGEN FOAM FRAC

Injection Rate 30 bbl/min

Figure 4.3.4.9: Summary Diagram Showing Where All Fractures Were Generated During Stimulation No. 4 in Zones 2-3 and 4

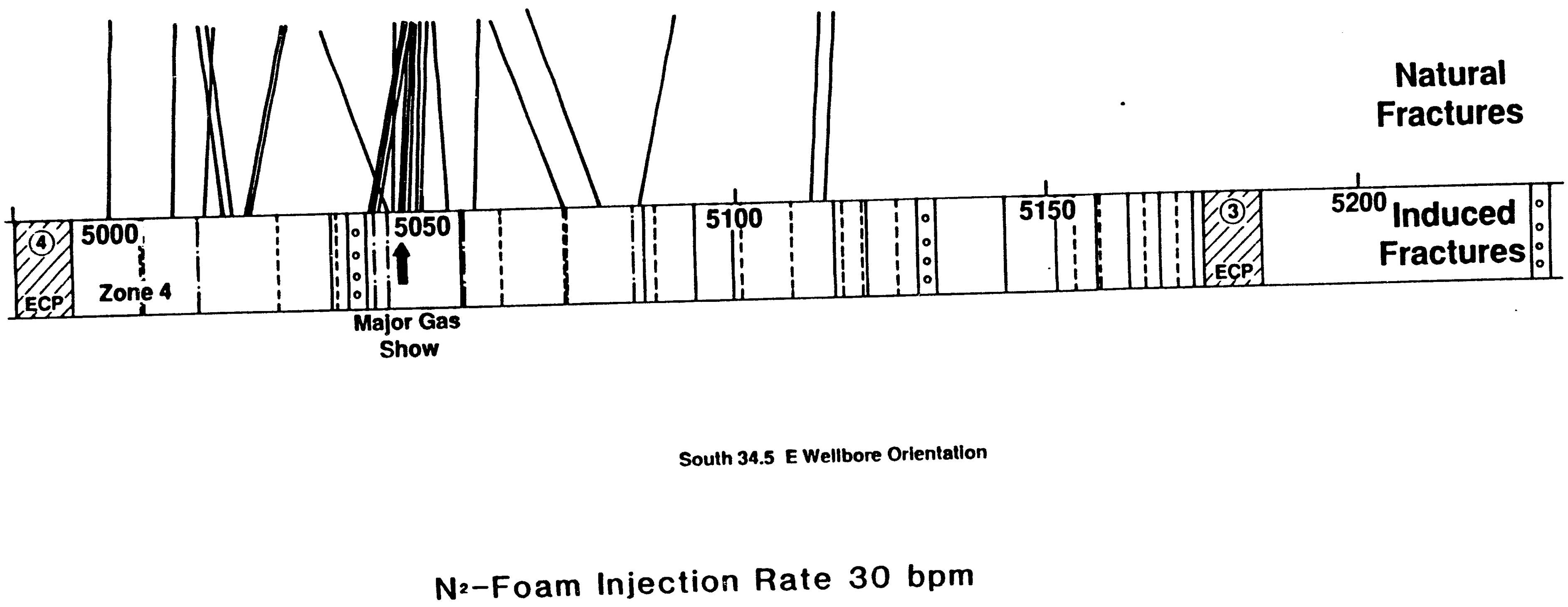


Figure 4.3.4.8: Diagram Showing Relationship of Natural Fractures and Induced Fractures During Stimulation No. 4 in Zones 2-3 and 4

5.0 WELL TEST AND ANALYSIS

To determine the beneficial effects of drilling a horizontal well to encounter natural fractures at a most favorable angle to augment natural gas production, and to determine the increased efficiency of the horizontal well by inducing or extending the existing natural fractures, methods of measurement must be tested and evaluated. This was the purpose of the well test and analysis tas.

5.1 Well Testing

Upon completion of the Recovery Efficiency Test (RET) #1 well in the Devonian shales in December, 1986, the well was shut-in for a preliminary 9-day pressure build-up test and put on production for 2 months (Figure 5.1.1). A series of choked flow tests were made culminating with a 28-day pressure build-up test (Figure 5.1.2) in April and May, 1978. Wellhead pressure data were monitored and measured with a high resolution pressure transducer and recorded on a battery powered portable data logger system. A backup recording was made with conventional chart recorder. Wellhead pressure data was converted first to absolute values then to bottomhole pressure.

5.1.1 Pressure Build-up Tests

Pressure build-up testing, probably the most familiar transient well testing technique, was first introduced by the groundwater hydrologists, but has been used extensively in the petroleum industry. Pressure build-up testing requires shutting in a producing well. The most common and simplest analysis techniques require that the well produce at a constant rate, either from startup or long enough to establish a stabilized pressure distribution before shut-in. The pressure is measured immediately before shut-in and is recorded as a function of time during the shut-in period. The resulting pressure build-up curve is analyzed for reservoir properties and wellbore conditions.

Stabilizing the well at a constant rate before testing is an important part of a pressure build-up test. If stabilization is

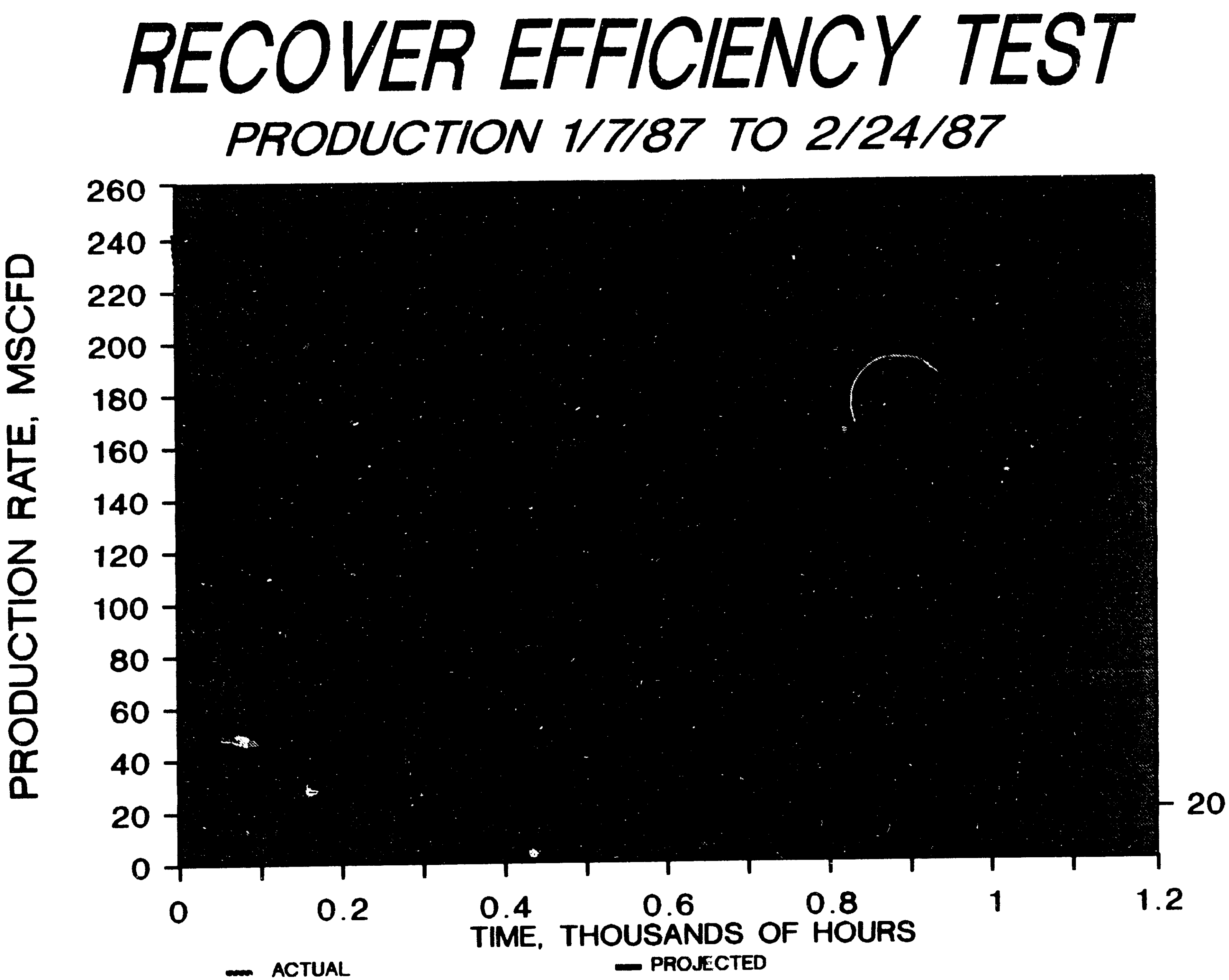


Figure 5.1.1: Production of RET #1 Well Prior to Stimulation of Any Zones

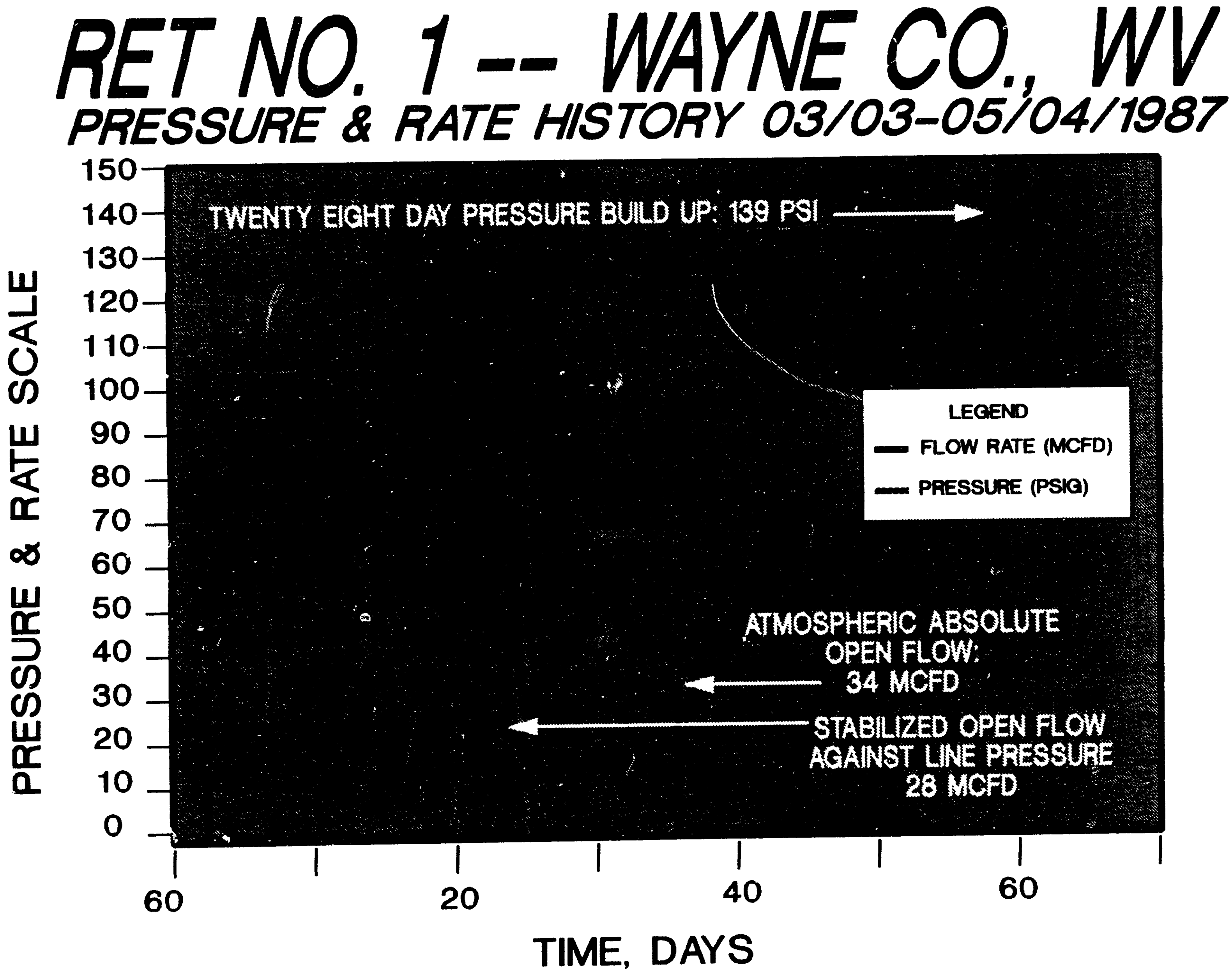


Figure 5.1.2: Plot of Pressure and Rate versus Time for Entire Well Prior to Stimulation Operations

overlooked or is impossible, standard data analysis techniques may provide inaccurate information about the tested formation. In a developed reservoir, it is recommended that field data be collected to enhance the test scheduling and hence increase the possibility of reaching pressure stabilization. Advance knowledge of the testing period is of importance, especially in highly-fractured, low permeable shale formations.

5.1.1.1 Instrumentation

The accuracy of the results depends on the accuracy of the recorded data. Therefore, due to the importance of such data, the pressure build-up data were measured at wellhead with a TerraTek "Terra Quartz" high resolution pressure/temperature transducer and recorded on a battery-powered portable data logger. A backup recording was made with a conventional chart recorder. The wellhead gauge pressure data were first converted to absolute pressure and then to bottomhole pressure.

5.1.1.2 Procedures

Several build-up tests were performed during the pre- and post-stimulation stages. Prior to any build-up test, the well/zone was subjected to a series of flow tests; a final stabilized flow was reached which will represent the average stabilized flow rate during a flowing period, known as 'tp'. The build-up test was performed by shutting-in the well/zone for a certain period of time during which the pressure values versus running time (delta t) were recorded. The duration of the build-up period is an important factor for the analysis and, in particular, when the Devonian shale is the formation in question.

Due to the fact that the shale produces from a very low permeable formation, the shut-in/build-up time becomes very critical. Based on previous build-up procedures and hands-on experience in the Devonian shale, and the allocated time to run several build-up tests, it was determined that an average 10-14 days of build-up time was sufficient to arrive at meaningful and accurate results for estimating the various reservoir parameters. In addition, design of build-up tests was performed to determine the required shut-in period. Factors such as the end of wellbore storage effects, the end of the semi-log straight line, the semi-log straight line slope, and the general magnitude of the pressure response were consistent for designing the build-up test.

A pre-stimulation build-up test was performed on the RET #1 when the well was shut-in for a period of 640 hours. Prior to this build-up, the well was flowing at a rate of 35 mcfd for approximately 264 hours. In addition, pre- and post-stimulation build-up tests were performed on Zones 1 (2-3, 4), 6, and (5,8). Analysis and results of the build-up tests are discussed in detail in this report.

5.1.2 Drawdown Tests

While most reservoir formation obtained from a drawdown test also can be obtained from a pressure build-up test, there is an economic advantage to drawdown testing since the well is produced during the test. The main technical advantage of drawdown testing is the possibility for estimating reservoir volume. The major disadvantage is the difficulty of maintaining a constant production rate.

Due to the fact that the RET #1 reservoir pressure was low (180-200 psia), maintaining a constant production rate was very difficult; so it was difficult to obtain a reasonable pressure drawdown. The constant rate drawdown test should be used if the well was shut-in long enough to reach static reservoir pressure before the drawdown starts. In which case, this condition was to a certain point difficult, due to the very low permeability of the shale; hence, the time needed to reach the reservoir static pressure via a build-up test required a length period of time.

In addition, the early part of drawdown data is influenced by wellbore storage, and sometimes it is possible to draw a straight line through the semi-log plot of data taken during this time. The slope of that line gives incorrect values of permeability and skin. Therefore, prior to any analysis, a log-log data plot of the drawdown data must be made to select the correct semilog straight line.

5.2 Analysis of Data

5.2.1 Analytical Methods

Build-up and drawdown of time-pressure data from horizontal shale producing wells present a new challenge to reservoir engineers. The vast majority of the analytical techniques that have been presented to date are mainly applicable to conventional vertical well testing and analysis. Since no one particular method of analysis has been developed solely for horizontal well testing, a combination of conventional techniques and a newly developed method was used to estimate values of formation flow capacity (Kh), skin factor (S), and average reservoir pressure ($\overline{P}$).

The validity of these values is tested by using a dual-porosity reservoir simulator to history match the pressure build-up data.

Type curve matching and Horner's technique are the two conventional techniques that were used in the analysis. In addition, a newly developed technique known as the Rectangular Hyperbolic Method (RHM) is implemented in the pressure build-up analysis for comparison to results determined by the conventional techniques.

Analysis of gas pressure data requires modification to the conventional techniques in order to evaluate the reservoir properties. The use of pressure-squared (P^2) or pseudo pressure values (m(P)) instead of pressure values (P) is essential for evaluating gas reservoir properties. The use of P^2 or m(P) accounts for the gas flow performance from the reservoir to the wellbore. Since the reservoir pressure in the study area was established between 180-200 psia, values of P^2 versus time are appropriate for the analysis of the pressure build-up data. It is important to note that as a rule of thumb, if reservoir pressure is less than 2000 psia, the P^2 values will establish a more accurate presentation of the flow performance than that of P values.

As a first step in the pressure build-up analysis, a FLOPETROL Johnson/Schlumberger type curve for wells with wellbore storage and skin effects in an infinite acting reservoir with a dual porosity system in a pseudo steady state flow regime was used. Plots of delta pressure squared (ΔP^2) and delta pressure squared derivatives ($d(\Delta P^2)$)

values versus time are generated on a log-log plot and matched on the aforementioned type curves. The wellbore storage effects, the condition(s) of the wellbore/formation (damaged or undamaged), and the start of the semi-log straight line region are determined from the type curve matches. The accuracy of the reservoir properties depends on the accuracy of matching the pressure-squared and the pressure-squared derivative curves simultaneously. Values of formation permeability and skin factor are calculated using the type curve matching analysis.

The range of data determined from the type curve matching that fall within the semi-log region is used for the Horner's analysis technique. A plot of pressure-squared versus Horner time $(\frac{tp + \quad t}{t})$, which incorporates the flowing time period, is generated and a straight line passing through the stabilized points having a slope 'm' is plotted. If enough build-up pressure data is available and the pressure has reached stabilization, a dual porosity system in the Devonian shale could be detected by having a straight line in the middle region with a slope m', where m' = ½ m. Values of average formation permeability, skin factor, and average reservoir pressure are determined using Horner's technique. A comparison of Horner's technique with the type curve matching technique is evaluated at this stage.

A newly-developed technique known as the RHM technique is utilized to estimate the various reservoir properties using the pressure build-up data that was used for the Horner plot (data points determined from the log-log plot falling within the semi-log straight line region). This technique enables one to determine $\overline{P}$ directly from the field data without prior knowledge of the drainage shape. The Horner's equation for a well shut-in after producing at a constant rate in an infinite acting reservoir is written as:

$$Pws = Pi - \frac{m}{2.303} \ln \left(\frac{tp + \quad t}{t}\right) \quad \text{---- 5.2.1.1.}$$

This equation was modified and rewritten as follows:

$$Pws = a + \frac{c}{b + \quad te} \qquad \text{---- 5.2.1.2.}$$

A linear regression can be performed for the variables Pws and $1/(b + \quad te)$ to determine optimal values of a, b, and c. Since the above equation is a three constant equation, a trial-and-error procedure has to be employed by assuming values of b until a value of the regression coefficient close to unity is obtained.

After determining the optimal correlation coefficient using the trial-and-error method, a straight line is plotted through these points and values of a and c are determined, where:

a = y-intercept = $\overline{P}$ = average reservoir pressure

c = slope of the straight line

b = trial-and-error value

m = slope of Horner's straight line = $\frac{1626\ q\mu ZT}{Kh}$.

Equations 5.2.1.1 and 5.2.1.2 are modified and a value of Kh is determined as follows:

$$Kh = \frac{282.39\ q\mu Bb}{-c} \qquad \text{---- 5.2.1.3.}$$

The above equation is rewritten for gas reservoirs as follows:

$$Kh = \frac{1423\ q_{avg}\ \mu ZT}{-c} \qquad \text{---- 5.2.1.4.}$$

Values of $\overline{P}$ using the RHM technique has an advantage over the conventional methods because knowledge of neither the well/reservoir configuration nor the boundary condition is required for a routine build-up analysis.

In addition to the above techniques, reservoir engineering stimulation is utilized to history match the pressure and/or production profiles to predict the reservoir properties. A combination of these techniques will enhance and accurately estimate the results.

5.2.2 Pre-Stimulation Analysis

5.2.2.1 Pre-Stimulation Data Analysis

Preliminary data analysis consisted of separately collecting wellhead gauge pressure and orifice meter run pressures, converting the wellhead data to absolute pressure, and then to bottomhole pressure. Gas meter run parameters were converted to flowing rates using the orifice meter procedure.

Figure 5.2.1 shows wellhead pressures and bottomhole pressures for the 640-hour pressure build-up test. It is appropriate to point out that classical transient analysis tedhniques are not strictly applicable to the horizontal wellbore geometry, but was done to obtain initial estimates of some reservoir properties so that these values could be used as a starting point for the simulation analysis.

5.2.2.2 Results of Permeability Determinations

Horner's Technique: A plot of P^2 versus Horner time on semi-log paper where a build-up pressure curve was obtained (Figure 5.2.2), a straight line passing through the last stabilized pressure value was constructed, having a slope 'm' (Figure 5.2.3). The following is the computation procedures to calculate values of kh, s, and initial reservoir risk pressure:

a) The y-intercept at f(t) = 0 is equivalent to the initial/estimated reservoir rock pressure.

$$P^2 = 36977 \text{ psia}^2 == \bar{P} = 192 \text{ psia.}$$

It is important to note that the average reservoir pressure in the surrounding wells was determined to be between 188-200 psia. The equation of the straight line is: y = m f(t) + b, where 'm' is the slope of the straight line; by taking two points on the straight line A(0,36977) and B (2.331,0):

$$m = \frac{36977 - 0}{0 - 2.331} = -15863.2 \text{ psia}^2\text{.log time}$$

$$f(t) = \log [(t_p + \quad t)/ \quad t]$$

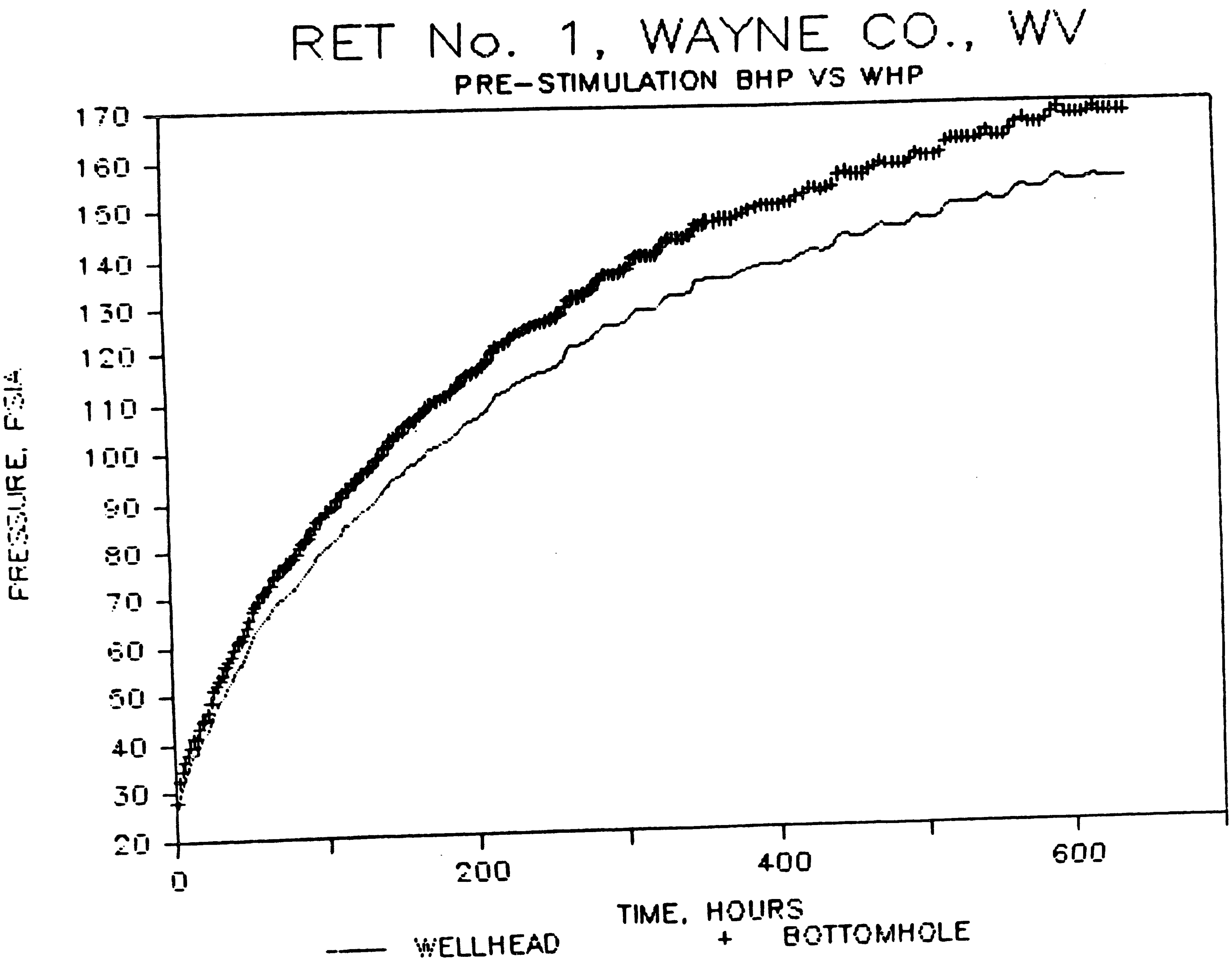


Figure 5.2.1: Plot of Pressure versus Time for Pre-stimulation 28-Day Pressure Build-up Curve

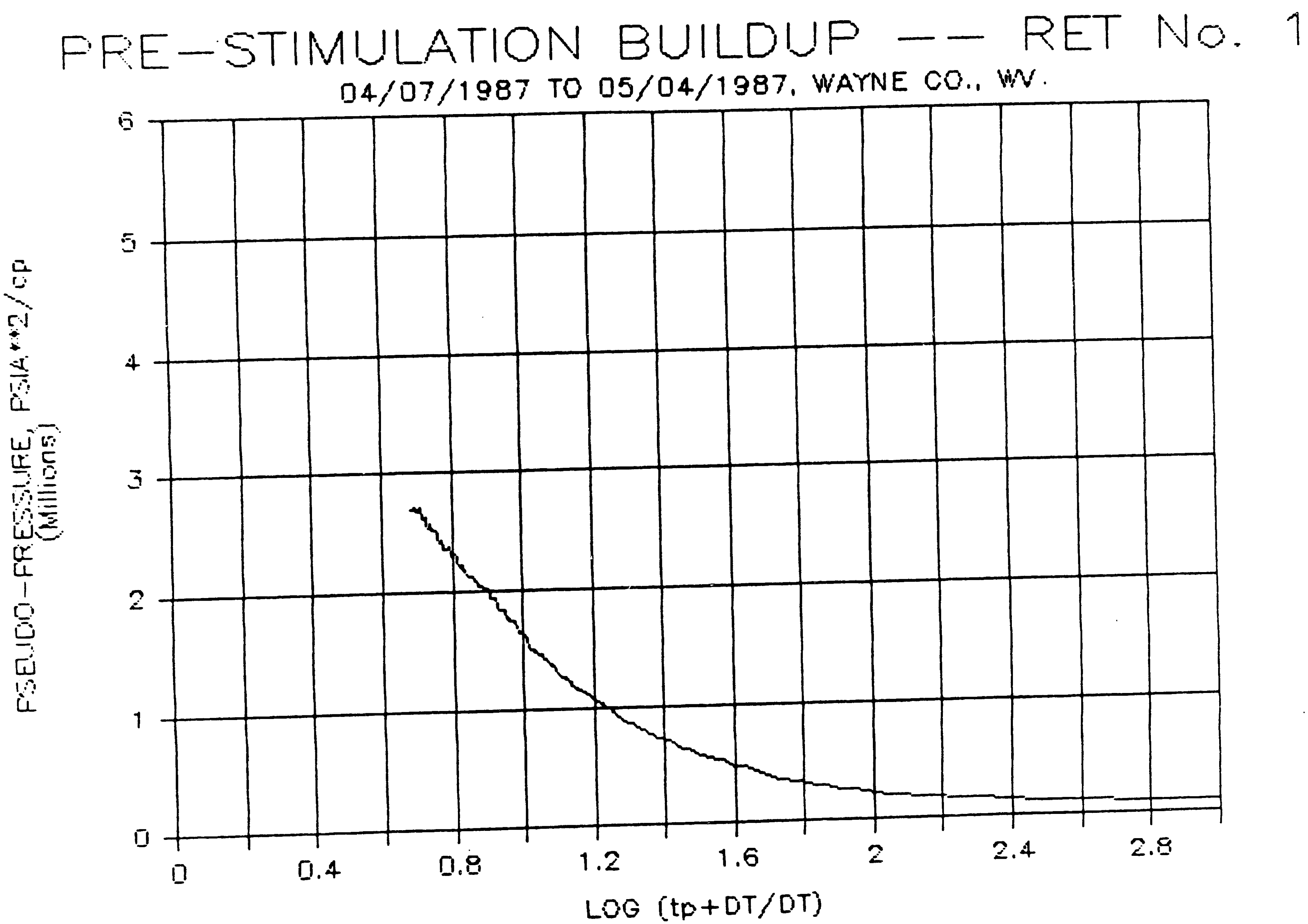


Figure 5.2.2: Plot of Pressure Squared versus Log of tp + dt/dt

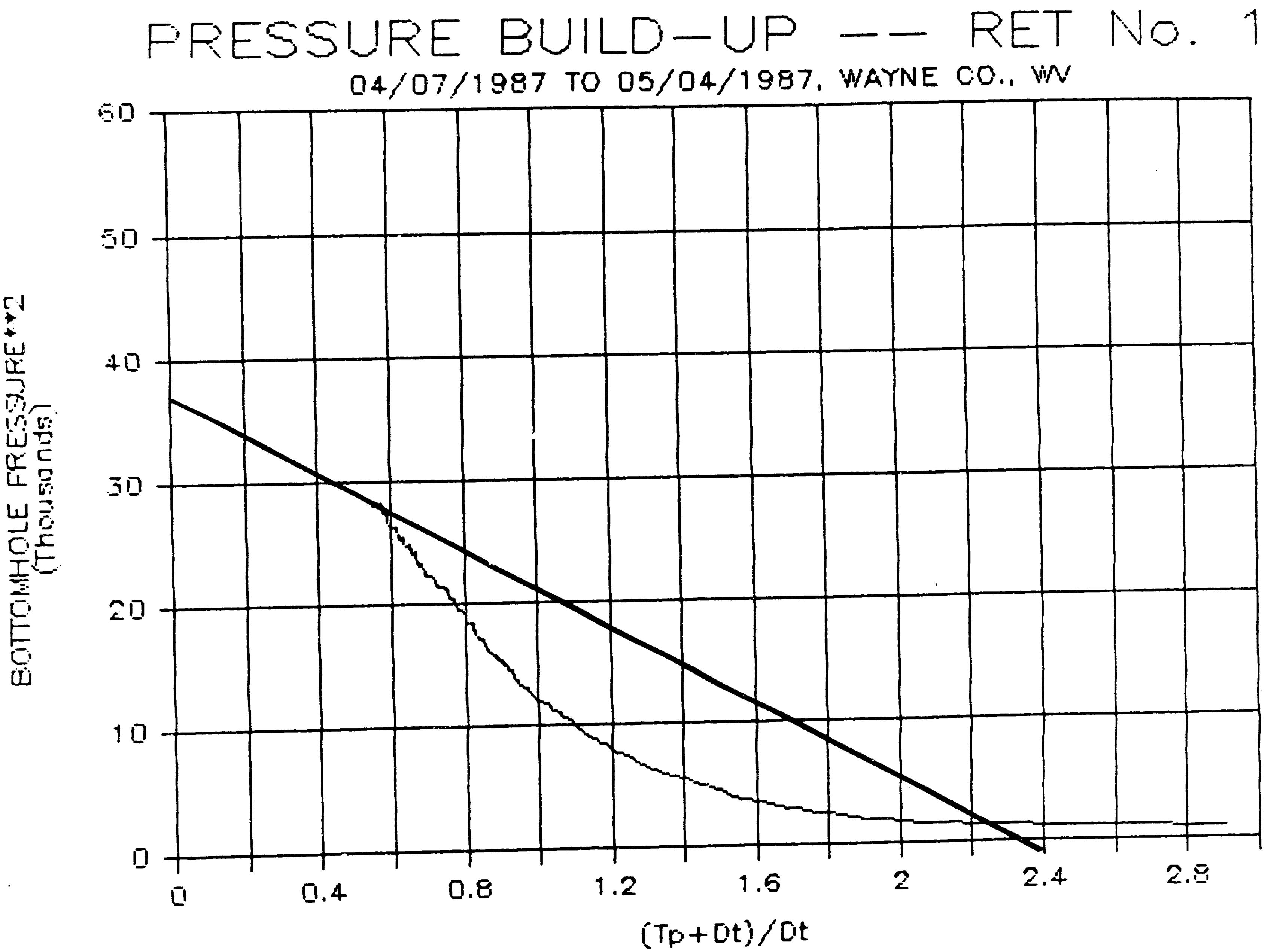


Figure 5.2.3: Determination of Slope from Pressure Build-up Data using Horner Technique

Therefore: $y = -15863.2 \quad + b$

$b = 36977$ = y-intercept

$y = -15863.2 \quad + 36,977.$

Writing the above equation in terms of P^2 and Horner's time, we get:

$$P^2 = -15863.2 \log \left(\frac{tp + \quad t}{t}\right) + 36,977 \qquad (1)$$

b) To compute the value of Kh, we can utilize the following equation:

$$Kh = \frac{1637\ q_{avg} \mu_i Z_i T}{m} \qquad (2)$$

where: m = slope = 15863.2

q_{avg} = average gas production rate, mscfpd

K = formation permeability, md

μ_i = gas viscosity, Cp evaluated at initial pressure, P_i

Z_i = gas-low deivation factor evaluated @ initial pressure.

T = formation temperature, degrees R.

h = formation thickness, ft.

Assuming the whole shale interval (h = 247 ft) to be productive and with a formation temperature of 93°F, gas production rate of 34 mcfpd, and slope from Figure 5.2.3 of 15863.2 psia²/cycle; therefore formation thickness (K) is:

$$K = \frac{(1637)(34)(0.0107)(0.980)(553)}{(15863.2)(247)} = 0.082 \text{ md}$$

c) The skin factor is computed from equation:

$$S = 1.151 \left[\left(\frac{P1hr^2 - Pwf^2}{m}\right) - \log \left(\frac{k}{\phi \mu\ C_i\ r_w{}^2}\right)\right. \qquad (3)$$

where ϕ = porosity, % = 1.73%

$C_{ti} = C_{gi}$ = initial gas compressibility, psia^{-1} = 0.010.

$Plhr^2$ is computed using equation (1). Therefore:

$$Plhr^2 = -15863.2 \log \left(\frac{1+2(4)}{1}\right) + 36{,}977$$

$$= -38440.4 + 36{,}977$$

$$= -1463 \text{ psia}^2$$

Therefore:

$$S = 1.151 \left[\left(\frac{-1463-217}{15863.2}\right) - \log \left(\frac{0.082}{(0.0173)(.0107)(.010)(.328)^2}\right) + 3.23\right]$$

$$S = 1.151 \left[-0.1059 - 5.615 + 3.23\right]$$

$S = -2.87$. Since $Sw = So = 0$, therefore, $C_{ti} = C_{gi}$.

The above estimated values for permeability and skin are similar to those of a conventional well in a low permeability reservoir with a very large fracture. As discussed previously, these analyses are not strictly applicable to the horizontal wellbore geometry, but we may assume a horizontal wellbore to represent a vertical well with a long, finite conductivity fracture.

5.2.2.3 Reservoir Modeling

Following the build-up test for RET #1, an attempt was made to isolate and individually test each of the eight zones representing a total of 2211 feet (3803 - 6014 feet)(see Table 5.2.2.3.1):

TABLE 5.2.2.3.1

ZONE	INTERVAL	
1	5610 - 6014	
2-3	5185 - 5601	(External casing packer failed; Zone 2-3 now combined to one zone)
4	4994 - 5175	
5	4346 - 4986	
6	4203 - 4337	
7	4104 - 4194	
8	4094 - 3803	

A twenty-four hour pressure build-up test followed by a 24-hour drawdown for each zone was performed. Since the periods in which these tests were conducted were very short, conventional methods of analyses (Horner plot, type curve matching, etc) may not be done accurately. In order to estimate permeability for each isolated zone, G3DFR, a three-dimensional, dual porosity, single phase gas simulator based on the original SUGAR-MD reservoir model was used to history match and simulate pressure data and compare it with actual field results.

The history-matching technique was iterative during which successive sets of simulated data were compared with actual test data. Upon comparison, pertinent variable(s) (bulk permeability, porosity, etc) were changed and another simulation was run. This process was repeated until a "match" of computer simulation to actual test data was obtained. The model critical parameters included:

Reservoir temperature = 93°F

Formation thickness = 247 feet

Initial reservoir pressure = 50-90 psia

Fracture spacing = 10 feet

Matrix porosity = 0.02%

Matrix permeability = 0.90 μd

Gas properties from Table 5.2.2.3.2

Bulk reservoir porosity - variable (to account for gas volume of each isolated zone)

Reservoir dimensions: 14 x 8 x 5

TABLE 5.2.2.3.2

RET NO. 1 GAS ANALYSIS (SAMPLE TAKEN 3/04/87)

PRE-STIMULATION

COMPONENT	PERCENT
Nitrogen	1.2
Oxygen	<0.05
Methane	75.7
Ethane	14.7
Propane	6.4
Iso-Butane	0.33
N-Butane	1.30
Iso-Pentane	0.14
N-Pentane	0.19
Hexanes	0.05
Carbon Dioxide	<0.05
BTU Value (Dry)	1255.6 BTU/CF
BTU Value (Saturated)	1233.7 BTU/CF
Specific Gravity	0.7225
T_c	398 degrees, R
P_c	655 psia

Table 5.2.2.3.3 represents a summary of each zone's 24-hour pressure build-up and corresponding permeability values predicted by the reservoir model:

TABLE 5.2.2.3.3

SUMMARY OF FIELD TEST DATA

ZONE	24-HOUR PRESSURE BUILD-UP (psia)	L (ft)	PERMEABILITY, md (PREDICTED BY MODEL)	KL
1	54	404	0.032	12.928
2-3	75	417	0.078	32.526
4	68	182	0.098	17.836
5	73	640	0.073	46.720
6	74	135	0.078	10.530
7	74	90	0.037	3.330
8	83	292	0.068	19.856
		2160		= 143.726

Pre-stimulated K = 0.0665

An arithmatic average of the pre-stimulation permeability values (predicted by the model) is computed:

$$\bar{K}\ prc = \frac{KL}{L} = \frac{143.726\ \text{ft-md}}{2160\ \text{ft.}} = 0.0665\ \text{md}$$

NOTE: Based on the 24-hour build-up pressure analyzed by zones and on the previous Horner's analysis for all the zones combined (Section 5.2.2), one can assume that the predicted $\bar{K}$ pre-stimulation value is accurate.

5.2.3 Results of Permeability Determinations

5.2.3.1 Pre-Stimulation Results

Following completion of the horizontal well (RET #1) in the Devonian shale in December, 1986, the well was on production through early April, 1987. During this period the well was subject to a series of flow tests, the last of which was an "open flow" test where the well produced at an average rate of 34-35 mcfd for 264 hours, and then was immediately shut-in for a 640-hour pressure build-up test.

Results of the pressure build-up analysis using Horner's technique has indicated the following reservoir properties; assuming a formation thickness = 247 feet, therefore:

K = reservoir permeability = 0.082 md

S = -2.87

Estimated initial reservoir pressure = $\overline{P}$ = 192 psia.

It is important to note that the average reservoir pressure in the neighboring wells prior to drilling the RET #1 was estimated between 185-200 psia.

Following the build-up test for RET #1, an attempt was made to isolate and individually test each of the eight zones representing a total of 2160 feet. A 24-hour pressure build-up test followed by a 24-hour drawdown for each zone was performed. Since the periods in which these tests were conducted were very short, conventional methods of analyses (Horner plot, type curve matching, etc.) may not be done accurately. In order to estimate permeability for each isolated zone, G3DFR, a three-dimensional, dual porosity, single phase gas simulator based on the original SUGAR-MD reservoir model was used to history match and simulate pressure data and compare it with actual field results. Table 5.2.3.1 represents a summary of each zone's 24-hour pressure build-up and corresponding permeability values predicted by the reservoir model.

An estimated arithmatic average pre-stimulation permeability value could be determined as follows:

$$\overline{K} = \frac{KL}{L} = \frac{143.73}{2160} = 0.0665 \text{ md.}$$

Therefore, a correlation of the average pre-stimulation permeability value between the Horner's technique and the reservoir modeling estimate was accurate. Based on the Horner's technique, a pre-stimulation permeability value is estimated at 0.082 md.

TABLE 5.2.3.1

SUMMARY AND ANALYSIS OF FIELD TEST DATA

ZONE NUMBER	24-HR PRESSURE BUILD-UP P (psia)	ZONE LENGTH L (ft)	PERMEABILITY PREDICTED BY G3DFR K (md)	KL (ft-md)
1	54	404	0.032	12.93
2-3	75	417	0.078	32.53
4	68	182	0.098	17.84
5	73	640	0.073	46.72
6	74	135	0.078	10.53
7	74	90	0.037	3.33
8	83	292	0.068	19.86
		= 2160		= 143.73

5.2.3.2 Post Stimulation Results

A post stimulation analysis of the pressure build-up/drawdown data resulted in determination of average reservoir pressure values, skin values, and average permeability values for the various zones with the different stimulation jobs. Results of the pressure build-up analysis using the various techniques are summarized in Table 5.2.3.2.1

Zone No. 1 was stimulated by 3 different frac jobs at various treating pressures and rates with nitrogen, liquid CO_2, and nitrogen-foam with proppants. Well testing procedures and data analysis were performed for each job. In the first job when the well was stimulated with N_2, pressure build-up data indicated a reservoir pressure of 290 psia which is above the current average reservoir pressure (185-200 psia as determined by the 7-day shut-in test). This is due to the fact that Zone No. 1 (N_2 frac) was still over-pressured by the amount of inerts present in the gas mixture at the time of testing. The simulation of the pressure build-up data using G3DFR model estimated an average permeability equal to 0.0477 md. Analysis of the pressure build-up data following the CO_2 frac job indicated a permeability value of 0.0480 and 0.0485 using Horner's technique and history matching, respectively. Using Horner's technique, reservoir pressure was estimated at 182 psia. Results of build-up pressure analysis following the third job (N_2-foam-proppant frac) indicated the presence of a dual porosity system with the middle region having a slope one-half that of the late region on the build-up curve which is characteristic of a dual porosity sytem in the Devonian shale. The average permeability was estimated at 0.090 md, and the average pressure was determined to be 184 psia.

Post stimulation analysis for Zone No. 6 indicated a post-frac permeability of 0.1835 md, but an average reservoir pressure of 205 psia using history matching process. Analysis of the pressure build-up data using Horner's technique was not possible due to the fact that the stabilized flow period prior to the build-up test was very short and hence accurate results of pressure and permeability could not be determined. Instead, type curve matching was implemented for the analysis and an average permeability value was calculated to be 0.1795 md. Both techniques indicated similar results, hence more confidence in the estimated post-frac permeability value.

Zones 2-3 and 4 were stimulated using N_2-foam/proppant. Following the clean-up period, Zones 2-3 and 4 produced at a rate of 62.2 mcfd for a period of 35 days. Pressure build-up analysis using Horner's technique indicated an average reservoir permeability of 0.1505 md and an average pressure of 182 psia.

Zones 5 and 8 were fraced using N_2-foam/proppant. Analysis of pressure build-up data has indicated an average reservoir pressure of 178 psia and an average permeability of 0.310 md. Various techniques were used in the analysis of the pressure build-up data assuring a confidence in the analysis. Estimates of permeability values using the different techniques is shown in Table 5.2.3.2.1. Systematic analysis of the results of the pressure build-up tests for the various zones were conducted to be able to correlate the different permeability results from the various zones. The different techniques used in the analysis were helpful in predicting an average reservoir pressure of 178-185 psia which is within the estimated range of the pressure in the study area. It is important to mention that a pressure build-up test, when all the various zones were opened, would have been valuable in estimating the post-frac permeability and the average reservoir pressure for RET #1, however, time was not available to conduct such a test. Hence, a comparison of pre-stimulation and post-stimulation permeability values is more accurate, but was not possible. It is believed that the results presented in Table 5.2.3.2.1 are reasonable in relation to current well production rates and overall reservoir pressures.

TABLE 5.2.3.2.1

POST STIMULATION PERMEABILITY ESTIMATES

	STIMULATION ZONE NUMBER			
PRESSURE ANALYSIS TECHNIQUE	ZONE 1 K (md)	ZONE(s) 2-3, 4 K (md)	ZONE 6 K (md)	ZONE 5,8 K (md)
Horner's	0.090 (N2 Foam) 0.0480 (CO2 Frac)	0.1505	---	0.327
Type Curve			0.1795	0.492
RHM *				0.303
Reservoir Simulation	0.0477 (N2 Frac) 0.0485 (CO2 Frac)		0.1835	

* Mainly for pressure estimates.

5.2.4 Results of Skin Value Calculations

The pre-stimulation analysis of the pressure build-up data resulted in a skin value of -2.87 which is indicative of a horizontal wellbore. This value, in conventional methods, is equivalent to a stimulated vertical well, but due to the fact that we have a wellbore 2160 feet long, the negative skin value is absolutely valid.

The type of stimulation and the success of the frac job are represented/indicated in the post stimulation skin values. Horner's technique and type curve matching were used to predict/estimate values of skin. Table 5.2.4.1 summarizes the post stimulation skin values.

TABLE 5.2.4.1

POST STIMULATION SKIN VALUES

	ZONE 6	ZONE 1	ZONES 2-3, 4	ZONES 5,8
Skin Value (S)	Non-damaged region	-3.212	-4.22	-0.881

Zones 1, 2-3, and 4 have indicated improvement in the skin values compared to the pre-stimulation value of -2.87. This is indicative of the success of the frac job and the possibility of creating/ opening more fractures in the zone in question. Zones 6 (and 5, 8) has shown a decrease in skin compared to the pre-stimulation. This could be due to damage around the wellbore as a result of the stimulation job, or it could be indicative of the presence of a barrier hindering the build-up process. Such is the case for Zones 5 and 8 where a sand problem was encountered during the clean-up process following the shut-in period for Zones 5 and 8.

5.3 Productivity Improvement

As a result of the different frac jobs in the various zones, the production per zone(s) was enhanced. This improvement in production could be correlated with the increase in permeability or the formation flow capacity and/or the more negative skin values. A combination of these factors shall accurately explain the improvement in production.

5.3.1 Permeability Improvement

A comparison of pre- and post-stimulation permeability values indicates the effectiveness of the different stimulation jobs, and in particular, the N_2 foam/proppant frac job. The pre-stimulation build-up analysis results indicated a permeability value of 0.082 md for the RET #1, whereas Table 5.2.3.1 listed the permeability values per zone based on a 24-hour build-up pressure data history matching. Table 5.3.1.1 summarizes the pre- and post-stimulation permeability results and their improvement ratios. The average improvement ratio based on a pre-stimulation arithmatic average permeability is 3.2, whereas based on a pre-stimulation average permeability of 0.082 md (Horner's), the improvement ratio is 2.58. Therefore, the expected average improvement in productivity should be by a factor of 2.5-3.0 times.

A more realistic improvement ratio could have been determined if a final post-stimulation build-up test was performed on RET #1 with all the zones in communication. But a comparison of pre-stimulation and post-stimulation production improvement with that of permeability improvement ratio indicates a correlation in these ratios.

5.3.2 Skin Factor Improvement

The improvement in skin value is a qualitative measurement of the productivity improvement. In addition, this improvement is indicative of the conditions around the wellbore which is translated into an increase in the surface area contributing to production due to the stimulation process. A negative skin indicates a stimulated wellbore, and hence, a successful stimulation.

In this case the pre-stimulation skin value was estimated at -2.87 due to the geometry of the wellbore (horizontal well), since horizontal wellbores are equivalent to stimulated reservoirs. As indicated in Table 5.2.4.1, the skin values showed an improvement for Zones 1 and 2-3, 4, whereas a decrease in skin from -2.87 to -0.881 was detected in Zones 5 and 8. This could be due to presence of sand in the wellbore or formation damage as a result of the frac job.

TABLE 5.3.1.1

PERMEABILITY IMPROVEMENT RATIOS

ZONE NO.	ZONE LENGTH L (ft)	PRE-STIMULATION PERMEABILITY K pre (md)	POST-STIMULATION PERMEABILITY K post (md)	KL (pre) md-ft	KL (post) md-ft	$\frac{K\ post}{K\ pre}$
1	404	0.031	0.090	12.52	36.36	2.90
2,3,4	599	0.084	0.1505	50.32	90.15	1.79
6	135	0.078	0.1795	10.53	24.23	2.30
5,8	932	0.071	0.310	66.17	288.92	4.40
7	90	0.037	---	3.33	---	--
	= 2160 ft.			= 142.87 md-ft	= 439.66 md-ft	

Average pre-stimulation permeability (md) = $\frac{142.87}{2160}$ = 0.066 md.

Average post-stimulation permeability (md) = $\frac{439.66}{2070}$ = 0.212 md.

Average Ratio Post K/Pre K = 0.212/0.066 = 3.2

It is important to note that an improvement in productivity is measured by a combined improvement in skin and fracture permeability values.

5.3.3 Production Improvement

Results of the pre- and post-stimulation production values are summarized in Table 5.3.3.1. The production improvement ratios indicate poor-to-good improvements in production as a result of the stimulation jobs. A comparison of the permeability improvement ratios to those of production improvement ratios indicates that the permeability is not the only factor that accounts for the increase in production. A combination of permeability and skin improvements will contribute to the increase in productivity. A pre-stimulation average production rate was established at 35 mcfpd whereas a post-stimulation production rate (after clean-up) has started above 140 mcfpd to drop to about 90 mcfpd, holding a back pressure of 50 psia. These values could be translated as saying that based on production, the improvement ratio is 2.6:1. Furthermore, by checking the post-stimulation production rates, one can predict that the well will produce at a rate of 150 mcfpd, but in reality, it is producing at a rate of 90 mcfpd. This can lead us to conclude that communication between the several zones does exist. In addition, the well as yet is not completely cleaned up, and stabilized production may still change.

5.4 Production Projections

5.4.1 Initial Reservoir Analysis and Production Projections

Prior to drilling RET #1 and during the site selection process, a reservoir simulation study was conducted using G3DFR, a three dimensional dual porosity reservoir simulator, to predict the 20-year cumulative production history and the performance of a horizontal well (RET #1) to that of a vertical well at the same location.

TABLE 5.3.3.1

PRODUCTION IMPROVEMENT RATIOS

ZONE NUMBER	q_{avg} PRE-STIMULATION (mcfd)	q_{avg} POST-STIMULATION (mcfd)	q_{post}/q_{pre} PRODUCTION IMPROVEMENT RATIO	PERMEABILITY IMPROVEMENT RATIO
6 (Data Frac)	2.2	10.7	5.0	2.3
1 (N_2-gas)	2.2	9.0	4.1	1.5
1 (CO_2-liquid)	2.2	55.0	25.0	1.56
1 (N_2-foam proppant)	2.2	29.0	13.0	3.0
2-3, 4	21.0	62.2	3.0	2.0
5, 8	9.6	50.0	5.2	4.5

q_{avg} = Average production rate.

For this study, we assumed a producing thickness of 160 feet, an initial average reservoir pressure (at the time of drilling) of 375 psia, a fracture permeability of 0.125 md, and an anisotropy ratio R = 1:1 (where R = Kx :Ky); a 20-year cumulative production case for an unstimulated well was projected at 502 mmcf by G3DFR, whereas the simulator projected 835 mmcf 20-year cumulative production for a stimulated case. Analysis and results of this study are summarized in SPE Paper No. 16411.

In addition, G3DFR was used to project an initial open flow potential (IOFP), prior to stimulation, equivalent to 126 mcfpd at a reservoir pressure of 375 psia.

5.4.2 Projection of RET #1 Production Before Stimulation and Testing

As mentioned earlier, G3DFR projected an IOFP of 126 mcfpd at 375 psia compared to actual production prior to stimulation of 35 mcfpd at a tested average reservoir pressure of 183 psia. This difference in the production rates is mainly due to the pressure difference. Furthermore, a formation flow capacity (Kh) of 20 md-ft was used in the simulation process whereas a Kh value of 19 md-ft was estimated from the pre-stimulation pressure build-up analysis performed on RET #1.

5.4.3 Projections of Production After Stimulation

G3DFR was implemented to predict/project a 20-year history of production based on estimated values of reservoir pressure, formation thickness, and average permeability. The average reservoir pressure and formation thickness were kept constant at 182 psia and 247 feet respectively due to the fact that geologic and engineering data were sufficient to accurately estimate these values. A post-stimulation permeability value for RET #1 remained unknown since a final build-up test was not conducted on the entire well when all the zones were in communication.

On the other hand, an arithmatic average post-stimulation permeability was calculated to be 0.200 md assuming an anisotropy ratio of 1:1 (R = kx:ky). A 20-year cumulative production history was projected using G3DFR, as shown in Table 5.4.1. The first yearly rate was estimated at 145 mcfpd and a cumulative production of 61,300 mcf was projected. The actual average daily rate after 2 months of production was 90 mcfd as shown in Figure 5.4.1). G3DFR was used to match the average production rate for the first year by varying the average post-stimulation permeability value. Values of 0.15 and 0.10 md were used, and a summary of the results are shown in Tables 5.4.2 and 5.4.3, assuming an anisotropy ratio R = 1:1 (where R = kx:ky).

It is believed that a permeability value of 0.1 md is representative of the formation's permeability. When R = 1:1, the first year's average production rate was projected at 83 mcfd, when R = 1:2 (Kx:Ky), the first year's average production rate is projected at 97 mcfd. Plots of cumulative production versus time for different anisotropy ratios are shown in Figure 5.4.2. In addition, a plot of the 20-year projected production rate versus time is shown in Figure 5.4.3.

It is reasonable to assume that a permeability anisotropy ratio of 1:2 (Kx:Ky) is valid since the average anisotropy ratio in the area was estimated at 1:5 ratio. It is important to mention that the direction is parallel to the direction of the 2160 feet wellbore whereas the Y-direction (fracture direction) is orthogonal to the horizontal wellbore.

The validity of the analysis depends on the accuracy of the average fracture permeability and the producing formation thickness values. Assuming all other reservoir properties are accurate and constant, a decrease in formation thickness will increase the anisotropy ratio in order to maintain a match of the actual production (fracture permeability remains constant). In reality, the formation thickness remains constant and the fracture permeability changes. This is obvious since fracture density and spacing varies along the length of the wellbore and undoubtedly throughout the reservoir.

TABLE 5.4.1

10-YEAR PROJECTED PRODUCTION HISTORY RET #1
K = 0.2 md   R (Kx:Ky) = 1:1

TIME (years)	RATE (mcfd)	CUMULATIVE PRODUCTION (mcf)
1	145	61,248
2	127	109,904
5	100	232,400
10	80	394,232

TABLE 5.4.2

10-YEAR PROJECTED PRODUCTION HISTORY RET#1
K = 0.15 md   R (Kx:Ky) = 1:1

TIME (years)	RATE (mcfd)	CUMULATIVE PRODUCTION (mcf)
1	116	47,950
2	102	86,712
5	82	185,830
10	67	319,620

TABLE 5.4.3
20-YEAR PROJECTED PRODUCTION HISTORY RET #1
K = 0.10 md   R (Kx:Ky) = 1:1

TIME (years)	RATE (mcfd)	CUMULATIVE PRODUCTION (mcf)
1	83	33,790
2	74	61,680
5	61	134,460
10	51	234,948
15	45	321,940
20	41	400,000

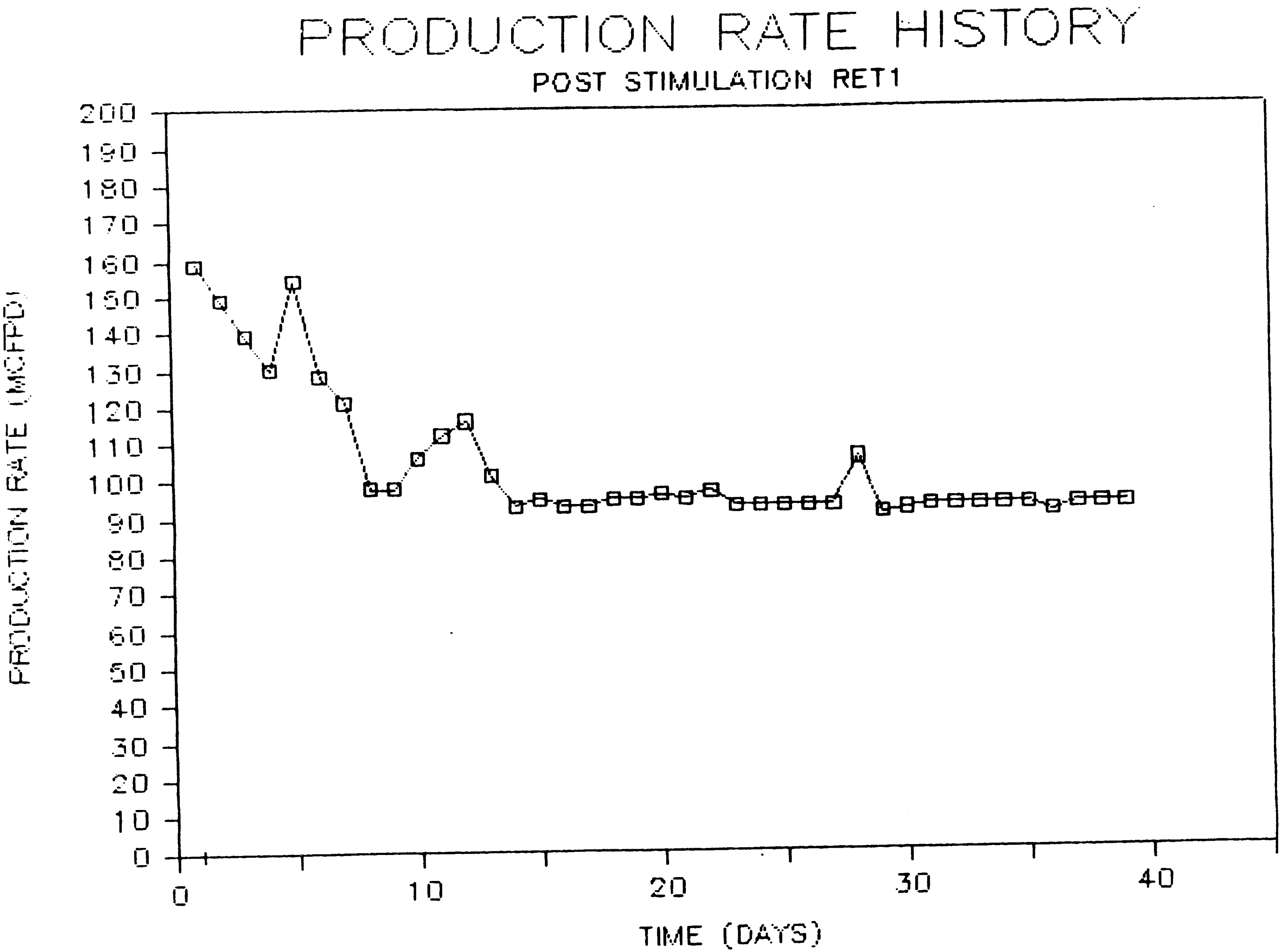


Figure 5.4.1: Plot of Production Rate versus Days on Production for All Zones in the Well after Final Stimulation

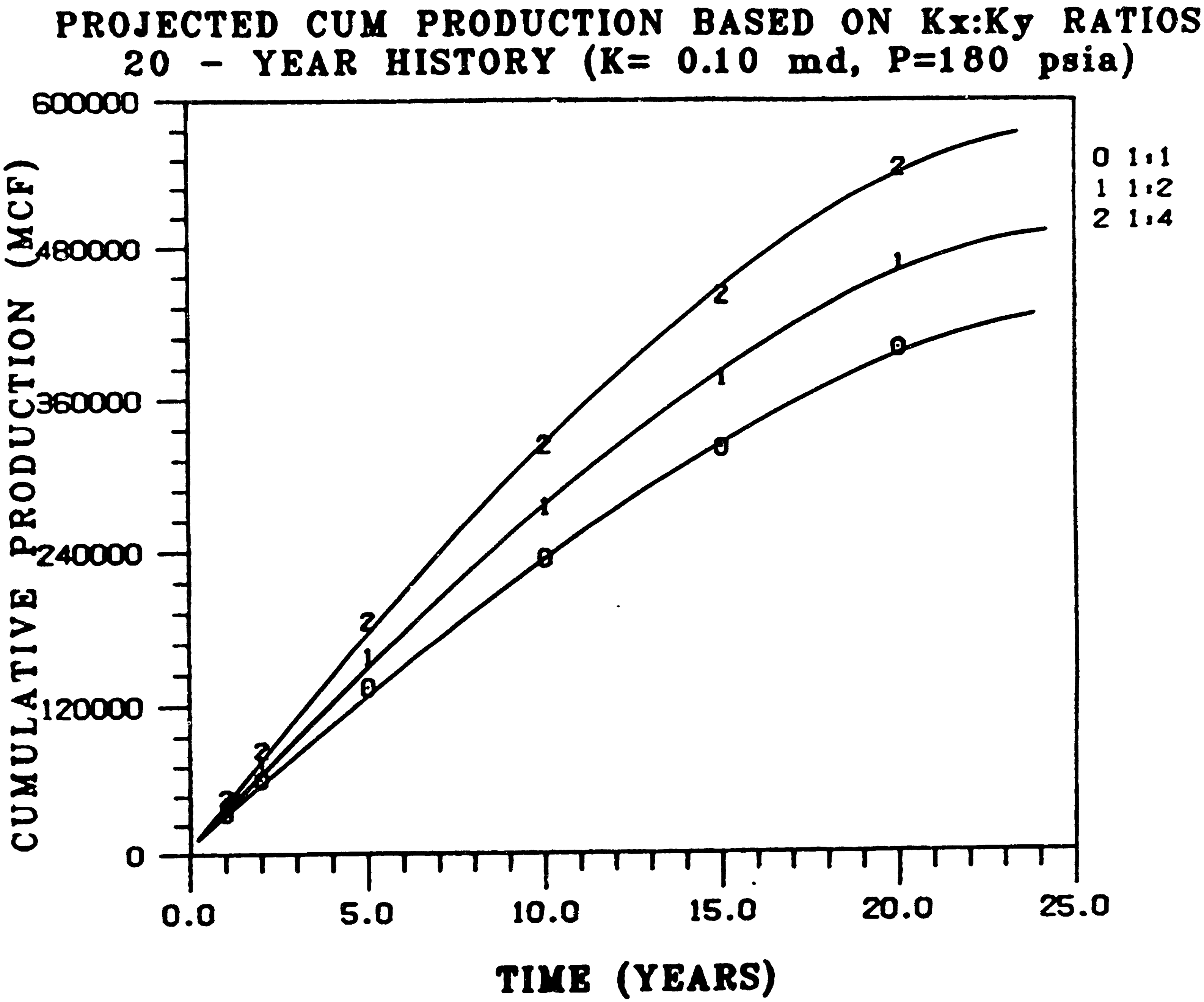


Figure 5.4.2: Projected Cumulative Production from the Well as a Function of Various Permeability Anisotropy Ratios

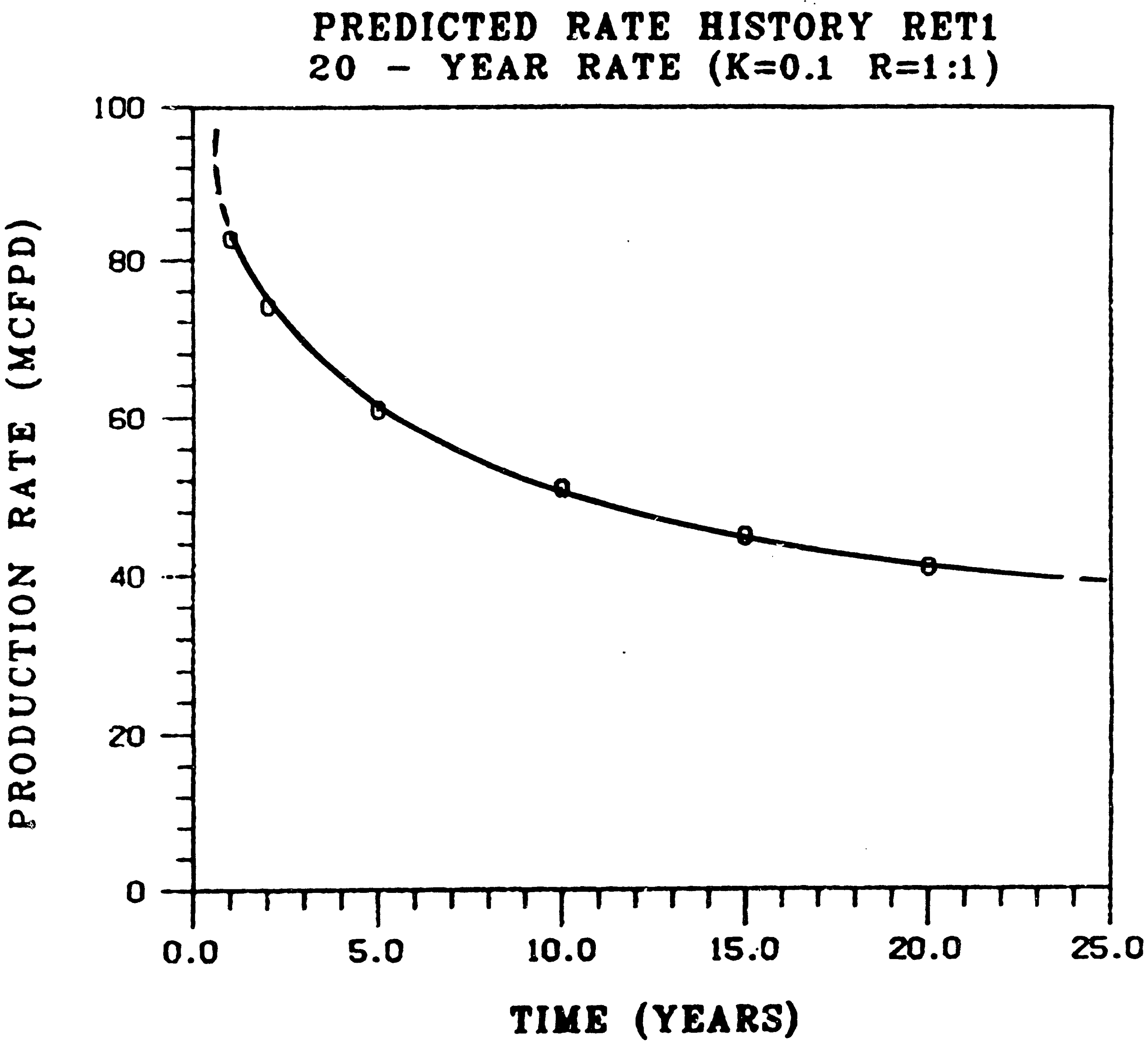


Figure 5.4.3: Predicted Production Rate Decline over a 20-year Period Based on 1:1 Permeability Anisotropy and 0.1 md Permeability

5.4.4 Comparison of Pre- and Post-Stimulation Well Projections

The various stimulation jobs on RET #1 has improved the productivity of the well by improving the fracture permeability and increasing the surface area contributing to production. Pre-stimulation analysis via build-up/drawdown tests indicated an average flow rate of 35 mcfpd, a fracture permeability of 0.082 md, and a skin value of -2.87. Post stimulation analysis has shown an improvement in the average fracture permeability and the skin value. Post stimulation production rate, after cleanup, started at 160 mcfpd and stabilized at a rate of 90 mcfpd, indicating an improvement ratio of approximately 2.6:1 based on actual production rates.

Post stimulation permeability value was calculated based on the arithmatic average of the different permeabilities for the various stimulated zones. An average arithmatic permeability value was determined at 0.20 md indicating an improvement ratio of 2.5:1. This permeability improvement ratio correlates with the production improvement ratio. Furthermore, improvement ratios based on early flow rates from separate zones indicated an average improvement of 9:1. This is mainly based on early production rates. For example, Zone 1 shows a pre-stimulation rate of 2.2 mcfpd; with N_2 frac and after 10 days the improvement ratio is 4:1, with CO_2 frac the improvement ratio is 30:1; and with N_2-foam proppant the improvement ratio is 15:1. These improvement ratios as indicated earlier were not sustained due to the drop in the post stimulation production rates. However, these ratios assisted in evaluating the various frac jobs and their effect on Devonian shale's production. It is important to mention that the summation of the post stimulation production rates from the different zones was higher than that of the final post stimulation production rates for RET #1. This indicates that communiation between the various zones does exist. In addition, a post stimulation value of 0.2 md used to project a 20-year production history via reservoir simulation showed higher rates compared to the actual current production rate. This observation indicates that either the post stimulation value was higher than actual, or the well has not reached the stabilized production rate and more cleaning up is needed.

As mentioned earlier, a post stimulation build-up test where all the zones were in communication, was not performed in order to estimate the final vlaues of permeability and skin. It is recommended for future studies that a final build-up/drawdown test be performed to enhance the accuracy of the results and hence predict a more accurate production history performance.

6.0 ECONOMIC ANALYSIS

The purpose of this project was to determine the recovery efficiency of a horizontal well when compared with a vertical well, both natural and stimulated production. BDMESC was successful in demonstrating that a horizontal well could be drilled and successfully stimulated five times.

6.1 Economic Projections

A review and analysis of the production projections for the well in light of the costs of this well, which was a research well, would not be very meaningful. There are many costs encumbered in a research well which would not be encumbered in a commercial well. Therefore, BDMESC compiled a set of costs which excluded the research costs as a baseline for projecting economics based on this well. Table 6.1.1 lists the major cost elements and their costs for the RET #1 had it been a commercial well.

An analysis of the first 2-1/2 months of production from the well is not much basis for projection, considering that production is declining rather abruptly and we are not sure where it will stabilize; however, some projection must be made.

The G3DFR model which was used to evaluate the potential production from the location prior to drilling the Recovery Efficiency Test No. 1 well was also used to predict production of the well after drilling and stimulation was completed. Figure 6.1.1 projects 20 year cumulative production for the RET #1 well utilizing developed parameters from well testing of 180 psia pressure. Using the full reservoir thickness of 247 feet as productive reservoir, we found that we had to reduce the permeability to an average of 0.09 md to match the current rate of production. This indicates that there are most likely heterogenities in the fracture system and that the flow path to the wellbore is not consistent. It is likely that the fracture permeability changes with time as fractures slowly close as pressure declines with production. This would seem to be one argument in favor of holding a back pressure on the formation during production.

TABLE 6.1.1

PROJECTED COSTS FOR A COMMERCIAL RET NO. 1 WELL

ITEM	1986 RET #1 COST	1988 PROJECTED COSTS
Drill Rig	$ 277,920	$ 219,310
Directional Services	169,912	83,243
Other Direct Costs	96,349	61,835
Logging	41,248	28,600
Casing and Completion Equipment	145,223	119,184
Cementing	10,998	16,400
Stimulation	283,826	220,000
TOTAL COSTS:	$ 1,025,476	$ 748,572*

* Costs for a 6000 foot well drilled at 8°/100' rate of angle build over a period of 35 days and 4 frac jobs being conducted on the well.

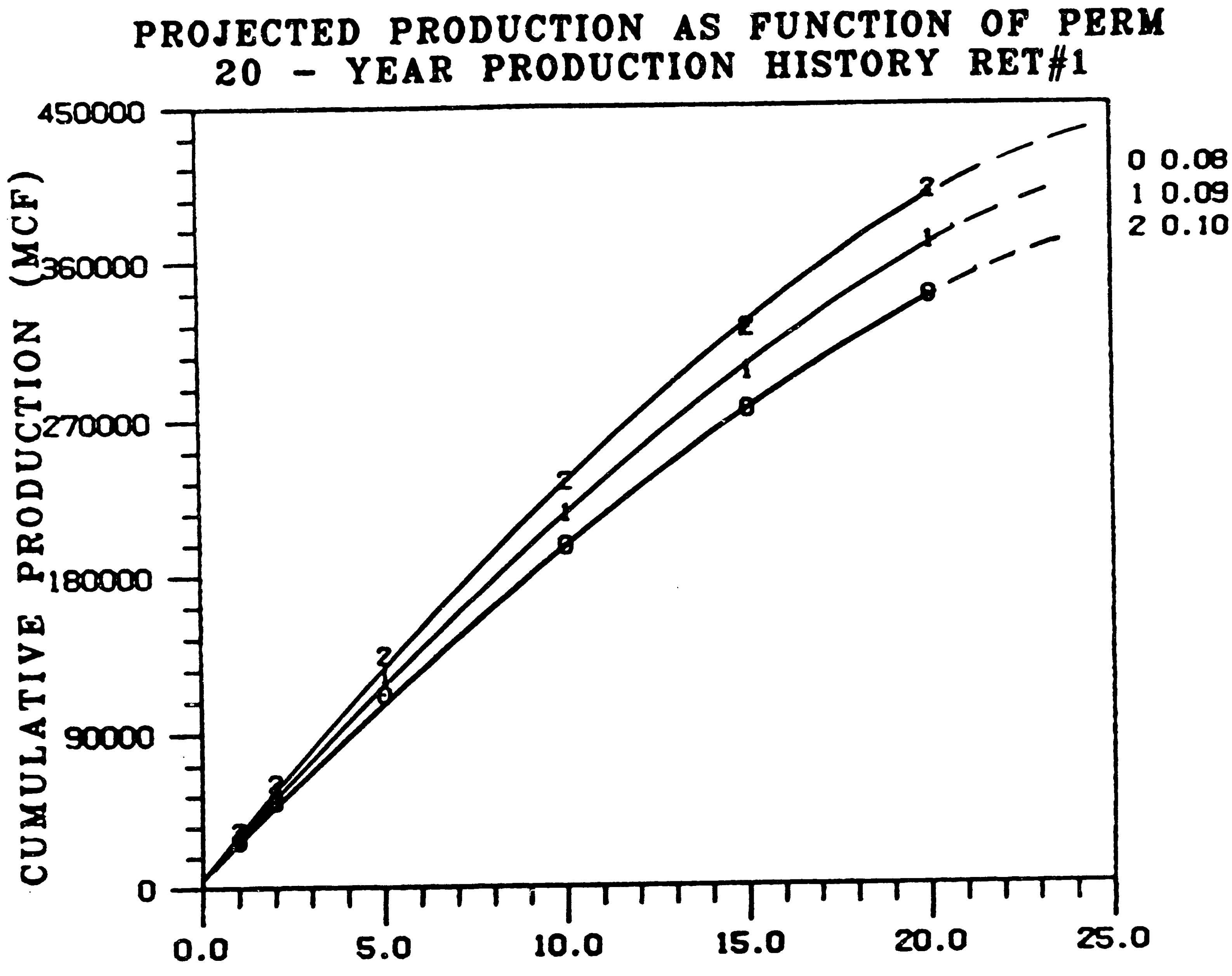


Figure 6.1.1: Projected Production as a Function of a Narrow Range of Permeabilities Believed to be Close to Actual Conditions for the RET #1 Well

Figure 6.1.2 compares the final projected production and decline curve with the pre-drilling estimate. The difference in the projections was primarily the difference in pressures used. The pre-drilling model used 350 psi reservoir pressure while the post-drilling projection used 180 psia. Pre-drilling model studies also projected a vertical well, drilled at the site where the horizontal well was drilled, would produce 88 mmcf in 20 years. This comparison indicates the horizontal well should produce 4.2 times more gas than a vertical well drilled at the same location.

The RET #1 well, which was a research well, cost 5.2 times the cost of a vertical well drilled in the area, and therefore, will not be an economic well since it will produce only 4.2 times the production. However, as the technology improves and matures, we believe economics will continue to improve. Planning a well as a commercial well without any research costs similar to the RET #1 can be drilled for considerably less costs as shown in Table 6.1.1. The costs for a commercial well drilled in 1988 would cost 3.84 times a vertical well and using the same 4.2:1 ratio, would be an economic well.

Considering the decline curve projected in Figure 6.1.2, if the first year's production is 35,000 mcf of gas and an inclined or nearly horizontal well can be drilled and placed in production for the costs presented in Table 6.1.2, and considering the equity investment in the well and cost of borrowing money, then the internal rates of return (IRR) are calculated. The presentation in this table points out that the well must produce gas at a higher initial rate than 35 million cubic feet annually or else the price of gas must be higher to make an acceptable rate of return. If the initial production for the well is doubled to 70 million and the price of gas is $2.00/mcf, then the IRR is presented in Table 6.1.3.

PRE and POST DRILLING PRODUCTION PREDICTION

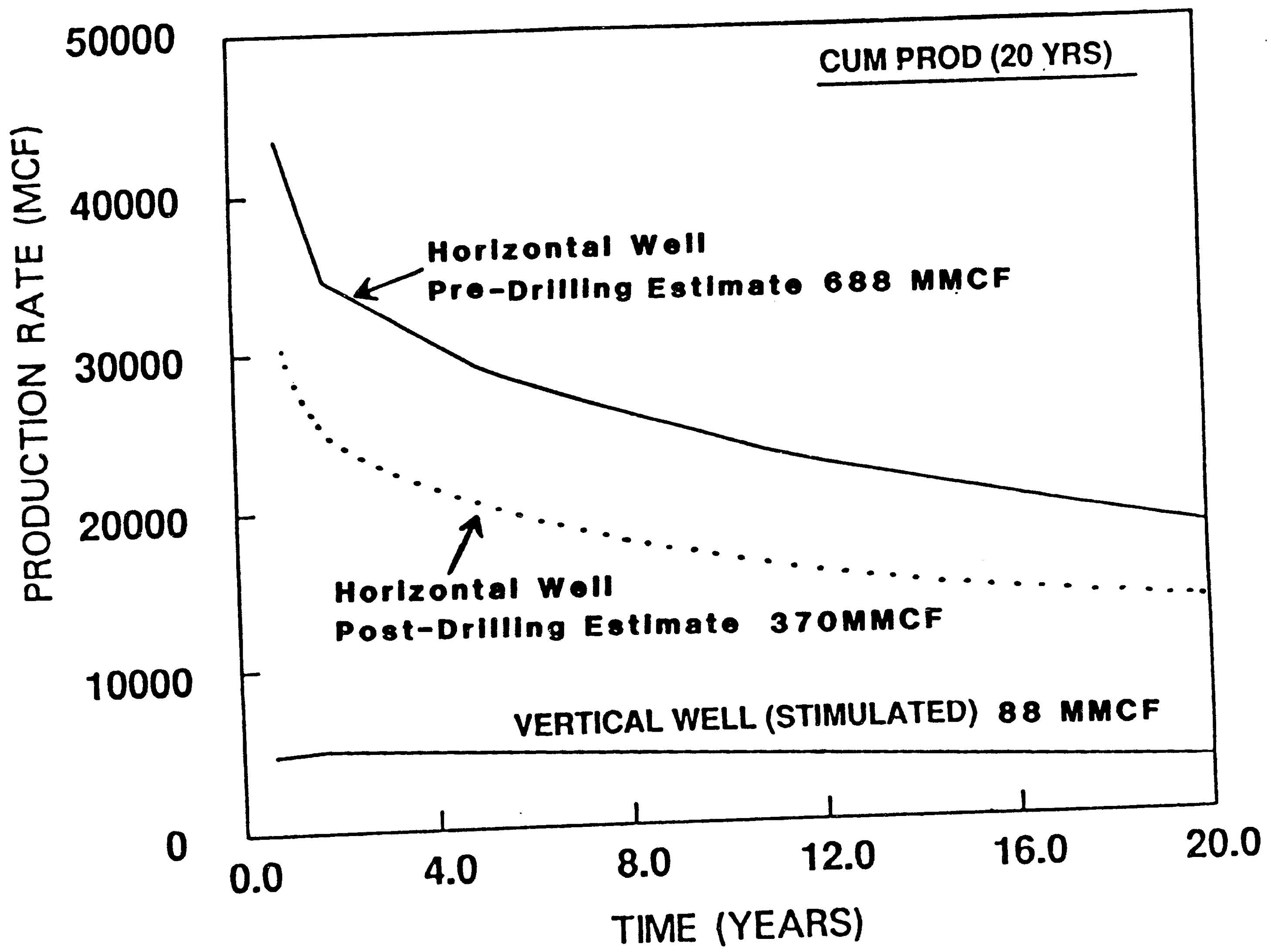


Figure 6.1.2: Comparison of Predicted Production Rates and Cumulative Production Using G3DFR Simulator Before and After Drilling the Well

TABLE 6.1.2

CALCULATED INTERNAL RATES OF RETURN FOR INCLINED OR HORIZONTAL WELLS AT VARIOUS COSTS AND PRICES (ASSUMING THE WELL PRODUCES 35 mmcf THE FIRST YEAR)

PRICE OF GAS @ $2.00/mcf

INVESTMENT	EQUITY	COST-OF-MONEY	IRR (before tax)
$400K	100%	---	6.78
"	50%	10%	5.63
"	50%	10%	4.93
$500K	100%	---	3.63
"	50%	10%	1.61
"	50%	12%	1.00
$600K	100%	---	1.36
"	50%	10%	-1.15
"	50%	12%	-1.71

PRICE OF GAS @ $3.00/mcf

INVESTMENT	EQUITY	COST-OF-MONEY	IRR (before tax)
$600K	100%	---	7.11
"	50%	10%	6.06
"	50%	12%	5.36
$700K	100%	---	4.86
"	50%	10%	3.15
"	50%	12%	2.52
$800K	100%	---	3.08
"	50%	10%	0.94
"	50%	12%	0.35

PRICE OF GAS @ $5.00/mcf

INVESTMENT	EQUITY	COST-OF-MONEY	IRR (before tax)
$700K	100%	---	13.75
"	50%	10%	15.53
"	50%	12%	14.58
$850K	100%	---	10.06
"	50%	10%	10.08
"	50%	12%	9.27
$1000K	100%	---	7.37
"	50%	10%	6.41
"	50%	12%	5.70

TABLE 6.1.3

CALCULATED RATE OF RETURN FOR A WELL THAT PRODUCES
70 mmcf AT A PRICE OF $2.00/mcf

INVESTMENT	EQUITY	COST-OF-MONEY	IRR (before tax)
$650K	100%	---	10.76
"	50%	10%	11.08
"	50%	12%	10.24
$750K	100%	---	8.29
"	50%	10%	7.65
"	50%	12%	6.91
$850K	100%	---	6.35
"	50%	10%	5.07
"	50%	12%	4.39
$900K	100%	---	5.52
"	50%	10%	4.00
"	50%	12%	3.34
$950K	100%	---	4.76
"	50%	10%	3.03
"	50%	12%	2.40
$1000K	100%	---	4.06
"	50%	10%	2.17
"	50%	12%	1.55

6.2 Comparative Costs for Directionally Inclined Wells versus Vertical Wells

The DOE/BDM/Eneger horizontal well cost \$170.00 per foot to drill and complete when only necessary third-party costs are considered. Presently BDMESC believes that by doubling the turning rate and effecting other savings, those costs for a horizontal well can be reduced to \$100 to \$110 per foot.

Using the same data, we calculate that a well inclined to 70° can be drilled for \$88 per foot. So there is not much difference in cost between a 70° inclined hole and a well drilled out to 90°. According to our estimates, a 6000 foot vertical well can be drilled, completed, and placed in production in the Appalachian Basin for \$30 per foot.

Based on these costs, Table 6.2.1 compares the costs and average annual production rate required to pay the wells out in 3, 4, and 5 years based on costs of \$2.00, \$2.50, and \$3.00 per mcf price for gas. A return on investment of 10% is also included in the estimate. Eighty-seven and one-half (87-1/2) percent is the assumed net revenue interest that will go to reduce debt and pay operations expenses. Generally this table indicates that horizontal wells should be drilled in areas where good reservoir pressure and production is likely to be found.

TABLE 6.2.1

PROJECTION OF FIRST YEAR PRODUCTION REQUIREMENTS NEEDED TO PAY OUT COST OF HORIZONTAL OR INCLINED WELL IN 3, 4, OR 5 YEARS BASED ON DECLINE CURVES PROJECTED FOR RET NO. 1 WELL

		BASED ON \$2.00/mcf + 10% ROI (mcf)			BASED ON \$2.50/mcf + 10% ROI (mcf)			BASED ON \$3.00/mcf + 10% ROI (mcf)		
6500' WELL	ESTIMATED COST (\$)	3 yrs	4 yrs	5 yrs	3 yrs	4 yrs	5 yrs	3 yrs	4 yrs	5 yrs
Inclined to 70°	575,000	134,162	109,250	94,312	107,330	87,400	75,450	89,406	72,804	62,850
Inclined to 90°	715,000	166,265	135,337	116,682	133,012	108,270	93,345	110,800	90,190	77,756
Vertical	195,000	46,988	38,608	33,568	37,590	30,887	26,854	31,312	25,730	22,370

7.0 SUMMARY OF RESULTS

7.1 Phase I Operations

During Phase I operations, a basin analysis of geologic and engineering factors controlling production was conducted to determine which geologic province would provide the best opportunity to drill a horizontal well that would encounter a significant number of natural fractures and subsequently good gas production.

The area selected was Cabel, Wayne and Lincoln Counties, West Virginia. Site selection studies conducted in these three counties led to the selection of a site in Lincoln District, Wayne County, owned by Cabot Oil and Gas Company. Cabot agreed to cooperate with BDM and DOE in making acreage and production and geologic data available for use in the project.

Remote sensing studies of the lease located lineaments which were oriented parallel or subparallel to regional joint trends and the validity of these lineaments was confirmed by resistivity surveys across the mapped lineaments. Three potential locations were submitted with recommendations for approval of one to DOE. The final location and orientation was selected by DOE.

A computer program was obtained that was used in sizing the rig and assisting in other phases of the well-planning operations. The original proposal to drill a small diameter hole and then ream it out was abandoned in favor of the more cost-effective plan of using large diameter drilling tools which had more stable drilling characteristics. The plan as revised and approved by DOE was to drill at a constant 4.5°/ 100' rate of angle build using downhole motors and air-mist drilling liquid to an 85 degree inclination, then set a hole protection string to insure that we did not lose the hole completed to that point. The plan was then to drill out of the casing to the target 90° inclination, then take 90 feet of oriented core before drilling the balance of a 2000-foot long horizontal section and logging the well.

Actual drilling operations went pretty much as planned until we reached a depth of 3459 feet and stuck the drill string while reaming the hole. We used a shot inside the drill string to back off of the 2 collars, bit and reamers, picked up a set of hydraulic jars and tried to work the drill string loose for 12 hours before deciding the sidetrack the hole. We pulled back up to 3200 feet and cemented the old hole and kicked off again. On the second try we built angle too quickly and was going to come in about 20 feet higher than the target zone and elected to sidetrack again to be able to hit the target zone when we had reached 3600 feet.

After the sidetrack which was accomplished again at 3200 feet, drilling proceeded on the planned trajectory, but at an inclination of 74 degrees, we were having so much problem with lifting the cuttings out of the hole that we decided to set the hole protection string at that point and then proceed. The 8-5/8 inch hole protection string was cemented at a depth of 3803 feet and conventional rotary drilling tools were employed to drill the remaining 16 degrees of inclination.

When we had reached 90 degrees inclination, three core barrels of oriented core was obtained. Two were drilled; one after the other, then we drilled ahead 100 feet before taking the last 30 feet of core. In the last core run we cut a fault zone and obtained complete core of the faults and associated fractures which was about 2 feet wide. This was the first air-drilled rotary core ever taken in a horizontal well.

When drilling operations resumed after coring, a slight building BHA was used to offset the effects of gravity, and the well was allowed to drop at the rate of 1/4 degree per 100 feet. This was maintained until the entire 2000 feet of horizontal section was completed. When completed on December 18, 1986, this was the longest air-drilled horizontal well in both the United States and the world.

When total measured depth (TMD) of 6020 feet was reached, the hole was logged by Dresser Atlas by pushing tools in on the drill string. Gamma ray, density, dual induction, caliper and temperature logs were run on two logging runs. A third logging run was made with a borehole television camera attached. This was the first time a TV camera was used to log a horizontal well (and quite successfully). More than 200 wellbore fractures were detected and oriented after extensive analysis of the log and development of an analytical technique which was tested with surface models and jigs.

After the logging operations were completed, the logs were examined to select the locations of the external casing packers (ECPs) and the port collars which would make up the unique "open hole" type completion, also a first-ever for a horizontal well.

The external casing packers and ported collars were installed in the 4-1/2 inch casing string to a total measured depth of 6017 feet. The well was then open-flow tested for 3 months before the ECPs were inflated and pressure tested. Seven of the eight ECPs installed functioned properly and we had successfully partitioned the well into 7 intervals varying from 91 feet to 649 feet in length. Each zone was subjected to a pressure build-up and flow test and permeability of each zone was calculated and skin factor determined for the entire well.

This completed the world-record-setting Phase I operations of the Recovery Efficiency Test.

7.2 Summary of Phase II Operations

Phase II operations began with preparation of a stimulation rationale and plan which included conducting an initial "mini frac" to obtain data for stimulation design. BDM had proposed to conduct 4 stimulations in the well and then to evaluate those and make recommendations for any additional stimulations that might be required. A rationale was developed and approved which examined fluid types (gases, liquids, foams) injected volumes (low vs high), and injection rates (low vs high) over the four stimulations planned and an evaluation and final major frac job on the balance of the well.

The mini-frac data revealed that we had a lower than anticipated fracture gradient and fracture closure pressure. Closure pressure of 850 and 1050 were determined for Zone 6 where the test was conducted. Later on, when Zone 1 was stimulated, a lower closure pressure of 760 psi was measured. The detection of multiple closure pressures was considered prima facie evidence that multiple natural fractures had been inflated which was a primary goal of the completion (open-hole) program and stimulation program (low injection rates).

The first stimulation was conducted in Zone 1 and was a nitrogen gas frac without proppant injected at low rates to inflate the 69 or so natural fractures detected on the borehole TV camera. Collection of bottomhole pressure data during and after the frac job indicated 3 separate closure pressures in Zone 1 which BDM interpreted to be due to fractures with different orientations with respect to present principal stress orientation. Flowing to clean up the gas and subsequent pressure build-up and drawdown tests revealed that the fractures opened up during the low injection rate, stimulation all closed up within 22 days and the zone returned to its original pre-frac production rate. This left us with the first major finding of Phase II, which was that nearly stress relieved reservoirs required proppant in fractures to maintain production conduits. This resulted in a revision of the test plan rationale to take advantage of the unique opportunity to conduct three stimulations using different fluids and different diagnostics experiments using tiltmeters to detect the orientation of induced fractures failed because of installation problems which could not be rectified.

The second stimulation in Zone No. 1 was a liquid CO_2 fluid pumped at 10 and 20 bbls/minute and using two different radioactive tracers to determine where the fractures were exiting the borehole. Evaluation of the tracer logs revealed that CO_2 was a very efficient frac fluid and had interconnected 16 natural fractures in Zone 1 with natural fractures in adjacent Zones 2-3 and 4. It was determined that higher injection rates tend to cluster fractures and that injection points moved up and down the wellbore as stresses from fluid loading of the fractures built up and caused shifting to areas of lower stresses. Again a rapid decline of production rate from 50 mcfpd back to the original 2.2 mcfpd in 40 days indicated the need for proppant.

The indications of fracture communications was tested by conducting a series of pressure build-up and drawdown tests in each of the zones. In addition, gas samples were collected from each zone and analysis revealed that Zones 2-3 and 4 which had not been stimulated contained CO_2 and NO_2 contents at 10 to 30 times the normal concentrations thus clearly demonstrating that fractures exited the wellbore in Zone 1 and came back to the wellbore in Zones 2-3 and 4.

The third stimulation in Zone No. 1 was a low volume, low rate nitrogen foam frac with sand proppant to keep inflated fractures propped open. The volume was 30,000 gallons of foam and 20,000 pounds of sand, but the results were a constant flow rate which showed very little decline in production over a period of 40 days. The interconnection of fractures in Zone 1 with Zones 2-3 and 4 were demonstrated when Zones 2-3, 4, 5, 6, and 8 were opened to flow while Zone 1 was flowing and the production rate dropped from 35 mcfpd to 20 mcfpd and then stabilizing at 25 mcfpd or 70 percent of the original flow rate. This is the first documented zone interference testing ever conducted in a horizontal well. The fracture diagnostics tests which showed multiple hydraulic fractures being propagated during a single pumping event is also a world's first demonstration. This is also believed to be the first use of radioactive tracers in a horizontal well for fracture diagnostics purposes.

After evaluation of the three stimulations in Zone 1, it was determined to conduct a large volume high rate stimulation in Zones 2-3 and 4 which are the best producing zones in the well. These zones were fraced with 138,000 gallons of foam and 250,000 pounds of sand.

A single radioactive tracer was used in the proppant stage to indicate that 54 fractures were pumped into during the stage. Production was fairly stable at a rate of 62 mcfpd for more than 60 days, but after being shut-in 14 days for a pressure build-up test, production rate declined to 42 mcfpd, a decline of 33 percent. No valid explanation of this behavior was determined by BDM.

The final frac job was conducted in Zones 5 and 8 but with a slightly smaller volume, but at a higher rate. The frac consisting of 105,000 gallons of nitrogen foam and 150,000 pounds of sand was pumped at 50 bbls per minute. Flowback tests after this stimulation revealed a fairly constant rate of 62 mcf for several days before the well was shut-in for a pressure build-up test.

After the build-up test the entire well was placed on production which started out at 155 mcfpd but declined over the next 6 weeks to 90 mcfpd.

Phase II operations concluded successfully when the well was turned over to the operator for production operations. Phase II operations successfully demonstrated the idea of inducing multiple hydraulic fractures from a horizontal wellbore and various methods of testing and cleaning out a horizontal well.

7.3 Publications Resulting from the Recovery Efficiency Test Project Work

Upon completion of the initial drilling operations under Phase I activities, a number of formal publications and oral presentations have been prepared and presented relative to this work. The following is a list of those presentations and publications.

1. Overbey, William K., Jr. "Recovery Efficiency Test", A paper presented at the Eastern Gas Shales Peer Review, February 24-25, 1987, Rockville, MD.

2. Overbey, William K., Jr. "Site Selection Studies, Coring and Logging Operations for a Directional Well Drilled in Lincoln District, Wayne County, West Virginia", A paper presented at the Eighteenth Annual Appalachian Petroleum Geology Symposium, Sheraton Lakeview Conference Center, March 23-26, 1987, Morgantown, WV.

3. Kulander, Byron R. and Stewart L. Dean. "Fractographic Logging for Determination of Natural and Coring-Induced Fractures in the RET #1 Well, Wayne County, West Virginia". Contained in Contract Phase I Activity Report, April 1987; submitted to DOE by BDM Corporation.

4. Yost, A.B. II, W.K. Overbey, Jr., S.P. Salamy, C.O. Okoye, and B.S. Saradji. "Devonian Shale Horizontal Well: Rationale for Wellsite Selection and Well Design", SPE Paper 16410, presented at Denver, Colorado, May 18, 1987.

5. Salamy, S.P., B.S. Saradji, C.O. Okoye, J.D. Mercer, and A.B. Yost II. "Recovery Efficiency Aspects of Horizontal Well Drilling in Devonian Shale", SPE Paper 16411, presented at the SPE/DOE Low Permeability Reservoir Symposium, Denver, Colorado, May, 1987.

6. Overbey, W.K., Jr., R.S. Carden, and J.B. Williams. "Computer Applications in the Planning and Drilling of a 2000-foot Horizontal Well in Wayne County, West Virginia", SPE Paper 16501, presented at the Petroleum Industry Applications of Microcomputers, Montgomery, Texas, June, 1987.

7. Yost, A.B., W.K. Overbey, and R.S. Carden. "Drilling a 2000-foot Horizontal Well in the Devonian Shale", SPE Paper 16681, presented at the SPE 62nd Annual Technical Conference, Dallas, Texas, September, 1987.

8. Overbey, William K., Jr. "Directional Drilling: Rationale for Selection of Targets", presented at 26th Annual Conference, Ontario Petroleum Institute, Toronto, Ontario, Canada, october 25-26, 1987.

9. Overbey, W.K., Jr., L.E. Yost, and A.B. Yost II. "Analysis of Natural Fractures Observed by Video Camera in a Horizontal Well", SPE Paper 17760, presented at SPE Gas Technology Symposium, Dallas, Texas, June, 1988.

10. Mercer, J.D., H.R. Pratt III, and A.B. Yost II. "Infill Drilling using Horizontal Wells: A Field Development Strategy for Tight Fractured Formations", SPE Paper 17727, presented at SPE Gas Technology Symposium, Dallas, Texas, June, 1988.

11. Yost, A.B. II, W.K. Overbey, Jr., D.A. Wilkins, C.D. Locke. "Hydraulic Fracturing of a Horizontal Well in a Naturally-Fractured Reservoir: Case Study for Multiple Fracture Design". SPE Paper 17759, presented at SPE Gas Technology Symposium, Dallas, Texas, June, 1988.

12. Wilkins, D.A., A.B. Yost II, W.K. Overbey, Jr.,. "Unique Completion Practices in a Horizontal Well", presented at Unitar Conference on Petroleum Production, Alberta, Canada, August, 1988.

13. Layne, A.W. and H.J. Sirwardane. "Insights to Hydraulic Fracturing of a Horizontal Well in a Naturally-Fractured Formation", SPE Paper 18255, Houston, Texas, October, 1988.

14. Overbey, W.K., Jr., A.B. Yost II, D.A. Wilkins. "Inducing Multiple Hydraulic Fractures from a Horizontal Wellbore, SPE Paper 18249, presented at 63rd Annual Technical Conference, Houston, Texas, October, 1988.

15. Overbey, W.K., Jr. "Results of Stimulation Conducted on RET #1 Well", Oral presentation given to Eastern Kentucky Society of Petroleum Engineers, Prestonsburg, Kentucky, May 19, 1988.

16. Overbey, W.K., Jr. "Drilling, Completion, and Stimulation Operations on a Horizontal Well in the Devonian Shale", Oral presentation presented to the Tennessee Oil and Gas Association, Crossville, Tennessee, November 17, 1988.

END

DATE
FILMED
4/17/92