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Recovery Efficiency Test Project
Phase I - Activity Report
Volume II: Well Testing and Analysis Data Evaluation and Report Preparation Site Reclamation

Topical Report

W.K. Overbey, Jr.
D.W. Wilkins
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April 1988

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

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

By
The BDM Corporation
Morgantown, West Virginia

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Volume II: Well Testing and Analysis Data Evaluation
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Morgantown, West Virginia 26507-0880

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1199 Van Voorhis Road
Morgantown, West Virginia 26505

April 1988

RECOVERY EFFICIENCY TEST PROJECT
PHASE I - ACTIVITY REPORT
VOLUME II

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1.0 EXECUTIVE SUMMARY

This report is the second volume of the Recovery Efficiency Test Phase I Report of Activities. Volume I covered site selection, well planning, drilling, coring, logging and completion operations. This volume reports on well testing activities, reclamation activities on the drilling site and access roads, and the results of physical and mechanical properties tests on the oriented core material obtained from a horizontal section of the well.

1.1 Well Test and Analysis Results

The purpose in well testing and analysis is to collect data which when analyzed provides the method of measuring the beneficial effects of drilling a horizontal well to intercept the maximum number of natural fractures (pre-stimulation testing) which might be encountered in the Devonian shales. To compare this data with that of the average unstimulated vertical well drilled in the area.

The initial natural open flow rate of the RET #1 well was 119 mcfpd, as measured eight hours after completion of drilling operations and prior to logging and selling of casing which required 72 hours to complete. Upon completion of casing operations on December 18, 1986, the well was shut-in until January 9, 1987 for an initial pressure build-up test. During this period of time the well built up to 135 psig. An open flow test was conducted in which the well was placed into the pipeline and produced against 39 psig line pressure. The well began producing at rates in excess of 120 mcfpd but rapidly declined within 6 days to 24 mcfpd.

The well was allowed to produce over the next 2 months and then another long-term pressure build-up test was conducted. After 28 days the well reached a surface pressure of 140 psig pressure (155 psia). The pressure build-up data was used to calculate bulk formation permeability from the well which was calculated to be 0.082 md. Skin factor for the whole well was calculated to be -2.87, indicating a fractured reservoir. Maximum pressure read by the pressure build-up test some distance from the wellbore was determined to be 182 psia.

Zone-by-zone isolation pressure tests were conducted to determine the differences in permeability of each zone. The results presented in Table 3.7.5.2 ranged from 0.032 to 0.098 md and averaged 0.066 md. The total product of formation thickness (usually designated 'h', but called 'L' in the horizontal well) times permeability was calculated to be 143.726 md/ft. The same product for well #972 located 3000 feet northwest of RET #1, which has produced 1.3 bcf of gas over the past 46 years, was 72 md/ft. This is the basic data describing the condition of the well prior to stimulation operations to be conducted during Phase II.

1.2 Reclamation Activities

A one-hundred sixty (160) foot deep, 20-inch wellbore, which was abandoned because of a lost bit during drilling operations, was plugged according to State of West Virginia Regulations. Within 6 months of completing drilling operations, the surface location and access roads to the RET #1 wellsite were reclaimed according to State Regulations. Additional reclamation work will be required after completion of all stimulation and testing operations on the well.

2.0 INTRODUCTION

Volume II of the Phase I Activity Report is designed to present the results of Recovery Efficiency Test Project Task 8 activities, which are well test and analysis results. In addition, Task 9 (data analysis and reporting) and Task 10 (reclamation activities) are discussed and reported.

2.1 Background

Although a considerable body of information has been generated during the past 10 years concerning well test and analysis of Devonian shale gas wells by DOE under their EGSP Resource Characterization studies, most of this data and the approach was not useful in the present effort, primarily because of the difference in geometry of the wellbore in respect to the reservoir and its natural production trends. In a normal vertical well, an induced hydraulic fracture drainage rate is controlled by the permeability of the matrix feeding into the induced fracture. In the case of the horizontal well, the greatest flow comes from the many natural fractures which are nearly normal to the axis of the wellbore. This is the highest bulk permeability direction in the reservoir.

In addition, when testing and calculating for skin damage, sand piled up in the casing or between the casing and the wellbore which impedes flow to the holes in the port collar, and even sand in the fractures created during stimulation may combine to give odd indications of skin effect. In a sense, we are learning about how to make these measurements and their significance as we proceed with the test and analysis operations.

2.2 Objectives of Well Test and Analysis Activities

The objective of this series of tests is to collect data that will allow us to quantify or measure the effects of the natural fractures encountered by the horizontal wellbore and how this production compares with production which is enhanced by various methods of stimulation.

This series of well tests will provide data that defines the "before stimulation" or natural production condition, of the wellbore and will serve as the base case by which "production improvement" is measured or calculated.

2.2.1 Production Build-up and Drawdown Testing

Production build-up and drawdown tests for each producing zone in the horizontal well will be made to use the curves generated to be able to determine permeability by history matching with the G3DFR simulator. This will provide a benchmark permeability for each zone prior to stimulation and provide a weighted average permeability determination for the entire well.

2.3 Objectives of Reclamation Activities

The objectives of reclamation activities is to comply with all State and Federal Regulations which apply to activities to restore the drilling location area and its access road to conditions required by these regulations. The general objectives will be to properly plug the initial well which was abandoned during drilling operations because of a lost bit in the hole. Another objective will be to test liquids in the drilling pits, treat them according to state-required procedures, dispose of the water by land disposal techniques, and then to cover the pits, restore the area to an acceptable contour, and revegetate the location.

2.4 Objectives of Reporting Activities

The objectives of the reporting activities is to satisfy all of the contract requirements regarding recording and reporting of all activities associated with planning, site selection, drilling, coring, logging, testing, analyzing, stimulating and placing in production the Recovery Efficiency Test No. 1 well.

3.0 WELL TESTING AND ANALYSIS ACTIVITIES

3.1 Background

Following completion of drilling, logging, and installation of the casing and external casing packers in the wellbore during Tasks 5, 6, and 7 of the Recovery Effeciency Test Project on December 19, 1986, the Well Test and Analysis Task (Task 8) was initiated. The first activity was to shut the well in for a 10-day pressure build-up test, then to flow the well to obtain data on the natural initial open flow rates. The well was to be produced for a period of time to clean dust and drill cuttings out of the fractures and to allow time for the preparation of plans for test and analysis operations. This was a unique opportunity since no one had ever drilled and completed a horizontal well in which the completion was to be open-hole sections isolated by external casing packers, in order that zones with differing natural fracture spacing could be tested individually.

3.2 Planning of Well Testing and Analysis Activities

3.2.1 Introduction

The purpose of Task 8 of the Recovery Efficiency Test Project was to analyze the natural open-flow production rate of the well and establish a data base relative to reservoir pressure and flow rates for comparison with results of subsequent stimulation tests which might be conducted. These plans were developed to obtain the required data to properly analyze the well and to meet the requirements of the contract.

3.2.2 Detailed Plans for Conducting Task 8 of the Recovery Efficiency Test Project

Task 8 is broken up into six (6) subtasks. Plans for each subtask are presented.

3.2.2.1 Plan Reservoir Test and Analysis Program

An examination of the data requirements as outlined by the contract Statement of Work were examined and the following requirements were identified:

1) Single (whole) well open flow capacity.
2) Single well flow capacity at fixed choke and back pressures.
3) Zone pressures (stabilized pressure or projected pressure for each isolated zone).
4) Zone fracture permeability.
5) Zone fracture porosity.
6) Zone skin factor.

The above data requirements became the objective of the planning activities. It immediately became obvious that to obtain data that would be useful in the SUGAR-MD model would require more time than was originally planned in the original proposal. Grace, Shursen, Moore and Associates are assisting with the planning operations. It is anticipated that Rahj Raghaven will review the plans.

The following subtasks are the plan for obtaining the required data.

3.2.2.2 Subtask 2 - Determine the Rate of Gas Production from the Well

3.2.2.2.1 Pressure Test

The first bit of data to be collected from the well is a whole-well 7-day pressure build-up test. This data was collected from December 19-27, 1986, using a static pressure gauge on the well. The pressure recorded was 135 psig.

3.2.2.2.2 Production Rate Test

BDM plans to conduct a four-point production rate test. The combined zones will be flow-tested as follows:

A. The well will be shut-in for 48 hours against a recording pressure meter. Pressure will be recorded and the well will be opened to flow through.

B. Flow-test with 1/16", 1/8", 3/16", 1/4" choke setting through a 3/8" orifice plate until stabilized flow is reached at line pressure. Rates and pressures will be recorded on a 24-hour chart.

C. Flow-test with 1/16", 1/8", 1/4", 3/8" choke settings through a 1/4" orifice plate until stabilized flow is reached at line pressure for each setting. We project that it will only take a few days at each setting with the longest period at 1/8" projected at three weeks. We will be trying to determine what the proper choke and orifice settings are to obtain the maximum efficient production rate. We project a need to hold 40 to 50% of total reservoir pressure as back pressure.

D. We plan to let the well produce with some back pressure for three weeks until flow is stabilized; four weeks if not stabilized. Unless DOE has a special requirement, we will not conduct flow tests longer than four weeks under these conditions.

3.2.2.3 Subtask 3 - Inflate ECPs and Test Zone Isolation Integrity

3.2.2.3.1 General Information

(1) There are fourteen (14) port collars, eight (8) external casing packers, and one (1) CTC cementing packer located in the 4-1/2" casing string. The location of each is shown in both Figure 3.2.1 and Table 3.2.1. The port collars are Halliburton FO Multiple Stage Cementers and the external casing packers are Lynes ECPs sold by Baker Oil Tools (see attached). The CTC cementing packer will be used only if the external casing packers all fail to test. A brief description of the CTC packer is given at the end of the proposed procedures.

(2) Nitrogen (N_2) will be used to test all of the ECPs so as not to put any fluids on the formation.

Completion Configuration

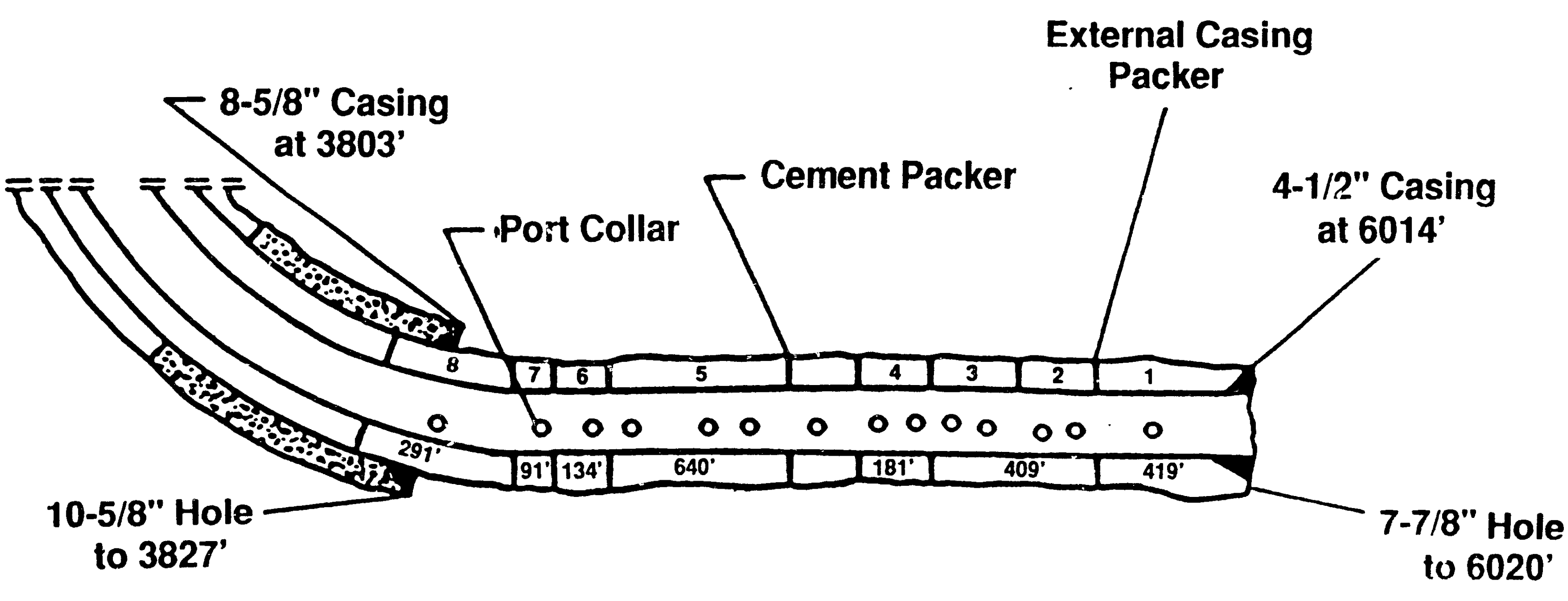


Figure 3.2.1

MEASURED DEPTH OF PORT COLLARS, EXTERNAL CASING PACKERS, AND DESIGNATION IN ILLUSTRATIONS

TABLE 3.2.1

(1) ITEM	(2) COLLAR DEPTH	(3) ITEM DEPTH MINUS PREVIOUS ITEM DEPTH	(4) NOMENCLATURE USED IN DRAWINGS FOR COLUMN (3)
Baker Guide Shoe	6013.12	-	-
Port Collar #1	5746.03	267.09	A
ECP #1	5601.66	144.37	B
Port Collar #2	5554.93	46.73	C
Port Collar #3	5463.53	91.40	D
ECP #2	5411.06	52.47	E
Port Collar #4	5318.87	92.19	F
Port Collar #5	5228.52	90.35	G
ECP #3	5175.85	52.67	H
Port Collar #6	5129.13	46.72	I
Port Collar #7	5038.07	91.06	J
ECP #4	4985.64	52.43	K
Port Collar #8	4893.80	91.84	L
Port Collar #9	4594.59	299.21	M
Port Collar #10	4383.31	211.28	N
ECP #5	4336.95	46.36	O
Port Collar #11	4290.51	46.44	P
ECP #6	4194.04	96.47	Q
Port Collar #12	4147.36	46.68	R
ECP #7	4094.72	52.64	S
Port Collar #13	3960.37	134.35	T
Port collar #14	3832.30	128.07	U
ECP #8	3735.79	96.41	V

(3) Two (2) top plugs will be "pushed" to the "bottom" of the hole on the first trip in the hole. The plugs will locate out on top of the Baker Guide Shoe at 6013 feet. These plugs will be needed prior to any stimulation work, and it will be easier to install them before setting the external casing packers.

3.2.2.3.2 Procedure

(1) Move in and rig up the completion rig.

(2) Unload and tally 6100 ft (minimum) of 2-3/8" 4.7#/ft J-55 EUE tubing. Clean all threads and visually inspect the pins and collars. Maintain as high of accuracy as possible on the pipe tally. An accurate pipe tally will eliminate potential problems locating the port collars and ECPs. Number each joint of pipe.

(3) Assemble Halliburton's FO Cementer Isolation Packer with Sleeve Positioners as shown in Figure 3.2.2. The FO cementer Opening Sleeve should be located a minimum of 20 feet (25 feet maximum) above the top cup of the isolation packer (shown as "AA" in Figure 3.2.2). A minimum of 10 feet of spacing between the top and bottom cups of the isolation packer is preferred (shown as "BB" in Figure 3.2.2). The end of the tool should be plugged off with a bull plug. Accurately measure each part of the tool and record it in Figure 3.2.2. Note the measurements "X" and "Y". These measurements will be critical in accurately locating the port collars and ECP inflate values. Install a 2-3/8" bumper sub (3-1/8" O.D. x 1-17/32" I.D.) directly above the opening sleeve. A stroke length of 20" should be adequate.

(4) Install the 2 top plugs in the 4-1/2" casing. These will be "pushed" to bottom. Pick up the bottom hole assembly and trip in the hole on 2-3/8" tubing to a depth of approximately 300 feet. Pressure up on the 2-3/8" tubing to 1000 psi with N_2 to verify that the isolation packer cups will effectively seal off inside the 4-1/2" casing with N_2. Hold the pressure on the tubing for 5 minutes.

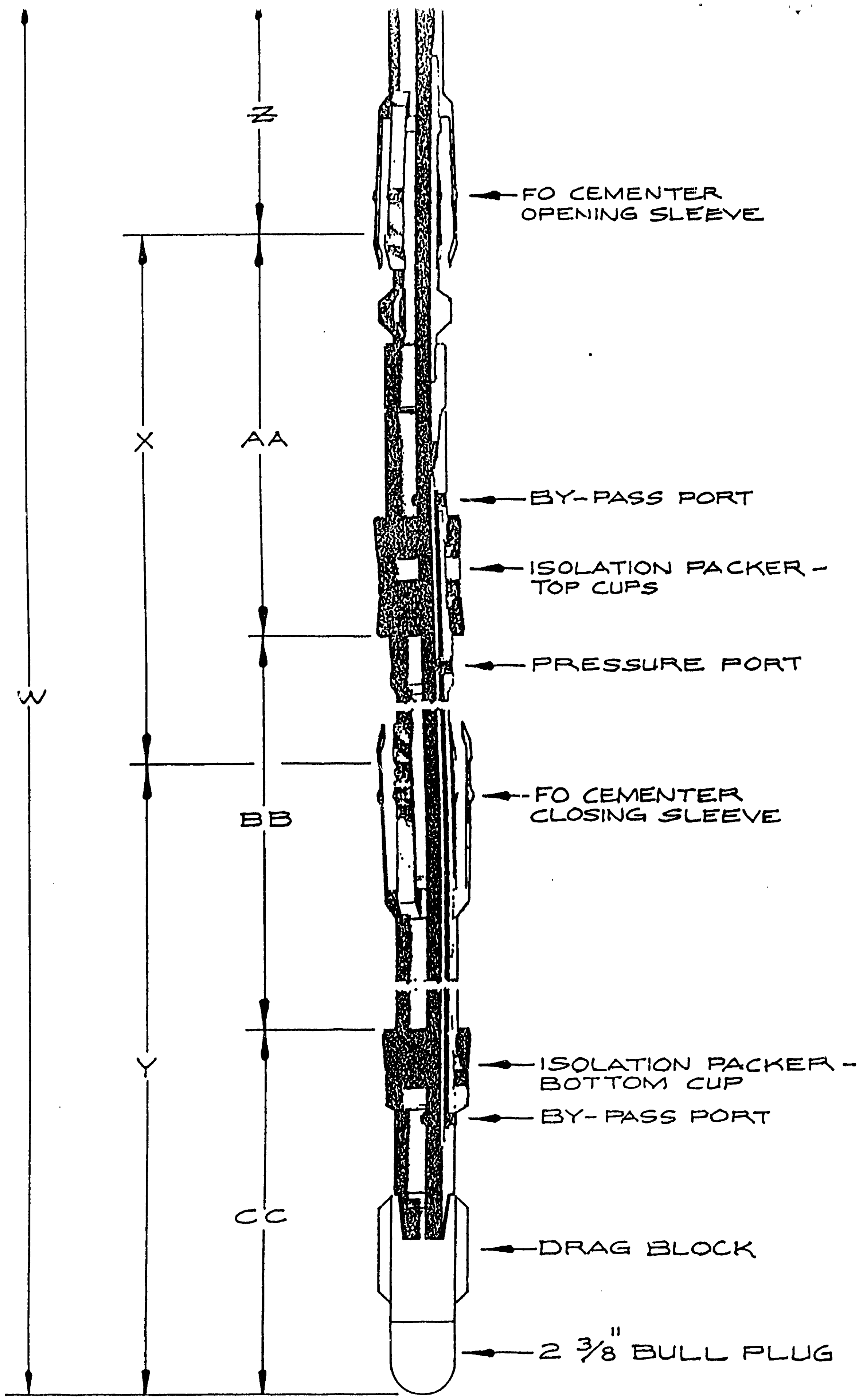


Figure 3.2.2 – HALLIBURTON FO CEMENTER ISOLATION PACKER WITH SLEEVE POSITIONER. BOTTOM OF THE TOOL IS PLUGGED OFF AS SHOWN.

(5) If the cups hold in step 4 above, continue tripping in the hole. If the cups should fail to seal off, pull back out of the hole and replace the cups. Repeat step 4.

(6) Trip in the hole with the bottom-hole assembly and tag the top of the Baker 4-1/2" guide shoe at 6013'. Leave all port collars in the closed position while tripping in the hole. Compare the tubing tally with the casing tally and note any differences.

(7) Slowly pull out of the hole a distance "A - (X + Y)" to position the opening sleeve across port collar #1 located at 5746' (see Figures 3.2.2 and 3.2.3). Open the port collar with an additional upward force of 10,000 lbs. The anticipated hook load at the surface required to open the port collar is 37,000 lbs.

NOTE:
a. Force required to open the FO cementer port collars - 10,000 lb
b. Force required to close the FO cementer port collars - 5000 lb
c. The bumper sub located just above the top positioning sleeve will aid in obtaining the necessary weight downhole to open and close the port collars.

(8) Pull out of the hole a distance "B + X" to position the opposing packer cups of the Halliburton Isolation tool across the first ECP inflate port located at 5601'. Rig up a nitrogen truck on the 2-3/8" x 4-1/2" annulus. Slowly inject N_2 down the annulus through the by-pass in the isolation tool, through the port collar at 5746' and up through the 4-1/2" x 8-5/8" annulus. Monitor the gas blow out the annulus at the surface. No increase in "gas blow" would indicate that the 4-1/2" x 8-5/8" annulus is plugged off and an alternate testing procedure will be needed. Proceed to the alternate testing procedure following step #31. If an appreciable amount of "gas blow" is seen at the surface, it can be assumed that the 4-1/2" x 8-5/8" annulus is not plugged off. Proceed to step #9.

(9) Slowly (i.e., 500 psi increments with 2 minute waits between) pressure the 2-3/8" tubing with N_2 to 1400 psi. Maintain the pressure for 5 minutes to allow the ECP to inflate.

NOTE:
a. All ECPs have 1250 psi shear pinned inflate values.
b. The CTC packer has a 1000 psi shear pinned inflate value.
c. None of the packers were equipped with optional breakoff rods.

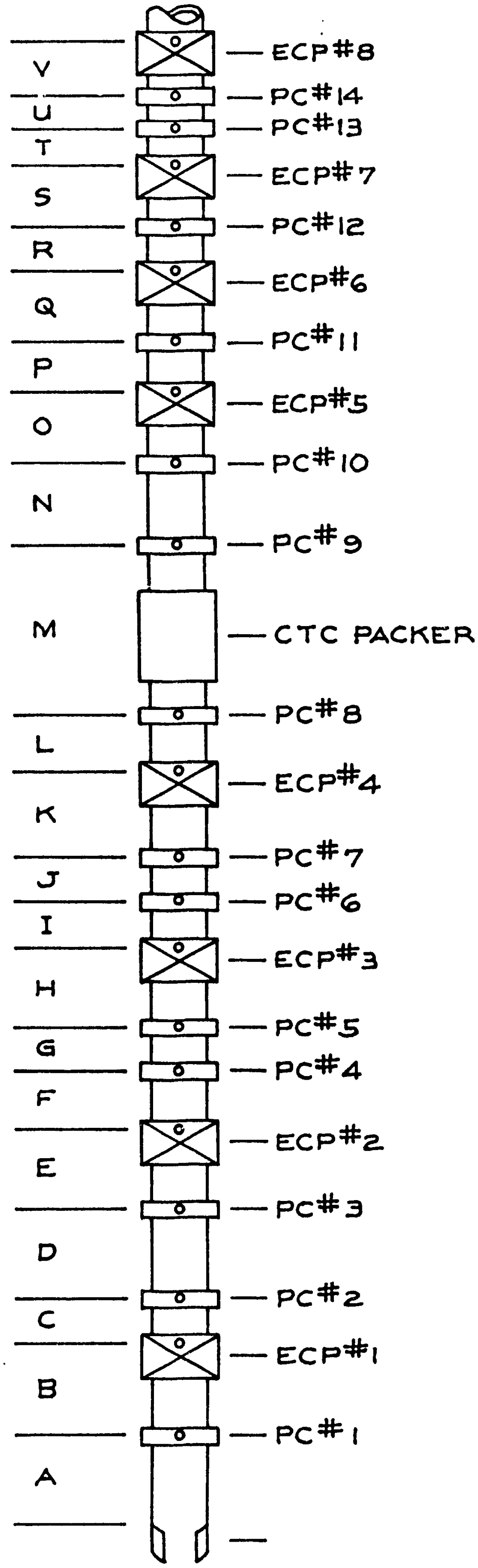


Figure 3.2.3 — LOCATION OF PORT COLLARS AND ECP'S IN THE 4 1/2" CASING.

The ECP should inflate until the inflate limit is reached at which time a second shear pin will shear, causing the valve to shut off. Since N_2 gas is being used as the inflation fluid, little or no pressure response will be seen at the surface while inflating the ECPs. Pressures and volumes of N_2 are estimated in Table 3.2.2.

(10) Hold the 1400 psi pressure on the 2-3/8" tubing. Open the 4-1/2" x 8-5/8" annulus and determine the strength of the "gas blow" once it has stabilized. Rig up and pump N_2 down the 2-3/8" x 4-1/2" annulus, through the by-pass in the isolation packer, and out the open port collar(s) below the ECP being tested. Monitor the "blow" on the 4-1/2" x 8-5/8" annulus. No increase in blow indicates a good packer seat. Proceed to step #11. An increasein blow indicates communication around the ECP. Increase the tubing pressure by 200 psi and repeat steps #9 and #10. If the ECP continues to fail, the following steps may be taken:

a) The Isolation tool may not be straddling the ECP inflate port. To verify the depths, trip in the hole and locate the port collar directly below the ECP which you are trying to inflate. Pull out of the hole the required distance to position the center of the isolation cups across the ECP inflate port (note any changes in depths from the previous attempt). Proceed with step #9 above.

b) The pressure required to shear the pin in the inflate valve of the ECP may be abnormally high. Pressure up on the ECP in step #9 to 2000 psi to insure that the valve opens. Do not attempt to pressure up over 2000 psi on the ECP inflate port.

c) If after steps 10(a) and 10(b) have been tried unsuccessfully, move on to the next ECP. Failure of an ECP will simply mean that two zones will be comingled during the flow testing.

(11) Pull out of the hole a distance "C - X" to position the opening sleeve across port collar #2 located at 5555'. Open port collar #2 as outlined in step #7.

(12) Pull out of the hole a distance "D" to position the opening sleeve across port collar #3 located at 5464'. Open port collar #3.

TABLE 3.2.2: INJECTION RATE AND MAXIMUM PRESSURES REACHED DURING INFLATION AND TESTING OF ECPs

STEP NUMBER IN PROCEDURE*	TASK	N_2 INJECTION RATE (scf/min)	TOTAL N_2 REQUIRED (scf)	MAXIMUM PRESSURE (psig)
#4	Test isolation tool @ 300'	Slow	450	1,000
#8	Circulate down 2-3/8" x 4-1/2", up 4-1/2" x 8-5/8". Depth - 5746 ft.	2,000	71,300	500
#9	Inflate ECP #1	500-1,000	11,800	1,400
#10	Test ECP #1 (assume a good seat) @ 1400 psi.	500-1,000	11,100	500
#13	Inflate ECP #2	500-1,000	11,500	1,400
#13	Test ECP #2	500-1,000	10,700	500
#16	Inflate ECP #3	500-1,000	11,000	1,400
#16	Test ECP #3	500-1,000	10,250	500
#19	Inflate ECP #4	500-1,000	10,600	1,400
#19	Test ECP #4	500-1,000	9,850	500
#23	Inflate ECP #5	500-1,000	9,250	1,400
#23	Test ECP #5	500-1,000	8,600	500
#25	Inflate ECP #6	500-1,000	8,950	1,400
#25	Test ECP #6	500-1,000	8,300	500
#27	Inflate ECP #7	500-1,000	8,750	1,400
#27	Test ECP #7	500-1,000	8,100	500
#30	Inflate ECP #8	500-1,000	7,600	1,400
#30	Test ECP #9	500-1,000	7,400	500
	TOTAL N_2 REQUIRED:		225,500 scf	

* Alternate procedure(s) nitrogen requirements not shown.
All tests assume that the packer held okay - no over-pumping.

(13) Pull out of the hole a distance "E + X" to position the opposing packer cups of the Isolation tool across ECP #2 inflate port located at 5411'. Repeat steps #9 and #10.

(14) Pull out of the hole a distance "F - X" to position the opening sleeve across port collar #4 located at 5319'. Open port collar #4.

(15) Pull out of the hole a distance "G" to position the opening sleeve across port collar #5 located at 5229'. Open port collar #5.

(16) Pull out of the hole a distance "H + X" to position the opposing packer cups of the Isolation tool across ECP #3 inflate port located at 5176'. Repeat steps #9 and #10.

(17) Pull out of the hole a distance "I - X" to position the opening sleeve across port collar #6 located at 5129'. Open port collar #6.

(18) Pull out of the hole a distance "J" to position the opening sleeve across port collar #7 located at 5038'. Open port collar #7.

(19) Pull out of the hole a distance "K + X" to position the opposing packer cups of the Isolation tool across ECP #4 inflate port located at 4986'. Repeat steps #9 and #10.

(20) Pull out of the hole a distance "L - X" to position the opening sleeve across port collar #8 located at 4894'. Open port collar #8.

(21) Pull out of the hole a distance "M" to position the opening sleeve across port collar #9 located at 4595'. Open port collar #9.

(22) Pull out of the hole a distance "N" to position the opening sleeve across port collar #10 located at 4383'. Open port collar #10.

(23) Pull out of the hole a distance "O + X" to position the opposing packer cups of the Isolation tool across ECP #5 inflate port located at 4337'. Repeat steps #9 and #10.

(24) Pull out of the hole a distance "P - X" to position the opening sleeve across port collar #11 located at 4291'. Open port collar #11.

(25) Pull out of the hole a distance "Q + X" to position the opposing packer cups of the Isolation tool across ECP #6 inflate port located at 4194'. Repeat steps #9 and #10.

(26) Pull out of the hole a distance "R - X" to position the opening sleeve across port collar #12 located at 4147'. Open port collar #12.

(27) Pull out of the hole a distance "S + X" to position the opposing packer cups of the Isolation tool across ECP #7 inflate port located at 4095'. Repeat steps #9 and #10.

(28) Pull out of the hole a distance "T - X" to position the opening sleeve across port collar #13 located at 3960'. Open port collar #13.

(29) Pull out of the hole a distance "U" to position the opening sleeve across port collar #14 located at 3832'. Open port collar #14.

(30) Pull out of the hole a distance "V + X" to position the opposing packer cups of the Isolation tool across ECP #8 inflate port located at 3736'. Repeat steps #9 and #10.

(31) The setting and testing of the ECPs is completed. Pull out of the hole and lay down the bottomhole assembly. Prepare for individual zone isolation and gas flow testing (Subtask #4).

3.2.2.3.3 Alternate Testing Procedure if the 4-1/2" x 8-5/8" Annulus is Plugged Off

(1) With the opposing packer cups of the isolation tool located across from the ECP inflate port, slowly pressure up the 2-3/8" tubing to 1400 psi and maintain the pressure for 5 minutes to inflate the ECP.

(2) Release the pressure on the 2-3/8" tubing at the surface.

(3) POOH to the next port collar and open same.

(4) POOH an additional distance "X" to position the opposing packer cups of the Isolation tool across the port collar.

(5) Open the 2-3/8" x 4-1/2" annulus at the surface and monitor the gas blow. Allow the blow to stabilize.

(6) Pump N_2 down the 2-3/8" tubing and out the port collar (port collar above the ECP to be tested). No increase in blow out the 2-3/8" x 4-1/2" annulus would indicate a good seal. Proceed to step #1 for the next ECP. If an increase in blow is seen at the surface out the 2-3/8" x 4-1/2" annulus, the packer is leaking, allowing N_2 to flow back into the casing through the open port collar below the ECP and through the by-pass in the Isolation tool. Proceed to step #7.

(7) If the ECP leaks in step #6, TIH with the Isolation tool and straddle the ECP inflate port with the Isolation tool. Re-pressure the ECP to the previous pressure plus 200 psi. (Do not exceed 2000 psi.) Hold for 5 minutes. Repeat steps 2, 3, and 4.

(8) Repeat procedure for all ECPs.

3.2.2.3.4 Alternate Testing Procedure
Inflating the CTC - Payzone Packer

(1) This alternate procedure will be implemented only if the previous procedures fail and the external casing packers do not seal off the 4-1/2" x 8-5/8" annulus.

(2) The shear-pinned primary control valve for the CTC packer was pre-set to 1000 psi differential prior to running it in the wellbore. This control valve is located at the top of the packer so as to sense true annulus pressure for accurate valve control.

(3) All port collars will need to be in the closed position. If any port collar is open, run in the hole with the FO cementer closing sleeve to close the port collar(s). Pull back out of the hole with the closing sleeve.

(4) Trip in the hole with the Halliburton Isolation packer (cups only - no sleeve positioners). On the bottom of the Isolation packer, install a single stroke tubing ball valve with a drag block. The ball valve should be positioned so it will open

on a downstroke and close on an upward stroke. A 2-3/8" bumper sub should be installed directly above the Isolation packer. Trip in the hole with this bottomhole assembly.

(5) Locate the CTC packer inflate valve at 4820'. Straddle the inflate valve with the opposing cups of the Isolation tool.

(6) Install a 2-3/8" pump-through bottom plug inside the 2-3/8" tubing at the surface.

(7) Mix and pump (slowly) 2 barrels of Class "H" cement (retarded for 24 hours) down the 2-3/8" tubing on top of the plug.

(8) With the tubing by-pass valve open, displace the plug and cement with N_2 to the top of the bumper sub located directly above the Isolation tool.

(9) When the bottom plug lands on top of the restricted ID of the bumper sub, it will begin to pressure up.

(10) Once it is determined that the cement is in place directly above the bumper sub, pick up the tubing and close the tubing by-pass valve.

(11) Continue pressuring up on the tubing and rupture the pump-through bottom plug at predetermined pressure allowing the cement to flow through the plug and out the port between the packer cups of the Isolation tool.

(12) A differential pressure of 1000 psi will be required to open the CTC packer inflate valve. When the valve opens, the cement will flow through the pressure limit valve to the interior of the rubber element (see attached literature on the CTC-payzone packer). When the inflation pressure reached a predetermined amount, a second shear pin will shear and the pressure limit valve will close, thus isolating the element. The anticipated cement capacity of the 20 ft packing element is 0.8 bbls. If the cement is correctly spaced, 200 to 300 ft of cement will be left inside the 2-3/8" tubing when the limit valve closes.

(13) Release the N_2 pressure off the tubing. Lower the tubing and open the tubing by-pass valve. Reverse out the cement left inside the tubing by pumping N_2 down the 2-3/8" x 4-1/2" annulus and up the 2-3/8" tubing.

(14) Trip in the hole to bottom and reverse out the hole a second time with N_2 to ensure that all cement is removed from the well bore.

(15) Pull out of the hole. Lay down the bottomhole assembly. Prepare for the gas flow testing (Subtask 4).

3.2.2.4 Subtask 4 - Zone Isolation/Gas Flow Testing

3.2.2.4.1 General Information

(1) After the external casing packers have been set and tested as outlined in Subtask 3, all port collars should be in the open position and all packers (8) should be set.

(2) The purpose of this Subtask is to individually test each of the eight (8) intervals (prior to any stimulation) and compare the results to those determined in Subtask 2.

(3) The equipment required to complete this subtask will include the string of 2-3/8" tubing used in Subtask 3 along with the Halliburton opening and closing sleeves for the port collars.

3.2.2.4.2 Procedure

(1) Assemble Halliburton's opening and closing sleeve positioners with a 20-25 ft spacing between the two positioners as shown in Figure 3.2.4. Accurately measure the spacing distance and record it. As in the previous procedure (Subtask 3), the closing sleeve positioners will be on the bottom of the tool and the opening sleeve positioner will be on the top. The bottom of the tool will remain open-ended throughout this subtask.

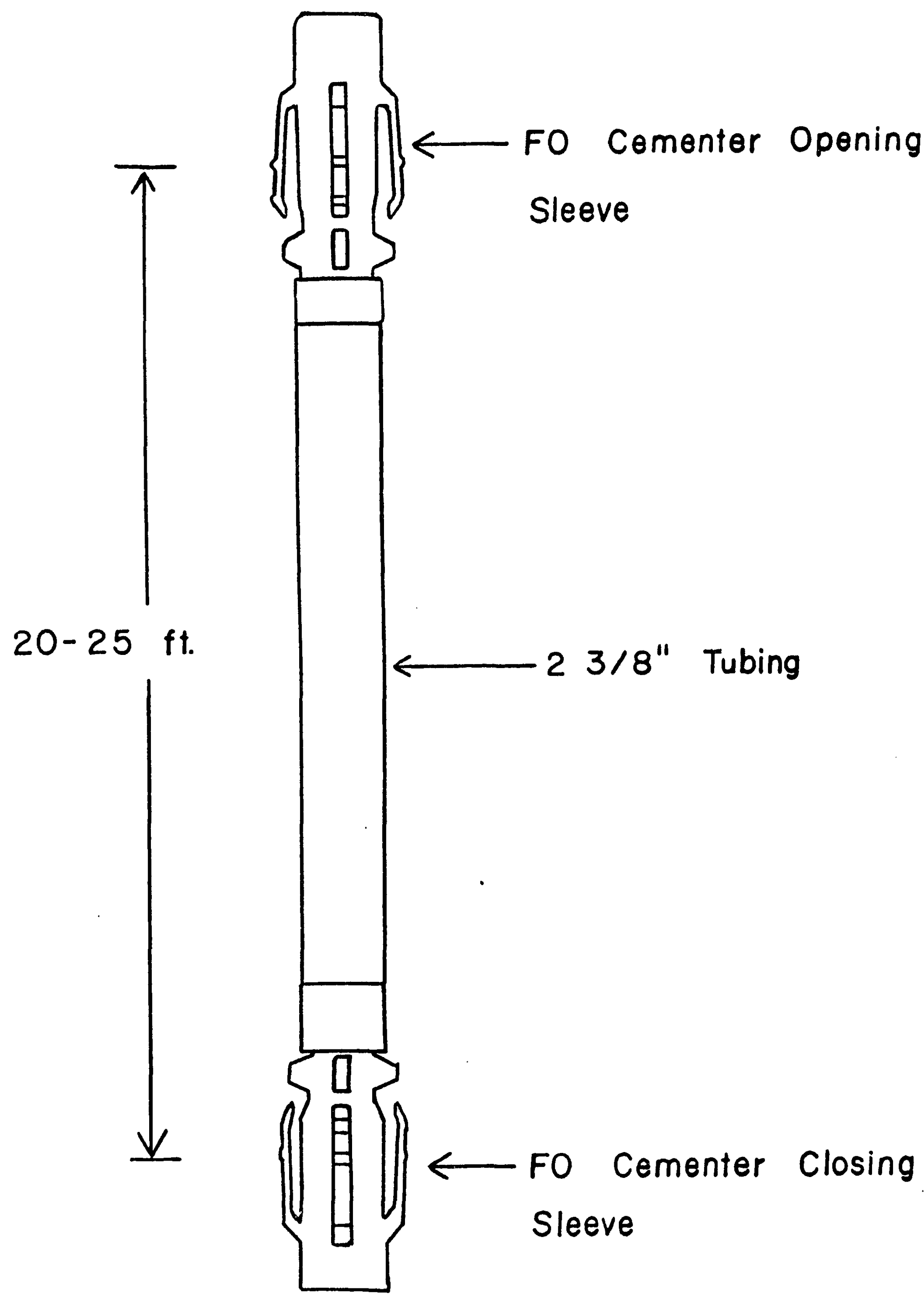


Figure 3.2.4 - Halliburton FO Cementer Sleeve Positioner.
Used in Subtask four.

(2) Pick up the Halliburton positioning tool and run it in the hole. Install a 2-3/8" bumper sub directly above the opening sleeve positioner. As in Subtask 3, the bumper sub will aide in obtaining the necessary weight "downhole" to open and close the port collars. Trip in the hole on 2-3/8" tubing.

(3) If Subtask 3 was successfully completed as outlined in the procedure, all of the port collars (14) will be in the open position. Each of the port collars will need to be closed on the initial trip in the hole. The depths of the collars are shown in Table 3.2.1 of Subtask 3. The bottom sleeve positioner will be used to close the port collars. A 5000 lb downward force is required to close the sleeves. An accurate tubing tally is crucial in locating each port collar. The first collar to close is port collar #14 located at 3832.30 ft.

(4) Once port collar #14 has been located and closed, slowly trip in the hole a distance of 128 ft and locate port collar #13. This distance can be determined from Table 3.2.1 of Subtask 3. Close port collar #13.

(5) Repeat step 4 for every PC.

(6) After locating and closing port collar #1, trip in the hole an additional 30 ft or so to ensure that the opening positioner is below port collar #1.

(7) Pull up and locate the collar with the opening positioner. With the required 10,000 lbs of pull, reopen port collar #1. Pull out of the hole an additional 30 feet. (NOTE: You may want to pull out an additional distance to provide adequate wellhead spacing at the surface.) Nipple up the wellhead and prepare to flow test the open interval.

(8) During the first 24 hours of flow, attempt to obtain a steady rate of production at an optimum producing back pressure (as determined in Subtask 2). Preliminary testing results from Subtask 2 indicate that 50 to 60 psig flowing back pressure at the wellhead will be required in order to sustain fracture propagation downhole. (NOTE: All 8 intervals will be individually flow tested against the same back pressure at the wellhead.) Additional flow time (past 24 hours) may be required in order to achieve stabilized flow.

(9) Once stabilized flow has been achieved in step 8, flow test the zone for a full 24 hour period. A dead weight tester should be used to verify the flowing back pressure on the well. The accuracy of the gas metering equipment should be of sufficient quality to measure flow rates as small as 1-5 mscfpd. If possible, a meter chart should be used during this flow period. The meter chart will need to be integrated in order to determine the actual 24 hour producing gas rate.

(10) After completing the 24 hour flow test, run in the hole and locate the port collar(s) with the closing sleeve positioner. With 5000 lbs force (downward), close the PCs.

(11) Pull out of the hole the known distance as determined from Table 3.2.1 in Subtask 3 and locate the next port collar(s) to be tested through. Refer to Figure 3.2.3 of Subtask 3 to determine which port collar(s) should be open while testing any particular interval. The following table summarizes the port collar(s) which are opposite each producing interval:

INTERVAL	PORT COLLARS TO BE OPENED
1	PC 1
2	PC 2, PC 3
3	PC 4, PC 5
4	PC 6, PC 7
5	PC 8, PC 9, PC 10
6	PC 11
7	PC 12
8	PC 13, PC 14

Open all port collars opposite the next interval to be tested. Nipple up the wellhead and prepare to flow test. Repeat steps 8, 9, 10, and 11 for all intervals to be tested.

(12) Close all port collars. Trip out of the hole with the bottomhole assembly.

(13) Prepare for Subtask 5.

3.2.2.5 Subtask 5 - Zone Isolation - Pressure Drawdown and Buildup Tests

3.2.2.5.1 General Information

(1) All port collars should be in the closed position at the conclusion of Subtask 4.

(2) All eight (8) intervals will be tested (i.e., drawdown and buildup) with the interval closest to the surface being the first interval to be tested.

(3) The pressure data obtained on the first interval tested will help dictate the pressure data required on the remaining intervals.

(4) Equipment needed for this Subtask include the string of 2-3/8" tubing, Halliburton's positioning tools, two downhole pressure recorders, one 2-3/8" bullplug, and one 2-3/8" perforated sub.

(5) Sufficient time should be allowed between Subtasks 4 and 5 in order to insure that stabilized shut-in pressures have been reached throughout all intervals to be tested.

3.2.2.5.2 Procedure

(1) Assemble and tally the bottom-hole assembly as shown in Figure 3.2.5. The bottom of the assembly will be closed with a 2-3/8" bull plug. The two 8-foot tubing pup joints will house the two Geoservices bottomhole pressure recorders (overall length of recorders is approximately 12 ft). The limitations and capabilities of the recorders are summarized in Table 3.2.3. The recommended sampling rates for the two recorders are 8 minutes for one and 16 minutes for the other. The 8 minute rate will only record for 22.7 days; however, it will provide additional data during the entire drawdown test and the first half of the buildup test. It will also aide as a "backup" for the 16 minute recorder. The recorders will rest on the bull plug and will be free to move inside the pup joints. A reduced "ID" seating nipple

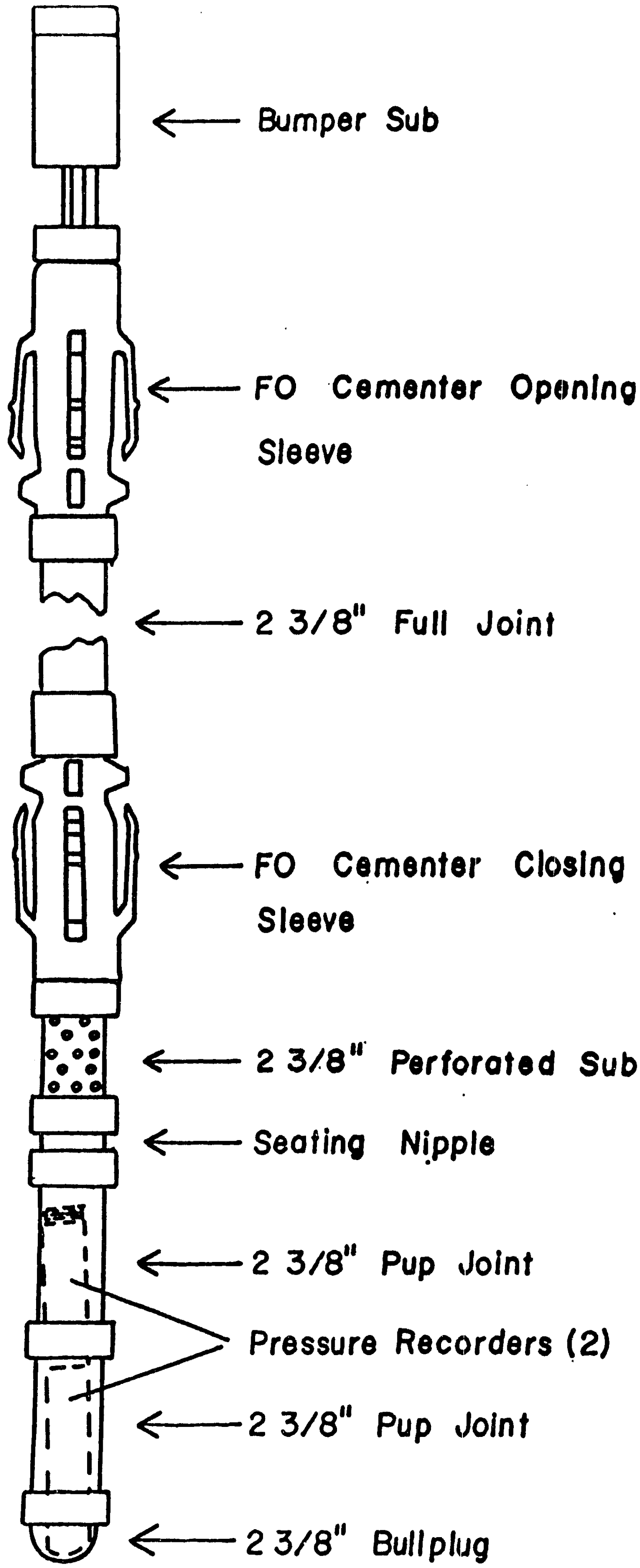


Figure 3.2.5: Bottomhole Assembly Used During the Pressure Drawdown and Build-Up Tests

TABLE 3.2.3

Pressure Recorder

Range - 0-5000 psi
Accuracy - greater than 2 psi at 5000 psi
Length - ≅ 6 ft
OD - 1 11/16"
Memory Capacity - 4096 data points
Time Delay - 1,2,4 or 8 hours

Sampling Rate	Total Survey Time
1/32 minute = 1.88 seconds	2.1 hours
1/16 minute = 3.75 seconds	4.3 hours
1/8 minute = 7.5 seconds	8.5 hours
1/4 minute = 15 seconds	17.1 hours
1/2 minute = 30 seconds	34.1 hours = 1.4 days
1 minute = 60 seconds	68.3 hours = 2.8 days
2 minutes	136.5 hours = 5.7 days
4 minutes	273.1 hours = 11.4 days
8 minutes	546.1 hours = 22.7 days
16 minutes	1092.3 hours - 45.5 days

will need to be installed above the pup joints in order to keep the recorders positioned inside the pup joints. A 2-3/8" perforated sub located above the seating nipple will be the point through which the gas will flow during the tests. This perforated sub should be positioned opposite the interval to be tested. The Halliburton opening and closing sleeve positioners along with the 2-3/8" bumper sub will be required in order to close the port collar(s) at the conclusion of the tests and open the collar(s) across the next test interval.

(2) Run in the hole with the bottom-hole assembly on 2-3/8" tubing. Care should be taken when handling the tubing so as not to harm the recorders. Locate port collars #14 and #13 at 3832' and 3960' respectively. Open both collars.

(3) Center the perforated sub across port collar #13.

(4) Nipple up the wellhead and prepare for the pressure drawdown test. It may be necessary to shut-in the well an additional period of time to insure that the bottomhole pressure is stabilized prior to starting the drawdown test.

(5) Open the well on a predetermined choke size (as determined from Subtasks 2 and 4) and maintain a constant flow rate throughout the test (if possible). Do not attempt to flow the well at too high of a rate thus reducing the bottomhole pressure to a point at which the fractures close and the gas rate drops off. Continue producing the interval for a period of two weeks while recording all surface pressures and gas flow rates. An accurate measurement of all gas sold will be crucial in the calculations involving the buildup test which will start at the conclusion of the drawdown test.

(6) After flowing the well the required 14 days, shut-in the well at the surface to start a 14-day build-up test. Record shut-in wellhead pressures.

(7) At the conclusion of the build-up test, close port collars #13 and #14. Pull out of the hole with the recorders. NOTE: The port collars can be closed on the trip in the hole to test the next interval.

(8) Verify that all pressure data was accurately recorded on the two recorders. Re-set the recorders for the next test. NOTE: If the recorders failed to work, the zone will need to be retested.

(9) Run in the hole with the same bottomhole assembly and pressure recorders. Locate the port collar(s) across the next interval "downhole". Open the collar(s).

(10) Center the perforated sub across the open collar(s). Repeat steps 4, 5, 6, 7, and 8. NOTE: After reviewing the pressure data obtained from the first drawdown and build-up test, the amount of flow and build-up time required for the tests may possibly be reduced. However, due to the "tightness" of the reservoir, 14 days for both drawdown and build-up tests should be planned for.

(11) Repeat steps 9 and 10 for all intervals to be tested.

(12) Geoservices has the capability of storing all pressure data on a floppy disk which will be very helpful when evaluating the data in Subtask 6.

(13) While tripping out of the hole after completing the last pressure test on the interval farthest away from surface, leave all port collars in the open position.

(14) Nipple up the wellhead. Open the well to sales. Release the completion rig.

(15) Prepare to evaluate all pressure as outlined in Subtask 6. NOTE: The completion rig should be released during the testing phase of each interval so as to eliminate all stand-by time.

3.2.2.6 Subtask 6 - Determine Fracture Permeability, Fracture Porosity, and Skin Effect by SUGAR-MD

The well test analysis consists of two parts: transient analysis and computer simulation via SUGAR-MD. The well test data will consist of 2 weeks of drawdown followed by shut-in and pressure build-up. The particular production rate is selected as a fraction (approximately 20 percent) of the absolute open flow potential of that zone of interest and should be maintained as constant as possible. This holds especially true for the very end of the production test.

Transient analysis begins with the preparation of log-log plots of change in pseudo pressure versus log production time during production test, and flowing pseudo pressure versus time during post-production build-up. These plots enable the periods of wellbore distortion to be identified and types of flow regimes to be characterized following wellbore distortion. Once the test periods of interest are isolated, they are evaluated with semi-log techniques to determine permeability and Skin.

Results of transient analysis provides the basis for computer simulation work via SUGAR-MD. The history-matching technique is an iterative one consisting of generating simulated data and comparing it with actual test data. Upon comparison, pertinent variables (permeability, porosity, Skin) are changed and another simulation is prepared. This process is repeated until a "match" of computer simulation to actual test data is obtained. At this point, the variables used in the simulation should match actual reservoir properties.

3.2.3 Proposed Performance Schedule

The following is the proposed schedule of operations for the various subtasks to be performed:

TASK 8

	1987						
SUBTASK	FEB	MAR	APR	MAY	JUNE	JULY	AUGUST
1.0 Planning	>------<						
2.0 Gas Flow Rate	>-------	---<					
3.0 Inflate ECPs		>----<					
4.0 Zone Testing			>------	------<			
5.0 Pressure Testing				>	-------	---------<	
6.0 Analysis							>------<

This is the schedule proposed to accommodate the present plans. If longer test periods are required, the schedule will have to be modified accordingly.

3.3 Production Rate Tests

The initial production rate test was taken on December 14 when all drilling operations were completed to a total measured depth of 6020 feet. A water-filled manometer with a 2-inch orifice was used to measure the flow rate through a swaged down section of the 7" air return flow line into the pit. Gas flow measured at this time was 119 mcfpd. This was 3 days after hitting a flow of gas while drilling calculated to be 1219 mcfpd.

3.3.1 Additional Production Rate Tests

After the casing was installed and the well was shut-in for a pressure build-up test, a flow meter was hooked up to the well (see Figure 3.3.1.1) and the flow rate test (Figure 3.3.1.2) was conducted. This initial test showing a rapid fall-off in production indicates Skin damage to the wellbore and the very reduced reservoir pressure encountered on the first build-up test of only 128 psig.

During the months of January and February, the well was being worked on to install various wellhead equipment (shown in Figure 3.3.1.1) and to repair a leak from the 11-3/4" casing. The interrupted flow patterns and the projected rate is shown in Figure 3.3.1.3. Because of the Skin damage, the flow rate continued to drop to about 24 mcfpd after 33 days.

3.4 Inflation and Integrity Testing of External Casing Packers

Eight (8) external casing packers (ECPs) with conventional casing centralizers located on either side (see Figure 3.4.1) were placed in the casing string along with 14 full opening sliding sleeve ported collars. A special isolation and washover tool (Figure 3.4.2) was placed

PRODUCTION/MONITORING COMPONENTS RET #1

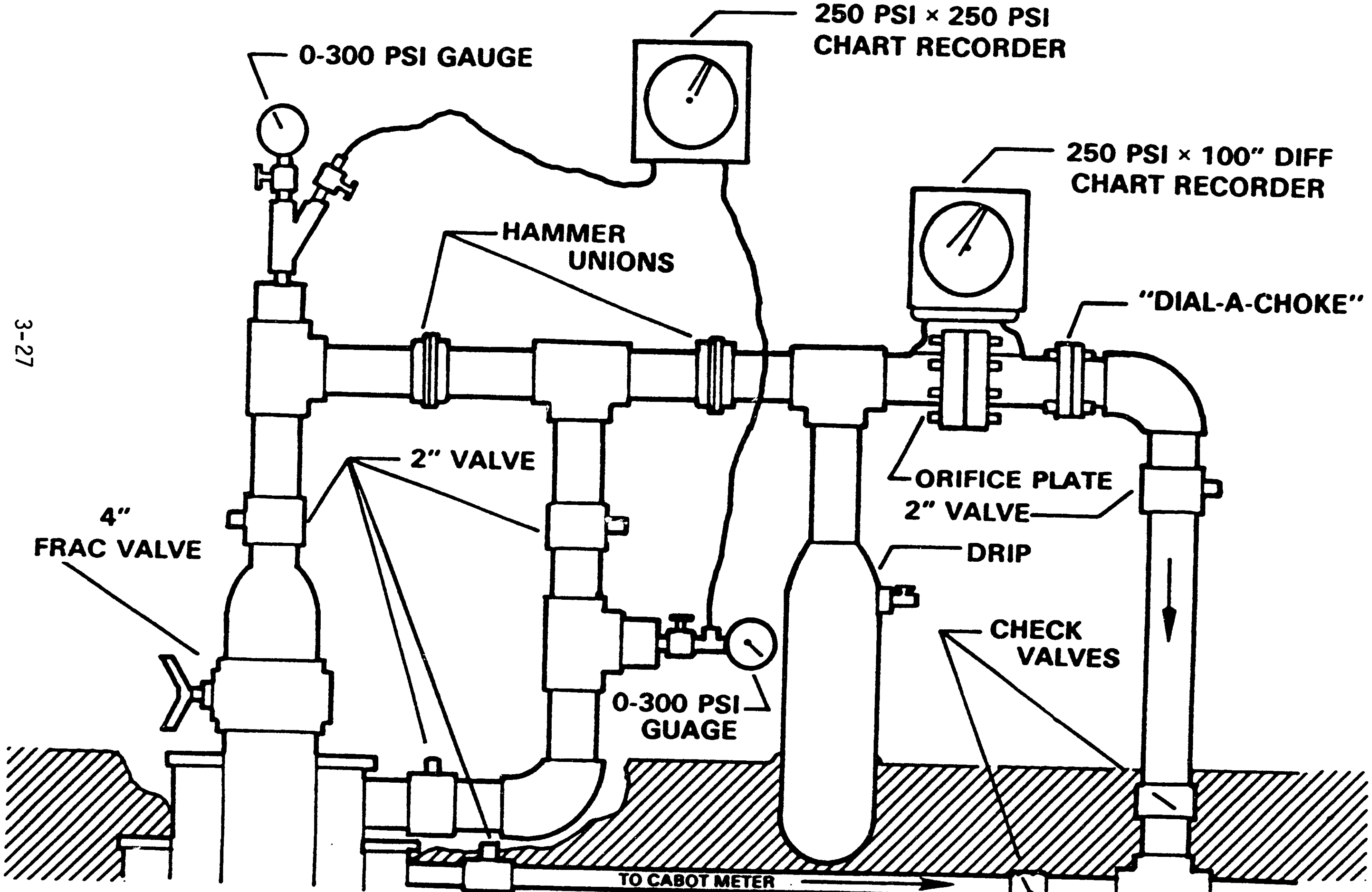


Figure 3.3.1.1

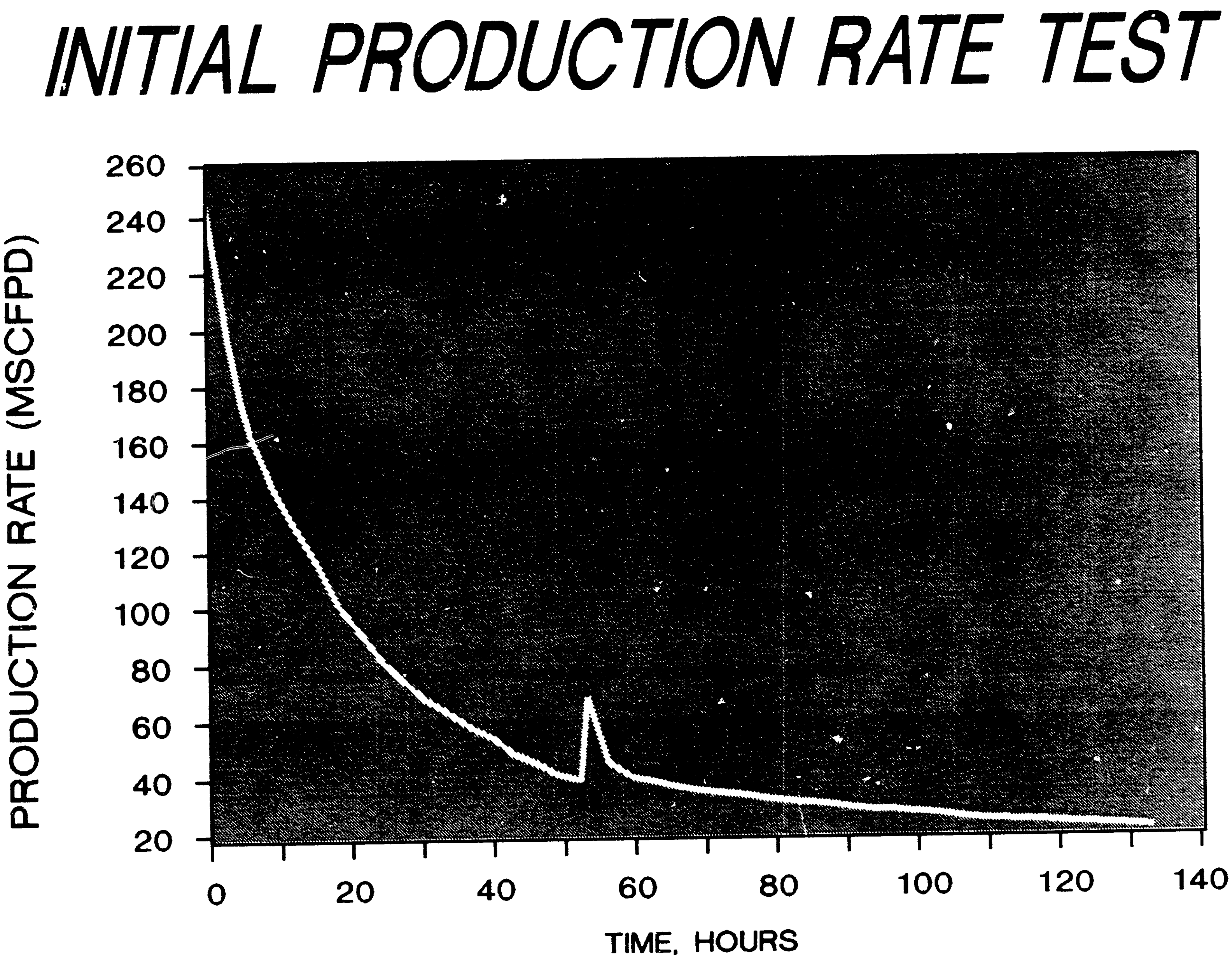

INITIAL PRODUCTION RATE TEST
PRODUCTION RATE (MSCFPD)
260
240
220
200
180
160
140
120
100
80
60
40
20
0
20
40
60
80
100
120
140
TIME, HOURS

Figure 3.3.1.2

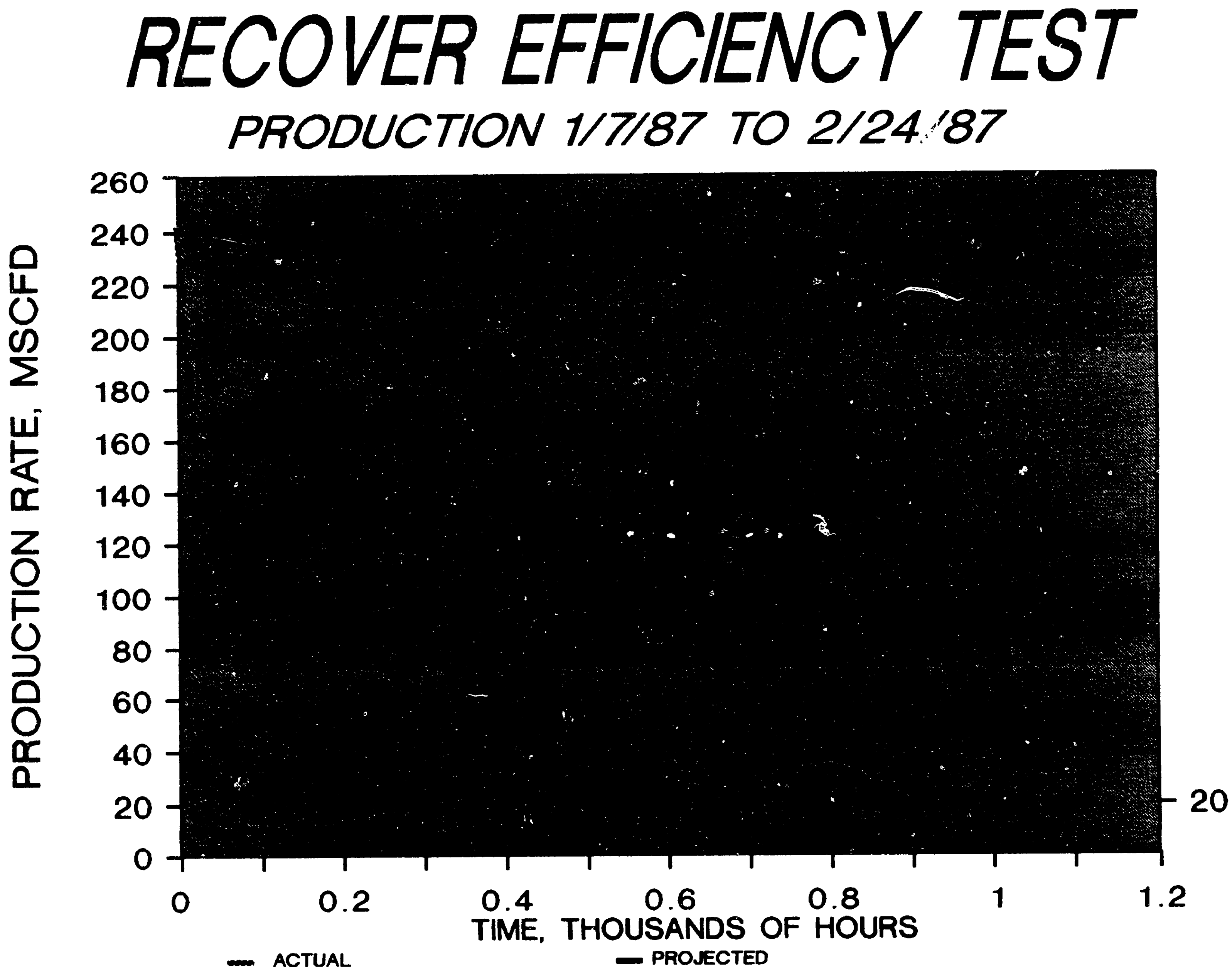

RECOVER EFFICIENCY TEST
PRODUCTION 1/7/87 TO 2/24/87
PRODUCTION RATE, MSCFD
260
240
220
200
180
160
140
120
100
80
60
40
20
0
0.2
0.4
0.6
0.8
1
1.2
TIME, THOUSANDS OF HOURS
ACTUAL
PROJECTED

Figure 3.3.1.3

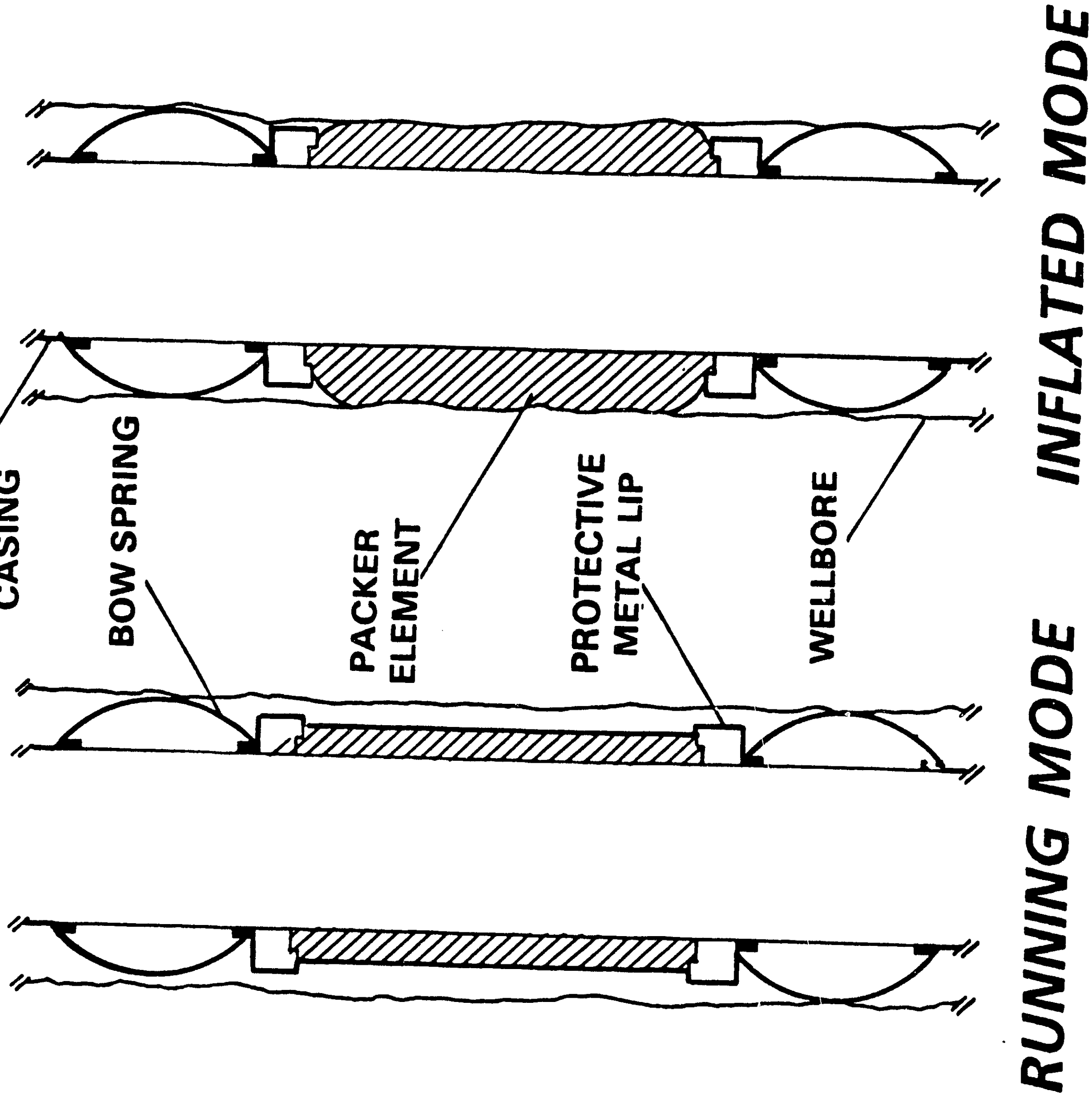

4-1/2" CASING
BOW SPRING
PACKER ELEMENT
PROTECTIVE METAL LIP
WELLBORE
RUNNING MODE
INFLATED MODE

Figure 3.4.1

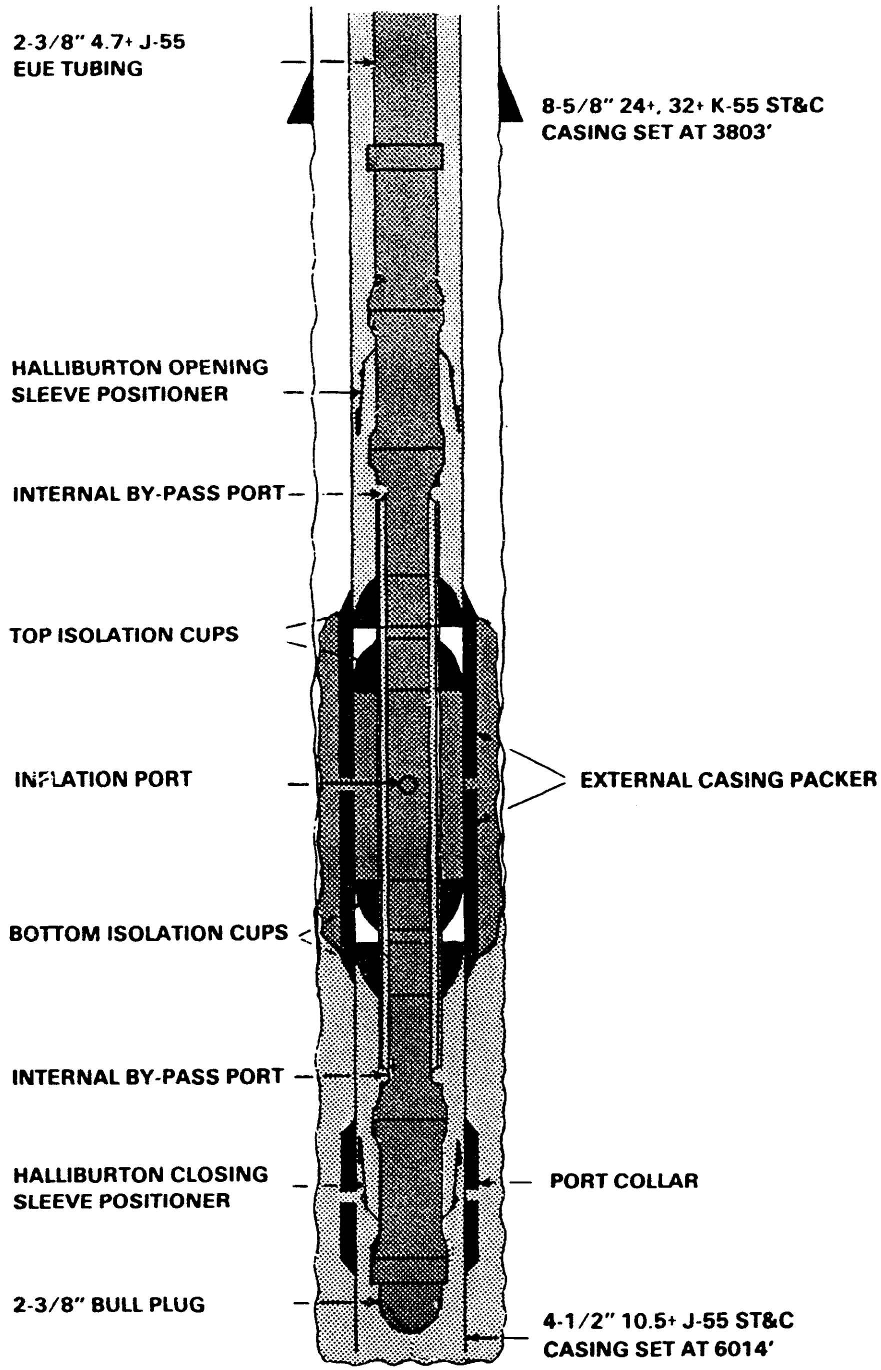

2-3/8" 4.7+ J-55
EUE TUBING
8-5/8" 24+, 32+ K-55 ST&C
CASING SET AT 3803'
HALLIBURTON OPENING
SLEEVE POSITIONER
INTERNAL BY-PASS PORT
TOP ISOLATION CUPS
INFLATION PORT
EXTERNAL CASING PACKER
BOTTOM ISOLATION CUPS
INTERNAL BY-PASS PORT
HALLIBURTON CLOSING
SLEEVE POSITIONER
PORT COLLAR
2-3/8" BULL PLUG
4-1/2" 10.5+ J-55 ST&C
CASING SET AT 6014'

Figure 3.4.2

on the 2-3/8-inch tubing string and pushed into position to isolate the inflation port of each packer. The opening and closing sleeve positioner on the tool was used to open the port collar below each ECP. Nitrogen was pumped down the annulus between tubing and casing through the open port collar and back up the outside of the 4.5-inch casing. This established flow past the back side of the packer. Nitrogen was then flowed down the 2-3/8-inch tubing to the isolated inflation port to a pressure of 1400 psi to inflate and set the ECP.

Nitrogen at 500 psi was again pumped down the annulus and the pressure began to build and no gas was flowing up through the annulus, indicating that the ECP was set and holding pressure. Each ECP was inflated and tested in the same manner. All ECPs except No. 2, located between Zone 2 and 3, held pressure and was successfully set. Therefore, Zones 2 and 3 are combined into one zone because of the ECP failure. The procedures outlined in Section 3.2 were followed with only minor modification.

3.5 Flow Tests

Prior to setting and testing the 8 external casing packers to separate the wellbore into 8 different zones, a series of flow tests were conducted to get an idea of the production potential of the well in its present unstimulated condition. The tests started off holding a back pressure of 110 psi on a 1/4-inch choke to see how long it would take to stabilize, but pressure and flow rate dropped continuously over a period of 5 days. The choke size was reduced to 1/8-inch and back pressure lowered to 45 psi. The well again opened up to flow. The results, as shown in Figure 3.5.1, show that production continued to decline even when the well was opened up to flow against pipeline presure of 39 psig. Production rate climbed from 30 to 39 mcfpd but was declining slowly.

It was obvious by this time that a typical isochronal test could not be run on the well. For the next test a back pressure of 48 psig was held on the well and the well was allowed to product until it stabilized production at 28 mcfpd after 6 days. The final test run was to see what the absolute open flow would be against 0 line pressure.

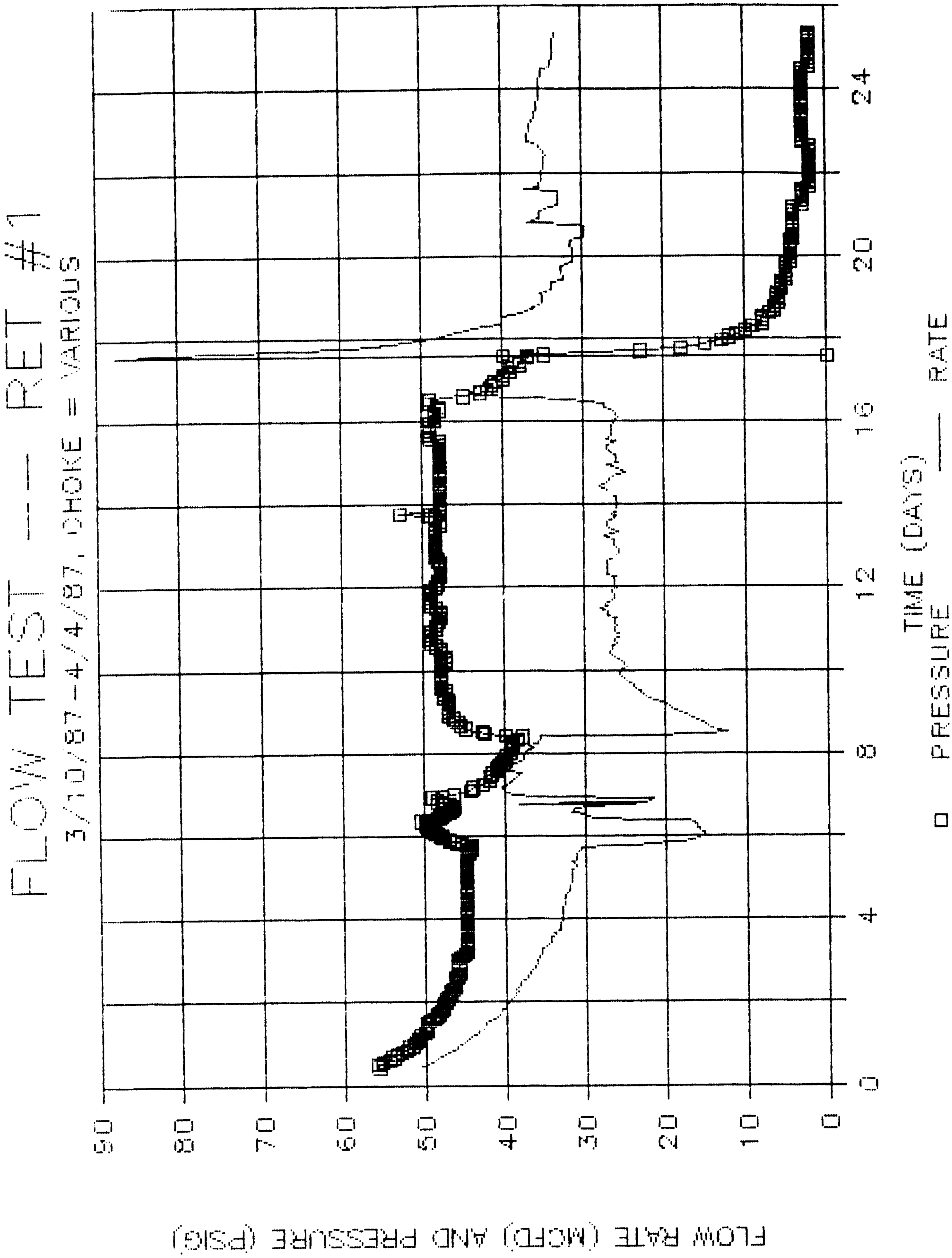

FLOW TEST — RET #1
3/10/87-4/4/87, CHOKE = VARIOUS
90
80
70
60
50
40
30
20
10
0
FLOW RATE (MCFD) AND PRESSURE (PSIG)
0
4
8
12
16
20
24
TIME (DAYS)
PRESSURE
RATE

Figure 3.5.1

As shown on Figure 3.5.1, the well flowed at an average rate of 34 mcfpd over a 6 day period with a surface flowing pressure of 3 psig.

After 7 of the 8 ECPs had been successfully set, a zone isolation and testing assembly (shown in Figure 3.5.2) was run in the well and a series of one-hour flow tests were run on each zone to determine what percentage of the total flow was coming from that isolated zone, as measured through the 2-3/8-inch tubing, and the balance that was measured as producing through the 4-1/2-inch casing. The results of these initial flow tests are presented in Table 3.5.1.

TABLE 3.5.1

RESULTS OF INITIAL FLOW TESTS

ZONE	TUBING FLOW RATE (mcfpd)	CASING FLOW RATE (mcfpd)	TOTAL (mcfpd)
1	2.2	20.4	22.6
2-3	4.4	28.3	32.7
4	16.7	17.8	34.5
5	4.4	30.0	34.4
6	2.2	32.4	34.6
7	0	35.3	35.3*
8	5.2	18.9	24.1
TOTAL	35.1		

* Note that production from the well is higher when Zone 7 is not producing, than when it is producing. This may indicate that zone 7 through the cored fault zone is losing gas to another well such as 1499 or 260.

3.6 Isolated Zone Pressure Build-up and Drawdown Tests

After the initial short-term tests were conducted and the data was examined, it was determined that a pressure build-up and drawdown test should be conducted for each zone. Initially a 7-day build-up and 7-day drawdown test was proposed, but this time period would take more than 3 months to complete, so a compromise short-term test of 24 hours was run on each zone.

ZONE ISOLATION & TESTING ASSEMBLY

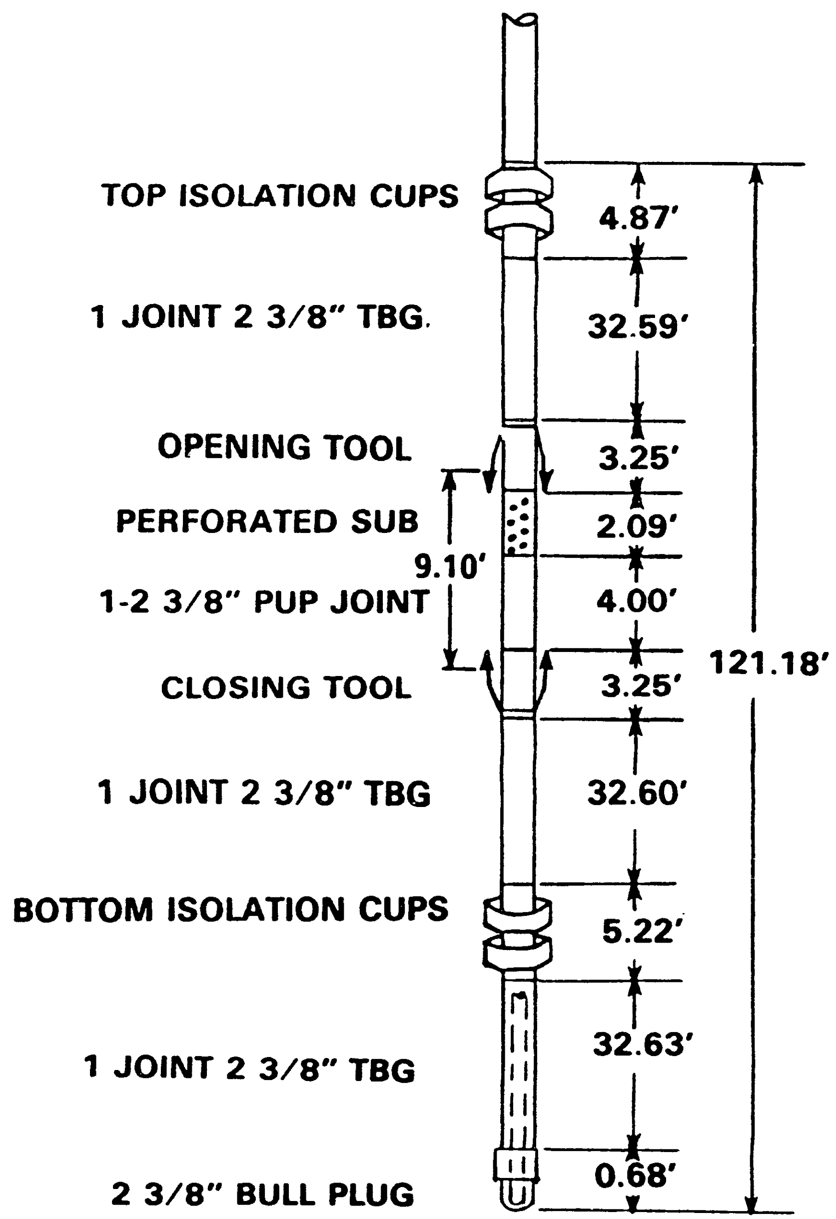


Figure 3.5.2

A typical build-up and drawdown curve as recorded by the pressure transducer and computerized data acquisition system is presented in Figure 3.6.1. A comparison of the curves for each zone is presented in Figure 3.6.2. This figure obviously illustrates the difference in bulk reservoir properties along the 2000-foot long section of wellbore.

The simulator G3DFR was used to determine permeability. A history match of the curve for Zone 8 is presented in Figure 3.6.3. Table 3.6.1 presents the results of the pressure build-up and drawdown tests and the permeabilities determined.

A log of the zone-by-zone operations is presented in Appendix 7.5 along with the pressure build-up and drawdown curve for each zone.

3.7 Data Analysis to Determine Whole Well and Isolated Zone Permeabilities and Skin Factors

3.7.1 Background

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 and prior to the pressure build-up test, 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 34.0 - 35.0 mcfd for approximately 264 hours, and then was immediately shut in for a 640-hour pressure build-up test (4/07/87). Wellhead pressure data were monitored and measured with a high-resolution pressure transducer and recorded on a battery-powered computer-controlled portable data logger. A back-up recording was made with a conventional chart recorder. The wellhead gauge pressure data were first converted to absolute pressure and then to bottomhole pressure. The test was concluded on May 4, 1987. Figure 3.7.1.1 illustrates the flow test period followed by the build-up test for RET #1. Flow rate of gas from the well for a 73-hour period immediately prior to the build-up is shown in Figure 3.7.1.2. Table 3.7.1.1 provides the gas sample analysis for RET #1.

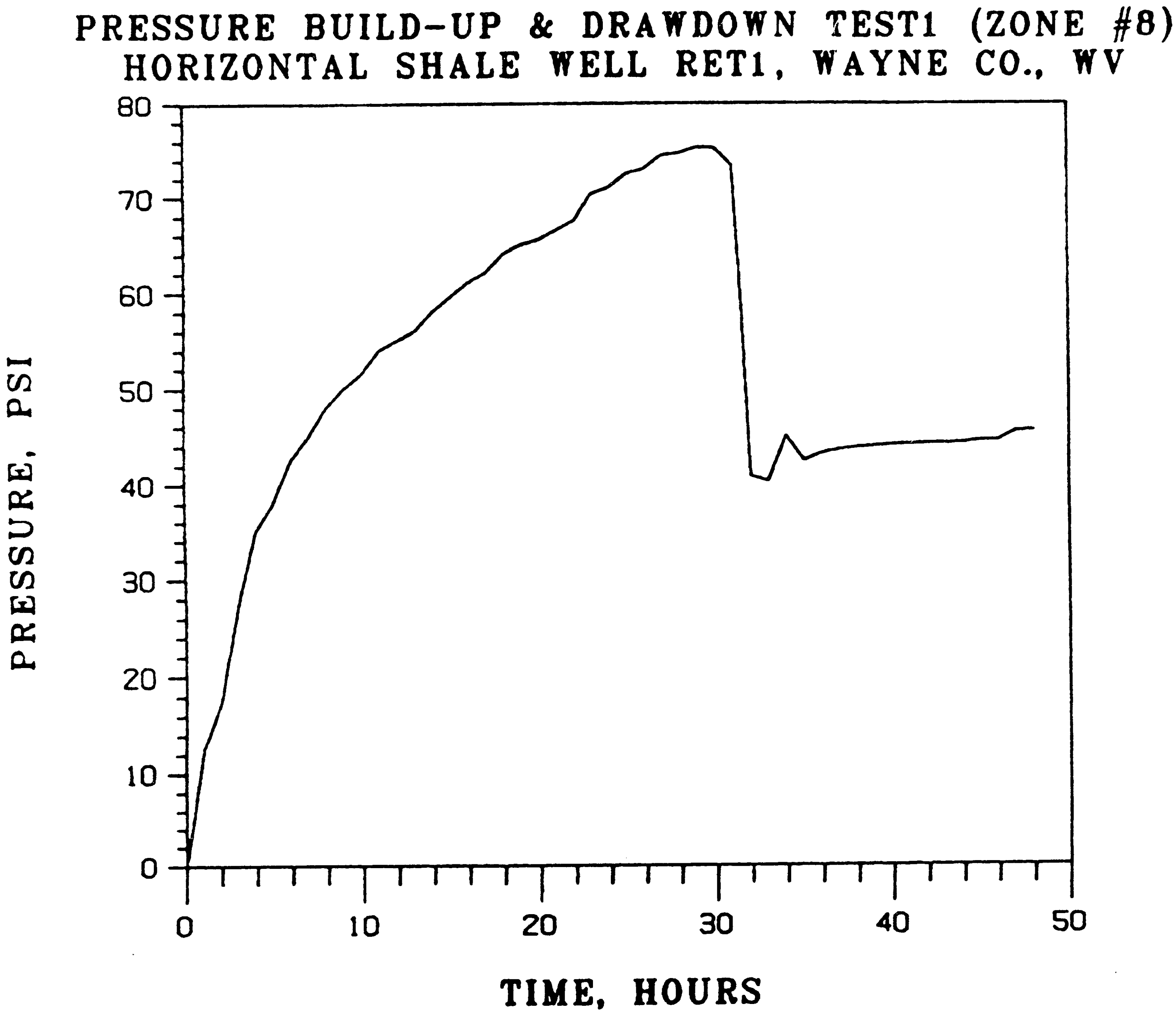

PRESSURE BUILD-UP & DRAWDOWN TEST1 (ZONE #8)
HORIZONTAL SHALE WELL RET1, WAYNE CO., WV
PRESSURE, PSI
0
10
20
30
40
50
60
70
80
0
10
20
30
40
50
TIME, HOURS

Figure 3.6.1

PRESSURE BUILDUP & DRAWDOWN FOR VARIOUS ZONES
2 3/8" TUBING, INTERVAL (3803-6014'), RET NO. 1

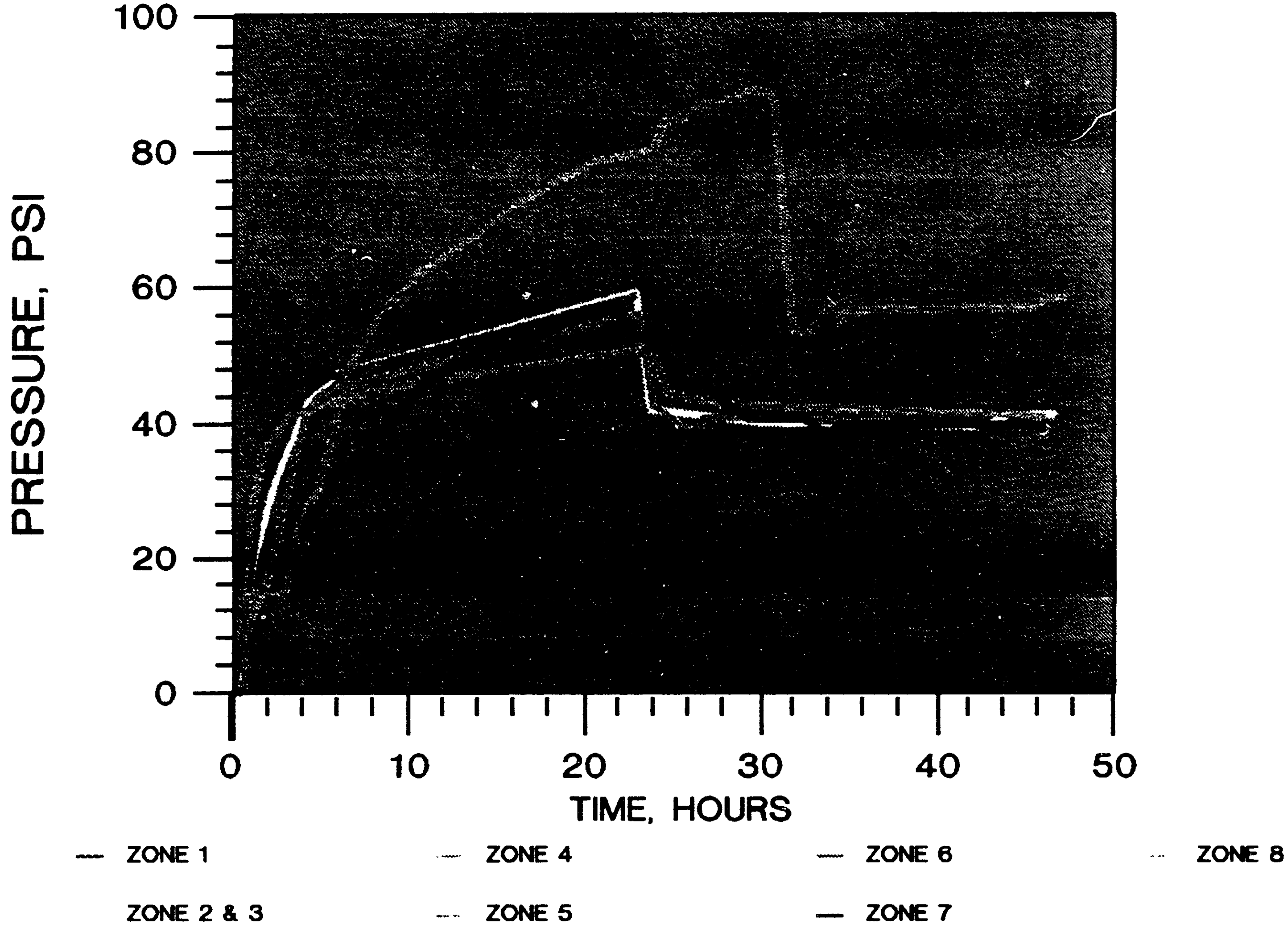


Figure 3.6.2

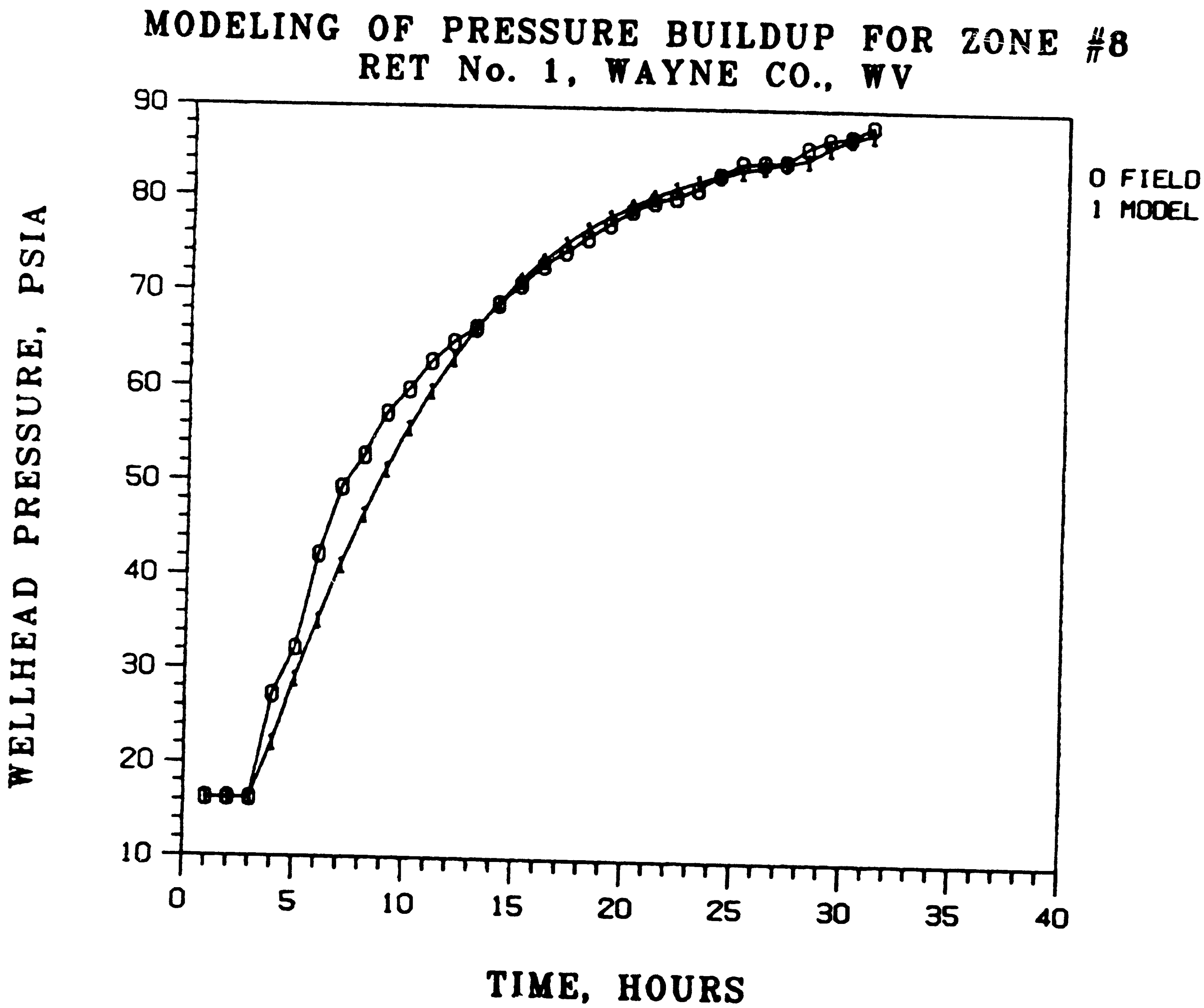

MODELING OF PRESSURE BUILDUP FOR ZONE #8
RET No. 1, WAYNE CO., WV
WELLHEAD PRESSURE, PSIA
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
TIME, HOURS
0 FIELD
1 MODEL

Figure 3.6.3

TABLE 3.6.1

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

* Predicted by reservoir simulation model G3DFR.

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

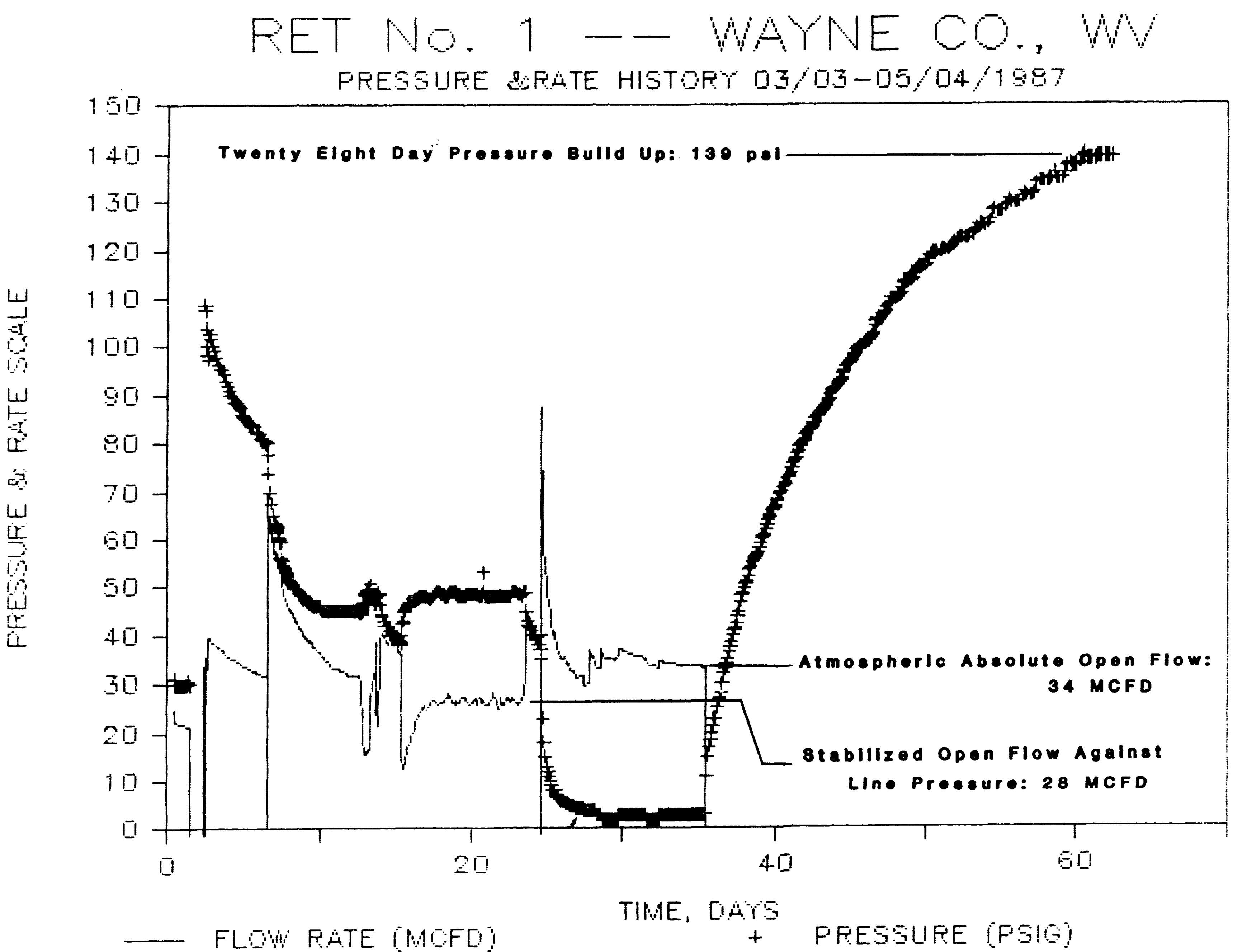

RET No. 1 -- WAYNE CO., WV
PRESSURE &RATE HISTORY 03/03-05/04/1987
Twenty Eight Day Pressure Build Up: 139 psi
Atmospheric Absolute Open Flow: 34 MCFD
Stabilized Open Flow Against Line Pressure: 28 MCFD
PRESSURE & RATE SCALE
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
0
20
40
60
TIME, DAYS
FLOW RATE (MCFD)
+ PRESSURE (PSIG)

Figure 3.7.1.1

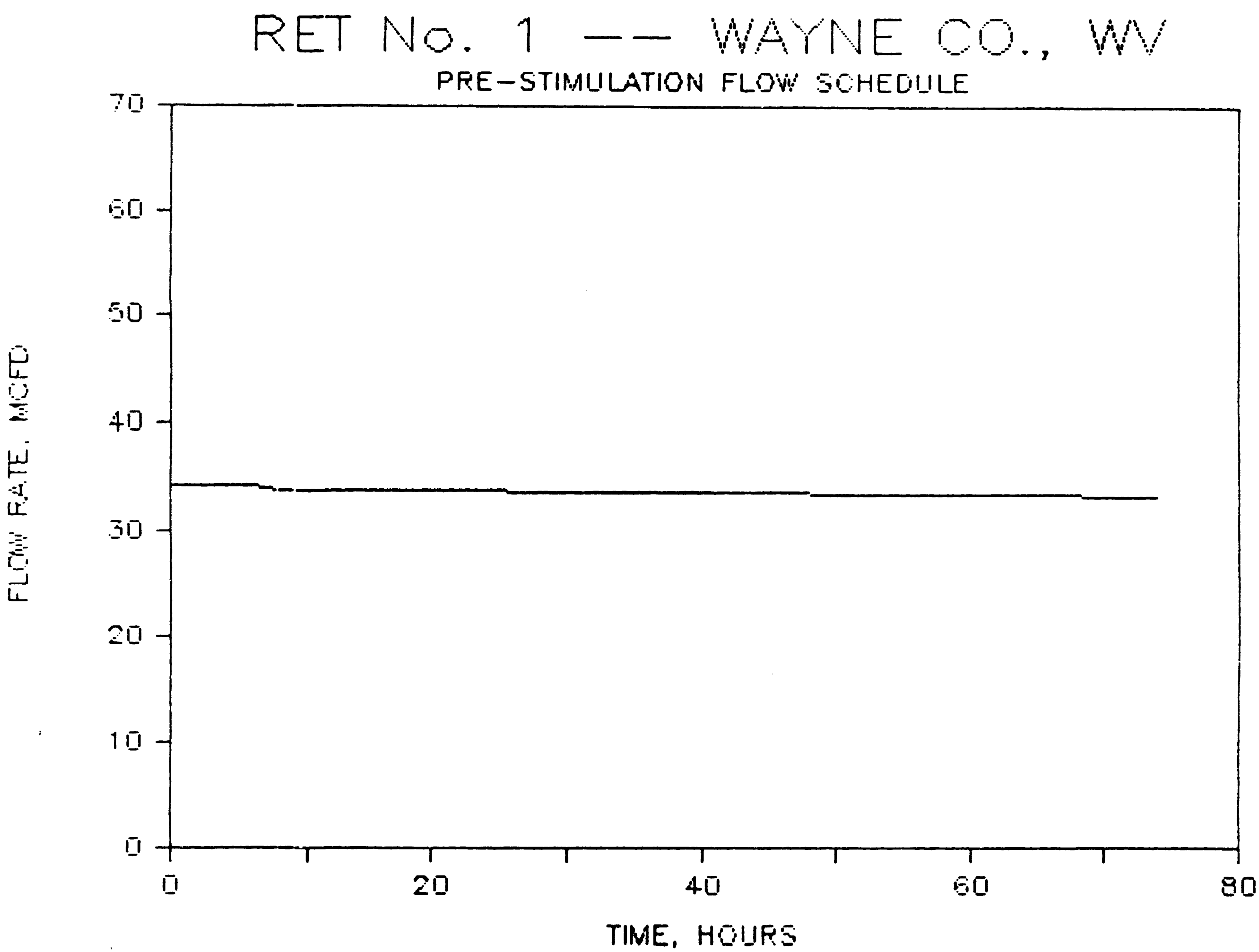

RET No. 1 -- WAYNE CO., WV
PRE-STIMULATION FLOW SCHEDULE
FLOW RATE, MCFD
70
60
50
40
30
20
10
0
0
20
40
60
80
TIME, HOURS
Figure 3.7.1.2

TABLE 3.7.1.1

RET NO. 1 GAS ANALYSIS (SAMPLE TAKEN 3/4/87)

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	1255.60 BTU/CF
BTU Value - Saturated	1233.70 BTU/CF
Specific Gravity	0.7225
Tc	398 degrees, R
Pc	665 psia

3.7.2 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 3.7.1.3 shows wellhead pressures and bottomhole pressures for the 640-hour pressure build-up test. It is appropriate to point out that classical transient analysis techniques are not strictly applicable to the horizontal wellbore geometry, but was performed to obtain initial estimates of some reservoir properties so that these values could be used as a starting point for the simulation analysis. The pressure response for a horizontal wellbore would be expected to resemble that of a long, finite conductivity fracture extending through a vertical well.

Analysis of the pressure build-up data from the RET #1 was performed using the following techniques: (a) "pressure-squared" method; (b) "pseudo-pressure" method.

3.7.3 "Pressure-Squared" Method

At the beginning of any production test, the surface flowing rates are greatly influenced by the amount of gas or liquid stored in the wellbore. In effect, all initial production originates in the wellbore volume and some period of production time elapses before subsurface rates predominates. This phenomena is sometimes referred to as wellbore storage effects. Therefore, it is necessary to characterize flow regimes encountered during production and build-up tests.

In order to determine flow regimes and to estimate permeability and "skin" factor, a series of plots were constructed. For part (a) of the analysis, Figures 3.7.1.4 and 3.7.1.5, which are respective plots of log log (p_{ws}^2 - p_{wf}^2) versus log time, and a Horner plot of p_{ws}^2 versus log $[(t_p + t)/\Delta t]$ were constructed. It should be noted that p_{ws} and t_p are defined as the shut-in bottomhole pressure and pseudo producing

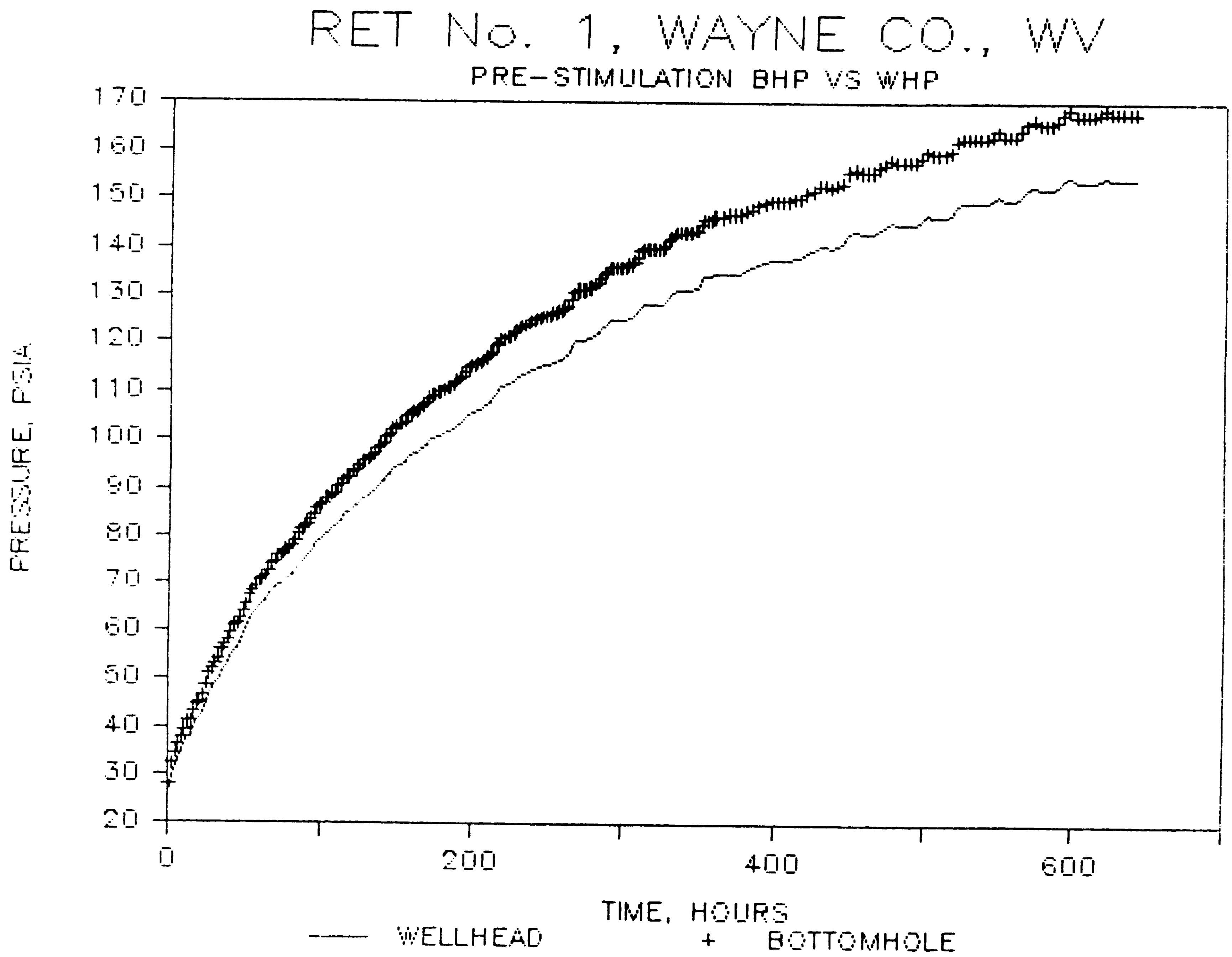

RET No. 1, WAYNE CO., WV
PRE-STIMULATION BHP VS WHP
PRESSURE, PSIA
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
0
200
400
600
TIME, HOURS
WELLHEAD
+ BOTTOMHOLE

Figure 3.7.1.3

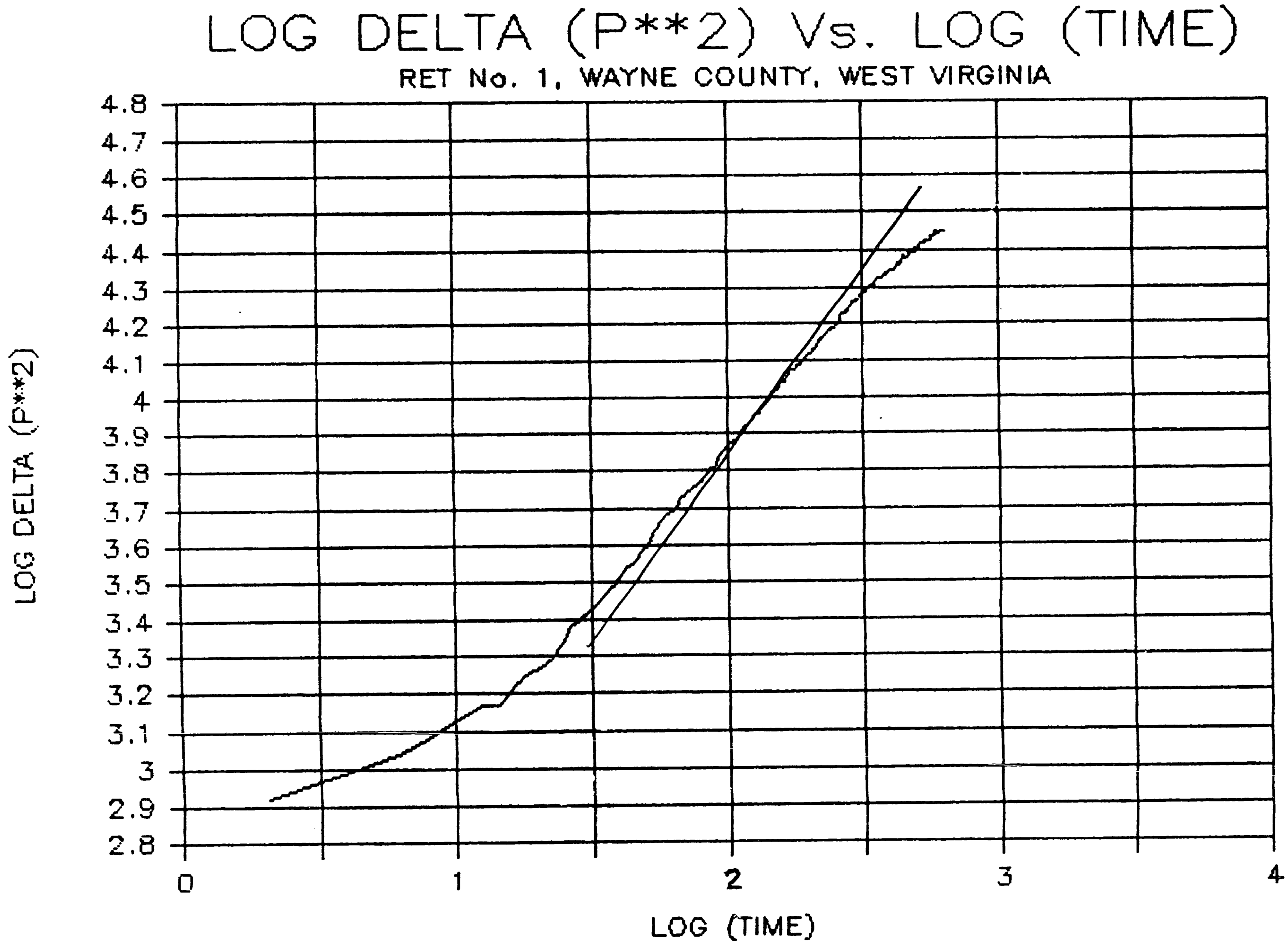

LOG DELTA (P**2) Vs. LOG (TIME)
RET No. 1, WAYNE COUNTY, WEST VIRGINIA
LOG DELTA (P**2)
4.8
4.7
4.6
4.5
4.4
4.3
4.2
4.1
4
3.9
3.8
3.7
3.6
3.5
3.4
3.3
3.2
3.1
3
2.9
2.8
0
1
2
3
4
LOG (TIME)

Figure 3.7.1.4

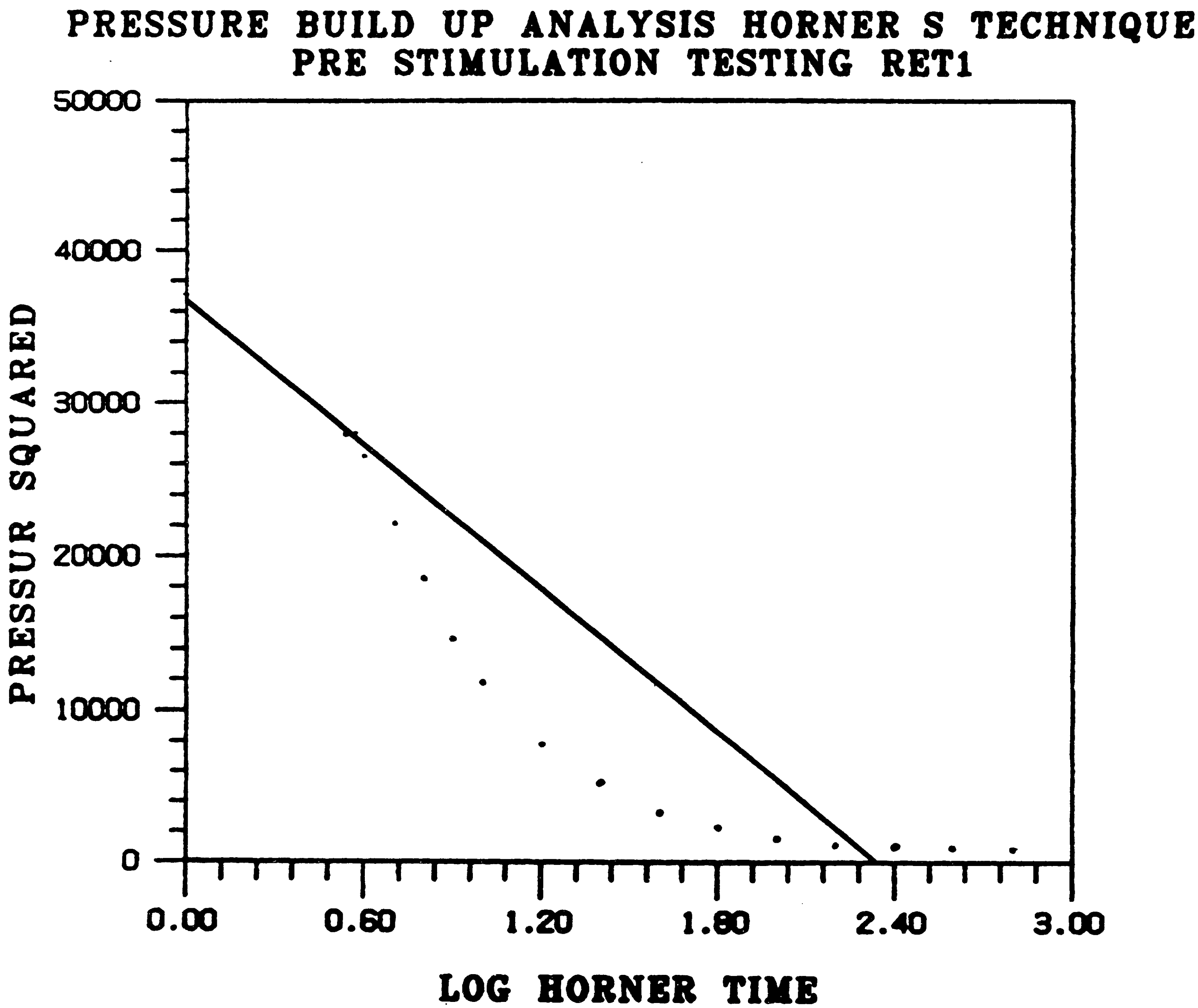

PRESSURE BUILD UP ANALYSIS HORNER S TECHNIQUE
PRE STIMULATION TESTING RET1
50000
40000
30000
20000
10000
0
PRESSUR SQUARED
0.00
0.60
1.20
1.80
2.40
3.00
LOG HORNER TIME

Figure 3.7.1.5

time, while p_{wf} is flowing bottomhole pressure. In this case, t_p was estimated to be 1632 hours. For this test, the first flow regime is characterized by the initial early time of slope = 1.0, which is indicative of wellbore storage (after flow) and apparent skin effects. Wellbore storage results from closing the well at the surface instead of at the sandface. Production continues from the formation into the wellbore for some time after the flow at the surface has been stopped. The data that fall in the middle time region with half slope period, represent a transition between wellbore distortion and linear flow into the horizontal wellbore which is very similar to the flow into a finite conductivity fracture.

As can be seen from Figure 3.7.1.4, wellbore distortion did not last very long and was not apparent after log time = 0.3 (time = 2 hours).

Horner's Technique:

A plot of P^2 versus Horner time on semilog paper where a build-up pressure curve was obtained (Figure 3.7.1.4) a straight line passing through the last stabilized pressure value was constructed having a slope 'm' (Figure 3.7.1.5). The following is the computation procedures to calculate values of Kh, S, and initial reservoir rock pressure.

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

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

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 determined as follows: $y = m \quad + b$, where m is the slope of the straight line; by taking two points on the straight line A(0,36,977) and B(2.331,01),

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

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:

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

(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, Pi

Z_i = gas - low deviation 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 3.7.1.5 of 15863.2 psia²/cp/cycle. Therefore, formation permeability (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:

$$S = 1.151 \left[\left(\frac{P_{1hr}^2 - P_{wf}^2}{m}\right) - \log \left(\frac{k}{\phi\mu_i C_{ti} r_w^2}\right) + 3.23\right] \qquad (3)$$

where: ϕ = porosity, % == 1.73%

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

$P1hr^2$ is computed using equation (1). Therefore:

$$P1hr^2 = -15863.2 \log \left(\frac{1+2(4)}{1}\right) + 36{,}977$$

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

$$= -1{,}463 \text{ psia}^2$$

Therefore,

$$S = 1.151 \left[\left(\frac{-1463 - 217}{15863.2}\right) - \log \left(\frac{0.082}{(0.0173)(0.0107)(0.010)(0.328)^2}\right) + 3.23\right]$$

$$S = 1.151 [-0.1059 - 5.615 + 3.23]$$

$$S = -2.87$$

Since $S_w = S_o = \emptyset$; therefore, $C_{ti} = C_{gi}$.

3.7.4 "Pseudo-Pressure" Method

Transient analysis is possible with compressible gas systems, if the real gas potential or pseudo pressure is used. The real gas pseudo pressure, m(p), can be calculated using:

$$m(p) = 2 \int_{p_b}^{p} \frac{p}{\mu(p)\ Z(p)}\, dp$$

A Fortran code was utilized to solve the above equation using the properties of the gas sample collected from the well. Based on the output generated by this code, a graph of pseudo-pressure versus bottomhole pressure was constructed, which is illustrated in Figure 3.7.1.6.

In order to determine flow regimes and to estimate permeability and "skin" factor, the same procedures of (a) was followed. Figures 3.7.1.4 and 3.7.1.5 are respective plots of log delta pseudo pressure versus log time and a semi-log plot of pseudo pressure versus log $[(t_p\ \ t)/t]$. From Figure 3.7.1.4, it is apparent that wellbore distortion is dominant until log time = 2.49 (time = 310 hours). From the results of m(p) plot, permeability is estimated from:

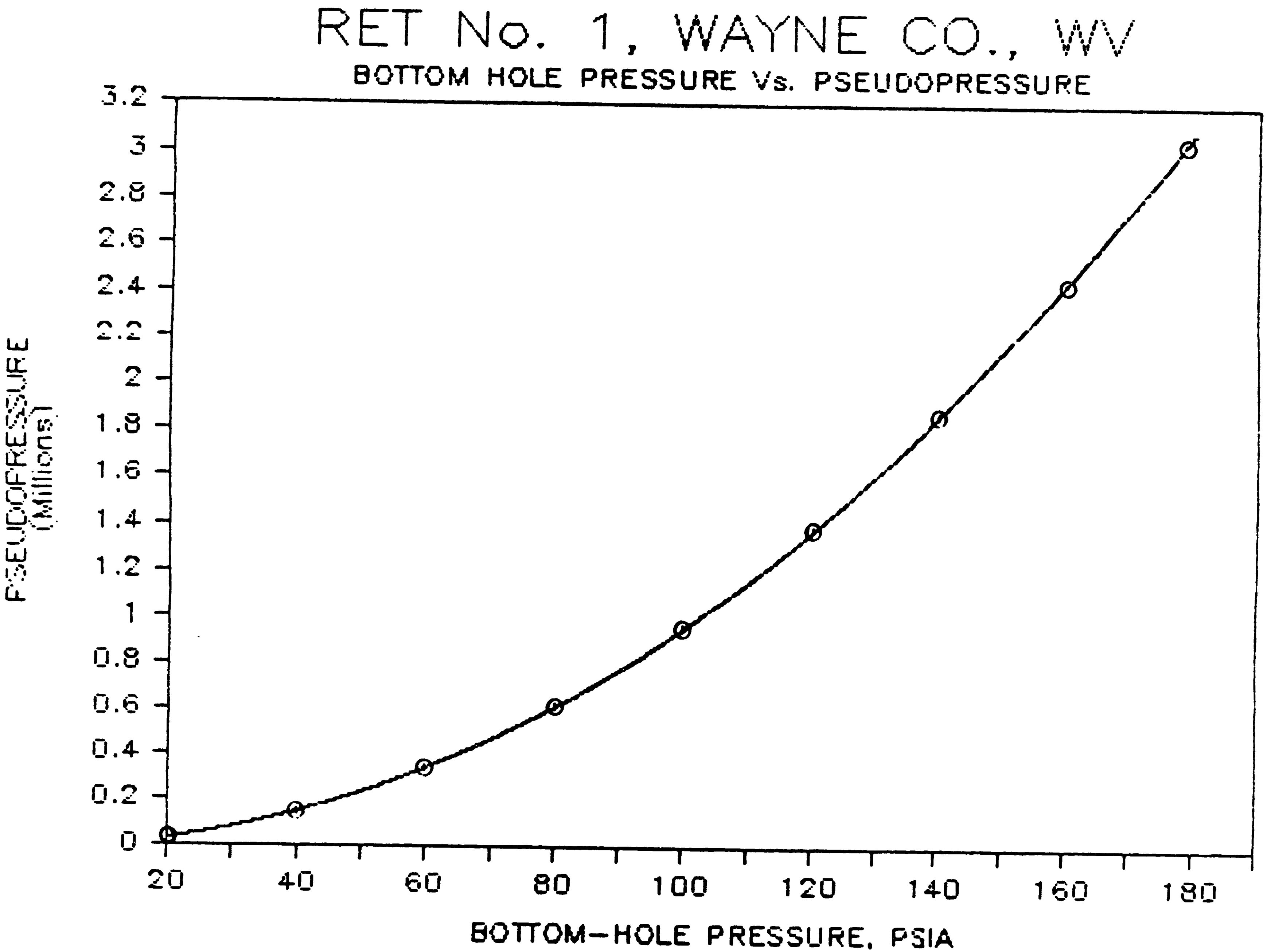

RET No. 1, WAYNE CO., WV
BOTTOM HOLE PRESSURE Vs. PSEUDOPRESSURE
PSEUDOPRESSURE (Millions)
BOTTOM-HOLE PRESSURE, PSIA

Figure 3.7.1.6

$$K = \frac{1637\ q_g T}{mh}$$

From Figure 3.7.1.5, slope is calculated as 1.56 x 10^6 psia^2/cp/cycle, formation permeability (k) was estimated to be:

$$K = \frac{1637 \times 34 \times (93 + 460)}{1.56 \times 10^6 \times 247}$$

$$K = 0.0798 \text{ md}$$

and

$$S = 1.151 \left[\frac{m(p)1\text{ hr} - m(p)\ @\ t{=}0}{m} - \log \left(\frac{k}{\phi \mu_i C_{ti} r_w^2} \right) + 3.23 \right]$$

$$S = 1.151 \left[\frac{-2\times10^6 - 0.020\times10^6}{1.56 \times 10^6} - \log \left(\frac{0.080}{0.0173 \times 0.0107 \times 0.0114 \times 0.328^2} \right) + 3.23 \right]$$

$$S = -4.00$$

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.

3.7.5 Reservoir Modeling

Following the build-up test for RET #1, an attempt was made to isolate and individually test each of the seven zones representing a total of 2211 feet (3803 - 6014') (see Table 3.7.5.1):

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.

TABLE 3.7.5.1

ISOLATED ZONES AND MEASURED INTERVALS

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	

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 (based on a 24-hr build-up test)

Fracture spacing = 10 feet

Matrix porosity = 0.02%

Matrix permeability = 0.90 μd

Gas properties from Table 1

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

Reservoir dimensions: 14 x 8 x 5

Table 3.7.5.2 represents a summary of each zone's 24-hour pressure buildup and corresponding permeability values predicted by the reservoir model:

TABLE 3.7.5.2

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

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

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

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

In order to check validity of the permeability values predicted by the model, a full-field simulation run for seven (7) active vertical shale wells along with an unstimulated horizontal shale well in the same area was prepared. The horizontal shale well performance for the first year revealed a cumulative production of 14,852 mscf which is an average production rate of approximately 41 mscfd, while the present actual well production is 34 - 35 mscfd. These results indicated that the model and derived permeability values are perhaps fairly close to actual field conditions. Table 3.7.5.3 shows a summary of these simulation runs:

TABLE 3.7.5.3

SUMMARY OF FULL-FIELD SIMULATION

20-year Cumulative Production (MMcf)	
7 vertical shale wells	4,316
7 vertical shale wells plus one unstimulated horizontal shale well	4,620
Unstimulated horizontal shale well (2211 feet)	304

Actual average production rate = 34 - 35 mscfd

Model predicted production rate for the first year = 41 mscfd

4.0 RECLAMATION ACTIVITIES

4.1 Introduction

This project conducted by the U.S. Department of Energy (DOE) is required by Internal Departmental regulation to comply with all Federal and State regulations regarding environmental issues. A preliminary environmental assessment of the potential impacts of the drilling, stimulation, and testing operations revealed that only short-term impacts of dust, noise, and mineral-laden water was projected for the operation. All of these impacts could be remedied by the normal reclamation activities required by the State of West Virginia.

4.2 Reclamation of Abandoned Hole

During the course of drilling the shallow, large-diameter vertical hole, the 20-inch bit broke and two-thirds of the bit were left on the bottom of the hole at a depth of 160 feet. An attempt was made to retrieve the bit but this was abandoned after two days, and the rig was skidded 20 feet and a new hole was started. A temporary plug and cover was placed over the hole while drilling operations continued. The temporary plug was to keep people or animals from accidentally falling into the 20-inch diameter hole.

After the second hole was completed and the rig was moved, reclamation of the abandoned hole was initiated. A workover rig was moved over the old hole and the temporary plug was drilled out. Prior to this operation, however, a permit to abandon the old hole was obtained from the West Virginia Department of Natural Resources, Oil and Gas Division. When the cleaned-out well was ready to plug, the local Oil and Gas Inspector was notified and cementing of the well was scheduled when he could observe the operations. The large diameter hole was cemented by pumping 255 sacks of Class A cement down two-inch diameter plastic pipe which was installed in the hole. The cement was pumped to the bottom of the hole and circulated all the way to the top.

A special 11-foot long 6" diameter steel monument was erected in the hole with the API number of the well welded onto the monument. Mr. Jerry Holcomb, West Virginia State Oil and Gas Inspector, approved the abandonment procedure conducted by BDM Corporation.

4.3 Reclamation of Pits

In accordance with State regulations, a composite sample of water from the drilling pits was obtained and sent to a state-approved laboratory in Charleston, West Virginia. The sample analysis indicated that upon neutralization, the water from the pits could be aerated and pumped onto the surface of the land for an approved land disposal procedure.

The pit was treated and a second composite sample was obtained and sent to the laboratory in Charleston. A copy of the analysis was sent to the State Water Resources Division and approval for land disposal was received. Water from the pit was then disposed over an area of two acres by utilizing a plastic hose with holes in it to allow spraying over the surface.

4.4 Reclamation of the Drilling Site

After the water was removed, the bit was filled in and the original contour was approximated by the reclamation crew. An area of about 100-foot square surrounding the wellhead was left level to facilitate the moving in and out of workover rigs while the rest of the 2 acre site was contoured by the bulldozer.

After the contouring was completed, a small tractor was used to smooth the surface, remove large stones, and prepare the soil for planting grass. A hand-held grass seed broadcaster was used to plant the seed over the drill site. Prior to planting of the grass seed, lime was mixed in the top layer of the soil to raise the ph of the soil. After the grass seed was planted, straw was placed over the seed to keep it in place and provide mulch. The initial reclamation work on the drill site was completed in May, 1987, five months after completion of drilling operations in December, 1986.

4.5 Reclamation of Lease Access Roads

Approximately 4.2 miles of improved (stoned) dirt road through Cabwaylingo State Forest had to be traversed to reach the Energer lease. A 2000-foot long access road had to be constructed to the drilling location. Of the 2000 feet, only 300 feet of new road had to be built; the rest followed old established logging trails which had been in existence for more than 20 years.

During drilling operations, and afterwards, more than 600 tons of limestone was placed on the Tick Ridge road and the lease road. The access road was regraded over a length of about 2.0 miles and 3 new drainage ditches constructed to help drain water from the road surface during the rainy season. Poor drainage resulted in the deep rutting of the road by heavy trucks and the need for large amounts of stone to recondition. BDM and the reclamation crew (Smith Excavating Company) worked directly with the State Road Commission in reconditioning the road. BDM provided the stone and the dozers to work the road, and the State Road provided graders and payloaders to place the stone and work it.

The 2000 feet of lease road was recontoured on uphill and downhill banks by a small tractor and then grass was sewn by the portable broadcaster. Again straw was placed over the seed to keep it in place and provide mulch. Within 6 weeks a strong, healthy stand of grass was growing along the banks of the access road and on the recontoured drill site. The new grass and access road as reclaimed was very attractive and did not detract from the surrounding Cabwaylingo State Forest area.

4.6 Future Reclamation Activities

During the summer and fall of 1987, several frac jobs will be conducted on the well and the use of heavy frac trucks will undoubtedly damage the reclained lease road and site. After all stimulation activities are completed, the location and access road will be worked and reclaimed for a final time before turning over all operations to the lease owner, Eneger Corporation. The same procedures used in the original reclamation work will be used to reclaim any pits which may be constructed to catch flowback fluids from the stimulation jobs. All reclamation work will be inspected and approved by both Cabwaylingo State Forest officials and the State Oil and Gas Inspector.

5.0 COMPILATION AND ANALYSIS OF DATA

5.1 Review and Analysis of Oriented Core Studies for Physical and Mechanical Properties

The bulk of the oriented core material was sent to Michigan Technological University where various mechanical properties tests were conducted on the material. The results of the various tests conducted (see detailed summary report in Appendix 7.3) generally agrees with the results of other data such as structure on the Berea horizon, trends of remote sensing lineaments and seismic fractures.

The orientation of ultrasonic velocity tests' maximum measurements wree oriented N60°E and N30°E. Point load failure tests were also oriented in this direction. These trends correspond with trends oriented N37°E, N48°E, and N57°E as mapped on Berea structure and found as joints in the core material itself.

Statistical analysis of the data indicates the trend of N48°E as the principal stress orientation. This correlates with an orientation of N52°E arrived at by BDM geologists prior to drilling operations. The N30°E ±15° value indicated by ultrasonic velocity tests and the N60°E ±15° trend indicated by the point load tests we believe identifies the additional natural fracture directions projected for the area. BDM concludes that the directional properties and other core studies verified pre-drilling analysis of geologic data for the area and the site.

Other physical properties which relate to reservoir properties or data needed for geophysical log interpretation are presented in Table 5.1.1. The complete report on core analysis and petrographic studies are presented in Appendix 7.2 and 7.3.

5.2 Review and Analysis of Petrographic Properties

The shale, as sampled by the core material, is best described as a brownish-gray, moderately lithified, fissile shale containing organic materials such as bone fragments and spores. The shales are thinly laminated as identified by alignment of elongated grains of silt, clay micas

TABLE 5.1.1

SUMMARY OF CORE ANALYSIS RESULTS

PARAMETER	RANGE OF VALUES	AVERAGE VALUE
Grain Density	2.41 - 2.59 g/cc	2.50 g/cc
Bulk Density	2.38 - 2.56 g/cc	2.47 g/cc
Porosity	1.3 - 2.3 percent	1.36 percent
Permeability	<0.01 - 1.6 microdarcies	0.818 microdarcies*
Water Saturation	9 - 18 percent	12.3 percent

* Test conducted at reservoir overburden pressure of 3335 psi.

and spores. The silt laminae contain quartz, feldspar and accessory muscovite, apatite, zircon and sphene. The matrix material consists of mixtures of illite, chlorite, and smectite interpreted to be detrital in nature. The shales are fairly high in cements such as pyrite, quartz, chert, dolomite, ankerite and anatase. Porosity is low, microporosity with occasional moldic, intragranular, shrinkage and microfracture porosity. Overall reservoir properties are determined to be poor and is only enhanced by extensive tectonic fracturing which seems to be localized rather than pervasive. These shales are obviously source rocks for hydrocarbons.

Potential problems which were defined as a result of the detailed petrographic studies by Core Laboratories, Inc., were identified as the precipitation of potential pluggic ferric hydroxide gels and the release of fines to produce plugging by migration. Introduction of incompatible water or chemical-laden fluids could produce these gels and release fines.

Water bonded to the clay matrix may give higher calculated neutron log values for porosity. The pyrite may tend to suppress resistivity values.

5.3 Review and Analysis of Well Testing Data

Well testing conducted on the whole well and on each individual zone revealed, as expected, that bulk reservoir properties are higher than those determined for the smaller core analysis samples. Permeability ranges from 0.032 to 0.098 and averages 0.066 millidarcies. Pressures determined from the well testing ranged from 178 to 185 psig and averaged 182 psig.

The skin factor of -2.87 calculated for the well before stimulation reflects the fractured nature of the reservoir. There could be some skin damage being exhibited by the formation which might otherwise have a higher negative skin, indicating one or several large fractures in contact with the wellbore.

The projected production for an unstimulated horizontal well was perhaps slightly high, but fairly close to actual conditions. Although the well, after producing episodically since January 9 to May 4, 1987, when the final results of 34 mcfpd were determined, had increased from a rate of 20 mcfpd as shown in Figure 3.3.1.2. This indicates that had the well been placed on natural production for a period of a year, production could well have increased to an average of 41 mcfpd which is the value required to match the simulation value.

This value is considerably below what we anticipated before drilling the well, primarily because we believed that reservoir pressure could well be over 250 psig when in fact it was only 182 psig. The one thing that seems apparent at this time is that a reliable projection of 20 years cumulative production is not likely until after 2 or 3 years of actual production data has been obtained. The highly fractured nature of the reservoir and the potential for complex interactions of flow paths and drainage cells from the horizontal wellbore make projections based on early data (less than 6 months production) very suspect.

6.0 DISCUSSION OF RESULTS

6.1 Discussion of Whole Well Testing

The whole well testing of the horizontal well could not be conducted as normal because the Devonian shale is a low pressure reservoir; in addition, the original reservoir pressure of 540 psi had been reduced to 182 psig as a result of 45 years of gas production in the area. Production testing was erratic because of weather and lease road conditions during the months of January through March, 1987, when testing was conducted. Production appeared to stabilize to a normal decline rate after 30 days of continuous production without interruption. The final open flow rate of 34 mcf, as shown in Figure 3.5.1, was a rate that had improved over the original rate test made in January because the well was cleaning up with production.

Future testing of low pressure reservoirs should probably be confined to an initial long-term atmospheric open flow test (7 to 10 days), followed by controlled rate and/or flow against back pressure.

6.2 Discussion of Zone Testing

The zone flow testing on the well was not conducted with a duration long enough to get data with unquestioned reliability. Because of scheduling problems and the high number of wells, approximately 60 days would have been required to conduct proper zone isolation flow tests on each zone. Budget and time constraints reduced this test to a 3-day test for each zone.

Permeabilities calculated for each zone, as presented in Table 3.7.5.2, may be somewhat optimistic, but are most likely in the right range. Future testing under these (or similar) conditions of multiple zones should include flowing from each isolated zone for a period of up to 14 days. A zone-by-zone test of flow rate could be made by using the isolation cup tool at the beginning of the flow period and again at the end of the flow period. There should be no doubts about the quality or accuracy of the data under these conditions.

SUMMARY

This summary highlights the major findings of a Petrographic Study, including detailed Thin Section Petrography and Scanning Electron Microscopy with Energy Dispersive Spectroscopy (SEM/EDS), recently completed on seven (7) shale samples (sample numbers 28H1 through 28H7, inclusive).

Fabrics, Textures, and Sedimentary Structures: The seven (7) submitted samples appear to be moderately lithified, brownish gray, fissile shales, as revealed by thin section and SEM studies. These shales are usually laminated, and the thin, plentiful, and well-defined laminae appear to have been locally disrupted. These laminations are defined by the indistinct to well-developed alignment of elongate and/or compacted grains of clay, silt, micas, and spores.

Silt and Clay Mineralogy: Detailed point count analyses of these shales reveal that quartz (both monocrystalline and polycrystalline varieties), feldspar (alkali and plagioclase), accessory grains (muscovite, apatite, zircon, and sphene), and biogenic materials (bone fragments and spores) dominate the silty portions of all seven (7) shales. These silt-size components occur either as individual grains or as discrete silty laminae. The matrix fractions of all seven (7) shales appear to be composed of undifferentiated clays and finer silts, which were most likely deposited by suspension. Elemental analyses of the matrix reveal varying proportions of silicon, aluminum, iron, potassium, and calcium, which suggest that the matrix constituents may be chemical and/or physical mixtures of illite, chlorite, and smectite. The non-descript morphology of the matrix also implies a detrital origin.

Cements: Total cement content is fairly high, as revealed by point count analyses. Pyrite is the most abundant cement, with lesser and variable amounts of quartz, chert, dolomite, ankerite, and anatase also present. The presence of authigenic clays was detected neither by thin section nor by SEM/EDS studies.

Organic Material/Residual Hydrocarbon: Organic material is most likely intermixed with detrital clays that comprise the matrix in these samples.

Porosity: Low amounts of ineffective microporosity are associated with the detrital matrix clays and silts. Rarer occurrences of grain-moldic, intragranular, and shrinkage porosity were also observed. *In situ* fractures, where they exist, may enhance permeability.

Estimated Reservoir Quality: Due to the negligible amounts of effective macroporosity and the permeability-inhibiting, fissile fabric of these shales, a poor to low reservoir quality is estimated for these samples. However, the presence of spores and the probable presence of other organic debris within the matrix suggests that, under favorable conditions, these shales may serve as possible source rocks for hydrocarbons.

Potential Production Problems and Formation Damage: Introduced fluids antagonistic to formation brines may lead to problems such as ferric hydroxide gel precipitation (pyrite, ankerite, and chlorite), calcium fluoride precipitation (ankerite), and "fines" migration (fine silt and clay particles).

Mineralogical Influences on Wireline Log Responses: Calculated neutron porosity values may be somewhat higher than anticipated due to the irreducible water associated with the microporous, clay-rich matrix. Iron-dominant chlorite and smectite (where present), ankerite, and pyrite may cause density porosity values to be somewhat optimistic. Where it occurs in appreciable amounts, pyrite may suppress resistivity values. A typical shale response can be anticipated on the gamma ray log.

Suggestions for Further Study: Definitive clay compositions can only be determined by X-ray diffraction methods.

INTRODUCTION

Seven (7), moderately consolidated shale samples (numbered 28H1 through 28H7) were received from Core Research, Inc. on March 10, 1987. Dr. Joel Walls requested the Reservoir Geology/Petrographic Services Group of Core Laboratories, Inc. in Irving, Texas to perform a Petrographic Study, including detailed Thin Section Petrography and Scanning Electron Microscopy with Energy Dispersive Spectroscopy (SEM/EDS), on all seven (7) submitted samples.

The objectives of this study include the determination of:

1. Megascopic features, fabrics, textures, and sedimentary structures;
2. Silt, matrix, cement, and clay compositions and abundances;
3. Types, amounts, and distribution of porosity;
4. Estimation of reservoir quality;
5. Occurrences of potential problem minerals;
6. Possible mineralogic effects on completion, production, enhanced recovery, and wireline logs; and
7. General recommendations to circumvent or mitigate these possible difficulties.

A list of the types of analyses performed and the information provided by each of these analyses is cited below.

Petrographic Analysis by Thin Section provides the following information:

1. Textural information (sorting, packing, grain-size, fabric, lithification);
2. Framework-grain mineral identification and quantification (based on modal point count analyses of 400 points);
3. Presence, location, distribution, and identification of matrix material;
4. Identification, quantification, and distribution of authigenic cementing agents;
5. Identification, quantification, and distribution of the different types of pores present; and
6. Reservoir quality evaluation.

Examination by Scanning Electron Microscopy reveals the following:

1. Low magnifications provide textural information concerning lithification, sorting, grain-size, distribution of matrix material, and distribution of pores;

2. Higher magnifications reveal the morphology (detrital or authigenic) and location of the "sensitive" minerals present;

3. Distribution and types of authigenic cements present;

4. Elemental analysis of clay minerals, cements, and framework grains by use of EDS; and

5. Reservoir quality evaluation.

DISCUSSION

A Petrographic Study, including detailed Thin Section Petrography, Thin Section Photomicroscopy, Scanning Electron Microscopy (SEM), and Energy Dispersive Spectroscopy (EDS), was recently completed on seven (7) shale samples (sample numbers 28H1 through 28H7, inclusive) submitted by Core Research, Inc., on March 10, 1987. This Discussion is a detailed presentation of the raw data as well as interpretations, conclusions, and implications derived from these data.

FABRICS, TEXTURES, AND SEDIMENTARY STRUCTURES

Examination of textural features using optical and scanning electron microscopy techniques reveal that all seven (7) mudrocks are moderately lithified, brownish gray (5YR 4/1; Goddard, et al., 1980), planar laminated, fissile shales (Picard, 1971). The laminar and fissile character of these shales has been created by original depositional conditions as well as by compaction. Original depositional conditions most likely have produced the parallel alignment of suspension-deposited clays and silts and elongate quartzofeldspathic grains. Compaction during diagenesis has emphasized the original layering and has flattened the more ductile components, such as spores. The plentiful, well-defined, and thin laminae occasionally appear disrupted, although no evidence of infaunal activity was observed either in thin section or with the SEM.

The seven (7) shales contain low to moderate volumes of silt-size grains of quartz (both monocrystalline and polycrystalline varieties), feldspar (both alkali and plagioclase), accessory phases (muscovite, apatite, zircon, and sphene), and biogenic materials (bone fragments and spores) which appear heterogeneously distributed throughout the detrital matrix. Silty detritus also occurs as randomly dispersed laminae. The detrital matrix is the most abundant component in all samples, and it appears less heterogeneously distributed than the silt fraction.

SILT AND CLAY MINERALOGY

For the detailed thin section study, a point count analysis of 400 points per sample was performed. The use of Alizarin red-S stain for calcite, potassium ferricyanide stain for ankerite, and sodium cobaltinitrite stain for potassium feldspar facilitated the identification of these minerals during point counting. Inspection of the point count data shows that the dominant constituent in all seven (7) shales is an undifferentiated matrix material, most likely composed of detrital fine silt and clay (62.5 to 73.8 volume percent). Considerably smaller volumes of quartz, both as monocrystalline (5.0 to 12.5 percent) and as polycrystalline (0.3 to 1.0 percent) grains, and alkali (0.5 to 1.5 volume percent) and plagioclase (0.0 to 0.5 percent) feldspars are the most easily discernable silt-size grains. Minor and varying amounts of accessory minerals (0.5 to 2.5 percent), such as muscovite, zircon, apatite, and sphene, and biogenic minerals (1.5 to 5.8 percent), such as bone fragments and spores, were also observed.

The generally fine-grained appearance of these laminated mudrocks suggests that they are suspension deposits. The presence of the somewhat coarser, very fine sand-size and coarse silt-size grains and laminae implies that suspension deposition was occasionally punctuated by depositional events with somewhat higher energy.

SEM examination of morphological characteristics of the matrix, coupled with qualitative chemical analysis by EDS, suggests that most, if not all, of the matrix material consists of unrecrystallized to very poorly recrystallized clays and fine silts. The lack of a distinct morphology, a feature usually associated with authigenic clays, indicates that these clay materials are probably detrital. The presence of fine crenulations along some clay margins indicates that minor recrystallization may have occurred. Varying proporations of silicon, aluminum, potassium, iron, and calcium detected by EDS are also highly suggestive of the wide range in chemical composition typically associated with detrital clays. Because no distinct morphology or composition can be discerned, the exact clay composition cannot be determined. However, the EDS data do suggest that the matrix may be composed of chemical (mixed-layer) or physical mixtures of illite, smectite, and chlorite. Definitive clay compositions can only be deduced by X-ray diffraction methods.

ORGANIC MATERIAL/RESIDUAL HYDROCARBON

The extremely fine-grained nature of the matrix makes it difficult to unequivocally determine the amount of organic material and residual hydrocarbon present in these shales. The presence of pyrite and spores, however, indicates that organic material may have originally been present in much greater quantities. Reduction of organic material by bacteria is thought to be the most likely cause of formation of authigenic pyrite. Geochemical studies, including source-rock evaluations, may provide more information on the types, amounts, and maturity of the organic and hydrocarbon material.

CEMENTS

Authigenic cements occur in significant quantities in all seven (7) shale samples (9.8 to 17.5 volume percent), the most common being pyrite (7.3 to 11.8 percent). Pyrite occurs in a variety of forms: as single octahedra, as single cubes, and as framboidal aggregates. Most of the pyrite is probably secondary after organic material. Lesser amounts of quartz, chert, dolomite, ankerite, and anatase were also detected in thin section and with the SEM. Quartz occurs as rare, poorly defined, secondary overgrowths on host grains of quartzose silt. Chert is generally recognized by its low birefringence and pinpoint extinction. Chert can most often be noted as isolated patches, or, more rarely, as elongate lenses. Dolomite and ankerite form euhedral to subhedral rhombohedra, which may occur singly or en masse. Dolomite can usually be distinguished from ankerite by staining techniques. Fine, needle-like crystals of titanium oxide, probably anatase, are rare cements.

Of all the cements, pyrite probably has had the most significant effect on sample lithification and porosity reduction. However, this effect is presumed to be minimal because of the replacive nature of the pyrite and the initial low porosity and permeability of these shales.

POROSITY

The predominance of clay- and silt-size particles in the matrix suggests that microporosity is the dominant porosity type. Thin section petrography generally provides accurate estimates of macroporosity, but typically does not provide an accurate measurement of microporosity. Special core analysis or Petrographic Image Analysis may provide a more accurate determination of microporosity.

In addition to microporosity, small amounts of grain-moldic, intragranular, and shrinkage porosity were detected in these samples. These pores are sparse and isolated. Grain-moldic pores are formed by the complete leaching of unstable framework grains, whereas intragranular pores are formed by the partial leaching of framework grains. Shrinkage pores most commonly occur due to desiccation of clays and/or organic material. The shrinkage pores occur in conjunction with spores, and the former are presumed to have been formed by dewatering during diagenesis. Thus, these shrinkage pores are very likely inherent to the formation.

Pore occlusion has been most affected by the original depositional characteristics of these samples: the close packing and subparallel alignment of silt and clay particles. Compaction and authigenic mineral formation during diagenesis has also caused porosity reduction. Diagenesis has created dissolution pores, but, on the whole, porosity reduction far exceeds porosity enhancement.

ESTIMATED RESERVOIR QUALITY

Low porosity values and assumed low permeability values indicate that the seven (7) shale samples have very poor reservoir characteristics. The presence of pyrite, organic material, and spores, however, suggests that these shales may represent source rocks for hydrocarbons. Geochemical studies may give an accurate assessment of the source-rock potential of these mudrocks.

POSSIBLE PRODUCTION PROBLEMS AND FORMATION DAMAGE

Certain minerals, due to their physicochemical characteristics or abundances, may cause production problems and formation damage if they are not properly treated during drilling and completion programs. Based on the results of this study, the following minerals and the problems commonly associated with them include:

Chlorite (including Mixed-Layer Illite/Chlorite)

Chlorite is a three-layered, hydrated alumino-silicate often containing significant amounts of iron. Iron-rich chlorite is sensitive to acid and oxygenated waters, and an iron-chelating agent and oxygen scavenger should be introduced with any acid stimulations in order to inhibit the precipitation of pore-plugging, colloidal silica gels. The acid should be retrieved before it is spent.

Illite

Illite is a three-layered, hydrated silicate containing potassium, silicon, and aluminum. Authigenic illite generally occurs as crenulated sheets with lath-like projections, and can create high microporosity and high irreducible water saturations. In the presence of high flow rates, the lath-like projections can break off and migrate to pore throats, resulting in a reduction of permeability. Illite may be dissolved with a weak mixture of HCl/HF acids.

Pyrite

Iron-rich pyrite is sensitive to acids and oxygenated waters. Therefore, an iron-chelating agent and oxygen scavenger should be introduced with any acid stimulations to inhibit the precipitation of pore-plugging ferric-hydroxide gel.

Silicate Minerals (Quartz, Feldspars, and Clays

The reaction of HF acid with silicates can result in the precipitation of colloidal silica. The extent of this precipitation depends upon HCl/HF concentration and the amount of clay in the reservoir rock.

Carbonate Minerals

Dissolution of dolomite and ankerite in HF acid can lead to the precipitation of insoluble calcium fluoride gels. Therefore, these carbonates should be dissolved first with HCl acid before treatment with HF or fluoboric acid. Iron-rich ankerite requires the introduction of an iron-chelating agent with any acid stimulations to inhibit the precipitation of ferric hydroxide. Preflushing with HCl is required with any acid stimulations for reservoirs in which carbonates are present.

MINERALOGICAL INFLUENCES ON WIRELINE LOG RESPONSES

Certain mineral and porosity characteristics of these shales may influence wireline log responses due to their abundances, chemical compositions, or physical characteristics. Formation parameters derived from these log responses may lead to erroneous evaluations of reservoir quality. Potential affects may be noted on the following logs:

1. Neutron Porosity Log: Hydrous minerals, such as clays, and "bound" water occurring in conjunction with clay micropores, will be recorded as part of the total formation porosity. Thus, porosity values derived from the neutron porosity log are anticipated to be more optomistic than they actually are.

2. Resistivity Log: Semi-conductive pyrite, an important constituent in

all these shales, may cause resistivity suppression. Water saturation (S_w) values calculated using resistivity logs, therefore, may not accurately reflect true ambient water saturations.

3. Density Log: Estimation of porosity values from density logs are usually based on an assumed grain density of 2.65g/cc for sandstone. However, significant quantities of pyrite (4.95-5.03g/cc) and clay (2.10-3.30g/cc) suggest that overall grain density may be increased and thus, if uncorrected, computed density porosity values may be higher than expected.

4. Gamma Ray Log: Due to the presumed fairly high illite content, these samples are anticipated to yield gamma ray responses characteristic for shales.

SUGGESTIONS FOR FURTHER STUDY

The fine size of clay minerals (less than 4 microns) makes thin section study of these materials unproductive for a detailed characterization of clay mineralogy. SEM analysis of clays yields more information if the clays are authigenic, but the clays in these shales are mostly detrital. The detrital nature of most of the clay material in these samples suggests that X-ray diffraction (XRD) may provide the most valuable information on the mineralogy of the clay-size material.

ANALYTICAL PROCEDURES

For the Scanning Electron Microscopy/Energy Dispersive Spectroscopy (SEM/EDS) Study, the samples are broken to form fresh surfaces. Each sample is then mounted on an aluminum stub and coated with a thin film of gold-palladium (Au-Pd) alloy using an ISI-PS2 Coating Unit (sputter-coating process). The SEM photomicrographs are back-scattered electron images (Robinson detector) taken with a Polaroid camera attached to an ISI-SX-40 Scanning Electron Microscope operating at 20kV. Qualitative elemental data of selected phases observed during SEM study are obtained through the use of an interfaced PGT System III Energy Dispersive Spectroscopy Unit equipped with a Si(Li) detector. Recognition of authigenic clays is based on the criteria proposed by Wilson and Pittman (1977).

The sample fractions are prepared for Thin Section Analysis by first impregnating the samples with epoxy to augment sample cohesion and to prevent loss of material during grinding. A blue dye is added to the epoxy to highlight the porosity. Each sample is mounted on a glass slide and then cut and ground in water to an approximate thickness of 30 microns. Samples containing known water-soluble phases are prepared using odorless kerosene. Prepared thin sections are subsequently stained for calcium carbonate (Alizarin Red-S stain), iron-bearing carbonate (potassium ferricyanide stain), and potassium silicates (sodium cobaltinitrate) as necessary. The thin sections are analyzed using standard petrographic techniques. Modal analyses of the sections are performed by the point-count method (400 points/sample) using a Swift Model F Automatic Point Counter. Mineralogy and porosity percentages are calculated from raw point count data using a special point count routine developed by Core Laboratories, Inc. Actual totals may deviate slightly from 100 percent due to computer rounding. Picard's (1971) classification is used for mudrock samples.

REFERENCES

Goddard, E.N., P.D. Trask, R.K. DeFord, O.N. Rove, J.T. Singewald, and R.M. Overbeck, 1980, Rock Color Chart: Geological Society of America, Boulder, Colorado.

Picard, M.D., 1971, Classification of fine-grained sedimentary rocks: Journal of Sedimentary Petrology, Volume 41, p. 179-193.

Wilson, M.D. and E.D. Pittman, 1977, Authigenic clays in sandstones: recognition and influence of reservoir properties and paleoenvironmental analysis: Journal of Sedimentary Petrology, Volume 47, p. 3-31.

TABLE 1
THIN SECTION ANALYSES: TEXTURE

Sample Number:	28H-1	28H-2	28H-3
Name (Picard, 1971):	Shale	Shale	Shale
Color of Hand Sample (Goddard, et al., 1980):	Brownish gray 5YR 4/1	Brownish gray 5YR 4/1	Brownish gray 5YR 4/1
Lithification:	Moderate	Moderate	Moderate
Fabric and Textures:	Well-developed alignment of elongate and/or compacted particles	Well-developed alignment of elongate and/or compacted particles	Well-developed alignment of elongate and/or compacted particles
Sedimentary Structures:	None	None	None
Fissility:	Well-developed	Well-developed	Well-developed
Porosity Types:	Shrinkage	Shrinkage	Shrinkage

TABLE 1 (Cont'd)

THIN SECTION ANALYSES: TEXTURE

Sample Number:	28H-4	28H-5	28H-6
Name (Picard, 1971):	Shale	Shale	Shale
Color of Hand Sample (Goddard, et al., 1980):	Brownish gray 5YR 4/1	Brownish gray 5YR 4/1	Brownish gray 5YR 4/1
Lithification:	Moderate	Moderate	Moderate
Fabric and Textures:	Well-developed alignment of elongate and/or compacted particles	Well-developed alignment of elongate and/or compacted particles	Well-developed alignment of elongate and/or compacted particles
Sedimentary Structures:	None	None	None
Fissility:	Well-developed	Well-developed	Well-developed
Porosity Types:	Shrinkage	Shrinkage	Shrinkage and intragranular

TABLE 1 (Cont'd)
THIN SECTION ANALYSES: TEXTURE

Sample Number:	28H-7
Name (Picard, 1971):	Shale
Color of Hand Sample (Goddard, et al., 1980):	Brownish gray 5YR 4/1
Lithification:	Moderate
Fabric and Textures:	Well-developed alignment of elongate and/or compacted particles
Sedimentary Structures:	None
Fissility:	Well-developed
Porosity Types:	Shrinkage

File: 187031

TABLE 2

THIN SECTION ANALYSES: COMPOSITION

Sample I.D.	28H-1	28H-2	28H-3	28H-4	28H-5
FRAMEWORK GRAINS	20.0	14.0	13.5	16.3	14.5
Quartz	13.5	8.5	5.5	9.0	10.5
Monocrystalline	12.5	8.0	5.0	8.8	9.5
Polycrystalline	1.0	0.5	0.5	0.3	1.0
Feldspar	0.5	0.8	1.3	1.5	1.8
Alkali Feldspar	0.5	0.8	0.8	1.3	1.5
Plagioclase	0.0	0.0	0.5	0.3	0.3
Accessory Grains	1.0	2.0	1.0	0.8	0.5
Muscovite	0.8	1.3	1.0	0.8	0.5
Zircon	0.0	0.3	0.0	0.0	0.0
Apatite	0.3	0.3	0.0	0.0	0.0
Sphene	0.0	0.3	0.0	0.0	0.0
Biogenic Materials	5.0	2.8	5.8	5.0	1.8
Bone Fragments	0.8	0.3	0.0	1.0	0.3
Spores	4.3	2.5	5.8	4.0	1.5
MATRIX	62.5	70.8	72.3	73.8	71.5
Undifferentiated	62.5	70.8	72.3	73.8	71.5
AUTHIGENIC CEMENT	17.5	15.0	14.0	10.0	13.8
Quartz	0.8	0.5	0.5	0.3	0.3
Chert	0.0	0.0	0.0	0.0	0.3
Dolomite	0.5	0.0	0.0	0.0	0.0
Ankerite	4.5	3.3	2.3	1.0	3.0
Pyrite	11.8	11.3	11.3	8.5	9.8
Anatase	0.0	0.0	0.0	0.3	0.5
POROSITY	0.0	0.3	0.3	0.0	0.3
Dissolution	0.0	0.0	0.0	0.0	0.0
Grain Moldic	0.0	0.0	0.0	0.0	0.0
Intragranular	0.0	0.0	0.0	0.0	0.0
Shrinkage	0.0	0.3	0.3	0.0	0.3
TOTAL	100.0	100.0	100.0	100.0	100.0

TABLE 2 (cont'd)

THIN SECTION ANALYSES: COMPOSITION

Sample I.D.	28H-6			28H-7		
FRAMEWORK GRAINS	14.8			18.0		
Quartz		10.3			10.8	
Monocrystalline			9.8			10.3
Polycrystalline			0.5			0.5
Feldspar		0.5			0.8	
Alkali Feldspar			0.5			0.8
Plagioclase			0.0			0.0
Accessory Grains		2.5			1.5	
Muscovite			2.0			1.5
Zircon			0.5			0.0
Apatite			0.0			0.0
Sphene			0.0			0.0
Biogenic Materials		1.5			5.0	
Bone Fragments			0.3			0.3
Spores			1.3			4.8
MATRIX	71.5			72.0		
Undifferentiated		71.5			72.0	
AUTHIGENIC CEMENT	13.3			9.8		
Quartz		0.8			0.3	
Chert		1.0			0.5	
Dolomite		0.3			0.0	
Ankerite		1.5			1.8	
Pyrite		9.5			7.3	
Anatase		0.3			0.0	
POROSITY	0.5			0.3		
Dissolution		0.3			0.3	
Grain Moldic			0.0			0.3
Intragranular			0.3			0.0
Shrinkage		0.3			0.0	
TOTAL	100.0			100.0		

THIN SECTION

PHOTOMICROGRAPHS AND DESCRIPTIONS

The scale of the photomicrographs in each Plate is a function of the magnification:

50X: Horizontal width of the photomicrograph represents 2.540mm.

200X: Horizontal width of the photomicrograph represents 0.635mm.

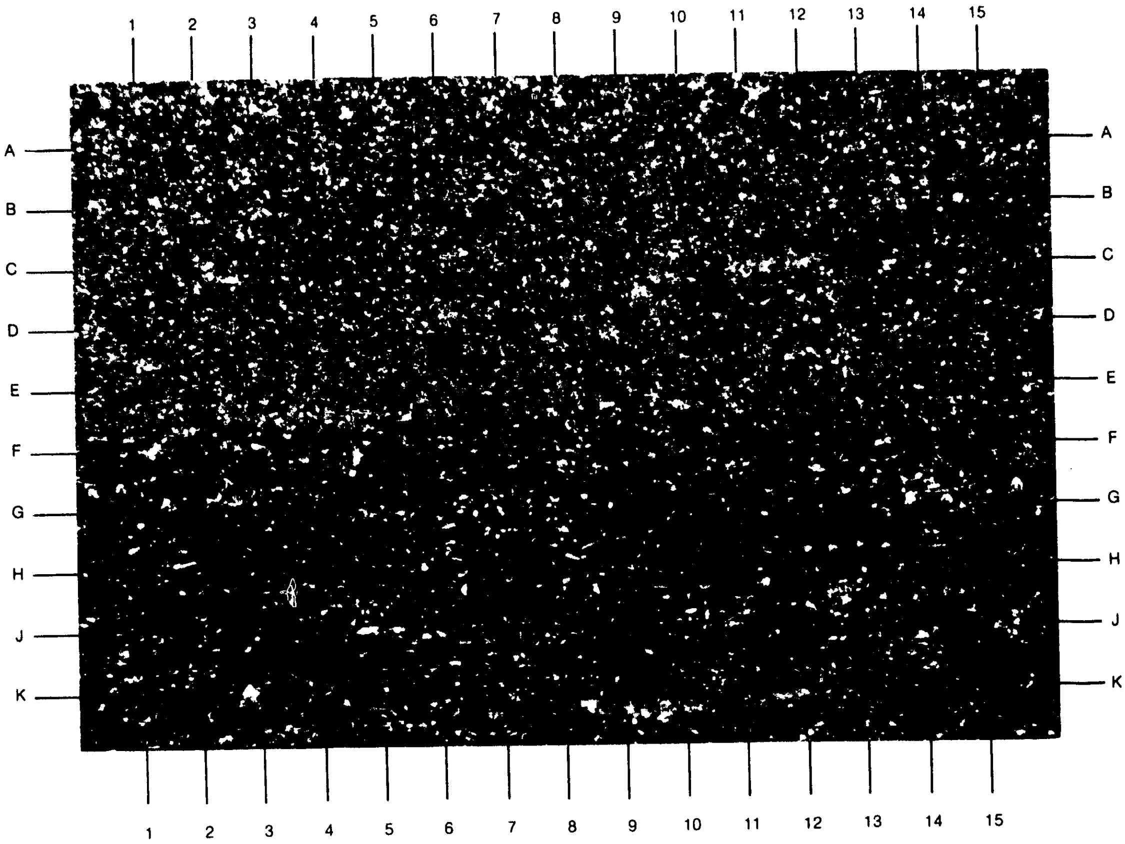
SAMPLE NUMBER: 28H-1

PLATE 1A

ROCK TYPE: Shale
SAND AND SILT-SIZED DETRITUS: Monocrystalline quartz (H-J13), spores (E6-7), and muscovite
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, pale to deep brown material
CEMENTS: Pyrite (E8) and ankerite (blue stain)
POROSITY TYPES: No visible porosity in this view
COMMENTS: Flattened spores (F12, J11-12) show the effects of compaction
MAGNIFICATION: 50X, plane-polarized light

PLATE 1B

The spore (E9) shown in this high-magnification view was flattened during the compactional phase of diagenesis. Partial replacement of the spore by authigenic ankerite (E-F7, blue stain) and pyrite (F10) occurred during a later stage of diagenesis. Ankerite (blue stain) and pyrite (H3, A10, E3) are the dominant authigenic phases in this shale. Silt-size detritus, consisting primarily of monocrystalline quartz (D1, E4), is abundant in this sample. The golden brown matrix material is a mixture of clay minerals, organic material, and clay-size pyrite. A shrinkage pore occurs at D-E9. (200X, plane-polarized light)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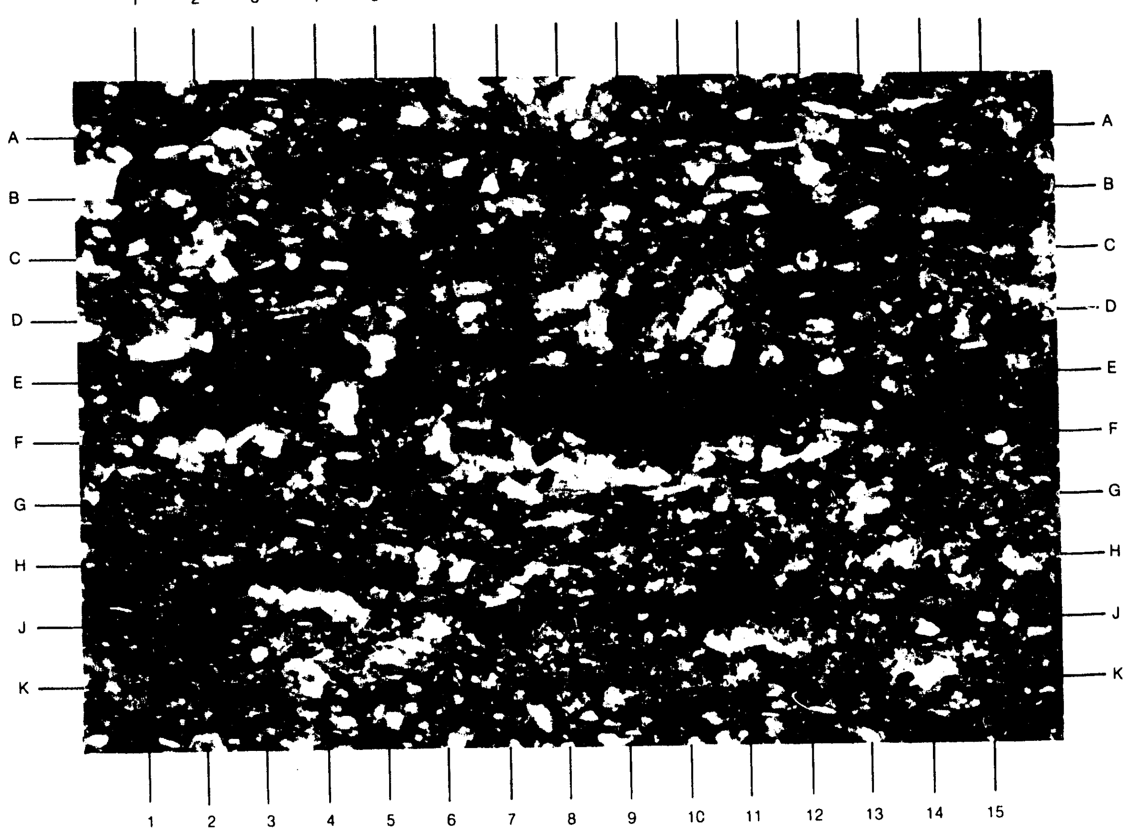
A B C D E F G H J K

A


1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
A B C D E F G H J K

B

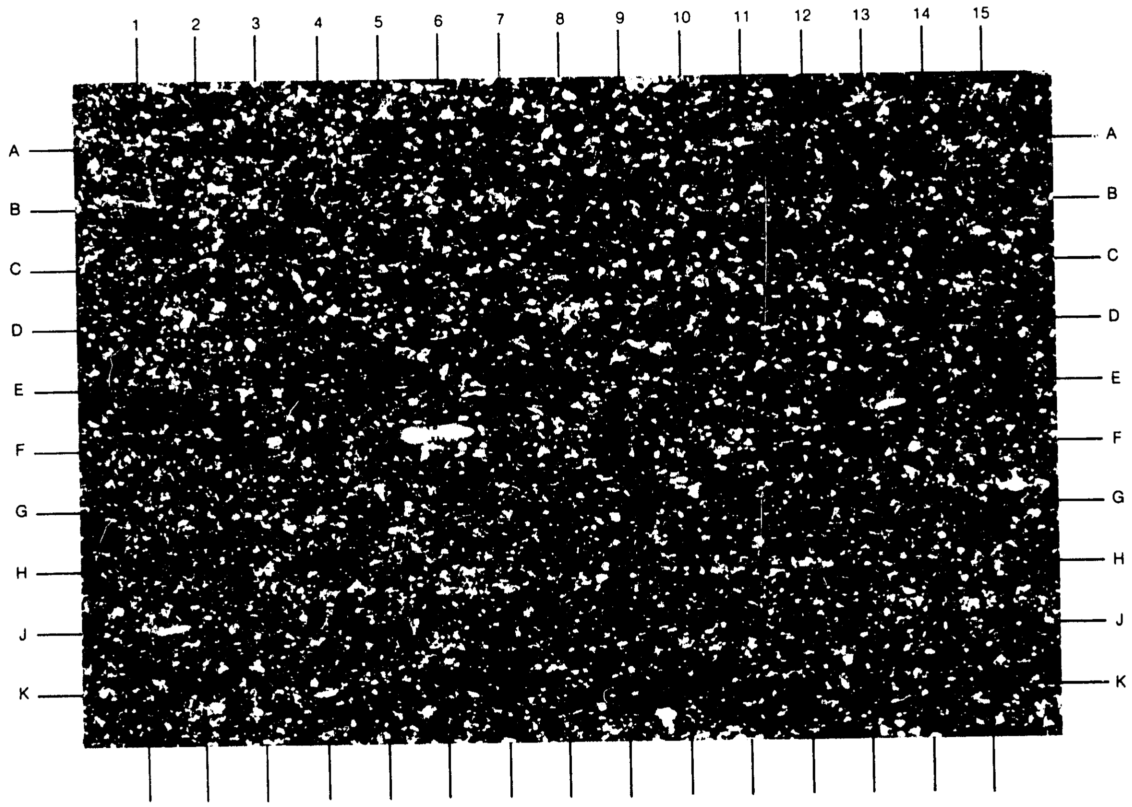
SAMPLE NUMBER: 28H-2

PLATE 2A

ROCK TYPE: Shale
SAND AND SILT-SIZED DETRITUS: Monocrystalline quartz (B2-3), spores (A2-3, A14), and muscovite
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, golden brown material
CEMENTS: Pyrite (A9-10) and ankerite (E9)
POROSITY TYPES: Shrinkage (E7)
PORE NETWORK: Heterogeneously distributed, isolated shrinkage pores
MAGNIFICATION: 50X, plane-polarized light

PLATE 2B

The spore shown at E8 has been deformed during two diagenetic phases, the compactional phase and the cementation phase. Compaction of the sample has caused flattening of the spore. The bowed aspect of this spore indicates that further distortion occurred during the growth of the ankerite crystals at F7. Ankerite (stained blue) crystals can be noted throughout this view, which also shows angular to rounded, silt-size monocrystalline quartz and feldspar floating in a golden brown matrix material. This matrix material is composed of a mixture of clay minerals, organic material, and clay-size pyrite crystals. (200X, plane-polarized light)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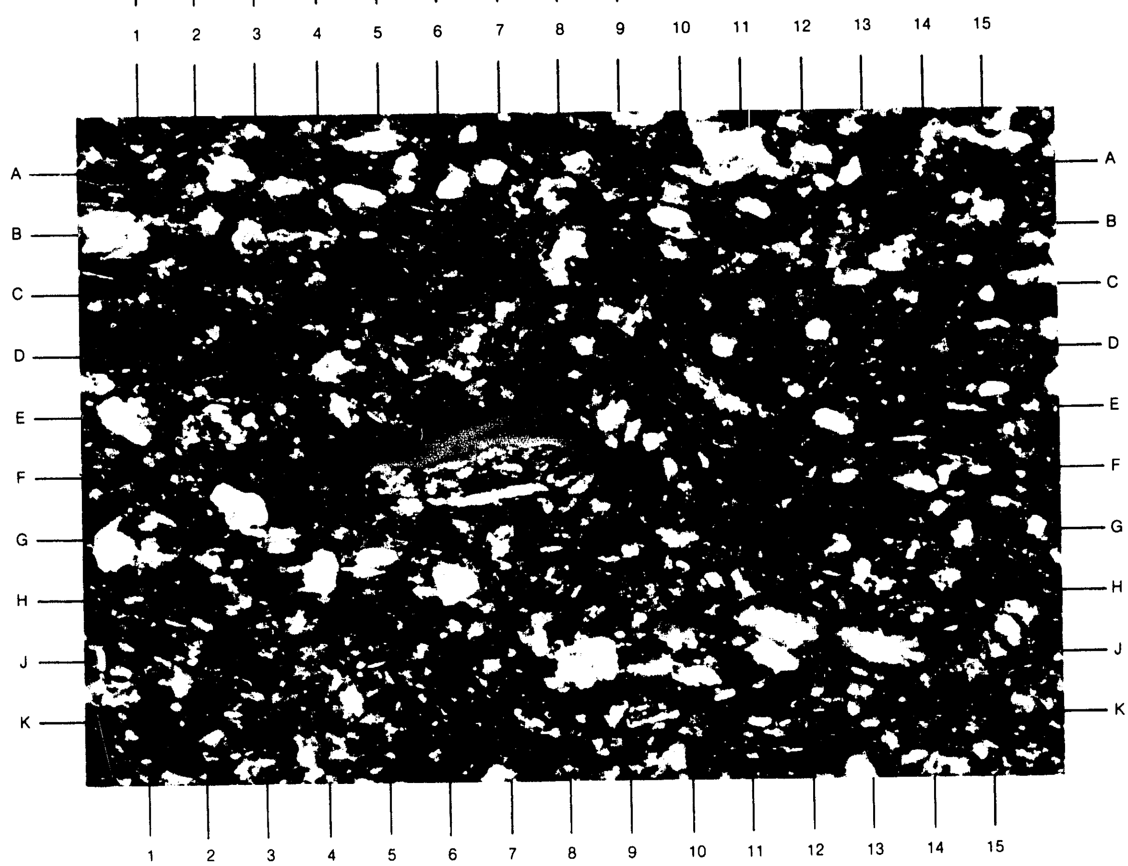
A B C D E F G H J K

A


1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
A B C D E F G H J K

B

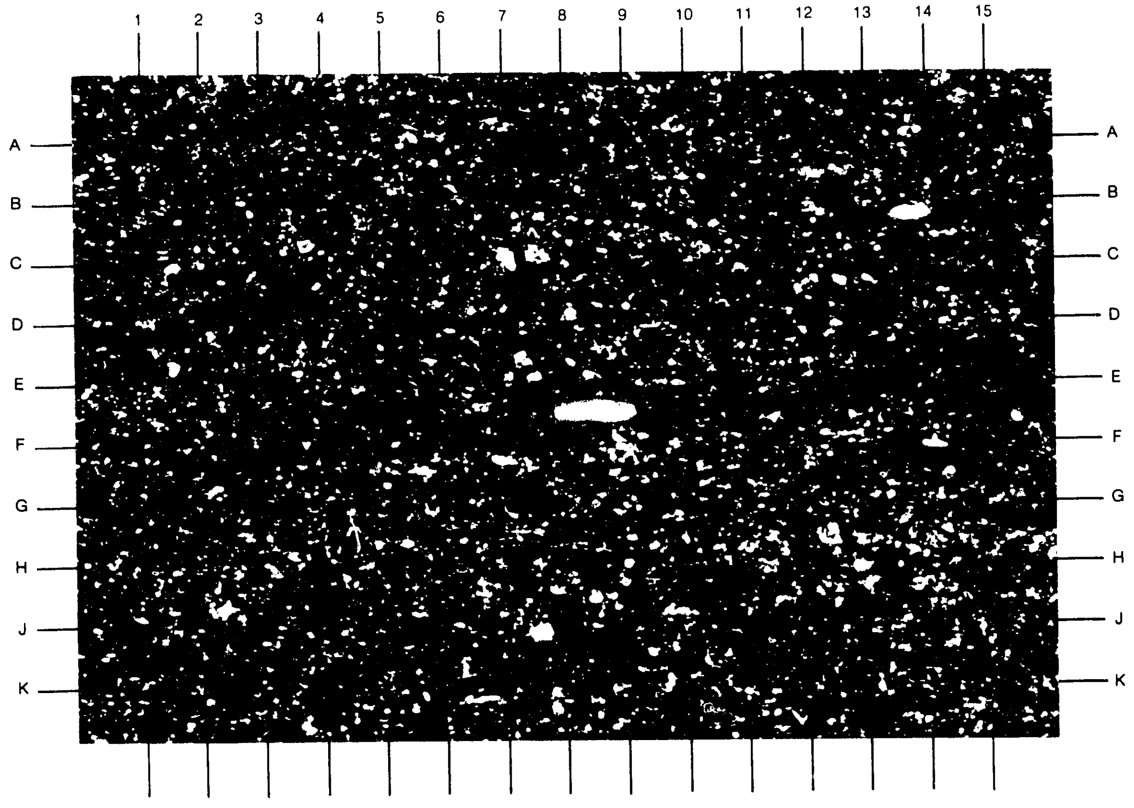
SAMPLE NUMBER: 28H-3

PLATE 3A

ROCK TYPE: Shale
SAND AND SILT-SIZED DETRITUS: Monocrystalline quartz (C8) and spores (C9-10)
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, deep brown material
CEMENTS: Pyrite (C13) and ankerite (blue stain)
POROSITY TYPES: No visible porosity
MAGNIFICATION: 50X, plane-polarized light

PLATE 3B

Abundant, deformed spores are shown in this high-magnification photomicrograph. The flattened, bowed outlines (D7, J12) of the spores illustrate how compaction has affected these ductile constituents. Silt-size particles of monocrystalline quartz and feldspar are suspended in a matrix of clay minerals, organic material, and clay-size pyrite crystals and siliciclastic detritus. Ankerite (E7, C11) and pyrite (J5, K10) are the dominant authigenic cements present in this sample. (200X, plane-polarized light)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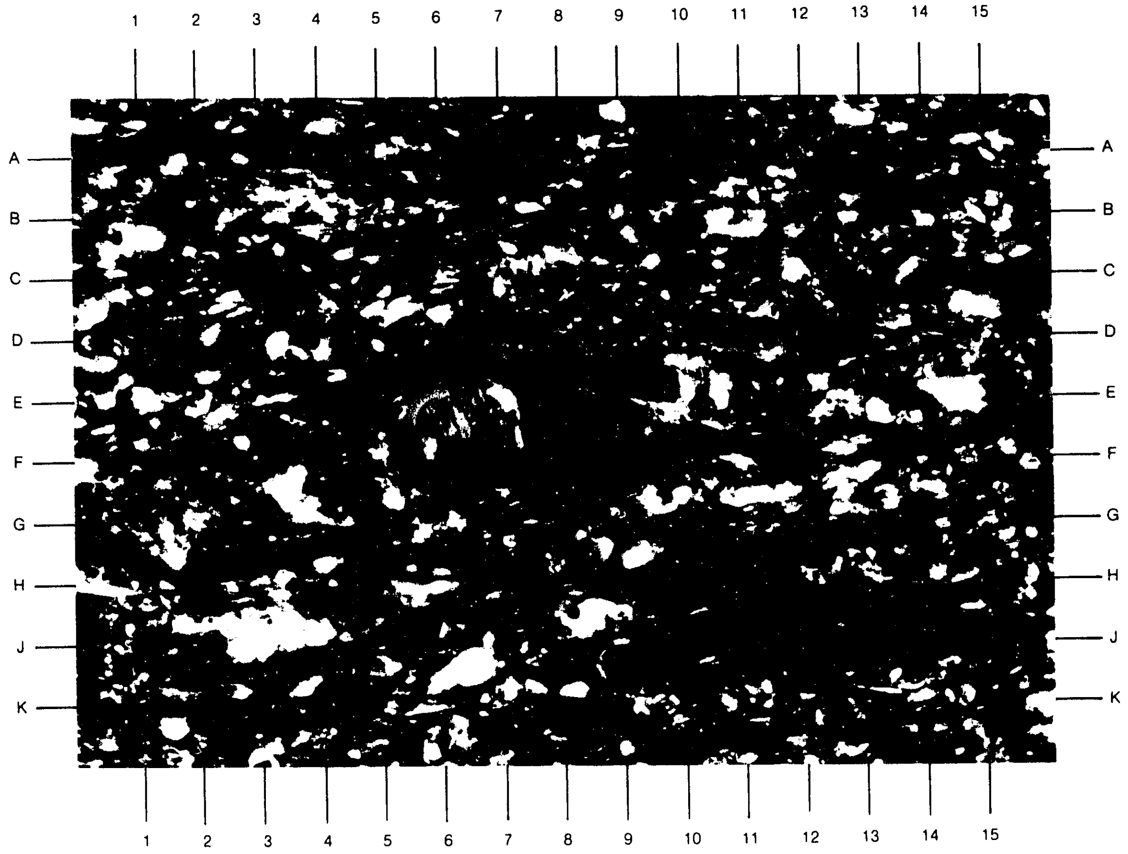
A B C D E F G H J K

A


1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
A B C D E F G H J K

B

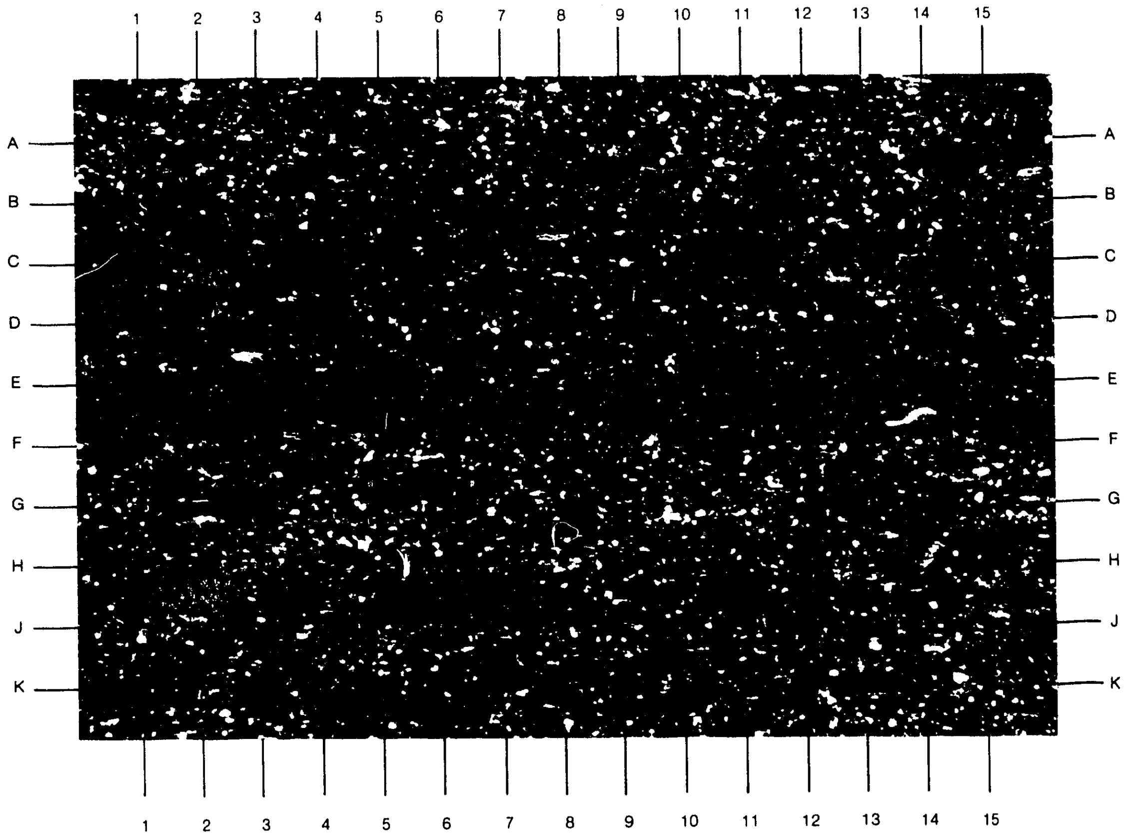
SAMPLE NUMBER: 28H-4

PLATE 4A

ROCK TYPE: Shale
SAND AND SILT-SIZED DETRITUS: Monocrystalline quartz (C6-7), spores (B11), and muscovite
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, deep brown material
CEMENTS: Pyrite (H12)
POROSITY TYPES: Induced fracture (H-J2-15)
PORE NETWORK: Rare, isolated shrinkage pores
MAGNIFICATION: 50X, plane-polarized light

PLATE 4B

Abundant, silt-size detritus, consisting primarily of monocrystalline quartz (J10), floats in a deep brown matrix material rich in clay minerals and organic material. Clay-size pyrite crystals also occur as part of the matrix material. Ankerite (deep blue stain at H8) and pyrite (G11-12) are the only authigenic cements observed in this view. (200X, plane-polarized light)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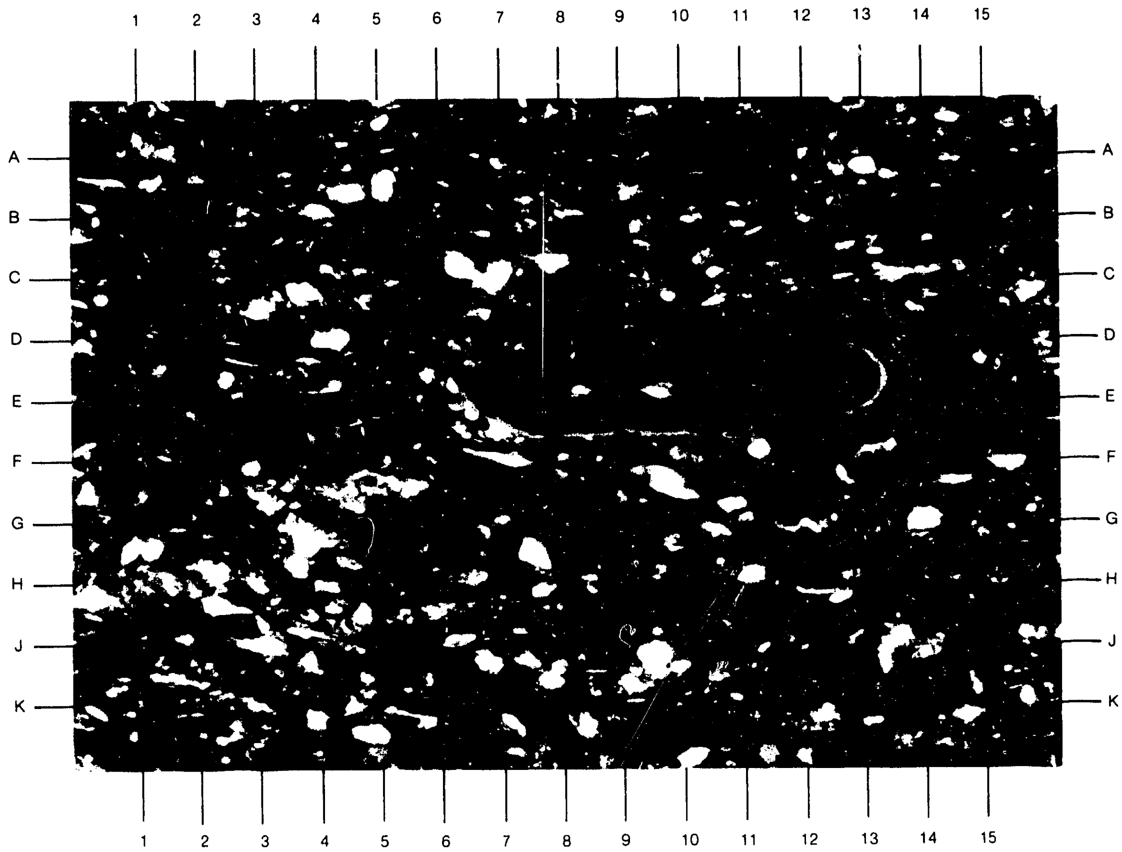
A B C D E F G H J K

A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A B C D E F G H J K

B

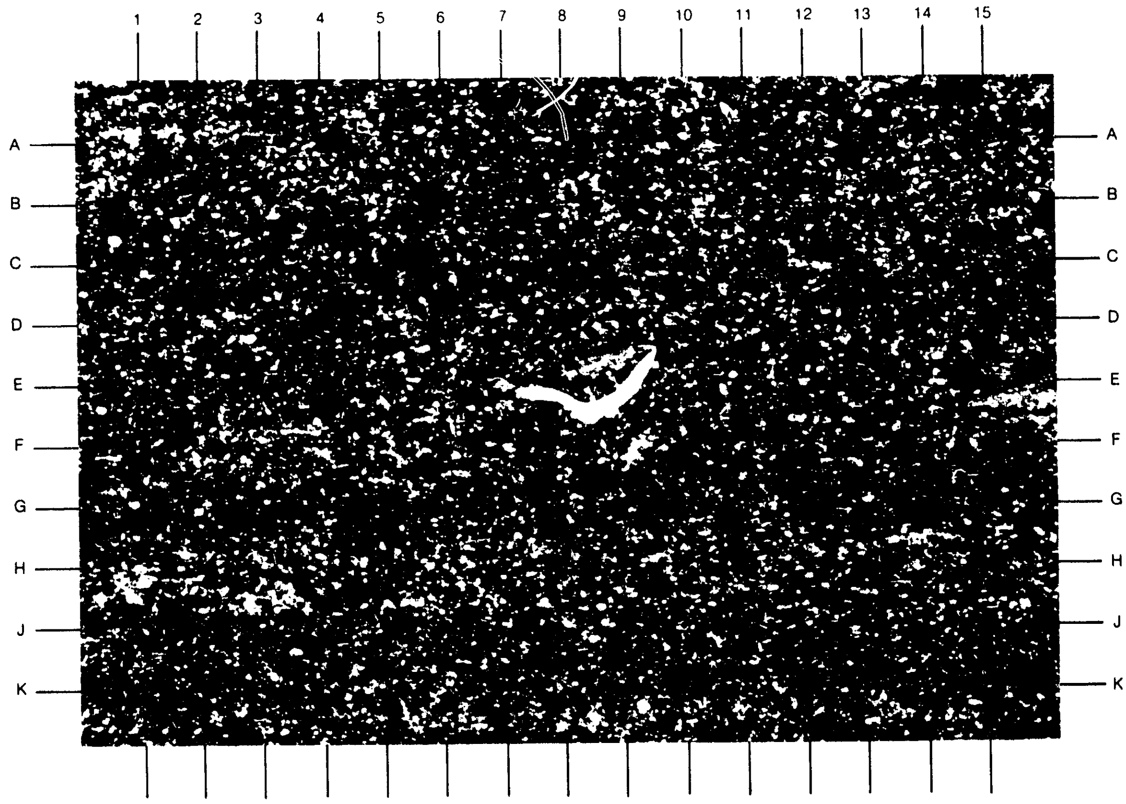
SAMPLE NUMBER: 28H-5

PLATE 5A

ROCK TYPE: Shale
SAND AND SILT-SIZED DETRITUS: Monocrystalline quartz (H1-2), spores (D9), and bone fragments (E9)
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, medium to deep brown material
CEMENTS: Pyrite (opaque mineral) and ankerite (blue)
POROSITY TYPES: No visible porosity
MAGNIFICATION: 50X, plane-polarized light

PLATE 5B

The relative abundance of siliciclastic detritus is highlighted in this photomicrograph. The siliciclastic detritus floats in matrix material composed of clay minerals, organic material, and clay-size pyrite, quartz, and feldspar. Ankerite (blue stain) and pyrite (F10) are the dominant cements. (200X, plane-polarized light)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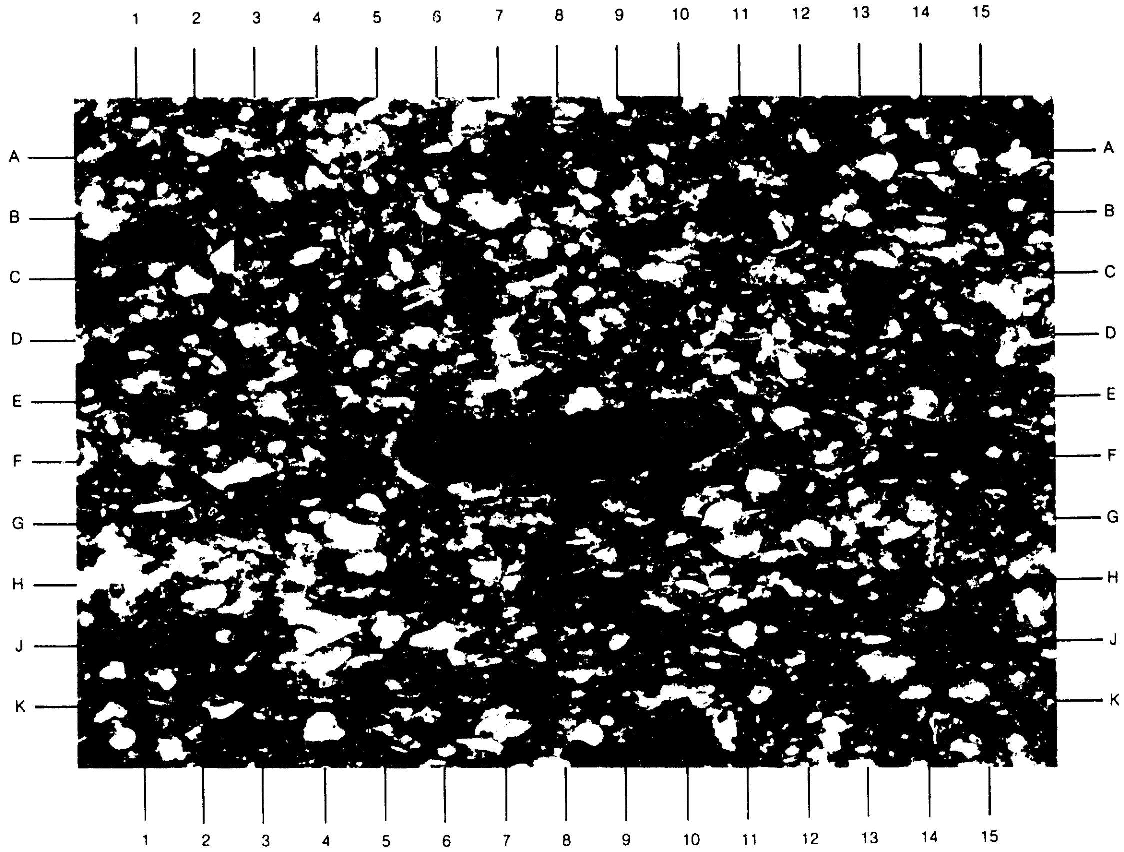
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A B C D E F G H J K

B

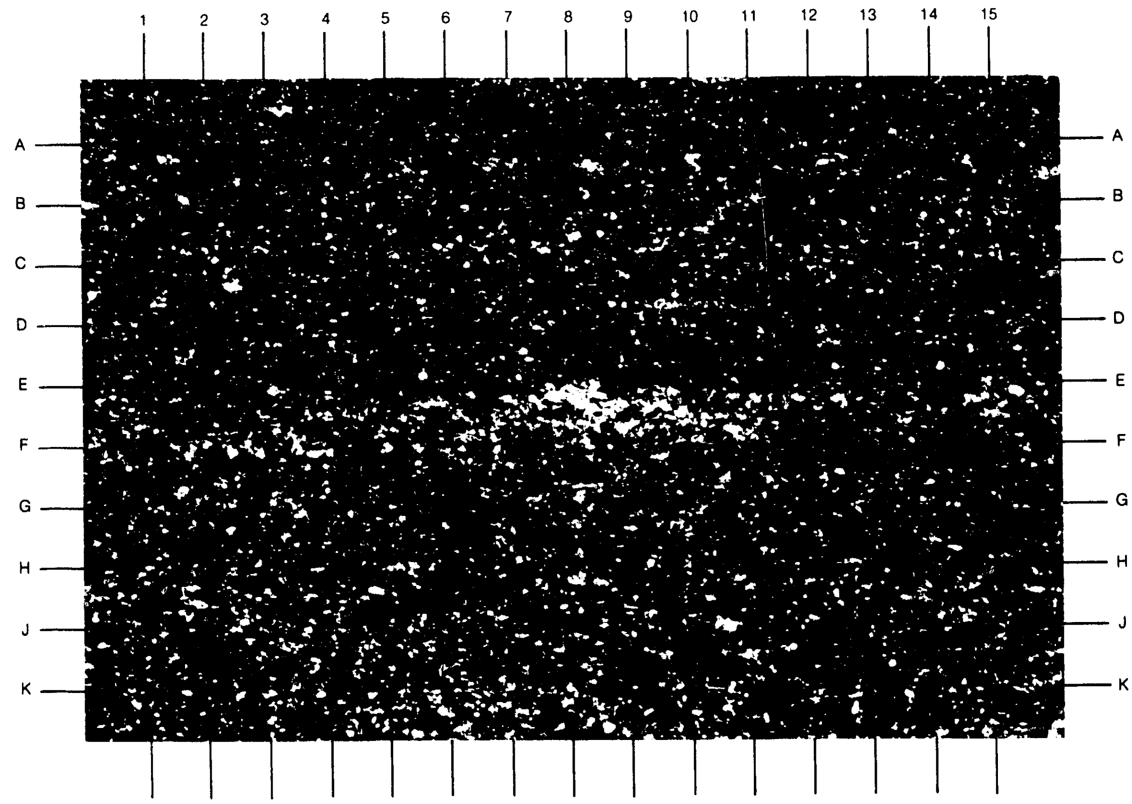
SAMPLE NUMBER: 28H-6

PLATE 6A

ROCK TYPE: Shale
SAND AND SILT-SIZED DETRITUS: Monocrystalline quartz (E-F8), spores (B13), and bone fragments (G15)
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, medium to deep brown material
CEMENTS: Pyrite (C2-3) and ankerite (blue stain)
POROSITY TYPES: No visible porosity
MAGNIFICATION: 50X, plane-polarized light

PLATE 6B

This high-magnification view highlights a matrix-rich area of the sample. The matrix material consists of clay minerals, authigenic chert, clay-size siliciclastic debris, and clay-size pyrite. Monocrystalline quartz (E9, G-H15) and fragmented spores (G6) are the dominant silt-size constituents. Authigenic pyrite cement occurs at A1, E13, H4, and G15. (200X, plane-polarized light)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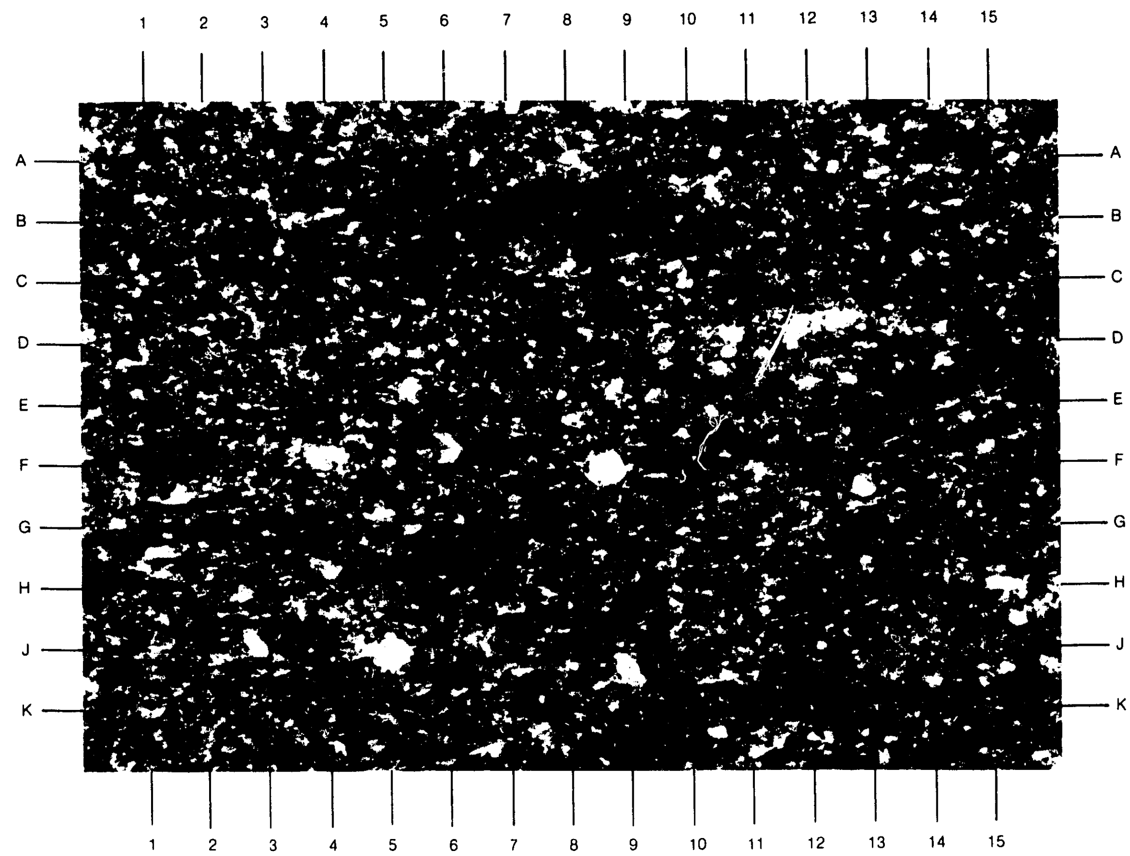
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A B C D E F G H J K

B

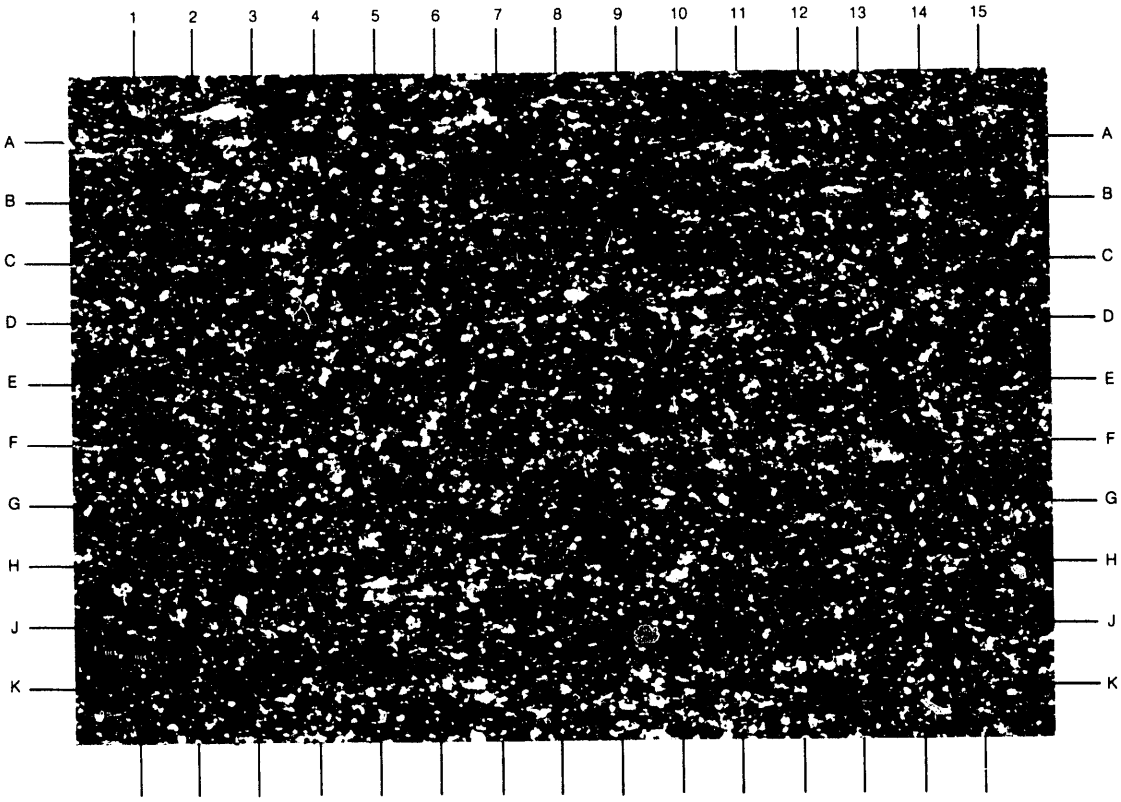
SAMPLE NUMBER: 28H-7

PLATE 7A

ROCK TYPE: Shale
SAND AND SILT-SIZED DETRITUS: Monocrystalline quartz (A11) and spores (B-C12, H4)
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, medium to deep brown material
CEMENTS: Pyrite (E8-9) and ankerite (blue stain)
POROSITY TYPES: No visible porosity
MAGNIFICATION: 50X, plane-polarized light

PLATE 7B

This high-magnification view of the sample shows the subparallel alignment of the spores relative to each other (A1, C6, G8). These spores are also aligned parallel to bedding. The golden brown matrix material is composed of clay minerals, organic material, and clay-size pyrite, quartz, and feldspar. Ankerite (blue stain) and pyrite (A10-11, H2) cement this sample. (200X, plane-polarized light)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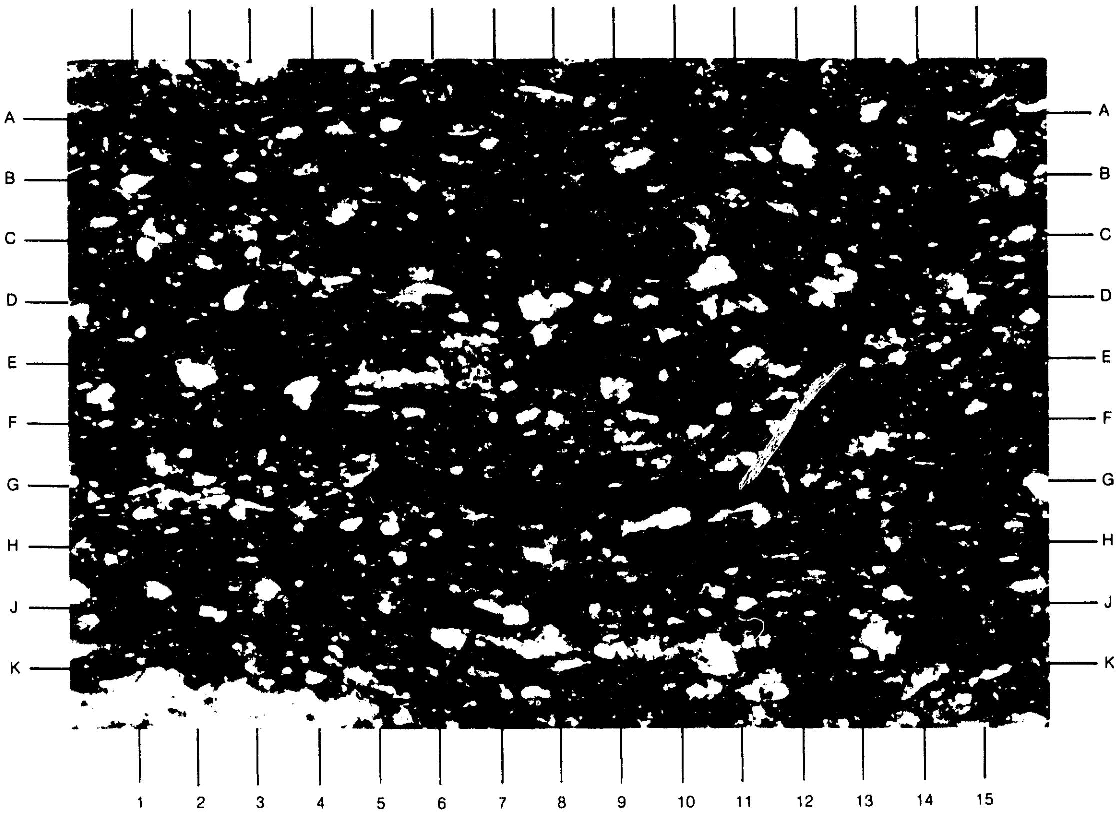
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A B C D E F G H J K

B

SCANNING ELECTRON MICROSCOPY

PHOTOMICROGRAPHS AND DESCRIPTIONS

Symbols appear at the bottom of all SEM photomicrographs in this report. From left to right, these are: 20kv (SEM electron accelerating potential, kilovolts), magnification (X1000), bar scale (microns), and photograph exposure number.

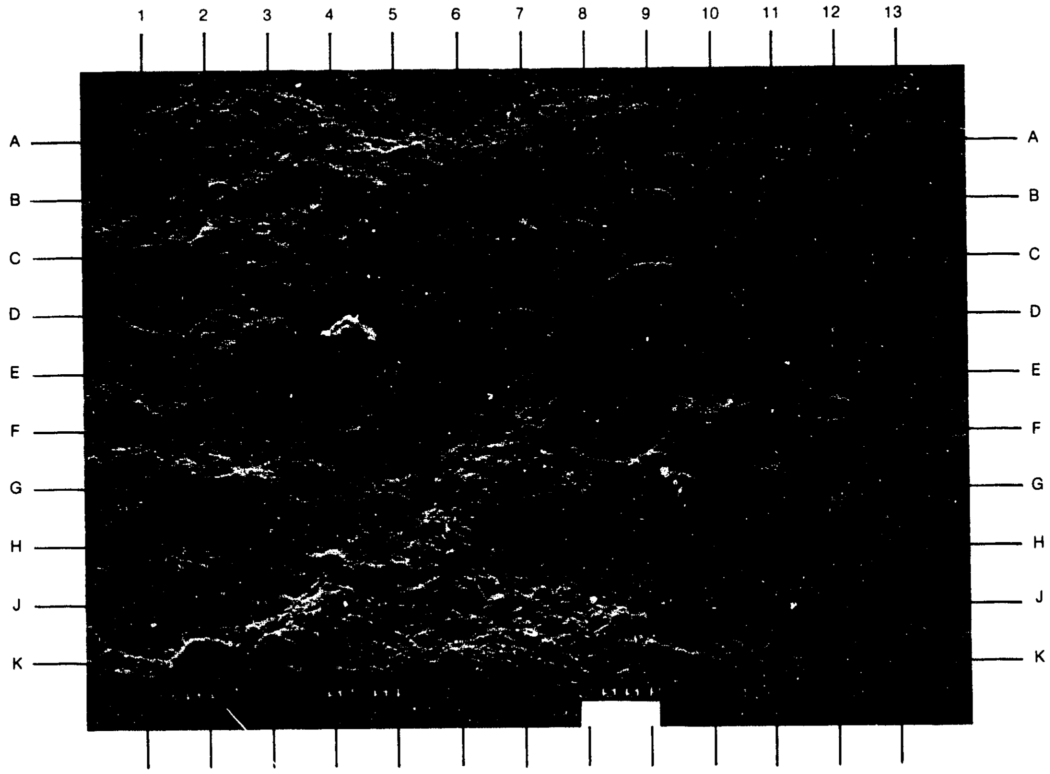
SAMPLE NUMBER: 28H-1

PLATE 8A

ROCK TYPE: Shale
SAND AND SILT-SIZE DETRITUS: Spores (B1, F8-9) and quartz
DETRITAL/RECRYSTALLIZED MATRIX: Detrital clay, partially recrystallized clay, and organic material
CEMENTS: Pyrite and ankerite (see Plate 9B)
POROSITY TYPES: Micropores (not visible in this view)
MAGNIFICATION: 50X

PLATE 8B

The concave areas in this image denote the former presence of two spores which were removed during sample preparation. Only the clay-dominant matrix is visible in this photomicrograph. Based on Energy Dispersive Spectroscopy (EDS), the elemental composition of the clay matrix includes silicon, aluminum, potassium, and iron. (200X)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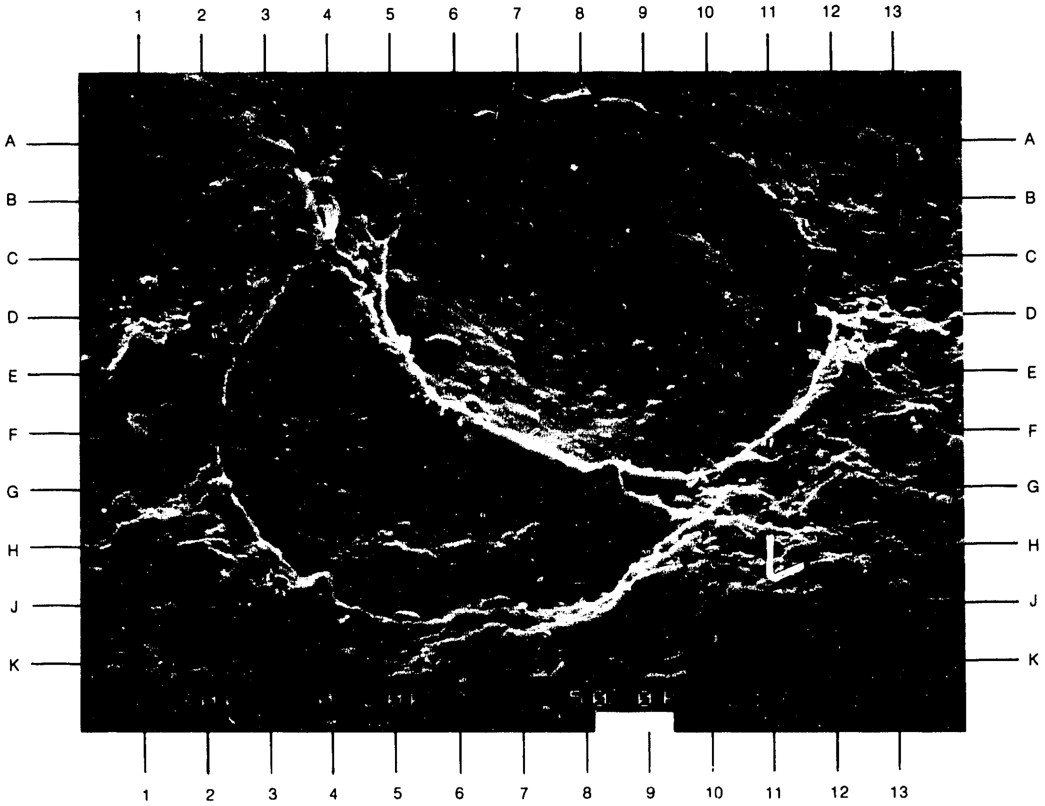
1 2 3 4 5 6 7 8 9 10 11 12 13
A B C D E F G H J K
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B

THE BDM CORPORATION
BDM/DOE RET NO. 1 WELL
WAYNE COUNTY, WEST VIRGINIA

VOLUME I
CORE ANALYSES

Performed by:

Litton Core Research
1500 Salado Drive
Mountain View, CA 94043
(415) 960-0964

May 1987
28H

PROGRAM PARTICIPANTS

Task Performed		Core Analyst	
1) Sample Preparation and Basic Core Properties		F. Hawkins	Frank Hawkins
		D. Phan	D Van Phan
	Reviewer:	A. Lund	Allen J. Lund
2) Gas Permeability		J. King	Jeffrey King
		K. Durst	Keith Durst
	Reviewer:	A. Ajufo	
3) Data Reduction and Analysis and Report Preparation		R. Ngo	
		L. Welte	Lynne Welte

Approved by: ______________________

Dr. Jude O. Amaefule
Director, Laboratory Services

VOLUME I
PART I

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SECTION 1
INTRODUCTION

Laboratory analyses were performed on six shaley samples taken from the BDM/DOE RET No. 1 well, Wayne County, West Virigina. Analyses included slabbing, petrographic description, vitrinite reflectance, physical properties, and gas permeability. Gas permeability was measured at elevated stresses representative of in-situ reservoir conditions. Physical properties included grain density, porosity, and water saturation.

Analytic results are presented here in two separate volumes. Volume I (Part I) contains physical properties data and gas permeability data. These data were obtained in testing performed at Core Research, Mountain View, California. Volume II (Parts II and III) contain results of the geochemical and petrographic analyses. These results were obtained from work performed by Core Laboratories, Inc., Dallas.

Visible light photography of slabbed core pieces will be submitted as an addendum to these two volumes.

SECTION 2

SUMMARY OF RESULTS

Well Name:	BDM/DOE RET No. 1	
Location:	Wayne County, West Virginia	
Sample Type:	Semipreserved plugs	
Lithology:	Shale	
Sample I.D. Nos.:	RET 1-1 RET 1-3 RET 1-5 RET 1-7	RET 1-2 RET 1-4 RET 1-6
Sample Depth:	This interval was cored horizontally; all samples are from a depth of 3390 feet.	
Analyses Requested and Performed:	Helium porosity, grain density, gas permeability, and water saturation (gravimetric)	
Results:	*Porosity Range:	1.3 to 2.3 percent
	*Grain Density Range:	2.41 to 2.59 g/cc
	As Tested Saturation Range:	9 to 18 percent
	**Permeability Range:	Net Stress 1: <0.01 to 97.8 μd Net Stress 2: <0.01 to 1.6 μd Net Stress 3: <0.01 to 0.10 μd

See Section 4 for all tabulated results.

* Measured at laboratory conditions.
** Sample RET 1-5 developed fractures during testing.

SECTION 3

TEST PROCEDURES

Core Sample Preparation

Six semi-preserved whole cores were received and slabbed lengthwise to expose flat vertical faces. Samples for vitrinite reflectance data were taken from the 3/4-inch slabs. Plugs, 1-1/2 inches in diameter, were taken from the slabbed core which was cut in a horizontally oriented hole These plugs were taken parallel to the long axis of core and therefore were horizontally oriented. The plugs were surface ground, weighed, and then lengths and diameters were measured with calipers. Core preparation was performed using liquid nitrogen as a cooling fluid. The horizontal core was cut at a depth of 3390 feet.

Helium Porosity Measurement

Plug samples were vacuum oven dried at 40°C until weights were constant to within 0.01g/24 hr. Weight change of the preserved core, together with water density data, was used to calculate as received water saturation. Samples were cooled to 25°C in a desiccator and then porosity was determined by measuring grain volume and bulk volume. Grain volume was measured using a helium gas expansion technique. Bulk volume was calculated from sample length and diameter measurements obtained with precision calipers.

Gas Permeability Measurement

After measurement of basic physical properties, plug samples were placed in a humidity oven at 60°C and 45 percent relative humidity until sample weights were constant to within 0.01g/24 hr. Weight gain in the samples was used to calculate equilibrium water saturation. The plugs were then installed in the gas permeameter. Gas permeability was measured at specified stress conditions using a transient pulse decay technique. The three net stress conditions used in these measurements were chosen as 0.5, 1.0, and 2.0 times the reservoir overburden stress. Overburden stress was assumed to be equal to 1 psi per foot of depth.

SECTION 4

TEST RESULTS

TABLE 4-1. SAMPLE IDENTIFICATION AND DIMENSIONS

Sample I.D.	Depth (ft)	Average Length (in.)	Average Diameter (in.)
RET 1-1	3390	1.1863	1.4890
RET 1-2	3390	1.1842	1.4872
RET 1-3	3390	1.2215	1.4870
RET 1-4	3390	1.1945	1.4820
RET 1-5	3390	1.0612	1.4885
RET 1-6	3390	1.2045	1.4872
RET 1-7	3390	1.1417	1.4897

TABLE 4-2. SUMMARY OF PHYSICAL PROPERTIES

Sample I.D.	Depth (ft)	Grain Density (g/cc)	Bulk Density, As Received (g/cc)	Porosity, Bench Conditions (%)	As Received[1] Water Saturation (%)	As Tested[2] Water Saturation (%)
RET 1-1	3390	2.53	2.52	1.3	100	18
RET 1-2	3390	2.59	2.56	2.2	83	13
RET 1-3	3390	2.49	2.47	1.3	100	13
RET 1-4	3390	2.41	2.38	1.9	87	11
RET 1-5	3390	2.51	2.48	1.6	91	8
RET 1-6	3390	2.54	2.52	1.5	100	14
RET 1-7	3390	2.41	2.38	2.3	83	9

[1]Before any testing conducted. [2]After humidity drying.

TABLE 4-3. EFFECTIVE GAS PERMEABILITY AS A FUNCTION OF STRESS
(As tested water saturation data are given in Table 4-2)

Sample I.D.	Sample Depth (ft)	Gas Permeability (μd)		
		P_{net} (psi)		
		1740	3335	6815
RET 1-1	3390	9.54	0.454	<0.01
RET 1-2	3390	20.52	1.621	0.100
RET 1-3	3390	<0.01	<0.01	<0.01
RET 1-4	3390	97.79	2.808	<0.01
RET 1-5	3390	2.047	<0.01	2.714*
RET 1-6	3390	7.451	0.452	<0.01
RET 1-7	3390	7.425	0.374	<0.01

*Sample apparently developed a thorough-going fracture at the higher stress which increased its apparent permeability.

SECTION 5
DISCUSSION

Physical Properties

Porosity of the six core samples ranged from 1.3 to 2.3 percent. Grain density ranged from 2.41 to 2.59 g/cc. Obviously these variations in grain density reflect minor mineralogic heterogeneity; please refer to Part II of this report for details of sample composition. The two samples with the lowest measured grain density, (RET 1-4 and RET 1-7) also contained the smallest amount of pyrite cement.

As received water saturation of these semi-preserved samples ranged from 83 to 100 percent. Because of the core retrieval and preservation techniques used, these saturation values are not necessarily representative of actual reservoir saturations. Equilibrium water saturation, obtained by humidity oven treatment of the vacuum dried samples, ranged from 9 to 18 percent. Gas permeability was measured while the samples were at this equilibrium saturation. All water saturation data are expressed as percent of sample pore volume.

Gas Permeability

Effective gas permeability, at in-situ reservoir stress, ranged widely from 2.8 to <0.01 μd. Sample RET 1-5 had an increase in permeability with an increase in stress (see Table 4-3). This suggests that the sample was fractured. Most permeabilities decreased by at least one order of magnitude when net stress was increased. Stress dependence of permeability is a common phenomenon in rock material of this type.

THE BDM CORPORATION
BDM/DOE RET NO. 1 WELL
WAYNE COUNTY, WEST VIRGINIA

VOLUME II
PETROGRAPHY AND GEOCHEMISTRY

May 1987
28H

VOLUME II
PART II

PETROGRAPHY

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APPENDIX 7-1

CORE ANALYSIS RESULTS FROM STUDY OF HORIZONTAL CORE MATERIAL FROM RET NO. 1 WELL

APPENDIX 7-2

PETROGRAPHIC AND GEOCHEMICAL STUDIES OF ORIENTED CORE MATERIAL

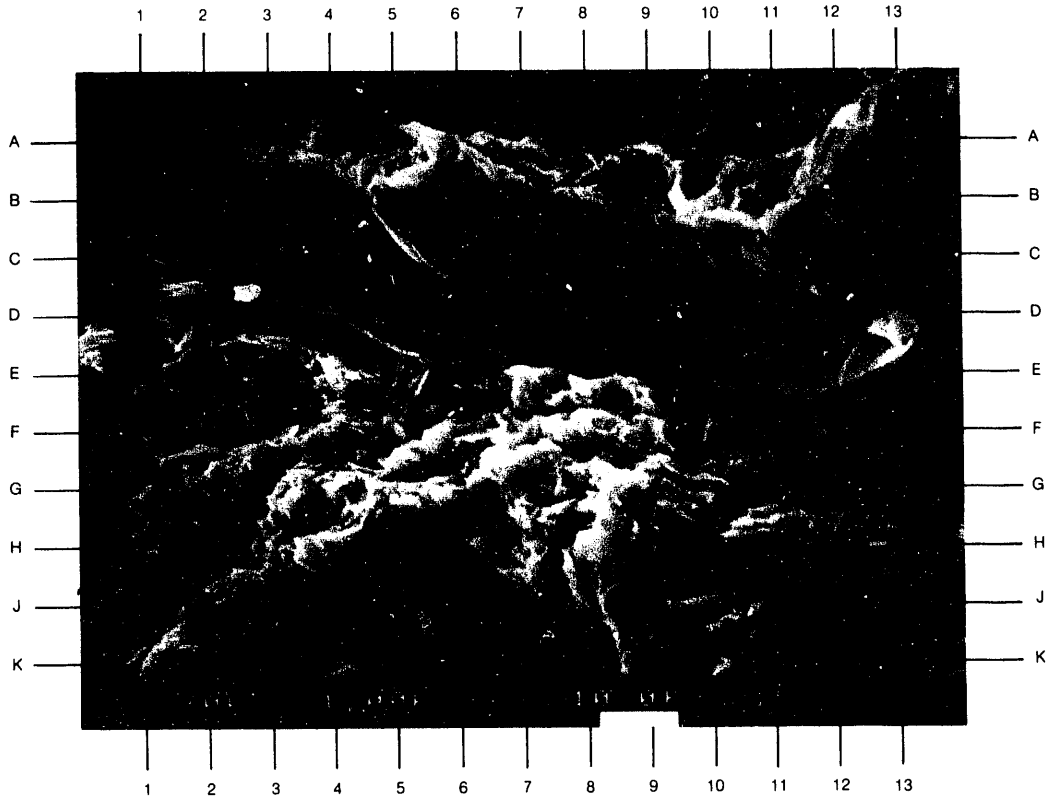
SAMPLE NUMBER: 28H-1

PLATE 9A

Detrital clay (A-B3-4) fills the interior of a spore (A-B2-4) in this view of another area of the sample. Because organic material is primarily composed of carbon and hydrogen, and because the EDS unit cannot detect elements with an atomic less than that of sodium, an elemental composition of the spore could not be obtained. EDS analysis of the surrounding clay material reveals an elemental composition which includes silicon, aluminum, potassium, and iron. A silt-size quartz grain protrudes through the clay matrix at E-F1-2. (1000X)

PLATE 9B

A small cluster of ankerite crystals has partially replaced a spore in this high-magnification photomicrograph. EDS analyses of the crystals at F-G3-4 and D-E8-9 show that calcium and iron, along with minor amounts of magnesium, are the elements present; this elemental composition, coupled with the distinctive rhombohedral morphology, is indicative of ankerite. (1500X)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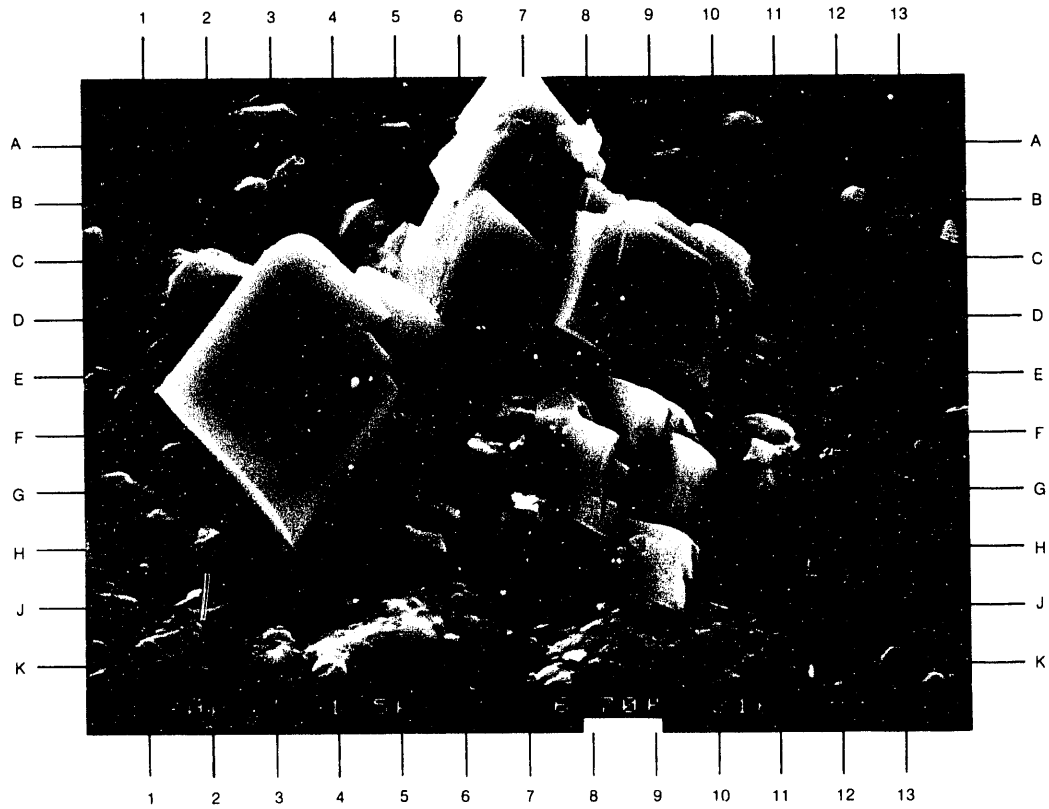
A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A B C D E F G H J K

B

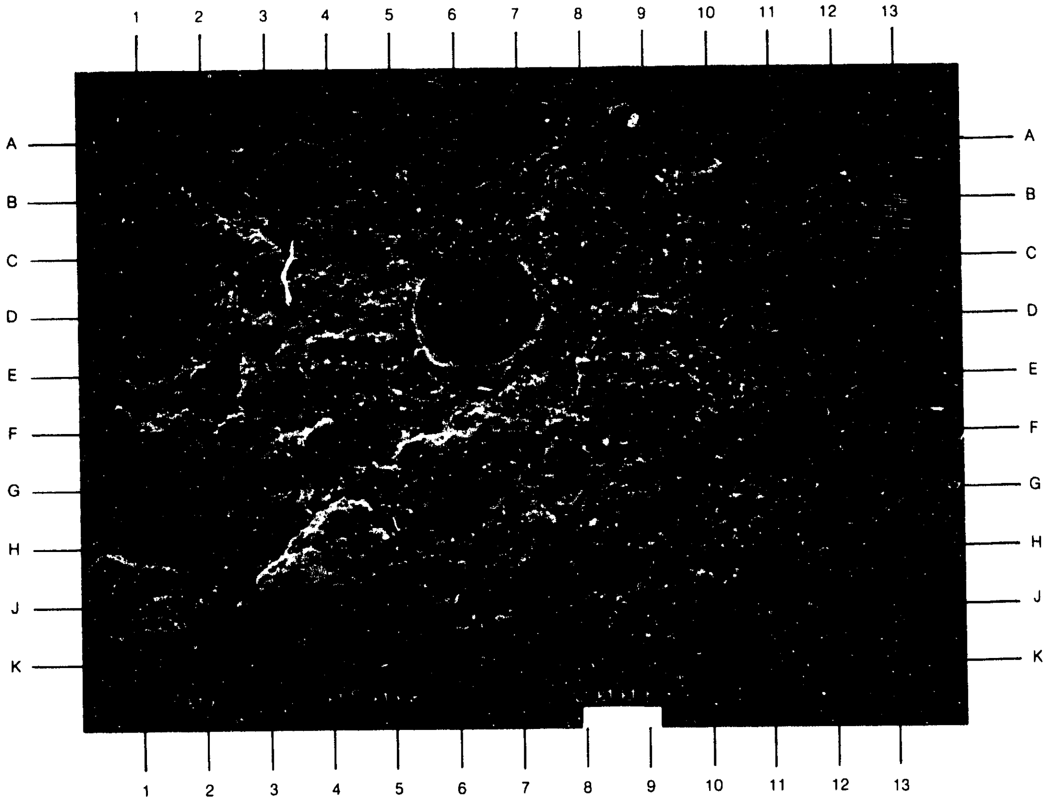
SAMPLE NUMBER: 28H-2

PLATE 10A

ROCK TYPE: Shale
SAND AND SILT-SIZE DETRITUS: Spores (C-D1-2, D6-7, D-E12-13), quartz (A-B9-10), and muscovite (see Plate 11A)
DETRITAL/RECRYSTALLIZED MATRIX: Undifferentiated detrital clay, partially recrystallized clay, and organic material
CEMENTS: Pyrite and ankerite (see Plate 11B)
POROSITY TYPES: Micropores (not visible in this image)
MAGNIFICATION: 50X

PLATE 10B

The area near D-E12-13 in Plate 10A is presented in greater detail in this photomicrograph. A spore impression is featured at A-G4-9. Small rhombs of ankerite cement protrude from this spore cast at A-B4 and B7. The matrix material in this sample may be a physical or chemical mixture of illitic, smectitic, and chloritic clay; this interpretation is based on EDS detection of silicon, aluminum, potassium, and iron within the matrix material. (200X)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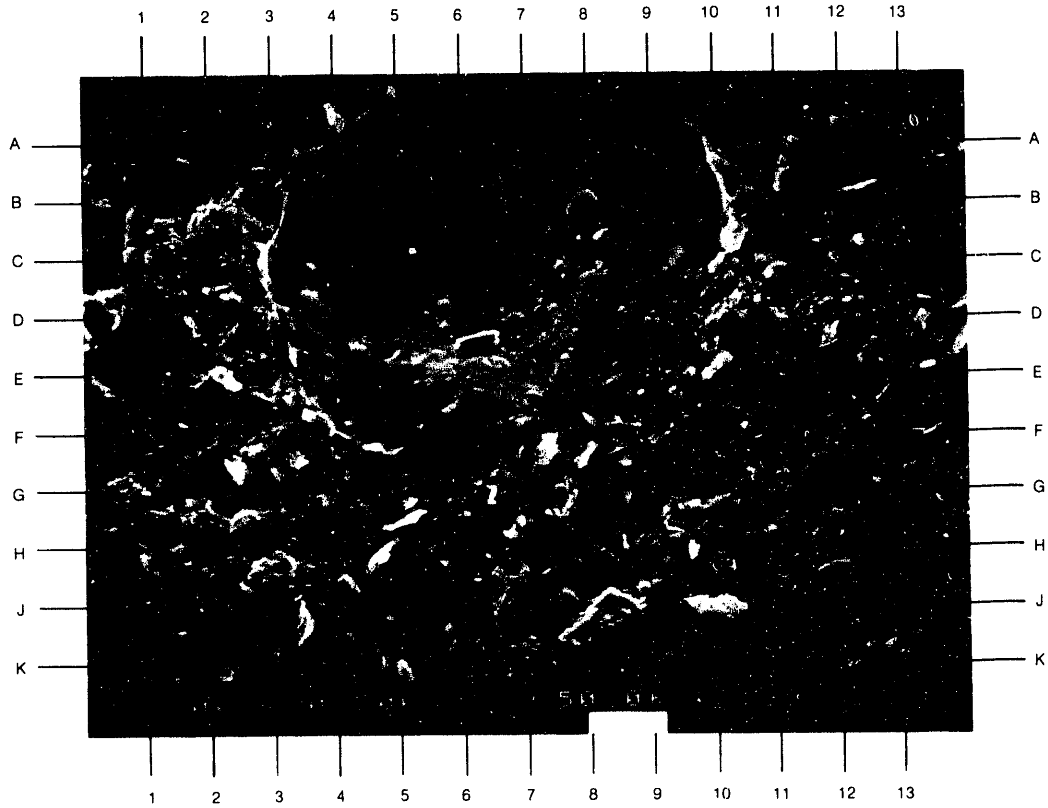
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A B C D E F G H J K

B

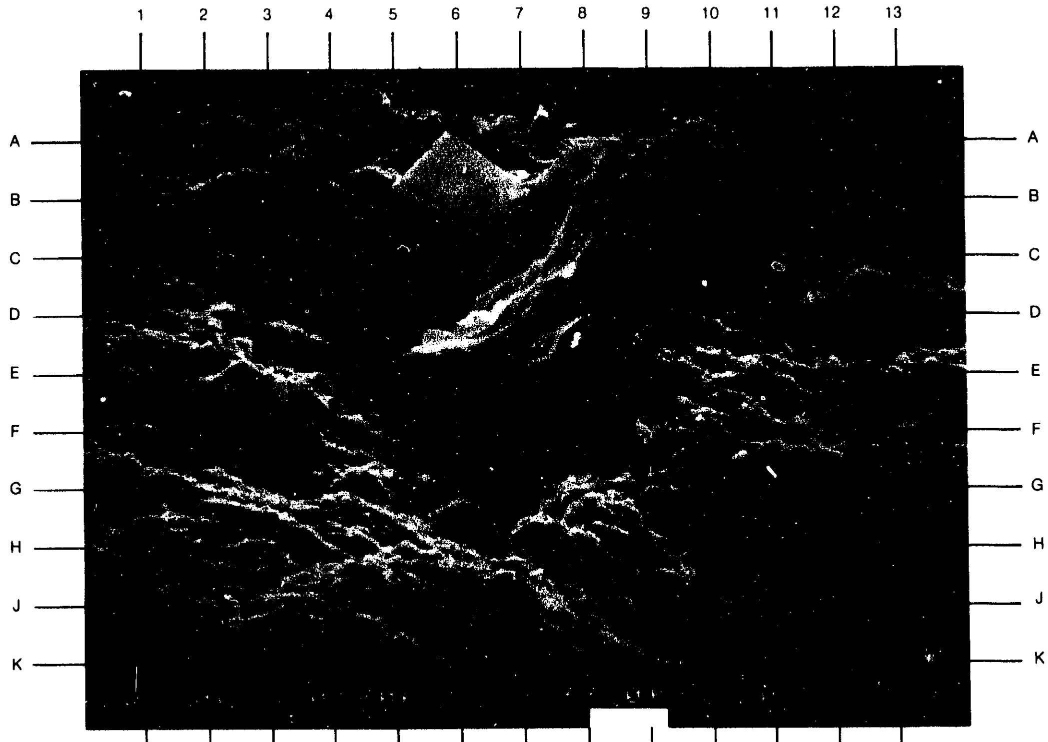
SAMPLE NUMBER: 28H-2

PLATE 11A

A flake of muscovite (B-E6-8) appears embedded within the silty-clayey matrix in this view. The presence of silicon, aluminum, and potassium and the absence of iron suggest that this material is muscovite. The lamination direction of this shale is indicated from C-D1-2 to J-K8-10. (300X)

PLATE 11B

A bent and contorted spore (D-G1-4) and two silt-size quartz grains (B-D11-13, H-K4-5) are illustrated in this high-magnification image. The microporous character of the clay matrix is emphasized in this photomicrograph. (1000X)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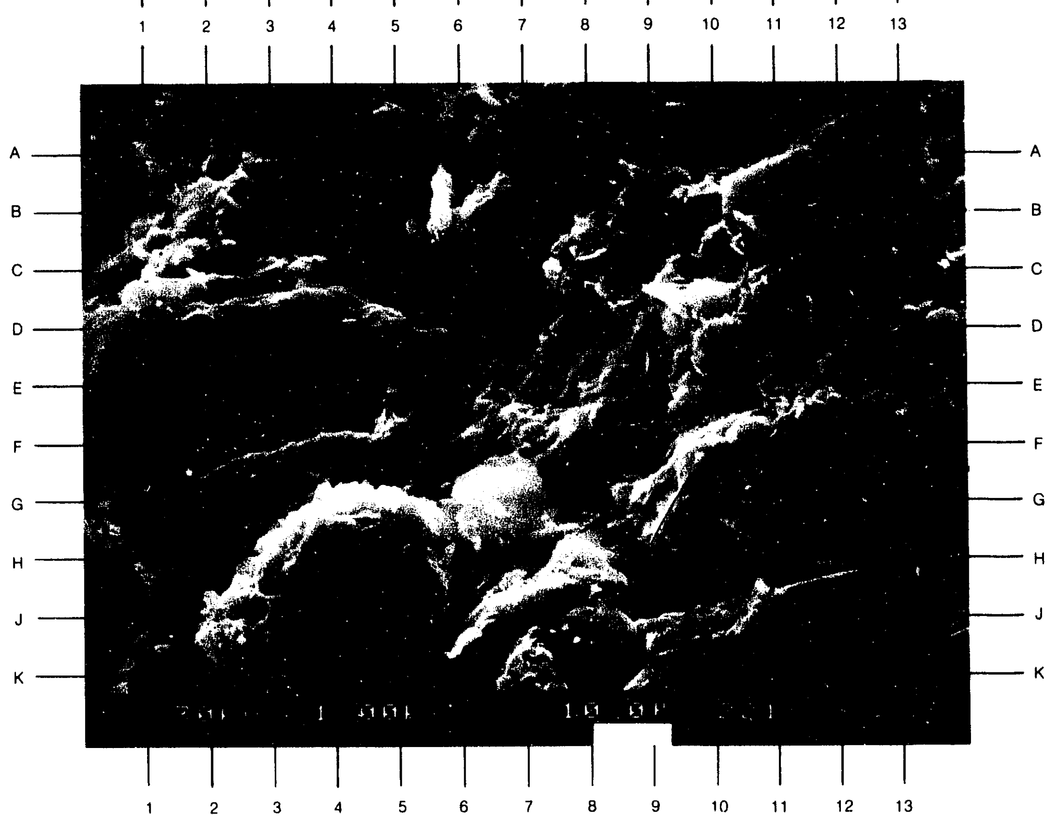
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A B C D E F G H J K

B

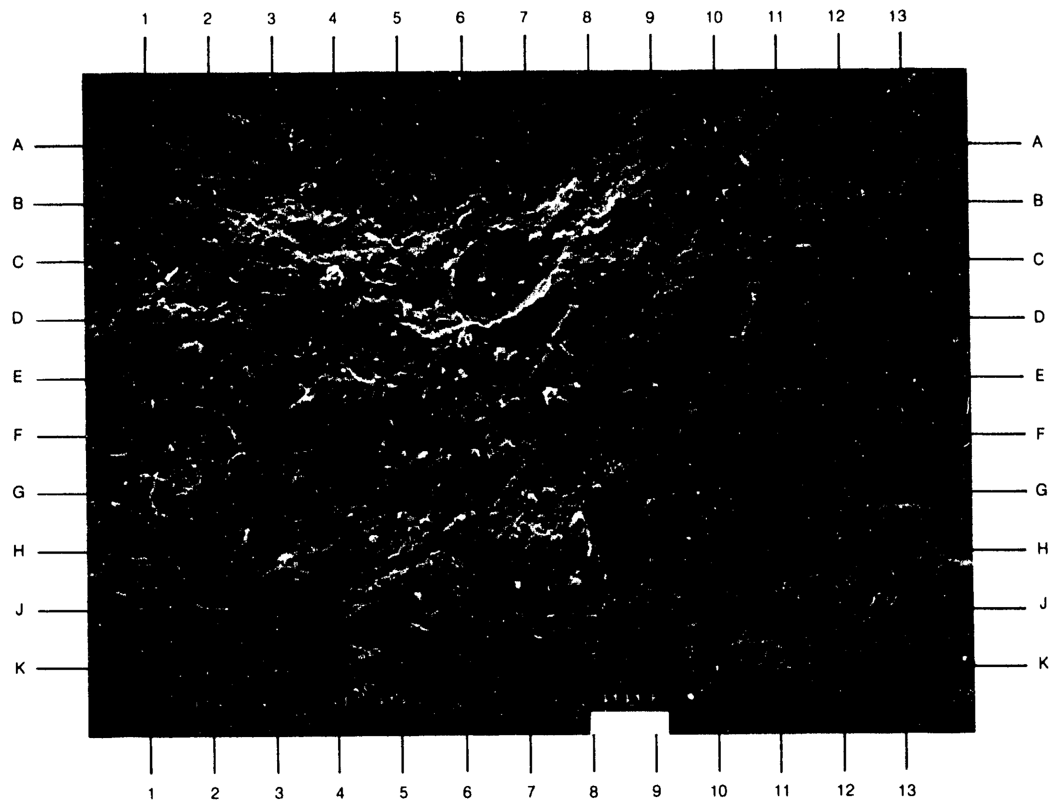
SAMPLE NUMBER: 28H-3

PLATE 12A

ROCK TYPE: Shale
SAND AND SILT-SIZE DETRITUS: Spores (A4, F-G5, B10-11) and quartz (H6, H8-9)
DETRITAL/RECRYSTALLIZED MATRIX: Undifferentiated detrital clay, partially recrystallized detrital clay, and organic material
CEMENTS: Pyrite (see Plate 13B) and ankerite
POROSITY TYPES: Micropores (not visible in this photomicrograph)
MAGNIFICATION: 50X

PLATE 12B

A spore (center of the photomicrograph) appears embedded in the clayey-silty matrix in this view of the sample. Note the shrinkage pore which has formed around the spore. Silicon, aluminum, iron, and potassium are the elements associated with the matrix material. (200X)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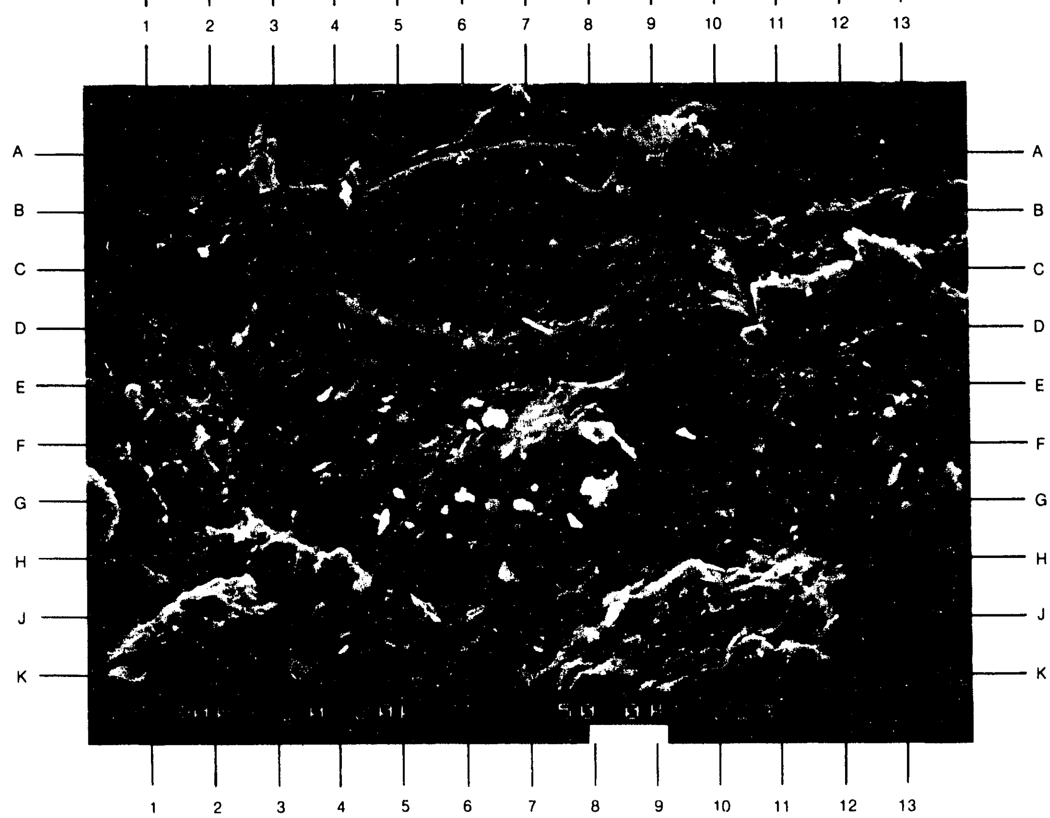
A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A B C D E F G H J K

B

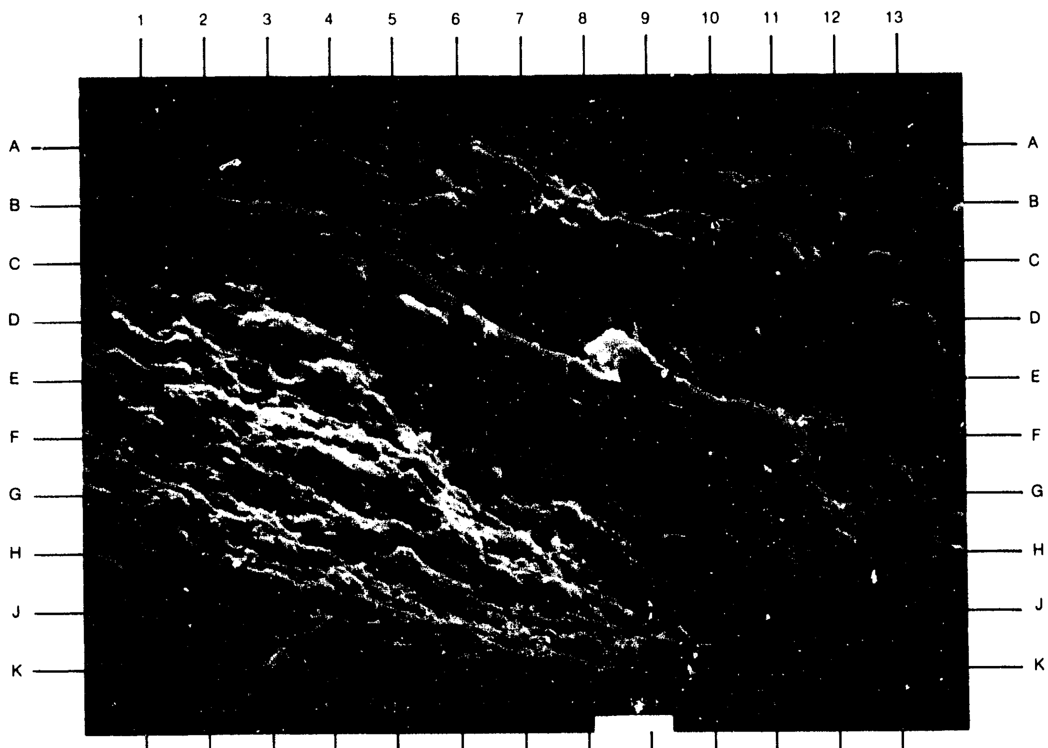
Sample Number: 28H-3

Plate 13A

Another view of the sample highlights the abundance of the poorly defined, clayey matrix material (G4, D9) that comprises the majority of this sample. In addition to the poorly defined matrix material, remnant exines of two spores are visible at C5 to G13 and B-C12. Minute shrinkage pores occur at C-D13 and G11-12. (300X)

PLATE 13B

Authigenic pyrite (F6) occurs frequently throughout this sample. Iron and sulfur were detected during EDS analysis, confirming the identification of pyrite. Poorly defined, clayey matrix material dominates this view. EDS analyses of the matrix material has revealed the presence of silicon, aluminum, iron, and potassium. Abundant, ineffective microporosity is associated with the matrix material. (1200X)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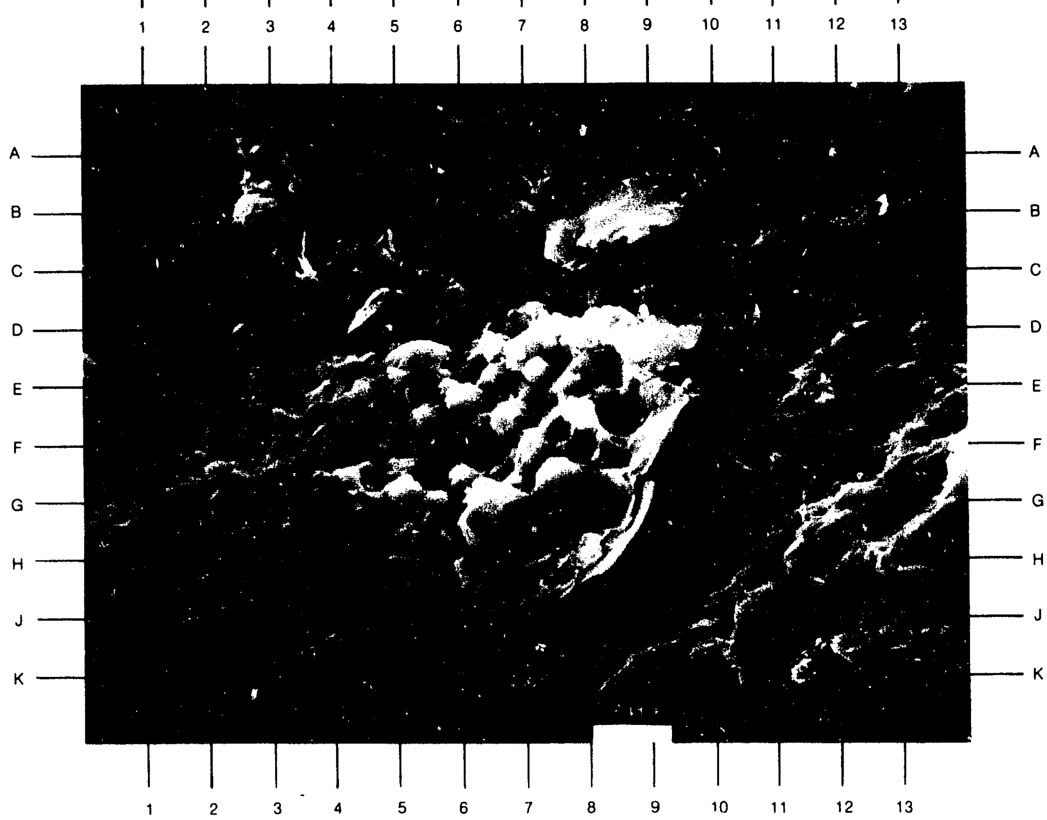

1 2 3 4 5 6 7 8 9 10 11 12 13
A B C D E F G H J K

B

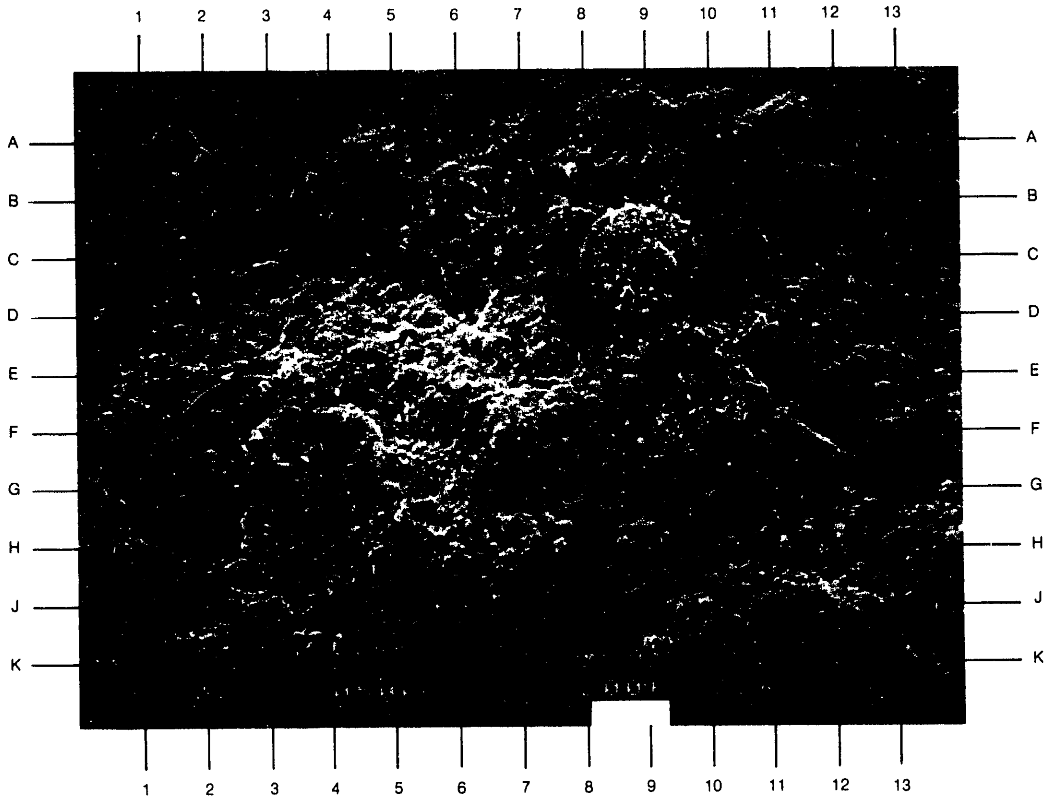
SAMPLE NUMBER: 28H-4

PLATE 14A

ROCK TYPE: Shale
SAND AND SILT-SIZE DETRITUS: Monocrystalline quartz (E8-9) and spores (C9, G3)
DETRITAL/RECRYSTALLIZED MATRIX: Poorly defined, undifferentiated clay
CEMENTS: Pyrite and ankerite
POROSITY TYPES: Microporosity
PORE NETWORK: Isolated and ineffective
MAGNIFICATION: 50X

PLATE 14B

Plate 14B reveals the fissile character of this shale. Parallel alignment of the undifferentiated clay minerals that comprise much of the shele is clearly shown at A-B10. In addition to the parallel alignment of the platy clay minerals, spore exines at C3, A12, G6, and H13 also are aligned more or less parallel to each other. (200X)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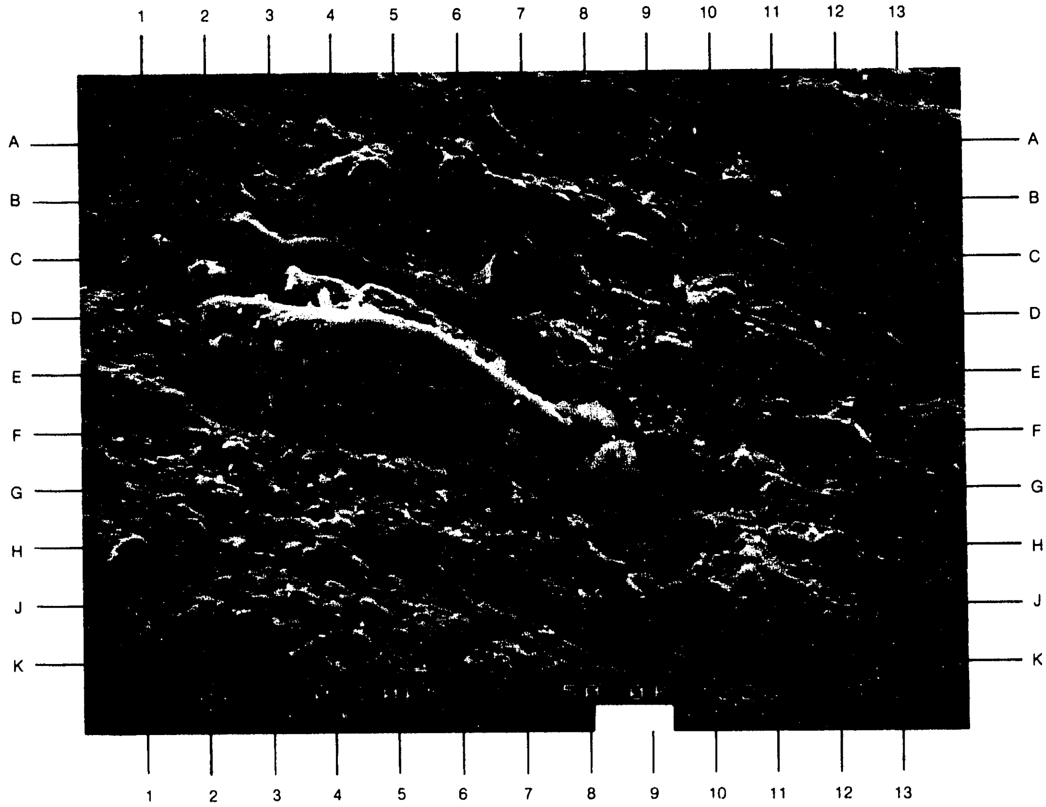
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A B C D E F G H J K

B

SAMPLE NUMBER: 28H-4

PLATE 15A

The abundant matrix material is featured in this high-magnification image. The preferred orientation of these clay minerals is characteristic of shales. No positive identification of the clay minerals was possible; this clayey matrix material may be a mechanical mixture of several different clay minerals. A silt-size quartz grain is shown at J5. (1200X)

PLATE 15B

The parallel alignment of clay minerals has been disrupted by the growth of framboidal pyrite (C2, G7). Pyrite framboids are commonly observed within the clayey matrix material and most likely represent pyritized organic material. A silt-size potassium feldspar grain occurs at G3. Abundant, microporosity occurs in conjunction with the clay in this shale. (2000X)

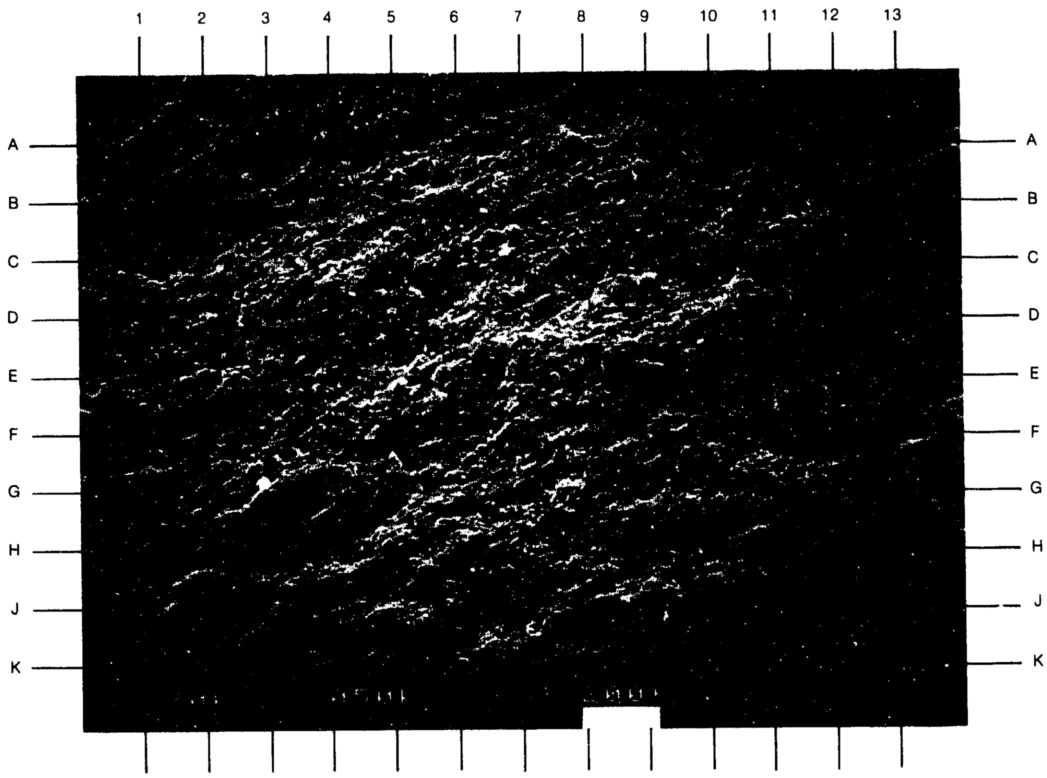
SAMPLE NUMBER: 28H-5

PLATE 16A

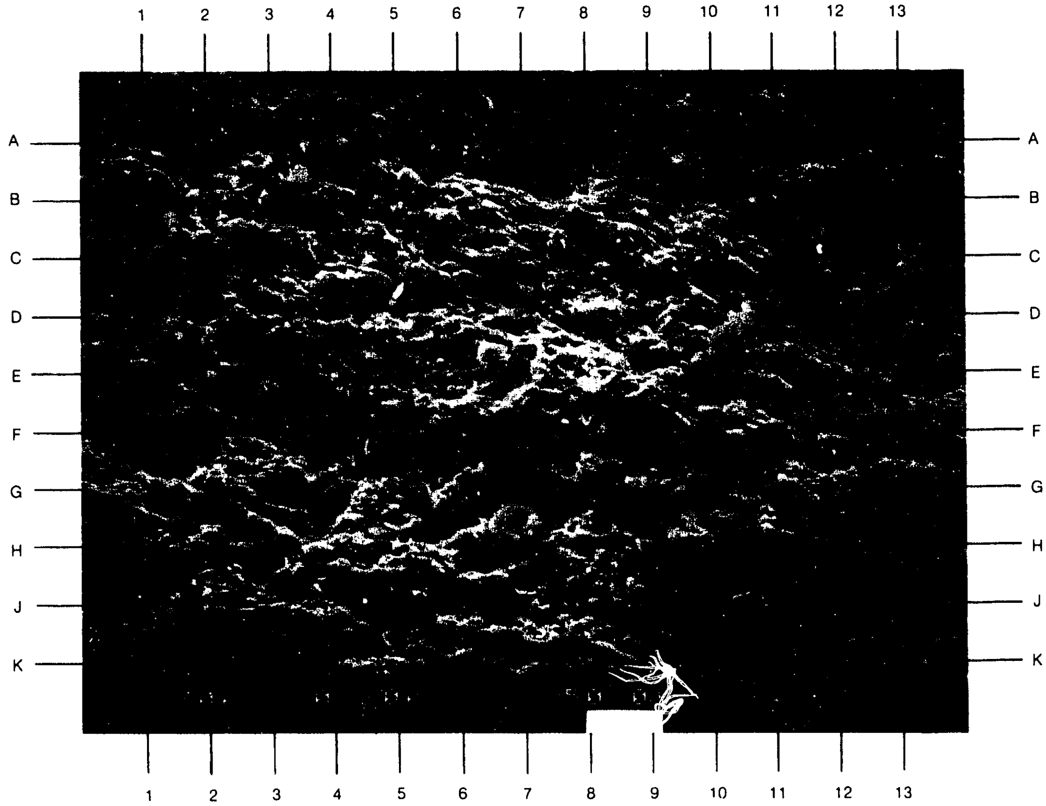
ROCK TYPE: Shale
SAND AND SILT-SIZE DETRITUS: Monocrystalline quartz and spores (G-H3-4)
DETRITAL/RECRYSTALLIZED MATRIX: Abundant, undifferentiated, clay
CEMENTS: Ankerite and pyrite
POROSITY TYPES: Microporosity
PORE NETWORK: Isolated
MAGNIFICATION: 50X

PLATE 16B

Preferentially oriented, platy clay minerals are highlighted in this view of the sample. Spores (A11) and pockets of silt-size quartz and feldspar grains fleck the clay-rich matrix material. The parallel alignment of the clayey matrix material has been disrupted by the growth of authigenic pyrite at E6. (200X)


1 2 3 4 5 6 7 8 9 10 11 12 13
A B C D E F G H J K

A


1 2 3 4 5 6 7 8 9 10 11 12 13
A B C D E F G H J K

B

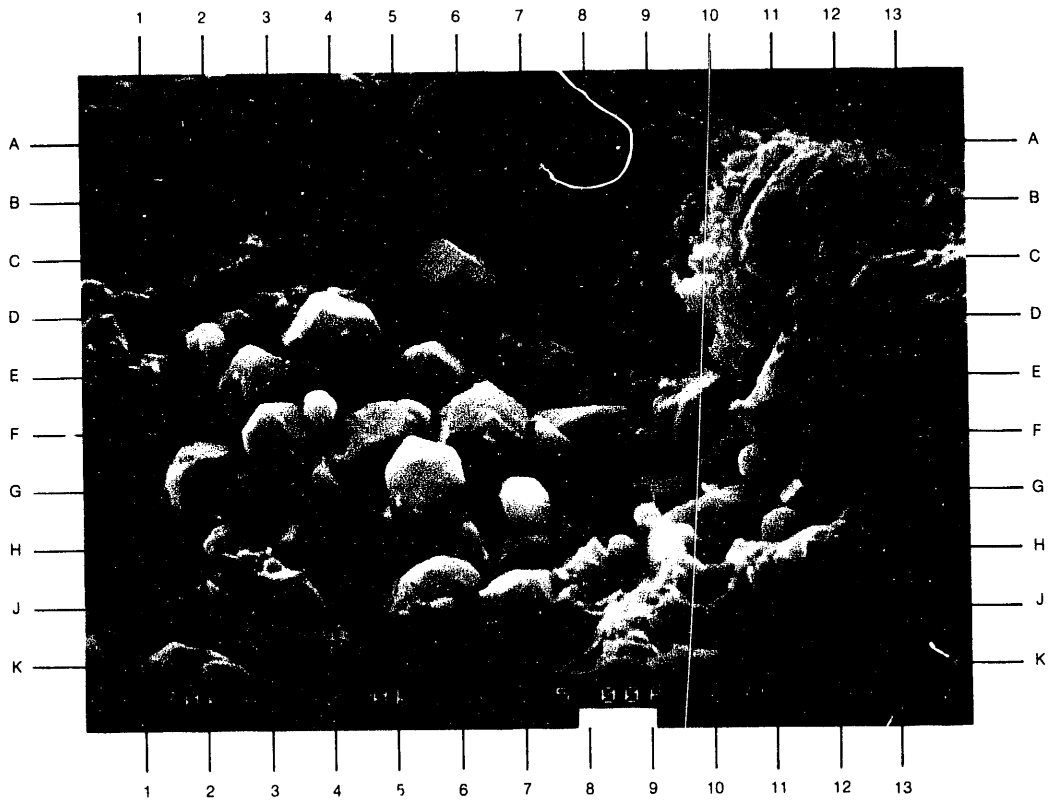
SAMPLE NUMBER: 28H-5

PLATE 17A

Well-defined pyritohedrons (F6) and framboids (B8) are shown in this high-magnification photomicrograph. Poorly defined, clayey matrix material incompletely coats (J5, J6) some authigenic pyrite crystals. Although silicon, iron, aluminum, and potassium were detected during EDS analyses of this sample, the absence of a well-defined morphology precludes the identification of the individual clay minerals. (2000X)

PLATE 17B

Nondescript clay minerals dominate this view of the sample. The orientation of these clay minerals reveals the fissile character of the shale. Authigenic pyrite crystals (D11), heterogeneously distributed throughout the matrix, also are present. The clay-rich matrix material most likely represents a mechanical mixture of different clay minerals. Abundant, noneffective micropores occur throughout the clayey matrix. (1250X)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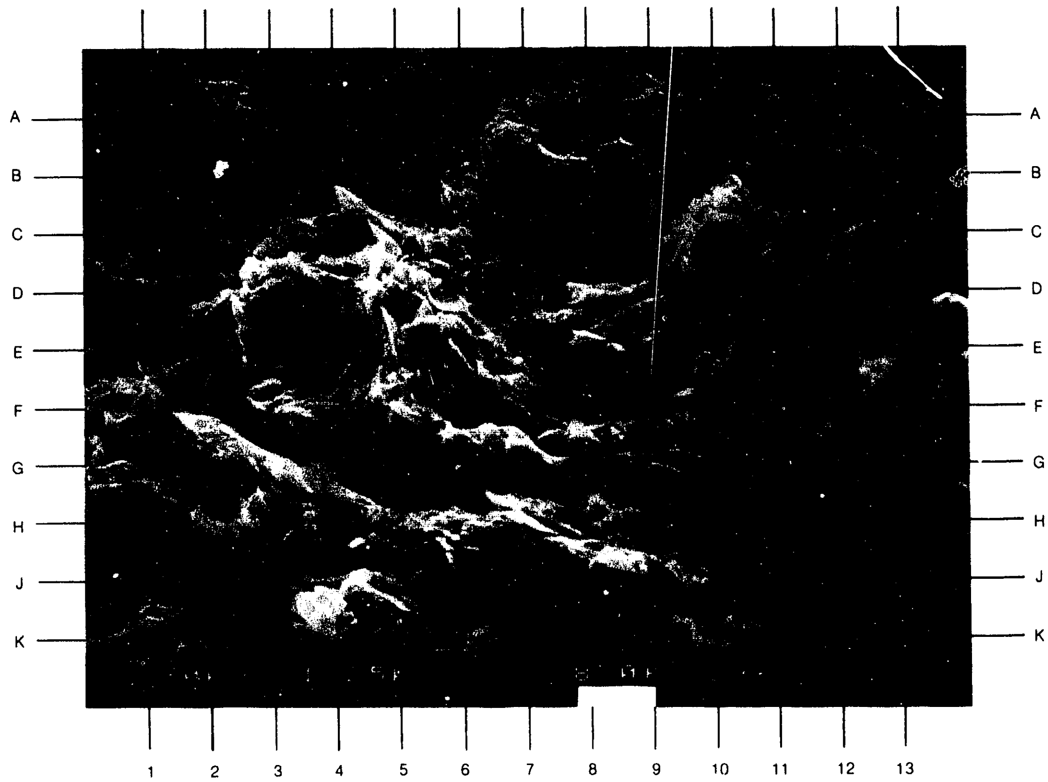

1 2 3 4 5 6 7 8 9 10 11 12 13
A B C D E F G H J K

B

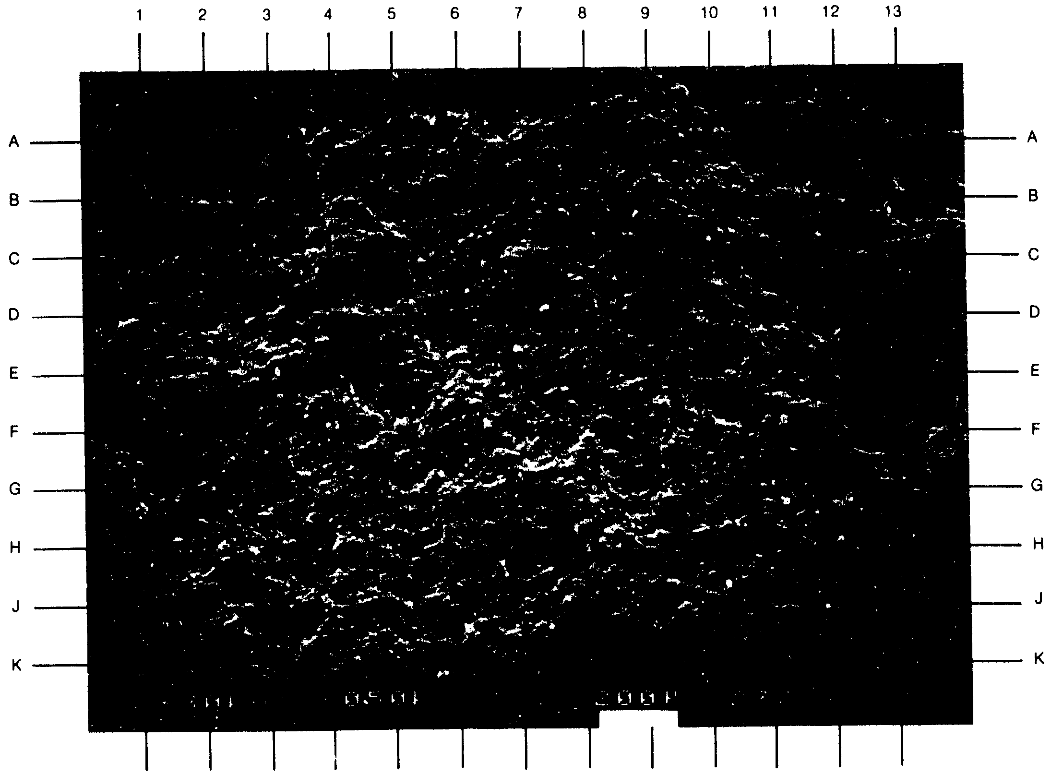
SAMPLE NUMBER: 28H-6

PLATE 18A

ROCK TYPE: Shale
SAND AND SILT-SIZE DETRITUS: Quartz and feldspar
DETRITAL/RECRYSTALLIZED MATRIX: Undifferentiated clay
CEMENTS: Pyrite and ankerite
POROSITY TYPES: Microporosity
PORE NETWORK: Isolated, noneffective micropores
MAGNIFICATION: 50X

PLATE 18B

This view of the sample shows the poorly defined character of the abundant, clayey matrix material that comprises most of this sample. Authigenic pyrite crystals fleck the matrix (E5-6, E-F10). Although abundant microporosity is associated with the clayey matrix material, this porosity type is genreally considered ineffective. (200X)



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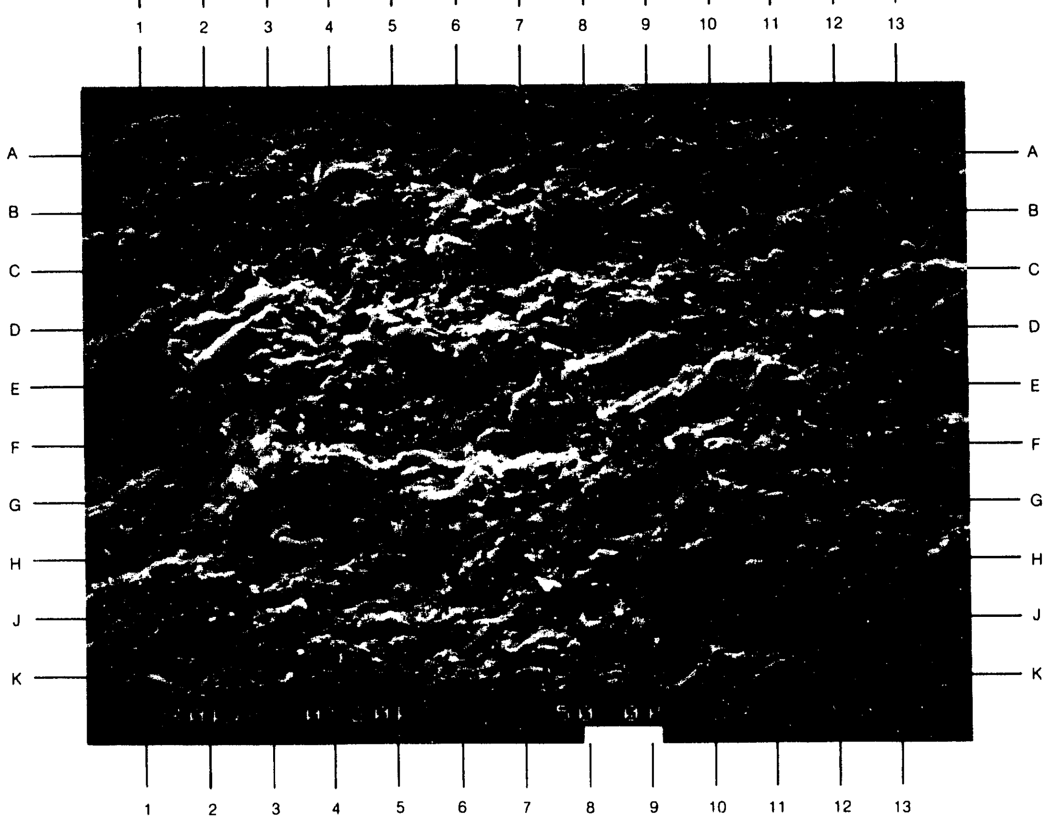


B

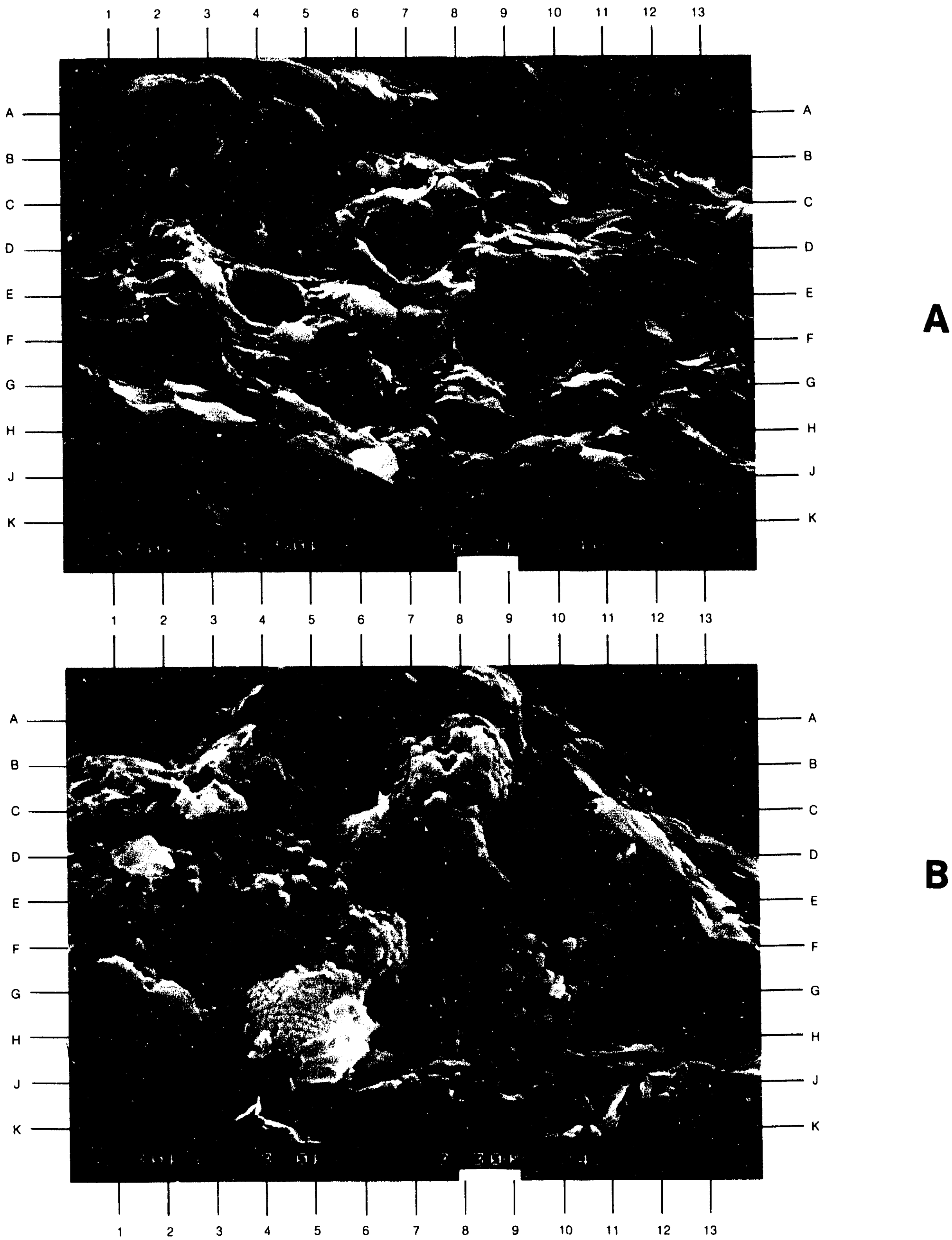
SAMPLE NUMBER: 28H-6

PLATE 19A

The platy character of the clay minerals present in this sample is clearly revealed in this detailed photomicrograph. Minor disruption of the lamination is due either to the presence of silt-size detritus or the growth of authigenic minerals. Quartz (A13, H12) and feldspar (B4) clasts occur throughout the matrix. (1500X)

PLATE 19B

Organic material that originally filled the interior of this spore has been converted to framboidal pyrite (A5, F8, H4) and pyritohedrons (D3). The spore exine which has not been pyritized can be noted at K7. Undifferentiated, platy matrix material occurs at D11 and A10. (3000X)


A
B

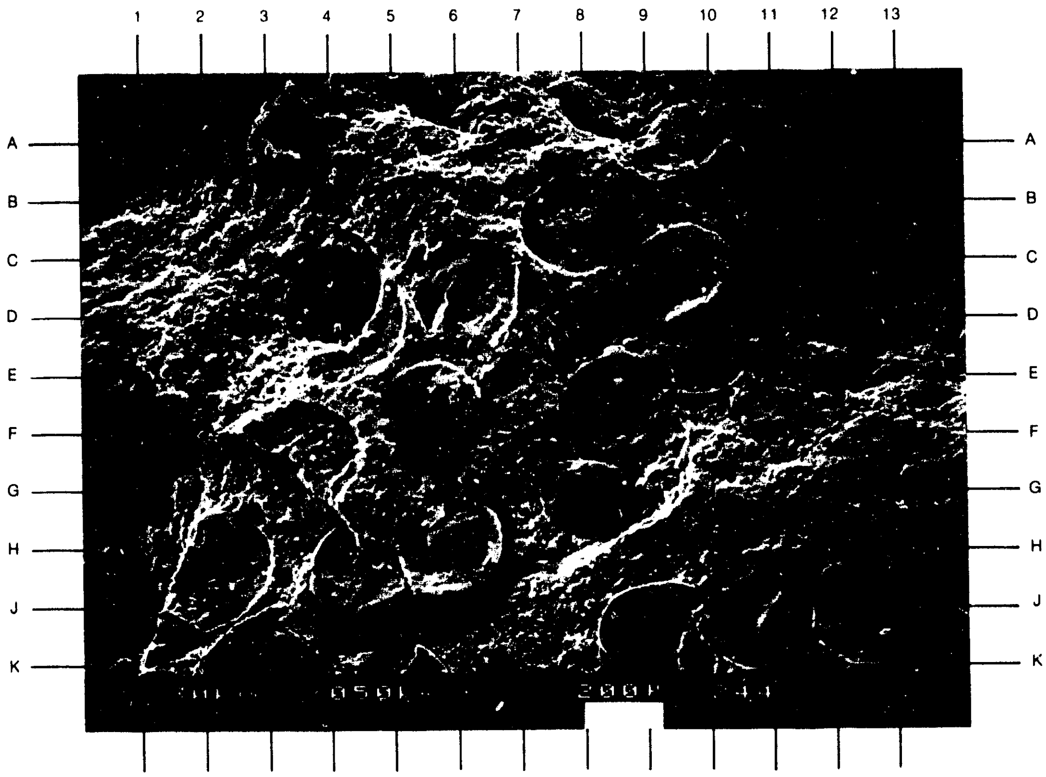
SAMPLE NUMBER: 28H-7

PLATE 20A

ROCK TYPE: Shale
SAND AND SILT-SIZE DETRITUS: Quartz and spores (C9-10)
DETRITAL/RECRYSTALLIZED MATRIX: Undifferentiated clay
CEMENTS: Ankerite and pyrite
POROSITY TYPES: Microporosity
PORE NETWORK: Noneffective, isolated micropores
MAGNIFICATION: 50X

PLATE 20B

The exines of two spores are visible at E3 and D8 in this view of the sample. The platy matrix material is most likely a mechanical mixture of clay minerals. Minute pyrite and ankerite crystals are the most common authigenic cements. (200X)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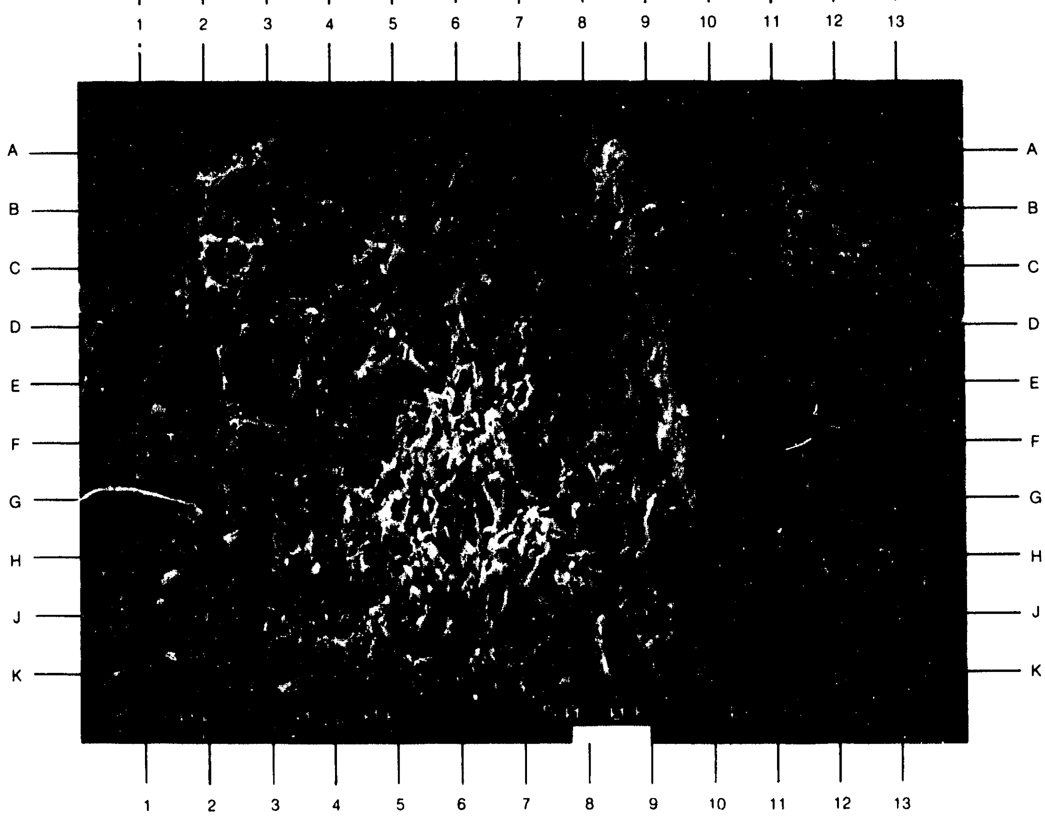
A B C D E F G H J K

A


1 2 3 4 5 6 7 8 9 10 11 12 13
A B C D E F G H J K

B

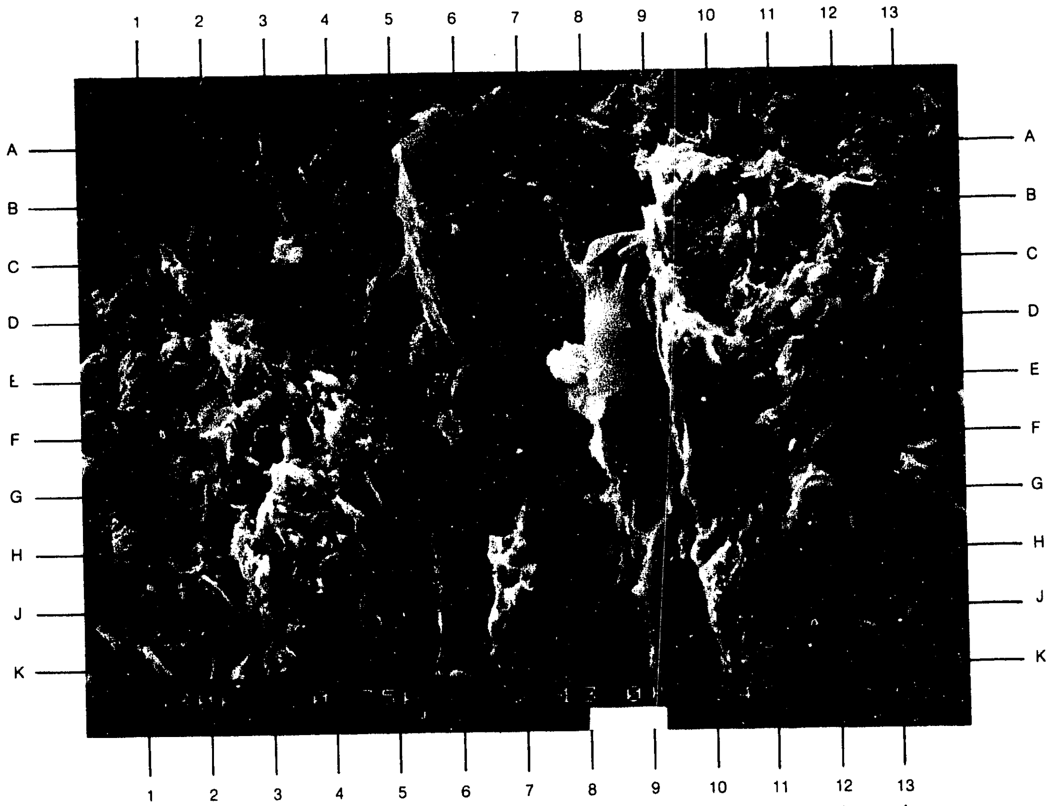
SAMPLE NUMBER: 28H-6

PLATE 21B

A detailed view of a spore exine (F8) is shown in this high-magnification image. The interior of the spore has been filled with undifferentiated matrix material. The platy, clay matrix defines the lamination characteristic of shales. (750X)

PLATE 21B

The smooth surface of a spore exine is featured in this high-magnification view. The molds at A7, A4, and H12 define areas once occupied by a rhombohedral mineral, probably ankerite. Some of the platy matrix material that comprises most of this sample is visible at J2 and A13. (500X)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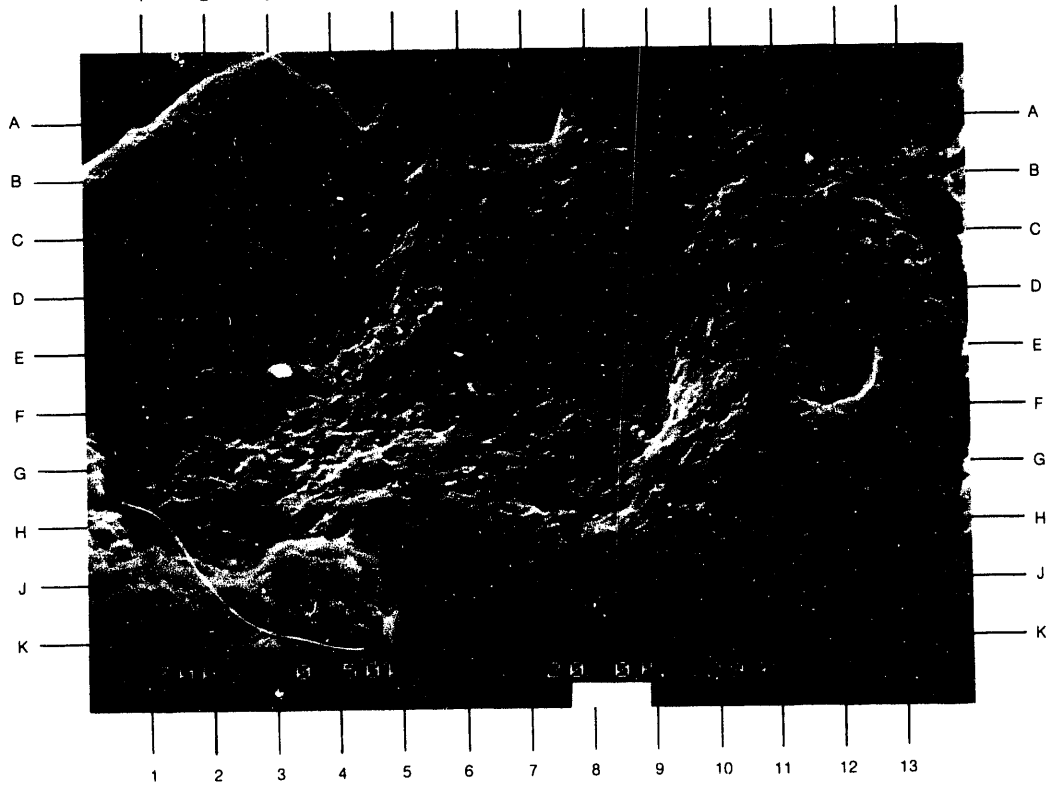
A B C D E F G H J K

A


1 2 3 4 5 6 7 8 9 10 11 12 13
A B C D E F G H J K

B

VOLUME II
PART III

GEOCHEMISTRY

TABLE OF CONTENTS

SUMMARY

Seven (7) core samples were analyzed for kerogen composition and vitrinite reflectance. True vertical depth for all samples is 3390 feet.

The subject samples all contained predominately amorphous kerogen which consisted of amorphous debris and small and large spores. Larger spores appear to be Tasmanites sp. Two samples contained small amounts of inertinite material which may be graptolite fragments. The kerogen data summary (Table 1, Part III) indicates that 90 to 100 percent of the kerogen is amorphous debris and spores.

Because no terrestrial polymorphs were observed, the thermal alteration index (TAI) was determined from the kerogen appearence in general. The amorphous debris is largely pyritized and appears artificially dark. However, the small spores appear light yellow to yellow orange in color and have bright yellow to yellow orange fluorescence. This suggests that the kerogen is immature to marginally thermally mature with respect to the main phase of hydrocarbon generation. The paucity of vitrinite particles prevented the aquisition of mean vitirinite reflectance values.

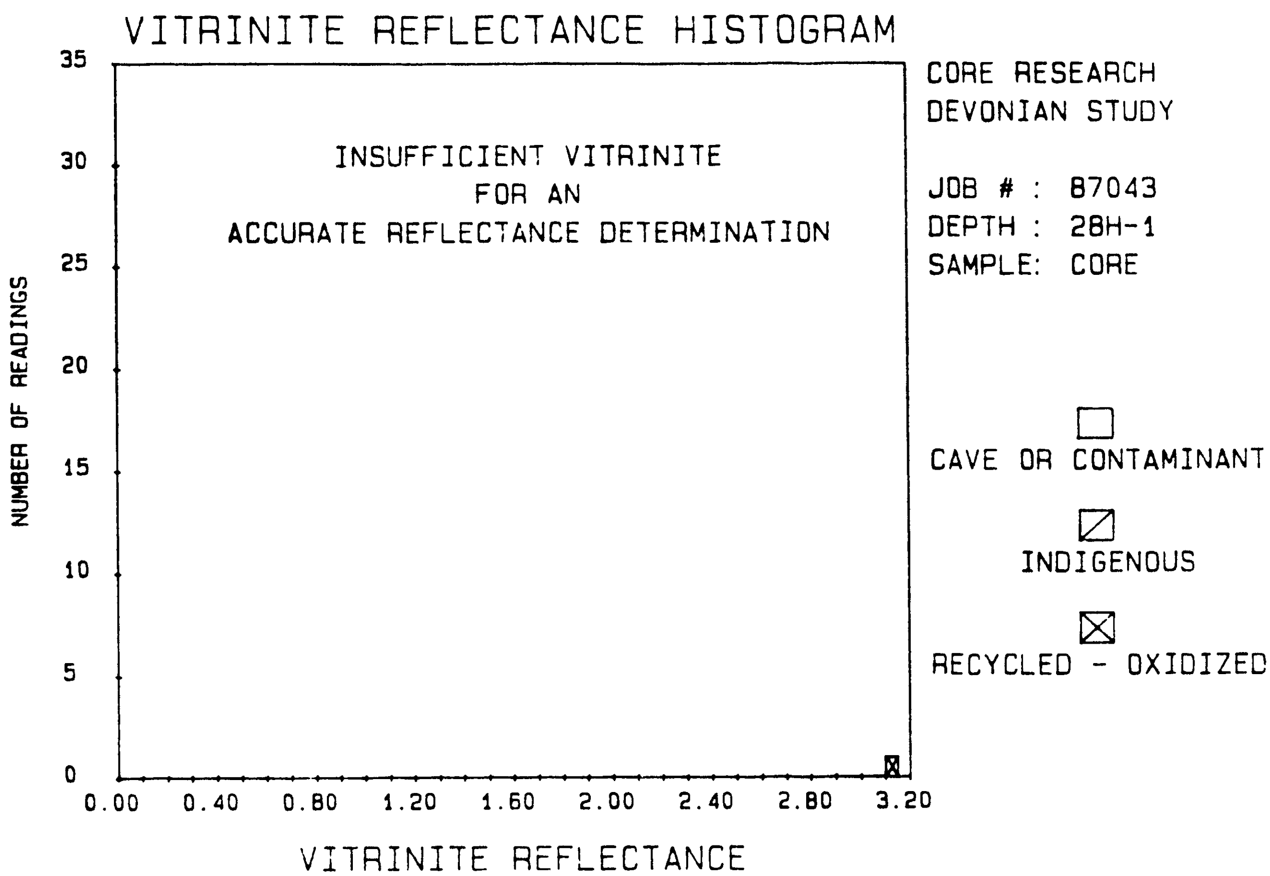
TABLE 1. KEROGEN DATA SUMMARY

Sample I.D.	Amorphous (%)	Exinite (%)	Woody (%)	Inertinite (%)	Alteration Index	Vitrinite Reflectance	Remarks
28H-1	100		T		2 TO 2+	ND	Semi-clumped amorphous
28H-2	100		T		2 TO 2+	ND	Dispersed amorphous
28H-3	90			10	2 TO 2+	ND	
28H-4	100				2 TO 2+	ND	Kerogen is degraded
28H-5	95			5	2 TO 2+	ND	Dispersed amorphous
28H-6	100		T		2 TO 2+	ND	
28H-7	100		T		2 TO 2+	ND	

Amorphous = algal debris + amorphous sapropels; Exinite = waxy and resinous materials materials generally having a characteristic form; i.e. plant cuticle, pollen, spores, resins, etc.

ND signifies no data available.

Figure 1



STATISTICS FOR THE INDIGENOUS POPULATION

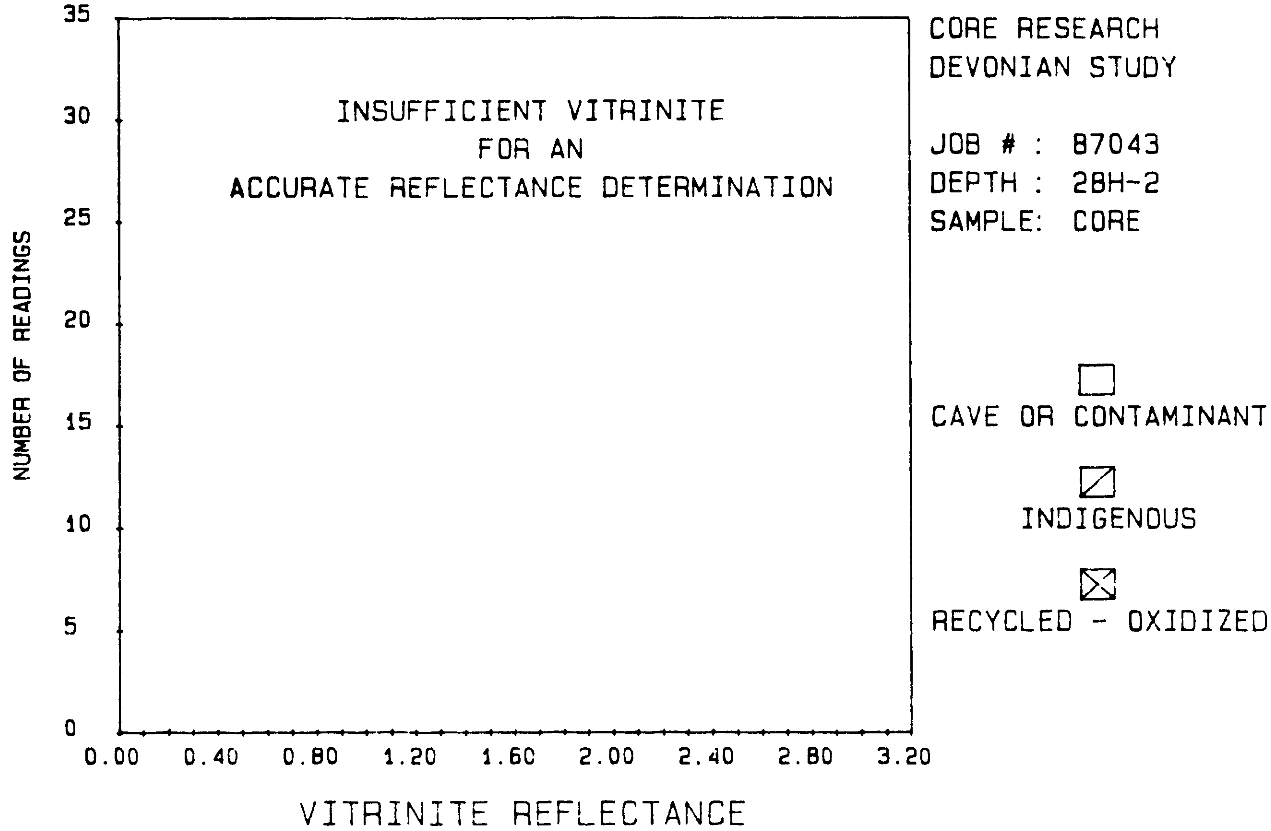
NUMBER OF READINGS	0	STANDARD DEVIATION	N/A
MEAN REF.	N/A	MEDIAN	N/A
MIN. REF.	N/A	MODE	N/A
MAX. REF.	N/A	SKEWNESS	N/A

STATISTICS FOR THE TOTAL POPULATION

READINGS		PERCENT OF POPULATION	
CAVE OR CONTAMINANT	0	CAVE OR CONTAMINANT	0.0 %
INDIGENOUS	0	INDIGENOUS	0.0 %
RECYCLED - OXIDIZED	1	RECYCLED - OXIDIZED	100.0 %
TOTAL	1	TOTAL	100.0 %

Figure 2

VITRINITE REFLECTANCE HISTOGRAM



CORE RESEARCH
DEVONIAN STUDY

JOB # : 87043
DEPTH : 28H-2
SAMPLE: CORE

STATISTICS FOR THE INDIGENOUS POPULATION

NUMBER OF READINGS	0	STANDARD DEVIATION	N/A
MEAN REF.	N/A	MEDIAN	N/A
MIN. REF.	N/A	MODE	N/A
MAX. REF.	N/A	SKEWNESS	N/A

STATISTICS FOR THE TOTAL POPULATION

READINGS		PERCENT OF POPULATION	
CAVE OR CONTAMINANT	0	CAVE OR CONTAMINANT	0.0 %
INDIGENOUS	0	INDIGENOUS	0.0 %
RECYCLED - OXIDIZED	0	RECYCLED - OXIDIZED	0.0 %
TOTAL	0	TOTAL	0.0 %

APPENDIX 7-3

MECHANICAL PROPERTIES TESTING OF ORIENTED CORE MATERIAL

APPENDIX 7.3

MECHANICAL PROPERTIES TESTING OF ORIENTED CORE MATERIAL

7.3 Mechanical Properties Testing

All core remaining after samples had been selected for desorption and petrophysical testing was forwarded to the Department of Geology and Geological Engineering, Michigan Technological University, for mechanical property testing. The tests performed provided information and data on the inherent mechanical properties in the shale and were used to further describe the geologic and engineering characteristics of the productive formation.

7.3.1 Procedures

The purpose of mechanical characterization of samples from the RET #1 well was to determine the orientation of preferred planes of weakness in the Devonian gas shales at the Wayne County, West Virginia, well site. A series of samples, representing 73 feet of core, were taken from the Upper Huron Shale Member of the Ohio Shale.

The physical property tests employed were: (1) directional ultrasonic velocity measurements; (2) point load induced fracturing; and (3) directional tensile strength tests. In addition, all fractures (hereafter referred to as "pretest fractures") were systematically recorded before the physical property tests were performed. The theories on which these tests are based are summarized as follows:

1) Pretest Fracture Analysis: Pretest fracture analysis consists of the observation and recording of all visible fractures that occur on the sanded ends of the test specimens. This procedure provides information on natural microcrack orientation, or on induced crack orientations that may originate at orientation grooves. The procedures are:

- The sanded surface of the specimen is dampened with a moist sponge so that water is absorbed into the microcracks. The surface is then air-dried until the cracks are accentuated because of water retention.
- The cracks were traced with a pencil while visible.
- Crack orienttion is determined by projecting a line parallel to the crack through the center of the oriented specimen and recording its orientation in degrees from true north.
- The length of the crack is recorded in inches.
- A sketch is made of each specimen illustrating pretest fractures.
- A composite sheet is kept with the orientation and length of each identified fracture for all tested specimens.

2) Directional Ultrasonic Velocity Measurements: Ultrasonic velocity measurements are used to detect the preferred orientation of microfractures in the gas shales. Fractures which are oriented perpendicular to the direction of wave propagation will impede the wave, whereas fractures which are oriented parallel to the direction of wave propagation will not. To detect these differences, measurements are performed diametrically on each core sample at 30 degree intervals from true north. Minimum values of sonic velocity occur in azimuths normal to the preferred direction of microfractures (Komar and Kovach, 1969). Directional ultrasonic velocity measurements are performed as follows:

- Pretest fractures including a description of bedding or other significant features are recorded.
- The center of the sample is taped with three strips of black vinyl tape which touch but do not overlap each other. The ends of the tape are positioned at an orientation groove so that the transducer heads are not positioned over the splice.
- The sample is placed on a foam rubber cushioned, indexed, rotating stage with the north orientation mark against the transmitting head.

- o High vacuum silicone grease is applied to each of the 12 contact positions at 30 degree intervals from true north.
- o The opposite traveling head is moved to close proximity to the core surface to avoid jarring the specimen.
- o The air valve is actuated and the specimen is gripped with an indicated air hydraulic pressure of 35 psi.
- o With the pulse rate set at 1/30 sec, the powerstat is turned on and increased to an indicated 62 percent.
- o A pause of three minutes is taken to allow for the decay and stabilization of indicated travel time.
- o After three minutes, ten consecutive travel time values, registered on the digital counter as the average of 100 pulses, are recorded.
- o The pressure is released on the sample.
- o The specimen is rotated on the stage to the next marked 30 degree interval and Steps 5 through 12 are repeated until the travel times in each of the six orientations, 0, 30, 60, 90, 120, 150 degrees, have been recorded.
- o The diameter of the core is measured for each position using a vernier caliper to 0.001 inch.

3) Point Load Testing: The point load testing apparatus consists of a load frame with two identical conical platens. These platens are applied so that the apical contact points are located on the center of the disk-shaped specimen. Fractures induced by a point load will be in a random orientation if the rock specimens contain no preferred planes of weakness; if the specimen is anisotropic, however, the induced fracture would be expected to occur in a preferred direction, parallel to preexisting microfractures. In the case of a rock body that is homogeneous, large numbers of point load specimens would therefore be expected to display a random orientation of included fractures. In the case of an anisotropic rock body, such as one containing a network of natural microfractures, the statistical analysis of a large number

of point load induced fractures will show a direction parallel to the natural preferred microcrack orientation. Thus the orientation of a weakness plane in rock specimens may be found by inducing tensile fractures in discs when a load is applied through the disc's central axis (Anderson and Lieberman, 1966; McWilliams, 1966). Point load tests were performed as follows:

- At intervals of 6 inches, 2-inch diameter by approximately 0.5 to 0.8 inch thick samples were undercored and surface-ground.
- Pretest fractures were recorded as outlined above.
- Sample dimensions were recorded (diameter and thickness in inches).
- The circumference of each sample was taped with masking tape to preserve the fracture after the point load test was performed.
- The sample was centered and placed vertically between the conical platens in the load frame.
- A compressive load was applied directly in the center on both the top and bottom sides of the sample.
- The magnitude of the applied load at failure was recorded and the point load strength index can be obtained by the formula (Roberts, 1977):

$$IS = P/D^2$$

where IS = point load strength index;
P = applied load at failure (pounds);
D = distance between load applicators (inches).

- The orientation of all induced fractures were recorded.

4) <u>Directional Tensile Strength Testing (DTS)</u>: The orientation of minimum tensile strength may be found by applying a compressive diametric loading across a series of cylindrical specimens oriented in various directions (Mellor and Hawkes, 1971). In this diametric or line load

test, tensile strength normal to the axis of loading is determined from the magnitude of the applied load at failure by the formula (Peng and Ortiz, 1972):

$$ST = 2P/(\pi dt)$$

where ST = tensile strength, psi
P = applied load at failure (pounds);
d = diameter of disc (inches);
t = thickness of disc (inches).

DTS measurement procedures are summarized as follows:

- o At the 6-foot interval, six closely grouped samples (2-inch diameter by approximately 0.5 to 0.8-inch thick) are selected.
- o Pretest fractures are recorded.
- o Each sample is oriented and marked in one of six directions (0, 30, 60, 90, 120, 150), and is sanded on the edges corresponding to this mark to ensure even loading.
- o The diameter and thickness of the sample are recorded, and if necessary, the samples are taped with masking tape.
- o The sample is placed diametrically between the platens in the load frame.
- o A compressive load is applied across the previously oriented diameter of the sample.
- o The magnitude of the applied load at failure is recorded.
- o The tensile strength normal to the axis of loading is determined using the formula: $ST = 2P/(\pi dt)$ as defined above.
- o The induced fractures are sketched, noting whether a bedding-plane failure or a diametric failure occurred.

7.3.2 Results

The results of the physical property measurements of pretest fractures, directional ultrasonic velocity, point load induced fracturing, and directional tensile strength tests are summarized in

Table 7.3.1. Velocity minimum and DTS maximum results are rotated 90 degrees to indicate the preferred direction in this table.

Pre-Test Fractures

Vertical pre-test fractures are generally absent in test specimens from this well. Only one such fracture was observed in the N150°E orientation. Pre-test fractures therefore do not indicate a statistically significant preferred direction of weakness.

Point Load Tests

Point load induced fractures, usually the most reliable indicator of a preferred fracture direction (Gregg, 1986), occur most frequently in the N60E±15° direction (11 out of 41 total induced fractures). The tendency to fracture in this direction is weak-to-moderate (Figure 7.3.1). Statistical analysis indicates that the precise fracture direction is N48E at the 80% confidence level.

Ultrasonic Wave Velocity Tests

Ultrasonic velocity tests indicate a direction N30E ± 15 degrees as a possible plane of weakness (Figures 7.3.2 through 7.3.5). There is good agreement between the directional occurrence of minimum (Figure 7.3.2) and maximum (Figure 7.3.3) velocity values. Residual analysis of velocity data, which eliminates effects of lithologic variation, shows the fabric to be weak-to-moderate (Figure 7.3.4). The residual velocity values were obtained by subtracting the average velocity value for each depth from each orientation value at that depth. These residual values were then averaged for the entire well by orientation.

In addition to the occurrence of velocity maximum and minimum data, the average ultrasonic velocities for the well, taken in each direction, also show a maximum velocity in the N30E ± 15 degree direction (Figure 7.3.5). The minimum average velocity occurs at N120E ± 15 degrees, and similarly indicates a preferred direction of weakness in the N30E ± 15 degree direction.

TABLE 7.3.1

FREQUENCY DISTRIBUTION OF PREFERRED DIRECTION
OF FRACTURING ORIENTATION IN DEGREES EAST OF NORTH

OHIO SHALE UPPER HURON MEMBER 4043 - 4156' tested	0°	30°	60°	90°	120°	150°	TOTAL
Pretest Fracture	0	0	0	0	1	1	2
Velocity (Minimum)	13	26	19	10	2	7	77
Velocity (Maximum)	14	29	21	3	5	4	76
Point Load	7	8	11	6	5	4	41
DTS (Minimum)	2	1	1	0	1	0	5 sets
DTS (Maximum)	1	1	1	2	0	0	5 sets

NOTE: Velocity (Minimum) and DTS (Maximum) results are rotated 90 degrees to correspond with other data.

Directional Tensile Strength Tests

The occurrences of maximum and minimum directional tensile strength values do not indicate a preferred direction of fracture in this well (Figures 7.3.6 and 7.3.7). Average directional tensile strength values (Figure 7.3.8) show a minimum tensile strength in the due N30E ± 15 degrees direction and in the N120E ± 15 degrees direction. These DTS results are thus inconclusive, as is typical in most of the EGSP wells.

7.3.3 Analysis

The data indicate that core samples from the RET #1 well exhibit a directional variation in physical properties. Prediction of the preferred direction of induced fracturing at the Wayne County, West Virginia, well site was based on inherent weaknesses in the core samples found by: (1) point load induced fractures; (2) directional tensile strength measurements; (3) normality to measured ultrasonic velocity minimum; and (4) the directional trend of pretest fractures. The overall agreement between these tests in the stratigraphic interval suggests that these physical property measurements do indicate a preferred direction of fracturing in core samples. The following conclusions may be drawn from this investigation:

- The preferred direction of fracturing in the Ohio Shale (Upper Huron Member, 4043 - 4156 feet tested) is N30°E ± 15° as indicated by ultrasonic velocity test results. This trend is weak-to-moderate. Point load test results indicate a direction of N60°E ± 15°.
- Statistical analysis of point load data indicates a unique preferred fracture direction of N48E at the 80% confidence level. This direction falls between the N30°E and N60°E classification intervals.

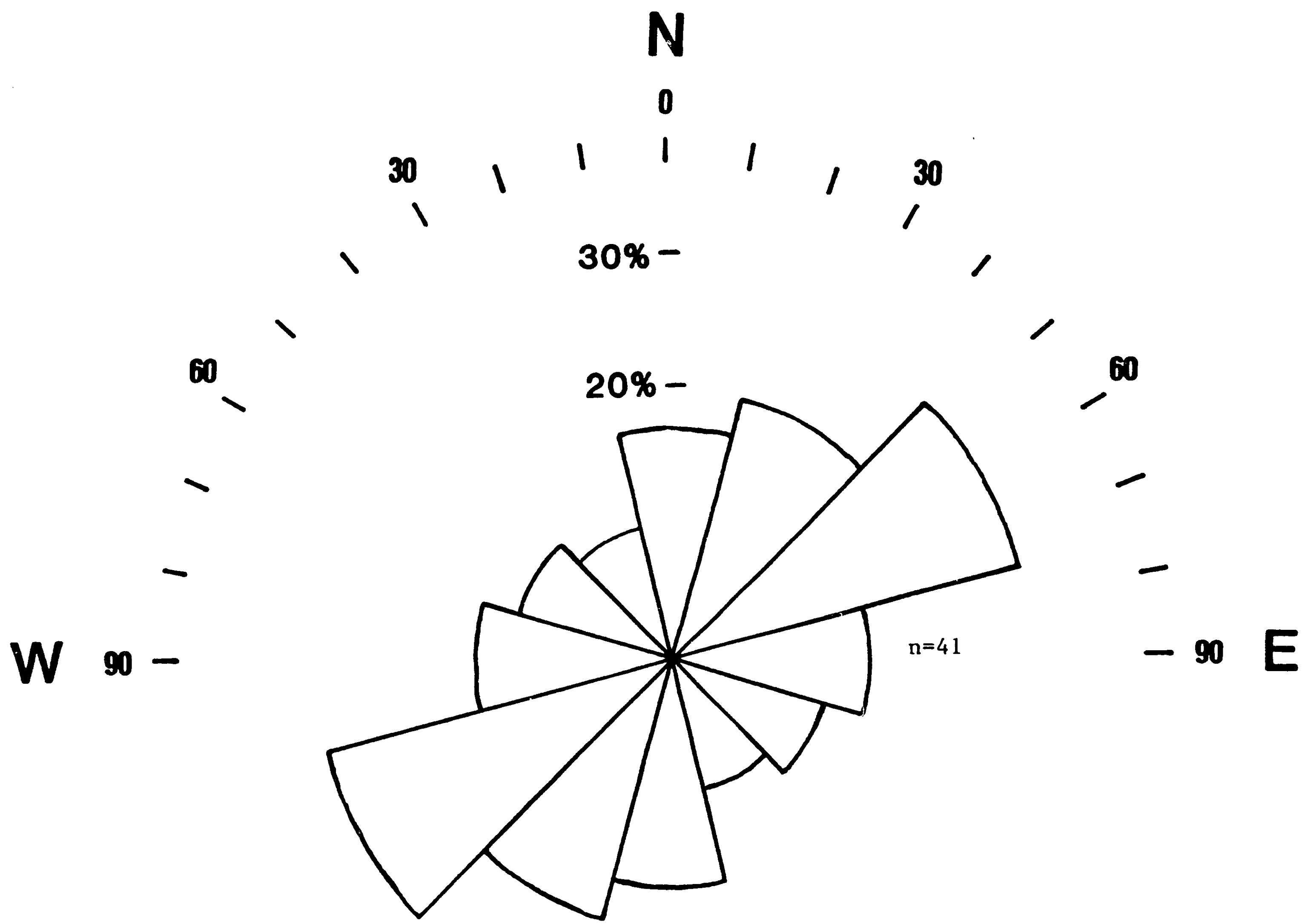


Figure 7.3.1

Point Load Fracture Orientation

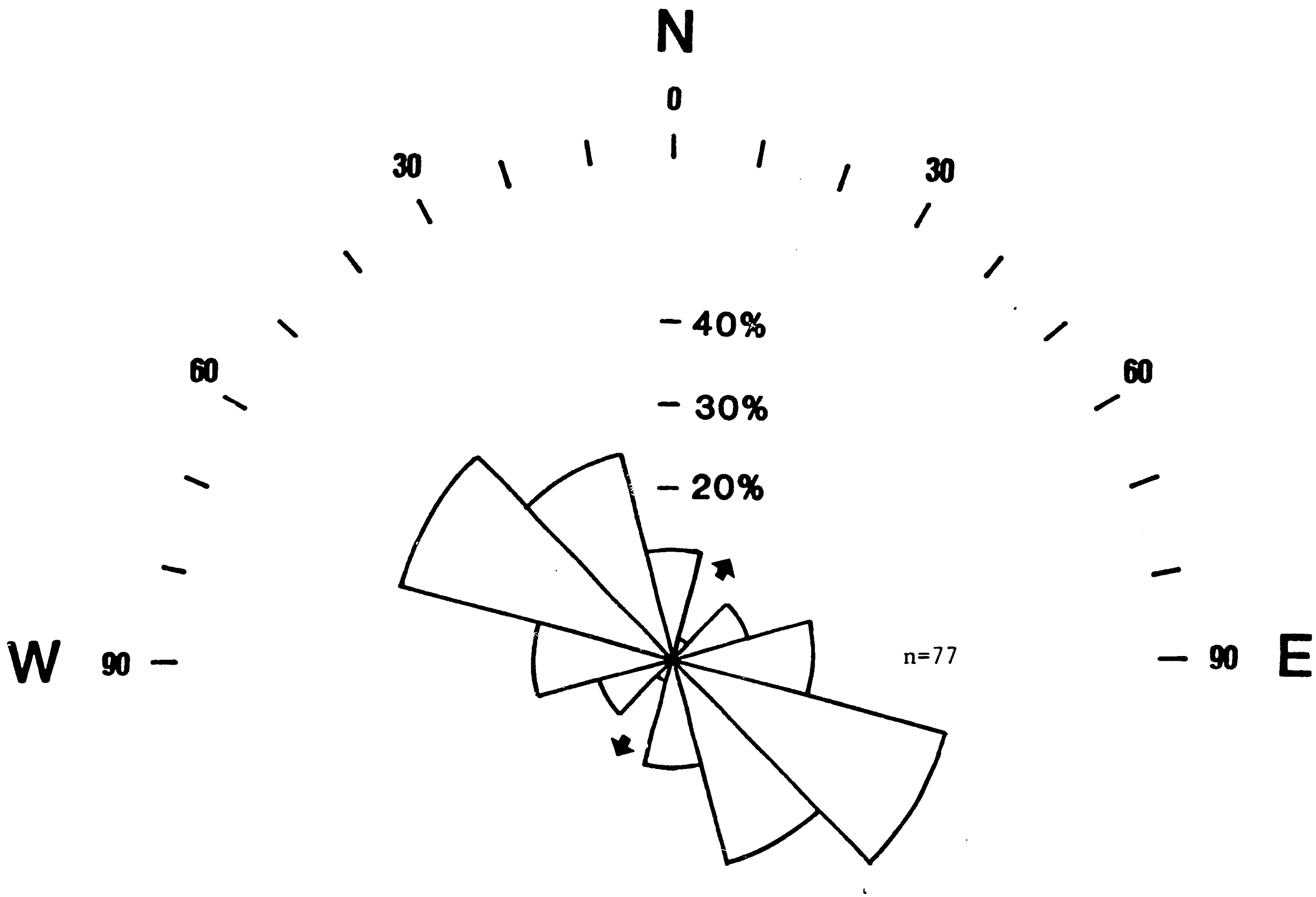


Figure 7.3.2

Orientation of Ultrasonic Wave Velocity Minima (Arrow Indicates Preferred Direction of Fracture)

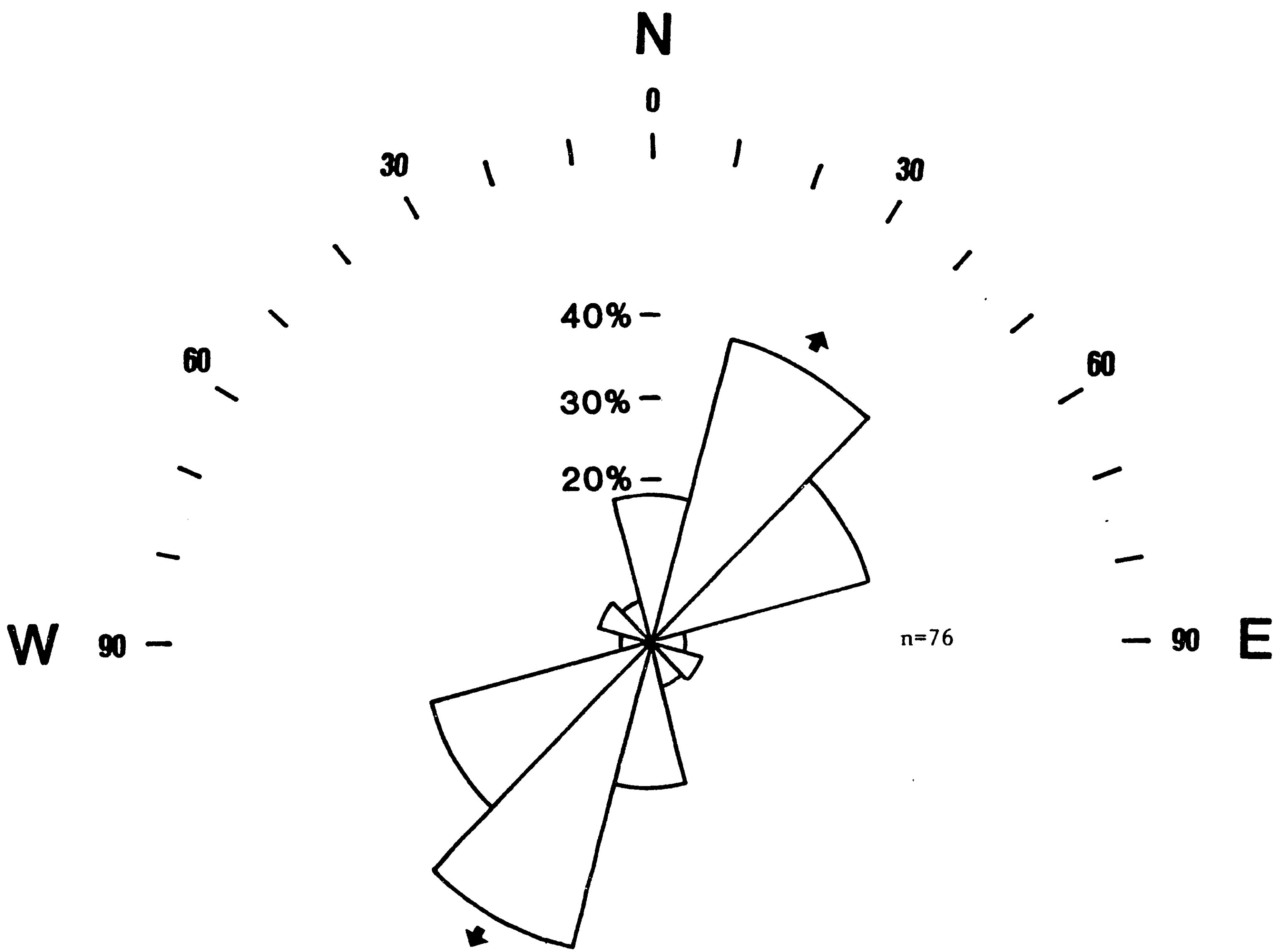


Figure 7.3.3

Orientation of Ultrasonic Wave Velocity Maxima (Arrow Indicates Preferred Direction of Fracture)

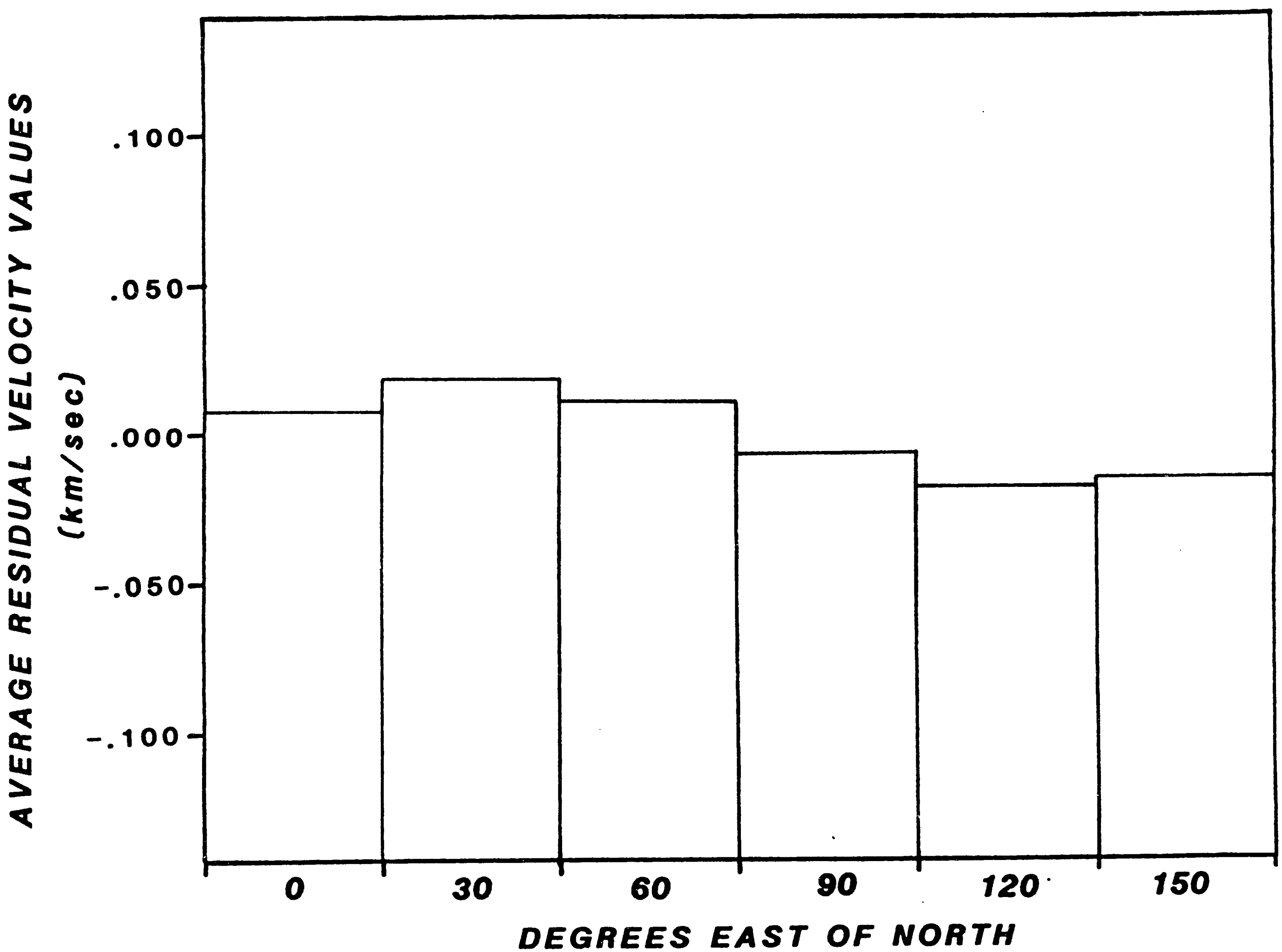


Figure 7.3.4 - Average Directional Residual Velocity Values

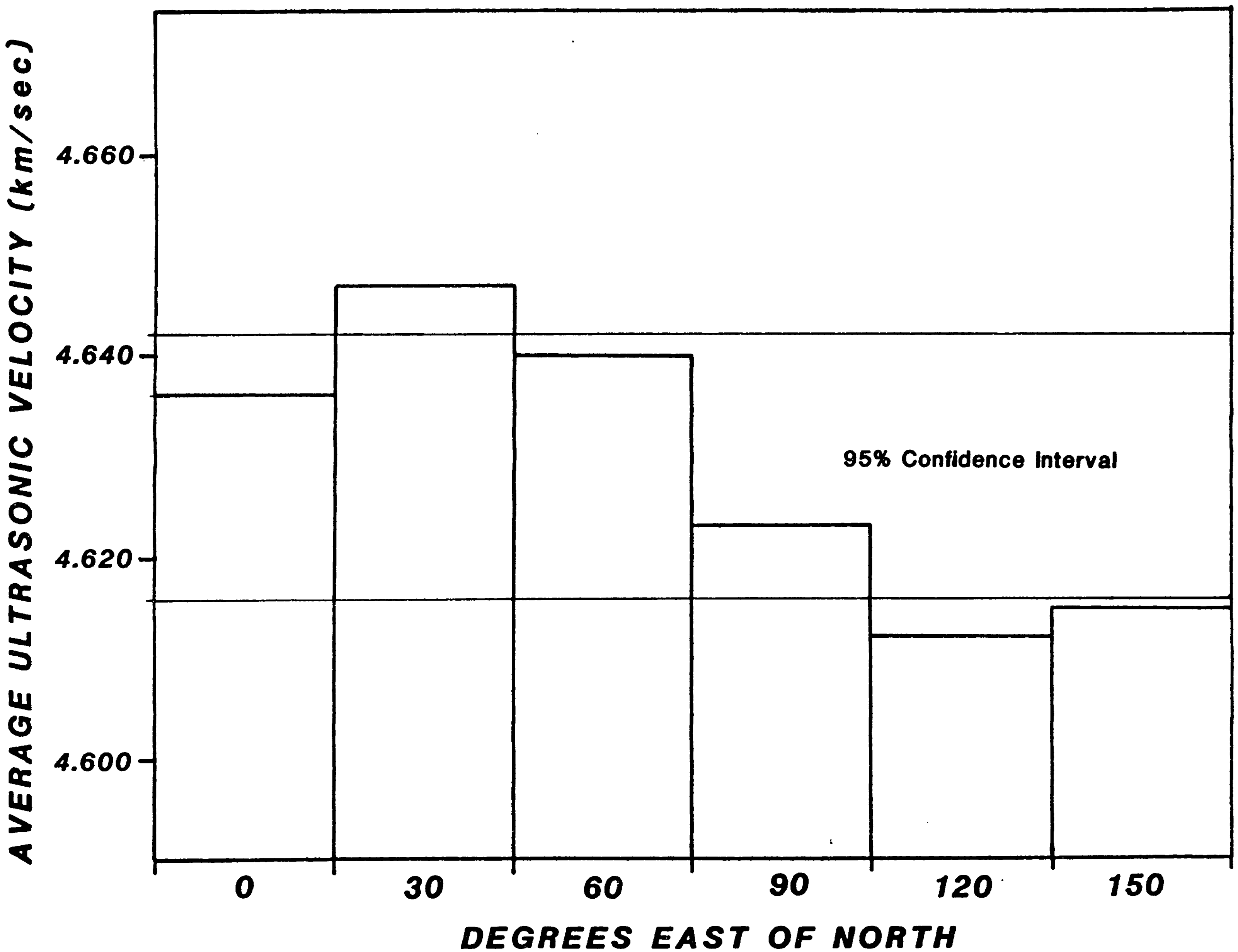


Figure 7.3.5 - Average Directional Ultrasonic Velocities

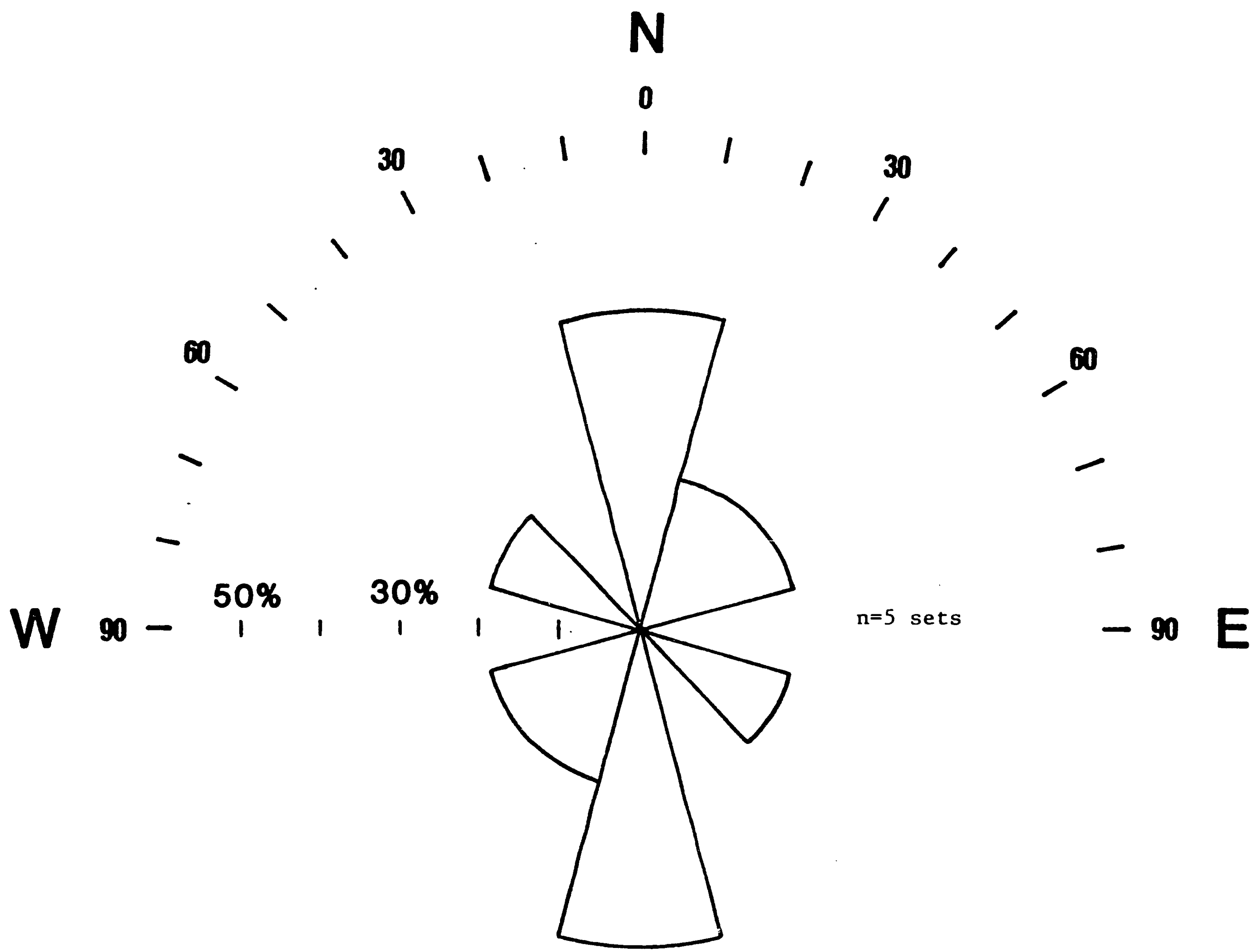


Figure 7.3.6 - Orientation of Minimum Tensile Strength Values

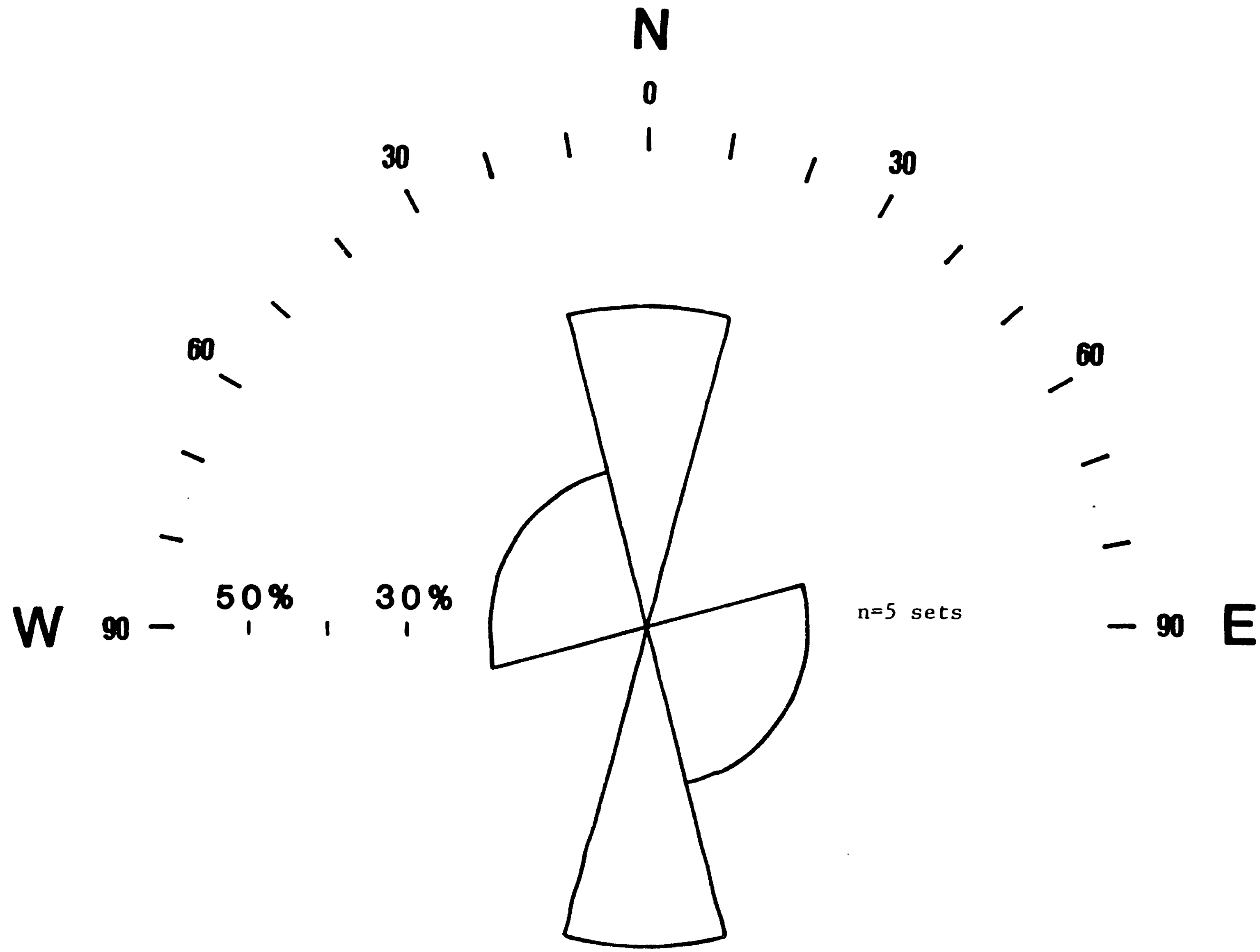


Figure 7.3.7 - Orientation of Maximum Tensile Strength Values

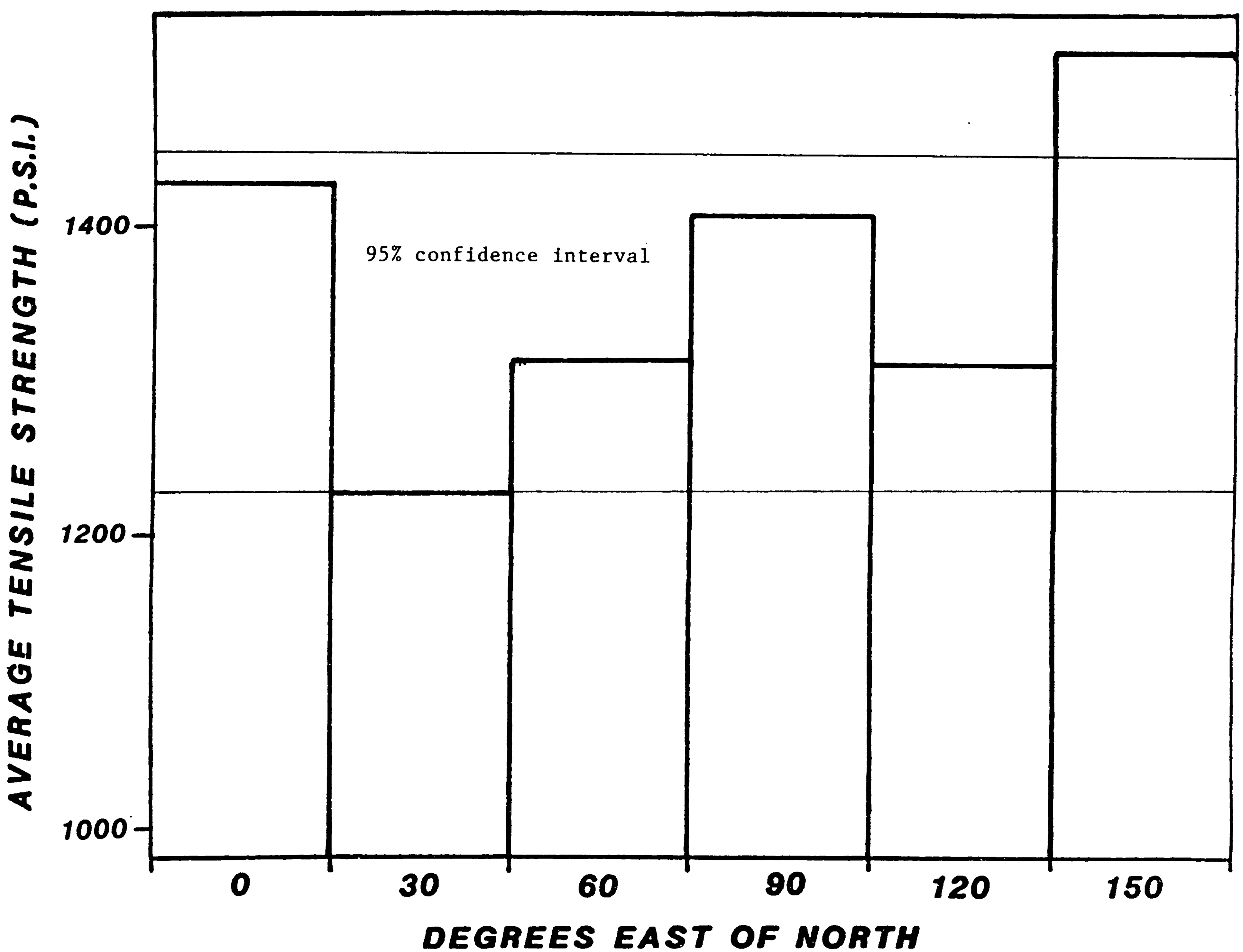


Figure 7.3.8 - Average Directional Tensile Strength Values

APPENDIX 7-4

EARTH RESISTIVITY PROFILING SURVEYS OF WELLSITE AREA

BDM
DIRECTIONAL WELL

EARTH RESISTIVITY PROFILING SURVEY (ERPS) STUDIES

WAYNE COUNTY, WEST VIRGINIA

MAMMOTH GEO, INC.

MAMMOTH GEO, INC.

P.O. Box 200 Barrackville, WV 26559 304/366-1810

February 24, 1988

The BDM Corporation
Mr. William K. Overbey
1199 Va~ Voorhis Road - Suite 4
Morgantown, WV 26505

RE: MOR000070
MGI PROJECT 439
FINAL ERPS REPORT

Dear Mr. Overbey,

Please find attached our final report entitled "BDM Directional Well - Earth Resistivity Profiling Surveys (ERPS) Studies - Wayne County, West Virginia". In summary 83 natural fracture zones were mapped in 23,100 feet of dual depth ERPS. The natural fracture zones mapped in ERPS Line 6 and 7 map apply to the fracture zones encountered in the horizontal part of the RET #1 Well.

If you have any questions or require further documentation, please do not hesitate to call.

Very sincerely,

E. Ray Garton
Project Director

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THE BDM CORPORATION
DIRECTIONAL WELL
EARTH RESISTIVITY PROFILING SURVEYS
(ERPS)

INTRODUCTION

At the direction of the project director, Mammoth Geo was retained to map and delineate, using Earth Resistivity Profiling Surveys (ERPS*), lineaments and natural fracture zones located in Wayne County, West Virginia. The ERPS were to be used in evaluation of the natural fracture potential of selected areas for a proposed directional well sponsored by the U.S. Department of Energy at METC (Morgantown Energy Technology Center) and implemented by The BDM Corporation. Following completion of our natural fracture (lineament) mapping studies using Landsat, U-2 and low altitude imagery we began the ground truthing of the lineaments we had mapped. A total of 7 ERPS lines were run, to gather the data needed to determine if: 1. the lineaments mapped are indeed natural fracture zones; 2. where the fracture zones are located on the surface; and 3. if there are additional significant natural fracture zones in the study area. The surveys required approximately 15 days of field work and data collection. ERPS were conducted at depths of 40 and 80 feet. Duel depth ERPS enables better confirmation and delineation of frcture zones and also provide a means of determining the dip angle of fracture zones encountered. A total of 2154 data stations were established and 7662 data points were made over a total distance of 23,100 feet. The raw field data were then fed into our computers which calculated the apparent resistivity which inturn was output in numeric and graphic form and is presented in the following report. The following table gives a statistical summary of each ERPS line.

ERPS STATISTICS FOR BDM DIRECTIONAL WELL PROJECT

ERPS LINE NAME	NUMBER OF STATIONS	LINE LENGTH	NUMBER OF DATA POINTS
BDM 40 FOOT ERPS 439 1	289	3000 FT	867
BDM 80 FOOT ERPS 439 1	289	3000 FT	867
BDM 40 FOOT ERPS 439 2	225	2360 FT	675
BDM 80 FOOT ERPS 439 2	225	2360 FT	675
BDM 40 FOOT ERPS 439 3	63	750 FT	189
BDM 80 FOOT ERPS 439 3	63	750 FT	189
BDM 40 FOOT ERPS 439 4	50	610 FT	150
BDM 80 FOOT ERPS 439 4	50	610 FT	150
BDM 40 FOOT ERPS 439 5	250	2610 FT	750
BDM 80 FOOT ERPS 439 5	250	2610 FT	750
BDM 40 FOOT ERPS 439 6	100	1110 FT	600
BDM 80 FOOT ERPS 439 6	100	1110 FT	600
BDM 40 FOOT ERPS 439 7	100	1110 FT	600
BDM 80 FOOT ERPS 439 7	100	1110 FT	600
TOTALS	2154	23100 FT	7662

A map showing where each ERPS was run and the location of each fracture crossed is shown on the attached map.

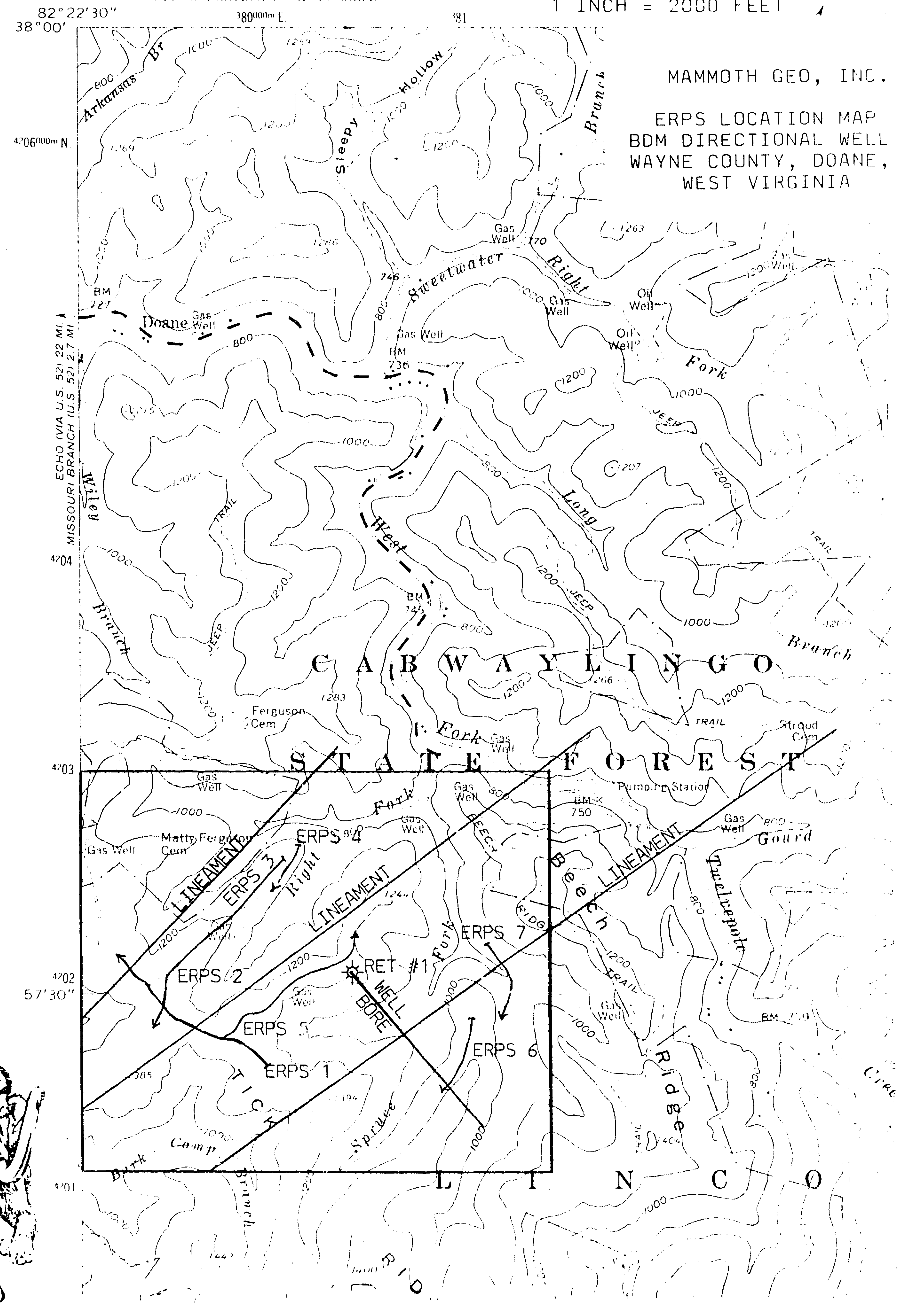
In summary, the ERPS indicate that numerous natural fracture zones actually exist in the study area and where they are located in the near surface.

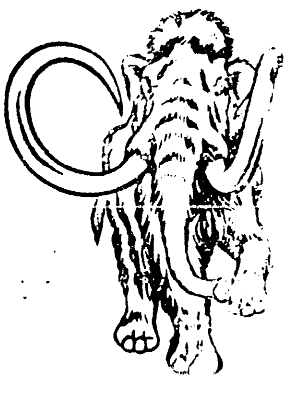
WILSONDALE QUADRANGLE
WEST VIRGINIA
7.5 MINUTE SERIES (TOPOGRAPHIC)
NE/4 NAUGATUCK 15' QUADRANGLE

SCALE
1:24,000
1 INCH = 2000 FEET

MAMMOTH GEO, INC.

ERPS LOCATION MAP
BDM DIRECTIONAL WELL
WAYNE COUNTY, DOANE,
WEST VIRGINIA

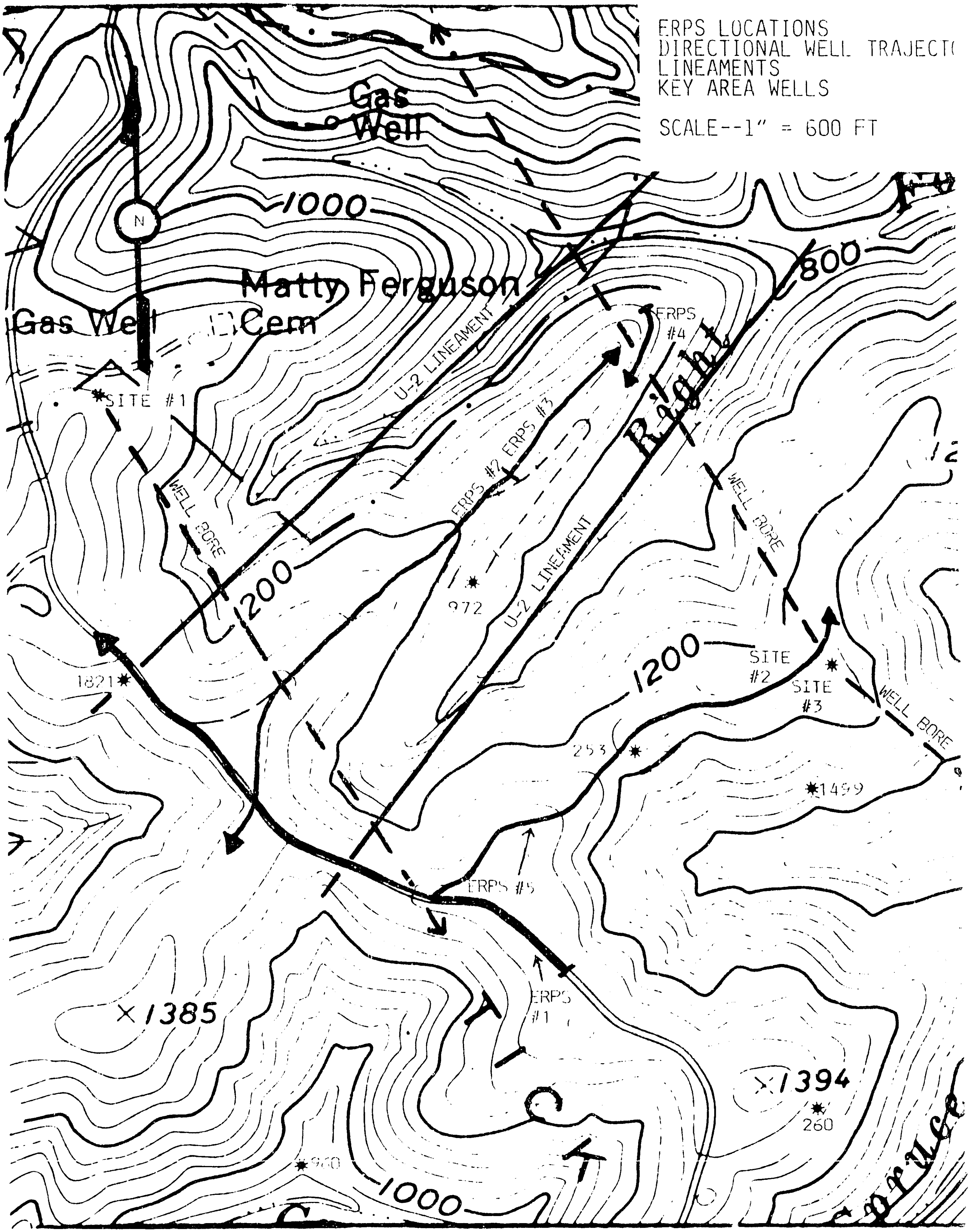


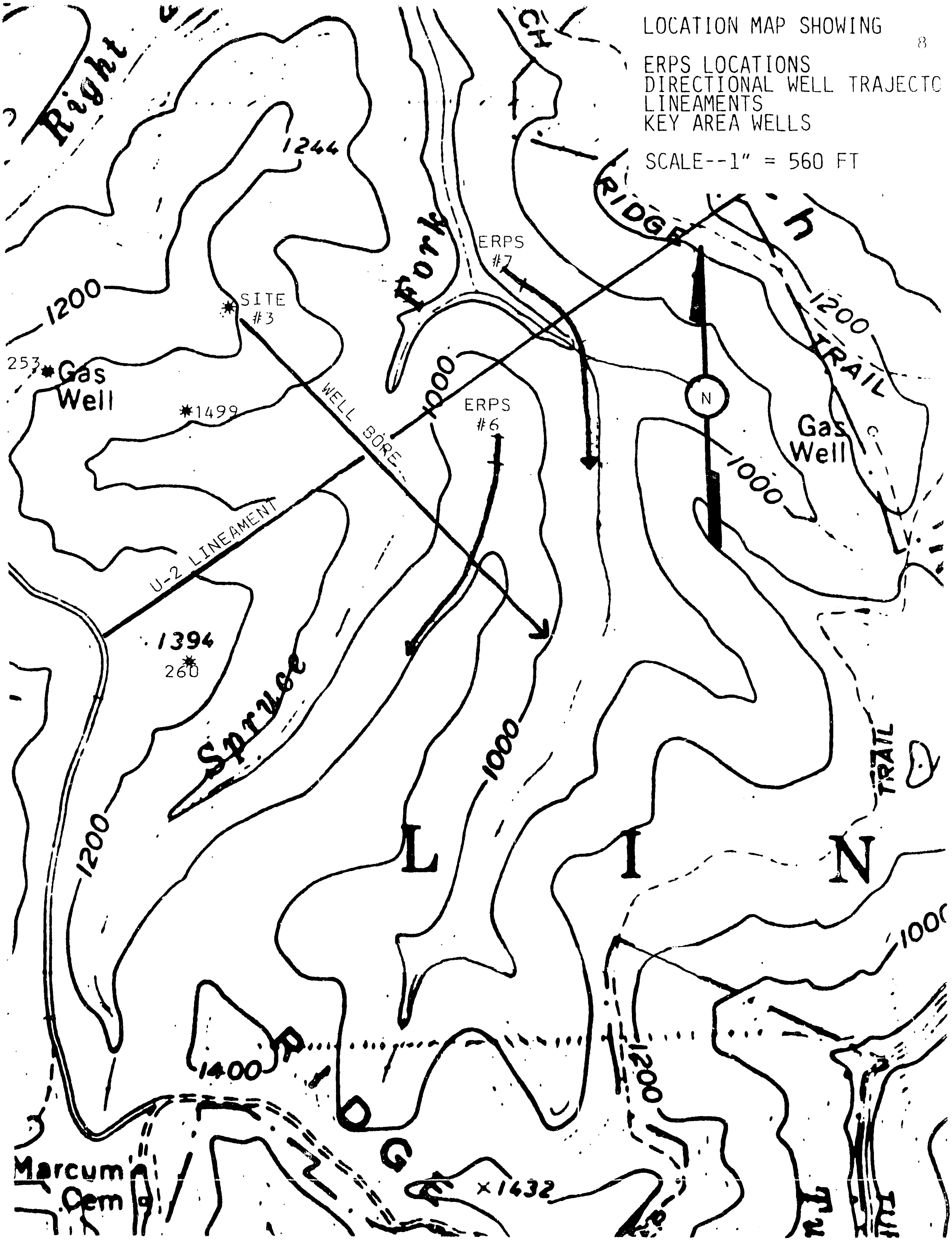


LOCATION MAP SHOWING

ERPS LOCATIONS
DIRECTIONAL WELL TRAJECT(
LINEAMENTS
KEY AREA WELLS

SCALE--1" = 600 FT




LOCATION MAP SHOWING
ERPS LOCATIONS
DIRECTIONAL WELL TRAJECTC
LINEAMENTS
KEY AREA WELLS
SCALE--1" = 560 FT
Right
Fork
RIDGE
TRAIL
ERPS #7
ERPS #6
SITE #3
253 Gas Well
1499
WELL BORE
U-2 LINEAMENT
Gas Well
N
1394
260
Spruce
L
I
N
1244
1200
1000
1400
1432
R
I
D
G
E
Marcum
Cem

DOE/BDM/ENEGER/RET #1
EARTH RESISTIVITY PROFILING SURVEY
SUMMARY AND CONCLUSIONS

PRE DRILLING

The 40 and 80 foot duel depth ERPS detected and delineated 83 and 53 prominent natural fracture zones respectively. Forty of the natural fractures delineated were common to both ERPS depths. In all cases where lineaments were mapped from remote sensing both depths delineated the lineaments as fracture zones. The fact that many of the fracture zones crossed in the 40 foot ERPS (83) are not seen in the 80 foot ERPS (53) is not uncommon. Generally rocks nearer the surface are more weathered and may show up as several closely spaced, narrow fracture zones. Deeper fracture zones are generally less weathered and are sometimes smaller than the resolution of the survey, 10 feet in this case. Deeper fracture zones may be detected with smaller station spacing which equals greater fracture resolution. Detection of natural fractures at both depths would seem to indicate that the feature is a more prominent fracture. Such fractures probably have the best chance of extending to the target depth of the directional well.

SUMMARY TABLE

ERPS LINE NAME	NUMBER OF FRACTURES AT 40 FEET	NUMBER OF FRACTURES AT 80 FEET	NUMBER OF FRACTURES IN COMMON
BDM 439 1	28	6	6
BDM 439 2	16	9	5
BDM 439 3	3	4	3
BDM 439 4	2	1	1
BDM 439 5	14	13	10
BDM 439 6	8	7	9
BDM 439 7	12	11	8
TOTALS	83	53	40

Based on the data presented herein and our 100 miles of ERPS experience which were used to select over 150 drilling locations in five states it does not seem unreasonable to assume that the ERPS delineated fractures are nearly vertical and will extend at least through the Marcellus.

One of the purposes of the BDM Directional Well is to intersect vertical natural fractures at or near 90 degrees. In our opinion, based on the extensive ERPS data gathered, the optimum site to intersect such fractures is Site #1 and Site #2.

POST DRILLING

While Site #2 was chosen for the directional well our preferred drilling direction was not. In our opinion had the well gone to the northwest at Site #2 more and larger natural fractures would have been intersected than were encountered in the southeast direction. This statement is based on the results of the remote sensing and ERPS lines 1-5. Since the directional well did not go to the northwest only ERPS lines 6 and 7 apply directly to the well.

While we have not had the opportunity to fully correlate the ERPS data with the cores and downhole video we have noted some strong correlations between them. For example, remote sensing indicated a lineament at 300 feet along ERPS line 7. The ERPS data indicated a natural fracture in both depths at about 310 feet along the survey. The ERPS crossed the lineament at about 90 degrees and 1900 feet from the well bore. If the trend of the lineament is projected through the well bore it crosses the well at about 1250 feet horizontally along the bore. This is very near the cored and faulted area of the well. Since the lineament was only crossed by one ERPS it is difficult to determine the exact trend of the lineament through the well bore. The trend of the lineament could be determined by extending ERPS line 1 about 2000 feet to the southeast. Even without this additional ERPS line it does not seem unreasonable to assume that the remote sensing identified and ERPS defined fracture zone at 295-310 feet along ERPS line 7 is associated with the faulting and fracturing seen in the well bore cores. Another major fracture was delineated by ERPS line 7 at about 585-600 feet along the survey. While this fracture was not seen in the remote sensing we believe it was crossed at about 90 degrees. If projected through the well it would cross at about 1525 feet horizontally along the bore. Additional ERPS fractures which may appear in the well bore are at about 950-1080 feet along the survey or 1090-1375 feet along the well bore. The fractures identified in the last half of ERPS line 7 are less likely to show up in the well bore because that portion of the ERPS line was ran nearly perpendicular to the well bore.

ERPS line 6 was also ran perpendicular to the well bore. This ERPS line was originally designed to be centered above the well bore. Our preliminary conclusions presented in our June 28, 1986, draft report were based on this assumption. However since the well location changed by about 150 feet and the well bore angle by 13 degrees it may

CORRELATION OF ERPS LINE 7
WITH WELL BORE FEATURES

DISTANCE ALONG ERPS	DISTANCE ALONG WELL BORE	FEATURE
295-310 Feet	1235-1250	Core Area
310 Feet	1250 Feet	U-2 Lineament
585-600 Feet	1525 Feet	Fracture Zone
950-1080	1090-1375	Fracture Zones

be that ERPS line 6 did not cross the well bore at all. If it did, and only a surface survey between the well and the ERPS line will tell for sure, cross the well bore it was only in the last 200 feet or so. A 120-140 foot wide fracture zone was crossed near the end of the ERPS line 6. This fracture zone is about 2500 feet horizontally along the well bore. This fracture zone may correspond to the fractures and big gas show at about 2180 feet along the bore. Once again the surface survey is needed to tie all the data together.

In conclusion three things are needed to accurately tie the ERPS data into the well bore data. First a surface survey is needed to accurately located the well bore with respect to the ERPS surveys; second, ERPS line 1 needs to be extended about 3500 feet southeast along Tick Ridge Road to parallel the entire well bore; and third, ERPS line 6 needs to be extended to cross the well bore.

In summary, the ERPS identified and located many natural fracture zones in the study area. Three of the major fracture zones were first identified in the U-2 remote sensing imagery and confirmed by the ERPS surveys. If the ERPS and well bore are tied in with a surface survey many of the fracture zones identified in ERPS lines 6 and 7 may correlate with the fracture zones seen in the cores and downhole videos.

APPENDIX 7-5

LOG OF FIELD OPERATIONS FOR ZONE ISOLATION TESTING

LOG OF FIELD OPERATIONS
FOR ZONE ISOLATION TESTING
OF DOE/BDM-RET WELL #1

May 13, 1987

8:00 a.m.	Met with J&F Well Service and Halliburton on location. The J&F pole rig did not have sufficient mast strength to open the port collars. Did not rig up. Ordered out new rig. Halliburton brought out the incorrect tools. Ordered out isolation tools from Baker Service Tools. Shut down over night.

DCC = $1200   CCC = $1200   CWC =

May 14, 1987

8:00 a.m.	Flowing casing pressure = 110 psi; shut-in 8-5/8" pressure = 126 psi. Rigging up Pool Well Service.
9:00 a.m.	Blowing down the well to atmosphere. The well unloaded a small amount of fresh water.
11:00 a.m.	Opened up the 8-5/8" casing to atmosphere. The well died down.
12:00 noon	Finished rigging up Pool. Nippled down the wellhead.
12:30 p.m.	Making up bottomhole assembly to set the external casing packers (ECP) and rigging up Halliburton.
1:00 p.m.	Tripped in hole with 2-3/8" tubing to 300 feet. Rigged up Halliburton and tested the Baker isolation tools to 1000 psi. Test okay. Continued tripping in the hole.
3:30 p.m.	A pneumatic control valve for the rig air slips ruptured. Unable to repair.
4:30 p.m.	Shut down overnight. Left 8-5/8" venting overnight.

DCC = $4049   CCC = $5249   CWC =

May 15, 1987

6:30 a.m.	Repaired pneumatic control valve.
6:45 a.m.	Continued tripping in the hole with the isolation tools.
8:00 a.m.	Shut down for bad weather.

Appendix

9:15 a.m.	Continued tripping in the hole. Checked hole drag (both up and down) every 10 joints while tripping.
12:00 noon	Tagged PBTD @ 6013'. Pulled back out of the hole and located port collar #1 @ 5746' and opened same with 36,000#. POOH to ECP #1 @ 5602'.
1:35 p.m.	Pressure testing Halliburton's iron. Repaired numerous leaks.
2:20 p.m.	Pumped N_2 down 2-3/8" x 4-1/2" annulus at a rate of 500 scf/minute. Circulated N_2 up the 8-5/8" casing. Pumped a total of 5000 scf N_2.
3:10 p.m.	Switched to tubing and pumped N_2 down tubing at a rate of 500 scf/minute to a maximum pressure of 1400 psi and set ECP #1. Total N_2 pumped = 16,100 scf.
3:30 p.m.	Checked packer by pumping N_2 down the 2-3/8" x 4-1/2" annulus. The N_2 did not circulate up the 8-5/8" casing. The ECP #1 held okay. Blew down the tubing and casing.
4:10 p.m.	POOH with tubing and opened PC #2 @ 5355' and PC #3 @ 5464'. POOH to ECP #2 @ 5411'.
4:30 p.m.	Rigged up Halliburton and circulated N_2 down the 2-3/8" x 4-1/2" annulus and out the 8-5/8" casing at a rate of 500 scf/minute. Pumped a total of 2800 scf N_2 with a maximum pressure of 65 psi.
4:51 p.m.	Pumped N_2 down the tubing and attempted to set ECP #2. The packer was leaking N_2 very quickly - did not test.
5:30 p.m.	Re-set the isolation tool in blank casing and tested same to 1400 psi. Tested okay.
6:02 p.m.	ECP #2 leaking - did not test or set.
6:10 p.m.	POOH w/tubing and opened PC #4 @ 5319' and PC #5 @ 5229'. POOH TO ECP #3 @ 5176'.
6:41 p.m.	Circulated down annulus and up 8-5/8" with N_2 at 700 scf/minute and a maximum pressure of 92 psi. Total N_2 pumped = 3100 scf.
6:46 p.m.	Switched to the tubing and pressured up the ECP #3. Total of 16,300 scf pumped at a rate of 500 - 1000 scf/minute.

7:01 p.m. Tested ECP #3 down the annulus at 700 scf/minute. N_2 did not circulate after 3300 scf and 114 psi. ECP #3 tested okay.

7:09 p.m. Performed small injection test on Zones 1, 2, and 3 together as follows:

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
7:09 pm	1350	103	500	--	ECP #3 still holding.
7:10 pm	1346	114	500	--	
7:11 pm	1346	114	500	1800	
7:12 pm	1341	119	500	--	
7:13 pm	1340	133	500	--	
7:14 pm	1336	146	500	--	
7:15 pm	1335	152	500	--	
7:16 pm	1332	159	500	--	
7:17 pm	1331	169	500	--	
7:19 pm	1325	186	500	6600	
7:20 pm	1323	193	500	--	
7:21 pm	1323	201	500	--	Reduced rate to 400 scf/m
7:22 pm	1320	204	400	--	
7:23 pm	1318	210	400	--	
7:24 pm	1317	214	400	--	
7:25 pm	1314	220	400	--	
7:26 pm	1314	224	400	--	
7:27 pm	1310	229	400	--	
7:28 pm	1309	238	400	--	
7:29 pm	1308	247	400	--	
7:30 pm	1305	251	400	--	
7:31 pm	1304	256	400	12,600	
7:32 pm	1300	260	400	13,200	Shut down.
7:33 pm	1306	242	S/I	13,200	Shut down.
7:34 pm	1209	238	S/I	13,200	
7:35 pm	1295	234	S/I	13,200	
7:36 pm	1293	232	S/I	13,200	
7:37 pm	1291	229	S/I	13,200	
7:38 pm	1290	228	S/I	13,200	
7:39 pm	1287	228	S/I	13,200	

7:40 p.m. Blew down tubing and casing.

8:30 p.m. Shut down overnight.

DCC = \$4679 CCC = \$9928 CWC =

May 16, 1987

8:00 a.m. POOH w/tubing to 4985' and isolated ECP #4 @ 5319'.

8:30 a.m. Rigged up Halliburton and pumped N_2 down the annulus at a rate of 700 scf/minute. The N_2 circulated up the 8-5/8" casing. The casing was 94 psi after 2900 scf and 140 psi after 4000 scf.

9:04 a.m. Shut down and switched to the tubing. Pumped N_2 down the tubing at a rate of 1000 scf/minute until the pressure reached 1250 psi at which time the rate was reduced to 500 scf/minute. Continued pressuring the tubing to 1400 psi. A total of 1500 scf of N_2 was used to pressure the tubing to 1400 psi. The 4-1/2" casing pressure fell off to 0 psi while pumping.

9:26 a.m. Shut in the tubing w/1400 psi and started pumping down the annulus to test ECP #4. Pumped at a rate of 700 scf/minute. Pumped a total of 4500 scf of N_2 down the annulus with a maximum of 123 psi pressure and the N_2 did not circulate up the 8-5/8" annulus.

9:34 a.m. Shut down and blew down the tubing pressure. Started pumping N_2 down the annulus at a rate of 700 scf/minute in order to test ECP #4 with no tubing pressure.

9:46 a.m. Pumping down annulus with N_2 @ 700 scf/minute. ECP #4 set okay.

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
9:46 am	0	0	700	--	Test w/o tubing pressure.
9:47 am	28	38	700	--	
9:49 am	37	96	700	--	
9:50 am	42	99	700	2600	No circulation.
9:51 am	46	105	700	2900	No circulation.

9:52 a.m. Shut down - blew down pressures.

10:00 a.m. Nippled down wellhead. POOH w/tubing and opened PC #8 @ 4894', PC #9 @ 4595', and PC #10 @ 4383'. Straddled ECP #5 @ 4337'.

10:45 a.m. RU Halliburton to set ECP #5. Pumped as follows:

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
10:50 am	0	0	700	--	Circ dn 4-1/2, up 8-5/8"
10:52 am	5	86	700	--	
10:53 am	10	106	700	--	Circ N_2 up 8-5/8"
10:54 am	16	117	700	2800	Circ N_2 up 8-5/8"

Switch from casing to tubing.

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
10:55 am	30	56	1000	--	Pumping N_2 down tubing.
10:56 am	188	40	1000	--	N_2 bleeding off 8-5/8.
10:57 am	242	29	1000	--	
11:00 am	594	9	1000	--	
11:05 am	1250	8	1000	13,900	No N_2 venting up 8-5/8". Reduce to 500 scf/m.
11:08 am	1400	9	500	15,800	ECP #5 set.

Shut down -- switch to casing.

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
11:10 am	1380	7	700	--	Pumping down 4-1/2" csg; 8-5/8" dead.
11:12 am	1358	92	700	--	Same as above.
11:14 am	1336	124	700	--	Same as above.
11:17 am	1312	119	700	2800	Same as above.

Shut down -- blew down pressures. Switched to casing.

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
11:28 am	28	54	700	--	Pumping N_2 dn casing to test ECP w/o pressure.
11:29 am	35	97	700	1200	Same as above.
11:30 am	41	110	700	--	No circ.
11:31 am	44	105	700	2600	No circ.

Shut down. ECP #5 set okay.

11:40 a.m. POOH w/tubing. Opened PC #11 @ 4291'. Straddled ECP #6 @ 4194' with isolation tool.

12:00 noon Nippled up wellhead. RU Halliburton and pumped as follows:

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
12:04 pm	--	--	700	0	Pumping down 2-3/8" x 4-1/2" annulus.
12:05 pm	9	35	700	--	Same as above.

12:07 pm	10	71	700	--	
12:08 pm	13	92	700	2000	Circulating N_2 up 8-5/8"
12:09 pm	16	87	700	--	Same as above.
12:10 pm	18	82	700	3100	Same as above.

Shut down -- switch to tubing.

12:11 pm	32	47	1000	0	Pump down tbg to set ECP
12:15 pm	610	5	1000	5100	Same as above
12:17 pm	872	3	1000	--	8-5/8" dying
12:19 pm	1250	4	1000	9500	8-5/8" not blowing N_2

Reduce rate to 500 scf/min

12:22 pm	1400	5	500	11200	ECP #6 set.

Switch from tubing to annulus.

12:25 pm	1373	78	700	1200	8-5/8" dead.
12:27 pm	1360	94	700	2200	8-5/8" dead.
12:28 pm	1355	98	700	3200	8-5/8" dead.

Shut down -- blew down tubing pressure and switch to annulus.

12:34 pm	24	37	700	--	8-5/8" dead.
12:36 pm	41	105	700	1500	8-5/8" dead.
12:37 pm	45	109	700	2400	8-5/8" dead.

Shut down and blew down pressures. ECP #6 set.

NOTE: After setting ECP #6, 8-5/8" almost completely dead.

12:45 p.m. POOH w/tubing and opened PC #12 @ 4147'. Straddled ECP #7 @ 4095'. 8-5/8" gas blow increased after opening PC #12.

1:00 p.m. NU wellhead and RU Halliburton. Pumped N_2 as follows:

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
1:07 pm	0	0	700	0	Start N_2 down annulus.
1:08 pm	4	45	700	--	
1:10 pm	12	87	700	2200	Good N_2 circ up 8-5/8"
1:11 pm	16	96	700	3000	Same as above.

Switch to tubing.

1:12 pm	22	40	1000	--	Pumping N_2 down 2-3/8"
1:15 pm	390	10	1000	2900	N_2 blow on 8-5/8" decreasing.
1:20 pm	1250	5	1000	8700	No N_2 blow on 8-5/8"

Reduced rate to 500 scf/min.

1:24 pm	1400	5	500	11700	No N_2 blow on 8-5/8"

Shut in tubing -- switched to annulus.

1:25 pm	1383	5	700	0	Start N_2 down annulus
1:27 pm	1364	87	700	1000	8-5/8" dead.
1:28 pm	1355	111	700	1700	8-5/8" dead.

Shut down -- blew down tubing pressure.

1:35 pm	18	26	700	--	Tested ECP w/o tubing pressure.
1:38 pm	32	109	700	1900	8-5/8" dead.
1:39 pm	36	112	700	3000	8-5/8" dead.

Shut down -- blew down pressures. ECP #7 set.

1:45 p.m. POOH and opened PC #13 @ 3960' and PC #14 @ 3832'. Straddled ECP #8 @ 3736'.

2:05 p.m. NU wellhead and RU Halliburton. Pumped N_2 as follows:

TIME	TP (#)	CP (#)	RATE (scf/m)	CUM	COMMENTS
2:15 pm	0	0	700	0	Start N_2 down annulus
2:16 pm	4	61	700	--	
2:18 pm	13	96	700	2300	Good N_2 blow out 8-5/8"
2:20 pm	23	104	700	3400	Same as above.

Shut in annulus and switched to tubing.

2:21 pm	135	38	1000	--	N_2 still bleeding off 8-5/8"
2:24 pm	600	9	1000	3400	N_2 blow decreasing
2:26 pm	885	5	1000	6100	
2:29 pm	1250	5	1000	8700	N_2 blow on 8-5/8" stopped

Cut back rate to 500 scf/minute.

2:30 pm	1366	6	500	--	No N_2 blow on 8-5/8"
2:31 pm	1400	7	500	9900	Same as above.

Shut down. Shut in tubing and switched to annulus.

2:33 pm	1387	53	700	--	8-5/8" dead.
2:34 pm	1378	67	700	1100	8-5/8" dead.
2:36 pm	1363	82	700	2300	8-5/8" dead.
2:38 pm	1347	92	700	4100	8-5/8" dead.
2:39 pm	1345	96	700	4500	8-5/8" dead.

Shut down. Blew down tubing and re-tested.

2:45 pm	18	27	700	--	8-5/8" dead.
2:47 pm	32	87	700	1200	8-5/8" dead.
2:51 pm	56	97	700	3800	8-5/8" dead.
2:53 pm	64	97	700	5400	8-5/8" dead.

Shut down. ECP #8 set and holding. Blowing down.

NOTE: After ECP #8 set, **all** gas blow on 8-5/8" stopped.

3:00 p.m. RD Halliburton. ND wellhead and TOOH.

5:30 p.m. Cut of the hole. Breaking out bottomhole assembly. Sent Baker's tool in to be re-dressed. Released Halliburton.

6:00 p.m. Shut the well in and shut down overnight.

DCC = $4436 CCC = $14,364 CWC =

May 17, 1987

8:30 a.m. All port collars are open. The 14-hour shut-in casing pressure on 4-1/2" casing = 39 psig. Hooked up the well to the orifice meter while venting the gas downstream through the orifice well tester. Had a 3/8" orifice plate in the 2" meter run. the orifice well tester had a 7/16" plate.

11:00 a.m. Initial test rate = 51.4 mcfpd @ 39 psig, 3/8" orifice plate.

12:00 noon Rate = 44.6 mcfpd @ 32 psig.

1:20 p.m. Rate = 40.4 mcfpd @ 29 psig.

2:00 p.m. Left well flowing overnight.

DCC = $920 CCC = $15,284 CWC =

May 18, 1987

8:00 a.m.	21 hour flowing casing pressure = 25 psig. Rate = 36.7 mcfpd.
8:30 a.m.	Nippling down the wellhead. Making up the bottomhole assembly. (BHA = Bull Plug + closing sleeve positioner + Baker Isolation Tool + Pup Joint + Opening sleeve positioner + bumper sub.)
9:30 a.m.	Tripping in the hole w/BHA. Closed port collar #13 @ 3960' and straddled port collar #14 @ 3832' with the Baker isolation tool.
11:30 a.m.	Nippling up the wellhead. Hooking up pressure recorders on the tubing and casing. NOTE: Zones 1 thru 7 in casing. Zone #8 in tubing.
12:00 noon	Tubing and casing shut in. Released the rig crew for the day. (Crew will return every other day.)
1:00 p.m.	SITP = 19 psig; SICP = 22 psig. Ordering out equipment to flow test the well on 5/19/87.

DCC = $2,647 CCC = $17,931 CWC =

May 19, 1987

9:30 a.m.	Waiting on test equipment.
12:00 noon	Hooking up test meters (2) -- one for tubing and one for casing.
6:58 p.m.	SITP = 75.3 psig; SICP = 51.2 psig (31 hours). Zone #8 open to tubing; Zones #1 - #7 open to casing. Both meters are 2" x 1/4" with 100" x 250# elements.
11:00 p.m.	Flow testing overnight. Pressures and rates as follows: (See Test Tables).

DCC = $565 CCC = $18,496 CWC =

May 20, 1987

8:45 a.m.	Flow test #1 in progress. Stabilized flow rates --Zone #8 = 5-6 mcfpd w/45 psi FTP Zones #1-#7 = 18-20 mcfpd w/51 psi FTP Line pressure = 44 psig.

12:00 noon — Left PC #13 @ 3960' and PC #14 @ 3832' open. TIH and positioned the Baker isolation tool at PC #12 @ 4147' to test Zone #7.

2:00 p.m. — Tubing and casing shut in for pressure build-up.

3:30 p.m. — SITP = 10 psig; SICP = 34.4 psig.

5:00 p.m. — Left well shut-in overnight. Recording pressures every 20 minutes with computer.

DCC = $1169   CCC = $19,665   CWC =

May 21, 1987

9:00 a.m. — Computer lost power during the night. Lost all memory from 3:30 p.m. on 5/20/87 through 9:00 a.m. on 5/21/87. Used pressure charts to obtain build-up pressures.

10:00 a.m. — Re-programmed computer and started scanning pressures every 10 minutes.

12:00 noon — SITP = 58.96 psig; SICP = 61.00 psig (22 hours).

12:08 p.m. — Opened up the casing for flow test #2 (Zones #1-6, #8).

12:24 p.m. — Opened up the tubing for flow test #2 (Zone #7).

6:30 p.m. — Left well flowing overnight with a line pressure of approximately 40 psig. (See Test Tables).

DCC = $385   CCC = $20,050   CWC =

May 22, 1987

9:00 a.m. — Zone #7 unable to flow any gas against the 40 psig line pressure. Zones #1-6, #8 flowing at a rate of 37 mcfpd.

9:15 a.m. — Shut-in Zone #7 (tubing) to see if the pressure will build up.

12:00 noon — Zone #7 built up to 43.56 psig (1.6 psi in 2.75 hours). The casing pressure also built up 2.2 psi when the tubing was shut in.

NOTE: Zone #7 appears to be in communication with another zone downhole.

End of Test #2. Blowing down the well. Moving the tubing for Test #3.

12:30 p.m. Positioned isolation tool over port collar #11 @ 4290'. All other port collars open to the annulus.

1:00 p.m. Shut in the tubing and casing for build-ups (Test #3). (See Test Tables.)

4:00 p.m. Left well shut-in overnight. Recording pressures every 20 minutes.

DCC = $989 CCC = $21,039 CWC =

May 23, 1987

12:00 noon Zone #6 -- SITP = 60.52 psig (23 hours).
Zones #1-5, #7, #8 -- SICP = 60.6 psig (23 hours).

NOTE: Tubing and casing pressures building up at the same rate.

Opened up the casing for Flow Test #3 (Zones #1-5, #7, #8). Casing meter orifice plate was changed to 2" x 1/2". Tubing pressure holding steady while flowing the casing.

12:30 p.m. Opened up the tubing for Flow Test #3 (Zone #6).

3:00 p.m. Left well flowing overnight with a line pressure of 40 psig. Scanning pressures every 20 minutes. (See Test Tables.)

DCC = $385 CCC = $21,424 CWC =

May 24, 1987

8:00 a.m. Flow Test #3.

12:00 noon Final flow rates: Zone #6 = 2.2 mcfpd w/41 psi FTP; Zones #1-5, #7, #8 = 32.4 mcfpd w/39 psi FCP. Line pressure = 39.3 psig. Left port collar #11 open @ 4291'. TIH w/tubing and shut port collars #10 @ 4383' and #9 @ 4595'. Centered isolation tool over port collar #8 at 4894' to test Zone #5.

1:00 p.m. Hooked up wellhead and flow lines. Shut-in the well for Build-up Test #4 (See Test Tables).

2:00 p.m. Left well shut-in overnight. Scanning pressures every 20 minutes.

DCC = $1016 CCC = $22,440 CWC =

May 25, 1987

12:00 noon — Zone #5 --- SITP = 58.48 psig (23 hours). Zones #1-4, #6-8 --- SICP = 56.40 psig (23 hours). Opened up the casing for Flow Test #4 (Zones #1-4, #6-8).

12:16 p.m. — Opened up the tubing for Flow Test #4 (Zone #5).

12:30 p.m. — Both tubing and casing 100% open. Line pressure set at 40 psig.

3:00 p.m. — Left well flowing overnight. Scanning pressures every 20 minutes (See Test Tables).

DCC = $385   CCC = $22,825   CWC =

May 26, 1987

12:00 noon — Final flow rates: Zone #5 = 4.4 mcfpd w/41 psi FTP. Zones #1-4, #6-8 = 30.0 mcfpd w/39 psi FCP. Line pressure = 39.4 psig. Blew down well. ND wellhead.

12:15 p.m. — Left port collar #8 @ 4894' open. Tripping in the hole.

12:30 p.m. — Closed port collar #7 @ 5038'. TIH and located port collar #6 @ 5129'. Spaced out tubing and centered the isolation tool over port collar #6.

1:00 p.m. — Hooking up wellhead and test equipment. Shut-in well for Build-up Test #5. (See Test Tables)

1:06 p.m. — Scanning pressures every 15 seconds.

1:40 p.m. — Scanning pressures every 1 minute.

2:00 p.m. — Left well shut-in overnight. Scanning pressures every 20 minutes.

NOTE: Dozer worked on the lease road for two hours.

DCC = $1089   CCC = $23,914   CWC =

May 27, 1987

12:00 noon — Zone #4 --- SITP = 53.64 psig (23 hours)
Zones #1-3, #5-8 --- SICP = 72.8 psig (23 hours).

12:15 p.m. — Opened up the casing for Flow Test #5 (Zones #1-3, #5-8).

12:30 p.m.	Opened up the tubing for Flow Test #5 (Zone 4).
2:00 p.m.	Left well flowing overnight. Scanning pressures every 20 minutes (See Test Tables).

DCC = $385   CCC = $24,299   CWC =

May 28, 1987

12:00 noon	Final flow rates for Test #5. Zone #4 = 16.7 mcfpd w/43.48 psig FTP. Zones #1-3, #5-8 = 15.8 mcfpd w/42.0 psig FCP. Line pressure = 39.5 psig. Blew down the well to atmosphere. Nippled down the wellhead.
12:10 p.m.	Laid down the pup joints. Left port collar #6 open. TIH w/tubing and closed port collar #5 @ 5229', port collar #4 @ 5319', and port collar #3 @ 5464'. Centered the isolation tool over port collar #2 @ 5555'. Spaced out same. Nippled up wellhead.
12:52 p.m.	Shut-in the well for build-up test #6. (See Test Tables.) Scanning pressures every 15 seconds. On build-up.
1:24 p.m.	Scanning pressures every 1 minute.
1:45 p.m.	Left well shut-in overnight while scanning pressures every 20 minutes.

DCC = $989   CCC = $25,288

May 29, 1987

12:00 noon	Zones #2, #3 SITP = 60.44 psig (23 hours). Zones #1, #4-8 SICP = 57.40 psig (23 hours). Opened up the casing for Flow Test #6 (Zones #1, #4-8).
12:10 p.m.	Opened up the tubing for Flow Test #6 (Zones #2, #3).
2:00 p.m.	Left well flowing overnight, scanning pressures every 20 minutes. (See Test Tables.)

DCC = $385   CCC = $25,673

May 30, 1987

12:00 noon	End of Flow Test #6. Final flow rates: Zones #2, #3 = 4.4 mcfpd w/41.76 psig FTP Zones #1, #4-8 = 28.3 mcfpd w/41.80 psig FCP Line Pressure = 39.28 psig. Blew down the well to atmosphere. ND the wellhead.

12:10 p.m.	LD the pup joints. TOOH. Left all port collars in the open position.
3:30 p.m.	Picking up Baker Model N-1 4-1/2" Hydro-Set Bridge Plug and bumper sub. Tripping in hole on 2-3/8" tubing. NOTE: The plug sets with 400-600 psi pressure and has shear-off pins set at 20,000 lbs.
6:30 p.m.	Tagged PBTD w/the plug @ 6013'. PU to 6008' and RU Halliburton nitrogen truck.
7:00 p.m.	Pressured up on the tubing to 600 psi with N_2. Bled pressure off to 200 psi. Picked up on the tubing a maximum of 25,000 lbs over string weight and sheared off the bridge plug. Bridge plug set @ 6008'.
7:30 p.m.	Tripping out of the hole with the setting tool.
8:00 p.m.	Tripped out 28 jts and shut down overnight.

DCC = $6,842   CCC = $32,515

May 31, 1987

6:30 a.m.	Finished tripping out of the hole with the bridge plug setting tool.
9:30 a.m.	Picked up Halliburton's opening and closing sleeve positioners and Baker's isolation packer (w/bull plug) and tripped in the hole to test Zone #1. Left all zones open to the casing and isolated port collar #1 @ 5746' with the isolation packer.
1:00 p.m.	Nippled up the wellhead and test equipment.
1:15 p.m.	Shut-in the well for build-up test #7.
2:00 p.m.	Left well shut-in overnight.

DCC = $1,277   CCC = $34,177

June 1, 1987

Zone #1 SITP = 39.32 psig (23 hours).
Zones #2-#8 SICP = 39.2 psig (23 hours).

12:10 p.m.	Left well shut-in for an additional hour to allow the pressure to build up over 40 psig.

1:15 p.m. SITP = 40.2 psig; SICP = 39.4 psig. Opened up the well for flow test #7.

2:00 p.m. Left well flowing overnight. Rates increasing.

DCC = $385 CCC = $34,177

June 2, 1987

12:00 noon End of flow test #7.
NOTE: Bad computer data from 6:36 p.m. on 6/1/87 to 12:00 noon on 6/2/87.

Final flow rates:
Zone #1 = 2.2 mcfpd w/41.68 psig FTP
Zones #2-#8 = 20.4 mcfpd w/38.60 psig FCP.
Line pressure = 39.10 psig.

12:15 p.m. Blew the well down to atmosphere. ND the wellhead. Tripped out of the hole while positioning the port collars for a build-up test on Zones #4 and #7. Isolated Zone #7 with the isolation packer @ 4147'. Zone #7 open to the tubing while Zone #4 is open to the casing. The following port collars are open: #6, #7, #12. All other port collars are closed.

3:30 p.m. Spaced out tubing w/pup joints. NU wellhead.

4:00 p.m. 10:00 p.m.
Working on test equipment. Unable to start build-up test due to heavy rainfall. Left well shut-in overnight.

DCC = $989 CCC = $35,166

June 3, 1987

8:00 a.m. Blew well down to atmosphere. Finished hooking up the test equipment. Monitoring both tubing (Zone #7) and casing (Zone #4) pressures with computers. Left computers scanning every 10 minutes.

11L50 a.m. Start build-up test. Well shut-in.

DCC = $1,750 CCC = $36,916

August 13, 1987

8:00 a.m.	Pool Well Service and Dowell-Schlumberger on location. Nippled down the wellhead and flowlines. Blew down the well to atmosphere.
9:00 a.m.	Tripped out of the hole with the tubing to check the packer element on the bottomhole assembly. Packer elements in good condition.
9:45 a.m.	Tripped in the hole with the bottomhole assembly + 100 jts tubing.
12:00 noon	Brake pads on the workover rig worn out. Shut down. Waiting for mechanic.
2:00 p.m.	Shut down overnight.

August 14, 1987

8:00 a.m.	Tore down brakes on the rig.
2:00 p.m.	Rig mechanic replaced worn out brake pads.
3:30 p.m.	Continued tripping in the hole with the tubing. Closed all port collars while tripping in the hole.
6:00 p.m.	Positioned the bottomhole assembly over closed port collar #1 at 5746'. Shut down overnight.

August 15, 1987

8:00 a.m.	Rigged up Dowell-Schlumber to pressure test port collar #1. with nitrogen.
9:30 a.m.	Tested port collar #1 to 1000 psi - held o.k.
10:00 a.m.	Blew down tubing. Tripped out of the hole and positioned the bottomhole assembly over port collar #2 at 5555'.
11:05 a.m.	Attempted to test port collar #2 with no success.
11:15 a.m.	Re-positioned the tubing to repeat the test.
11:50 a.m.	Pressure tested port collar #2 to 1000 psi - held o.k.
12:00 noon	Pulled out of the hole to port collar #3 at 5464'.
12:30 p.m.	Attempted to test port collar #3 with no success.
1:00 p.m.	Re-positioned the tubing over port collar #3 in order to repeat the test.
1:20 p.m.	Attempted a second test on port collar #3. with no success. Port collar #3 did not test.

1:30 p.m. Pulled out of the hole and positioned the tubing over port collar #4 at 5319'.

2:05 p.m. Pressure tested port collar #4 to 1000 psi - held o.k.

2:10 p.m. Pulled out of the hole and positioned the tubing over port collar #5 at 5229'.

2:30 p.m. Pressure tested port collar #5 to 1000 psi - held o.k.

2:40 p.m. Pulled out of the hole and positioned the tubing over port collar #6 at 5129'.

3:05 p.m. Pressure tested port collar #6 to 1000 psi - held o.k.

3:15 p.m. Pulled out of the hole and positioned the tubing over port collar #7 at 5038'.

3.45 p.m. Pressure tested port collar #7 to 1100 psi - held o.k. Pressure tested port collars #8, #9, #10, #11, #12, #13 and #14 to 500 psi - held o.k. Note: Dowell did not have enough nitrogen on location in order to test port collars #8 - #14 to 1000 psi.

4:00 p.m. Tripping out of the hole with the tubing leaving all port collars except #11 in the closed position. Port collar #11 was left open for the mini-frac in zone #6.

6:00 p.m. Shut down overnight.

August 16, 1987

2:00 p.m. Finished tripping out of the hole with the bottomhole assembly and laid down same.

4:30 p.m. Made up new bottomhole assembly consisting of 2-3/8" bull plug + 2-2 3/8" pup joints + one set Baker bottom isolation cups + 1 jt 2-3/8" tubing + perforated sub. Tripped in the hole with the bottomhold assembly on 133 jts 2-3/8" tubing. (Total length = 4357.91') Top of the Baker Isolation cups at 4346' which is 55' below port collar #11 at 5291'. Note: Installed an Amerada bottomhole pressure recorder in the bottomhole assembly (2000 #Spring - 24 hr clock). Started clock at 4:30 p.m. on 8/16/87.

7:30 p.m. Nippled up the wellhead and flowlines.

8:00 p.m. Shut-in the well and shut down overnight.

August 17, 1987

9:00 a.m. Rigged up Dowell-Schlumberger (D-S) to perform Data-Frac on zone #6. Waited 1 1/2 hrs for treatment monitor vehicle. (TMV).

10:30 a.m. TMV arrived on location. Tested D-S lines to 3000 psi w/ N_2. - found numerous leaks (7 tests). Repaired pressure transducers on TMV unit.

1:17 p.m. Started treatment #1. Faulty transducers on TMV. Shut down and repaired same.

2:20 p.m. Re-started treatment #1. Pumped nitrogen down the 2-3/8" x 4-1/2" annulus at a rate of 2500 scf/minute. Shut in tubing pressure increased from 0# to a maximum of 804# at which pressure the downhole pump rate was equivalent to 8.8 BPM. A total of 62,500 SCF N_2 was pumped during this stage. Total pump time = 25 minutes. One pressure break was seen after 12 minutes of pumping - tubing pressure dropped from 761# to 726#.

2:45 p.m. Shut-down. ISIP = 754# 5 minutes = 707# 10 minutes = 680# Left well shut-in for a total of 55 minutes. Final SITP = 555#

3:41 p.m. Started pumping treatment #2. Pumped nitrogen down the annulus at a rate of 7500 - 10,000 scf/m. Shut-in tubing tubing pressure increased from 555# to 916# at which pressures the downhole pump rates ranged from 38 BPM to 23 BPM. A total of 112,500 SCF N_2 was pumped with a total pump time of 15 minutes. The shut-in tubing pressure stabilized at approximately 900 psig after 7 minutes of pumping and remained stabilized throughout the treatment.

3:56 p.m. Shutdown pumping and shut-in the well. ISIP = 901 psig 5 minutes = 788 psig 10 minutes = 738 psig Total shut-in time = 1 hr 25 minutes. Final SITP = 574 psig.

5:21 p.m. Started pumping treatment #3. Pumped 80 quality foam down the annulus at a downhole rate of 5 BPM. Nitrogen injection rate ranged from 1200 to 1600 Scf/minute while holding the liquid rate constant at 1 BPM. Tagged the foam with 5 millicurries of radioactive scandium 46. A total of 24,000 scf N_2 plus 20 Bbls 2% KCL water was pumped with a total pump time of 20 minutes. The foam was flushed to bottom with 45 Bbls of 80 quality foam at a pump rate of 5 BPM. The flush was tagged with radioactive Iodine #131 for treatment #4. The maximum casing pressure for treatment #3 was 888 psig. Maximum SITP = 907 psig.

5:52 p.m. Shut-down pumping and shut-in the well. Tubing ISIP - 907 psig. 5 minutes = 877 psig. 10 minutes = 873 psig. Total shut-in time = 1 hr Final SITP = 765 psig.

6:50 p.m.	Started pumping treatment #4. Pumped 80 quality foam down the annulus at a downhole rate of 15 BPM. Nitrogen injection rate ranged from 4100 scf/minute to 4600 scf/minute while holding the liquid rate at 3 BPM. Tagged the foam with 10 millicurries of radioactive Iodine #131. A total of 74,000 scf N_2 plus 51 Bbls 2% KCL water was pumped with a total pump time of 17 minutes. The foam was flushed to bottom with 33,600 scf N_2 at a rate of 5100 scf/m. (overflushed 35 Bbls).
7:14 p.m.	Shut-down pumping and shut-in the well. Tubing ISIP=1114 psig 5 minutes = 1055 psig 10 minutes = 1043 psig. Total shut-in time = 50 minutes Final SITP = 966 psig. Rigged down D-S.
9:45 p.m.	SITP = 880 psig SICP = 905 psig Opened the well to the test seperator on a 1/16" choke. Initial gas/N_2 rate = 195 mcfpd.

<u>August 18, 1987</u>

12:00 Mn	Gas/N_2 Flowrate = 170 mcfpd FTP =695 psig SICP = 725 psig 1/16" choke.
1:15 a.m.	Increased tubing choke to a 17/64". Flowrate increased to 500 mcfpd (Gas/N_2). FTP= 580 psig SICP = 640 psig
2:00 a.m.	Increased tubing choke to 48/64".
2:10 a.m.	First fluid to surface. Well unloading foam and liquid.
2:30 a.m.	Well unloading steady stream of fluid. FTP = 40 psig SICP = 320 psig.
4:30 a.m.	FTP = 40 Psig SICP = 40 psig, 48/64" choke.
4:45 a.m.	Recovered a total of 6 Bbls fluid. No fluid recovery last 15 minutes. Reduced tubing choke to 36/64". Gas/N_2 rate = 120 mcfpd.
6:00 a.m.	FTP = 25 psig SICP = 25 psig Gas/N_2 rate = 93 mcfpd 36/64" choke.
9:00 a.m.	FTP = 25 psig SICP = 30 psig Gas/N_2 rate = 76 mcfpd
11:00 a.m.	Opened the well to atmosphere. Nippled down the wellhead. Pulled out of the hole with the tubing and bottomhole assembly. Removed the Amerada pressure chart and sent in to be evaluated.
4:30 p.m.	Shut down overnight. Left well shut-in overnight.

<u>August 19, 1987</u>

8:00 a.m.	Met with Dresser-Atlas wireline on location. Inspected tools for running tracer survey log. Dresser-Atlas

wireline was 9/16" diameter which was too large to safely run inside the 4-1/2" casing outside of the 2-3/8" tubing string. Note: Dresser was instructed to bring 5/16" line.

12:00 noon Ordered out Nowsco coiled tubing unit for 8/20/87.

4:00 p.m. Ordered out special tubing connections for coiled tubing shut-down overnight.

August 20, 1987

6:00 a.m. Nippled down wellhead Rigged up Dresser-Atlas and Nowsco coiled tubing unit.

6:45 a.m. SICP = 205 psig (18 hrs) Blew down well to atmosphere.

8:30 a.m. Run in the hole with gamma ray and temperature logging tools on 9/16" wireline to 3374'. (50° deviation).

9:00 a.m. Made up 2-3/8" side entry sub on bottom of 1" coiled tubing. Run in the hole with the coiled tubing to the top of the loging tools at 3374'.

11:00 a.m. Tagged wireline tools with coiled tubing. Pushed the tools in the hole at a rate of 50ft/minute to a maximum depth of 4666'. (Ran temperature log while running in the hole) Unable to get below 4666'.

12:00 noon Pulled out of the hole with coiled tubing and wireline to 4586'. Attempted to run in the hole at a higher speed with no success.

12:35 p.m. Logged with the spectro-gamma ray from 4578' to 3400' at 12 ft/minute.

2:25 p.m. Tripped back in the hole with logging tools and coiled tubing to 4698'. Logged Run #2 from 4698' to 3400'.

4:55 p.m. Pulled out of the hole with coiled tubing and wireline. Note: Coiled tubing and wireline wrapped around each other while tripping in and out of the hole which made it necessary to cut off the last 90 + feet of coiled tubing in order to remove it from the hole. Rigged down Dresser and Nowsco.

8:30 p.m. Shut well in and shut down overnight.

August 21, 1987

7:00 p.m. Tripped in the hole with the opening and closing sleeve positioners on 2-3/8" tubing to 4020'. Nippled up the wellhead and flowlines. Note: All port collars are in the closed position except port collar #11 at 4291' (Zone 6).

11:00 a.m. Shut-in the well for a pressure buildup. Flow test will start on 8/22/87. Shut down overnight.

TEST TABLES -- ZONE ISOLATION TESTING
BDM/DOE-RET WELL #1

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
5/19/87										
6:51 pm	75.28	53.40	---	---	---	50.0	20.0	12.3	12.3	START FLOW TEST #1. Stabilizing Rates: Tubing = 2" x 1/4" meter run-Zone 8. Casing = 2" x 1/4" meter run - Zones 1-7. LP - Line Pressure TP - Tubing Pressure CP - Casing Pressure
7:00 pm	73.48	51.20	---	---	---	50.0	20.0	12.3	12.3	
8:00 pm	40.80	52.00	40.0	45.0	17.0	32.0	100.0	23.4	40.4	
9:00 pm	40.24	47.40	35.0	60.0	18.7	40.0	80.0	22.6	41.3	
10:00 pm	44.96	53.00	40.0	1.0	2.8	45.0	40.0	16.7	19.5	Line pressure up due to casing pressure.
11:00 pm	42.40	54.80	37.0	10.0	7.8	45.0	41.0	16.9	24.7	
5/20/87										
12:00 MN	43.12	53.00	37.0	6.0	6.0	45.0	43.0	17.3	23.3	
1:00 am	43.52	51.80	38.0	6.0	6.1	45.0	44.0	17.5	23.6	NOTE: Difference in LP is due to meter. Corrected meter @ 11:00 am on May 20, 1987.
2:00 am	43.72	51.20	38.0	6.0	6.1	45.0	44.0	17.5	23.6	
3:00 am	43.88	50.40	38.0	5.5	5.8	45.0	44.0	17.5	23.3	
4:00 am	44.00	50.00	38.0	5.5	5.8	45.0	44.0	17.5	23.3	
5:00 am	44.08	49.60	38.0	5.0	5.6	45.0	44.0	17.5	23.1	NOTE: 2:00 am thru 9:00 am -- Rates estimated on casing meter -- chart stopped.
6:00 am	44.12	49.60	37.5	5.0	5.5	45.0	44.0	17.5	23.0	
7:00 am	44.16	49.60	37.5	5.0	5.5	45.0	44.0	17.5	23.0	
8:00 am	44.20	50.00	37.5	5.0	5.5	45.0	44.0	17.5	23.0	
9:00 am	44.44	50.40	38.0	5.0	5.6	47.0	49.0	18.8	24.4	
10:00 am	44.44	50.40	40.0	4.0	5.1	47.0	49.0	18.8	23.9	

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
11:00 am	45.40	51.80	44.0	4.0	5.2	45.0	51.0	18.9	24.1	Adjusted meter pressure with dead weight tester (off 4#) on tubing meter.
12:00 N	45.44	51.60	44.0	4.0	5.2	45.0	51.0	18.9	24.1	
1:00 pm	END OF TEST #1.									
2:00 pm	MOVING TUBING FOR TEST #2.									
3:00 pm	10.00	34.40	---	---	S/I	---	---	S/I		Tubing & casing shut-in for Test #2 build-up @ 2:00 pm. Tubing - Zone 7; Casing - Zones 1-6, 8. "C" pressures read from meter chart. Computer lost memory from 4:00 pm to 9:00 am.
4:00 pm	C 15.00	41.00	---	---	S/I	---	---	S/I		
5:00 pm	C 20.00	44.50	---	---	S/I	---	---	S/I		
6:00 pm	C 25.00	46.50	---	---	S/I	---	---	S/I		
7:00 pm	C 29.50	47.50	---	---	S/I	---	---	S/I		
8:00 pm	C 32.50	48.50	---	---	S/I	---	---	S/I		
9:00 pm	C 36.00	49.00	---	---	S/I	---	---	S/I		
10:00 pm	C 39.50	49.50	---	---	S/I	---	---	S/I		
11:00 pm	C 42.50	50.50	---	---	S/I	---	---	S/I		
5/21/87										
12:00 MN	C 45.00	51.00	---	---	S/I	---	---	S/I		
1:00 am	C 47.00	51.50	---	---	S/I	---	---	S/I		
2:00 am	C 49.00	52.00	---	---	S/I	---	---	S/I		
3:00 am	C 50.50	52.50	---	---	S/I	---	---	S/I		
4:00 am	C 52.00	53.00	---	---	S/I	---	---	S/I		
5:00 am	C 53.00	54.00	---	---	S/I	---	---	S/I		
6:00 am	C 53.50	54.50	---	---	S/I	---	---	S/I		
7:00 am	C 54.00	55.00	---	---	S/I	---	---	S/I		
8:00 am	C 55.00	55.50	---	---	S/I	---	---	S/I		
9:00 am	C 56.00	56.00	---	---	S/I	---	---	S/I		
10:00 am	57.56	60.00	---	---	S/I	---	---	S/I		
11:00 am	58.16	61.00	---	---	S/I	---	---	S/I		
12:00 N	58.96	61.00	---	---	S/I	---	---	S/I		Opened up casing @ 12:08 pm. Opened up tubing @ 12:24 pm.

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
1:00 pm	54.84	57.60	51.88	1.0	2.8	51.88	96.0	27.4	30.2	2"x1/4" LP regulated w/Big Joe.
2:00 pm	54.68	58.0	51.74	1.0	2.8	51.84	78.0	24.6	27.5	2:08 pm - S/I for 17 minutes -- Change out orifice in casing meter run. Replaced 1/4" with 3/8" plate.
										2:45 - Lowering line pressure.
3:00 pm	52.24	55.20	49.36	1.0	2.7	49.36	75.0	53.1	55.8	
4:00 pm	47.40	50.40	45.06	1.0	2.6	45.06	100.0	59.2	61.8	
5:00 pm	47.64	50.20	44.84	1.0	2.6	44.84	69.0	49.1	51.7	Reducing line pressure.
6:00 pm	45.36	47.80	42.78	1.0	2.6	42.78	83.0	52.9	55.5	
7:00 pm	43.64	46.20	41.06	1.0	2.6	41.06	96.0	56.0	58.6	
8:00 pm	43.04	44.40	40.60	.5	1.8	40.60	84.0	52.2	54.0	
9:00 pm	42.84	43.60	40.40	.5	1.8	40.40	76.0	49.5	51.3	
10:00 pm	42.68	43.20	40.26	0.0	0.0	40.26	71.0	47.8	47.8	
11:00 pm	42.60	43.00	40.16	0.0	0.0	40.16	66.0	46.1	46.1	
5/22/87										
12:00 MN	42.52	42.40	40.08	0.0	0.0	40.08	63.0	45.0	45.0	
1:00 am	42.44	42.20	39.98	0.0	0.0	39.98	59.0	43.5	43.5	
2:00 am	42.36	41.80	39.92	0.0	0.0	39.92	57.0	42.7	42.7	
3:00 am	42.28	41.60	39.86	0.0	0.0	39.86	54.0	41.5	41.5	
4:00 am	42.20	41.40	39.78	0.0	0.0	39.78	52.0	40.7	40.7	
5:00 am	42.16	41.40	39.78	0.0	0.0	39.78	49.0	39.6	39.6	
6:00 am	42.12	41.40	39.78	0.0	0.0	39.78	47.0	38.7	38.7	
7:00 am	42.08	41.20	39.78	0.0	0.0	39.78	46.0	38.3	38.3	
8:00 am	42.04	41.20	39.78	0.0	0.0	39.78	44.0	37.5	37.5	
9:00 am	41.96	41.00	39.78	0.0	0.0	39.78	43.0	37.0	37.0	@ 9:15 am - Shut-in tubing to see if pressure will build up.
10:00 am	42.80	42.20	39.60	---	S/I	39.60	42.0	36.6	36.6	
11:00 am	43.40	43.00	39.68	---	S/I	39.68	40.0	35.7	35.7	
12:00 N	43.56	43.20	39.80	---	S/I	39.80	39.0	35.3	35.3	
	END OF TEST #2.									
1:00 pm	SHUT-IN FOR TEST #3.									Tubing - Zone 6 Casing - Zones 1-5, 7, 8.

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
2:00 pm	24.48	38.40	---	---	S/I	---	---	S/I	---	
3:00 pm	34.04	43.40	---	---	S/I	---	---	S/I	---	
4:00 pm	39.72	46.00	---	---	S/I	---	---	S/I	---	
5:00 pm	45.00	47.20	---	---	S/I	---	---	S/I	---	
6:00 pm	46.92	48.00	---	---	S/I	---	---	S/I	---	
7:00 pm	48.36	48.60	---	---	S/I	---	---	S/I	---	
8:00 pm	49.60	48.40	---	---	S/I	---	---	S/I	---	
9:00 pm	50.64	48.80	---	---	S/I	---	---	S/I	---	
10:00 pm	51.56	49.40	---	---	S/I	---	---	S/I	---	
11:00 pm	52.44	50.00	---	---	S/I	---	---	S/I	---	
5/23/87										
12:00 MN	53.24	50.60	---	---	S/I	---	---	S/I	---	
1:00 am	54.00	51.40	---	---	S/I	---	---	S/I	---	
2:00 am	54.76	52.00	---	---	S/I	---	---	S/I	---	
3:00 am	55.48	52.60	---	---	S/I	---	---	S/I	---	
4:00 am	56.20	53.40	---	---	S/I	---	---	S/I	---	
5:00 am	56.84	54.20	---	---	S/I	---	---	S/I	---	
6:00 am	57.48	54.80	---	---	S/I	---	---	S/I	---	
7:00 am	58.12	55.40	---	---	S/I	---	---	S/I	---	
8:00 am	58.72	56.20	---	---	S/I	---	---	S/I	---	
9:00 am	59.32	57.20	---	---	S/I	---	---	S/I	---	
10:00 am	59.88	58.80	---	---	S/I	---	---	S/I	---	
11:00 am	60.40	60.00	---	---	S/I	---	---	S/I	---	
12:00 N	60.60	60.60	---	---	S/I	---	---	S/I	---	START FLOW TEST #3.
										Opened casing @ 12:00 noon.
										Opened tubing @ 12:30 p.m.
1:00 pm	46.24	49.20	43.02	8.0	7.4	43.02	80.0	92.4	99.8	Casing - 2"x1/2" meter run.
2:00 pm	43.60	46.20	41.52	4.0	5.1	41.52	46.0	69.2	74.3	Tubing - 2"x1/4" meter run.
3:00 pm	43.44	43.60	41.36	3.0	4.4	41.36	36.5	61.5	65.9	
4:00 pm	43.16	42.60	40.92	2.0	3.6	40.92	32.0	57.4	61.0	
5:00 pm	42.88	43.00	40.80	2.0	3.6	40.80	28.0	53.6	57.2	
6:00 pm	42.76	42.40	40.66	2.0	3.6	40.66	26.0	51.6	55.2	
7:00 pm	42.24	41.80	40.32	2.0	3.6	40.32	24.0	49.4	53.0	
8:00 pm	42.48	41.00	40.30	1.5	3.1	40.30	22.0	47.3	50.4	

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
9:00 pm	42.32	40.40	40.14	1.25	2.8	40.14	20.5	45.6	48.4	
10:00 pm	42.20	40.20	40.00	1.0	2.5	40.00	19.0	43.9	46.4	
11:00 pm	42.08	39.80	39.92	1.0	2.5	39.92	18.0	42.7	45.2	
5/24/87										
12:00 MN	42.00	39.60	39.78	1.0	2.5	39.78	17.0	41.4	43.9	
1:00 am	41.92	39.40	39.64	1.0	2.5	39.64	16.0	40.1	42.6	
2:00 am	41.84	39.20	39.52	1.0	2.5	39.52	15.0	38.8	41.3	
3:00 am	41.76	39.00	39.40	1.0	2.5	39.40	14.5	38.1	40.6	
4:00 am	41.68	38.80	39.30	1.0	2.5	39.30	14.0	37.4	39.9	
5:00 am	41.60	38.60	39.20	.75	2.2	39.20	13.5	36.7	38.9	
6:00 am	41.56	38.60	39.20	.75	2.2	39.20	13.0	36.0	38.2	
7:00 am	41.52	38.60	39.14	.75	2.2	39.14	12.5	35.3	37.5	
8:00 am	41.48	38.60	39.10	.75	2.2	39.10	12.0	34.6	36.8	
9:00 am	41.44	38.60	39.08	.75	2.2	39.08	12.0	34.6	36.8	
10:00 am	41.44	39.00	39.08	.75	2.2	39.08	11.5	33.8	36.0	
11:00 am	41.44	40.00	39.12	.75	2.2	39.12	11.0	33.1	35.3	
12:00 N	41.48	38.60	39.26	.75	2.2	39.26	10.5	32.4	34.6	
	END OF TEST #3.									
1:00 pm	SHUT-IN FOR TEST #4.									Tubing - Zone 5 Casing - Zones 1-4, 6-8.
2:00 pm	11.20	26.00	---	---	S/I	---	---	S/I	---	
3:00 pm	22.48	34.00	---	---	S/I	---	---	S/I	---	
4:00 pm	32.64	39.00	---	---	S/I	---	---	S/I	---	
5:00 pm	41.44	41.60	---	---	S/I	---	---	S/I	---	
6:00 pm	45.52	42.20	---	---	S/I	---	---	S/I	---	
7:00 pm	46.80	43.20	---	---	S/I	---	---	S/I	---	
8:00 pm	47.80	44.00	---	---	S/I	---	---	S/I	---	
9:00 pm	48.72	44.80	---	---	S/I	---	---	S/I	---	
10:00 pm	49.52	45.60	---	---	S/I	---	---	S/I	---	
11:00 pm	50.28	46.40	---	---	S/I	---	---	S/I	---	
5/25/87										
12:00 MN	51.32	47.00	---	---	S/I	---	---	S/I	---	
1:00 am	51.76	47.60	---	---	S/I	---	---	S/I	---	

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
2:00 am	52.48	48.20	---	---	S/I	---	---	S/I	---	
3:00 am	53.16	48.80	---	---	S/I	---	---	S/I	---	
4:00 am	53.80	49.40	---	---	S/I	---	---	S/I	---	
5:00 am	54.48	50.00	---	---	S/I	---	---	S/I	---	
6:00 am	55.12	50.60	---	---	S/I	---	---	S/I	---	
7:00 am	55.72	51.20	---	---	S/I	---	---	S/I	---	
8:00 am	56.32	52.00	---	---	S/I	---	---	S/I	---	
9:00 am	56.92	52.80	---	---	S/I	---	---	S/I	---	
10:00 am	57.44	53.80	---	---	S/I	---	---	S/I	---	
11:00 am	57.96	55.20	---	---	S/I	---	---	S/I	---	
12:00 N	58.48	56.40	---	---	S/I	---	---	S/I	---	END OF BUILD-UP TEST #4. START FLOW TEST #4.
1:00 pm	44.20	45.00	42.34	5.0	5.8	42.34	60.0	79.6	85.4	Casing - 2"x1/2" meter run
2:00 pm	43.12	44.40	41.02	3.0	4.4	41.02	34.0	59.2	63.6	Tubing - 2"x1/4" meter run.
3:00 pm	42.52	43.80	40.78	3.0	4.4	40.78	27.0	52.7	57.1	
4:00 pm	42.24	43.20	40.56	2.5	4.0	40.56	24.0	49.5	53.5	
5:00 pm	42.12	40.80	40.34	2.0	3.6	40.34	21.0	46.2	49.8	
6:00 pm	41.92	38.60	40.22	2.0	3.6	40.22	19.0	43.9	47.5	
7:00 pm	41.80	40.20	40.10	2.0	3.6	40.10	18.0	42.7	46.3	
8:00 pm	41.56	40.00	39.98	2.0	3.6	39.98	17.0	41.5	45.1	
9:00 pm	41.36	39.60	39.86	2.0	3.6	39.86	16.0	40.2	43.8	
10:00 pm	41.36	39.20	39.76	2.0	3.6	39.76	15.0	38.9	42.5	
11:00 pm	41.36	39.00	39.66	2.0	3.6	39.66	14.0	37.5	41.1	
5/26/87										
12:00 MN	41.36	39.00	39.58	2.0	3.6	39.58	13.0	36.1	39.7	
1:00 am	41.36	39.00	39.52	2.0	3.6	39.52	12.5	35.4	39.0	
2:00 am	41.36	39.00	39.46	2.0	3.6	39.46	12.0	34.7	38.3	
3:00 am	41.36	38.80	39.38	2.0	3.6	39.38	11.5	33.9	37.5	
4:00 am	41.36	38.80	39.32	2.0	3.6	39.32	11.0	33.2	36.8	
5:00 am	41.36	38.80	39.28	2.0	3.6	39.28	10.5	32.4	36.0	
6:00 am	41.36	38.60	39.22	2.0	3.6	39.22	10.0	31.6	35.2	
7:00 am	41.36	38.60	39.18	2.0	3.6	39.18	10.0	31.6	35.2	
8:00 am	41.36	39.00	39.16	2.0	3.6	39.16	9.5	30.8	34.4	
9:00 am	41.36	39.20	39.18	2.0	3.6	39.18	9.0	30.0	33.6	

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
10:00 am	41.36	40.40	39.48	2.0	3.6	39.48	9.0	30.0	33.6	Casing pressure increased
11:00 am	41.56	40.40	39.48	2.5	4.0	39.[illegible]	9.0	30.0	34.0	slightly. No changes in equipment.
12:00 N	41.48	38.40	39.38	3.0	4.4	39.38	9.0	30.0	34.4	Tubing rate increasing slightly. Tubing - Zone 4. Casing - Zones 1-3, 5-8.
	END OF FLOW TEST #4.									
1:00 pm	SHUT-IN WELL FOR BUILD-UP TEST #5.									
2:00 pm	31.28	13.20	---	---	S/I	---	---	S/I		
3:00 pm	37.84	23.60	---	---	S/I	---	---	S/I		
4:00 pm	41.20	28.80	---	---	S/I	---	---	S/I		
5:00 pm	42.72	36.40	---	---	S/I	---	---	S/I		
6:00 pm	43.52	41.40	---	---	S/I	---	---	S/I		
7:00 pm	44.60	43.80	---	---	S/I	---	---	S/I		
8:00 pm	45.32	46.20	---	---	S/I	---	---	S/I		
9:00 pm	45.96	48.80	---	---	S/I	---	---	S/I		
10:00 pm	46.64	50.60	---	---	S/I	---	---	S/I		
11:00 pm	47.24	52.40	---	---	S/I	---	---	S/I		
5/27/87										
12:00 MN	47.76	54.20	---	---	S/I	---	---	S/I		
1:00 am	48.32	55.80	---	---	S/I	---	---	S/I		
2:00 am	48.84	57.40	---	---	S/I	---	---	S/I		
3:00 am	49.40	59.00	---	---	S/I	---	---	S/I		
4:00 am	49.88	60.40	---	---	S/I	---	---	S/I		
5:00 am	50.40	61.80	---	---	S/I	---	---	S/I		
6:00 am	50.92	63.00	---	---	S/I	---	---	S/I		
7:00 am	51.40	64.20	---	---	S/I	---	---	S/I		
8:00 am	51.88	65.80	---	---	S/I	---	---	S/I		
9:00 am	52.36	67.20	---	---	S/I	---	---	S/I		
10:00 am	52.76	69.40	---	---	S/I	---	---	S/I		
11:00 am	53.18	71.80	---	---	S/I	---	---	S/I		
12:00 N	53.64	72.80	---	---	S/I	---	---	S/I		START FLOW TEST #5. Tubing - 2" x 1/4" meter run. Casing - 2" x 1/2" meter run. Open casing @ 12:18 pm. Open tubing @ 12:30 pm.

			TUBING METER			CASING METER			TOTAL	
DATE/TIME	TP	CP	LP	DIFF	RATE	LP	DIFF	RATE	RATE	COMMENTS
1:00 pm	51.80	48.00	43.66	86.0	24.2	43.66	65.0	83.8	108.0	
2:00 pm	47.04	44.00	41.10	93.0	24.7	41.10	12.0	35.2	59.9	
3:00 pm	45.92	43.20	40.32	82.0	23.0	40.32	8.0	28.5	51.5	
4:00 pm	45.44	42.60	40.26	78.0	22.4	40.26	7.0	26.7	49.1	
5:00 pm	44.88	42.60	40.14	75.0	22.0	40.14	6.0	24.7	46.7	
6:00 pm	44.92	41.60	39.92	72.0	21.5	39.92	5.0	22.5	44.0	
7:00 pm	44.76	41.00	39.74	70.0	21.1	39.74	4.5	21.3	42.4	
8:00 pm	44.60	38.60	39.60	67.0	20.6	39.60	4.0	20.0	40.6	
9:00 pm	44.44	39.60	39.48	65.5	20.4	39.48	3.5	18.7	39.1	
10:00 pm	44.28	39.40	39.42	64.0	20.1	39.42	3.5	18.7	38.8	
11:00 pm	44.20	39.00	39.36	62.0	19.8	39.36	3.0	17.3	37.1	
5/28/87										
12:00 MN	44.08	38.80	39.28	61.0	19.6	39.28	3.0	17.3	36.9	
1:00 am	43.96	38.60	39.24	59.0	19.3	39.24	3.0	17.3	36.6	
2:00 am	43.88	38.60	39.18	58.0	19.1	39.18	3.0	17.3	36.4	
3:00 am	43.76	38.40	39.14	56.5	18.9	39.14	3.0	17.3	36.2	
4:00 am	43.68	38.20	39.10	55.0	18.6	39.10	2.5	15.8	34.4	
5:00 am	43.60	38.20	39.06	54.0	18.4	39.06	2.5	15.8	34.2	
6:00 am	43.52	38.20	39.04	53.0	18.3	39.04	2.5	15.8	34.1	
7:00 am	43.44	38.20	39.00	51.5	18.0	39.00	2.5	15.8	33.8	
8:00 am	43.40	38.60	39.00	50.0	17.7	39.00	2.5	15.8	33.3	
9:00 am	43.36	39.20	39.10	47.5	17.3	39.10	2.5	15.8	33.1	
10:00 am	43.44	40.40	39.36	45.5	17.0	39.36	2.5	15.8	32.8	
11:00 am	43.40	41.60	39.46	44.5	16.8	39.46	2.5	15.8	32.6	
12:00 N	43.48	42.00	39.50	44.0	16.7	39.50	2.5	15.8	32.5	
	END OF FLOW TEST #5.									
1:00 pm	SHUT-IN WELL FOR BUILD-UP TEST #6.									Tubing - Zones 2,3. Casing - Zones 1, 4-8.
2:00 pm	21.92	30.00	---	---	S/I	---	---	S/I	---	
3:00 pm	31.00	37.60	---	---	S/I	---	---	S/I	--	
4:00 pm	37.68	41.40	---	---	S/I	---	---	S/I	---	
5:00 pm	42.24	43.80	---	---	S/I	---	---	S/I	---	
6:00 pm	46.04	44.40	---	---	S/I	---	---	S/I	---	

DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
7:00 pm	48.64	45.00	---	---	S/I	---	---	S/I	---	
8:00 pm	50.00	45.20	---	---	S/I	---	---	S/I	---	
9:00 pm	50.96	45.60	---	---	S/I	---	---	S/I	---	
10:00 pm	51.76	46.00	---	---	S/I	---	---	S/I	---	
11:00 pm	52.56	46.60	---	---	S/I	---	---	S/I	---	
5/29/87										
12:00 MN	53.28	47.20	---	---	S/I	---	---	S/I	---	
1:00 am	54.00	47.80	---	---	S/I	---	---	S/I	---	
2:00 am	54.68	48.20	---	---	S/I	---	---	S/I	---	
3:00 am	55.32	48.80	---	---	S/I	---	---	S/I	---	NOTE: From 4 pm to 10 pm, the computer pressures are inaccurate. The recorded pressures are averaged.
4:00 am	55.89	49.70	---	---	S/I	---	---	S/I	---	
5:00 am	56.46	50.60	---	---	S/I	---	---	S/I	---	
6:00 am	57.03	51.50	---	---	S/I	---	---	S/I	---	
7:00 am	57.60	52.40	---	---	S/I	---	---	S/I	---	
8:00 am	58.17	53.30	---	---	S/I	---	---	S/I	---	
9:00 am	58.74	54.20	---	---	S/I	---	---	S/I	---	
10:00 am	59.31	55.10	---	---	S/I	---	---	S/I	---	
11:00 am	59.88	56.40	---	---	S/I	---	---	S/I	---	
12:00 N	60.44	57.40	---	---	S/I	---	---	S/I	---	END OF BUILD-UP #6. START FLOW TEST #6.
1:00 pm	45.44	45.20	42.20	16.0	10.3	42.20	53.0	74.7	85.0	
2:00 pm	43.72	45.00	40.94	8.0	7.2	40.94	31.0	56.5	63.7	
3:00 pm	43.04	44.00	40.26	6.0	6.2	40.26	26.0	51.4	57.6	
4:00 pm	42.96	42.80	40.22	5.0	5.7	40.22	21.0	46.2	51.8	
5:00 pm	42.72	42.80	40.06	4.5	5.4	40.06	20.0	45.0	50.4	
6:00 pm	42.24	42.00	39.72	4.0	5.0	39.72	18.0	42.6	47.6	
7:00 pm	42.40	41.60	39.*0	4.0	5.1	39.80	16.5	40.8	45.9	
8:00 pm	42.32	41.00	39.68	3.5	4.7	39.68	15.5	39.5	44.2	
9:00 am	42.20	40.60	39.58	3.0	4.4	39.58	14.0	37.5	41.9	
10:00 am	42.12	40.20	39.50	3.0	4.4	39.50	13.5	36.8	41.2	
11:00 am	42.08	40.00	39.48	3.0	4.4	39.48	12.0	34.7	39.1	

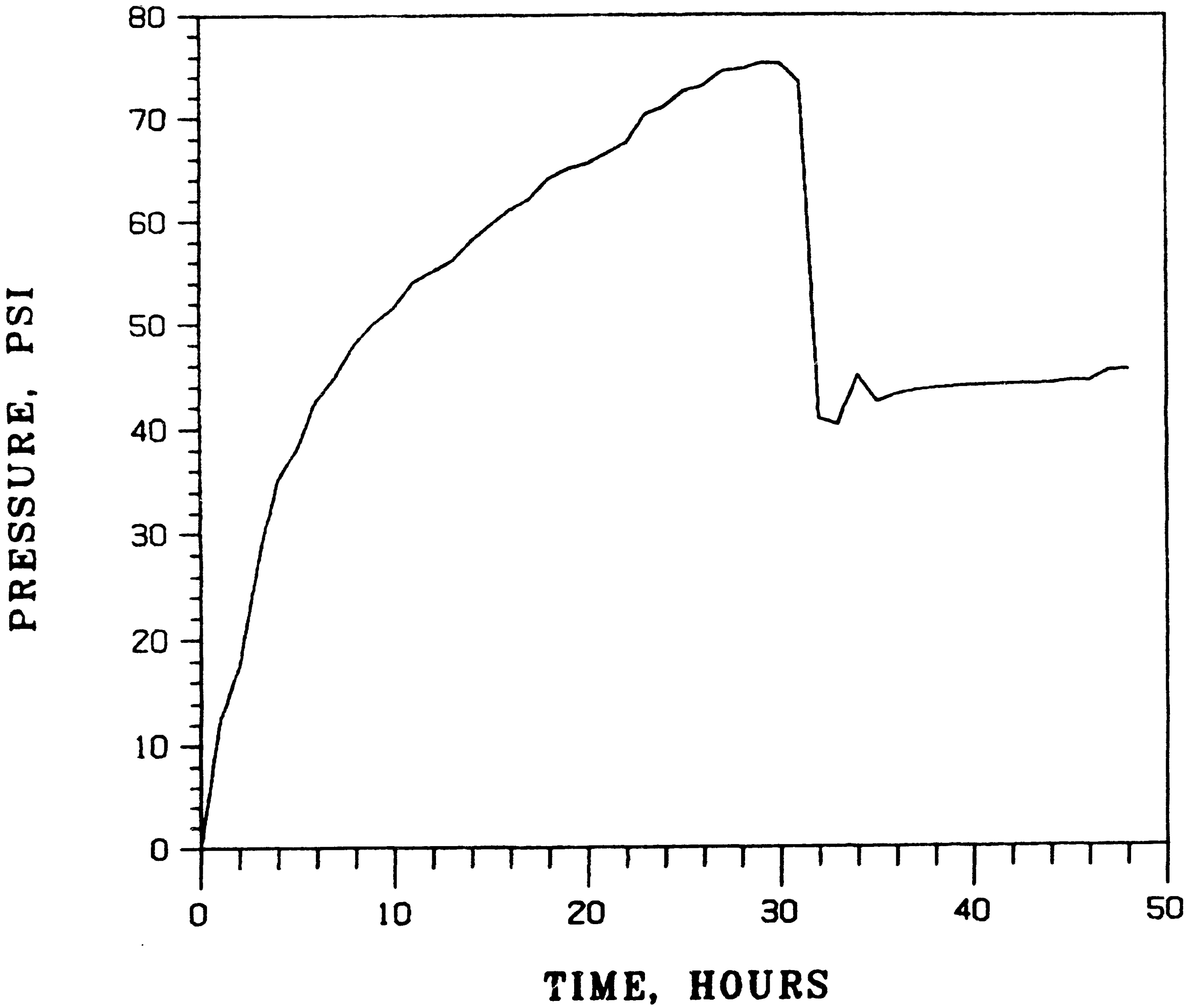
DATE/TIME	TP	CP	TUBING METER LP	TUBING METER DIFF	TUBING METER RATE	CASING METER LP	CASING METER DIFF	CASING METER RATE	TOTAL RATE	COMMENTS
5/30/87										
12:00 MN	42.12	39.80	39.54	3.0	4.4	39.54	12.0	34.7	39.1	
1:00 am	42.00	39.60	39.46	3.0	4.4	39.46	11.5	34.0	38.4	
2:00 am	41.96	39.60	39.40	3.0	4.4	39.40	11.0	33.2	37.6	
3:00 am	41.88	39.40	39.30	3.0	4.4	39.30	10.5	32.4	36.8	
4:00 am	41.84	39.20	39.24	3.0	4.4	39.24	10.0	31.6	36.0	
5:00 am	41.80	39.00	39.18	3.0	4.4	39.18	9.5	30.8	35.2	
6:00 am	41.72	39.00	39.12	3.0	4.4	39.12	9.0	29.9	34.3	
7:00 am	41.68	38.80	39.06	3.0	4.4	39.06	9.0	29.9	34.3	
8:00 am	41.64	39.40	39.04	3.0	4.4	39.04	8.5	29.1	33.5	
9:00 am	41.64	39.60	39.04	3.0	4.4	39.04	8.0	28.2	32.6	
10:00 am	41.68	40.40	39.12	3.0	4.4	39.12	8.0	28.2	32.6	
11:00 am	41.72	41.20	39.04	3.0	4.4	39.04	8.0	28.2	32.6	
12:00 N	41.76	41.80	39.28	3.0	4.4	39.28	8.0	28.3	32.7	
	END OF FLOW TEST #6. RUNNING HYDRO-SET BRIDGE PLUG (MODEL N-1)									
5/31/87										
1:15 pm	SHUT-IN FOR BUILD-UP TEST #7.									Tubing - Zone 1. Casing - Zones 2-8.
2:00 pm	C 9.50	6.00								
3:00 pm	14.00	13.20	---	---	S/I	---	---	S/I		
4:00 pm	18.00	19.40	---	---	S/I	---	---	S/I		
5:00 pm	21.04	22.40	---	---	S/I	---	---	S/I		
6:00 pm	23.20	22.40	---	---	S/I	---	---	S/I		
7:00 pm	24.80	24.60	---	---	S/I	---	---	S/I		
8:00 pm	26.16	25.40	---	---	S/I	---	---	S/I		
9:00 pm	27.28	26.20	---	---	S/I	---	---	S/I		
10:00 pm	28.32	26.60	---	---	S/I	---	---	S/I		
11:00 pm	29.24	27.40	---	---	S/I	---	---	S/I		

DATE/TIME	TP	CP	TUBING METER LP	DIFF	RATE	CASING METER LP	DIFF	RATE	TOTAL RATE	COMMENTS
6/1/87										
12:00 MN	30.12	28.00	---	---	S/I	---	---	S/I		
1:00 am	30.92	28.80	---	---	S/I	---	---	S/I		
2:00 am	31.76	29.40	---	---	S/I	---	---	S/I		
3:00 am	32.52	30.20	---	---	S/I	---	---	S/I		
4:00 am	33.32	30.80	---	---	S/I	---	---	S/I		
5:00 am	34.08	31.60	---	---	S/I	---	---	S/I		
6:00 am	34.84	32.40	---	---	S/I	---	---	S/I		
7:00 am	35.52	33.00	---	---	S/I	---	---	S/I		
8:00 am	36.24	34.20	---	---	S/I	---	---	S/I		
9:00 am	36.80	35.20	---	---	S/I	---	---	S/I		
10:00 am	37.24	37.00	---	---	S/I	---	---	S/I		
11:00 am	37.84	38.00	---	---	S/I	---	---	S/I		
12:00 N	39.32	39.20	---	---	S/I	---	---	S/I		OPENED WELL FOR FLOW TEST #7.
1:15 pm	40.20	39.40	---	---	S/I	---	---	S/I		Well still building pressure
2:00 pm	40.36	43.40	37.26	1.0	2.5	37.36	1.0	9.8	12.3	against 40# psi LP.
3:00 pm	40.28	39.40	37.78	1.0	2.5	37.78	1.0	9.9	12.4	NOTE: Well was vented to atmos-
4:00 pm	40.64	40.80	37.84	1.0	2.5	37.84	1.25	11.0	13.5	phere for 24 hours prior to
5:00 pm	40.80	C 40.80	37.78	1.0	2.5	37.78	1.5	12.1	14.6	build-up.
6:00 pm	40.96	C 40.96	37.78	1.0	2.5	37.78	1.75	13.0	15.5	
7:00 pm	41.04	C 41.04	C 38.00	.75	2.2	C 38.00	2.0	14.0	16.2	Computer reading inaccurate
8:00 pm	41.08	C 41.08	C 38.00	.75	2.2	C 38.00	2.0	14.0	16.2	data for CP & LP. Readings
9:00 pm	41.20	C 41.20	C 38.00	.75	2.2	C 38.00	2.0	14.0	16.2	taken from meter charts (C).
10:00 pm	41.24	C 41.24	C 38.00	.75	2.2	C 38.00	2.25	14.8	17.0	CP tracking TP on pressure
11:00 pm	41.28	C 41.28	C 38.00	.75	2.2	C 38.00	2.5	15.6	17.8	recorder.
6/2/87										
12:00 MN	41.36	C 41.36	C 38.00	.75	2.2	C 38.00	3.0	17.1	19.3	
1:00 am	41.44	C 41.44	C 38.00	.75	2.2	C 38.00	3.0	17.1	19.3	
2:00 am	41.52	C 41.52	C 38.00	.75	2.2	C 38.00	3.25	17.8	20.0	
3:00 am	41.76	C 41.76	C 38.00	.75	2.2	C 38.00	3.5	18.5	20.7	
4:00 am	41.72	C 41.72	C 38.00	.75	2.2	C 38.00	3.5	18.5	20.7	
5:00 am	41.60	C 41.60	C 38.00	.75	2.2	C 38.00	3.5	18.5	20.7	

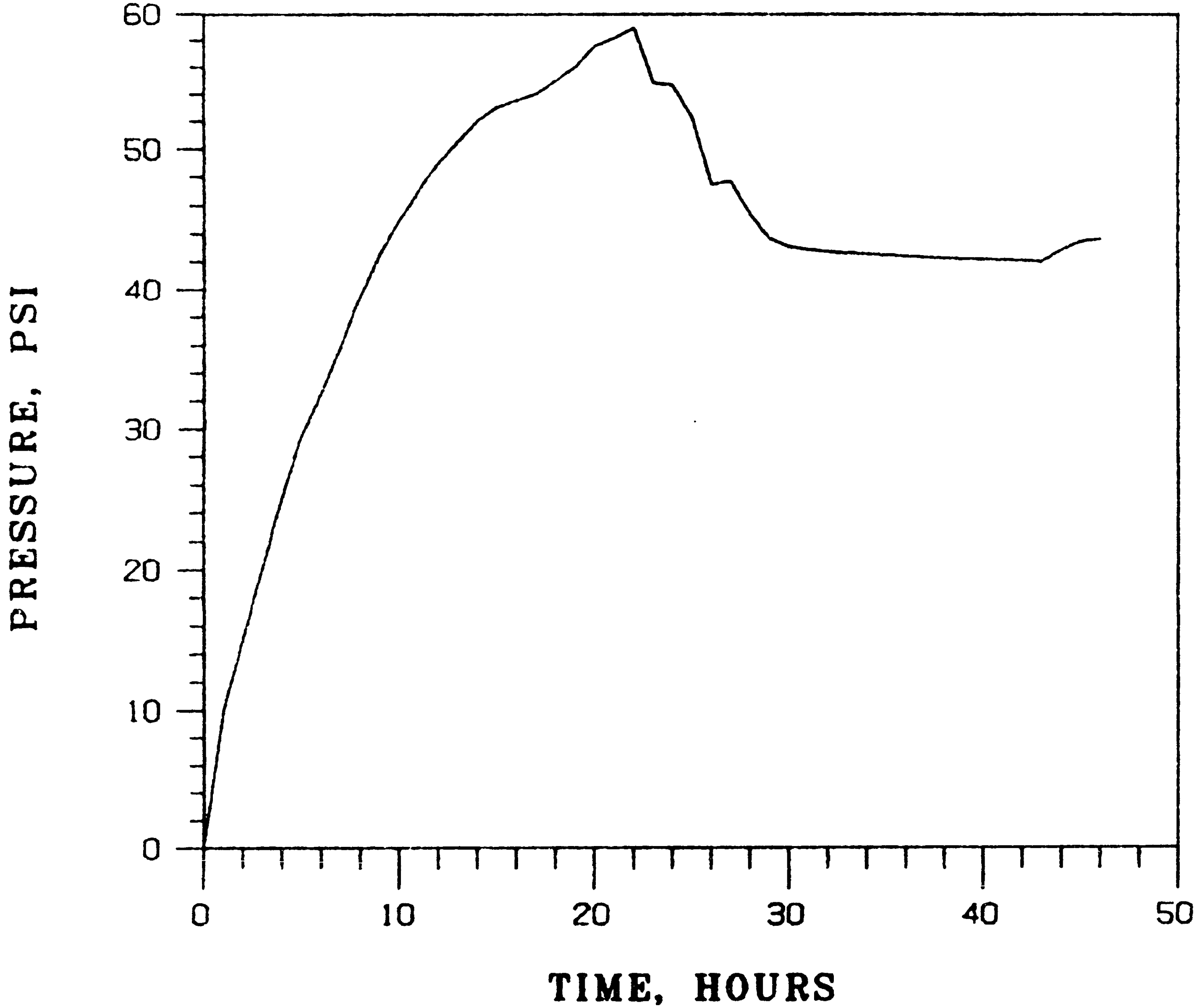
DATE/TIME	TP	CP	TUBING METER LP	DIFF	RATE	CASING METER LP	DIFF	RATE	TOTAL RATE	COMMENTS
6:00 am	41.64	C 41.64	C 38.00	.75	2.2	C 38.00	3.5	18.5	20.7	
7:00 am	41.68	C 41.68	C 38.00	.75	2.2	C 38.00	3.5	18.5	20.7	
8:00 am	41.84	C 41.84	C 38.00	.75	2.2	C 38.00	3.75	19.1	21.3	
9:00 am	41.96	C 41.96	C 38.00	.75	2.2	C 38.00	4.0	19.8	22.0	
10:00 am	42.16	C 42.16	C 38.00	.75	2.2	C 38.00	4.0	19.8	22.0	
11:00 am	42.16	C 42.16	C 38.50	.75	2.2	C 38.50	4.0	19.8	22.0	
12:00 N	41.68	38.60	39.10	.75	2.2	39.10	4.0	20.4	23.0	All pressures taken from computer.

END OF FLOW TEST #7.

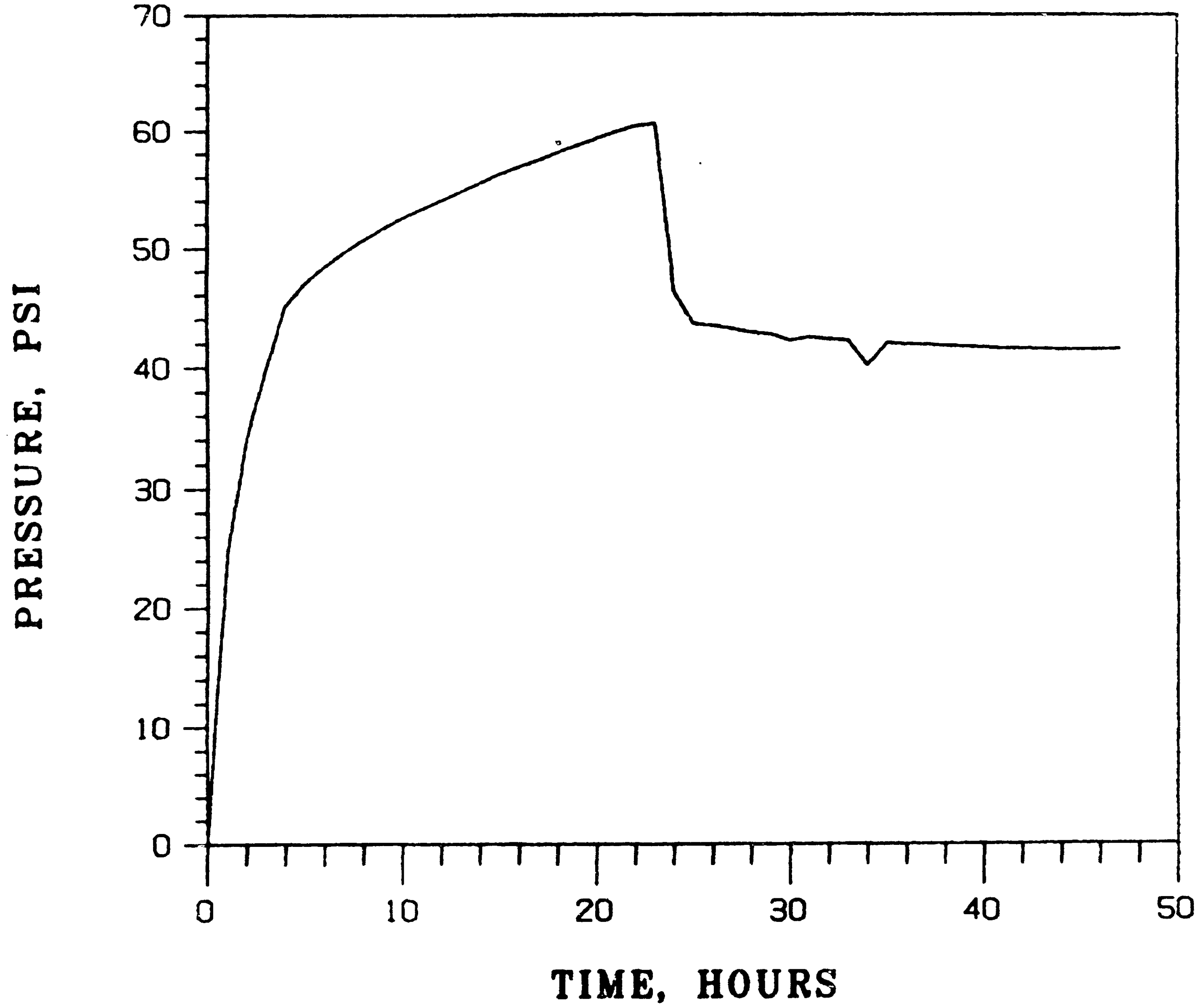
PRESSURE BUILD-UP & DRAWDOWN TEST1 (ZONE #8)
HORIZONTAL SHALE WELL RET1, WAYNE CO., WV



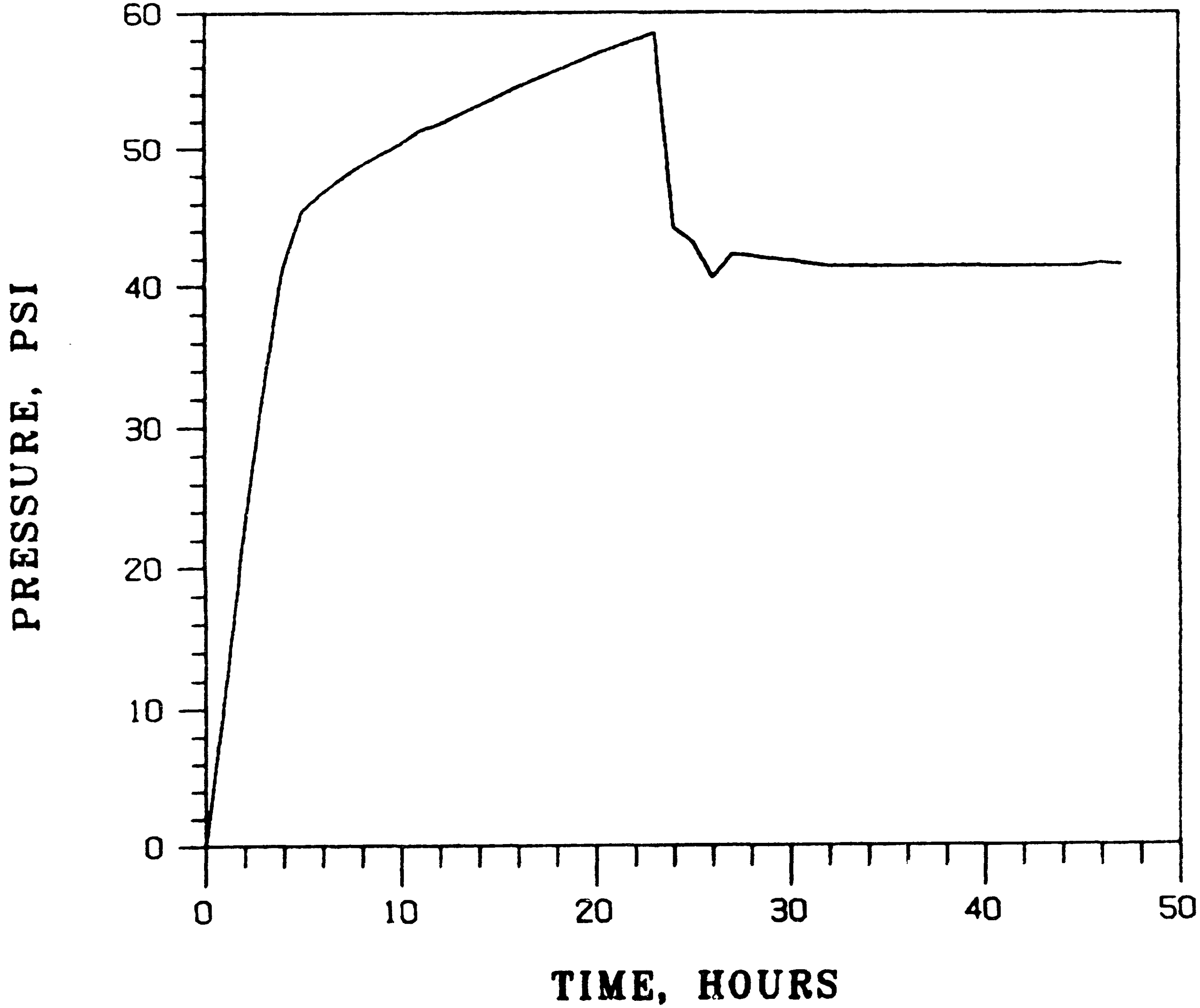
PRESSURE BUILDUP & DRAWDOWN FOR TEST2 (ZONE #7)
2 3/8" TUBING, INTERVAL (4095-4194')



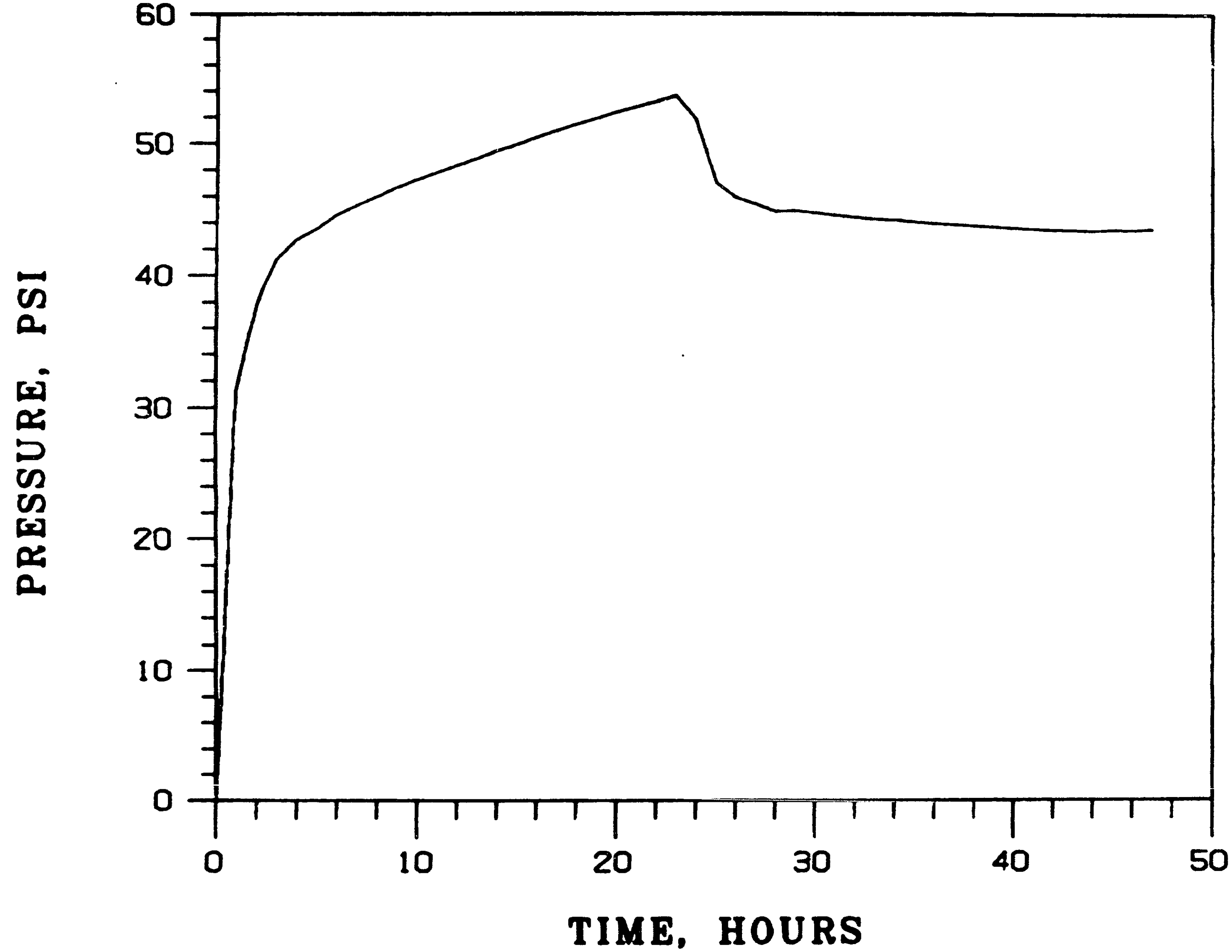
PRESSURE BUILDUP & DRAWDOWN FOR TEST3 (ZONE #6)
2 3/8" TUBING, INTERVAL (4194-4337')



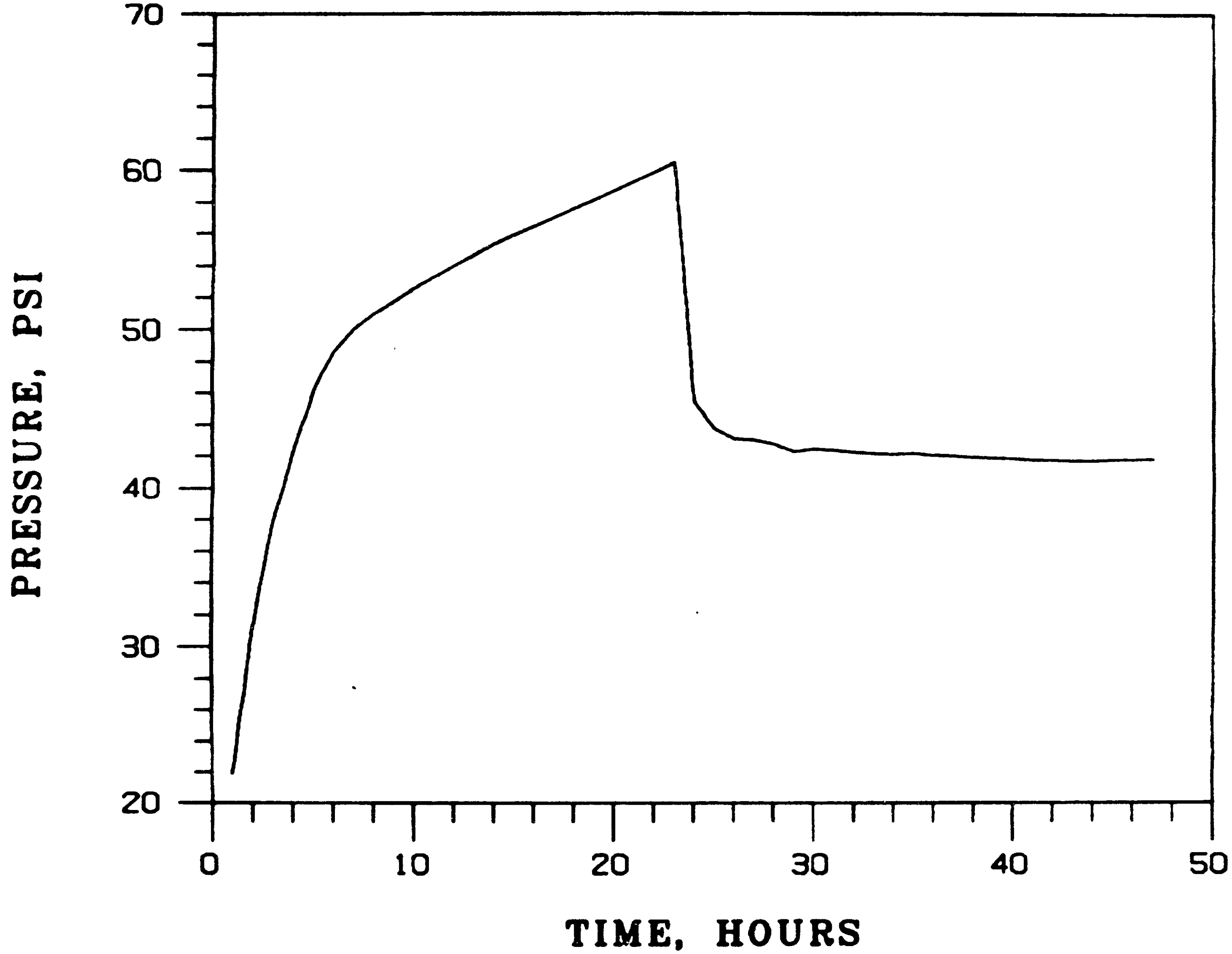
PRESSURE BUILDUP & DRAWDOWN FOR TEST4 (ZONE #5)
2 3/8" TUBING, INTERVAL (4337-4986)



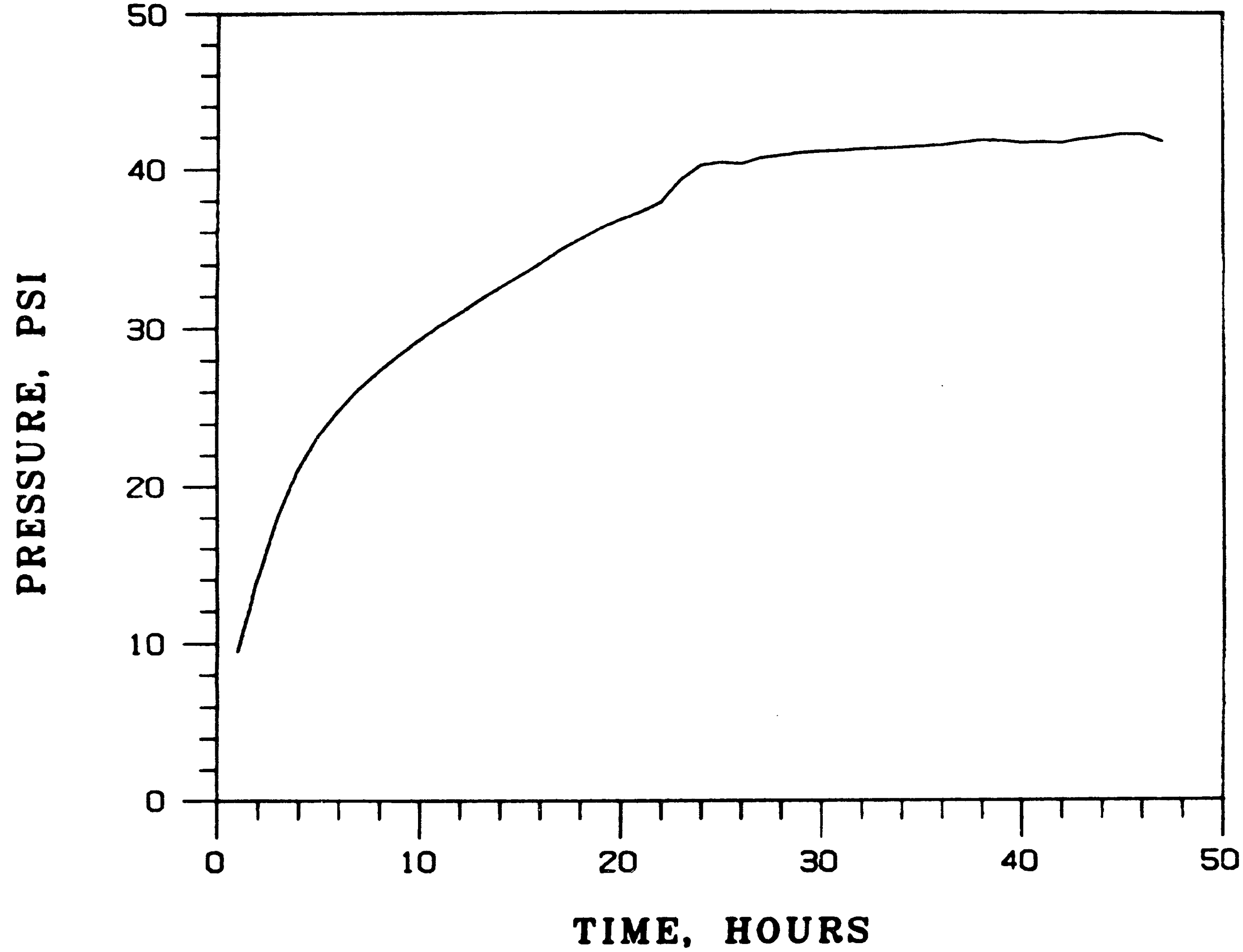
PRESSURE BUILDUP & DRAWDOWN FOR TEST5 (ZONE #4)
2 3/8" TUBING, INTERVAL (4986'–5176')



PRESSURE BUILDUP & DRAWDOWN FOR TEST6 (ZONES 2,3)
2 3/8" TUBING, INTERVAL (5176-5601')



PRESSURE BUILDUP & DRAWDOWN FOR TEST7 (ZONE #1)
2 3/8" TUBING, INTERVAL (5601-6014')



APPENDIX 7-6

SUPPORTING MATERIAL FOR INFLATION AND TESTING OF ECPs

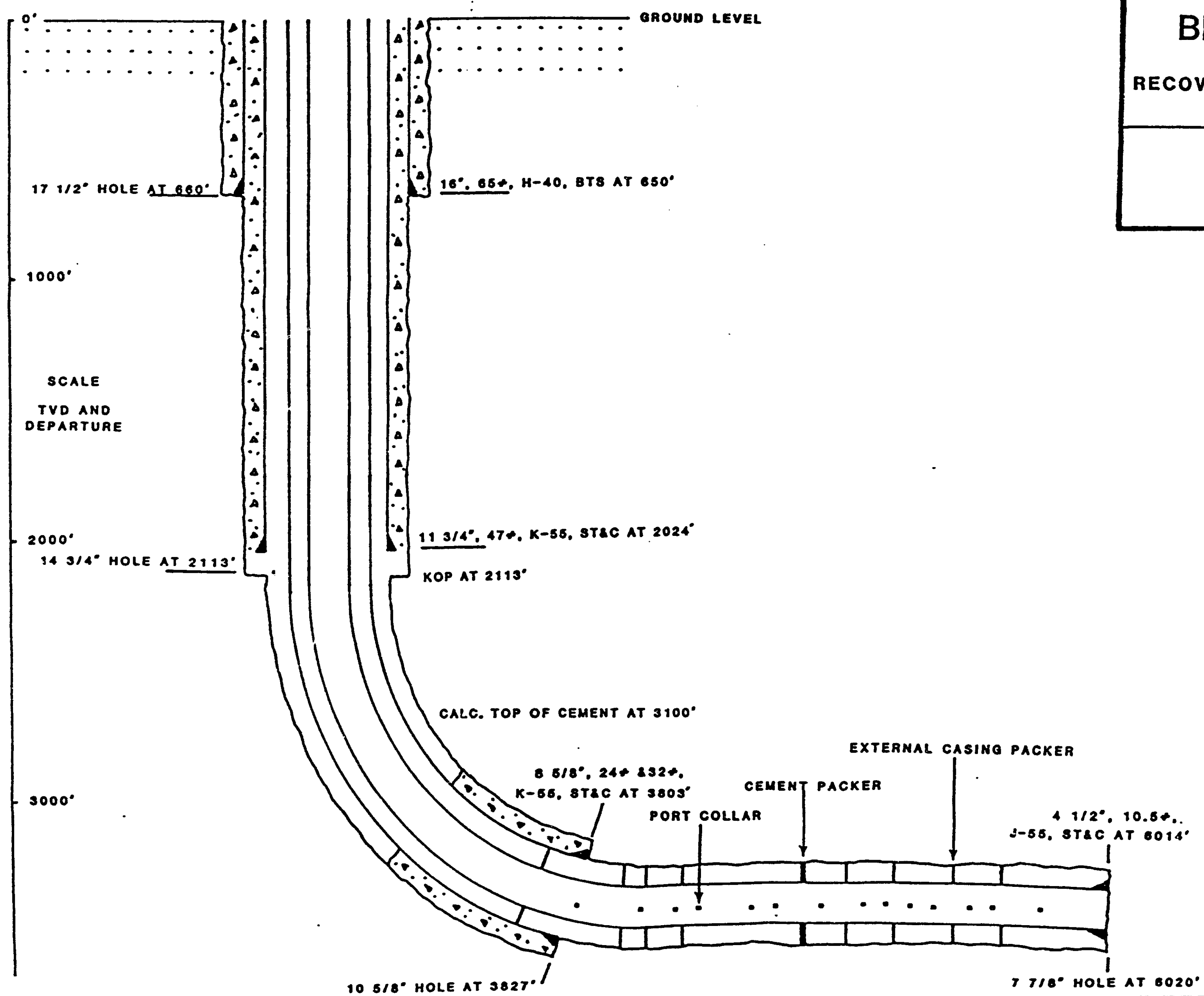
- WELLBORE SCHEMATIC
- CASING TALLEY
- ECP INFORMATION
- PORT COLLAR INFORMATION
- CTC - PAYZONE PACKER
- NITROGEN DATA

WELLBORE SCHEMATIC

BDM CORPORATION

RECOVERY EFFICIENCY TEST WELL #1

WELLBORE DIAGRAM



CASING TALLEY

21	43.62	2000.54	
22	43.87	1956.67	
23	45.28	1911.39	
24	43.68	1867.71	
25	43.86	1823.85	
26	45.12	1778.73	
27	45.34	1733.39	
28	43.62	1689.77	
29	45.81	1643.96	
30	43.65	1600.31	
31	43.65	1556.66	
32	43.87	1512.79	UP 40000 DOWN 35000
33	45.88	1466.91	
34	43.60	1423.31	
35	41.91	1381.40	
36	43.85	1337.55	
37	38.85	1298.70	
38	43.86	1254.84	
39	43.84	1211.00	
40	42.25	1168.75	
41	43.59	1125.16	
42	38.57	1086.59	
43	43.64	1042.95	
44	37.24	1005.71	UP 40000 DOWN 32000
45	43.86	961.85	
46	43.60	918.25	
47	43.84	874.41	
48	43.86	830.55	
49	42.43	788.12	
50	37.36	750.76	
51	43.84	706.92	
52	43.85	663.07	
53	44.59	618.48	
54	43.60	574.88	
55	43.82	531.06	
56	43.62	487.44	42000 LBS DOWN 31000
57	43.89	443.55	
58	43.88	399.67	
59	43.87	355.80	
60	43.85	311.95	
61	43.85	268.10	
62	43.85	224.25	
63	45.13	179.12	
64	43.85	135.27	
65	44.76	90.51	
66	43.87	46.64	UP 42000 DOWN 31000
67	43.64	3.00	
68	43.62	OUT	
69	43.87	OUT	
70	43.65	OUT	
	6142.06		

	8.83	4336.95	PACKER 5
107	43.56	4293.39	
	2.88	4290.51	PORT COLLAR 11
108	43.81	4246.70	
109	43.83	4202.87	
	8.83	4194.04	PACKER 6
110	43.80	4150.24	
	2.88	4147.36	PORT COLLAR 12
111	43.81	4103.55	
	8.83	4094.72	PACKER 7
112	43.85	4050.87	
113	43.80	4007.07	
114	43.82	3963.25	
	2.88	3960.37	PORT COLLAR 13
115	37.51	3922.86	
116	43.85	3879.01	
117	43.83	3835.18	
	2.88	3832.30	PORT COLLAR 14
118	43.83	3788.47	
119	43.85	3744.62	
	8.83	3735.79	PACKER 8
120	43.83	3691.96	
121	42.94	3649.02	
122	45.10	3603.92	
123	43.80	3560.12	
124	43.60	3516.52	
125	43.82	3472.70	
126	43.60	3429.10	
127	42.15	3386.95	
128	43.58	3343.37	
129	43.81	3299.56	
130	38.97	3260.59	
131	43.83	3216.76	
132	39.15	3177.61	
133	38.23	3139.38	
134	44.48	3094.90	
135	43.55	3051.35	
136	42.10	3009.25	
137	43.85	2965.40	
138	43.83	2921.57	
1	43.64	2877.93	
2	43.68	2834.25	
3	45.35	2788.90	
4	43.90	2745.00	
5	43.61	2701.39	
6	43.64	2657.75	
7	43.87	2613.88	
8	44.75	2569.13	
9	43.64	2525.49	
10	43.89	2481.60	
11	43.69	2437.91	
12	43.89	2394.02	
13	43.69	2350.33	
14	43.67	2306.66	
15	43.60	2263.06	
16	43.89	2219.17	
17	43.61	2175.56	DRAG 1-2000LBS
18	43.63	2131.93	
19	43.88	2088.05	
20	43.89	2044.16	DRAG 2000 LBS

4 1/2" CASING TALLY ON 12-13-86 RUN ON 12-17-86
INFLATE PORT IS 13" BELOW THE TOP OF ECP
INFLATE VALVE IS 9.7' BELOW TOP OF CTC PACKER

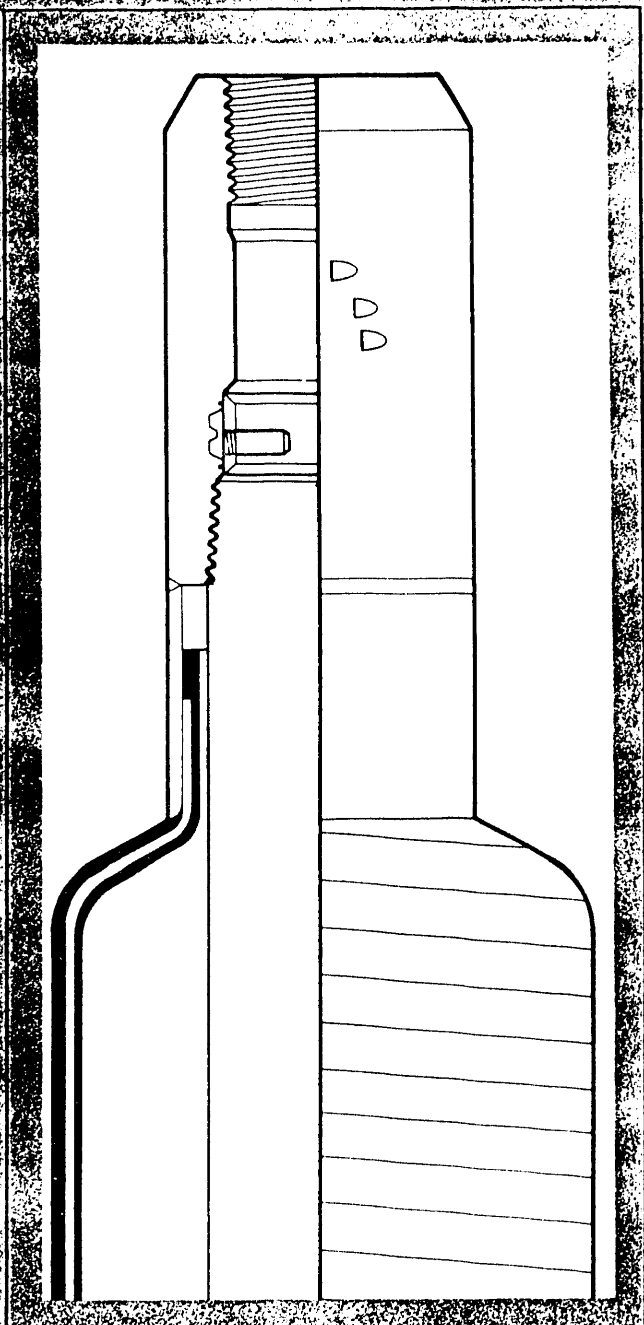
JOINT NUMBER	LENGTH	COLLAR DEPTH	COMMENTS
BOTTOM		6013.92	
	0.80	6013.12	
71	43.81	5969.31	
72	43.84	5925.47	
73	43.58	5881.89	
74	43.83	5838.06	
75	43.85	5794.21	
76	45.30	5748.91	
	2.88	5746.03	PORT COLLAR 1
77	45.16	5700.87	
78	45.41	5655.46	
79	44.97	5610.49	
	8.83	5601.66	PACKER 1
80	43.85	5557.81	
	2.88	5554.93	PORT COLLAR 2
81	44.97	5509.96	
82	43.55	5466.41	
	2.88	5463.53	PORT COLLAR 3
83	43.64	5419.89	
	8.83	5411.06	PACKER 2
84	45.50	5365.56	
85	43.81	5321.75	
	2.88	5318.87	PORT COLLAR 4
86	43.83	5275.04	
87	43.64	5231.40	
	2.88	5228.52	PORT COLLAR 5
88	43.84	5184.68	
	8.83	5175.85	PACKER 3
89	43.84	5132.01	
	2.88	5129.13	PORT COLLAR 6
90	43.55	5085.58	
91	44.63	5040.95	
	2.88	5038.07	PORT COLLAR 7
92	43.60	4994.47	
	8.83	4985.64	PACKER 4
93	43.82	4941.82	
94	45.14	4896.68	
	2.88	4893.80	PORT COLLAR 8
95	45.58	4848.22	
	37.25	4810.97	CTC PACKER
96	43.82	4767.15	
97	43.85	4723.30	
98	39.00	4684.30	
99	43.01	4641.29	
100	43.82	4597.47	
	2.88	4594.59	PORT COLLAR 9
101	38.18	4556.41	
102	43.61	4512.80	
103	43.56	4469.24	
104	43.85	4425.39	
105	39.20	4386.19	
	2.88	4383.31	PORT COLLAR 10
106	37.53	4345.78	

ECP INFORMATION

BAKER
PRODUCTION TECHNOLOGY

A Baker Oil Tools Company

The inflatable packer company

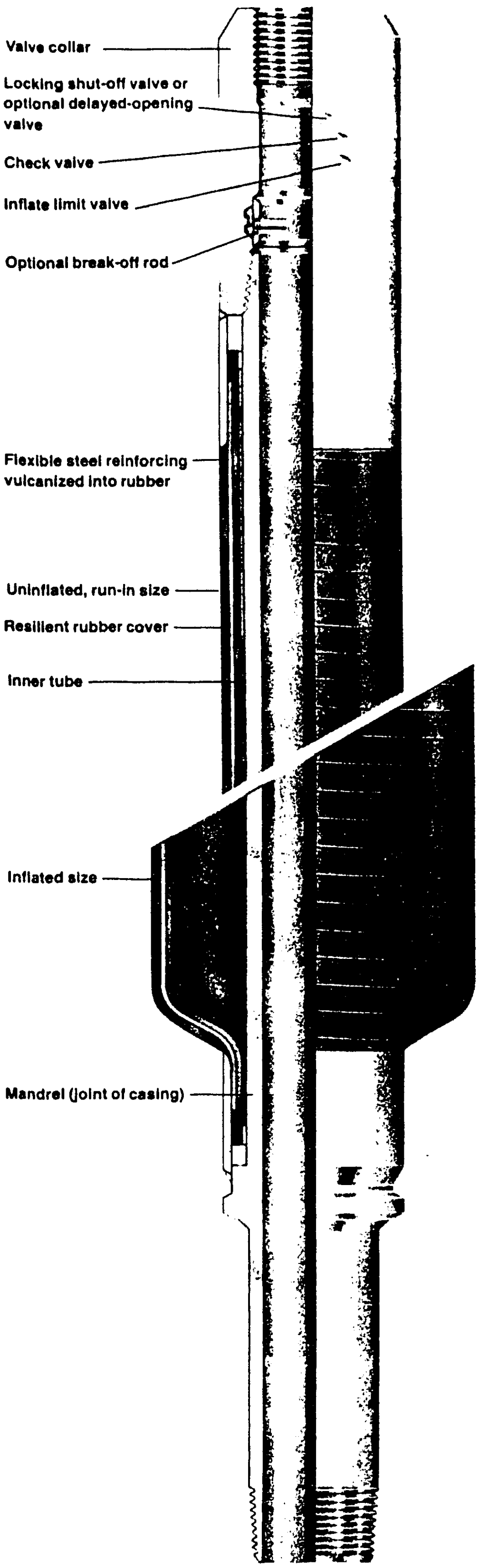


ECP®

Lynes™ External Casing Packer

BAKER
PRODUCTION TECHNOLOGY
A Baker Oil Tools Company

Lynes External Casing Packer (ECP®)



Lynes External Casing Packer
(Product No. 301-03)

Lynes ECPs do the jobs cement can't.

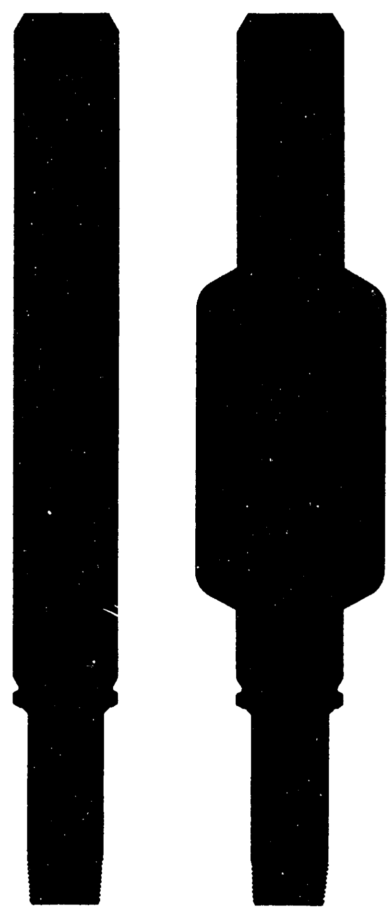
By ensuring the integrity of your primary cement, the Lynes ECP saves you the expense of remedial cementing. Not only does it block fluid and gas migration and interrupt channeling, but strategically placed, it can also isolate lost circulation zones, helping you reduce cement costs.

The mandrel of the ECP is a joint of casing with the same specifications as the rest of your string. You run it into the hole the same way you would a joint of casing without making any changes in your established cementing procedures. And there is nothing inside the mandrel nor any reduction in ID to interfere with subsequent operations.

ECPs are casing-to-formation or casing-to-casing packers that:

- Provide a positive, mechanical barrier to fluid and gas migration
- Conform to and seal in casing and irregular open holes
- Act faster and more positively than cement additives
- Centralize casing
- Interrupt channels that may form in the cement column
- Adjust automatically to changing differential pressure
- Reduce the ramming effect with maximum run-in clearance

No mechanical packer has as great a differential between run-in size and set size as the Lynes ECP. In many cases the outside diameter of the uninflated ECP compares to that of a casing coupling.



Uninflated element Inflated element

BAKER
PRODUCTION TECHNOLOGY
A Baker Oil Tools Company

Lynes ECP Differential Pressure Curves

ECPs and related tools

These packer selection charts plot the recommended maximum differential pressure across the tool against the diameter of the open hole or casing.

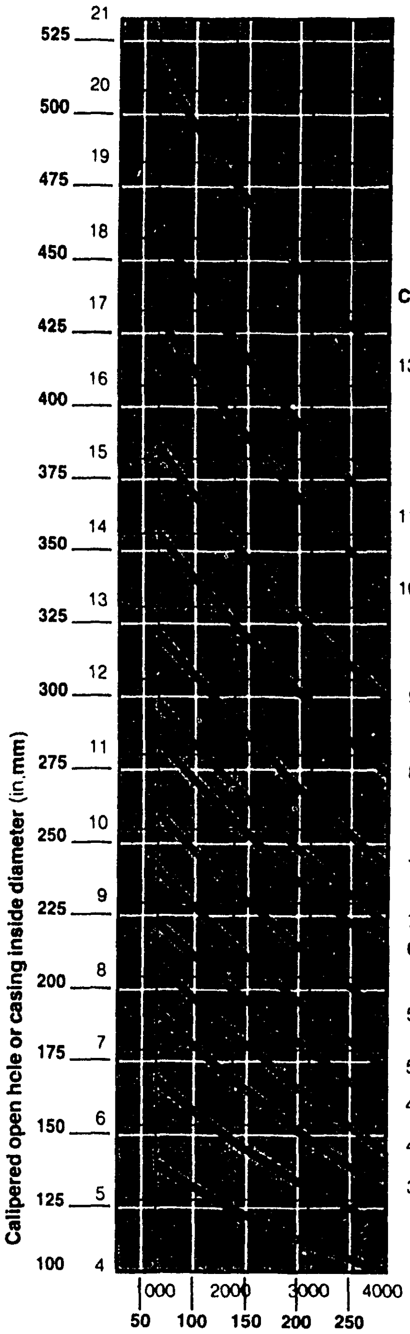
These curves are not recommended inflation pressures.

Inflation pressure calculations can only be made based on the actual application of the tool. A complete technical unit on the ECP is available from the Baker Production Technology Communications Department, Houston. Should any questions arise, please contact a Baker Production Technology representative.

ECP packer selection example

A wellbore has a 10 inch (254 mm) calipered open hole ID and the intended casing size is 6⅝ inch (168 mm). The maximum allowable differential pressure across that tool is a little more than 2000 psi (150 kg/cm²). From this chart, the packer choice is the 7¹⁵⁄₁₆ inch (202 mm) OD tool.

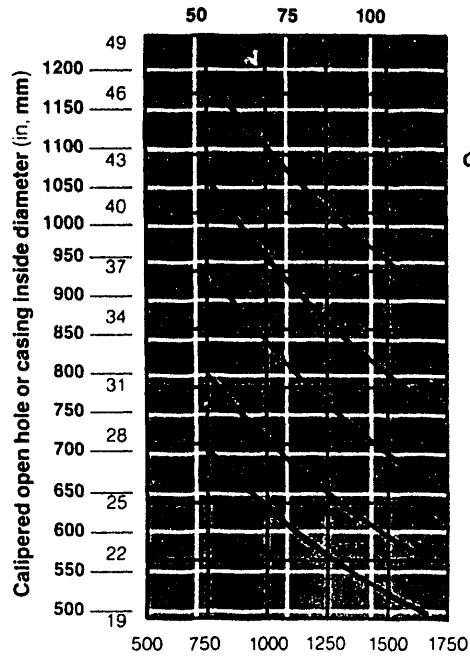
ECPs and Related Tools



Casing size (in.	mm)	Tool OD (in.	mm)
13⅜	339.7	15¾	400
11¾	298.5	13¾	349
10¾	273.1	12¾	324
9⅝	244.5	11¼	286
8⅝	219.1	10.150	258
7⅝*	193.7	9*	229
7*	177.8	8¼*	210
6⅝*	168.3	7¹⁵⁄₁₆*	202
5½*	139.7	7*	178
5*	127.0	6⅜*	162
4½*	114.3	5¾	146
4	101.6	5¼	133
3½	88.9	4⅝	118

*Special clearance models ("RTSX") are available for these casing sizes. Refer to the specification/selection chart (page 6) for complete dimensional information and reduce the above indicated differential pressure by 1000 psi (70 kg/cm²).

Large ECP sizes: 16 to 30 inches
(406 mm to 762 mm)



Casing size in	mm	Tool OD in	mm
30	762	35	889
24	610	29	737
20	508	24	610
18⅝	473	21½	546
16	406	18½	470

Special clearance models (RTSX) are available for charted sizes. Reduce limiting differential pressure by 400 psi (28kg/cm²).

Casing Size in	mm	Tool OD in	mm
16	406	17⁹⁄₁₆	446
18⅝	473	20⅝	523
20	508	23¼	641

Lynes External Casing Packer (ECP)

The inflation process

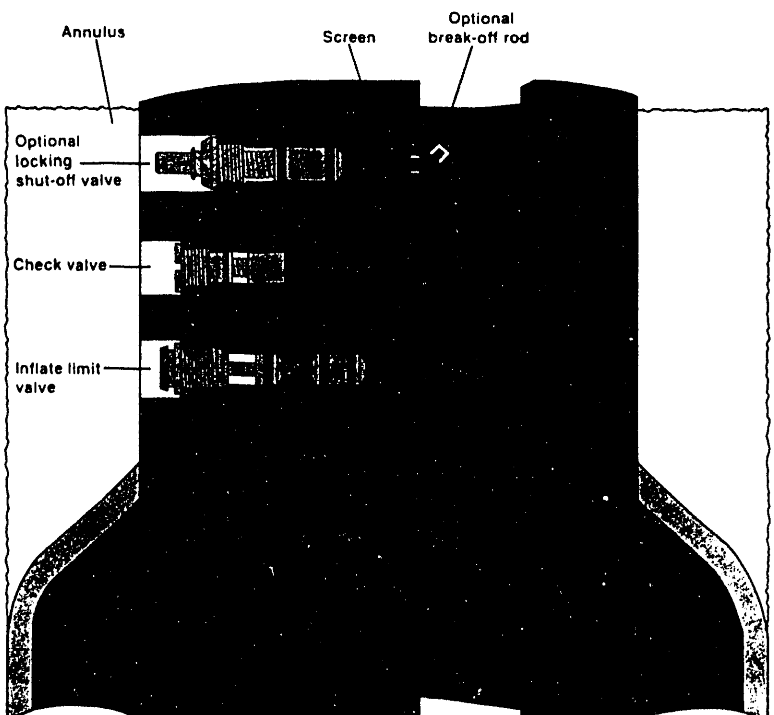
The Lynes ECP incorporates a series of protective devices to ensure against premature and over-inflation. Two optional break-off rods prevent any fluid in the casing from entering the element until they are sheared by the cement wiper plug as it passes through the mandrel. If required in multiple-stage cementing, the rods can be removed prior to running the packer.

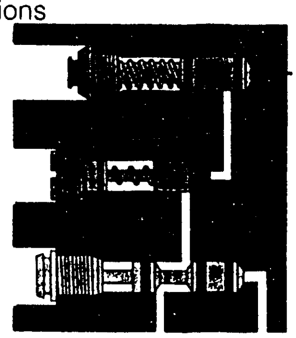
Once the rods are broken off, pressure applied to the casing forces the inflation fluid through the valve collar screen to the shear-pinned locking shut-off valve. The size of the shear pin, which is installed from the outside of the tool before it is run, determines the casing pressure at which the tool begins to inflate. Using different sizes of pins, multiple ECPs can be set individually without prematurely inflating any one of them.

After the fluid passes through the shut-off valve, it opens the spring-loaded check valve, passes through the inflate limit valve and inflates the steel-reinforced rubber element. The inflate limit valve is also shear pinned at the surface to close when the inflation pressure within the element reaches a factory-set pressure. Regardless of casing pressure, this valve is designed to keep the amount of inflation within the differential pressure limitations of the element. (See Differential Pressure Curves.)

Once the packer is set, a substantial reduction in casing pressure will close the locking shut-off valve and provide extra protection for the element from any subsequent changes in casing pressure. As an option, this valve can be replaced with a delayed-opening valve, which is also shear pinned to open at a predetermined pressure but does not lock closed.

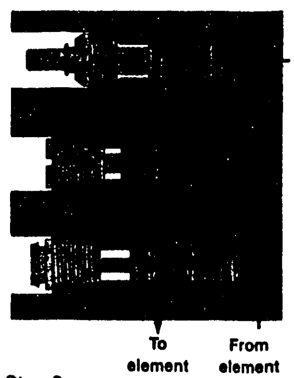
The inflation mechanism





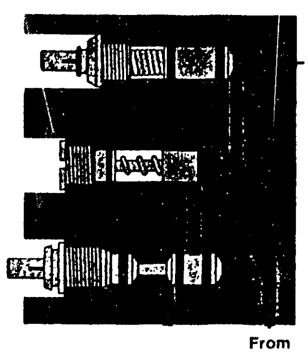
Step 1

During running in, the locking shut-off valve is shear pinned closed against the pressure exerted by fluids in the casing.



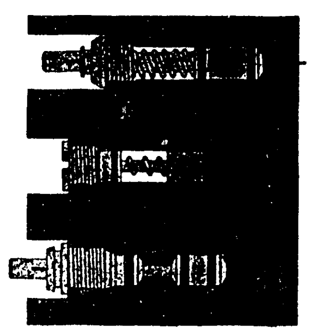
Step 2

When applied casing pressure reaches a predetermined limit, the pin is sheared allowing fluid to enter through the shut-off valve and inflate the element.



Step 3

When the differential pressure between the element and the annulus reaches the limit predetermined by the size of the shear pin in the inflate limit valve, the valve shifts permanently to the closed position.

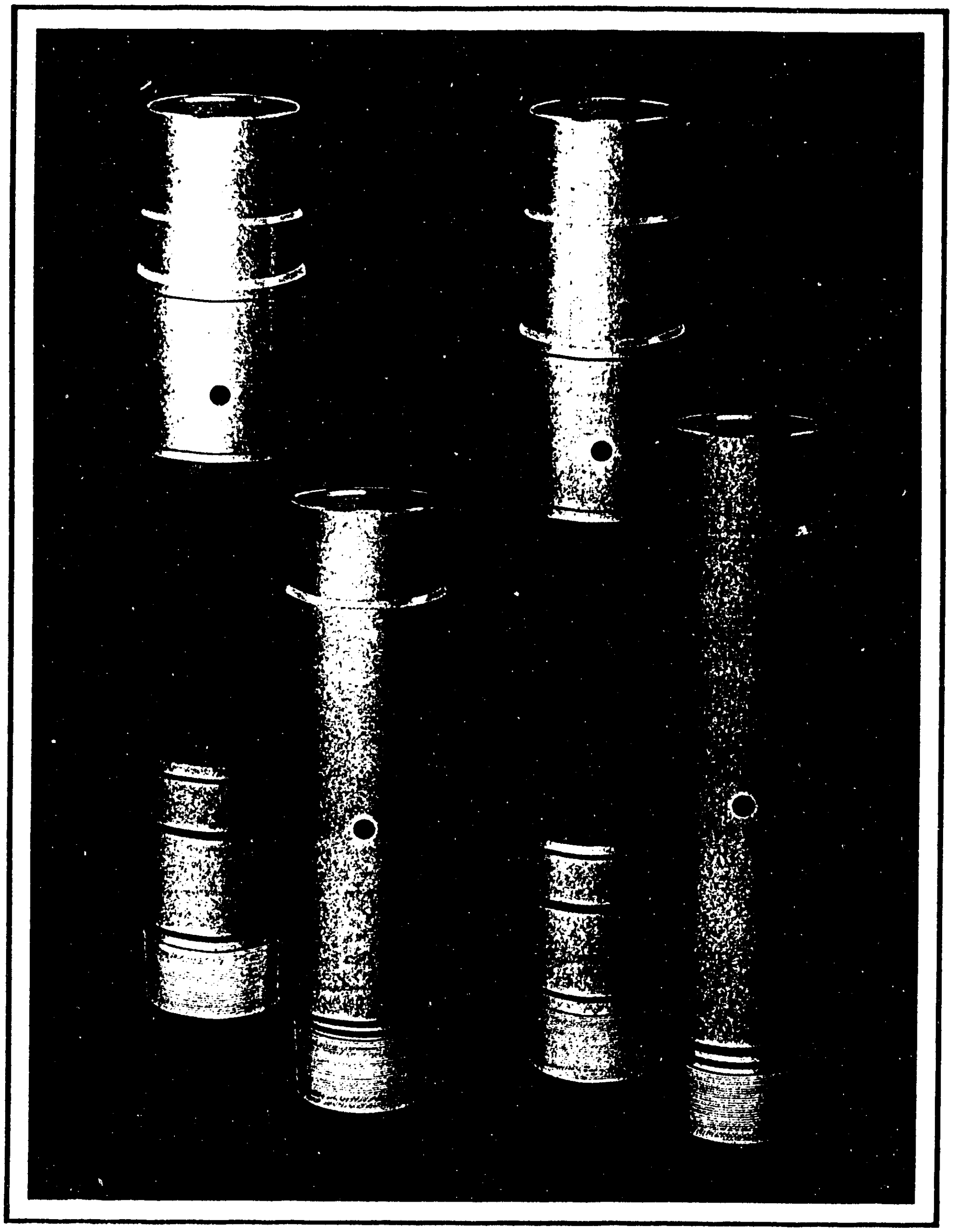


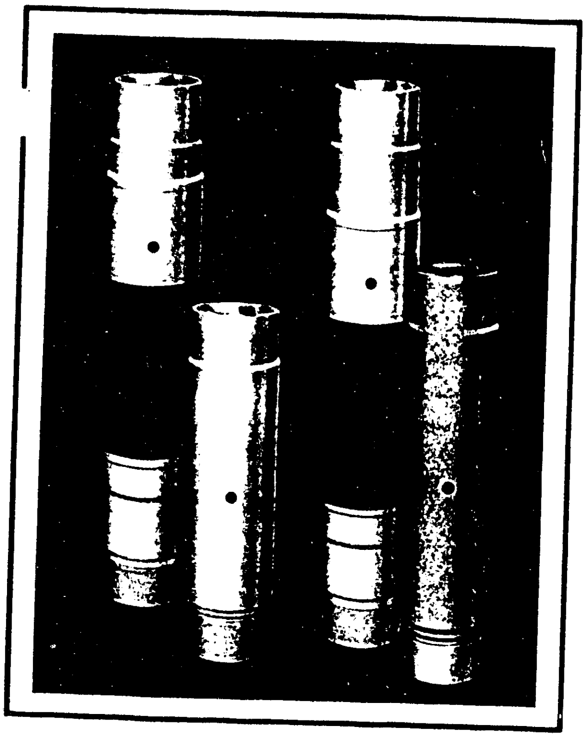
Step 4

For extra protection of the inflated element from any subsequent changes in casing pressure, a reduction in casing pressure permanently closes the locking shut-off valve.

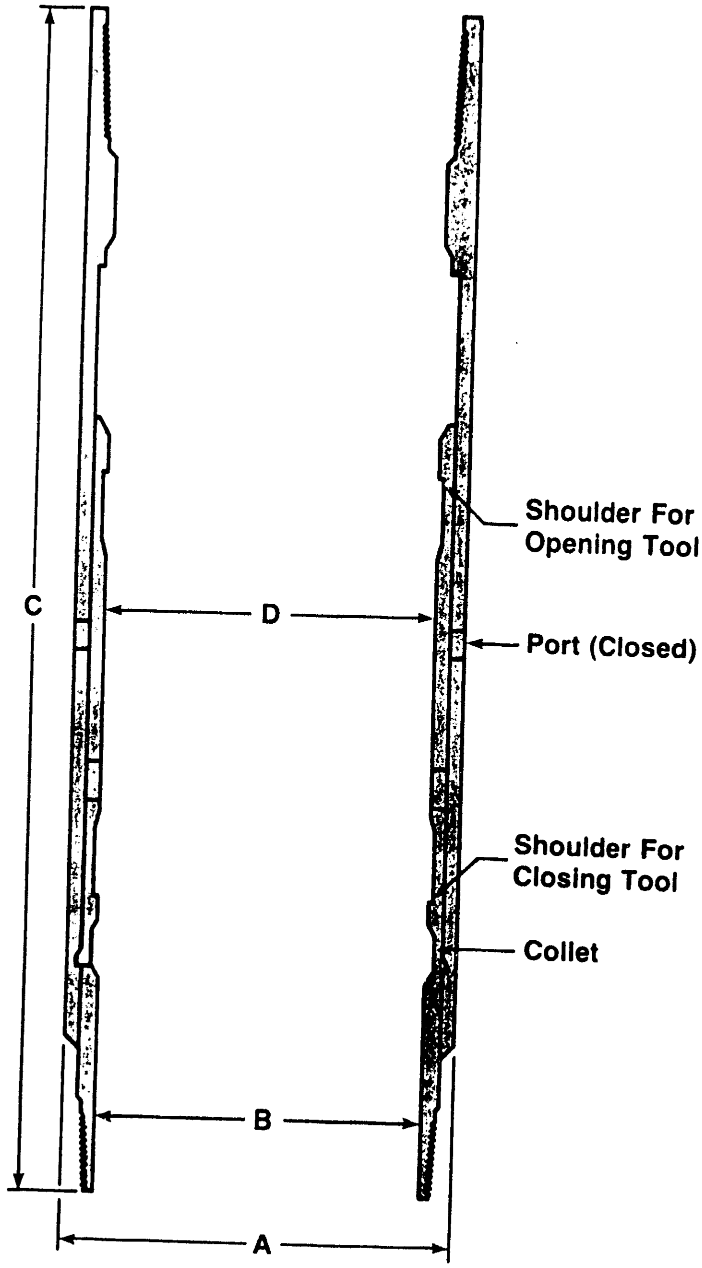
PORT COLLAR INFORMATION

Essential tools for better multiple stage cement jobs





FO Multiple Stage Cementer



One or more FO Multiple Stage Cementers in the casing string present several advantages not possible with plug operated stage cementing collars. In addition to their use for full depth cementing, minimizing loss of cementing slurry to weak formations and reduction of channeling, some of the features and applications are:

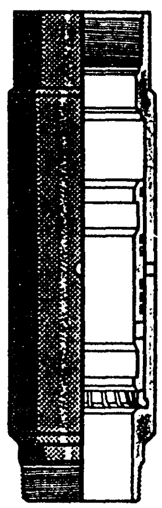
1. An FO Cementer has no plugs or seats to be drilled out.
2. Well may be cemented in any number of stages depending only on number of FO Cementers installed in casing.
3. Stage cementing or testing operations may be performed through any FO Cementer in any sequence at pre-selected depths for cement bonding.
4. FO Cementers may be reopened for testing, squeeze cementing or retesting of the primary cement job.
5. A formation opposite an FO Cementer may be tested, treated and evaluated for production purposes.
6. Eliminates need of perforating when used in production string opposite a zone which has not been cemented off.
7. In dual completions, one or more zones may be left uncemented between casing and tubing.
8. Full opening through FO Cementer permits swabbing and running full diameter tools easily to lower sections.
9. Casing strings may be cemented in stages using tubing or drill pipe as the slurry conductor string.
10. Permits economical stage cementing of mixed diameter casing strings.
11. Use in wells for selective water production or water injections.
12. FO Cementers located adjacent to uncemented loss circulation zones would allow mud disposal into that zone at completion of well.

The FO Multiple Stage Cementer consists of a high strength steel outer case with large diameter ports and a full bore, pressure balanced, sliding steel sleeve with ports, collet, and packer type seals above and below the ports between the sliding sleeve and outer case.

FO Multiple Stage Cementer

One or more FO Multiple Stage Cementers in the casing string present several advantages not possible with plug operated stage cementing collars. In addition to their use for full depth cementing, minimizing loss of cementing slurry to weak formations and reduction of channeling, some of the features and applications are:

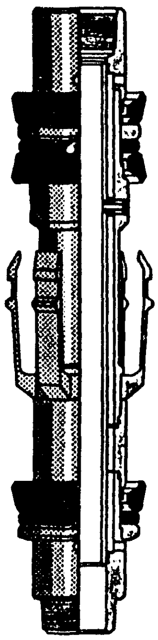
1. An FO Cementer has no plugs or seats to be drilled out.
2. Well may be cemented in any number of stages which allows more flexible cementing completions and may eliminate expensive squeeze jobs.
3. FO Cementers may be reopened for testing, squeeze cementing or retesting of the primary cement job.
4. A formation opposite an FO Cementer may be tested, treated and evaluated for production purposes.
5. Casing strings may be cemented in stages using tubing or drill pipe as the slurry conductor string.
6. Permits economical stage cementing of mixed diameter casing strings.
7. Use in wells for selective water production or water injections.
8. FO Cementers located adjacent to uncemented loss circulation zones would allow mud disposal into that zone at completion of well.
9. Eliminates the need for perforating casing and allows the ports to be opened and sealed closed as needed.
10. Allows inner string cementing without affecting stage tools for upper stage cementing.



FO Multiple Stage Cementer

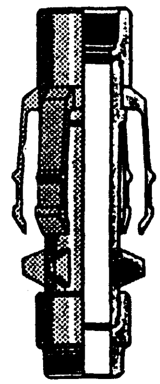
The FO Multiple Stage Cementer consists of a high strength steel outer case with large diameter ports and a full bore, pressure balanced, sliding steel sleeve with ports, collet, and packer type seals above and below the ports between the sliding sleeve and outer case.

One or more FO Cementers, locked in the initial closed position, are placed in the casing string at predetermined spacing and run to the preselected point in the well bore. Normally the first stage of cement is then placed down through the shoe joint and into the annulus behind the casing. A cementing plug follows the first stage cement and serves to hold pressure from above while cementing the upper stages. The first stage can also be cemented by the inner string cementing method. Drill pipe with sleeve positioners would then be in the casing to operate the FO Cementer for the upper stages.

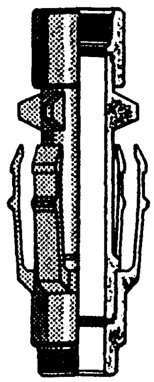


FO Cementer Isolation Packer

When the first stage is cemented conventionally, a drill pipe string with the Sleeve Positioners on bottom is run to a point below the lower FO Cementer. The Opening Sleeve Positioner is moved upward when desired and automatically



FO Cementer Opening Sleeve



FO Cementer Closing Sleeve

locates the nearest FO Cementer. When the FO Cementer is reached, the sleeve positioner fingers engage and lock into a groove in the sliding sleeve. An upward pull of approximately 20,000 lb force for 7" and larger sizes (10,000 lb for 4½" and 5½") will disengage the collet that has held the sleeve closed and move the sliding sleeve to expose the ports in the sleeve to the matching ports of the outer case. The Sleeve Positioner is disengaged from the FO Cementer automatically when the sleeve has moved to the fully open position.

Following the cementing operation through the FO Cementer, the Closing Sleeve Positioner, which is located approximately 10 feet below the Opening Sleeve Positioner, is lowered to automatically locate and engage the sliding sleeve. A weight of approximately 10,000 lb for 7" and larger sizes (5,000 lb for 4½" and 5½") is applied downward to the positioning tool. This moves the pressure balanced sleeve down, covers the outer ports, and locks the sliding sleeve closed. The ports will remain closed until an upward mechanical force of approximately 10,000 to 20,000 lb is again applied to the sleeve. The sleeve positioner will release from the sliding sleeve when the sleeve has moved fully closed. While in this position excess cement should be reversed out. Care should be taken not to allow the Opening Sleeve Positioner to move below the FO Cementer since the sleeve will be reopened when the tubing or drill pipe is picked up. The same cementing procedure is followed on each stage operation.

When a cementing operation is to be performed through the drill pipe an adequate bradenhead or other type pressure pack-off head must be used at the top between the drill pipe and casing, unless the Isolation Packer is run to pack-off across the FO Cementer. The Isolation Packer must be run when the fluid level behind a full casing string is below surface or when cementing a liner to direct flow of fluid into the casing annulus.

The ports between the opposing cups on the Isolation Packer are connected to the internal bore. This permits cement or other fluids to be pumped down drill pipe, out the Isolation Packer ports and through the opened FO Cementer. The Isolation Packer cups seal on both sides of the FO Cementer; thereby directing the flow of fluid through the cementer ports. A by-pass is provided to allow reverse circulation of excess cement and to allow by-pass of fluids on way in the hole.

FO MULTIPLE STAGE CEMENTER

Cat. Number	Size-OD (Inches)	Weight Range Lb/Wt	Max. OD (Inches)	Min. ID (Inches)	Opening Force Lb	Closing Force Lb
813.0141	4½ 8-Rd	9.5-13.5	5.593	3.985	10,000	5,000
813.0146	5 8-Rd	11.5-15.0	6.090	4.455	10,000	5,000
813.0151	5½ 8-Rd	14-17	6.665	4.935	10,000	5,000
813.0155	5½ 8-Rd	17-23	6.665	4.800	10,000	5,000
813.0161	7 8-Rd	20-23	8.290	6.351	20,000	10,000
813.0163	7 8-Rd	26-32	8.062	6.171	20,000	10,000
813.0177	9⅝ 8-Rd	43.5-53.5	11.040	8.619	20,000	10,000
813.0178	9⅝ 8-Rd	32.3-40.0	11.040	8.865	20,000	10,000
813.0181	10¾ 8-Rd	55.5-65.7	12.250	9.625	20,000	10,000
813.0187	13⅜ 8-Rd	61-72	15.000	12.359	20,000	10,000
813.0822	18⅝ Buttress	87.5	20.800	17.587	20,000	10,000
813.0842	20 Buttress	94	23.000	19.124	20,000	10,000

Casing Attachments

Roto Wall Cleaner

Primary casing cement jobs are more satisfactorily completed when Halliburton Roto Wall Cleaners are used to remove mud cake from the walls of the hole, thereby minimizing precautionary or remedial squeeze jobs.

It is often desirable to remove mud cake a few joints above the bottom of the hole before cementing surface, intermediate or production strings, especially in areas where formations are porous and unconsolidated. When plugging back, Roto Wall Cleaners are installed on tubing below the oil string and rotated in the same manner as any other casing job. A satisfactory water shut-off is usually obtained.

Roto Wall Cleaners help remove mud cake by rotation of casing. A Halliburton Casing Swivel is the only extra equipment required.

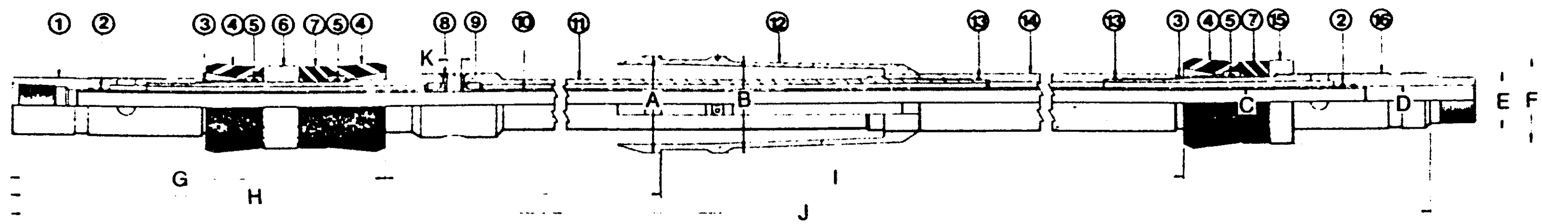
Roto Wall Cleaners (1) are economical to use . . . one cleaner base fits all OD sizes casing and tubing; (2) do not bridge off the annulus; (3) provide an open passageway for free flow of fluids while running casing, circulating, cementing, etc.; (4) minimum disturbance of mud cake while running casing to bottom reduces lost circulation problems; (5) minimize the hazards of "sticking casing" off casing point as casing is at desired point when cementing job begins; mud cake is then removed at the selected point by rotation of casing and (6) distribute the cement placed around the casing more evenly by rotating action of the cleaning spikes.

Special claw-type cleaning spikes are high tensile strength spring steel with the ends angled to give maximum action in the cutting and removal of filter cake during rotation. The special steel spikes will not break or bend beyond effective use under normal conditions where casing is centralized.

The coiled springs inside the cleaner base minimize damage to the spikes or filter cake while running casing. The spring design provides maximum force for cleaning when casing is rotated.

The mounting base for the regular and long cleaning spikes is closed on each end and the body has holes arranged to allow free circulation of fluid or cement through the body while rotating the casing.

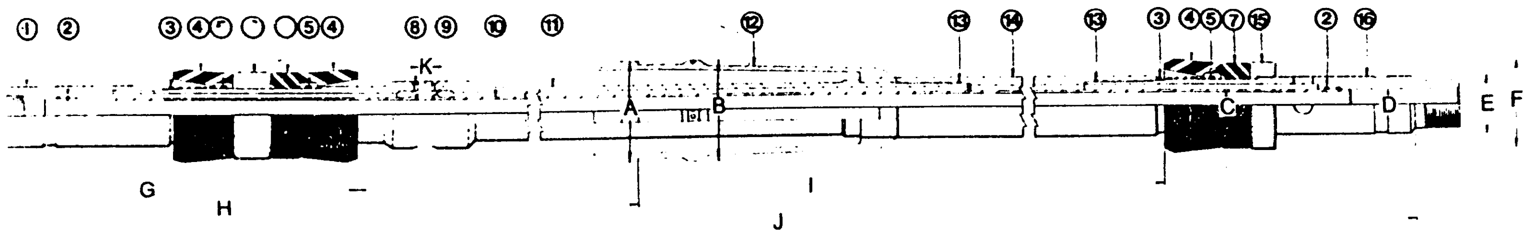
Slim Hole Roto Wall Cleaner spikes are made of high quality steel cable effectively mounted on a flat type base.



PARTS LIST

ITEM NUMBER	QUANTITY REQUIRED	DESCRIPTION	4½ in. ISOLATION PACKER PART NUMBER	
1	1	Upper Body	[illegible]	
2	4	O Ring	[illegible]	
3	2	Spacer	[illegible]	
4	3	Cup	[illegible] 9.5-11.6 lb/ft	[illegible] 13.5-15.1 lb/ft
5	3	O Ring	[illegible]	
6	1	Upper Shoe	[illegible]	
7	2	Packer	[illegible] 9.5-11.6 lb/ft	[illegible] 13.5-15.1 lb/ft
8	2	Nozzle	[illegible]	
9	2	O Ring	[illegible]	

ITEM NUMBER	QUANTITY REQUIRED	DESCRIPTION	4½ in. ISOLATION PACKER PART NUMBER	
10	1	Inner Mandrel	[illegible]	
11	1	Port Mandrel	[illegible]	
12	1	Spring Body	[illegible]	
13	2	O Ring	[illegible]	
14	1	Coupling	[illegible]	
15	1	Lower Shoe	698.70106 9.5-11.6 lb/ft	698.70145 13.5-15.1 lb/ft
16	1	Lower Body	[illegible]	
17	1	Cap Not Shown	[illegible]	



SPECIFICATIONS

PART NUMBER	TUBING OR DRILL PIPE SIZE OD in.	TUBING OR DRILL PIPE THREAD	CASING SIZE OD in.	CASING WEIGHT lb ft	A in. (mm)	B in. (mm)	C in. (mm)	D in. (mm)	E in. (mm)	F in. (mm)	G in. (mm)	H in. (mm)	I in. (mm)	J in. (mm)	K TWO PORTS in. (mm)
	2 3/8	8 Rd EUE	4 1/2	9.5-15.1	4.40 (111.76)	4.40 (111.76)	1.60 (40.64)	1.808 (45.92)	3.12 (79.25)	3.82 (97.03)	20.9 (530.86)	53.15 (1350.01)	61.73 (1567.94)	99.21 (2519.93)	.83 (21.08)
	2 3/8	8 Rd EUE	5	11.5-21	4.90 (124.46)	4.90 (124.46)	1.60 (40.64)	1.808 (45.92)	3.12 (79.25)	4.25 (107.95)	20.9 (530.86)	53.15 (1350.01)	61.73 (1567.94)	99.21 (2519.93)	.83 (21.08)
	2 3/8	8 Rd EUE	5 1/2	15.5-23	5.40 (137.16)	5.40 (137.16)	1.60 (40.64)	1.808 (45.92)	3.12 (79.25)	4.68 (118.87)	20.9 (530.86)	53.15 (1350.01)	61.73 (1567.94)	99.21 (2519.93)	.83 (21.08)

CTC - PAYZONE PACKER

THE PAYZONE™ PACKER

Completion Tool Company 7444 Getty Road Houston, Texas 77086 713·591·1900 Telex 775·781

Seven years of experience with hundreds of installations led to CTC's development of the Payzone™ Packer, industry's most reliable long inflatable packer. The original Pack/Perf™ packer was developed by CTC. However, the new tool has important innovations that allow it to run better, inflate with a high degree of success, and sense true downhole conditions for accurate control of the inflation pressure. These innovations, which are so unique they are nearly all patent protected, are indications of our commitment to quality. Positive proof of success is the high rate of trouble-free installations using the modern Payzone Packer. Key features and their advantages are noted on the illustration:

PAYZONE™ PACKER FEATURES

Top mounted inflation system to sense true annulus pressure for accurate valve control*

Redundant valves provide insurance against run-in damage

Pressure Balanced™ seals for accurate shear-valve opening*

Improved end assemblies for reliable rib expansion in larger holes*

Rough coating on mandrel prevents element slippage and packer sticking in tight-hole or deviated well conditions*

Abrasion resistant, ozone protected Nitrile rubber minimizes element wear, increases shelf life

Progressive Inflation™ for bottom-up filling to optimize mud removal, prevent pressure-locking*

One-piece mandrel to 40-foot lengths eliminates undesirable casing weld

Cement-filled packer may be perforated, allows optimum use directly across pay zones*

*Patents issued or pending.

Improved valve design

Reliable valve operation is critical to successful opening, and pressure control. The Payzone Packer contains two identical sets of valves. This redundancy assures access to a functional system, should one set be damaged during handling or run-in.

Valves are top-mounted on Payzone Packers to assure that true annulus hydrostatic pressure is sensed by the pressure limit valve. This patent-protected feature is illustrated later.

Another important development is CTC's Pressure Balanced™ system, to be described in detail. Without this protection, the primary control valve will not reliably, and predictably, open at designed pressure.

Inflation system—How it works

The schematic representation of the Payzone Packer's inflation system shows the fluid pathway from the casing interior to the packer element through ports and valve pockets contained within the metal wall of the assembly. The system is shown in the inflate mode, with cement slurry being pumped into the packer.

Run-in protection

During run-in, the fluid path shown would be isolated from casing pressure by knock-off plugs (typically two). This allows pipe to be run, and washed through bridges or fill, with confidence. After pipe is landed and conventional cementing is begun, the first wiper plug to pass the packer removes the knock-off plugs. The pathway is then exposed to cement but remains isolated by the shear-pinned primary control valve.

Inflation

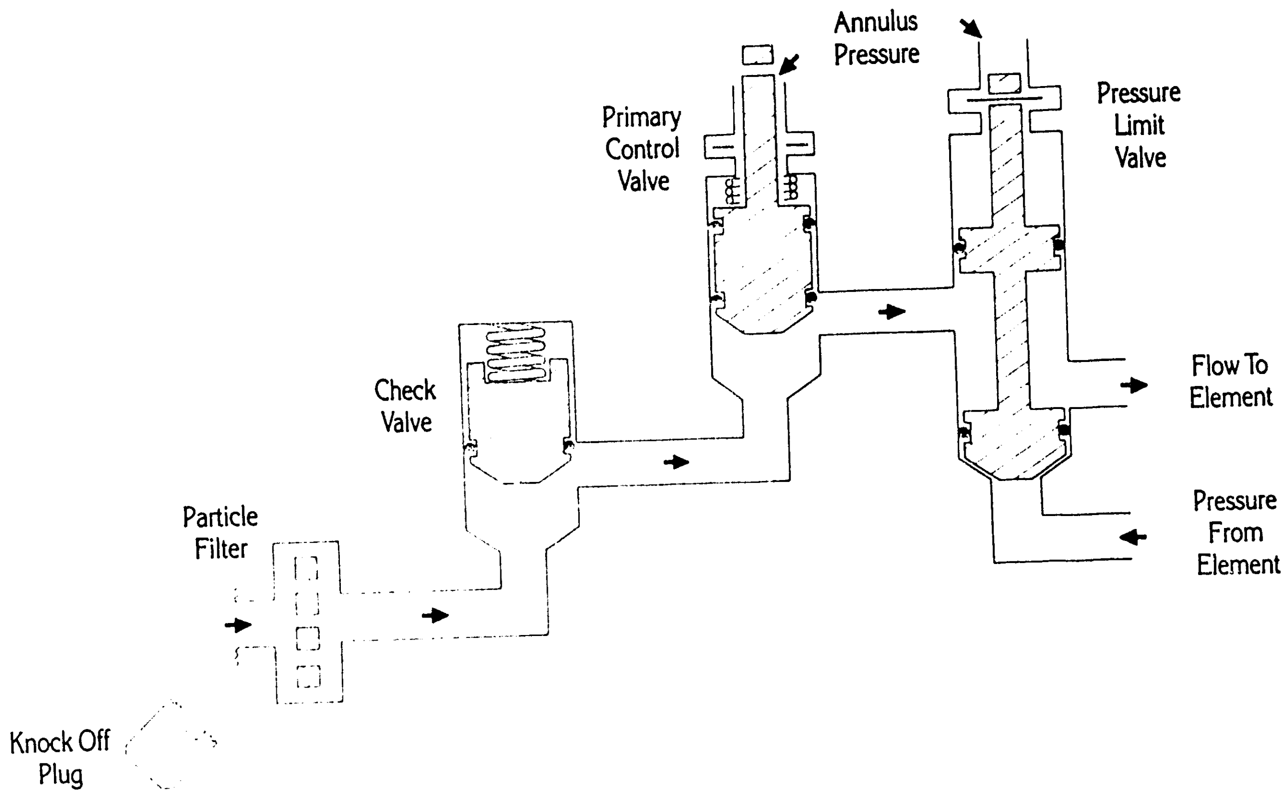
To open the pathway for inflation, casing pressure is increased from surface after the first top (solid) wiper plug contacts the landing collar, indicating primary cement displacement is complete. This increasing pressure acts through the particle filter and check valve, on the primary control valve, which is held closed by a shear pin of a predetermined strength. Note: 600-2,700 psi (42.2-189.8 kg/sq.cm.) pins are available; valves are shop-tested to assure friction-free operation.

When differential pressure (casing to annulus) exceeds shear pin rating, the primary control valve opens and cement flows through the pressure limit valve to the interior of the rubber element as shown in the illustration. Larger particles are removed from the stream by the filtering device.

Automatic pressure control

As inflation proceeds, the rubber element fills and differential pressure between element and annulus hydrostatic is created. This element pressure acts on the end of the pressure limit valve, in opposition to annulus pressure. The valve is held open by a second shear pin designed to shear at a selected differential pressure that the packer will safely withstand. When that differential is reached, the pressure limit valve closes to seal the flow path and permanently isolate the element.

For added integrity, the spring loaded check valve closes when flow stops. Also, the entire flow path is packed with cement, which assures a permanent seal when set.



INFLATION SYSTEM SCHEMATIC

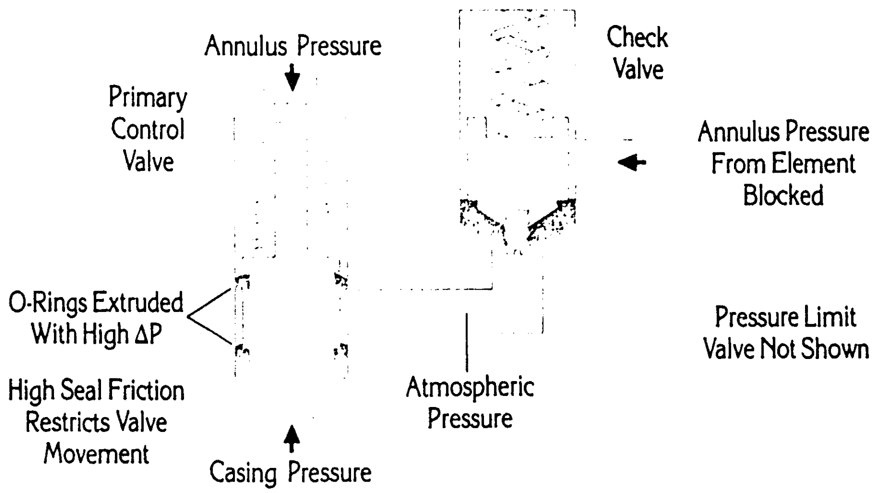
Pressure Balanced™ seals

The problem

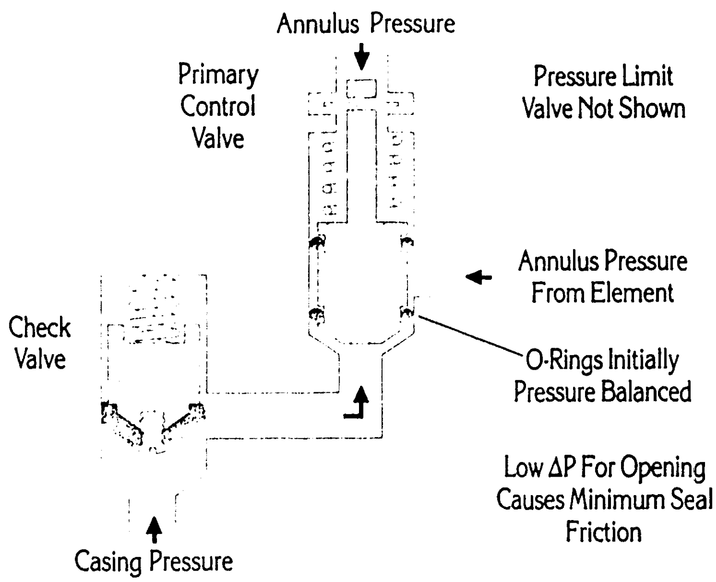
Valving designed like the upper schematic is common in conventional inflatable packers. This design can adversely affect valve performance in the critical operation of shearing open the primary control valve. Note that O-rings in this configuration are installed at atmospheric pressure, then subjected to total bottomhole pressure of the well as casing is run. The high differential pressure extrudes the elastomer seals, thus creating friction that prevents free valve movement. Experience indicates that this problem can increase designed shear-open pressure, in an unpredictable manner, by hundreds to thousands of psi. Note: Pressure limit valves are not shown in illustrations.

The solution

In the patented Pressure Balanced™ seal system in the Payzone Packer designed and manufactured by Completion Tool Company, O-rings are exposed to high bottomhole pressure on all sides, and the elastomer is compressed uniformly to offer minimum friction. When casing pressure is increased relative to annulus pressure to open the primary control valve, maximum differential is essentially equal to the shear pin rating. With this system, and rigorous quality control, Payzone Packer valves perform reliably even in deep, high pressure wells.



CONVENTIONAL VALVE SYSTEM



PRESSURE-BALANCED™ VALVE SYSTEM

The advantage of top-mounted valves

Payzone Packers are run with the inflation system in the top of the tool (a patented feature). To open at designed pressure and to prevent over-inflation, primary control and pressure limit valves must sense true hydrostatic pressure in the annulus. Note in the illustration that there is no restriction in the annulus above valves in the top of either packer.

With bottom-mounted valves, as featured in conventional inflatable packers, the annulus is bridged-off when the packer seals against the formation, and the entrapped pressure below the packer may be abnormally high, with a short open hole section exposed, thus increasing internal pressure required for pressure limit valve closure. The packer may be over-inflated and fail. Or, with high permeability or long open hole below the packer, isolated annulus pressure may drop below true hydrostatic, causing premature valve closing.

With multiple packers that are inflated sequentially, top mounted valves allow the upper packer to be safely inflated without sensing abnormally high annulus pressure entrapped between the packers.

MULTIPLE PACKERS

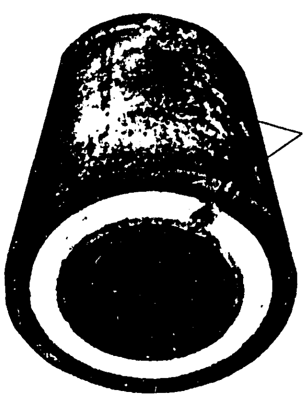
Perforating the Payzone Packer

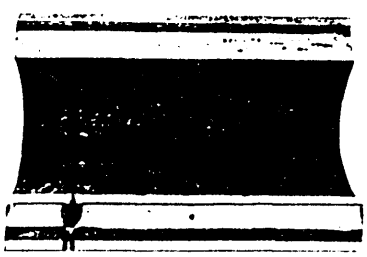
Completion Tool Company holds patents allowing an inflatable packer to be 1) set across a formation 2) filled with cement and 3) perforated. Thus, the Payzone Packer can be used in any downhole application—directly across the producing (or injection) zone, or at any other location where its unique benefits apply.

Perforating through the Payzone Packer, after excess inflation cement is drilled out of the casing, may be done by conventional means. After perforating, the set cement retains the benefits of the Payzone Preparation service. And the resulting system is compatible with all types of subsequent completion methods, including natural, stimulation or sand control operations.

Effective seal

The two photographs show results of a 7-inch CTC packer inflated with cement in 9⅝ inch casing. After cement cured, packer and casing were perforated with a conventional jet gun. One perforation in the casing was tapped and 1,500 psi liquid pressure was applied, with no communication to the next perforation, 6-inches away. The test packer then was cross sectioned in two planes to produce the models illustrated.





PERFORATION TEST MODEL

Progressive Inflation™ System

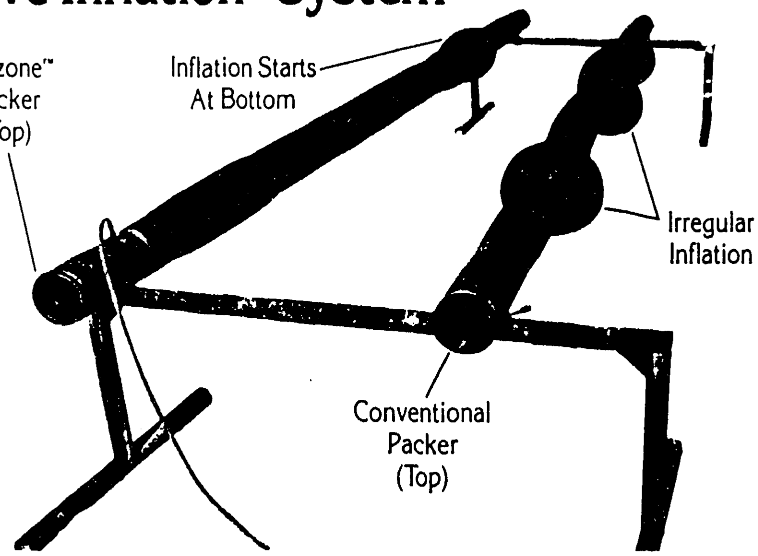
The problem

The photograph of a conventional packer that is partially inflated shows that the element has variable tensile properties along its length and that it may inflate first at nearly any point. Such random behavior downhole may entrap fluid in the borehole and cause partial fill-up. The packer would not engage the borehole along its entire length. Without complete fill-up and proper formation contact, surface control of calculated volume and pressure is lost, and full benefit of the installation may not be achieved.

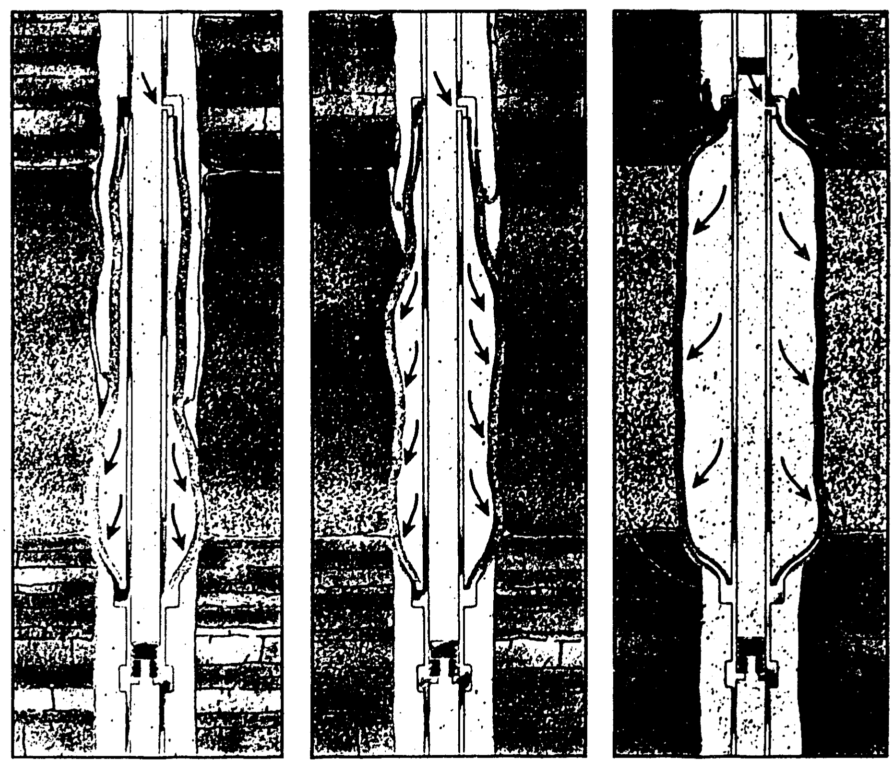
The solution

Modern Payzone Packers are designed to inflate from the bottom up, as illustrated here. The top mounted inflation system is opened, and cement slurry flows downward between the element and the mandrel. As pressure is increased within the packer, special rubber properties controlled by a patent pending process force the element to expand first at the bottom, then progressively upward. When the element contacts the wellbore at all points, additional pressure activates overlapping reinforcing ribs at each end, forcing them outward against the borehole.

Progressive filling expands the flexible, unreinforced part of the element into washouts and hole irregularities to efficiently displace any remaining mud channels within the primary cement job.



PROGRESSIVE INFLATION™ TEST



Inflation Starting — Progressive Fill-Up — Applying Pressure

PROGRESSIVE INFLATION™

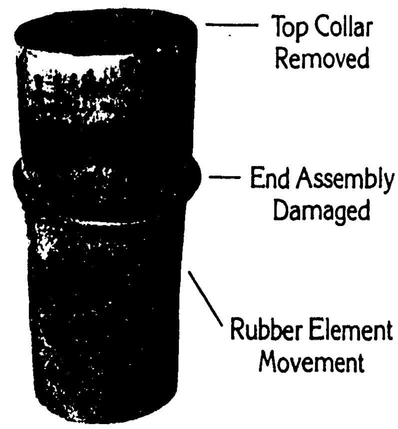
CTC PAYZONE SERVICES

Form No. 7402 5M 7/84 WP
Printed in USA

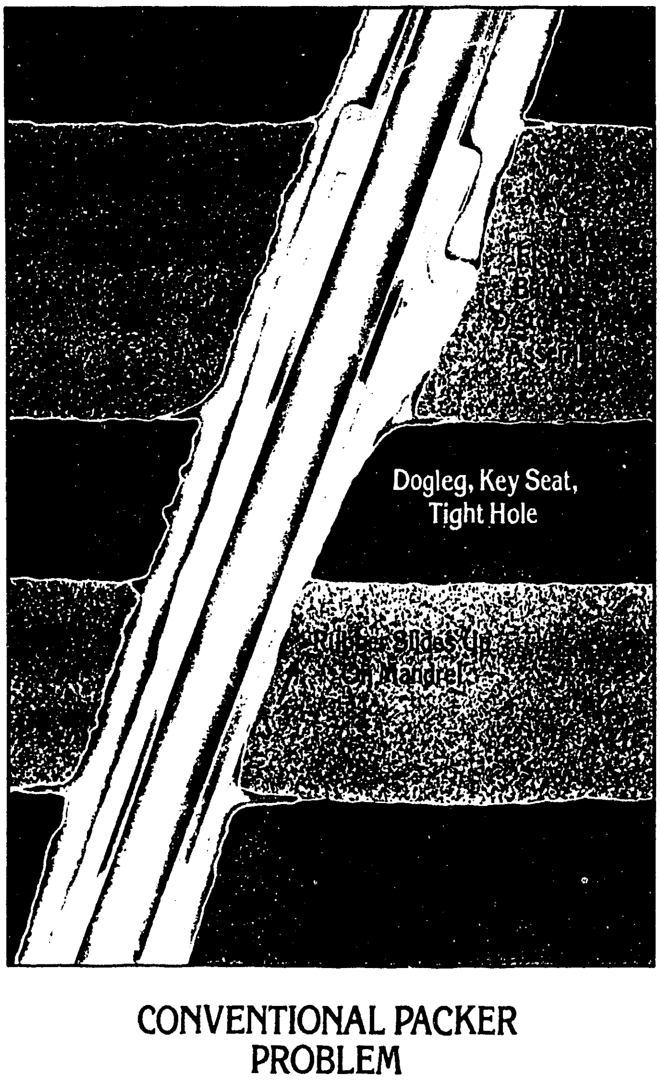
Run-in protection

The Payzone Packer has a rough coating on the mandrel to prevent run-in failures such as that illustrated in drawing (left). In early tools, the rubber element could slide upward on the mandrel while running through tight holes, doglegs, etc., occasionally preventing pipe entry. Several packers that were recovered showed that the upper end assembly was damaged (see photo).

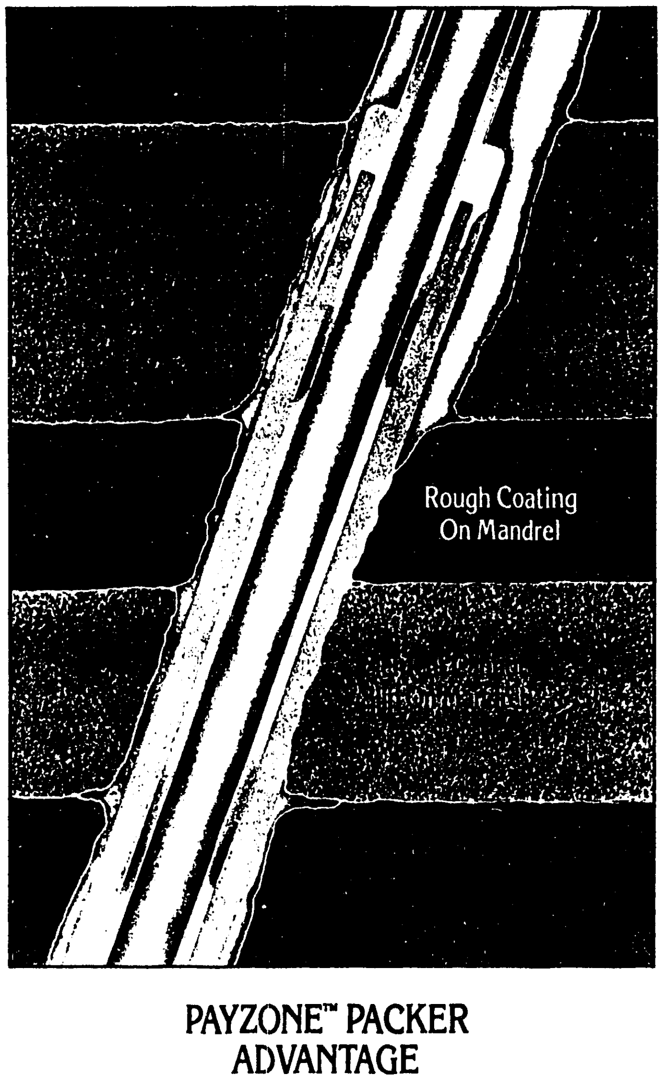
In a patented process, one piece, non-welded mandrels of the Payzone Packer are sand blasted and coated with a special epoxy. Coarse flint particles are embedded into the epoxy base and, after curing, the Nitrile rubber element is wrapped tightly onto the mandrel. The flint particles are, in turn, embedded into the element. The high friction effect securely grips the element to prevent slippage in response to external drag forces. With this protection, 40-foot long Payzone Packers have been successfully run in difficult downhole conditions.



RUN-IN DAMAGE WITHOUT ROUGH COATING

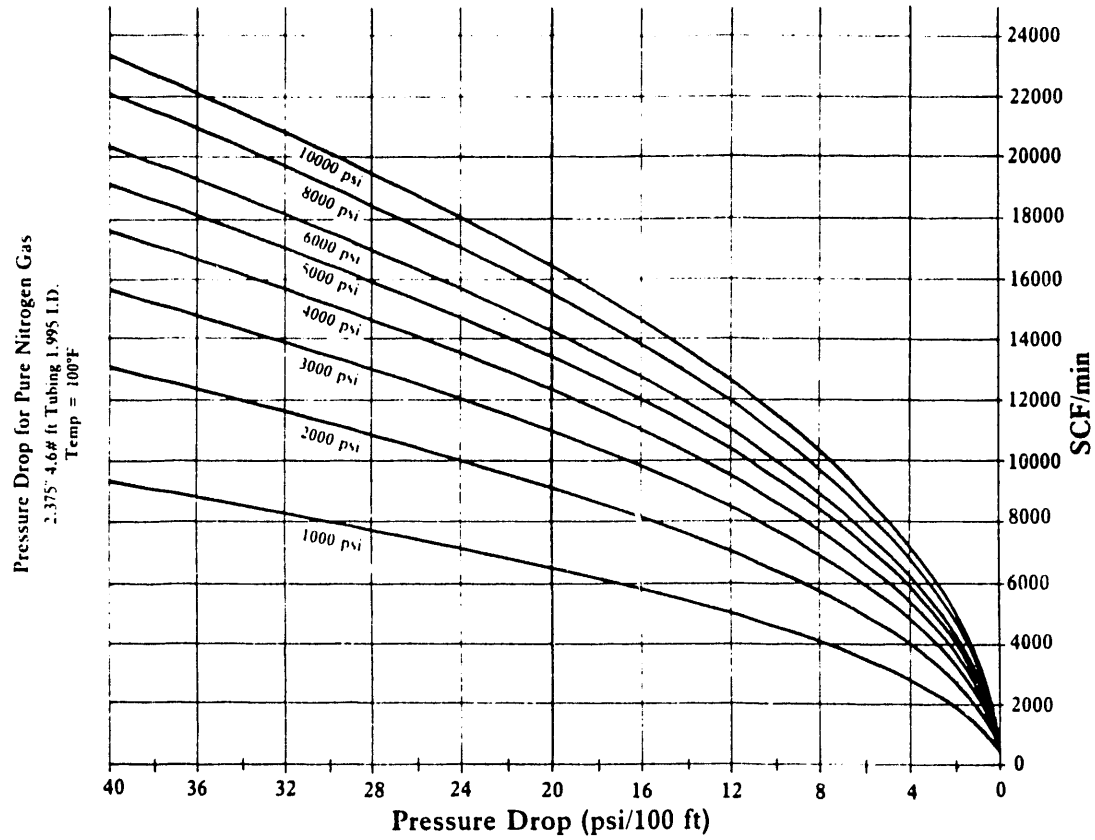


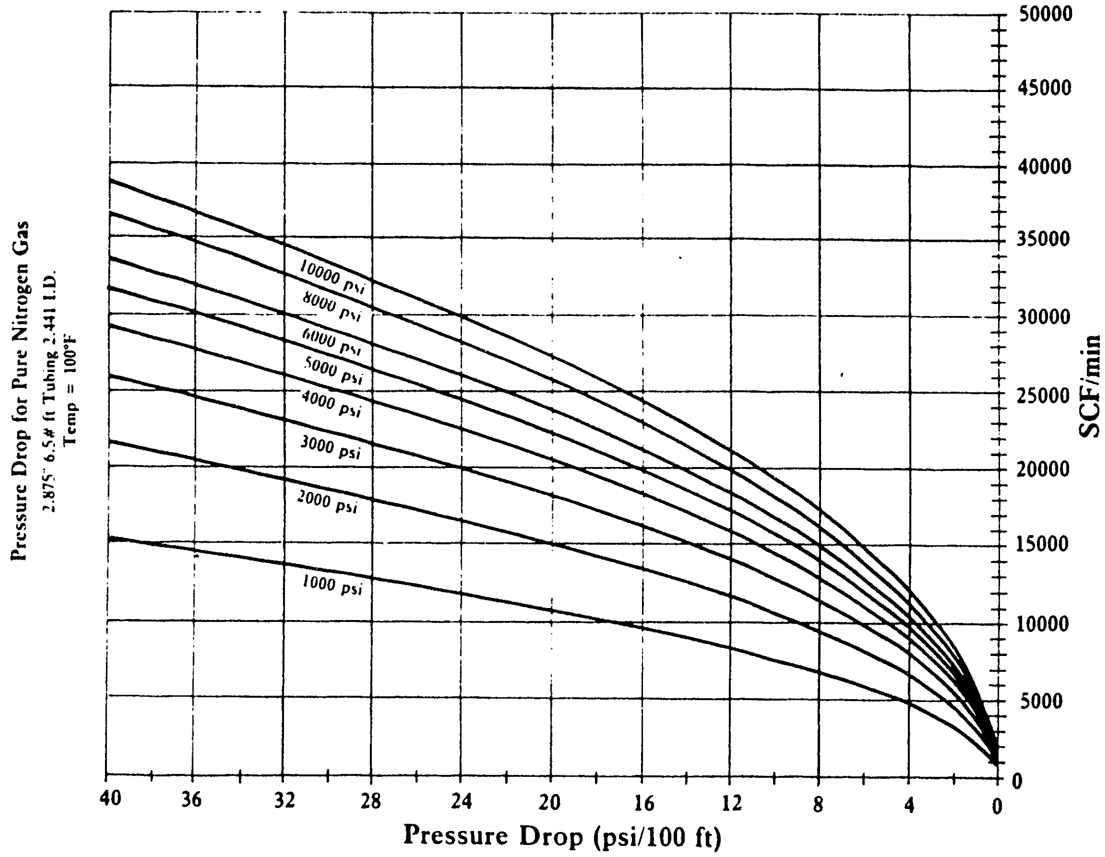
CONVENTIONAL PACKER PROBLEM



PAYZONE™ PACKER ADVANTAGE

NITROGEN DATA


Pressure Drop for Pure Nitrogen Gas
2.375" 4.6# ft Tubing 1.995 I.D.
Temp = 100°F
10000 psi
8000 psi
6000 psi
5000 psi
4000 psi
3000 psi
2000 psi
1000 psi
24000
22000
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
SCF/min
40
36
32
28
24
20
16
12
8
4
0
Pressure Drop (psi/100 ft)


Pressure Drop for Pure Nitrogen Gas
2.875" 6.5# ft Tubing 2.441 I.D.
Temp = 100°F
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8000 psi
6000 psi
5000 psi
4000 psi
3000 psi
2000 psi
1000 psi
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
SCF/min
40
36
32
28
24
20
16
12
8
4
0
Pressure Drop (psi/100 ft)

II

PRESSURE-TEMPERATURE VOLUME TABLES FOR NITROGEN GAS*

V'/V IN SCF/BBL

PSIG

P	60°F	80°F	100°F	120°F	140°F	160°F	180°F	200°F	220°F
100	45	43	41	40	39	37	36	35	34
200	84	80	78	75	72	70	68	66	64
300	122	118	114	110	106	103	99	96	94
400	161	155	150	145	140	135	131	127	123
500	200	193	186	180	174	168	163	158	153
600	239	230	222	214	207	201	194	188	183
700	278	268	258	249	241	233	226	219	213
800	317	305	294	284	275	266	258	250	242
900	356	343	330	319	308	298	289	276	267
1000	395	380	367	354	342	326	315	305	295
1100	434	418	403	389	371	358	345	334	324
1200	473	455	439	424	403	389	375	363	352
1300	511	493	475	452	435	420	405	392	379
1400	550	530	506	485	467	450	435	420	407
1500	589	567	540	518	499	481	464	449	434
1600	628	599	574	551	530	511	493	477	461
1700	667	635	608	583	561	541	522	504	488
1800	706	670	641	615	592	570	550	532	515
1900	738	705	674	647	622	599	578	559	541
2000	774	739	707	678	652	628	606	586	567
2100	810	773	739	709	682	657	634	612	593
2200	845	806	771	740	711	685	661	639	618
2300	879	839	802	770	740	713	687	668	647
2400	913	871	833	799	773	744	718	695	672
2500	946	903	868	833	801	772	745	721	698
2600	979	939	899	863	830	800	772	746	723
2700	1016	971	929	892	858	827	798	772	747
2800	1049	1002	959	921	886	854	824	797	772
2900	1081	1033	989	949	913	880	850	822	796
3000	1113	1063	1018	978	941	907	875	846	820
3100	1144	1093	1047	1005	967	933	900	871	843
3200	1174	1122	1075	1033	994	958	925	895	867
3300	1204	1151	1103	1060	1020	983	950	919	890
3400	1234	1180	1131	1086	1046	1008	974	942	913
3500	1263	1208	1158	1112	1071	1033	998	965	935
3600	1291	1235	1184	1138	1096	1057	1022	988	958
3700	1319	1262	1211	1164	1121	1081	1045	1011	980
3800	1346	1288	1236	1189	1145	1105	1068	1033	1001
3900	1373	1314	1262	1213	1169	1128	1090	1055	1023
4000	1399	1340	1286	1237	1192	1151	1113	1077	1044
4100	1424	1365	1311	1261	1216	1174	1135	1099	1065
4200	1455	1395	1339	1284	1238	1196	1156	1120	1086
4300	1481	1420	1364	1312	1265	1218	1178	1141	1106
4400	1506	1444	1388	1336	1288	1244	1203	1161	1126
4500	1532	1469	1411	1359	1310	1266	1224	1186	1150

Continued

*National Bureau of Standards Technical Note 648 (Dec. 1973)

VI

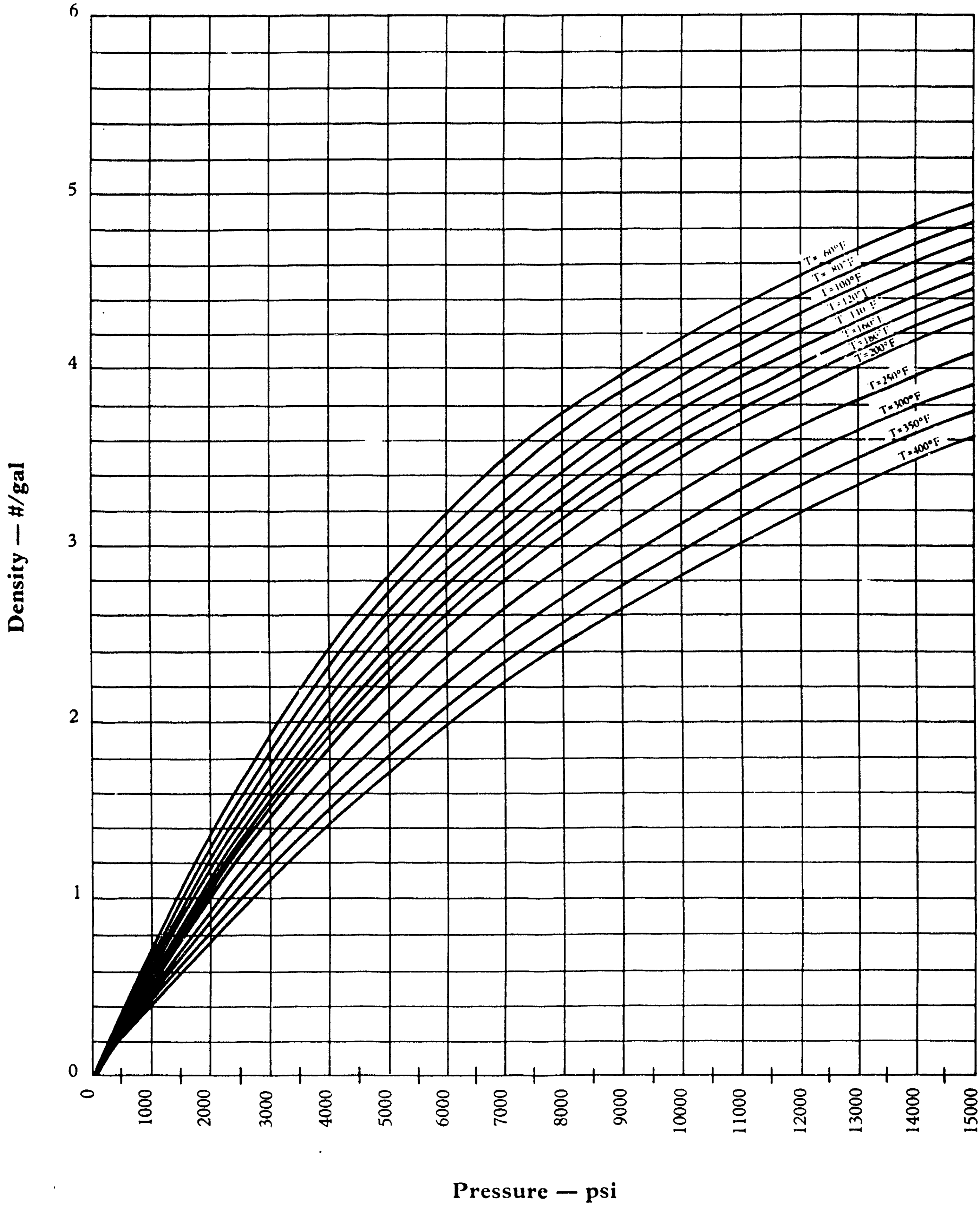
WELL HEAD PRESSURE (WHP) AND VOLUME FACTOR (V'/V) VS BOTTOM HOLE PRESSURE AND DEPTH

GEOTHERMAL GRADIENT = 1.1 DEG. F/100 FT

DEPTH (FEET)		BOTTOM HOLE PRESSURE (PSIA) 500.	1000.	1500.	2000.	2500.	3000.	3500.	4000.	4500.	5000.	
500.	WHP	492.	983.	1475.	1967.	2460.	2953.	3446.	3940.	4435.	4929.	(PSIA)
	V'/V	188.	375.	559.	736.	903.	1060.	1205.	1339.	1462.	1576.	(SCF/BBL)
1000.	WHP	483.	967.	1451.	1935.	2420.	2906.	3393.	3881.	4370.	4860.	(PSIA)
	V'/V	185.	370.	551.	726.	891.	1046.	1190.	1324.	1447.	1560.	(SCF/BBL)
1500.	WHP	475.	951.	1427.	1904.	2382.	2861.	3342.	3824.	4308.	4793.	(PSIA)
	V'/V	183.	365.	544.	716.	880.	1033.	1176.	1309.	1431.	1544.	(SCF/BBL)
2000.	WHP	468.	936.	1404.	1873.	2345.	2817.	3292.	3768.	4246.	4726.	(PSIA)
	V'/V	180.	360.	536.	706.	868.	1020.	1162.	1294.	1416.	1528.	(SCF/BBL)
2500.	WHP	460.	920.	1382.	1844.	2308.	2774.	3243.	3714.	4186.	4661.	(PSIA)
	V'/V	178.	355.	529.	697.	857.	1008.	1149.	1280.	1401.	1513.	(SCF/BBL)
3000.	WHP	453.	906.	1360.	1815.	2273.	2733.	3195.	3660.	4128.	4598.	(PSIA)
	V'/V	176.	351.	522.	688.	846.	996.	1135.	1265.	1386.	1498.	(SCF/BBL)
3500.	WHP	446.	892.	1338.	1787.	2238.	2692.	3148.	3608.	4070.	4535.	(PSIA)
	V'/V	173.	346.	515.	679.	836.	984.	1122.	1252.	1372.	1483.	(SCF/BBL)
4000.	WHP	439.	878.	1318.	1760.	2204.	2652.	3103.	3557.	4014.	4474.	(PSIA)
	V'/V	171.	341.	509.	671.	825.	972.	1109.	1238.	1358.	1469.	(SCF/BBL)
4500.	WHP	432.	864.	1298.	1733.	2171.	2613.	3058.	3507.	3959.	4414.	(PSIA)
	V'/V	169.	337.	502.	662.	815.	960.	1097.	1225.	1344.	1454.	(SCF/BBL)
5000.	WHP	425.	851.	1278.	1707.	2139.	2575.	3014.	3458.	3905.	4355.	(PSIA)
	V'/V	167.	333.	496.	654.	805.	949.	1085.	1211.	1330.	1440.	(SCF/BBL)
5500.	WHP	419.	838.	1259.	1682.	2108.	2538.	2972.	3410.	3852.	4297.	(PSIA)
	V'/V	165.	329.	490.	646.	796.	938.	1073.	1199.	1316.	1426.	(SCF/BBL)
6000.	WHP	413.	826.	1240.	1657.	2077.	2502.	2930.	3363.	3800.	4241.	(PSIA)
	V'/V	163.	325.	484.	638.	786.	928.	1061.	1186.	1303.	1413.	(SCF/BBL)
6500.	WHP	406.	813.	1222.	1633.	2048.	2466.	2889.	3317.	3749.	4186.	(PSIA)
	V'/V	161.	321.	478.	631.	777.	917.	1049.	1174.	1290.	1399.	(SCF/BBL)
7000.	WHP	400.	801.	1204.	1609.	2018.	2432.	2849.	3272.	3699.	4131.	(PSIA)
	V'/V	159.	317.	472.	623.	768.	907.	1038.	1161.	1277.	1386.	(SCF/BBL)
7500.	WHP	395.	790.	1187.	1586.	1990.	2398.	2810.	3228.	3650.	4078.	(PSIA)
	V'/V	157.	313.	466.	616.	759.	897.	1027.	1150.	1265.	1373.	(SCF/BBL)
8000.	WHP	389.	778.	1170.	1564.	1962.	2365.	2772.	3185.	3603.	4026.	(PSIA)
	V'/V	155.	309.	461.	609.	751.	887.	1016.	1138.	1253.	1360.	(SCF/BBL)
8500.	WHP	383.	767.	1153.	1542.	1935.	2332.	2735.	3143.	3556.	3974.	(PSIA)
	V'/V	153.	306.	456.	602.	742.	877.	1005.	1126.	1240.	1348.	(SCF/BBL)
9000.	WHP	378.	755.	1137.	1521.	1908.	2301.	2698.	3101.	3510.	3924.	(PSIA)
	V'/V	152.	302.	450.	595.	734.	868.	995.	1115.	1228.	1335.	(SCF/BBL)
9500.	WHP	372.	746.	1121.	1500.	1882.	2270.	2663.	3061.	3465.	3875.	(PSIA)
	V'/V	150.	299.	445.	588.	726.	858.	984.	1104.	1217.	1323.	(SCF/BBL)
10000.	WHP	367.	735.	1106.	1479.	1857.	2240.	2628.	3021.	3421.	3826.	(PSIA)
	V'/V	148.	295.	440.	582.	718.	849.	974.	1093.	1205.	1311.	(SCF/BBL)

IV

Nitrogen Density vs. Pressure



VI

END

DATE FILMED

3/24/92