A STIMULATION TECHNIQUE USING ONLY NITROGEN

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ABSTRACT

Nitrogen alone has demonstrated success as a fracturing fluid in reservoirs normally found sensitive to liquid systems. It has proven useful in shales of the Ohio Valley and West Virginia areas, and in similar lithology of the Fort Worth Basin located in North Central Texas. The fracturing efficiency of nitrogen, as related to leakoff and flow capacity testing with no propping agent, has been investigated to analyze the effectiveness of nitrogen stimulation. Also, field data are presented which demonstrate successful results of the nitrogen technique in both oil and gas reservoirs. From the laboratory studies and field results, several conclusions were drawn concerning nitrogen stimulation. Of primary interest is that most of the width reduction in an unpropped fracture will occur in the early stage of production which indicates a sharp decline of the well flow rate after a relatively short period.

INTRODUCTION

Nitrogen has for many years been applied in the stimulation process to enhance the recovery of oil and gas.[1] The properties of nitrogen, including its relative inertness, low solubility, compressibility as well as other advantages, are well documented.[1,2] Although gaseous nitrogen was initially introduced in the oil field to assist in drilling operations, it was eventually employed to complement and energize liquid or gelled treating fluids.

In recent years, nitrogen has increasingly been used as a major part of foam fracturing systems. These foams can be prepared with a variety of base liquids and typically contain 60 percent to 90 percent nitrogen. Foam treatments are particularly beneficial in low pressure gas wells and in water-sensitive reservoirs such as the shale formations described in this paper.[3-7] Indeed, it appears that foam is one of the most suitable fluids for the stimulation of such formations.

However, in certain lithological areas of the Devonian Shale Formation, namely Washington County, Ohio, virtually little success with foam has been encountered. Thus, the use of nitrogen alone has been pursued as a less damaging method of treatment. This stimulation technique, applied to over 300 wells for nearly two years, has been found to have considerable merit. Discussed in this paper are treatment design, case histories, and laboratory evidence which corroborates present success and encourages further interest in the sole use of nitrogen as a stimulation technique in these formations.

STIMULATION HISTORY

Formations having a high shale content and natural fractures, such as those found in the Ohio Valley and the Fort Worth Basin, have been difficult to stimulate. These formations are characterized by low flowing pressures and low permeability. The presence of these natural fractures is crucial to the economics of the well because they provide the needed drainage system for production. Forthermore, these formations are water sensitive and have a tendency of cleaning up slowly following a stimulation treatment. For the ideal movement of fluids, such as is necessary for well productivity, the primary concern is to have a continuously fractured reservoir.

Shale specimens also absorb moisture and upon drying become very brittle and unstable. This, too, is a determining factor in selecting a fracturing fluid. Aqueous-base foams, a primary candidate, are composed of water containing a foaming agent and of nitrogen that forms a homogeneous gas in water emulsion when mixed at predetermined rates. Foam properties seem to be ideal for shale formations.[8] The Berea Formation, which lies above the Ohio Shale Formation, has been stimulated very successfully using foam. However, results of foam treatments in the Ohio Shale Formation were less than encouraging. Estimates of potential gas in these shale basins indicate that the production of recoverable gas could be increased by using a more efficient stimulation techique.[9]

In August 1979, an unconventional fluid was used to treat the first well ever produced from the Bayard Zone in the Ohio Shale Formation.[7] This was the No. 1 Edgar Unit well in Newport Township, Washington County, Ohio, described below as Well No. 1. Following a cleanup acid treatment, gaseous nitrogen was pumped at a very high rate and at sufficient pressure to fracture the formation. Results using this technique have been very encouraging on both oil and gas wells in the Ohio Shale Formation.

JOB DESIGN

Nitrogen fracturing design should be given the same careful consideration as more conventional treatments. In addition, special attention should also be given to the inherent differences of nitrogen fracturing designs. For instance, treatment rates and volumes should be calculated using a modified version of the real gas law. This will allow the downhole volume of the nitrogen and equivalent flow rate to be determined. The volume, viscosity, density and rate of the gas can then be used in conjunction with well data to determine leak-off coefficients, fluid efficiencies and fracture geometry. A representative job design is listed in Table 1.

CASE HISTORIES

Five case histories of nitrogen treatments on such shale formations have been investigated for this study. Well and treatment data are presented below, and treatment summary is shown in Table 2.

Well No. 1

Located in Washington County, Ohio, this well was completed in the Bayard Zone of the Ohio Shale Formation. The perforated interval was from 2,436 feet to 2,480 feet. This was a new well and the first to be fractured using only nitrogen. In

August 1979, the well had been given a 500-gallon cleanup acid treatment using 15 percent hydrochloric (HCl) acid. Immediately following the cleanup acid treatment, the well was fractured with 370 Mscf of nitrogen. Twelve hours after the treatment, the well was producing nitrogen at normal levels of 2 percent to 3 percent. Initial production was 85 BOPD, and it has produced over 10,000 barrels of oil during the first 150 days of production.

Well No. 2

Located in Pleasants County, W. Va., this well was completed in the Ohio Shale Formation. The well was drilled to 3,471 feet and perforated from 3,414 feet to 3,424 feet. The well was producing 14.5 BOPD before the nitrogen frac treatment. In February 1981, the well was fractured using 720 Mscf of nitrogen at an average rate of 27,750 scf/min, or an equivalent rate of 44 bbl/min. Surface treating pressure was 2,340 psi. The original production obtained was 50 BOPD. Production stabilized after 11 weeks to 21 BOPD.

Well No. 3

Located in Washington County, Ohio, and completed in the Ohio Shale Formation, this well was drilled to a depth of 3,456 feet. The perforated interval was 3,442 feet to 3,452 feet. This was a new well which had been flow tested. The stabilized production for the test was 42.6 BOPD and 64 Mcf/D. In May 1980, the well was fractured using 354 Mscf of nitrogen at a rate of 27,300 scf/min (36 bbl/min equivalent) at a surface treating pressure of 2,450 psi. Initial production after the treatment was 116.4 BOPD and 77.01 Mcf/D. By December 1980, the well had produced 14,674 barrels of oil and 7.36 MMcf of gas. The production has since stabilized at 21 BOPD and 29 Mcf/D.

Well No. 4

Located in Jack County, Texas, this well was completed in the impregnated shale rock unit of the Boonsville Bend Conglomerate. The perforated interval was from 4,358 feet to 4,395 feet. The well was completed in May 1980. After swabbing runs showed a heavy emulsion, the well was originally acidized with 4,000 gallons of 15 percent HCl acid containing carbon dioxide (CO_2). A cleanout acid job was performed to break the emulsion, and then another swabbing run was made until a gas show occurred. The well was producing 20 Mcf/D for eight months.

The well was fractured February 1981 using 1.02 MMscf of nitrogen at an average rate of 10 Mscf/min (18 bbl/min equivalent) and at a surface treating pressure of 1,800 psi. Immediately following treatment, the well was making water, oil and what appeared to be drilling mud. One week later, the well was producing 125 Mcf/D and 4 B/D of oil and water. Currently, the production has stabilized to 50 Mcf/D and 1 B/D of oil and water.

Well No. 5

Located in Hood County, Texas, and completed in the Atoka Formation in December 1980, this well was perforated from 4,450 feet to 4,470 feet. This was a new well and had been acidized with 1,500 gallons of 15 percent HCl acid, and then swabbed dry. The well was fractured using 1 MMscf of nitrogen at a rate of 23 Mscf/min and at a surface treating pressure of 2,950 psi. One week after the treatment, the production rate was 220 Mcf/D, and currently production is 44 Mcf/D.

LABORATORY TESTS

Laboratory experiments were performed to investigate the fracture flow change due to the pressure and fracture surface condition, and the fluid loss rate at various pumping rates. Testing apparatus and procedures are described below.

Fracture Flow Capacity Testing

The presence of fractures, either natural or manmade, is crucial to the economics of the recovery methods used in many oil and gas fields. Thus, it is imperative to study the fluid movement in the fractured rock masses. In most low permeable, fractured rock masses, the conductivity of the fractures generally exceeds the intrinsic permeability of the rock by several orders of magnitude such that the intrinsic permeability may usually be neglected. Field experiences and laboratory studies indicate that only a small percentage of the fractures actually serve as fluid channels under pressure. This suggests that occasional, singular continuous fractures play the predominant role of fluid flow in fractured formations.

As part of the study on the mechanism of crack closure under pressure and the effects of fracture surface condition to the fluid flow, initial laboratory test results are reported in this paper. This information is included in an attempt to describe fluid flow in unpropped fractures.

Tests were conducted on limestone using naturally fractured core samples from a depth of 4,386 feet and 4,391 feet in Young County, Texas, and using naturally fractured outcrops in Stephens County, Texas. All samples had a single, vertical fracture parallel to the sample axis passing through the center of the sample cross-section. Another type of limestone from Somervell County, Texas, was tested. These Glen Rose Limestone Formation samples were first cored out of the rock block and hydraulically fractured in the laboratory to induce a vertical fracture.

The prepared samples were approximately 4 inches in diameter and 8 inches in length. Their ends were surface ground parallel to within 0.001 inches from end to end.

During the sample preparation, special care was exercised not to disturb the already fractured cores. The cores were carefully retrieved to the original shape and clamped laterally with tape and a C-clamp. After they were cut and ground, the finished samples were opened and washed with water. Several 0.003- or 0.005-inch thick spacers were placed between the two split pieces of the sample to create an initial opening of the fracture. Then the samples were placed back into the original shape and taped along the circumference. Before the test, the samples were saturated with demineralized water.

The test apparatus is shown schematically in Figure 1. Tests were conducted in a servo-controlled, closed-loop hydraulic loading system, equipped with a 10-inch bore pressure vessel. The confining pressure system was independently controlled and separated from the pore fluid system and the axial loading system.

A stainless steel end cap with a center hole and radial grooves (Figure 2) was affixed to both ends of the sample to allow even fluid flow through the entire end surfaces of the sample. A wire screen of 100-mesh stainless steel was placed at the bottom end surface of the sample between the sample and the grooved disc to catch any rock fragments during the flow test. This sample assembly was placed between two stainless steel pistons (Figure 3). Each piston had one vertical hole in the center for fluid entrance and exit. Then the sample assembly was jacketed with a rubber sleeve.

This jacketed, fractured sample was lowered inside the pressure vessel, and approximately 100 psi of hydrostatic pressure was applied to the sample. Then, demineralized water was introduced into the upstream side, through the sample and into the downstream side. Following this, the flow system was pressurized with a pressure intensifier to approximately half the total confining pressure. The upstream and downstream pressure lines were connected through both the sample and a bypass line with a shutoff valve. With the bypass valve closed, only flow through the sample can occur. A differential pressure transducer (DPT) capable of measuring $\pm$1,000 psi was also connected between the upstream and the downstream lines parallel to the sample.

With the bypass valve opened, the axial, confining and pore pressures were increased simultaneously to the first measurement point. Throughout this investigation, the total axial to confining pressure ratio was maintained at 10 to 7. The upstream pressure was maintained at 500 psi on all tests. After the desired stress values were attained, the bypass valve was closed and the valves at the downstream line were opened. By adjusting the micro-metering valve, the desired flow rate was achieved. The DPT monitored the pressure difference between the upstream and downstream pressures while the fluid was flowing. When no significant pressure change in the DPT occurred after adjustment of the micro-metering valve, a stable flow condition was assumed to exist throughout the system, i.e., the hydraulic gradient (dP/dL) was constant throughout the sample length. Discharged fluid volume was measured at the downstream end against time. Once pressure and flow rate were stabilized at the start of the test, a small adjustment was needed to maintain the proper flowing pressure and flow rate at different pressure levels.

During the test, the axial, confining, upstream and differential pressures were continuously monitored and recorded on two strip chart recorders. From several preliminary tests on the intact rock samples, it was observed that a minimum effective confining pressure of 150 psi was necessary to prevent surface flow between the sample periphery and the rubber sleeve. Thus, the first measurement was taken at a total confining pressure of 700 psi. All tests were performed at room temperature.

Fluid Loss Testing

A schematic of the equipment used in this study is shown in Figure 4. The apparatus was designed and constructed to facilitate flow past one exposed face of a core measuring 1 inch in diameter by 2 inches in length. The core was sealed within the rubber sleeve of a specially fabricated test cell depicted in Figure 5.

All leak-off tests were run using an upstream flowing pressure of 1,500 psi and a downstream pressure of 500 psi. This pressure differential was selected to minimize gas expansion that could cause potential flow disturbances in the rock matrix as gas moved from high pressure to low pressure.[10] The 1,000 psi differential pressure (ΔP) was the same as recommended in the API procedure for evaluating fluid loss coefficients.[1]

A turbine flow meter with digitial readout was available to monitor nitrogen flow rates on the upstream side of the core. Various flow rates set with a needle valve were employed to determine the effect of both laminar and turbulent flow regimes on the fracture efficiency of nitrogen, as related to leakoff. Cumulative nitrogen leakoff during each test was recorded on a wet test meter.

The testing employed various depth cores from both the Ohio Shale Formation in Washington County, Ohio, (2,060 feet to 2,589 feet) and the impregnated shale rock unit in the Boonsville Bend Conglomerate of Jack County, Texas, (4,163 feet to 4,210 feet). Core plugs removed from these samples were oven dried at 300 F and cooled in a dessicator. Plugs were subsequently placed in the test cell at room temperature. The specified pressure was then applied to the downstream and upstream sides of the core, and a nitrogen flow rate of 2.4 scf/min was initiated. Periodically, cumulative upstream flow was measured with a totalizer, and volume of leakoff was measured with a wet test meter. After 36 minutes, upstream flow was adjusted to 3 scf/min. This was continued in the laminar flow range to 4.2 scf/min. Afterward, flow rates progressed to 5.7 scf/min in the turbulent regime.

LABORATORY RESULTS

Laboratory test results for fracture flow capacity and fluid loss testing are discussed below.

Fracture Flow Capacity Test Results

Fracture flow measurements were made based on the assumption that Darcy's law holds.

$$q = \frac{\bar{k}A}{\mu}\frac{dP}{dL} \qquad (1)$$

Thus, the calculated permeability values were the average values ($\bar{k}$) across the whole sample cross-sectional area (A) which contains the fracture, i.e., the law of parallel flow[11] holds. This method will not give an absolute value of permeability (k) for the fracture itself, but will allow a direct comparison between the intact rock and the rock with a fracture. Note that Equation 1 describes the flow rate (q) as proportional to the average permeability multiplied by the whole cross-sectional area of the sample, ($\bar{k}A$). Thus, a direct comparison between the two rocks can be made by using the $\bar{k}A$ value. It was assumed that the fluid viscosity (μ) does not change with pressure.

Figures 6, 7, 8 and 9 show the plot of $\bar{k}A$ vs. σc for various fractured samples. The measured average permeability values ($\bar{k}$) are also included in the figures. The value σc represents the net effective closure stress in the sample, i.e., the confining pressure less the mean pore pressure. kA_o represents the corresponding value for the respective intact rock samples measured at zero closure stress.

For all rocks tested, as the σc increases, the $\bar{k}A$ decreases. The rate that the $\bar{k}A$ value decreases in correspondence with the increase in σc is greatest at low pressure and decreases rapidly near to zero as pressure increases. The rate of decline of $\bar{k}A$ with pressure depends upon the surface condition of the fracture. Figure 6 shows two extreme cases of fracture surface conditions. One case has a relatively smooth surface made by a saw-cut. This fracture closes very rapidly and reaches the original intact rock permeability at approximately 4,000 psi of closure stress. Much higher closure stress has been reported on granite samples.[12] Beyond the 4,000 psi of closure stress, the permeability still continues to decrease and reacts as would the intact rock. Studies by others[12,13] on permeability changes due to pressure increase on intact rock samples indicate the same trends as noted in this investigation. In the other case with naturally-fractured surfaces, fractures closed at a much slower rate. Within the experimental pressure range of this study, the fracture did not close and subsequently did not reach the original permeability of the rock.

Comparisons of two rough surfaces of a natural fracture and of a hydraulic fracture indicate that the closure rate of the latter was more rapid. The more rough and irregular the surface of a fracture is, the smaller the pressure effects are at all pressures.

Fracture flow capacity at low pressures is very much governed by the initial opening size of the fracture. However, the difference diminishes rapidly as the pressure increases.

Fluid Loss Tests Results

The effect of varying shale permeabilities on the leak-off coefficient (C_I) of nitrogen is illustrated in Figure 10. This range of permeabilities was found to be representative of the formation samples that were tested. However, these representative permeabilities seemed to be primarily due to natural fractures (Figure 11) since core plugs without natural fractures yielded no leakoff over the examined rates of flow. Moreover, testing with these same flow rates also showed that the fluid loss rate increased in proportion to the flow rate. This resulted in laboratory test data that could be directly scaled to accommodate actual nitrogen injection rates used in the field (Figure 12).

DISCUSSION

Figure 13 shows a plot of production rate vs. time after a well was fractured with nitrogen. The wellbore storage effect portion of the curve is due to producing fluids in the immediate vicinity of the wellbore. Nitrogen fracturing stimulation actually enhances this wellbore storage effect by providing additional space for leakoff when communication occurs between natural fractures. This can be reasoned since the reservoir matrix is virtually impermeable and wall-building effects are not applicable.

The linear section is indicative of a vertically fractured well. In pre-frac testing, the formations showed no indication of effective natural fractures prior to nitrogen stimulation. This was probably because the randomly distributed fractures did not allow communication to the wellbore or to each other. Once these fractures were connected, they provided the channels for fluid flow. Fracture connection will accompany fracture widening. The duration of the linear flow period is a function of fracture length, conductivity, porosity, permeability and other parameters. Normally for tight formations, linear flow periods last much longer than indicated. This short linear flow period is typical in nitrogen stimulated wells.

This phenomenon can be explained as a function of fracture closure as related to fracture surface condition and applied stress. For any given surface condition or roughness, the greater the pressure is, the greater the real contact area between two opposing surfaces will be. Similarly, at any given pressure, the smoother and more regular the surface is, the larger the contact area between the two surfaces will be. Thus, the surface condition can be related to the mean asperity height of the fracture face.[12] The effect of surface roughness can easily be seen by comparing the two cases in Figure 6. Asperities in the saw-cut surfaces are small so the fracture closes rapidly at low pressures. Closure continues until enough of these asperities make contact with the opposing surface to decrease fluid flow. In contrast, the asperities of naturally fractured surfaces are large and tend to prop the fracture open. This allows more fluid flow through the fracture. Thus, the natural fractures are still effective for fluid flow even at relatively high closure stresses.

Fracture closure rate is also a function of applied pressure. The rate is much faster in the low stresses than in the high stresses. Moreover, the closure amount is extremely sensitive to changes in applied pressure at the lower stresses. Immediately following stimulation, a higher production rate due to the widening of the fracture width can be expected. As production continues, the anticipated producing pressure will decrease. Thus, closure stress will increase until it reaches the point where the fracture is almost closed. Beyond this point, the production rate will decrease rapidly.

From the closure experiments on naturally fractured samples (Figures 6 and 8), it can be seen that the amount of pressure drop required to close the effective fracture width is very small. Production time corresponding to this pressure drop will be relatively short. This observation could be applied to the reduced linear flow period shown in Figure 13.

The hysteresis effect in rock mass is well documented. It is natural to expect the same hysteresis effect in fracture closure. Due to the applied load, some asperities or contact points must be deformed plastically or crushed. Thus, lowering the pore pressure will increase closure stress and will subsequently leave nonrecoverable fracture surface damage. This surface damage will increase the contact area and thus increase the fluid flow tortuosity. The rate of permanent surface damage will be significant at high closure stresses. Thus, the only method for increasing the fracture flow capacity is by increasing the crack width. This crack widening can be accomplished by increasing internal pore pressure in the fracture. Repeating this procedure will eventually lead to more damage of the fracture surfaces, which, in turn, will lower the asperity height and produce fines along the fracture face. During subsequent treatments of the same well, a crack width comparable to a previous treatment can be obtained. The crack closure rate, however, will be more rapid than previously experienced.

Therefore, from this investigation it is possible to make the following recommendations for field applications. First, existing natural fractures should be fully utilized by widening them. This is the most effective method for developing an unpropped flow capacity. Secondly, equipment should be made available for recording accurate producing pressures. This will allow for determination of the optimum pressure at which surface damage will be minimal. At this point, nitrogen stimulation is again recommended. Frequent restimulation at an optimum producing pressure will prolong performance of the well rather than depleting at one time all the available well pressure.

CONCLUSIONS

Based on field and laboratory results, several conclusions were drawn from this study.

1. Nitrogen is an effective stimulation fluid in low permeability, naturally fractured shale formations.

2. Most of the width reduction in an unpropped fracture will occur in the early stage of production which indicates a sharp decline of the well flow rate after a relatively short period as shown in Figure 13.

3. The same initial fracture widths will yield fracture closure rates that are minimal in natural fractures and maximal in saw-cut, smooth fractures. Hydraulically-induced fractures will close at an intermediate rate.

4. Wall building effect is not a controlling factor in nitrogen leakoff.

5. Frequent restimulation at an optimum producing pressure will enhance well recovery.

NOMENCLATURE

A = cross-sectional area of sample
C_I = fracturing fluid coefficient, viscosity and relative permeability effect
k = permeability of intact sample
$\overline{k}$ = average permeability of fractured sample
kA_o = permeability multiplied by cross-sectional area of intact sample
$\overline{kA}$ = average permeability multiplied by cross-sectional area
ΔP = differential pressure
dP/dL = pressure gradient
q = flow rate
Q = production rate
T = time
μ = viscosity of fluid
σc = net closure stress

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TABLE I

NITROGEN FRACTURING DESIGN
AND JOB PROCEDURE, WELL NO. 2

Well Data

Permeability	.02 md
Porosity	3%
Bottomhole Temperature	90 F
Reservoir Pressure	1,600 psi
Depth	3,424 Ft
Well Spacing	20 Acres
Casing	4-1/2 In.
Net Height	134 Ft
Perforations	27 Holes

Physical Properties of Nitrogen at Well Conditions

Viscosity	.023 cps
Density	1.547 lbs/gal
Leak-Off Factor	6.3×10^{-3} Ft/$\sqrt{\text{Min}}$

Treatment Data

Nitrogen Volume	720 Mscf
Nitrogen Rate	27,750 scf/min
Equivalent Rate of Nitrogen	44 bbl/min
Surface Treating Pressure	2,340 psi

Fracture Area Calculations

Fracture Orientation	Vertical
Fracture Area	5,144 Ft^2
Fracture Length	428 Ft
Pumping Width	.158 In.

Job Procedure

1. Set up to pump down 4-1/2 inch casing.

2. Pump into casing 500 gallons of 15% HCl acid containing 1 gallon of demulsifier, 1 gallon of clay stabilizer and 1 gallon of inhibitor.

3. Start injecting nitrogen at 5 Mscf/min to load hole, then break down.

4. When pressure stabilizes, start all trucks injecting nitrogen, and then bring total rate to 28 Mscf/min.

5. After pumping, rig down frac iron and bring well back slowly. This will limit the return of fines to the wellbore and reduce crushing of any eroded shale. Test as desired.

TABLE 2

WELL, TREATMENT AND
JOB RESULT DATA

Well No.	Formation and Total Depth	Nitrogen Volume (scf)	Nitrogen Rate (scf/min)	Surface Treating Pressure (psi)	Production Before	Production After	Remarks
1	Ohio Shale at 2,480'	370,000	24,000	1,750	New Well	85 BOPD	Produced over 10,000 barrels of oil first 150 days.
2	Ohio Shale at 3,471'	720,000	27,750	2,340	14.5 BOPD	50 BOPD	After 11 weeks, stabilized at 21 BOPD.
3	Ohio Shale at 3,456'	354,000	27,300	2,450	42.6 BOPD 64 Mcf/D	116.4 BOPD 77 Mcf/D	After 7 months, produced 14,674 barrels of oil and 7.36 MMcf of gas. Now stabilized at 21 BOPD and 29 Mcf/D.
4	Impregnated Shale at 4,395'	1,020,000	10,000	1,800	20 Mcf/D	125 Mcf/D 4 B/D oil and water	Currently producing 50 Mcf/D and 1 B/D of oil and water.
5	Atoka at 4,470'	1,000,000	23,000	2,950	New Well	220 Mcf/D	Now producing 44 Mcf/D.

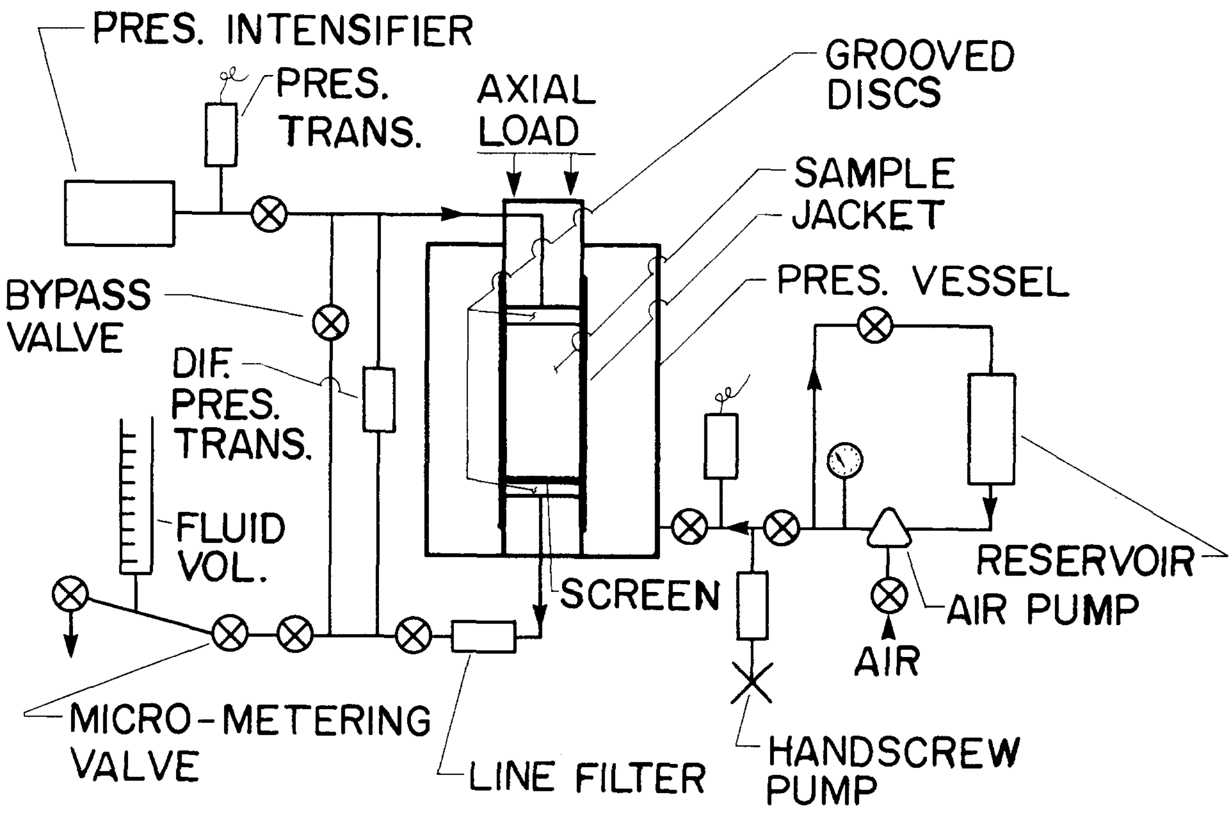

Fig. 1 — Schematic of laboratory apparatus for fracture flow test.

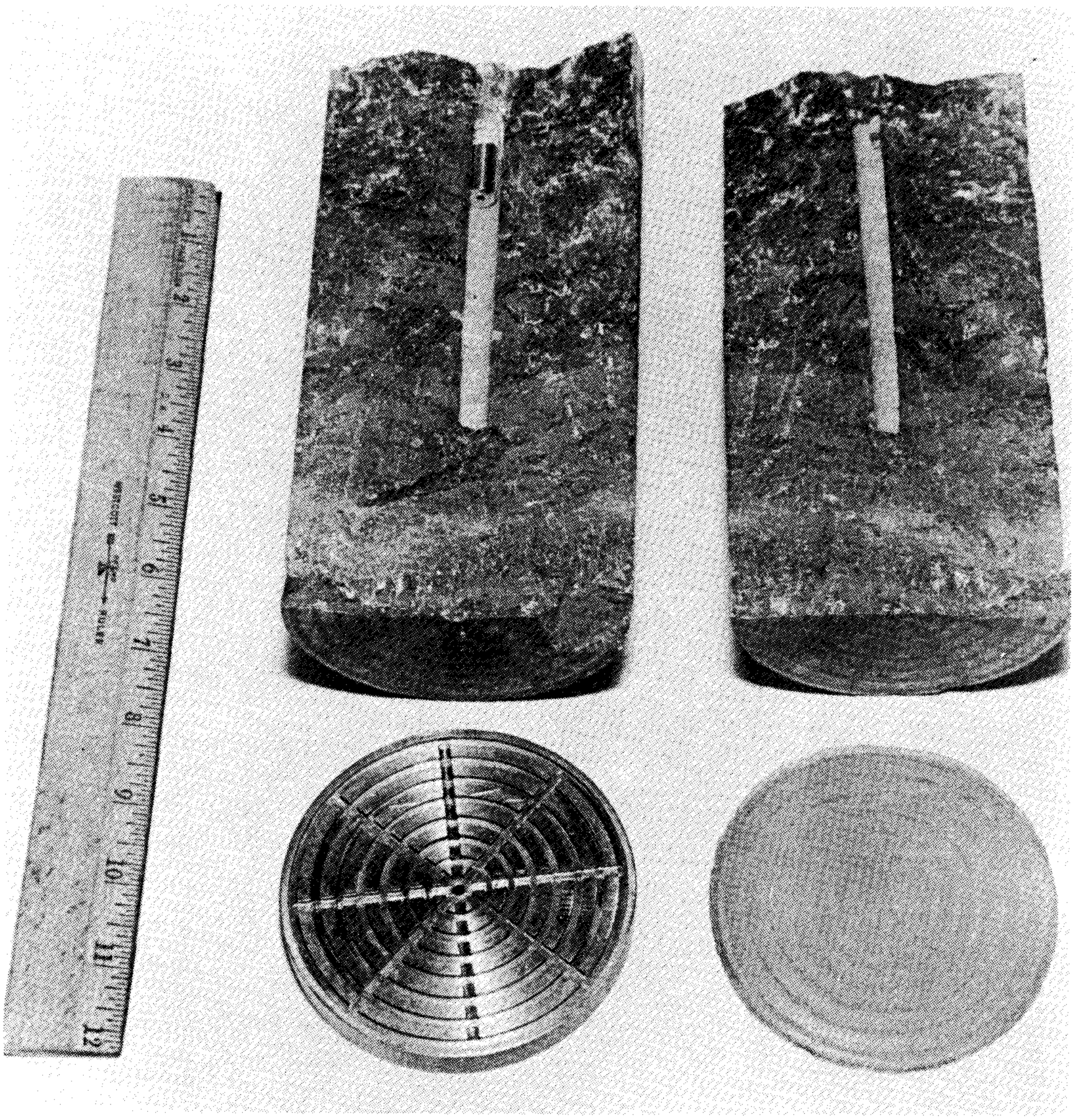

Fig. 2 — Natural fracture surface. Grooved disc and wire screen are shown at the bottom of sample.

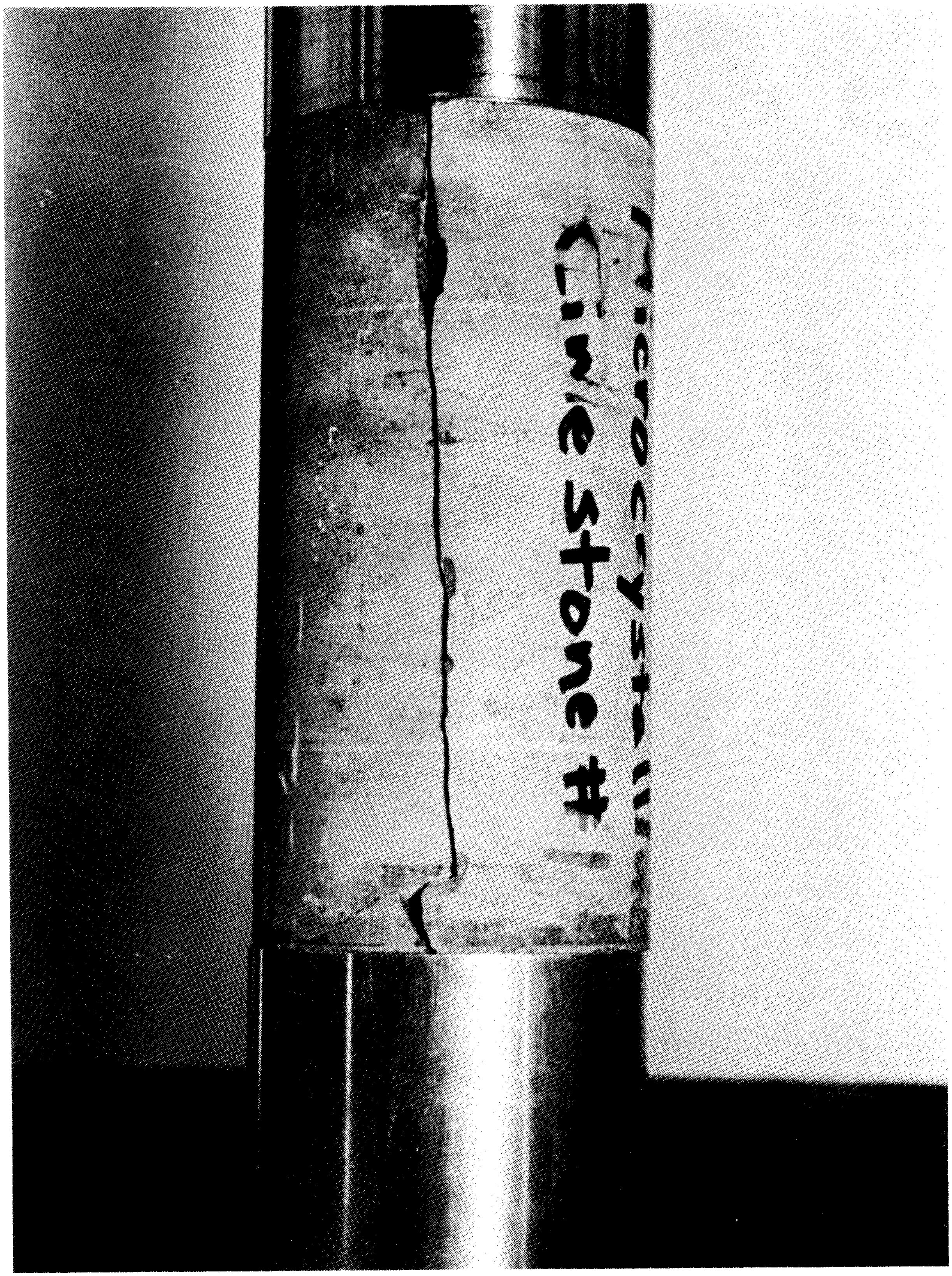

Fig. 3 — Sample assembly showing hydraulically induced fracture.

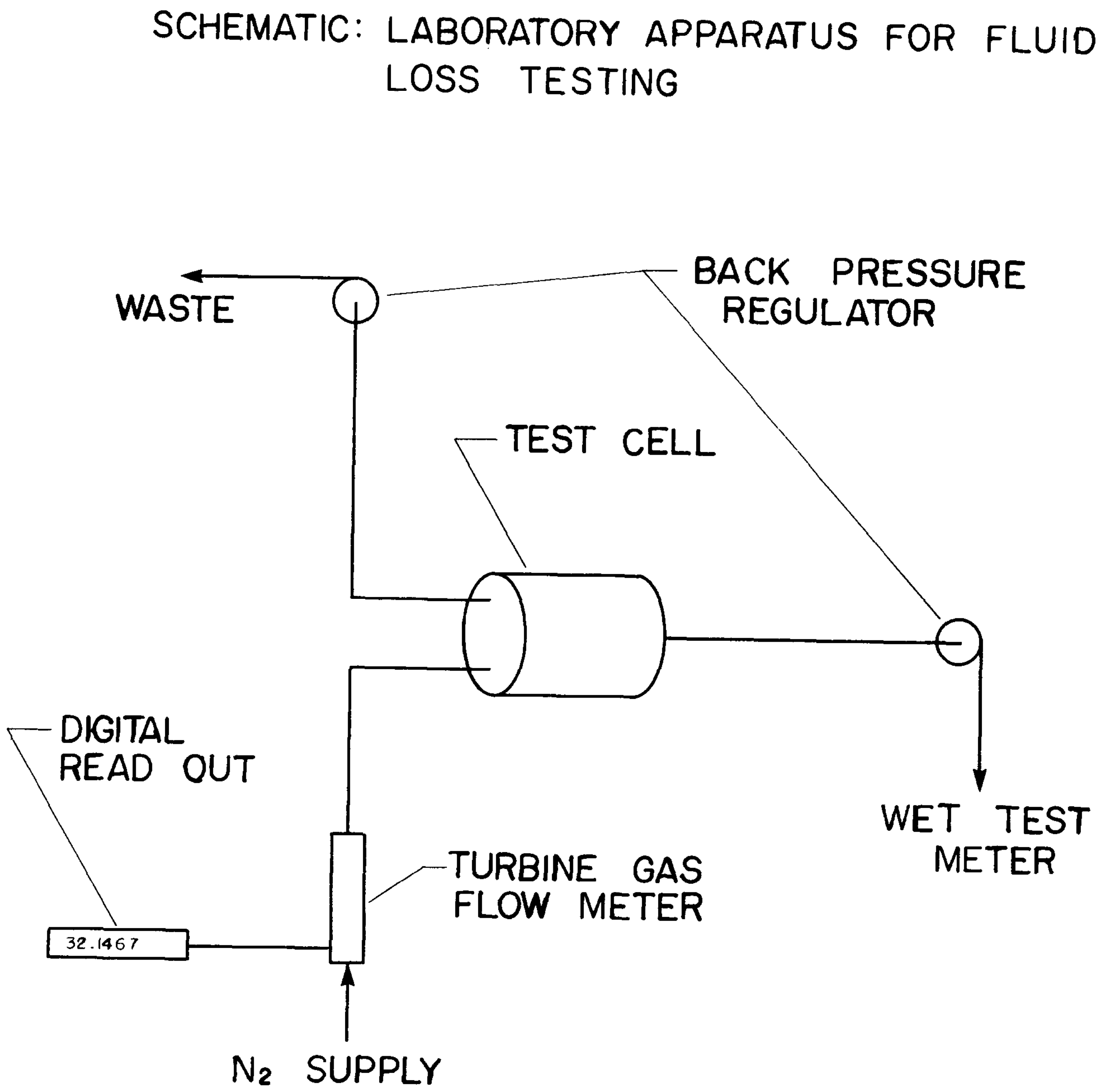

Fig. 4 — Schematic of laboratory apparatus for fluid loss testing.

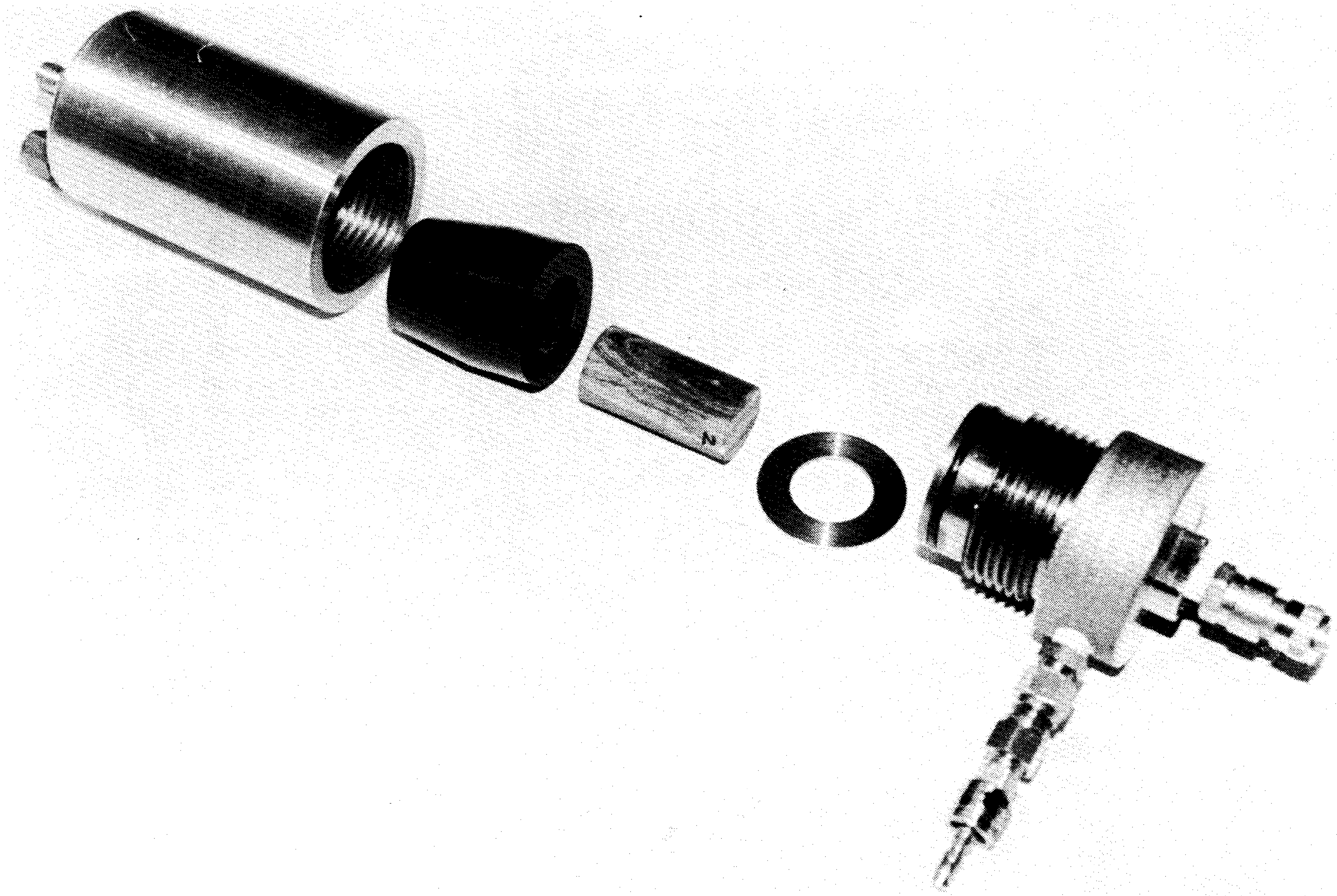

Fig. 5 — Disassembled cell used in fluid loss testing.

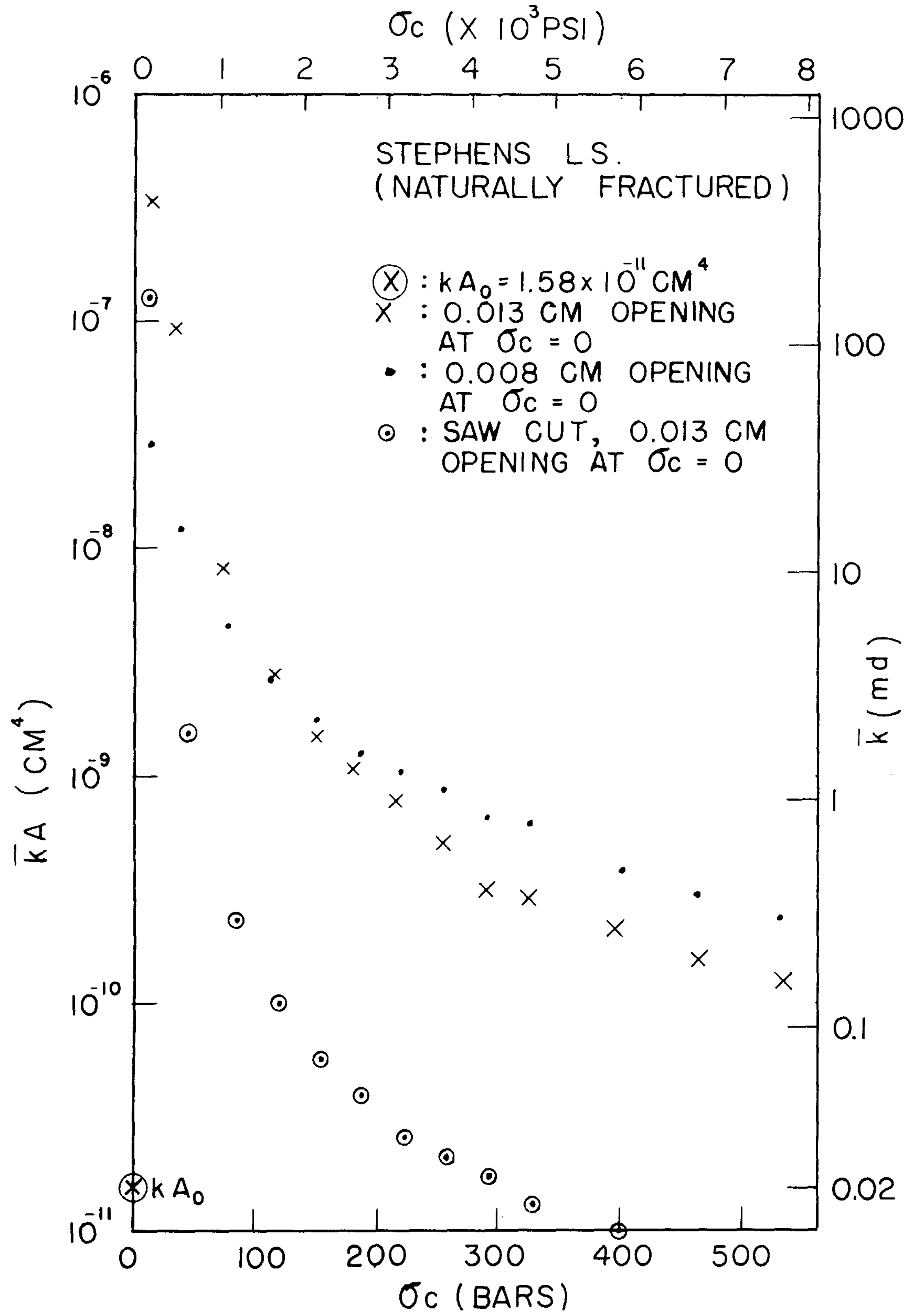

Fig. 6 — Average permeability times cross-sectional area ($\bar{k}A$) at different closure stresses. Outcrop in Stephens County, Texas.

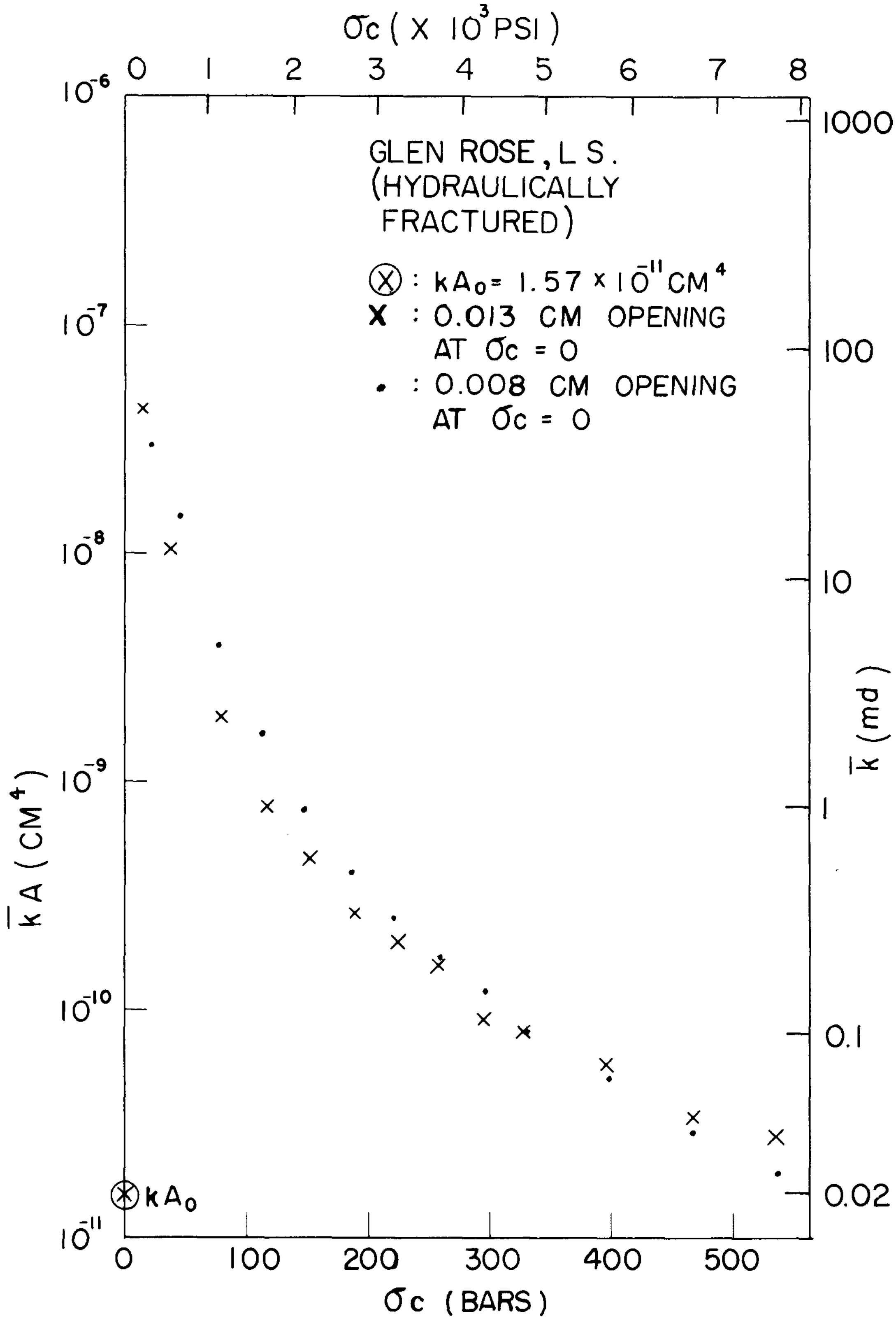

Fig. 7 — Average permeability times cross-sectional area ($\bar{k}A$) at different closure stresses. Outcrop in Glen Rose, Texas.

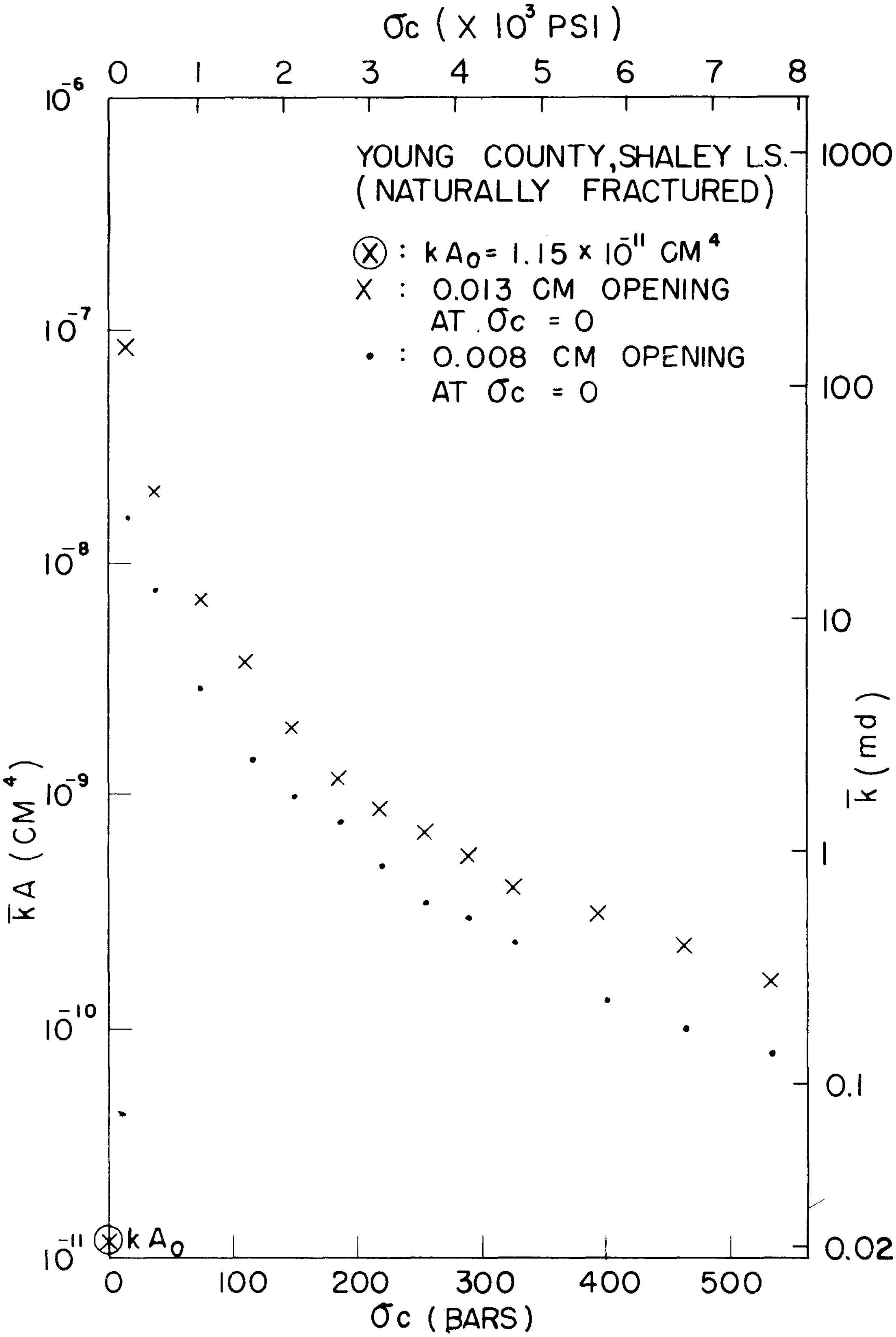

Fig. 8 — Average permeability times cross-sectional area ($\bar{k}A$) at different closure stresses. Cores from 4,386 ft. in Young County, Texas.

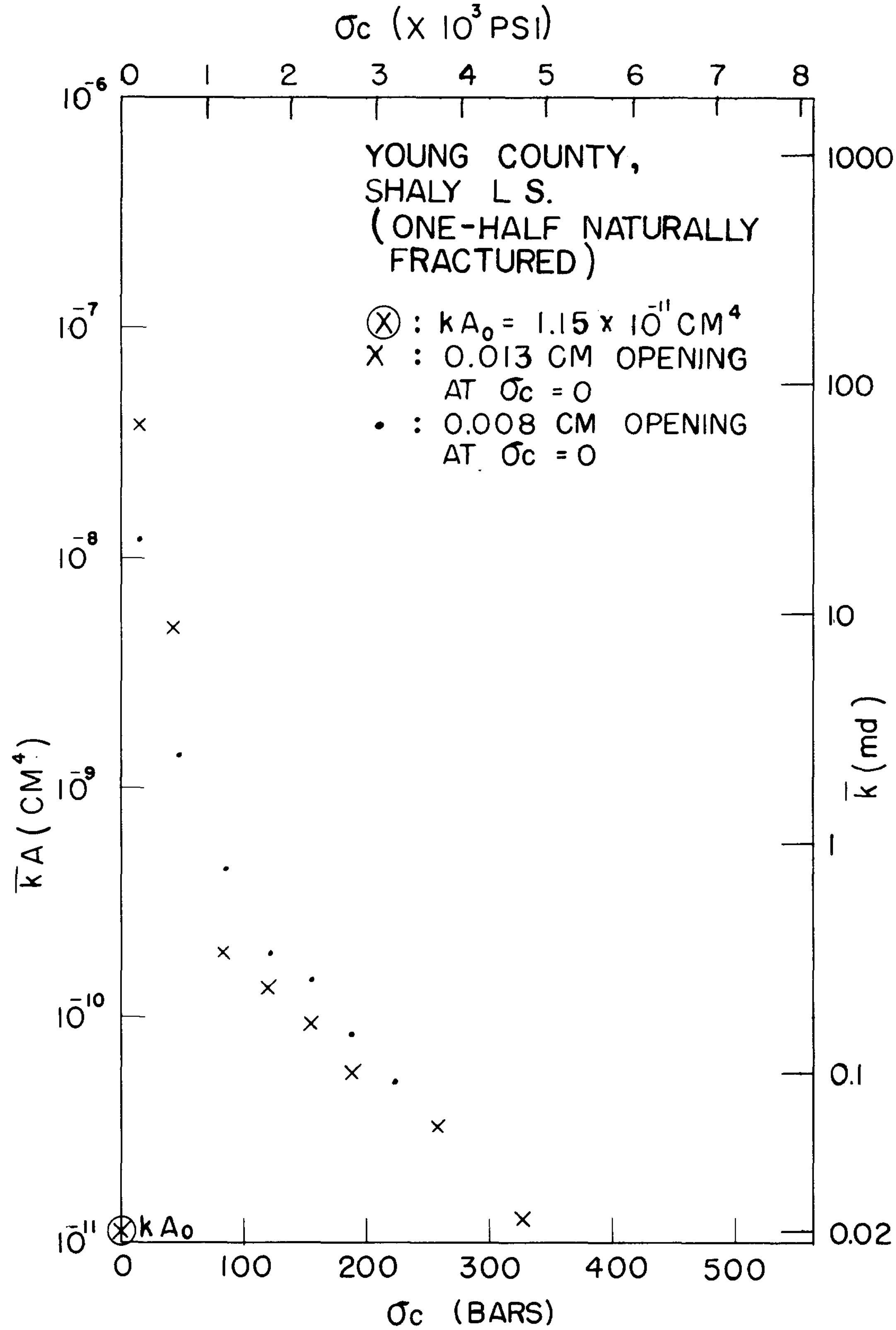

Fig. 9 — Average permeability times cross-sectional area ($\bar{k}A$) at different closure stresses. Cores from depth 4,391 ft. in Young County, Texas.

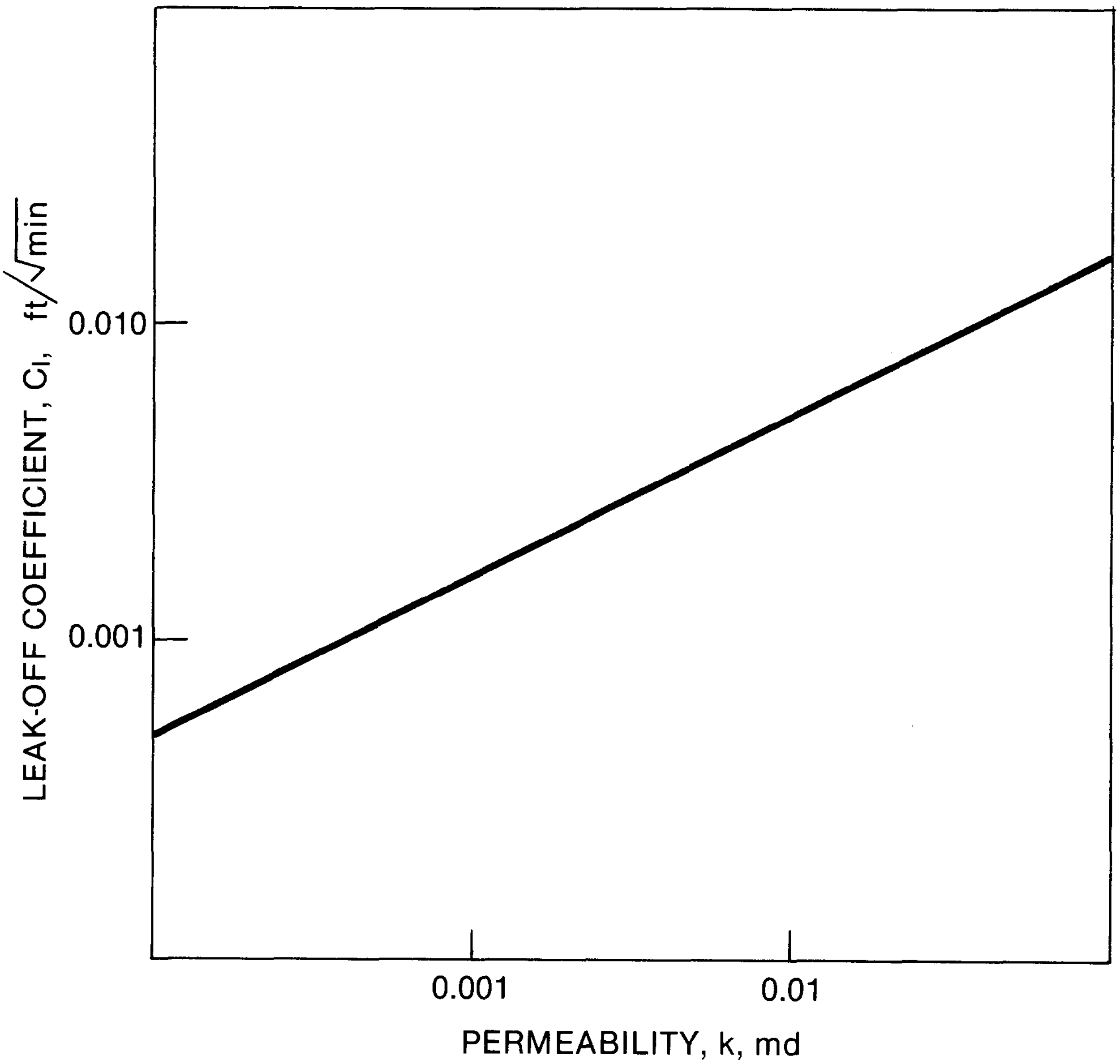

Fig. 10 — Effect of permeability on leak-off coefficient.

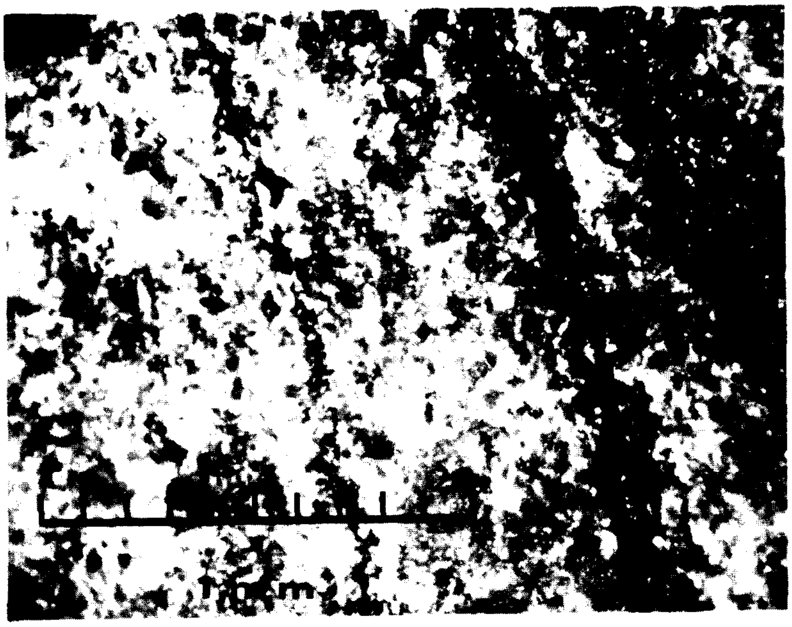

Fig. 11 — Photograph of a shale sample surface showing a natural fracture.

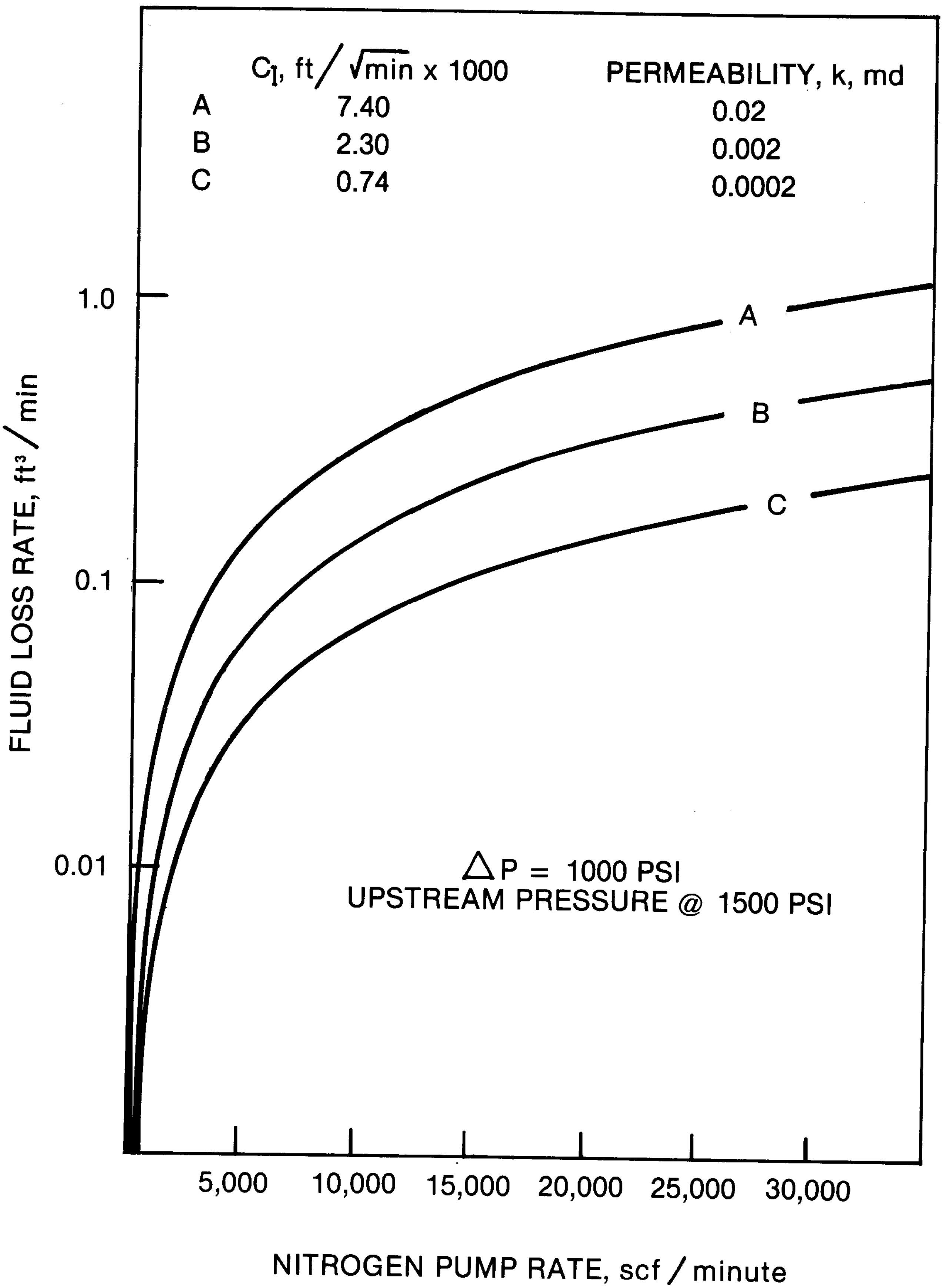

Fig. 12 — Effect of nitrogen pumping rate on fluid loss rate.

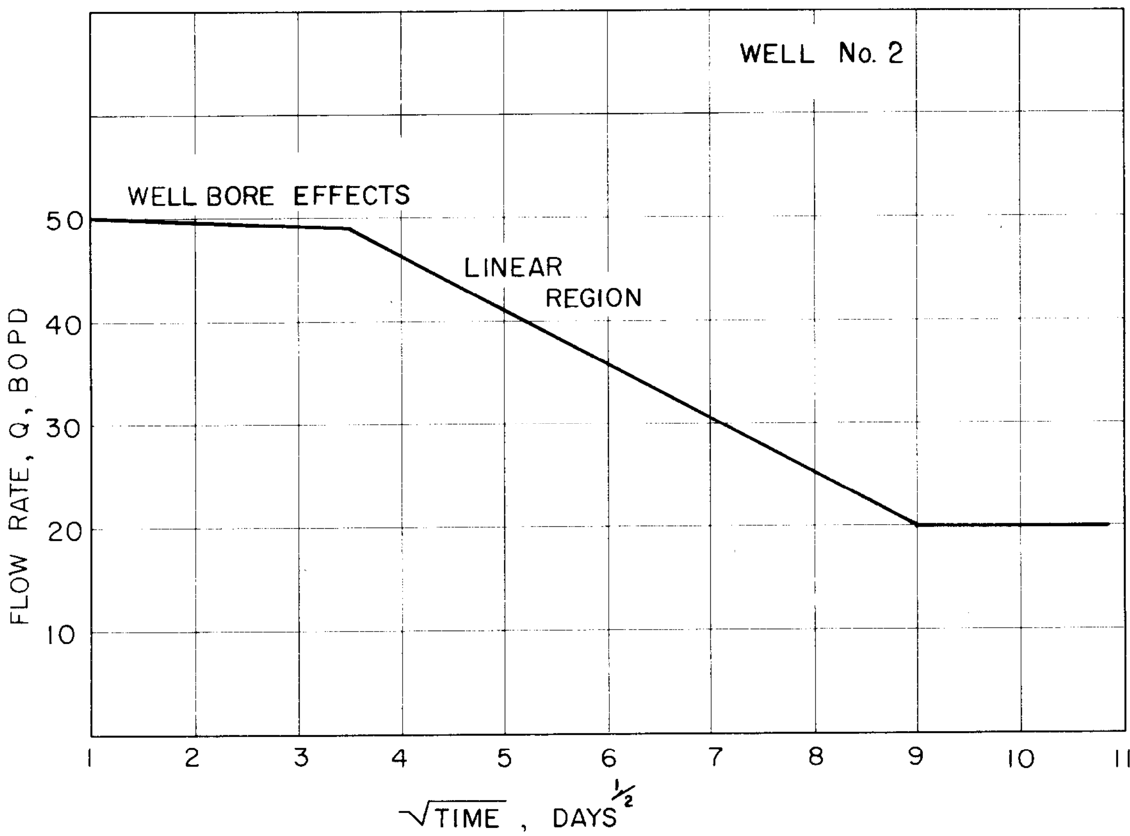

Fig. 13 — Production rate vs. (time)$^{1/2}$