LABORATORY STUDIES IN SUPPORT OF COMPLETION PRACTICES OF OIL AND GAS RESERVOIRS

Glenn S. Penny and Michael W. Conway

STIM-LAB, Inc.

INTRODUCTION

The economical exploitation of domestic oil and gas reserves has become more and more difficult to achieve as the quantity and quality of available reservoirs has declined. Under these marginal conditions, the implementation of optimum completion practices will make the difference between economic success and failure. The purpose of this paper is to highlight the role of laboratory testing in optimizing completion practices.

The laboratory tests that are useful in optimizing completion practices include reservoir description, drilling fluid, cement, perforating fluid and kill fluid compatibility tests as well as acidizing and fracturing fluid interaction tests. All of the above are discussed as well as recent research efforts in the area of matrix and fracture acidizing, which are aimed at determining parameters such as mass transfer and diffusion coefficients, which are commonly estimated.

In the area of hydraulic fracturing, recent findings and research efforts in the area of rheology, proppant transport, leakoff and conductivity of proppants are discussed. Large scale laboratory equipment is shown that simulates downhole conditions for each phase of testing. The work emphasizes the need to use laboratory testing to provide answers that can be implemented in field operations to immediately improve completion design and thus optimize production. Finally, the concept of consortia to leverage research dollars to achieve workable answers to difficult completion problems is addressed.

DISCUSSION

The first step in optimizing production from a well or a field is to develop an understanding of the basic rock characteristics of the reservoir. In most wells, our first look at the reservoir is through the electric log. Any reservoir properties discovered from more detailed studies must be tied to the electric log if the information is to be generally transferable to new wells in a given reservoir. To do so, a logged well is also cored or at least drill cuttings are obtained and a foot by foot description is developed to calibrate the log responses.

The reservoir description is accomplished by utilizing a host of specialized laboratory equipment and procedures, including x-ray diffraction analysis, scanning electron microscopy and thin section petrography. This data is integrated with the electric logs to form a complete description of the reservoir. An example of such a reservoir description format is shown in Figure 1 for the Upper Morrow formation in the northwestern Oklahoma and Texas panhandle.[1] This type of information is essential to make informed decisions about the next drilling location and the selection of perforation intervals. The reservoir description information is also integrated with laboratory tests to select the most compatible completion fluids, including not only drilling fluids but cementing fluids, perforation fluids, kill fluids, and acidizing and fracturing fluids.

DRILLING FLUIDS

Before drilling of a new well begins, several questions can be addressed with simple tests on previously cored wells. The questions that are most frequently asked are 1) what is the potential damage to the reservoir by the proposed drilling fluid; 2) what is the least damaging means of reducing fluid invasion into the producing reservoir, and 3) what additives will minimize shale sloughing. In dealing with these questions laboratory tests would generally include, a roller oven shale stability test, capillary suction time (CST) test, fluid leakoff tests and core flow tests utilizing a multiport Hassler sleeve device.

The Capillary Suction Time Test (CST) device is pictured in Figure 2. The test has been useful in selecting the least damaging base fluid for drilling fluids and kill or workover fluids.[2,3] The multiport cell pictured in Figure 3A and 3B is used to determine the depth of damage of the drilling fluid during a dynamic mud leakoff test by following the permeability along each inch of the core sample. After leakoff and damage assessment the degree of damage removal by acid can be assessed (see acidizing below).

CEMENTING FLUIDS

After completion of the drilling phase, the next step is cementing the casing in the hole. The primary areas of concern in this phase are cement pumping time, compressive strength of the cement, and fluid loss characteristics. These tests are primarily performed by service company laboratories in the process of designing a cement job. Occasionally, routine cement jobs on similar wells will lead to the use of slurries that have not been tested for a particular well. In the case of a failure, specialized laboratory testing is used to identify the cause of the job failure.

The testing of cement filtrate invasion has proved useful in optimizing formation compatibility and leakoff control. CST evaluations of cement filtrate with formation core samples and multiport core flow tests (Figures 2 and 3)[3] have identified cement formulations with minimum damage potential.

PERFORATING

The perforation of the well is one of the most important completion steps because it establishes communication of the formation with the wellbore. Simple core flow tests and CST tests can be used effectively in the laboratory to show the impact of perforating fluids upon the permeability of the reservoir rock.[2] Underbalanced perforating[4,5] has become the state-of-the-art in perforating, but does not always result in a nondamaged completion. There are only a few specialized laboratories that conduct detailed perforating studies and evaluate the mechanical factors occurring during perforation. Some promising new perforating techniques have recently been proposed and patented[6] which were modeled and developed as an outgrowth of laboratory studies conducted by an Industrial Consortium studying perforation practices.[7]

After perforation, the initial breakdown of the well must be considered. The most often asked questions are, what fluid should be used to breakdown the well. Does that fluid remediate drilling damage, and/or stimulate native permeability? Also, the eventual workover of a well requires an understanding of potential formation damage that may occur from kill fluids used in workover operations. Recent studies in our laboratories have identified several formations which are highly sensitive to kill fluid invasion. Problems that may result are fines migration and plugging upon the invasion of water. Clay or fines stabilizers may prove important in maintaining near wellbore permeability. A more common problem is the increase in water saturation surrounding the wellbore. Laboratory core flow tests are useful in measuring the relative permeability following kill fluid invasion and the selection of surfactants to aid in the displacement of water to restore production. Simple screening tests are very necessary to insure that the selected surfactant package prevents the formation of emulsions, sludge and iron release.

PRODUCTION PERFORMANCE TESTS

During the life of a well a decline in performance can be related to several potential problems as a result of the decline in pore pressure such as fines migration, the deposition of asphaltenes and paraffins,[8] and the formation of scale. Core flow tests can be performed that examine the impact of confining stress and velocity upon permeability. For example, low permeability sandstone,[9,10] coal[11] and other naturally fractured reservoirs display a stress dependent permeability. As the well is produced, the net stress can increase causing a drop in permeability. High production velocity can impair permeability through fines migration. If this is the case, the critical flow velocity can be determined from core flow tests and preventive measures taken in the form of fines stabilizers and reservoir management practices which minimize damage.

Simple laboratory tests can be performed to predict problems associated with oil related problems such as asphaltene or paraffin deposition. Laboratory tests such as cloud point, percent paraffin and asphaltene can be used to indicate potential problems. Water analyses can be used to predict potential inorganic scale problems. In either case, preventive measures can be taken in the form of constant or slug injections of inhibitors. If the permeability of the area surrounding the wellbore is impaired by depositional products, laboratory solubility and core flow tests are extremely useful in selecting the most effective, compatible remedial treatment.

ACIDIZING

Acid is the aspirin of the oil patch. If the well is not producing, the quick fix is to "give 'er a shot of acid". Some wells in west Texas have been acidized no less than a dozen times.

Some jobs are successful, but in many cases the results are less than satisfactory. The use of acid can be categorized into breakdowns, matrix acidizing and fracture acidizing.

Breakdowns. The most common application of acid is in the breakdown of the well. The design of breakdowns is usually considered routine and independent of formation type. Very mixed production results are generally seen after breakdown treatments. Both acidic and non-acidic fluids are used and in some cases laboratory tests and field results have shown that breakdown with HCl results in severe damage. In sandstone formations the predominate problem is iron; it is either put into the formation from the tubulars or released from the formation. In coal, severe permeability damage can result if the wrong acid corrosion is used. In carbonates, reduced permeability surrounding the perforation can result due to fines plugging if the strength and volume of the acid are not properly selected or if the treatment fluid and formation fluids are found incompatible due to emulsions, sludge and acid by-product precipitation. The fluid compatibility problems can be averted by simple bottle shake tests conducted at the temperature of the reservoir. Rock-fluid interactions, however, require the use of more sophisticated tests such as those performed with the multiport cell to evaluate the depth of stimulation or damage as described under matrix acidizing.

Matrix Acidizing. The effectiveness of a matrix acidizing treatment depends upon the degree and rate of dissolution of the rock in the acid, the depth of penetration, the competence of the remaining rock and the solubility of the by-products of the acid-rock reaction. A combination of the above parameters can be investigated on the formation of interest in a multiport core flow device pictured in Figure 3A and 3B. In these tests, the degree of stimulation and depth of penetration can be determined vs acid composition and temperature. A simulated acid treatment can be performed with the appropriate preflushes, acids and overflushes. Following the acid treatment, core plugs can be tested for compressive strength. Samples of effluent can be sampled vs length during the treatment to track the ion content of the spent acids. This permits an analysis of deposition products vs depth of acid penetration, acid concentration and retarder concentration. These type of tests have been used successfully to select the appropriate acid concentration for successful acid stimulation treatment.[12]

The drawback of linear flow cells is that the test results do not accurately predict the volume of acid necessary to produce a satisfactory stimulation. Field practices have adopted on-site pressure measurements to determine optimum treating volumes and rates.[13] Equipment has recently been developed at STIM-LAB to measure acid response in a radial configuration (Figure 4).[14] The system features a 1 ft diameter rock sample penetrated by a simulated wellbore. Permeability damaging materials such as mud are circulated through the wellbore and the filtrate is allowed to leakoff. The effectiveness of various acid treatments are evaluated in removing the damage and improving permeability. A typical procedure is to establish the permeability of the radial system, damage to a predetermined skin factor, then treat with a selected acid system. The pressure at the simulated wellhead and within the rock is monitored during the treatment to calculate *in-situ* skin factors. The goal is to relate the laboratory test protocol to formation responses observed in actual acid treatments.

Acid Diversion. The diversion of acid down the wellbore is a major problem in vertical and inclined well completions. Laboratory equipment has been developed to evaluate the effectiveness of various methods of diverting by assessing leakoff control and cleanup of the diverting material (Figure 5). Fifty percent of the inclined wells treated today involve slotted liners and/or prepacked screens, 20% are open-hole, and 30% are cemented. Two models are used to simulate these three scenarios, with and without natural fractures. The first evaluates materials such as particulates that divert at the matrix level. This is accomplished by the flow of acidizing fluids and additives between 10 sq in. by 3 in. thick cores of various permeabilities in STIM-LAB's modified conductivity and acid flow cells. Two cells are put in-line allowing up to four permeability options in a run. Once the initial permeability is known, the acid and diverter is flowed through the system in an effort to even out the permeability profile. The regained permeability of the rock is then conducted. Fluids examined include various foams as well as common oil soluble resins, benzoic acid flakes and gel pills.

Diversion in cemented and perforated intervals is carried out using a multiple perforation model. A schematic of the wellbore model is shown in Figure 5 in the horizontal configuration. A closeup of each perforation is shown in Figure 6. The model features a 6 in. long by 2 in. diameter core with a 0.5 in. perforation. Using this model various diversion techniques can be evaluated in a radial configuration. For example, foam can be evaluated vs permeability, foam quality and surfactant concentration. Particulates and mechanical ball diverters can also be examined in this model. In perforated completions, ball sealers are the most often used method of diversion. However, field failure as judged by the lack of a ballout, occurs all too often. Previous studies have examined many of the important design parameters such as ball and fluid density and fluid velocity, but the results are not available to the engineer routinely designing these jobs.

Fracture Acidizing. Fracture acidizing of carbonates represents the largest usage of acid by volume worldwide. The design of the job varies widely, and typically involves pumping stages of non-acid gelled water with other diverting aids. The acid itself is varied in strength from 7½ to 28% and may also be gelled and/or commingled with oil (emulsified) or nitrogen and CO_2 (foamed). To optimize treatments, both laboratory tests and computer simulators are used.[15] Unfortunately, most design programs are run using assumed reaction rates, mass transfer and diffusion coefficients, rheological parameters and leakoff coefficients. When reaction rates are measured, they are typically measured in a rotating disc device using only the straight HCl without any of the viscosifying agents (Figure 7), or in a linear or annular flow cell without leakoff. The available parameters are generally assumed from data generated on clean systems without shear history. Measured fracture conductivity is typically measured on relatively small samples in radial or linear systems and does not generally match any of the assumptions in the design simulators. That is, the measured fracture conductivity is not generally related to the amount of rock dissolved by the acid as is assumed by the design programs. Recent equipment developments and procedures now allow the measurement of these unknown parameters for commonly pumped fracture acidizing fluids on selected formation core. Fracture acidizing studies are conducted in Hastelloy linear flow cells that accommodate either a 10 sq in. by 3 in. deep core, or in a large scale 100 sq in. by 3 in. acid flow cell (Figure 8A and 8B), which are also used to determine the conductivity of proppants. Both cells allow the measurement of leakoff while flowing between the rock. Other equipment includes pipe and slot rheometers to measure in-line acid rheology. All pumps, piping and heat exchangers are constructed of Hastelloy. An elemental analysis system is used for measuring dissolution rates of sandstone. The dissolution of carbonate reservoirs is measured using an infrared detection of carbon dioxide and confirmed by ion analysis and weight loss.

Computerized data acquisition includes differential pressure, temperatures, and rates in the pipe and slot rheometer and the conductivity apparatus. The data is acquired with LabTech Notebook® software. The raw data is imported into Quattro® Pro Worksheets and automatically processed using specially designed macros and worksheets. The newly developed procedures allow the measurement of laboratory data required for today's state-of-the-art fracture acidizing programs such as heat and mass transfer coefficients, diffusion coefficients, acid reaction rates with leakoff as well as leakoff coefficients, rheology, conductivity and non-Darcy flow factors through the acidized fracture.

Conductivity. The desired final result of a fracture acidizing treatment is the creation of a conductive zone extending well into the producing zone. The ultimate objective of fracture acidizing experiments is to quantify the conductivity of the acidized fracture after treatment with fluid which has been shear history conditioned and at the temperature and leakoff conditions expected in an actual reservoir. The experiments are be conducted between 100 sq in. slabs of core that are 4 in. thick. Previous experiments on San Andreas core indicate that fracture conductivity disappears on 10 sq in. core samples at a closure of 3000 psi. The larger sample is necessary to get a better feel for field scale conductivity measurements.

HYDRAULIC FRACTURING

The use of hydraulic fracturing is a necessary step to bring about economical production rates from low permeability reservoirs. A propped fracture is used to create a highly conductive channel leading to the wellbore from deep in the reservoir. In low permeability reservoirs the fracture is typically designed for 500 to 1000 ft in length on each side of the wellbore. Another common practice is to conduct what is known as a "frac pack" in high permeability reservoirs to by-pass near wellbore damage. Such fracs may be designed to penetrate only 30 to 50 ft into the formation.

It has been said that we know everything about the hydraulic fracture upon completion of a treatment except its width, length, height, and conductivity. Fortunately, laboratory tests have been developed to simulate the downhole process of hydraulic fracturing to get a better handle on the rheology, proppant transport and fluid leakoff during pumping of the pad and slurry. This information allows a better estimate of fracture geometry following the treatment. Likewise, fracturing treatment simulation procedures have been developed to measure the long-term conductivity of proppants in the presence of fracturing fluids.[16]

Rheology and Proppant Transport. The rheology of the fracturing fluid determines the pressure drop through the tubulars which is the friction pressure and in the fracture, which is responsible for the width of the fracture. Conventional methods of determining rheology of fracturing fluids are the use of Model 50 Fann viscometers.[17] API procedures are being developed to simulate shear history conditioning prior to measuring the fluid. The viscosity of the time and shear dependent crosslinked fluids used today may vary by an order of magnitude depending on the time, temperature and shear conditions experienced by the fracturing fluid. One problem of measuring the rheology alone is that the rheology may not predict the transport of proppant. To address this issue, full scale mixing equipment has been assembled at STIM-LAB to evaluate the rheology and proppant transport of commonly pumped fracturing fluids including foamed fluids.[18]

The equipment is shown in Figure 9A and 9B. The system features batch mixing tanks, a blender for adding sand, a full size intensifier pump and a crosslinker addition system. The fluid is pumped through 3000 ft of 1 in. coiled tubing to simulate pumping downhole at shear rates of 1500/sec. The fluid is then loaded into a formation shear and heatup simulator consisting of 720 ft of 1 in. stainless steel tubing surrounded by 4.5 in. heating jackets. The fluid is displaced from the simulator at a shear rate of 10 to 40/sec for 1 hour. In this manner, the rheology and proppant transport of the slurry can be evaluated with breaker for up to one hour as the fluid exits the simulator. The rheology of the conditioned fluid is measured in a heated 4 pipe rheometer consisting of 0.25 to 1.0 in. tubing. The rheology and proppant transport is measured in various slot devices. One such slot measures 4 ft high by 16 ft long (Figure 10) and consists of 1½ in. Plexiglas walls contained within a reinforced steel frame. This slot is useful for observing perforation entry effects and settling velocities of low temperature fluids such as linear gels and borates. A second slot device pictured in Figure 11 is a high pressure device for measuring the rheology and proppant transport of foam fluids using either nitrogen or carbon dioxide and high temperature crosslinked fluids.

One of the applications of the system is to observe the proppant transport character of one fracturing fluid system vs another. For example, the transport of proppant by borate fluids vs pH is shown in Figure 12. The pH 8.5 fluid shows little if any transport, while the pH 10 fluid shows perfect transport. Figure 13 shows the typical transport observed with a titanate crosslinked guar or hydroxy-propyl-guar (HPG) fluid. The fluid typically shows settling which results in density segregation as the slurry travels down the fracture. These results, together with the conductivity results shown below, have been responsible for the renewed use of borates in hydraulic fracturing.

Other fracturing fluid results showing the impact of sand concentration and breaker on rheology and proppant transport have been reported.[19] Data is reported in the form of rheograms from which n and K can be calculated in pipe and slot flow. It was recently noted that the pressure drop in slot flow for crosslinked fluids does not increase as the sand concentration is increased to as high as 20 lb/gal. This is contrary to previously reported findings in concentric cylinder viscometers.[20] The proppant transport information gathered in recent years points to the need for extremely low shear viscosity data on crosslinked fluids to predict proppant transport behavior.[21]

Dynamic Fluid Leakoff. The leakoff rate of the fracturing fluid to the formation is one of the most important factors in determining fracture geometry. The efficiency of the fluid can vary from 20% to 70% depending on the leakoff rate. The dynamic leakoff rate of fracturing fluids to the formation and the conductivity of the proppant placed within the fracture is determined between formation core in a cell designed and patented by STIM-LAB.[22] The cell is a 10 sq in. cell shown in Figure 14A and 14B. Slabs of core which are ⅜ in. thick are placed on each side of the flow path. Leakoff is measured while flowing a shear history conditioned fluid between the core slabs at a shear rate of 40 1/sec and a pressure differential of 500 to 2500 psi. Shear history conditioning of the fluid is as described above in the rheological studies when slurries are evaluated. Pad fluids are often evaluated with a 0.25 in. tubing simulator in line with a 0.75 in. formation simulator in the small scale studies. These tubing sizes and a 1 lb min pump rate give shear rates of 1500/sec in the tubing simulator, and 50/sec in the formation simulator. The leakoff profile has been found to vary with shear rate and differential pressure, as well as permeability, gel type and concentration, and type of fluid loss additive and concentration.[23]

Proppant Conductivity. Once the fracturing treatment is completed and the well is flowed back, the only thing remaining in the formation is the proppant. Thus, every dollar spent on the fracturing treatment is for proppant conductivity. In early years short term conductivities of various proppants measured with gas at room temperature between steel plates were used to design fracturing treatments. Recent data has provided realistic downhole data between core vs time, temperature and closure, with and without fracturing fluids.[16] This data shows that the conductivity of proppants can be as much as a 90% lower than anticipated when all factors are considered. This makes it all the more important to know the performance of a potential proppant and fracturing fluid at reservoir conditions.

Figure 15 shows the long-term conductivity of common 20/40 proppant types, all at 2 lb/ft^2 and 200°F between Ohio sandstone without fracturing fluids. The sand clearly falls below 1000 md-ft at 5000 psi. Resin-coating improves the strength of sand to achieve 1000 md-ft up to 8000 psi. The intermediate strength ceramic and bauxite proppants show improved strength at higher closures, with bauxite typically being favored at 8000 psi and above.

Size and concentration must be considered together when selecting a proppant, particularly with sands. At 2 lb/ft^2 a larger size generally means higher conductivity as can be seen in Figure 16 with Hickory sands (Brady). However, if the concentration is decreased to 1 lb/ft^2, the advantage disappears at around 4000 psi (Figure 17). Note that the 12/20 has less conductivity at 4000 psi than the 16/30 at 1 lb/ft^2. Thus, the smaller 20/40 material may be a better choice if only 1 lb/ft^2 is possible at higher closures.

The selection of fracturing fluid can have a dramatic influence upon the conductivity of the proppant pack. Early data has shown that fracturing systems which use guar as the gelling agent and titanium as the crosslinker and are broken with conventional persulfate breaker loadings of 0.5 - 2 lb/1000 gal (at 150°F) result in retained conductivities of 50% or less at proppant loadings of 2 lb/ft^2, and around 20% at 1 lb/ft^2 proppant loadings (Figure 18). On the other hand, the guar-borate system provides 80% retained conductivity at the same conditions at 2 lb/ft^2 and 60% at 1 lb/ft^2. Thus, laboratory tests show that the borate system offers the advantage of superior cleanup and proppant transport at the correct pH. Recent work has centered on the development of delayed or encapsulated breakers that allow the breaker to remain in the filter cake and then is released after the treatment is completed to achieve high retained conductivities.[24]

Proppant Flowback. Once the proppant is placed within the fracture, a problem exists in many areas with the flowback of proppant. One solution to the problem has been the use of resin-coated sands. To study flowback, a series of specialized cells have been designed to look at flowback vs proppant size, concentration, closure, and flow rate of water and gas. Studies are underway to determine the minimum tensile strength of resin-coated sand necessary to withstand flowback in the presence of fracturing fluids and well cycling. The cells are modified versions of the 10 sq in. cell shown in Figure 14 and the 100 sq in. vertical cell shown in Figure 8.

UTILIZING LABORATORY DATA

An important consideration in any test or procedure is how closely actual field and reservoir conditions can be simulated. This has always been a primary concern at STIM-LAB and has led to the development of significant new laboratory testing procedures and equipment that address the wide range of variables found in individual wells and reservoirs. Obviously, the more accurate the simulation is, the more accurate and valuable the final data will be.

The resulting laboratory data derived through the various tests and simulations discussed is just that–laboratory data. To be of any value whatsoever, this data must be interpreted and placed in its proper perspective and context in relation to the particular well or reservoir being studied. Often the data from a single test is meaningless on its own, yet when combined and referenced with data from other tests, it forms a relevant piece of the puzzle. All of the interdependencies must be considered in order to form a complete picture. Producers are discovering that given the proper input, almost any completion project can be closely simulated in the laboratory and the results used to select the optimum drilling fluid, cement, acid, fracturing fluid, proppant and/or production conditions. The dollars spent on completions research or on up-front testing to optimize the treatment in a well or field often results in improved completion design and improved production.

SUMMARY OF RESEARCH ACTIVITIES

In today's economic climate, sound decisions concerning oil and gas well development and completion are critical. These decisions must be based on an understanding of the reservoir rock and fluids with completion fluids supported by the most up-to-date laboratory research data available. However, the cost of highly specialized equipment and testing procedures necessary to generate this data are often beyond the economic means of many producers. Even large producers with worldwide operations have made significant cutbacks in research and testing operations.

In 1985, STIM-LAB, Inc. addressed this problem by launching its first Completion Technology Research Consortium. The Consortium now consists of thirty-eight member companies that contribute an equal dollar amount on a yearly basis to fund research carried out by STIM-LAB. Each member provides input on the selection of research topics, methods and procedures, and shares equally in the findings and technology developed. The concept has proven so successful that STIM-LAB now conducts three completions consortia, including the original consortium to study the Long-Term Conductivity of Proppants. The second started in 1986 studies the Rheology and Proppant Transport Characteristics of Common Fracturing Fluids, and the third started in 1992 Investigates Matrix and Fracture Acidizing Fluids and Techniques.

Future work in the area of proppants includes 1) the investigation of proppant flowback and control in high rate oil and gas wells, 2) the investigation of curable resin-coated sand interactions with fracturing fluids and additives such as encapsulated breakers, 3) use of the larger scale (100 sq in.) system to examine conductivity, leakoff, non-Darcy flow, and flowback and 4) multiphase non-Darcy flow correlations.

Rheology and proppant transport issues requiring further work include 1) evaluation of parameters to predict proppant transport such as normal forces, elastic properties and low shear viscosity, 2) rheology and transport vs proppant size and concentration including resin-coated sands and ceramics and encapsulated breakers, and 3) measurement of rheology and transport in slot flow while leaking off to the formation.

Laboratory based research on acidizing has lagged behind other forms of stimulation in recent years. In carbonate acidizing, the measurement of the basic design parameters such as the mass transfer coefficients are required to analyze the laboratory reaction rate data and design treatments with computer simulators. Other areas of study are, 1) effect of leakoff on reaction rates, 2) effect of emulsified, foamed, and viscosified acid on reaction rates, 4) factors which promote improved fracture conductivity, 5) matrix acidizing characteristics in radial flow and, 6) foam diversion in matrix acidizing.

REFERENCES

1. Gale, P. and Conway, M.W.: "Reservoir Description and Completions Engineering Study of the Upper Morrow Formation," Final Report December 1988.

2. Underdown, D.R. and Conway, M.W.: "Minimize Formation Damage by Rapid/Inexpensive Method of Completion and Stimulation Fluid Selection," paper SPE 19432 presented at 1990 SPE Formation Damage Control Symposium, Lafayette, Louisiana, February 22-23.

3. Jones, R.R., Carpenter, R.B., and Conway, M.W.: "A Study of Formation Damage Potential During Cementing Operations," paper SPE 22777 presented at the 1991 Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, TX, October 6-9.

4. King, G.E., Anderson, A., and Bingham, M.: "A Field Study of Underbalance Pressures Necessary to Obtain Clean Perforations Using Tubing-Conveyed Perforating," paper SPE 14321 presented at the 1985 Technical Conference and Exhibition of the Society of Petroleum Engineers, September 22-25.

5. Colle, Ed, "Increase Production with Underbalanced Perforation," *Petroleum Engineer International*, July 1988, Pg. 39.

6. Dees, John, et al., "Overbalance Perforating and Stimulation Method for Wells", U.S. Patent No. 5,131,472, July 21, 1992.

7. Behrmann, L.A., "Cooperative Project for Perforation Technology," Schlumberger, 1989-92.

8. Conway, M.W.: "Laboratory Supported Completions Engineering Practices," paper presented at the 1991 Southwestern Petroleum Short Course, Proceedings of the Thirty-eighth Annual Meeting, Texas Tech University Lubbock, TX, April 17-18, 60-68.

9. Jones, S. C.: "Two-Point Determinations of Permeability and PV vs. Net Confining Stress," paper SPE 15380 presented at the 1986 Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, LA, October 5-8.

10. Warpinski, N.R., Teufel, L.W., and Graf, D.C.: "Effect of Stress and Pressure on Gas Flow Through Natural Fractures," paper SPE 22666 presented at the 1991 Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, TX, October 6-9.

11. Penny, G.S., Conway, M.W. and Klem, R.C.: "Laboratory Tests to Determine Parameters for Hydraulic Fracturing of Coalbed Methane," paper SPE 21812 presented at the 1991 Rocky Mountain Regional Meeting and Low-Permeability Symposium, Denver, CO, April 15-17.

12. Bartko, K.M., Conway, M.W., Krawietz, T.E., Marquez, R.B., and Oba, R.G.M.: "Field and Laboratory Experience in Closed Fracture Acidizing the Lisburne Field, Prudhoe Bay, Alaska," paper SPE 24855 presented at the 1992 Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Washington, D.C., October 6-9.

13. Paccaloni, G. and Tambini, M.: "Advances in Matrix Stimulation Technology," presented at the 1990 65th Annual Technical Conference, New Orleans, LA, September.

14. Conway, M.W., Penny, G.S.: "The Investigation of Matrix and Fracture Acidizing Fluids and Techniques in Vertical and Inclined Wellbores," 1992 STIM-LAB Acid Consortium Meeting, Washington, D.C., October 6-9.

15. Settari, A.: "Modelling of Acid Fracturing Treatment," paper SPE 21870 presented at the 1991 Rocky Mountain Regional Meeting and Low-Permeability Reservoirs Symposium, Denver, CO, April 15-17.

16. Penny, G.S.: "An Evaluation of the Effects of Environmental Conditions and Fracturing Fluid upon the Long-term Conductivity of Proppants,", paper SPE 16900 presented at the 1987 Annual Technical Conference, September 1987, Dallas, Tx.

17. Conway, M.W., Almond, S.W., Briscoe, J.E., and Harris, L.E.: "Chemical Model for the Rheological Behavior of Crosslinked Fluid Systems", JPT, **315**, February 1983.

18. Conway, M.W., Slabaugh, B., and Hurst, G.D.: "An Investigation of the Rheology and Proppant Transport of Common Fracturing Fluids," *1991 STIM-LAB Rheology Consortium Final Summary Report*, (February 1992).

19. Penny, G.S. and Conway, M.W.: "Fracturing Fluid Leakoff and Damage Mechanisms in Coalbed Methane Reservoirs," paper SPE 25863 to be presented at the 1993 SPE Joint Rocky Mountain Regional Meeting and Low Permeability Reservoir Symposium, Denver, CO, April 26-28.

20. Keck, R. G., Nehmer, W.L., and Strumolo, G.S.: "A New Method for Predicting Friction Pressure and Rheology of Proppant-Laden Fracturing Fluids," paper SPE 19771 presented at the 1989 Annual Technical Conference and exhibition, San Antonio, TX, October 8-11.

21. Conway, M.W., Slabaugh, B., Hurst, G.D.: "An Investigation of the Rheology and Proppant Transport of Common Fracturing Fluids," *1992 STIM-LAB Rheology Consortium Final Summary Report*, (February 1993).

22. Penny, G.S.: "Cell Assembly for Determining Conductivity and Permeability," U.S. Patent No. 4,791,822, December 20, 1988.

23. Penny, G.S. and Conway, M.W.: "Fluid Leakoff," *Recent Advances in Hydraulic Fracturing,* Gidley, J.L, Holditch, S.A., Nierode, D.E. and Veatch, R.W., eds. Monograph Series, SPE, Richardson, TX (1989) **12**.

24. Elbel, J., Gulbis, J., King, M.T., and Maniere, J.: "Increased Breaker Concentration in Fracturing Fluids Results in Improved Gas Well Performance," paper SPE 21716 presented at the 1991 Production Operations Symposium, Oklahoma City, OK, April 7-9.

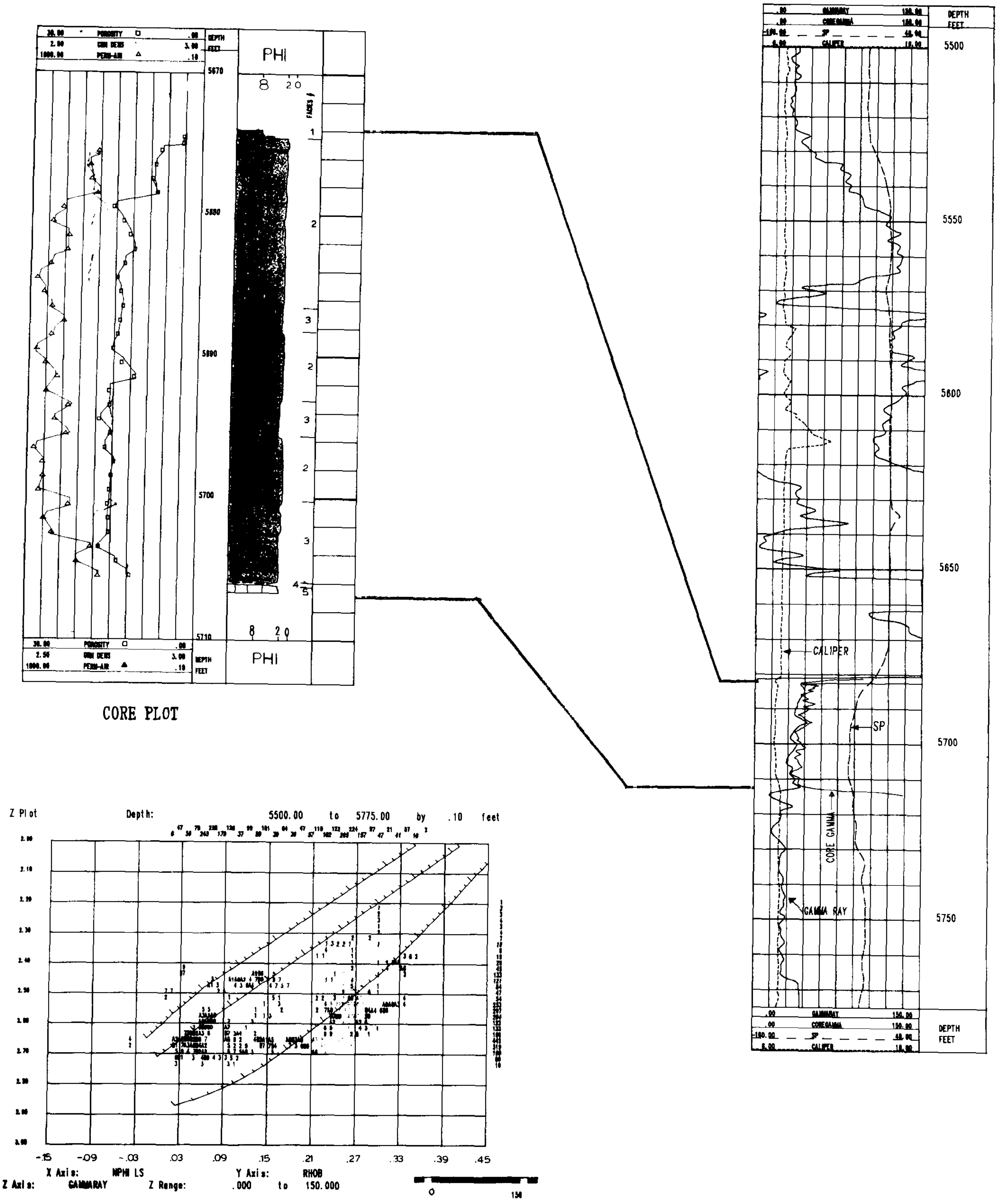


Figure 1a - Log montage for the Upper Morrow Formation. Above right shows gamma ray, core gamma and SP (spontaneous potential) with core properties of porosity, grain density, air permeability and facies number (upper left). Lower left shows a neutron (X) vs. density (Y) with gamma ray (Z) crossplotted.

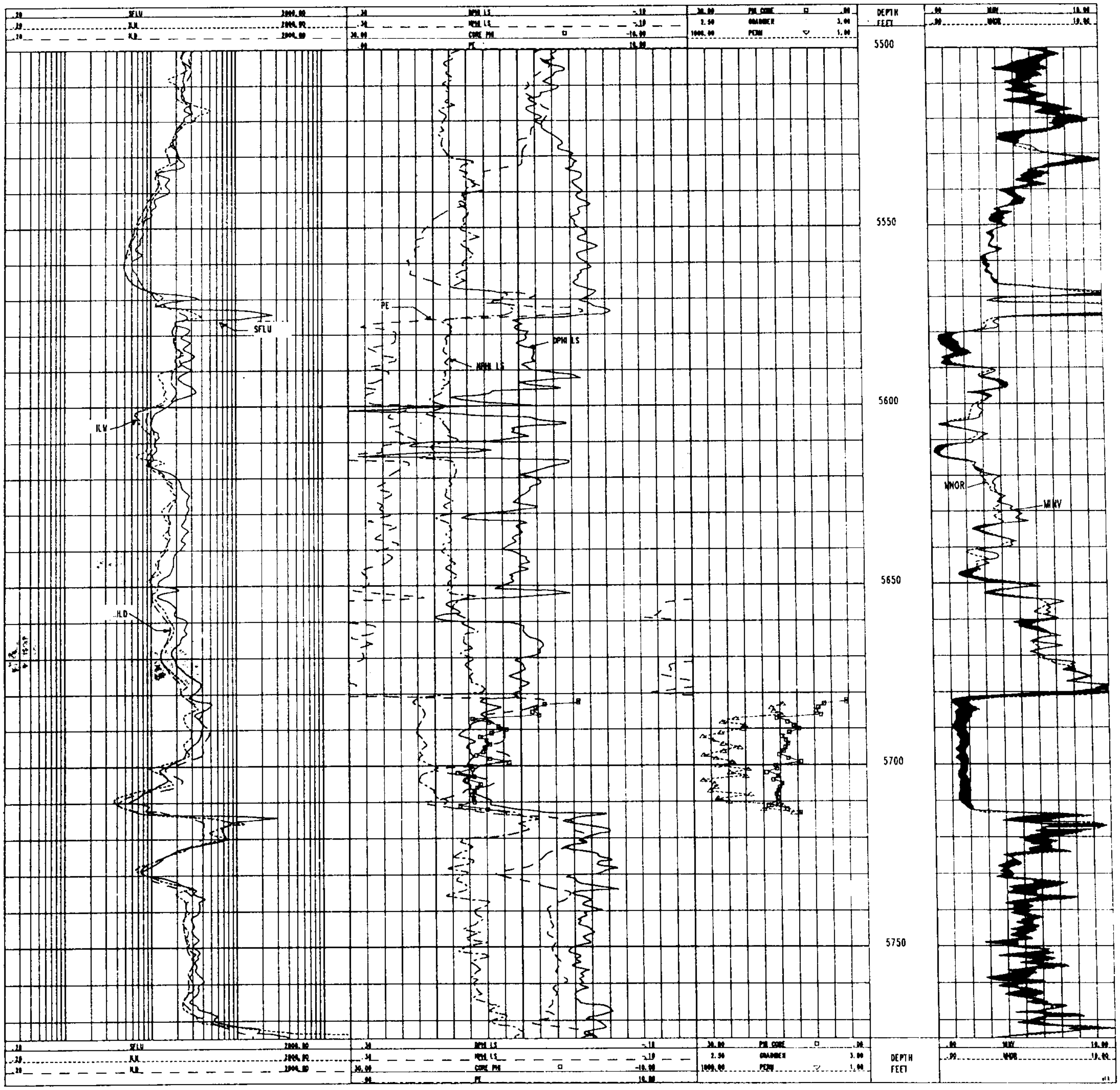


Figure 1b - Log montage (continued). From right to left, MINV = micronormal, MNOR = micronormal, phi = porosity, grainden = grain density, perm = permeability, DPHI LS = density porosity limestone base (2.71 g/cc), NPHI LS = neutron porosity limestone base, SFLU = shallow focus log, ILM = medium induction log, ILD = deep induction log, and SP = spontaneous potential. From Target Reservoir Analysis.

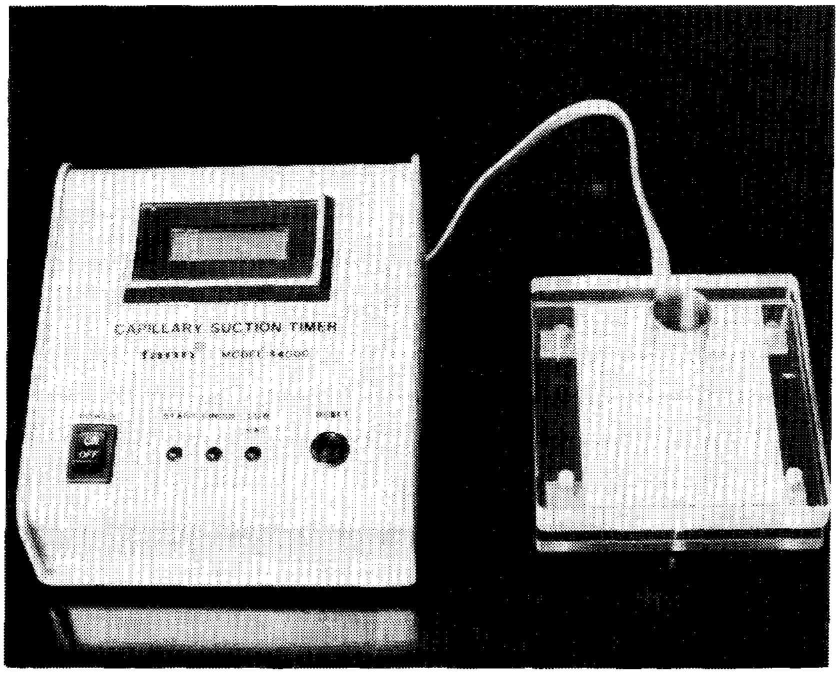


Figure 2 - Capillary suction time testing device

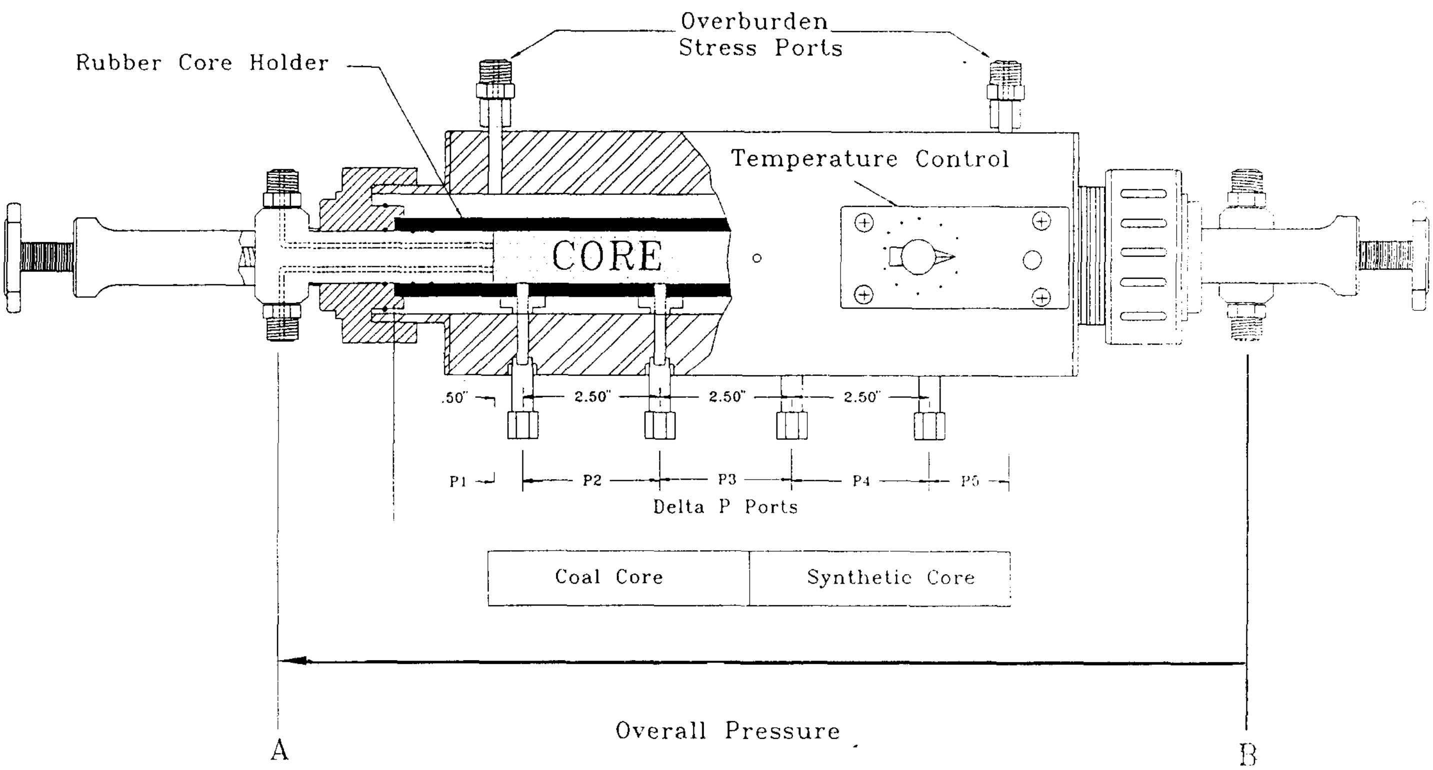


Figure 3a - Multiport Hassler Sleeve device for fluid damage testing and matrix acidizing

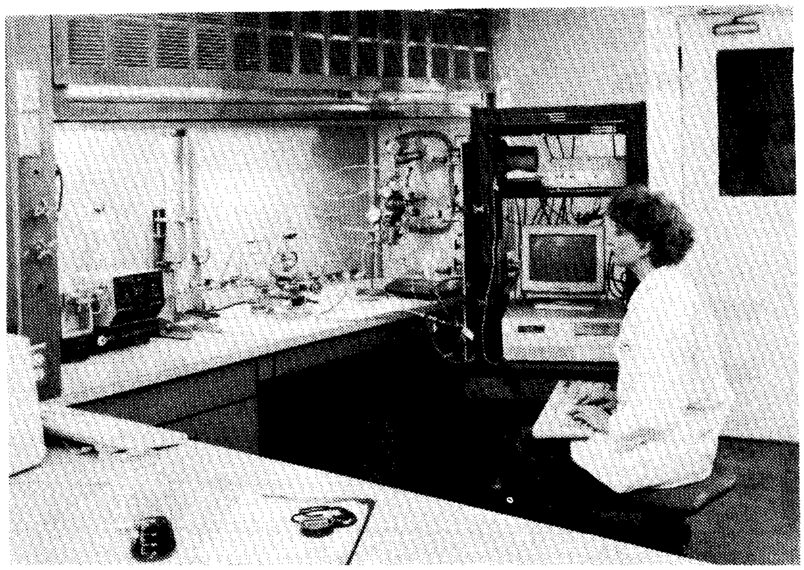


Figure 3b - Overall view of automated core flow and acidizing equipment

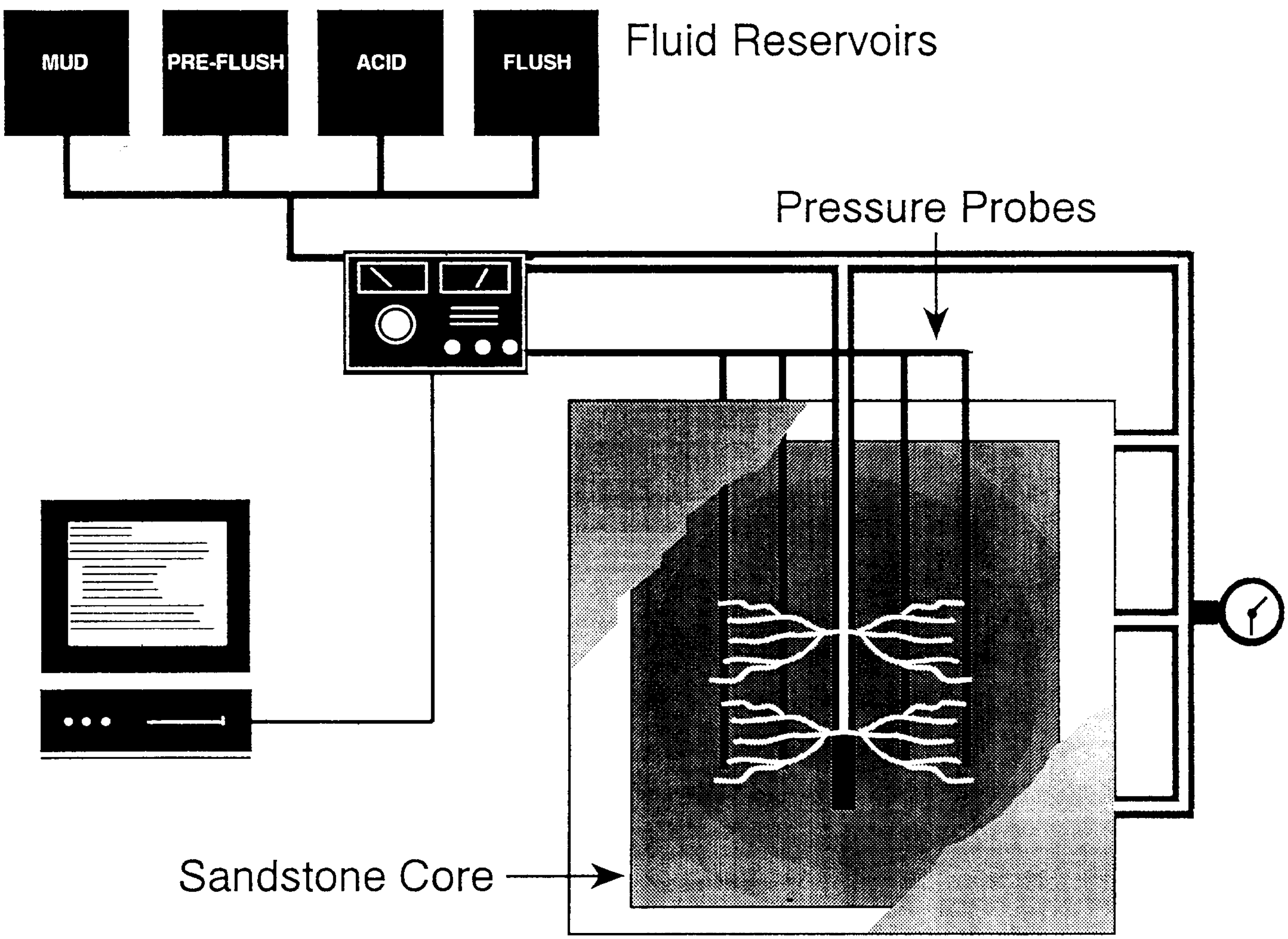


Figure 4 - Schematic of radial matrix acidizing equipment

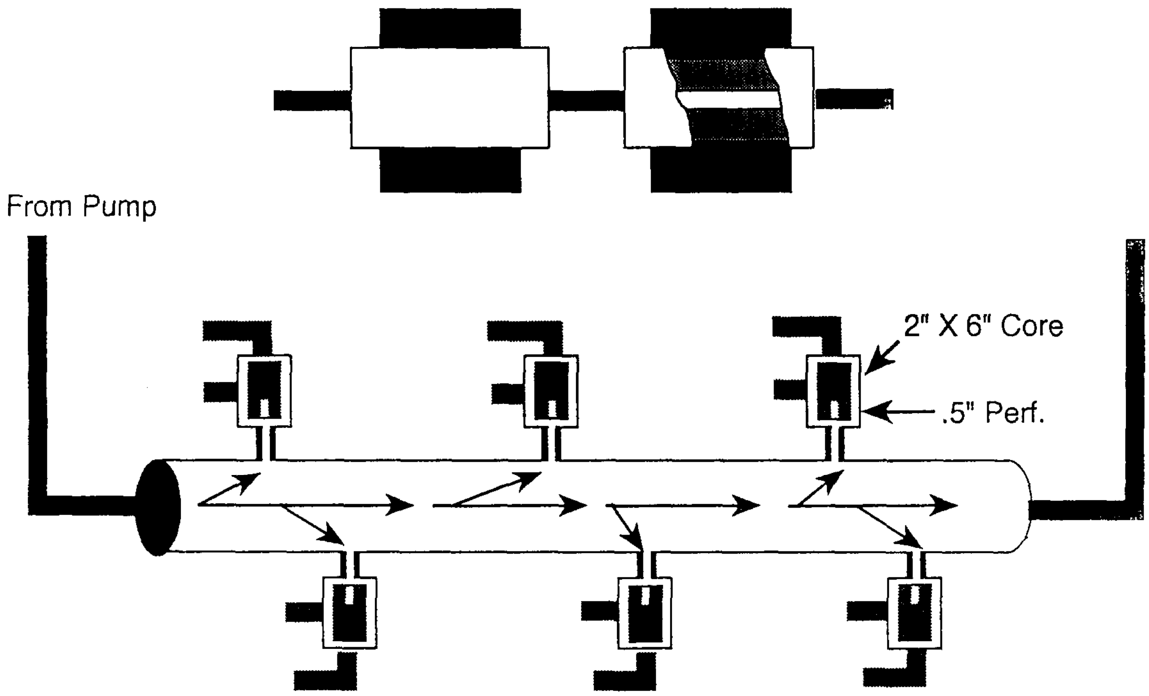


Figure 5 - Schematic of matrix diversion equipment including a slotted liner/open hole model (top) and a perforation model (bottom).

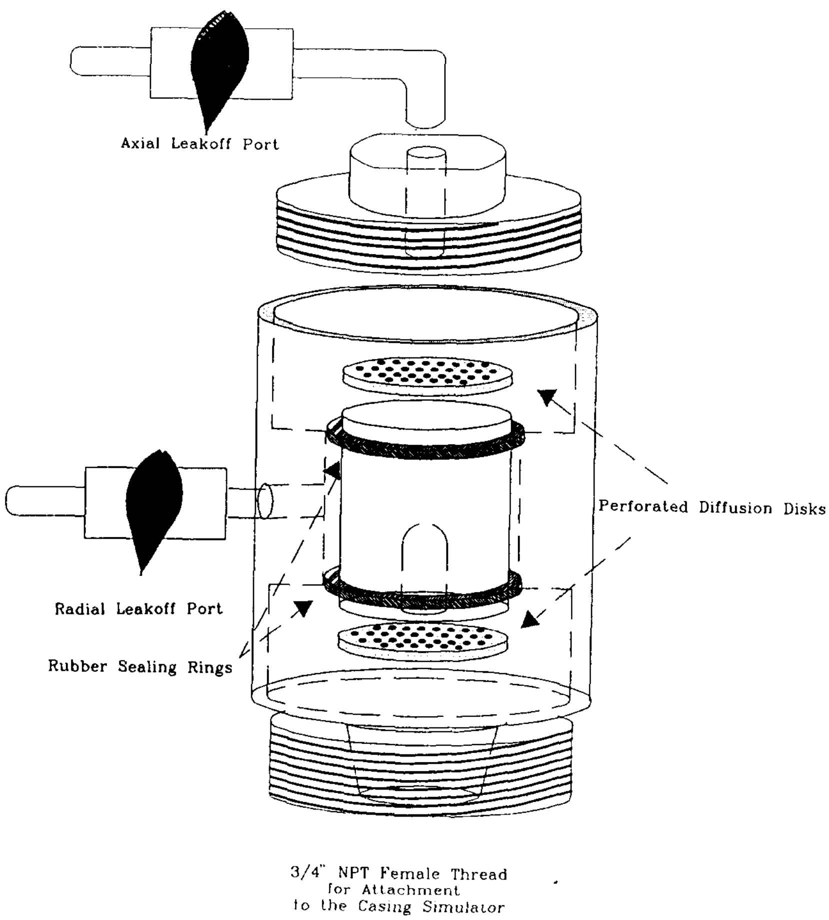


Figure 6 - Radial leakoff perforation assembly featuring a 2 in. diameter by 6 in. long core with a 0.5 in. perforation

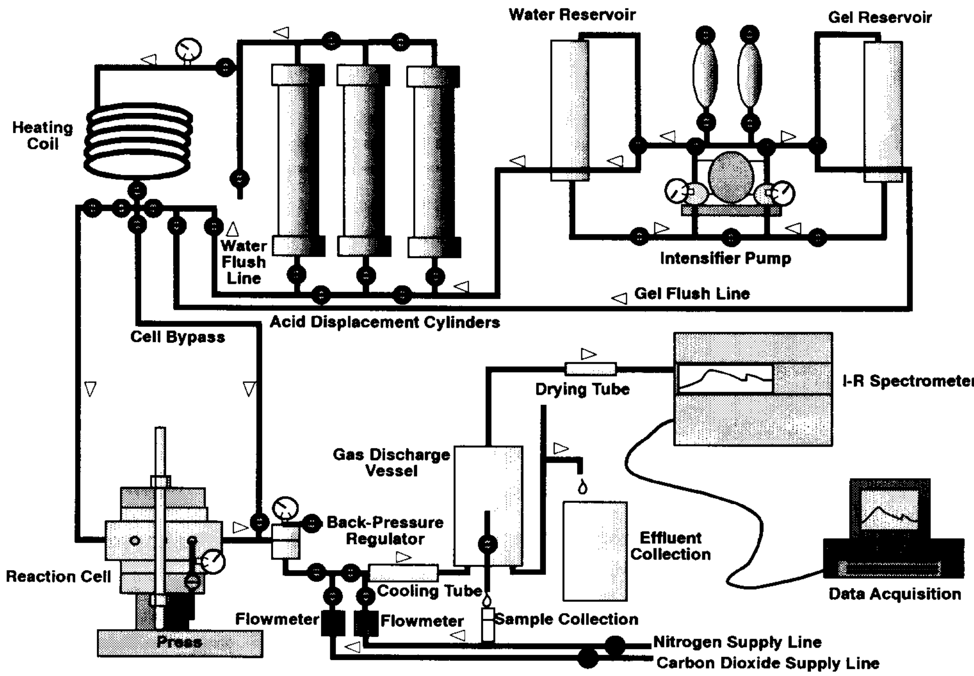


Figure 7 - Schematic of STIM-LAB fracture acidizing reaction rate apparatus with a 10 sq. in. core slabs on each side of the reaction cell

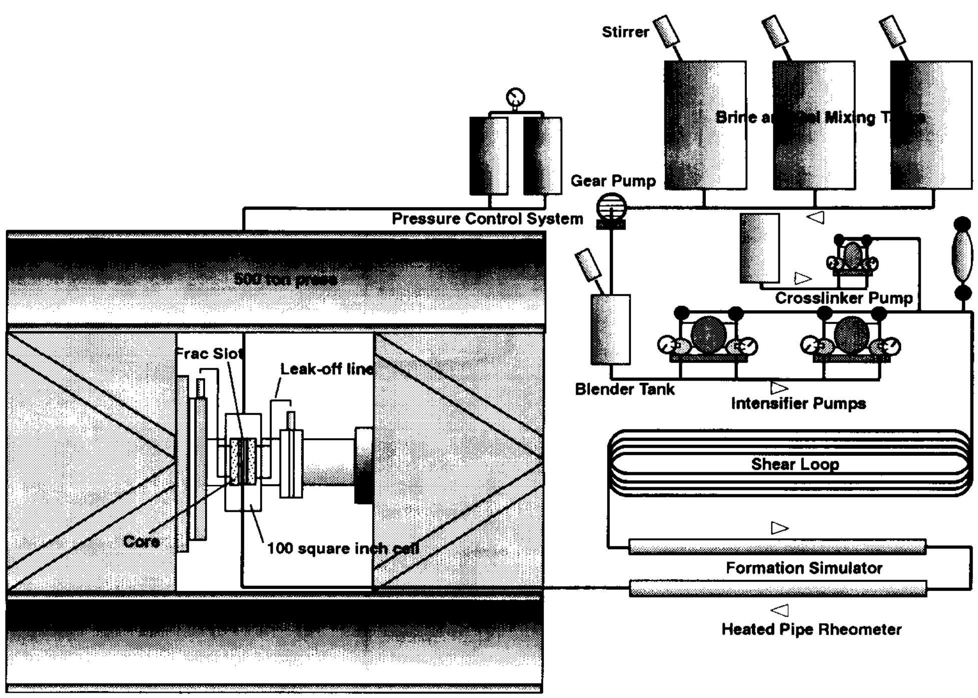


Figure 8a - Schematic of large scale fracture simulation system. There is a 100 sq. in. core slab on each side of the flow path.

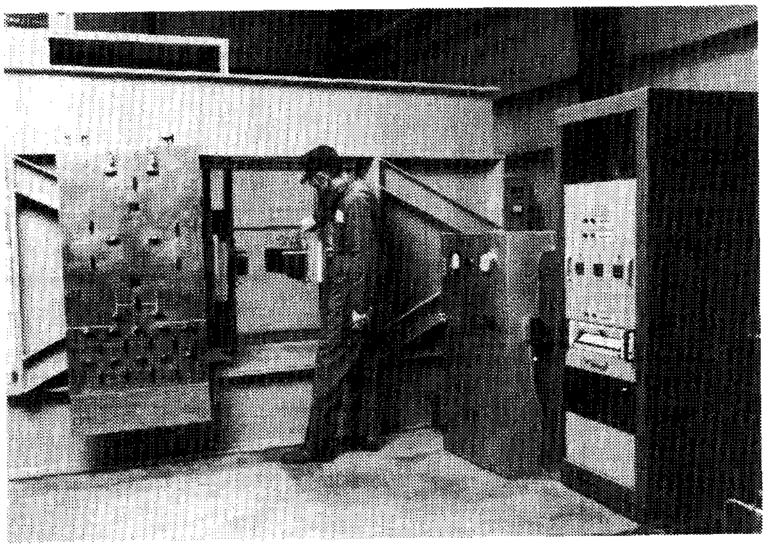


Figure 8b - Photograph of the million pound press assembly to house the 100 sq. in. fracture simulation cell

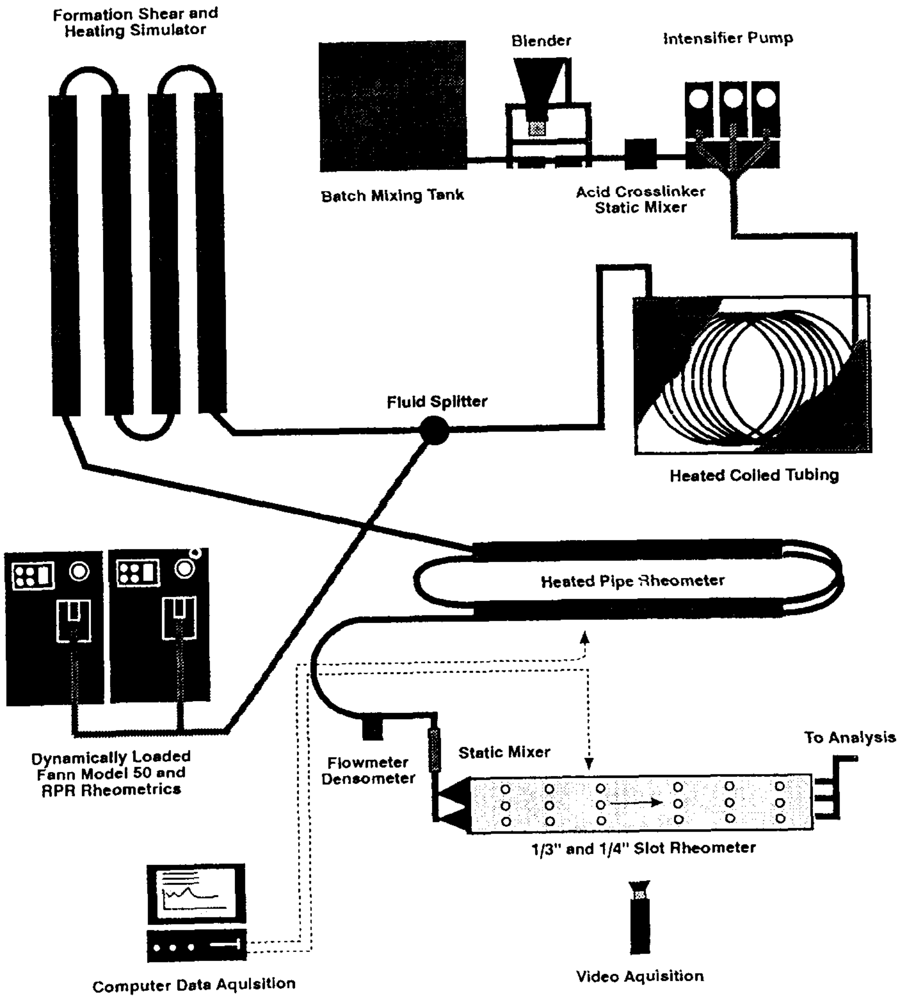


Figure 9a - Schematic of large scale rheology and proppant transport equipment. The system features full scale pumps and blending equipment.

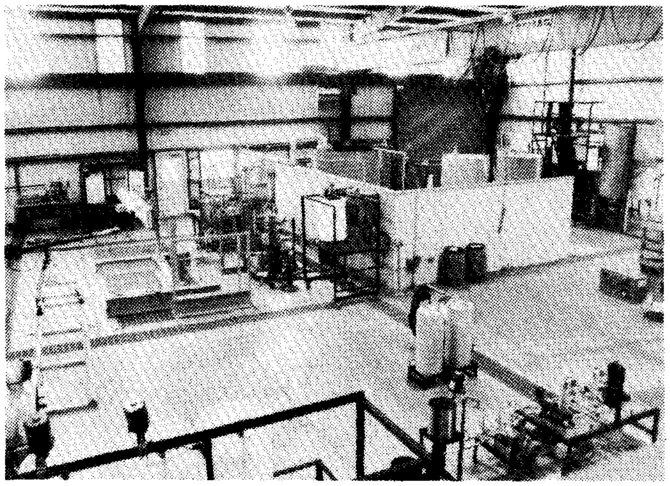


Figure 9b - Overview of STIM-LAB fracturing treatment simulation lab to characterize the rheology and proppant transport of fracturing fluids

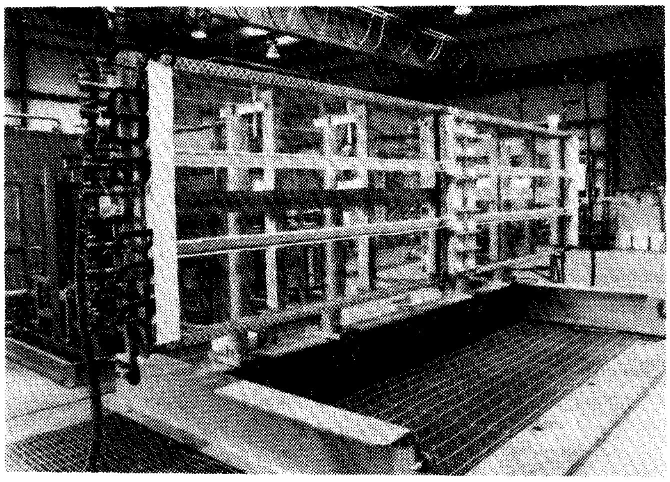


Figure 10 - 4 ft. by 16 ft. see-through slot device for measuring rheology and proppant transport in slot flow at low pressures

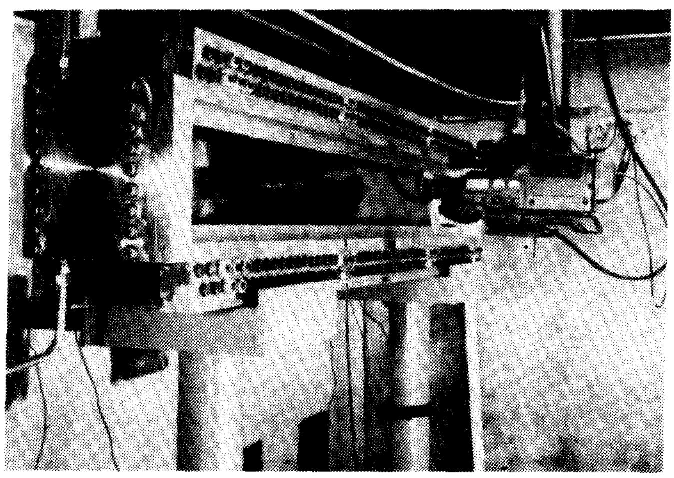
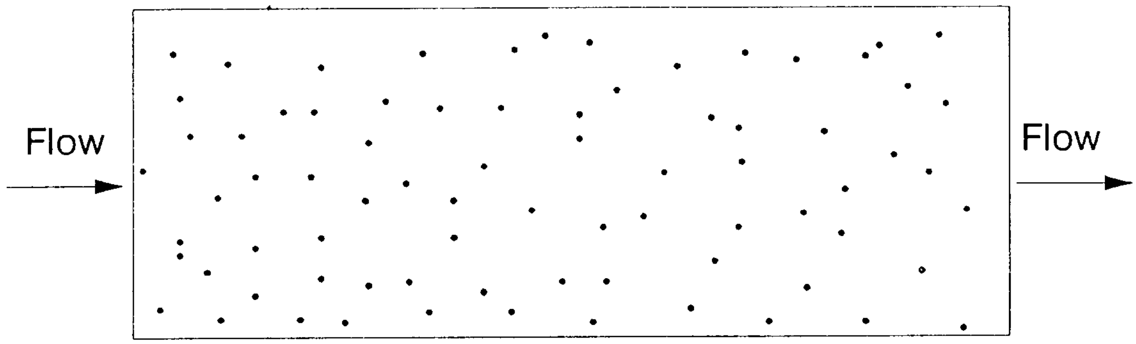
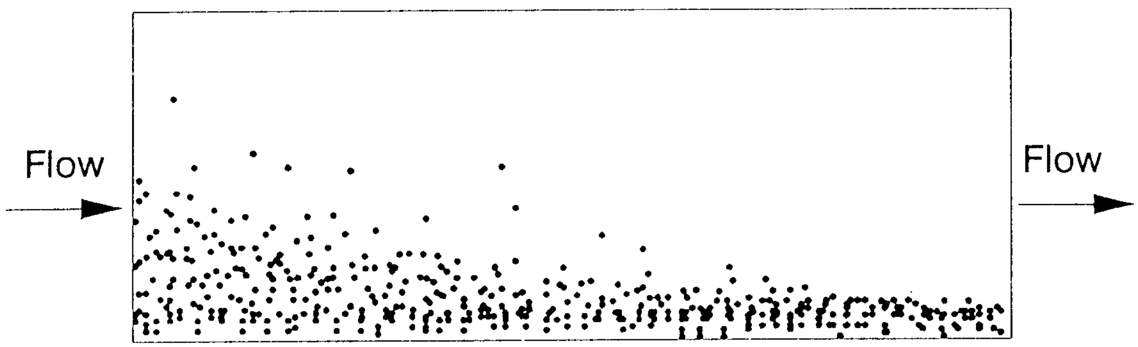


Figure 11 - 6 ft. long high pressure slot for measuring the rheology and proppant transport of fracturing fluids including foams up to 1500 psi and 300° F. The device is housed underground and is videotaped remotely.



pH 10



pH 8.8

Figure 12 - Proppant transport appearance of a 4 lb./gal. 20/40 sand in
35 lb. guar + 1.2 lb. borate at pH 10 and 4 lb borate
at pH 8.8 at 150° F

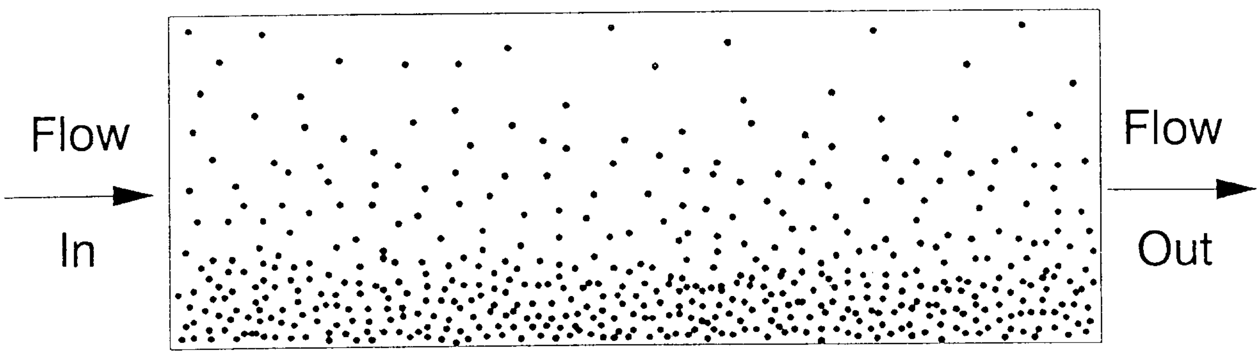


Figure 13 - Proppant transport of 20/40 sand in 40 lb. HPG + titanates
and zirconates at temperatures of 150 to 250° F

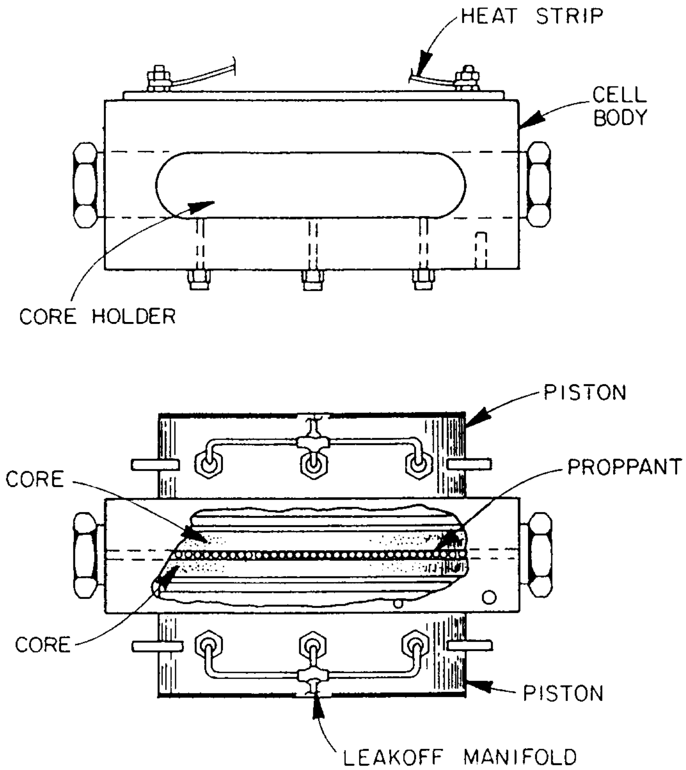


Figure 14a - Patented STIM-LAB cell for the measurement of leakoff and conductivity with core and fracturing fluids

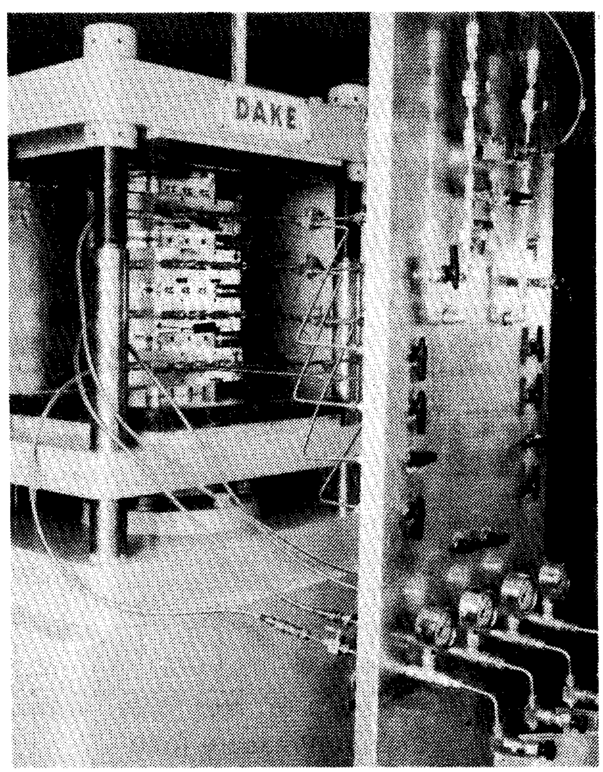


Figure 14b - Photograph of leakoff and conductivity cells in a Dake press

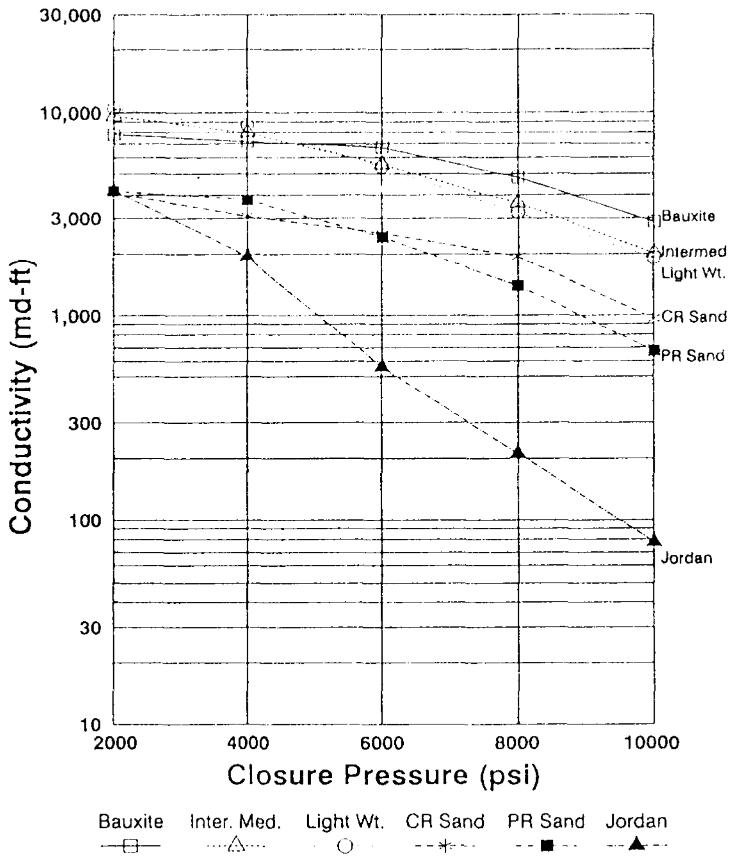


Figure 15 - Long term conductivity of 2 lb./sq. ft. 20/40 proppants between Ohio sandstone with 2% KCl at 200° F

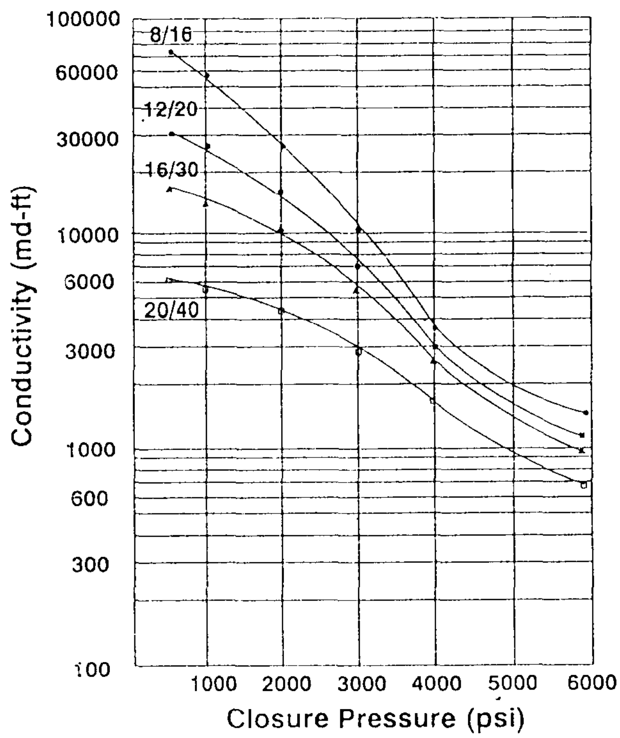


Figure 16 - Long term conductivity of 2 lb. sq. ft. Brady sands between Ohio sandstone with 2% KCl and 150° F

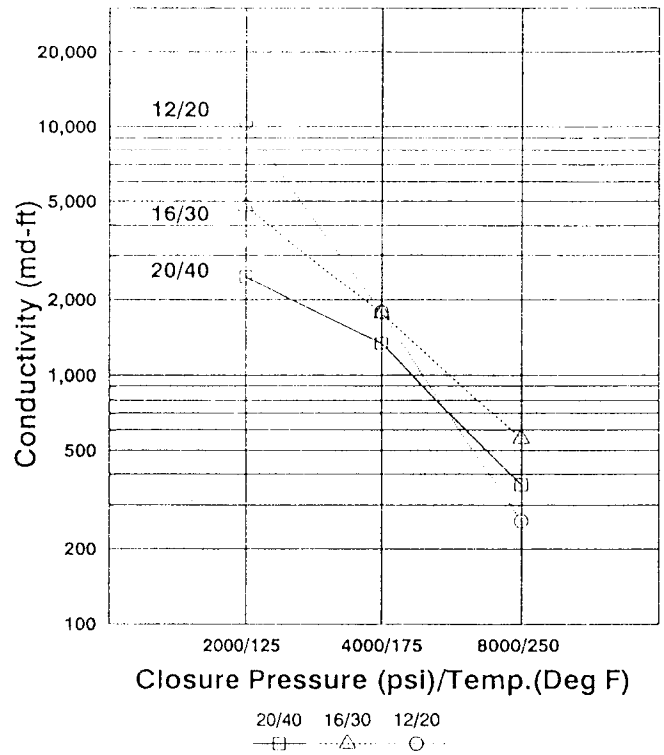


Figure 17 - Long term conductivity of 1 lb./sq. ft. Brady sands between Ohio sandstone at the indicated closure and temperature

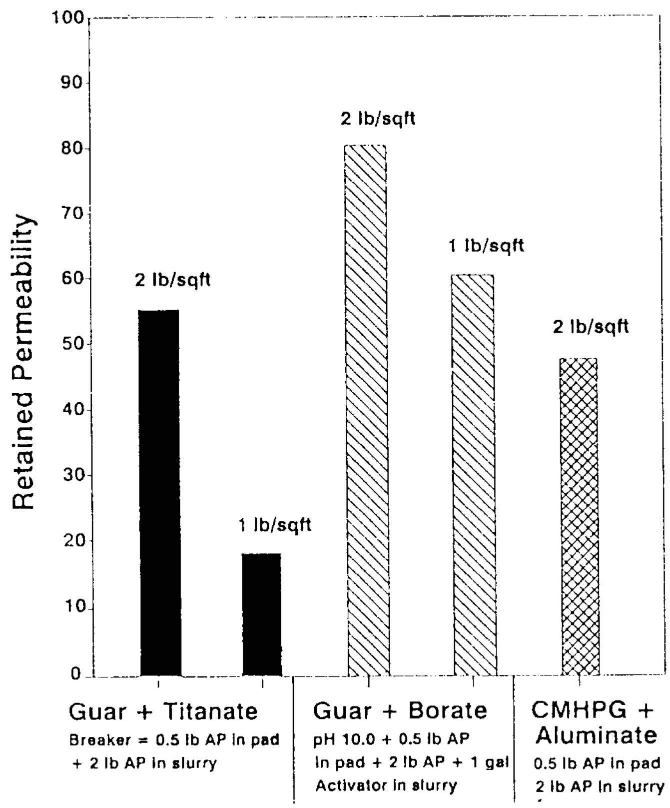


Figure 18 - Retained permeability vs. fracturing fluid for 1 and 2 lb./sq. ft. 20/40 Jordan sand between Ohio sandstone at a closure of 3000 psi and a temperature of 150° F. Fracturing fluid leakoff was conducted at 120° F.