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GEOPRESSURED AQUIFER SIMULATOR

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Abstract

Ten natural gas companies have funded the Institute of Gas Technology (IGT) development of a laboratory facility for fluid and core analyses at temperatures and pressures characteristic of geopressured aquifers. The facility has been designed and constructed to measure the following parameters at pressures up to 20,000 psi and temperatures to 450^{O}F:

- Solubility of methane in brines from actual geopressured aquifers
- Dependence of compression and compaction reservoir drive upon pressure
- Dependence of permeability upon reservoir pressure and temperatures
- Dependence of relative permeabilities to gas and to water upon the water saturation of pores, pressure, and temperature.

Brine pumped through the core can be either gas-free or from a reservoir of brine with gas in solution. The facility is modular in design with major components including the reservoir of gas-saturated brine, high-pressure positive displacement pumps, and the core holder housed in a large oven. All components contacted by high-pressure, high-temperature brine are fabricated from Hastelloy C-276, Elgaloy, or Inconel 625 to avoid corrosion.

The temperatures, pressures, differential pressure, and flow rates are controlled and/or recorded by a digital microcomputer/microprocessor. Operation will be controlled from a separate room and programmed; hands-off operation will be the normal mode of operation.

The facility has been constructed and is now being tested. Following performance testing with Berea sandstone, initial emphasis will be upon studies of brine and available core from DOE's Pleasant Bayou No. 1 and No. 2 wells.

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Introduction

Production of reservoir fluids depends on fluid properties, the rock properties, and their interaction under the dynamic conditions of in situ stresses and temperatures. Since the early 1950's, studies have been performed on the effects of confining pressure, pore pressure, and temperature on all the properties important to reservoir modeling. Every property is affected to some extent by changes in either the mechanical or chemical environment. Because of the complexity of rocks (including mineralogy, grain size, lithology, previous stress history of contained minerals, pore size distribution, diagenesis, and cementing), the degree to which rocks respond to environmental changes can be highly variable. Insufficient work has been done to permit empirical correction of routine core analysis data to the conditions in real reservoirs. Therefore, understanding the properties of rocks and the production of natural gas from geopressured aquifers requires the careful application of established core and fluid analysis techniques under more extreme conditions of temperature, pressure, and fluid chemistry characteristic of these reservoirs. A system has been built to accommodate these new extreme *in situ* conditions. The system is modular in design and microprocessor controlled. It is capable of measuring absolute and relative permeabilities; bulk, pore, and fluid compressibility; methane solubility in brine; capillary pressure; and porosity at pressures up to 20,000 psi and temperatures up to 450°F. The system will measure properties of fluids and core taken from wells in geopressured aquifers using simulated or actual formation fluids. All wetted parts of the system are made of the most corrosion-resistant components available.

This paper reviews briefly recent studies on the effects of pressure and temperature on reservoir properties as they are measured by core analysis and describes the apparatus and its operation.

Background

A very brief description follows on the effects of environmental changes on core properties. Most of these studies concentrated on only one property change as a function of one change in the core environment. Few studies have been conducted under the pressures and temperatures found in actual reservoirs, nor has any work extended into the range of conditions experienced in geopressured-geothermal aquifers. The applicability of independently measured property changes in different apparatus on different cores has not been evaluated.

The permeability of porous media is primarily affected by pore geometry which is, in turn, strongly affected by stress, temperature, and pore fluid chemistry. Investigators [1, 2, 3, and 4] have shown that absolute permeability is reduced by as much as 10% to 50% at net confining pressures of 7000 psi for sandstones. The large range is due primarily to the extent of consolidation and nature of the cementing material. Recent evidence [5, 6] indicates that permeability is dependent on both the pore pressure and confining stress rather than only the difference between these, the effective stress, as had been assumed. Differences in permeability of as much as 25% have been found between permeabilities measured at the same net confining pressure, but at pore pressures of atmospheric and 2000 psi for Berea [6].

Little work has been performed on the dependence of relative permeability on pressure. Fatt [7] found no effect up to 3000 psi confining pressure for a gas-oil system. Wilson [8] determined that relative permeability to water-oil is marginally sensitive to effective stress at confining pressures up to 10,000 psi and pore pressures up to 5000 psi. However, none of these studies were conducted in the high, partial-water-saturation region similar to geopressured-geothermal aquifers, and no studies have been performed for gas-water systems at high pore pressures.

Single-phase permeability to water flow has been found to decrease with increasing temperature [9, 10, 11, 12, 4, 13]. Temperature effects are hypothesized to be due to both the thermal effects on mechanical stresses and fluid-rock surface effects. Permeability to water was reduced by as much as 35% in packed Ottowa sand [9], 70% in Prieto sandstone [12], and between 40% and 60% for Berea and Boise sandstone [4, 11] at temperatures less than $300^{o}F$. This effect is less pronounced for oil-saturated cores at higher temperatures.

Capillary pressure curves. irreducible water saturation, and relative permeabilities are also strongly temperature-dependent [11, 14, 15].

Non-wetting phase relative permeability increases significantly while wetting phase relative permeability decreases slightly with increasing temperature. Sinnokrot [15] reported that the drainage-imbibition curve hysteresis for oil-water systems became less pronounced as temperature increased, finally disappearing at 300^{o}F for the saturation ranges studied. In general, these investigators have found with increases in temperature that 1) irreducible water saturation increases, 2) residual oil (non-wetting phase) saturation decreases, 3) the relative permeability to water at flood-out increases, 4) the relative permeability to oil increases, 5) the relative permeability ratio K_w/K_{nw} decreases, and 6) absolute permeability decreases.

In addition to these studies, Geffen et al. [18], reported trapping of gas on imbibition-drainage cycling. This also would result in different K_{rg}/K_{rw} versus S_w curves, possibly resulting in waterflood cutoffs [19]. However, these tests were conducted at low temperatures.

Empirical formulae have been reported by Corey [16] and used for estimates of gas-water relative permeability curves. However, little research has been done at the high water saturation/low gas saturations that would be characteristic of geopressured aquifers. Pirson et al. [17], have formulated a very different empirical formula than Corey for describing both imbibition and drainage relative permeability curves. At high water saturations (90%), the Corey and Pirson approaches give significant differences in both wetting and non-wetting relative permeability curve shapes.

In a geopressured aquifer, there are at least four major driving forces that contribute to brine production. These forces are fluid compressibility;

rock compressibility; compaction of bounding shales; and gas drive from a gas cap or form gas coming out of solution. Some of these forces involve mechanisms that reduce permeability and thereby flow rates.

Compressibility of reservoir fluids is strongly dependent on temperature, pressure, and the amount and composition of dissolved solids and gases. The effect of pressure and temperature on solids in solution have been studied up to $212^{o}F$, 7117.7 psig, and 300,000 ppm NaCl [20]. Compressibilities decrease linearly as a function of dissolved solids and increase as a function of dissolved gas. Increase in compressibility of as much as 18% has been reported for a gas solubility of 20 SCF/bbl [21]. Unfortunately, these studies of compressibility do not extend into the pressure and temperature range of geopressured-geothermal aquifers.

Rock pore compressibility is an important factor in evaluating the compaction drive mechanism and rock bulk compressibility provides an estimate of the reservoir compaction, which in turn can lead to surface subsidence. Various investigators have reported the pressure and temperature dependence of pore and bulk compressibilities [2, 10, 22]. Mann and Fatt [23] have reported a 600% change in pore compressibility of Berea sandstone under a confining pressure change from 1000 to 10,000 psi. Fatt [24] found the pore compressibility variation to range from 100% to 500% in sandstones. The extent to which these compressibilities change with internal as well as external stress vary for individual rocks. The concept of effective stress attempts to represent the effects of both external and internal pressures through a single variable. There does not seem to be universal agreement as to the validity of this concept. The pressure dependence of compressibility implies nonlinear stress-strain relationships. The exact form of these relations would depend on the mineralogical composition and the degree of consolidation of the rocks. It is therefore necessary to conduct the compressibility studies at in situ pressures and temperatures on the particular rocks of interest to obtain realistic interpretations of well test data.

These studies have all demonstrated the significant effects that pressure, temperature, and solution chemistry can have on all the properties of reservoir rocks and therefore on reservoir models. The need for determination of rock properties under complete in situ conditions has been well demonstrated. Only by study under complete in situ conditions is it possible to evaluate the interaction and possible synergistic relations of environmental conditions on core analysis.

Design Constraints

The geopressured aquifer simulator is designed to determine absolute and relative permeabilities, and bulk, pore and fluid compressibilities at temperatures and pressures found in geopressured aquifers. These properties are determined by measuring and controlling 1) gas and liquid flow rates, 2) gas and liquid delivered volumes at specific flow rates, 3) absolute pressure, 4) differential pressure, 5) temperature, 6) water saturation in the core, and 7) solution chemistry. These measurements and controls must be possible over the wide range in reservoir characteristics. The reservoir characteristics which have been designed for are described below.

Lithostatic Pressure. Reservoir confining pressures vary with overburden pressure and tectonic stress. In general, the lithostatic pressure gradient for sediments is approximately 1 psi/ft of depth. The deepest production depth will probably not exceed 20,000 feet, and, therefore, the maximum confining pressures range from routine core analysis pressures (~200 psi) to lithostatic pressures (20,000 psi). Because of the complexity of tectonic stresses, initial research will concentrate on hydrostatic confining pressure. Provisions have been made for retrofitting to accommodate uniaxial stress loading for future work. The absolute pressures are measured with 0.1%-accuracy gauges and transducers.

Reservoir Pressure. Pore pressures can range from hydrostatic (~.47 psi/ft) to near lithostatic (1.0 psi/ft). For Gulf Coast geopressured areas, the assumed height of geopressure is roughly 10,000 feet. Therefore, pressures range from 4700-20,000 psi. Pressures can be measured in this system to an accuracy of 0.1% using pressure transducers or are subject to a maximum error of 20 psi at 20,000 psi. Differential fluid pressures across the core are measured from 0.005 psid to hundreds of psid at total pressure up to 20,000 psi.

Temperature. Geothermal gradients may range widely for different areas and formations. In hydropressure regions, gradient may range from 2.1^{o}F/100 ft to 3.2^{o}F/100 ft. Some geopressured thermal gradients may be as high as 6.4^{o}F/100 ft. It was assumed that for most geopressured aquifers, temperatures would range from 150^{o}F at 10,000 feet to 450^{o}F at 20,000 feet. These assumptions set upper temperature and pressure limits for the system at 20,000 psi and 450^{o}F. Temperatures are measured using chromel-alumel thermocouples to within 0.5^{o}F.

Compressibility. The three types of compressibility, fluid, pore, and bulk each have different ranges of values. Fluid compressibilities can range from compressibility of pure water (~3 X 10^{-6}/psi) to that of brine with dissolved gas (~5 X 10^{-6}/psi). Rock pore compressibilities as high as 400 X 10^{-6}/psi have been measured for unconsolidated material. A more reasonable maximum value that might be expected is 100 X 10-6/psi. Based on the fluid and rock compressibilities, the expected range in measured compressibility for geopressured aquifers may be between 3 X 10^{-6}/psi and 100 X 10^{-6}/psi. To obtain an accuracy of 1.0% in compressibility measurements for the volume in this system, volume changes of 1 X 10^{-3}cc must be measurable for pressure changes of 500 psi.

Absolute Permeability. Maximum routine core analysis permeabilities have been measured to 1000 md. From kh calculations, assuming a block 200 feet thick produces 10,000 bbl/day, a minimal economically feasible reservoir permeability of 0.1 md is required. Therefore, the range in absolute permeability designed for is 0.1 md to 1000 md.

Porosity. Porosity values will most likely range from 10% to 35%. For a 1-inch diameter X 2-inch long core, the total volume is 25.75cc with a range of pore volume of 2.58cc to 9.0cc.

Core Sizes. Cores cut parallel or perpendicular to the bedding plane must be cut from whole core that will probably be no greater than 4-1/2 inches in diameter. Design was for cores up to 2 inches in diameter.

Gas Solubility. For the ranges in pressures and temperatures discussed above, the gas solubilities can range from 160 SCF/bbl for fresh water at 20,000 psi and 450^{o}F to zero SCF/bbl for reservoir fluids with no dissolved gas.

Relative Permeability. To determine the expected relative permeability for a geopressured-geothermal aquifer, certain approximations must be made. As a rough first approximation, it is assumed that K_{rg}/K_{rw} is independent of pressure, temperature, and salinity. For the case where free gas flow is equal to solution gas flow (solution gas is that gas dissolved in reservoir fluid), the $K_{rg}/K_{rw} = 1 \times 10^{-3}$ to 3×10^{-3}. For a potential range where free gas flow is significantly greater or less than solution gas flow, the value of K_{rg}/K_{rw} would range from 1×10^{-4} to 1×10^{-2}. For $K_{rg}/K_{rw} = 1 \times 10^{-4}$, we may approximate that $K_{rw} = 1$, so that $K_{rg} = 1 \times 10^{-4}$. For the upper bound, $K_{rg}/K_{rw} = 1 \times 10^{-2}$, more detailed approximations must be made. In that case, the equation formulated by Corey to obtain approximate relative permeabilty curves was used. For critical or irreducible water saturations from 10% to 30% and critical gas saturations from 0% to 10%, values for K_{rw} are approximately 0.5 so that $K_{rg} = 5 \times 10^{-3}$. For an absolute permeability range of 0.1 md to 1000 md, this leads to the effective permeabilities shown below.

$10^{-4} < K_{rg}/K_{rw} < 10^{-2}$	$0.1 \text{ md} < K_{ABS} < 1000 \text{ md}$
$10^{-4} < K_{rg} < 5 \times 10^{-3}$	$10^{-5} < K_{eg} < 5 \text{ md}$
$0.5 < K_{rw} < 1$	$0.05 \text{ md} < K_{ew} < 1000 \text{ md}$

To accomodate the dynamic range in permeability of 10^8, different relative permeability techniques are utilized for different ranges. These are described below. The techniques are individually capable of making measurements in the full range desired, but have regions of highest accuracy. Different regions overlap, including regions inside and outside of the range of geopressured-geothermal aquifers. Accuracy of the measurement of absolute and effective ($K_r \times K_{ABS}$) permeabilities on core for the range shown above involves the accurate measurement of flow rates, differential pressures, partial water saturation in the core, and an understanding of the physical properties, primarily viscosity, of the fluids used.

Flow rates, pressures, and differential pressures are capable of being measured with accuracies of greater than 1%. However, partial water saturation in the core and viscosities are more difficult to determine. To measure partial water saturations at reservoir conditions (confining pressure, pore pressure, temperature), either a direct measurement of the fluid volumes used or expelled to impose a specific saturation on the core is made, or a measurement is made of a secondary property such as electrical resistivity, emissions of radioisotope tagged fluids, etc., that is affected by saturation changes. Because the positive displacement pumps can be monitored to obtain flow rate and total volume, it is possible to impose known saturations on the core for some of the steady-state permeability measuring methods. It is therefore necessary to use these methods to calibrate changes in a property such as resistivity to be used for another permeability measurement. This introduces greater error than a primary measurement and, though calibrations have not been performed to date, will probably reduce accuracies of water saturation measurement to 1 to 3%. Tests have indicated that electrical resistivity is temperature dependent and is dependent on the rock used. Thus, for measurements of permeability by non-steady-state methods, detailed pretesting is required.

Calculation of permeability from the Darcy equation using flow rate and differential pressure measurements also requires a value for viscosity. Although empirical relations exist for mixtures of two fluids at high pressures and temperatures, no measurements have been made of viscosity for gas-saturated brines such as those found in geopressured-geothermal aquifers. Extrapolation of viscosity data taken at lower pressures and temperatures introduces possible large errors. For this system, values for $K\mu$ (permeability X viscosity) can be measured to within 1-3%, but without separate measurements on viscosities of the above fluids used at pressure, temperature, and particularly chemistry, the accuracy of the permeability alone is tied to the accuracy to which the viscosity is known.

Apparatus Description and Methods

As discussed, the geopressured aquifer simulator is designed to measure methane solubility in brine; absolute permeability; gas and/or liquid relative permeability; bulk, pore, and fluid compressibilities; capillary pressure, and pore volume at pressures up to 20,000 psi and temperatures up to 450°F. Core with dimensions between 3/4 inch and 2 inches in diameter and up to 12 inches long can be accommodated in a hydrostatic core holder. The end caps of the core holder have electrical feedthroughs for strain gauges and electrical resistivity probes.

To minimize corrosion, the wetted parts of the system are made of Hastelloy C-276, Elgaloy, or Inconel 625. These materials are required in order to accommodate actual reservoir fluids at reservoir pressures and temperatures. Most of the components are contained within a large air-heated oven.

The flow rate through the core and back pressure regulation are established with pumps where displacement rate is microprocessor-controlled. A special feature of the system is a battery of three differential pressure transducers capable of measuring 0 to 5 psid, 0 to

50 psid, and 0 to 500 psid across the core for pore pressure up to 20,000 psi.

The system has a modular design and can perform several distinct functions. The system is illustrated in Figure 1, schematically in Figure 2, and pictured in Figure 3. A functional description of the subsystems follows. These subsystems are —

1. Core holder
2. Lithostatic pressure generating module
3. Gas delivery system
4. Liquid delivery system
5. Gas-liquid saturation and separating loop
6. Minicomputer/microprocessor control system.

Core Holder

The core holder and end caps are made of Hastelloy C-276. Access ports for pore fluids and differential pressure measurements are contained in one vessel head. Electrical feedthrough for strain gauges and resistivity probes and a port for the confining fluid are in the opposite head. O-ring seals on the vessel heads are made of the fluorocarbon Kalrez (T. M. DuPont Co.). For low-temperature measurements, the cores are contained in rubber sleeves. At high temperatures, metal sheaths are used to contain the cores.

The core and pore fluid temperatures may be controlled together by controlling the oven temperature, or the core temperature may be controlled independently of the pore fluid temperature. The independent control is obtained by a separate temperature contol on the confining fluid reservoir. Effects of fluid reinjection on the core may be

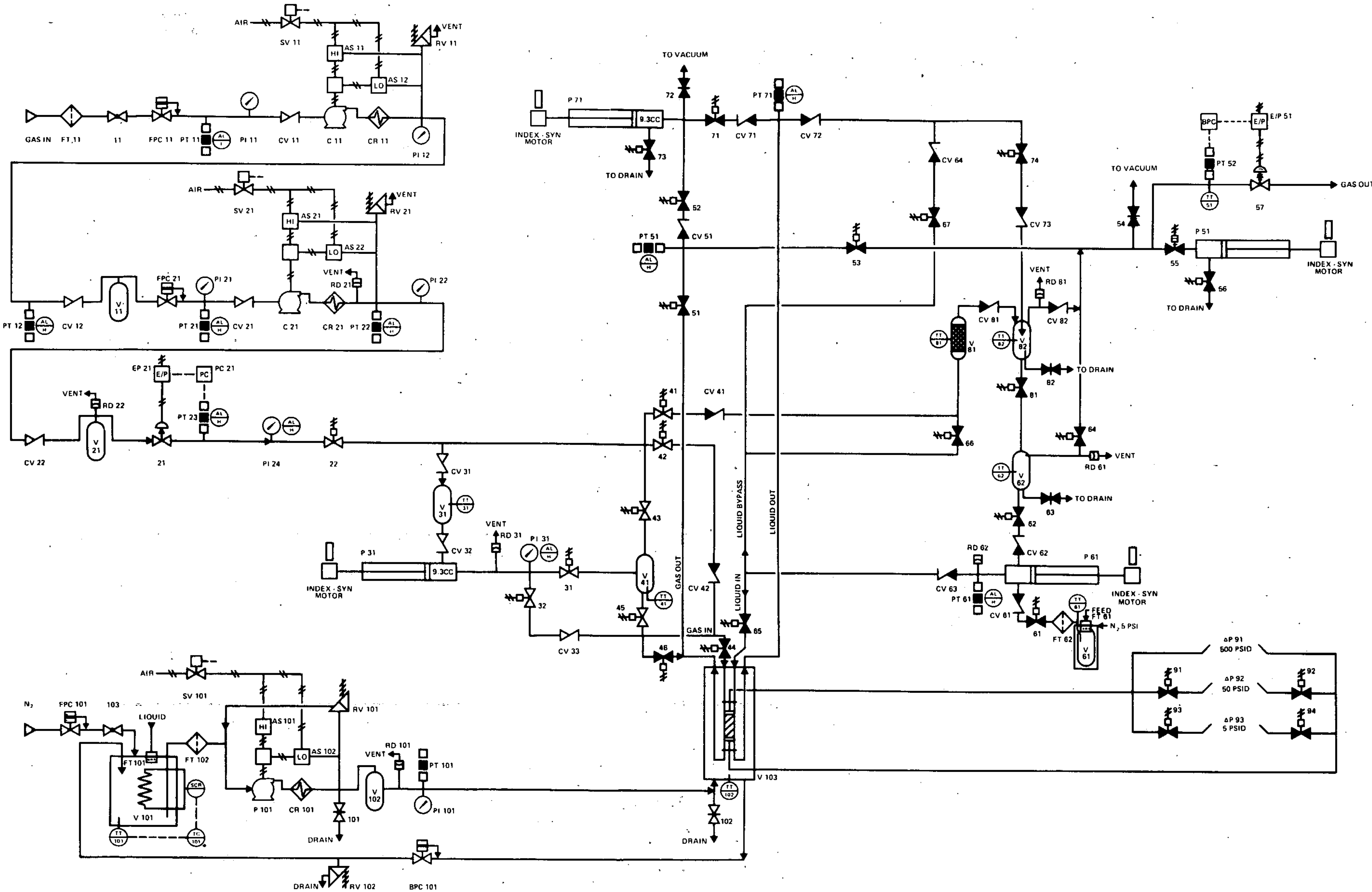

Figure 1. FLUID FLOW DIAGRAM OF THE GEOPRESSURED AQUIFER SIMULATOR (GAS)

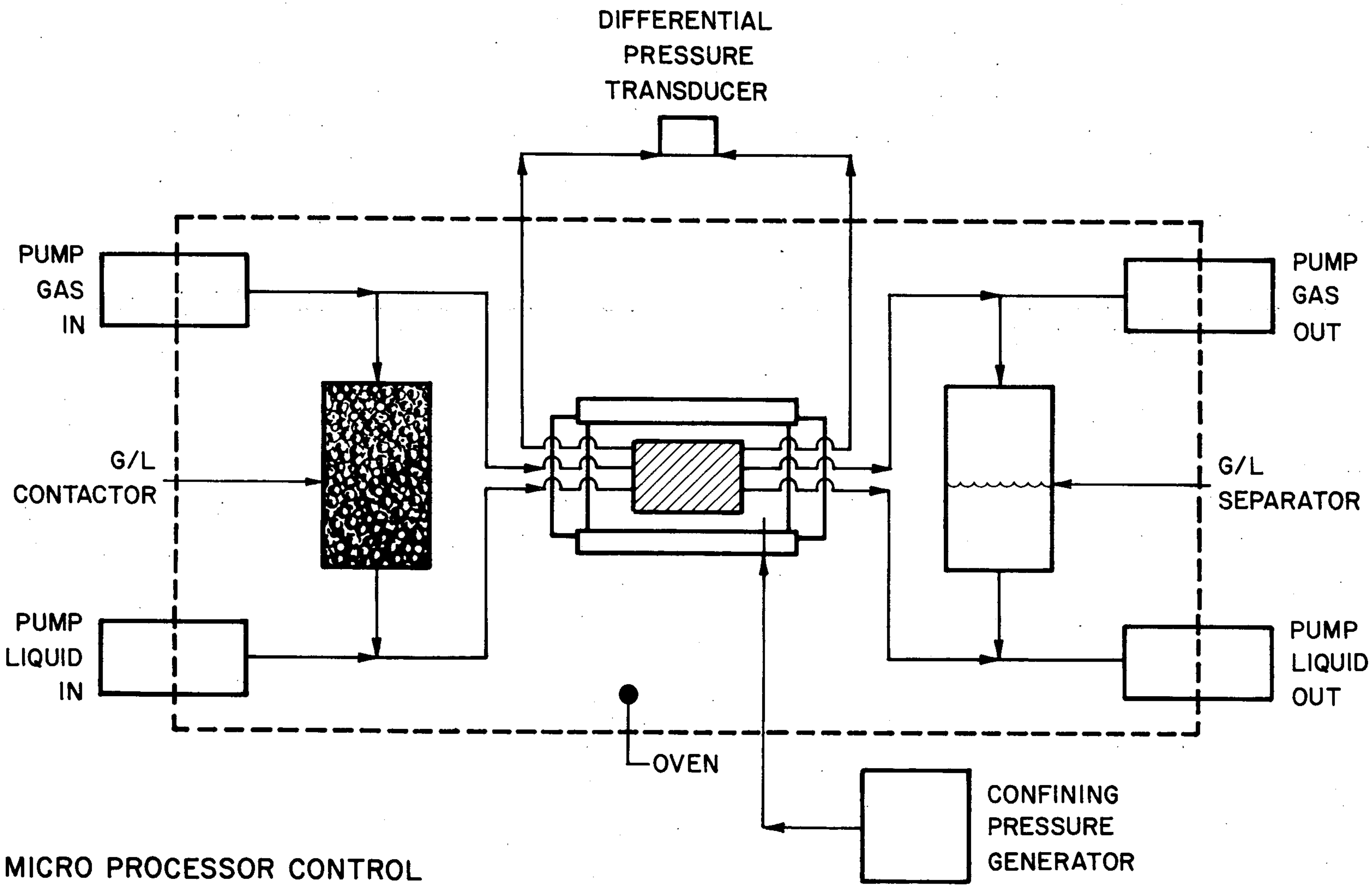

Figure 2. SIMPLIFIED FLOW DIAGRAM OF THE APPARATUS

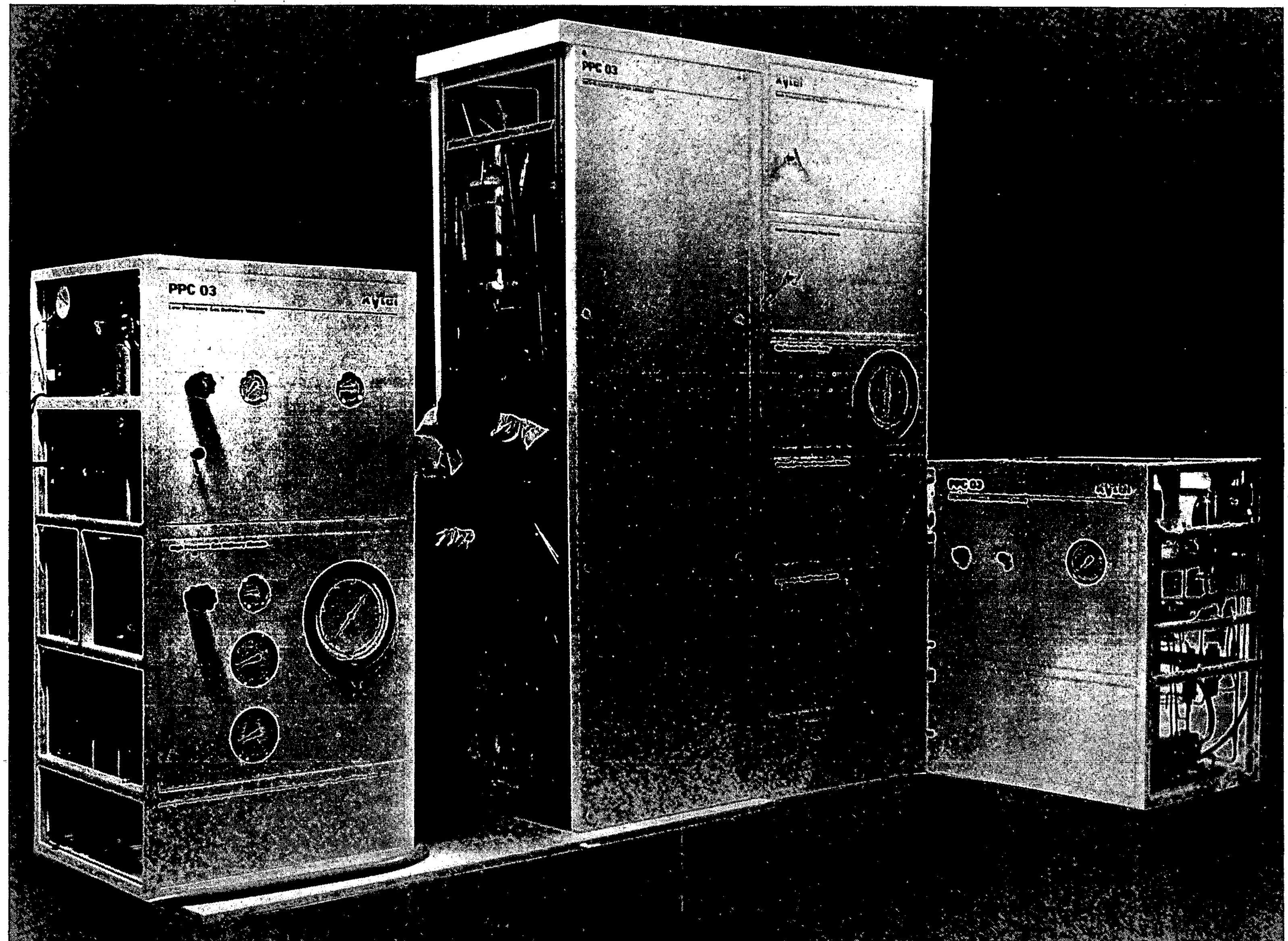

Figure 3. GEOPRESSURED AQUIFER SIMULATOR WITHOUT MICROPROCESSOR

investigated using this second form of temperature control. The confining fluid is a special combination of silicone oils.

Lithostatic Pressure Generating Module

This module supplies the silicone fluid that is used to provide the hydrostatic confining pressures. The module contains a heater and high-pressure pump to deliver the silicone fluid to the core holder. The microprocessor controls the heater and the pump and back pressure regulator to maintain the desired pressure and temperature or to change the confining pressure and core temperature along any predetermined P-T path.

Gas Delivery Subsystem

Gas can be provided to the system at carefully controlled pressure and flow rates. This subsystem consists of the high-pressure gas delivery module, upstream pump (P31), downstream back pressure control valve (V57), and reciprocating pumps (P51, P71). The high-pressure gas delivery module is capable of receiving a sample gas at pressures as low as 20-30 psi and boosting the pressure up to 20,000 psi. The microprocessor-regulated forward pressure control loop provides gas pressures to within an accuracy of 0.1% to surge vessels in the system (V31, V41). Upstream and downstream pressures are maintained by the reciprocating d.c. motor-driven pumps (P31, P71). Various arrangements of forward and back pressure control loops can deliver differential pressures to the core between 0.005 psid and hundreds of psid and at flow rates between 10^{-4}cc/hr and 500cc/hr. The microprocessor control records flow rate and delivered volume continuously.

Liquid Delivery Subsystem

As with the gas subsystem, accurate control of the flow rate in the liquid subsystem is achieved through microprocessor control of reciprocating pumps. Upstream liquid is delivered from a 250cc Hastelloy C-276 constant rate displacement pump. Downstream liquid pressure is controlled by the gas subsystem pump. To prevent liquid entry into the downstream back pressure control pump, gas and liquid are separated in a gas/liquid separator vessel. The fluid flow rate can be controlled between 1cc/hr and 1 X 10^3cc/hr. Small volume liquid compressibility measurements can be made using a 10cc pump (P71). Bulk core compressibility, pore compressibility, and fluid compressibility measurements can be made by coordinating the fluid displacement values with the pressure and strain gauges values from the core.

Gas-Liquid Saturation and Separation Loop

This loop permits the mixing or separation of gas and brine. Saturation is achieved by co-current flow of gas and liquid through a Hastelloy C-276 packed bed. The produced gas-saturated liquid serves as a feed source for flow through the core. A gas-liquid separation vessel is used to collect liquid that has flowed through the core as well as prevent liquid entry into the back pressure control loops. Core-liquid chemical interaction can be detected by analysis of the collected liquid. Equilibrium gas saturations can be determined for many gas-liquid systems by varying the brine and the gas composition.

Solution-mineral equilibrium can similarly be examined by observing the precipitation or dissolution of mineral species due to pressure and temperature changes.

Microprocessor Control Subsystem

While there are manual controls and overrides, the microprocessor provides the capability for programmed hands-off operation of the entire system. The microprocessor is capable of the following functions:

1. Monitor pressure transducers and thermocouples
2. Control the solenoid valves
3. Maintain pressure, flow, and temperature control by servo loops to the heaters, pump drives, and valves
4. Display the valve status, pump speeds, pressure, and temperature of all system components on a CRT terminal
5. Permit remote operation behind safety shields via terminal keyboard.

Operation

The modular nature of the system as well as the independent control of the various subsystems permit a wide variety of operational schemes. The modes of operation are discussed below.

Permeability

Permeability may be measured for single-phase or two-phase flow. Single phase or absolute permeability is measured for gas, de-aerated liquid, or gas-saturated liquids by using the gas subsystem. Values of permeability are determined by measuring the differential pressure across the core at constant flow rates. Permeability can also be determined as a function of changing confining pressure or temperature at different pore pressures.

The procedures used for gas-saturated liquids are slightly more involved for gas alone or liquid alone. In the former case, the core must first be evacuated using a vacuum system, then filled with a non-gas-saturated liquid. This liquid is displaced from the core by the gas-saturated fluid. This method permits the complete filling of the core with fluid and prevents the flashing of the gas-saturated liquid.

Because of the system flexibility, several variations of the permeability measuring procedures are used to examine more subtle reservoir characteristics. For example, the effects of fluid reinjection on the core permeability can be simulated by maintaining a temperature difference between the fluid and the core. Simultaneous measurement of pore compressibility and liquid permeability can be made. The procedure is to first measure liquid permeability at a given confining pressure and pore pressure. The differential pressure is then equalized, and a pore volume compressibility determination is performed. This determination results in a lower pore pressure. Subsequently, another liquid permeability measurement is made, and the sequence is repeated. This procedure may be followed for a de-aerated liquid or a gas-saturated liquid. If a gas-saturated liquid is used, changes in water saturation of the core, because of liberation of gas due to a pressure drop, can be monitored by changes in electrical resistivity.

Relative Permeability

Relative permeability is measured by three different techniques: two-phase steady-state flow (both phases flowing), single-phase steady-state flow (the second phase held stationary), and unsteady-state gas drive.

Two-Phase Steady-State

In this method, relative permeability is determined by pumping a fixed ratio of gas and liquid through the core until equilibrium pressures and saturation are achieved. Starting with liquid flow only and holding the differential pressure constant, successively lower liquid flow rates and higher gas flow rates establish the liquid saturation of the core. Errors introduced by capillary end effects can be minimized by the use of sintered metal or very high permeability rock for end caps and control of flow rates.

Single-Phase Stationary

Numerous methods have been developed for achieving a uniform saturation and fixed water saturation in the pores. At very high water saturations, the pore size distribution plays a large role in the extent to which uniform saturation can be achieved. By the use of semi-permeable end plates, desaturation of the wetting phase is obtained by introduction of the non-wetting phase at successively higher pressures. This permits simultaneous determination of a capillary pressure curve and calibration of electrical resistivity as a function of partial water saturation in the core. With the wetting phase held stationary by capillary pressures, non-wetting phase (gas) may flow at pressures sufficiently low to not disturb the capillary equilibrium. In turn, the gas may be held stationary and the water (wetting phase) made to flow. By the use of semi-permeable membranes, gas trapping, which can result from blotting or evaporation at one end of the core, is avoided. This gas trapping can significantly affect results at water saturations greater than 90%.

Unsteady-State Gas Drive

In this method, a constant gas pressure is introduced to the upstream side of a water-saturated core. The displaced liquid is drawn off from the core face after flowing through a semi-permeable membrane, and the resulting dynamic saturation change is monitored as a function of time. Gas flow rate as a function of time is available from the microprocessor as the upstream pumps deliver gas to the core at a constant upstream pressure. Liquid saturation in the core is monitored by resistivity. Additionally, the liquid saturation in the pores is equal to the volume of fluid aspirated by the back pressure control pump less the volume of gas introduced by the forward pressure control pump. Using the Welge-type frontal drive equations, the relative permeability to gas and liquid can be calculated.

Compressibility

Fluid compressibility can be determined by monitoring the decrease or increase in pressure of the system as a small volume of fluid is removed or added to the system. The liquid volume is changed by a 10cc constant rate displacement pump.

Pore volume compressibility is similarly measured. A saturated core is maintained under constant confining pressure and constant temperature. By shutting-in one side of the core, the differential pressure transducer monitors very small pressure changes as a fixed volume of fluid is withdrawn by the 10cc pump (P71). In spite of the high fluid pressures, the special differential pressure transducers are capable of measuring very small changes in pressure.

Bulk compressibility measurements are obtained by maintaining the core at a constant pore pressure, while increasing the net confining pressure. Changes in the volume of the core are measured by noting the output of strain gauges mounted on the core surface by epoxy.

All of the compressibilities can be measured as functions of temperature.

Summary

Many investigators have presented evidence for the strong effects that confining pressure, pore pressure, temperature, and solution chemistry can have on core analysis. Previous studies have usually measured only two properties simultaneously. Because of the problems in correlating measurements obtained in different apparatus, on different core, or core which is altered by previous testing, an apparatus has been designed and built to measure rock properties under nearly complete *in situ* conditions. Of particular importance to development of geopressure-geothermal reservoirs are measurements of fluid and pore compressibility and relative permeability to gas and water. Initial calibration and testing has begun on Berea sandstone, and once accuracy and precision of the apparatus are determined, testing will commence on core from the depth of 14,759 feet from the Pleasant Bayou No. 1 well.

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Texas Gas Transmission Corp.

Transcontinental Gas Pipe Line Corp.

United Gas Pipe Line Co.

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