Heat Treatment for Clay-Related Near-Wellbore Formation Damage

A.K.M. Jamaluddin & L.M. Vandamme
Noranda Technology Centre
T.W. Nazarko
Norcen Energy Resources Limited
(Presently with Petro-Soft System Inc.)
D.B. Bennion
Hycal Energy Research Laboratories Ltd.

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ABSTRACT

During drilling and completion, the primary mechanisms of near-wellbore formation damage include pore-throat constriction, water blocking, plugging with drill solids and mud products, and loading of the reservoir with drilling or completion fluids. Among these mechanisms, some of the most severe ones encountered in clastic reservoir applications are the pore-throat constriction due to clay swelling, and water blocking resulting in a reduction in the relative permeability to hydrocarbons.

A novel matrix stimulation concept which involves the application of intense heat for the treatment of water-blockage and clay-related formation damage in water-sensitive formations is presented in this paper. Bench-scale heating tests were carried out on water-sensitive sandstone cores to determine the effect of heat on effective permeability, fluid saturation, and mineralogy (i.e., degradation of in-situ minerals). Results indicated that heat treatment at 600°C can improve air permeability of a damaged core by about 51% above the initial permeability. Dramatic permeability increases of 764% and 988% above the initial reservoir permeability occurred at 800°C for the cores taken from the gas- and oil-bearing formations, respectively.

INTRODUCTION

Formation damage can occur at any time during a well's history from the initial drilling and completion of the wellbore through the depletion of the reservoir during production. Operations such as drilling, completion, workovers, and stimulation, which expose the formation to a foreign fluid, may cause formation damage because of adverse wellbore-fluid to formation interactions. Such damage is usually severe in horizontal wells, because of the longer exposure of the wellbore to the offending fluids.[1] During the drilling and completion phases, the primary mechanisms of near-wellbore formation damage can be explained by the following factors:

- pore-throat constriction, caused either by clay swelling due to incompatible fluids or by clay migration,
- water blocking due to reduction in relative permeability to hydrocarbon,
- plugging with drill solids and mud products, and
- loading of the reservoir with drilling or completion fluids.

Clay-related formation damage during drilling and completion has long been identified to be a major problem. Preventive measures to stabilize clay swelling and migration, mostly consisting of the use of various chemicals (*e.g.*, KCl) in the drilling or completion fluid, have been discussed in the literature.[2-7] However, prevention of clay damage is not always possible or effective, and curative measures may then become necessary. Several curative methods have been attempted and presented in the literature.[8-15]

Non-Thermal Curative Processes

One approach is to bypass the near-wellbore damage using hydraulic fracturing. This technique is very effective in sandstone formations and in vertical wells. However, there are situations where hydraulic fracturing is not desirable (*e.g.*, in water- or gas-flooding situations, zones containing active bottom water or gas caps) or not economical (*e.g.*, in some horizontal wells).

Another approach is to stimulate the near-wellbore region using acids, which dissolve either the clay minerals themselves (HF acid) or the surrounding formation rock (HCl and HF acids). Matrix-stimulation techniques using acids have been applied to carbonate reservoirs for productivity improvement. Later, acid stimulations were also found to be successful in removing damage by dissolving clay minerals near the wellbore in sandstone reservoirs.[8] In some cases, however, the reaction of HF[9] (or HBF_4)[10-11] acid with clays, feldspars and other minerals can result in the formation of various insoluble precipitates. In addition, many acids have a limited effective penetration due to rapid spending when in contact with the formation.[9] In both hydraulic-fracturing and acid-stimulation techniques, the proper design of the fluid system is very important. When the fluid systems contain fresh water, the chances of further clay swelling and migration are particularly high.

Other non-thermal curative methods include dehydration of hydrated argillaceous materials by decreasing the water of hydration or otherwise reducing the amount of water adsorbed on clay particles. In one example,[12] the clay material is first contacted with a hydrogen donor to convert it by ion exchange from the existing base form, such as the calcium, magnesium, or sodium clay, to the hydrogen-base clay form. The hydrogen-base clay is then treated with an aqueous salt solution to convert it to a potassium or ammonium-base clay. In another example,[13] the author injects non-reactive gas (*i.e.*, nitrogen) into the formation at atmospheric temperature to fluidize the clays, including migratable fines, for their removal. Subsequently, an aqueous solution of soft water containing potassium chloride is proposed to be injected into the formation to cause a potassium-sodium cationic exchange within the swellable clays to reduce their swelling.

Thermal Curative Processes

One of the earliest reports of in-situ thermal treatment was that of Albaugh,[16] on a field test that was carried out in an oil well in California. During the field test, an electrical heater was lowered into a 6.5-in diameter well and positioned close to the formation face. Natural gas was injected to push the oil back into the reservoir and subsequently, the well was heated to 375°C (733°F) for 6 days. After this time, the heating ceased and when the temperature had decreased to 175°C (373°F), the well was put on production. The pre-treatment rate was 21 bbl/day, while the post-treatment oil rate was increased to 37 bbl/day. An incremental production of 16 bbl/day was achieved and maintained for several months.

Since then, many other curative thermal processes have been described for a variety of purposes including the removal of wax[17] or asphaltene[18] buildups, thermal fracturing of the formation,[19] and the consolidation of unconsolidated formations.[20] More specifically related to clay damage are methods aimed at dehydrating clays at low[21] or high temperature,[19] transforming a sensitive type of clay (*e.g.*, smectite) into a less sensitive type (*e.g.*, illite),[22] or simply removing water by evaporation.[23,24]

It is a well known fact[25] that the lattice structure of almost all clay minerals responds to thermal shock and that the degree of change in the lattice structure of various minerals depends on the temperature level. This phenomenon is exploited routinely in the laboratory for clay determination. For instance, the effect of a one-hour heating period at certain temperatures on some selective clay minerals is shown in Table 1. Based on these temperature effects on clay structure, a new matrix-stimulation concept was designed and tested in the laboratory. The process involves the application of heat for the treatment of near-wellbore damage. Bench-scale heating tests were carried out on clay-sensitive sandstone cores taken from both oil- and gas-bearing formations to determine the effect of heat on permeability, fluid saturation, and mineralogy (*i.e.*, degradation of in-situ minerals). In addition, simulation studies were carried out to evaluate the effect of the increase in near-wellbore permeability on productivity. The experimental and simulation results are presented in this paper.

FORMATION HEAT-TREATMENT (FHT) CONCEPT

The concept of applying intense heat for the treatment of near-wellbore formation damage was evaluated. The process[26] consists of exposing the formation to an elevated temperature to cause:

- ✓ vaporization of blocked water,
- ✓ dehydration of the clay structure,
- ✓ partial destruction of the clay minerals, and
- ✓ possibly, micro-fracturing of the formation in the near-wellbore area due to thermal induced stresses.

The dehydration and vaporization of bound and blocked water occur at temperatures higher than the saturation temperature corresponding to the reservoir pressure. The extent of clay destruction also depends on the heating temperature.

We based the selection of our experimental temperature conditions on X-ray diffraction (XRD) results from isolated kaolinite and smectite samples in the laboratory (Figures 1 and 2). In Figure 1, the spectra from a kaolinite sample treated at five different temperatures are presented. One can see that heating to 107°C and 300°C produces no change in the XRD spectrum, compared to that of the air-dried sample. This indicates that heat treatment up to these temperatures does not affect the kaolinite structure. However, at 550°C, it is observed that all of the kaolinite peaks disappear, indicating complete destruction of the kaolinite structure at this temperature. The Al-hydroxyl bonds become dehydrated, and the well-ordered crystalline form degenerates into an amorphous arrangement. The only remaining peak is at 3.52 Å, which corresponds to anatase, a TiO_2 phase that was present in the original sample.

Similarly, six XRD spectra from a smectite sample are plotted in Figure 2. The top spectrum is that of the wet sample. The peak at 19.09 Å corresponds to the swelled state of smectite, in which each Ca ion on the clay surface is surrounded by four layers of water. As the sample is heated up to 300°C, this peak shifts progressively to the right, indicating progressive vaporization of the water. No major change in the XRD spectrum is observed between the 300°C and 550°C treatments, revealing that the interlayer dewatering process is complete after heating to 300°C. At 800°C, the peak intensities decrease significantly. As with kaolinite, the crystallinity of smectite is destroyed, resulting in an amorphous structure that does not generate any strong XRD peak.

Based on the above results and on the literature data presented in Table 1, various temperatures (*i.e.*, 200, 400, 600, and 800°C) were selected to evaluate the effect of intense heating on the permeability of two test cores described below.

RESERVOIR DESCRIPTION AND FORMATION EVALUATION

Extensive petrographic studies were carried out to characterize an oil- and a gas-bearing formation. Comparative thin-section petrology, X-ray diffractometry (XRD), and scanning-electron microscopy (SEM) were used in these characterization studies. A brief description of the results is presented below.

Gas-Bearing Formation

The gas-bearing formation under consideration is a glauconitic sandstone, deposited in a shallow marine environment. The average porosity is estimated to be 20%, the permeability on the order of 20 md, and the reservoir pressure on the order of 2,500 kPa.

The petrographic studies on core indicate that the reservoir sandstone consists of very fine-grained, argillaceous, glauconitic litharenite to sublitharenite. The formation contains 78% quartz, 8% to 9% clay material, and 12% to 13% glauconite peloids on a bulk basis. The major clay fraction components are illite (58%), illite-smectite mixed-layer (38%), and kaolinite (4%). The core samples also contain a small amount of iron-rich authigenic dolomite irregularly distributed throughout the pore system. In addition, some iron-bearing chlorite and trace amounts of feldspar were detected in both XRD clay and bulk analyses. Some accessory grains include pyrite, mica, phosphatic bioclasts, peloids, and heavy minerals.

The samples are representative of a moderate-quality reservoir, with 3% to 5% moldic porosity formed by dissolution of feldspar grains. Unstable rock fragments, bioclasts and peloids are responsible for an additional 7% to 10% modified intergranular porosity. The pores appear to be moderately connected, explaining the moderate (18 md to 20 md) permeability values measured.

The petrology of the sandstone samples suggests that the reservoir is extremely susceptible to fresh-water damage caused by clay swelling (mixed-layer clays) and fines migration (kaolinite). As clays and glauconite peloids expand, porosity and permeability decrease. These results suggest that severe near-wellbore damage must be expected upon contact with fresh water.

Oil-Bearing Formation

The oil-bearing formation under consideration is a Basal Quartz sandstone which was most likely deposited in distributary channels around the edges of a delta plain. The average porosity is about 15%, the permeability to air on the order of 25 md, and the reservoir pressure on the order of 16,000 kPa. The oil has a viscosity of 20 mPa.s.

The petrographic studies on core indicate that the formation is a moderately sorted, fine-grained, quartzose sublitharenite with good porosity and moderate permeability. The XRD analysis indicates that quartz material dominates the sandstone mineralogy (85%). The total clay content is about 15%. Kaolinite dominates the clay mineralogy (86%) and illite constitutes the remaining 14%. Smectite and mixed-layer illite-smectite clays were not found in the XRD analysis.

The reservoir has a modified intergranular porosity of about 8% and a supplemental grain moldic porosity of about 3%. The sandstone formation appears to be sensitive to deflocculation damage induced by fresh water contact and to conditions that could induce fines migration.

EXPERIMENTAL EQUIPMENT & PROCEDURE

Cores from Gas-Bearing Formation

A conventional apparatus was used to measure the effective permeability of the core samples. The samples (3.81-cm O.D. and 5.89-cm long) were saturated with the respective test fluids using a high-speed centrifuge capable of spinning the samples at 2,300 rpm. The samples were then mounted in a tri-axial core holder and confined at a nominal overburden pressure. The portions of the core holder directly adjacent to the injection and production ends of the core were equipped with radial distribution plates to ensure evenly distributed nitrogen flow into and out of the core specimen. Pressure, temperature, and velocity of the nitrogen flow through the core were measured using a nitrogen permeameter. Rotameter-style flow meters were used to facilitate the flow measurements. All permeability measurements referred to below were carried out using this procedure.

Heat cycling was carried out by placing the respective core samples into an inconel reactor and heating the reactor in a high-temperature oven. A schematic diagram of the apparatus used during the heat cycling is presented in Figure 3. A constant pressure of 2,413 kPa was maintained inside the reactor using a regulated nitrogen source and a back-pressure regulator. Temperature was monitored with a thermocouple that displayed the internal reactor temperature. Gas samples were taken by diverting the nitrogen flow out of the back-pressure regulator and into a sampling vessel. These gas samples were analyzed using a Hewlett Packard 5880 gas chromatograph.

The testing procedure was as follows:

- ➢ Saturate sample with produced formation water using high-speed centrifuge.
- ➢ Desaturate sample by nitrogen flooding to irreducible water saturation; measure gas permeability.
- ➢ Saturate sample with drilling-mud filtrate using high-speed centrifuge.
- ➢ Desaturate sample by nitrogen flooding to irreducible fluid saturation; measure gas permeability.
- ➢ Heat core sample to specified temperature at constant pressure (2,413 kPa) inside inconel reactor, kept at temperature from 2 hours to 9.5 hours, depending on desired temperature level, while circulating nitrogen slowly through reactor.
- ➢ Cool reactor to room temperature; remove sample; measure air permeability.
- ➢ Saturate sample again with produced formation water in high-speed centrifuge.
- ➢ Desaturate sample to irreducible fluid saturation; measure gas permeability.
- ➢ Subject samples to X-ray diffraction (XRD), scanning-electron microscopy (SEM), and thin-section analysis.

A multiple-temperature (*i.e.*, 200, 400, 600, and 800°C) heating cycle was carried out in one core sample, and three one-time heat cycling tests were carried out on three separate samples.

Cores from Oil-Bearing Formation

In these tests, a conventional fluid permeameter was used to facilitate the liquid permeability measurements. A representative 3.81-cm-O.D. and 5.89-cm-long core sample was mounted in a flexible viton sleeve. The core, mounted within the flexible sleeve, was placed in a 316SS bi-axially loaded core cell capable of applying overburden pressures of up to 70,000 kPa. A positive displacement pump displaced oil, brine, or mud filtrate at a pre-specified rate through the overburden confined core sample and the resulting pressure drop was measured using a 0-kPa to 2,000-kPa Validyne capacitance transducer, accurate to ± 0.05% of the full-scale reading. The permeability values were later calculated using known core dimensions and fluid viscosity values.

A schematic diagram of the heating apparatus is presented in Figure 4. The setup used in these experiments is essentially the same as that of Figure 3. However, a modification was made to the previous apparatus to facilitate the "flow-through" displacement into the core sample at temperatures up to 800°C and at a pressure of 10,400 kPa. A special 316SS annular collar was inserted inside the inconel reactor which was sized to fit tightly around the core material. Nitrogen was injected at the base of the sample, flowed upward, passing through the core material, to be produced at the top of the system. Elevated temperatures were applied by placing the entire core-holding apparatus in an oven capable of reaching temperatures in excess of 1000°C. Back-pressure was maintained using a back-pressure regulator accurate to 0.5% of the setpoint value. Flow was controlled using a mass-flow valve connected to the high-pressure nitrogen source.

The testing procedure was as follows:

- ➢ Mount core in core permeameter assembly; stabilize at ambient temperature (22°C); apply 16,500 kPa of confining stress.
- ➢ Evacuate core to remove trapped gas.
- ➢ Vacuum saturate core (100%) with dead reservoir crude; measure permeability to oil at 100% oil saturation.
- ➢ Flood core with 2 pore volumes of formation brine to create initial brine saturation.
- ➢ Flood to S_{wr} with oil; measure reduction in oil permeability caused by introduction of formation

brine.

- Flood core with 2 pore volumes of mud filtrate.
- Flood to S_{wr} with oil; measure reduction in oil permeability caused by reaction of mud filtrate on core.
- Flush core with formation brine, then with nitrogen to irreducible oil and brine saturation.
- Heat to 800°C with continuous nitrogen flow (approx. 20 L/hr @ 10,600 kPa) through core with 10,600 kPa confining pressure; maintain at constant temperature for four hours; cool to ambient temperature.
- Saturate core (100%) with oil; measure permeability to oil.
- Flood core with 2 pore volumes of formation brine to create connate water saturation.
- Flood core to S_{wr} with oil; measure reduction in oil permeability caused by presence of brine in heat-treated core.

EXPERIMENTAL RESULTS

Several experiments were carried out using cores from both oil- and gas-bearing formations described above. In each case, the core was exposed to high temperatures and subsequently cooled to room temperature before the permeability was measured and compared to the original permeability. Petrographic studies were also carried out on the heat-treated cores, with the following results.

Measurements on gas-bearing formation

The initial air permeability of the core samples taken from the gas-bearing formation was measured to establish a baseline permeability of about 18 md.

The permeability changes caused by the sequential treatment outlined above are presented in Figure 5. The corresponding fluid-saturation values after each step are presented in Figure 6. As can be seen in Figure 5, the core showed a 75% reduction in air permeability after treatment with mud filtrate. This reduction in permeability is partly due to the increased fluid saturation in the core and partly due to clay swelling and migration. Further results indicate that heat treatment at 600°C can improve the permeability of the damaged core to about 50% above the initial permeability. A dramatic increase of about 760% occurred at 800°C. Even when the sample was rehydrated with formation water, air permeability remained 622% above the baseline. In the heat-treated cores, the high fluid saturation did not cause as dramatic a permeability reduction as that observed initially. Comparable results were obtained from the other three heating tests (Table 2A). The measured fluid volumes for all four tests are presented in Table 2B.

The petrographic studies indicated that the mud-filtrate flood caused an expansion of both the mixed-layer illite-smectite swelling clays and the glauconite peloids. The expanded clays were observed to block small pore throats. After heating the core to 800°C, the crystallinity of smectite and kaolinite was indeed destroyed. The illite-smectite mixed-layer clay lattices collapsed and contracted around grains, and the glauconite peloids shrank. The fines generated from the alteration of the clay minerals and from the collapse of the glauconite peloids are susceptible to velocity-induced transport. However, the permeability measurements did not indicate any damage related to fines migration. The petrographic studies also showed some evidence indicating that the collapsed clays had lost their ability for reswelling.

Measurements on oil-bearing formation

It was anticipated that the exposure of an oil-saturated core to heat would result in coking of the oil and eventual reduction in permeability. The baseline permeability to oil was found to be about 0.9 md.

The results indicated that the invasion of mud filtrate caused a substantial (38%) reduction in oil-phase permeability, likely due to a combination of phase trapping and clay deflocculation. However, the high-temperature (800°C) exposure for four hours increased the oil permeability by an order of magnitude (about 1000%) over the original permeability. Even after rehydration with connate water, the permeability was still about 750% larger than the initial "undamaged" baseline permeability. The results are presented in Figure 7 and tabulated in Table 3.

The petrographic studies indicated that most of the kaolinite was destroyed, with only a few kaolinite pseudomorphs remaining. The SEM studies suggested that the hydrocarbon was not coked to insoluble carbon. The increase in permeability is mostly due to the destruction of the kaolinite minerals and subsequent transport of the degraded clay with the hydrocarbon phase through the pore system.

Discussion

At this point, it is important to summarize the various mechanisms which have affected the effective permeability of these cores upon intense heating. The foremost effect of heat was to vaporize the water of clay hydration. Secondly, the water inside the pore channels was also vaporized, thus cleaning the channels and allowing for increased fluid flow. Finally, it was evident from the petrographic studies that various clay minerals were degraded at very high temperatures, and that this effect contributed to the drastic increase in effective permeability observed after the high-temperature treatments.

Besides water vaporization and clay degradation, the application of heat may also have generated substantial thermal stresses in the rock. Such high temperatures may have been sufficient to exceed the yield strength of the constitutive grains or cementing material, which in turn would have introduced microfractures into the system. These microfractures would allow increased fluid flow and thus serve as a secondary mechanism of permeability enhancement. However, this microfracture mechanism was not apparent from the petrographic studies on the heat-treated samples.

The gas analyses that were carried out on the gas samples collected during the heat cycle showed only nitrogen and an insignificant concentration of carbon oxides. Similarly, the brine samples collected after flushing in the case of the oil-bearing cores did not show any significant change in pH or solids content.

SIMULATION STUDIES

A numerical simulation study using a black oil simulator was carried out to study the productivity improvement of typical vertical and horizontal oil wells after FHT treatment. The reservoir and fluid parameters used in this simulation study are tabulated in Tables 4 and 5, respectively.

In the case of the vertical well, a zone of reduced permeability around the wellbore was assumed to extend 5 ft into the formation and the permeability of the damaged zone was assumed to be 5 md, while the average reservoir permeability was assumed to be 25 md. The production rates were estimated for the following three cases: original damaged near-wellbore permeability, treated near-wellbore area with permeability restored to the original 25 md, and treated near-wellbore area with permeability of 50 md. The productivity ratio as a function of time is presented in Figure 8. One can see that a maximum productivity ratio of 3.0 can be obtained with a 10-fold increase in the near-wellbore permeability. With a 5-fold permeability increase, a maximum productivity ratio of 2.5 can be achieved. As expected, there is a gradual decrease in the productivity ratio with time. The treated well produces at a higher rate than the untreated well for about 2 years.

In the case of the horizontal well, the formation considered in the simulation was assumed to have a significant near-wellbore formation damage: a skin factor of 100 was used throughout the horizontal length. The parameters used in the original horizontal model are tabulated in Table 5. The production rates were estimated for the following three cases: original damaged near-wellbore permeability, treated near-wellbore area with no skin on 50% of the well length, and treated near-wellbore area with no skin on 12% of the original length. The results indicate that removing skin on 12% of the horizontal length doubles the productivity, and that removing skin on 50% of the horizontal length triples the productivity (Figure 9). The sustained productivity improvement is solely due to reservoir potential.

TENTATIVE FIELD SCHEME

The field implementation of the FHT process would involve the placement of a tubing- or wireline-conveyed heating device across the perforations or the producing sand face, and the injection of an inert gas (*e.g.*, nitrogen) into the wellbore, through or around the heating device. The heating device can be made of an electrical-resistance heating element or any other device that can generate heat downhole. This downhole heater raises the temperature of the injection gas, which in turn heats up the formation.

This heating process could be designed for both cased and open holes, vertical and horizontal wells, as long as the formation and the casing are able to sustain the thermal stresses generated by the heat source. In the case of tubing-conveyed heaters, reduction of wellbore heat losses can be achieved by injecting cool gas through the annular space

CONCLUSIONS AND RECOMMENDATIONS

Experimental results obtained to date in the laboratory indicate that the application of intense heat vaporizes bound and blocked water, destroys clay lattices, and ultimately increases the permeability of clay-rich formations. An order-of-magnitude increase in permeability can be achieved in cores exposed to 800°C. This intense heating process can be used to increase the permeability of cores from both gas- and oil-bearing formations.

Simulation studies indicate that the productivity of both vertical and horizontal wells with high near-wellbore damage due to clay swelling and clay migration and/or water blocking could be increased 2 to 4 fold. The potential benefit of the FHT process could be very high indeed in the case of horizontal wells.

If the in-situ results are comparable to those obtained to date in the laboratory, the FHT process would be most suitable in situations where conventional treatment methods are not effective (*i.e.*, horizontal wells) or not desirable (*i.e.*, hydraulic fractures in vertical wells with active bottom water). The process would be applicable in sandstone formations with moderate permeability, to insure proper nitrogen injectivity, with high reservoir potential, and containing swellable clays and shales. Reservoirs where fluid blocking is a common phenomenon would also be suitable candidates for the FHT process.

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Table 1: Effect of temperature on clay minerals.[25]

Clay Materials	**Temperature (°C)**	**Effect after 1-hour Exposure**
Montmorillonite group (smectite)	300	Original 15-Å spacing disappears; 9-Å spacing develops (shrinking effect)
Illite and clay mica	125-250	Loss of hydroscopic water
Kaolinite, well crystallized	575-625	Replacement by amorphous meta-kaolin
Chlorite group	600-800	Gradual weight loss; no structural change
Mg-chlorite	650	14-Å spacing is intensified
Fe-chlorite	500	14-Å spacing less intense, becoming broad and diffuse
Mixed-layer clays	< 600	Varies with amounts and types of minerals present
Glauconite	530-650	Loss of interlayer water; reverts to mica structure

Table 2A: Permeability data (Gas-Bearing Formation)

Sequential Treatment	**Air Permeability Values, md**			
	Test Core #1	**Test Core #2**	**Test Core #3**	**Test Core #4**
Initial permeability	17.85	19.45	13.41	19.82
After brine desaturation	5.19	9.96	2.90	5.74
After mud desaturation	2.86	2.90	4.11	7.51
After 200°C treatment	7.80	16.06	-	-
After 400°C treatment	15.73	-	13.48	-
After 600°C treatment	26.98	-	-	26.48
After 800°C treatment	154.3	-	-	-
After brine desaturation	129.0	11.24	6.34	20.24

Table 2B: Fluid volume data (Gas-Bearing Formation)

Sequential Treatment	Fluid Volumes, mL			
	Test Core #1	**Test Core #2**	**Test Core #3**	**Test Core #4**
Initial dry sample	0.0	0.0	0.0	0.0
Brine saturated sample	8.37	8.21	7.74	7.88
After brine desaturation	6.18	5.08	5.62	5.18
After mud filtrate desaturation	6.31	5.42	4.91	4.29
After 200°C heat cycle	4.55	0.83	-	-
After 400°C heat cycle	0.0	-	0.0	-
After 600°C heat cycle	0.0	-	-	0.0
After 800°C heat cycle	0.0	-	-	-
After brine desaturation	8.94	4.44	4.86	4.612

Table 3: Permeability summary (Oil-Bearing Formation)

Sequential Treatment	Permeability to Oil, md
Initial permeability (@100% S_o)	0.91
Permeability after brine flood	0.82
Permeability after mud exposure	0.52
Permeability after 800°C heat cycle (@ 100% S_o)	9.82
Permeability after brine flood	6.97

Table 4: Parameters used in the vertical well simulation (2-phase gas-oil model)

Parameter		**Value**
Pay Thickness, ft		45
Oil Gravity, °API		35.2
Gas Gravity		0.786
Oil Viscosity, mPa.s		1.097
Oil FVF, rm^3/sm^3		1.253
Permeability (vertical & horizontal), md:	Reservoir	25
	Damaged Zone	5
	Treated Zone	25 and 50
Porosity		0.1128

Table 5: Parameters used in the horizontal well simulation (2-phase oil-water model)

Parameter		**Value**
Pay Thickness, ft:	Top Layer	26
	Middle Layer	39
	Bottom Layer	49
Oil Density, g/L		829.48
Dead Oil Viscosity, mPa.s		0.39
Dead Oil FVF, rm^3/sm^3		1.703
Horizontal Permeability, md:	Top Layer	15
	Middle Layer	1
	Bottom Layer	5
Vertical Permeability, md:	Top Layer	1.5
	Middle Layer	0.1
	Lower Layer	0.5
Porosity:	Top Layer	0.16
	Middle Layer	0.06
	Lower Layer	0.15
Skin Factor		100

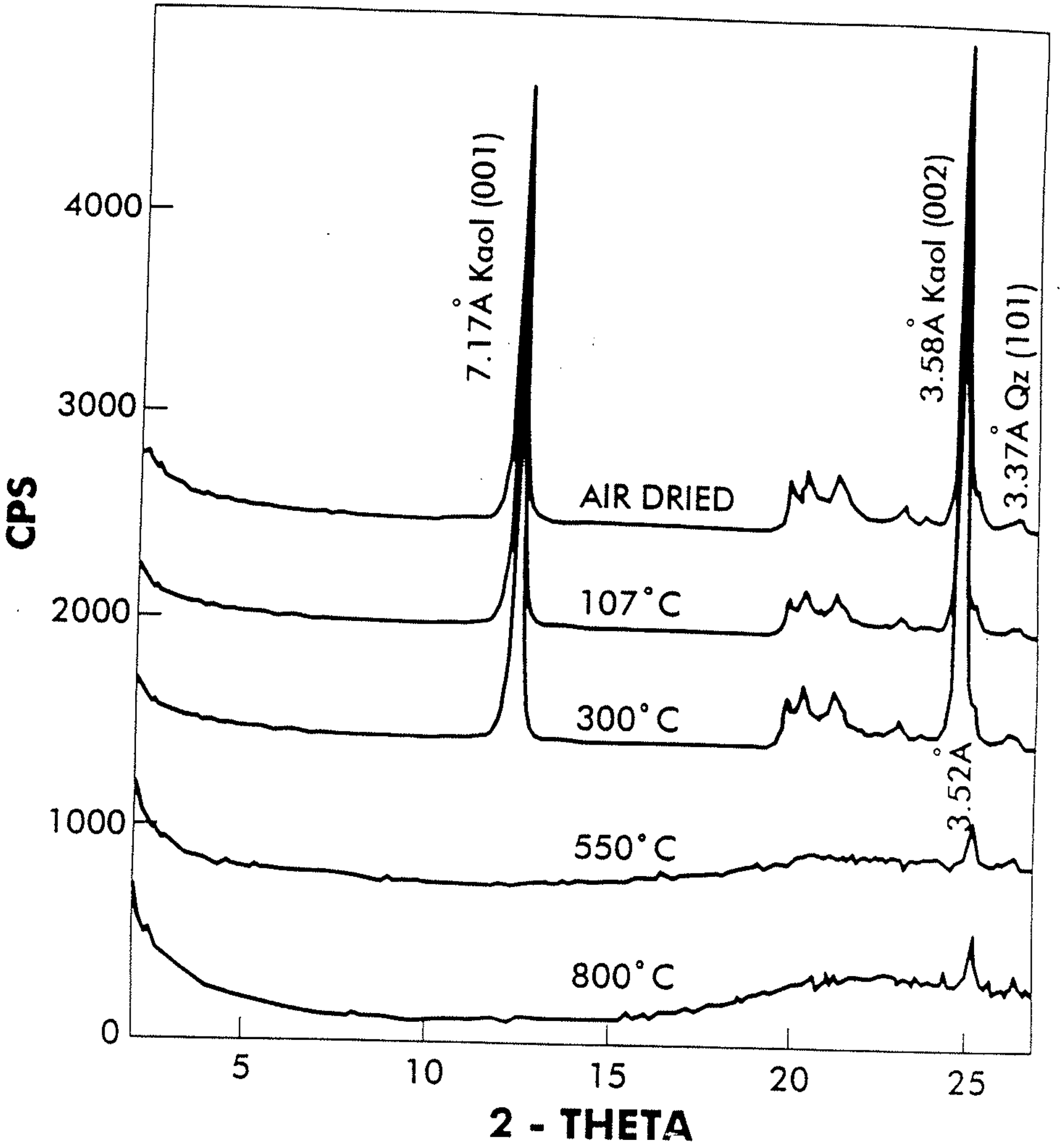

Figure 1: X-Ray Diffraction Spectra of Kaolinite at Various Temperature

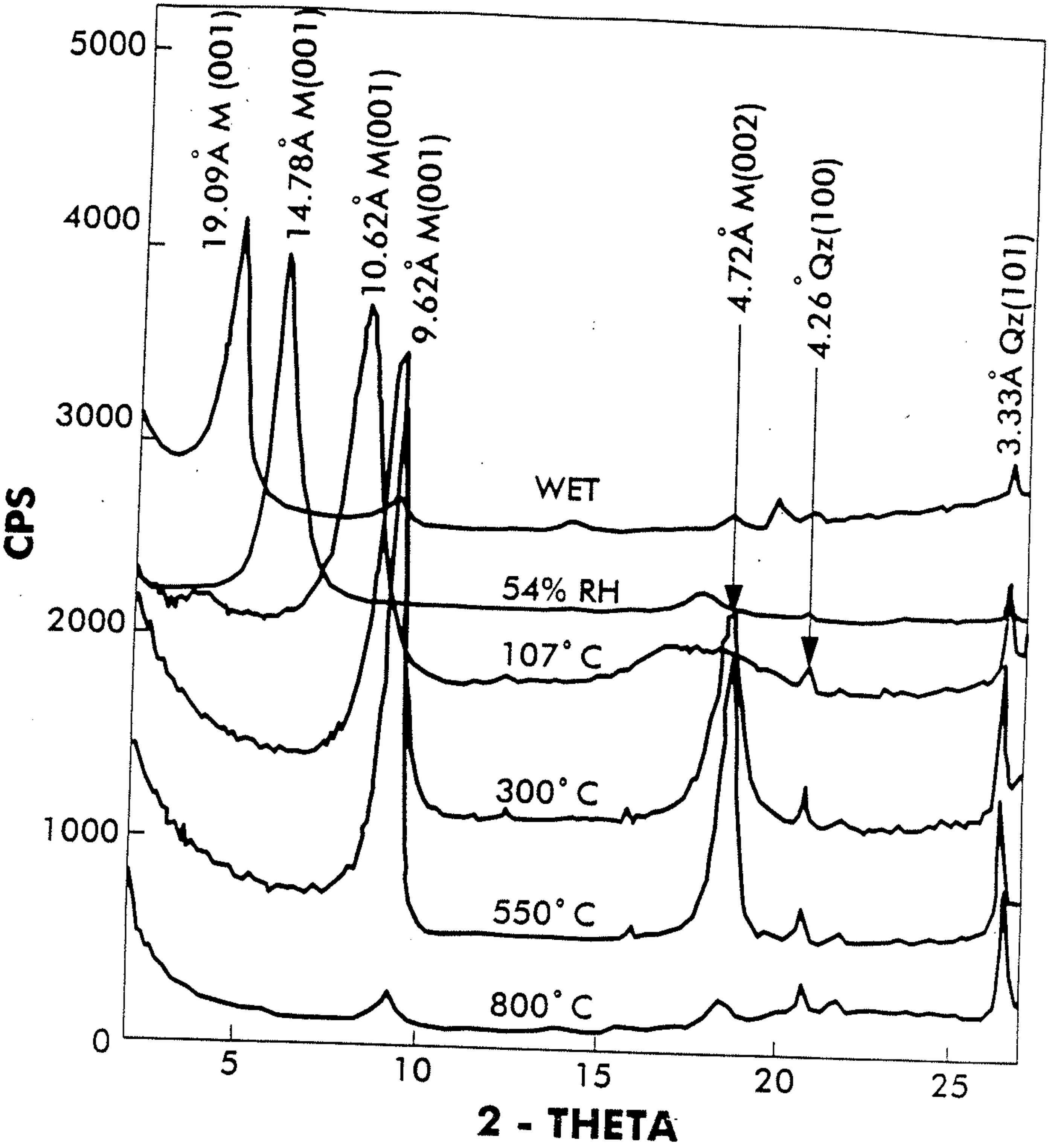

Figure 2: X-Ray Diffraction Spectra of Smectite at Various Temperature

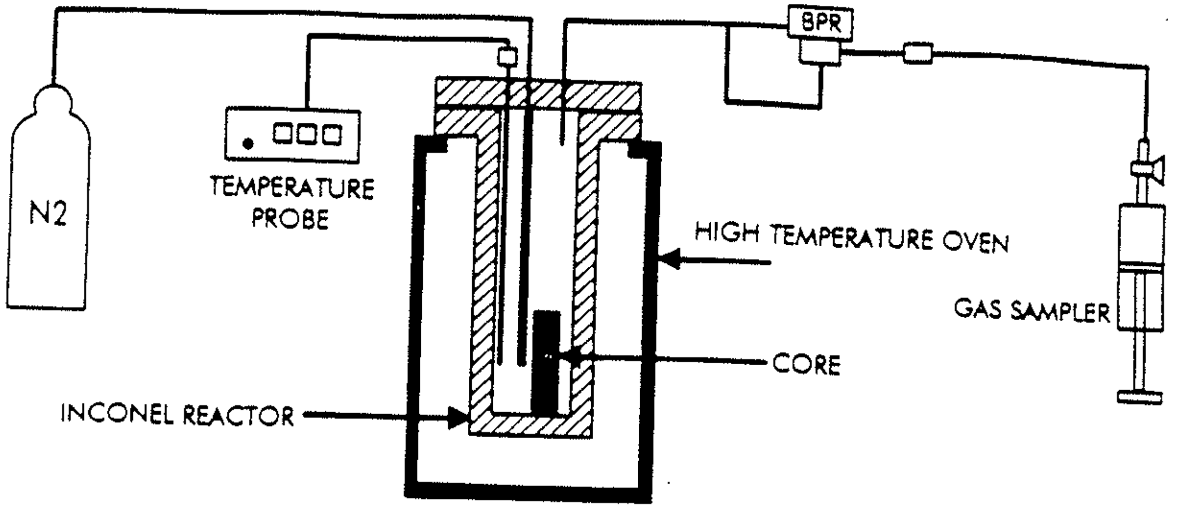

Figure 3: Heat Cycle Apparatus (Cores from gas-bearing formation)

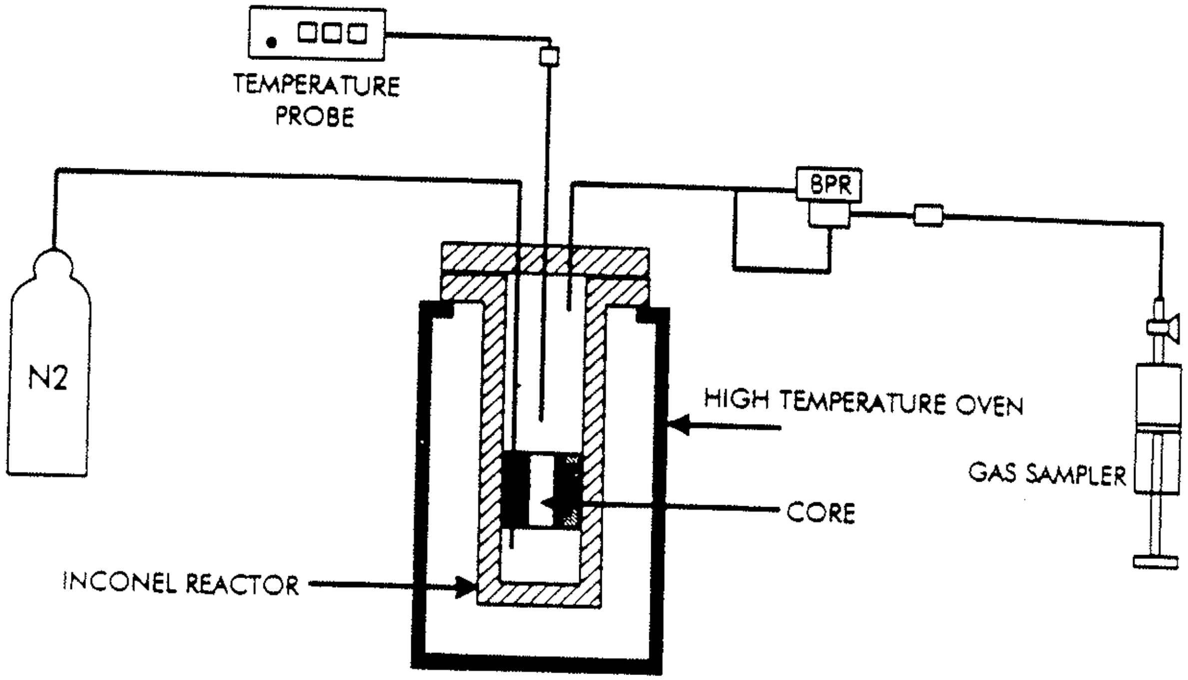

Figure 4: Heat Cycle Apparatus (Cores from oil-bearing formation)

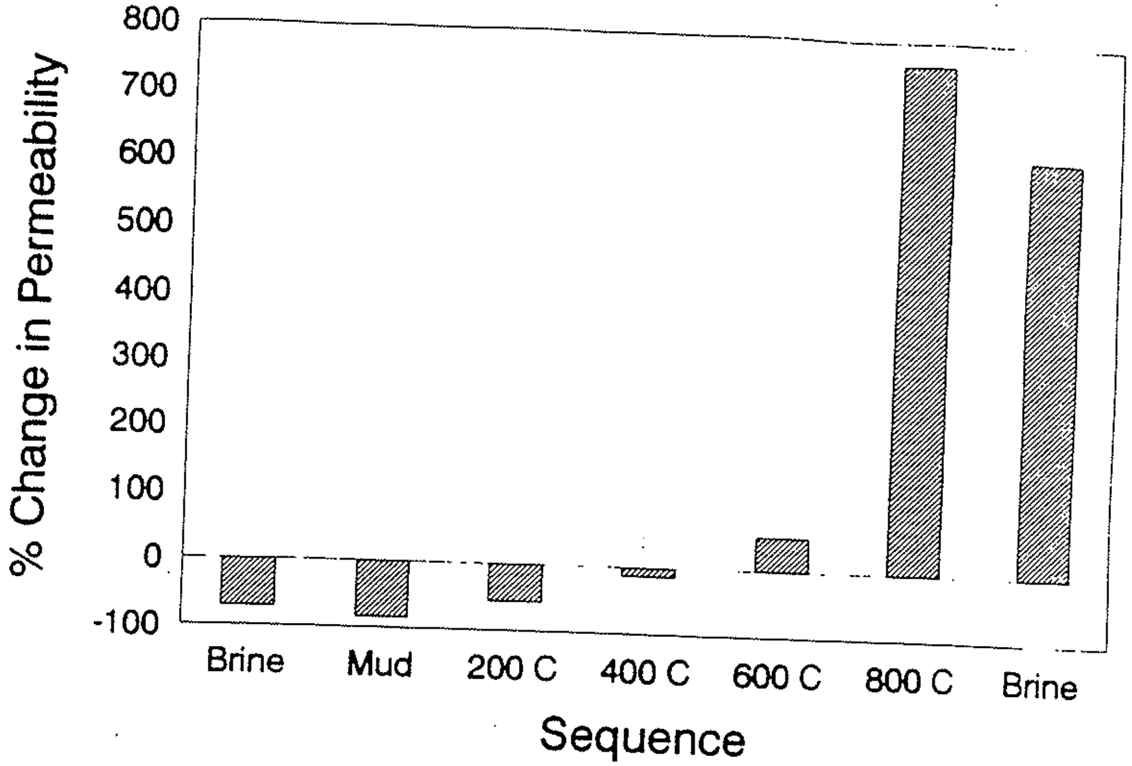

Figure 5: Change in Gas Permeability during Sequential Treatment (Initial Gas Permeability = 18 md; Cores from Gas-Bearing Formation)

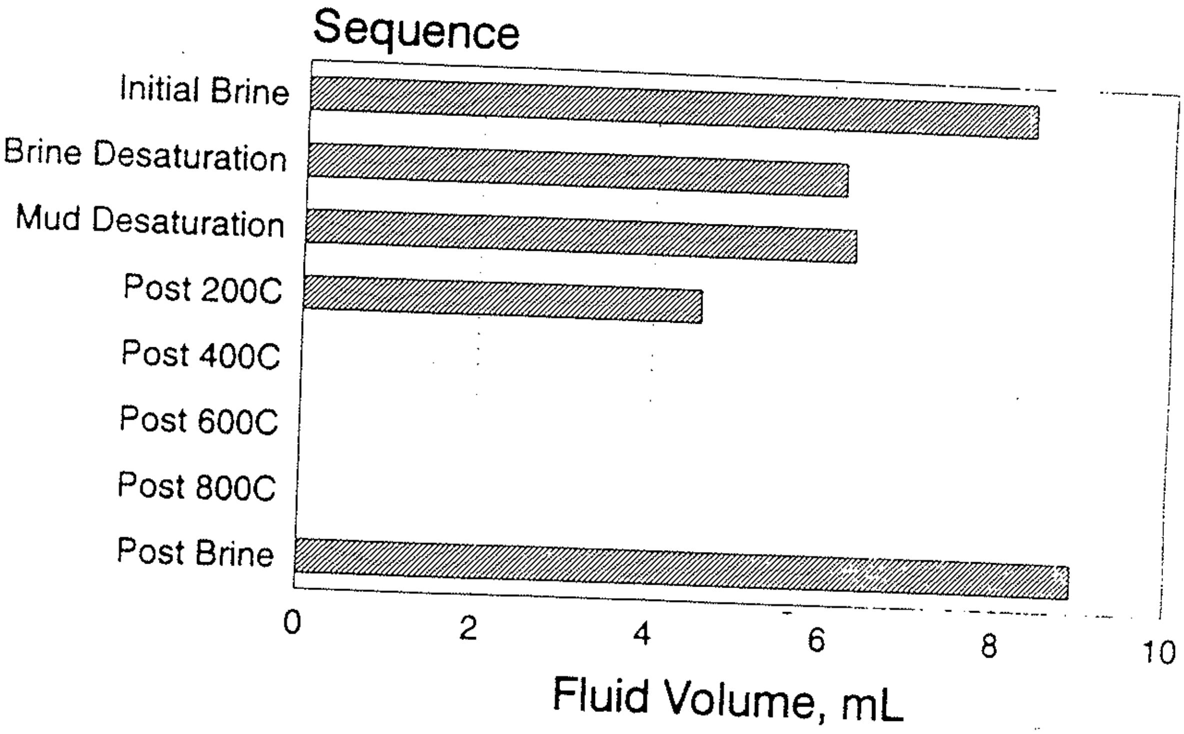

Figure 6: Water Volume in the Pore Space (Cores from Gas-Bearing Formation)

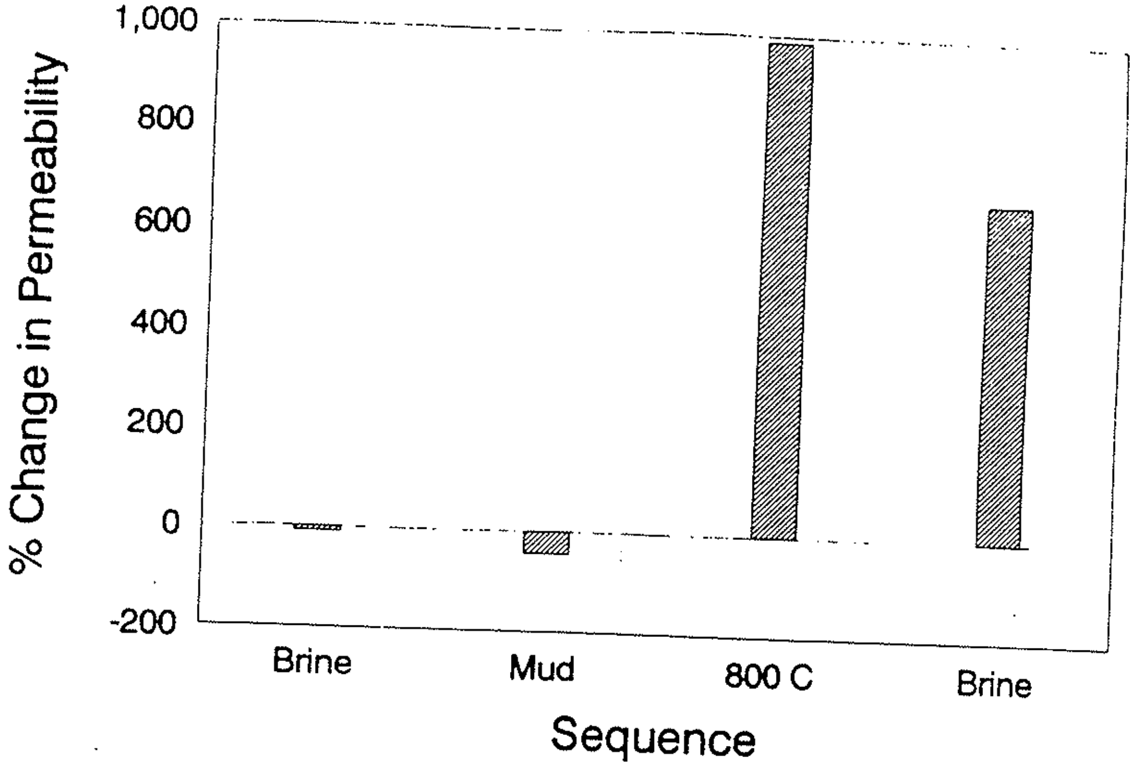

Figure 7: Change in Oil Permeability during Sequential Treatment (Initial Oil Permeability = 0.9 md; Cores from Oil-Bearing Formation)

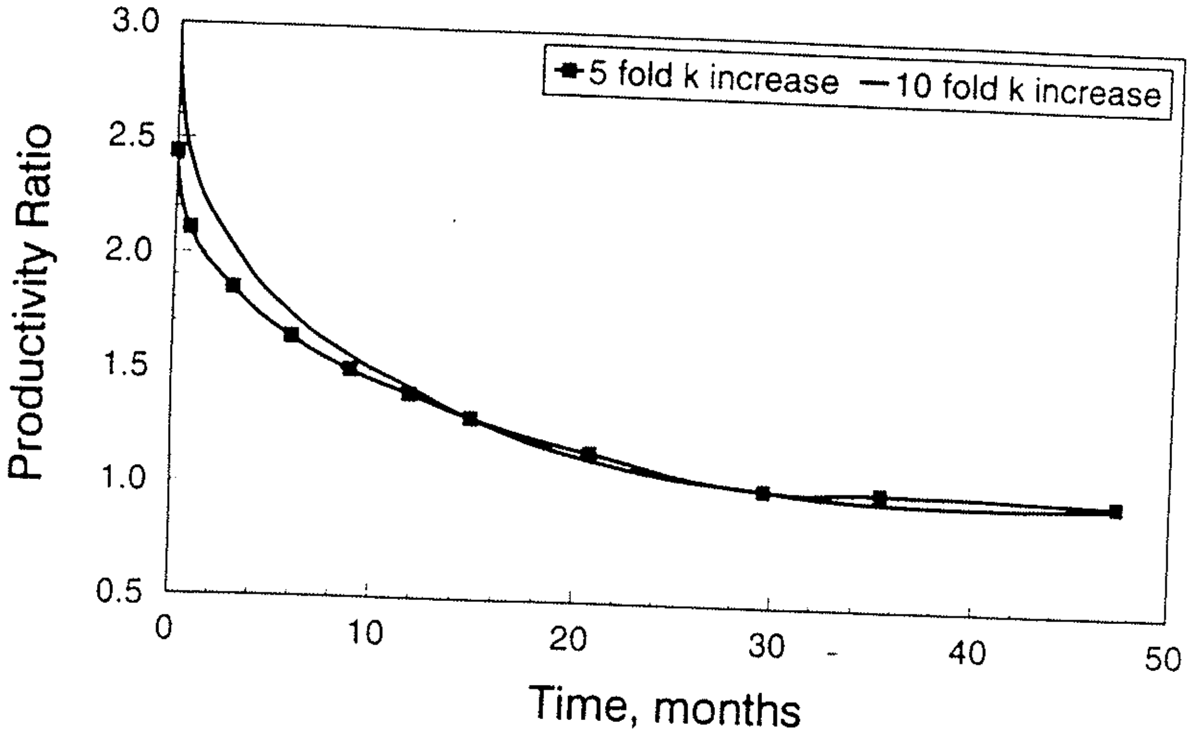

Figure 8: Productivity Improvement by Heat Treatment (Vertical Oil Well)

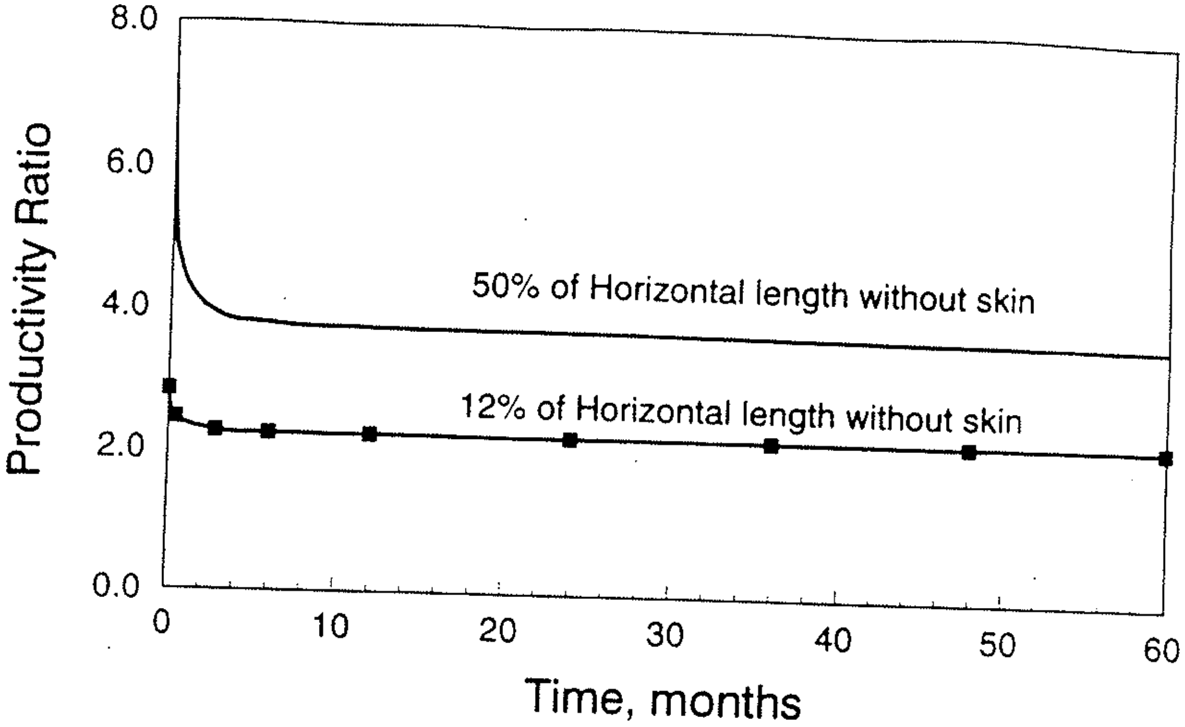

Figure 9: Productivity Improvement by Heat Treatment (Horizontal Oil Well)