CHEMICAL PROCESS SEALS LEAKS IN INJECTION WELLS

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ABSTRACT

A chemical gel has been developed to plug leaks in injection wells to provide effective zone isolation and casing protection. Since it is a gel material, the sealant can easily be removed from the casing-tubing annulus for workover operations.

This chemical forms a thick gel after placement in the annulus which helps (1) seal casing leaks, (2) protect fresh water aquifers from contamination, (3) protect steel casing from corrosion, and (4) can be removed from the casing-tubing annulus by rotating and reciprocating the tubing and washing out. Chemicals used in this process are nontoxic and are compatible with fresh water aquifers.

Field case histories are presented to show operational procedures and injection pressures before and after treatment and to illustrate effectiveness of the treatment.

INTRODUCTION

The sealant described in this paper was developed to be used instead of cement for the task of squeezing off casing leaks and re-establishing zone isolation. This sealant system, developed in 1982, was chemically tailored to allow flexibility of job design, competent sealing, casing protection, and ease of removal if desired. The sealant and associated service is marketed under the trade name ANGARD Service. In this presentation it will be referred to as casing protective sealant (CPS).

Use of CPS instead of cement has these advantages:

1. Users have reported savings of $25,000 over squeeze cementing or liner installations.
2. Unlike cement filtrate, CPS fluid lost during squeezing, gels and forms a seal.
3. The CPS gel is friable, with very little structural strength, yet forms an effective seal.
4. The soft texture of the CPS gel offers a new concept for repair of leaking casing, etc. This sealant is simply left in place, because there is no need to drill out as with cement.

Before the above-mentioned points are explained, the following background scenario is presented to better define the problems being routinely solved using CPS and some of the reasons why prior methods have met with failure or short-lived success.

BACKGROUND

The purpose of cementing a casing string in an oil, gas, or injection well is to seal off all zones which produce fluid from one another and from the surface, regardless of type. Often this is not thoroughly accomplished. A microannulus or hairline fracture not detected by bond logs may be present in the original cement sheath thus allowing for subsequent passage of fluids and gases through these spaces. If allowed to continue, several undesirable things can happen:

1. The passages through which the fluids are flowing can become larger through erosion.

2. Production zone pressurization can be lost.
3. Hydrocarbon production can be lost.
4. Corrosion of the casing can take place, particularly if high salinity brines are in constant contact with the casing string.
5. Cross flow between zones can occur.

In many older fields containing wells completed prior to 1960, when the importance of zone isolation and casing corrosion were not completely understood, many "false economy" measures were followed. Extremely short surface casing strings were used. In a further effort to be economical, cement was purposely run only a few hundred feet above the zone of interest. These older wells have sustained extensive casing damage due to constant exposure to corrosive brines. Examples of this are many wells completed into the Arbuckle formation in central Kansas. Zones such as the ones underlying the Anhydrite can produce copious amounts of brine containing up to 170,000 ppm total dissolved solids. In Oklahoma particular problems have been experienced with wells completed into the Leyton and Arbuckle formations. In central and west Texas the Coleman Junction formation at about 2400 to 3000 ft produces a fairly concentrated brine. In the Permian Basin, the Santa Rosa formation has been cited as a very offensive brine producer. Brine from this formation also contains sulfides.

Incompetent casing strings can cause problems other than those discussed above. In order to comply with state regulations, injection wells and wells converted to injectors must now pass mechanical integrity tests (MIT).[1] These state regulations presently force well operators to either correct the existing problems or lose the use of the well.

By far the most common approach to repairing corroded, leaking well casing has historically been squeeze cementing, a technique that has also been frequently applied to fluid migration problems behind sound pipe strings.[2] Superficially, squeezing with cement seems to be a logical choice especially when so little is known about any other available treatment. It seems simple enough, just fill the voids in the annulus with cement to prevent entry of formation fluids into the wellbore. If successful, cement plugs the formation matrix, water is shut off, corrosion is abated, and the casing string holds fluids under pressure. Dalrymple, Sutton, and Creel[3] report a high incidence of failure when attempting squeeze cementing procedures, however. Shryock and Slagle[4] observed that:

> "Squeezing casing leaks or holes is probably one of the most difficult squeeze jobs. The squeezed cement has many avenues, and accomplishing a pressure buildup can be most difficult. Even when a pressure buildup does occur, and a pressure test is performed after cleaning out the casing, the hole can break down at relatively low pressure."

Research indicates that poor formation bonding, or none at all, has developed adjacent to the area being squeezed, or there has been incomplete fill around the pipe. As many as eight squeeze attempts have been reported on a single casing string problem. McKown, et al[5] suggests that most cement squeeze failures occur because of: (1) lack of knowledge about downhole conditions or (2) overly optimistic expectations about the job results. They report nine key reasons for nearly all failures when squeeze cementing is used to repair casing strings, and methods perhaps of avoiding these causes. Since this paper deals with an alternate approach to casing repair, a review of these factors will not be restated. It should suffice to say, however, that success is far from guaranteed when squeezing with cement, regardless of how precise or well the job is performed.

Dwight Smith[6], in the SPE Monograph Series "Cementing," points out three erroneous concepts which account for both faulty squeeze procedures and also for high failure rates.

1. Whole cement enters the formation. The truth is that in low-pressure squeezing, that cement filtrate, not whole cement, enters the formation. When the formation is fractured, then cement can be squeezed into the fractures.

2. Breakdown from injecting mud automatically opens all perforations and pipe openings. In reality, it is rare to get all perforations and pinholes open.
3. A single horizontal pancake or wedge of cement is formed around the wellbore. When the formation is fractured, the cement slurry may enter a series of irregular wedges. This may leave voids or open formation near the pipe.

PROPERTIES OF CPS

With the true and complex behavior of cement during the squeeze process well in mind, it is appropriate now to return to CPS, the new material and technique whose physical properties work more in favor of achieving a successful repair than does cement. The physical properties discussed below account for the capabilities of CPS.

Gel Forming Agent

The gel forming agent in CPS is a special grade of inorganic silicate. Although not uncommon in the oilfield as a sealant, it is used in CPS in a very minimal concentration so that no excess gel former is used and maximum economy is attained. The low concentration of this silicate is balanced, however, by the co-reactant gel initiator. This chemical causes a gel to form in the pH range of 10 to 11. Once the gel is formed chemically, no fluid can pass through it until the gel is broken up physically.

When the CPS gel is formed surrounding a pipe wall or inside it, at pH 11 the pipe becomes protected from corrosion due to either exposure to high-salinity brines or fresh water. Figure 1 shows the results of a 90 day study in which the corrosion rate of J-55 grade tubing surrounded by CPS gel was compared to that of J-55 immersed in tap water. This feature indicates increased life expectancy for treated well casings which were formerly exposed to formation brines.

Viscosity

Ungelled CPS without fillers, referred to as neat CPS, has a viscosity only slightly higher than that of water (2.6 centipoise), thus it is able to penetrate even into tight formations. This is important because it is this liquid which becomes the filtrate lost from the CPS slurry during low pressure squeezing. It is capable of forming a competent gel in itself, without fillers.

Inert Fillers

Several properties of CPS are enhanced by inclusion of specific types of inert fillers. The principal filler used is a grade of diatomaceous earth. and the optimum filler loading for CPS yields a slurry density of 9.2 lb/gal. When attempting to establish a fluid seal against a porous formation, it is important to attain a certain amount of fluid loss from the slurry being squeezed, especially when the fluid lost can actually enter the pores of the formation and form a gel seal. Conversely, it is also important to limit fluid loss so as not to completely dehydrate the CPS. It is very important to maintain a hydrostatic head on the formation being squeezed to help prevent brine from percolating up through the slurry as the gel is forming.[7] The nature of the CPS filler allows some slow fluid loss through the structure of the diatoms. Figure 2 shows the structure of these diatoms. The comparatively low density and high surface area of this filler minimizes the chance of filler settling out of the ungelled CPS.

A small amount of supplemental suspending aid is also used as part of the composite filler to further help in prevention of filler settling. In the event that pipe is pulled through the CPS, settled-out and compacted filler of any type could prevent success.

A third type filler included in CPS, is a bridging agent which has been shown to be effective in correcting severe lost circulation. In situations where there is a brine column behind the pipe and a 9.2 lb/gal slurry inside the pipe, too much fluid loss could jeopardize a successful squeeze. The CPS could continue to U-tube,
consuming unnecessarily large amounts of sealant. The use of the bridging agent allows a complete fill-up inside the pipe, if desired.

A final purpose of the collective fillers is that they provide additional strength to the CPS gels.

Gel Strength and Sealing Ability

The texture of the CPS gel can be described as a friable, yet rigid gel. When removed from the container in which the gel formed, it retains the shape and the markings of the container, thus the term "rigid gel" is applied. The unsupported gel can be easily broken up by very light physical disturbances such as jabbing with a pencil, after which it does not recongeal. Broken pieces of CPS can act as check valves across pin holes and split pipe openings, however.

The principal method used to evaluate CPS gel strength was to use a penetrometer to measure the gel's resistance to penetration by a sharply pointed cone weighing 200 grams (Figure 3). The depth of penetration of the cone tip into the gel serves as an indication of the strength of the gel structure, i.e., the more penetration, the weaker the gel.

Penetration into Neat CPS Gel	Penetration into CPS Slurry
Averaged 23.5 mm	Averaged 17.4 mm

The above comparison indicates the degree to which a full filler loading enhances the strength of CPS gels (25%).

Applying the more normally accepted standard test method, i.e., compressive strength measurements, yields little helpful information for the user except that the CPS is weak. Compressive strength of CPS-filled gel is 1.0 to 1.5 psi. CPS is seldom expected to survive stand-alone mechanical pressure although it can withstand high hydraulic pressure when confined in a pipe or annulus.

Tests described below were performed to determine the amount of hydraulic pressure the CPS can withstand and still provide an adequate seal.

Sealing Test 1 for CPS

This pressure test was performed to determine whether the CPS gel system could seal against a differential hydraulic pressure of 300 psi. A chamber having an inside diameter of 2 in. and length of 10 in. was packed with 200 gm of 70-170 U.S. mesh silica sand (Figure 4). The chamber was filled with water and the flow rate of water through the sandpack was measured at 10 psi applied pressure. The empty part of the chamber was then filled with CPS. The chamber was pressured with nitrogen to 10 psi and the fluid loss through the sand pack during treatment was measured for 30 minutes. The CPS gel was let set overnight at room temperature. After the CPS gel was completely set, the pressure was increased slowly to 300 psi in increments of 50 psi. At each pressure increment a flow rate was measured. The fluid loss was also determined at 30 minute intervals. The water behind the CPS gel was dyed red to investigate any damage in the CPS gel due to pressure. The test results are presented in Data Table 1. Even after 300 psi was applied, no dye was observed to flow through the sand. After the test, the gel was visually examined and found to have no damage.

Sealing Test 2 for CPS

A section of 2 3/8 in. tubing was placed inside a 4½ in. casing to simulate the placement of CPS sealant in the annulus space. Twelve 3/4 in. holes were drilled on a 3 in. spacing in a 1 ft section of the casing to simulate casing damage. Three sets of four holes were oriented 90° apart around the casing. The holes were packed with resin consolidated Ottawa 40-60 mesh sand to simulate the leakage of fluid from the hole into the formulation matrix. The average permeability of the consolidated Ottawa 40-60 mesh sand was about 80 darcies (Figure 5).

Enough CPS solution was placed in the annular space to cover the entire 1 ft section. The annulus space was then filled with dyed water. After the CPS was squeezed with 100 psi for an hour, the test was shut-in to allow the CPS gel to form. After 48 hours of shut-in, the pressure test was performed by slowly increasing the pressure from 0 to 500 psi with nitrogen. The leakoff rate was measured at each pressure increment. Results are shown in Data Table 2. This test presented an extreme condition, wherein only enough CPS was used to just cover the target leaks. It was concluded that even with 12 high permeability holes present in a 1 ft section of pipe that they can be sealed off to a sufficient degree to pass an MIT. Only 1.0 psi was lost in 30 minutes at 500 psi test pressure. Usually, several hundred feet of CPS is run above the shallowest known point of leakage.

Allowance for Pipe Retrieval

The friable consistency of CPS allows partial or complete filling of an annulus space with sealant, leaving it there, and subsequent retrieval of the workstring. If cement is used, it would be necessary to either reverse out liquid cement after a squeeze pressure was attained, or allow the cement to attain a soft set and drill out what remains in the casing. Drilling out cement can cause severe damage to casing strings and liners.

From laboratory tests, it was soon recognized that CPS type gels might have the properties to allow a permanent annulus application that would permit easy inexpensive removal. Now it has been determined that tubing, with or without a packer, can be pulled through CPS gel. Eight full-scale tests were conducted using a test rig to determine the pull required to lift 180 ft of tubing string through a casing filled with CPS gels, both neat and slurry. In four of the eight tests an unseated retrievable type packer of the size corresponding to the casing size used was attached to the bottom of the tubing string. The various pipe specifications used are given in Data Table III along with the pull data from all eight tests.

Tests were conducted by preparing CPS slurries under field conditions, then pumping the liquid sealant into the annulus between the pipes being used in each test. The CPS was allowed to polymerize and age overnight. Samples of the CPS material were saved to verify that a gel had formed in each case, and that its strength was normal. Then, the tubing was pulled without rotation, reciprocation, or fluid circulation to break the initial bond.

It was shown that the following amounts of pull will probably be required per sq ft of tubing surface area to lift 2 7/8 in. to 4.0 in. tubing out of casing filled with CPS materials:

	No Packer	With Packer
CPS, Neat	20.6 lb/sq ft (1)	39.0 lb/sq ft (3)
CPS, Slurry	34.4 lb/sq ft (2)	56.8 lb/sq ft (4)

(1) Average of tests 1 and 3, Table 3.
(2) Average of tests 2 and 4, Table 3.
(3) Average of tests 5 and 7, Table 3.
(4) Average of tests 6 and 8, Table 3.

Non-Toxic

The CPS gel is composed of gelling agents which are then mixed with other solid material to give body and fluid loss control to the sealing gel. The gelling agent is composed of inorganic silicate in water. This silicate is routinely utilized as a soil stabilizing or solidification agent. Its oral toxicity is considered to be low.

The co-reactant gel initiator is mixed at low percentages with fresh water, it is no more toxic than concentrated fruit juice.

The following solid components are added to the above solution. Principal filler is diatomaceous earth, which is 88% pure silicate. A hydratable clay is utilized in the CPS gel mixture at a low concentration. This clay is a natural component of soils and is not considered to be toxic.

The fluid loss agent in CPS consists of small pieces of cellulose product, which is essentially regenerated cellulose produced from wood pulp by the viscose process.

Based on the above information, one can tell that the components of the CPS system are naturally occurring or are derived by rather simple means from common materials that are routinely found in the environment.

JOB DESIGN AND PERFORMANCE

CPS jobs are designed to place sealant over the entire corroded casing zone. Although placing sealant just to cover the leak has been shown to seal sufficiently to withstand 500 psi, it is advisable to place at least 300 to 500 ft of CPS above the shallowest known point of corroded casing. This is advisable for two reasons:

1. Inaccuracies in determining the location of the leak may lead to use of insufficient CPS volume. If several hundred feet of leaking casing exist, some small section may be overlooked. Some sections of the leak may be temporarily plugged at the time of testing, also resulting in the use of insufficient sealant.
2. If the leaks are fairly large, or the temporarily plugged sections of the leak become open, more CPS is lost to the voids outside the casing than anticipated. This could result in some of the upper holes being left uncovered.

If the precise location of the leaks is not known, it is best to run CPS up to where the bottom of the surface casing is located, or to surface.

Two typical placement procedures are being used. One is to preflush with fresh water or light sodium or potassium chloride brines, then pump the sealant into the annulus with the production packer seated. In effect this can be considered a "bullhead squeeze" technique. Although many good results have been achieved with this procedure, it can allow sealant contamination. With this procedure, pump rates are restricted by the leak size, not the annulus size. Therefore, with very low placement rates CPS could fall through the brine in the annulus and become contaminated, resulting in no gel and no seal.

A better approach is to unseat the packer, pump a preflush of light sodium or potassium chloride brine and then spot (pump rapidly with circulation to get the CPS in the proper position) the CPS down to the packer. The packer is then set or the bypass closed. The required pressure is then applied to the annulus to accomplish a squeeze. When a squeeze is achieved, the well is shut-in for 24 hours after which it is ready to pressure test. It is recommended that any pressure test be carried on in a step-wise fashion so that if a premature failure occurs, at least the extent of improvement will be known.

Example Treatment 1: The Oklahoma Corporation Commission (OCC) required a customer in Pawnee County, Oklahoma to pressure test the annulus of a disposal well. The annulus between 7 5/8 in. casing and 5 1/2 in. casing would take fluid at 3 bbl/min at 150 psi. A retrievable packer was set inside the 5 1/2 in. casing and pressure applied to the 2 7/8 in. - 5 1/2 in. annulus. It held pressure with no leakage. At the same time fluid was flowing to surface from the 7 5/8 in. - 5 1/2 in. annulus. This indicated a leak inside the 7 5/8 in. casing. A 3000 gallon (71.5 bbl) batch of CPS was decided upon to repair this leak.

Time (Minutes)	Operation
0000	CPS Solution was mixed.
0020	Solid fillers were added to the neat CPS.
0065	Began to pump the 3000 gal of composite CPS down the 7 5/8 in. -5 1/2 in. annulus at 2 bbl/min at 0.0 psi.
0085	Pump rate was slowed to 1 bbl/min (52 bbl pumped).
0095	Stopped pumping. The annulus was dead.
0097	Resumed pumping CPS at less than 1 bbl/min (61 bbl pumped).
0115	Stopped to reprime pump.
0120	Rate was slowed to 1/4 bbl/min as pressure began to build.
0125	All 71.5 bbl of CPS were in place in the annulus. The pressure had reached 300 psi.
0130	The well was shut in.

Results

At 68 hours after the well was shut in, it held 1200 psi for 10 minutes. In the final pressure test the annulus held 800 psi for 30 minutes, and passed the OCC test. The customer estimated that in terms of manpower, rig time, down time on the well, and the cost difference between the CPS job and other means of repairing the leak, has saved about $25,000.

Example Treatment 2: In Kansas, a disposal well completed into the Arbuckle formation was suffering from a casing leak. Initially, when 300 psi pressure was applied to the annulus, bleed off to 75 psi occurred in 10 minutes.

Step No.	Operation
1	Packer bypass was opened.
2	70 bbl of fresh water pumped down the annulus.
3	A volume of 17 1/2 bbl of a CPS-type treatment pumped down the annulus and displaced to the packer.
4	Packer bypass was closed.
5	A tubing volume of light sodium chloride brine was pumped down the tubing to displace any CPS below the packer.

6 Squeeze pressure was applied to the annulus.
7 Well was shut in for 48 hours.

Results

The well was pressure tested in three steps. In the final pressure buildup the annulus held 285 psi for 30 minutes. The state accepted the test and, one year later, the well is being used for disposal.

OTHER CPS CASE HISTORIES IN OKLAHOMA

Table 4 presents a list of wells that have received CPS treatments as a result of casing leaks. All of these wells were given approval by the OCC and were put into service as injector or brine disposal wells shortly thereafter.

ACKNOWLEDGEMENTS

The authors wish to express thanks to the management of Halliburton Services for permission to publish this paper. A special thanks and recognition is due Hyok Chong Tan for his developmental work and his laboratory support data on this sealant system, and to Susan V. Fulton for engineering assistance.

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Table 1

Data from CPS Pressure test as performed using the apparatus shown in Figure 3. The CPS formulation containing fillers was used in this test.

	Fluid Loss in 30 min (cc)	Flow Rate Thru Sand (cc/min)	Pressure (psi)
Before Treatment		960.0	10
During Treatment	107.0	3.56	10
After Treatment	1.2	0.04	10
	4.0	0.1333	50
	16.0	0.5333	100
	19.0	0.6333	150
	20.5	0.6833	200
	21.0	0.7000	250
	21.0	0.7000	300

Table 3

Pull test data obtained from full scale testing using 180 feet of tubing inside casing.

Pull Test Data for CPS Neat Formulations (No Filler)

Test No.	Casing Size (in.)	Tubing (in.)	Packer	Final Pull lb/ft²
1	7.0	4.50	no	19.47
3	7.0	2.875	no	21.7
5	7.0	2.875	yes	34.37
7	4.5	2.875	yes	43.72

Pull Test Data for CPS Slurry Formulations

Test No.	Casing Size (in.)	Tubing (in.)	Packer	Final Pull lb/ft²
2	7.0	4.50	no	28.42
4	7.0	2.875	no	40.40
6	7.0	2.875	yes	57.00
8	4.5	2.875	yes	56.63

Table 2

Data from CPS Sealing test, as performed using the apparatus shown in Figure 5. The CPS formulation containing fillers was used in this test.

No. of holes per foot = 12
Pack sand = Consolidated Ottawa 40-60 mesh sand
CPS Volume = 3 liters (13" - 14" from bottom)
Temperature = 75°F

Before Treatment

Flow Pressure (psi)	Flow Rate (cc/min)	Leak Off Rate (cc/min/psi)
2.5	4500	1800
2.5	4420	1768
4.5	5240	1164
4.5	5220	1160
		Avg. = 1473

Flow During Treatment

Squeeze Pressure (psi)	Flow Rate (cc/min)	Leak Off Rate (cc/min/psi)
10	0	0
20	0	0
30	0	0
40	0	0
50	0	0
60	0	0
70	0.02	0.0003
80	0.02	0.0003
90	0.02	0.0002
100	0.0366	0.0004

After Treatment

Test Pressure (psi)	Flow Rate (cc/min)	Leak Off Rate (cc/min/psi)	Leak Off Pressure Per 30 Min (psi)
100	0.56	0.0056	--
200	1.10	0.0055	--
300	2.10	0.0070	--
400	2.9	0.0073	--
500	1.42	0.0028	1 psi

Table 4

This table presents some recent CPS jobs performed on wells in Oklahoma to repair casing leaks.

Case No.	Date	Oklahoma County	Depth (ft)	CPS Volume (gal)	OCC Required Test Press.	Test Press. Achieved
1	7-11-86	Creek	60	630	300	300
2	8-01-86	Kay	2600	250	250	350
3	8-13-86	Osage	1290	600	200	200
4	0-08-86	Tulsa	712	500	200	100
5	9-11-86	Osage	2205	2000	200	300*
	9-18-86	Osage	2205			1000*
6	9-15-86	Osage	2200	1500	200	200
7	9-18-86	Kingfisher	±5400	1000	750	650
8	10-20-86	Garfield	±3375	1000	300	300
9	11-06-86	Garfield	±4000	1000	300	300,
10	10-21-86	Garvin	±1270	800	1000	1000
11	10-23-86	Pawnee	±2800	3000	800	800
12	11-24-86	Okfuskee	2481	1200	300	400
13	12-06-86	Lincoln	4586	750	300	300**
14	12-10-86	Osage	±2100	2000	200	75

*Returned on 9-18-86 and repressure tested the annulus. No more CPS was run.

**Stopped the big leaks.

Small leak above CPS.

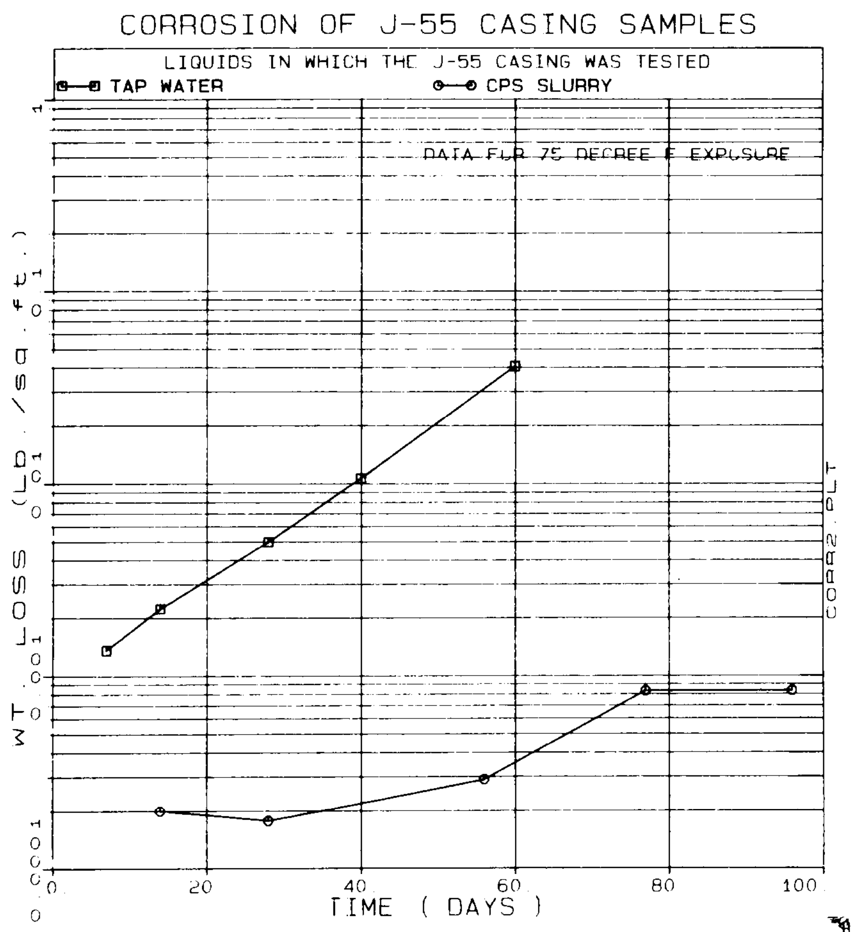

Figure 1—The maximum acceptable corrosion rate is 0.04 lb/sq ft. This occurred with water after 60 days exposure

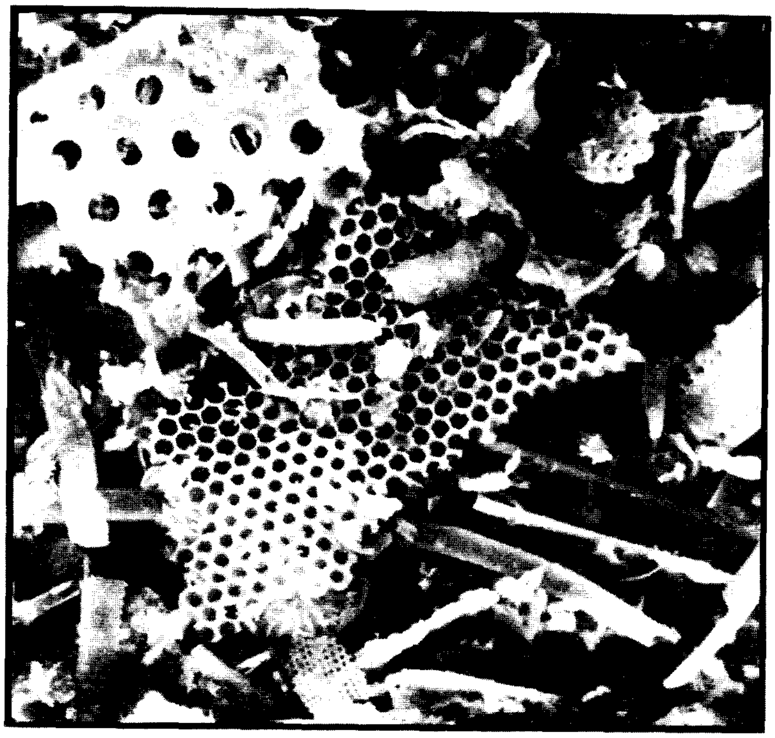

Figure 2—Photomicrograph showing the CPS filler structure through which some very limited fluid loss into adjacent formation is achieved.

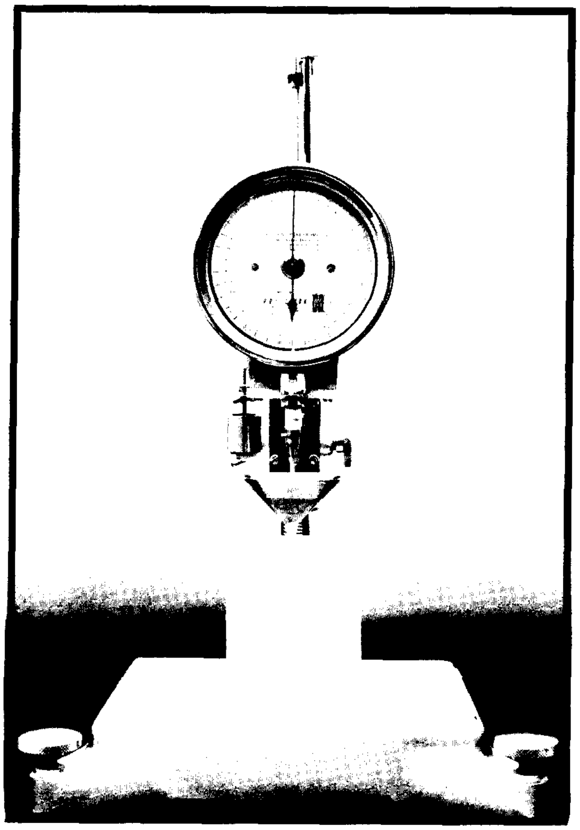

Figure 3—A precision scientific penetrometer. This instrument is used to determine the relative strength of CPS gels by measuring the distance of penetration attained by the cone point into the gel structure. ASTM (D-217) test procedures and specifications were used in these determinations.

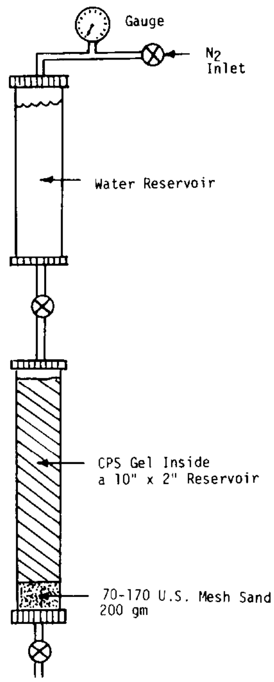

Figure 4—Pressure test apparatus used to evaluate CPS gels

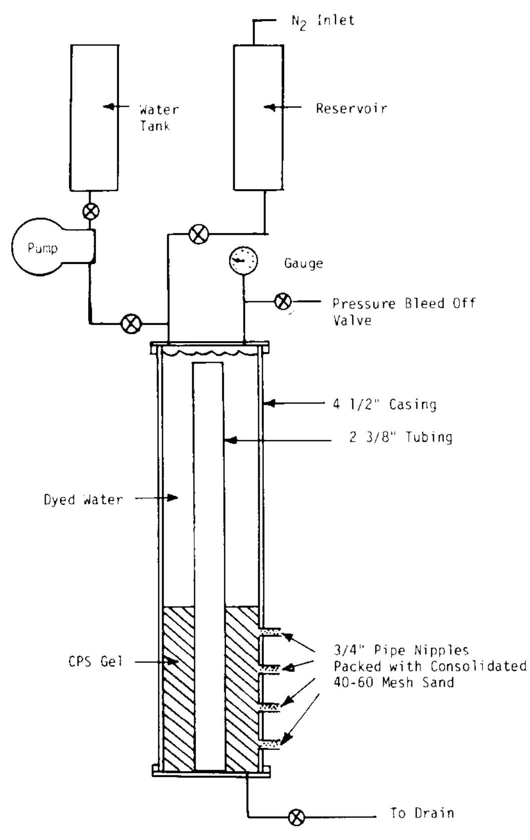

Figure 5—Schematic of the apparatus used to test the sealing ability of CPS gels