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DEVELOPMENT OF GEOTHERMAL WELL COMPLETION SYSTEMS

Phase I Report, July–September 1977

By

L. H. Eilers
D. L. Free
E. B. Nelson
B. E. Simpson
L. B. Spangle
J. F. Williams

Work Performed Under Contract No. EG-77-C-02-4190

Dow Chemical Company
Dowell Division
Tulsa, Oklahoma

U. S. DEPARTMENT OF ENERGY Geothermal Energy

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Contributors:

L. H. Eilers	D. L. Free
E. B. Nelson	B. E. Simpson
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Work Performed for the

DIVISION OF GEOTHERMAL ENERGY
UNITED STATES DEPARTMENT OF ENERGY

Washington, D. C. 20545

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DOWELL DIVISION
DOW CHEMICAL U.S.A.

Tulsa, Oklahoma 74102

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ABSTRACT

Information has been gathered from companies experienced in geothermal well cementing. Most companies expect problems to develop as well conditions become more severe, and the wells age. Such things as thermal shock effects, high temperatures, and high reservoir permeabilities point out a need for light weight cements with good bonding and compressive strength characteristics. Previous high temperature cement research has led to doubts concerning the stability of pozzolan cement systems. Also, the use of silica flour at up to 40 percent concentration has been shown to be beneficial. Initial test procedures for cement systems in this present study will enable many cement formulations to be screened before long term evaluation under conditions of high temperature, high pressure, and brine contact is started.

INTRODUCTION

Whenever a well is drilled to tap geothermal resources, a steel casing must be run into the hole and secured with some type of cementing material. Various methods of cementing these wells have been reported in the literature (7,10,12,13,15), but little has been written about the stability of the cementing systems used in these operations. Many authors have pointed out, however, the tendencies of Portland cement systems to degrade under extreme temperatures. (1,6,10,11) These observations along with the reported failures of some geothermal wells (5,6,8,9), lead to the conclusion that severe strength retrogression in geothermal cementing materials can lead to dangerous and costly blowouts. According to some industry spokesmen, control of such failures can cost up to five times the original cost of drilling the well (14), not to mention damage to the sometimes fragile eco-systems in the immediate area of the well-site. For these reasons, a program to determine the optimum cementing system for use in geothermal wells has been undertaken and consists of two thrusts: (1) Phase I- definition of problem and (2) Phase II- actual development of a suitable geothermal cementing system. As a part of the Phase II work, a study of the basic chemistry of systems similar to those already in place will be conducted in order to help predict the in-service properties of those materials. This report describes research carried out during Phase I of the described program.

During the period of May 1 to September 30, 1977, background data on high temperature cementing and related problems was gathered. Many existing publications on high temperature cementing were studied, and Dowell's proprietary information on research and records of wells cemented were reviewed for information applicable to this project.⁽¹⁻⁴⁾ A major source of information for this study was a series of interviews with engineers and drilling personnel of companies having geothermal drilling and completion experience. This enabled us to define current cementing practices and problems and help set objectives for future research. Initial test procedures were then designed based on this background study.

Variables to be determined during the Phase I study included the following: (1) expected well life in different type fields, (2) expected characteristics of fluids, (3) static and circulating temperatures expected for the various types of fields, (4) the weight range needed for cementing slurries, (5) the thermal variations expected in the life of a well, (6) the type of drilling muds expected, (7) economic limitations on completion systems, (8) minimum and/or acceptable strength for cement, (9) desired and/or acceptable porosity and permeability of cement, (10) heat transfer properties of cement, and (11) desired and/or acceptable cement bonding strength to pipe and rock. The first seven are from our original proposal and the last four were suggested as the study began.

SUMMARY OF INFORMATION GATHERED IN OPERATOR INTERVIEWS

1. Wells are rarely cemented under geothermal conditions.

Drilling programs of all the operators responding to our questions call for setting surface and production pipe above the reservoir. Bottom hole temperatures, where measured, seldom exceed 116°C. Mud flow line temperatures are 93-104°C.

In some cases, slotted liner is hung through the producing zone, but cementing the liner is not considered critical.

In one area the producing zone is so shallow that the reservoir may be encountered before surface pipe has been run. In this case the hole is cooled by circulation to a temperature where the cementing operation can be conducted without problems. This is thought to be in the 116°C range although the operator did not have a precise measurement.

2. Rock formations are highly permeable. The nature of an economical geothermal reservoir is such that large quantities of hot water or steam must be produced from each well. Permeabilities therefore must be in the darcys. Highly fractured rocks and poorly consolidated sandstones are the most common reservoir rocks.

3. Chemistry of reservoir fluids varies from fresh water to extreme salinity. Dry steam fields containing relatively few salts have low percentages of noncondensable gases, the most noticeable being H_2S . Hot water fields in some cases have virtually no salt and only a small percentage of silica, but in one major field salinities as high as ten times sea water are reported.
4. Pressures are seldom above hydrostatic except geopressure zones. Dry steam fields report measured reservoir pressures that vary from 3500 to 3800 kPa at depths from 900 to 3000 m. In hot water fields, pressures at the bottom of a 3000 m hole will be less than 3500 kPa. Reservoirs appear to be slightly under pressure relative to hydrostatic in some fields.

Exceptionally high pressures of 69,000 to 138,000 kPa have been reported for geopressured zones which are found from 3700 to over 6000 m deep.

5. Bottom hole static temperature and bottom hole circulating temperature data are often unreliable and misleading. Published reservoir temperatures vary as much as 66°C higher than data reported by the operator for the field. This is because many authors do not have proprietary data retained by the operator and often make unwarranted

assumptions. Also, the promotional nature of many geothermal ventures leads to a slight exhuberance on the part of the authors. The operators themselves use different methods to measure temperatures with results that vary as much as 10°C for the same well.

The highest accurately measured temperature reported to us is 357°C. One well was reported to be higher, but all others were less than 316°C.

6. Thermal shock effects on cement may be significant. All operators expressed concern over the cement to pipe bond, when subject to the temperature cycling of drilling, testing, shutting in, and producing. In areas where feasible, wells are left on a bleed system to keep temperature up, but in most areas this is not possible.

Several operators expressed concern over the possible changes in permeability from microfractures in the cement sheath induced by thermal shock.

GENERAL DIRECTION OF PHASE II RESEARCH

Long Term Strength

Although all operators do not currently cement wells under conditions of high temperatures, the cement will ultimately be subjected to the maximum reservoir temperature under production. Since these wells are expected to produce for twenty to thirty years the cement will be subjected to these temperatures for most of the life of the field.

For these reasons, long term strength has been given priority in our research effort.

Bond Strength

Information on bond strength is inconclusive but the likelihood of bond failure as a result of thermal shock or long periods of time at high temperatures suggests the need for careful research along this line.

Lightweight Cements

The nature of the geothermal reservoir, high permeability, makes it imperative that cement formulations developed have low density or other characteristics that will prevent loss of cement or formation damage.

These three criteria, long term strength, bond strength, and lightweight, are often incompatible with each other. As a result, many cement formulations will have to be screened and evaluated.

In addition, it is expected that as geothermal exploration develops, higher temperatures may be encountered in rocks of very low permeability. This will require cementing pipe in the hottest zones to enable stimulation techniques to be employed. While wells are not now cemented under conditions of high temperature, it is very likely that they will be in the future.

We have selected the following test criteria for our long term tests. It is expected that hot water tests will occupy 75% of the effort, with dry steam tests 20% and dry air tests 5%.

TEST ENVIRONMENTS

I.	Dry	225°C 325°C
II.	Dry Steam Dry Steam + H ₂ S	225°C 325°C
III.	1. Hot Water	Brackish < 10,000 ppm TDS 225°C 325°C
	2. Hot Water	High salinity - 200,000 ppm TDS 225°C 325°C

Pressures - 3500 kPa - dry steam
35,000 kPa - hot water
69,000 to 138,000 kPa - geopressure

The general guidelines we will follow during the screening tests will be as follows:

INITIAL TEST CRITERIA

Placement Ability - 3-4 hours retardation at BHCT

Compressive Strength - Greater than 3500 kPa
at 24 hours for
lightweight cements

Permeability - Less than 0.1 md to water

Stability - Strength loss no greater than 30 percent
in 30 days

BACKGROUND INFORMATION PROVIDED BY COMPANIES INTERVIEWED

On the following pages the information gathered from companies operating geothermal wells, in a series of contacts by mail, phone, and in interviews with drilling personnel is listed. All responded to some extent. Most of the companies were very cooperative although some provided significantly more information than others. Some of the companies utilized consultants for drilling and completion guidance and therefore had little information on cement problems. Usually they referred us to the service companies who did the cementing to provide specific strength, permeability, weighting, and cement formulations. Specific data is reported where provided but some of our questions were thought to involve proprietary data and were not answered, particularly data on reservoir temperatures and costs.

It was originally planned to characterize each geothermal field by the geochemistry of the waters and then report information on each company's experiences in that field without identifying the company by name. Unfortunately, because there are so few geothermal fields and so few companies operating in each, it was felt that the geochemical data were too distinctive and would serve to readily identify each operator providing information.

In order to persuade the companies contacted to cooperate freely, we agreed to report all information given by each separately as "Company A", "Company B", etc., and make few, if any, distinctions between fields.

The small size of the geothermal industry makes even this approach difficult to use in protecting anonymity but most of the companies preferred it.

"Company A"

The average age of wells has been four years, with the oldest in service eight years. No workover operations have been required on ninety percent of the wells. A few have required squeeze cementing and casing replacement. Each well has a planned life of 30 years but it may be possible to continue in production longer. Wells may decline in production from formation plugging. This operator believes that these wells can be revitalized but no attempts have been made so far. No wells have been lost from cement failures.

Cement formulation used:

Class G, 1:1 perlite

40% silica flour

3% gel

Retarders, friction reducers

1.52 kg/l slurries were used on surface pipe, and 1.87 to 1.92 kg/l neat G plus 40% silica flour was used on production string. It is preferred to use as light a slurry as possible because of low fracture gradient. No correlations have been noted between cement density and stability. Two to three hours of pumping time, including safety factor, is normal.

Geothermal Fluid Composition

Dry Steam contains up to two percent noncondensable gases. One to fifteen percent of the noncondensibles is H_2S which does not appear to affect cement. Few abrasive solids are contained in steam after initial flow begins. Fifteen percent of the fluids are reinjected. These fluids could be used to mix cement but it is probably unnecessary as other sources are available.

Temperature

Reservoir temperature is 246-249°C in dry steam fields as measured by wireline logging tools. The mud flow line temperature is usually 104°C when drilling near the reservoir. Downhole circulating temperatures are 150°C maximum and can be lowered by circulating before cementing.

Depths vary from 1500 to 3000 m and maximum pressures are 3500 kPa for dry steam and hydrostatic for other parts of the field.

Thermal Variations

Temperatures the cement sheath is subjected to will vary 93°C during drilling and completion. Conditions for production string cements will change from 116 to 204°C during WOC time.

During testing and production a change of 150 to 232°C in less than one hour may occur. This may fracture cement. Maximum temperature encountered was 254°C in dry steam fields, and 288-316°C in hot water.

Drilling Muds

Standard bentonite gel - water mixtures are used. Caustic and other additives are minimized because of environmental aspects of drilling permits.

Rocks drilled are serpentine, graywacke and sandstones. Serpentine will make mud but otherwise it does not present a problem.

This Company would be willing to change muds if necessary to improve cement jobs.

Casing Programs

Usual casing practice is to cement 150 m of 20 in. conductor to surface, followed by up to 760 m of 13-3/8 in. surface pipe also cemented to surface. Great care is taken to insure complete

return of cement in the annulus to the surface. If the cement falls back, it is topped to the surface. This prevents casing elongation or at least minimizes it. The 9-5/8 in. production string is set above the reservoir by either hanging at approximately 700 m or in some cases cementing to surface. The wells are always completed open hole.

Approximately 100 barrels of water are used as a spacer and occasionally hydrazine is used as a flush.

The cement cost is up to \$40,000 per well - a 10% increase in cost could be accepted if performance improvements were demonstrated. WOC time is seldom a factor as up to 24 hours is required to connect blowout preventers.

Minimum Strengths

Class G, 1:1 perlite plus 40% silica flour - 7580 kPa 24 hours
Neat G and silica flour - 15,860 to 16,550 kPa after 8 hours
This company would like higher strengths.

Porosity and Permeability

No specific data is available on permeability of cements now in use. It is expected that permeability would increase with time but the amount is unknown.

Heat Transfer Properties

The company does not consider it important.

Bonding

It is believed that the bond of cement to pipe is quite good. Failed casing recovered during a workover had a cement sheath which was strongly bonded to the casing. This well had experienced the normal stresses of drilling and testing. Bond strength was not quantified.

This company believes that thermal shock probably will cause failure of the cement-pipe bond in some cases.

Casing does not elongate if properly cemented. Special care is taken to complete cement sheath from surface to T.D. of 13-3/8 in.

All wells are placed on bleed system after initial tests to prevent thermal shock.

No bond logs are available for examination.

"Company B"

No wells are currently on production. Several have been drilled and tested during the last six years. Workover has consisted of replacing slotted liners on some wells. Liners are hung and not cemented.

Cements used:

Class G, 1:1 perlite

35% silica flour

2-3% gel

With up to 0.5% friction reducers.

Water is used as a spacer. Slurries are retarded to provide 2-3 hours emplacement time including safety factor.

Wells are designed to last thirty years and the only problems expected will be occasional sand inflow which will require removal.

Fluid Characteristics

Reservoirs are in low salinity brines (2500 to 3800 ppm TDS) and in saline (44,000 ppm) waters. In the lower salinity reservoirs few salts or gases are troublesome. In the high salinity reservoirs carbonate and sulfate minerals as well as halite may cause formation plugging. It is not necessary to use reservoir fluids as mix water as other sources are available. Spent fluids will be reinjected.

Temperatures

Precise reservoir temperatures are classified, but low salinity fields vary from 177 to 204°C. Higher salinity fields are over 204°C. These temperatures are measured by wireline logging

instruments. BHCT is not measured, but probably does not exceed 104°C. All wells can be cooled by circulating. Mud flow line temperatures are less than 93°C. Depths vary from 1200 to 2100 m and pressures are hydrostatic.

Weight Range

Slurries are adjusted to 1.44 to 1.56 kg/l range. This company would like to use 1.2 kg/l or less if possible. Low formation pressures are the primary reason for using lightweight cements. No correlations have been noted between cement weight versus stability.

Thermal Variations

During drilling and completion operations temperature cycles of less than 93°C are expected. When undergoing tests, a well can cycle 93°C to over 204°C in less than one hour. When shut in, cooling will be at a lower rate. This company believes that thermal shock may fracture cement but it does not appear to be a problem at this time.

Drilling Muds

Standard bentonite gel muds are used with few additives both to simplify procedures and to abide by environmental restrictions. Mud costs can be up to \$50,000 per well particularly if salt based muds are used. Mud is usually mixed to provide 10 ml or less water loss.

Rock types being drilled include poorly consolidated sandstone and clay.

Economic Limitations

Casing programs include 30 to 60 m of 20 in. conductor cemented to surface, 13-3/8 in. surface pipe is run to a point above the reservoir, depth up to 760 m. Special care is taken to get cement returns to surface when cementing 13-3/8 in. casing. No spacers or scratchers are used but centralizers every 120 m are used. 9-5/8 in. or 8-1/2 in. liner with 1/4 in. slots is hung in the 13-3/8 in. pipe and extends through the reservoir. It is not cemented. Average cement cost is \$17,000 to \$20,000. WOC time is not a factor.

Strength

Compressive strength data is not available. Referred to service company literature.

Porosity and Permeability

Data not available.

Heat Transfer

Heat transfer properties of cement are not considered important.

Bonding

This company believes that bond to pipe is good and will hold with time. Variations in temperature will not cause bond failure. Cementing of surface pipe is considered to be the key to successful completion of geothermal wells. If 13-3/8 in. pipe is cemented to surface then pipe will not elongate and cement to pipe bond will remain intact.

"Company C"

Well Life

No wells are currently producing but design life is expected to be 20-25 years. Wells are cemented using the following slurry formulations:

- Class B, 1:1 perlite
- 40% silica flour
- 2% gel
- 0.5% friction reducer
- 1 to 3% retarder

Weight Range

Weight range of slurries now in use is 1.57 to 1.63 kg/l.

This company would like to have lighter cements because of the low fracture gradient.

Water is used ahead of the cement to clean the hole.

Geothermal Fluids

Salinity of this hot water field is very low, 1500 ppm TDS. Water does not contain any abrasive solids and can be used as cement mix water. Spent fluids will be reinjected.

Temperature Data

Static reservoir temperatures are greater than 204°C as measured by wireline logging tool. Mud flow line temperatures are as high as 93°C. Wells may flow while drilling. Depths are 305 to 915 m and pressures are hydrostatic.

Thermal Variations

During drilling, temperature changes of 93°C are possible in a few hours. Under testing, wellbore temperatures can change 93°C to 204°C in less than one hour. The operator does not know if this fractures cement.

Drilling Muds

Standard fresh water bentonite gel is used with some lost circulation materials. Mud viscosity of 32-36 cp is usually maintained. Rock types are principally granite.

This operator would change muds if the cement system required it. They emphasized a need to clean the well with some spacer or wash before cementing.

Economic Limitations

The casing program now in use includes 30 m of 20 in. conductor pipe, and 305 to 610 m of 13-3/8 in. surface pipe. Some wells are completed with only 13-3/8 in. casing. A few have 9-5/8 in. pipe either hung and cemented or cemented to surface.

Typical well completion costs range from \$350,000 to \$450,000. Cement costs are \$35,000. This company would pay 10% more for improved cement. WOC time is not a factor.

Strengths

Compressive strength of cements now in use is 15,860 kPa at 24 hours, with not less than 6895 kPa after extended time.

Porosity and permeability data are not available.

Heat transfer properties are not considered important by this operator.

Bond

This company believes that the cement does not bond well to the pipe but acts as a "snug" fit which both supports the pipe and provides an effective seal. Variations in temperature therefore have no effect on bond strength. The casing elongates 0.10 to 0.35 m during testing. Bond logs have been run and may be made available.

"Company D"

Well Life

The longest period a well has been in use is seventeen years. In one area fifty percent of the wells require no additional work after completion. The rest require squeeze cementing and some casing replacement. The average well age is 12 years so far with a planned life of 25-30 years.

The cement formulation used on early wells is unknown; however, an analysis of this cement has indicated that perlite was probably used to extend the slurry. The lack of free quartz in the X-ray and the presence of calcium hydroxide, some of which has apparently converted to calcium carbonate, indicate the cement was not stabilized and has deteriorated.

Cement formulations using pozzolan as an extender have been tried in this area, but not enough time has elapsed for evaluation of effectiveness. Laboratory studies indicate probable strength retrogression with time.

Recently drilled wells in this area use a cement based on the following:

- Class G, 1:1 perlite
- 40% silica flour
- 2% gel
- 0.5% friction reducer
- 0-1% retarder
- Water ratio: .46:1
- Density: 1.46 kg/l

Standard methods of emplacement are used with water as a spacer. Cement is retarded for 1 hour pumping time with 1/2 hour safety factor.

Characteristics of Geothermal Fluids

Dry Steam contains 1-2% noncondensable gases which will decline to 0.5% with production. Analysis of the noncondensable gases by weight percentage:

CO ₂	82.5	
CH ₄	6.6	
H ₂	1.4	
N ₂ + A _r	1.2	
H ₂ S	4.5	(can be as high as 15)
NH ₃	3.8	

Hot water and brine fields have varying percentages of dissolved solids that range from fresh through brackish to extreme salinity.

Temperature

Reservoir temperatures vary from 177 to over 371°C. The static temperatures are calculated from temperatures recorded while taking deviation surveys. In a few cases static temperatures were measured by wireline logging methods. Dry steam reservoir temperatures are 240°C. Most hot water fields are less than 260°C. One brine field is much greater than 260°C. The highest temperature is 399°C. This was determined on one

measurement in which the logging tool (rated to 399°C max) broke during the run. It is not known whether the device broke from the heat or from other causes.

Circulating temperatures vary between 93°C and 204°C depending on whether the measurements are taken in the reservoir or above it. Mud flow line temperatures are usually 82°C. Temperatures downhole can be lowered by circulating before cementing.

Slurry Weight Range

Cement slurries currently used vary from 1.52-1.68 kg/l. Because of the low formation pressures, and low fracture gradients in most reservoirs, weights as low as 1.12 kg/l would be ideal. No correlation has been noticed between cement weight versus stability.

Thermal Variation

During drilling and completion of a well the range of temperature variations is probably less than 93°C. However, when a well is tested the casing and cement are subject to 149 to 204°C temperature changes during the testing period of a few hours (1 to 6). After placing the well on production no significant variations occur unless workover of the well is necessary.

Dry steam wells are left on a bleed system after testing which reduces thermal shock. Hot water wells do not presently employ

a bleed system, but probably will in the future. This operator believes that thermal shock will definitely fracture cement systems now in use. This is not thought to be a serious problem at present.

Drilling Muds

Wells are drilled with both air and mud. Mud systems are usually standard gel-water mixtures. Additives such as lignin-tannins and acrylates, sepiolite, and caustic are sometimes used. Mud systems are rarely changed except in cases of low formation stability.

Drilling muds would be changed to accommodate newly developed spacers and cements if overall costs and performance warrant.

Rock types drilled vary depending on field. Tuffs, andesite, basalt, serpentine, sandstones, shales and graywacke are most commonly drilled.

Economic Limitations

Casing programs now in use vary with fields but usually include 30 to 150 m of 20 in. conductor cemented to surface, 305 to 760 m of 13-3/8 in. surface pipe cemented to surface, 9-5/8 in. production pipe hung or cemented to surface.

Use of specialized equipment such as scratchers and centralizers varies with each field. Completion costs vary widely, but cement costs are as high as \$50,000 per well.

Strength

The minimum strength desired for cement is 6890 kPa, but 689 kPa after 25 years of service is acceptable. Cements now in use are 20,685 kPa. Inadequate data are available to project downhole strengths of cements now in use.

Porosity and Permeability

Little information is available, but some data from wells which failed after five to seven years of service indicate a limit of no more than one md permeability to gas after 25 years.

Heat transfer properties of cement are not considered important by this operator.

Bonding Strength

Information on bonding to pipe or rock is inconclusive at this time. This operator believes that variations in temperature cause failure of cement to pipe bond. Casing elongates as much as 0.76 m, while the cement sheath does not elongate at all. Self-stress cements may be desirable.

Cement bond logs have been run but appear to be inconclusive.

DOWELL'S HIGH TEMPERATURE CEMENT RESEARCH

Dowell has been conducting research on cement systems for geothermal wells since the early 1960's; as a result, a great deal of useful information has been acquired.⁽¹⁻³⁾ This summary of Dowell's high temperature cement research program reports the principal findings concerning the physical and chemical behavior of cement systems exposed to conditions thought to exist in a geothermal environment.

Testing has been performed on an extremely wide range of systems. Over a thousand tests have been run on approximately 160 different systems incorporating nearly every type of cement, cement additive and cement extender commonly used by the well cementing industry. These cement systems have been exposed to saturated steam pressures at temperatures ranging from 110°C to as high as 1093°C, and cured for periods ranging from one to 720 days.

Dimensional and Weight Stability

The only systems that change more than one percent in size and five percent in weight during exposure are high-water extended cements. They tend to increase in size and weight as they deteriorate.

Stabilized pozzolanic cements, especially those containing fly ashes, occasionally develop a roughened surface or nodule along a water line.

Strength

Neat Portland cement systems weaken greatly during the first day of heating at both 204 and 316°C; however, those systems containing the API recommended amount of water maintain compressive strengths above 3500 kPa. 3500 kPa is thought to be the minimum strength required for proper operation of a well.⁴ Extended systems with 100 percent water by weight of cement and no silica drop below 1380 kPa during the first month and complete disintegration can occur.

The addition of 30 to 40 percent silica by weight of Portland is sufficient to stabilize most systems against high temperature strength retrogression. Any additional silica acts simply as an extender or filler. Reduction of the amount of mix water reduces the degree of strength retrogression but not as effectively as the addition of silica. Class J cement, essentially a mixture of dicalcium silicate and quartz, requires no additional silica for stability.

The stabilized cement formulations can tolerate most additives without strength retrogression. This includes those additives that do not change or react with normal cement hydration such as weighting agents, extenders and lost circulation materials. It is important to realize that extended systems are not necessarily as strong as normal water systems. Test results show that extended systems with silica do not experience significant strength retrogression upon heating.

A notable exception is that pozzolans are detrimental. Fly ashes can cause more strength retrogression than natural pozzolan materials. Fly ash systems tend to gain strength for the first 30 days at 316°C and 180 days at 232°C then begin to lose strength. This type of degradation occurs according to a different mechanism than the usual high temperature deterioration.

Permeability

The permeabilities of all cement systems aged at 232°C and 316°C are high as compared to most cements maintained below 93°C. Most systems cured at 93-107°C have permeabilities in the range of one microdarcy and do not increase greatly in permeability when maintained at this temperature under moist conditions. The permeability increase is usually more rapid at 316 than at 232°C. Some neat G and A cement systems at 316°C increase in permeability from 0.001 millidarcy to six or eight millidarcys on heating one day and thereafter do not change appreciably.

Permeability increase is less severe with silica stabilized systems. These systems usually stabilize at 0.07 to 0.2 millidarcys. Reduced permeability can also be achieved in a neat cement with a very low (32 percent) water content. Portland systems with 35 percent silica flour and Class J cement slowly gain permeability over several months. Additives, except fly ash, generally have little effect; however, increased water results in increased permeability. Fly ash cements give a delayed increase in permeability; thus, it can be surmised that permeability varies indirectly with strength.

X-Ray Analysis

The chief composition of all the cement systems is non-crystalline. Tobermorite ($C/S = 0.833$) is the principal crystalline phase below 150°C as detected by X-ray. After one day of heating at 232 and 316°C the tobermorite converted to alpha dicalcium silicate which is a weak porous component of heated cement accounting for most of the initial degradation. Addition of 35 percent silica to Portland cement is sufficient to greatly reduce the amount of alpha dicalcium silicate formed. Instead, a much stronger cement component, xonotlite ($C/S = 1.00$), is formed on heating. These chemical transformations occur within the first month.

The cements containing pozzolan degrade by a different mechanism and require much more time to react. Initially these systems react to form xonotlite as did the other systems; however, over a period of several months at 316°C and a year at 232°C , these compounds convert to a truscottite type ($C/S = 0.66$) compound weaker than xonotlite but stronger than alpha dicalcium silicate hydrate.

Differential Thermal Analysis

Differential thermal analysis (DTA), which measures the internal heat change as a function of temperature, has been used to analyze some systems after aging at 232 and 316°C . By this method it has been established that calcium hydroxide is present in all of the Portland cement systems without silica

even though it is not always detectable by X-ray. The presence of excess alpha quartz has also been confirmed in 50 percent silica systems despite the absence of such information on X-ray diffraction patterns.

Effect of Results on Future Testing

Neat Portland cement systems normally degrade at elevated temperatures by rapid conversion of tobermorite or other hydration products to alpha dicalcium silicate hydrate resulting in low strength and high permeability. This occurs very rapidly; thus, at temperatures of 232°C or above, a test lasting one or two weeks will show the worst conditions that will occur for this type of degradation. These short length tests are adequate to show whether sufficient silica has been added to prevent degradation, and also to show the properties of cements containing non-reactive additives.

There are two exceptions. One is where the Portland cement is stabilized with very fine (-325 mesh) silica. In this instance, the permeability increases slowly for the first 90 to 180 days. The second exception where short term tests are inadequate is when a slowly reactive additive is used such as fly ash. Such systems begin to degrade only after 30 days at 316°C and one year at 232°C.

Principal Conclusions

1. Most Portland cement systems change composition rapidly at 232 or 316°C but stabilize within one or two weeks.
2. The same reactions occur over the 232 to 316°C temperature range but are more rapid at high temperatures.
3. The normal Portland cement strength retrogression caused by conversion to alpha dicalcium silicate hydrate at elevated temperatures is largely alleviated by adding 30 to 40 percent fine silica. The strength is stabilized but the permeability still increases many fold.
4. Most non-reactive cement additives can be admixed in moderation with a stabilized cement system without adversely affecting the temperature stability.
5. A delayed high temperature retrogression occurs in pozzolan extended Portland cement systems, especially those containing fly ash. This is due to a gradual conversion of xonotlite to a truscottite type compound.
6. A high temperature cement should not contain extensive amounts of bentonite, diatomaceous earth, or expanded perlite unless silica is added to stabilize the system.
7. A non-Portland cement, Class J, has the least overall variation of all the systems tested.

INITIAL TEST PROGRAM

The testing program for possible geothermal cement systems must be comprehensive and discriminating. The block diagram of Figure One gives a condensed picture of the proposed Dowell procedure. Cement systems to be tested will include the listed mixtures as well as variations and combinations of the mixtures. A standard system will be tested which represents a typical cement system presently used by the geothermal industry. Each system will first be tested on a high temperature (150°C), high pressure (35,800 kPa) consistometer to determine adaptability to downhole placement criteria. This means the system must be capable of maintaining a liquid state for at least three hours. Systems which can meet this thickening time criterion will be tested in high pressure, high temperature autoclaves for compressive strength. A series of tests up to 28 days is expected to show trends of retrogression or failure to reach minimum acceptable strength. Those systems showing good compressive strength characteristics will be tested for permeability. Poor adaptability of a cement system to geothermal conditions will usually result in permeability increases to excessive levels.

The next test for the surviving cement systems is a bonding test which generally involves cement to steel bond strength.

This test will show poor quality for a cement which either shrinks after set or has little adherence to the steel pipe. Following the bond tests, an ASTM expansion test will be conducted which can help to compliment the bond tests. Again, a shrinkage condition would be undesirable.

The final proposed test in the initial work will be an erosion test to monitor the effects of dynamic steam contact. Any system which shows tendencies of continuous sloughing should be considered unstable and rejected.

Following this testing program the long term tests will be set up to establish stability over many months of geothermal environment contact.

Figure 1

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Appendix A

List of Companies Contacted

AMAX Production Co.	Denver, CO.
Aminoil U.S.A.	Santa Rosa, CA.
Amoco Production Co.	Tulsa, OK.
Anadarko Production Co.	Houston, TX.
Argonout Enterprises	Denver, CO.
Chevron Oil Co.	San Francisco, CA.
Dow Chemical U.S.A. Oil and Gas Division	Walnut Creek, CA.
Exploration Logging of U.S.A., Inc.	Sacramento, CA.
Geothermal Kinetics, Inc.	Phoenix, AZ.
Geothermex	Berkeley, CA.
Hathaway Engineering	Sacramento, CA.
Intercontinental Energy Corp.	Denver, CO.
Magma Energy	Los Angeles, CA.
McCulloch Oil Corp.	Los Angeles, CA.
Micro Geophysics Corp.	Golden, CO.
Oxy Geothermal	Bakersfield, CA.
Phillips Petroleum Co.	Del Mar, CA.
Republic Geothermal	El Centro, CA.
Southwestern Exploration Assoc.	Tucson, AZ.
Sunoco Energy Development Co.	Dallas, TX.
Thermal Power	San Francisco, CA.
Thermogenics, Inc.	Santa Rosa, CA.
Union Oil Co.	Brea, CA.

Appendix B

List of Abbreviations and Conversion Factors Used in this Report

API	American Petroleum Institute
Ar	Argon gas
ASTM	American Society for Testing and Materials
B	API Class B Portland cement
BHCT	Bottom hole circulating temperature
C.	Celsius (centigrade) temperature
C/S	Calcium oxide to silicon dioxide ratio
CH ₄	Methane gas
CO ₂	Carbon dioxide gas
G	API Class G Portland cement
G,1:1 perlite	One cubic foot (94 lbs) Class G cement combined with one cubic foot (about 8 lbs) perlite
H	API Class H Portland cement
H ₂	Hydrogen gas
H ₂ S	Hydrogen sulfide gas (highly toxic)
in.	Inches
J	API Class J cement
KCl	Potassium chloride salt
kg	Kilogram
kPa	Kilopascal

Appendix B (cont'd.)

l	Liter
lbs	Pounds
m	Meters
max	Maximum
md	millidarcy (unit of permeability)
N ₂	Nitrogen gas
NH ₃	Ammonia
NaCl	Sodium chloride (common salt)
ppm	Parts per million
TD	Total depth of well at time mentioned
TDS	Total dissolved solids
T.T.	Thickening time
WOC	Waiting on cement (to harden) time

Metric to English Conversion Factors

(Degrees C. x 1.8) + 32 = Degrees Fahrenheit

kg/l (or specific gravity) x 8.33 = pounds per gallon

kPa X 0.145 = Pounds per square inch

(kPa ÷ 6.89) = Pounds per square inch

m x 3.28 = Feet

md = One thousandth of a Darcy (see below)

Darcy = A unit of permeability where a fluid of one centipoise (water) under a pressure gradient of one atmosphere per centimeter would flow one cubic centimeter (milliliter) per second per square centimeter cross section. No normal English equivalent is used.