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Workshop on Geothermal Drilling Fluids

Maurer Engineering, Inc.

Prepared by Sandia Laboratories, Albuquerque, New Mexico 87185
and Livermore, California 94550 for the United States Department
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WORKSHOP ON GEOTHERMAL DRILLING FLUIDS

Hosted by Maurer Engineering, Inc.
at the Albert Pick Motor Inn, Houston, Texas
9 October 1979

Sponsored by Sandia Laboratories for
The Department of Energy, Division of Geothermal Energy

ABSTRACT

Thirteen papers relating to the development of geothermal drilling fluids are presented.

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AGENDA

WORKSHOP ON GEOTHERMAL DRILLING FLUIDS SPONSORED BY SANDIA LABORATORIES FOR THE DEPARTMENT OF ENERGY - DIVISION OF GEOTHERMAL ENERGY

Albert Pick Motor Inn, Houston, Texas
October 9, 1979

- 8:45 Welcome
Dr. William J. McDonald - Maurer Engineering Inc.
- 8:55 Geothermal Well Technology Program
Jon Barnette - Sandia Laboratories
- 9:10 Evaluation of Geothermal Foams
Gary Matula - Maurer Engineering Inc.
Jon Barnette - Sandia Laboratories
- 9:25 Development of Foams for Geothermal Drilling
Pete Rand - Sandia Laboratories
- 9:45 Nitrogen Generation
A. By Cryogenic Methods
Dr. Bernard T. Kenna - Sandia Laboratories
B. By Catalytic Treatment of Diesel Engine Exhaust
Dr. Bernard T. Kenna - Sandia Laboratories
- 10:00 Coffee Break
- 10:20 Geothermal Drilling Fluid Testing System
Dr. Kenneth Walter - NL Baroid Petroleum Services
A. B. Maish - Sandia Laboratories
- 10:40 High-Temperature Clay Chemistry
Leroy Carney - Texas Tech University
Dr. Nicep Guven - Texas Tech University
Dr. B. T. Kenna - Sandia Laboratories
- 10:55 Performance Characteristics of Geothermal Muds at Temperature and Pressure
Dr. Edward Blick - University of Oklahoma
A. B. Maish - Sandia Laboratories
- 11:15 Field Trial of HTM-1
Larry J. Remont - Maurer Engineering Inc.
L. E. Baker - Sandia Laboratories
- 11:30 Computing Downhole Temperatures During Geothermal Drilling Operations
Dr. Gary R. Wooley - Enertech Engineering and Research Co.
A. Ortega - Sandia Laboratories
- 11:50 Effect of Stagnation Time on Wellbore Permeability
Dan Ennis - Terra Tek
Dr. T. E. Hinkebein - Sandia Laboratories
- 12:10 Lunch
- 1:10 Panel Discussion
Dr. George R. Gray - Moderator
Use of Sepiolite to Improve Mud Performance on Geothermal Wells
Neal Davis - Gulf Research and Development Co.
Control of Corrosion in Air-Drilled Geothermal Holes
Paul Fischer - Union Oil Company of California
Hot Well Stimulation Technique
G. W. Anderson - Chevron USA, Inc.
Field Experience With Geothermal Drilling Muds
Roger Daniel - Professional Drilling Fluids Service
- 3:10 Adjournment

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SANDIA/DOE GEOTHERMAL DRILLING AND COMPLETION
TECHNOLOGY DEVELOPMENT PROGRAM*

Jon H. Barnette

Sandia Laboratories
Albuquerque, NM 87185

ABSTRACT

The high cost of drilling and completing geothermal wells is an impediment to the development of geothermal energy resources. Technological deficiencies in rotary drilling techniques are evidenced when drilling geothermal wells. The Division of Geothermal Energy (DGE) of the U. S. Department of Energy (DOE) has initiated a program aimed at developing new drilling and completion techniques for geothermal wells. The goals of this program are to reduce well costs 25% by 1982 and 50% by 1986. Sandia Laboratories has managed this technology development program since October, 1977, and this paper presents an overview of the program. A statement of program goals and structure is given. The content of the FY-79 program is presented and recent results of R&D projects are given. Plans for development of an advanced drilling and completion system are discussed.

INTRODUCTION

In view of the existing technological difficulties associated with drilling and completing geothermal wells, DOE/DGE has initiated a program directed at developing and commercializing the technology required to reduce the cost of geothermal wells. An analysis of existing geothermal well cost data indicates that evolutionary technological developments within the framework of existing drilling practice have the potential for reducing the cost of geothermal wells drilled with conventional rotary technology by approximately 25%. Cost reductions in excess of 25% will require the use of new and advanced drilling and completion techniques, and the successful implementation of these new techniques could possibly reduce well costs by as much as 50%. Based on these facts, goals to develop the technology capable of reducing costs by 25% by 1982 and 50% by 1986 have been set for the DOE/DGE Geothermal Drilling and Completion Technology Program (Polito and Varnado, 1978).

In October of 1977, or the beginning of FY-78, Sandia Laboratories was selected by DOE/DGE to manage the Drilling and Completion Technology Development Program. During FY-78 considerable program planning was conducted, some in-house (Sandia) research conducted, the technical and financial management responsibility for existing contracts was assumed and contracts issued for new externally conducted research. Most research activity was of a type aimed at the 25% cost reduction goal.

Internal research primarily involved the continued development of the Chain Drill, a bit concept providing downhole replaceable cutting surfaces. External contract work on drilling technology fell under three major headings:

- 1) Bits -- Research in manmade diamond compact bits, fluid jet drilling, and high temperature steels, seals and lubricants
- 2) Downhole Motors -- Design and testing of high temperature bearings and seals
- 3) Drilling Fluids -- High temperature and pressure instrumentation was built, a high temperature mud formulated, and drilling foam investigated.

Completion-oriented activity consisted of state-of-the-art studies with emphasis on sand control in geopressured wells and reinjection well analysis in all reservoirs. Included was the demonstration of a cavitating water jet descaling technique.

FY-79 PROGRAM

The majority of the FY-79 program has been aimed at the 25% cost reduction goal, though planning activities and some feasibility studies for an advanced system have been undertaken. Projects not completed in FY-78 were continued, and new research initiated. Highlights are given following the previously used breakdown:

- 1) Bits -- Laboratory tests were conducted by General Electric on

*This work supported by U. S. Department of Energy.

Barnette

full-scale polycrystalline diamond compact (PDC) bits. Penetration rates to seven times those of roller cone bits were observed (see Figure 1). Field tests of these bits are planned in FY-79 and 80.

Terra Tek conducted field tests of unsealed roller cone bits developed under this program. Research bits using substituted materials with higher hot hardnesses performed noticeably better than control bits using standard materials. Data reduction by A. Maish of Sandia Labs is represented in Figure 2.

Fig. 1 Penetration rate as a function of simulated depth

Fig. 2 Gage loss as a function of drilling time

The Chain Drill developed by Sandia Laboratories was successfully field tested. Details are presented in a separate paper.

Hydronautics is assessing the performance of cavitating flow nozzles for use in augmenting the cutting performance of conventional bits. This work also provides background information for the possible use of fluid jets in an advanced drilling system.

- 2) Downhole Motors -- Terra Tek and Maurer Engineering have designed and tested seals utilizing graphite elements which show two to three times the life, at high temperature, of previously tested elastomeric seals. A combined package of similar seals and high load capacity bearings is being tested in a simulated geothermal drilling environment.
- 3) Fluids -- A 500°F, 3000 psi fluid test flow loop at the University of Oklahoma is operational and design is nearing completion at Baroid on a 700°F, 20,000 psi, autoclave-contained fluid tester.

A state-of-the-art study on foam drilling fluids was completed by Maurer Engineering with a favorable recommendation for further research. The next phase of foaming agent screening tests is being undertaken at Sandia and is detailed in a separate paper by P. Rand.

Feasibility studies have been initiated on the generation of pure nitrogen for drilling fluid use for the purpose of corrosion control. Catalytic treatment of diesel exhaust, cryogenic air separation, and swing pressure adsorption separation are being considered.

Enertech has completed a dynamic wellbore thermal simulator code allowing temperature profile calculations of wellbores during drilling, production and injection.

The Completion Program has continued its state-of-the-art studies, screened completion fluids for high temperature characteristics, investigated high temperature open hole packers, and initiated studies on fluid-formation interactions. As a follow-on to the previously demonstrated cavitating jet descaling technique by

Daedalean Associates, the technique is being extended for borehole workover use. An underreamer using water jets is being developed at the University of Missouri.

Research conducted internally by Sandia has also expanded. A bit hydraulics laboratory is being fabricated. Initial studies will involve polycrystalline diamond compact bits and include the use of aerated fluids. The development of a low-cost steel composition resistant to H₂S is being undertaken beginning with laboratory tests of existing steels.

Rock mechanics studies are being made of the cutting action of drag bits using finite difference computer codes. Results will be used primarily to assist the design of PDC bits.

Some work has been initiated on feasibility studies for possible advanced systems. The work done by Terra Tek on bearings and seals will assist in the downhole motor assessment. The previously mentioned cavitating nozzle work at Hydronautics is being strengthened with basic research into cavitating flow at Hydronautics, the University of Missouri, and the University of San Diego. System studies on the economic feasibility of the overall system needed for fluid jet drilling have begun. The state-of-the-art of percussion drilling is being assessed at Sandia and will include laboratory testing of drills under geothermal conditions.

ADVANCED DRILLING AND COMPLETION SYSTEM

Planning for the advanced system necessary to meet the 1986 cost reduction goal of 50% was begun with a workshop held in New Orleans in January, 1979. Attended by approximately 40 industry representatives, the workshop defined the limitations of present technology and made recommendations for feasible elements of advanced drilling and completion systems capable of development in the required time frame.

Barnette

Four panels within the workshop investigated 1) Rock Drilling, 2) Borehole Technology, 3) Directional Drilling, and 4) Surface Equipment. Output from these groups has been published and the information utilized as the basis for performing a network analysis of the necessary development programs (Varnado, 1979). Activity networks have been or are being generated in the following major areas:

- 1) Straight Hole Drilling Systems, with sub-networks for:
 - a) Downhole Motors/High Speed Bits,
 - b) Fluid Jet Drilling, and
 - c) Percussion Drilling
- 2) Directional Drilling Systems
- 3) Lost Circulation Control Techniques
- 4) Completion Systems
- 5) Supporting Systems and Activities (e.g., corrosion control, computer codes, borehole stability)

Generally, these networks identify the flow of events and their interactions through a state-of-the-art study and data gathering phase, the generation of requirements, hardware design and fabrication or procedures compilation, laboratory testing and field demonstration. Initial time estimates and critical path identification

indicate program lengths of seven to eight years. Optimization may shorten these times. Decision points are provided to select the most promising element or systems of those under study in the early program phases for complete development for a field demonstration.

The desired major milestone schedule for the program is:

Advanced System Development	
Planned	11/79
New Drilling and Completion System Selected	9/81
25% Cost Reduction Technology Developed	12/82
New System Fabricated	10/85
Field Test of New System Complete	12/86

REFERENCES

- Polito, Joseph; and Varnado, Samuel G., 1978, "A Program in Geothermal Well Technology Directed Toward Achieving DOE/DGE Power-on-Line Goals, SAND78-0766, Sandia Laboratories Report, October, 1978.
- Varnado, Samuel G.; 1979, "Report of the Workshop on Advanced Geothermal Drilling and Completion Systems," SAND79-1195, Sandia Laboratories Report, June 1979.

EVALUATION OF GEOTHERMAL FOAMS

by

Gary W. Matula
Maurer Engineering Inc.

Houston, TX

Background

Problems resulting from inadequate drilling fluids are the most frequently quoted reasons for high geothermal drilling costs. Severe corrosion and erosion problems are common when air drilling; yet slow drilling rates, poor filtration control, loss of circulation, and mud gelation often occur when using muds. In order to ascertain how drilling foams might be utilized in geothermal drilling to solve some of these problems (hence reducing geothermal well costs) Sandia Laboratories contracted with Maurer Engineering to evaluate drilling foams for geothermal applications and to recommend a program for developing geothermal drilling foams.

Drilling fluid related problems are the single most frequently cited reason for drilling problems in geothermal wells. The most apparent problems are the failures of the fluid to perform essential functions under high-temperature conditions. For example, gelation of conventional muds when circulation is stopped for operations other than drilling can lead to stuck pipe, aborted logging runs, stuck tools, etc. The related high pumping pressures can cause unexpected failure of casing seats or formation breakdown with consequent loss of circulation. Fluids formulated to remain reasonably stable at higher temperatures do not have adequate filtration characteristics, resulting in possible formation damage.

* This report covers work performed under Sandia Laboratories Contract 07-7068 and was sponsored by the U. S. Department of Energy Division of Geothermal Energy.

Less obvious are the high direct costs which can be incurred with geothermal drilling fluids. Expensive treatment and replacement of materials are required to keep the fluid properly conditioned. Difficulties in corrosion control in geothermal environments lead to more frequent drill pipe replacement and drill pipe related problems than is experienced in non-geothermal applications.

Least obvious is the indirect cost from slower drilling, lost time for peripheral operations such as mixing mud, adding lost circulation materials, drill pipe inspection, etc.

The selection and use of drilling fluids for geothermal application requires greater care and technology than oil and gas operations. The high cost of these operations and the sensitivity of geothermal formations to irreparable drilling damage to productivity necessitates improvements in the effectiveness of drilling fluids in geothermal applications.

Where geothermal drilling allows the use of air as the drilling fluid, i.e., the Geysers area in California, the potential benefits of drilling foams may be applicable especially where formation pressure control is not a problem. Foams offer advantages over air in their increased lifting capacity, reduced compression requirements, higher bottomhole densities, and improved borehole stabilization. A broad survey of industry personnel indicates that geothermal drilling could use foams up to 80% of the time. Use of foams could increase drilling rate, decrease downtime, decrease corrosion/erosion effects, help control lost circulation, and help alleviate other geothermal drilling problems. Yet many technical problems must be overcome to accomplish these things.

Some of the other advantages of foam drilling include:

- Good Hole Cleaning
- High Drilling Rate
- Reduced Lost Circulation Problems
- Potential High-Temperature Capability
- Reduced Capital Cost

The disadvantages of mixing, breaking, and disposal of the foams along with corrosion and borehole stability have limited present applications. However, there are some borehole zones that favor the use of foam as the drilling fluid. These areas are:

1. Lost Circulation Zones Above Permeable Rock
2. Dry Fractured Rock
3. Hot Lost Circulation Zones
4. Variable Density Requirements

The shallowest and coolest environmental zone that favors the use of foam as a drilling fluid is in the upper section of the hole where the temperature does not exceed 250°F. Foam would be the favored drilling fluid if the rock was wet and fractured or had a lost circulation zone above a wet zone with a water drive. The water in the zones could preclude the use of air as a drilling fluid. The compressible nature of the foam system makes it possible to have a light fluid at the top of the hole so as to avoid lost circulation and a denser fluid below that zone to repress the water flow.

So in general, foam drilling is used when:

1. There is severe lost circulation that is difficult or impossible to control with conventional muds.

2. Air drilling is unsuitable because some hydrostatic pressure is required to stop fluid influx into the wellbore and/or fractured or broken formations make the wellbore unstable; or
3. The insulating properties of foam make it desirable.

In most foam drilling applications one of several types of foaming agents are used:

1. Alcohol Ether Sulfate. These foaming agents are formed with long chain alcohol ethoxylates which are sulfonated. They are the most widespread foaming agents and can be formulated for either fresh water or salt water solutions.
2. Alkyl Benzene Sulfonate. These foaming agents have better temperature stability than (1) above, but they are not as effective. More agent is needed per gallon of water foamed.
3. Alpha Olefin Sulfonate. These agents perform very similarly to (2) above.

In each application where foam drilling is to be considered, it is necessary to determine the amount of time the foam will be in the well and the temperature of exposure before concentrations can be estimated. Usually 1/2 to 1% foaming agent (by volume) is sufficient. Also, corrosion inhibitors can be added to control corrosion problems. The pH of the water used to generate the foams should be kept around 10 with additions of sodium hydroxide or lime.

Selection and Testing of Foams

During the course of the investigation, a total of 36 samples were submitted by 15 suppliers for testing. Eight of the submitted materials were selected for actual testing. Selection was based on availability of a sufficient amount of sample to complete all tests and timely reception of the samples. The number of samples which could be tested was limited by time restraints to eight samples. All the materials selected for testing were liquids with the exception of the LAS-90 sample, which was in solid flake form. The following materials were selected to be tested:

- AQUANESS M/A - 945
- TRETOLITE TOL-FOAM TD - 1
- TEXTILANA SULFOTEX RIF
- TEXTILANA SULFOTEX LAS-90
- BAROID SURFLO S-375
- CARDINAL CF-2
- MILCHEM AMPLIFOAM
- MAGCOBAR DRILLING SOAP B

The foamers were tested before and after exposing water solutions of the materials to 500°F at an applied nitrogen pressure of 375 psi for 16 hours. Foams were generated by injecting a solution of the foamer into an airstream in a column (API Procedure) and by stirring a solution of the foamer with a high speed mixer (Chevron Test). The volume of liquid carry-over was measured in the column test. Tests with a standard ten foot API column (API RP-46) were compared with those from a five foot column to determine if any correlation between column height and volume of foam and fluid collected existed.

When 0.15% foamer in distilled water was tested with both the five foot and the ten foot columns, the overall results were about the same. The Textilana Sulfotex LAS-90 generated the most amount of foam initially and after static aging at 500°F - 375 psi for 16 hours. The amount of foam collected with the two columns were almost identical. However, the amounts of foam collected with the other samples were less with the ten-foot column than with the five-foot column. Also, the difference in the volumes collected from the five and ten foot columns was not the same for all the samples. For example, the volume collected from the ten-foot column was 20% less than from the five-foot column with the Sulfotex RIF sample. There was hardly any reduction in volume with the LAS-90 sample. After exposure to 500°F - 375 psi for 16 hours, half of the samples did not foam at all on either column. In general, this test indicates that the LAS-90 sample foamed the most. Also, there does not seem to be a direct correlation in volume of foam collected versus column height.

When 0.75% foamer in 10% sodium chloride solution was tested, different results were obtained than when the samples were tested in fresh water. In saltwater, the LAS-90 initially produced the lowest volume of foam of all eight samples. After the samples were subjected to 500°F - 375 psi, the only sample to foam at all was the Magcobar Drilling Soap B. Again, there did not seem to be a direct correlation between volume of foam collected and column height.

The next series of tests involved using a modified version of the Chevron test. The test was designed to indicate foam quality and stability. The procedure involves adding 100 ml of a 0.5% solution of the foamer to a 1,000 ml beaker followed by

stirring at high shear for some time period. Then the maximum foam volume is read. After stirring, the time required for half of the original volume (50 ml) to drain from the foam is measured in seconds with a stop watch. The solution is restirred and the same measurements are made. After these measurements are made, 25 ml of a 1% sodium chloride solution are added to the foamer solution to act as a contaminant. Then the same foam heights and drainage times are determined again. The tests were repeated after aging the samples.

With the 0.5% foamer solution, all samples generated more foam after the addition of the salt contaminant than they did initially. However, the drainage time on all samples was reduced when the salt solution was added except for the Magcobar sample. When the samples were aged, the LAS-90 was the only sample to foam at all. The results from testing the LAS-90 before and after addition of the salt contaminant showed very little difference in foam volume and in drainage time. The foam volume and drainage time initially before salt contamination were almost identical to the aged sample results before salt contamination. A similar comparison holds for the initial and aged samples with salt contamination. Doubling the foamer concentration to 1% did not affect either foam volume or drainage time both before and after salt contamination to any extent at all for any sample. Every test run with the 0.5% sample was almost identical to the 1% sample.

The effect the samples had on surface tension was also studied. The surface tension measurements were made on fresh samples, usually right before the column tests were run. All samples prepared in distilled water effectively lowered the surface tension of distilled water alone by about 50%. The same

is true when the samples prepared in saltwater were compared to saltwater alone. The reductions in surface tension in the saltwater by the foamers were all about the same, just as in the fresh water case. However, the reduction the samples made in surface tension of the saltwater alone was not as great as in the fresh water case. Even so, no correlation could be made between surface tension and foam stability and quality.

The effect the eight samples had on the corrosion rate of mild steel coupons was also determined in fresh and in saltwater. Mild steel coupons were placed into solutions of the foamers with the same concentration as was used in the column tests. The entire contents were placed into a sealed aging cell, pressured to 375 psi with nitrogen and exposed to 500°F for 16 hours. In fresh water all the samples except the LAS-90 increased the corrosion rate of the coupons compared to fresh water alone. Similar results were obtained in saltwater. All the samples except the LAS-90 increased the corrosion of the saltwater alone.

Lastly, the pH of all the samples was determined in fresh and in saltwater, before and after aging. It was measured immediately before the surface tension and column tests. In fresh water, the pH of all the samples was reduced after exposure to 500°F - 375 psi. Initially the pH was basic, mostly between 7 and 8, for all samples but dropped considerably after exposure to 500°F. Only the pH of the Magcobar Drilling Soap B, Milchem Amplifoam and the LAS-90 remained relatively unchanged and alkaline after exposure to the temperature. Similar results were obtained in pH for the samples in saltwater. All the saltwater samples started out alkaline, but slightly less than the fresh water samples. All samples except the three mentioned above exhibited a drop in pH after exposure to 500°F.

Summary and Conclusions

Temperature stable and salt stable foams must be developed. This is exemplified by the fact that although several samples foamed after exposure to high temperature in fresh water only one, Magcobar Drilling Soap B, foamed after exposure to 500°F in the salt environment. Handling equipment must be improved including developing processes for breaking, cleaning, and reusing foam materials. Also, corrosion results indicates that corrosion characteristics must be improved through the use of inert gases or chemical additives. Numerous laboratory procedures were considered for testing foams; all have some usefulness, yet all have limitations. Probably the single most descriptive test is a modified Chevron test after high-temperature static aging. This is based on a comparison of the results obtained on the Chevron test and results from all column testing. The Chevron test was easier, simpler and faster than the column tests. This makes it more desirable for field applications. Compatibility and performance of different systems could be determined in the field using a modification of the Chevron test. However, even though present procedures are useful screening tools, better test equipment and procedures (such as a high-temperature flow simulator for foams) should be developed. Tests of representative foams gives insight into anticipated behavior of families of materials and the performance which can be expected from field drilling foams. These tests indicate that completely new materials will have to be developed in order to satisfy geothermal applications.

SURFACTANT FOR AQUEOUS FOAM
DRILLING FLUIDS FOR GEOTHERMAL APPLICATIONS*

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ABSTRACT

Aqueous foam is a promising drilling fluid for the under-pressured hard rock formations frequently found in geothermal reservoirs. Its primary advantages are: 1) It should not harm producing formations, 2) It allows high drilling rates, and 3) Low annular velocities will eliminate the erosion problems of air drilling. Successful use of aqueous foam for geothermal drilling will require a surfactant system which will have sufficient chemical stability to withstand the harsh thermal and chemical environment found in geothermal wells. In addition, the surfactant must be capable of forming stable foams at high temperatures. Procedures have been developed to expose aqueous surfactant solutions to a 260°C (500°F) temperature cycle, to generate aqueous foams, and to test the foams before and after exposure. These tests have been used to determine the thermal stability of a wide variety of surfactants in aqueous solutions.

Uniform small celled foams with controlled density were made for evaluation by metering the solution and a gas into a static mixer. Density and drainage time were measured on all foams. The foams were also evaluated qualitatively by observing their cell structure. Solution pH was also measured before and after exposure. Surfactants were selected on the basis of their chemical structure and/or suppliers recommendations. Amphoteric, anionic, cationic, and nonionic types were included. More than fifty surfactants have been evaluated before and after exposure to a

260°C (500°F) temperature cycle in deionized water as a first step in finding surfactants for use as foaming agents for geothermal drilling fluids.

NITROGEN GENERATION METHODS TO BE USED IN GEOTHERMAL DRILLING*

SAND79-1893C

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A major contributor to the high costs associated with geothermal wells is the extensive corrosion of the drill pipe by oxygen present in the drilling fluid. The importance of controlling the corrosive attack of oxygen in the drilling operation is evident when the cost and availability of drill pipe is considered.

A possible method for reducing the corrosive attack of oxygen is the utilization of an inert drilling fluid such as nitrogen. Nitrogen could replace air in foam drilling, air drilling, and for the aeration of drilling muds. The major problem with using nitrogen is producing a sufficient quantity of it with a purity of less than 5 ppm of oxygen at the drilling site. The volume of nitrogen required for geothermal drilling ranges from 8×10^4 to 3×10^6 standard cubic feet per day, thus making the transportation of liquid nitrogen to a drilling site prohibitively expensive. Two methods for producing nitrogen on site that are being studied are: 1) catalytic conversion of diesel exhaust, 2) cryogenic separation of air.

The catalytic conversion of diesel exhaust involves the combustion of diesel exhaust-fuel mixtures slightly rich in fuel (i.e., above stoichiometric proportions) over a noble metal catalyst. The main reaction products are N_2 , H_2O , CO_2 , and some NO_x and O_2 . The areas that require further study in this process are a qualitative and quantitative analysis of the product gases from the catalytic converter, fuel consumption, and catalyst life studies.

Englehard Industries has been contracted by Sandia Laboratories on behalf of the DOE/DGE Geothermal Drilling and Completions Technology Program to perform investigations into these areas. Personnel assignments have been made only recently, consequently, no test results are available.

To conduct the studies previously mentioned, Englehard will employ a diesel generator unit, utilizing the generator as a dynamometer, and put the

*This work is supported by the U. S. Department of Energy.

engine exhaust through their proposed catalytic converter. Variables will be 1) engine-air-fuel ratio to cover altitudes from sea level to 8,000 ft., 2) engine loading of 25%, 50%, 75%, and 100%, 3) exhaust temperature, and 4) amount of fuel doping applied prior to entry into the converter.

A quantitative and qualitative analysis of exhaust products will be provided and the condition of the catalyst will be monitored. Expected results will be catalyst life, input information for design of downstream treatment processes, and identification of criteria for scale-up from the laboratory apparatus to a field test unit capable of producing 130,000 standard cubic feet per hour of nitrogen.

Cryogenic separation of air yields a nitrogen product with less than 5 ppm of oxygen on a regular commercial basis. The major problems associated with the cryogenic production of nitrogen with respect to geothermal drilling are essentially engineering design problems. A portable nitrogen plant that can produce as much as 3×10^6 scfd of nitrogen with less than 5 ppm of oxygen and can be transported to remote drilling locations must be designed. It is essential that the plant be assembled, started-up, disassembled, and transported in a time frame compatible with the drilling operation and that it have a high degree of reliability.

Production operators, through Mr. R. J. Hamaker, has made Sandia Labs aware of the availability of a portable cryogenic nitrogen production plant for field testing. Output is 1 million standard cubic feet per day of nitrogen with 10 ppm oxygen content. Sufficient supplementary nitrogen can be supplied by truck to allow drilling of a geothermal well.

Sandia expects to arrange with Production Operators, Loffland Brothers Drilling Co., and Union Oil Co. to fund a 45-day field test at a geothermal site. Quantity and quality of the output gas, plant performance and portability, and effect of the nitrogen on corrosion rates will be monitored.

GEOHERMAL DRILLING FLUID TESTING SYSTEM*

The basic purpose of the Geothermal Drilling Fluid Testing System (GDFTS) is to allow measurement of fluid properties ranging up to 700°F. and 20,000 psi. Measurement of these properties will facilitate development of new drilling fluids to withstand these extreme conditions.

Major fluid properties to be measured are rheology, filtration characteristics, density and corrosivity. Currently used drilling fluids break down as the temperature increases, and the GDFTS will monitor the effect of this breakdown upon the properties.

Figure 1 shows a possible layout of the GDFTS laboratory. In its center is a pit (shown in cross section in Figure 2) which houses the pressure vessel. Inside the vessel are the drilling fluid and testing devices, which will be described shortly. The vessel is pressurized by argon gas. Liquid argon will be pumped to a vaporizer, operating up to 6000 psi, and the gas stored in argon reservoir cylinders. For higher pressure operation, an intensifier boosts the pressure up to a maximum of 20,000 psi. The hand operated hoist is used to lift off the vessel head after electrical and coolant connections have been broken.

The operator and microcomputer control system are located in a control room, which may be remote from the laboratory building. Instead of barricade and blowout walls for the building, recent design suggests a specially reinforced cover for the pit and blowout ducts in the pit.

The pressure vessel is shown in Figure 3. It houses the mud bucket (below) and the package containing drive motors and instrumentation (above). The mud bucket will hold about two gallons of drilling fluid. The walls and block are water cooled and insulated from the hot mud bucket. Inside diameter of the pressure vessel is 14 inches and length 49 inches. National Forge Company is fabricating the vessel with top and bottom threaded closures. Conventional high pressure steel will be used.

Projecting into the mud bucket are the continuous dynamic filter (left), dispersator or agitator (center), rotary rheometer (right), continuous corrosion sensor (not shown), and densitometer (not shown).

* 50-50 NL Baroid-DOE cost shared project "Development Of A Laboratory Instrument To Measure Mud Properties At High Temperatures And Pressures".

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FIG. 1

FIG. 2

G.D.F.T.S. LABORATORY

GEOHERMAL DRILLING FLUID TESTING AUTOCLAVE

FIG. 3

The mud is heated with immersion heater coils, and can be cooled down using a second coil through which air is blown. In order to prevent the inert gas atmosphere from influencing property measurements, a lift system slowly raises the mud bucket and forces mud to ooze from openings in the diffusion shield at a rate sufficient to minimize gas dissolving in the mud below. The suspension spider holds the diffusion shield. The drip pan collects condensate liquid from the cooling coils and directs it to the top of the diffusion shield to prevent mud caking. The dispersator continuously agitates the drilling fluid and maintains adequate circulation across heating coils.

The rotary rheometer bob and sleeve will have conventional geometry. The drive motor and torque transducer, both housed in the instrumentation block, will receive and relay electrical signals through the pressure vessel head. The dispersator is of conventional design, except for providing the drive motor within the block. Drilling Fluid corrosivity will be measured by a continuous corrosion rate meter having standard electronics and a specially designed high pressure, high temperature probe. The fluid density will be measured continuously by weighing a bob submerged in the fluid.

The computer system to measure, control and record data is micro-processor-based. It consists of Intel's MDS-800 (Microcomputer Development System), supported by its double density diskette drive for program and data storage, serially interfaced with a CRT terminal and a line printer for hard-copy print-outs. The total system is shown in Figure 4. It will be running under M.T.O.S. (Multi Tasking Operational System) with real time and interrupt capabilities. The system will have a front end input for data acquisition and an output for control. The front end will accept the analog signal from different transducers measuring physical parameters. The MDS will digitize these analog signals, perform computations, and output digital bits to control devices (e.g., relays, solenoid valves, motors, etc.). The system will have a high speed math board for fast number computation.

Figure 5 shows the block diagram of the data acquisition and controller system. It has several subsystems with different and precise functions to carry out. A control loop for a typical subsystem, together with its record and report layout, are shown in Figure 6 and 7.

A small pressure vessel, shown in Figure 8, was used to test hydraulically some of the electronic components which were intended to be inside the instrumentation package. An amplifier potted in epoxy inside a tennis ball mold is shown in Figure 9.

FIG.4

COMPUTER SYSTEM

TYPICAL CONTROL LOOP FOR OUTPUT DEVICE

FIG.6

FIG.7

TEST PRESSURE
VESSEL

FIG.8

ELECTRONIC TENNIS BALL

FIG.9

Components could survive pressure cycles for about eight hours, but not beyond. Failure required that electronic components, except for transducers and drive motors, be located outside the vessel, thus necessitating an increase in electrical lead-throughs in the head.

The conceptual design for the continuous dynamic filter is shown in Figure 10. The filter medium is supported by a perforated photoetched continuous metal belt, which moves at a speed determined by the belt drive sprocket. After passing over the idler wheel, it passes across two filtration zones of perforated metal. Filtrates from the first (spurt-loss section) and second (cake-loss section) zones are collected and weighed separately. The plate separating the two zones can be made movable to adjust for filtrate filtered primarily by the filter medium (spurt-loss) and filtrate filtered by the filter cake itself. The shearing bob regulates shear experienced by the filter cake, and can simulate drill pipe rotation. A baffle prevents shearing off of the cake after it leaves the filtration chamber.

The filter medium containing the cake is reeled up for possible later inspection. Drive motors for the belt drive sprocket, take-up reel and shearing bob are housed in the water-cooled block.

The differential pressure across the filter medium will be approximately 100 to 500 psi, and is controlled by the argon gas pressure supplied to the weighing cups and filtration chambers. It will be possible to advance the filtration medium rapidly and then stop, in order to determine a conventional filtration rate, either with or without the shear bob.

This system can be modified to add other types of control or measurement information as desired, subject to space limitations.

The filter medium, tested satisfactorily for reproducibility by Maurer Engineering, is manufactured by Tetko Inc. It consists of a calendered Dutch twill weave of stainless steel filaments. Figure 11 shows the prototype filter fabricated and tested by Maurer Engineering, together with some Tetko screen and a portion of a photoetched backing belt.

Figure 12 shows static filtration results using a 3½% bentonite slurry at 350°F. The vertical prototype filter clearly shows filtration characteristics different from the same Tetko media in a horizontal position. This is attributed to settling of the bentonite slurry during the preheating and testing period.

GEO THERMAL DRILLING FLUID CONTINUOUS DYNAMIC FILTER

FIG. 10

Figure 13 shows results on the prototype filter intended to show reproducibility. It is expected that the unsatisfactory reproducibility will be remedied in the actual test system by keeping the drilling fluid agitated.

Figure 14 shows the construction site of the NL Petroleum Services' North Belt Complex. The GDFTS Laboratory will be located at the Complex.

FIG. 14

HIGH TEMPERATURE CLAY CHEMISTRY

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Clay minerals in the drilling fluids may undergo chemical and structural changes under increased temperatures and pressures, and in complex chemical environment of geothermal wells. Understanding of these changes is necessary in order to design appropriate clay-based fluids for drilling geothermal wells. For this purpose we are conducting hydrothermal experiments with the clays such as sepiolite, attapulgite, saponite and bentonite. We are following the rheological and the mineralogical changes in the clays subjected to hydrothermal treatments with and without the addition of the salts and the hydroxides of Na, K, Ca, and Mg.

Hydrothermal reactions in the pure sepiolite/H₂O system have been examined between 300 and 600°F. Approximately 10-20% of the sepiolite was converted to a smectite at 400°F within 24 hours. Similar results were obtained when CaCl₂, Ca(OH)₂, NaOH, or Mg(OH)₂ was added to the system. In the presence of NaCl, about 60% of the sepiolite was converted to smectite, whereas, only 5% smectite formed in the presence of MgCl₂. More smectite develops in these systems as temperature is increased. At 600°F, 60-80% of the sepiolite was converted to smectite in 24 hours, regardless of the presence or absence of the salts and the hydroxides. Within the experimental conditions (up to 600°F and 20,000 psi for 24 hours) temperature is the most important factor in the sepiolite to smectite conversion. The smectite phase in the above reaction is the rare variety known as "stevensite". The latter is a defect trioctahedral magnesian

smectite with octahedral vacancies and its chemical composition is very similar to that of sepiolite.

The conversion of sepiolite with a fibrous morphology to smectite with a flaky morphology is extremely important for the rheology of the drilling fluid, and it can be formulated as:

Thus a sepiolite without a layer charge converts to a smectite with (-x) layer charges and some H^+ becomes available in the fluid. It is also important to realize that the smectite (stevensite variety) has octahedral vacancies although it is a trioctahedral magnesian smectite. These vacancies can further be filled as Mg becomes available in the fluid e.g. from formation or by the partial breakdown of the same smectite. This may fill the octahedral vacancies and another layer silicate will develop. The latter is known as talc and it has the following chemical formula:

Since talc does not possess a layer charge, this may again affect the rheology of the fluid. We therefore intent to investigate the sepiolite $\rightarrow$ smectite $\rightarrow$ talc reaction by increasing the temperature.

At or below 500°F sepiolite appears to transform into stevensite by dislocation involving c/2 glides that are triggered by the stresses of the hydrothermal conditions. Above this temperature, sepiolite seems to completely breakdown and this is followed by direct precipitation of stevensite.

Attapulgit, a hydrous magnesium/aluminum silicate with a fibrous morphology,

has been also subjected to similar hydrothermal treatments as described above for sepiolite. The attapulgite used in these runs is the sample which is known with the trade name "Floridan attapulgite 150". The results show that considerable amounts of attapulgite convert to a smectite already at 400°F. The conversion is fully completed at 600°F. Thus attapulgite seems to be less stable than sepiolite under the hydrothermal conditions. The nature of the smectite is now under investigation. Electron microscopic examination shows that the attapulgite with a fibrous morphology converts to a smectite with a flaky morphology.

 

PERFORMANCE CHARACTERISTICS OF GEOTHERMAL MUDS
AT TEMPERATURE AND PRESSURE

by
Dr. Edward Blick
University of Oklahoma

Drilling mud tests were completed on Baroid and Mudtech drilling muds. These muds were tested on the University of Oklahoma Flow Loop. This loop has the capacity for testing drilling muds at pressures and temperatures up to 2,000 psia and 500°F. The two drilling muds were pumped through the loop for several hours under simultaneous high shearing and high heating conditions. The fluids were heated in one portion of the loop and cooled in another portion. Records were noted on the temperature and flow times at which each fluid became unstable.

Work sponsored by Sandia Laboratories for the Department of Energy.

FIELD TRIAL OF HTM-1

by

Larry J. Remont
Maurer Engineering Inc.

Work completed in 1977 identified the following mud-related problems which are encountered in geothermal drilling:

- Mud Solidification
- Lost Circulation
- Corrosion

Research sponsored by the D.O.E. showed that mud solidification is related to the accumulation of bentonite from drilled solids as well as from additions of drilling mud bentonite. Mud solidification is aggravated by the thermal decomposition of thinners at temperatures encountered in geothermal drilling. Loss of mud is caused by low formation pressures, fractured reservoirs and pressure surges caused by high-temperature mud gelation. Rapid corrosion rates are experienced in geothermal drilling operations because of the high temperatures encountered, the intrusions of salt formation fluids, the decomposition of thinners into acidic by-products, the influx of hydrogen sulfide and carbon dioxide, and the erosional effects when air is used as a drilling fluid.

A mud which has desirable properties when prepared at room temperature and retains these properties even after being heated to 500°F was developed. The mud has the following formulation:

Work sponsored by Sandia Laboratories for the Department of Energy.

HTM-1

Water	1	bb1
Sepiolite	15	lb
Bentonite	5	lb
Brown Coal	20	lb
Sodium Polyacrylate	2½	lb
Sodium Hydroxide	2	lb

The mud was compounded from both sepiolite and bentonite in order to take advantage of the high-temperature stability of sepiolite and the filtration control properties of bentonite. Brown coal, identified as Knife River Fuel Grade lignite, and sodium polyacrylate were added to the mud to stabilize the high-temperature filtrate. Sodium hydroxide was used to maintain the mud in an alkaline state. Table 1 shows a comparison of brown coal and regular drilling mud lignite.

Table 1

COMPARISON OF BROWN COAL AND REGULAR
DRILLING MUD LIGNITE

	<u>Brown Coal</u>	<u>Regular Lignite</u>
Moisture, % by wt.	30	17
Ash, % by wt.*	16	26
pH of 5% Dispersion in Distilled Water*	5.3	4.1
Solubility* in 2% NaOH	6	69
Soluble Salts*		
Calcium, ppm	670	7700
Magnesium, ppm	Nil	600
Sulfate, ppm	6800	32,800
Chloride, ppm	4	6

* Dry Basis

Maurer Engineering Inc. has recently received a contract from Sandia Laboratories to locate a suitable well for testing HTM-1. MEI will also be responsible for conducting laboratory and field testing of the mud system in order to monitor its performance. A field trial of HTM-1 is planned for early in 1980. The Imperial Valley of southern California contains four Geothermal Areas which are potential candidates for the field trial. All of the constituents except for the Brown Coal are readily available from commercial mud suppliers. A car-load of Brown Coal was purchased from American Colloid Company by Sandia Laboratories for the field trial. The entire stock of this material is presently stored at Sandia's facility on Kirtland Air Force Base in Albuquerque, New Mexico.

A typical well in the Imperial Valley would be drilled to about 7,000 feet. Table 2 shows the volumes of mud required for this typical well.

Table 2
ESTIMATED MUD VOLUMES

	Surface <u>Hole</u>	Final <u>Hole</u>
Depth, ft	3,000	7,000
Bit Size, in	12-1/4	7-7/8
Actual Hole Size, in	19	9-1/2
Actual Hole Volume, bbl	1,080	630
Pit Volume, bbl	500	500
Average Mud Volume, bbl	1,000	800

A lightly treated bentonite mud could be used to drill the surface hole. The interval from 3,000 ft to 7,000 ft would be drilled with HTM-1. Tables 3 and 4 shows the estimated cost per barrel for each mud.

Table 3
ESTIMATED COST PER BARREL FOR
THE SURFACE MUD

	<u>Amount</u>	<u>Cost/lb</u>	<u>Cost</u>
Bentonite	20 lb/bbl	\$.069	\$1.38
Regular Lignite	1 lb/bbl	.31	.31
Sodium Hydroxide	1 lb/bbl	.50	.50
			<u>\$2.19</u>

Table 4
ESTIMATED COST PER BARREL
FOR HTM-1

	<u>Amount</u>	<u>Cost/lb</u>	<u>Cost</u>
Sepiolite	15 lb/bbl	\$.16	\$ 2.40
Bentonite	5 lb/bbl	.069	.35
Brown Coal	20 lb/bbl	.40	8.00
Sodium Polyacrylate	2-1/2 lb/bbl	2.46	6.15
Sodium Hydroxide	2 lb/bbl	.50	1.00
			<u>\$17.19</u>

The total mud cost for drilling a typical well in the Imperial Valley is the sum of the maintenance cost plus the cost to prepare each barrel of mud. Table 5 shows the costs assuming 2 days for drilling surface hole and 12 days for drilling from 3,000 ft to 7,000 ft. Maintenance costs are estimated at \$0.20/bbl/day for surface hole and \$1.00/bbl/day for HTM-1.

Table 5
ESTIMATED COST

Surface Hole

1,580 bbl x \$2.19/bbl	=	\$ 3,460	
Maintenance Costs:			
\$0.20/bbl/day x 1,000 bbl x 2 days	=	<u>400</u>	
			\$ 3,860

Final Hole

1,130 bbl x \$17.19/bbl	=	\$19,425	
Maintenance Costs:			
\$1.00/bbl/day x 800 bbl x 12 days	=	<u>9,600</u>	
			\$29,025
			<u>\$32,885</u>

COMPUTING DOWNHOLE TEMPERATURES DURING GEOTHERMAL DRILLING OPERATIONS

By

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A computer code, called GEOTEMP, has been constructed to compute downhole temperatures in a geothermal well during injection, production, circulation and drilling. Temperatures are computed in flowing fluids, annulus fluids, drill pipe and casings, cement, and in the formation at all depths and as a function of time. Model predictions show good agreement to exact solutions and to field temperature data. Sensitivity studies have established the importance of flow rate, inlet temperature, and depth on transient bottom-hole temperature and steady fluid temperature profile while circulating.

Development of the code was conducted under Sandia Contract 13-0212. Results of the study have been documented in a report to Sandia and in a technical paper, SPE 8441 entitled "Computing Downhole Temperature in Petroleum and Geothermal Wells" and presented at the Society of Petroleum Engineers 54th Annual Technical Conference and Exhibition, Las Vegas, Nevada, September 26, 1979. A copy of the paper is included as a basis for this presentation.

SPE 8441

COMPUTING DOWNHOLE TEMPERATURE IN PETROLEUM AND GEOTHERMAL WELLS

by Gary R. Wooley, Member SPE-AIME, Enertech
Engineering and Research

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ABSTRACT

Downhole temperatures are an important part of the drilling and completion of any well. For unusual environments, such as in geothermal, arctic, or deep hot wells, downhole temperatures are more difficult to define and are more important for design of a well. A better understanding of downhole temperatures can improve well designs by aiding in casing design, cement and drilling fluid formulation, packer selection and many other applications.

A computer model has been developed to determine downhole wellbore and earth temperatures. Temperatures are computed in flowing or shut-in fluid streams, in the well outside the flowing stream and in the formation. Flowing options available in the model include

- injection/production
- forward/reverse circulation
- drilling.

A special feature for circulation and drilling is simultaneous fluid loss or production.

Model predictions are compared to an exact solution and to field temperature data collected from petroleum and geothermal wells. Good agreement has been achieved with the comparisons.

Sensitivity studies define the importance of inlet temperature, flow rate, and depth on downhole temperatures during production and during forward circulation. Transient bottom hole temperatures for circulation and surface temperatures for production are provided for two values of each variable. Also, the steady temperature profiles are provided for the same two values. Results show that each of these three variables has a strong influence on downhole temperatures

References and illustrations at end of paper.

INTRODUCTION

Temperatures in a well are important for many aspects of drilling, completion, and production or injection. A few of the applications that require an understanding of the downhole temperature history in a well include the following:

- Cement composition, placement, and setting time
- Drilling mud and annulus fluid formulation
- Packer design and selection
- Logging tool design and log interpretation
- Wax deposition in production tubing
- Corrosion in tubing and casings
- Thermal stresses in casings and tubing
- Permafrost thaw and refreezing
- Wellhead and production equipment design
- Drill bit design
- Elastomer and seal selection

Of course, many other applications may exist. Two interesting possibilities are computing undisturbed formation temperatures from flowing stream temperature measurements, and anticipating abnormal pressure zones from fluid temperature changes while drilling.

Hostile environments present even more challenging needs for downhole temperatures, while making it more difficult to determine what temperatures to expect. Any unusual temperature conditions can make previous temperature experience and intuition unreliable. Abnormal temperature gradients can cause a rapid rise in flowing fluid temperature, and unusually deep wells expose fluids to hotter temperatures for longer times. In arctic environments cool permafrost zones can cause unexpectedly low temperatures throughout the length of a well, both in and below the permafrost. Conversely, geothermal wells exist in unusually hot regions, resulting in abnormally high temperatures in a well. An understanding of downhole temperatures is needed in hostile environments for the same applications as more conventional wells, and perhaps for additional needs, but determining those temperatures is more difficult.

Determination of downhole wellbore and earth temperatures is a complex task. Many variables influence the temperatures, which are continuously changing with time. Temperature recording devices have been developed, but these provide only isolated data points for a transient quantity, and furthermore cannot provide sufficient information to establish the relative importance of the variables influencing temperatures. Therefore, a means of predicting downhole temperatures is needed to determine important design criteria such as maximum temperature and time for exposure to high temperatures. Many simplified analytical techniques and some correlations of experimental data have been constructed in the past, each with limited success in predicting downhole temperatures. Experience has demonstrated that a computer model is needed to account for the complexities of heat transfer in a well.

This paper describes a computer model that has been developed to predict downhole temperatures in geothermal and petroleum wells. Comparisons of computer predictions to analytical solutions and to field data are presented. Finally the code is used to establish the importance of three variables on downhole temperatures during production and during forward circulation. Temperature plots are presented to illustrate the sensitivity of downhole temperatures to inlet temperature, flow rate, and depth.

MODEL FORMULATION

There are basically three components of wellbore thermal simulators - flowing stream, well completion, and formation. Figure 1 is a well schematic showing the three components. The relative importance of each component depends on the particular application and the desired result. For predicting surface temperatures in high rate production wells, such as geothermal wells, the formation calculation is much less important than the flowing stream calculation. Conversely, for predicting permafrost thaw around an arctic well the flowing stream is less important than the formation analysis.

Several methods have been used in the past to determine flowing stream temperatures. Many of the early models assumed constant temperatures in the flowing fluid, or used experimentally determined correlations to compute temperatures, [1,2,10,20,22].* Later studies performed a steady state analysis to estimate fluid temperature, followed by models employing a pseudo steady state scheme whereby the temperatures in the flowing stream are assumed to be steady at each time step, [3,5,11-14,19]. Recent models have included the full transient response of the flowing stream [4,6-9,15-18,21,23]. For short time periods, the transient response is very important, such as for drilling

and cementing operations or for production and injection startup.

Resistance to heat transfer exists between the flowing fluid and the earth. During drilling in an open hole, the resistance results simply from the convection coefficient between the drilling fluid and the formation. However, when circulating inside casing, or during production and injection, the heat transfer resistance is more complex. Indeed, some well completions use this resistance to advantage with varying methods of insulation.

Figure 1 shows that heat must pass through several materials to travel from flow stream to the formation. Moreover, the resistance to heat flow varies with depth as casing is set, introducing steel, cement, and annular fluids where there once was earth. Some previous work has neglected the wellbore resistance, [12,13,15], but more recent papers have indicated a trend to detailed analyses of the well components, [18,19,23].

In the earth, heat is transferred both radially and vertically by conduction. Early attempts to model wellbore temperatures assumed a constant undisturbed geothermal temperature in the earth, or employed an analytical solution to the steady state or transient radial heat conduction problem. Later models included numerical solutions to transient radial heat flow, or both radial and vertical conduction.

Historically, computer models have been developed as needs arise for specific heat transfer analyses. For example several models appeared at the time interest in steam stimulation surged in the 1960's [13-17,34,42], and additional models were introduced in the early 1970's [18,19,23], as a result of the interest in arctic completions. Most existing wellbore thermal simulators have been designed for one of the following four applications:

1. drilling, cementing, circulation
2. single phase injection or production
3. two phase injection or production
4. permafrost thaws.

The present model is designed for the first two of these applications. Particular emphasis has been placed on highly transient short time intervals, complex flow histories such as occur in drilling, and flexibility to allow sequential combinations of all flowing possibilities. With the code described in this paper, the complete life of a well can be modeled with one computer run for drilling and circulation during completion, through production and circulation during workovers, additional production or injection through the life of the well, and even shut-in after a well is dead.

*See References

Flowing Stream

Energy is transferred in the flowing stream by various mechanisms. Some of the mechanisms are much more important than others, but the relative importance is dependent on the particular application. Figure 2 shows a cell in the flowing fluid through which energy is transferred and accumulated. The directions and energy flow shown are positive coordinate directions and coincide with injection for the tubing, denoted by $i = 1$, or reverse circulation for the tubing/casing annulus, $i = 2$. A dashed line outlines the cell to be considered.

In the radial direction heat conduction transfers energy into and out of the cell in Figure 2. Fourier's law of heat conduction establishes the rate of heat conduction into the cell [41],

$$E_{i-1}^c = \Delta z U_{k-\frac{1}{2}, i-1} \Delta T_{k-\frac{1}{2}, i-1} \quad (1)$$

Similarly, the rate at which heat is conducted out of the cell is

$$E_i^c = \Delta z U_{k+\frac{1}{2}, i} \Delta T_{k+\frac{1}{2}, i} \quad (2)$$

Energy transport in the flowing stream is more complex than simple conduction. A change in flow energy along a streamline is the sum of the change in enthalpy, potential energy and kinetic energy, [24],

$$\Delta E^f = \Delta H + \Delta PE + \Delta KE, \quad (3)$$

where ΔE^f is the rate of change of the flow energy. An expansion of the definition of enthalpy leads to

$$\Delta h = c_p \Delta T + \frac{\Delta P}{\rho} (1 - \beta T). \quad (4)$$

For this application the temperature T must be in absolute units. Rate of energy flow ΔH is obtained by multiplying the specific enthalpy Δh by the mass flow rate. The enthalpy expression in Equation 4 can be simplified and the kinetic and potential energies can be neglected by consideration of the relative magnitudes of each term.

In addition to energy being transferred through the cell in Figure 2, energy may be accumulated within the cell. The rate at which energy is accumulated, ΔE^a , is the rate at which the sensible heat of the fluid in the cell changes,

$$\Delta E^a = V c_p \frac{\Delta T}{\Delta t}, \quad (5)$$

where V denotes the volume of the cell, ΔT is a change of temperature in the cell with time, and Δt is the time increment. This transient behavior term is a key feature for modeling short time periods and rapidly changing conditions.

Another energy form that must be considered is heat generation. Heat may be generated by fluid friction against pipe walls, by chemical reaction such as cement hydration, or by external sources such as bit work during drilling. Other phenomena such as electric resistance heating in an electrode well may be modeled with a heat gener-

ation term. The rate at which heat is generated is denoted Q in the energy balance to follow.

All the energy terms discussed must obey the first law of thermodynamics, an energy balance. Consider again the fluid cell in Figure 2. An energy balance requires

$$\Delta E^c + \Delta E^f + Q = \Delta E^a \quad (6)$$

Substituting the expressions given above for the terms in Equation 6 and rearranging terms gives an expression of the form

$$\begin{aligned} T_{k,i}^{n+1} = & A_{k,i} T_{K-1,i}^{n+1} + B_{k,i} T_{k+1,i}^{n+1} \\ & + C_{k,i} T_{K,i-1}^{n+1} + D_{k,i} T_{k,i+1}^{n+1} + E_{k,i} T_{k,i}^n \\ & + F_{k,i} T_{k-1,i-1}^{n+1} + G_{k,i} T_{k-1,i+1}^{n+1}, \end{aligned} \quad (7)$$

where the coefficients $A_{k,i}, B_{k,i}, \dots$ are constants to be evaluated from thermal properties and dimensions. This equation can be written for every position k, i in the wellbore to yield a system of simultaneous linear algebraic equations. The unknowns are the temperatures at each node at time step $n+1$ and there is one linearly independent equation at each node.

Eight flowing options have been modeled with the formulation given above.

1. Injection
2. Production
3. Forward circulation
4. Reverse circulation
5. Fluid loss while circulating
6. Fluid production while circulating
7. Shut-in
8. Drilling

Options 5-8 are special applications of the first four options. In particular, the drilling option allows the circulation depth to vary with time at any specified variable rate. Of course, options 5 and 6 are available while drilling.

Soil

Heat conduction controls the transfer of energy in the soil surrounding a well. Figure 3 shows a mathematical cell used to analyze radial and vertical energy transfer in the soil. Contrast the cell location with that for the wellbore in Figure 2. Cell boundaries are located between nodes for conduction in the soil, but are located along nodes for convection in the flowing fluid.

Radial conduction in the soil is formulated much like that in the flowing stream. Applying Fourier's law for heat conduction to the cell in Figure 4 produces a radial heat flow out of the cell

$$E_i = \Delta z U_{k,i} \Delta T_{k,i} \quad (8)$$

and a similar expression for the heat flow in, E_{i-1} .

Fourier's law governs the vertical transfer of energy also. Based on the energy flow illustrated in Figure 4, the heat conducted out of a cell vertically is,

$$E_k = -K_{k+1/2,i} A_1 \frac{(T_{k+1,i} - T_{k,i})}{\Delta z} \quad (9)$$

The heat flow vertically into a cell is, E_{k-1} .

Heat generation and heat accumulation in a soil cell are formulated similar to a well fluid cell. An energy balance is required on each cell in the soil based on the geometry of Figure 4. Radial and vertical heat conduction into the cell plus the heat generated within the cell less the heat conducted out of the cell must equal the rate of energy accumulated,

$$\Delta E_r^c + \Delta E_v^c + Q = \Delta E^a \quad (10)$$

As with the flowing fluid analysis, Equation 10 can be rearranged to yield the form of Equation 7.

Wellbore Description

Linking the flowing fluid temperature calculations in the well to the soil temperatures is an important part of the formulation of a wellbore thermal simulator. Presently, most thermal simulators perform computations in the two regions independently, with one acting as a boundary for the other. For example, at a given time step the wellbore temperatures are computed based on the existing soil temperatures fixed as a boundary condition. Then the soil temperatures are computed with the wellbore temperatures fixed. Of course an accurate solution can be achieved in this fashion by iterating between the well and soil temperatures, but considerable computation time would be required. As a result most simulators simply perform one iteration, with hope that the error introduced remains small.

The present model does not decouple the soil and well calculations. Temperatures in the two regions are computed simultaneously from one set of algebraic equations. This technique of simultaneously solving for soil and well temperatures improves speed and accuracy of computation as compared to most existing models.

To make the link between flowing fluid and the soil, a conductance must be formulated to transfer heat between the two. Consider the wellbore description given in Figures 1 and 4. For heat to flow between the well and soil it must pass through various combinations of steel, cement, fluid, and soil. The conductance is computed from the well geometry and the properties of these materials. Heat passes from temperature node $k,2$ to node $k,3$ through a composite radial system of various materials. The rate of heat flow through such a system may be written as,

$$q = \Delta z U \Delta T, \quad (11)$$

where U is the thermal conductance [28].

The components of U are dependent on the temperatures in the well and on depth. Since the convection coefficient between flowing fluid and pipe wall is a function of viscosity, it must be allowed to vary with temperature. Although the thermal conductivities of steel, cement, and soil do not vary significantly with temperature, the natural convection occurring in the fluid in some annular regions is temperature dependent. Both the rate of convection and the fluid-pipe surface coefficient are temperature dependent. As a result of all these viscosity effects, the coefficients in Equation 7 are temperature dependent, resulting in a system of non-linear equations. However, these equations are weakly non-linear and may be linearized by simply evaluating the coefficients at the temperatures from the previous time step. In fact, the coefficients need not be updated at every time step, particularly in view of the computation time required to reconstruct the conductance, U , and the coefficients in Equation 7.

As a result of casing strings cemented at various depths, the conductance of Equation 10 changes with depth. Figure 6 illustrates the five sections in a well with different formulations for conductance as a result of a different number of casing strings at each depth. Near the surface there are five casing strings and five annuli between the injected fluid and the soil. Near the bottom of the well there is only one casing string and one annulus between the fluid and soil. Three other intervals can be identified between these two extremes as indicated in Figure 6. Moreover, there is an interface between cement and fluid to be located in each annulus. Above this interface, fluid properties are used for the annulus. Below the interface, cement properties are used.

Laboratory measurements have determined the rate of heat transfer between a fluid and solid surface. Experimental results correlate the Nusselt number with the Reynolds and Prandtl numbers, [29-31]. For some high viscosity oils another correlation is needed, [32,33].

Natural convection in a fluid filled annulus increases the rate at which heat is transferred across the annular region. The rate of heat flow during natural convection is a function of well dimensions, fluid properties, and temperature difference across the annulus. Laboratory measurements have determined the rate of heat flow and expressed the results in terms of an effective thermal conductivity. If heat is transferred by conduction through the annulus, a material with the effective thermal conductivity would transfer heat at the same rate as the convecting fluid. A correlation of experimental data for concentric vertical pipe provides an estimate of the effective thermal conductivity, [34,35].

A power law fluid model is used to compute viscosity for the non-Newtonian fluids present in most wells. An effective viscosity is defined by the ratio of the shear stress to the shear strain rate, $\dot{\gamma}$,

$$\mu_{\text{eff}} = M \dot{\gamma}^{n-1} \quad (12)$$

where M and m are fluid properties. The thermal simulator described herein requires input of the plastic viscosity and the yield point from which M and m are computed, [38-40]. Well fluid viscosity is allowed to change with temperature.

Solution

A grid system has been selected whereby three temperatures are computed in the wellbore at each depth. Mechanical cells are constructed with radial boundaries at the well centerline, at the outside surface of the drill pipe or tubing, at the wall of the open hole or the outside of the largest casing string. Such a grid is illustrated in Figure 4 and shows the three wellbore temperatures. The centerline of the third cell is located at the well/soil interface.

Temperature nodes are located at the centers of the cells as shown in Figure 3. The first node is for the fluid in the drill pipe or tubing, which gives the flowing production, injection or circulating fluid temperature, or simply a temperature at the center of the well during shut-in. The second node is located to compute annular fluid temperature during circulation. The third node serves as an interface between the wellbore and soil calculations by being located at the boundary between the two regions.

Vertical heat conduction is neglected in the wellbore. Cell dimensions in the wellbore and the presence of vertical convection in the flowing streams make vertical conduction negligible. Each cell is selected to be several hundred feet long and is generally a few inches to a few feet in radial width. A length to width ratio of 100 to 1000 clearly allows a much greater path to radial heat flow. Moreover, the vertical temperature gradients are generally less than the radial temperature gradients for most applications. Finally, for a flowing stream the vertical forced convection transports heat at a much faster rate than vertical conduction.

Nodal points in the soil are located at the same vertical positions as those in the wellbore. Cell length should be small enough to permit acceptable grid refinement to realistically model a well, yet sufficiently long to avoid unnecessary calculations by employing too many grid points. Experience indicates that 100 to 500 feet is a reasonable compromise. Two rows of soil cells are placed below the maximum depth for fluid flow in the well. One provides a transient response of the soil below the bottom of the well and the second serves as a fixed temperature boundary.

In the radial direction temperature gradients are much greater near the well so nodal locations are concentrated in this region. A program routine has been written to generate the radial positions of the nodes. Cell width is exponentially increased with radius to produce a grid as illustrated in Figure 5. The exponent chosen is determined from the specified maximum radius and number of radial points. Selection of the maximum radius and number of nodes requires some understanding of the expected rate of radial heat flow. High rates of heat flow should be modeled with a large maximum radius to locate an outside boundary that is suf-

ficiently far from the well to be unaffected by the temperature disturbance caused by the well. Smaller rates of heat flow do not require as large a maximum radius. Similarly, large temperature gradients near a well indicate that many nodes are needed in the radial direction.

Equation 7 can be applied to every temperature node to form a system of simultaneous linear algebraic equations. Of course there are many solution techniques, of varying degrees of sophistication and speed, available for computing the new temperatures at each new time step, $n + 1$. A Gauss elimination direct solution or a Gauss-Seidel iteration solution are the two simplest methods to apply, with variations of each available for improving speed or efficiency of solution.

A modified Gauss-Seidel iteration is employed in the present code to solve for the new temperatures. Equation 7 is repetitively applied until two successive calculations of each temperature are sufficiently close. The minimum computation time required for applications of the model does not justify an extensive effort to speed up the process. However, one simple procedure has been applied. Temperatures in the soil converge faster than in the well, so they need not be recomputed with every iteration. A check for local convergence reduces wasted effort in subsequent iterations. Successive overrelaxation may also be used to accelerate convergence, but it is well known that only a slight improvement is achieved unless the proper relaxation factor can be determined fairly accurately, to two or three digits. Since the value of the relaxation factor is dependent on the geometry of the grid, some attention must be given to the computation of the proper factor, [25,26]. Another procedure to be considered is the implicit alternating direction method, which provides even greater convergence than successive overrelaxation. However, this method too requires the determination of an iteration parameter, [25,27].

TESTING COMPUTER CODE

Exact Solution

The code has been tested against an exact solution to a simplified heat conduction problem. Two tests have been made in order to

- compare transient radial conduction analysis to exact solution
- evaluate the importance of time step size on solution accuracy.

By setting the flow rate equal to zero, the flowing stream energy balance reduces to transient radial heat conduction. This simplification has been applied to an exact solution with a fixed temperature T_p at outer boundary R , [41]. Figure 7 illustrates the exact solution temperature profiles at various times, and the thermal simulator predictions at four evenly spaced grid points. Even though a rather coarse grid is used to approximate the field, an accurate approximation of the exact solution is obtained. Only at early times and where the temperature gradients are large is there a noticeable difference, but a denser grid in the region of large gradients would reduce the difference.

It is worth noting that for wellbore thermal simulation the temperature gradients are larger near the well. But Figure 5 illustrates that the grid is denser near the well, reducing the error revealed in the comparison to exact solution. For an appropriate grid dimension relative to the temperature gradient, at later times or away from the heat source, Figure 7 demonstrates close agreement between computer and exact solutions.

Also illustrated in Figure 7 is the effect of time step size on solution accuracy. Two conclusions are apparent from the figure. First, time step size does not significantly influence the solution, except near the large gradient region, which can be eliminated as described above for solution accuracy. Second, convergence is clear as the time step size is reduced. For smaller time step sizes the computer solution approaches the exact solution monotonically.

Production Field Data

Several sets of existing field data have been collected to evaluate the accuracy of the computer model. Two of these data sets are presented here for comparison to model predictions, one from the geothermal industry and one from the petroleum industry.

Figure 8 shows a comparison between data supplied by Republic Geothermal and computer predictions. Downhole temperatures are provided after 44 hours of production at 14,500 BPD. At these high rates there is little change in temperature as the production fluid travels toward the surface, until flashing of water into steam occurs near 1000 feet. The low heat capacity of steam causes a rapid drop in temperature near the surface. Model predictions do not account for the phase change, but can be used to predict the location where flashing begins. The figure shows the excellent agreement between the calculated curve and measured data up to the flashing location. Also shown in Figure 8 are the well dimensions, and the undisturbed formation temperatures.

The calculated variation of fluid temperature with time is illustrated in Figure 9. As a result of the high flow rate, temperatures increase rapidly to a steady state within three or four hours after start up. Measured data after 44 hours show excellent agreement with the calculated steady temperatures.

A study conducted by the American Petroleum Institute provided field data on downhole temperatures during circulation, [36,37]. Figure 10 shows the data recorded in a well operated by Gulf Oil Co. and the computer predictions for the test well. The well schematic shows that temperatures were recorded during circulation at the bottom hole depth of 13,000 feet and at a depth above bottom in the return annulus at 11,000 feet. The well was shut-in for an extended period of time prior to the test to allow the downhole temperatures to return to undisturbed conditions. Figure 10 contains a plot of the transient temperature measurements at both depths. As one might expect from intuition, both measured data and computer

predictions show that the bottom hole region continuously cools from the beginning of circulation. One might also expect that up hole in the return annulus the temperature would increase when circulation begins as warm fluid near bottom hole rises, and then decrease as circulation cools the annulus. This pattern does not occur in the test data at 11,000 feet, but was predicted by the computer code. To understand the unusual test data, additional study of test preparation and measurement revealed that a short period of circulation occurred at a depth just above 13,000 feet prior to beginning the circulation test. As a result, the fluid below the temperature probe at 11,000 feet was cooled to less than the undisturbed temperature, and therefore, the predicted early temperature increase at 11,000 feet shown in Figure 10 did not occur when the test began.

Predictions by the computer code agree very well with measurements at bottom hole. However, in the return annulus, the predicted temperature pattern disagrees with the early time measurements as a result of the circulation before the test. But as the effect of the pre-test circulation fades, the return annulus prediction agrees with the measured data. Similar circulation tests in other wells demonstrated the expected pattern in the return annulus of an early increase in temperature followed by a steady decline.

Temperature profiles along the circulation test well are presented in Figures 11 and 12 after 30 minutes and after 3 hours of circulation respectively. Also shown are the undisturbed geothermal temperatures and the measurements at 13,000 feet and 11,000 feet. The agreement between prediction and measurement at 13,000 feet and the previously discussed early disagreement at 11,000 feet are apparent. At this early time the fluid temperatures have moved away from the initial distribution after three hours of circulation. Also the improved agreement with measured data at 11,000 feet is clear.

IMPORTANCE OF FLOW VARIABLES

Many variables influence the downhole temperatures in a well. Three of the more important variables have been tested for their influence on temperature predictions. The three variables selected and the range studied for each are as follows:

- Fluid inlet temperature, 50 to 150°F
- Fluid flow rate, 100 to 1000 GPM (circulation)
15 to 150 GPM (production)
- Depth, 5,000 to 10,000 feet.

The sensitivity of downhole temperatures to a change in each of these variables is presented for forward circulation and for production. Casing and tubing dimensions used for the calculations are listed below:

- tubing - 4-1/2" to TD
- production casing - 9-5/8" to TD
- intermediate casing - 13-3/8" to 3000'
- surface casing - 20" to 1000'.

Forward Circulation

Figures 13 and 14 show the effect of a change in inlet temperature on downhole temperatures during circulation at 500 gal/min to 5000'. The change in transient bottom hole temperature with inlet temperature is plotted in Figure 13. For two inlet temperatures of 50 and 150°F there is little difference in bottom hole temperatures shortly after circulation begins. Cooling occurs initially with each inlet temperature. For the 50°F inlet temperature cooling continues to a steady value of 70°F after five hours of circulation. But for an inlet of 150°F, the bottom hole temperature increases after one hour to a steady value near 130°F in five hours. Initial cooling at bottom hole occurs as cooler fluid from above moves down the well, but for an inlet of 150°F, when the warm fluid reaches bottom the temperature increases. A 100°F inlet temperature difference (150-50) results in a bottom hole temperature difference of 60°F (130-70). Figure 14 shows steady temperature profiles computed for five hours of circulation for each of the inlet temperatures.

Sensitivity of downhole temperatures to a change in flow rate are presented in Figures 15 and 16 for circulation to 5000' with a 100°F inlet temperature. Transient bottom hole temperatures at 100 and 1000 gal/min are plotted in Figure 15. At high flow rates the steady temperature is reached sooner and greater cooling is achieved. However, for an increase in flow rate from 100 to 1000 gal/min the bottom hole temperature is lowered only 10°F. Steady temperature profiles are plotted in Figure 16 for each flow rate. The slower rate tends to respond to the surrounding earth temperatures, but at 1000 gal/min the fluid travels to bottom and returns too quickly to change temperature. Of course at earlier times both curves closely follow the initial undisturbed temperatures.

For forward circulation, the change in downhole temperatures with circulation depth is illustrated in Figures 17 and 18. Bottom hole temperature is plotted in Figure 17 for circulation depths of 5000 feet and 10,000 feet. At the shallow depth a steady state is achieved earlier. And of course the bottom hole temperature is greater for the deeper well. Figure 18 shows the steady temperature profiles for circulation to 5000 feet and to 10,000 feet. Warmer temperatures are observed along the entire length of the well for deeper circulation. Note that there is little change in temperature at the surface for either depth. Also notice the zero slope on the temperature curves at bottom hole, which is to be expected for circulation.

Production

Two flow variables have been tested for their importance on downhole temperatures during production. Figures 19 and 20 illustrate the effect of a change in flow rate. In Figure 19 surface temperatures are plotted for production rates of 500 and 10,000 BPD. Two results evident are that a steady surface temperature is reached faster for the higher rate, and the steady surface temperature

is greater for the higher rate. In Figure 20 steady temperature profiles are plotted for the same two production rates. At the lower rate, temperatures begin to decrease as soon as the production fluid begins its trip uphole, approaching a path parallel to the undisturbed formation temperatures. For the high production rate, fluid travels to the surface too fast to be significantly effected by the surrounding earth.

The importance of depth on production wellbore temperatures is given in Figures 21 and 22. Surface temperatures are plotted in Figure 21 for depths of 5000 and 10,000 feet. This curve shows only a small difference, but the fluid from 10,000 feet is slightly hotter as expected. Figure 22 gives the steady production temperature profiles for the same two depths. Two results are clear. First, for both depths as fluid rises in the well it cools and approaches a path parallel to the undisturbed temperatures. And second, the surface temperatures are not much different for the two depths. Also, by comparison with Figure 20 one can conclude that the production rate for the curves of Figure 22 is sufficiently low to allow the fluid temperature to be strongly influenced by the surrounding earth temperatures.

CONCLUSIONS

The following conclusions are based on the results presented in this paper.

1. Improved well design can be achieved with a better understanding of downhole temperatures in a well. Applications include cementing, logging, casing design, drilling mud formulations, and packer selection.
2. A computer model is needed to accurately predict the full range of transient downhole temperatures in a well. Field measurements provide only isolated data points for a transient phenomena, and simple analytical techniques do not sufficiently account for the complexity of the problem.
3. Field temperatures can be predicted by the model presented here for circulation, production, and injection. Good agreement between model predictions and field data has been achieved for petroleum and geothermal wells.
4. Inlet temperature can strongly influence downhole temperatures. A 100°F difference in inlet temperatures for forward circulation has limited effect early, but changes the steady bottom hole temperature 60°F in a 5000 foot well flowing at 500 gal/min through 4-1/2" tubing.
5. Downhole temperatures during forward circulation can be strongly dependent on flow rate. During forward circulation in a 5000 foot well a change in flow rate from 100 to 1000 gal/min changes the bottom hole temperature in less than one hour to a new steady value, but only a 10°F change at bottom is noted with an inlet change of 100°F.

6. At very high flow rates well fluids experience little temperature change during circulation, production, or injection.
7. Flow rate strongly influences the surface temperature for a production well. For a 5000 foot well the steady surface temperature changes 35°F for a change in flow rate from 500 to 10,000 BPD in a 4-1/2" tubing.
8. For a constant undisturbed temperature gradient, the depth of a well significantly effects the bottom hole temperature during circulation, but does not significantly change the surface temperature during production. These results hold only providing the flow rate is not too high. At very high flow rates the converse is true.

NOMENCLATURE

a	subscript denoting energy accumulation
A_i	cross sectional area of cell i
$A_{k,1}$	coefficient of temperature in energy balance
β	volumetric coefficient of thermal expansion
$B_{k,1}$	coefficient of temperature in energy balance
c_p	specific heat capacity
c	superscript denoting heat conduction
$C_{k,1}$	coefficient of temperature in energy balance
$D_{k,1}$	coefficient of temperature in energy balance
E	energy
$E_{k,1}$	coefficient of temperature in energy balance
ΔE	energy change or difference
f	superscript denoting flow energy
$F_{k,1}$	coefficient of temperature in energy balance
$\dot{\gamma}$	shear strain rate
$G_{k,1}$	coefficient of temperature in energy balance
Δh	specific enthalpy change
ΔH	total enthalpy change
i	radial index subscript
k	vertical index subscript
K	thermal conductivity
ΔKE	change in kinetic energy
μ_{eff}	effective fluid viscosity
m	fluid viscosity model exponent
M	fluid viscosity model coefficient
n	time index superscript
p	subscript denoting constant pressure
ΔP	change in pressure
ΔPE	potential energy change
q	rate of heat flow
Q	rate of heat generation
ρ	density
r	subscript denoting radial direction
Δt	time change
T	temperature change
U	heat conductance
V	cell volume
Δz	vertical length interval

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Fig. 1 - Wellbore completion model.

Fig. 2 - Energy exchange in a fluid cell.

Fig. 3 - Energy exchange in a soil cell.

Fig. 4 - Mathematical cells in wellbore.

Fig. 5 - Grid for soil nodes.

Fig. 6 - Well intervals for conductance formulation.

Fig. 7 - Model comparison to exact solution.

Fig. 8 - Republic Geothermal well steady production temperature profile.

Fig. 9 - Republic Geothermal well transient temperature behavior.

Fig. 10 - API cementing temperature study - Gulf well.

Fig. 11 - API study - Gulf well fluid temperature profile after 30 minutes.

Fig. 12 - API study - Gulf well fluid temperature profile after 3 hours.

Fig. 13 - Sensitivity of bottom hole temperature to inlet temperature.

Fig. 14 - Sensitivity of steady temperature profile to inlet temperature.

Fig. 15 - Sensitivity of bottom hole temperature to flow rate.

Fig. 16 - Sensitivity of steady temperature profiles to flow rate.

Fig. 17 - Sensitivity of bottom hole temperature to depth.

Fig. 18 - Sensitivity of steady temperature profile to depth.

Fig. 19 - Sensitivity of surface temperature to flow rate.

Fig. 20 - Sensitivity of steady temperature profile to flow rate.

Fig. 21 - Sensitivity of surface temperature to depth.

Fig. 22 - Sensitivity of steady temperature profile to depth.

EFFECT OF STAGNATION TIME UPON WELLBORE PERMEABILITY

By

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Program Summary

Drill and mud solids deposited in a producing formation of a geothermal well can irreversibly damage the formation by permeability reduction¹. Field experiences in Imperial Valley have suggested that the "aging" of drilling mud deposition in a producing formation can have deleterious effects upon well productivity². The residence time of the "internal filter cake" (cake formed actually within the formation) after deposition and before backflow is termed the "stagnation time" and is investigated in this program. Permeability impairment was determined as a function of varying stagnation times, mud types and temperatures. This work was performed under Sandia contract #13-9407.

Samples were prepared from core taken from East Mesa, Imperial Valley and saturated with brines representative of their *in situ* state. An initial (undamaged) permeability measurement was made on samples while at simulated *in situ* conditions including overburden pressure [34.5 MPa (5000 psi)], pore fluid pressure [14.9 MPa (2165 psi)] and temperature (to 200°C). All permeability measurements were made in the direction of backflow. Samples were then subjected to simulated "hot" mud circulation and stagnation times. Stagnation times varied from ½ to 7 days. Following this "damage" sequence, permeability was measured again in the backflow direction and compared with the original value. Three mud types were tested including a bentonite based system, a sepiolite based system, and HTM-1, a special mixture specifically designed for geothermal drilling.

Temperatures were controlled at 100°C and 200°C (bentonite transformation temperature is approximately 150°C). Post-test analysis included scanning electron microscope examination and x-ray diffraction studies.

Testing was performed at Terra Tek's geothermal testing facility shown in Figure 1. Special mud circulation equipment designed for this specific type of testing is shown in Figure 2.

Figure 1. Photograph of Terra Tek geothermal test facility.

Figure 2. Photograph of drilling mud circulation flow cart.

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USE OF SEPIOLITE TO IMPROVE MUD
PERFORMANCE ON GEOTHERMAL WELLS

By

Neal Davis
Gulf Research & Development Company

Sepiolite-based drilling fluids have been used in geothermal areas as a substitute for the conventional bentonite-based drilling fluids. This system has been used successfully in the Southern California Imperial Valley area and also to a lesser degree of success in the geysers area of Northern California. Usage of the clay material has decreased in the past two years.

Sepiolite is a fibrous, magnesium-rich clay mineral with a structure similar to attapulgite clay. In contrast to attapulgite, sepiolite also imparts some fluid loss control in a mud system as well as being viscosity. The clay can build viscosity in all water-based fluid systems.

Sepiolite mud systems have been tested in both the laboratory and in the field drilling operations to determine temperature effects. Data from these applications indicate that the system can be used without experiencing severe bottom hole gelation resulting from high temperature that normally occur with other water-based mud systems.

CONTROL OF CORROSION IN AIR-DRILLED GEOTHERMAL HOLES

by

Paul W. Fischer
Union Oil Company of California

Air drilling in both vapor and liquid dominated reservoirs produces rapid drill pipe deterioration. Corrosion-erosion in geothermal air drilling is a combination of factors, including high-temperature steam, water, salts, oxygen, and high-velocity abrasive drill cuttings. Severe corrosion-erosion problems led Union Oil Company of California to develop a resin that forms a protective coating on pipe down-hole. The resin is totally water soluble at ambient temperature, but becomes a viscous non-water soluble polymer at about 250°F. This material coats drill pipe and prevents both erosion and corrosion in vapor-dominated reservoirs. However, geothermal fluids normally are acidic and the inhibitor is less effective at low pH. When pH is maintained at 9.5 or above, inhibitor effectiveness is improved.

HOT WELL STIMULATION TECHNIQUES

By

G. W. Anderson

Data will be presented to show that preformed stable foam can be heated to 400°F + with live steam and circulated in a well bore to do useful work.

Hot foam has been used to soften and remove asphaltic and paraffin plugging materials from producing wells. A comparison of the downhole temperature generated by circulating steam and hot foam indicated that hot foam produced higher bottom hole temperatures. However, due to the low specific heat of a foam, since it contains only about 10% water with 90% air, and the short contact time during foam circulation, it was found that large amounts of heat could not be transferred to the surrounding well bore.

This characteristic has been used successfully to remove debris loosened by hot fluid wash jobs in steam stimulated producing wells without the detrimental effects of cooling the well bore.

An anticipated use of this hot foam technique is in clean-out and work over operations in steam stimulated true tar sand projects. Once the tar is mobilized by heating, it cannot be cooled significantly or it will recondense in and around the well bore.

Since most geothermal reservoirs are by nature low pressured, the demonstrated thermal stability and superior lifting ability of preformed stable foam should be a valuable consideration for geothermal drilling and work over operations.

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