

PROCEEDINGS SIXTH WORKSHOP GEOTHERMAL RESERVOIR ENGINEERING

December 16-18, 1980



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INTRODUCTION TO THE PROCEEDINGS OF THE SIXTH GEOTHERMAL RESERVOIR
ENGINEERING WORKSHOP, STANFORD GEOTHERMAL PROGRAM

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The Sixth Workshop on Geothermal Reservoir Engineering convened at Stanford University on December 16, 1980. As with previous Workshops the attendance was around 100 with a significant participation from countries other than the United States (18 attendees from 6 countries). In addition, there were a number of papers from foreign contributors not able to attend.

Because of the success of all the earlier workshops there was only one format change, a new scheduling of Tuesday to Thursday rather than the earlier Wednesday through Friday. This change was in general considered for the better and will be retained for the Seventh Workshop. Papers were presented on two and a half of the three days, the panel session, this year on the numerical modeling intercomparison study sponsored by the Department of Energy, being held on the second afternoon. This panel discussion is described in a separate Stanford Geothermal Program Report (SGP-TR42).

This year there was a shift in subject of the papers. There was a reduction in the number of papers offered on pressure transients and well testing and an introduction of several new subjects. After overviews by Bob Gray of the Department of Energy and Jack Howard of Lawrence Berkeley Laboratory, we had papers on field development, geopressured systems, production engineering, well testing, modeling, reservoir physics, reservoir chemistry, and risk analysis. A total of 51 papers were contributed and are printed in these Proceedings. It was, however, necessary to restrict the presentations and not all papers printed were presented.

Although the content of the Workshop has changed over the years, the format to date has proved to be satisfactory. The objectives of the Workshop, the bringing together of researchers, engineers and managers involved in geothermal reservoir study and development and the provision of a forum for the prompt and open reporting of progress and for the exchange of ideas, continue to be met. Active discussion by the majority of the participants is apparent both in and outside the workshop arena.

The Workshop Proceedings now contain some of the most highly cited geothermal literature.

Unfortunately, the popularity of the Workshop for the presentation and exchange of ideas does have some less welcome side effects. The major one is the developing necessity for a limitation of the number of papers that are actually presented. We will continue to include all offered papers in the Summaries and Proceedings.

As in the recent past, this sixth Workshop was supported by a grant from the Department of Energy. This grant is now made directly to Stanford as part of the support for the Stanford Geothermal Program (Contract No. DE-AT03-80SF11459). We are certain that all participants join us in our appreciation of this continuing support.

Thanks are also due to all those individuals who helped in so many ways:

- The members of the program committee who had to work so hard to keep the program to a manageable size - George Frye (Aminoil USA), Paul G. Atkinson (Union Oil Company), Michael L. Sorey (U.S.G.S.), Frank G. Miller (Stanford Geothermal Program), and Roland N. Horne (Stanford Geothermal Program).
- The session chairmen who contributed so much to the organization and operation of the technical sessions - George Frye (Aminoil USA), Phillip H. Messer (Union Oil Company), Leland L. Mink (Department of Energy), Manuel Nathenson (U.S.G.S.), Gunnar Bodvarsson (Oregon State University), Mohindar S. Gulati (Union Oil Company), George F. Pinder (Princeton University), Paul A. Witherspoon (Lawrence Berkeley Laboratory), Frank G. Miller (Stanford Geothermal Program) and Michael J. O'Sullivan (Lawrence Berkeley Laboratory).
- The many people who assisted behind the scenes, making sure that everything was prepared and organized - in particular we would like to thank Jean Cook and Joanne Hartford (Petroleum Engineering Department, Stanford University) without whom there may never have been a Sixth Workshop.

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IDENTIFICATION OF GEOTHERMAL RESERVES
AND ESTIMATION OF THEIR VALUE

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ABSTRACT

This paper discusses a procedure for estimating the value of a hot water geothermal property from a resource owner's point of view. Two methods make up the procedure: a "conservative" method of estimation and an "optimistic" one. Value of a property by both methods is estimated to equal the present value of future income less the cost of resource extraction. The two methods share a common set of assumptions (e.g., that the price of hot water at the start of cash flow from a project will be the same). However, the methods differ in important ways. The optimistic method, for example, allows for future increase in price that in turn offsets discounting of future income. Together the methods define a range of values that might reasonably be assigned to a property.

INTRODUCTION

This paper describes and illustrates a procedure for estimating the wellhead value of a hot water geothermal resource. The procedure also provides a basis for estimating what part of a geothermal resource is a reserve. The procedure may be applied to property for which no specific development plans have been formulated or announced. It may be termed "property appraisal." The procedure should not be confused with the procedure one would follow in deciding upon the financial merit of a specific, complete development plan for a resource. Such a procedure is usually called a "project evaluation."

ASSUMPTIONS ABOUT PRICE, COST, AND GEOLOGY

To carry out this analysis, we begin with a series of assumptions regarding: 1) price that one would expect to receive for sale of geothermal fluid (Howard, 1980 a,c), 2) cost to establish the capability to produce the resource (Howard, 1980 b,c), and 3) the plan and schedule to bring the resource into service (Howard, 1980 d). We assume complete knowledge of the resource, that heat contained in the fluid only is recovered, and that fluid is completely recovered. We assume that any well drilled into the resource will yield an ultimate recovery of approximately 10^{10} lbm (Howard, 1980 b). We assume that enough wells are available to service demand at all times during production.

Consideration of possible plans for bringing a resource on stream is particularly complex. This problem is reviewed in some detail in Howard (1980 d) and is discussed briefly below. It has been necessary to make assumptions regarding: a) the use to which the hot water property will be put (low temperature direct use, industrial heating at medium temperatures, or to produce electricity), b) to assign annual and lifetime loads accordingly and c) to define a time for start of cash flow.

ARGUMENT FOR THE PRESENCE OF A RESERVE

According to the definition of a reserve, a reserve exists if the geothermal energy can be extracted and used at costs competitive with other energy sources at the present time (Muffler and Guffanti, 1979). The price of hydrothermal geothermal fluid, p , at the wellhead is proposed to depend on its energy content as shown in Figure 1 and is a function of relative specific enthalpy (see Howard, 1980 a,c). On the other hand, the cost, c , of bringing hydrothermal fluid to the wellhead is proposed to depend on its depth of occurrence and ultimate recoveries per well (Howard, 1980 b,c). Figure 2 shows the cost function. Both functions are given on a mills per pound mass basis. To a first approximation that volume of fluid for which

$$p > c$$

can be considered a reserve.

Table 1 lists information regarding a specific resource. This information can be used to make price and cost estimates in order to determine the part, if any, of the resource that is a reserve. The volume under consideration in this example is actually only a part of a still larger resource. The example is bounded by the 310°F isothermal surface, the 7500 foot depth plane, and the vertical sides of the property.

Study of Table 1 shows that, according to definition, volumes between 2500 and 6500 feet are reserves. No reserve exists below 6500 feet because cost exceeds price.

ASSUMPTIONS REGARDING DEVELOPMENT

The value of a reserve depends not only on its size, average price, and cost per unit mass, but also on the plan and schedule for its development. Income to be received at some future time is generally discounted in order to compare cumulative income over the life of a project with costs borne at the start of the project. In order to discount future income, however, we need to make some assumptions regarding the way in which a resource is to be developed. Assumptions regarding plan and schedule for development are discussed in Howard (1980 d) and are summarized in Table 2. If the representative temperature is greater than 350°F, for instance, we assume that the resource will be used for electrical power generation. The

annual load is assumed to be in the range of 20 to 100 x 10⁹ lbm depending on temperature (cf. Austin, 1975) and the 30 year lifetime load is assumed to be in the range of 650 to 3000 x 10⁹ lbm.

We also assume, for example, that an application in the less than 250°F temperature range will start its cash flow one year after purchase and will produce a constant cash flow equal to the product of annual load and price per pound mass (dependent on temperature) for 30 years. For an application in the 250-350°F range, we assume that a constant cash flow will start three years after purchase and will continue for 30 years. For electric power production we assume the start of cash flow to begin six years after purchase. We assume that all costs to establish a 30 year capability to produce are borne at the start of development of the project.

CONSERVATIVE ESTIMATES OF VALUE

A reasonable estimate of the monetary fair market value of a property can be determined by calculating the present worth of the initial project one might logically expect the property to support. Such a determination can be made if one accepts the assumptions that: 1) the size and representative temperature and depth to the resource are known, 2) estimates for the average price and cost of the fluid in the resource are valid, and 3) the plan and schedule for development of the first project on the property are those sketched in the previous section and summarized in Table 2. If one accepts these assumptions, it is a straightforward procedure to calculate a present worth as a function of discount rate. One may then use these quantities as a measure of the value of the property.

We calculate the present worth of the anticipated initial project on the property as follows.

The annual mass use of the resource, Q_A , expressed in pounds-mass, varies with the type of project and more fundamentally, with the representative temperature of the resource (see Table 2). The price that one might expect to realize from sale of a pound-mass of the resource, p , is a function of relative specific enthalpy given in mills per pound mass (see Figure 1). Annual cash income, I_A , is the product:

$$(1) \quad I_A = Q_A p$$

We assume a 30 year lifetime for a project and a constant annual income. Thus the value of all income from the 30 year life of the project is, at the start of cash flow, given by:

$$(2) \quad I' = I_A D';$$

where D' is the discount factor given by

$$(3) \quad D' = \frac{(1+i)^{30} - 1}{i(1+i)^{30}} .$$

The quantity i is the annual discount rate.

Inasmuch as income from the 30 year life of the project will start at various future times depending on the type of project, anticipated 30 year income at the start of cash flow must itself be discounted to zero time. This discount factor is given by

$$(4) \quad D'' = \frac{1}{(1+i)^m}$$

where, as before, i is interest rate and m is years until start of cash flow.

The present value of future incomes, I'' , is equal to all income discounted to the start of cash flow, I' , and then discounted again to zero time.

Algebraically:

$$(5) \quad I'' = I'D''$$

$$(6) \quad = I_A D' D''$$

$$(7) \quad = I_A \frac{(1+i)^{30} - 1}{i(1+i)^{30}} \cdot \frac{1}{(1+i)^m} .$$

Present worth, PVP, is the difference between present value, I'' , and present cost, C . We estimate present cost by determining the lifetime mass requirements of the project and multiplying by a cost per unit mass, c . The lifetime requirements are listed in Table 2 and Figure 2 shows costs on a pound-mass basis as a function of representative depth to the reservoir (see Howard, 1980b). Thus:

$$(8) \quad PVP = I'' - C.$$

OPTIMISTIC ESTIMATES OF VALUE

Although an estimate of present worth, discounted appropriately as explained above, provides a basis for estimating value of a property, still other considerations should be

addressed in order to fully appreciate its value: 1) escalation of prices (and costs) over the lifetime of the project; 2) the assignment of value to that part of the property in excess of the requirements of the initial project; 3) factoring in the likelihood that development will actually occur in view of geographic and demographic considerations.

DISCUSSION

We propose to treat the question of escalation of costs and prices in a simple way. In making an appraisal we propose to treat all costs as incurred at the start of the project. In brief, our reasoning is that deferred escalated costs (discounted at about 12%) and present costs are more or less equivalent (Howard, 1980d).

Escalation of prices for energy had been dramatic in the 1970's and recently has been on the order of 20-25% (Howard, 1980a,c). Increases in price on the order of 12% or more per year are in the range of rates of return on investment that appear to be acceptable to resource developers. Comparison of escalation of prices and rates of return suggests that increases in prices and the process of discounting future incomes may cancel each other. The consequence of this cancellation is that the present value of a project is equal to annual income times duration of the project.*

The question of mass of the resource much greater than 30 year load, or in other words, assignment of value to that part of the property in excess of that required for the initial project, can be handled in several ways. First is to define the property areally (or volumetrically) so that it is insignificantly bigger than that required for the initial project. The second is to expect no present value of the excess but to ask a royalty on production from it, should production of the excess ever occur.

The possibility that development will ever occur on a property is impossible to generalize about because it is dependent upon the specific property and on individual judgment. This subjective uncertainty and the uncertainty associated with escalation of

*A more rigorous analysis could have been carried out wherein future prices (and income) are increased according to an equation involving an escalation factor. Among the solutions derivable from such an approach is the solution wherein escalation just offsets discounting (i.e., the so-called optimistic case, likelihood of 1, of this paper). Other solutions would also be available, in principle, however, whereby one could estimate the value of the property as a function of escalation as well as other parameters discussed in the paper. The importance of such escalation was emphasized to me by my colleague, A.N. Graf, however, its investigation is beyond the scope of this paper.

prices offsetting discounting of future income may be combined in a single factor, f ($0 < f < 1$), that we have called a "likelihood" factor. We recognize it as a subjective factor and feel that the best way to handle it is to display it clearly.

Treatment of the considerations introduced in this section of the paper may be summarized as follows:

1) the value of an anticipated initial project on an undeveloped geothermal property is equal to annual income from the project times a 30 year expected project lifetime:

$$(9) \quad V = I_A \times 30;$$

2) the value of the project should be discounted by the factor f

$$(10) \quad 0 \leq f \leq 1$$

to reflect the likelihood that development will occur and that discounting of future income is unnecessary:

$$(11) \quad V' = Vf = f I_A \times 30;$$

3) the cost of the project, C , is calculated as in the conservative case;

4) the value of the property is its present value profit, V'' :

$$(12) \quad V'' = V' - C = f I_A \times 30. - C$$

COMPARISON AND GENERAL COMMENT

It can be shown that the estimated value of the property is the same according to either method for certain conditions. For $i = 0$ and $f = 1$, $V'' = PVP$.

Furthermore, the two estimates are equal, $V'' = PVP$, when

$$(13) \quad f = \frac{D'D''}{30}$$

The quantity $D'D''$ depends on the discounting rate, i . For discount rates in the range of 10-20%, namely the range most commonly mentioned as reasonable for discounting, $D'D''$ has value of about 5. Thus, roughly, $V'' > PVP$ if $f > 1/6$. Based on this argument, feeling that most of the time f will be a bit greater than $1/6$ and will therefore lead to higher values, we have termed the method involving the likelihood factor, f , as the optimistic method.

It should be fairly clear from the previous discussion that only a range of values can be reasonably defined by the procedure. Subjectivity cannot be avoided, and perhaps it is unreasonable to expect that it could be avoided. The procedure does, however, define a finite range of values and helps to elucidate the consequences of certain subjectively set prejudices, particularly acceptable discount rates and "hunches" regarding energy prices in the future. We anticipate that sellers will favor the optimistic method; buyers, the conservative method--for obvious reasons. We also propose that the range of values will be practically limited by the conservative methods using discount rates close to the prime rate (a low estimate) and by the optimistic method using a likelihood factor of about 0.5. It would be surprising to us if any property were appraised for more than its optimistic value with a likelihood factor of 1.0.

EXAMPLE CALCULATION

In this section, we illustrate the procedures explained previously by application to a specific example. Information about the illustrative example is listed in Table 3.

We wish to calculate and display information about the property using both conservative and optimistic methods.

Figure 3 shows present value profit for the property as a function of discount rate and of likelihood factor. Inspection of the figure shows the following. For interest rates greater than 8%, value of the property is negative. For an interest rate of 12% value is -\$125 K. In contrast, value of the property is estimated to be almost \$200 K for a likelihood factor of 0.5.

Study of a report on this property suggests that ultimate recoveries of more than 10×10^9 lbm per well may be attainable and thus that our general cost estimating should be modified in view of specific information. Initial flow rates per well (pumped) are on the order of 400,000 lbm/hr. The calculations shown in Figure 3 are based on a representative well having an ultimate recovery of 10×10^9 lbm, an hourly mass flow of 240,000 lbm, and a lifetime of at least 5 years. Thus we have recalculated the example using only 60% of costs (i.e., $240,000/400,000$). (If even greater ultimate recoveries could be shown costs would decline still more and property value increase even more.) Recalculation leads to the conclusions shown in Figure 4. For interest rates greater than about 14%, value of the property is negative. For an interest rate of 12%, value is \$40,000. In contrast, value of the property is approximately \$372,000 for a likelihood factor of 0.5.

Clearly a fairly wide range of values results from the two methods and two appraisals. Some subjectivity and arbitrariness are necessary if the range is to be cut down. As a seller we would argue for a value of at least \$372 K. As a buyer we would

propose a nominal price of 0 (current price rate being more than 14%). Thus a reasonable compromise value, which obviously must be negotiated, would be \$186 K, namely half the difference.

ACKNOWLEDGMENTS

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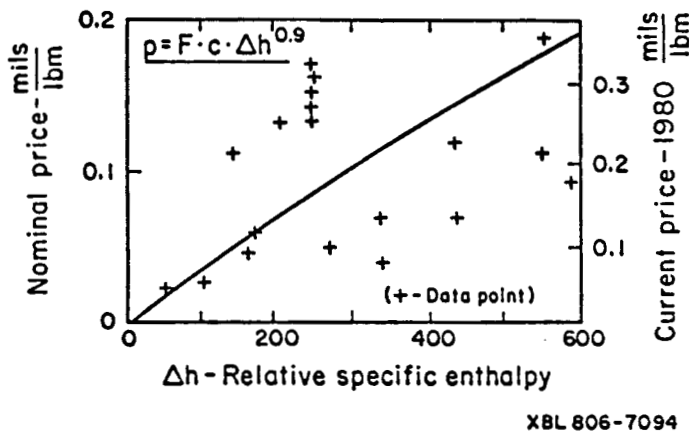


Figure 1. Proposed equation for estimating price of geothermal hot water based on its energy content.

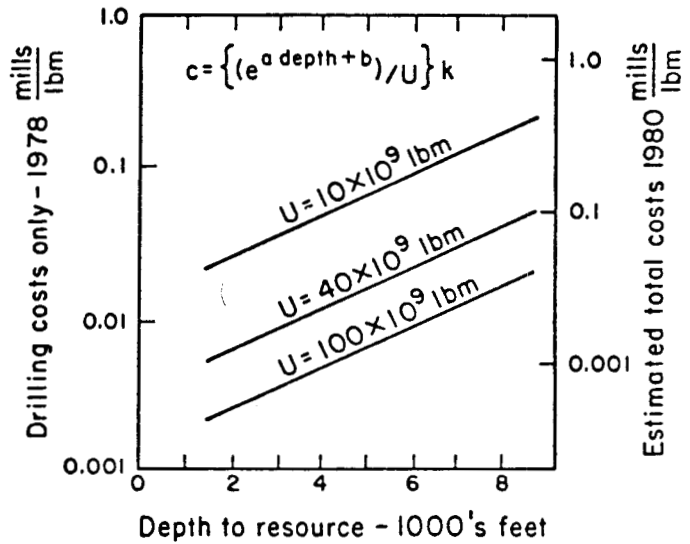


Figure 2. Proposed equation for estimating cost of geothermal hot water based primarily on its representative depth of occurrence.

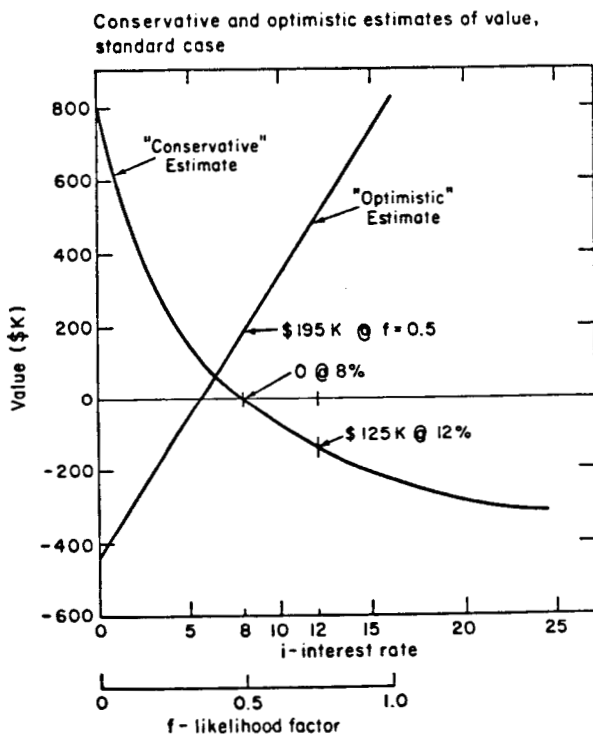


Figure 3. Conservative and optimistic estimates of value for the illustrative example, standard case.

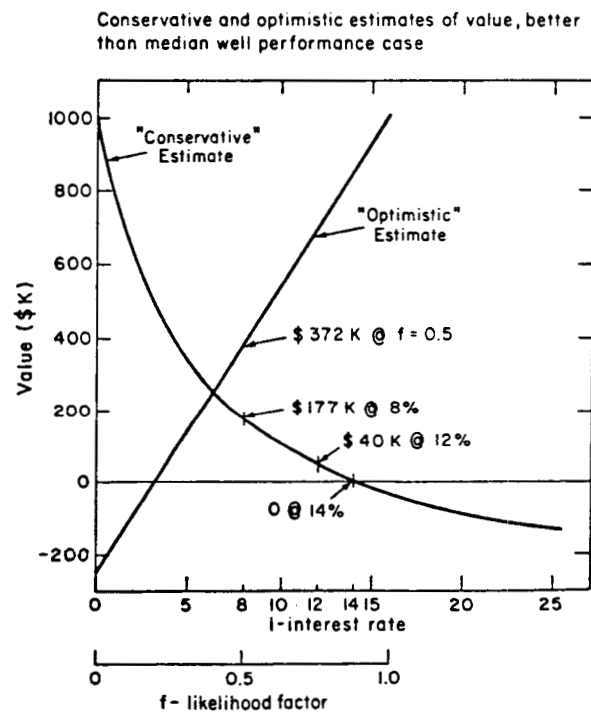


Figure 4. Conservative and optimistic estimates of value for the illustrative example, for better than median well performance.

TABLE 1. DATA ON PROPERTY A*

DEPTH INTERVAL (Feet)	MASS OF FLUID (lbm) X10 ⁹	AVERAGE TEMPERA- TURE °F	AVERAGE ENTHALPY PER POUND MASS (Btu/lbm)	AVERAGE RELATIVE SPECIFIC ENTHALPY (Btu/lbm)**	ESTIMATED PRICE PER POUND MASS (Mills/lbm)	**REPRESENTATIVE DEPTH (Feet)	ESTIMATED COST PER POUND MASS (Mills/lbm)	DIFFERENCE (Mills/lbm)	COMMENT
2500-3500	7.81	320	264	237	0.171	3000	0.051	0.120	Reserve
3500-4500	7.56	326	270	243	0.174	4000	0.070	0.104	Reserve
4500-5500	11.7	329	273	246	0.176	5000	0.097	0.079	Reserve
5500-6500	17.1	334	278	251	0.180	6000	0.134	0.046	Reserve
6500-7500	16.4	338	282	255	0.182	7000	0.185	- 0.003	Not a Reserve

*Reservoir originally defined by 310°F surface, 7500 foot depth plane, and lateral boundaries of the property.

**Relative to 27 Btu/lbm reference point.

TABLE 2. ASSUMPTIONS FOR DEVELOPMENT OF A HOT WATER GEOTHERMAL RESOURCE

CLASS	TEMPERATURE RANGE °F	USE	ANNUAL LOAD X 10 ⁹ lbm	LIFETIME LOAD (30 YEARS) X 10 ⁹ lbm	INSTANTANEOUS WELL REQUIREMENTS NO.	LIFETIME (30-YEAR) WELL REQUIREMENTS NO.	DELAY TO START OF CASH FLOW-YEARS
LOW	250°F	residential heating	0.5	15	1	2	1
MEDIUM	250-350°F	commercial heating	5.0	150	3	15	3
HIGH	350°F	produce electricity	20-100	600-3000	10-50	60-300	6

TABLE 3. INFORMATION ABOUT THE ILLUSTRATIVE EXAMPLE

ITEM	COMMENT
$\bar{T}_r$	representative temperature 180°F
$\bar{d}_r$	representative depth 1300 ft.
R_r	total mass of fluid in the reservoir 2.79×10^{11} lbm
I_A	anticipated annual income from initial project \$42,470 0.5×10^9 lbm x 0.0849 $\frac{\text{mills}}{\text{lbm}}$
I_{30}	30 year income from initial project, no "discounting" \$1,274,100
C_{30}	anticipated total cost to service initial project \$442,564 15×10^9 lbm x 0.029504 $\frac{\text{mills}}{\text{lbm}}$
$\dot{q}_r$	reported flow rates 800 gpm (~400,000 lbm/hr)

PRODUCTION HISTORY OF THE GEYSERS STEAM FIELD

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INTRODUCTION

A rather comprehensive reservoir engineering study made by Ramey (1968) of the Big Geysers area contains a table of yearly production, cumulative production, and average pressure of wells producing from the shallow zone in the Big Geysers area for the period from 1957 to 1967. Production prior to 1957 is not included in the cumulative production because of incomplete records. He used the information to plot a p/z curve versus cumulative production to obtain an ultimate steam recovery of 135 billion pounds from the shallow zone to an abandonment pressure of 65 psig.

A brief engineering study was presented by Lipman, et al (1977), at which time eleven power generating plants were in operation. Included in that study is a brief picture of the regional drainage system around the Sulphur Bank, Happy Jack, and Big Geysers area showing the shallow reservoir anomaly in relation to the larger regional fracture system. Also presented is a pressure map showing the change of the 500 psia isobar with time and an isobaric map as of April 1977. These two maps cover the area from which wells produced steam into Units 1 to 11. These authors, however, did not present production data to correlate with the pressure behavior that they described.

This paper presents a brief history of the development of the field, followed by several examples of production decline curves for wells having six or more years of history. The wells selected have varying production rates and original well spacings. The paper concludes with a section on the monthly, yearly, and cumulative production data as reported to the California Division of Oil and Gas.

BRIEF HISTORY OF DEVELOPMENT

The development of the Geysers Field began in 1921 with the drilling of a well in the Big Geysers area. By 1925 eight wells had been drilled but further development ceased because of a lack of market for energy developed from steam (Allen and Day, 1927).

In 1955 development started again when Magma Power Company obtained a lease from the Geysers Development Company and drilled well Magma 1. Magma Power Co. then joined with Thermal Power Co. to drill additional wells to test the potentialities of the Geysers steam reservoir and to aid in marketing the steam. (McMillan, 1970; Garrison, 1972) Drilling continued until by the end of 1959 thirteen more wells had been drilled.

In September, 1960, the first power plant of 12 MWe was installed. Experience with this plant indicated the viability of produced steam as a source of energy for generating electric power. In 1961 two wells were drilled and in 1963 eight more wells were drilled with Unit 2 of 14 MWe installed in March of that year. Drilling continued until by the end of 1965 the Magma-Thermal group had drilled 37 wells.

In 1966 Union Oil Company drilled and completed Ottoboni Federal 1 as a successful producing well. In that year Union and the Magma-Thermal group pooled their leases to further develop the area with Union as the operator. By the end of 1968 a total of 54 wells had been drilled, of which two were drilled by Geothermal Resources International, and Units 3 and 4 had been installed for a total generating capacity of 80 MWe.

The drilling activity increased in 1969 in anticipation of additional power plants to be put in operation. In the years 1971 through 1974 seven more units were installed and placed on line. It was almost five years before another plant was placed on line. By September 1980 fourteen units were on line with a total installed generating capacity of 930 MWe.

A list of the plants in operation along with field operator, date of installation, and size of plant is given in Table 1. In addition to Union, Thermogenics and Aminoil now also supply steam to power plants. As can be seen Aminoil supplies steam to the largest plant.

INDIVIDUAL WELL PRODUCTION BEHAVIOR

The initial steam production rate of a new well depends on the size and number of fractures penetrated by the well, on the hole and casing size, on the depth of the well, on the reservoir pressure, and on the reservoir itself. For high rates the well will be limited primarily by hole size. For low rates the well will be limited by the effective kh (permeability-thickness product) of the reservoir around the wellbore. The wellbore effects of depth and hole size were illustrated by Budd (1972) who presented two graphs showing how rate versus wellhead pressure was effected by hole size and by depth.

Typical production decline curves for eleven wells are shown in Figs. 1 to 7. The data plotted are as reported by the operator to the California Division of Oil and Gas. The history period ranged from six to twelve years. The initial rates varied over about a five-fold range. The initial well spacing varied also being about five acres per well for the Happy Jack, Sulphur Bank, and Thermal wells in the old part of the field to about 40 acres per well for the other wells. All of the production data were not available for wells Sulphur Bank 7 and Thermal 10 because prior to April, 1968, only the kilowatt-hours generated were reported. Thermal 10 actually went on production into Unit 1 in September 1960; Sulphur Bank 7 into Unit 3 in July, 1967.

These production curves can be compared with those of Budd (1972) for well spacings of 45, 20, and 5 acre spacing. The average curve for these wells falls about midway between the 20 and 5 acre curves with the actual curve showing a decline at the end of six years that is greater than the decline of the calculated curves presented by Budd.

FIELDWIDE PRODUCTION

The monthly production rate of the Geysers Field based on reported data is shown in Figure 8. As of the end of 1979, when 684 MWe were on stream, the maximum rate was 7489 million pounds of steam for the month of December, 1979.

Yearly production data and cumulative data are shown in Table 2. The total steam production data include field production from wells on stream and estimated production consisting of flow from blowout well Thermal 4; from wells that are being vented; and from tests on wells that are being drilled (PG&E 1979). The reported production was obtained from the files of the California Division of Oil and Gas. The cumulative production at the end of 1979 was 624 billion pounds of steam.

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TABLE 1

POWER PLANTS INSTALLED
GEYSERS FIELD, CALIFORNIA

<u>Unit</u>	<u>Operator</u>	<u>Date on Line</u>	<u>MWe</u>	<u>Cum MWe</u>
PG&E 1	Magma-Thermal (a)	September 60	12	12
PG&E 2	Magma-Thermal (a)	March 63	14	26
PG&E 3	Union	April 67	27	53
PG&E 4	Union	November 68	27	80
PG&E 5 & 6	Union	December 71	55/55	190
PG&E 7 & 8	Union	Aug. & Nov. 72	55/55	300
PG&E 9 & 10	Union	Oct. & Nov. 73	55/55	410
PG&E 11	Union	May 75	110	520
PG&E 12	Union	March 79	110	630
PG&E 15	Thermogenics	June 79	55	685
PG&E 13	Aminoil	May 80	135	820
PG&E 14	Union	September 80	110	930

(a) Magma-Thermal group was operator prior to joining with Union

TABLE 2

YEARLY PRODUCTION*
GEYSERS FIELD, CALIFORNIA

<u>Year</u>	<u>Field Production (a)</u>	<u>Estimated Other (a)</u>	<u>Total Steam Production (a)</u>	<u>Reported Production</u>	<u>Cum. Production (b)</u>
1957	110	997	1107		1.11
1958	113	2470	2583		3.69
1959	442	2429	2871		6.56
1960	1013	2192	3205		9.77
1961	2273	2219	4492		14.26
1962	2422	2024	4446		18.70
1963	4025	2098	6123		24.83
1964	5892	2058	7950		32.78
1965	5763	1988	7751		40.53
1966	6639	1864	8503		49.03
1967	9079	1722	10801		59.83
1968	9822	1791	11613		71.44
1969	15019	1743	16762	15019	88.21
1970	14365	1892	16217	(c)	104.44
1971	17321	1720	19041	17226	123.46
1972	34783	2039	36822	34783	160.29
1973	47320	2231	49551	47320	209.84
1974	58045	2418	60463	58046	270.30
1975	67387	2440	69827	67229	340.13
1976	71015	2191	73206	70498	413.33
1977	71567	1714	73281	71709	484.57
1978	--	--	--	60960	545.53
1979	--	--	--	79140	624.67

* In million pounds

(a) Reference (PG&E 1979)

(b) In billion pounds

(c) October production data missing from files

STEAM PRODUCTION RATE VS. TIME

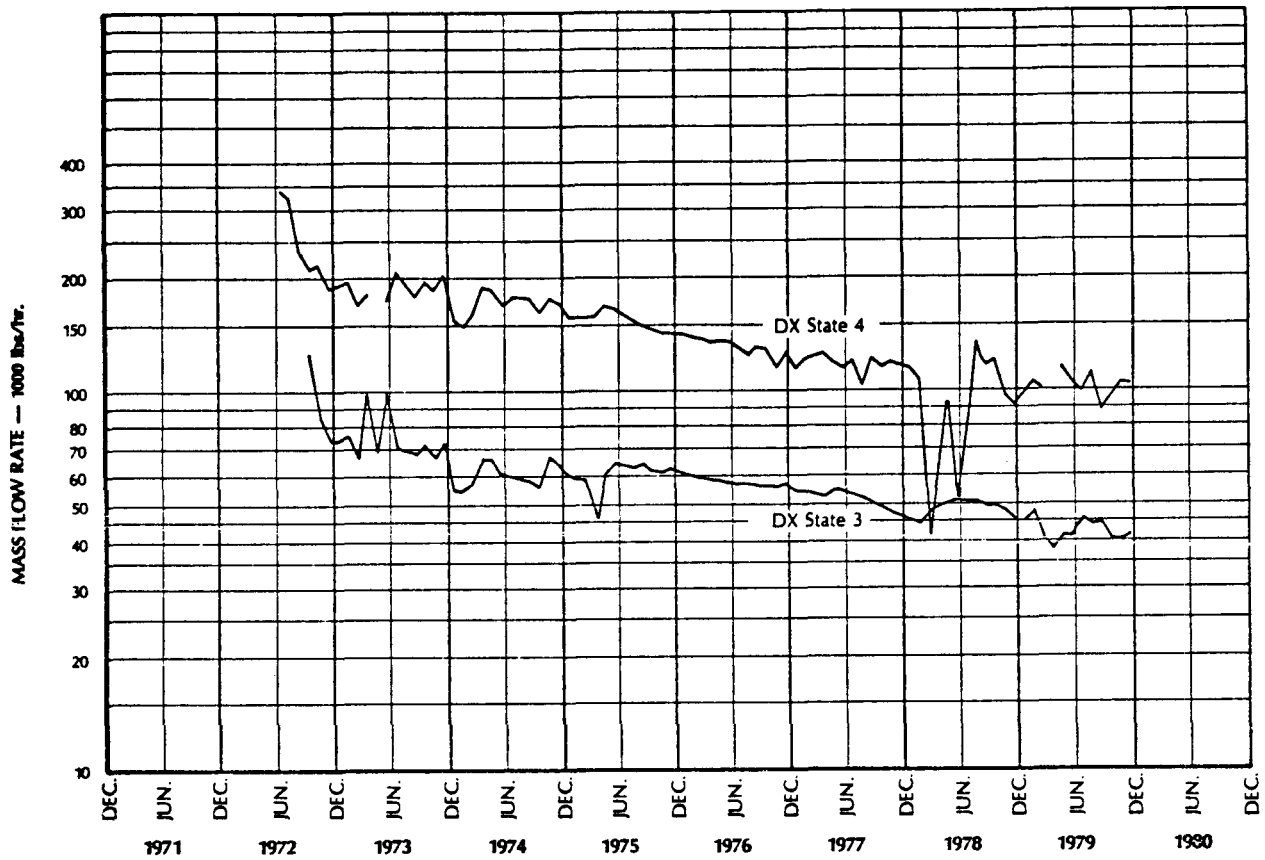
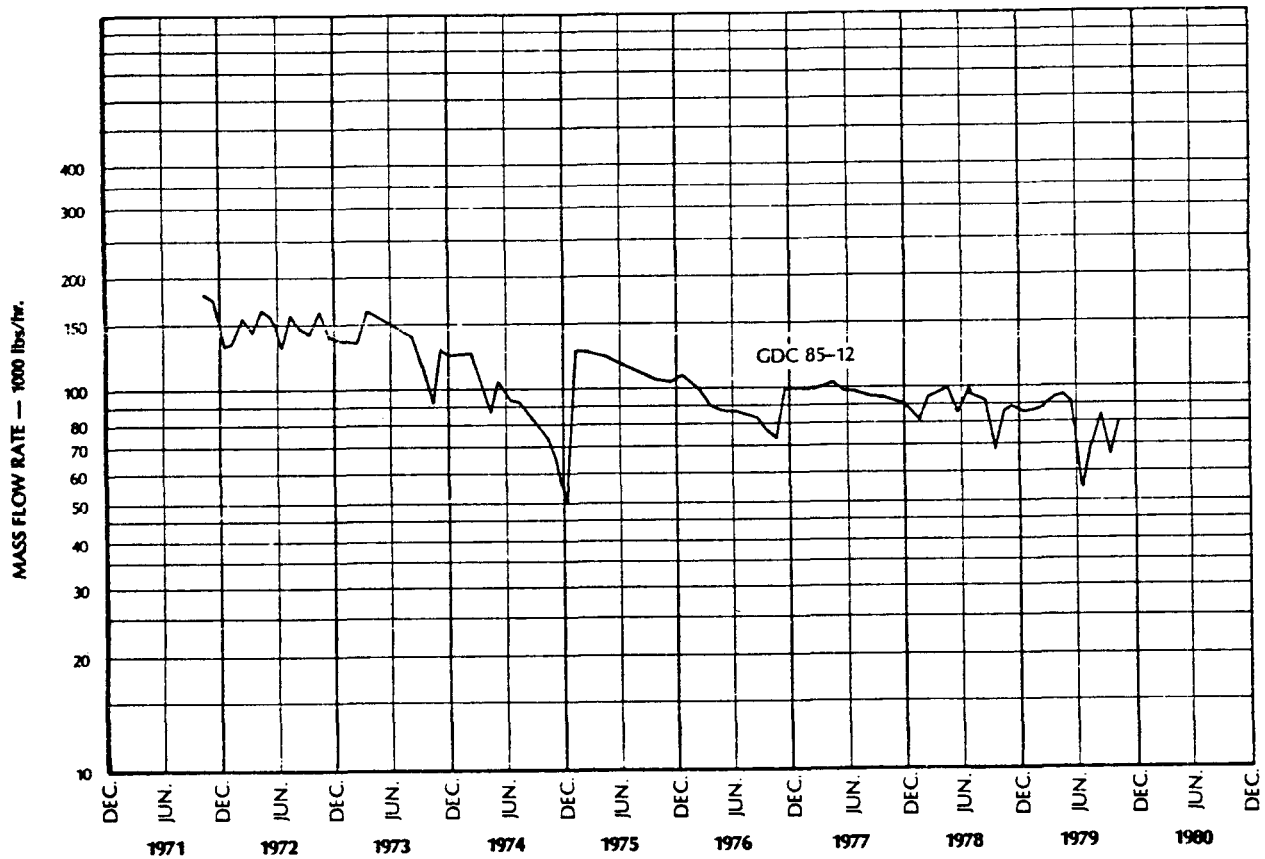


Figure 1

STEAM PRODUCTION RATE VS. TIME



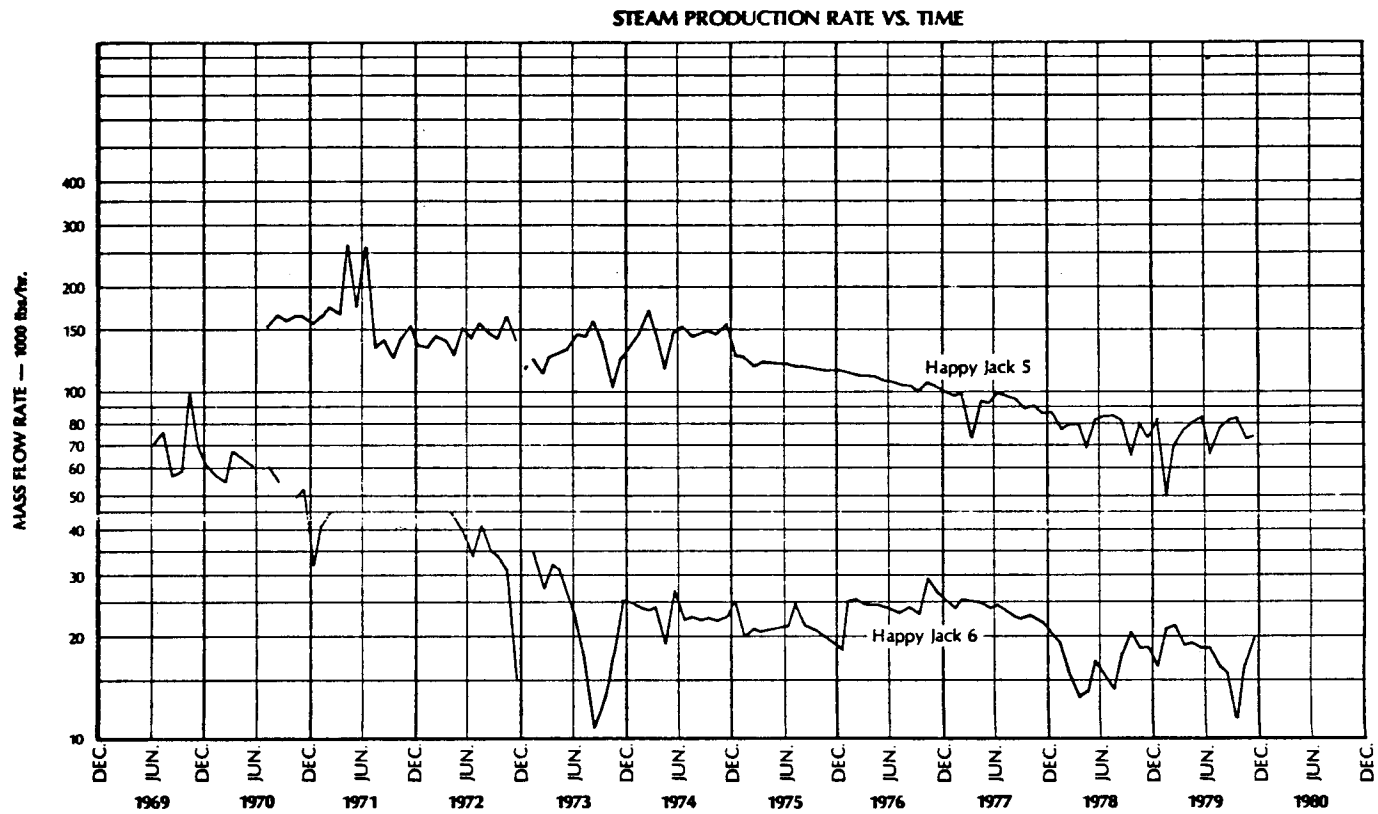


Figure 3

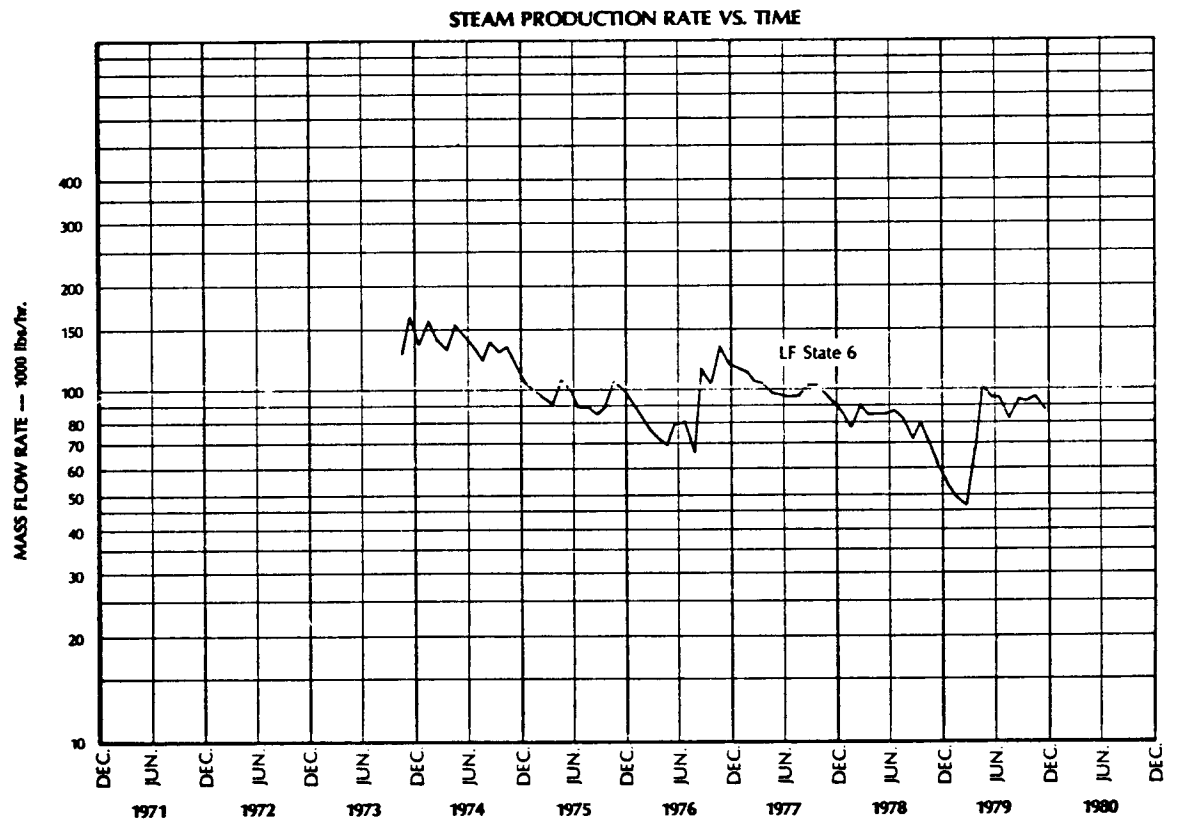


Figure 4

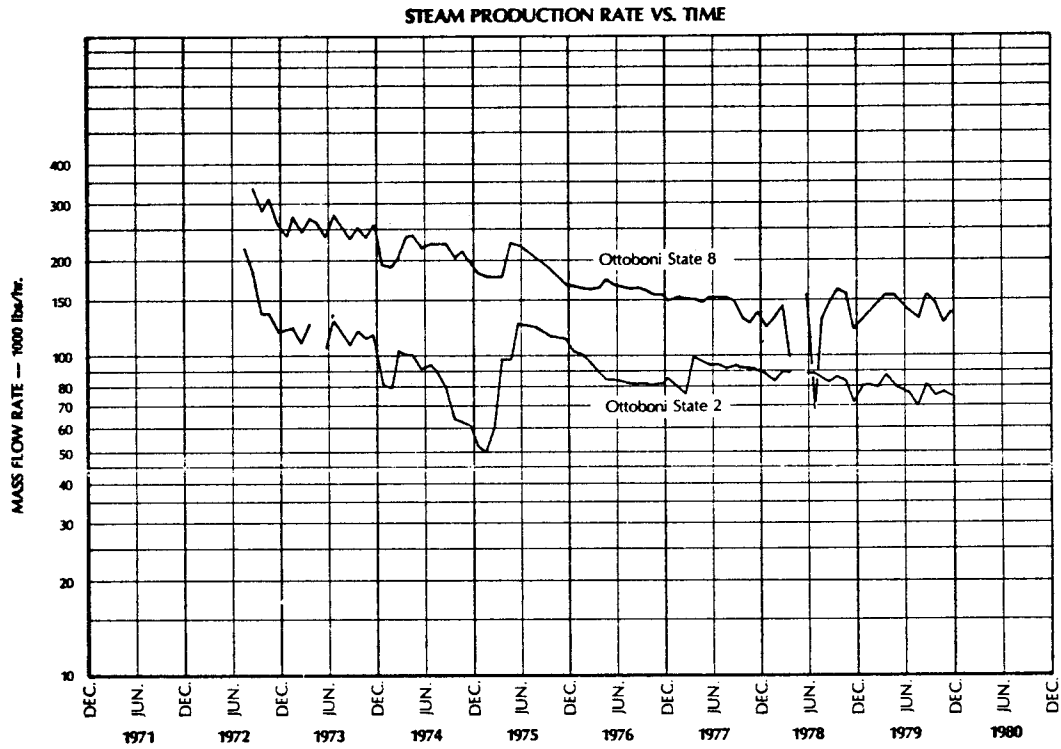


Figure 5

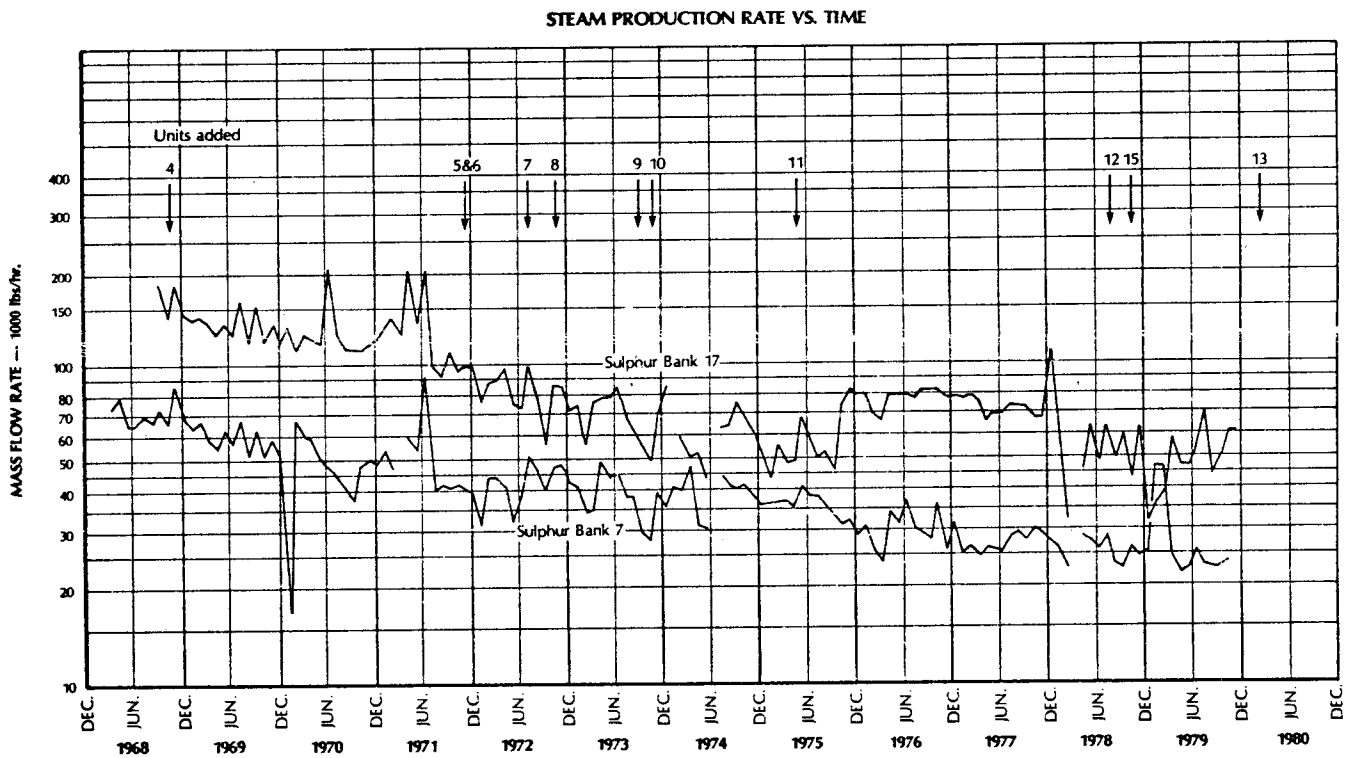


Figure 6

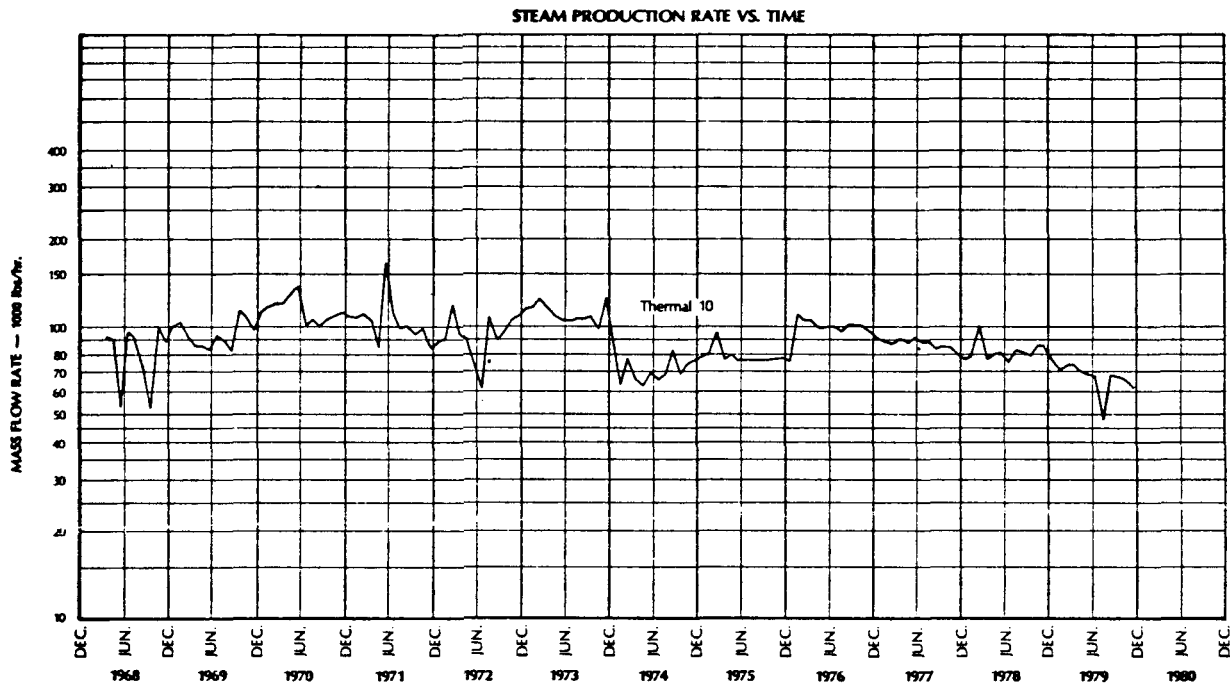


Figure 7

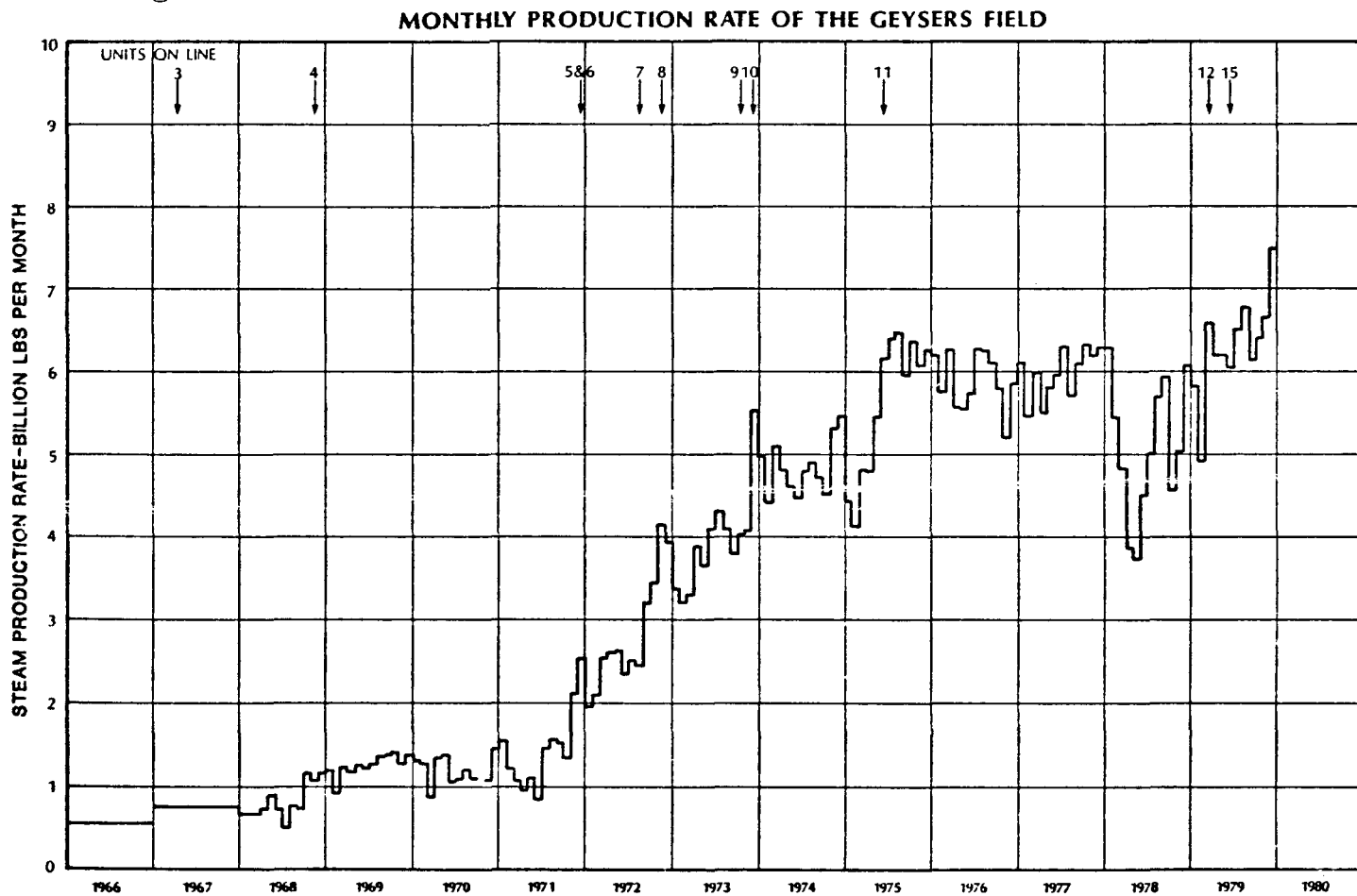


Figure 8

A GEOLOGIC, HYDROLOGIC AND GEOCHEMICAL MODEL OF THE SERRAZZANO ZONE OF THE LARDERELLO GEOTHERMAL FIELD

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INTRODUCTION

The large number of nonproductive wells lying along the northern and western margins of the Larderello field have indicated some boundaries of the productive area but have also prevented us, so far, from fully understanding the phenomena controlling the behavior of the geothermal system in these areas.

In 1980 ENEL re-opened some wells that had been shut-in immediately after drilling, thus offering us the possibility to complete the geochemical picture by means of numerous samplings of steam, gas and water in both productive and nonproductive wells. Some recent physical parameters measured in nonproductive and abandoned wells also helped in further defining the hydrogeological and thermal situation.

GEOCHEMICAL STUDY OF THE GEOTHERMAL FLUIDS IN THE SERRAZZANO AREA

This study covered the Serrazzano area and most of the southwestern sector of the Larderello field, as shown in Figure 1. The fluids from the wells in this zone have an extremely varied geochemical composition. The study was directed at individuating the recharge mechanism prevailing in the area (local infiltration, regional water circulation, steam from high pressure zones, condensate re-evaporation, etc.) and at comparing spatial variation in composition with the results of the Raleigh condensation model.

Wherever possible we used the average values of the period 1971 through 1978 for the wells joined to the distribution network. The wells joined to the distribution network in the intensely drilled zone, all of which are pre-1950 bores, were considered to give a gas/steam ratio of the order of 20 Nl/gk. This value is the maximum for the last 15 years and also the norm in the 1950's. During the last ten years the gas/steam ratios in the zone have, in fact, been seen to decrease slightly. The gas/steam value for the Cieccaie well is that of the 1950 period (25 Nl/kg).

Geographic trends in steam composition

The distribution of steam composition in the Larderello field is usually clearly defined (Celati et al., 1973; Panichi et al., 1974; D'Amore et al., 1977; D'Amore and Truesdell, 1979). With the exception of the zones next to the recharge areas, the concentrations of the noncondensable gases generally increase from the center of the field outwards; the concentrations of the species more soluble in the liquid phase (^{18}O , H_3BO_3 , HCl), on the other hand, decrease in the same direction. These distribution trends of the chemical species suggest a lateral flow of steam from zones in which steam of deep origin forms and rises, towards the margins, with a partial condensation and depletion of the species that are more soluble in the liquid phase. Figures 2, 3, 4, and 5 show the spatial distributions in the study area of H_3BO_3 , HCl , ^{18}O , and the gas/steam ratio (90-98 per cent of which is CO_2). Ammonia presented no clear geographic distribution, although the lowest recorded values (150 ppm) were found in the central zone of the study area (Val de Cornia) and around VC/10 well.

These four parameters (CO_2 , H_3BO_3 , Cl , and ^{18}O) have clearly defined spatial distributions, especially in the northern part of the study area. The distributions were interpreted by means of a simple physical model based on a Raleigh's condensation process. The model was successfully applied in the "classic zone" of the Larderello field (D'Amore and Truesdell, 1979). This model traces an appropriate flow-path for the fluid coming from one or more main sources. The heat loss in the upper part of the reservoir leads to condensation of part of the steam; while the condensate is drained downwards, the residual steam continues to flow towards the margins of the reservoir. In the unexploited state the condensate flows slowly down a hydrologic gradient to the center and is revaporized.

Figure 6 is based on analysis of the trends of these four parameters along the flow line (wells VC/10, Grottitania, densely drilled area, Cioccaie, Pozzaie 2, no. 8, no. 10, no. 14) represented by the A-B line of Figures 2-5. The trends are in excellent agreement with the theoretical trends (Figure 6, D'Amore, Truesdell, 1979). They suggest that the steam coming from one major feeding source in the southeast undergoes progressive condensation, reducing the less volatile elements of the residual fluid and increasing the more volatile or lighter components. In other words, the fluid moves from a deeper, high pressure zone along the upper margin of the reservoir, dissipating heat through the cover, which gradually becomes thinner the further the steam flows on.

However, condensation does not appear to keep the temperature of the residual steam at constant values in this area, considering the temperatures calculated at well-bottom. The initial values of about 260°C become about 200°C in the densely drilled zone. Figure 7 was drawn from the distribution constants at 230°C. However, the variations in these constants, between 260° and 200°C, are of no great significance compared to the uncertainties of the data used.

The A-B flow line (from well VC/10 to no. 14) was chosen on the basis of the permeability variations, the highest permeability being in the area with the structural high of the reservoir (Celati et al., 1975). From the distribution of the low permeability wells (Figure 1) we obtain a corridor which was then chosen as the probable main flow-path of the steam.

The mathematical basis of Raleigh's condensation process is quite simple (D'Amore and Truesdell, 1979). The condensate in this process is continually removed as fast as it appears, so that the residual steam becomes richer or poorer in certain chemical and isotopic species as the initial mass of steam gradually decreases. The theoretical equation that can be used for each species is:

$$C/C_0 = (m/m_0)^{(1/K-1)} \quad (1)$$

m/m_0 represents the fraction of residual steam, equal to zero for 100 per cent condensation. C/C_0 is the increase or decrease in the residual steam concentration of one species with respect to the initial value C_0 . K is the distribution constant between steam and liquid for each species. The following equation was used for $\delta^{18}O$:

$$\delta - \delta_0 = 1000 (m/m_0)(\alpha - 1) - 1 \quad (2)$$

where α is the fractionation factor between steam and liquid.

The overall agreement between the observed and calculated trends show that Raleigh condensation along the selected steam flow path can probably explain the trend of CO_2 , H_3BO_3 , Cl and $\delta^{18}O$. The NH_3 trend is not shown in Figure 7 as it is nearly flat. However, it should be noted at this point that the NH_3 content of the steam is strongly dependent on the pH value of the condensate liquid. With a pH between 5.8 and 5.2, and a temperature between 200° and 250°C about half of the ammonia is in ionic form (NH_4^+) and remains trapped in the liquid. The pH of the liquid forming during real condensation is actually an unknown. We can only hypothesize that, in a rapid condensation simultaneous with an increase in CO_2 pressure, the pH values in the condensate become so low as to camouflage any significant increase in the NH_3 content of the steam in the area north of Serrazzano. This phenomenon will be studied later in greater detail.

Figure 8 shows the $\delta^{18}O$ trend versus δD in some wells of the study area. Analysis of Figure 8 leads us to distinguish between the various wells; Group A, including VC/10, is characterized by primary steam at 250-260°C. Groups B and C, on the other hand, probably contain D- and ^{18}O -depleted fluids caused by condensation (non-isothermal). The slope of the line indicates that condensation took place at temperatures of less than 220°C.

The extremely positive $\delta^{18}O$ values (+10 to +12) of the reservoir waters taken from the nonproductive wells in the northern margin of the field (wells Serra, no. 12) exclude the possibility of this fluid feeding the productive wells of Serrazzano. If these waters did contribute to the steam produced, then $\delta^{18}O$ values in the Serrazzano field would be far more positive. These waters probably consist of the residual fluid of a long boiling process within the bore, with little recharge from the reservoir water because of the very low local permeability of the formations.

The fluid from Serrazzano Sperimentale well, which lies within the densely drilled area and is much deeper than the surrounding wells, has a higher gas/steam ratio (24 Nl/kg), more than 800 ppm of H_3BO_3 and about 10 ppm of HCl . This confirms that condensation takes place at the top of the reservoir where the species in question reach new equilibria.

The gas in the study area is usually far more radioactive (about 5 times as much) than in the zone of well VC/10 (D'Amore, 1975). Higher radioactivity could simply be due to stronger emanating power of the rock, together with the presence of water in the liquid phase (D'Amore et al., 1976). The latter could also have formed from the same condensation phenomenon, followed, at different times and perhaps even in different places, by re-evaporation.

Temperature evaluation of the area based on gas composition

A semi-empirical geothermometer was applied in the study area, based on the H_2 , H_2S and CO_2 concentrations in the dry gas and on the CO_2/H_2O ratio in the fluid. A more detailed description of the theoretical and empirical basis of this geothermometer will be given in a separate report. However, the main principles are as follows:

Concentrations of H_2 and H_2S have been noted to vary with respect to the gas/steam ratio as a hyperbolic function in the case of wells with similar temperature (between 240 and 260°C) and different total gas concentrations in the fluid. The geothermometer keeps the calculated temperature at a constant value when there is an increase in the gas/steam ratio and corresponding decrease in the $(H_2+H_2S)/CO_2$ ratio.

If the gas/steam ratio and the H_2 and H_2S concentrations decrease simultaneously, the reservoir is in the cooling phase (usually because of dilution with steam from recent meteoric waters). The geothermometer used is:

$$\log(H_2/CO_2) + \log(H_2S/CO_2) + 1.25 \log(N_2/CO_2/kg_v) = 13.87 - (6935/T) - 0.79 \log T$$

The spatial distribution of the calculated temperatures was used to construct Figure 9, which shows the calculated temperature trends. The calculated temperatures in the northern margins of the study area are about 30 degrees higher than the values calculated at well-bottom. This suggests that cooling is fast enough to prevent any rapid re-equilibration of the reactive species H_2 and H_2S .

Further results of the hydrogeological and thermal surveys

The new temperature and water-level data from wells on the northern margin of Serrazzano have led to a reconstruction of the piezometric surface on this margin and of the temperature trend along a NW-SE cross-section of the field. Previous piezometric surfaces have referred only to small areas northwest of Serrazzano and Larderello (Celati et al., 1975). Using a few data on the northern part of Serrazzano, an attempt made to correlate the various zones produced the trends shown in Figures 10 and 11. Assuming the level data as reliable, we note that the piezometric surface is characterized by an isolated relative high, corresponding with the northern margin of the Serrazzano productive area. The reservoir in this zone has a very low permeability and temperatures are relatively low. There being no evidence of surface infiltration in the area of the high, we can only presume that the low permeability formations acted as cold barriers and, consequently, as condensation zones for all the nearby hot areas. These formations are, in fact, little affected by fluid circulation and have remained colder during the formation of the field.

These hot areas could be represented by the VC/10 zone, in the western part of Larderello, and the Lustignano-Canneto zone, west of Lustignano and Serrazzano. This second zone was included as past data and recent drilling results have identified it as containing a vapor-dominated system. This hypothesis is backed by the decrease in water levels across the zone.

The isotherms in the central part of the section have more or less the same trend as the top of the reservoir, but clearly decrease on the northwestern and southeastern margins. This phenomenon is much stronger in the southeastern zone, and the cooling could be attributed to the vicinity of wide absorption zones of meteoric waters. On the northwestern margin, on the other hand, where the phenomenon is less marked, the cooling could partly be ascribed to a limited infiltration through the ophiolites and underlying limestone flysch; but the main cause is the low permeability of the reservoir formations which, immediately north of the Serrazzano structure, are made up predominantly of phyllites.

CONCLUSIONS

The geochemical study of the northern margin of Serrazzano leads to the following conclusions,

- (1) The geochemical characteristics, the temperature and present-day pressure distributions, as well as the distribution of permeability as inferred from the geographic position of the nonproductive wells (Figure 1), all suggest that the main steam source for the northern sector of Serrazzano is an area around VC/10 well in which the deep fluids are able to rise (point A in Figure 1).
- (2) The condensation mechanism seems to control the distribution of the geochemical parameters.
- (3) During field exploitation a part of the steam could derive from re-evaporation of condensate that accumulated in periods of higher pressure; to a lesser degree, it could even derive from a deep regional water circuit or from a steam source in layers well below those exploited at present. There appears to be no major contribution of recent meteoric waters, such as those infiltrating the ophiolitic complex.
- (4) The cold area north of the productive field seems to have been caused mainly by low permeability and, consequently, by the lack of efficient fluid circulation. Slight infiltration through a cover complex that is not totally impermeable may have contributed to some extent in cooling the area. In the contact areas between these cold zones and the vapor-dominated system there once was, and in some places still is, a continuous process of steam condensation. The accumulated condensate still exists even in zones drained by the field, if permeability is very low. The piezometric gradients show where drainage is taking place. The gradient on the western margin is particularly interesting, as further evidence of the existence of an important area between Lustignano and Canneto. A careful study of the in-hole water-levels would be useful whenever the borehole encounters relatively cold marginal aquifers in poorly permeable zones.

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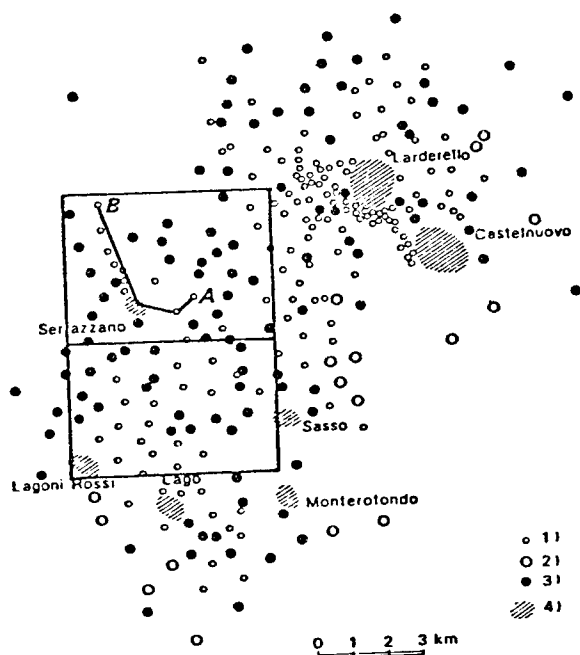


Figure 1. Geographic outline of the study area. The upper part of the rectangle represents the marginal area of Serrazzano field, which is dealt with in some detail in this report. The line from A to B is the direction taken by the fluid flow.

- (1) productive wells;
- (2) non-productive wells in areas of relatively low temperature;
- (3) non-productive wells due to low permeability;
- (4) densely drilled areas.

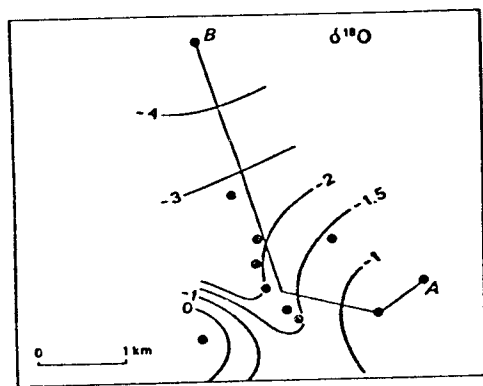


Figure 4. Spatial distribution of the $\delta^{18}\text{O}$ content in the steam in the marginal zone of the area.

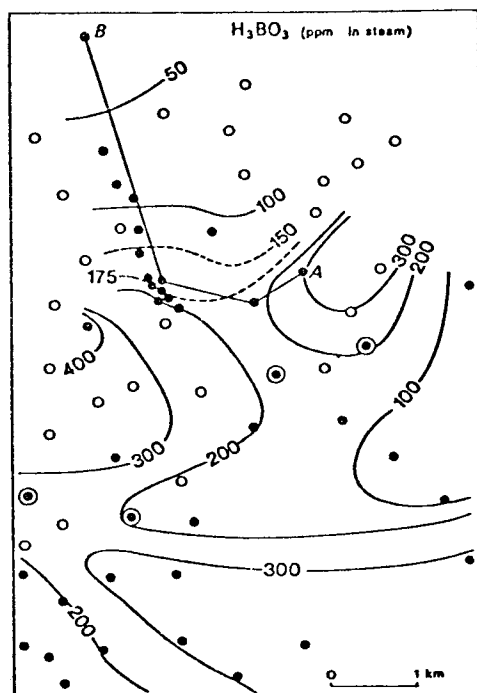


Figure 2. Spatial distribution of the H_3BO_3 concentration in the steam (ppm)

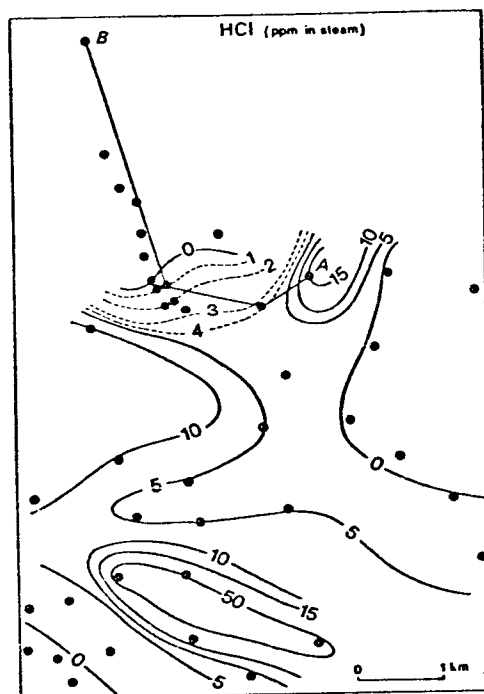


Figure 3. Spatial distribution of the HCl content in the steam (ppm)

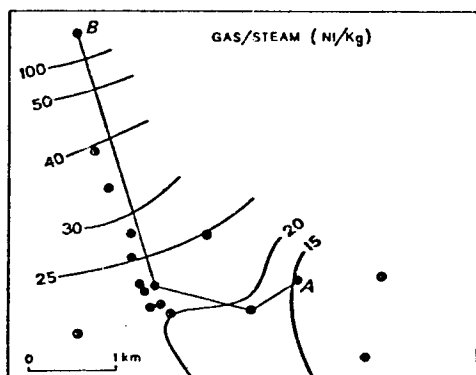


Figure 5. Spatial distribution of the gas/steam ratio expressed as liters of gas in normal conditions (STP) per kg of steam, in the marginal zone of the area.

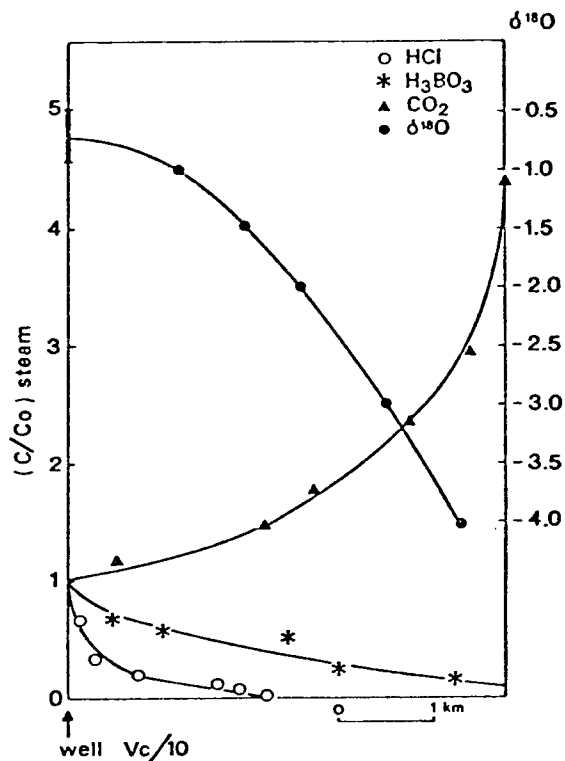


Figure 6. Trends of the gas/steam ratio of H_2BO_3 , HCl and ^{18}O along the profile A-B (from the spatial distributions of Figures 2, 3, 4, and 5).

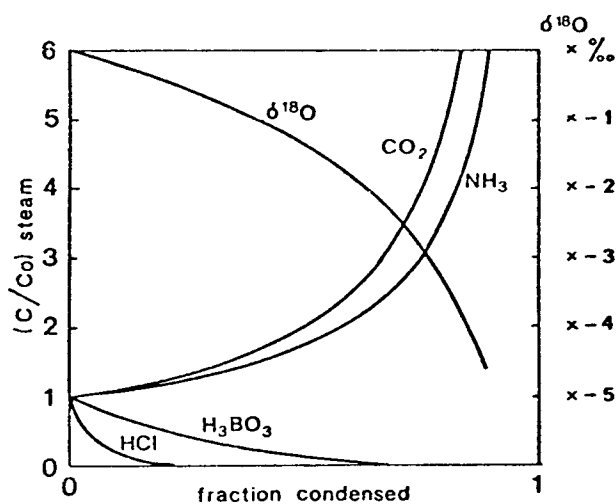


Figure 7. Solution to Raleigh condensation (1) at $230^{\circ}C$ for ^{18}O , CO_2 , NH_3 , H_3BO_3 , and HCl (from D'Amore and Truesdell, 1979).

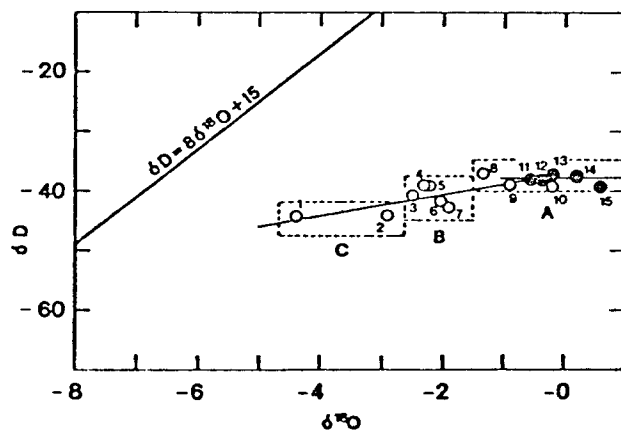


Figure 8. Trend of ^{18}O versus D in the steam from some wells in the study area. The black dots are well VC/10 and some others south of Serrazzano marginal zone, with temperatures of the order of 250° - $260^{\circ}C$.

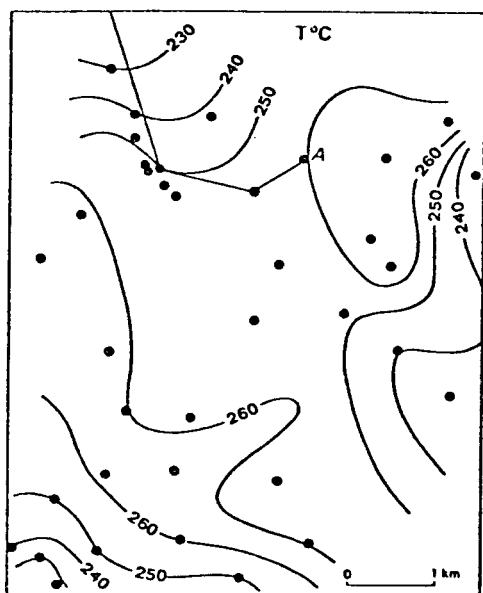


Figure 9. Spatial distribution of the reservoir temperatures, calculated by the equation described in the text, using the ratios H_2/CO_2 , H_2S/CO_2 and CO_2/H_2O .

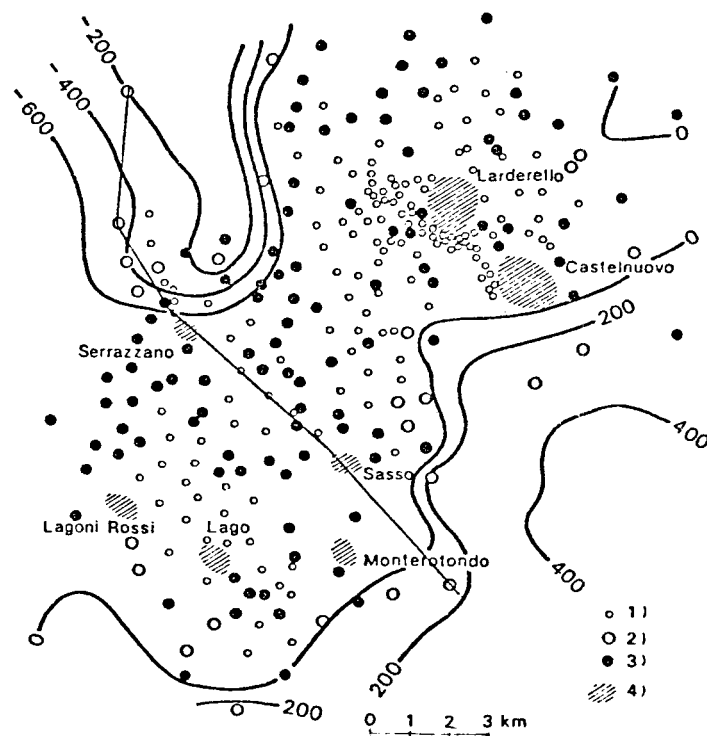
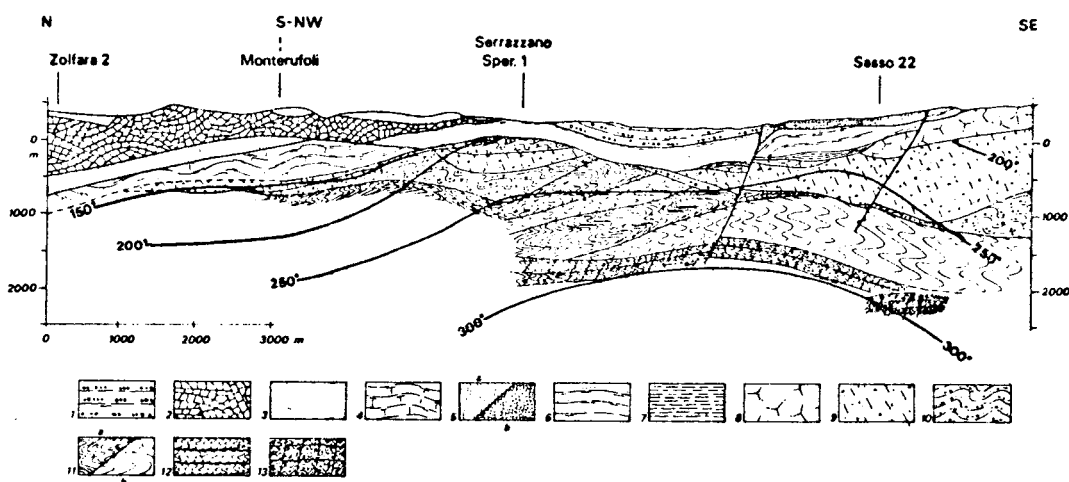


Figure 10. Piezometric surface in the boundary areas of the Larderello field. Elevation in m above sea level.

- (1) productive wells
- (2) wells where water levels have been measured
- (3) dry or low productivity wells
- (4) densely drilled areas



ON THE EXISTENCE OF TWO-PHASE FLUID IN GOOD COMMUNICATION WITH LIQUID WATER

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ABSTRACT

It has been argued that wells of high discharge enthalpy (two-phase wells) at Baca must be isolated from communication with an extensive liquid reservoir. It is shown that such communication has existed, and been maintained, during the history of Wairakei and Broadlands fields.

Interpretation of downhole measurements in two-phase fields, and the nature of the two-phase reservoir fluid, is also treated.

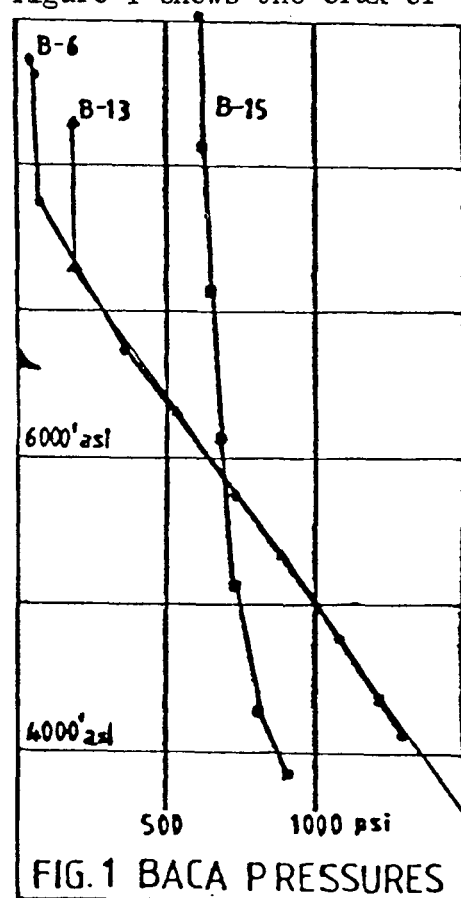
INTRODUCTION

This paper stems from conflicting interpretations of down-hole data from Baca field, New Mexico. Figure 1 shows the crux of the most important conflict (4,5).

Shown are the stable pressure profiles in three wells (1-3). Wells B-6 & B-13 show very similar profiles, each well containing a column of water with a water level within the casing, and the pressures in the two wells are very similar. B-15 shows a markedly different profile. The pressure gradient is intermediate between steam static and hydrostatic. Beneath 5850' (above sea level) B-15 has a lower measured pressure, and from 5850' to 6610' (casing shoe in B-15 (2,3)) the pressure in B-15 exceeds that in the other two wells. The profile in B-15 was interpreted by Union Oil (1,4,6) as reflecting a zone of different reservoir pressure, and because of this pressure difference, a zone not in communication with the rest of the reservoir - an "underpressured steam zone" (1).

The author has presented a different interpretation (5,7), which interpretation is the same as has been presented in other published and unpublished discussions of similar wells: that a strong upflow of steam and water is present in the wellbore, disguising the reservoir profile.

The pressure profile in B-15 immediately leads to the question - what fluid is in the wellbore? The profile is that of a flowing well, discharging not to surface pipework but to a shallow feed zone of the well. Steam and water enter B-15 near bottomhole, flow up and are injected between 5850' and 6610'. This was termed an "internal discharge" (5,7). The pressure profile does not reflect static reservoir pressures, no more than in any flowing well, and



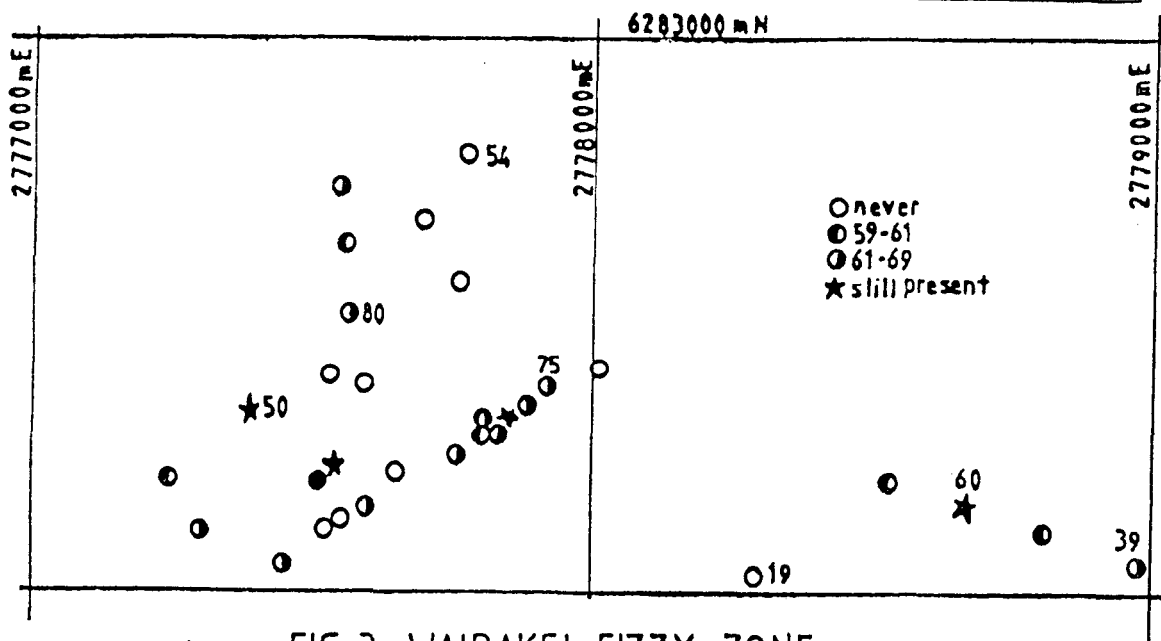
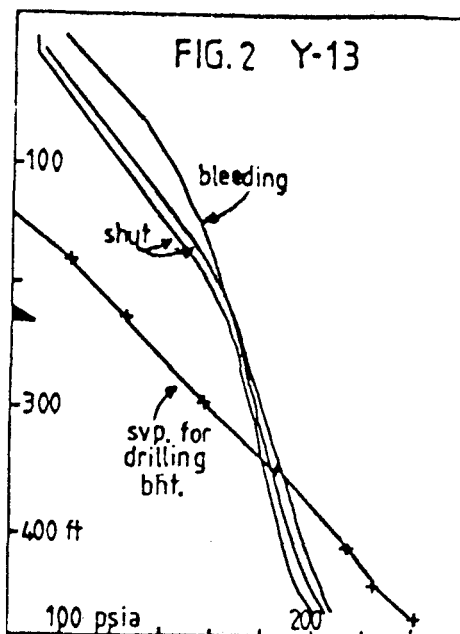
so there is no inference that B-15 differs in pressure from the other Baca wells, which have pressures similar to B-6 and B-13.

The two interpretations can be tested against field and well data in other places where the same phenomenon has occurred.

OTHER FIELDS

Yellowstone

Internal discharges were found in wells drilled at Yellowstone National Park (8). Figure 2 shows measurements in Y-13. Bottomhole temperatures were measured during drilling, and these show that the stable pressure profile in the well does not correspond to the pressures present in the reservoir before drilling. It was concluded "Boiling water and steam from a zone near the bottom of the hole apparently flow up and out...near..227 ft". To infer, on the basis of the stable downhole pressures, that Y-13 was isolated from other wells (eg the adjacent Y-4) would be quite incorrect.



★28 FIG. 3 WAIRAKEI FIZZY ZONE

Wairakei

Before large-scale discharge began at Wairakei, the stable profile in a shut well was a column of water, with pressure on the wellhead. Now it is a column of water in the lower part of the well, above which is a column of steam ("steam cap" profile, reflecting the artificially-created vapor zone in the reservoir). Between these two states, some wells showed internal discharges for a period of time, most commonly during 1959-64. This was referred to as the "fizzy zone". Figure 3 shows the borefield.

Only wells open below 2000', and drilled before 1962 are shown. A few are numbered for orientation. The map indicates the period of time when the wells exhibited the internal discharge profile: divided into those that never did, those that did within 1959-61, those that did within 1961-69 (usually within 61-64), and the five that still do. No systematic pattern is apparent. Wairakei is so well known for its high horizontal uniformity and rapid pressure transmission that all modelling attempts concentrate on a single field pressure. The disparate nature of the well behaviour indicates that the variations in pressure profile from well to well reflect only peculiarities of each well, and that the pressure profile in each well cannot be interpreted as reflecting reservoir profiles.

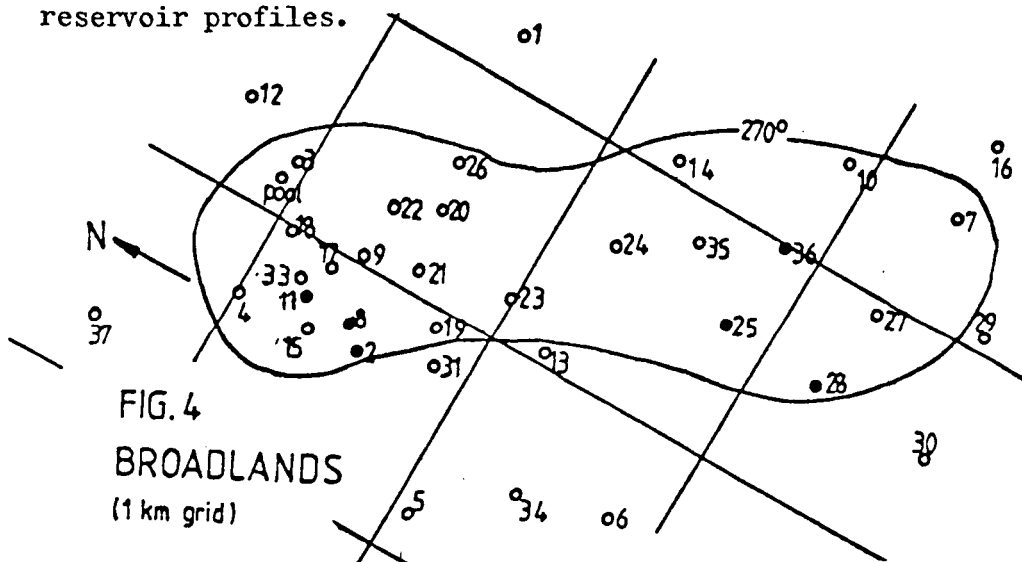


FIG. 4
BROADLANDS
(1 km grid)

Broadlands

Internal discharges have been a feature of wells at Broadlands since the drilling of BR2: "Many of the wells after their initial discharge are found to contain a column of low-density water-steam-gas mixture existing over a considerable depth and in an apparently stable condition. Pressures in such a column are unlikely to represent the pressures in the surrounding aquifers.." (9). Persistent and severe internal discharges appeared in BR2 (8/66-5/70), BR8 (12/67-2/70), BR11 (7/68-8/73), BR25 (1/71 on), BR28 (12/74 on) and BR36 (3/79 on). Figure 4 above shows well locations. In each case the internal discharge began soon after completion of the well, after a heating period during which the well contained a water column.

BR2, 8 & 11 are closely spaced, interfere with each other and with the shallow BR33. There is also a questionable observation of interference with Ohaki Pool, which responds well to BR3. All these wells and the Pool lie near the Ohaki Fault. Interference between BR2 & 8 gives $kh = 15$ darcy-m (9), using fracture relative permeabilities (15). BR2 & 11 show a poorly-observed response of similar magnitude. At their feed depth (500m) BR2, 8 & 11 are so strongly coupled that the author has tended to regard them as one well. From 5/70 to 8/73 there is a marked contrast between the pressure profiles in BR11 on the one hand and BR2&8 on the other. From this disparity it would be incorrect to conclude that there is no communication.

Changes in the vertical pressure and fluid distribution at Broadlands have been estimated and reported elsewhere (11).

RESPONSE TO COMMENTS

Atkinson (4) has made specific criticisms of the author's interpretation of Baca data. Most of these are answered by the preceding discussion. However it should be noted that "large lateral pressure gradients" are Union's interpretation, and no such gradients in reservoir pressure exist in the author's interpretation. Carbon dioxide partial pressures needed to contain a given amount of gas in solution are readily calculated. If downhole data is interpreted to deny the presence of such partial pressures, this contradicts either the discharge sampling or the assertion that the reservoir fluid is wholly liquid. Partial pressures in flowing wells are irrelevant - whatever the steam fraction of the reservoir fluid, additional steam flashes with falling pressure as fluid flows to the well, reducing partial pressure far below the undisturbed reservoir value.

NATURE OF TWO-PHASE FLUID

Behind the disagreement about the interpretation of the B-15 measurements are apparently different concepts of the nature of two-phase fluid in the reservoir. The interpretation of B-15 as a "two-phase gradient" apparently corresponds to the concept of two-phase fluid as a low-density steam-water mixture - a froth - with static pressure gradient corresponding to low mixture density. This concept has been used by others.

The author's concept is different, and is now outlined. A reservoir containing two-phase fluid has in its permeable passages - pores or fractures - a steam-water mixture. Thus the average density of the fluid in place lies between that of water and that of steam. This density appears frequently in computer codes for two-phase flow. But the vertical pressure gradient does not correspond to a static column of this density; nor indeed is the reservoir fluid ever static.

Darcy's Law for the volume flux density of each phase is:

$$V_i = - \frac{k}{\mu_i} k_{ri}(S_i) \left(\frac{dP}{dz} - \rho_i g \right) \quad i = s, w$$

The net pressure gradient driving each phase upward is the vertical pressure gradient, less the weight of a static column of that phase alone. This contrasts with the flow up a well, where water flows upwards despite a subhydrostatic pressure gradient. A static froth is not permitted. There are only two possible static two-phase reservoir states: a reservoir containing immobile water, mobile steam and with a steam-static gradient (ie a vapor reservoir); and a reservoir containing immobile steam, mobile water and a hydrostatic gradient (apparently never realised).

The observation of discharge enthalpies well above liquid, but not dry steam, in reservoirs such as Baca or Broadlands, reflects the presence in the reservoir of both steam and water, both mobile. Such a reservoir fluid cannot be static. The presence of two-phase fluid requires a vertical flux of fluid, and so two-phase fluid in an undisturbed reservoir depends upon the natural upflow.

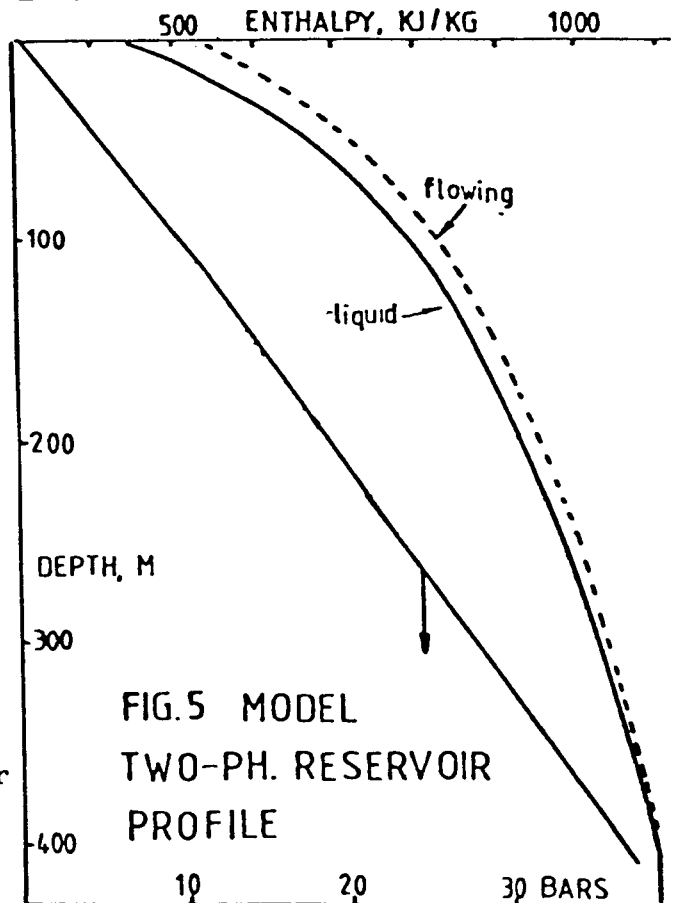
In a liquid-dominated reservoir, the upflow is primarily liquid. Water, or a mixture of steam and water, flow upward. To do this, the pressure gradient must exceed static for both phases, and in particular exceed hydrostatic. If the steam flux is smaller (as is often the case) the steam saturation must be near residual. It can be calculated from the enthalpy of the upflow and the pressure gradient (12,13). The profiles so calculated show a pressure gradient somewhat above hydrostatic, and a steam saturation somewhat above residual. Figure 5 shows a calculated profile for a simple upflow model of Wairakei, assuming a base temperature of 250°C and no gas. Rather than the unobservable saturation, the (horizontally) flowing enthalpy is shown, along with the enthalpy of liquid at local temperature. The reservoir fluid profile is very similar to a column of liquid water, which coincidentally happens to be at boiling point. The pressure gradient is no different in character from a reservoir containing only liquid. The two-

phase column could well be adjacent to a column of liquid (such a column could be found toward the field margin) and there is little in the pressure distribution to cause an lateral flow of fluid. The two-phase liquid-dominated reservoir contains in its natural state fluid with a pressure profile similar or identical to that of liquid water, but distinguished by the presence of some free (mobile) steam.

This steam is recognised by the presence of saturation pressure/temperatures (for the actual reservoir fluid) and by discharge enthalpies above liquid (at temperature of the well feed or entry).

Figure 5 shows that this discharge enthalpy can be little above liquid, so despite the importance of identifying two-phase conditions in a new reservoir (4,14), this may be difficult. A well penetrating a column of fluid such as that in Figure 5 will look little different from a well penetrating liquid. Only the temperature profile is definitive - and that is easily disguised by convective effects in the well.

The model of Figure 5 applies to situations of uniform upflow. If there is also lateral flow in the natural state, considerably higher steam fractions will occur towards the top of the upflow zone, as the local upflow enthalpy is increased by the loss of water to lateral outflow. Hence the higher steam fraction in wells such as B-15.



ACKNOWLEDGEMENT

I thank R.N. Horne and M.L. Sorey for stimulating discussion.

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AN OVERVIEW OF GEOTHERMAL DEVELOPMENT
IN TIWI AND MAK-BAN, PHILIPPINES

G. D. Raasch, Philippine Geothermal, Inc., Philippines

INTRODUCTION

Commercial-scale geothermal development in the Philippines began in 1972 with the completion of the discovery well in the southeastern portion of Luzon Island. A second geothermal anomaly was discovered in 1975 on the southern flank of Mt. Makiling, forty miles south of Manila. Both fields are being developed and operated by Philippine Geothermal, Inc. (PGI), a wholly-owned subsidiary of Union Oil Company of California. Currently the Philippines ranks second worldwide in installed geothermal-powered electrical generation capacity with 443 MW and PGI has developed 440 MW of the 443 MW country total. Additional generation capacity is planned or under construction in both fields. Over 1.9 billion kilowatt-hours of electrical power have been produced to date. This represents a savings of approximately three million barrels of imported fuel oil for power generation.

TIWI FIELD OVERVIEW

The Tiwi geothermal field, located 220 miles southeast of Manila was discovered in 1972 with the completion and testing of well Naglagbong No. 1. Development and exploratory well drilling has confirmed that at least 3225 acres are commercially productive. Figure 1 is a well location map showing the current scale of development. The eastern portion of the field has been well-defined by a series of dry and sub-commercial wells, but the limits of the resource on the western side of the field have not yet been determined. As of December 1, 1980, sixty-seven wells have been drilled and three are currently being drilled. Forty-three wells are commercially productive. The twenty-four remaining wells are non-commercial for different reasons: 1) nine wells have excessively high wellbore scaling rates, 2) six wells are too corrosive for the carbon steel production system, 3) five wells are dry holes and define the eastern limits of the field, 4) two wells were P and A due to mechanical problems during completion, and 5) two wells were drilled to monitor possible seawater encroachment from the Lagonoy Gulf. The average well depth for all wells drilled to date is 5040 feet. The shallowest commercial well is 1574 feet and the deepest is 9000 feet.

PRODUCTION SYSTEM

The Tiwi production system differs from most hot water geothermal production systems in its use of satellite stations, regional community separators that collect the production from three to six wells and separate the steam from the brine at 140 psia. This type of a production system eliminates the need for long distance two-phase pipelines. High pressure steam and high pressure brine flow from several satellite stations to the plant station located adjacent to each power plant. At the plant station the high pressure steam passes through a scrubber and then to the power plant. The high pressure water flows to a low pressure separator operating at 40 psia. The low pressure steam flows from the separator through a steam scrubber to the power plant. The brine from the low pressure separator flows to a large concrete diffuser where it is flashed to the atmosphere. The residual brine flows by canal to the sea. A simplified flow diagram is shown in Figure 2.

Electrical power generation is accomplished by two 55 MW dual-pressure, dual-flow Toshiba turbine-generators installed in each of two power plants. The total plant steam requirements are 1,840,000 lbs/hr of 115 psia steam. and 650,000 lbs/hr of 35 psia steam at saturated conditions. An additional power plant containing two 55 MW dual-flow turbines is currently under construction, and should be fully operational by the first quarter of 1982.

More than 134 billion pounds of fluid have been produced from the Tiwi reservoir as a result of reservoir testing and electrical generation. Over 1.1 billion net kilowatt-hours of electrical power have been produced in less than two years of commercial operation.

RESERVOIR DESCRIPTION

The Tiwi geothermal anomaly is primarily a liquid-dominated reservoir. Production is from a highly fractured andesite. The entire region is geologically very active. Numerous seismic events are recorded each month. The dominant feature in the western portion of the field is the Malinao volcano. The extremely rugged topography in this area has been a deterrent to development. Exploratory drilling has begun this year in this area. The eastern portion of the field is very flat and covered by rice fields. It is in this area that most of the development has taken place.

The maximum static wellbore temperature varies from

510°F up to 575°F. The typical produced fluid composition is: 4500 ppm Cl⁻, 2450 ppm Na⁺, 471 ppm K⁺, 440 ppm SiO₂⁺, 58 ppm Ca⁺⁺, with an average pH of 6.0. All other chemical species are less than 50 ppm each.

Each well is flow tested for 5 to 20 days shortly after completion. Upon shut-in a pressure buildup is taken. Most wells behave as if they are vertically fractured in an infinite system, with wellbore storage. The permeability-thickness product (kh) for Tiwi wells ranges from 1000 md-ft to greater than 150,000 md-ft. The skin values are generally slightly negative but range from +40 to -10. In addition to the individual well tests, two long-term production tests have been conducted. Both tests have confirmed sufficient reserves for at least 330 megawatts for thirty years. In addition to the tests, the reservoir pressure response to production is continuously monitored. Five wells are outfitted with nitrogen-charged Sperry-Sun capillary tubes. Surface pressures are measured daily in these wells. Moreover, downhole pressure are monitored weekly in four wells with Kuster pressure bombs. In this manner, a constant surveillance is kept on the reservoir.

SUMMARY

The Tiwi anomaly is a high temperature low salinity resource. The extensive reservoir pressure response to production and the completion of 67 wells have defined a minimum of 3225 acres of productive reservoir. The installed electrical generating capacity is currently 220 megawatts with an additional 110 megawatts under construction and scheduled for commercial operation in early 1982. More than 1.1 million megawatt-hours of electrical power have been produced in less than two years of operation.

MAK-BAN FIELD OVERVIEW

A detailed review of the Mak-Ban field (at the time it was called Bulalo) was presented at the Fourth Annual Stanford Geothermal Workshop by P. H. Messer and P. F. de las Alas in 1978. This is an update of their presentation. Sixty-four wells have been drilled since the discovery well, Bulalo No. 1, was completed in 1975. Figure 3 is a well location map also showing the power plant sites. Four exploratory wells have been drilled at the Maibarara prospect located approximately three miles northwest of the Mak-Ban field. Additional drilling is currently in progress to evaluate the extent of the Maibarara prospect.

Of the sixty-four wells drilled at Mak-Ban, forty-two are commercially productive. Eight wells are non-commercial for the following reasons: four wells are dry holes, three wells have mechanical restrictions preventing production, one well is too corrosive to produce. An additional fourteen wells have been drilled as injection wells. Eight of these wells have been drilled on the field periphery and six wells are located adjacent to producing wells.

PRODUCTION SYSTEM

The Mak-Ban production system is similar to Tiwi in its use of satellite stations with one significant difference. After separation in Mak-Ban, the high pressure brine is injected back into the reservoir. The high pressure steam flows through steam scrubbers and on to the power plant. Electrical power generation is accomplished by four Mitsubishi 55-megawatt single-pressure, dual-flow turbine-generators. As of December 1, 1980, 77 billion pounds of geothermal fluid have been produced in Mak-Ban. Over 34 billion pounds of brine have been injected back into the reservoir with no observed negative effects. This leaves a net withdrawal from the Mak-Ban reservoir of 43 billion pounds. This net withdrawal includes not only the steam required for electrical power generation but also the extensive well testing that was performed in the years prior to commercial startup. A total of 800 thousand megawatt-hours have been produced in Mak-Ban.

MAK-BAN SUMMARY

Exploratory and development drilling in Mak-Ban have defined the limits of this anomaly. It covers 2200 acres and contains sufficient reserves for at least 220 megawatts of electrical generation for thirty years. Additional drilling in the Maibrara area may confirm a resource sufficient for commercial power generation.

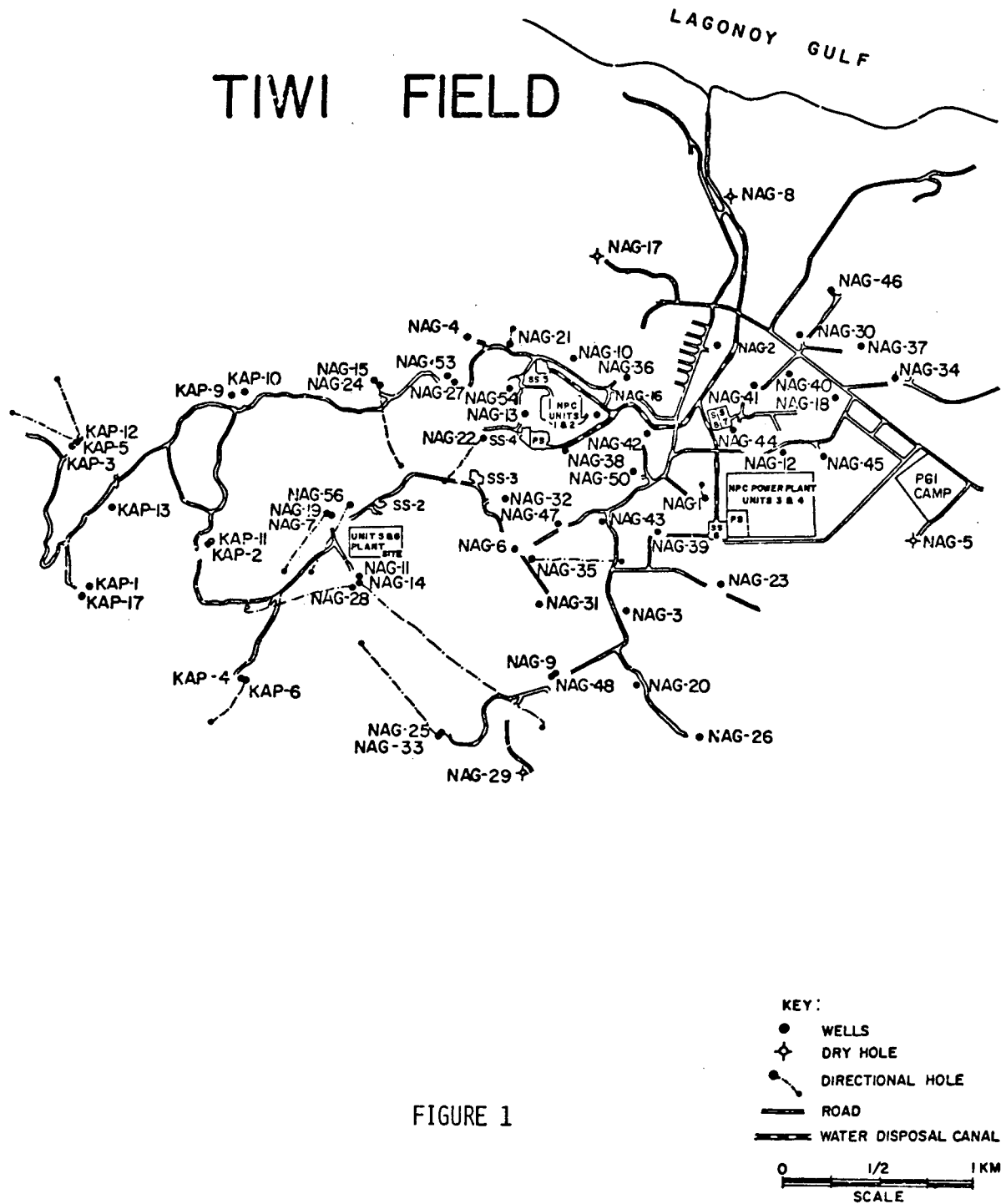
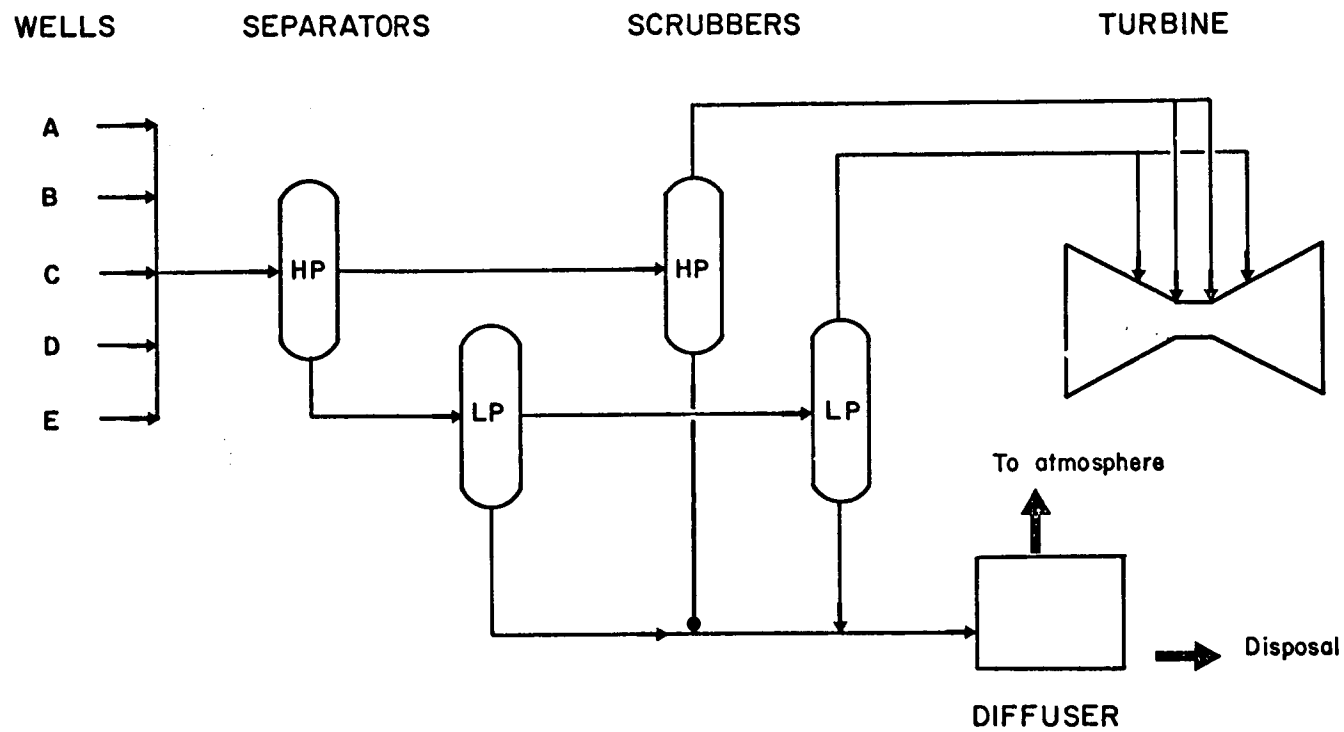


FIGURE 2



TIWI PRODUCTION FLOW DIAGRAM

MAK-BAN FIELD

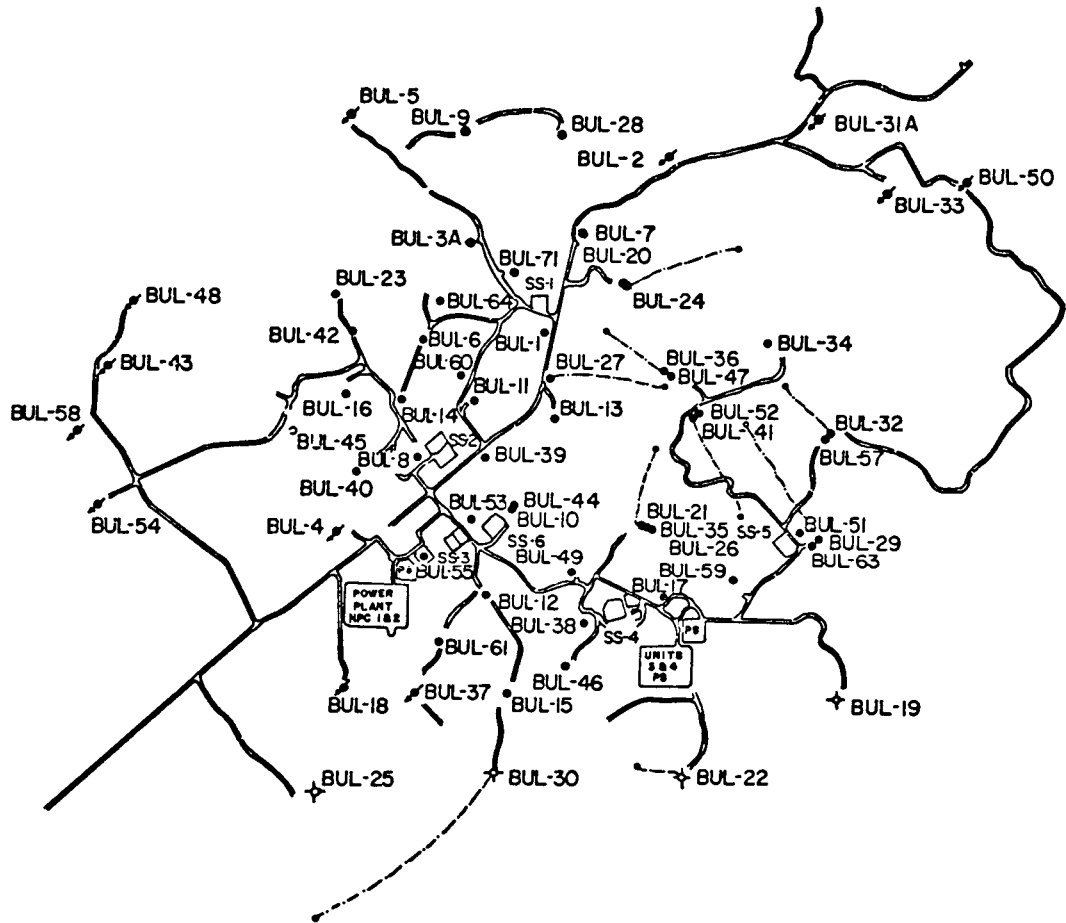


FIGURE 3

KEY :

- WELLS
 - ✦ DRY HOLE
 - DIRECTIONAL HOLE
 - ✦ INJECTION WELLS
 - ROAD
- 0 1/2 1 KM.
SCALE

GEOHERMAL ENERGY RESOURCES CAN ALSO BE TOURIST RESOURCES:
LESSONS FROM WAIRAKEI AND ROTORUA-WHAKAREWAREWA, NEW ZEALAND

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INTRODUCTION

To date we have tended to dedicate our geothermal systems to a single use; i.e. either as an energy source, as is the case with The Geysers field in California, or as a tourist reserve, as with Yellowstone National Park. With increased energy demand on a local scale we may wish to extract some energy in some areas but at the same time retain the tourist attractions that these areas have. This is already the case in the Whakarewarewa-Rotorua area in New Zealand. The questions currently being asked of us with regard to that area are:

"Is such combined use possible?"

"How much energy will be available (or what are the energy costs of the retention of the tourist features)?" and

"What are the costs in terms of the tourist features of various levels of energy extraction?"

As these questions are almost certain to be asked elsewhere in the future it is relevant to introduce and discuss them here. In this attempt at some answers, I will look first at our experience in the Wairakei, New Zealand, area and then discuss the Whakarewarewa-Rotorua case.

WAIRAKEI, NEW ZEALAND

A general map of Wairakei, showing locations of early drillholes and the hydrothermal areas as they were prior to exploitation, is shown in Fig. 1. This drilling commenced in 1950 and the wells illustrated are those that were drilled by the end of 1956. 18 of these wells were discharged before the end of 1954, the total discharge by that time being 12.5×10^9 kg of fluid (a mean discharge of about 200 kg s^{-1} over a two-year period). By 1968 there were 125 wells drilled into the Wairakei reservoir. The discharge peaked at about 2500 kg s^{-1} at the end of 1964.

Before production commenced there were several areas of natural activity in and around Wairakei. The most prominent of these were the water-based features of Geyser Valley (to the north) and the steam-based features of Waiora Valley (to the west) and Karapiti (to the south). There was also activity in and around Taupo, but this, being some distance from Wairakei, was not thought to be connected with the borefield at that time.

*Manager, Stanford Geothermal Program, 1980/81.

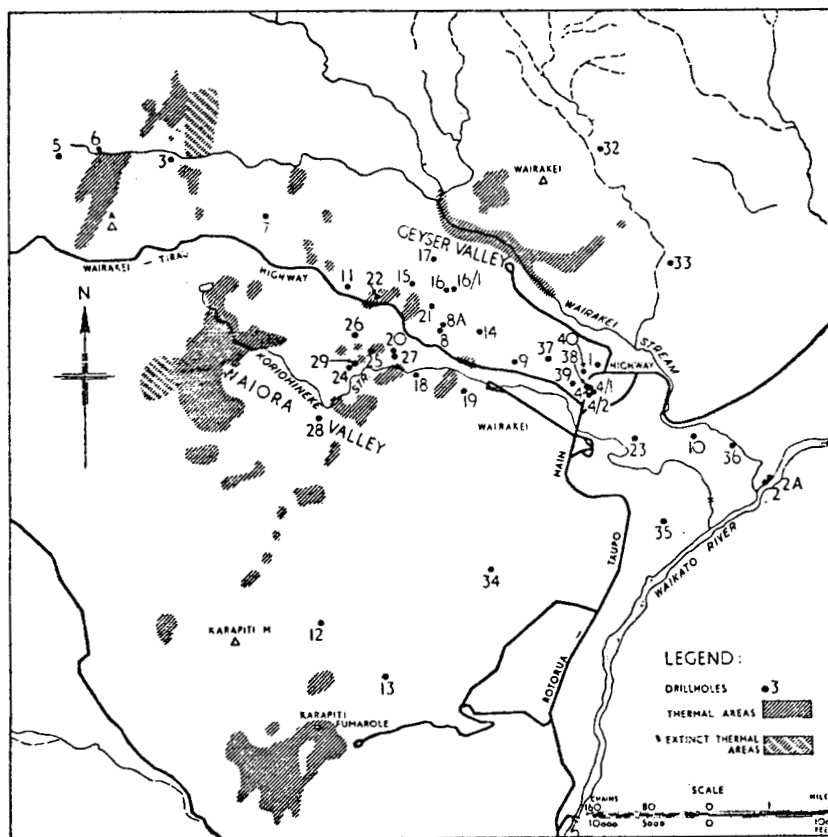


FIG. 1: GENERAL MAP OF WAIRAKEI, SHOWING LOCATIONS OF DRILLHOLES AND HYDROTHERMAL AREAS (Studdt, 1957)

Effects of Exploitation

As early as 1954 the activity in Geyser Valley was showing signs of deterioration due to the withdrawals from the Wairakei reservoir, even though these withdrawals were only on the order of half the natural discharge (c. 400 kg s^{-1}). The overall deterioration of the features in this area was quite fast, although the tourist reserve was not finally closed until 1972.

In contrast, the steam-based sections showed no such early decay. Grindley (1974) suggested, in fact, that the total natural heat flow had increased from about 450 to about 750 megawatts over the first 20 or so years of lifetime of the exploited field. With the decay of the water-based features, this would require an increase in the steam heating. Since Grindley's report there has been a marked dying off of these features and zones of activity.

Although the activity within and around Taupo showed a slower response, that response has been similar to that for similar features known to be directly linked with the Wairakei reservoir. Steam-heated features in Taupo, for example, appeared to increase in both size and intensity in the early- to mid-1970's.

Lessons from the Wairakei Experience

This Wairakei discussion unfortunately leaves a lot of questions unanswered. Wairakei is, for example, still exploited heavily, at about 3-4 times the natural discharge rate, and hence we have no direct measure of the likely effects of lower rates of exploitation. Nonetheless, the early effect on Geyser Valley does suggest that we must take care.

Wairakei is also exploited much more deeply than we may need to exploit for local use. This could be either a gain or a loss as far as the tourist features are concerned. We are also continually removing mass from the reservoir, so that we are restricting the availability of liquid water and making no effort to maintain pressure.

Finally, in spite of our observations of the features in Geyser Valley, we still have little knowledge of their sensitivity to drawdown and water supply.

Nonetheless, the effects are much as we might expect from an analysis of fluid removal from a liquid-dominated geothermal reservoir. Removal of mass (fluid) from the reservoir results in a local drop in pressure. This may act to reduce the flow to the surface. This pressure drop will, however, also induce additional boiling and this, in turn, can modify relative permeability factors and hence affect the flow still further. For the water phase it is the change in vertical pressure gradient that is critical. This vertical pressure gradient is usually only slightly above hydrostatic for the fluid temperatures involved. A small change may thus have a significant effect. The pressure change and the decrease in relative permeability will thus act conjunctively to markedly decrease the water discharge.

For steam the pressure effect is relatively insignificant and the greater relative permeability may well act to increase the flow. Ultimately, with significant drawdown and little additional boiling, this balance may no longer be maintained. The discharge will then go down.

It is interesting to note that in spite of the demise of the natural tourist features in the area, Wairakei has maintained its tourist image. The development itself is still sufficiently unique to attract the interest. It is, however, most unlikely that this state of affairs would apply in any future New Zealand situation.

WHAKAREWAREWA-ROTORUA, NEW ZEALAND

The Whakarewarewa thermal area is New Zealand's primary geothermal tourist reserve and obviously there is a lot of pressure to maintain this status. The immediately adjacent city, Rotorua, however, extracts heat from a shallow hot water aquifer that is now known to be connected to the Whakarewarewa system and some energy is also extracted from the system itself, just outside the reserve boundaries. As, with time, the evidence of interaction between the withdrawals and the tourist features is increasing, there is an associated increase in demand for control of the exploitation and the protection of the Whakarewarewa field.

Description of the System

Although the data are limited, the analyses and tests that have been carried out have led to a model of the combined system that appears both consistent and meaningful (Donaldson, 1980; Grant & Donaldson, 1980). This model of the system is illustrated in Fig. 2. In this model the Whakarewarewa features are the main water-based discharge features for the reservoir. Just to the north of these we have some steam-heated features, while further to the north we have a mixed geothermal fluid/groundwater flow out through a horizontal aquifer, or series of flow channels. This is the hot water flow that is tapped by most of the Rotorua wells. To the northeast, and not illustrated in this N-S section, we appear to have other fracture zones or flow paths running out from the main geothermal reservoir. When tapped, these give hotter, higher pressure fluid than is found in the hot water aquifer. This, coupled with their high discharge characteristics, suggests some direct connection with either the deeper water or the two-phase zone adjacent to Whakarewarewa. In either case these flow channels may be considered simply as an extension of that two-phase reservoir.

Effects Attributed to the Withdrawals to Date

The major effects of the withdrawal of heat and fluid from this system that we need to consider are the changes that have taken place in the Whakarewarewa surface discharge features and the changes that we can identify in the reservoir itself. Although there has been a marked decay in surface activity within the Rotorua City area, at the moment this is being taken as an acceptable cost of exploitation. We thus do not consider this directly here.

Changes within the boundaries of the Whakarewarewa Thermal Reserve have been occurring throughout the lifetime of the system. Hence we must expect some natural modification of some features. Several recent changes have, however, occurred during particularly high rainfall (and high groundwater) periods--the highest this century, and hence it is difficult to associate these with the main natural cause, a slow drop in the overall groundwater level.

The main changes that have occurred, both historically and recently, have been the reduction of outflow from hot springs and the cessation of activity of various geysers. Most of these changes have been discussed in some detail by Lloyd (1975). Of particular interest is the more recent cessation of activity of Papakura Geyser. This geyser has only been recorded at stopping once before, for 3 months in 1924, at the end of the driest period (and lowest groundwater levels) this century. The recent cessation of Papakura Geyser was monitored and studied by Grant & Lloyd (1980) and a brief return to activity after an initial cessation has been attributed by them to a 10 millibar change in atmospheric pressure. This shows the sensitivity of such features near their critical point. The water level in this geyser is now down more than a metre from its pre-dormant level.

The most important change in the reservoir itself is the marked pressure drop, estimated by Donaldson (1980) at about 0.5 bar, over the period 1955-75. This drop appears to be relatively uniform throughout the hot water section of the reservoir. As there are no historic data available for the Whakarewarewa area, we cannot get a direct measure of the drawdown there. It is unlikely that in the section of reservoir underlying the tourist features the drawdown would be less than half the hot water zone figure. The drawdown, which might be translated as 2.5-5 metres of water head, must therefore be considered "significant." For management and protection of the tourist features it would obviously be preferable for it not to be increased. To allow for full maintenance of the present features during future dry periods, it may, in fact, need to be decreased.

Controlling the Pressure Drawdown

If we assume that we must reduce the pressure drawdown, we have three potential management alternatives available:

- (1) we may reduce the rate of withdrawal and restrict any future expansion;
- (2) we may reinject all the extracted fluid or extract heat alone; or
- (3) we may resite the withdrawal and injection wells.

As the first of these is likely to be both socially and politically unacceptable it is currently being considered the approach of last resort. Nonetheless, more care and efficiency in usage of the energy could be a big gain.

In considering reinjection we must treat the two sections of the reservoir independently. Within the water section of the reservoir either withdrawal of heat alone or total reinjection of the extracted water should maintain the aquifer pressures. Currently such reinjection is written into the permits. The general drawdown, which could only be established by some distributed withdrawal of fluid from this section, suggests, however, that this reinjected water is not all getting back to the aquifer from which it was taken. It appears that greater care may be necessary in the future.

When we come to the two-phase section of the reservoir the picture is somewhat different. Here, withdrawal of either fluid or heat will instigate a pressure drop. Reinjection of the cool fluid will, in most cases, increase the pressure drop rather than reduce it (Grant, 1980). The options for this section of the reservoir are thus no withdrawal or some pressure drawdown.

By juggling with the siting of withdrawal and injection wells we both increase our options and complicate the problem. The alternatives will depend primarily on our overall approach. We might for example decide on some controlled drawdown of the system to stimulate more heat and fluid flow into the hot water zone. We would then need to balance our withdrawal and reinjection to achieve the state desired. Alternatively, we may wish to mine some of the stored heat from one area. The siting and operation of the wells in that area would then depend on this new requirement.

Within the hot water zone there is little problem foreseen unless we approach an over-production situation. That is something that we will have to work to prevent. In the two-phase areas we do, however, have problems. Here no well is likely to be "far enough away" to be able to be used without some drawdown propagating through to the feature zone. Thus here we have little option but to accept resiting or some drawdown.

Heat Considerations

Total control of the drawdown, at any specific level, must result in the limitation of the heat withdrawal. If, for example, we permit no drawdown, i.e. insist that the field be returned as closely as possible to its original pressure condition, we can permit no withdrawal at all from the two-phase areas, and only a limited amount from the hot water zone. This latter would be controlled by the amount of heat naturally entering that zone, the recoverability factor of the system (which could depend on the well layout and extraction rates as well as the structural composition of the withdrawal and injection zones), and such management decisions as whether to mine some of the stored heat or not.

If, alternatively, some drawdown were permitted, there may be different but still limited amounts of heat available depending on whether we induce that drawdown by withdrawals from the hot water zone or some section of the two-phase one.

Protecting the Tourist Features

Clearly the greater the drawdown the greater the risk for the tourist features. Thus the drawdown limit in the feature zone is the "critical" parameter of this exercise.

At the two extremes are the argument that the current drawdown is a satisfactory limit and the counter-argument that there should be no drawdown at all. The former of these is presumably based on the assumption that if we don't change anything we won't do any more damage. This, however, does not take natural effects into account, and unfortunately, we have little or no idea of just how much a long dry spell may contribute in the future.

The argument for the return to the pre-exploitation condition is presumably based to some extent on the idea that such a return will result in the re-awakening of features that have become dormant over more recent years. Unfortunately, even the full recovery of pressures may be of little benefit to some such features. Reversed flows, cooling, erosion and deposition of silica, etc. from the cooler water means that some features may never recover and others may need much greater pressures than those that existed 30 years ago to restart. We note, for example, that the water in Papakura Geyser has dropped about 1 metre in level in a year since it became dormant. There has been no similar drop in pressures in the reservoir with which we can relate that decay.

Hopefully, there will be a balance at which we should aim. More and better data will, however, be needed before we can even guess where.

CONCLUSIONS

To the "tourist-environmentalist," New Zealand's excursions into geothermal energy extraction at Wairakei and Rotorua may appear to be disasters. We have, however, learned a lot from our experiences and, while we must now recognise Wairakei as an alternative man-made feature to the natural ones that existed prior to exploitation, we feel that there is still time to protect Whakarewarewa and that it is technically possible to do so. Our current theoretical considerations indicate that, with care and good management, utilisation of geothermal energy from this field should be compatible with the retention of the surface thermal features in the tourist reserve.

Limits of withdrawal will depend on the limits on drawdown that can be tolerated by these features and on the location of the withdrawal and reinjection. For the Rotorua-Whakarewarewa system, under the tightest restraints and the most conservative assumptions, it has been estimated that we could still extract about 13 megawatts of heat energy (above 20°C) on a continuous basis (using a recovery factor of 50%). Hopefully, with the optimal management plan we will be able to extract several times that figure.

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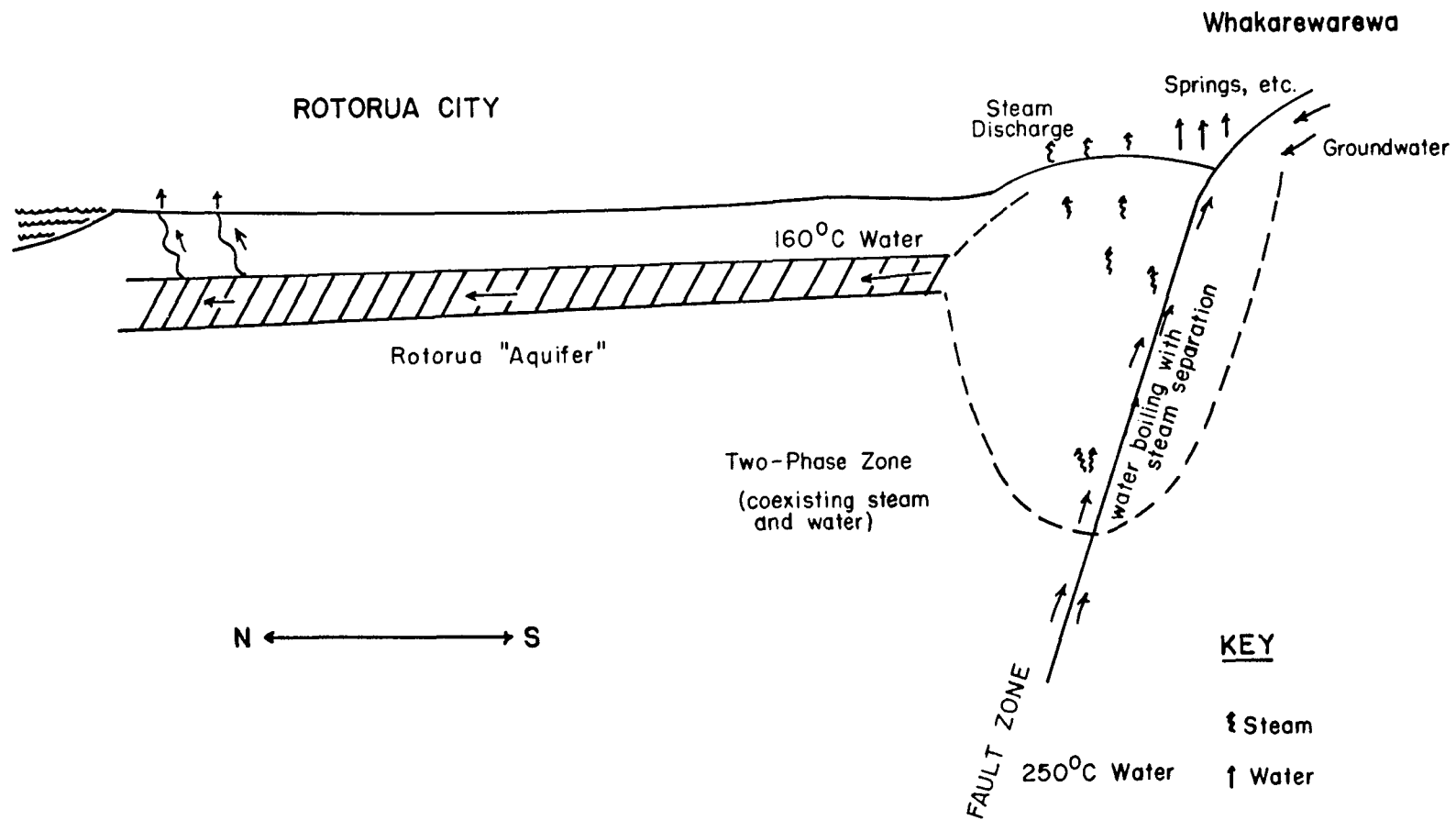


FIG. 2: A NORTH-SOUTH SECTION THROUGH THE UPPER LAYERS OF THE WHAKAREWAREWA-ROTORUA GEOTHERMAL RESERVOIR TO ILLUSTRATE THE LIKELY HYDROLOGICAL CONNECTIONS (Grant and Donaldson, 1980)

PRODUCTION CHARACTERISTICS OF WELLS TAPPING
TWO PHASE RESERVOIRS AT KRAFLA AND NÁMAFJALL

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INTRODUCTION

Geothermal fields have been classified in several different ways, covering geological, chemical and physical aspects. The most common distinction is to refer to the physical state of the fluid in geothermal systems. This is the division into vapor dominated and liquid dominated fields. In recent years, two phase reservoirs have been found in numerous high temperature geothermal fields (Grant 1977, Björnsson 1978, Stefánsson 1980, Whittome and Smith 1979). Some characteristics of two phase geothermal systems are markedly different from those in single phase systems (vapor or liquid) and classification into three groups seems to be justified. Table I shows some of the properties associated with each of the three groups.

TABLE I Classification of geothermal systems

	Liquid Dominated	Boiling (two phase)	Vapor Dominated
Pressure gradient	$\frac{dp}{dz} \approx \rho_1 \cdot g$	$\rho_1 \cdot g > \frac{dp}{dz} \geq \rho_v \cdot g$	$\frac{dp}{dz} \approx \rho_v \cdot g$
Temperature	$T \leq T_s$ $T(z)$ independent of P	$T = T_s$ $T(z)$ depends on P	$T \geq T_s$ $T(z)$ independent of P
State of fluid	Water (gas)	Water, vapor, gas	Vapor, gas

ρ_1 : density of liquid water

T_s : Saturation temperature

ρ_v : " " vapor

g : Constant of gravity

In general, the pressure gradient has been used to distinguish between vapor and liquid dominated systems. Boiling systems may have pressure gradients somewhere between these two extremes. However, boiling systems described so far in the literature seem to have undisturbed pressure gradients close to hydrostatic.

In this work we will describe some typical production characteristics of wells tapping the boiling reservoirs in the Krafla and the Námafjall field in Iceland. The characteristics selected are meant to show some of the differences between boiling reservoirs and single phase systems.

Field characteristics

General description of the Krafla geothermal field has been given by Stefánsson (1980). The geothermal system has been found to be complex, consisting of two zones. A shallow liquid dominated zone with temperature of approximately 210°C whereas the deeper zone is a two phase system with temperatures ranging from 300°C at the top at 1000 m depth to 340°C at about 2000 m depth. The main features of the geothermal system are shown in Fig. 1.

The Námafjall field has until recently been considered as a liquid dominated system (see Arnórsson 1978). Recent drilling some hundreds of meters east of the older drill sites has revealed that at least that part of the field is boiling.

Reevaluation of the Námafjall field is now being carried out, and the present data indicates that the temperatures and the pressures of all aquifers below 1000 m depth lie on the saturation curve. Similar conditions are found in the lower zone of the Krafla system as is shown on Fig. 2.

Properties of wells

- a) The first signs of a boiling reservoir can be found during the warming-up period of the well after drilling. Boiling aquifers recover usually faster than other parts of the well and boiling begins at the aquifers in the well. This boiling will initiate a convection in the well and

heat the column above the boiling aquifer until the temperature aligns to the boiling point curve.

- b) A boiling convection in a well increases the rate at which the water level rises until equilibrium is reached. A record of the depth of the water level will therefore show when boiling starts in the well.
- c) The discharge history of wells in Krafla and Námafjall may be divided into two different stages. In the first stage which covers the first weeks of discharge, the water phase decreases continuously whereas the steam flow is fairly constant. The enthalpy of the discharged fluid will therefore increase during this period. After the first stage, the total discharge of the well will be nearly constant. The further development of the well seems to depend on whether the water flow decreases to zero or not. Fig 3 shows the discharge history of well KG-12 in Krafla. The water flow from this well stopped after one week of discharge, and the enthalpy reached equilibrium few weeks later. Since then the well has been producing superheated steam at a fairly constant rate for almost two years. On the other hand the water flow from well BJ-11 (Fig 4) reached a constant non zero value, but the well has since then increased considerably in steamflow and enthalpy.
- d) The flow rate of wells tapping two phase reservoir varies little with well head pressure as shown in Fig 5. In comparison the production characteristic of the liquid dominated well KW-2 is shown on the same figure. One well (KJ-11) in the Krafla field had two modes of flowing. One was when only the liquid dominated zone contributed to the flow and the other was when both zones were active. These production characteristics are shown in Fig 5.
- e) During discharge, the drawdown in the well is large. This can be monitored by running a temperature log immediately after shutin of a well. The temperatures then found will be considerably lower than immediately before discharge. For wells with a mixed flow (steam and water), temperatures close to the saturation temperature at the well head pressure during discharge have been recorded. This indicates that the pressure gradient in two phase well is close to zero during discharge and that the temperature is fairly constant. The well head pressure controls

the temperature in the well as well as the drawdown during discharge. Fig 6 and 7 show temperature and pressure logs in KG-12 before and during discharge. The large drawdown and pressure gradient in the flowing well is clearly demonstrated. As this is a dry steam well no saturation relation is between the temperature and the pressure during discharge and the temperature changes only slightly when wellhead pressure is changed as Fig 7 shows. Compared to the initial temperature (Fig 6) the temperature during discharge shows that during discharge, a considerable cooling of the wellbore will take place. This cooling is, however, much less than the cooling taking place when the well discharges saturated steam (Fig 7).

Discussion

The above description shows that the characteristics of wells tapping two phase reservoirs give quite a different performance compared to that given by ordinary single phase wells. In order to explain the differences the laws governing boiling and two phase flow have to be considered.

All the wells discussed are high enthalpy wells discharging fluid of high steam content. The density of the discharged fluid is, therefore, close to the density for steam. As a consequence the pressure gradient is small in the wells during discharge and a large drawdown can be achieved by lowering the wellhead pressure. The constant mass flow for different wellhead pressures is a direct consequence of the large drawdown. As can be seen in Fig 7 the pressure against the main inflow at 1500 m depth in well KG-12 is 19-23 bar (1,9-2,3 MPa) during discharge, whereas the undisturbed pressure of this aquifer is 126 bars (12.6 MPa). The discharge causes therefore a drawdown of the order of 100 bar (10 MPa) and changes in the wellhead pressure of the order of 10 bar (1 MPa) will not influence the flowrate significantly. This performance is of great importance in utilization as desired steam pressure can be selected independantly of yield, over a wide range of well head pressures.

The discharge history of two phase wells shows some unexpected characteristics. Large variations in flow rate and enthalpy are observed in the beginning of a discharge period, while the drawdown is being developed, in the vicinity of the well. This process can take weeks. The increase in enthalpy accompanied with a decrease in the water flow rate is a consequence of the

different mobility of the steam - and the water phase in the two phase reservoir together with a non adiabatic flashing in the vicinity of the well. The most unexpected observation in some of these wells is that after some weeks of discharge the mass flow starts to increase, Fig 4.

In addition to wells in Krafla and Námafjall in Iceland, increased mass flow has also been observed in some wells in the Tongonan field in the Philippines (Sarmiento 1980). Increased flow rate in wells in Krafla and Námafjall is in the steam part only, whereas the wells in the Tongonan field increase both in steam and water flow rate. Common feature for the three thermal fields is that they are all boiling, and the wells that increase in flow rate all produce a mixture of steam and water, whereas the dry steam wells at Krafla show a constant flow rate after the first few weeks of discharge.

As flowrate is not observed to increase with time in single phase reservoirs, it seems natural to associate this with some processes common to two phase reservoirs but not to single phase reservoirs. We suggest here that the process responsible for the increase in flow rate is the thermal contraction of the rocks surrounding the well caused by cooling of the wellbore during discharge. When operated at the wellhead pressure of the order of 10 bar, the temperature in the well producing steam and water at Krafla and Námafjall is 100-150°C lower than undisturbed rock temperatures in the production zone. The cooling of the dry steam wells during discharge is on the other hand lower (30-60°C) (Fig 7). The cooling of the wellbore will propagate out in a similar way as the convective downward migration (CDM) described by Böðvarsson and Lowell (1972), Lister (1974, 1980a and b), Böðvarsson (1979), and Björnsson et al. (1980). Böðvarsson (1979) concluded that in the CDM-process only few tens of degrees were needed to form fissures in solid rock. For a discharging well new crack or widening of already existing cracks in the rock matrix will increase the permeability close to the well. Thermal contraction can therefore explain the increased flow rate. Also it indicates a difference between two phase and dry steam wells tapping two phase reservoir, although it does not exclude a less prominent increase in flow rate for the well discharging dry steam. Finally, as seen in figures 3 and 4 the levelling off in flow rate after long term flowing is similar to the discharging history of a three dimensional well tapping single phase reservoir. Two phase systems have 10^2 - 10^4 times higher compressibility than single phase reservoirs (Grant 1978). The radius of influence of a well tapping such a reservoir will therefore be orders of magnitude smaller than in a single phase system. This relatively

short radius of influence in two-phase reservoir makes it reasonable to compare wells tapping two-phase reservoirs with three dimensional wells.

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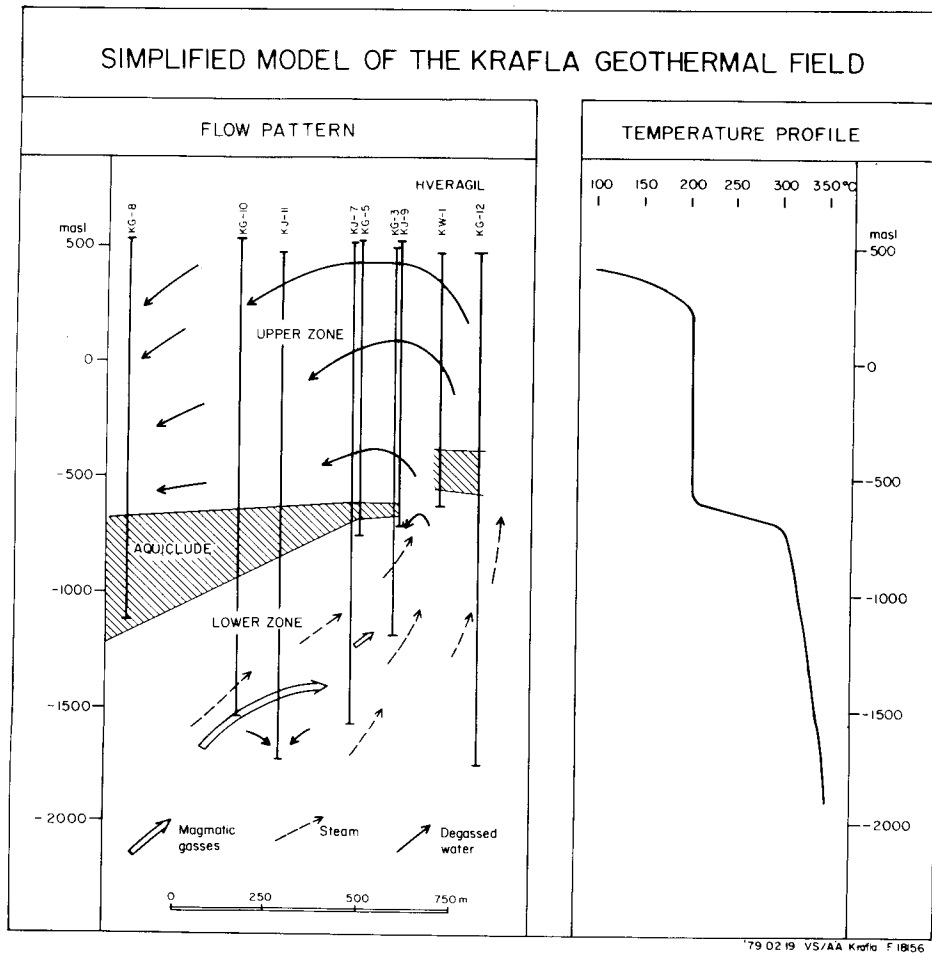


Fig. 1. Simplified model of the Krafla geothermal field.

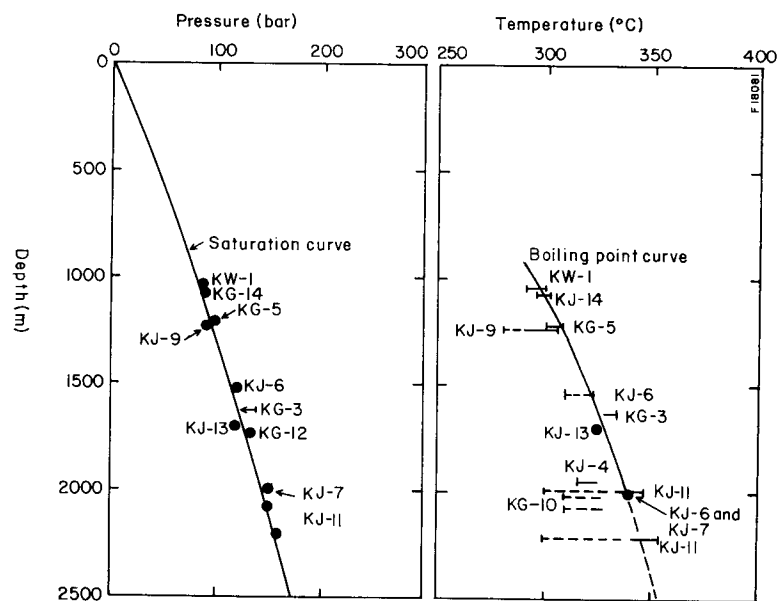


Fig. 2. Temperature and pressure in the Krafla reservoir.

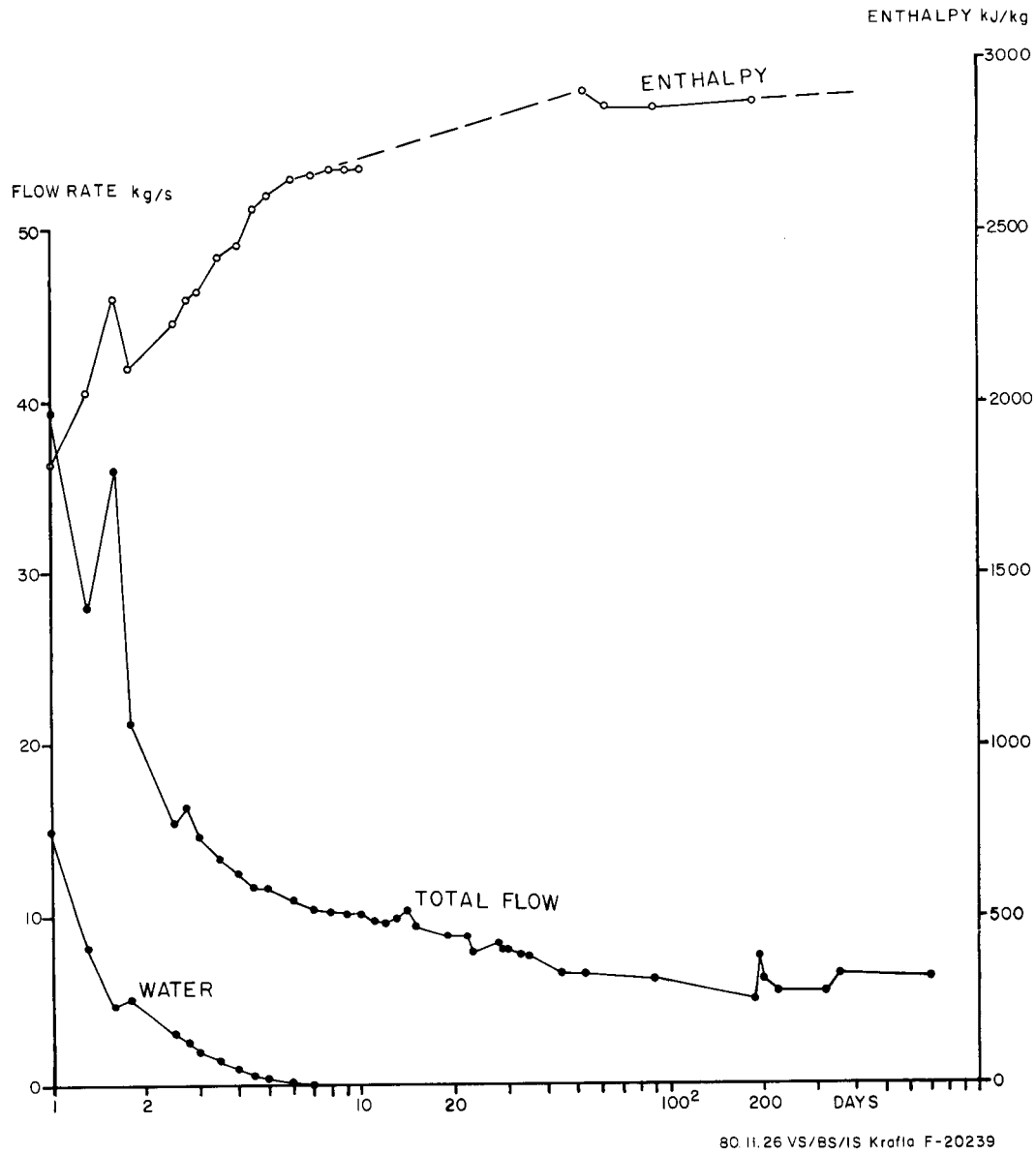
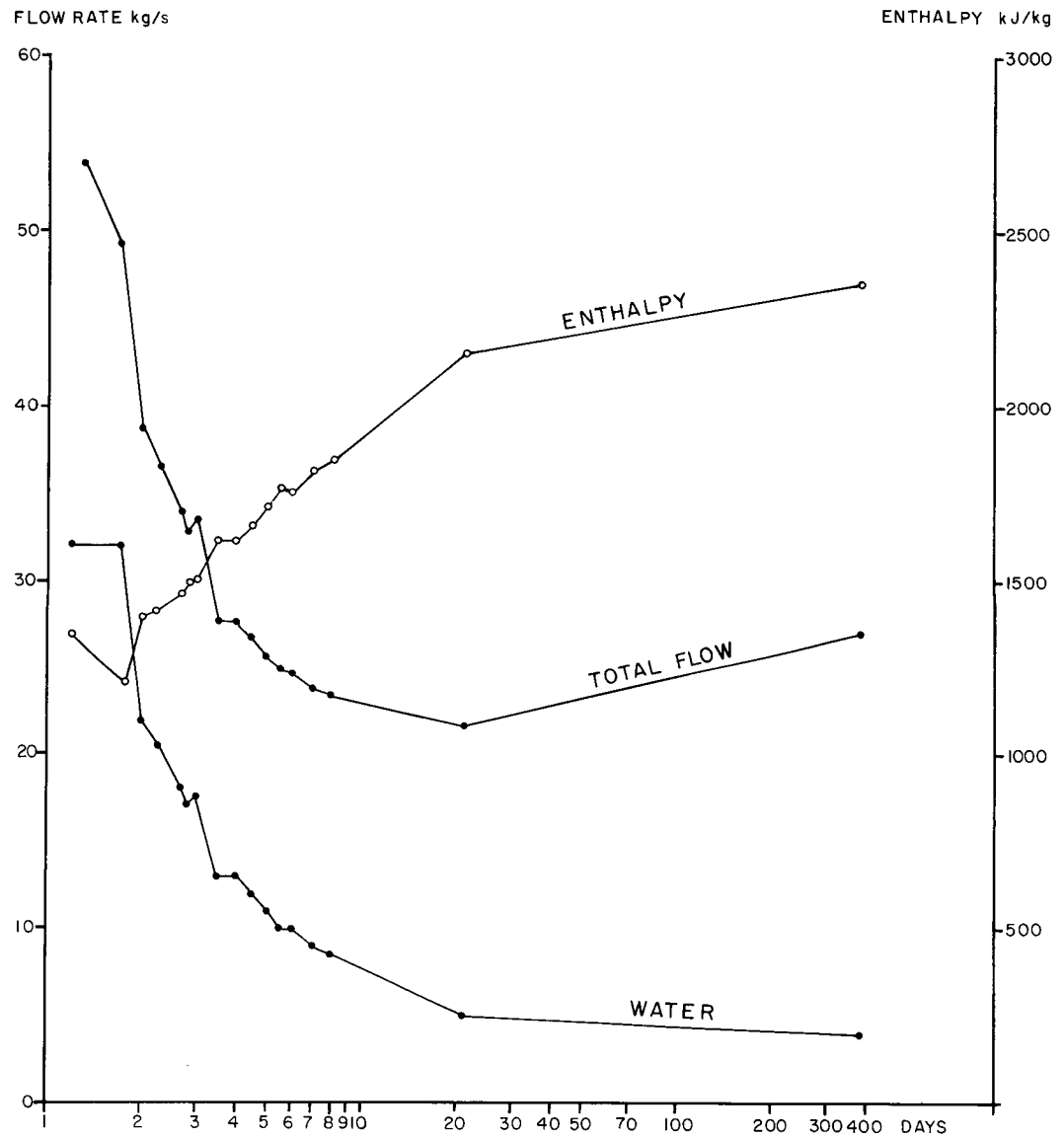


Fig. 3. KRAFLA KG-12
Discharge History



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Fig. 4. NÁMAFJALL BJ-11
Discharge History

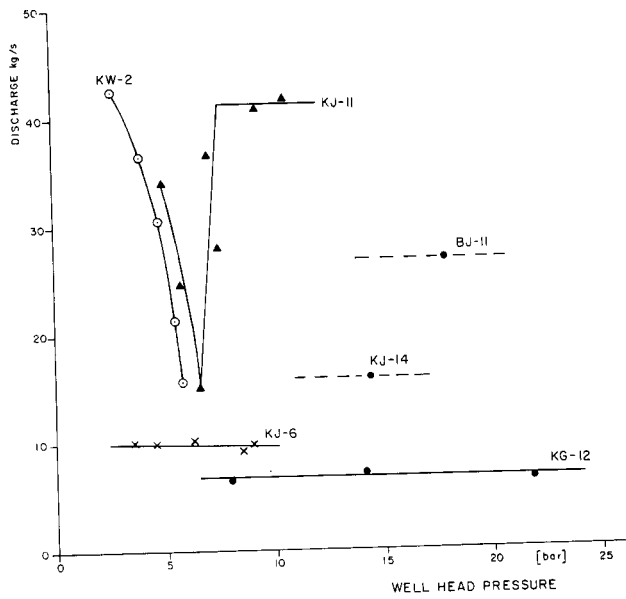


Fig. 5. Productions Characteristics of Wells in Krafla and Námafjall.

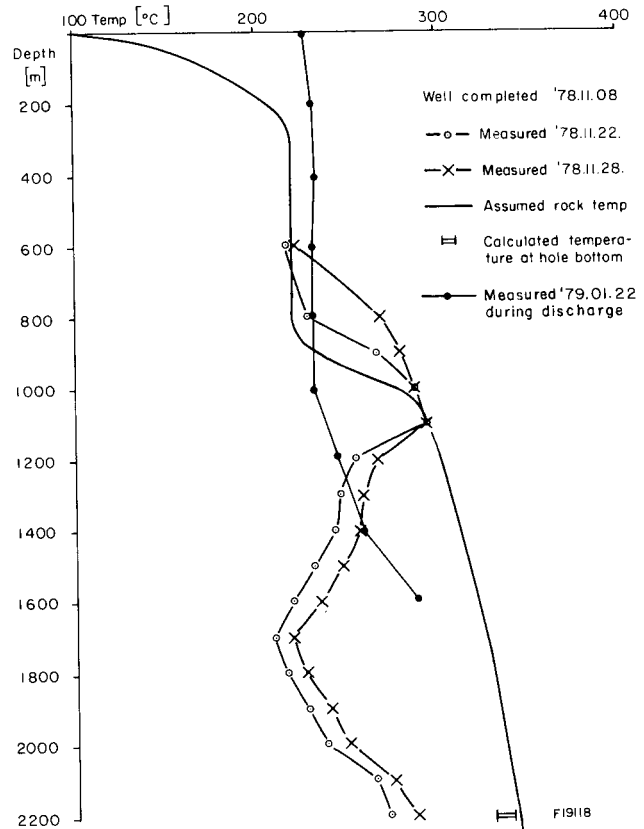


Fig. 6. Krafla Temperature Measurements in KG-12.

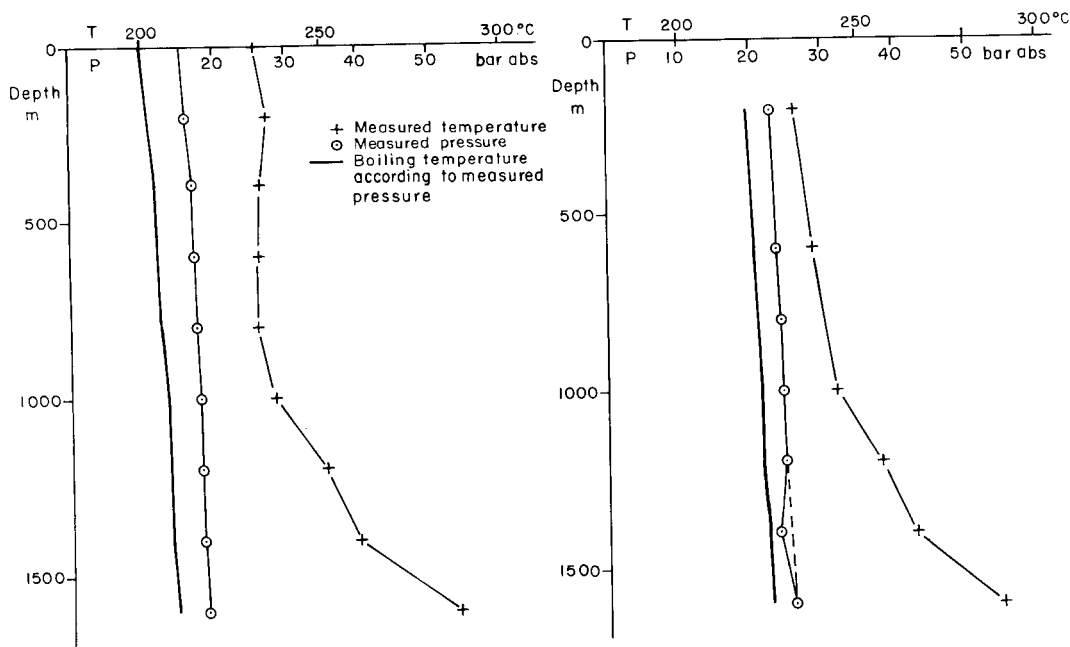


Fig. 7. Krafla KG-12, Temperature and pressure profiles during discharge.

GEOHERMAL FIELDS ON THE VOLCANIC AXIS OF MEXICO

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INTRODUCTION

At present in Mexico, geothermal energy is receiving a great impulse due to the excellent results obtained in the Cerro Prieto geothermal field, in which a geothermoelectric plant is operated. This plant has four units of 37.5 MW each, with a total capacity of 150 MW, and under program 470 MW more by 1984.

The Government Institution, Comisión Federal de Electricidad, is in charge of the exploration and exploitation of geothermal fields as well as construction and operation of power plants in Mexico. By this time CFE has an extensive program of exploration in the central part of Mexico, in the Eje Neovolcánico. In this area, several fields with hydrothermal alteration are under exploration, like the Michoacán geothermal area, where Los Azufres geothermal field is being developed. Seventeen wells have been drilled and twelve of them presented excellent results, including two dry steam wells. In other areas, such as Araró, Cuitzeo, San Agustín del Maiz, Ixtlán de Los Hervores and Los Negritos, geological, geophysical and geochemical explorations have been accomplished, including shallow well drilling with good results.

Another main geothermal area is in the State of Jalisco with an extension of 5,000 m², where La Primavera geothermal field shows a lot of volcanic domes and has an intensive hydrothermal activity. Deep wells have been drilled, one of them with a bottom temperature of 290°C. Other fields in this area, like San Marcos, Hervores de La Vega, La Soledad, Villa Corona, etc., have a good geothermal potential.

A new geothermal area has been explored recently in the eastern part of the country named Los Humeros, Puebla. In this area studies are being made and there are plans for well drilling exploration by the beginning of 1981. Like this one, there are many other areas in the country in which 300 hydrothermal alteration zones are been classified and 100 of them are considered economically exploitable.

EXPLORATION IN LOS AZUFRES, MICH.

This field is located at 200 km West of Mexico City, with an elevation of 2,900 m, 19°47' N Lat. and 100°39'W Long. Studies and drilling in this area started three years ago. The geological and geophysical studies as well as the drilling performed, have proved the existence of a geothermal field of about 25 km². The geological

exploration indicates outcrop of volcanic rocks among which acid rocks, silica rocks, basic intermediate rocks (granitic-rhyolite) diorite, andesite and gabbrobasalts are more prominent.

Geophysical studies performed were mainly geoelectric and magnetometric. The geoelectrical studies consisted of more than 100 Schlumberger vertical soundings, with 4000 m of separation AB permitting the identification of well defined zones of low resistivity, which were useful in locating the first exploratory wells.

The magnetometry study was made using a Sharper Magnetometer MF-1-100 of vertical field. The interpretation presented some difficulties requiring detailed geological support.

Geochemical studies, made by analysis and interpretation, indicated the presence of hot water and dominant steam systems, with temperatures higher than 200°C in several hot springs. Reservoir temperatures of 300°C were calculated with gas thermometry.

The location and drilling of the first well A-1, was performed after these studies. This well has a depth of 2,193 m, with a bottom temperature of 290°C and produces a water-steam mixture of high enthalpy. To date, seventeen wells have been drilled, of which twelve are productive, the most outstanding being well A-2 with a production of 378 ton/hr of water-steam mixture; well A-4 producing 50 ton/hr of steam and 50 ton/hr of water; well A-5 which produces 70 ton/hr of steam and 65 ton/hr of water; well A-6 which produce 50 ton/hr of steam; well A-13 with a production of 65 ton/hr of steam and 15 ton/hr of water; and well A-17 producing 82 ton/hr of dry steam. Some of this wells have 850 psi shut-in pressure at well head. In this field, there are plans for reinjecting the waste brine, having for this purpose, well A-7 with a capacity to receive 100 ton/hr of separated water; well A-10 with 70 ton/hr; well A-15 with 120 ton/hr, etc.

With all these studies several modules have been detected related with the future geothermal exploitation of the area, like Tejamaniles, Agua Fría, El Chino, El Gallo y Laguna Verde. Projects are on line for the installation of five portable units of 5 MW each, with plans for having them into operation by the end of 1981. At the same time, interference well tests have been started in the module of Tejamaniles, to define the reservoir capacity and size of the first installed plant for generation. It is considered feasible that 300 to 600 MW may be installed at the geothermal field of Los Azufres.

CUITZEO, MICHOACAN

This area has several points with hydrothermal manifestations like San Sebastián, Las Arenas, Huandacareo, Nismpo, San Agustín del Maiz, Taratameo, La Mina, Huingo y Araró. The last one being studied in detail, planning to drill two deep wells by next year. The geochemical studies show that reservoir temperatures are higher

than 200°C.

EXPLORATIONS IN LA PRIMAVERA, JALISCO

La Primavera geothermal field is located only 5 km West of the City of Guadalajara, in a mountainous zone with many volcanic domes which are part of a caldera of big dimensions. This area has many hot springs of great volume, as well as large fumaroles and steam vents. The hot springs area is located 20°40'N Lat. and 103°35' W Long., covering an area of 3 km². At the emanation point of these springs, deposits of calcite and silica are found on the rhyolitic rocks. The resulting streams (400 liter/seconds); some of which are Arroyo Nuevo, Arroyo Verde, Agua Brava y Río Caliente, have a characteristic green color in the bottom due to the presence of thermophilic algae, which grow at a temperature of 50°C. In the central highest part of La Caldera, there is the graven named El Colorado, which has a big number of fumaroles and steam emanation which together with the manifestations of La Azufrera and Las Barrancas, indicate the existence of great geothermal potential. Drilling has already been started in this area, as a result, there is well PR-1 with a depth of 1159 m and a bottom temperature of 290°, near its completion and testing stage. Well PR-2, under drilling, with a depth of 650 m, presents very similar conditions. In one of the extreme sites of the field, in the hot spring area named Río Caliente, a well of 1,900 m, of geological support was drilled, but no high temperature condition was found.

LA SOLEDAD, JALISCO

La Soledad geothermal field is located on 20°52'N Lat. and 103°25'W Long., North of Guadalajara City on the banks of Río Santiago, at 1000 m above sea level. Large emanations of water-steam mixtures are found in this place, with an extension of 4 km² and two types of water, high salinity brine and low salinity brine.

SAN MARCOS Y EL PANTANO, JALISCO

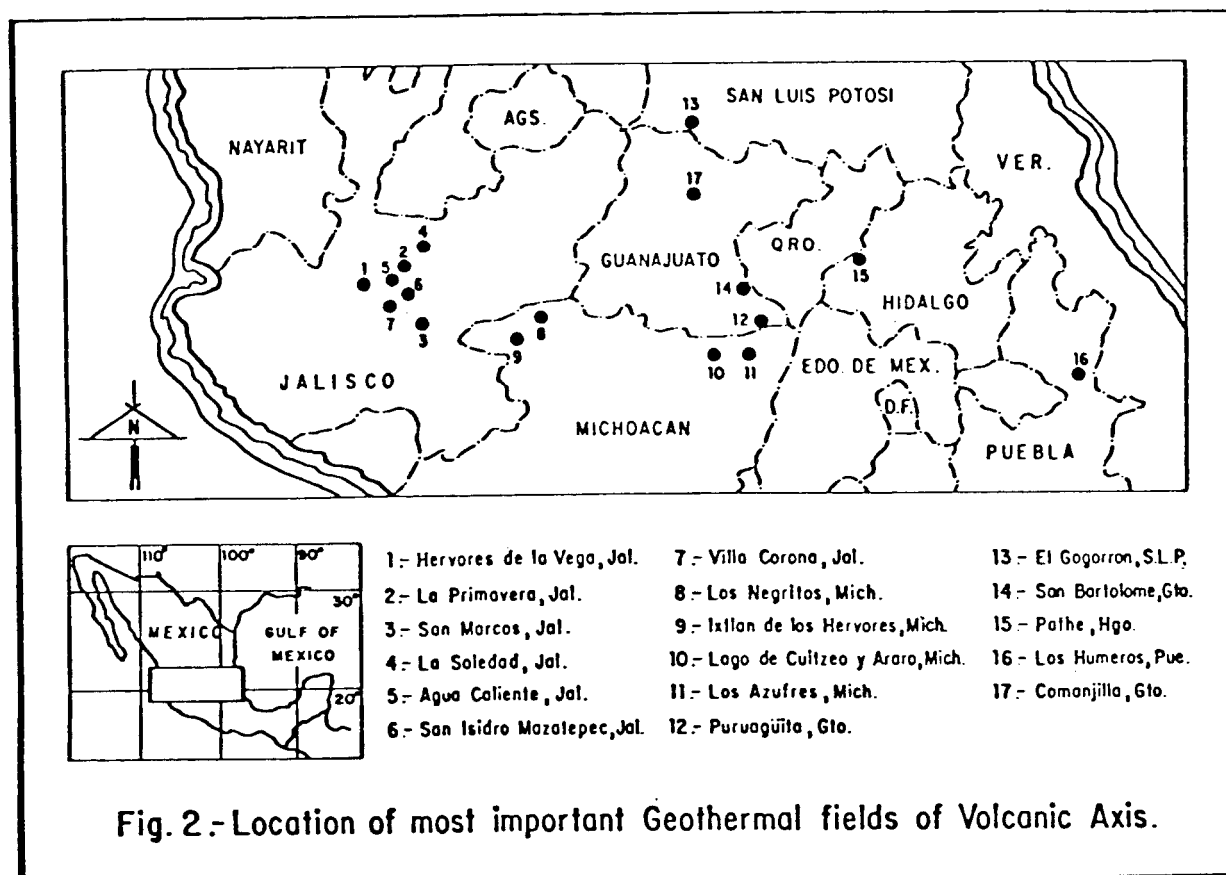
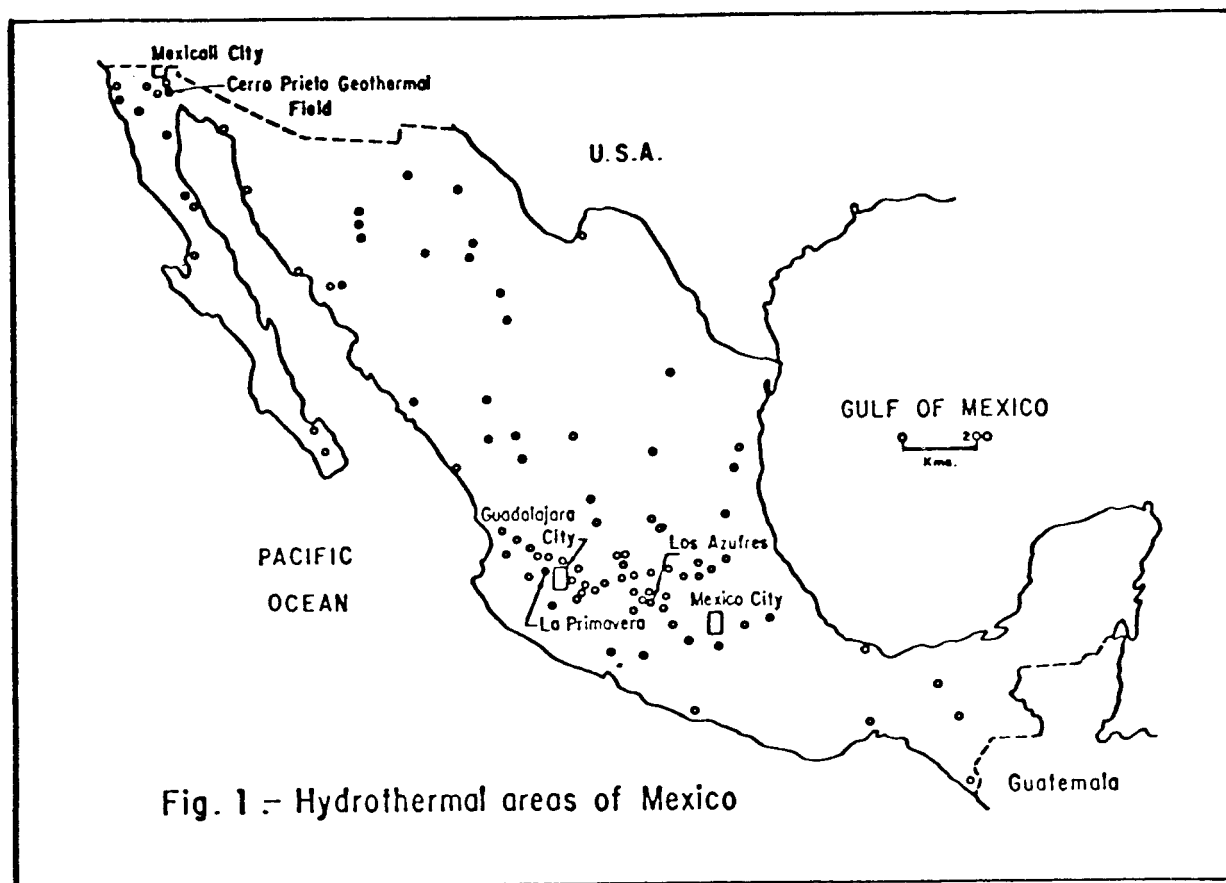
This field is located at 20°36' N Lat. and 103°30'W Long., with an elevation of 1,350 m, West of Lago de Chapala. It has an extension of 11 km². Several manifestations like hot springs, fumaroles, hot water lagoons, mud volcanos, etc., are found in this zone. The water is of medium salinity brine and the geothermometers like Na-K-Ca and the ones obtained by gases show temperatures higher than 200°C. In this area several shallow wells were drilled and used for thermal gradient measurement and to obtain fluid samples.

OTHER GEOTHERMAL AREAS OF JALISCO

At the Chapala geothermal area (Jalisco State), sites like Hervores de La Vega, Agua Caliente, Villa Corona, Mazatepec, Cosalá, Jocotepec, Colimilla, Cacaluta and Verdía are in exploration at the present time. The high thermal activity of the zone is caused by the intersection of the faults system of Mexico's Eje Neovolcánico with the Colima's Trench; the extension of this area is more than 5,000 km².

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PROPOSAL FOR RESERVOIR ENGINEERING STUDIES
IN THE STATE OF ALASKA

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Eugene Wescott
University of Alaska, Fairbanks

Alaska has a significant geothermal potential. While other sources of energy such as petroleum and coal are in abundance, there has been a definite move towards geothermal exploitation. The State has recognized the opportunity cost of petroleum as a source of materials and has expressed interest in the development of geothermal energy as a desirable and alternative resource.

More than 11 million acres ¹ have been identified as potential geothermal reservoirs capable of producing electric power as well as direct heating. Reservoirs of the latter type are found in the interior of the state. Considering the winter temperatures of these regions (at times dipping to -60°F) direct utilization is attractive.

A comprehensive reservoir engineering proposal is presented to better assess the extent and potential of the geothermal areas in Alaska. The purpose of this paper is to acquaint the participants of the Stanford Geothermal Workshop with the enormous potential, as yet untapped, of the State of Alaska.

Introduction

Figure 1 is a map of Alaska with a number of potential geothermal sites. Of these reservoirs, Chena Hot Springs and Pilgrim Hot Springs have had considerable geological and geophysical work. ^{2,3} At Pilgrim Springs, two small wells were drilled at 200 feet and they encountered hot water at 178°F. No deeper drilling was attempted since the available equipment was incapable for such a task. The flow rate was measured at 32,000 lb/hr. At Chena Hot Springs and at a depth of only 18 feet a temperature of 138°F was recorded.

Two other exploration projects are to begin in calendar 1981. Personnel from the Geophysical Institute and the Petroleum Engineering Program at the University of Alaska, Fairbanks will cooperate in the "Geophysical Exploration for Geothermal Energy at Manley Hot Springs" and in the "Investigation of Radiogenic Heated Aquifers in the Lower Susitna Basin".

Potential sites in Alaska are: Pilgrim Hot Springs, Kotzebue, west side of Mount Drum (Klawasi), Willow, Chena Hot Springs, Circle Hot Springs, Manley Hot Springs, Homer Hot Springs, Clear Creek Hot Springs, Central Baranof Island, Tenakee Hot Springs, Northern part of Unalaska Island, Unnak Islands, Emmons Caldera and Northeastern Atka Island. (Reference 1)

As it can be seen, the developable sites in the state span the entire area.

Many of these areas occur in sedimentary basins, containing ancient volcanic formations. Often, geothermal formations may be associated with hydrocarbon deposits. Fractures, which are characteristic of other major geothermal formations, also penetrate the Alaskan reservoirs.

RESERVOIR ENGINEERING WORK

The University of Alaska will purchase Amerada bombs in order to facilitate a comprehensive well testing program. Following intensive geophysical exploration it is anticipated that an aggressive drilling program will ensue. Drawdown and buildup well tests will be done in the first well. If they are encouraging then a second and third well will be drilled preferably forming a right angle with the first well. One direction should follow identified faults while the other will be perpendicular. Interference well testing will allow the estimation of the directional permeabilities and the identification of the principle axes of permeability.

Subsequent drilling will take into account the findings of the well testing. Well logging during the drilling phase will supply the final formation evaluation which along with the results of well testing will define the economic attractiveness of each project.

While reservoir engineering work in the state is still in its infancy, it is expected to grow rapidly. The comprehensive geophysical and geological work done thus far have prepared a highly favorable ground for the reservoir engineer.

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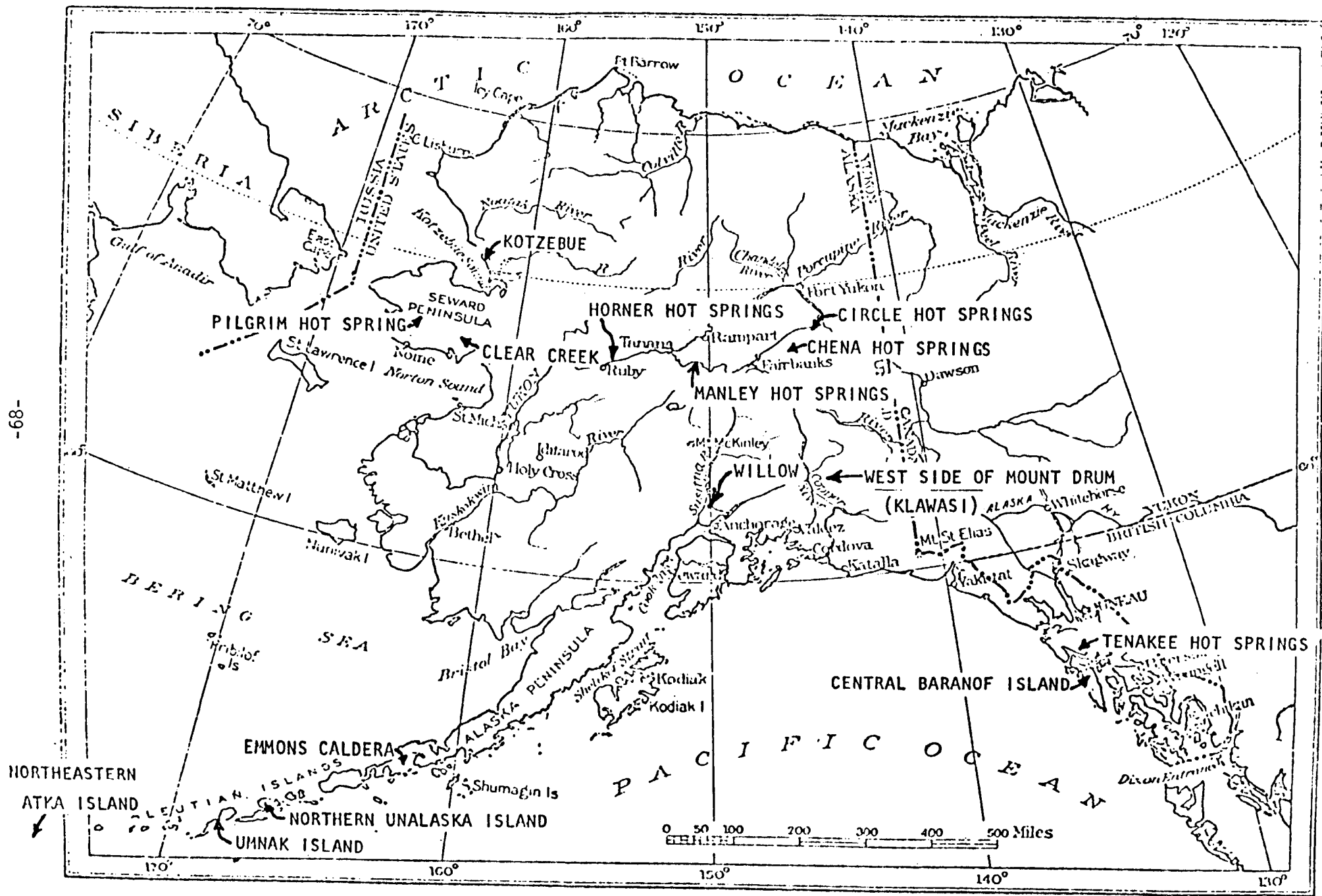


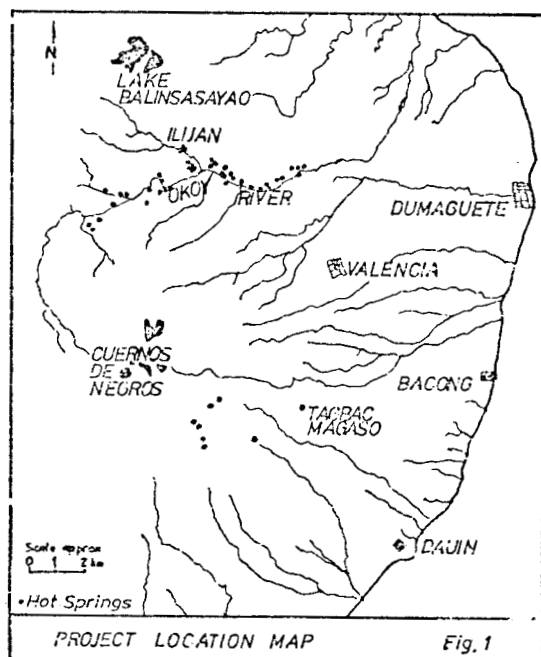
Figure 1. Alaska map with potentially developable sites.

HYDROLOGY AND MODEL OF THE OKOY GEOTHERMAL FIELD,
NEGROS ORIENTAL, REPUBLIC OF THE PHILIPPINES

E.W. Smith, Geothermal Engineer, New Zealand

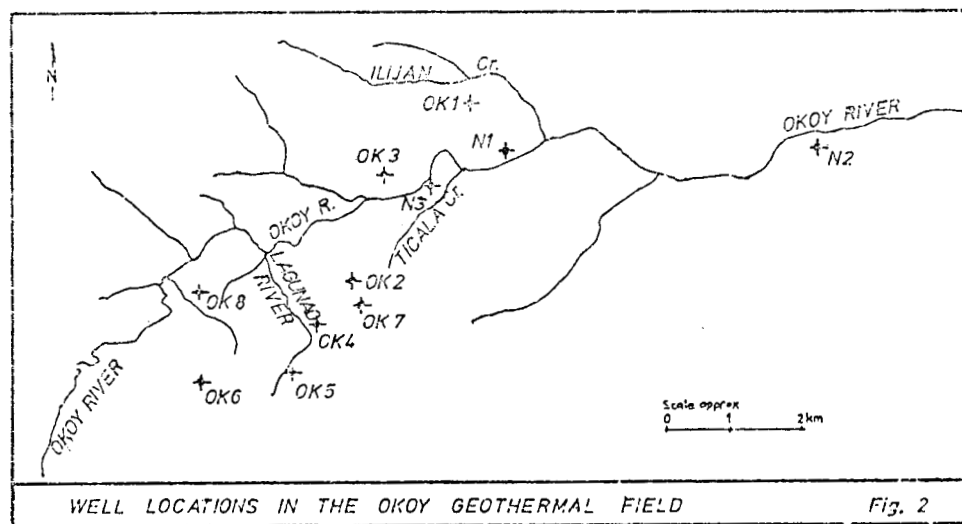
INTRODUCTION

Ward (1980) described the exploration of the Okoy geothermal field. Resistivity surveying using Schlumberger traverses has covered an area of approximately 800 km² in the southern part of the Island of Negros. Hot springs and other thermal manifestations (Fig. 1) occur in the Okoy valley, Valencia and at Tabac Magaso, Dauin.



Initial shallow exploratory drilling indicated a possible sub-surface flow of hot water in the Okoy valley. Further deep exploratory drilling to the West has located two high temperature reservoirs.

Figure 2 shows the well locations within the Okoy geothermal field.



HYDROLOGY

Due to the complex nature of the Okoy geothermal field, wells drilled into the hydrothermal system generally balance well and reservoir pressures with internal flows. These internal flows cause difficulty in interpreting the downhole temperature and pressure measurements.

Most of the wells within the field penetrate a single phase reservoir and some have multiple permeable zones. Wells with multiple permeable zones generally have one zone with larger permeability and at this point the measured pressures equal the reservoir pressure. This point is known as the pressure control point. Elsewhere in the well the measured pressures do not equal the reservoir pressure.

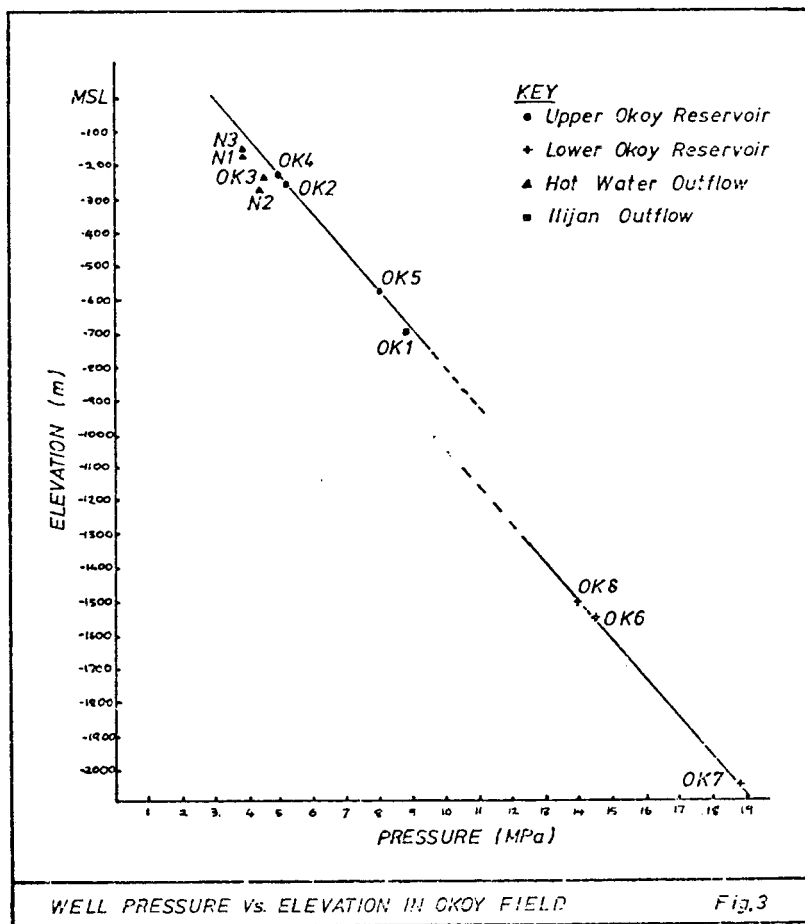
After examination of the well measurement data the pressure control point for each well was identified and listed in Table 1.

The pressure survey data was examined and rejected where the surveys showed transient effects, strong internal flows or obvious measurement errors. The remaining surveys were used to calculate the average pressures at the pressure control point for each well and listed in Table 1.

Table 1: Elevation - Pressure Data

Well	Pressure Control Point m MSL*	Average Pressure kPa
N1	- 169	3870
N2	- 268	4360
N3	- 152	3860
OK1	- 687	8810
OK2	- 246	5170
OK3	- 232	4500
OK4	- 223	4930
OK5	- 568	8020
OK6	- 1544	14540
OK7	- 2040	18810
OK8	- 1496	14000

The elevation - pressure data of Table 1 is graphed in Figure 3.



* MSL = mean sea level

Examination of Figure 3 and a knowledge of the physical geography, geology and chemistry of the Okoy field suggests that the data can be grouped into four categories:-

- (a) Upper Okoy reservoir (OK2, OK4, OK5)
- (b) Lower Okoy reservoir (OK6, OK7, OK8)
- (c) Hot water outflow (N3, OK3, N1, N2)
- (d) Ilijan outflow (OK1)

UPPER OKOY RESERVOIR

The upper Okoy reservoir is a single phase system existing between +300m and -1000m MSL consisting of neutral chloride water with chloride concentrations of approximately 3600ppm. Deep drilling has encountered temperatures of up to 310°C and no re-charge system has yet been identified.

Some small two phase steam dominated zones overlies the reservoir.

Least square linear regression analysis gives an 'elevation - pressure relationship' for this category (a) data of Table 1 as $P = 2960 - 8.91 z$. Where P is pressure (kPa) and z is elevation (m) relative to mean sea level. The co-efficient of determination for the analysis is 1.000 indicating an excellent fit.

The implications of the 'elevation-pressure relationship' are:-

- (i) The piezometric water level of the reservoir is +330m MSL.
- (ii) All Chloride springs which derive fluid from the reservoir will occur at elevations less than +330m MSL.
- (iii) Surface thermal manifestations at elevations greater than +330m MSL which derive fluid from the reservoir are likely to be steam heated or discharge free steam.
- (iv) The pressure gradient of 8.91 kPa/m corresponds to water of approximately 160°C. The average reservoir temperature is greater than 160°C thus the pressure gradient is super-hydrostatic.

LOWER OKOY RESERVOIR

The lower Okoy reservoir is a neutral chloride water system at elevations below -1000m MSL. Deep drilling so far has encountered temperatures ranging from 250 to 303°C and no recharge or outflow systems have been indicated.

Least squares linear regression analysis gives an 'elevation-pressure relationship' for the category (b) data of Table 1 as $P = 970 - 8.75 Z$. The co-efficient of determination for the analysis is 0.999 indicating a reasonable fit.

The implications of the 'elevation-pressure relationship' are:-

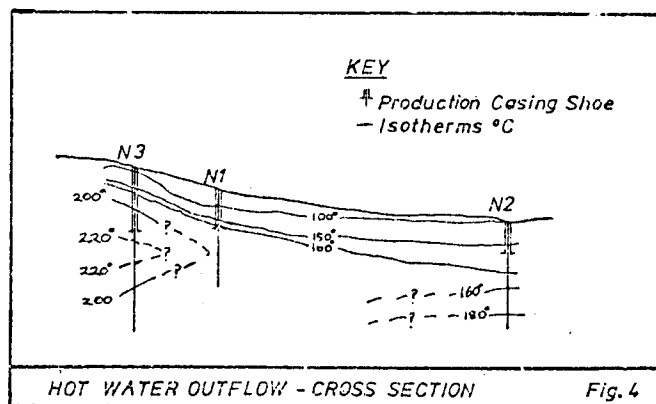
- (i) The piezometric water level of the reservoir is +110m MSL.
- (ii) All chloride springs which derive fluid from the reservoir will occur at elevations less than +110m MSL.
- (iii) The pressure gradient of 8.75 kPa/m corresponds to water of approximately 175°C. The average reservoir temperature is greater than 175°C thus the pressure gradient is super-hydrostatic.
- (iv) At an elevation of -1000m MSL the pressure difference between the upper and lower reservoirs is 2150 kPa. If permeability exists between these reservoirs, within the known field area, fluid will flow from the upper to the lower reservoir.

HOT WATER OUTFLOW

The shallow wells N1, N2 and N3 penetrate a hot water flow which supplies the Okoy valley springs.

Geochemical evaluation (Barnett, 1977) of the Okoy valley wells and springs indicated a general westerly direction as the source of the fluid.

Figure 4 shows isotherms drawn through wells N3, N1 and N2 also suggests a source to the west.



The Okoy geothermal field cross sections (Smith, 1980 b) suggested wells N3, N1 and N2 are in an outflow from the Upper Okoy reservoir with OK3 in the outflow edge.

Comparison of the data from Table 1 for these category (c) wells with the derived 'elevation-pressure relationship' for the upper Okoy reservoir is given in Table 2. The pressure departures of Table 2 show a sequence of increasing pressure drop in the order: N3, OK3, N1, N2 indicating the flow direction.

Table 2: Pressure Comparison

<u>Well</u>	<u>Pressure Control</u> <u>Point m MSL</u>	<u>Average Pressure</u> <u>kPa</u>	<u>P=2960-8.91%</u> <u>kPa</u>	<u>Pressure</u> <u>Departure</u>
N3	- 152	3860	4314	- 450
OK3	- 232	4500	5030	- 530
N1	- 169	3870	4470	- 600
N2	- 268	4360	5350	- 990

ILIJAN OUTFLOW

The Okoy geothermal field cross sections (Smith, 1980 b) suggested OK1 is on the edge of a second hot water flow.

Comparison of the data from Table 1 for OK1 with the derived 'elevation-pressure relationship' for the upper Okoy reservoir is given in Table 3.

Table 3: OK1 Pressure Comparison

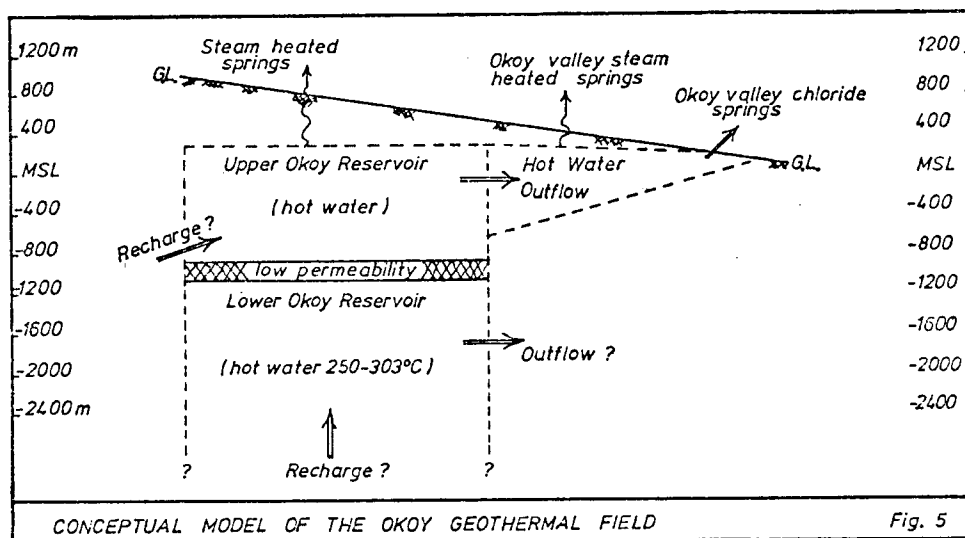
<u>Pressure Control</u> <u>Point m MSL</u>	<u>Average Pressure</u> <u>kPa</u>	<u>P=2960-8.91%</u> <u>kPa</u>	<u>Pressure</u> <u>Departure</u>
- 687	8810	9080	- 270

The pressure departure of Table 3 does not fit the sequence for the flow direction indicated by Table 2. It can be speculated that this second hot water flow may be from a geothermal system in the Balinsasayao area.

MODEL

A simple two dimensional conceptual model is given (Fig. 5) based on the descriptions of the upper and lower reservoirs and the hot water outflow.

Further exploration and delineation wells are being drilled in the Okoy geothermal field and it is hoped the information obtained will help clarify the complex nature of this field.



ACKNOWLEDGEMENTS

I am deeply indebted to my former colleagues in the Philippines National Oil Company and Kingston Reynolds Thom & Allardice Limited, who have collected all the data and developed ideas expressed in this paper.

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ANALYSIS OF PRELIMINARY FLOW DATA FROM PLEASANT BAYOU NO. 2
GEOPRESSURED WELL

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I. INTRODUCTION

For the last several years, the University of Texas at Austin (UTA) and, more recently, Louisiana State University (LSU) have analyzed the geopressed tertiary sandstones along the Texas Gulf Coast and the Louisiana Gulf Coast with the objective of locating prospective reservoirs from which geothermal energy could be recovered. Of the "geothermal fairways" (areas with thick sandstone bodies and estimated temperatures in excess of 300°F) in Texas, the Brazoria Fairway in Brazoria County appears most promising and the Austin Bayou Prospect has been developed within this fairway. The first well drilled at the Austin Bayou Prospect (DOE Pleasant Bayou No. 1, drilled in 1978) is being used for reinjection since well completion problems precluded its use for geopressed reservoir testing. A second well (DOE Pleasant Bayou No. 2) was drilled in 1979 in the immediate vicinity of the first to obtain the transient flow data needed to evaluate the geopressed reservoir.

Preliminary short term production and buildup tests of the Pleasant Bayou No. 2 well were conducted during the second half of 1979. A series of five pressure drawdown (production times ranging from 13 minutes to 10.5 days) and buildup tests were performed with flow rates up to about 20,000 bbl/day in an effort to evaluate formation parameters for the geopressed sand perforated at 14,644 feet to 14,704 feet (net sand thickness 60 feet). The relevant flow and pressure data are given in a report by Clark [1].

The Pleasant Bayou No. 2 well has 7 inch casing set through the Frio sand at 14,644 feet to 14,704 feet (mean depth 14,674 feet). The well has 5-1/2 inch production tubing. Bottom-hole pressure was measured using the Hewlett-Packard quartz crystal surface recording element. A nickel-iron alloy sensor with solid state transmission was employed to measure the bottom-hole temperature (~ 301°F). Some pressure and temperature gradients at 1,000 feet intervals were also taken. Surface pressures were obtained using a dead weight tester and a Panex 1100 pressure transducer. Independent temperature sensing capability was also available. A turbine pulse meter was used to record flow rates.

Due to various problems with the bottom-hole pressure gauges and the instrument cable, bottom-hole pressures were measured at different depths (ranging from 14,500 feet to 14,750 feet) at different times during the drawdown/buildup tests. In order to use these data to evaluate formation properties, it is

convenient to reduce the measured bottom-hole pressures to a common depth. Since the majority of buildup data were obtained at the 14,600 feet datum we have elected to refer all bottom-hole pressure data to this depth. The initial reservoir pressure at the 14,600 datum is estimated to be 11,206.3 psi. It is also worth noting here that a change in the instrument cable design after flow period 4 may have resulted in a systematic error in the measured bottom-hole pressures. Bottom-hole pressures for well shutdown period 4, flow period 5 and shutdown period 5 apparently need to be corrected by 20-40psi.

It was originally planned to measure the liquid and gas flow rates separately at the well head. However, due to problems with the separator, the entire flow stream had to be directly passed through the turbine meter. For purposes of analysis, it is necessary to estimate the liquid and gas flow rates separately. We describe elsewhere [2] the procedures employed to reduce the flow data to standard conditions.

Southern Petroleum Laboratory, Inc. reported a salinity of 175,435 ppm based on measurements on fluid samples obtained from the reservoir. The salinity may also be estimated from the static pressure gradient and the measured temperature. Based on a static pressure gradient of 0.4607 psi/feet and a temperature of 301°F, salinity at standard conditions is estimated to be 169,548 ppm. The latter value of salinity is in good agreement with the value reported by Southern Petroleum Laboratory, Inc., but is at considerable variance with the value of 130,000 ppm given by Kharaka et al [3]. In the absence of additional data, we will assume that the reservoir fluids have a salinity of 169,548 ppm. The latter value of salinity, together with the S^3 methane/brine equation-of-state data [4], yields a methane content of 22.47 SCF/STB at saturation. Although the GWR (Gas Water Ratio) was not measured for the greater part of the flow test, Clark [1] mentions that at the end of the first hour of the third flow period, the GWR averaged around 19.6 cu. ft./bbl at $p \sim 766.7$ psia and $T \sim 172^\circ\text{F}$ (separator pressure and mean temperature of flow stream). This implies that the reservoir fluids are most probably saturated with gas.

The main purpose of this study is to analyze pressure drawdown and buildup data to evaluate formation parameters. In this connection, we note that the flow periods 1 and 2 were too short (13 minutes and 184 minutes respectively) to give meaningful data for analysis purposes. Also, flow data for part of flow period 3 and pressure buildup data for practically all of buildup period 4 are missing. The complete flow and pressure drawdown/buildup data are, however, available for flow/shutin period 5 (flowing time ~ 10.5 days, shutin time ~ 20 days). For the aforementioned reasons, our analysis will be primarily concerned with the flow/shutin period 5.

II. ANALYSIS OF BUILDUP PERIOD 5 PRESSURE DATA

Pleasant Bayou No. 2 well was flowed at an average rate of approximately 12,746 STB/D from December 3, 1979 (19:31:50 hours) to December 14, 1979 (7:59 hours). Buildup pressures were measured from the shutin time on December 14, 1979 to January 3, 1980 (8:00 hours). The flow stream, at bottom-hole conditions, contained less than 1 percent by volume of free gas; it is, therefore, felt that classical single-phase analysis methods should be adequate to analyze the buildup data. In analyzing the buildup data for shutin period 5, the question arises as to how the production periods 1-4 influence the buildup pressures. One could, in principle, utilize superposition to account for the prior flow periods; in practice, this procedure is rather cumbersome. An alternate method is to assume a constant flow rate, and calculate an equivalent flow time. Since the prior flow periods mainly influence the late-time buildup data, the latter procedure should suffice for present purposes. Given a total production of 210,506 STB, and an average producing rate (q) of 12,746 STB/D, the equivalent producing time (t) is 396.37 hours.

The buildup data versus $(t + \Delta t)/\Delta t$ are shown in Figure 1. It can be seen from Figure 1 that the buildup data may be approximated by two straight lines with slopes (m) of 60 psi/cycle and 66 psi/cycle respectively. These slopes yield the following values for formation permeability:

(i) Near 'well bore' permeability, $k = 177.6$ md

(ii) Far field permeability, $k = 161.5$ md

The two straight-line segments on the Horner plot intersect at $(t + \Delta t)/\Delta t \sim 17.5$ (corresponding to $\Delta t \sim 24$ hours). The transition from near well permeability to far field permeability occurs approximately at (see e.g. Matthews and Russell [5]):

$$r_{\text{trans}} = \left(\frac{0.00105 k \Delta t}{\phi \mu C_T} \right)^{1/2}$$

where Δt = Shutin time corresponding to the intersection of the straight lines on the Horner plot, hours; ϕ ~ Formation porosity; C_T ~ Total formation compressibility ($= [(1-\phi)/\phi] C_m + C_f$), psi⁻¹; C_m ~ Uniaxial formation compressibility, psi⁻¹; and C_f ~ Pore fluid compressibility, psi⁻¹.

With $k = 177.6$ md, $\mu = 0.295$ Cp, $C_m \sim 10^{-6}$ psi⁻¹, $C_f \sim 3 \times 10^{-6}$ psi⁻¹, $\phi \sim 0.176$ and $\Delta t \sim 24$ hours, r_{trans} is approximately 3350 ft.

The skin factor s is given by the relation [5]:

$$s = 1.151 \left[\frac{P_{1hr} - P_f}{m} - \log \frac{k}{\phi_{\mu} C_T r_w^2} + 3.23 \right],$$

where P_{1hr} ~ Shutin pressure at $\Delta t \sim 1$ hour extrapolated from the straight line on the Horner plot, psi; P_f ~ Last flowing pressure, psi; and r_w ~ Well radius, ft.

With $P_{1hr} \sim 11,018$ psi, $P_f \sim 10,466$ psi, and $r_w \sim (3.5/12)$ ft, the skin factor s is 3.12.

The radius investigated by the buildup test is approximately given by r_{inv} [5]:

$$r_{inv} = \left(0.00105 \frac{k \Delta t}{\phi_{\mu} C_T} \right)^{1/2}$$

where Δt = buildup time. With $\Delta t = 480$ hours (shutin period 5), the formation radius investigated during buildup is approximately 14,960 ft.

The preceding analysis indicates that no definite boundaries (permeability barriers) can be identified from the 20 day buildup test. This conclusion is, however, somewhat uncertain in so far as the MUSHRM history-match calculations, discussed in Section III, indicate that late-time buildup data can be better matched by assuming a closed boundary. It is also appropriate to mention here that the two-mobility interpretation of the buildup data was first suggested by MacDonald [6]; this interpretation is, however, at variance with the one given by Clark [1]. Clark attributes the upward shift in the slope on the Horner plot to a minor fault of less than the sand thickness that causes an area of flow constriction at the fault position.

III. HISTORY - MATCH CALCULATIONS

In this section, we will employ the formation properties derived in Section II in the reservoir simulator MUSHRM to history match the observed drawdown/buildup pressures and flow rates. For our initial simulation, the reservoir is assumed to be a right circular cylinder with radius $R \sim 37,200$ feet (Note that this radius is approximately two and one-half times the maximum radius, 14,960 feet, explored during the 20 day buildup test, and should be adequate to simulate an infinite reservoir.) and height $h=60$ feet (depth 14,644 -14,674 feet). The details regarding the numerical grid, production history, initial fluid state and the formation properties utilized are given elsewhere [2].

Figures 2-4 compare the calculated bottom-hole pressures with observed drawdown/buildup pressures for flow/shutin periods 1-4. The calculated flowing pressure at $t = 13$ minutes (end of

first drawdown period) is almost 200 psi more than the measured value; on the other hand, the calculated flowing pressure at the end of drawdown period 2 ($t \sim 229$ minutes) is approximately 200 psi less than the observed value. Due to the uncertainties in flow data for these short term drawdown tests, no inference can be drawn from this disagreement between the observed and calculated values. Calculated drawdown pressures for flow-periods 3 and 4 (Figures 3 and 4) generally follow the observed pressure response; the calculated values are, however, about 20 psi greater than the measured pressures. This suggests that the flow rates used in the simulation are somewhat lower than the actual flow rates for periods 3 and 4.

The calculated drawdown response for flow period 5 is compared with the relevant data in Figure 5. Note that 24 psi were added to all measured pressure values to match measured and calculated pressures at the start of flow period 5. In general, there is good agreement between the observed and simulated pressures. Figure 6 compares the observed buildup pressures with the calculated buildup pressures for shutin period 5; for Δt (Δt = shutin time) $< 10^4$ m, there is close agreement between the two sets of values. For $\Delta t > 10^4$ m, the calculated buildup pressures (shown by a broken line in Figure 6) lie above the actual pressures; this suggests the possible presence of a permeability barrier. A second simulation was therefore, run by assuming the reservoir to be bounded at $R \sim 16,700$ feet ($R \sim 16,700$ feet represents the radius at which the maximum pressure drop, in the initial simulation, was less than 1 percent of the maximum pressure drop at the sand face); all other parameters for this calculation were identical to those for the initial simulation. The finite reservoir simulation results are identical with those obtained for the infinite reservoir except for the late part of the fifth buildup period ($\Delta t > 10^4$ minutes). Figure 6 clearly shows that the bounded reservoir assumption leads to a closer agreement between the observed and calculated pressures. We, therefore, speculate that the geopressured reservoir in question may have a permeability barrier at a distance of about $R \sim 16,700$ feet.

The total calculated brine and methane production during the flow periods 1-5 are 210,487 STB and 4,672,469 SCF respectively. The calculated brine production is practically identical with the estimated actual production (210,506 STB). The calculated methane content of the produced brine is 22.2 SCF/STB.

IV. CONCLUDING REMARKS

Analysis of pressure buildup data from the preliminary 10 day flow/20 day buildup test indicates the presence of a mobility change at approximately 3500 feet (assuming a uniaxial compressibility of 10^{-6} psi $^{-1}$), and possibly a mobility barrier at approximately 17,000 feet. The formation parameters derived from the preceding analysis were employed in the MUSHRM

reservoir simulator to successfully history-match the available drawdown/buildup data from the various short-term flow/buildup tests. Current DOE plans call for extensive long-term testing of the Pleasant Bayou No. 2 well. These tests will include separation of the gas and liquid fluid components. Long-term testing will determine reservoir limits (30 day producing at 20,000 bbl/day; 60 day buildup; test started September, 1980), and well productivity (six months producing up to 40,000 bbl/day). The data from these tests are required to confirm the presence of the mobility barrier at 17,000 feet.

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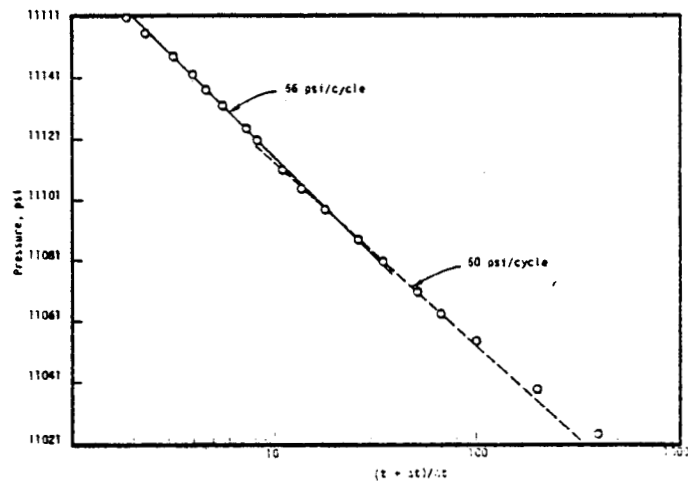


Figure 1. Horner plot for buildup period 5.

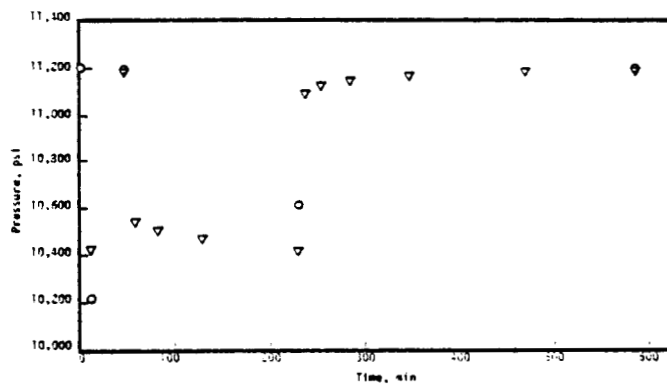


Figure 2. Comparison of calculated and measured bottom-hole pressures for drawdown/buildup periods 1 and 2. The abscissa denotes time from the start of drawdown test 1. O - measured values. ▽ - calculated values.

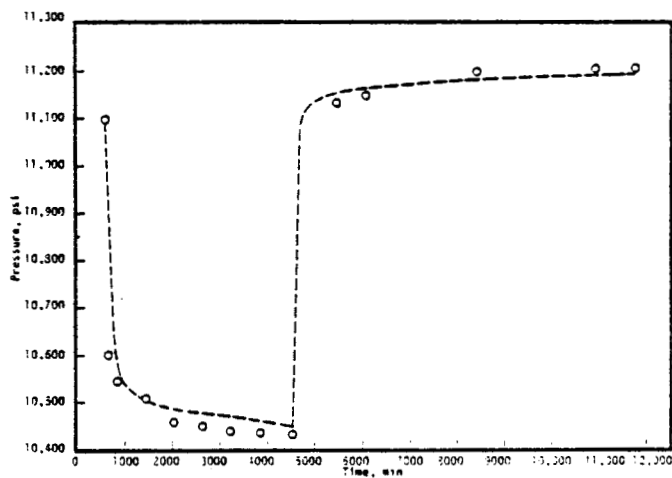


Figure 3. Comparison of calculated and measured bottom-hole pressures for drawdown/buildup period 3. The abscissa denotes time from the start of drawdown test 1. — calculated; O - measured.

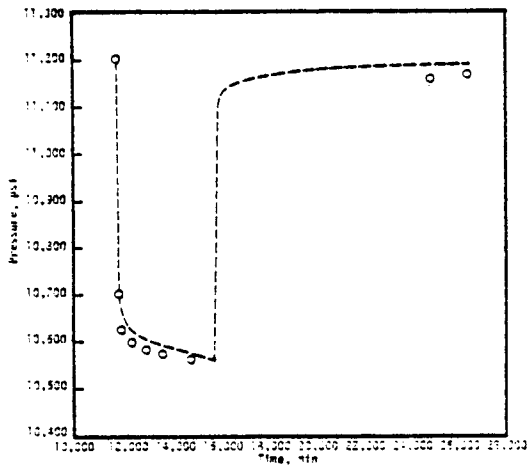


Figure 4. Comparison of calculated and measured bottom-hole pressures for drawdown/buildup period 4. The abscissa denotes time from the start of drawdown test 1. — calculated; o - measured.

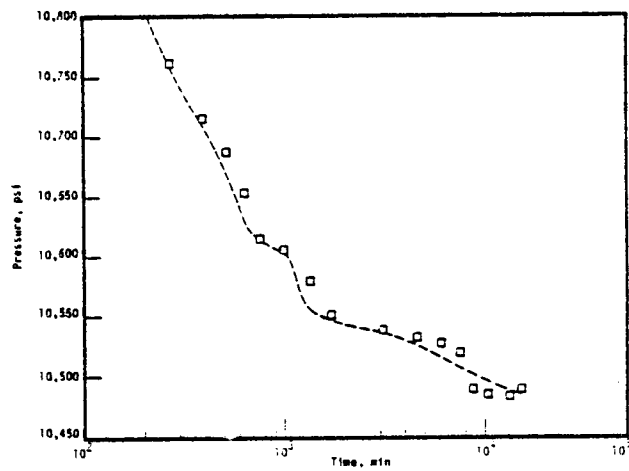


Figure 5. Calculated and measured pressure data for drawdown period 5. All measured pressure values were increased by 24 psi to match measured and calculated values at start of flow period 5. Abscissa denotes time from the start of flow period 5. □ - measurements; --- calculated.

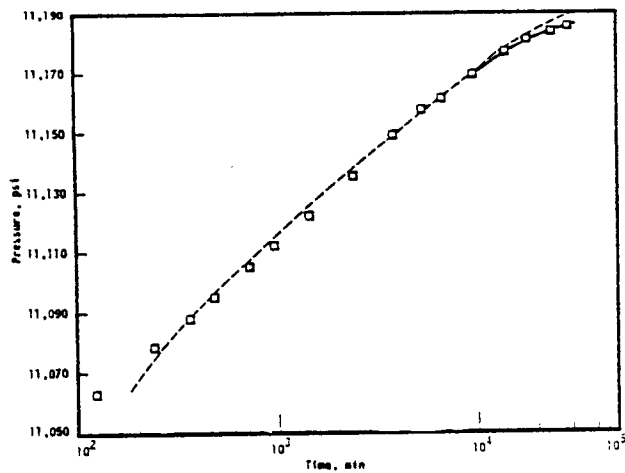


Figure 6. Calculated and measured pressure data for buildup period 5. All measured values were increased by 24 psi to match observed and calculated values at the start of flow period 5. Abscissa denotes time from the start of buildup period 5. □ - measurements; --- calculations (infinite reservoir); — calculations (finite reservoir).

SAMPLING GEOPRESSURED FLUIDS: SOME CONTRIBUTIONS
FROM THE PROPERTIES OF THE H_2O-CH_4 SYSTEM

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I. INTRODUCTION

The geopressured formations of the United States Gulf Coast are being probed for methane recovery feasibility. One of the critical variables involved is the amount of methane actually dissolved in the pore brines. Sampling and subsequent analysis of these geopressured fluids is therefore important for the economic assessment of the resource. Thus, interest in use of conventional downhole fluid samplers and, recently, in development of samplers especially designed for geopressured environments, has been stimulated.

The purpose of these tools is to obtain fluid samples at reservoir conditions and to bring them to the surface, preserving their integrity, for subsequent chemical analysis. The sampling process may be envisioned as the following simplified sequence. First the sampler is lowered along the wellbore to the reservoir depth (hereafter the bottomhole). At the bottomhole the sampler is filled with formation fluid. The valve(s) are then closed and the sampler is pulled back to the surface. There it is housed in the wellhead lubricator. A valve isolating the lubricator from the wellbore is then closed. The next stage is to dispose of the hot, high pressure fluid contained in the lubricator in order to reach the sampler. The sampler is then recovered. Finally, the fluid enclosed in the sampler is transferred to suitable containers for subsequent chemical analysis.

Pore fluids in geopressured formations are subjected to very high (up to 1400 atm $\approx$ 20000 psi) pressures, and moderately high (up to 200°C) temperatures (e.g., Dorfman and Fisher, 1979); significant amounts of methane, sodium chloride and lesser chemical species are dissolved in the formation waters. During the sampling process described above, the temperatures of the fluid in the sampler in the wellbore may depart significantly from the common bottomhole value; furthermore, the pressure of the fluid surrounding the sampler decreases with decreasing depth. Correspondingly, various effects associated with the thermodynamic properties of the fluids would be induced. These effects may include; gas exsolution, both in the sampler and in the wellbore; vertical compositional changes along

the wellbore due to slippage between the gas and the liquid phase; temperature-induced pressure drops in the fluid sample; substantial changes of the differential pressure exerted on the sampler walls, which relate to possible leaks; and formation in the sampler of a solid methane hydrate.

Prediction of such effects, and estimates of their magnitudes are useful for both users and designers of downhole geopressured fluid samplers. For example, this knowledge may help interpret field results, be used in assessment of sampling conditions to avoid those that favor leakage of the sampler, and suggest safer procedure for handling the sampler in surface operations, as will be shown in this paper.

This paper is devoted to predicting and quantitatively estimating geopressured fluid behavior during sampling of reservoirs in their natural, unperturbed conditions. Both the fluid in the sampler and the wellbore fluid are considered. To that end, I have developed a simple model (an "equation of state") to estimate thermophysical properties of geopressured fluids. This model is briefly described in Section II; full details are given elsewhere (Iglesias, 1980).

In Section III the "equation of state" is applied to compute and discuss fluid properties associated with the different stages of the sampling process. Questions explored include: the probable range of CH_4 content of the samples; pressure, phase transitions, fraction of total volume corresponding to each phase, and composition of each phase present in the sample, over the expected range of temperatures; whether and under what conditions the fluid collected at wellhead in a flowing well provides a representative sample of the bottomhole fluid composition; the expected range of fluid pressures in the lubricator; and the expected range of differential stresses on the sampler. Bottomhole temperatures and pressures generally increase with depth in the geopressured formations of the Gulf Coast (e.g., Dorfman and Fisher, 1979). Thus, two well depths, representing approximately the top and the bottom of the geopressured zone, were considered in detail to assess effects associated with depth.

Finally, results and recommendations are summarized in Section IV.

II. A SIMPLE MODEL FOR GEOPRESSURED FLUIDS

With the exception of a correction factor for methane solubility in NaCl solutions, I neglected the complications posed by the presence of dissolved solids and considered a system composed only of water and methane. This approach is appropriate for the estimative purposes of the present work.

In this model, the thermophysical properties of the water-methane mixture are formulated in terms of five main variables; namely, pressure P , absolute temperature T , molar volume v , mole fraction of methane in the system λ , and volumetric gas saturation S . The contributions of methane to the liquid- and gas-phase molar volumes are estimated from a correlation (Brelvi and O'Connell, 1972), and from the ideal gas law, respectively. The corresponding quantities for liquid water and steam are estimated from the IFC Formulation*.

Methane solubility is computed from an empirical correlation (Haas, 1978), which assumes that steam exists in the gas phase at its saturated pressure and defines the methane partial pressure as the difference between P and the saturation pressure of pure steam.

III. RESULTS AND DISCUSSION

i) Bottomhole Compositions

The geopressured brines of the Gulf Coast are believed to be saturated with dissolved methane. Methane solubilities in water and in NaCl solutions depend on temperature and pressure. Thus, given the ranges of pressures and temperatures found in the geopressured formations, the probable range of methane content in bottomhole fluid samples can be estimated from known solubilities, as follows.

Bubble-point curves for the water-methane system were computed from Haas' correlation. These results are shown in Figure 1. The shaded area represents, roughly, the P , T ranges spanned by the fluids of the Gulf Coast (e.g., Dorfman and Fisher, 1979 and references therein). Assuming that in the unperturbed reservoir the pore water is saturated with methane, $\text{CH}_4\text{-H}_2\text{O}$ ratios can be estimated from Figure 1 for given pressures and temperatures. Multiplying these results by the factor f_{NaCl} , which has been plotted in Figure 2 as a function of the NaCl content, corrects these solubilities for salinity (Haas, 1978).

From Figure 1, the maximum methane solubility in the shaded area (for zero NaCl) is about 14,400 ppm at 1400 atm (this pressure corresponds approximately to the bottom of the geopressured zone). This solubility may decrease to about 5000 ppm, corresponding to $f_{\text{NaCl}} \approx 0.35$ for 250,000 ppm of NaCl (Figure 2). Taking 700 atm (corresponding to about 3000 m, the top of the geopressured zone, if the lithostatic pressure gradient is adopted), the minimum methane solubility is about 4000 ppm for zero NaCl.

*International Formulation Committee, 1967, "A Formulation of the Thermodynamic Properties of Ordinary Water Substance," IFC Secretariat, Verein Deutscher Ingenieure, Dusseldorf, Prinz-Georg-Strasse 77/79.

(Figure 1) which converts to about 1400 ppm for 250,000 ppm of NaCl.

Two cases were considered in detail: a deep well ($Z_B = 6000$ m) representing an approximate upper limit to the pressures expected, and a "shallow" ($Z_B = 3600$ m) well sunk to near to the top of the geopressed formations. The corresponding bottomhole pressures were estimated from the lithostatic gradient. Bottomhole temperatures were then picked from Figure 1, and methane solubilities in pure water computed from inversion of $P(\lambda, T)$ as defined by Haas. These results are presented in Table 1.

ii) Wellhead

It is appropriate to consider here the question of whether and under what conditions does the fluid collected at wellhead from a flowing well provide a representative sample of the bottomhole fluid composition.

Since until the present time no geopressed reservoir has been under significant production, the scope of this paper is limited to unperturbed reservoirs. In these conditions the pore fluids are believed to consist of a single, liquid phase saturated with methane. Wellbores penetrating geopressed reservoirs are filled with formation fluid due to the high pore pressures. Along the wellbore pressure decreases with decreasing depth causing gas (mostly methane but also some steam) exsolution. Buoyancy then tends to separate the gas bubbles from the parent liquid. This effect may cause the fluid composition at wellhead to differ significantly from the bottomhole composition.

To estimate the wellhead overall composition, slippage between the gas and the liquid phase must be considered. The typical slippage length, ΔZ , at wellhead can be derived from Z_B and the ratio of the bubble-liquid relative velocity, v_r to the flow velocity v_f ,

$$\Delta Z = Z_B (v_r/v_f)$$

The extremely high bottomhole pressures imply near sonic flow velocities when friction losses are considered (C. Miller, private communication). Sound velocities may range from approximately 1000 m s^{-1} to perhaps 100 m s^{-1} , depending on gas saturation; a typical value for v_r is 0.5 m s^{-1} (e.g., Haberman and Morton, 1953). Thus ΔZ may range up to a few hundred meters for geopressed wells. One can therefore neglect slippage and take $\lambda_w = \lambda_B$ in these fast flowing wells. In this argument, small bubble regime has been tacitly assumed for the wellbore flow. Due to the relatively small temperature gradients and high pressures involved, this is a very reasonable assumption; this assumption is supported by the small gas saturations found later in this paper.

To investigate the differential stresses exerted on the sampler at surface level, estimates of wellhead pressures and temperatures are needed. For simplicity I considered steady-state, fast flowing wells for the two well depth cases described above.

Neglecting drawdown and friction effects associated with finite flow velocity, the wellhead pressure P_W was approximated as the bottomhole pressure minus the hydrostatic head. The assumed steady-state flow conditions imply wellhead temperatures T_W not far from T_B . Thus, for convenience I assumed a linear temperature profile for the wellbore, with T_W ranging from T_B to $(T_B - 50^\circ\text{C})$. These temperatures result in small gas saturations in the well, which are negligible in terms of mass. Neglecting the contributions of the gas phase and of the small amounts of dissolved methane to the total density, I approximated $\rho_1 \cong \rho_1^L(P, T)$. Results so computed for the two well depths considered are shown in Table 1. Note the small differences in P_W arising from the temperature dependence of the density.

From P_W , T_W , and λ_W , which completely specify the thermodynamic state of the system, other wellhead variables of interest such as S , x , y and r were computed using the "equation of state." The corresponding results are summarized in Table 1.

In addition to yielding the wellhead conditions sought, these results provide semiquantitative information of interest for planning actual production. This information can be summarized as follows: if at bottomhole conditions the brine is saturated with methane, gas will first evolve within the wellbore early in the production history, but the concomitant drawdown will eventually result in phase separation within the formation. The volume fraction corresponding to the gas phase anywhere along the wellbore is small, most likely less than about 4%. Therefore, the flow is expected to be in the small bubble regime. A substantial fraction of the total methane remains in solution at wellhead: about 50% if thermal losses along the wellbore are significant, and substantially more otherwise for the cases considered (Table 1). However, the computed values of r_W are upper limits because the actual wellhead pressures will be smaller than shown in Table 1 due to neglected friction losses and drawdown, and consequently there will be greater methane exsolution. Note that these results apply to the early stages of production; i.e., before a gas phase develops in the reservoir. After separation of the fluid in the reservoir slippage may become non-negligible.

iii) Sampler

This subsection focuses on thermodynamic changes (pressures, phase transitions, etc.) taking place in the fluid sample over the expected range of temperatures.

Neglecting leaks and thermal expansion effects, the sampler can be regarded as a closed, isochoric system. On this basis, fluid variables of interest were computed as functions of temperature as the fluid is cooled from T_B to 25°C. The necessary initial conditions (P_B , T_B , λ_B) were taken from Table 1.

Gaseous methane and steam evolve in the process. The corresponding gas saturation values range from zero at bottomhole temperatures to less than 10% at 25°C, and increase (i.e., correlate, via the multiple correlation linking depths, temperatures and pressures of geopressured fluids) with well depth (Figure 3). Methane is computed (Figure 4) to constitute in excess of 98 mole % of the gas phase over the range of temperatures considered; however, our model probably underestimates the gas phase steam mole fraction. The fraction of total methane remaining in solution correlates negatively with well depth; r decreases as cooling proceeds, until a minimum, whose position is insensitive to well depth, is reached near $T = 50^\circ\text{C}$ (Figure 4). The minimum value of r ranges upward of 20% indicating that considerable methane exsolution will take place upon depressurization for sample transfer, even at near ambient temperatures.

As expected, the sampler's fluid pressure correlates with well depth. Cooling effectively decreases the sampler's fluid pressures from bottomhole values of up to about 1400 atm at 200°C to a maximum value of about 300 atm at 25°C, where calculations were terminated (Figure 3). These results imply that formation of a methane hydrate, that takes place at pressures in excess of 463 atm at 25°C (Kobayashi and Katz, 1949), will not constitute a problem if the sampler is cooled to that temperature. However, the possibility of methane hydrate formation in and near transfer valves exists because of possible local overcooling due to depressurization, if transfer is attempted at near ambient temperatures. This problem should be easily controllable by use of local heating (e.g., electric wires) of the affected zone.

iv) Differential Pressure

In this section we consider the differential pressure on the sampler, which is defined as

$$P = P (\text{sampler fluid}) - P (\text{surrounding fluid}).$$

As shown above, the internal pressure of the sampler is controlled by the temperature, sample volume and composition being constant. On the other hand, the wellbore fluid pressure is mainly controlled by the hydrostatic head. The typical time taken to bring the sampler back to the surface (a few hours) considerably exceeds the thermal equilibration time between the fluid contained in the metallic sampler and the surrounding fluid. Thus, in the journey to the surface the fluid sample temperature follows the temperature profile of the well. Therefore, the internal and external pressures along the wellbore must be compared at the wellbore temperature.

Assuming, for the sake of the argument, approximately linear profiles for P and T , the wellbore pressure at a given depth is proportional to the corresponding temperature. This linear relationship, if superimposed on the P - T diagrams of Figures 3 or 7, would appear as straight lines (one for each well depth) running between (P_B, T_B) and (P_w, T_w) , the points corresponding to bottomhole and wellhead conditions respectively. For given bottomhole conditions these straight lines would pivot around (P_B, T_B) if P_w or T_w are varied. As discussed, P_w is determined mainly by the hydrostatic head. Therefore T_w is the main variable controlling the slope of the straight lines representing the wellbore fluid pressure in the P - T diagram. The slope decreases with decreasing values of T_w . At a given temperature the difference between the curve representing the fluid sample pressure and the straight line representing the wellbore fluid pressure for each well depth is ΔP , the differential pressure. For T_w sufficiently large, the straight line lies below the fluid sample pressure, and ΔP is positive. But decreasing T_w causes the straight line to pivot around (P_B, T_B) towards high pressures, and eventually ΔP becomes negative in the wellbore. In actual wells the relationship between wellbore fluid and temperature generally shows some curvature. But the argument made above still applies qualitatively. Thus, in "hot" ("cold") wells, ΔP tends to be positive (negative).

At wellhead, the sampler is enclosed in the lubricator. The fluid in the lubricator is isolated from the wellbore fluid by means of valves. In this condition the fluid in the lubricator is at constant volume and composition, neglecting leaks and thermal expansion. Thus, the lubricator fluid pressure is controlled by the temperature, given the initial values of the composition λ_w , pressure P_w and temperature T_w .

Using λ_w , P_w , and T_w from Table 1 as initial conditions, I computed temperature dependent lubricator fluid quantities from the "equation of state", at constant molar volume v and composition λ , for both well depths considered. Two curves resulted for each quantity (Figures 5 through 7) because for each well, two different wellhead conditions (i.e., λ_w , P_w , T_w) were considered. Results closely resemble those obtained for the sampler.

In Figure 7 the fluid sample pressures are compared with the pressures of the surrounding fluid in the lubricator at the common equilibrium temperatures. This Figure indicates that in the lubricator ΔP may be positive or negative. This comparison is valid for cases in which the wellhead parameters during sampling are comparable to the wellhead parameters of fast flowing wells, as defined above. Negative values of ΔP are favored when $(T_B - T_w) \sim$ several tens of degrees C.

These results are useful to assess the performance of certain samplers in which the valves are kept closed by the combined pressures of a spring and of the internal (or external) fluid. Since the pressure exerted by the springs is negligible with respect to the fluid pressures involved, these samplers will leak when ΔP is negative (positive).

v) Sampler Recovery

High (up to about 840 atm) internal pressures are expected for the lubricator at steady state wellhead temperatures. Even higher internal pressures, up to essentially P_B , are also indicated for the sampler. These high pressures are accompanied by high temperatures in a saline ambient which may include sulfur (and other) compounds, resulting in especially favorable conditions for micro-crack development that may result in catastrophic material failures. Hot, high pressure leaks through joints and valves constitute another unpleasant possibility. These circumstances bear not only on the material aspects of sampling geopressured fluids, but also on the risk level faced by the crew in charge of sampler recovery.

A simple procedure, which would significantly lessen the material and personal risks concomitant with sampler recovery, is suggested by the results of this section. This procedure consists of two steps. First, the lubricator is isolated from the fluid flow by closing appropriate valves, to minimize thermal contact. Then the lubricator is externally cooled down to near ambient temperatures. The second step would substantially decrease the internal pressures of both the lubricator and the sampler (Figure 7). Thermal shocks on the sampler would be minimized this way. This procedure has the added advantage of minimizing the differential pressure felt by the sampler walls. For example, in the extreme conditions corresponding to the deep well case ΔP may reach (Figure 7) a maximum value of 554 atm, as compared to 1400 atm if no cooling were performed; the value of ΔP would be reduced to essentially the internal sampler pressure of 310 atm, at recovery, if the lubricator were brought to 25°C before pressure release.

iv) SUMMARY

A simple model for the "equation of state" of the $H_2O - CH_4$ system has been used to predict fluid behavior during sampling operations of unexploited geopressured reservoirs of the United States Gulf Coast. The main results are as follows.

The methane content of the fluid samples may vary widely, from about 1400 ppm to about 14400 ppm. The former figure corresponds to hypothetical, highly saline (250,000 ppm NaCl) samples from near the top of the geopressured zone; the later figure corresponds to hypothetical, very low salinity samples from near the bottom of the geopressured zone. Sample methane content tends to increase rapidly with increasing bottomhole temperatures and pressures, and to decrease with increasing salinity.

When a geopressured well is initially tested, the overall (liquid and gas phases included) concentration of methane at wellhead differs negligibly from that of the reservoir fluid, if large flowrates (velocities $\gtrsim 100 \text{ m s}^{-1}$) occur. This provides an approximate check on results obtained with samplers.

At surface temperatures (assumed to range approximately from 25°C to nearly 200°C), and before depressurization, the fluid samples consist of a two-phase mixture (liquid and gas), but gas saturations are small ($\lesssim 10\%$ by volume) and significant fractions ($\gtrsim 20\%$) of CH_4 remain in solution, indicating considerable methane exsolution upon depressurization for sample transfer. This information is useful in planning procedures and hardware for fluid sample transfer.

Cooling rapidly decreases sample pressures, e.g. from bottomhole values of up to about 1400 atm at 200°C to a maximum value of about 300 atm at 25°C. Therefore, formation of a methane hydrate, that takes place at pressures in excess of 463 atm at 25°C, is not normally expected in the sampler before transfer. However, local overcooling due to depressurization concomitant with sample transfer might cause methane hydrate formation in and near transfer valves.

The differential pressures exerted on the sampler may be positive or negative, depending on the wellbore temperature profile. Substantial temperature gradients along the wellbore ($T_B - T_w \approx$ several tens of degrees C) favor situations where the external fluid pressures exceed the internal pressure. This indicates that samplers relying on a combination of spring and internal (external) fluid pressure to keep the valve(s) closed will leak when used in "cold", non-preheated ("hot", preheated) wells.

Finally, a simple procedure to reduce personal and material risks associated with sampler recovery is suggested. It consists of externally cooling the closed lubricator containing the sampler to near ambient temperatures. This would substantially decrease the internal pressures of both the lubricator and the sampler, and also the differential pressure exerted on the sampler.

ACKNOWLEDGMENTS

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NOMENCLATURE

Variables

f_{NaCl} : Correction factor for CH_4 solubility in NaCl solutions
 n : mole number
 P : pressure
 $r = n_2^L / (n_2^L + n_2^G)$: fraction of total methane in the liquid phase
 S : volume fraction corresponding to the gas phase
 T : temperature

Table 1

Bottomhole-Wellhead Relations

	Z(m)	P _B (atm)	T _B (°C)	T _W (°C)	λ _W (mole%)	λ _W (ppm)	P _W (atm)	S _W (%)	x _W (mole%)	y _W (mole%)	r _W (%)
-94-	6000	1400	200	200	1.555	14,029	846	1.64	1.19	98.19	76.0
	6000	1400	200	150	1.555	14,029	834	3.53	0.72	99.44	45.9
	3600	800	150	150	0.704	6,297	460	1.51	0.51	98.98	72.9
	3600	800	150	100	0.704	6,297	454	2.40	0.37	99.78	52.0

NOMENCLATURE

Variables (continued)

v: molar volume

x: CH₄ mole fraction in the liquid phase

y: CH₄ mole fraction in the gas phase

z: well depth

$\lambda = (n_2^L + n_2^G) / [(n_2^L + n_2^G) + (n_1^L + n_1^G)]$:
mole fraction of methane in the system

Super- and sub-indexes

B: bottomhole conditions

G: gas phase

L: liquid phase

W: wellhead conditions

1: H₂O

2: CH₄

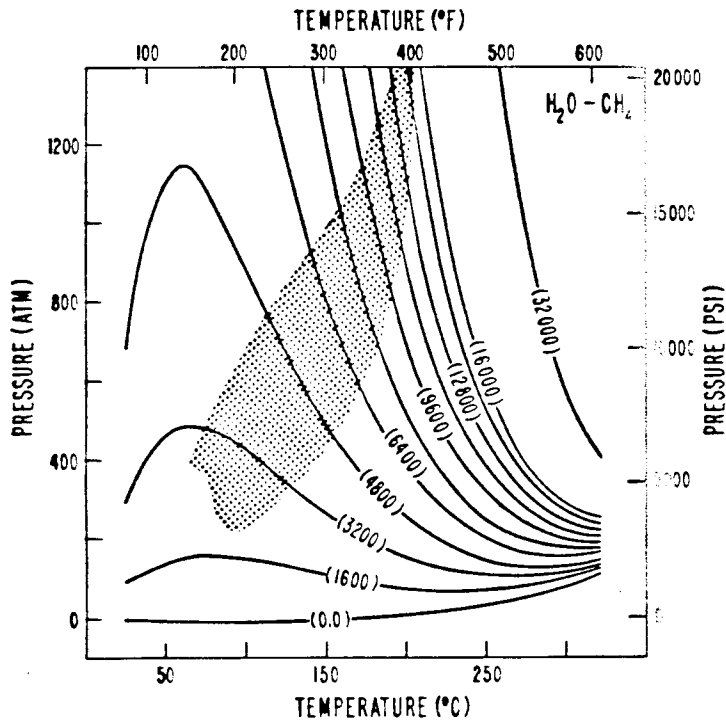


Fig. 1. Solubility curves for the H_2O-CH_4 system. (ppm) methane concentrations are indicated. The shaded area represents, approximately, the range of pressure and temperature covered by the formation fluids of the Gulf Coast in the United States.

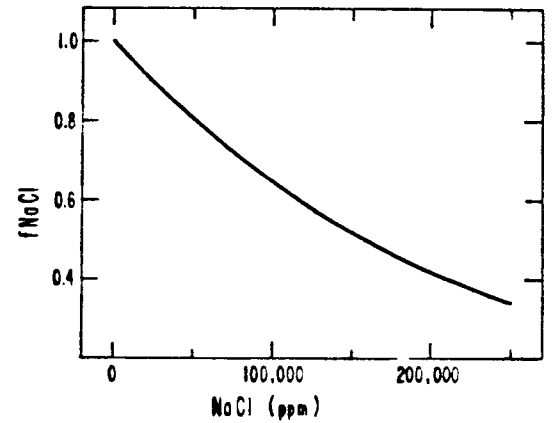


Fig. 2. Salinity correction factor. The solubilities of CH_4 in NaCl brines may be estimated by the product of f_{NaCl} times the solubility of methane in pure water at the same pressure and temperature.

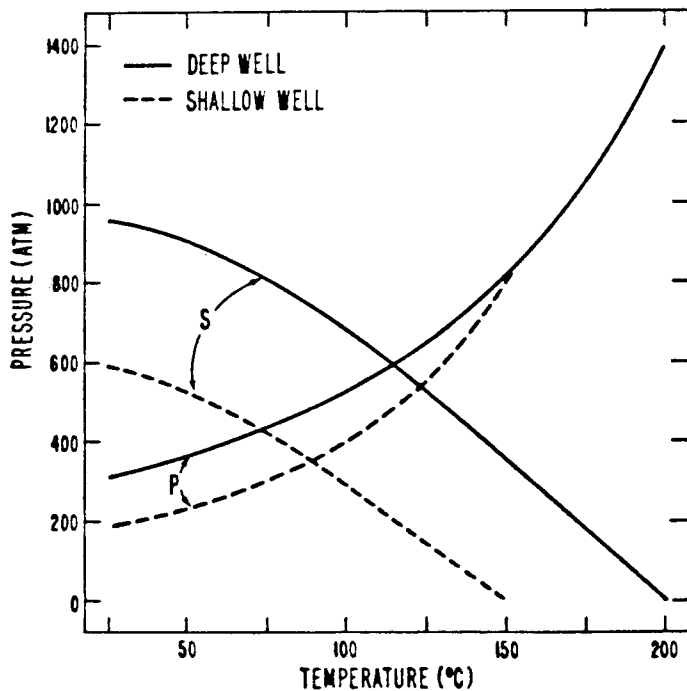


Fig. 3. Pressure and (volumetric) gas saturation responses of the sampler's fluid to cooling for two well depths: 6000 m (---) and 3600 m (—).

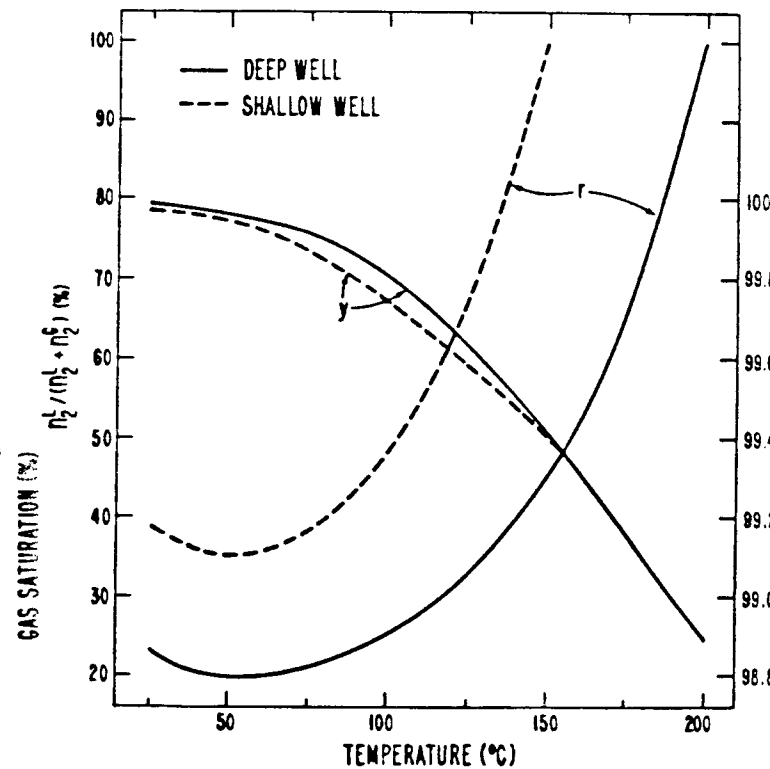


Fig. 4. Fraction of total methane in solution and gas phase methane mole fraction responses to sampler cooling for two well depths.

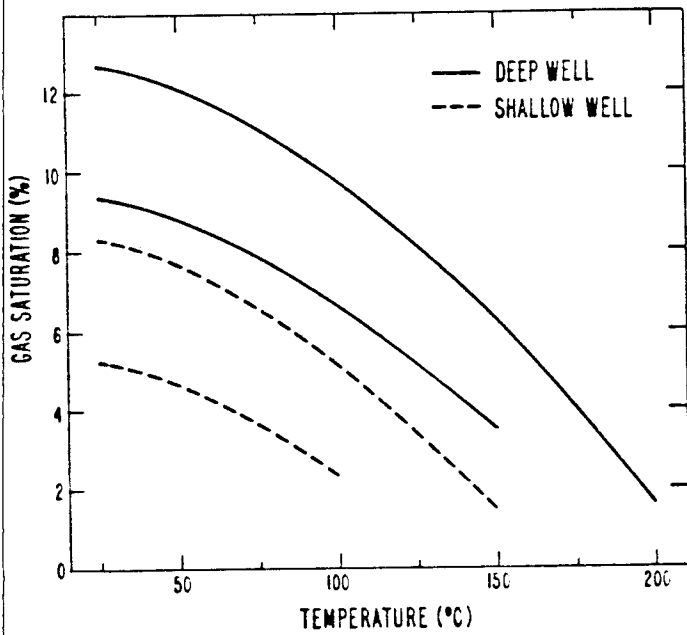


Fig. 5. Gas saturations vs. temperature for the (closed) lubricator. Two curves, corresponding to two different assumed values for the steady-state wellhead temperature, are shown for each well depth.

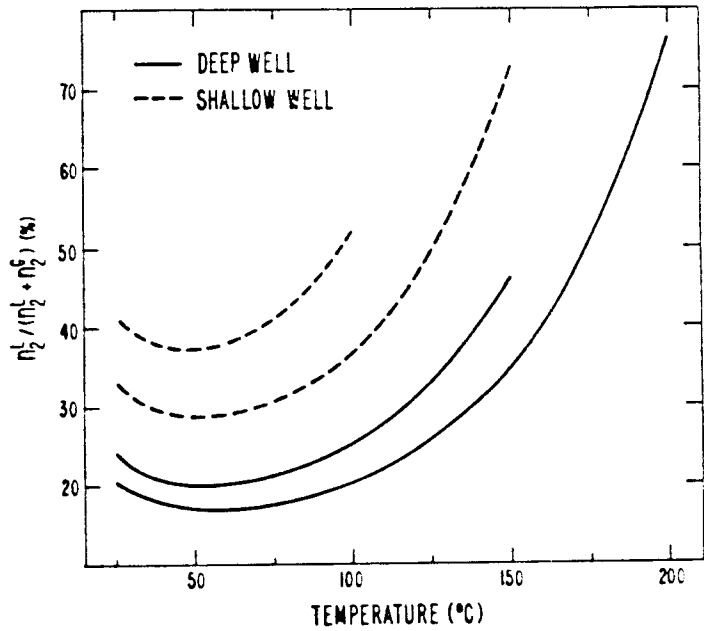


Fig. 6. Fraction of total methane in solution vs. temperature for the (closed) lubricator. Two curves, corresponding to two different assumed values for the steady-state wellhead temperature, are shown for each well depth.

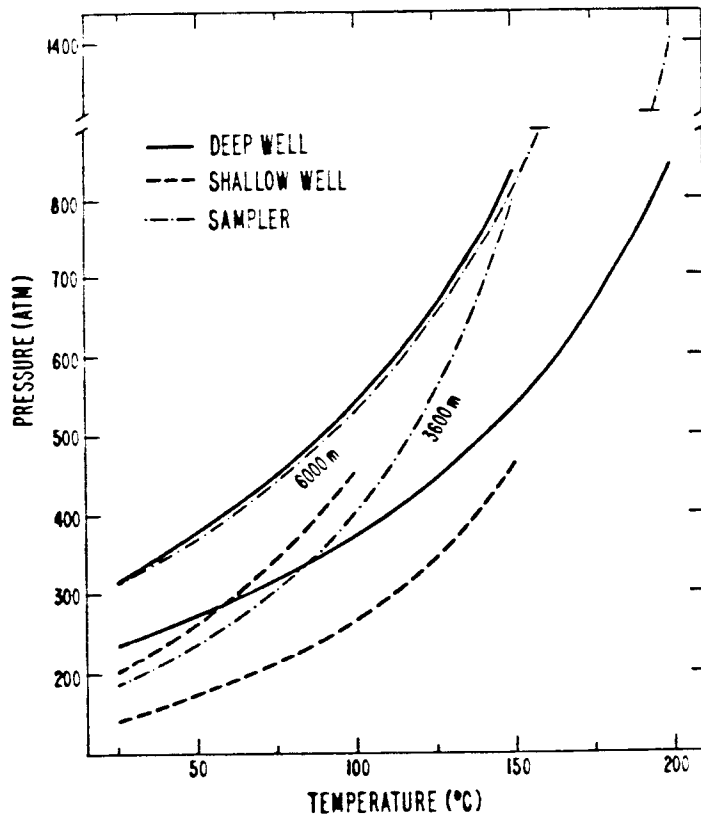


Fig. 7. Fluid pressure vs. temperature for the (closed) lubricator. Two curves, corresponding to two different assumed values for the steady-state wellhead temperature, are shown for each well depth. For comparison, the P-T curves corresponding to the sampler fluid for each well depth are also shown.

An Evaluation of Geopressured Brine Injectability

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INTRODUCTION

New concepts for the high temperature/high pressure recovery of methane from geopressured brine have been developed by Lawrence Livermore National Laboratory (LLNL).¹⁻² The primary objective of these methane recovery processes is to preserve sufficient hydraulic energy to drive the subsequent subsurface disposal of spent brine effluents at substantial reductions in operating and maintenance costs associated with use of injection pumps. However, a key element in determining the feasibility of the overall methane recovery process is the need to quantitatively establish injectability characteristics of geopressured brine at elevated temperature and pressure.

We have developed an apparatus with a capability for evaluating geopressured brine injectability at elevated pressures and temperatures. The apparatus utilizes membrane filters as injection zone reservoir analogs and permits injectability tests to be performed in accordance with Barkman and Davidson Methodology.³ A field evaluation of geopressured brine injectability was completed during September 22-25, 1980 at the DOE, Brazoria test site in Texas. Membrane filters, with pore sizes of 0.4- μ m and 10.0- μ m, were used as the basis for obtaining suspended solids data and for developing performance-life estimates of typical spent brine injection wells. Field measurements were made at 130°C and line pressures up to 3800 psig. Scale inhibited (phosphonate-polyacrylate threshold-type, carbonate scale inhibitor), prefiltered-scale-inhibited, and raw (untreated) brine were evaluated. Test results indicated raw brine was highly injectable, while scale-inhibited brine had extremely low quality. The poor injectability of scale-inhibited brine resulted from partial precipitation of the scale inhibitor.

INJECTABILITY TESTING METHODOLOGY

The most reliable method of establishing water quality in conjunction with full-scale injection tests is based on the use of membrane filters (and core samples) as analogs of the injection formation.³⁻¹¹ Membrane filtration data reveal the matrix permeability impairment potential of injected water resulting from scale formation or deposition of suspended solids. Loss of disposal capacity resulting from insufficient disposal formation volume, pre-existing skin damage, or other reservoir insufficiencies, however, cannot be directly identified by filtration tests.

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Similarly, factors which may favorably impact disposal capacity such as the presence of high permeability thief zones or fractures within the disposal interval cannot be directly accounted for by the membrane filtration methodology.

Selection of membrane filters with the appropriate pore size for the work reported here was based on an empirical method described by Champlin et al,¹² which permits calculation of mean formation pore size if formation porosity and permeability are known. We selected Nuclepore, polycarbonate, 10- μ m pore size membrane filters as conservative analogs of shallow, high permeability disposal zones. Nuclepore, polycarbonate membrane filters with 0.4- μ m pore size, were also used to obtain baseline suspended solids data and as conservative analogs of deep geopressured disposal zones where formation permeability might be less than 100md.

TEST APPARATUS DESIGN

A schematic of the injectability test apparatus is shown in Figure 1. The test frame, based on previously field proven designs,¹³⁻¹⁴ was connected, as a bypass system, to the main site flow system, shown schematically in Figure 2, via a suitably designed high pressure manifold. Injectability tests were carried out at constant differential pressure across the filtration membrane. Coarse and fine control valves were used to initially set and maintain differential pressure. Cumulative flow and instantaneous flowrate were obtained by direct measurement using 2 litre graduated cylinders. Flashing of the brine following passage through the membrane filter was prevented by use of a water-cooled, Inconel-600 heat exchanger upstream of the final control valve. All system piping was constructed from Inconel-600 high pressure tubing for adequate corrosion control. Valves and fittings were made of 316 stainless steel. The system was designed for in-line testing of geopressured brine at pressures and temperatures to 2000 psi and 150°C, respectively. Inclusion of the by-pass manifold permitted testing geopressured brine at wellhead pressure to 4000 psig.

INJECTION WELL HALF-LIFE ESTIMATES

Half-life estimates for the Brazoria test site brine disposal well were calculated after the method of Barkman and Davidson³ for a constant pressure drop process (Appendix I). The calculated half-life is the time required for the injection rate to decline to one-half of its initial value. Disposal well impairment was calculated for the cases of well bore narrowing and invasion. Well bore narrowing results when a filter cake forms on the sand face and then builds inward eventually partially filling the well bore. The invasion model accounts for penetration of the disposal formation by fine suspended solids which ultimately form an internal filter cake within the disposal formation. Relevant formation and injection parameters that form the basis for the half-life estimates are provided in Table 1. Half-life estimates are provided in Table 2.

Figure 1. SIMPLIFIED SCHEMATIC OF THE MEMBRANE FILTRATION
INJECTABILITY TEST APPARATUS

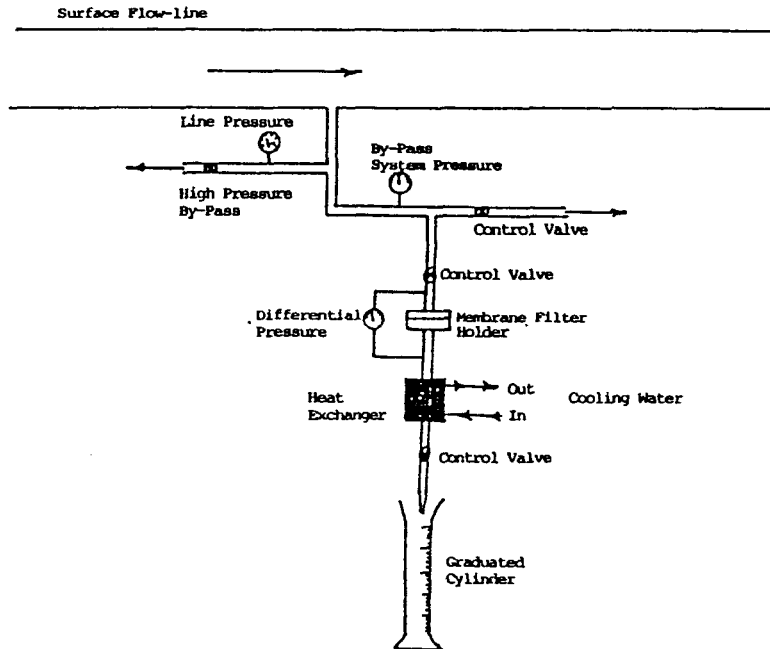


Figure 2. GENERALIZED SCHEMATIC OF DOE'S
BRAZORIA GEOPRESSURED-GEOTHERMAL TEST SYSTEM

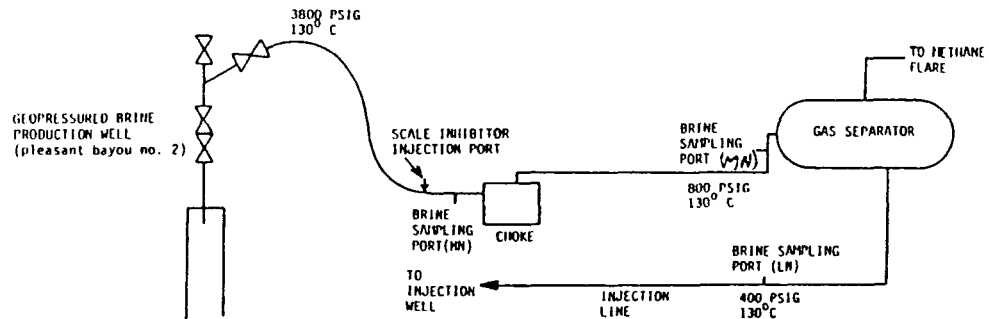


TABLE 1

ASSUMED DISPOSAL FORMATION AND INJECTION PARAMETERS:
DOE'S BRAZORIA GEOPRESSURED-GEOTHERMAL TEST SITE

Brine Temperature	130°C
Brine Salinity	13.5 wt % NaCl
Brine Density	1.1 g/cc
Brine Viscosity	0.32 cp
Injection Rate	22,000 BBL/Day
Radius of Injection Tubing	0.0699 m
Length of Injection Interval	53 m
Injection Formation Permeability	1000 md
Injection Formation Porosity	20%
Radius of Effect	182.9 m
Invasion Radius	3.05 m
Filter Cake Density	2.70 g/cc
Exposed Area of Membrane Filters	13.2 cm ²

Table 2.

INJECTION WELL HALF-LIFE ESTIMATES FOR THE DOE-BRAZORIA GEOPRESSURED TEST SITE

Run	Date (Sept, 1980)	Membrane Filter Pore Size (µm)	1 µm Cuno Cartridge Prefilter	Pressure (PSI)		Membrane Filter ΔP (PSI)	Temperature (°C)		Scale Inhibitor (PPM)	Filtered Volume (ml)	Suspended Solids (mg/l)
				Source	Head, Filter		Source	Filter			
LN-1	22	0.4	No	360	360	50	130	90	50	2,598	10.0
LN-3	22	10.0	No	350	350	50	130	90	50	2,920	6.0
LN-5	22	0.4	No	360	360	50	130	107	50	1,920	6.0
LN-7	22	10.0	No	360	360	50	130	122	50	2,300	8.7
LN-11	23	10.0	Yes	300	300	0.03	130	126	50	39,400	0.05
LN-13	23	0.4	No	370	370	50	130	119	50	1,620	14.8
LN-14	23	10.0	No	400	400	50	130	115	50	1,610	9.9
LN-15	24	10.0	No	400	400	50	130	115	50	1,960	8.0
LN-16	25	10.0	No	400	400	0.03	130	130	0	28,310	0.021
MN-1	23	0.4	No	800	800	50	130	112	50	2,530	13.5
MN-2	23	10.0	No	800	800	50	130	120	50	3,340	11.8
MN-3	23	10.0	Yes	760	760	0.03	130	129	50	36,000	0.031
MN-1	24	0.4	No	3000	400	50	130	120	50	2,630	1.4
MN-2	24	10.0	No	3000	400	5	130	128	50	19,300	0.067
MN-3	24	0.4	No	3000	1000	70	130	119	50	4,320	0.69
MN-4	24	10.0	No	3000	1000	0.1	130	130	50	13,540	0.27
MN-5	25	0.4	No	3000	1800	50	130	120	15	4,620	1.3
MN-6	25	10.0	No	3000	1000	1	130	120	15	5,160	1.3
MN-7	25	10.0	No	3800	1500	20	130	125	50	10,110	0.41
MN-9	25	10.0	No	3800	1000	1	130	127	50	5,850	0.48
MN-8	25	10.0	No	3800	1000	0.03	130	129	0	31,000	0.026

Filtration Curve		Water Quality (PPM/nd)	kc (nd)	F-Factor (22,000 B/D)	G4-Factor (No Invasion)	* Half-life (YRS)	G4-Factor (Invasion)	* Half-life (YRS)	Run
Intercept (ml)	Slope (mV/n)								
- 1.4	674.2	2801.2	0.0032	0.17			0.0061	—	LN-1
+ 510.5	640.2	2662.9	0.0021	0.29			0.0038	—	LN-3
- 91.1	482.9	4680.3	0.0013	0.75	3.0x10 ⁻⁶	—		—	LN-5
+ 365.3	514.9	3814.5	0.0021	0.20			0.0038	—	LN-7
-28627.2	13579.4	0.0036	12.8	34.4	0.27	9.3	20.8	717.3	LN-11
- 507.2	546.1	3659.7	0.0037	0.12	0.0001	—		—	LN-13
- 3.9	383.2	7437.5	0.0012	0.17	3.0x10 ⁻⁶	—		—	LN-14
+ 71.8	462.1	5111.1	0.0014	0.22			0.0031	—	LN-15
-23497.7	14853.9	0.0030	6.4	81.9	0.14	11.8	11.0	902	LN-16
- 770.9	708.7	2173.0	0.0057	0.13	0.0001	—		—	MN-1
- 157.1	740.5	1990.9	0.0054	0.15	0.0001	—		—	MN-2
-29990.0	17009.7	0.0023	12.5	55.5	0.26	14.7	20.3	1129	MN-3
- 325.4	737.7	2005.5	0.0064	1.23	<1x10 ⁻⁶	—		—	MN-1
-12272.7	9090.9	1.32	0.046	25.7	0.0011	0.028		—	MN-2
- 1400.8	1447.2	729.6	0.0006	2.5	2x10 ⁻⁴	—		—	MN-3
+15300.0	833.3	3.14	0.078	6.4			0.14	0.89	MN-4
- 1587.0	1527.7	467.6	0.0025	1.3	0.0001	—		—	MN-5
- 2474.0	740.4	39.0	0.030	1.3	0.0007	—		—	MN-6
+ 5250.6	944.0	409.9	0.0008	4.2			0.0015	0.0063	MN-7
+ 4417.5	797.0	256.0	0.0017	3.6			0.0030	0.011	MN-9
-30202.8	15676.7	0.0027	8.9	66.2	0.20	12.8	14.9	985	MN-8

* Half-life
Estimates Denoted
By — Are Less
Than One Day

A summary of average suspended solids data for the Brazoria system is provided in Table 3. If we assume an average suspended solids concentration of 11.8 mg/l is supplied to the injection well at a brine flow rate of 22,000 BBL/day, then approximately 91 pounds of solids would be deposited in the injection well on a daily basis (16.5 tons per year). The suspended solids data suggest that about 24% of the suspended solids in the injection line are less than 10- μ m in diameter.

The test results indicated, as shown in Figure 3, that brine treated with scale inhibitor had extremely low quality even after passage through the gas separator. Brine which was prefiltered with a 1- μ m pore size Cuno cartridge filter had high quality. Ultimately it was demonstrated, by temporarily interrupting the injection of scale inhibitor, that the scale inhibitor itself was the cause of the poor injectability characteristics of the brine. Untreated brine had equivalent or higher quality than prefiltered scale-inhibited brine!

The solids collected on several of the membrane filters were analyzed by x-ray diffraction and by energy dispersive x-ray fluorescence (EDAX) in conjunction with scanning electron microscopy. When no inhibitor was being injected, the small quantity of solids were mostly silicon, perhaps sand from the formation, and some particles of BaSO_4 . When the inhibitor was being injected, a large amorphous component was present in the solids, which was rich in phosphorous, calcium, sodium, and chlorine. This is a strong indication that the phosphonate inhibitor either precipitated directly or reacted with the brine calcium to form a precipitate, and in the process occluded some of the brine NaCl . Calcite could not be identified in the solids from the brine being injected.

CONCLUSIONS

Test results and subsequent analysis of filtered solids demonstrated conclusively that the threshold carbonate scale inhibitor, which was injected into the top of a two-phase (noncondensable gases-brine) mixture, upstream of the wellhead choke, caused precipitation of up to 15 ppm of suspended solids. The suspended solids carried through the gas separator and ultimately were deposited within the injection well and/or the injection formation. In the absence of scale inhibitor, the raw geopressured brine had extremely high quality.

Based on these results, it can be concluded that Brazoria brine has high injectability at pressures varying from 380 to 3800 psi, even after gas separation, provided scale control additives, if required, do not degrade brine quality.

It is of interest to speculate about the fact that the injection well at the Brazoria site (Pleasant Bayou No. 1) continued to accept low quality brine with a moderate rate of back-pressure

buildup while half-life estimates predicted an extremely short operating life for the well. A plausible explanation for this apparent anomalous behavior is related to the rather unique completion of the injection well.

The injection well was originally designed as a production well. However, problems encountered during drilling necessitated plugging of the borehole back from 15,675 ft. to about 8,500 ft. The hole was then recompleted for use as a disposal well.

Our half-life estimates were based on an injection interval of about 160 feet. However, if brine was able to flow past the cement retainer, at the bottom of the completion interval, via an annulus behind the casing, then the actual injection interval could have been literally thousands of feet in length. Altering the injection interval length by a factor of 20 to 30 would be sufficient to yield much longer half-life estimates.

ACKNOWLEDGEMENTS

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Figure 3. 10.0 MICRON MEMBRANE FILTRATION DATA
LOW PRESSURE INJECTION LINE
(380 PSI; 130°C)

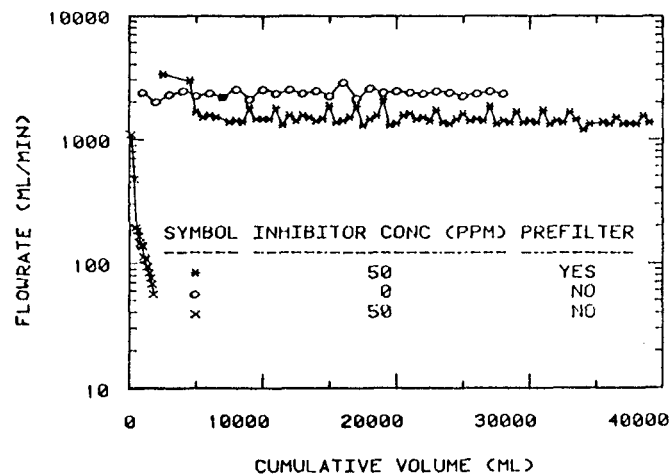


TABLE 3

SUMMARY OF SUSPENDED SOLIDS DATA FOR THE
DOE-BRAZORIA GEOPRESSURED TEST SITE

Brine Source	Membrane Filter Pore Size (μ m)	1-mm Prefilter	Carbonate Scale Inhibitor (PPM)	Suspended Solids (mg/l)
LN-Series Low Pressure Injection Line (400 PSIG; 130°C)	0.4	No	50	10.8
	10.0	No	50	8.2
	10.0	No	0	0.02
MN-Series Moderate Pressure Pro- duction (800 PSIG; 130°C)	0.4	No	50	13.5
	0.4	Yes	50	0.07
	10.0	No	50	11.8
	10.0	Yes	50	0.03
HN-Series High Pressure Wellhead (3800 PSIG; 130°C) about 5 feet upstream of scale inhibitor injection port	0.4	No	50	1.1
	10.0	No	50	0.5
	10.0	No	0	0.03

APPENDIX 1: HALF-LIFE CALCULATIONS

$$T_{1/2} = (F)(G) \quad (1)$$

where:

$T_{1/2}$ = Injection well halflife

$$F = (1.723 \times 10^4) \left(\frac{\pi \cdot r_w^2 \cdot h \cdot \rho_c}{i_o \cdot w \cdot \rho_w} \right) \quad (2)$$

where: F = time to fill the wellbore with solids at the initial flow rate (years)

r_w = wellbore radius (meters)

h = injection interval (meters)

i_o = initial injection rate (STBD)

w = concentration suspended solids (μ g/g)

ρ_c/ρ_w = density ratio, filter cake: brine

Estimates of the permeability of filter cakes were developed from calculation of the water quality ratio given by:

$$\frac{w}{K_c} = (8166.11) \left(\frac{1}{S^2} \right) \left(\frac{2 \rho_c A^2 \Delta P}{\mu \rho_w} \right) \quad (3)$$

where: w = weight concentration of solids in water (μ g/g)

K_c = filter cake permeability (md)

S = slope of cumulative volume vs. square root of time (ml/ $\sqrt{\text{min}}$) S is determined by linear regression of the linear portion of the filtration curve.

ρ_c = bulk density of filter cake (gm/cm³)

ρ_w = density of water (gm/cm³)

A = exposed area of filter cake (cm²)

ΔP = total pressure differential across filter (psi)

μ = fluid viscosity (cp)

Equations yielding exact G-factors for wellbore narrowing and invasion are given in Reference 3.

PRELIMINARY TEST RESULTS OF THE FIRST GEOPRESSURED-GEOTHERMAL
DESIGN WELL, BRAZORIA COUNTY, TEXAS

R.C. MacDonald
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The University of Texas at Austin

INTRODUCTION

The Pleasant Bayou #2 Geopressured-Geothermal test well was completed in the summer of 1979. The C sand of the Frio formation was selected for completion on the basis of core analysis, well logs, and drillstem tests. The purpose of this paper is to summarize the results of the short term production tests run on the Pleasant Bayou #2 well during 1979 and the Fall of 1980. These tests were analyzed using conventional transient pressure test analysis methods.

The most significant test run during 1979 was a ten day drawdown test from December 3 to December 14 followed by a 20 day buildup period, during which reservoir pressure response was observed. After a hiatus of nine months, a second production test was conducted over a period of 45 days beginning on September 16, 1980. The well was shut in on October 31, 1980. Pressure buildup data continues to be monitored.

Both production tests indicate a formation permeability of 200 millidarcies. The presence of a permeability interruption located approximately 3700 feet from the wellbore is also suggested by these tests.

During the last production test, a producing gas-water ratio of 20 standard cubic feet per barrel of produced water was observed. An additional 9-12 standard cubic feet of gas per barrel was found in the water downstream of the separator. The total gas-water ratio of 29-32 SCF/bbl is in reasonable agreement with laboratory data and correlations for this produced brine.

The major growth fault which forms the reservoir boundary to the northwest of the well is evident from the pressure drawdown data obtained during the last production period. The last production test also indicates an apparent rate dependent skin effect.

RESERVOIR PARAMETERS

The C sand reservoir is separated from the other sand members of the Frio formation by shale zones. As shown on the isopach map of the C sand after Bebout et al (1), Figure 1, the reservoir is approximately 30 miles long in the southwest-northeast direction along the major growth fault which bounds the reservoir and averages 5 miles in width perpendicular to this major fault. The C sand reservoir body may be fragmented by cross faulting perpendicular to the major fault. However, the effects of this cross faulting on reservoir continuity must await the results of flow testing over extended production periods.

IXTLAN DE LOS HERVORES, MICH.

This field is located East of Lago de Chapala, at an altitude of 1,535 m (a.s.l.). In this area there are thermal manifestations of high intensity in more than 2 km², mainly hot springs which have a temperature of 90°C, boiling mud lagoons, fumaroles and steam vents. Geological, geochemical and geophysical studies have been made in this area. Three wells of large diameter have been drilled with one of them discharging a low enthalpy steam-water mixture for more than 20 years. To determine the potential of this area, deep drilling is planned.

LOS NEGRITOS, MICH.

This field is located at the intersection of La Sierra Madre Oriental and the Eje Neovolcánico. It is East of Lago de Chapala, 27 km of the Ixtlán de Los Hervores field, at an altitude of 1,535 m (a.s.l.). This is a flat area characterized by a great number of thermal manifestations such as mud volcanos and bubbling ponds with temperatures of 40 to 90°C. Geological, geochemical and geophysical studies have been performed in this area. Twenty wells of 100 to 400 m deep were drilled to measure thermal gradients obtaining in some of them low pressure, water steam discharges. One well of 700 m deep was drilled obtaining a flow of low enthalpy.

EXPLORATIONS IN LOS HUMEROS, PUEBLA

This field is located in the State of Puebla, 30 km West of Ciudad Perote, Ver. Studies have been made in an area of 7,000 km². According to these studies, this area is very promising for commercial exploitation. Los Humeros, El Xalapazco and Las Derrumbadas are the most outstanding for their geothermal activity. At present, it is planned to start exploratory drilling in the first months of 1981.

GOALS OF GEOTHERMAL ENERGY IN MEXICO FOR THE NEAR FUTURE

The geothermal resources that are being developed in Mexico, have the goal of exploiting commercially this alternative source of energy. The Comisión Federal de Electricidad has supported the use of this energy source along with the utilization of coal, hydroelectricity, nuclear and solar energy. As far as geothermal energy is concerned, the goal to be reached by the year 2000 is to generate a total of 20 millions of KW every year. This will be feasible with the exploitation of the geothermal fields located in the Northwestern part of the country, in the Eje Neovolcánico and in the Southeastern part in the Chiapas State.

The C sand found in the Pleasant Bayou #2 well is 60 feet thick with a porosity of 17.6% determined from standard core analysis. Compaction coefficients on the order of 5×10^{-7} psi⁻¹ have been reported by Gray et al (4) for the reservoir sand. However, these investigators have noted that this material exhibits creep behavior and therefore caution must be observed when using these data under the assumption of elastic rock behavior. Water properties have been computed from correlations (3) assuming a gas saturated brine containing 130,000 ppm of dissolved solids. The following table summarizes the data used in the transient pressure test calculations:

Reservoir thickness	60 feet
Average porosity	17.6%
Uniaxial compaction coefficients	5×10^{-7} psi ⁻¹
Pore compressibility	2.3×10^{-6} psi ⁻¹
Water compressibility	4×10^{-6} psi ⁻¹
Water viscosity	0.25 cp
Water formation volume factor	1.05 RB/STB
Wellbore radius	3.5 inches

PRODUCTION TEST DATA

Clark (2) has summarized the production test information obtained during the initial period in 1979. The first production from the well occurred on July 9-10, 1979, immediately after the well was perforated. Surface pressure measurements were taken as the pressure gauge would not operate at bottom hole conditions. Clean up of the perforations during this flow period caused interference with the test results.

From November 15 to November 18, 1979, three production periods occurred, the first two of rather short duration. The third flow period lasted over 2 days and provided the first significant test data. Problems with the bottom hole pressure gauge forced the termination of this test. The well was again put on production on November 23, 1979, and was shut-in on November 25 due once again to gauge problems. This testing period served primarily as a check out of the equipment and procedures, as well as providing preliminary reservoir data.

The first substantial flow period for the well occurred from December 3, 1979 to December 14, 1979. During this ten day period, the well produced at an average rate of approximately 13,500 barrels per day. During this test, it was necessary to periodically move the pressure gauge in the well and, thus, the pressure information is somewhat suspect, although later tests have confirmed the general validity of the results obtained from this drawdown period.

The first definitive data with respect to reservoir properties was obtained from the pressure buildup behavior observed after the December 3 - 14 ten day production test. This data is presented in Figure 2 in the form of the conventional Horner plot, in which the logarithm of the time factor

$$\frac{T + \Delta t}{\Delta t} \quad (1)$$

is plotted against the observed pressures. The flowing time, T, is taken as the cumulative production divided by the last sustained flowrate before closing in the well. The time after shutin, Δt , corresponds to the measured bottomhole pressure observations. In this case, the cumulative production was taken to be 240,000 barrels, which includes all production from tests since July 1979. The last sustained production rate was 13,650 barrels per day, resulting in an equivalent Horner flow time of 422 hours.

Beginning on September 16, 1980, a 45 day variable rate production test was carried out. The production rate schedule for this test is given below:

<u>Time Period</u>	<u>Δt (Hours)</u>	<u>Production Rate (bbls/day)</u>
Sept 16 11:30 am	127	6750
Sept 21 7:50 pm	232	10920
Oct 1 11:00 am	67	19102
Oct 4 6:00 am	103	14060
Oct 8 12:45 am	555	13500
Oct 31 5:32 am	to present	well shut in

The results of this multirate drawdown test are given in Figure 3, in which the data has been reduced by the superposition principle as discussed by Earlougher (3) to a plot of

$$\frac{P_i - P_{wf}}{q_n} \quad \text{versus} \quad \sum_{j=1}^N \frac{q_j - q_{j-1}}{q_n} \log_{10} (t - t_{j-1}) \quad (2)$$

If only one flowrate occurred in the test, then this plot would reduce directly to the more familiar plot of pressure drawdown versus the logarithm of the time. The initial pressure for this test was measured as 11116 psig @ 14560 feet.

The well was closed in on October 31, 1980, and the pressure buildup data continues to be monitored. The Horner plot of this information is given in Figure 4 and includes data through November 24, 1980. In reducing this buildup data, it was assumed that the reservoir had stabilized over the 10 month period, since the last production in December 1979, and that only production during the current testing period would affect the pressure buildup results. The Horner flow time, T, was computed to be 1011 hours based on a cumulative production since September 16, 1980, of 568,900 barrels of water and a final sustained rate of 13,505 barrels per day.

The buildup data obtained in December of 1979 and the multirate production test together with the subsequent pressure buildup data form the basis of the analysis presented in this paper.

FORMATION PERMEABILITY

Formation permeability is computed from the slope of the pressure

buildup or drawdown plots shown in Figures 2 - 4 by the relationship (3):

$$k = \frac{162.6 \text{ q}\mu B}{mh} \quad \text{or} \quad \frac{162.6 \mu B}{m'h} \quad (3)$$

where q - production rate (bbls/day)
 μ - viscosity (cp)
 B formation volume factor (RB/STB)
 h - formation thickness (feet)
 m - buildup slope (psi/ $\sqrt{t}$)
 m' - multirate drawdown slope (psi/ $\sqrt{t}$ -bbls/day)

It is important to select the slope from pressure data which is no longer affected by wellbore storage effects caused by flowrate changes, but as yet is not affected by reservoir boundaries or lateral changes in formation properties. The permeability computed from the three tests is as follows:

<u>Buildup Tests</u>	<u>Production Rate</u> (bbls/day)	<u>m</u> (psi/ $\sqrt{t}$)	<u>Permeability</u> (md)
December 1979 (Figure 2)	13650	54.5	178
November 1980 (Figure 4)	13505	48.0	200
<u>Drawdown Test</u>	<u>m'</u> (psi/ $\sqrt{t}$ - bbls/day)	<u>Permeability</u> (md)	
October 1980 (Figure 3)	0.0034	209	

The somewhat lower permeability computed from the December 1979 buildup test data may be the result of uncertainties in the measurement of production rates during the preceding drawdown period.

Based upon these results and discounting the December 1979 test, we conclude that the formation permeability in the neighborhood of the well is 200 md.

FAULTING AND BOUNDARIES

A perceptible change in the initial slope was observed in each of the three tests analyzed in this study. These slope changes are too subtle to be construed as a boundary or a sealing fault. However, they do indicate the presence of a change in formation transmissivity. The presence of a non-sealing fault could produce such an effect. The distance away from the wellbore at which this interruption might be found can be estimated from the relationship given by Earlougher (3):

$$r_{inv} = \sqrt{\frac{kt}{0.00105 \phi \mu c_T r_w^2}}$$

where k - permeability (md)
 t - time of investigation (hours)
 ϕ - formation porosity
 μ - viscosity (cp)

c_T - total effective compressibility (psi^{-1})
 r_w - wellbore radius (feet)

The following table summarizes these computations:

<u>Test</u>	<u>Time at slope change (hours)</u>	<u>Radius (feet)</u>
Dec. 1979 buildup	20	3672
Oct. 1980 drawdown	25	4449
Nov. 1980 buildup	18.4	3733

As observed on the plots, Figures 2 - 4, the time at which the slope changes is open to broad interpretation. Minor changes in the slope will substantially alter this time value. It is felt that the drawdown data is the most tenuous in this respect, and thus it is concluded that the alteration in formation transmissivity occurs at a distance of approximately 3700 feet from the well.

Neither buildup test has indicated as yet any evidence of sealing boundaries. However, the multirate production test data does indicate the presence of a sealing fault, which we interpret to be the major growth fault that bounds the reservoir to the northwest. The slope of the data taken during the last half of the test is $0.0096 \text{ psi}/(\text{~} - \text{ bbls/day})$ as compared to a consistent of $0.0053 \text{ psi}/(\text{~} - \text{ bbls/day})$ slope before this time. The virtual doubling of the slope is usually interpreted as indicating a sealing boundary. Determining the precise time at which the change in slope occurs is made difficult by the multirate effect on the generation of the reduced data used in the drawdown analysis. A time value of 530 hours was selected as the best estimate of the time when the slope change occurs. This value corresponds to a distance of investigation of 3.9 miles which agrees reasonably well with the geological interpretation of the growth fault. The buildup data presently being monitored should provide more definitive results in this regard.

SKIN EFFECT

Analysis of the recently concluded multirate production test suggests that apparent near well damage effects (i.e., the skin effects) are dependent on the production rate. The skin effect may be computed from the pressure drawdown equation as documented by Earlougher (3):

$$P_i - P_{wf} = m \left[\log_{10} \left(\frac{kt}{\phi \mu c_T r_w^2} \right) - 3.23 + 0.87S \right] \quad (7)$$

It is the usual convention to select the drawdown time as one hour, or

$$b = P_i - P_{wf} (1 \text{ hour}) = m \left[\log_{10} \left(\frac{kt}{\phi \mu c_T r_w^2} \right) - 3.23 + 0.87S \right] \quad (8)$$

where $P_{wf}(1 \text{ hour})$ is the pressure inferred from the straight line portion of the drawdown plot at a flow time of one hour. In the case of a multirate test, the analysis is similar except that both the slope, m , and the intercept (i.e., $t = 1 \text{ hour}$), b , are normalized with respect to the last flowrate

$$m' = \frac{m}{q_n} \quad b' = \frac{b}{q_n} \quad (5)$$

and the skin factor is computed as

$$S = 1.151 \left[\frac{b'}{m'} - \log_{10} \left(\frac{k}{\phi \mu c_T r_w^2} \right) + 3.23 \right] \quad (6)$$

As shown in **Figure 3**, the initial flow period of the drawdown test exhibits a slope of 0.0034 psi/(ν - bbls/day) and an intercept of 0.0316 psi/(bbls/day). The skin effect computed from the above equation for these conditions is 2.96 indicating moderate well damage.

The method of superposition is used to analyze the effects of the multiple production rates on the drawdown behavior. As such, the plot of,

$$\frac{P_i - P_{wf}}{q_n} \quad \text{versus} \quad \sum_{j=1}^N \frac{q_j - q_{j-1}}{q_n} \log_{10} (t - t_{j-1}) \quad (2)$$

should be a continuous progression of points. However, as observed in **Figure 3** there is a noticeable upward discontinuous shift in the data as the production rate is stepwise increased. The slope of each curve does remain the same. We have interpreted this behavior as an indication of a rate dependent skin effect.

The skin factor for each flowrate has been computed from equation 8 by extrapolating a value for the intercept b' , taking into account the change in slope observed during the initial flow period. The skin factors computed are:

Flowrate (bbls/day)	Skin Factor
6750	2.96
10920	4.96
19100	6.98

These skin factors are plotted versus production rate in **Figure 5**. Also shown on **Figure 5** are the skin factors computed from each of the buildup tests. The buildup test skin factors fall below the multirate drawdown trend, but are greater than the initial low flowrate skin factor.

The most plausible explanation for this behavior is the possibility that particle fines loosened in the formation near the wellbore during drilling and completion are pushed into pore throats at high production rates, thus reducing the permeability near the well.

An alternative explanation may be that non-darcy or 'turbulent' flow occurs near the well at higher flowrates. For this to occur, only a relatively small portion of the perforated interval could be open to flow in order to generate localized fluid velocities high enough to cause the non-darcy effect. Furthermore, if it were postulated that only a few feet of perforations were open to flow, then the skin effect caused by limited entry alone would be substantially higher than that observed.

The effects of gas evolution about the wellbore, should it occur, would not explain the observed behavior since the accumulation process is a gradual one rather than an abrupt transition as indicated by the test data.

FUTURE TESTING

In the short term, the pressure buildup following the last 45 day production test will continue to be monitored. It is hoped that a buildup period of at least 90 days will be observed before recommencement of production, so that the maximum amount of reservoir information such as the presence of boundaries and potential reservoir depletion can be extracted. Although the sensitivity of the pressure measurements are excellent, the degree of accuracy in the measurements necessary to detect depletion at the current cumulative production level is questionable. Note the pressure discontinuity shown in Figure 4 at the late time buildup due to pulling and rerunning the pressure gauge in the hole for necessary maintenance.

The most crucial reservoir data to be obtained will require an extended production period. Specifically, the continuity of the reservoir laterally along the growth fault and the overall areal extent of the reservoir must be detected by depletion. The contribution of water from the contiguous shale zones and the accessibility of other sands through the shale zones will require extended production and reservoir pressure monitoring.

Finally the in situ effects of reservoir compaction on reservoir production may only become evident after a substantial pressure drawdown is obtained in the reservoir.

The analysis of long term production behavior and the effects described above will require the use of reservoir simulation models.

CONCLUSIONS

Analysis of test data from the Pleasant Bayou #2 well completed in the Frio C sand indicates:

- (1) The reservoir permeability is approximately 200 md.
- (2) The producing gas-water ratio is 20 SCF/Barrel and the total gas-water ratio is 29 to 32 SCF/Barrel.
- (3) A permeability alteration due to a change in sand characteristics or, alternatively, a non-sealing fault is located about 3700 feet from the well.
- (4) The major growth fault that bounds the reservoir to the north is evident in the last multirate pressure drawdown test data.
- (5) An apparent rate sensitive skin effect has been interpreted from the multirate production test data.
- (6) Moderate skin damage in the well has been determined from each of the pressure transient tests.

NOMENCLATURE

B - formation value factor (RB/STB)
b - intercept of drawdown test (psi)
b' - intercept of multirate drawdown test (psi/(bbls/day))
c_T - total effective compressibility (1/psi)
h - formation thickness (feet)
k - formation permeability (md)
m - buildup or drawdown slope (psi/√)
m' - multirate drawdown slope (psi/(√ - bbls/day))
P_i - initial static reservoir pressure (psig)
P_{wf} - flowing bottomhole well pressure (psig)
q - flowrate (bbls/day)
r_{inv} - radius of investigation (feet)
r_w - radius of the wellbore (feet)
S - skin factor
T - Horner flow time (hours)
t - time since start of flow (hours)
Δt - time since shut-in (hours)
μ - viscosity

subscripts j, N - indicate time periods

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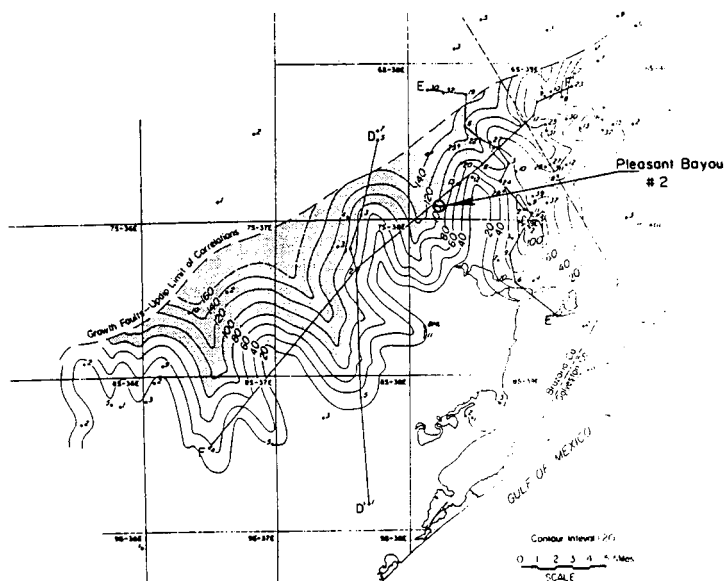


Figure 1

NET SAND THICKNESS
C-SAND FRIO FORMATION
BRAZORIA COUNTY

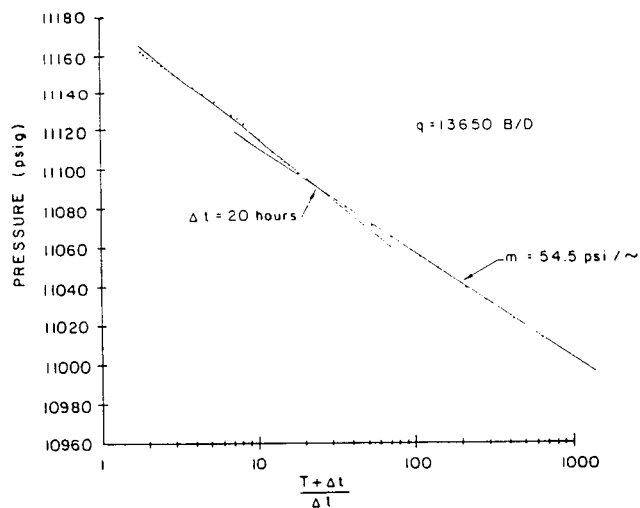


Figure 2

PLEASANT BAYOU #2
DECEMBER 1979 BUILDUP TEST
 $q = 13650 \text{ B/D}$

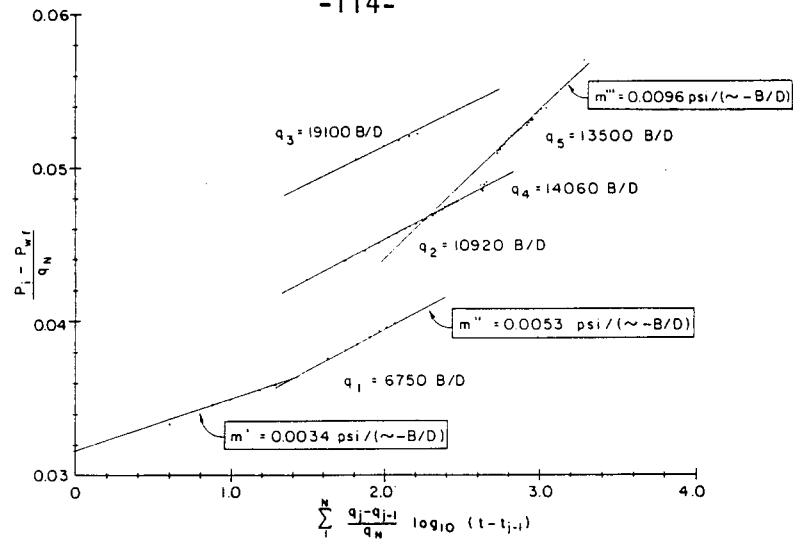


Figure 3

PLEASANT BAYOU #2
OCTOBER 1980 DRAWDOWN TEST
 $q_3 = 19100$ B/D

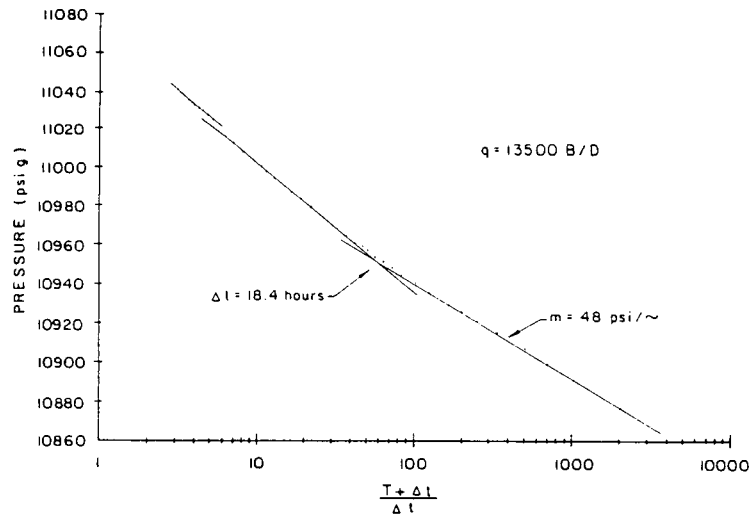


Figure 4

PLEASANT BAYOU #2
NOVEMBER 1980 BUILDUP TEST
 $q = 13500$ B/D

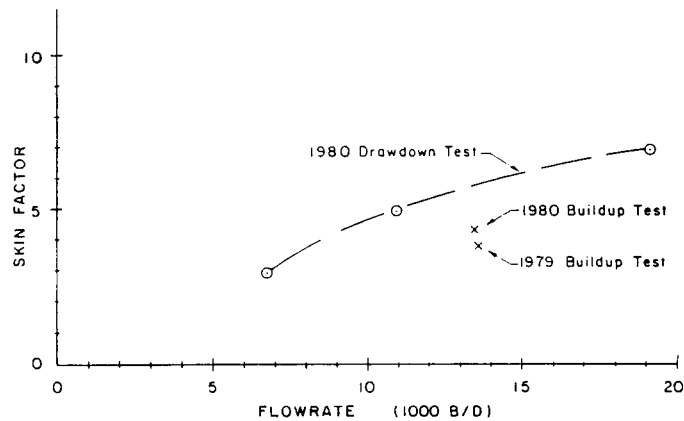


Figure 5

PLEASANT BAYOU #2
RATE SENSITIVE SKIN FACTORS

COLLECTION AND ANALYSIS OF RESERVOIR DATA FROM
TESTING AND OPERATION OF THE RAFT RIVER 5 MW POWER PLANT

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INTRODUCTION

The Raft River 5 MW power plant will be on-line some time this spring. During testing of the supply and injection system prior to plant start-up and during testing of the plant itself, data can be collected and used to calibrate computer models, refine predicted drawdowns and interference effects, monitor changing temperatures, and recalculate reservoir parameters.

Analytic methods have been used during reservoir testing at Raft River to calculate reservoir coefficients. However, anisotropy of the reservoir due to fractures has not been taken into account in these calculations and estimates of these coefficients need to be refined. From refined estimates of reservoir coefficients better predictions of interference effects and long-term drawdown in the wells can be made.

In conjunction with the USGS, Faust and Mercer's 3-D finite difference model has been used to simulate the Raft River geothermal field. Intera used a 2-D simulator to predict temperatures, pressures over 30 years and movement of dissolved solids in the reservoir. Data collected during production of the field will be compared to these simulations and the models refined.

DATA COLLECTION

Instrumentation

For collection of data during production at the field a permanently installed downhole pressure gauge was needed. During reservoir testing several types of downhole tools were tested, including a Hewlett-Packard downhole quartz pressure-temperature probe, continuous flow bubbler gauges, and bubbler gauges purged periodically when data are taken. The Hewlett-Packard probe failed frequently during testing. Continuous flow bubbler gauges used excessive amounts of nitrogen, possibly due to inaccurate flow metering devices. At present, stainless steel tubing strapped to the pump tubing extends to the total depth of the pump intake. The tubing is purged periodically with nitrogen and pressure read from a 0-6895 KPag Heise gauge. This gives fairly accurate relative measurements. Pressure at the injection well is recorded using a Paroscientific pressure transducer with a digital readout.

Temperature is monitored only at the wellhead to reduce downhole electronics prone to electric cable failure. A type K thermocouple is installed in the wellhead with a strip chart recorder readout. Temperature is also recorded manually with an in-line mercury thermometer as backup.

Flow is controlled at both the production and injection wells using automatic electrically-closed valves in the piping from the pump production tubing and in the piping after the injection pumps and strainers. Orifice plates with differential pressure transducers are used both to measure flow rates and to control the automatic valves at the injection wells. Line pressure is maintained by adjustment of valves at the production wells.

Collection Intervals

Although it was planned to automate data collection during operations, budget restrictions have prevented this so far. At present, data are manually collected from the bubbler gauges at the production wells and from pressure gauges and thermometers with no recorded readout. Data are collected on one minute intervals during the first 20 minutes of start-up or shut-down of any well and at increasing intervals thereafter.

INTERFACE WITH PLANT OPERATIONS

Testing of Pumps

During the past year an effort has been made to find a high capacity submersible pump suitable for geothermal operations. Line shaft pumps have been successfully used at Raft River with few problems in wells where deep drawdown is not encountered. However, deep setting depths for high production rates and large drawdowns require the use of large submersible pumps. It is planned to use various designs of geothermal submersible pumps during the coming year at Raft River to determine which design is most reliable. During this phase of wellfield operation much useful data can be collected if operations are planned with reservoir engineering in mind. For instance, no long-term, high rate test of RRGI-7 or RRGE-1 had been completed until this date. The recent need for a test of a newly installed REDA oilfield submersible pump at RRGE-1 allowed for planning of a high rate test of RRGE-1. Well RRGE-1 was produced for a total of 4 days at 66 lps with injection initially into RRGI-7. Due to high line pressures it was necessary to reduce the flow rate to 57 lps. The effect of this reduction is shown in Figure 3. The intrinsic transmissivity calculated from the late time data from this curve is 1.1×10^4 md-m, more than an order of magnitude lower than intrinsic transmissivities calculated from earlier low rate tests. The intrinsic transmissivity calculated from late-time recovery data is almost identical to this value (Figure 4). Due to pump failure at RRGI-7 the test could not be continued beyond 96 hours.

Testing of the supply and injection system at Raft River will for the most part involve wells RRGE-1, RRGE-2, RRGE-3 and RRGP-5. The geothermal reservoir at Raft River is highly fractured. Fracture direction is controlled by two major structural features: the Bridge Zone and the Narrows Zone. Prediction of interference effects is complicated by the differing directions of these two major structural trends. During testing of RRGP-5 prior to stimulation, wells RRGP-4, RRGE-1 and RRGE-2 were used as observation wells. (See Figure 1 and 2.) The response of well RRGP-4 is suggestive of drainage of a single, near vertical fracture of limited extent or production from a totally bounded system. The intrinsic transmissivity calculated from this observation well is 6.2×10^4 md-m while the storage coefficient is 2.9×10^3 . The

intrinsic transmissivity calculated using RRGE-1 as an observation well is 5.0×10^4 md-m which is close that calculated from RRGP-4. However, the storage coefficient is an order of magnitude larger, 3.1×10^4 . Pump tests at these wells show that RRGP-4 has very low intrinsic transmissivity while RRGE-1 is around 2.0×10^4 md-m. Because the reservoir is in fractured rock it is not possible to determine whether these results are an actual indication of the intrinsic transmissivity and storage coefficients averaged over this area of the reservoir or if the methods used are inappropriate to the situation.

Faulting related to the uplift of the Jim Sage Range may also affect communication between wells. Predicted interference at RRGE-1 from production at RRGP-5 and RRGE-3 is of the order of magnitude of 200 kPa using the method of images. However, the total effect may be much larger given the suspected degree of communication between these wells and the anisotropy of this fractured system.

As data are collected during supply and injection system tests, numerical simulation of the system can be refined. A modeling effort by Intera for the injection aquifer assumed a single high conductivity fracture communicating with upper aquifers. This resulted in a perturbation of these aquifers with increasing pressures, temperatures and TDS over the 30-year life of the project. This modeling effort did not, however, simulate production. Further modeling efforts by EG&G in conjunction with the USGS using the Faust and Mercer's 3-D, single-phase code will be directed toward prediction of long-term pressure and temperature effects of production on the geothermal reservoir.

TESTING OF 5 MW POWER PLANT

All testing of the Raft River injection system to date has been accomplished using water at 140°C instead of the plant outlet temperature of 65°C. Because wellhead pressures will limit the injection rate it is necessary to predict pressure build-up at the wellhead in the injection wells. This will be affected by the temperature of the injected geothermal effluent from the power plant. Previous predictions of pressure build-up at the wellhead have been done using linear regression analysis of the semilog plot of pressure build-up during hot water testing. Assuming that the temperatures of the injected effluent will be 65°C, year pressure build-up was calculated using the equation :

$$\Delta P_{\text{total}} = P_{i \text{ } 65^{\circ}\text{C}} + \Delta P_{\text{skin}} + \frac{Q\mu}{2\pi kh} \text{Ei} \left(\frac{kht}{Sr^2\mu} \right)$$

where ΔP_{total} is the pressure build-up at the wellhead, Q is the flow rate, kh is the intrinsic transmissivity, t is time, S is the storage coefficient, P_i is the initial pressure, ΔP_{skin} is the pressure build-up due to skin effects, and μ is the viscosity at the temperature of the injected water. The pressure predicted from hot water injection was 2020 Kpa after 1 year of injection at 63 lps. After 1 year of injection of 65°C water at 63 lps the predicted pressure is 3510 Kpa. Data collected during testing of the power plant will provide data to validate this prediction.

As testing of the power plant continues turbine trips can be expected. In this binary system such trips will result in bypass of the geothermal fluid around the heat exchangers and hence an increase in the temperature of the injected effluent. This will allow for further comparison of the injection system response to cold and hot water injection.

As production of the reservoir continues during plant operation total volumes and reservoir pressures and temperatures will be closely monitored. These data will be used for constructing decline curves which can be used to predict future temperature and pressure declines. These predictions can then be checked against actual production records and predictions made using numerical simulation.

CONCLUSION

Through planning of testing of pumps and the supply and injection system at Raft River, data can be collected which will aid in calibration of commercial models and prediction of the long-term pressure and temperature response of the reservoir to production. Data collection and pump malfunction proved to be the major barrier to collection of reservoir engineering data during production of the well field. A fully automated data collection system would allow collection of high quality data without requiring excessive manpower. Predictions of wellfield behavior made by analytic methods, numerical simulation methods and decline curves can be compared to each other and to production data to ascertain the effectiveness of these techniques.

PRODUCTION DECLINE ANALYSIS
USING INFLUENCE FUNCTIONS

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We previously reported (Zais, 1979) that Arps's exponential equation works quite well on geothermal production data. The hyperbolic equation should probably not be used. In this paper we show the progress made in using influence functions to describe reservoir production behavior.

Influence functions arise in many areas of science and engineering under the names of Green's function, memory function, response function, and resistance function. They are used to relate the response of a system to an input. In a geothermal reservoir we can find an influence function relating reservoir pressure to production rate. Once this function is calculated, it can be used to predict the behavior of the reservoir. van Everdingen and Hurst (1949) developed an influence function method for aquifer drive petroleum reservoirs using Laplace transforms. Hutchinson and Sikora (1959) and Jargon and van Poolen (1965) developed algebraic water drive analysis methods for reservoirs and individual wells, respectively.

Coats et al (1964) made a major improvement over the algebraic methods mentioned above by requiring derivative constraints. His formulation may be written as

$$\Delta p = \int q(\tau) \frac{dF(t-\tau)}{d\tau} d\tau = \int \frac{dq(t-\tau)}{d\tau} F(\tau) d\tau \quad (1)$$

$$\Delta p_i \approx \sum (q_j - q_{j-1}) F_{i-j+1} \quad (2)$$

with the constraints

$$F > 0, \quad t > 0 \quad (3)$$

$$\frac{dF}{dt} \geq 0$$

$$\frac{d^2 F}{dt^2} \leq 0$$

These constraints are necessary to ensure that the function derived is physically meaningful. We analyzed some data from Cerro Prieto both with and without the constraints. The derived influence functions are shown in Figure 1. The irregular curve is the "best fit" to data, but it is physically meaningless and cannot be extrapolated.

Some other results obtained by Coats's method are shown in Figures 2 and 3. The ρ is a measure of goodness of fit and is defined as

$$\rho = \frac{1}{n} \sum \frac{1}{\Delta p_i} (u_i + v_i) \quad (4)$$

where u_i and v_i are slack variables in the linear programming formulation.

We used three different kinds of extrapolations for the influence functions assuming 1) a bounded aquifer, 2) an aquifer which crops out, and 3) an infinite aquifer. Geologic data can help in choosing the correct extrapolation.

The methods so far discussed are all "black box" methods because no physical model of the reservoir mechanism is assumed. We also studied a linearized free surface (LFS) model proposed by Bodvarsson (1977). If a reservoir has a free liquid surface with relatively small vertical movement, the equations describing the movement can be linearized. The equation for surface drawdown at a general field point P becomes

$$h(t) = \int G(t - \tau) q(\tau) d\tau \quad (5)$$

$$\approx \sum G(t - \tau) q(\tau) \Delta \tau \quad (6)$$

$q(t)$ is a production rate and $G(t)$ is a Green's function which can be defined for an infinite half space, a reservoir with an impermeable bottom layer, and other configurations as necessary. The equations for the first two cases are

$$G = \frac{-1}{2\pi\phi\rho} (wt + d)(x^2 + y^2 + (wt + d)^2)^{-3/2}, \quad t > 0 \quad (7)$$

$$G = \frac{-1}{2\pi\phi\rho} \left[(wt + d)(x^2 + y^2 + (wt + d)^2)^{-3/2} + \frac{2H - dwt}{(x^2 + y^2 + (2H - d + wt)^2)^{-3/2}} \right] \quad (8)$$

w is the sinking velocity and equals $\frac{kg}{\nu\phi}$ = permeability x gravity divided by kinematic viscosity x porosity. The other symbols are distances as shown in Figures 4a and 4b.

Only the Wairakei data set (Pritchett et al) was complete enough for us to use the LFS method. The results are shown in Figure 5. Curve 1 is the observed pressure drawdown, curve 2 the calculated drawdown using equation 7, and curve 3 the calculated drawdown using equation 8. The fit is quite good over 25 years.

The full results of this project are available in Zais and Bodvarsson (1980).

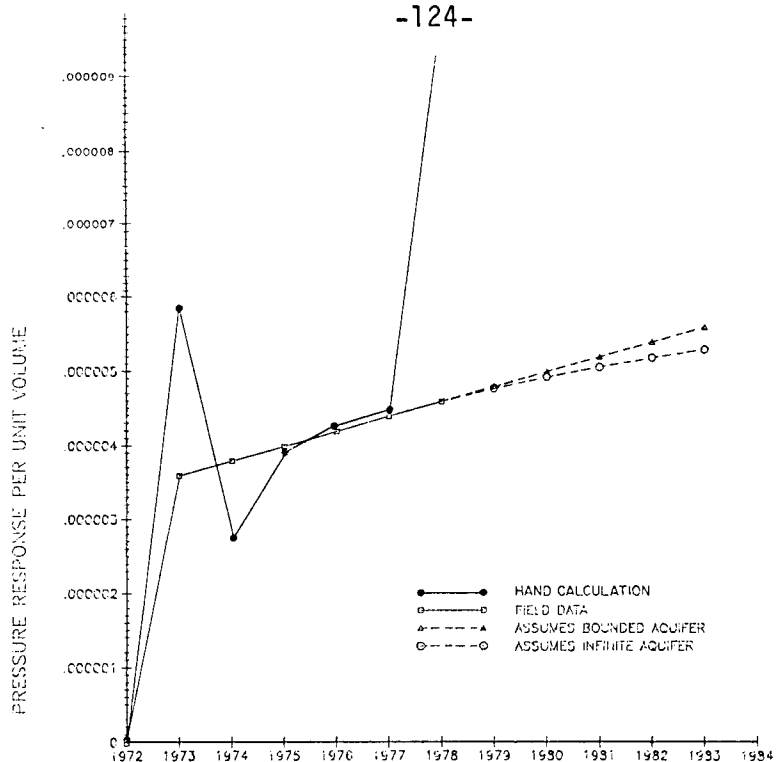
Acknowledgements

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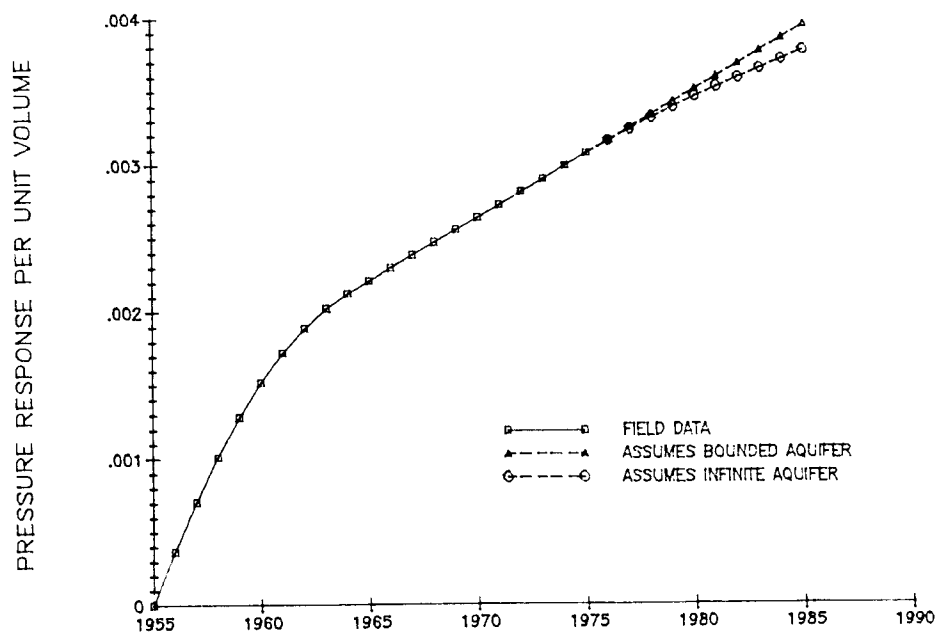
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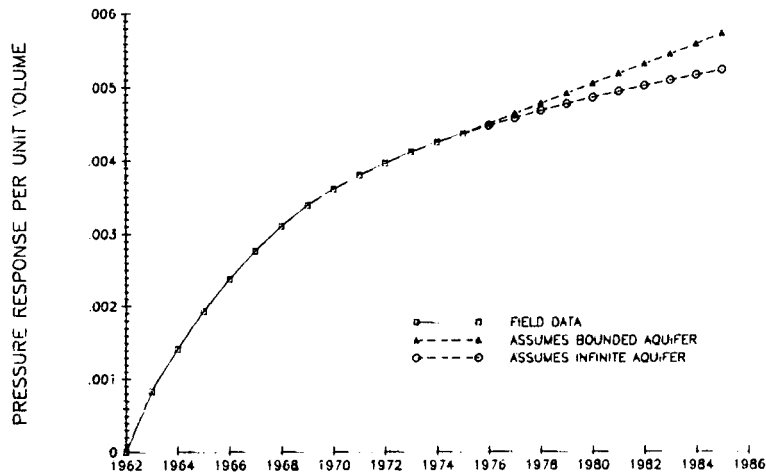
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LIQUID INFLUENCE FUNCTION -- CERRO PRIETO TOTAL FIELD -- 1972-1978
Figure 1 (Fitness measure $\rho = .100058$)

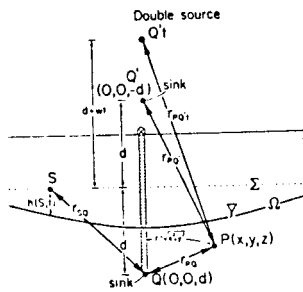


INFLUENCE FUNCTION -- WAIRAKEI TOTAL FIELD -- 1955 TO 1975
Figure 2 (Fitness measure $\rho = .195863$)

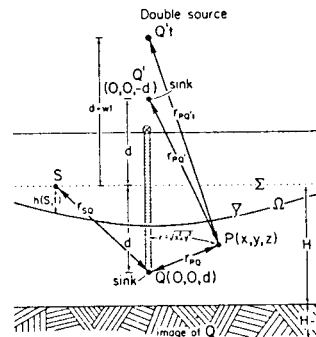


INFLUENCE FUNCTION -- BORE83 -- 1962 TO 1975

Figure 3 (Fitness measure $\rho = .023756$)



4a. Infinite half space for linearized free surface method.



4b. Reservoir half space for linearized free surface method with bottom layer. Q'' , the image of the image of Q with respect to the equilibrium Σ plane is not included. $Q''t$, the moving image of the image of Q , is also not included.

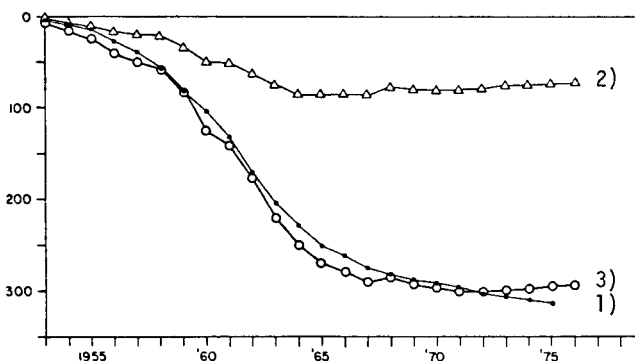


Fig. 5 Linearized free surface fits to Wairakei data

APPLICATION OF A DOWNHOLE FLOWMETER TO DETECTING
CASING BREAKS IN A GEOTHERMAL WELL

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The downhole flowmeter logging system for high temperature geothermal wells developed at Wairakei, New Zealand, is proving to be an invaluable tool for use during workovers to repair or reinstate problem wells. This contribution describes a straightforward example of identifying breaks in plain casing near the top of a productive well.

THE DOWNHOLE FLOWMETER

The flowmeter (described in Syms, 1980) contains an impeller, or spinner, which is rotated by water flowing through the tool. The flowmeter is operated while it is travelling up or down a well and the frequency of spinner rotation is recorded at the surface. The frequency is made up of two components: one due to the movement of the tool and the other due to water flowing in the well. These components either reinforce each other or tend to cancel depending on their relative directions; and the magnitude of each depends on the cross-sectional area of the well at the depth of the flowmeter. The sign convention adopted is that flow incident on the tool from above is positive, for example when the tool is moving upwards in stagnant water. The spinner frequency is given a sign to conform with this.

THE REPAIR OF WELL WAIRAKEI 216

This well has been supplying steam to the Wairakei power station since 1961. During a routine inspection in 1978, several large pieces of casing were found in the wellhead equipment. Two breaks in the casing and a pulled coupling were identified by a casing caliper survey in 1979. When the well was shut or on bleed, the measured internal pressure exceeded the calculated formation pressure at the level of the shallowest break, indicating potential blowout conditions. It was therefore decided to repair the casing and this was commenced in February 1980.

Just after the well had been quenched the injection pressure suddenly built up and no further water could be pumped, even at a pressure of 60 bg. The well was found to be blocked at 19 m, and a major casing collapse was suspected. Subsequent events showed that once the well had been quenched, pressure at the level of the breaks was reduced and the loose, water saturated, pumice breccia formation flowed into the well through the casing break(s). This material was then drilled

out to 149 m depth. Several obstructions were found in the 8 $\frac{5}{8}$ inch casing, even with a 4 $\frac{1}{2}$ inch drill bit, so the casing was realigned with a roller tool.

At this stage there were at least seven sites of possible casing damage above 149 m and it was desirable to know which of these possible breaks would accept fluid from the well so that cement could be placed at the appropriate levels. The purpose of this cementing operation was to hold the 8 $\frac{5}{8}$ inch casing in the properly aligned position so that a smaller casing could be run and cemented inside it.

Investigations were carried out with the spinner flowmeter while injecting 6 litres/second of cool water from the surface at 10 bg wellhead pressure. Figure 1 shows three logs of spinner frequency against depth, two made with the tool moving upwards in the well and one with the tool moving downwards. Since the measurements were made inside plain casing (i.e. the well area is uniform) and the logging speed for each run was constant, in any one log the frequency should only change when water enters or leaves the well. Regular cycles of small amplitude on these logs are caused by fluctuating delivery rate of the piston pump. Logs made in wells which are not under pressure during injection do not have these regular variations, but do have a small amount of noise.

In the upper part of the well (above 107 m) the injected water flow is causing the spinner to rotate faster than it would if operated in a stagnant well for the up runs and slower for the down run. The tool is overtaking the flow on the down run so the spinner frequency is negative (water entering the tool from below). Five logging runs were made altogether and all logs show distinct changes in frequency at 107 m and 127 m depth. Water flow is leaving the well at both these depths since the frequency magnitude decreases on the up run logs and increases on the down run logs.

Relative flow quantities are shown by the relationship of logging speed to average spinner frequency, Figure 2. The interpolated spinner frequency corresponding to zero logging speed is proportional to volumetric flow. About 25% of the injected flow is lost at 107 m and most of the remainder at 127 m depth. The small remaining flow (7% of injected) that is indicated below 127 m is within the error limits of the measurements, so there may be no flow there.

The spinner flowmeter revealed that only at 107 m and 127 m depth were there any significant breaks in the casing. These breaks were grouted, taking 450 and 730 litres of grout

respectively. Plain casing of smaller diameter (7 inch) was then cemented inside the repaired $8\frac{5}{8}$ inch casing and the well is now back on production.

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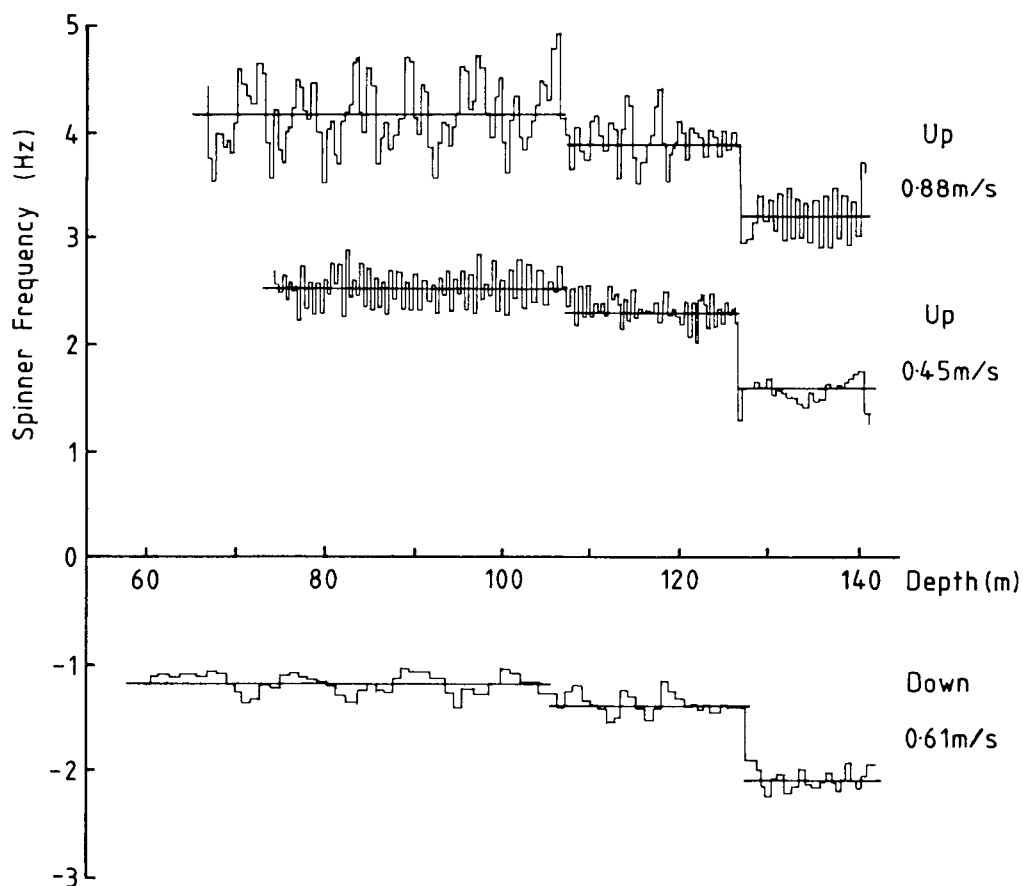


Figure 1: Three flowmeter logs made in well Wairakei 216 with 6 l/s being injected from the surface. The logging direction and speed are shown beside each record. Average values of spinner frequency have been drawn to remove cyclic variations caused by the piston pump.

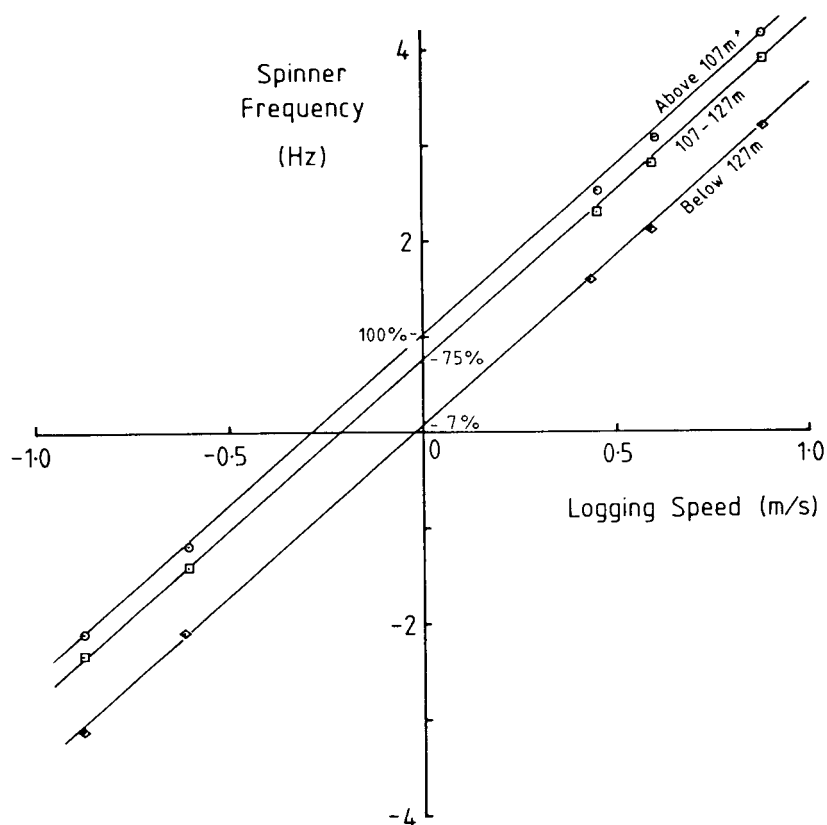


Figure 2: A plot of average spinner frequency against logging speed for the three constant-flow regions in the upper 149 m of Wairakei 216. Intercepts with the frequency axis indicate the relative amounts of flow in each region.

EFFECT OF MEASURED WELLHEAD PARAMETERS AND WELL SCALING
ON THE COMPUTED DOWNHOLE CONDITIONS IN CERRO PRIETO WELLS

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INTRODUCTION

The primary objective of modeling a geothermal system is to be able to predict with some confidence the energy production capacity and longevity of the field under various production and injection scenarios. To achieve this goal, a modeler needs to construct a comprehensive mathematical model based on available data and validate this model against the production history of the field. This, in turn, requires the data associated with the evolution of the field due to its exploitation. Typically, the information related to the variations in the mass flow rate, enthalpy, pressure, temperature and fluid saturation as a function of time is used to validate the model. The production data is routinely measured at the wellhead whereas most reservoir models compute the changes in the temperature, pressure, enthalpy, fluid velocity and other physical properties of the fluid at the sandface. To validate any model, wellhead data must be corrected to reflect the downhole conditions. In this paper, we shall confine ourselves to the discussion of computing bottomhole pressures from the measured wellhead data by using a wellbore model. Several wellbore models which compute wellhead conditions from the given bottomhole data have been cited in the literature. (Sanyal, et al., 1979; Aydelotte, 1980; Gould, 1974). Such calculations are of interest in predicting the conditions under which an optimum production could be obtained from a given well. This approach does not suit us since our primary goal is to study the evolution of the field due to production. The following paragraphs are devoted to the discussion of the wellbore model and its describing equations, comparison between the computed and measured pressures and the effect of measured wellhead parameters on the downhole pressures in the well. Finally a wellbore model with multiple inside diameters is discussed and the effect of well scaling on the bottom hole pressures is studied.

WELLBORE MODEL

The steady state computer program WELFLO used in this study calculates the bottomhole conditions if the wellhead conditions such as mass flow rate, pressure and enthalpy (or dryness fraction) are prescribed. The length of open interval and heat loss from the well bore are also considered in the program. However, the effect of the radial pressure gradient responsible for inflow to the well is not taken into account. The total mass inflow to the well is assumed to be distributed evenly throughout the open interval. Also, in-place internal energy in the open interval is assumed constant. The equations, describing a transient two-phase flow through a well are discussed in Miller (1979). The steady-state equations

of mass, momentum and energy as obtained from that set for a constant diameter well are as follows:

$$\frac{\partial}{\partial x} (\rho u) = 0 \quad (1)$$

$$\frac{\partial p}{\partial x} = -\rho g - \frac{f \rho u^2}{2D_i} - \frac{\partial}{\partial x} (\rho u^2) - \frac{\partial}{\partial x} \left[\frac{(1-\alpha) \rho_l \rho_g (u_r^2)}{\rho} \right] \quad (2)$$

$$\begin{aligned} \rho u \frac{\partial e}{\partial x} = & -P \frac{\partial u}{\partial x} - \frac{\partial}{\partial x} \left[\frac{(1-\alpha) \rho_l \rho_g u_r (e_g - e_l)}{\rho} \right] - P \frac{\partial}{\partial x} \left[\frac{(1-\alpha) \rho_l \rho_g (u_r^2)}{\rho} \right] \\ & + \frac{4H}{D_i} (T_{res} - T_w) \end{aligned} \quad (3)$$

The above equations describe average fluid properties over the cross section and thus do not satisfy the no-slip boundary condition at the wall of the well. The slip is given as a function of flow regime. The limits of these regions (bubble, slug, transition and mist) that were used are defined in Orkiszewski (1967). Slip for these regions is discussed in Orkiszewski, (1967) and Wallis (1969). The program uses an overall friction factor as described in Chisholm (1973). Empirical relations, correlating steam tables for the properties of water and wet steam are used in the program (Miller, 1978). These relations are accurate to within 5% of the steam table values.

MEASURED AND COMPUTED PRESSURES IN WELL M90

An attempt was made to calculate the pressures at various depths in the bore and then to compare them with those measured in the Cerro Prieto wells. Figure 1 shows the measured and computed pressures in well M-90 for the given wellhead conditions. The well is of uniform diameter. Calculated pressure profiles for two different wellhead pressures are shown in the figure. One of them is for the measured wellhead pressure of 37.4 kg/cm² gauge. The computed pressures are lower than those measured throughout the depth of the well with a maximum difference of about 11% at a depth of 1380 meters. The second calculated profile is for the wellhead pressure of 39.5 kg/cm²-gauge which is obtained by extending the measured pressure profile to the surface. The maximum pressure difference in this case is only about 6%. It was observed from the computer output that a two-phase slug flow regime existed throughout the well and thus a drastic change in pressure gradient is not likely near the wellhead. In other words, one would expect a wellhead pressure of 39.5 kg/cm² gauge at the wellhead if the pressures measured in the well are correct. Or alternatively, if the measured wellhead pressure of 37.4 kg/cm² gauge is correct, then the measured downhole pressures should be in error. This

shows that there exists a discrepancy between the pressures measured at the wellhead and those in the well. As in any other field work or experimentation, such discrepancies do arise as a direct result of human errors, instrumental errors or both. The computed and measured profiles for M-90 are in good agreement. However, it must be emphasized that even a 5% error in the calculation can lead to a large absolute error. For M-90, 5% error is about 70 psi. A comparison between the measured and computed pressures in the Cerro Prieto well M-51 was also made. It was found that computed pressures were within 6-7% of those measured in the well.

EFFECT OF HEAT LOSS AND OPEN INTERVAL ON COMPUTED DOWNHOLE PRESSURE

The effect of heat loss from the wellbore to the surroundings on the well pressure was also studied by considering that a linear temperature profile (assumed to approximate the natural geothermal gradient) exists in the reservoir at a distance (R_1) of 1 m and 5 m from the well. A hyperbolic profile was then fitted between the well and the geothermal gradient to obtain the temperature gradient at the well. It was found that the maximum pressure drop associated with heat loss for $R_1 = 1$ m was about 2.5% while negligibly small for $R_1 = 5$ m in well M-90. Thus, for all practical purposes, steady state heat transfer from Cerro Prieto production wells can be neglected. Gould (1974) also arrived at the same conclusion for high production wells. To study the effect of the thickness of open interval on the bottom hole pressures, we varied the thickness from 10 m to 160 m in the well M-90. It was found that an increase of only about 0.5% occurred in the bottom hole pressures for an open interval of 160 m. Thus, for all the cases discussed hereafter, we assume that the heat loss from the well is negligibly small, and that the depth of the open interval is equal to the distance between two nodes in the finite difference mesh.

EFFECTS OF WELLHEAD PARAMETERS

As noted, a possibility exists that the measured wellhead parameters such as pressure, mass flow rate, dryness fraction, enthalpy, etc., may be in error by a few percent. Thus, it seems appropriate to find the effect of such errors on the calculated downhole pressures in the well. We varied three important wellhead parameters (mass flow rate, pressure, and enthalpy) within $\pm 20\%$ of their measured value in well M-90 and calculated the change on the bottom hole pressures.

Table 1 shows bottom hole pressures (BHP) for different mass flow rates in well M-90. For a 20% increase in mass flow rate at the wellhead, the bottom hole pressure increased by about 6.5% the for a 20% decrease in flow rate there is about 5% decrease in BHP. The difference between wellhead and downhole pressure is not affected significantly by the mass flow rate. However, it maybe noted that the wellbore model is independent of the reservior.

Table 2 shows the effect of well head pressures (WHP) on the BHP in well M-90. It may be observed that a 20% increase in WHP results in an increase of about 25% in BHP while a 20% decrease in

the WHP leads to about 18% decrease in BHP. The error in the WHP in this case shows up directly in the BHP.

Effect of enthalpy on BHP is shown in Table 3. It may be observed that an enthalpy increase of 20% reduces BHP by about 14% but a corresponding decrease leads to an increase of about 70% in BHP. An increase in enthalpy results in more steam and lighter fluid giving rise to lower pressures at the bottom of the well as shown in Table 3. BHP is not affected as much by an increase in enthalpy as it does by decreasing the same. This may be attributed to the fact that a decrease in the enthalpy results in a denser, heavier fluid giving rise to higher pressures at the bottom of the well. Effect of flowing dryness fraction at the wellhead on BHP was also studied. It was found that a variation in enthalpy affects the downhole pressures more than a corresponding change in the dryness fraction. The fluid enthalpies at Cerro Prieto wells are calculated by using dryness fraction and steam properties at the separator pressure. Thus, it is advisable to compute BHP by using dryness fraction rather than enthalpy to avoid the possibility of a compounding error.

EFFECTS OF WELLBORE DIAMETER AND SCALING

In addition to the measured wellhead data, the inside diameter of the well is needed to calculate the BHP. A study was done to find its effect on the calculated bottom hole pressures. Table 4 shows the calculated BHP in M-90 for various inside radii. The BHP was 41% more for 12 cm inside diameter and 150% more for 8 cm diameter compared to that for 16.3 cm diameter. Thus, in the 8 cm diameter case, a reduction of 76% in area leads to a much higher increase (150%) in the downhole pressure. This figure may be unrealistic since a large reduction in the area is assumed throughout the wellbore. In any event, it is clear that the effect of inside diameter on the BHP is considerable. Some Cerro Prieto wells do have large scale deposits. For example, well M-30, which, as of 1976, had scaling in excess of 60 mm at a depth of 1,500 meters. Similar scale deposits were also observed in many other wells in the field. Thus, to obtain reasonable values for downhole pressures, it is necessary to have a computer program which accounts for variations in the wellbore diameters. Using the control volume concept, the following equations of mass, momentum and energy were derived for a finite volume in which the diameter change occurred.

$$(\rho A u)_L + g \Big|_{\text{up}} = (\rho A u)_L + g \Big|_{\text{down}} \quad (4)$$

$$\begin{aligned}
 & \left(P_{av} - \rho A \frac{\Delta x}{2} g + \rho A u^2 \right)_{\ell} + g - \frac{f \rho u^2 \pi D_1 \Delta x}{16} \Big|_{\text{up}} \\
 & = \left(P_{av} + \rho A \frac{\Delta x}{2} g + \rho A u^2 \right)_{\ell} + g + \frac{f \rho u^2 \pi D_1 \Delta x}{16} \Big|_{\text{down}} \quad (5)
 \end{aligned}$$

$$\left[\rho A u \left(e + \frac{u^2}{2} \right) + P A u \right]_{\ell} + g \Big|_{\text{up}} = \left[\rho A u \left(e + \frac{u^2}{2} + g \Delta x \right) + P A u \right]_{\ell} + g \Big|_{\text{down}} \quad (6)$$

In deriving the above equations, we have neglected energy dissipation due to friction and eddy losses. In these equations 'up' stands for the upstream side and 'down' for the downstream side. Subscript ℓ stands for liquid and g for steam. Given the conditions at point 'up', the parameters at point 'down' could be calculated. Figure 2 shows the computed and calculated pressures in the Cerro Prieto well M-91. The inside diameter of the well changes at a depth of about 1940 meters. It was found from the computer output that a two phase slug flow exists in the well above 900 metres and a single phase liquid water flows below 950m. A change in the pressure gradient at about 900-1000 m depth is noticed. It is clear from the figure that there is an excellent agreement between the measured and computed pressures. The percentage difference in BHP is less than 1%.

Well M-39 of Cerro Prieto field was also selected to show the effect of multiple inside casing diameters on downhole pressures (Figure 3). Production data for June 1976 was used to compute downhole pressures. Pressures calculated using the actual casing diameters are highest among all the cases shown. Pressure gradient between 1000 m to 1100 m depth change in response to changes in inside casing diameters. Higher pressure gradients below 1200 meters indicate single phase liquid flow. The computed pressures for the uniform inside diameters of 0.2012 m and 0.2736 m, as shown in Figure 3, are lower than those obtained using the actual diameters. In fact, bottom hole pressures decrease by 31.6% and 67.8% for the internal diameter of 0.2012 m and 0.2736 m, respectively. Pressures calculated assuming a uniform diameter of 0.177 m were very close to those computed using the actual casing diameter. This indicates that the gravity effect dominates the pressures more than the inertia effect when there is single phase liquid flow. Unfortunately, no data for measured downhole pressures were available to compare with these computed pressures. These results indicate that the computed downhole pressure may be significantly in error if actual inside casing diameters are not taken into account.

Figure 4 shows the effect of size and position of the scale deposits or of a liner of 200 m length on the pressure distributions in the Cerro Prieto well M-51. Pressures are larger for thicker scale deposits since one would require higher pressures to push the fluid through a small opening. A liner of small diameter set near the wellhead needs higher bottom hole pressure compared to the one set near the bottom of the well bore. This is due to the pressure propagation in the well bore. A similar profile was measured in test 11-3 of the well BR-11 where solid scale deposits up to 2 inches thick were found in the liner (Gould, 1974).

CONCLUSIONS

We have found that calculated downhole pressures are quite sensitive to measured well head conditions and well inside diameter data. The parameters to be measured, in order of decreasing accuracy, are well inside diameter, wellhead pressure, dryness fraction and mass flow rate. Based on the data presented we consider that LBL's computer program WELFLO calculates reasonable downhole conditions provided that accurate data is provided.

ACKNOWLEDGEMENTS

We want to thank the Coordinadora Ejecutiva de Cerro Prieto of CFE for making available the data used in this study. This work was performed under the auspices of the U. S. Department of Energy, Division of Geothermal Energy, under contract No. W-7405-ENG-48.

NOMENCLATURE

$A_{up(down)}$ = inside area of the well at upstream (downstream) side, m^2
 A_{av} = average area of the well = $(A_{up} + A_{down})/2$, m^2
 D_i = inside diameter of the well, m
 e = internal energy, of the steam-water mixture, J/kg
 $e_l(g)$ = internal energy of water (steam), J/kg
 f = coefficient of friction in the two-phase flow
 g = gravitational acceleration, m/sec^2
 H = film heat transfer coefficient in the well, $J/sec-m^2-^{\circ}K$
 P = pressure in the well at any cross section, Pascals
 T_{res} = reservoir temperature, $^{\circ}K$
 T_w = well temperature, $^{\circ}K$
 u = mass averaged velocity in x-direction, m/sec
 $u_l(g)$ = velocity of water (steam) in the well, m/sec
 u_r = slip velocity = velocity of steam - velocity of water, m/sec
 x = coordinate axis passing through the center of the well, upward positive, m
 α = saturation of steam
 Δx = interval between two nodes in the finite difference scheme, m
 ρ = density of the steam-water mixture, Kg/m^3
 $\rho_l(g)$ = density of water (steam) in the well, kg/m^3

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TABLE 1: Effect of mass flow rate on the bottom hole pressures (B.H.P.) in the Cerro Prieto well M-90

PERCENTAGE CHANGE	MASS FLOW RATE (Tonnes/hr)	B.H.P. (Kg/cm ² -g)	% DIFF B.H.P.
+20%	195.60	95.6146	+6.5
+15%	187.45	94.0685	+4.8
+10%	179.30	92.6014	+3.184
+ 5%	171.15	91.1352	+1.57
0%	163.00	89.7122	0
- 5%	154.85	88.3324	-1.52
-10%	146.70	86.996	-2.99
-15%	138.55	85.9179	-4.18
-20%	130.40	84.9890	-5.2

TABLE 2: Well head pressures and corresponding bottom hole pressures (B.H.P.) in the Cerro Prieto well M-90

PERCENTAGE CHANGE	WELLHEAD PRESSURE (Kg/cm ² -g)	B.H.P. (Kg/cm ² -g)	% DIFF B.H.P.
+20%	47.40	112.776	+25.42
+15%	45.43	107.047	+19.10
+10%	43.45	101.205	+12.66
+ 5%	41.48	95.2621	+ 6.12
0%	39.5	89.7122	0%
- 5%	37.53	84.9074	- 5.29
-10%	35.55	80.6937	- 9.94
-15%	33.58	77.0025	-14.00
-20%	31.6	73.7173	-17.63

TABLE 3: Effect of well head enthalpy on the downhole pressures in the Cerro Prieto well M-90

PERCENTAGE CHANGE	ENTHALPY (Kcal/kg)	B.H.P. (Kg/cm ² -g)	% DIFF B.H.P.
+20%	387.60	77.1392	-13.85
+10%	355.30	77.6372	-13.31
+ 5%	339.15	80.4552	-10.20
0%	323.00	89.7122	0
- 5%	306.85	111.342	+23.83
-10%	290.70	131.156	+45.67
-15%	274.55	146.203	+62.252
-20%	258.40	153.316	+70.09

TABLE 4: Effect of well inside diameter on the bottom hole pressures in the Cerro Prieto well M-90

INSIDE RADIUS (m)	AREA (m ²)	% AREA CHANGE (m ²)	B.H.P. (Kg/cm ² -gauge)	% DIFF B.H.P.
0.08172	2.098x10 ⁻²	0	89.7122	0
0.06	1.13097x10 ⁻²	-46.1	127.071	41.17
0.04	5.0265x10 ⁻³	-76.04	225.592	149.74

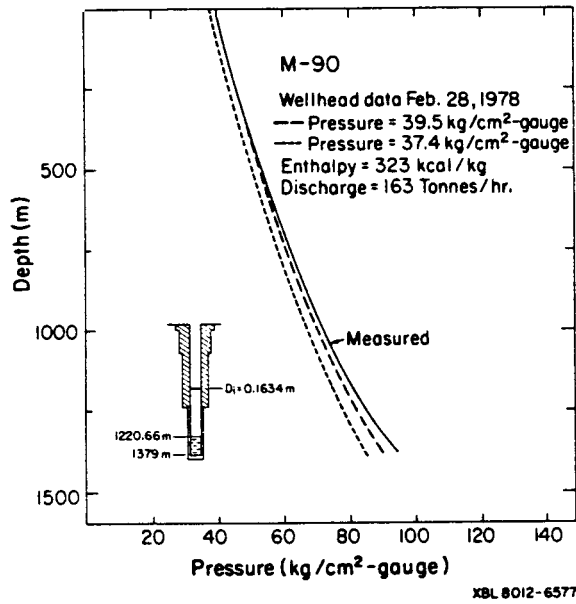


Figure 1. Measured and calculated pressures in the Cerro Prieto well M-90.

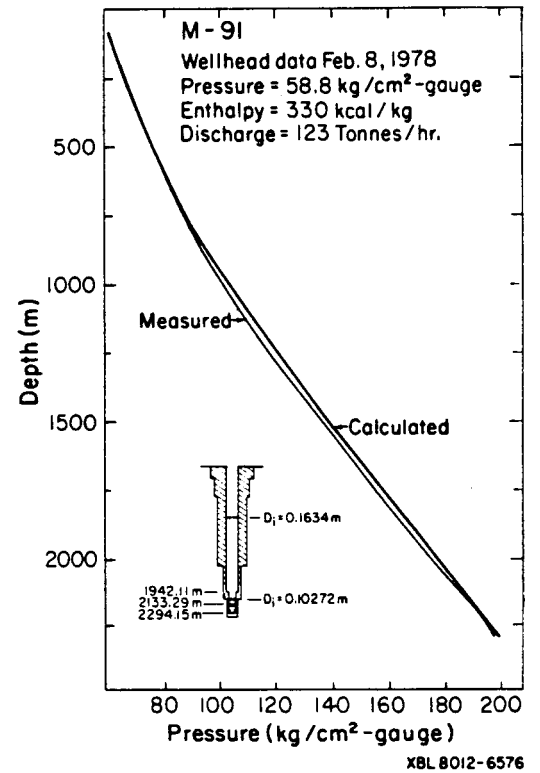


Figure 2. Computed and measured pressures in the Cerro Prieto well M-91.

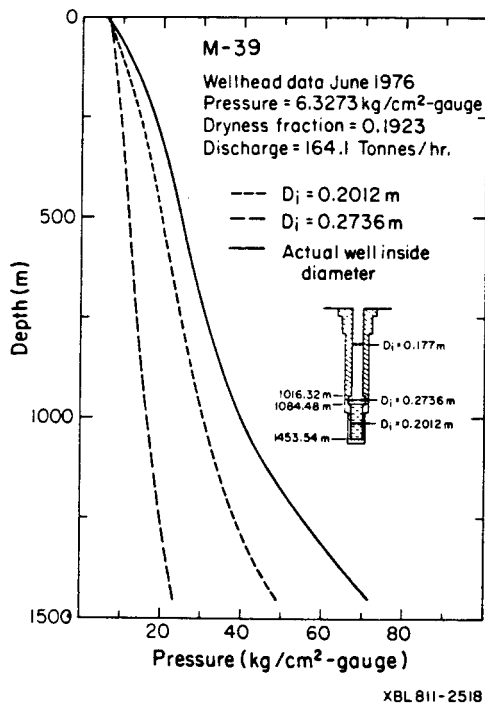


Figure 3. Effect of inside diameter on the calculated pressures for the Cerro Prieto well M-39.

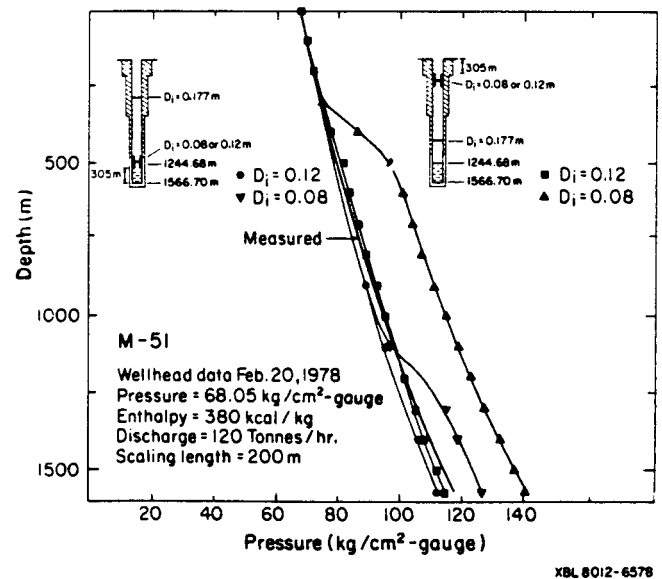


Figure 4. Effect of size and location of scaledeposits on the pressures in the well.

ESTIMATING MAXIMUM DISCHARGE OF GEOTHERMAL WELLS

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ABSTRACT

We cannot tell how 'good' a well is unless we can estimate the maximum flow possible under such ideal conditions as complete permeability at the production horizon and boiling point throughout the depth of the reservoir. Calculated Lip pressures for vertical wide-open discharge under these conditions are surprisingly independent of the kind of fluid tapped by the well, whether dry saturated steam or saturated hot water.

The status of an actual well can be established by comparing the measured Lip pressure with the calculated theoretical maximum.

Discharges are simply determined from the values of Lip pressure and supply fluid enthalpy.

INTRODUCTION

Some years ago, I was working on a Wairakei well which tapped a supply of saturated hot water (water at the boiling point for its pressure). During a period of about a month, the fluid changed to dry saturated steam at the same temperature and pressure, but no change was observed in the Lip pressure attached to the vertically discharging well when blown wide-open. Of course, the actual flow-rate would have decreased considerably as this is related to Lip pressure and fluid enthalpy in the following equation, James (1962).

$$G = \frac{1839 P_c^{0.96}}{h_o^{1.102}} \quad (1)$$

G Flow, t/m²s
P_c Lip pressure, bars
h_o Fluid enthalpy, kJ/kg

Obviously the driving force and controlling factor was the presence of the compressible vapour phase, with the water being merely dragged along as a passenger; at least that was the superficial hypothesis advanced at the time. It would, of course, be extremely difficult to experimentally verify this phenomenon over a range of well depths and fluid temperatures and types. Hence, the approach undertaken here is to calculate Lip pressures over a range of well depths and bore diameters for (a) dry saturated steam, and (b) saturated hot water. This is accomplished specifically for the condition shown in Figure 1 where the well is discharged wide-open vertically and where supply horizon permeability is considered as perfect with no restriction on flow into the well at depth.

As an unmanageable mix of well depths and bottom hole conditions is possible to envisage, it was decided to simplify matters by imposing a relationship between these factors. Fortunately, such a relationship exists in practice as it appears that geothermal reservoirs either are, or tend towards Boiling Point with Depth (BPD), so that both pressure and temperature increase progressively with depth from the ground surface, often down to a so-called Base temperature. Over the depth at which BPD obtains, boiling water and steam co-exist, and depending on the permeability-porosity of the rocks, the well may draw either of these fluids from the supply horizon or even a mixture of both. When supplied with saturated hot water, steam generation (flashing) starts immediately and continues as the fluid ascends to the wellhead. Supplementary steam from the rock matrix may increase the fluid enthalpy above that expected from the horizon water temperature but we shall only consider the extreme conditions here, of all-water or all-steam entering the well.

For the case where water is boiling at the ground surface at 100°C and at greater temperatures at depth due to the increasing hydrostatic head imposed by boiling water, we have the following equation derived by James (1970) and in the metric form:

$$C = 69.56 H^{0.2085} \quad \text{for } 30 < H < 3\,000 \quad (2)$$

C Reservoir temperature, $^{\circ}\text{C}$ Celsius
H Depth in metres

So for any particular depth of well, under conditions of BPD, we may take the supply fluid temperature from the above equation and hence obtain from published Steam Tables, the associated pressure, specific volumes of steam and water as well as enthalpies and other data.

DRY SATURATED STEAM CALCULATION

Lapple (1943) theoretically estimated the flow of compressible fluid through long pipes to the atmosphere and this was later experimentally confirmed by James (1964) specifically for dry saturated steam. The method of calculation is given in detail by James (1970) where charts are presented of flow, viscosity and specific volume together with formulas to estimate Reynold Numbers of flows and friction factors in commercial steel pipes.

The approach is to select a temperature, say 250°C and, from Steam Tables, obtain the steam pressure of 39.73 bars, and from equation (2) the depth of 462 m. The steam flow to atmosphere is now calculated and converted to Lip pressure employing equation (1) in which the steam enthalpy $h_o = 2801.5 \text{ kJ/kg}$ at 250°C . A trial method is required after initial guessing of the friction factor, and assumption of a well bore diameter. Results are charted on Table 1 against $\frac{f_c}{d_c}$ which gave a reasonable

straight line on log-log paper when plotted against supply fluid as shown on Figure 2.

Table 1 Plot relating supply steam temperature to
Lip pressure and well bore diameter

C	$\frac{P_c}{d_c^{0.602}}$
175	7.46
200	9.60
225	12.13
250	15.08
275	18.56
300	22.75
320	26.88
340	32.25

SATURATED HOT WATER CALCULATION

As for dry saturated steam, detailed calculations are presented by James (1970) together with charts of viscosity and specific volume for homogeneous mixtures of steam-water substance, at various pressures and enthalpies. The acceptance of no-slip between the steam and water is assumed valid for the case of maximum unrestricted vertical flow to the atmosphere as it agrees with measured values on powerful wells.

As in the case for dry saturated steam, a downhole temperature is selected which permits the depth to be calculated from equation (2) and thermodynamic data derived from Steam Tables, but here we have all-water entering the well and increasing in steam fraction as it rises to be discharged to the atmosphere. This discharge takes place at the speed of sound at the Lip pressure located on the rim of the pipe outlet. A trial method is necessary in which both Lip pressure and pipe friction factor have to be initially guessed. Overall pressure-drop is the sum of hydrostatic pressure-drop, frictional pressure-drop and pressure-drop due to the increase in kinetic energy within the pipe from bottom entry to top exit.

Results are charted on Table 2 similar to that for dry saturated steam, and then plotted on Figure 2.

Table 2 Plot relating supply water temperature to Lip
pressure and well bore diameter

C	$\frac{P_c}{d_c^{0.602}}$
200	9.35
250	15.60
300	22.71
330	27.75
350	31.00
360	33.70

CONCLUSIONS

It should be pointed out that the extraordinary agreement shown on Figure 2 for both steam flow and flashing hot water would most probably not have been investigated if unobserved on a geothermal well at Wairakei, where hot water at the bottom changed over to steam at the same temperature and pressure.

As both bottom hole and exit pressures are identical, one might assume that the pressure curve over the well depth is also the same and hence it may be possible to estimate the steam-water pressure-drop at any location by calculating that for the steam curve, but this would need verification by experiment.

If the match is so good for vertical flow, would we expect a similar match for horizontal flow? Provisional calculations indicate what one would suspect, namely an increasing divergence with depth as the weight of the water fraction in the steam-water mixture exerts its dominance. Presumably vertical flow has some compensating factors which bring close agreement with the homogeneous model, at least over the temperature range common to geothermal reservoirs suitable for power exploitation (175° to 350° C).

The straight line on Figure 2 passes through all the plotted points with good agreement and has the following equation:-

$$\frac{P_c}{d_c^{0.602}} = \left(\frac{C}{72.2} \right)^{2.195} \quad (3)$$

ILLUSTRATIVE EXAMPLE

If a 0.2 m diameter geothermal well is drilled 800 m into a reservoir which is at boiling point throughout its depth, what is the maximum flow possible?

Maximum flow occurs at wide-open vertical discharge as shown in Figure 1, and for perfect permeability at the downhole supply horizon, which is here assumed.

The temperature at a depth of 800 m is calculated from equation (2)

$$C = 69.56 (800)^{0.2085} = 280.32^{\circ} \text{C}$$

From Figure 2, the equation of the line is now used:-

$$\frac{P_c}{d_c^{0.602}} = \frac{P_c}{(0.2)^{0.602}} = \left(\frac{280.32}{72.2} \right)^{2.195} \quad P_c = 7.45 \text{ bars}$$

If the fluid entering the well is saturated hot water at 280.32° the enthalpy from Steam Tables is 1238 kJ/kg. Then from equation (1),

$$G = \frac{1839 (7.45)^{0.96}}{(1238)^{1.102}} = 4.87 \text{ t/m}^2 \text{s}$$

$$\begin{aligned} \text{Fluid flow in tonnes/hour} &= 4.87 (3600) \frac{\pi}{4} (0.2)^2 \\ &= \underline{550.31 \text{ t/h}} \end{aligned}$$

If fluid entering the well is dry saturated steam, the enthalpy from Steam Tables is 2779 kJ/kg.

Then from equation (1),

$$G = \frac{1839 (7.45)^{0.96}}{(2779)^{1.102}} = 2.01 \text{ t/m}^2 \text{s}$$

$$\begin{aligned} \text{Steam flow in tonnes/hour} &= 2.01 (3600) \frac{\pi}{4} (0.2)^2 \\ &= \underline{226.91 \text{ t/h}} \end{aligned}$$

These are the maximum flow-rates possible; actual wells have reduced discharges due principally to relative impermeability of reservoir rocks retarding inflow at the supply horizon (granulated bed, fissure or fractures).

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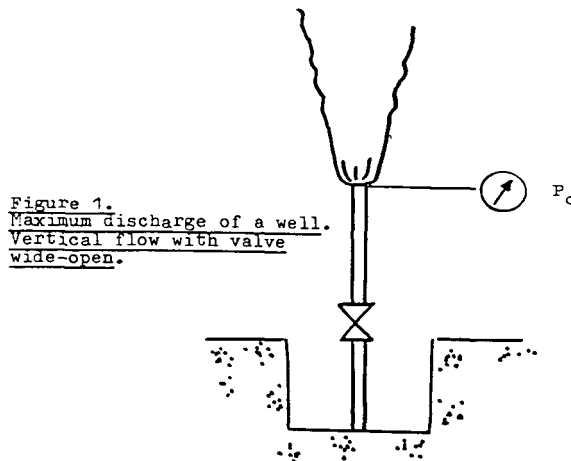
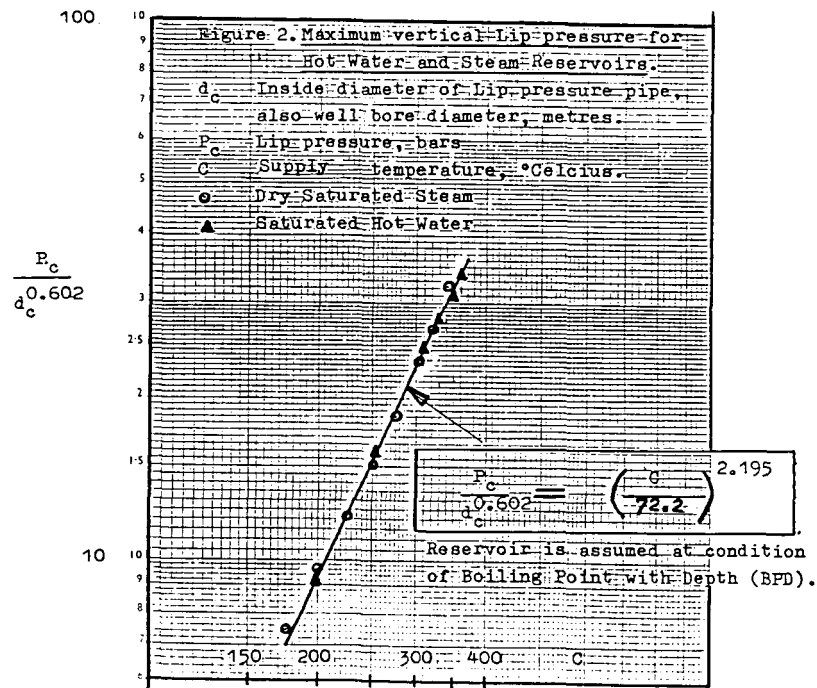


Figure 1.
Maximum discharge of a well.
Vertical flow with valve
wide-open.



SIGNIFICANCE OF THE MAXIMUM DISCHARGING-PRESSURE
OF GEOTHERMAL WELLS

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ABSTRACT

It would be impressive to raise the wellhead pressure of a hot-water geothermal borehole to the maximum sustainable by flow and from this deduce the supply water temperature, rate of discharge, dryness fraction and density of the wellhead fluid. All this data can, in fact, be obtained from the reading of the pressure gauge installed below the wellhead control valve so long as the flow condition is that given above. The tentative results can be valuable for untested wells drilled in isolated areas; and for monitoring production wells as it permits estimates to be made of changing subterranean conditions.

INTRODUCTION

From the early days at Wairakei, it was noted that wellhead pressures could only be raised to a certain maximum value when throttling discharge. Any attempt to raise it further resulted in collapse of the flowing steam-water mixture and closure of the well. From a wide-open vertical discharge of about 500 t/h, the most productive wells would reduce to about 110 t/h at a Maximum Discharging-Pressure (MDP) of 25.7 bars or thereabouts. This was for 0.2 m diameter boreholes drilled into the Wairakei reservoir, which approximated to Boiling Point with Depth (BPD) down to about 460 m at 250°C. A correlation between the essential factors was calculated by James (1970) as:-

$$C = 99.75 P_m^{0.283} \quad \text{for } 8 < P_m < 80 \quad (\text{see Notation}) \quad (1)$$

Borehole tests in a number of countries have shown this equation to be surprisingly accurate (confirmed by downhole Kuster measurements on flowing wells) in estimating supply water temperatures from values of MDP; this in spite of steam-water mixtures being considered as homogeneous. Also, frictional pressure-drop was ignored, as was kinetic energy increase in the flowing fluid and potential energy requirements to elevate fluid to the wellhead. These were found negligible compared with the hydrostatic head imposed by the column of ascending steam-water mixture.

$$\text{Hence} \quad P_s - P_m = \frac{0.981 L}{10 V_{sw}} \quad (2)$$

where V_{sw} is the homogeneous steam-water specific volume taken at the average pressure of $P_s + P_m$ over the flashing length L and at the enthalpy

h of the supply water temperature C . The temperature with depth relationship in a reservoir which has a boiling mixture down to a level below which pressurised hot water exists is shown on Figure 1 and has the equation:-

$$C = 69.56 L^{0.2085} \quad \text{for } 30 < L < 3000 \quad (3)$$

Even if a well is drilled to below depth L and then discharged at MDP, boiling will first start within the casing at very close to depth L associated with temperature C in the above equation. This, no doubt, explains the accurate results obtained whether fluid is supplied from the BPD zone or from greater depth within the pressurised hot water underlying it.

Equations (2) and (3) are required to solve for P_m . The results are given in equation (1), which is independent of well diameter due to the dominance of the hydrostatic head over frictional and kinetic energy effects. Using the latter equation, for various values of P_m , the associated supply water temperatures and enthalpies are given in Table 1.

DRYNESS FRACTION AND SPECIFIC VOLUME AT THE WELLHEAD

When the wellhead pressure equals P_m , it is of interest to see how the dryness fraction and specific volume of the steam-water mixture varies. Values are calculated and given in Table 1 and it is seen that, over a range of P_m up to 70 bar, dryness fraction

$$q\% = \frac{P_m}{4} \quad (4)$$

while V_{sw} is approximately constant at $6 \text{ m}^3/\text{t}$.

In other words, whatever the water temperature (up to 332°C) supplying the well at MDP, the density of the steam-water mixture at the wellhead is fairly constant. It appears likely that 'Bubble' flow takes place over the lower levels of the well with 'Churn' flow at higher levels, as described by Taitel et al. (1980). For these conditions, at MDP, both steam and water phases travel at approximately the same velocity, hence the concept of homogeneity adopted here is a realistic one.

FLOW-RATE AT MDP

MDP values of boreholes in New Zealand are recorded by the Ministry of Works and Development, and a study of flow-rates at different supply water enthalpies h and bore diameters d , gives the pragmatic rule

$$W = 2.5 h d^2 \quad (5)$$

Values of flow-rate are given in Table 1 for a well of 0.2 m diameter.

MIXTURE VELOCITY AT THE WELLHEAD

To determine the velocity of the steam-water mixture at the wellhead, upstream of the control valve.

$$\text{At MDP, } u_{sw} = \frac{W}{\frac{\pi}{4} d^2} \frac{V_{sw}}{3600}$$

Substituting W of equation (5), and taking the value of $V_{sw} = 6$ as constant over the range of interest where $P_m \leq 70$ bars.

$$u_{sw} = \frac{h}{188.5} \quad (6)$$

As expected, mixture velocity is independent of borehole diameter and increases with supply water temperature and P_m as shown in Table 1.

TABLE 1 Physical Factors related to P_m for a Geothermal Well flowing at Maximum Discharge Pressure. W values for $d = 0.2$ m.

P_m	C	h	q%	V_{sw}	W	U_{sw}
10	191.4	814	2.54	6.03	81.4	4.32
20	232.9	1002	4.93	6.03	100.2	5.32
30	261.2	1140.6	7.36	6.03	114.0	6.05
40	283.3	1254	9.73	5.97	125.4	6.65
50	301.8	1354.1	12.19	5.94	135.4	7.18
60	317.8	1445	15.27	6.07	144.5	7.67
70	332	1535	17.81	5.99	153.5	8.14
80	344.7	1627	21.53	6.15	162.7	8.63
90	356.4	1724.7	26.21	6.41	172.5	9.15
100	367.2	1848	33.4	6.99	184.8	9.8

CONCLUSIONS

From a simple test on a /^{hot-water} geothermal well, the Maximum Discharging-Pressure gives a lot of information, and it is hoped it will gain world-wide use. Production wells can be occasionally checked for fall in P_m due to decline in the supply water temperature at depth, as a change as^m small as 1 degree C will be reflected in a measurable variation in the wellhead pressure gauge as determined by equation (1).

The concept of homogeneity, although not popular in the literature of two-phase flow, appears to apply to the ascent of geothermal steam-water mixtures over large distances and within the enthalpy range of hot-water reservoirs.

NOTATION

C	boiling water temperature at depth L, ° Celcius
d	wellbore diameter, metres
h	boiling water enthalpy associated with C, kj/kg
L	depth, metres
P	Maximum Discharging-Pressure (MDP) at wellhead, bars
P^m	boiling water pressure associated with C, bars
q^s	dryness fraction of steam-water mixture at wellhead
u	velocity of steam-water mixture at wellhead, m/s
V^{sw}	specific volume of steam-water mixture at wellhead, m^3/t
W^{sw}	flow-rate at Maximum Discharging-Pressure, t/h

ILLUSTRATIVE EXAMPLE

Under discharging conditions, the wellhead pressure of a previously untested borehole is throttled to a maximum value of 37 bars gauge. What provisional deductions can be made, assuming a borehole diameter of 0.2 m, and atmospheric pressure of 1 bar?

Maximum Discharging-Pressure $P_m = 37 + 1 = 38$ bars

From Figure 1 or equation (1), $C = 99.75 (38)^{0.283} = 279.25^\circ C$

This is the temperature of the water supplied to the well at depth, and from Steam Tables has an enthalpy $h = 1235$ kj/kg

From equation (5), $W = 2.5 (1235) (0.2)^2 = 123.5$ t/h which is the flow at a wellhead pressure of 38 bars.

Conditions at the wellhead are as follows:-

From equation (4)

$$\text{Dryness fraction as a percent } q\% = \frac{P_m}{4} = \frac{38}{4} = 9.5\%$$

As the value of P_m is less than 70 bars, the specific volume of the steam-water mixture is constant at $6 m^3/t$ and density is the reciprocal $0.167 t/m^3$. Wellhead mixture velocity (homogeneous) from equation (6),

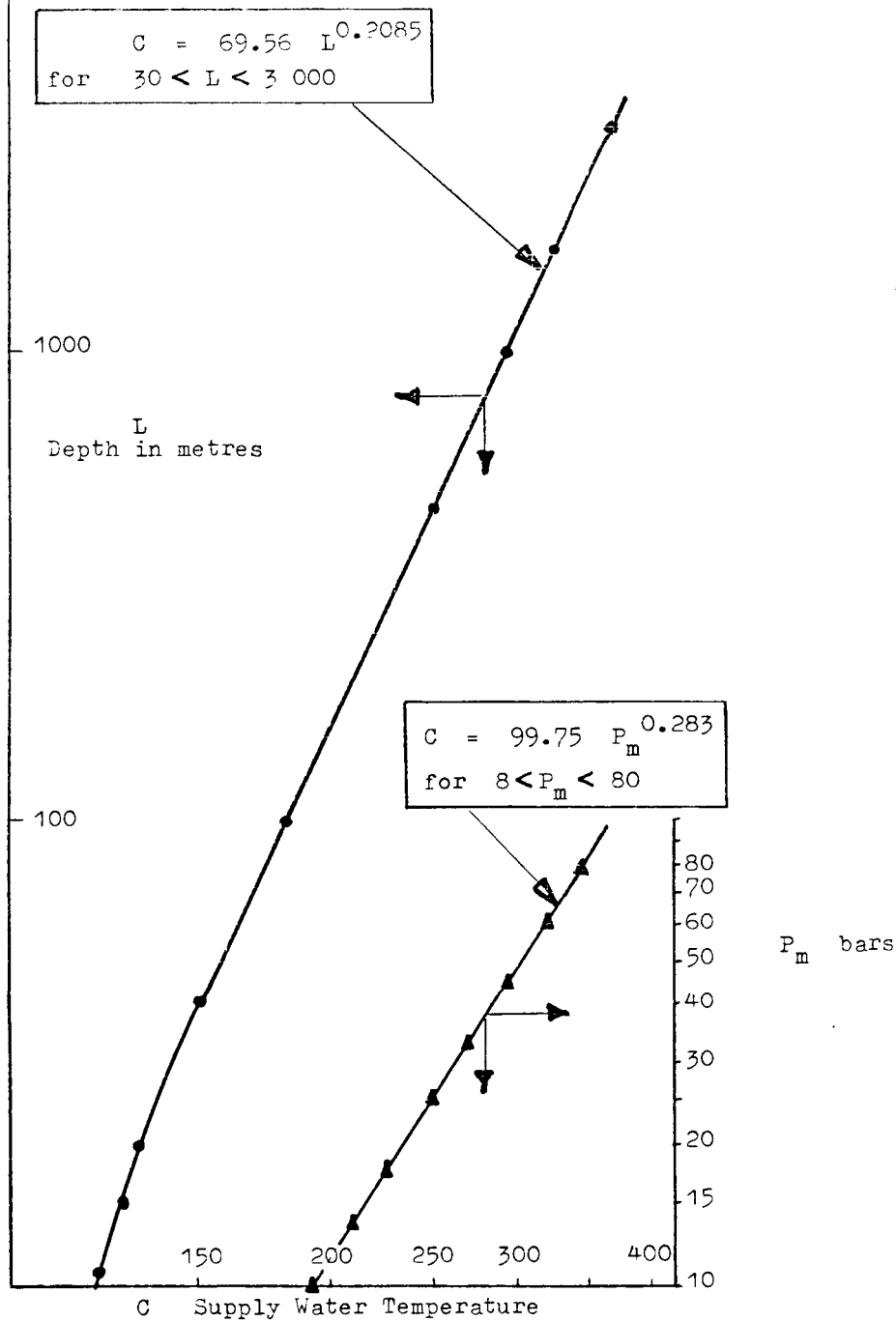
$$u_{sw} = \frac{1235}{188.5} = 6.55 \text{ m/s}$$

Note This is not just an academic exercise as the above example is taken from the new Kawerau well KA 30 which was afterwards tested over a range of wellhead pressures. At the MDP of $P_m = 38$ bars, enthalpy was measured as 1235 kj/kg and flow W as 121 t/h, which is close confirmation of the above estimates.

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Figure 1 Temperature versus depth and Maximum Discharge Pressure P_m for boiling throughout Reservoir, with 100° at Surface.



WELL TEST ANALYSIS RESEARCH

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INTRODUCTION

Well test analysis offers a rapid way to perform an initial assessment of geothermal systems. Well testing includes both pressure drawdown and buildup testing, and interference testing. Development of new well test analyses receives major emphasis in the Stanford Geothermal Program. During the year, quite a few studies were completed, and reports and papers presented on a variety of well test analysis methods. The following summarizes some of the more important results.

(a) Constant Pressure Testing

Although the conditions which result in constant pressure flow often exist for geothermal production and injection wells, the methods for analyzing the resulting rate transients and pressure buildup for such wells have been incomplete or nonexistent. The objective of this work was to review the existing methods of analysis and to contribute new solutions where needed in order to produce a comprehensive well test analysis package for wells produced at constant pressure. The work was completed during the year, and a technical report, SGP-TR-36, has been published. Other publications of results from this project are given by Ehlig-Economides and Ramey (April, September, November 1979).

(b) Parallelepiped Models

These models have been successful in demonstrating three-dimensional boundary effects in geothermal reservoirs. Last year's work in this area focused on a three-dimensional reservoir contained on all sides and at the top by impermeable boundaries, with a constant pressure boiling surface at the base. These models (either with a partially penetrating well or fracture) were used successfully to analyze well test data from The Geysers and the Travale-Radicondoli fields (see Economides et al., 1980). This year's activities extended the model to include the configuration of a three-dimensional reservoir with a boiling surface at the base and a condensation surface at the top. This situation is characteristic of the Kawah Kamojang field in Indonesia, and also of some parts of The Geysers. Typical drawdowns for such a system are illustrated in Fig. 1. The objective of this study is to produce generally useful type-curves with an emphasis on detection of the outer limits of the reservoir. It is also intended that these models be used to represent the entire drainage volume for a power plant (encompassing ten or more wells).

(c) "Slug Test" DST Analysis

The solutions for the slug test (decreasing flowrate) drill stem test (DST), including wellbore storage and skin effect, were presented by Ramey et al. in 1975. In field data from slug test DSTs, an initial period of constant flowrate can often be observed. A new model which includes the initial constant flowrate for a slug test was developed. Type-curves were graphed which were then matched with field data. The slug test type-curves can be applied to both the flow period and the pressure buildup after a short initial shut-in in a DST. A special feature of the new type-curves is that they may be used to estimate the initial formation pressure from the initial cleanup flow pressure buildup data even when the flow is so short that a Horner buildup graph is not possible (see Shinohara and Ramey, 1979a).

In deep, high-rate wells, the inertia and momentum of the liquid moving in the wellbore become important. Most available pressure transient solutions neglect these phenomena. Sometimes the inertia effect can cause oscillation of the liquid level in the wellbore. An approximate method using an exponentially damped fluctuation was presented by van der Kamp in 1976. However, this method cannot be applied to the early time pressure behavior, which is often of interest. A complete analytical solution for this problem was found, and the resulting type-curves were graphed and matched with field examples. Figure 2 shows some of the new solutions. The parameter x_D represents the fractional liquid level rise following the sudden removal of the liquid from a static wellbore. This acts like opening a bottomhole valve in a DST when there is air in the drill pipe. The parameter α^2 is:

$$\alpha^2 = \frac{L}{g} \left(\frac{k}{\phi \mu c_t r_w^2} \right)^2$$

where L is the well depth and g is the acceleration of gravity. Other symbols have their usual interpretation. The term α^2 is a parameter which considers momentum or inertia of fluid in the wellbore. A value $\alpha^2 = 0$ is the usual slug test. When α^2 reaches values of 10^5 or more, the results differ greatly from the slug test. Oscillations occur when $\alpha^2 = 10^8$ or more. Both the skin effect and wellbore storage affect the results significantly.

This theory can also be applied to closed-chamber DSTs and water injection falloff tests. These results were published by Shinohara and Ramey (1979b), and by Shinohara (1980), to be published as SGP-TR-39.

(d) Analysis of Wells with Phase Boundaries

The analysis of pressure tests in geothermal reservoirs is often complicated by two-phase effects. This work investigated the effect of a phase boundary at a constant radial distance from the well, produced, for example, by the flashing of a water reservoir during production or by the injection of water into a steam or two-phase reservoir.

The results indicate the possibility of determining compressibility and permeability contrasts across the phase boundary. This enables estimation of the reservoir porosity and relative permeabilities in the two-phase region. In some cases, wellbore storage effects can disguise the pressure response and make parameter determination difficult.

Figure 3 shows an injection falloff in Broadlands well number BR26 which proved accessible to the new method of analysis.

This work was presented by Horne and Satman (1980), and Horne, Satman, and Grant (1980a). As an informal cooperative program with the New Zealand Department of Scientific and Industrial Research, it was also presented at the 1980 New Zealand Geothermal Workshop in November 1980, as Horne, Satman, and Grant (1980b).

(e) Internal Well Flows

Experience in analysis of temperature and pressure profiles in geothermal wells has indicated that flow frequently occurs from one production (interval) level to another--even though the well may be shut in at the wellhead. This flow occurs because pressure gradients in the reservoir are frequently greater than hydrostatic, while those in the well are restricted to be hydrostatic unless the fluid is moving. The recognition of these flows has been the subject of study by Grant (1979) based on a number of observations, including temperature profiles during heatup, injection, etc. The present study investigated the difference between the observed pressure gradient in a shut-in well, and the inferred hydrostatic pressure gradient calculated using the simultaneously measured temperature.

Analyzing a shut-in temperature/pressure log from well M-9 at Cerro Prieto, it was determined that internal flow occurred below a depth of 2500 feet since the observed well pressure gradient changed sharply from hydrostatic at this depth (see Fig. 4). This well proved to be an excellent demonstration of the method because it is actually perforated at this depth; thus confirming the conclusion of the pressure gradient comparison.

Further tests using different Cerro Prieto wells are in progress. It is anticipated that the method may be useful for the one-step recognition of producing levels and internal flows, and may even be able to detect other perturbations such as casing leaks. The rapid evaluation of internal flows is of importance in the correct interpretation of all other pressure tests, and should be considered a first step in any pressure test.

(f) Naturally Fractured Reservoirs

This study presents solutions for declining production rates under constant pressure production in a naturally fractured reservoir. Solutions for dimensionless flowrate are based on the model presented by Warren and Root (1963). The model was extended previously by Mavor and Cinco-Ley (1979) to include wellbore storage

and skin effect. In the present study, the model was extended to include constant producing pressure in both infinite and finite systems. Figure 5 shows the results obtained for a finite, no-flow outer boundary. The flowrate shows a rapid decline initially, becomes nearly constant for a period, and then a final decline in rate takes place. The new type-curves of the analytical solutions are graphed in terms of the following dimensionless parameters:

$$q_D = \frac{141.2 q_B \mu}{k_f h (p_i - p_{wf})}$$

$$t_D = \frac{2.637 \times 10^{-4} k_f t}{[(\phi v C)_f + (\phi v C)_m] \mu r_w^2}$$

$$\lambda = \alpha \frac{k_m}{k_f} r_w^2$$

$$\omega = \frac{(\phi v C)_f}{(\phi v C)_m + (\phi v C)_f}$$

where k_f and k_m are fracture and matrix permeabilities, respectively, v is the volume fraction of the fractures or matrix, $\phi_f C_f$ and $\phi_m C_m$ are fracture and matrix porosity-compressibility products, respectively, and α is the interporosity shape factor. The two parameters ω and λ are new governing dimensionless groups, and the remaining symbols have their standard SPE interpretation.

Portions of this work were presented at the SPE of AIME Annual Fall Meeting in Dallas, Texas, 1980 (Da Prat, Cinco-Ley, and Ramey, 1980). Work will continue in this area.

(g) Temperature-Induced Wellbore Storage Effects

Wellbore storage is usually attributed to pressure changes occurring in the well. This study found that wellbore storage is also affected by heat transmission and the resulting temperature changes that result from flow in the well. The inner boundary condition for solution of the diffusivity equation for a single-phase well in an infinite radial reservoir was stated so as to include a wellbore storage term depending on temperature changes. Using Laplace transform methods, an exact solution describing the pressure behavior of the fluid in the system was sought. However, due to the form of the term describing temperature changes in the wellbore, it was not possible to find a simple solution form. Nonetheless, the problem was prepared for solution using numerical inversion. Two-phase systems were also considered, and the inner boundary condition describing such a situation was also derived. Several examples

of two-phase systems were described wherein the importance of temperature changes was apparent. A Master's Report was completed by Araktingi (1980). Further work is planned on this important class of problems.

CONCLUDING REMARKS

In addition to the preceding, many other field applications of well test analysis were conducted and reported during the year. Tests were performed and analyzed in the Ching-Shui Field, Taiwan (see Ramey and Kruger, eds., 1979), a new type-curve for interference testing was reported by Ramey (Third LBL Well Testing Workshop, 1980), and planning and analysis of preliminary well tests in the Miravalles Field, Costa Rica, were completed (Ramey, November 1980) during July 1980. Research on well test analysis should continue to be fruitful, and opportunities for field applications are becoming more frequent.

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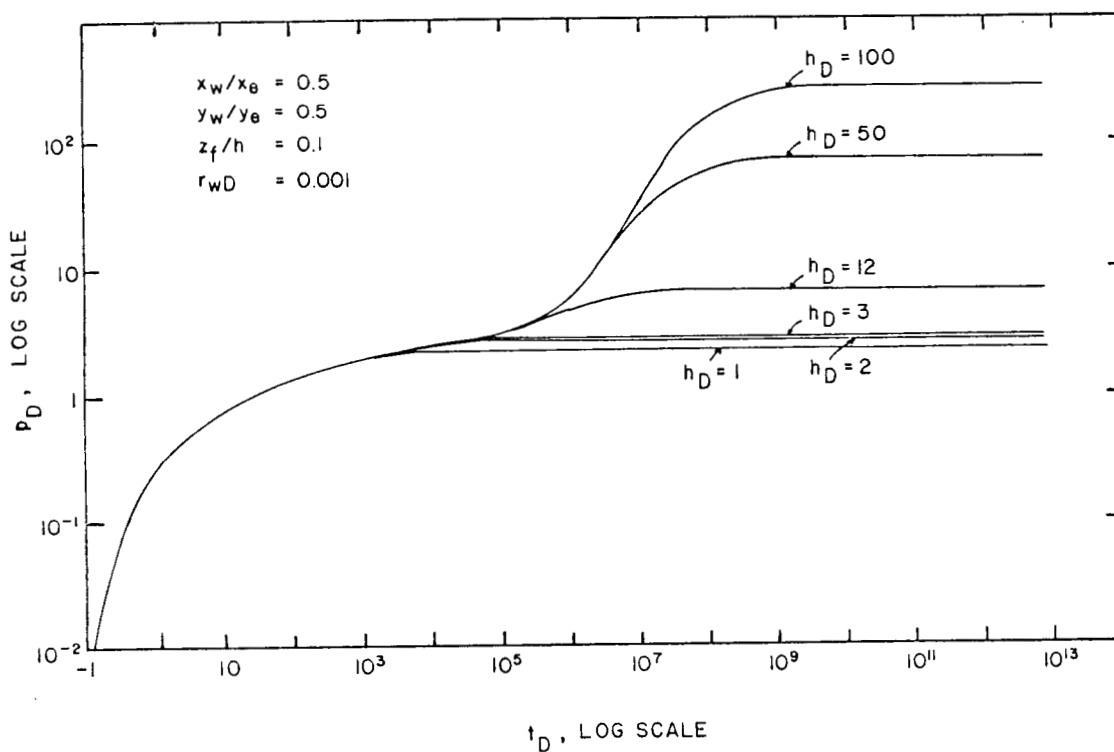


FIG. 1: LOG-LOG TYPE-CURVE FOR A PARALLELEPIPED MODEL.

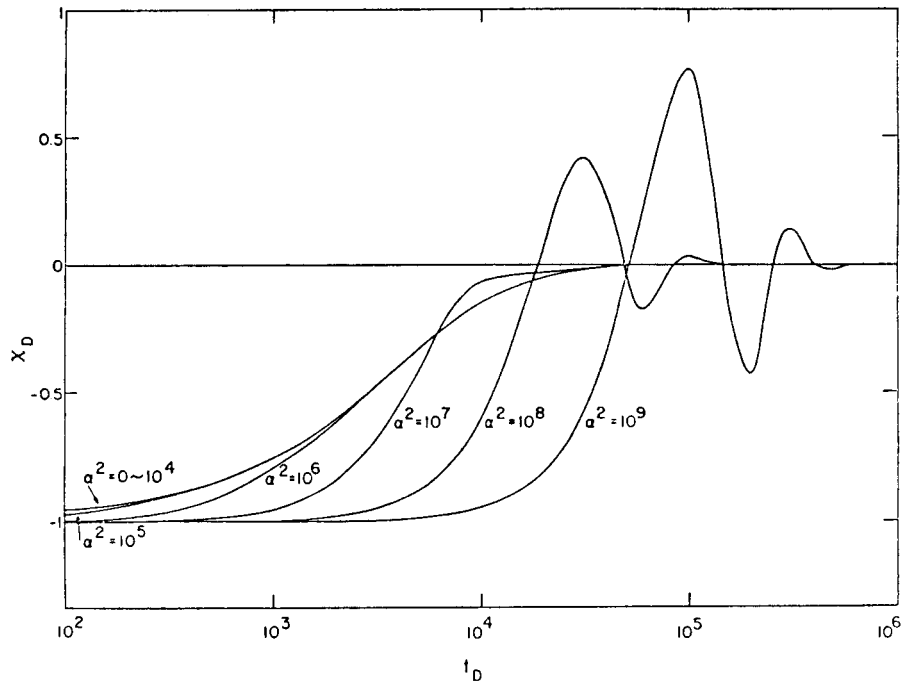


FIG. 2: UNDAMPED SLUG TEST (Shinohara, Apr. 1980)

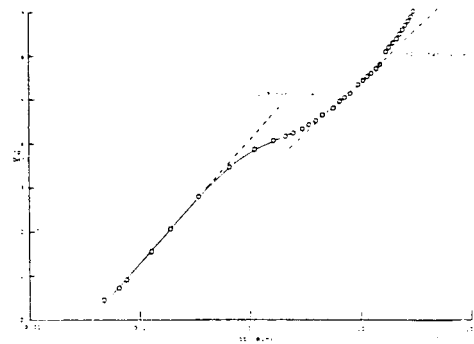


FIG. 3: PROJECTION FALLOFF TEST ON WELL BR26. SEMILOG COORDINATES.

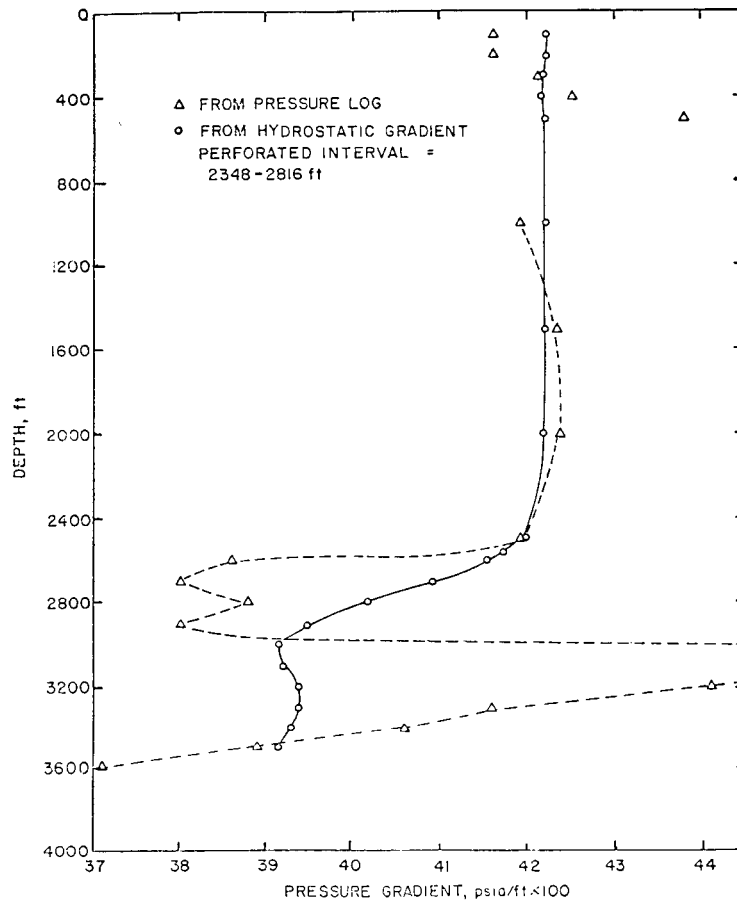


FIG. 4: PRESSURE VS DEPTH FOR WELL M-9, CERRO PRIETO, MEXICO

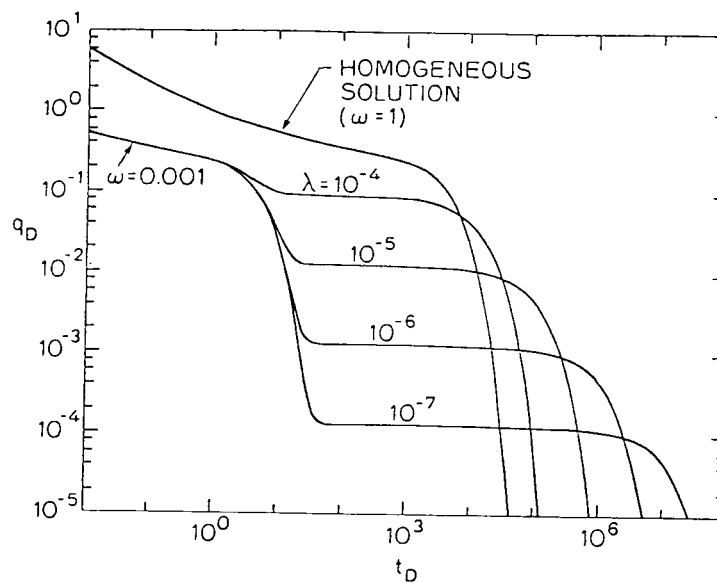


FIG. 5: q_D VS t_D FOR CONSTANT PRESSURE PRODUCTION; CLOSED BOUNDARY
($r_{eD} = 50$, SKIN FACTOR = 0)

ELIMINATING THE WELLBORE RESPONSE IN TRANSIENT WELL TEST ANALYSIS

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Introduction

When testing a production well to determine the characteristics of a fluid filled reservoir, one usually waits until wellbore storage is over, and then one determines both the slope of the downhole pressure versus log (time) plot (to calculate kh/μ), and the intercept of the line (to obtain $\phi c h r_e^2$). However, in a geothermal field it may not always be possible to run a test for a sufficiently long time to insure an accurate measurement of these parameters. The testing of a geothermal field requires instrumentation that can withstand high temperatures and high salinities, and, at present, available instrumentation is limited. Another problem is that non-isothermal effects in the bore increase the time of wellbore storage. The slow heating of the fluid in the well results in a slight change in slope of the p versus $\log t$ plot, and the duration of this heating effect can be much longer than wellbore storage due to pressure changes alone. In addition, the slope of the p versus $\log t$ graph can be very flat because of the large values of kh/μ in geothermal fields. With a positive skin effect wellbore storage lasts longer, so the slope will be even flatter in this pseudo-steady region.

Very small changes in pressure must be measured over long times requiring accurate instrumentation. It is desirable to be able to use the pressure transient data taken while wellbore storage is important. The transient test can be relatively short (say 20 minutes) and the changes in pressure are still large enough (say on the order of a psi/minute) so that the error in the measurements because of the accuracy and resolution of the pressure gauge is small. The pressure data taken at early times can be used if the response of the wellbore is eliminated from the well test data, and a variable flowrate pressure transient analysis is performed. By modeling the transient flow in the well, it is also possible to explain differences between the pressure transient data from a geothermal field and that of an oil field.

The response of the flow in the wellbore is eliminated by calculating the actual conditions at the sandface (well/reservoir boundary). Given the sandface flow and enthalpy and knowing the downhole pressure, one can use a variable well test analysis method to determine kh/μ and $\phi c h r_e^2$. For a liquid filled reservoir, a variable well test method that uses a minimization technique is available (Benson and McEdwards, 1980). For a two-phase reservoir, a method of analyzing transient flow data is more difficult than from a single phase reservoir for even a constant mass flowrate. However, one could use a numerical

simulator and try to match the pressure data by varying the reservoir parameters until a "best fit" is obtained.

A numerical model of transient, one-dimensional two-phase flow in a well has been developed (Miller, 1979). This model is used to simulate the wellbore flow in the calculations below. Numerous steady state wellbore flow models have been reported (Gould, 1974; Nathenson, 1974; Sugiura and Farouq, 1979). However, in such models, one must naturally have the flow into the bore equal to the flow out of the bore. Therefore, these models cannot be used to obtain the sandface flowrate when wellbore storage is important.

The main purpose of this work is to show that it is possible to calculate the sandface flowrate given wellhead conditions and the downhole pressure transients. It is not necessary to know anything about the reservoir itself. First, it is of interest to look at the nonuniform pressure changes in the well, and to illustrate nonisothermal effects on pressure transient data.

Pressure Transients

When calculating the amount of mass that exits the wellbore during a transient test, it is not possible to calculate some average wellbore compressibility, and then say the difference between the wellhead and downhole flowrate is just $\rho c_g (dp/dt)$. The problem lies in the fact that the downhole pressure change with time is not characteristic of the average pressure change throughout the bore. This problem is illustrated in Figure 1 where both the wellhead and downhole pressure change with time is plotted for a flowrate change at wellhead from 20 to 40 kg/s and from 40 to 60 kg/s. One can see that initially the pressure at wellhead drops suddenly to achieve the desired flowrate while the downhole pressure hardly changes. Also, even after the initial transients in the well die out, the pressure change at wellhead is slower than the change downhole. No one pressure measurement will give the average pressure change in the bore during a well test.

Figure 2 shows the effect of a slow heating of the fluid in the wellbore on the pressure transient data. The well is 4500 m deep and is liquid filled. Two cases are plotted here. In one case, the temperature is held constant at 150°C throughout the bore. In the second case, the initial temperature of the stagnant fluid in the bore goes from 20°C at wellhead to 150°C downhole. The mass flowrate in the well was changed from 0 to 28.7 kg/s over 1 minute. The duration of wellbore storage based on pressure changes only should last about 20 s after the flowrate change is completed. One can see that the heating in the bore lasts orders of magnitude longer than these initial pressure transients. The effect of the heating is to make the sandface flow be slightly less than the wellhead flow until the energy change in the well is negligible. The energy change in the well is becoming small after 40 minutes. If

one calculates the actual sandface flow during this time, the data taken in these first 40 minutes could be used.

To determine the sandface flowrate in the well, it is necessary to know the wellhead flowrate and enthalpy and the downhole pressure change as a function of time. Enthalpy for a flashing system is obtained by measuring the quality and pressure. For a single phase system, enthalpy is obtained from pressure and temperature. If the reservoir is single phase then the enthalpy flowing out of the reservoir is not a function of flowrate, so it only needs to be measured once. For a two-phase reservoir, the flowing enthalpy from the reservoir changes when the steam saturation is altered around the bore because of relative permeability effects, and therefore, the enthalpy into the bore will change during a test. In such a case, one must measure the flowing quality at wellhead and correct it to obtain the downhole conditions.

Examples

The sandface flowrate is calculated for two different cases. In the first case the reservoir remains liquid filled, while in the second case the reservoir is two-phase. Included also is a calculation of a match of the pressure transients in a field case where wellbore transients are important, and an example of the two-phase flow in a well during shut in.

Because no field data were available, the data needed for the calculation of the sandface flow were generated numerically. To generate the downhole pressure used for the calculation of the sandface flowrate, the wellbore model was connected to a reservoir model. For the single phase case, the radial diffusion equation was finite differenced with a variable grid spacing. For the two-phase case, the reservoir model was provided by M.J. O'Sullivan and is a modified form of that given in Zyvoloski and O'Sullivan, 1979. A kh of $3 \times 10^{-11} \text{ m}^3$ was used for both cases. The resultant drawdown pressure for the single phase case is given in Figure 3a. A similar drawdown profile was obtained for the two-phase case. For the single phase case, the temperature downhole corresponded to an enthalpy of 1.5 MJ/kg.

Single Phase Reservoir

Given the downhole pressure and the wellhead flowrate change (20 to 40 kg/s), the sandface flowrate was calculated. Because there is no change in enthalpy from the reservoir during the test, the calculated sandface flow, plotted in Figure 3b, and corresponding to slip as a function of flow regime, is exactly equal to the sandface flow calculated when the drawdown pressure was generated. (The exact correlations used for slip are given in Miller, 1980a). However, since accurate correlations for the slip between the phases is not well known, the sandface flowrate was calculated for two additional cases, 1) $s = 0$, and 2) $s = \sqrt{\rho_f/\rho}$. The same drawdown pressure as

given in Figure 3a was used. Agreement is good except at very early times when $s = 0$. When $s > 0$, the steam quality of fluid in place is less than when $s = 0$. The compressibility of the two-phase mixture is greater for a lower steam quality mixture, so the wellbore is able to supply more of the surface flow for longer times than for the $s = 0$ calculations.

Two Phase Reservoir

It is more difficult to calculate the sandface flowrate when the reservoir fluid is two phase. The problem that arises is that the value of the flowing enthalpy from the reservoir as a function of time must be known to calculate the sandface flowrate. Figure 4a is a plot of wellhead and downhole enthalpy as a function of time calculated when the downhole pressure data were generated. (The reservoir was initialized at a liquid saturation of .78. The system was steadied out at a flow of 12.7 kg/s before the flow was increased to 25.4 kg/s so the drawdown pressure could be generated.) The enthalpy can only be measured at wellhead, but changes in enthalpy occur downhole first. The sandface flowrate was calculated using the wellhead enthalpy as the downhole enthalpy, but corrected for the delay in the arrival at the wellhead. To calculate the sandface flow, the wellhead enthalpy starting at 420 s was assumed to be the downhole enthalpy that occurred at time 0. Figure 4b shows both the sandface flowrate calculated when the downhole and wellhead data were generated, and then the sandface flow calculated, using the corrected wellhead enthalpy, the wellhead flowrate, and downhole pressure. The agreement is reasonable as this is a first attempt. A better correction of the wellhead enthalpy would result in a better agreement.

Field Case

Figure 5 illustrates how the transient wellbore model plus a reservoir can be used to match field data. The important point here is that the initial slope of $\log p$ vs $\log t$ is greater than unity. The downhole pressure data is from a buildup test at Raft River on RRGE2 taken by Narasimhan and Witherspoon (1977), using a Hewlett Packard Model 2811A quartz pressure gauge. The well was flowing 13 kg/s before being shut in. Because the time to shut in the well was not recorded, and because wellbore storage lasts only about 1 s, it is not reasonable to look at different values of kh and ϕch to determine the best fit from the early time data. The values of kh and ϕch given in the figure are close to those obtained previously. However, pressure transients in the well last longer than wellbore storage, and a model of the transient flow in the well is needed to explain this very early data. More detail of this effect is given in Miller, 1980b.

Build-up Analysis

The transient wellbore program can also be used to investigate the response of the fluid in the well when the bore is completely shut in. One can look at the sandface flow when the two phases separate out. Figure 6 is a plot of the density profile in the well after a shut in. However, these calculations are merely illustrations because the slip correlation used has no experimental basis. The liquid is flowing down while steam is rising. The slip function used was $5.6 \alpha^3(1 - \alpha)^{1/3}$ where α is the steam quality in place. This function was used so that the constraint $s = 0$ when $\alpha = 0$ or 1 was satisfied, and so it would be approximately the size of the slip in the bubble regime. The calculation shows a transition from steam to liquid. The density profile in the well after thirty-five minutes does show one point that does not follow the smooth transition. The reason for this deviation could be in the choice of a slip correlation that is too small. Nevertheless, one sees the two phases separate out and liquid can flow back into the reservoir.

Conclusions

It is possible to use pressure data obtained during a well test when wellbore storage is still important if one uses a transient wellbore flow model to calculate the actual sandface flow. The calculation is more difficult for a two-phase reservoir and some improvement of the calculation given in this study can be made. Given a technique of analyzing a variable flow test, one can use all data obtained during a well test. It is possible to explain the initial slope of the $\log p_{dh}$ vs $\log t$ plot that is greater than unity. Also, in the future, it may be possible to analyze shut in tests where phase redistribution is important.

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NOMENCLATURE

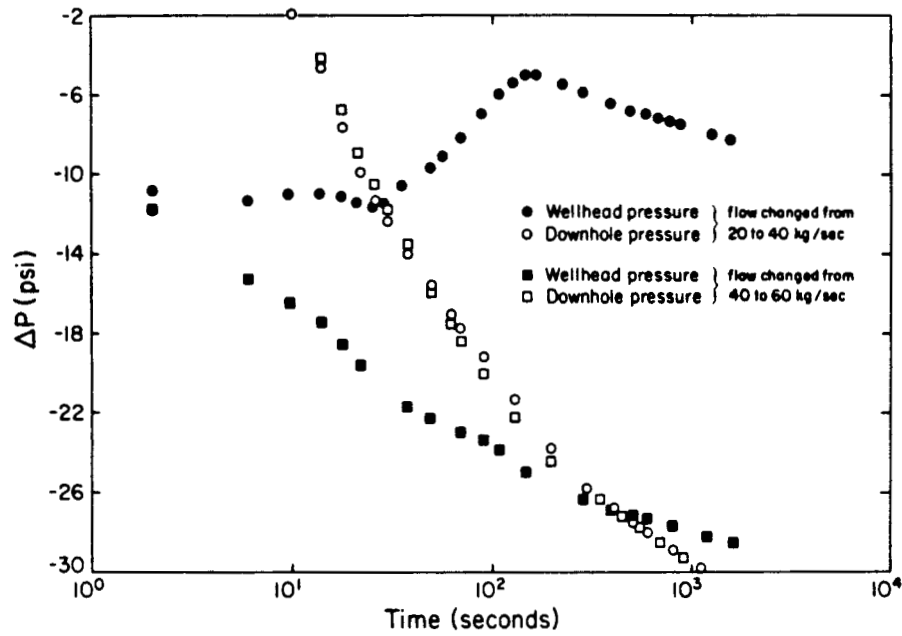
c	reservoir compressibility
c_s	average isentropic compressibility, $(1/\rho)(d\rho/dp)_s$
h	reservoir thickness
k	permeability
p	pressure
r_e	effective radius
s	slip
t	time
μ	viscosity
ϕ	porosity
ρ	density

SUBSCRIPT

dh	downhole
f	liquid

ACKNOWLEDGEMENT

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XBL 8011-6418

Figure 1. Plot of wellhead and downhole pressure transients for two drawdown tests.

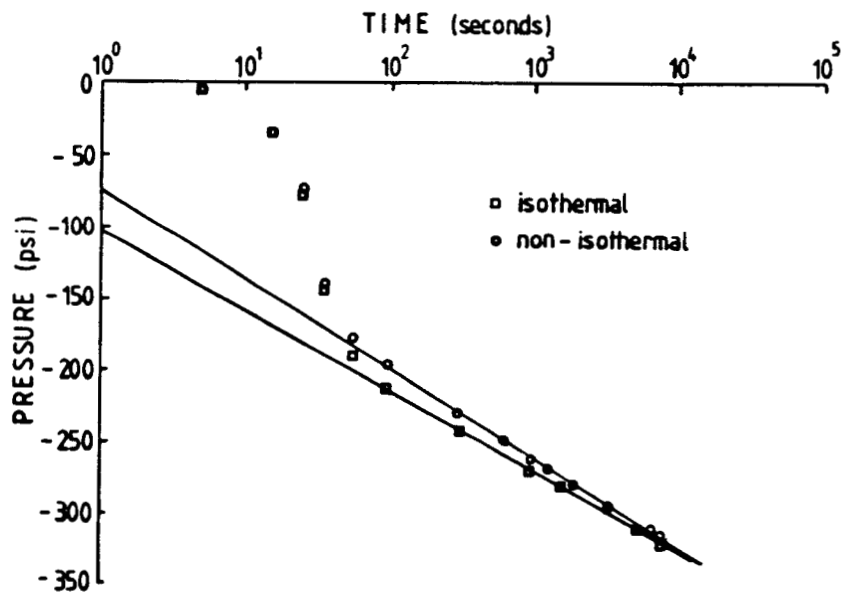


Figure 2. Effect of energy changes of fluid in the well on pressure transient data.

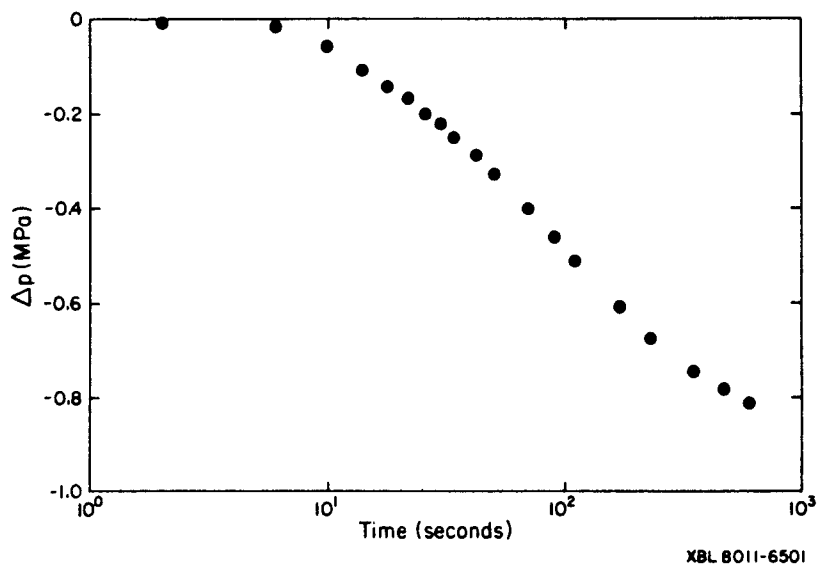


Figure 3a. Generated drawdown pressure.

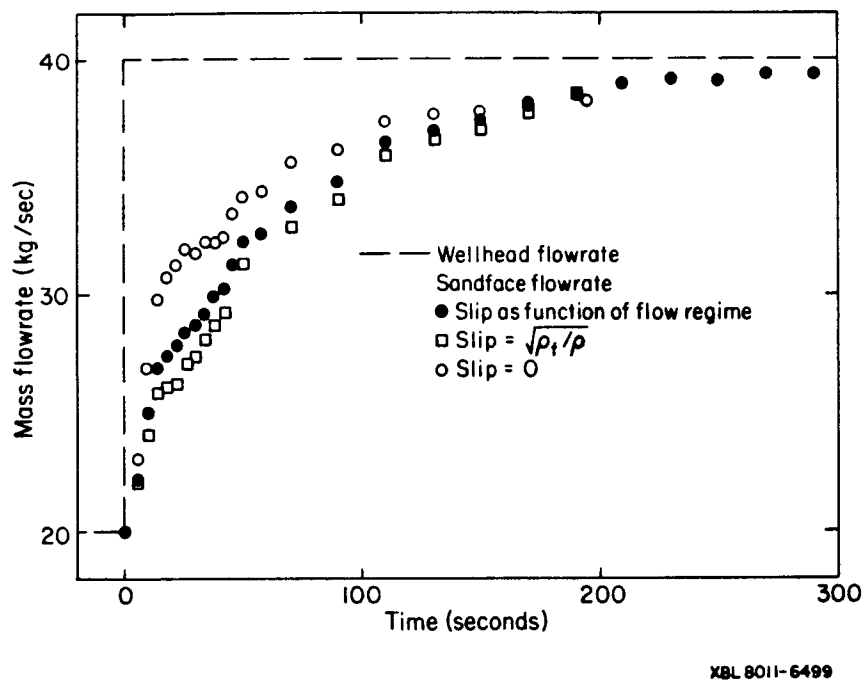


Figure 3b. Calculation of sandface flowrate using different slip correlations.

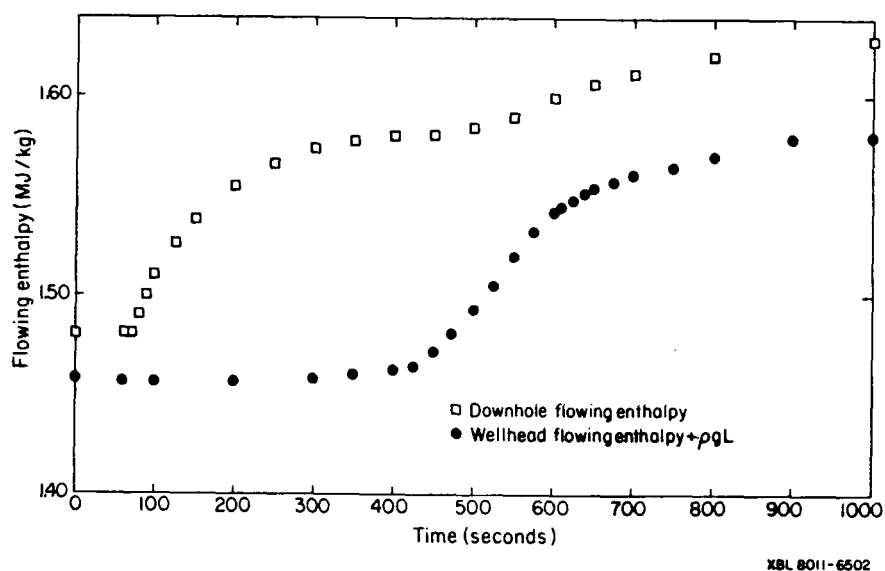


Figure 4a. Wellhead and downhole enthalpy as a function of time after a flowrate change.

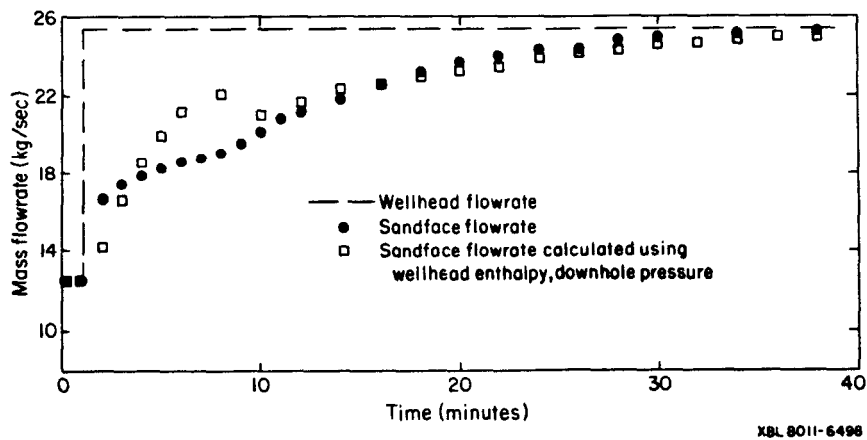


Figure 4b. Calculation of sandface flowrate for two-phase flow throughout the well.

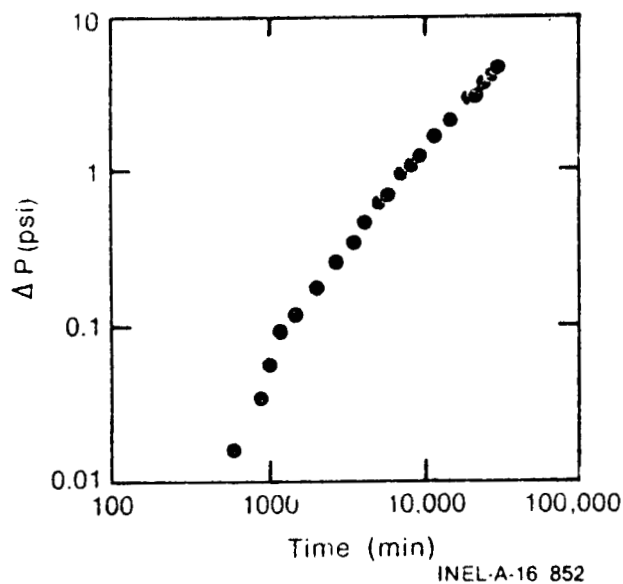


Figure 1 Drawdown at RRG-4 during production from RRG-5.

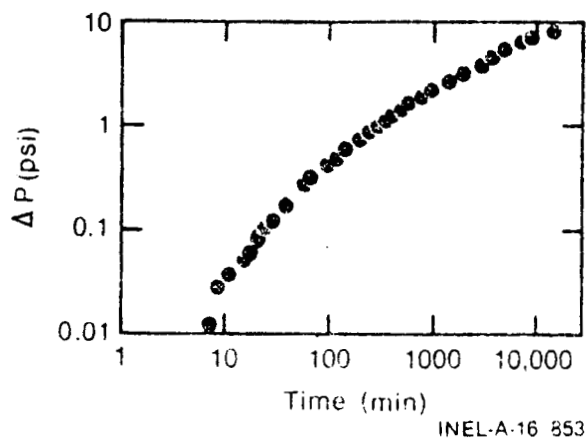


Figure 2 Drawdown at RRG-1 during production from RRG-5.

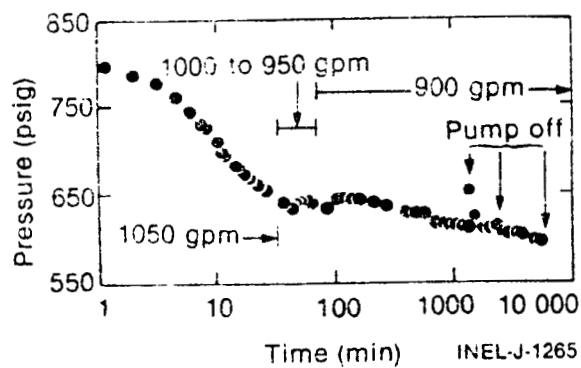


Figure 3 96 hours production at RRG-1

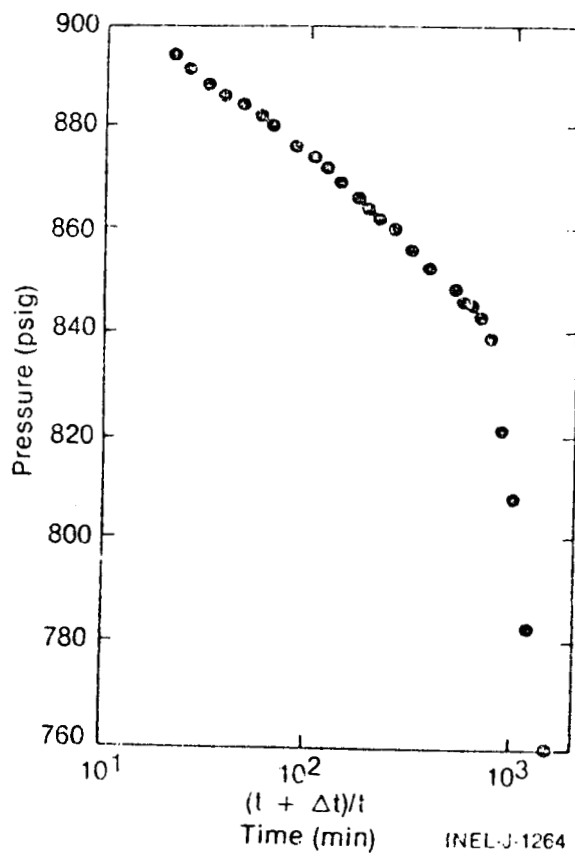


Figure 4 Recovery from production at RRG-1

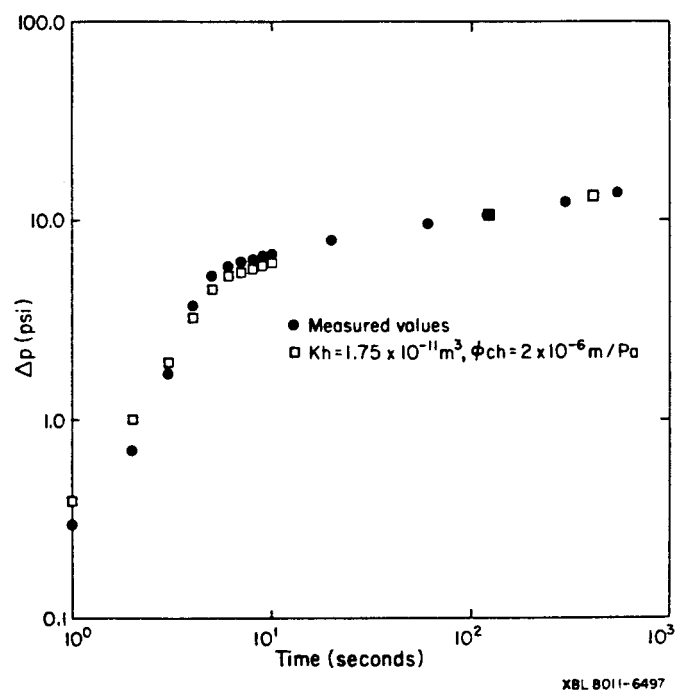


Figure 5. Match of pressure data with a field case.

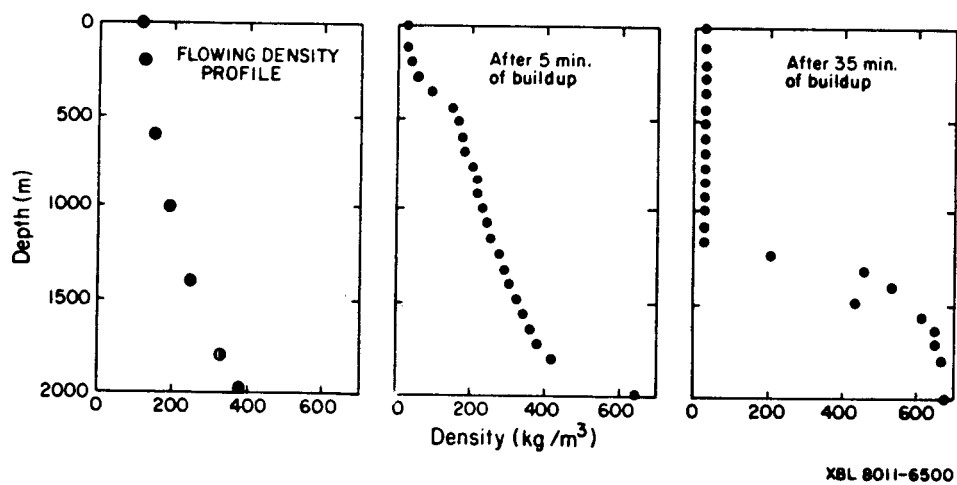


Figure 6. Calculation of density profile in a two phase well during a shut in test.

THE TESTING OF KA28 - PRESSURE ANALYSIS IN A TWO-PHASE RESERVOIR

Malcolm A. Grant

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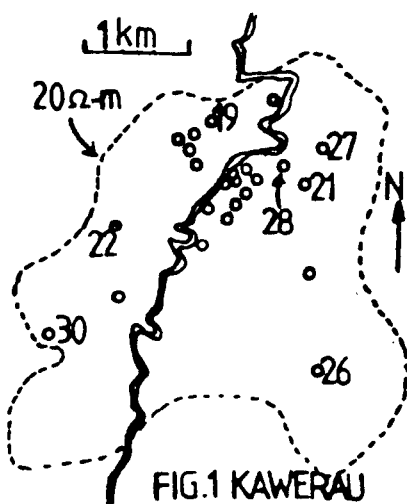
ABSTRACT

Examples of two-phase pressure transient analysis are given, for injection and discharge. Transients measured in KA28 are used to identify the fluid feeding the well and to measure permeability.

INTRODUCTION

Kawerau geothermal field in New Zealand has been exploited at a low level (20 MWe) since 1956. Separated steam is used by a pulp mill. The field has an area of 10 sq. km. (1). Investigatory drilling has continued slowly (2,3).

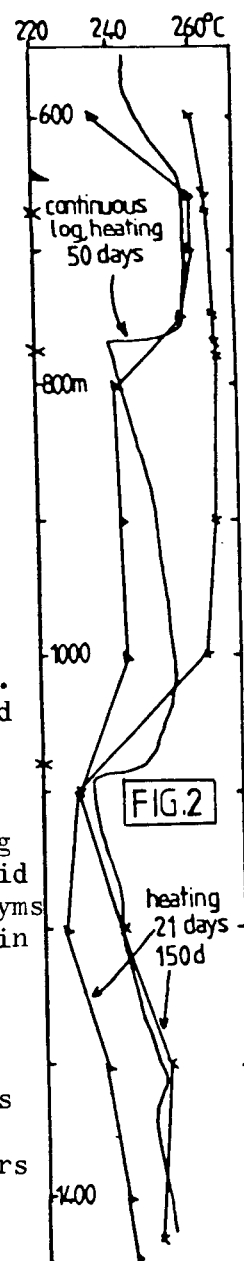
The reservoir consists of fractured volcanics over a greywacke basement (4). Base temperature is over 290°C. Permeability is on average very good, and also very erratic. KA21 found immeasurably large permeability in the greywacke at 1100m, in 286°C water. Its flow of 600 t/h makes it the world's largest producer (electrical equivalent). KA30 at the other end of the field is nearly as good. Between are some duds and some good wells.



KA28

KA28 was drilled as a stepout, 300m from KA21. It was a surprise and a disappointment, as it found lower temperature and permeability. Temperature increases to 266°C at 770m (Fig.2), similar to the adjacent wells. Beneath there is cooler water.

Detailed measurements with a surface-recording spinner and temperature tool identify zones of fluid loss or gain at 674m, 778m and around 1080m. (M. Syms pers. comm.) The two upper feeds are very similar in character and are hereafter lumped together as a single upper feed, represented by values at 700m. Stable downhole temperature at 700m is 264°C, and reservoir pressure 62 bars gauge. Temperature at 1080m is about 230°C, and reservoir pressure 93 bars gauge (5). The quoted reservoir pressures are the measured downhole pressures at which no fluid enters or leaves the well at that depth. They are not the same as stable downhole pressures (6), as a well cannot in general reach equilibrium at two depths.



The lower zone, in a temperature inversion, must contain liquid water. Pressure at the upper zone is 12.8 bars above saturation for pure water. Kawerau discharges contain up to 1% of gas, and partial pressures of up to 20 bars are observed. The upper zone might be boiling. The 150-day temperature profile is very smooth above 800m, and could be a boiling-point profile due to the upflow of boiling fluid from 778m to 674m (6); suggesting two-phase conditions at this depth.

Normally the completion testing and warmup would identify the dominant feed to the well, and the type of fluid in it. This was not possible in KA28. The well might produce: 230° liquid; 264° liquid; 264° two-phase; or a combination of the first with one of the latter. In a double-feed well, interzonal flows (7) normally cause oscillatory or erratic pressure transients. In the case of KA28, transient analysis of the injection and discharge tests indicates performance consistent with a well with one dominant feed, that feed containing two-phase fluid.

INJECTION

The usual completion test for New Zealand wells consists of cold water injection at various rates with measurement of downhole pressure and temperature. Two transients were measured (Fig.3), both at pump shut from 11½ l/s. In the second test a good result was obtained. In the first test (34731) the chart trace becomes irregular after 3 minutes, and agrees with the later test before then. The

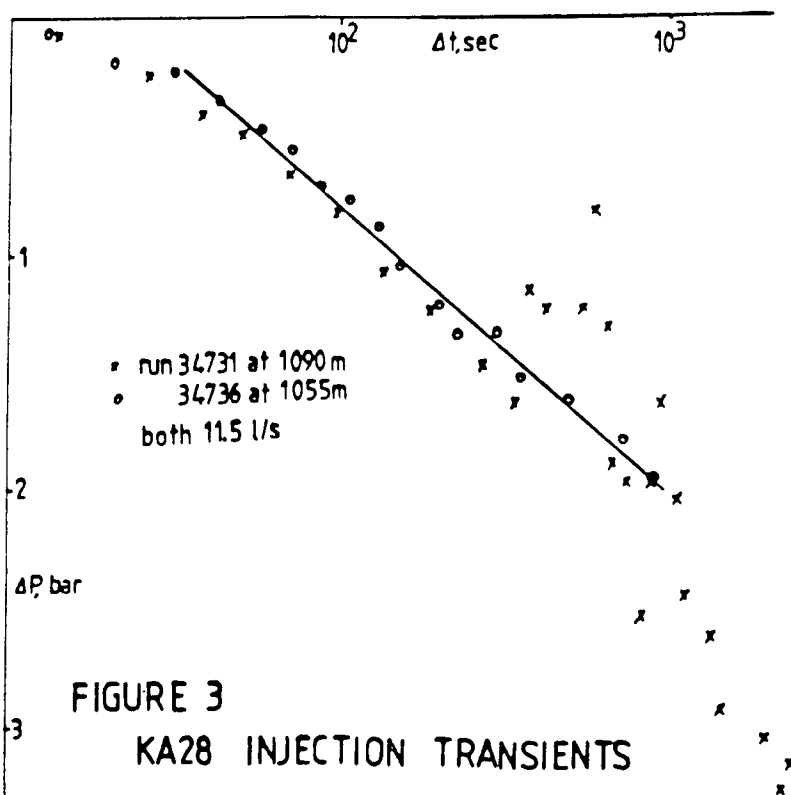


FIGURE 3
KA28 INJECTION TRANSIENTS

common straight line has a slope of 1.4 bar/cycle, giving (8,9)

$$kh/\mu_t = (11.5 \times 10^{-3})(2.303)/(4\pi \times 1.4 \times 10^5) = 1.5 \times 10^{-8} \text{ m}^3/\text{pa.s}$$

In an injection test it is assumed that there is a cold water region near the well, beyond which is heated injected water and hot reservoir fluid. The region affected by pressure change is much greater than the injection volume, so that the value of kh/μ_t measured reflects the reservoir fluid, not the injected water (H.J. Ramey, pers. comm.) Aquifer thickness, porosity, and reservoir fluid compressibility are all unknown, although ϕh is presumably less than 100m or so. Evaluating for skin gives:

$$\phi c_t h e^{-2s} = 6.7 \times 10^{-5} \text{ m/pa}$$

The assumption of a single-phase feed can now be examined. If the well is water-fed, feed temperature is $230-264^\circ$. Then $\mu_t = \mu_w \cong 110 \times 10^{-6} \text{ pa.s}$, and $c_t = c_w \cong 1.4 \times 10^{-9} \text{ pa}^{-1}$, giving

$$kh \cong 1.7 \text{ darcy-metre, } \phi h e^{-2s} \cong 50,000 \text{ m}$$

Skin must be negative (about -3). With the kh of 1.7 d-m, the expected discharge would be over 300 t/h, at water enthalpy.

Transient measurements should normally be made opposite the well's major feed, to minimise the effects of changes of fluid density in the well. It was hoped that good permeability would be found at depth in KA28, so measurements were made near 1080m. So long as the record does not oscillate, pressure changes during injection are the same at all depths in the well, and so this analysis remains valid, whatever the feed depth of the well.

DISCHARGE

This was delayed because of proximity to the mill. After heating for 7 months, there was 23 days' discharge (Fig4). During this, two output (deliverability) tests were performed (Fig5) and two pressure recoveries. The maximum flow recorded was 165 t/h and the enthalpy was 1200-1350 kJ/kg. (5) 264° water has enthalpy 1155 kJ/kg. Performance is not consistent with production from an aquifer containing compressed liquid. It now remains to be seen if it is consistent with production from one aquifer of two-phase fluid.

Gas content was 0.63-0.74%, by mass, measured at enthalpies of 1200-1250 kJ/kg. The gas was mainly carbon dioxide. 264° water with a partial pressure of 12.8 bar contains 0.59% CO_2 . Thus the pressure and temperature are saturated, for the actual reservoir fluid.

A pressure buildup at 750m, run 34864, gives a respectable straight line (Fig. 6), after a period dominated by storage and skin. The slope of the straight line is 10 bar/cycle. The flow was 135 t/h = 37.5 kg/s, at 1285 kJ/kg. From the mass flow and slope

$$kh/\nu_t = (2.303)(37.5)/(4\pi \times 10 \times 10^5) = 6.9 \times 10^{-6} \text{ m-s}$$

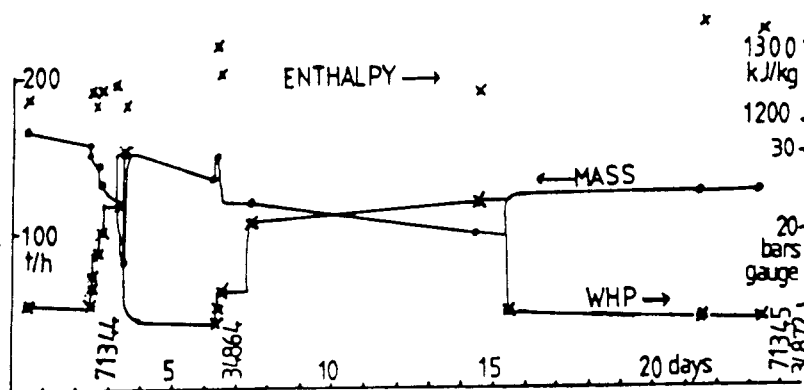


FIGURE 4 DISCHARGE HISTORY

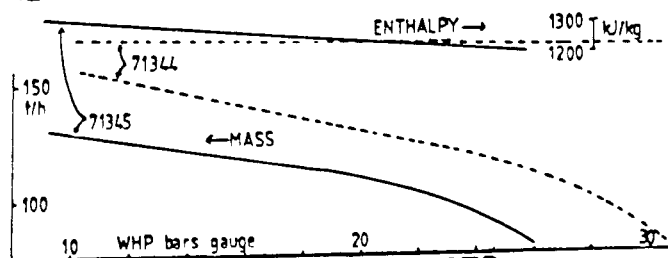


FIGURE 5 OUTPUT TESTS

Note that it is kh/ν_t that is the measured quantity. The discharge is measured as a mass flow, and this cannot be converted to a volume flow without knowledge of the flowing density ρ_t at reservoir conditions. This density is not equal to liquid water density.

Matches to Ramey log-log type curves (9) were tried, but no match was possible.

The skin equation uses kh/μ_t , and so the unknown density ρ_t enters it.

Evaluating

$$\rho_t \phi c_t h e^{-2s} = 3.1 \times 10^{-3} \text{ kg/pa.m}^2$$

The density ρ_t is found from the discharge enthalpy (10). The enthalpy before shut-in was 1285 kJ/kg. At 264° this enthalpy corresponds to a steam-water mixture that contains 7.9% by mass of steam, and the density of this mixture is 235 kg/m³. Using this value, the discharge test implies

$$kh/\mu_t = (kh/\nu_t)(1/\rho_t) = 2.9 \times 10^{-8} \text{ m}^3/\text{pa.s}$$

However the enthalpy of the well has varied, with the lowest value being 1200 kJ/kg. There is a strong argument that there should be used not the parameters of the disturbed situation, but those of distant reservoir fluid. This fluid has flowing enthalpy equal to that discharged by the well at small flows. The greater enthalpy at larger flow rate reflects extraction of heat from rock near the well. (13). The enthalpy of 1200 kJ/kg corresponds to a density of 430 kg/m³, and hence

$$kh/\mu_t = 1.6 \times 10^{-8} \text{ m}^3/\text{pa.}$$

COMBINED RESULTS

Alternatively, one could take the results of the injection and discharge tests and use them to find the flowing density:

$$\rho_t = \mu_t/\nu_t = (kh/\nu_t)/(kh/\mu_t) = 450 \text{ kg/m}^3$$

Using this density, the skin equation gives for the discharge test

$$\phi c_t h e^{-2s} = 7 \times 10^{-6} \text{ m/pa}$$

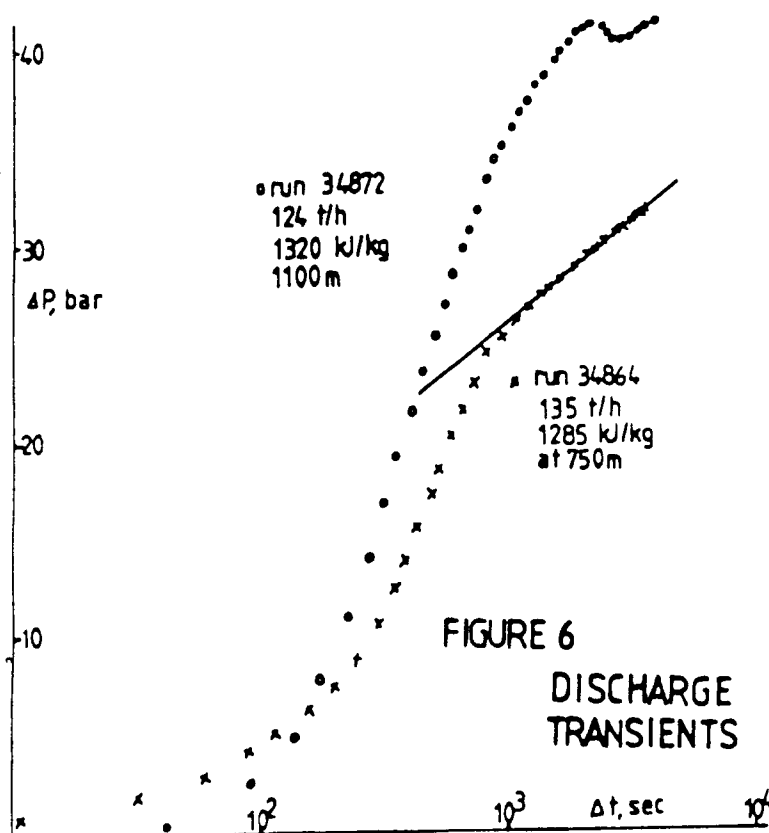


FIGURE 6
DISCHARGE
TRANSIENTS

There is now a consistent interpretation of the discharge and injection transients, where all parameters refer to fluid distant from the well:

$$\begin{aligned} kh/\mu_t &= 1.5 \times 10^{-8} \text{ m}^3/\text{pa.s} \\ kh/\nu_t &= 6.9 \times 10^{-6} \text{ m.s} \\ \rho_t &= 450 \text{ kg/m}^3 \\ h_t &= 1200 \text{ kJ/kg} \\ \phi h c_t e^{-2s} &= (7-70) \times 10^{-6} \text{ m/pa} \end{aligned}$$

Two-phase compressibility with gas present and saturation near unity is given by (11)

$$\frac{1}{\phi c_t} = \frac{\rho_w \rho_s}{\rho_w - \rho_s} \frac{d\rho_s}{dT} \frac{h_s - h_w}{\langle \rho C \rangle} + \frac{1}{\phi a} \frac{M_g}{18} \frac{\rho_s P_g}{\rho_w P_s}$$

where P_g is gas partial pressure, M_g gas molecular weight, and $a = a(T)$ is the solubility of gas. The first term on the right is the two-phase compressibility of pure water (10), while the second corresponds to isothermal dissolution-exsolution of gas, and is equivalent to the corresponding expression (8) for oil & gas.

A simpler numerical expression can be given, to save looking up steam tables. For a volumetric specific heat of the wetted rock $\langle \rho C \rangle = 2.5 \text{ MJ/m}^3 \text{ } ^\circ\text{C}$, and with pressures in bars and compressibility in bar^{-1} ,

$$c_t^{-1} = \frac{\phi}{48} P_s^{1.66} + 8 P_g P_s^{-0.21}$$

The first term is accurate to $\frac{1}{2}\%$ for $150-300^\circ$ (10). The second term is limited by accuracy in solubility data, but is probably within 5% over $200-300^\circ$.

The compressibility varies strongly with partial pressure and temperature. Partial pressure falls rapidly as pressure is drawn down, and it is common for the compressibility to change by a factor of 10 at wellface during drawdown and recovery. Again the choice is made to evaluate at undisturbed reservoir conditions, in which case the second term dominates in all New Zealand fields except Wairakei. At 264° and a partial pressure of 12.8 bar, $c_t = 2.2 \times 10^{-7} \text{ pa}^{-1}$, so

$$\phi h c_t e^{-2s} = 40-400 \text{ m.}$$

A small negative skin is implied.

The final task is to calculate kh from the value of kh/μ_t or kh/ν . This requires definition of the relative permeability functions. From the enthalpy of 1200 kJ/kg

$$k_{rw}/k_{rs} = (\nu_w/\nu_s)(h_s - h_t)/(h_t - h_w) = 5.4$$

If fracture relative permeabilities are assumed (13), $k_{rw} + k_{rs} = 1$, and $k_{rw} = .84$, $k_{rs} = .16$. Then

$$1/\mu_t = (k_{rw}/\mu_w + k_{rs}/\mu_s)$$

gives $\mu_t = 59 \times 10^{-6} \text{ pa.s}$, or about half that of liquid water. Then

$$kh = \mu_t \cdot (kh/\mu_t) = 0.88 \text{ darcy-metre}$$

A different value, 3.0 d-m, would result from the use of Corey relative permeabilities. And this estimate is even more sensitive to the enthalpy than the fracture value. If the results of a test are used in modelling, it is important that consistent assumptions are used for the relative permeabilities. It may be better to report not kh but the measured test result: kh/μ_t for injection test and kh/ν_t for discharge test.

PROBLEMS OF TWO-PHASE ANALYSES

These divide into practical problems due to fluid behaviour in the well and theoretical ones due to the flow in the reservoir. The practical problems are much the same as for high-temperature water-fed wells: misidentification of storage and skin or special feature, pressure gauge at wrong depth in the well, interzonal flow effects. In KA28, the humped response of run 34872 has been discarded. But there remains a nagging doubt that a lesser amount of the same effect could be present in 34864, so that the chosen straight line is not real.

The theoretical problems peculiar to two-phase are the gross nonlinearity of the parameters, and the variations in enthalpy (which is also a nonlinear effect). The compressibility is a strongly varying function of pressure and partial pressure - as is the compressibility of a dry gas - and there appears no simple alternative to taking the undisturbed value. This means possible errors in skin, perhaps up to ± 2 . More important is the variation in the flowing viscosities and density, ν_t , μ_t , & ρ_t . They vary strongly with saturation, or, equivalently, with flowing enthalpy h_t and temperature. They are also dependent upon the ill-defined relative permeabilities. If the flowing enthalpy is everywhere constant or nearly so, a pseudopressure can be defined, analogous to the gas pseudopressure. The requirement of constant enthalpy can be satisfied in steady flow (14) or if water is immobile (15).

However, in transient flows the dominant nonlinear effect is the changing of the flowing enthalpy (13). And the viscosity is so sensitive to the enthalpy that it is difficult even in principle to measure it accurately enough (12). An accurate analysis would require a match to both pressure and enthalpy histories. The author has tried enthalpy transient analyses, without success to date. Lacking such a better technique, simple analyses based on constant parameters are the only easily useable alternative now available. Fortunately results at large drawdown can be quite close to linear behaviour (13).

CONCLUSION

In the past year, two-phase transient analyses have become sufficiently polished to yield sometimes credible results, including agreement between interference and single-well test, between discharge and injection tests, and between repeat tests. At KA28, the dominant feed has been identified as two-phase, and the characteristics of the two-phase fluid defined; and the cause of the poor production identified as low intrinsic permeability.

ACKNOWLEDGEMENTS

All measurements were made by MWD & DSIR, Wairakei, who also interpreted the downhole profiles. I thank P.F. Bixley and M.C. Syms for additional comment and discussion.

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NOTATION

This follows ref. 10.

APPENDIX: DATA

On the next page are given the data for the two pressure buildups after discharge, and the two pressure falloffs after injection, illustrated in Figures 6 & 3. Flowing profiles were also measured before each buildup, and these are also given. Flow data and other information is given in text.

34731		34736		34864		34872	
Δt	$-\Delta P$	Δt	$-\Delta P$	Δt	ΔP	Δt	ΔP
sec	bar	sec	bar	sec	bar	sec	bar
14	0.10	13 $\frac{1}{2}$	0.10	10	0.8	44	0.4
26	0.25	21	0.25	31	1.9	88	1.7
39	0.40	33	0.30	58	2.9	132	4.1
51	0.50	44	0.45	87	4.1	176	6.7
71	0.70	59	0.55	114	5.2	220	10.0
100	0.85	73	0.65	158	6.2	264	13.1
138	1.10	90	0.85	195	7.4	308	15.8
191	1.25	169	0.90	249	8.8	352	18.3
275	1.55	134	1.00	295	10.4	396	20.6
346	1.70	157	1.20	341	12.2	440	23.6
385	1.20	209	1.40	378	13.8	484	24.4
432	1.25	240	1.50	424	15.5	528	25.9
564	1.25	314	1.50	482	17.3	572	27.4
609	0.85	370	1.75	528	18.7	617	28.6
655	1.35	525	1.85	590	20.3	661	29.6
688	1.95	759	2.00	656	21.8	705	30.6
753	2.05	906	2.20	729	23.1	793	32.2
853	2.65	960	2.20	833	24.6	837	33.2
902	2.05			935	25.3	881	33.8
989	1.70	$P_{wf}=92.6$		1064	26.1	969	34.6
1081	2.10			1226	26.9	1035	35.3
1151	2.55			1359	27.4	1101	35.9
1384	2.70			1454	27.8	1211	36.9
1447	3.05			1662	28.3	1321	37.4
1993	3.15			1870	28.8	1431	38.1
2317	3.40			2077	29.5	1497	38.5
2400	3.30			2285	29.8	1651	39.0
				2493	30.3	1761	39.4
				2701	30.6	1806	39.6
				2908	30.9	2092	39.9
				3116	31.2	2224	39.7
				3324	31.4	2334	39.4
				3600	31.7	2422	39.1
						2642	39.1
						2862	39.2
						3083	39.4
						3303	39.7
						3600	40.0

$P_{wf}=98.6$ bars gauge

$P_{wf}=25.2$

Flowing profiles

34864 & 27814			34872 & 27824		
Z	P	T_o	Z	P	T_o
m	b.g.	$^{\circ}C$	m	b.g.	$^{\circ}C$
1100	36.2	243	1400	48.1	251
1060	35.6	242	1300	40.9	247
780	26.0	226	1200	33.9	241
750	25.1	223	1100	31.0	236
680	22.5	218	1060	29.9	233
660	22.1	216	900	25.4	223
0	12.4		760	19.9	211
			660	16.9	202
			0	8.6	

$P_{wf}=31.0$

FISSURE-BLOCK MODEL FOR TRANSIENT
PRESSURE ANALYSIS IN GEOTHERMAL
STEAM RESERVOIRS

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Introduction

The fissure-block model considered in this paper is sometimes called a dual-porosity model or a naturally fractured reservoir model. Ground water and petroleum literature commonly refer to the pioneering analytical work on this subject by Barenblatt and others (1960) and Warren and Root (1963). These early papers consider flow from primary porosity blocks to secondary porosity fissures but they do not describe the flow within these blocks. Kazemi (1969) presents a finite-difference solution for single-phase flow which does account for flow within the blocks and Boulton and Streltsova (1977) give exact solutions for this problem.

At an earlier Stanford workshop, Moench (1978) presented a nonisothermal, radial flow, fissure-block, finite-difference model for geothermal steam reservoirs which was later used to simulate pressure buildup data for a steam well in Larderello, Italy (Moench and Neri, 1979). The model assumed the blocks to be impermeable but capable of conducting heat to the fissures which had been cooled by vaporization. In the present paper the model is revised to account for steam transport and vaporization within the blocks. This is a necessary consideration in order to account for the longevity of production wells in The Geysers. The blocks, which may be initially saturated with liquid water, are assumed to have low intrinsic permeability and low porosity relative to the fissures.

Results computed with this finite-difference model are compared, for isothermal conditions, with the solutions of Boulton and Streltsova (1977). Under these conditions the model is similar to that of Kazemi (1969). When vaporization occurs in the blocks from a small amount of uniformly-distributed liquid water it is also possible to apply Boulton and Streltsova's solutions. This is done by allowing for the apparent compressibility of the two-phase fluid mixture in the block. Comparison with Boulton and Streltsova's solutions under two-phase conditions is given in order to verify the finite-difference code.

Numerical results are also presented showing pressure buildup following production with the blocks initially nearly saturated with liquid water. Effects of different thermal boundary conditions, block sizes and production times on pressure buildup curves are examined.

After further refinements the model will be calibrated, using available pressure buildup data from representative wells in The Geysers, and used to provide a means for estimating pore pressure and temperature gradients within reservoir blocks. This information will be used to calculate changes in effective stress in the vicinity of a boiling front: a mechanism proposed to account for earthquake activity in the vicinity of The Geysers (Denlinger and Moench, 1979).

Approach

The conceptual model illustrated in figure 1a is idealized as shown in figure 1b. Alternating layers of fissures and blocks of constant thickness are assumed to extend radially to infinity. The thickness of the fissure and block is assumed to represent the average thickness of the fissures and blocks in the reservoir. In the model radial flow in the fissure is coupled with one-dimensional planar flow in the blocks perpendicular to the fissures. With the onset of well discharge, pressure reductions in the fissure induce vaporization of liquid water in the blocks. Liquid in the fissures and blocks is assumed to be immobile. This assumption is justified for the blocks by their low porosity and for the fissures by their low liquid saturation. Large capillary forces brought about by these conditions are assumed to hold the liquid in place. Saturations, therefore, change only in response to vaporization or condensation. The relative permeability to steam is assumed to change with liquid saturation in accordance with the Corey (1954) relationship.

Equations for the radial flow of steam through porous reservoirs in the presence of immobile vaporizing or condensing liquid water are given by Moench and Atkinson (1978). It was assumed in that study that the only temperature changes that take place in the reservoir are those due to phase change: conduction, convection, and pressure-work are considered negligible by comparison. In this paper heat is conducted from the fissure into the block or vice versa. Temperature changes in the block occur in response to both phase change and heat conduction. The exterior ($Z=H$) thermal boundary of the block is assumed to be either constant temperature or insulating. The exterior flow boundary of the block is assumed to be no flow.

A finite-difference code is used to compute pressure, temperature, and saturation changes at each node in the fissure and block. These computations are carried out in the manner described by Moench and Atkinson (1978) with the added dimension that planar flow in the block is computed for as many vertical arrays as there are nodes in the fissure. Fissure nodes serve as boundaries for the block arrays. The distance between the nodes in the block is increased logarithmically with distance from the fissure in the same way as the nodes in the fissure become more widely separated with distance from the well.

Model Verification

Exact solutions for single-phase flow in a fissure-block system by Boulton and Streltsova (1977) are used in this study to validate the results of the finite-difference model. Their solutions are presented in the form of semi-infinite integrals which are quite difficult to solve numerically. However in the Laplace transformed space the solutions appear in a simpler form and can be inverted numerically by the method of Stehfest (1970). The results so obtained will be referred to as the analytical solutions.

The Laplace transform solution for pressure drawdown in the fissure appears as follows:

$$\bar{p}_{D1} = \frac{K_o(r_D k)}{s} \quad (1)$$

where
$$k = \sqrt{\eta^2 \frac{\alpha_2}{\alpha_1} + \eta \frac{T_2}{T_1} \frac{r_w}{H} \tanh\left(\eta \frac{H}{r_w}\right)}$$

$$\eta = \sqrt{\frac{s r_w^2}{\alpha_2}}, \quad T_1 = k_1 h, \quad T_2 = k_2 H$$

Symbols are defined in Table 1.

The Laplace transform solution for pressure drawdown in the block appears as follows:

$$\bar{p}_{D2} = A \frac{K_o(r_D k)}{s} \quad (2)$$

where
$$A = \cosh\left(\eta \frac{Z}{r_w}\right) - \tanh\left(\eta \frac{H}{r_w}\right) \cdot \sinh\left(\eta \frac{Z}{r_w}\right)$$

Figure 2 shows a comparison of the analytical and numerical results for dimensionless pressure drawdown (p_D vs $\log t_D$) at the well bottom and at a specified point within the block for single-phase steam. Parameters required for the comparison are given in Table 1. The deviation in the results which is most apparent at an early time can be attributed primarily to spatial discretization at the block-fissure contact. Care was taken in the numerical model to reduce nonlinearities by avoiding large pressure changes.

The model of Boulton and Streltsova (1977) can also be used to validate the finite-difference model for vaporization in the reservoir block. With immobile liquid water distributed uniformly throughout the block, the liquid-steam combination in the block can be considered to have an enhanced compressibility. The amount by which the compressibility is enhanced can be calculated as shown in the appendix using the equations of either Grant and Sorey (1979) or Moench and Atkinson (1978).

Figure 3 shows the results obtained when a small amount of liquid water ($S_i=0.01$) is introduced in the block. Because of the increased compressibility, the ratio of diffusivities between the fissure and block is increased over that which applies to the results in figure 2 by a factor of 430 (see appendix). This causes the pressure response shown in figure 3 to be shifted toward larger values of dimensionless times. The displacement between the finite-difference and the analytical results can again be attributed to discretization at the block-fissure contact. In figure 3 however there is, in addition, a lack of pressure support in the finite-difference model which results from the fact that no vaporization occurs at the "fissure" node of the block array; hence the computed pressure drawdown is greater than indicated by the analytical solution. In view of the magnitude of the change in pressure response over that shown in figure 2, brought about simply by introducing liquid in the block, the authors feel that the agreement with the analytical solution is adequate and that the model has been validated by these results.

Results

Computer runs were made to simulate hypothetical conditions using different parameters. Results are presented that illustrate the variations in pressure buildup that can be expected when thermal boundary conditions, block size, or production time are changed. In all cases the block was assumed to have very low porosity and permeability relative to the fissure and an initial liquid-water content close to saturation. Hydraulically connected steam is considered the more mobile phase even under these conditions because liquid water, as the wetting phase, can be assumed to be held in place by capillary forces. This assumption is supported in part by the work of Chen and others (1978) who found by experimentation that a core with porosity of 34 percent and a permeability of 36 md appeared to have a practical irreducible liquid-water saturation in excess of 60 percent. Parameters used in the simulations are given in Table 2.

Figure 4 shows the pressure buildup at the well bottom after 1666 h (69 days) of production for a case in which the exterior boundary of the block ($Z=H$) is maintained at the initial reservoir temperature. The block itself is cooled by vaporization during production but is reheated by conduction. In figure 4 sufficient time has elapsed during production for temperatures in the block and fissure to have very nearly recovered to the initial reservoir temperature. The early time pressure buildup is due to the flow of superheated steam. After about one hour the pressure has recovered close to the initial reservoir pressure after which condensation commences.

Figure 5 shows pressure buildup for three different production times using the same parameters as shown in figure 4 but with the inner boundary of the block thermally insulated. This is considered a more realistic possibility in a fissured reservoir. The figure shows a systematic downward progression of the

pressure buildup curves as production time increases. After 4015 h (167 days) of production all the liquid in the block near the well has vaporized and the block and fissure have cooled to the point where steam at the well bottom is only slightly superheated. Consequently, almost immediately after shut in, condensation occurs in the fissure. The shape of the buildup curve after that is the result of condensation in both the fissure and block and the dissipation of latent heat by conduction. When the same well is produced for shorter times not as much cooling occurs in the block and fissure and consequently condensation occurs at higher pressures. When the well is produced for only 78 hours the fissure still retains much of the heat it had initially because it has not had time to cool by conduction into the block. As a consequence the early portion of the pressure buildup curve exhibits effects of superheating.

Figure 6 shows pressure buildup after a production time of 1130 h (47 days) using the same conditions as in figure 5 except that the thickness of the block is increased and the production rate is doubled. The pressure buildup in the first 30 minutes after shut in is due to the flow of superheated steam.

Figures 4-6 show the variability that can be expected in the shape of pressure buildup curves when model parameters are varied. It can be inferred from these results that the degree to which vaporization has depleted the liquid in the block has an important bearing upon the shape of the curves. These factors should be considered when interpreting pressure buildup tests in steam reservoirs.

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Nomenclature

c_t	steam compressibility	r	radial dimension
C_D	well bore storage	Δr_s	skin thickness
H_c	reservoir heat capacity	R	gas constant
H	block half thickness	S_i	initial liquid saturation
h	fissure half thickness	s	Laplace transform variable
K_0	modified Bessel function, 2nd kind, zero order	t_D	$\frac{k_1 \tau}{\phi_1 \mu_v c_t r_w^2}$
K	thermal conductivity	t	time
k	permeability	Z_i	initial compressibility factor
k_s	skin permeability	z	planar dimension in block
L_v	latent heat of vaporization	α	fluid diffusivity
M_w	molecular weight of water	β	steam thermal expansivity
P_D	$\frac{\pi k h M_w}{q \mu_v Z_i R T} (P_i^2 - P^2)$	μ_v	steam viscosity
P_i	initial pressure	ρ_v	steam density
P	pressure	ϕ	porosity
q	production rate	subscripts	
r_D	r/r_w	1	fissure
r_w	well radius	2	block
		D	dimensionless

Appendix

Following the discussion given by Moench and Atkinson (1978) the diffusivity of the steam in the fissure is given by:

$$\alpha_1 = \frac{k_1}{\phi_1 \mu_v c_t} \quad , \quad (A1)$$

and the diffusivity of the steam-liquid combination in the block is given by:

$$\alpha_2 = \frac{k_2}{\phi_2 \mu_v c_t (1+A)} \quad (A2)$$

where
$$A = \frac{H_c}{L_v} \frac{dT}{dP} - \frac{1}{\phi_2 \rho_v c_t} - \frac{\beta}{c_t} \frac{dT}{dP}$$

If there is no liquid in the block $A=0$. Neglecting the relatively small effects of steam compressibility, specific heat, and thermal expansivity the combination of terms $c_t(1+A)$ become equivalent to the approximate total compressibility, β_t , given by Grant and Sorey (1979). They give a useful expression for $\phi \beta_t$ which is a function of pressure and reservoir heat capacity:

$$\phi_2 \beta_t = 1.92 \times 10^{-5} H_c P^{-1.66} \quad (A3)$$

where P is in bars and H_c is in $J/m^3 \cdot ^\circ C$.

The ratio of diffusivity in the fissure to that in the block thus appears as:

$$\frac{\alpha_1}{\alpha_2} = \frac{k_1}{k_2} \frac{\phi_2 \beta_t}{\phi_1 c_t} \quad (A4)$$

When only steam is present $\beta_t = c_t$ and for the parameters of figure 2 the ratio $\alpha_1/\alpha_2 = 10^3$. When liquid and steam coexist at 30 bars initial pressure, $\phi_2 \beta_t = 0.172 \text{ bar}^{-1}$ and the ratio $\alpha_1/\alpha_2 = 430 \times 10^3$.

Table 1

Parameters used for comparison of model with analytical solutions*

H_{c1}	0.55 cal/°C cm ³	q	2.77 g/s
H_{c2}	0.61 cal/°C cm ³	r_w	16 cm
H	75 cm	S_{i1}	0.0
h	10 cm	S_{i2}	0.0, 0.1
K	0.0 cal/(°C cm sec)	T	234°C
k_1	10 ⁻⁸ cm ²	ϕ_1	0.1
k_2	10 ⁻¹² cm ²	ϕ_2	0.01
P_i	30 bars		

Table 2

Parameters used for the pressure buildup simulations*

C_D	166	P_i	30 bars
H_{c1}	0.55 cal/°C cm ³	q	27.7 g/s, 55.4 g/s
H_{c2}	0.62 cal/°C cm ³	r_w	16 cm
H	104 cm, 374 cm	Δr_s	16 cm
h	10 cm	S_{i1}	0.0
K	0.006 cal/(cm sec °C)	S_{i2}	0.8
k_1	10 ⁻⁸ cm ²	T	234°C
k_2	10 ⁻¹³ cm ²	ϕ_1	0.1
k_3	10 ⁻⁷ cm ²	ϕ_2	0.01

*parameters not listed are known properties of water at prevailing temperature and pressure.

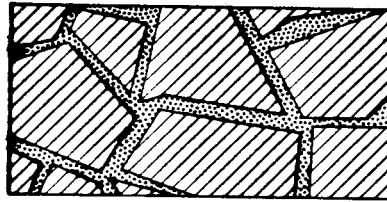


Figure 1a
Conceptual model
with porous
blocks and fissures

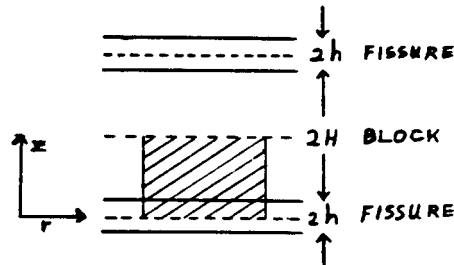


Figure 1b
Idealized fissure-
block reservoir
used in the
analysis

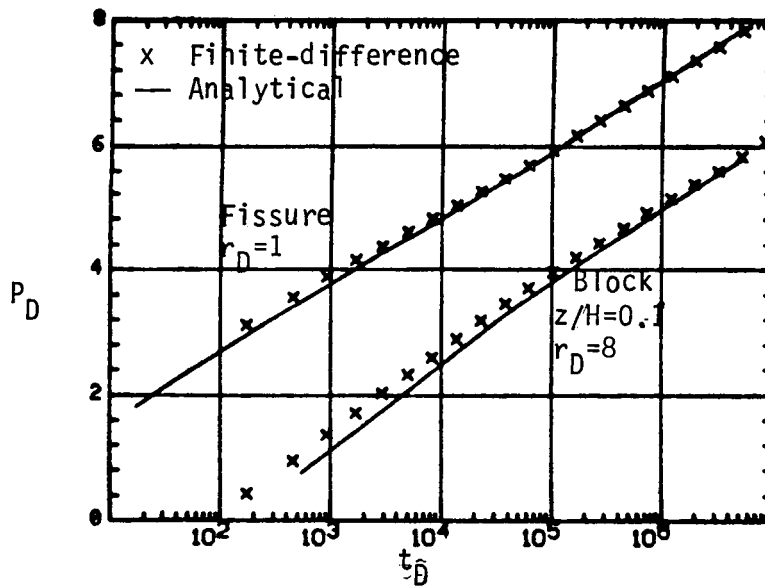


Figure 2
Comparison of
analytical and
numerical results
for single phase
steam in block
and fissure.

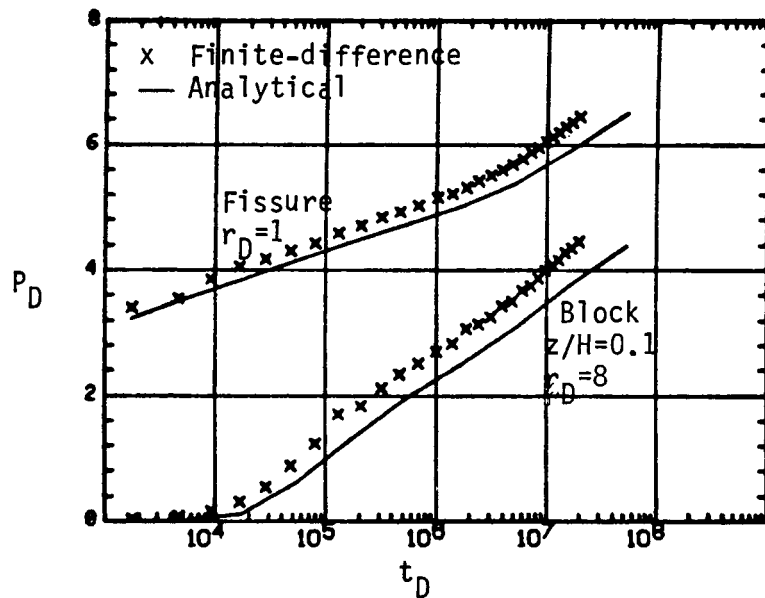


Figure 3
Comparison of
analytical and
numerical results
with liquid and
steam in the block
and single-phase
steam in fissure.

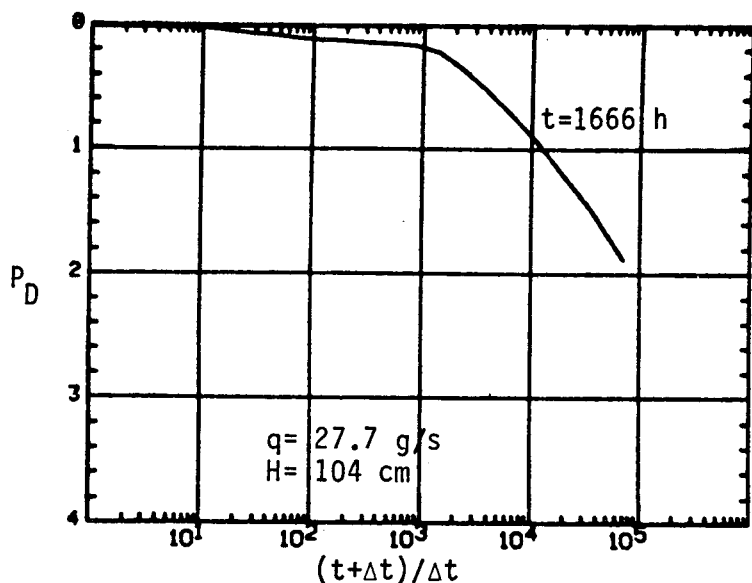


Figure 4
Pressure buildup
at well bottom
using constant
temperature bound-
ary in the block.

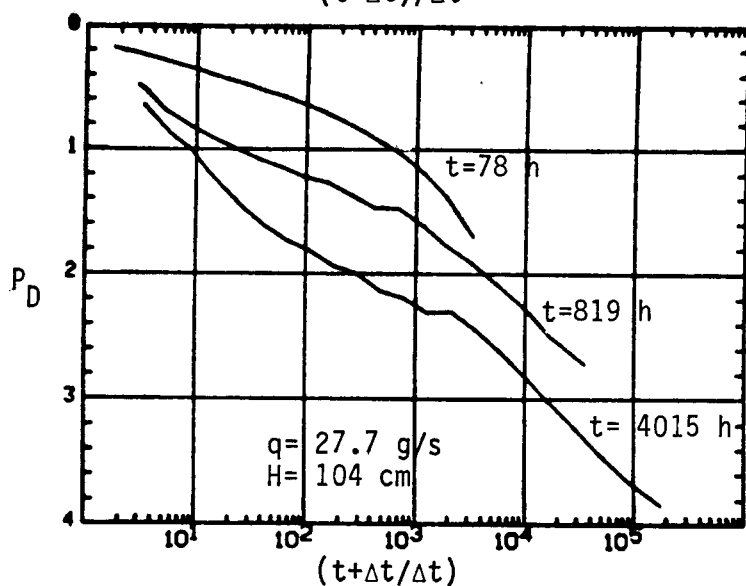


Figure 5
Pressure buildup
at well bottom
using thermally
insulated boundary
in the block.

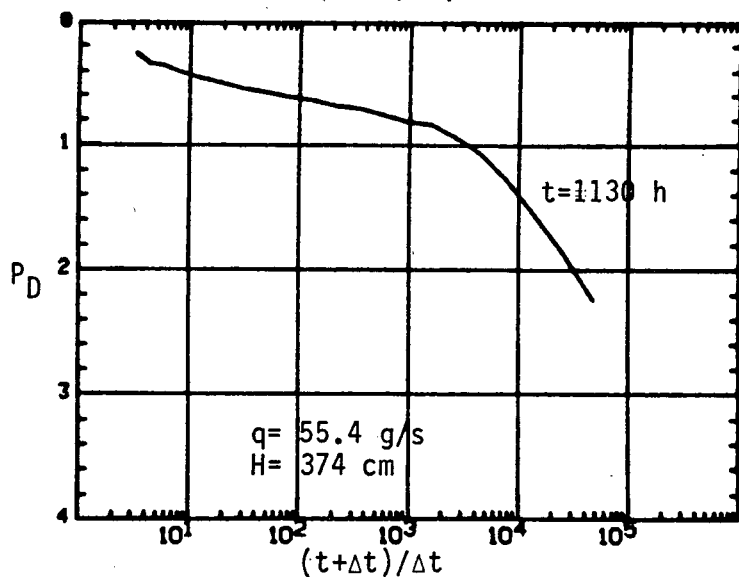


Figure 6
Pressure buildup
at well bottom
using thermally
insulated boundary
in the block.

Three-Dimensional Geothermal Reservoir Simulation

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The authors present a three-dimensional model for reservoir simulation to show some behaviors of fluid flow in a geothermal reservoir, assuming water influx and heat conduction from heat sources under the reservoir.

Basic Equations The following three equations describe a system, where mass transfer and heat conduction occur.

Mass conservation equation

$$-\frac{\partial}{\partial t}(\phi S_w \rho_w + \phi S_g \rho_g) = \text{div}(\rho_w \vec{v}_w + \rho_g \vec{v}_g) + q_w + q_g + q_{we} \quad (1)$$

Energy balance equation

$$-\frac{\partial}{\partial t}[\phi S_w \rho_w U_w + \phi S_g \rho_g U_g + (1-\phi)(\rho C_p)_f T] = \text{div}(H_w \rho_w \vec{v}_w + H_g \rho_g \vec{v}_g) + \text{div} \vec{t} + q_H + q_L \quad (2)$$

Equation of state (in case of water-steam equilibrium)

$$P = P_S(T) \quad (3)$$

where, $\vec{v} = -\frac{K k_r}{\mu} \nabla \Phi$, $\vec{t} = -T_c \nabla T$ and $S_w + S_g = 1$

The boundary conditions for solving the above equations are $\partial \Phi / \partial n = 0$ and $\partial T / \partial n = 0$ for mass and heat flow, respectively. Both mass and heat production terms are also considered to account for water encroachment and heat flow from the boundaries.

Potential equilibrium and heat equilibrium are adopted for the initial conditions which in turn imply no mass flow and steady state heat flow.

Difference Equations Equations 1 through 3 are approximated by the finite difference equations as follows.³⁾

$$\frac{V}{\Delta t} \delta(\phi \rho_w S_w + \phi \rho_g S_g) = \Delta T_w \Delta \Phi_w + \Delta T_g \Delta \Phi_g - Q_w - Q_g - Q_{we} \quad (4)$$

$$\begin{aligned} \frac{V}{\Delta t} \delta[\phi \rho_w S_w U_w + \phi \rho_g S_g U_g + (1-\phi)(\rho C_p)_f T] \\ = \Delta H_w T_w \Delta \Phi_w + \Delta H_g T_g \Delta \Phi_g + \Delta T_c \Delta T - Q_H - Q_L \end{aligned} \quad (5)$$

$$-P'_T \delta T + \delta P = -P^n \quad \text{----- (6)}$$

The right hand sides of the eqs. 4 and 5 are expressed in terms of δP using $\Delta \Phi = \Delta \delta P + \Delta P^n - \rho g \Delta Z$. The eqs. 4 and 5 can be written in the following matrix form²⁾ with δS_w , δT and δP as independent variables.

$$\begin{pmatrix} C_{11} & C_{12} & C_{13} \\ C_{21} & C_{22} & C_{23} \\ C_{31} & C_{32} & C_{33} \end{pmatrix} \begin{pmatrix} \delta S_w \\ \delta T \\ \delta P \end{pmatrix} = \begin{pmatrix} Y_1 \\ Y_2 \\ 0 \end{pmatrix} + \begin{pmatrix} R_1 \\ R_2 \\ R_3 \end{pmatrix} \quad \text{----- (7)}$$

where, $Y_1 = \Delta(T_w + T_g) \Delta \delta P$ and $Y_2 = \Delta(H_w T_w + H_g T_g) \Delta \delta P$
By elimination, eq. 7 is transformed into

$$\begin{pmatrix} 1 & C'_{12} & C'_{13} \\ 0 & 1 & C'_{23} \\ 0 & 0 & C'_{33} \end{pmatrix} \begin{pmatrix} \delta S_w \\ \delta T \\ \delta P \end{pmatrix} = \begin{pmatrix} B_{11} & 0 & 0 \\ B_{21} & B_{22} & 0 \\ B_{31} & B_{32} & B_{33} \end{pmatrix} \begin{pmatrix} Y_1 \\ Y_2 \\ 0 \end{pmatrix} + \begin{pmatrix} R'_1 \\ R'_2 \\ R'_3 \end{pmatrix}$$

The third row of the above equation contains only one independent variable, δP , which satisfies the following set of finite difference equations.

$$f \delta P_{k-1} + d \delta P_{j-1} + b \delta P_{i-1} + a \delta P + c \delta P_{i+1} + e \delta P_{j+1} + g \delta P_{k+1} = R'_3$$

These equations are solved by the direct method.⁶⁾ Fig. 1 is a simplified flow chart that shows the program's basic logic.

Heat Loss Heat flow perpendicular to the top and bottom boundaries is assumed. In calculating heat flow at the boundaries, some more blocks are added above and below the reservoir.

The heat conduction equation,

$$\frac{\partial}{\partial z} \left(T_c \frac{\partial T}{\partial z} \right) = \rho C_p \frac{\partial T}{\partial t}$$

is solved in such blocks with appropriate boundary and initial conditions at the newly formed boundaries. In this procedure, the heat flow at the new time step calculated with the following equation.

$$Q_L^{n+1} = Q_L^n + \alpha \delta T, \quad \alpha = A \cdot T_B / L \cdot \text{erf} (L / 2\sqrt{\kappa \Delta t})$$

Water Influx Based on the solution of the diffusivity equation for the linear flow case by van Everdingen and Hurst,⁵ water influx is

$$Q_{we}^{n+1} = \frac{A\phi C_w(\Delta P + \Delta P^n)Q(t) - A\phi C_w \Delta P^n Q(t^n)}{\Delta t}$$

The reservoir is divided into 10 x 10 x 5 blocks in X - Y - Z directions, respectively (Fig. 2). The size of the blocks and physical properties of the rock and fluid are shown in Table 1. For simplicity, the model treats an initially hot-water system and the bottom hole pressure of the well is assumed to be constant. Plots of potential distributions at various times are shown in Fig. 3 without water influx, while Fig. 4 with water influx.

NOMENCLATURE

- A = cross sectional area, cm²
- C = compressibility, vol/vol-atm
- C_p = specific heat, cal/g-°C
- H = enthalpy, cal/g
- g = gravitatal acceleration
- K = absolute permeability, darcy
- k_r = relative permeability
- T_c = thermal conductivity, cal/cm-°C-sec
- P = pressure, atm
- Q = production rate, g/sec
- Q_H = enthalpy production rate, H_wQ_w + H_gQ_g, cal/sec
- Q_L = rate of heat loss to surroundings, cal/sec
- Q(t) = fluid influx, dimensionless
- S_w = saturation, fraction
- t = time, sec
- T = temperature, °C
- T_w = water transmissibility, f AKk_r/μL, g/atm-sec
- T_g = steam transmissibility, g/atm-sec
- U = internal energy, cal/g
- V = bulk volume, cm³
- Z = depth, cm
- Φ = potential, P - ∫ρg dZ, atm
- φ = porosity, fraction
- δ = time difference, δP = Pⁿ⁺¹ - Pⁿ
- Δt = time increment, tⁿ⁺¹ - tⁿ
- μ = viscosity, c.p
- ρ = density, g/cm³
- k = diffusivity, T_c/ρC_p, cm²/sec
- P'_{ST} = derivative of the saturated curve with respect to temperature

Subscripts

- we = water encroachment, f = formation
- w = water, g = steam, i, j, k = grid, n = time level

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Table 1. Example data of Physical Properties and Block Dimensions

Initial temperature (1,1,1)	= 260°C
Initial temperature gradient	= 5°C/100m
Initial pressure (1,1,1)	= 70 atm
Horizontal permeability	= 100 md
Vertical permeability	= 10 md
Porosity	= 0.38
Initial water saturation	= 1.0
Water compressibility	= 1.65×10^{-4} vol/vol-atm
Formation compressibility	= 4.4×10^{-5} vol/vol-atm
Thermal conductivity	= 1.53×10^{-3} cal/cm-°C-sec
NX = 10, NY = 10, NZ = 5	
$\Delta X = 150\text{m}$, $\Delta Y = 150\text{m}$, $\Delta Z = 15\text{m}$	
Initial production rate	= 1.2×10^4 g/sec
Bottom-hole pressure	= 60 atm

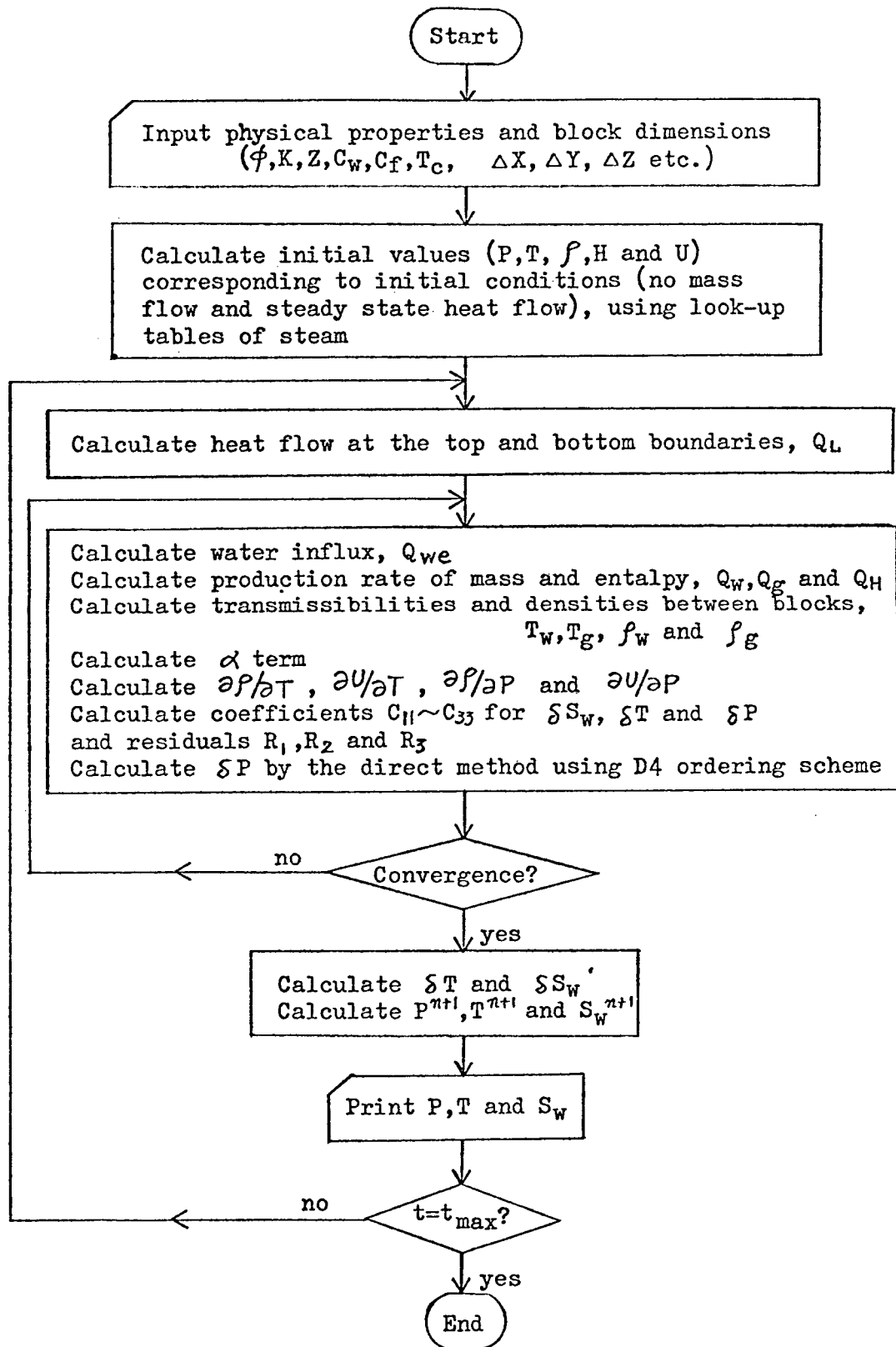


Fig. 1 Simplified Flow Chart

Figure 1 is a contour plot showing depth (15m) on the vertical axis (ranging from 1 to 5) versus horizontal distance (150m) on the horizontal axis (ranging from 1 to 5). The plot displays several contour lines representing different values, with labels such as 69.0, 67.0, 67.8, 67.5, 67.2, 62.7, and 62.9. The contours are generally curved, indicating a non-linear relationship between the variables.

Fig. 4 Potential Distribution Behaviors (with water influx)
Solid curve, after 50 days of production. Dashed curve, after 100 days of production.

A NUMERICAL SIMULATION OF THE NATURAL
EVOLUTION OF VAPOR-DOMINATED HYDROTHERMAL SYSTEMS

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Introduction

The natural state and the evolution of vapor-dominated hydrothermal systems have been the subject of considerable research and controversy (see References 1-4, and references therein). White, Muffler, and Truesdell have formulated a comprehensive qualitative model of vapor-dominated reservoirs.³ Their work forms the basis for more recent attempts to understand reservoir processes in more quantitative detail.⁵

Most previous computational studies of natural fluid and heat flow in geothermal reservoirs have attempted to model specific reservoirs or have investigated more generalized steady-state convection in single-phase fluid (Ref. 6 and references therein) or in two-phase fluid.^{7,8} In contrast, we describe simulation of the transient evolution of a "cold" hydrothermal system into a steady-state partially vapor-dominated system.

In our study we have neglected the effects of salts and gases and have assumed that rock properties are time independent and homogeneous within each part of the system. Despite these simplifications we believe that our model demonstrates the essential features of a natural hydrothermal convection system (NHCS).

Parameters of the System

The model system consists of a main permeable reservoir of water-saturated porous rock, overlain by a cap of less permeable rock (Figure 1). Through the caprock, the reservoir communicates with surface waters of ambient conditions (discharge and recharge). Also, conductive heat flow can occur across the caprock. The system is driven by a powerful heat source at its base.

A system of this type has a long transient period. Very large amounts of fluid must flow before convection patterns evolve into a steady state. Several thousand time steps are required for a computer simulation of this process. In order to make the computation economically feasible, a prudent design of system geometry and spatial discretization is required. We model a system with cylindrical symmetry, which allows us to employ a two-dimensional grid (Figure 2). The most critical element in the simulation is vertical pressure resolution. A coarse discretization in the vertical direction would average pressures and thereby inhibit onset and spreading of boiling. Finer gridding introduces more and smaller elements, which increases the computational work per time step and, moreover, reduces time step sizes due to throughput limitations. While our test calculations showed that a vertical grid spacing of 100

m or less is desirable, we had to use a compromise value of 400 m to contain computing costs (Figure 2).

The system design represents a "simplest meaningful case," appropriate for a first exploratory study. It is a regular cylinder with plane upper and lower boundaries, and uniform formation properties throughout the "caprock" and "reservoir" sections, respectively (see Table 1). There is no permeability contrast between horizontal and vertical directions. Mass and heat flow across the vertical boundaries is assumed to be negligible.

The grid consists of 30 elements with 49 interfaces (Figure 2). One additional element and 5 interfaces are needed to realize the surface boundary condition. The spacing is uniform with 400 m vertical and 1000 m horizontal distance.

The simulation was extended over a physical time of 94,232 years, requiring 2775 time steps and a total CPU time of approximately 1,500 sec on a CDC 7600 computer. The calculations were made with the simulator SHAFT79, developed at LBL, which features an accurate representation of the thermophysical properties of water substance.

Evolution History

The convection system goes through a series of quite different and distinct evolution patterns before, after about 90,000 years, it reaches a steady state. Interesting mechanisms with positive and negative feedback occur on different time scales. Table 2 summarizes the main evolutionary phases, while figures 3-5 present some illustrative data. In the subsequent discussion, we shall refer to the various reservoir regions by means of grid block names as shown in Figure 2.

The system starts out in gravitational equilibrium (no mass flows), with a typical "natural" temperature gradient of .04 °C/m (see Table 1). The temperature gradient gives rise to a vertical heat flow of .084 W/m², corresponding to 2.0 HFU. The total rate of heat loss through the ground surface is 6.6 MW, so that heat injection at the bottom at a rate of 98.2 MW gives rise to net energy gain at a rate of 91.6 MW (see Figure 3). The system starts to heat up at the bottom, center (elements R5 and S5). This process is accompanied by thermal expansion of the pore water and pressure increase. Subsequently water begins to flow upward and outward, and discharge is initiated near the center. Upflow in the center and the heating and accompanying reduction in density of the central water column slow the pressure increase in R5, S5, and after 32 years pressures start to decrease above the heat source. This causes water to flow towards the center at the bottom, which spreads

the pressure decline outward and initiates downflow near the periphery. Gradually the mass flow pattern changes from upward and outward into a toroidal type of configuration, where fluid flows up near the center, flows outward in the shallower portions of the system, downward near the margins, and towards the center near the bottom. After about 200 years pressures start to decrease at the margins below the surface. Mass discharge therefore diminishes near the margins, while it continues to increase near the center. This gives rise to the pronounced peak in net mass discharge after 280 years (see Figure 3). After about 700 years recharge begins at the margins. As time goes on, the convective flow rates increase (Figure 4), and the pattern expands towards the margins to establish a coherent motion throughout the reservoir. The steep increase in convection rates in the period from 300 - 1000 years is caused by a positive feedback process: upflow of hot water in the center begins to heat up shallower portions of the reservoir (see the increase in temperature of R1 after 600 years, Figure 5), thereby reducing the viscosity of the flowing water and increasing convection rates. Convection rates become so large that the temperatures immediately above the heat source start to decline, due to large inflow of colder waters (see the temperature maximum for R5 after 600 years). This process counteracts the preceding increase in convection rates, and stabilizes flows at somewhat smaller values after about 2000 years (Figure 4). Temperatures below the surface start increasing after 1000 years (element C1, Figure 5), slowly increasing conductive heat loss and decreasing the net rate of energy gain. Subsequently the system goes through a long period characterized by a slow increase in temperatures throughout, while minor rearrangements in convection patterns continue to take place. The latter is illustrated by the changes in flow direction between S3/R3 and T2/T3 (Figure 4). The particular way in which these changes occur is obviously dependent upon the spatial discretization employed in the simulation. It is likely that some of the non-linear feedback processes mentioned above are also affected (exaggerated) by discretization effects. No significant event occurs until, after 39,000 years, boiling commences in element R1. This gives rise to a number of important changes. Steam saturation in R1 increases fairly rapidly, reaching 10% after 40,000 years, and 15% after 46,000 years. After the transition to two-phase conditions, temperatures and hence pressures remain practically constant in the two-phase zone (see Figure 5), additional heat inflow being absorbed by boiling. Pressures continue to decline in the single-phase regions, due to heating up and reduction in density with increasing temperature. Thus the pressure gradients which drive flow towards the two-phase zone diminish. The consequences can be read from Figure 4: the upflow near the center diminishes rapidly (R2/R3), and the hot upwelling waters are diverted outward in a funnel-like pattern (cf. the steep increase in flow rates for S3/R3 and T2/T3 as

examples). This outward diversion of upwelling hot waters is the main mechanism by which the boiling spreads laterally. A minor contribution to the spreading comes from horizontal outward flow of water. The latter is inhibited by permeability reduction for water flow due to buildup of steam saturation. Relative permeability for water is reduced to 40% and 24%, respectively, for steam saturations of 10% and 15%. Horizontal steam flow remains small at all times, and does not contribute significantly to the lateral spreading of boiling. Subsequent phase transitions occur in S1 (after 43,500 years), T1 (after 46,000 years), and U1 (after 49,000 years). Temperatures and pressures remain essentially constant in the two-phase zones. Therefore, pressures do not change much in the caprock overlying the two-phase zones, so that mass discharge remains approximately constant. However, pressures continue to decline at the margins, causing recharge rates to increase and giving rise to the sharp drop in net rate of mass loss after 50,000 years (Figure 3). Several additional phase transitions occur (elements R2, S2, C1) until, after about 90,000 years, the system approaches a steady state.

The Steady State

As the rate of surface heat loss approaches the rate at which energy is injected at the base, and as the rate of mass recharge approaches the rate of discharge, the net rates of energy gain and mass loss go to zero (Figure 3). In the steady state all flow patterns are stationary (time-independent), and mass- and energy-content of the system remains constant. Table 3 presents data on the rates of mass and energy flow through the ground surface after 92,979 years. The rate of energy discharge is to within 0.1% of the injected energy. (A more accurate steady state could be obtained using a finer mesh.) The energy discharge is approximately 90% conductive and 10% convective, with energy flux largest above the heat source, as expected. Fluid discharge is also strongest above the heat source. It tapers off away from the center, and changes into recharge towards the margins. In the steady state, the system has lost 21.6% of its initial mass content, but its energy content has increased 3.2 times. Of the heat injected in 92,979 years, only 27.2% remains in the system, the rest having been discharged to the atmosphere.

Conclusions

This work demonstrates the application of numerical simulation methods to study the natural evolution of vapor-dominated geothermal reservoirs. However, the large computational effort involved in this presently limits obtainable spatial resolution and accuracy of results.

The numerical simulation reveals several mechanisms, which are operative at different stages in the evolution of the system. The more important mechanisms are: (1) initiation of intense reservoir-wide convection by means of a positive feedback between convective heat transport and reduction in fluid viscosity, and (2) the lateral spreading of boiling by means of displacement of upward convection away from two-phase zones.

Although only a relatively thin vapor-dominated zone was produced in these calculations, the steady state results demonstrate many of the features inferred from the study of natural systems, including: 1) vertical counterflow of steam and liquid water with steam rising and condensate falling; 2) lateral movement of steam from the center toward the edges of the system; 3) condensation of steam due to upward conductive heat loss with condensate draining downwards to a liquid dominated zone where it flows toward a central zone of boiling; 4) an interface between a shallow, liquid saturated zone and the vapor-dominated zone that is at a temperature near the enthalpy maximum of saturated steam (236 °C); 5) boiling in the central part of the underlying liquid dominated zone with boiling rates increasing with depth to a maximum close to the bottom of the two-phase zone.

It is to be emphasized that the present study was made for a rather schematic reservoir model, and more realistic features will be incorporated in future simulations.

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TABLE 1: RESERVOIR PARAMETERS

GEOMETRY

Cylinder with 2.4 km height, 5 km radius

FORMATION PARAMETERS

	CAPROCK (top 400 m)	RESERVOIR (bottom 2000 m)
density	2600 kg/m ³	2600 kg/m ³
porosity	.10	.10
permeability	.3 x 10 ⁻¹⁵ m ²	100 x 10 ⁻¹⁵ m ²
specific heat	775 J/kg °C	775 J/kg °C
heat conductivity	2.1 W/m °C	2.1 W/m °C

(no compressibility or thermal expansivity)

Corey relative permeability functions with $k_{rw} = .5$, $k_{rs} = 0$

BOUNDARY CONDITIONS

top: average ambient ground surface conditions of

$$T = 10^{\circ}\text{C}, \quad p = 10^5 \text{ Pa} \quad (\cong 1 \text{ bar})$$

mantle: "no flow"

bottom: over circle with 2 km radius at center have heat flow of

7.8125 W/m² (corresponding to an average heat flow of
1.25 W/m² over the entire bottom area); otherwise "no flow"

INITIAL CONDITIONS

temperature gradient $|\nabla T| = .04^{\circ}\text{C/m}$ (i.e., "natural" heat flow of
.084 W/m² $\cong$ 2.0 HFU)

pressure gradient is hydrostatic (gravitational equilibrium with no
mass flow)

TABLE 2: EVOLUTION OF A VAPOR-DOMINATED HYDROTHERMAL SYSTEM

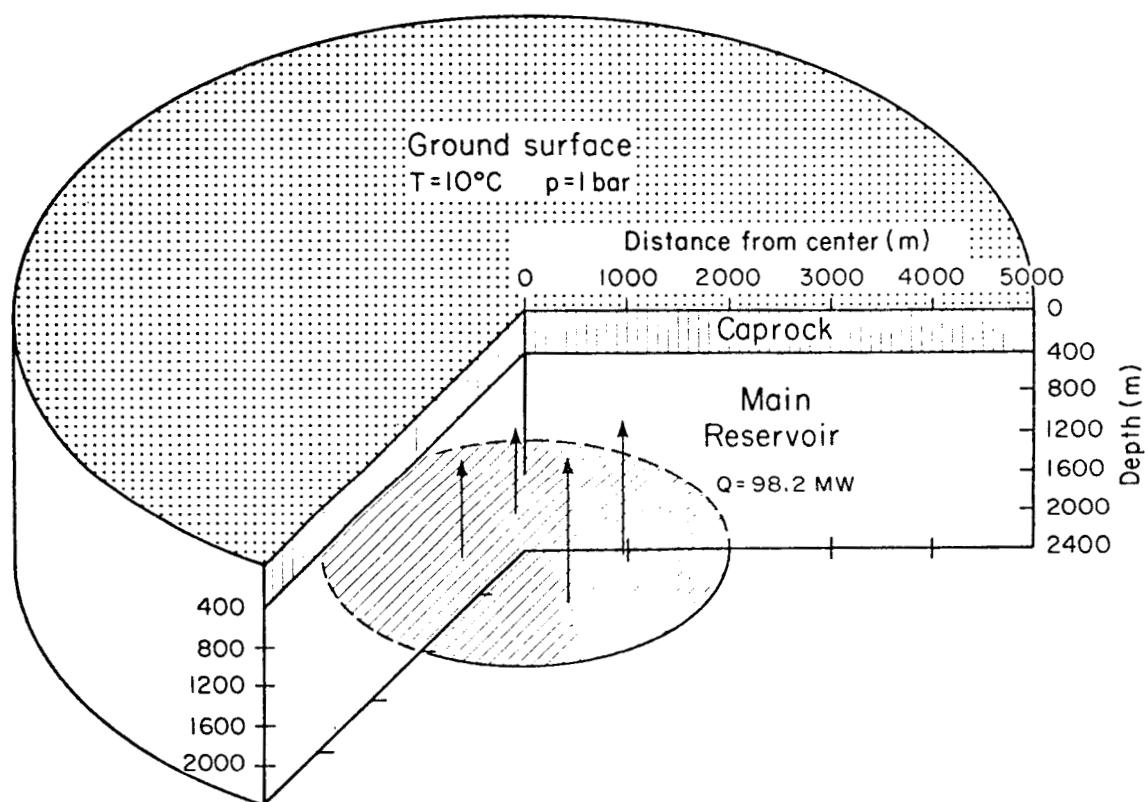
PHASE	HEAT EFFECTS	FLUID FLOW
initial state	"natural" heat flow	no mass flow (gravitational equilibrium with surface waters)
"dormant" state (0-300 years)	temperature rises above heat source	slow mass flow away from heat source (thermal expansion)
evolution of intense convection above heat source (300-1,000 years)	rapid increase in temperatures upward from heat source	rapid increase in mass flow (positive feedback from temperature-dependence of viscosity)
evolution of reservoir- wide convection (1,000-39,000 years)	spreading of elevated temperatures throughout system	slowly rearranging "toroidal" flow pattern
evolution of boiling (39,000-90,000 years)	stabilization of temperatures (hence pressures) in two-phase zones	"funnel-like" displacement of convective upflow away from two-phase zones, with lateral spreading of boiling
steady state (after 90,000 years)	surface heat loss equals base heat inflow	recharge equals discharge

TABLE 3: Surface Heat Flow and Fluid Discharge and Recharge in Steady State.

Element	Distance from Center (km)	Surface Area (km ²)	Mass Flux ^{a)} (kg/sec.km ²)	Energy Flux ^{b)} (MW/km ²)	Total Mass Flow (kg/sec)	Total Energy Flow ^{b)} (MW)
C1	.5	3.142	1.082	3.018	3.40	9.48
C2	1.5	9.425	.7820	2.371	7.37	22.35
C3	2.5	15.71	.0700	1.348	1.10	21.18
C4	3.5	21.99	-.1251	1.096	-2.75	24.11
C5	4.5	28.27	-.3250	.7417	-9.19	20.97
Entire Surface		78.54			-0.07	98.09

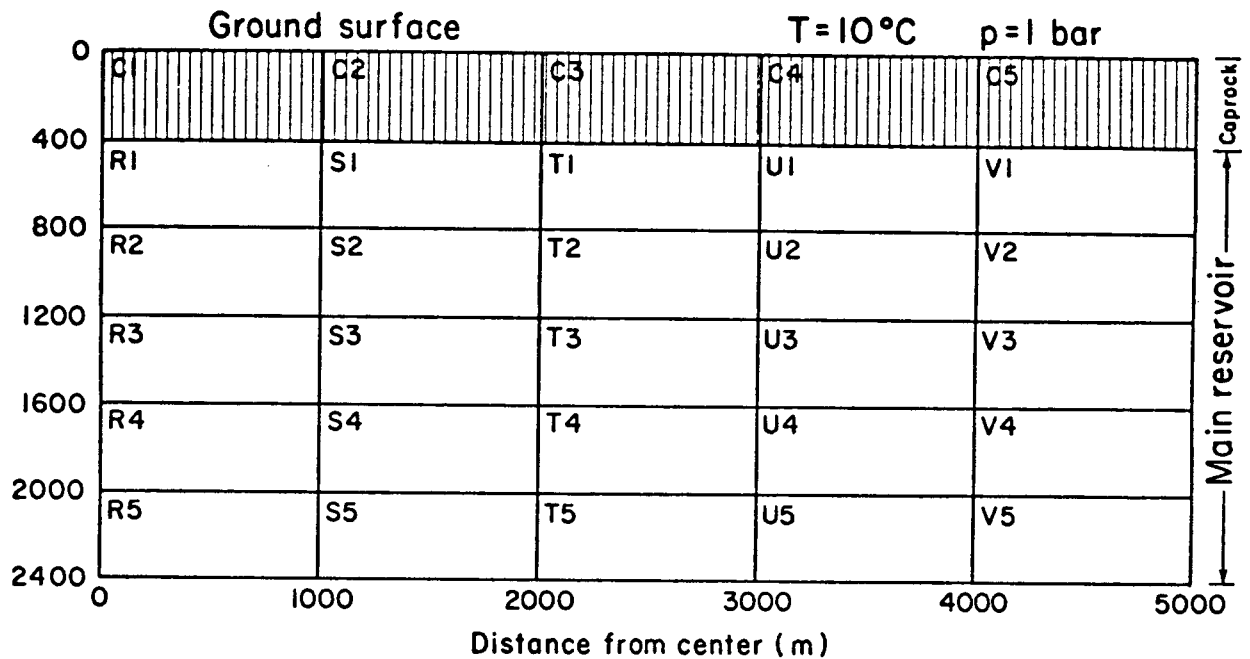
a) Positive for discharge, negative for recharge.

b) Contains conduction and convection.



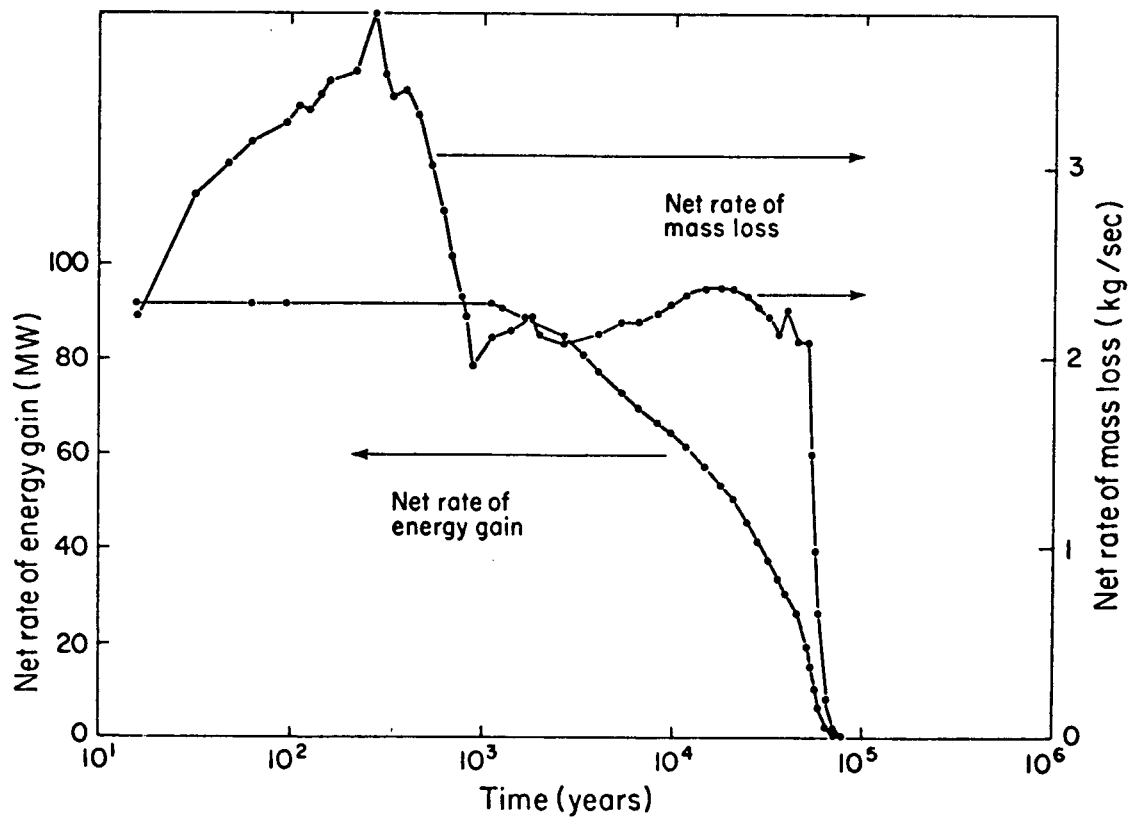
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Figure 1. Model of Natural Hydrothermal Convection System (NHCS).



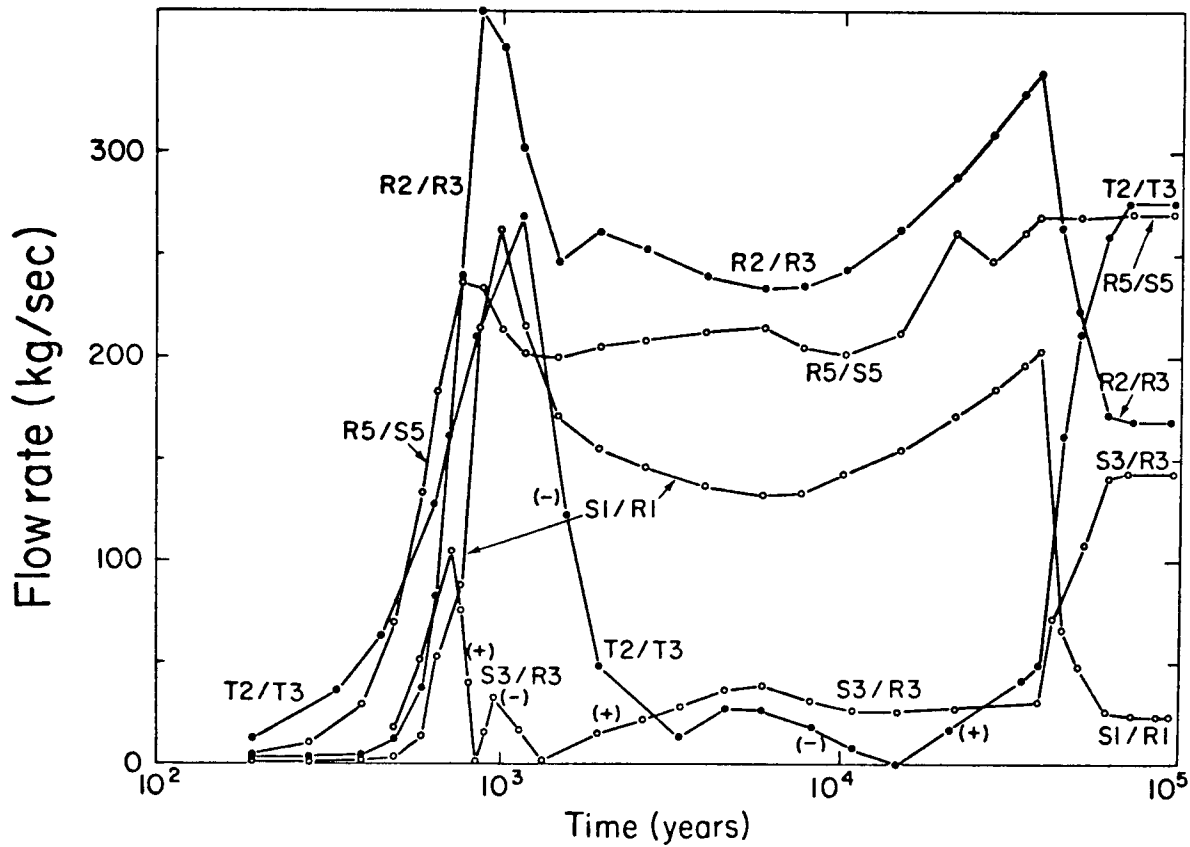
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Figure 2. Vertical Cross Section of NHCS. The center line is on the left, and the space discretization with element names is shown.



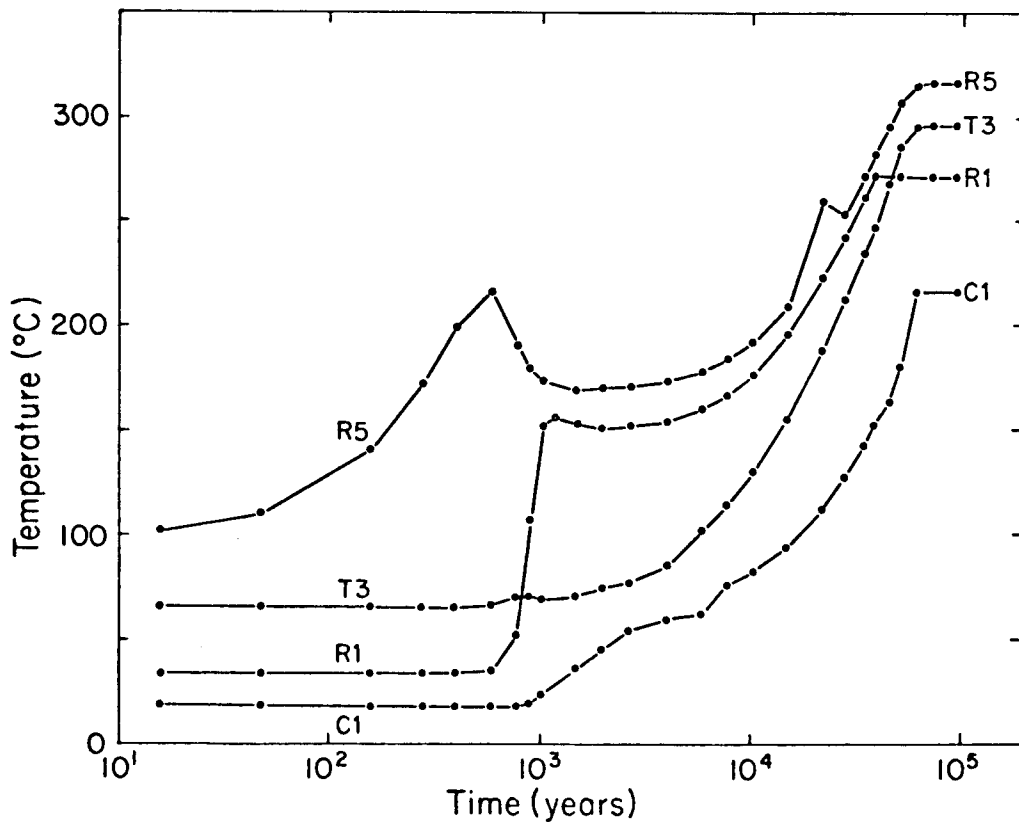
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Figure 3. Energy Gain and Mass Loss for NHCS.



XBL 8012-6529

Figure 4. Mass Flow Rates in NHCS. The curves are labeled with the elements between which the flow occurs. Flows are from the second element into the first, unless a curve is labeled (-).



XBL 8012-6527

Figure 5. Temperature Evolution in NHCS.

NUMERICAL STUDIES OF THE ENERGY SWEEP IN
FIVE-SPOT GEOTHERMAL PRODUCTION/INJECTION SYSTEMS

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INTRODUCTION

Most recent interest in the injection of cold water into a geothermal reservoir has been related to the disposal of geothermal brines. Injection also offers the potential benefit of prolonging the useful life of a vapor-dominated system by providing additional water to extract energy out of the rock matrix. In a liquid-dominated reservoir injection may help to maintain pressures near the production wells by pushing the hot water toward them and preventing too much local boiling. Pressure maintenance can also be achieved for superheated steam zones, because injection will cause pressures to increase towards the saturation pressure (Schroeder et al. (1980)).

The general physical principles governing these processes are understood but no quantitative information is available. The present work is aimed at helping to improve the qualitative and quantitative understanding of injection into a geothermal reservoir by considering a few idealized problems. First a vapor-dominated, single layer reservoir is considered, next a vapor-dominated, four layer reservoir, and finally a liquid-dominated, single layer reservoir. In each case varying injection rates are considered and in some cases the injection is changed at different times.

The SHAFT79 simulator (see Pruess and Schroeder (1979) for example) is used to calculate the reservoir behavior in each case. It is only with the advent of efficient geothermal reservoir simulators, such as SHAFT79 and other codes (see Coats (1977), Faust and Mercer (1979) and Brownell et al. (1975), for example), that it is possible to calculate the behavior of a two-phase reservoir during injection. The condensation of steam and the movement of thermal and hydrodynamic fronts through the reservoir as a cold zone around an injection well expands are severe tests of the capabilities of a simulator and are very difficult phenomena to model accurately. Previous work by the authors (O'Sullivan and Pruess (1980), Schroeder et al. (1980)) has demonstrated the accuracy of SHAFT79 in modeling injection problems.

Our calculations are made for a five-spot configuration of alternate, off-set rows of producers and injectors (see Figure 1). A calculation mesh with 34 nodes (see Figure 1) is used, which is barely sufficient to give accurate results. In fact, some of the results exhibit small oscillations with time due to this relatively coarse discretization.

Five-spot problems for water flooding of oil reservoirs have received considerable attention over the years, and more recently steam flooding problems are also being considered (see Taschman (1980), Greaser and Share (1980)). In oil reservoir injection/production problems the basic problem is one of mass recovery and the injected and produced fluid are not miscible. For geothermal reservoirs the problem involves both mass and energy recovery and the injected fluid may be usefully produced once it absorbs heat from the rock. The interaction of heat and mass transfer makes the geothermal five-spot problem more difficult than the corresponding oil problem. And so far little work has been done on it.

For the injection of cold water into an entirely hot water reservoir no two-phase effects are present, making the problems much more tractable, and several workers have investigated them (see Lippmann et al. (1977), for example).

VAPOR-DOMINATED RESERVOIR

The reservoir parameters are listed in Table 1. They were chosen to be similar to those for vapor-dominated fields such as that at Larderello, Italy, but are basically rather arbitrary. The production rate was selected to give a fluid supply of approximately 30 years. The reservoir was produced at a constant rate of 0.0025 kg/s.m in all cases, and different injection rates tested. The calculation was stopped when the pressure in the production node dropped below 0.7 MPa, taken to be a representative minimum value required to sustain flow in the well.

The results in Table 2 summarize the energy and fluid production data (for the calculation zone and a reservoir of 10 m thickness). With no injection the reservoir lasts 33.2 years, at which time nearly all the fluid has been extracted, but of the original 57.4×10^{13} J of energy in the reservoir only 7.3×10^{13} J have been extracted. Not all of the original energy could be easily extracted. For comparison, the rock alone at 180 °C would contain 40.8×10^{13} J, indicating that there is more high quality energy left in the rock than was produced. Towards the end of the life of the field when little mass remains, the pressure drops very fast (see Figure 2).

If cold water (40 °C) is injected at the same rate as it is produced, the reservoir lasts 39.7 years, and an extra 1.0×10^{13} J of energy are extracted. Now the pressure declines not because the reservoir is running out of mass, but because the mass is too far from the production well, and the pressure gradient required to cause it to flow across is so great that the pressure in the production block drops until the cut off of 0.7 MPa is reached.

An injection rate of double the production rate causes the field to last 49.6 years, and the final energy content is now 47.5×10^{13} J. But again the pressure drops too low, trying to induce the fluid to flow from the injection well to the producing well. An injection rate of three times the production rate produces a premature break-through of cold water. The high injection rate causes a tongue of cold water to reach the producer at around 40 years. However, energy recovery can be improved by a high initial injection rate and then cutting off all injection. The last figures in Table 2 are for 26.9 years of 300% injection followed by a period of no injection up to 57.3 years. At this stage only 45.6×10^{13} J remain in the reservoir. This strategy results in the extraction of 11.8×10^{13} J as opposed to 7.3×10^{13} J with no injection.

The pressure decline curves in Figure 2 show clearly the slightly faster rate of pressure drop resulting from the reduction of the volume available for boiling when injection takes place.

GRAVITY EFFECTS

No further attempts were made to optimize energy extraction because the reservoir considered has some limitations in its practicality. Probably the most severe limitation is that in a single layer reservoir all vertical flow is neglected. When dense cold water is being injected into a hot high vapor saturation region, gravity induced vertical flows will be large. To investigate this effect a four layer reservoir, each 25 m thick, was considered. The reservoir properties used were identical to those for the single layer case. As expected, the injected water mostly moves to the bottom of the reservoir and after 11.6 years the production from the bottom layer is a two-phase mixture rather than dry steam. The vapor saturation profile between the production and injection wells in each layer, labeled A,B,C,D, in descending order, is shown in Figure 3 with the single layer result given for comparison. Because the mesh used is three-dimensional, the calculation is expensive and no further experimentation was carried out, but obviously gravity is very important in determining the optimum energy recovery strategy for a reservoir.

LIQUID-DOMINATED RESERVOIR

A single layer reservoir with the same properties as those given in Table 1 for the vapor-dominated case was considered. The initial pressure was taken as 3.58 MPa, approximately 0.13 MPa above the boiling pressure at 240 °C. With no injection, the reservoir quickly boils and as the vapor saturation increases near the production well, and the mobility therefore declines, the pressure drops in the production block steadily with failure of the reservoir after 9.6 years. At this stage, plenty of mass and energy remain in the reservoir. The failure has occurred solely as a result of local boiling near the production well. With an injection rate equal to the production rate, boiling in the reservoir is kept at a low level, and production can be continued for 120 years with the useful heat in the reservoir mostly swept out. An injection rate half of the production rate maintains production pressures for approximately 16 years, but then local boiling again causes a sharp decline in pressure (see Figure 4). The effect of delaying injection was investigated by having no injection for six years and then injecting at the same rate as production. In this case the production block pressure first drops even more steeply. This occurs because the first effect of injection is to reduce the volume of boiling fluid available for steam production. After a short time the extra steam produced by the injected fluid near the injection well reaches the production block, increasing the pressure and temperature there. This effect is shown in the temperature profiles at 7.2 years and 8.7 years respectively (see Figure 5).

As the steam production in the middle of the reservoir proceeds, it cools (see Figure 5 at 10.7 years) and is not able to sustain such a high rate of steam production. Then boiling near the well increases and the pressure subsequently drops, reaching a failing level at about 20 years. Thus delayed injection cannot maintain pressures in this reservoir.

A further liquid-dominated reservoir was considered with a higher permeability (100 md). In this case, boiling is not so localized, and with no injection the reservoir lasts approximately 26 years (see Figure 6). In this case the failure results from localized cooling near the production well. The temperature there drops to around 180 °C, where the pressure of saturated steam is 0.8 MPa. As for the previous case injection at the same rate as production will maintain pressures in the reservoir until most of the energy is swept from it.

CONCLUSIONS

The calculations presented here are limited in their scope. Virtually only one set of reservoir parameters was considered.

However, some tentative conclusions can be reached. In a two-phase vapor-dominated reservoir, injection cannot maintain pressures, but it can increase the energy recovered. In liquid-dominated systems, injection can be used to maintain production pressures and increase longevity, but it should be started early and at a high rate.

Much work remains to be done, particularly with regard to gravity effects, the combined effects of injection and natural recharge, and the effect of fractures.

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Table 1. Reservoir Parameters

$\phi = 0.1$

K = 40 mD

Production Rate 0.0025 kg/s.m

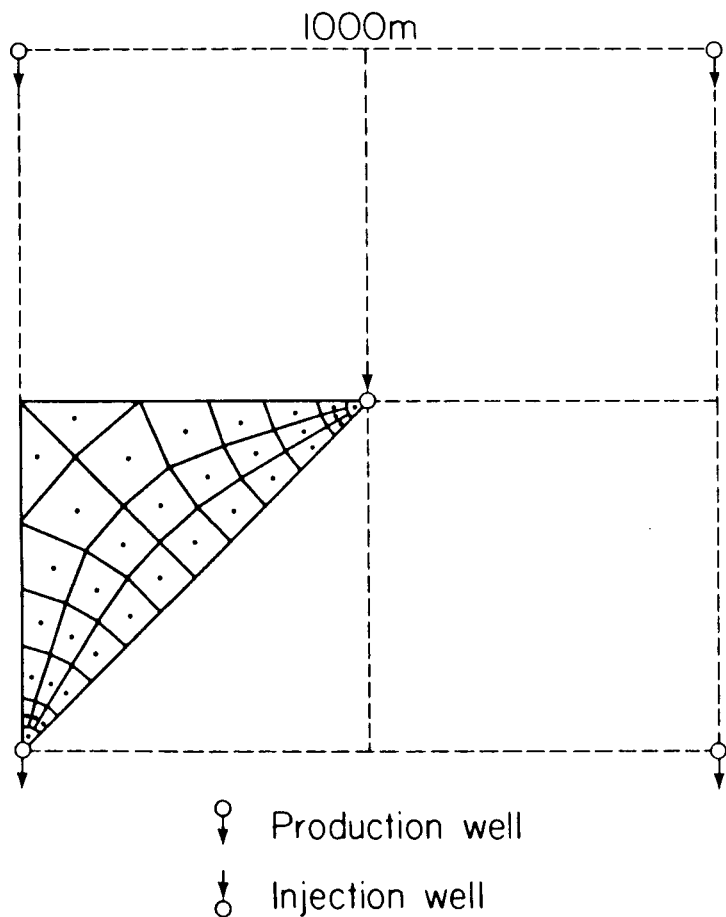
Well Spacing 1000 m

Initial Temperature 240 °C

Initial Liquid Saturation 0.75

Table 2. COMPARISON OF EXPLOITATION STRATEGIES

DESCRIPTION	TOTAL ENERGY (10^{13} J)	FLUID ENERGY (10^{13} J)	FLUID MASS (10^6 kg)
INITIAL STATE (240°C)	57.4	2.6	27.0
ROCK AT 180°C	40.8	0.0	0.0
33.2yrs production no injection	50.1	0.2	0.8
39.7yrs production 100% injection	49.1	2.2	27.0
49.6yrs production 200% injection	47.5	4.9	66.1
57.3yrs production 300% injection for 26.9yrs	45.6	3.3	45.3



XBL 8010-12543

Figure 1. Five Spot Geometry. The spacing between production (or injection) wells is 1000 m, corresponding to ≈ 700 m distance between producers and injectors. The mesh design covering 1/8 of the five-spot is also shown.

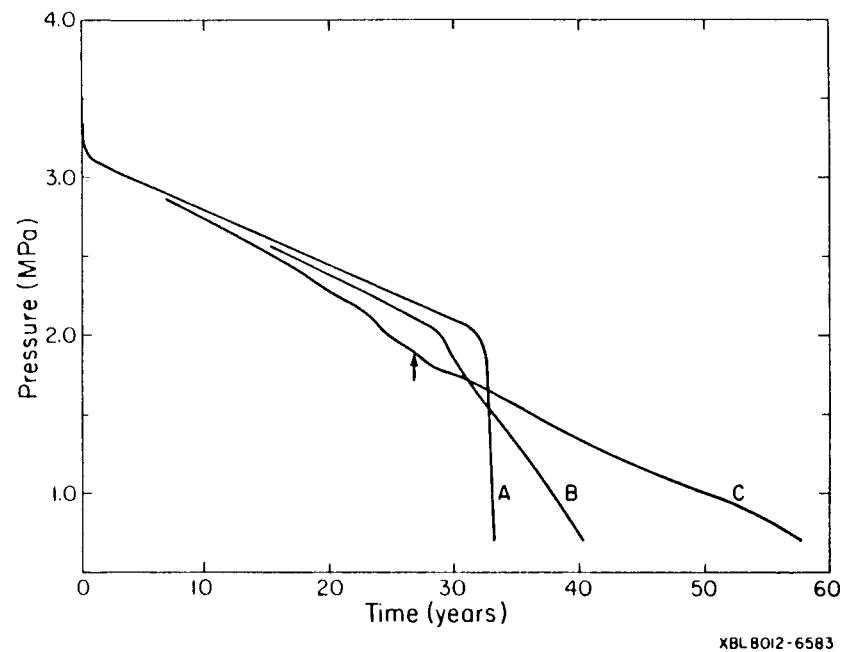
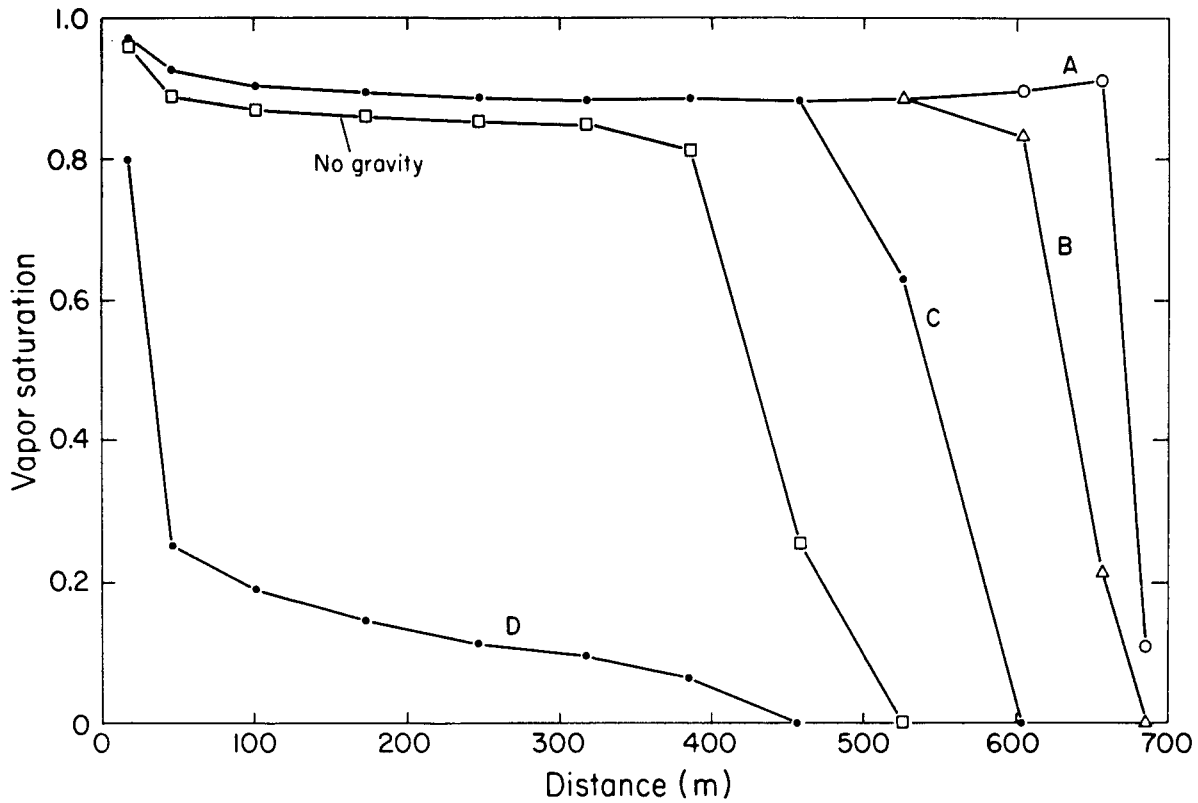
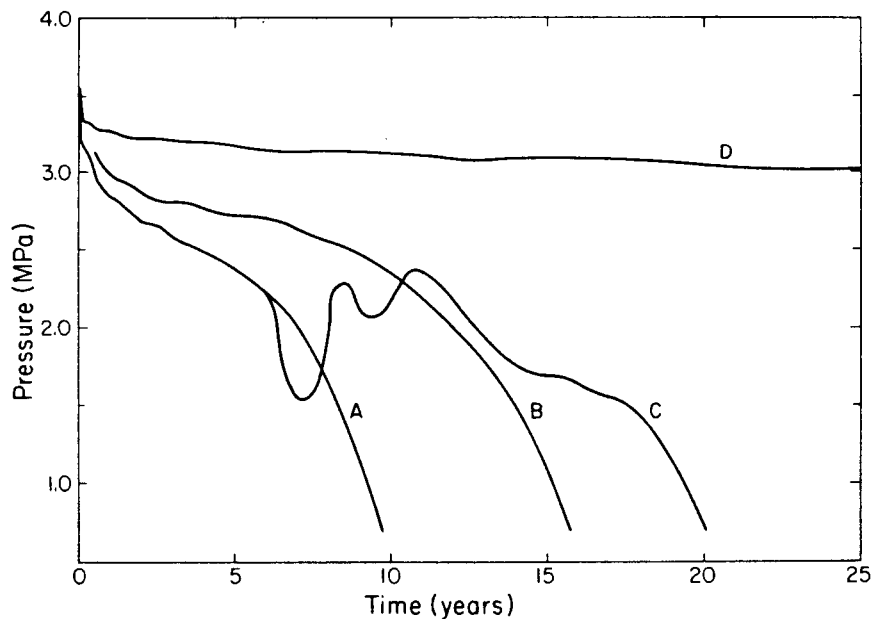


Figure 2. Pressure in the production block for the vapor-dominated reservoir. A - no injection, B - 100% injection, C - 300% injection.



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Figure 3. Vapor saturation profiles in the four-layer reservoir after 11.4 years of 200% injection compared with the no-gravity case.



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Figure 4. Pressure decline in the production block for a liquid-dominated reservoir. A - no injection, B - 50% injection, C - 100% injection after six years, D - 100% injection.

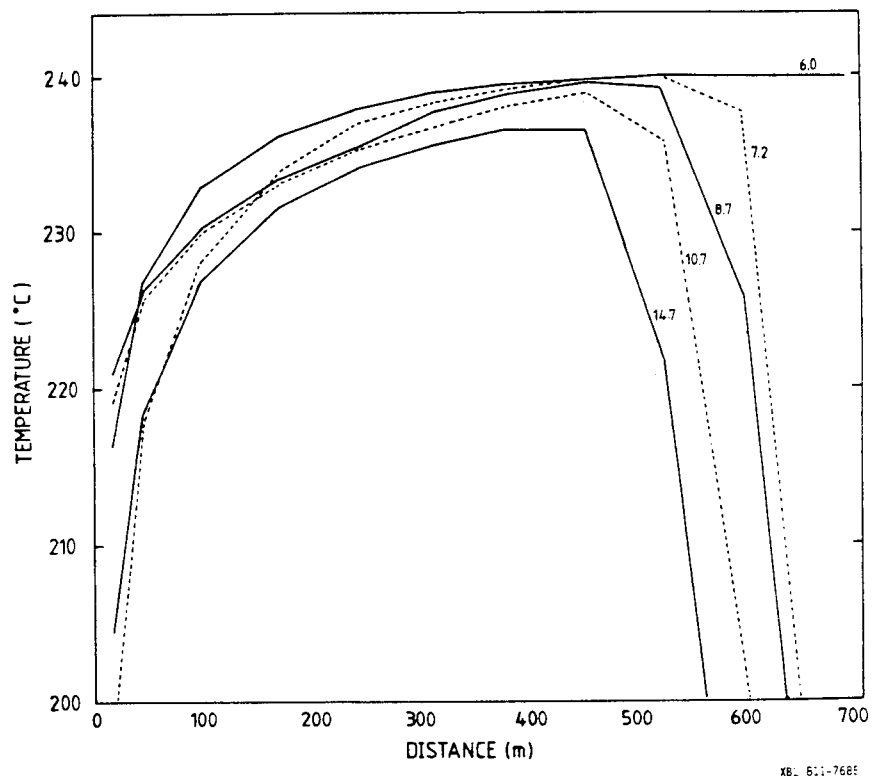


Figure 5. Temperature profiles at various times (in years).

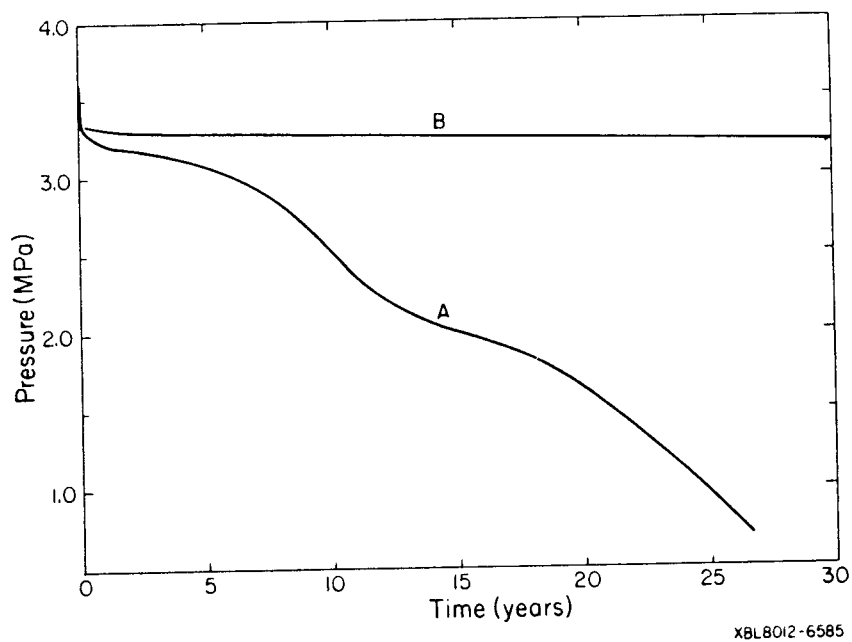


Figure 6. Pressure decline in the production block for the liquid-dominated reservoir with high permeability. A - no injection, B - 100% injection.

IS GEOTHERMAL SIMULATION A "CATASTROPHE"?

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INTRODUCTION

All numerical simulators of geothermal reservoirs depend upon an accurate representation of the thermodynamics of steam-water systems. These relationships are required to render tractable the system of balance equations derived from the physics of flow through porous media. While it is generally recognized that the steam-water system (i.e. two phase) is not in thermodynamic equilibrium, equilibrium thermodynamics are employed in its description. In this paper, we present an alternative view based on non-equilibrium thermodynamics. The underpinnings of this approach are found in a branch of topology generally referred to as "catastrophe theory". [Thom, 1975]

THERMODYNAMICS

Consider the thermodynamic relationships presented in figure 1. Generally available theory dictates the use of the curve (A-B-D-F-G) in describing the change in density encountered in moving from the single-phase water region (A-B) through the two phase region (B-D-F) to the single phase steam region (F-G). Thus, there is one pressure and temperature for the steam-water mixture irrespective of its liquid-gas composition. This is the curve (A-B-D-F-G) that is now employed in all geothermal simulators known to the authors. Note that the "kinks" encountered at points B and F lead to discontinuous derivatives with respect to the thermodynamic variables; this, in turn, generates serious numerical problems.

With the recognition that "metastable" water and steam states could, and indeed do, exist in the two-phase region, attention focused on the use of Van der Waals' equation to describe the thermodynamics of the two phase region. This curve (A-B-C-D-E-F-G) indicates that metastable water can exist along (B-C) and metastable steam along (E-F). The curve (C-D-E) does not correspond to a stable or even metastable state and is never observed. While these curves are of theoretical interest they do not, in and of themselves, enhance our understanding of the non-equilibrium two-phase region because the dynamics of the system are lacking.

CATASTROPHE SURFACES

The dynamics of the two-phase region can be uncovered using catastrophe theory. While the mathematical foundations of catastrophe theory are rather abstract, the practical ramifications are easily understood. The catastrophe surface representing the Van der Waals' equation for the steam-water system is presented in figure 2. It is simply the three-dimensional representation of the information presented in figure 1; temperature has been added as a third coordinate. In the nomenclature of catastrophe theory this surface is referred to as the "slow manifold".

The information presented in figures 1 and 2 is combined in figure 3. The letter nomenclature is the same as that appearing in figure 1. The reader is encouraged at this point to examine the three figures until the surface appearing in figure 2 is evident in figure 3. It is this figure that will guide us through the two phase region.

THERMODYNAMIC EVOLUTION

We begin by identifying a location in thermodynamic space of figure 3 designated by the numeral 1. This represents the initial condition or state at a physical point in our geothermal simulator. In this instance the point is in the hot water region of the well documented Arihara experiment [Arihara et al, 1976]. As the numerical simulation of this experiment evolves through time the pressure decreases dramatically and the thermodynamic state of the point of observation evolves along the trajectory defined by the curve (1-2). At the point denoted by the numeral 2, a second phase begins to appear. According to the catastrophe theory concept at this point, the specific volume of the steam phase is denoted by the thermodynamic state at point 4 and that of the water phase by the location 2. The trajectory continues along the line (2-3). During this interval of time the evolution of the specific volume of the water phase is described by the curve (2-3) and that of the steam phase by the curve (4-5). At the point 3, the thermodynamic trajectory describing the behavior at our observation point suddenly changes. Suddenly the state moves along the line (3-5) and only steam exists at this point in the system. Thereafter, the evolution of the state of the system at the observation point is described by the trajectory (5-6).

While this description may appear quite straight-forward, it is certainly unorthodox. It proposes an evolution in water and steam densities within the two-phase region whereas current thinking assumes the steam and water densities do not change within the two phase region and are described by the two points 2 and 5 respectively as when the two fluids are maintained at equilibrium. The difference in our approach arises from our intention to model behavior in the two-phase region when the fluids are not in equilibrium. Our approach also requires the existence of different pressures for water and steam within the two-phase region. In other words, the pressure of the steam associated with the point 4 is quite different than that of the water described by point 2 although these thermodynamic states would coexist in the proposed thermodynamic model. The existence of a higher pressure in the steam phase than the water phase is apparent to anyone who has watched a pan of boiling water. Because the steam forms a bubble, it must have a higher pressure than the surrounding water.

PRACTICAL SIGNIFICANCE

Let us now investigate the practical ramifications of the above theoretical argument. Figure 4 presents saturation profiles computed for the Arihara experiment using the standard approach and the methodology founded on Van der Waals' equation and catastrophe theory. While the solutions are similar in shape, they are quite different in magnitude. Unfortunately, because the exact solution is unknown we cannot determine unequivocally which solution is more accurate.

A second more subtle difference in the two approaches involves the numerical treatment of the phase change. Because there is no sudden discontinuity in the derivatives of the thermodynamic variables when one crosses the two-phase boundary, the non-linear aspects of the problem are less troublesome. Early test runs suggest an order of magnitude larger time steps can be accommodated with the new approach as compared to the same simulator formulated using the standard equilibrium thermodynamic methodology.

CONCLUSIONS

Geothermal simulation which accounts for the non-equilibrium thermodynamic nature of the steam-water system generates saturation profiles similar to but distinctly different from those obtained using standard methodology. The approach is intuitively simple, mathematically rigorous, and gives rise to a system of algebraic equations more amenable to solution than those generally encountered in alternative formulations.

ACKNOWLEDGEMENT:

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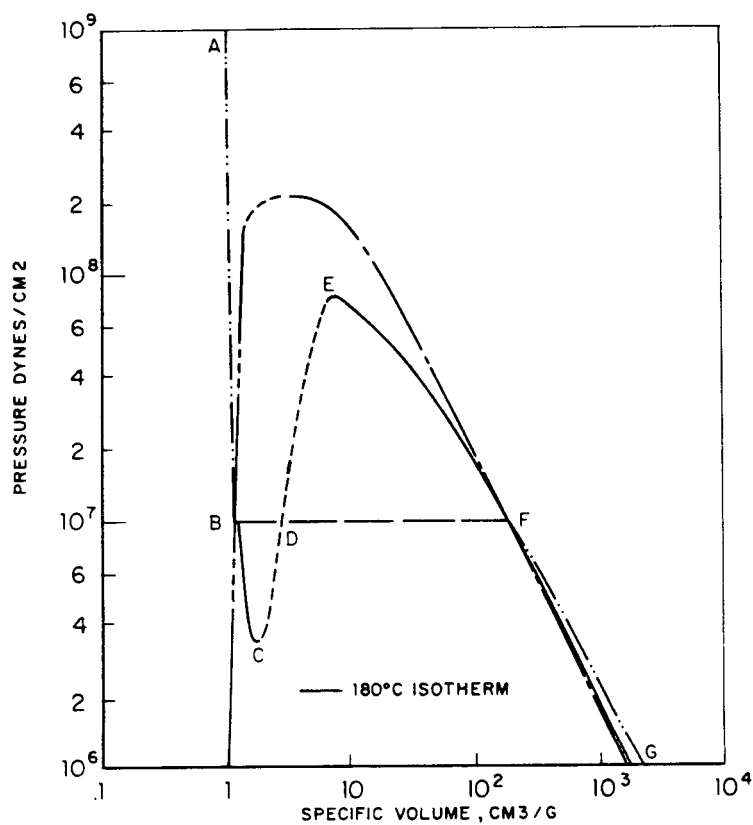


Figure 1: Thermodynamic relationships for a steam-water system employing equilibrium theory and Van der Waals' state equation.

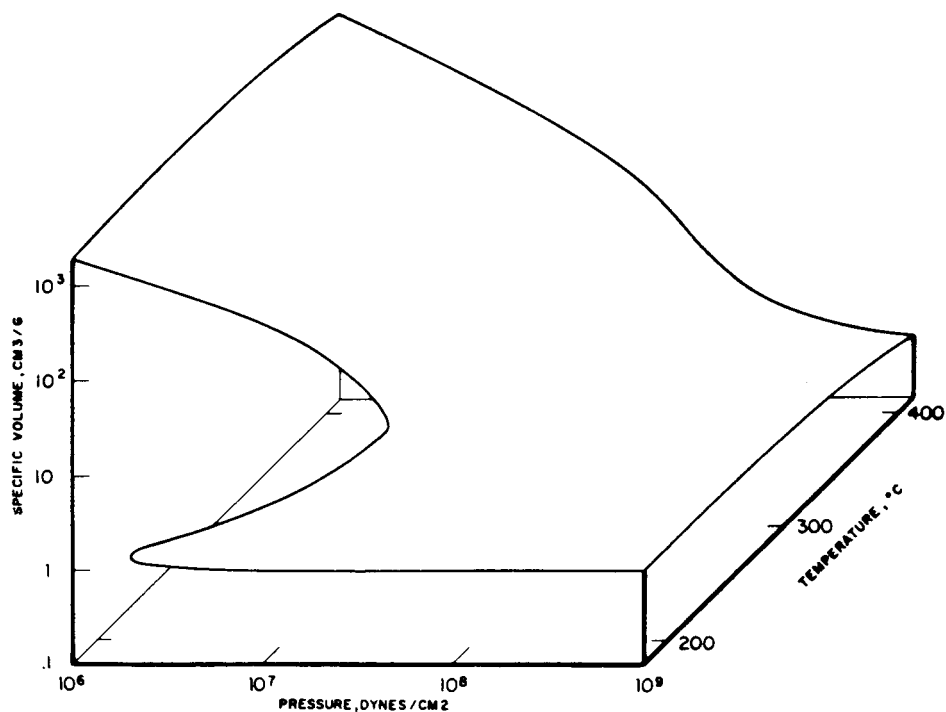


Figure 2: Geometry of the Van der Waals' state equation.

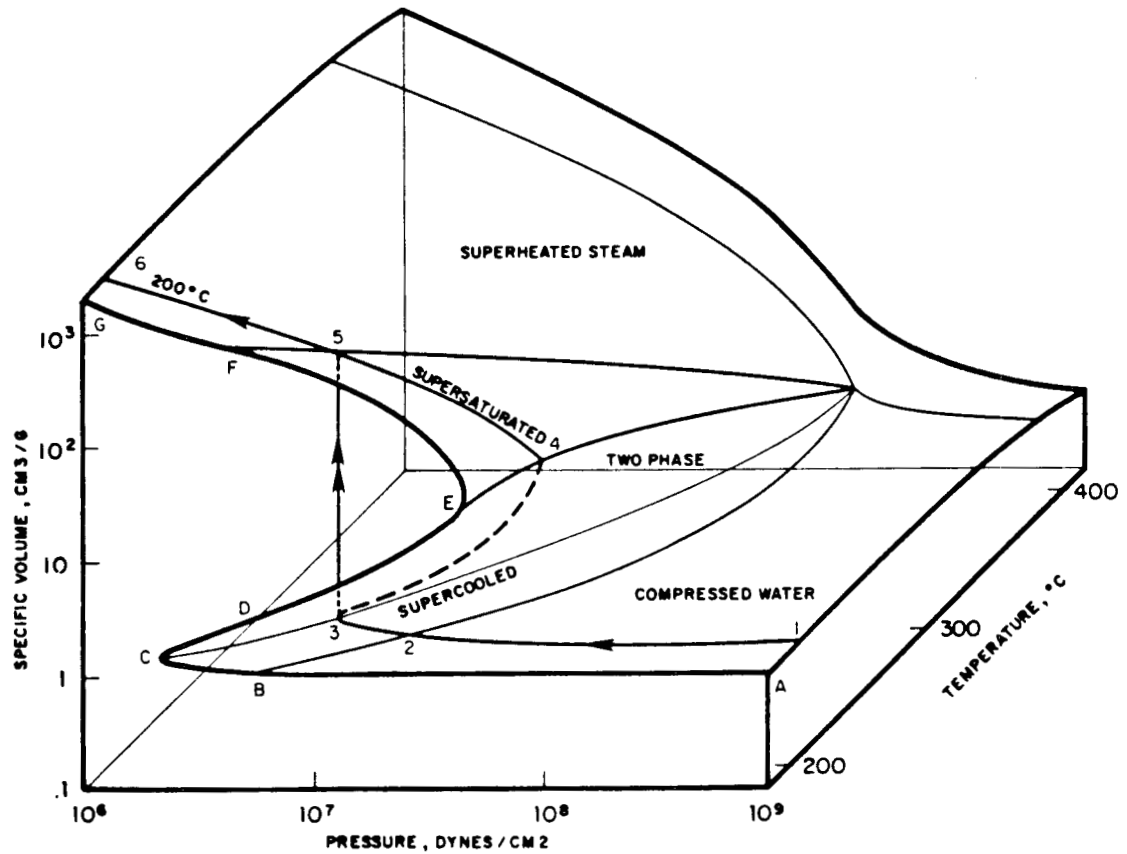


Figure 3: Morphological representation of steam-water dynamics as the Riemann-Hugoniot catastrophe.

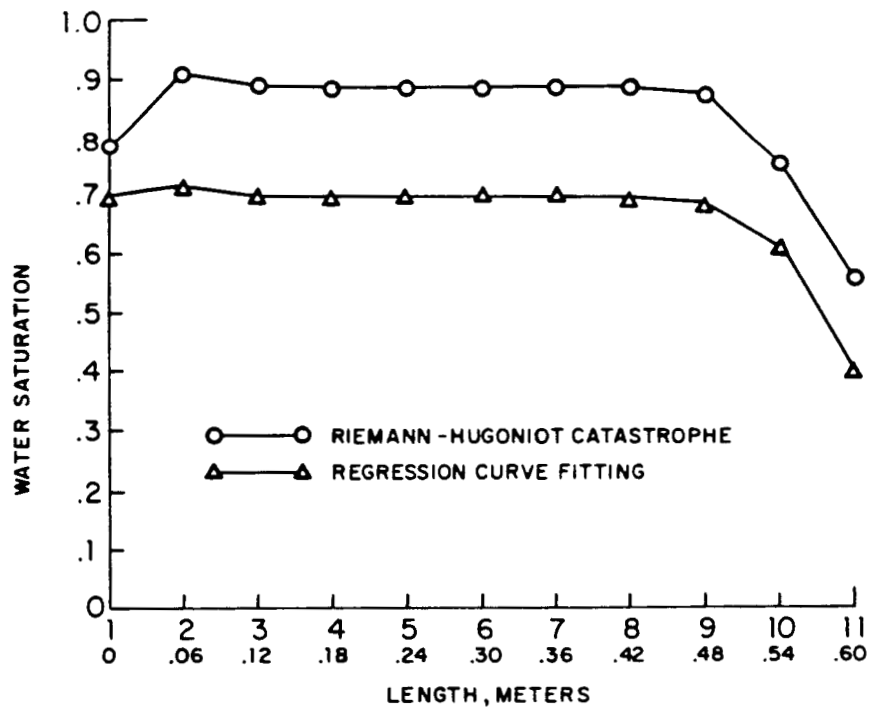


Figure 4: Contrast in saturation profiles from topological and standard statistical estimates of thermodynamic variables for the two-phase domain.

INFLUENCE OF STEAM/WATER RELATIVE PERMEABILITY MODELS ON PREDICTED
GEOTHERMAL RESERVOIR PERFORMANCE: A SENSITIVITY STUDY

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INTRODUCTION/STATEMENT OF THE PROBLEM

The concept of relative permeabilities represents an attempt to extend Darcy's Law for single-phase flows through porous media to the two-phase flow regime.¹ In this regime, the flowrate of each phase is related to the macroscopic pressure gradient imposed on the flow through the relative permeability parameters k_L (for the liquid phase) and k_G (for the "gas" or vapor phase), expressed as fractions of the bulk permeability (k) of the medium to all-liquid flow. Accurate "models" for k_L and k_G as functions of some independent flow variable (historically liquid saturation) are required if one is to solve the complex two-phase flow problems associated with geothermal energy extraction, nuclear waste isolation, enhanced oil recovery and others.

Figure 1 shows a schematic of a generalized relative permeability model (RPM) which incorporates all of the features ("limits") potentially encountered for a two-phase, liquid/ vapor, flow through a porous medium. Here s is liquid saturation, defined as the fraction of the pore volume occupied by liquid; f , the dynamic quality of the flow, defined as the fraction of the total mass flowrate attributed to the vapor phase, $(W_G/W_L + W_G)$; k' , the bulk permeability of the medium to all-vapor flow at a specified pressure (p). The four saturation limits of interest, and their corresponding flow regimes, are defined below:

- A. $s(f \rightarrow 0)$ is the saturation at which f goes to zero. Thus, for $s \geq s(f \rightarrow 0)$, the vapor phase does not flow, i.e., it is "trapped" ($W_G = 0$).
- B. $s(k_L \rightarrow k)$ is the saturation at which k_L goes to k . Thus, for $s \geq s(k_L \rightarrow k)$, the trapped vapor phase no longer influences the flow of the liquid phase.
- C. $s(f \rightarrow 1)$ is the saturation at which f goes to unity. Thus, for $s \leq s(f \rightarrow 1)$, the liquid phase does not flow, i.e., it is "trapped" ($W_L = 0$).
- D. $s(k_G \rightarrow k')$ is the saturation at which k_G goes to k' . Thus, for $s \leq s(k_G \rightarrow k')$, the trapped liquid phase no longer influences the flow of the vapor phase.

The occurrence of trapped phases is generally attributed to capillary effects.¹ For certain geologic materials, the saturation regime in which a trapped phase can exist may be quite extensive (e.g., Fig. 2-5 of Collins² presents data for sandstone cores indicating potential values for $s(f \rightarrow 1)$ increasing from 0.2 to 0.7 as k decreases from 10^{-12} m^2 to 10^{-15} m^2). Should a trapped phase initially reside solely within the non-interconnected regions of the pore space, it would not be expected to influence the flow of the other phase. However, as the volume percent of a trapped phase increases, it may also begin to reside in portions of the interconnected flow channels within the porous medium. At this point, the trapped phase would begin to adversely affect the flow of the other phase. For these reasons, restrictions must be imposed on the above-noted limits:

$$s(k_G \rightarrow k') \leq s(f \rightarrow 1) \text{ and } s(k_L \rightarrow k) \geq s(f \rightarrow 0)$$

Further, since the vapor phase is a "gas," $k' > k$ due to molecular effects, with k' approaching k "from above" only as pressure becomes infinite. It can be seen, therefore, that the functions $k_L(s)$ and $k_G(s)$ depend on the "physical properties" of both the working fluid and the porous medium. Hence, no universal correlation for these functions can exist. Such models must be determined experimentally for each fluid/medium combination of interest.

A state-of-the-art computer code currently utilized to predict geothermal reservoir performance (SHAFT³) incorporates a RPM based on the oil/gas data analysis of Corey.⁴ In its current form, this model allows trapped phases to exist, but does not allow for either trapped phase to influence the flow of the other phase. Two saturation values are input, $s(k_G \rightarrow k)$ and $s(k_L \rightarrow k)$. However, the equations used to describe $k_L(s)$ and $k_G(s)$ in this model possess asymptotic limits which require $s(f \rightarrow 1)$ to be identical to the input value for $s(k_G \rightarrow k)$ and $s(f \rightarrow 0)$ to be identical to the input value for $s(k_L \rightarrow k)$. No dependence of k_G on p is modelled.

The objective of the present effort was to conduct a sensitivity study, using the SHAFT code³, to demonstrate the influence of various RPMs on predicted geothermal reservoir performance. A basic model devised to accomplish this goal was one which would allow each of the four noted saturation limits to be specified (input) independently; $k_L(s)$ and $k_G(s)$ were then modeled as having a linear dependence on s between these specified limits. As with the Corey model, k' was set equal to k .

Since the primary objective was to investigate a broad spectrum of possible "saturation limit" combinations, thereby requiring a relatively large number of computer runs, a one-dimensional problem was chosen for study (Fig. 2). An infinite porous reservoir containing liquid water at $p_1 = 10.4$ bars and $T_1 = 180^\circ\text{C}$ was connected to a permeable stratum initially at the same pressure and temperature. The stratum was assumed to be bounded above and below by layers of impermeable rock. Heat conduction from these layers to the stratum was neglected. At time (t) zero, a well-bore was "joined" to the stratum, i.e., a boundary condition of $p_2 = 1.06$ bars was specified at the stratum exit. The transient problem was then solved for $p(x,t)$, $T(x,t)$ and $s(x,t)$ until a steady-state solution was achieved. In all cases, a short region of liquid water flow, followed by an extended region of two-phase, steam/water, flow was predicted to occur. Reservoir "performance" or "output" was quantified by the product of the total, steady-state, mass flux (W) and the mixture enthalpy (H) at the stratum exit (i.e., into the well). All such steady-state convective energy fluxes (WH) were non-dimensionalized by the product (WH_{REF}) predicted to occur at the same location for a "reference case" RPM. The reference case utilized in the present study is one which possessed no trapped phases, while still maintaining the stated linear dependence of k_L and k_G on s .

RESULTS

Consistent with the scope of the present investigation, it was first necessary to define an absolute permeability for the stratum which would meet the following two criterion: "low enough" to be representative of

consolidated geologic materials, i.e., those capable of "trapping phases," and "high enough" to ensure that the problem remained convection dominated.

The reservoir problem was first solved with k as the primary independent variable ($10^{-12} \leq k \leq 10^{-16} \text{ m}^2$), incorporating several representative $k_L(s)$, $k_G(s)$ models utilized in the sensitivity study itself. Results showed non-dimensionalized reservoir output to be insensitive to k , and energy transfer along the stratum to remain convection dominated, for all $k \geq \approx 10^{-14} \text{ m}^2$. Factoring in the "trapping effectiveness" data reported by Collins,² and the tradeoff between permeability and computer run time, a final choice for k , of 10^{-12} m^2 , was made.

Detailed scrutiny of these solutions led to the discovery of some features which, at first, were puzzling, but, in the final analysis, were shown to be entirely consistent with the physics included in the analysis and the boundary conditions imposed upon it. In summary, predicted steady-state saturation distributions, for convection-dominated flows, were found to contain "discontinuities," or "zones of exclusion," from unity to $s(f \rightarrow 0)$ and from $s(f \rightarrow 1)$ to zero. Predicted $p(x)$, $T(x)$ and $f(x)$ distributions were found, however, to be continuous and "smooth." What this says is that, in the steady-state limit, no physical regions within the stratum were predicted to contain a trapped phase. However, under transient conditions, and under conditions where conduction effects were non-negligible, physical regions containing trapped phases were predicted to exist. The mathematical explanation for these solutions is reviewed below.

In the steady-state limit, the continuity equation reduces to $W = W_L + W_G = \text{constant}$. Similarly, the energy equation reduces to $W_L H_L + W_G H_G + Q = \text{constant}$, where Q is the axial conductive heat flux at any station along the stratum. Darcy's Law (the momentum equation) for each phase requires that $W_L \propto k_L (dp/dx)$ and $W_G \propto k_G (dp/dx)$. Within a finite s regime ($s(f \rightarrow 0) \leq s \leq 1$) let k_G be set equal to zero. The momentum equation then dictates that $W_G = 0$, the continuity equation dictates that $W = W_L = \text{constant} > 0$, and the energy equation, for convection-dominated flows ($W_L H_L + W_G H_G \gg Q$), dictates that $W_L H_L = \text{constant}$. A combination of these latter two results thus requires $H_L = \text{constant}$. For a two-phase mixture of water and steam in equilibrium, if $H_L = \text{constant}$, then p and T must also be constant, hence (dp/dx) must be zero. A mathematical inconsistency then arises, since, for $(dp/dx) = 0$, W_L must also be zero, contrary to the continuity requirement. Therefore, no computational solutions can exist in the "zones of exclusion."

Systematic variations of the four independent saturation limits defined above were equivalent, therefore, to systematic variations in the following quantities: (a) the extent of the saturation regime within which steady-state two-phase flow solutions could be achieved, (b) the maximum values of k_L and k_G at the boundaries of this saturation regime, and (c) the slopes of the $k_L(s)$ and $k_G(s)$ curves within this regime. As noted, even though no physical regions within the stratum were predicted to contain a trapped phase, "interactions" between "incipient trapped" and flowing phases could still be "simulated" through items (a) and (b) above. Simply put, when k_G first exceeded zero, k_L could be "specified" as being less than one; alternatively, when k_L approached zero, k_G could be "forced" to approach a value less than one.

In an attempt to present results of this sensitivity study in a concise manner, two distinct correlating parameters were introduced. The first of these was β , defined as the ratio of the absolute values of the slopes for the $k_L(s)$ and $k_G(s)$ curves:

$$\beta \equiv \frac{|\Delta k / \Delta s|_G}{|\Delta k / \Delta s|_L} = \left[\frac{s(k_L \rightarrow k) - s(f \rightarrow 1)}{s(f \rightarrow 0) - s(k_G \rightarrow k)} \right] \begin{matrix} > \\ < \end{matrix} 1$$

This parameter is a measure of the incremental change in the mass flowrate ratio, $\Delta W_G / \Delta W_L$, for an incremental change in s . Results plotted as a function of β are shown in Figure 3.

For those cases where only a single trapped phase regime was specified in the RPM, reservoir performance was seen to depend solely on β . At $\beta=1$, a limit common to both "branches" in this plot, reservoir output was seen to be identical to that predicted for the reference case model. It may be concluded, therefore, that specifying trapped-phase regimes without allowing for "interaction" between the trapped and flowing phases has no net influence on predicted reservoir performance. As β approached both zero (trapped liquid for all s) and infinity (trapped vapor for all s), reservoir output monotonically approached zero, consistent with mathematical arguments already discussed. Concerning "sensitivity," for "single-trapped-phase" RPMs, a $\pm 50\%$ change in β about 1 resulted in ≈ 20 to 25% reductions in predicted reservoir output. This correlating approach proved unsatisfactory, however, since calculations using "two-trapped-phase" RPMs yielded results which fell everywhere below the two "envelope curves" just discussed.

A more successful correlation resulted with the introduction of Γ :

$$\Gamma \equiv \left[\frac{s(f \rightarrow 0) - s(f \rightarrow 1)}{s(k_L \rightarrow k) - s(k_G \rightarrow k)} \right] \leq 1$$

This parameter is a ratio of "saturation regimes": the numerator is the extent of the total saturation regime for which steady-state solutions can be obtained; the denominator is the maximum extent of the total saturation regime in which the two phases exhibit "interdependence." As such, this parameter is a "measure" of all three quantities in the basic RPM subject to systematic variations (recall previous discussions). Results plotted as a function of Γ are shown in Fig. 4.

Once again, two discrete "envelope curves" were found to exist, one for each "single-trapped-phase" RPM. However, in these coordinates, the two curves were nearly identical, with all predictions for the more general "two-trapped-phase" RPMs falling between them. In the limit of $\Gamma=1$, trapped phases are included in the RPM, but each trapped phase is not allowed to influence the flow of the other phase. As noted earlier for such cases, reservoir output was found to be identical to that predicted for the reference case RPM. In the limit of $\Gamma \rightarrow 0$, no steady-state solutions are possible, hence output approaches zero. Concerning "sensitivity," a $+50\%$ increase in Γ resulted in a ≈ 25 to 35% reduction in predicted reservoir performance.

In closing, it should be noted that Γ equals one for all variations of the modified-Corey RPM. Consequently, all predictions of reservoir performance made utilizing this RPM were found to be insensitive to variations in the two specified (input) saturation limits.

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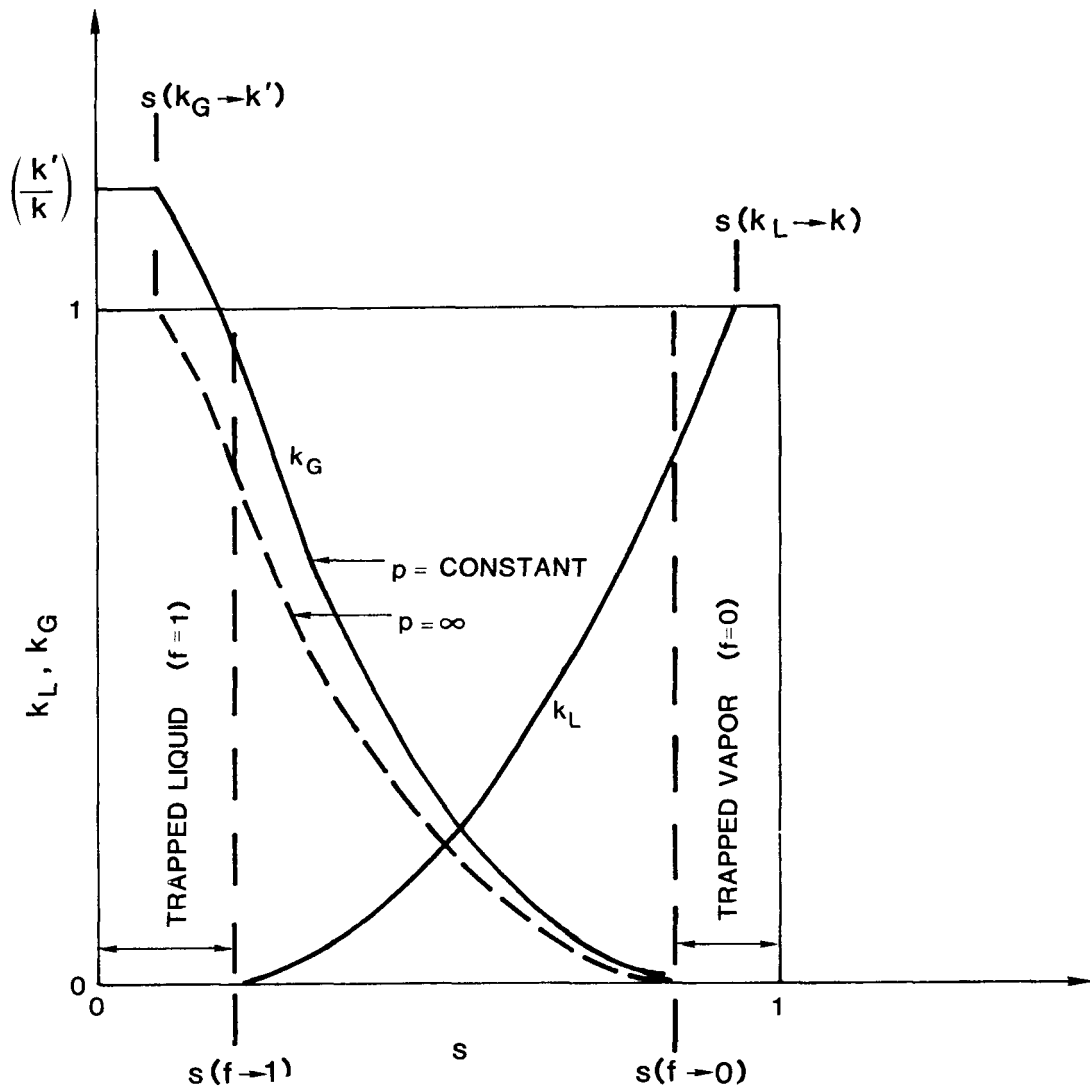


FIGURE 1

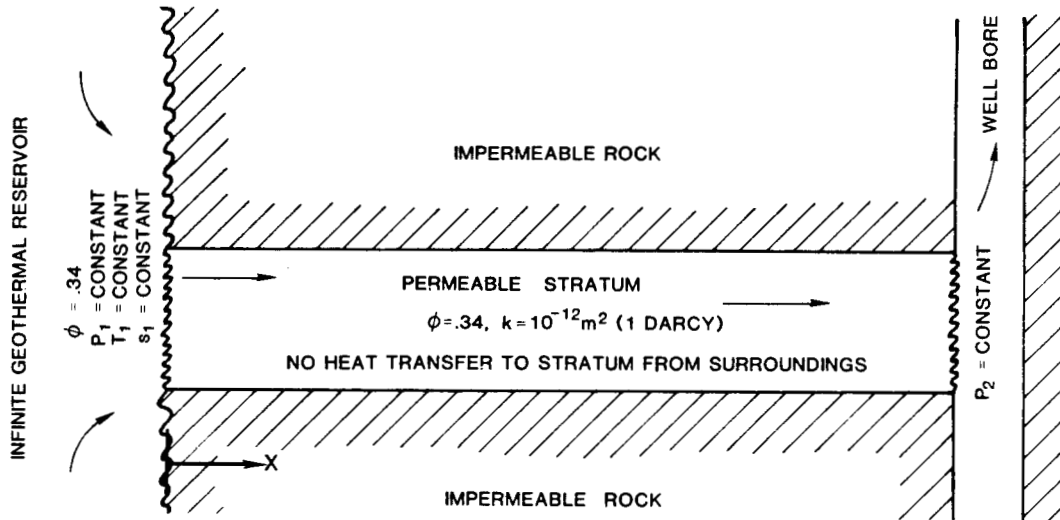


FIGURE 2

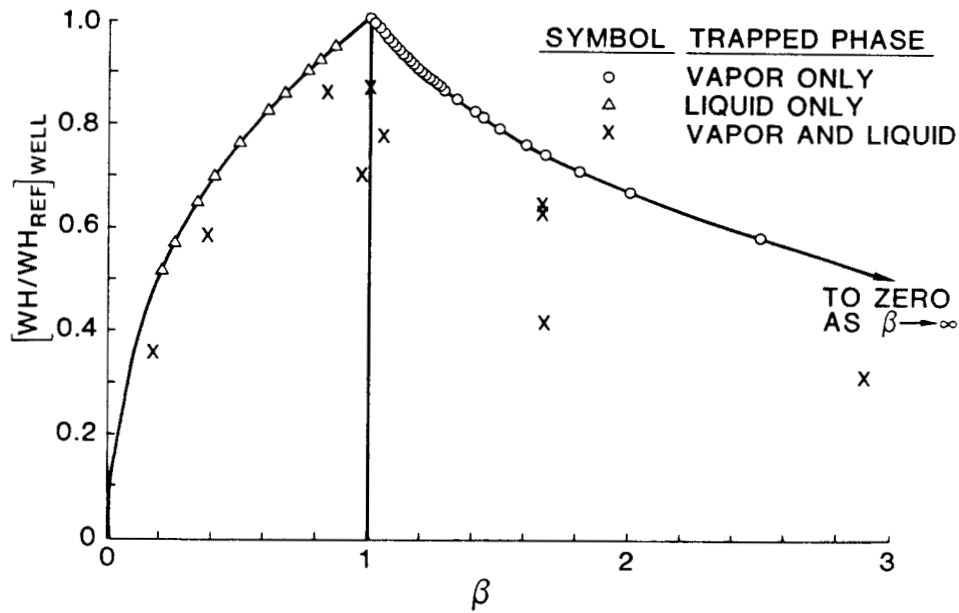


FIGURE 3

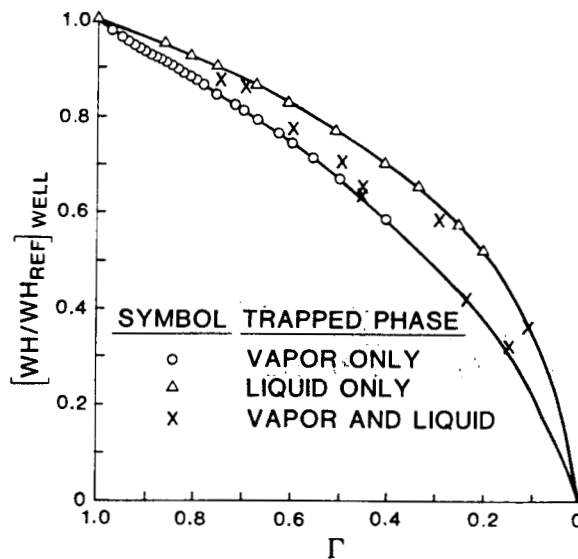


FIGURE 4

THE SENSITIVITY OF GEOTHERMAL RESERVOIR BEHAVIOR
TO RELATIVE PERMEABILITY PARAMETERS

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INTRODUCTION

In two-phase flow through a porous material, the movement of each individual phase is retarded by the presence of the other; the degree of interference depending, among other things, on the volumetric proportion of the two phases. This phenomenon is expressed mathematically by the saturation dependent relative permeability functions k_{rl} and k_{rv} , for the liquid and vapor phases respectively. Because the two phases move differentially (weighted by the relative permeability functions) the mixture behaves like a fluid with a saturation-dependent "effective" or total kinematic viscosity v_t given by:

$$\frac{1}{v_t} = \frac{k_{rl}}{v_l} + \frac{k_{rv}}{v_v} \quad [1]$$

where v_l and v_v are the kinematic viscosities of the liquid and vapor phases respectively. Similarly, the enthalpy transported by the mixture depends on the relative permeability functions and is different from the in-place enthalpy. This "flowing" enthalpy h_f is given by:

$$h_f = v_t \left[h_l \frac{k_{rl}}{v_l} + h_v \frac{k_{rv}}{v_v} \right] \quad [2]$$

where h_l and h_v are the liquid and vapor enthalpies respectively.

The movement of mass and energy in a geothermal reservoir is very strongly influenced by the magnitude of the total kinematic viscosity and the flowing enthalpy, which in turn obviously depend on the nature of the relative permeability functions (equations 1 and 2). Unfortunately the functional forms of k_{rl} and k_{rv} in terms of liquid saturation S_l are not presently known and are very difficult to deduce from laboratory experiments or field data. Various preliminary curves have been assumed and used by a number of modelers.

In the present work three problems are considered; (1) the sensitivity of v_t and h_f to variations in the relative permeability functions; (2) the determination of v_t and h_f from well-test data, following which a method of is suggested to use these results together with theoretical plots of k_{rl} and k_{rv} versus h_f to deduce the general shape of the relative permeability functions is suggested; and (3) the effect of the

relative permeability functions on the pressure decline and flowing enthalpy build-up during a constant rate production test. It is shown that the characteristic rise in the flowing enthalpy from its initial value to a stable value after a moderate time is strongly influenced by the dependence of h_f on S_1 (and hence k_{r1} and k_{rv} on S_1).

PREVIOUS WORK

Various investigators have studied the relative permeability functions. Experimental work to determine the relative permeability curves has been reported, among others, by Corey (1954), Chen et al., (1978), and Counsil and Ramey (1979). Grant (1977) and Horne and Ramey (1978) used flowrate and enthalpy data from the Wairakei geothermal field in New Zealand to obtain information about the relative permeability parameters. Numerical modeling studies of the sensitivity of reservoir behavior to relative permeability curves have been reported by Jonsson (1978), Sun and Ershaghi (1979) and Bodvarsson et al., (1980). Finally, Sorey et al., (1980) illustrated effects of the relative permeabilities on the pressure drop and enthalpy variations during production from a single well by considering relative permeability curves suggested by Corey (1954) and Grant (1977).

SENSITIVITY STUDY

Various relative permeability curves for steam and liquid water have been proposed in the literature (Corey, 1954; Chen et al., 1978; Horne and Ramey, 1978; and Counsil and Ramey, 1979). However, since the suggested curves vary widely, the choice of relative permeability curves to be used in studies of geothermal systems is rather arbitrary. Therefore at this stage it is important to determine which characteristics of the relative permeability curves are significant.

In the present study attention is mainly confined to either Corey type curves or straight line curves (see Figure 1). The most important characteristics of these curves are the "cutoffs" where steam or water becomes either fully mobile or immobile (four possible cutoffs).

We have conducted a sensitivity study to determine the relative importance of each of the cutoffs. The approach used is quite simple; for horizontal flow (no gravity) the relative permeability curves influence reservoir behavior only through the flowing enthalpy, h_f , and the total kinematic viscosity, ν_t . Therefore, by observing the effect of the individual cutoffs on these quantities, their relative importance can be determined. In this sensitivity study, five straight line functions are considered: four possible curves each having one 30% cutoff, and what we call the "X" curves, which correspond to the case without any cutoffs (broken lines in Figure 1).

Figure 2 shows the effect of the cutoffs on the flowing enthalpy. For comparison the "X" relative permeability curve is shown as the thick solid line. The figure shows that when considering flowing enthalpy, the immobile liquid cutoff is much more important than the other cutoffs.

Figure 3 shows the effect of the cutoffs on the total kinematic viscosity (v_t). Again results based on the "X" relative permeability curves are included for comparison. In this case, both of the liquid water cutoffs are considerably more important than the vapor cutoffs. However, in terms of the percentage deviation from the "X" curve (the thick solid line), the immobile liquid water cutoff is more significant than the fully mobile liquid water cutoff. The vapor cutoffs again are not very important. Similar conclusions regarding the importance of the cutoffs are obtained by Sun and Ershagi (1979), in considering the heat output from a one-dimensional system.

WELL TEST DATA

During well tests in a two-phase reservoir, the downhole pressure follows a decline curve similar to that shown in Figure 4. The exact shape of the curve varies with reservoir conditions but in general does not follow a straight line (Theis curve) because the mobility changes as the saturation changes near the well. Nevertheless, the slope at any point on the decline curve can be used to calculate the mobility at the corresponding pressure using the formula:

$$\frac{kH}{v_t} = \frac{2.303Q}{4\pi m} \quad [3]$$

(See Garg, 1978; Sorey et al., 1980; or O'Sullivan, 1980.) The flowing enthalpy of the produced fluid typically follows a curve like that shown in Figure 5, rising from an initial value to a higher stable value after a moderate time. Simultaneous measurements of pressure and flowing enthalpy thus enable the determination of v_t and h_f provided kH is known (e.g., from an injection test).

Using equations (1) and (2), k_{rv} and k_{rl} can then be calculated. By making these calculations for a number of values of flowing enthalpy (either at different times during the test or by using different production rates), plots of k_{rv} and k_{rl} versus h_f can be obtained. However, because the corresponding liquid saturation S_l is not known and cannot be measured satisfactorily, the relative permeability curves cannot be obtained in terms of the saturation.

RELATIVE PERMEABILITIES VERSUS FLOWING ENTHALPY

Although conventional relative permeability curves cannot be obtained from field data, the plots of k_{rl} and k_{rv} versus

h_f are useful. Theoretical plots of this type for the "X" curves and Corey curves (Figure 1) are shown in Figures 6 and 7.

At present the Corey relative permeability curves are most widely used in reservoir numerical modeling. The curves, illustrated in Figure 1, indicate that under two-phase conditions, where both phases are mobile, the mobility of each phase is severely retarded by the presence of the other. The sum of the individual relative permeabilities never reaches unity, except where one of the fluids is immobile. The other curves shown in Figure 1 are the "X" relative permeability curves. For these curves, the mobility of each phase is a linear function of the saturation, and no cutoffs are present. The "X" curves represent the other extreme; that is, the phases are independent of each other and their mobilities are only a function of their volume fraction. Thus these relative permeabilities represent the likely extremes of what the real relative permeability functions may be.

Figure 6 shows the flowing enthalpy as a function of the liquid relative permeability for the Corey and "X" curves. The figure shows that although the two curves have distinctly different characteristics, they enclose a relatively small zone. It is probable that $k_{rl} - h_f$ values determined from field data will fall within this zone. The vapor relative permeability, when plotted against flowing enthalpy for the Corey and the "X" relative permeability curves (Figure 7), also illustrates the basic difference between the two cases, although the curves are further apart.

The comparison of field results with the curves shown in Figures 6 and 7 should give a clear indication of whether the relative permeability curves at the geothermal field in question more closely resemble the Corey or the "X" relative permeability curves.

THE RISE IN FLOWING ENTHALPY

As explained earlier, the flowing enthalpy in a constant rate well test reaches a stable value after some time. Sorey et al., (1980) studied the rise in flowing enthalpy using an approximate analytical method and found it depended strongly on which relative permeability curves were used. We have used a semi-analytic technique developed by O'Sullivan (1980) to make a more detailed study of the effect of the relative permeability curves on the rise in the flowing enthalpy. In order to explain the main features of the results a brief outline of the basic equations is required.

Basic Equations

Using the transformation $\eta = r/t$ the mass and the energy balance equations for a two-phase system can be written as (O'Sullivan, 1980):

$$\frac{dQ_m}{d\eta} + \frac{\eta^2}{2} \frac{dA_m}{d\eta} = 0 \quad [4]$$

$$\frac{dQ_e}{d\eta} + \frac{\eta^2}{2} \frac{dA_e}{d\eta} = 0 \quad [5]$$

In equations (4) and (5), A_m and A_e are the mass and the energy accumulation terms, respectively, where

$$A_m = \phi \rho \quad [6]$$

$$A_e = (1 - \phi) \rho_r C_r T + \phi(\rho h - p) \quad [7]$$

The density (ρ) and enthalpy (h) of the fluid mixture are defined as:

$$\rho = \rho_l S_l + \rho_v S_v \quad [8]$$

$$h = (\rho_l h_l S_l + \rho_v h_v S_v) / \rho \quad [9]$$

The mass (Q_m) and the energy (Q_e) fluxes can be written (ignoring conduction) as:

$$Q_m = T_m \eta \frac{dp}{d\eta} \quad [10]$$

$$Q_e = h_f Q_m \quad [11]$$

where the mobility T_m is given by $T_m = k/v_t$. Using Q_m , p , and S_l as independent variables, equations (4), (5), (10), and (11) can be combined to yield:

$$\eta \frac{dS_l}{d\eta} = - \frac{Q_m}{T_m} \frac{Q_m \frac{dh_f}{dp} + \frac{\eta^2}{2} \left[\frac{dA_e}{dp} - h_f \frac{dA_m}{dp} \right]}{Q_m \frac{dh_f}{dS_l} + \frac{\eta^2}{2} \left[\frac{dA_e}{dS_l} - h_f \frac{dA_m}{dS_l} \right]} \quad [12]$$

Similarly, equations (4) and (5) can be combined to give:

$$Q_m \frac{dh_f}{d\eta} = - \frac{\eta^2}{2} \left[\frac{1}{\eta} \left(\frac{dA_e}{dp} - h_f \frac{dA_m}{dp} \right) \frac{Q_m}{T_m} + \left(\frac{dA_e}{dS_l} - h_f \frac{dA_m}{dS_l} \right) \frac{dS_l}{d\eta} \right] \quad [13]$$

Equations (12) and (13) will be used as a basis in the following discussion.

Numerical Studies

The phenomenon of stable enthalpy during a constant rate well test has been observed in well data from Wairakei and in numerical simulations of well tests (Sorey et al., 1980; and O'Sullivan, 1980). Analytical verification of a long-time stable flowing enthalpy can be obtained by considering equation (13) in the limit as $\eta \rightarrow 0$ (large times) which yields simply:

$$\frac{dh_f}{d\eta} = 0 \quad \text{or} \quad h_f = \text{constant} \quad [14]$$

As $\eta \rightarrow 0$ and h_f approaches its constant value, equation (12) can be approximated by:

$$\eta \frac{dS_1}{d\eta} = - \frac{Q_m}{T_m} \frac{\frac{dh_f}{dp}}{\frac{dh_f}{dS_1}} \quad [15]$$

In the above derivations, the chain rule for partial differentiation has been used in the formula:

$$\frac{dh_f}{d\eta} = \left(\frac{\partial h_f}{\partial S_1} \right)_P \frac{dS_1}{d\eta} + \left(\frac{\partial h_f}{\partial p} \right)_{S_1} \frac{dp}{d\eta} \quad [16]$$

The second term on the right hand side of equation (16) is small and therefore this equation can be used in a discrete form to approximate the rise in flowing enthalpy as follows:

$$\Delta h_f \approx \left(\frac{\partial h_f}{\partial S_1} \right)_P \Delta S_1 \quad [17]$$

The accuracy of this formula is confirmed by independent calculations. In equation (17), ΔS_1 represents the total change in saturation up to the time when a stable value of the flowing enthalpy is reached. From equation (17) the strong dependence of Δh_f on the relative permeability curves is obvious. However, the saturation change ΔS_1 , and therefore also Δh_f , is dependent upon several other factors, including initial conditions (T, S_i), porosity, mass flowrate and total kinematic mobility. The relationships between Δh_f and these parameters must be established before Δh_f can be used to investigate the shape of the relative permeability curves.

Figure 8 shows the rise in flowing enthalpy versus the initial flowing enthalpy for three initial temperatures. The curves in Figure 8 show that the rise of flowing enthalpy is

dependent upon the initial temperature and the initial saturation in the reservoir. The dependence on the initial temperature can be explained by considering equations (12) and (17).

The saturation changes given by equation (12) are more pronounced at lower temperatures (or equivalently at lower pressures), primarily due to the lower total kinematic mobility (T_m) at lower temperatures. Consequently, the flowing enthalpy changes will be larger at lower temperatures (Equation 17). The dependence of Δh_f on the initial saturation can be explained using Figure 9. For the Corey relative permeability curves, the change in flowing enthalpy is most pronounced at medium values of saturation and the rise in the flowing enthalpy is therefore largest at those initial saturation values.

The rise in flowing enthalpy also depends on the porosity ϕ and the mass flow rate Q_m . Figure 10 shows a plot similar to that in Figure 8, but a higher porosity is used in the simulation ($\phi = .25$). Sorey et al., (1980) developed curves similar to the ones shown in Figures 8 and 10 using an approximate analytical procedure. Their curves in general show a considerably smaller rise in flowing enthalpy than the curves shown in Figure 8 and 10. The difference is due to the approximations involved in deriving the analytical expressions used by Sorey et al.

The relationship between the rise in flowing enthalpy and porosity is shown in Figure 11 for an initial temperature of 250°C and several values of initial saturation. In all of the cases, the lower the porosity, the greater is the rise in flowing enthalpy. In cases of high initial liquid saturation, a linear relationship between the rise in flowing enthalpy and $(1-\phi)/\phi$ is observed for porosity values higher than $\phi = .05$. At lower initial liquid saturations non-linear effects are more pronounced. We have confirmed these results by an independent analytical study, but the limited space does not allow elaboration of this work.

The relationship between the mass flowrate and the stable flowing enthalpy is shown in Figure 12. Three curves representing different values of the initial saturation are shown, but in all three cases, the initial temperature of 250°C and a porosity of 0.05 was used. The curves representing high initial saturation ($S_i > .80$) show an approximately linear relationship between the flowrate and the stable flowing enthalpy, but at lower initial saturations ($S_i = .64$) a more non-linear behavior is observed. The near linear relationship at high initial liquid saturations can be derived analytically by considering equations (12) and (17). At high initial saturations, the derivatives dh_f/dp and dh_f/dS_1 are negligible for the Corey relative permeability curves (see Figure 8), and equation (12) can be written as:

$$\eta \frac{dS_e}{d\eta} = - \frac{Q_m \frac{dA_e}{dp} - h_f \frac{dA_m}{aP}}{T_m \frac{dA_e}{dS_1} - h_f \frac{dA_e}{dS_1}} \quad [18]$$

The terms in the numerator and denominator of equation (18) are almost constant at higher initial liquid saturations. Consequently,

$$\Delta S_i \propto \frac{Q_m}{T_m} \quad [19]$$

and from equation (17),

$$\Delta h_f \propto \frac{Q_m}{T_m} \quad [20]$$

The slight non-linear effects in the high initial saturation curves shown in Figure 11 are probably due to the fact that T_m decreases slightly with pressure and saturation.

Sorey et al. (1980) observed a near linear relationship between the flowing enthalpy and flowrate from wells in Wairakei, New Zealand. Their use of linear plots, such as the one shown in Figure 11, to obtain the initial reservoir enthalpy for the wells in New Zealand is well justified. However, in the case of a low initial saturation, linear approximations may be somewhat in error.

In light of the preceeding discussion it is clear that the rise in flowing enthalpy is complicated by various factors such as the porosity, flowrate, and the initial conditions. However if all of these factors are known, the change in saturation may be approximated and the slope of the h_f versus S_1 curves (dh_f/dS_1) determined (equation 17). This in turn will yield information regarding the relative permeability parameters.

Calculations have been carried out for several different relative permeability curves. For example, Corey curves and linear curves which produce the same flowing enthalpy but a different gradient for dh_f/dS_1 at a particular initial saturation have been investigated. Work on the problem is continuing.

CONCLUSIONS

The primary results obtained in this study are as follows:

- 1) The liquid cutoffs are the most important characteristics of the relative permeability curves
- 2) The relative permeability parameters can be determined from field data in terms of the flowing enthalpy, and

compared to theoretical curves (e.g., Corey and "X" curves)

- 3) The rise in flowing enthalpy can give information regarding the relative permeability curves providing parameters such as kH and ϕ are known (e.g., from injection and interference tests).

NOMENCLATURE

C_r = specific heat of rock
 h = enthalpy
 h_f = flowing enthalpy
 h_l = enthalpy of saturated liquid
 h_v = enthalpy of saturated vapor
 H = reservoir thickness
 k = permeability
 k_{rl} = relative permeability of liquid phase
 k_{rv} = relative permeability of vapor phase
 K_m = thermal conductivity
 m = slope of semi-log pressure response
 P = pressure
 Q_m = mass flowrate per unit thickness
 r = radial distance
 S_l = liquid saturation
 S_v = vapor saturation
 S_{re} = residual liquid saturation
 S_{rv} = residual vapor saturation
 t = time
 T = temperature
 ϕ = porosity
 ρ = density of vapor liquid mixture
 ρ_l = liquid density
 ρ_r = rock density (kg/m^3)
 ρ_v = vapor density
 ν_e = kinematic viscosity of liquid water
 ν_t = total kinematic viscosity
 ν_v = kinematic viscosity of vapor

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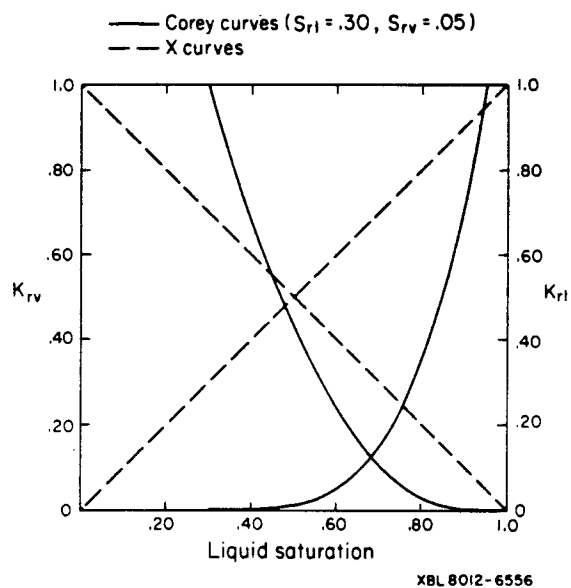


FIGURE 1. The Corey and the "X" relative permeability curves.

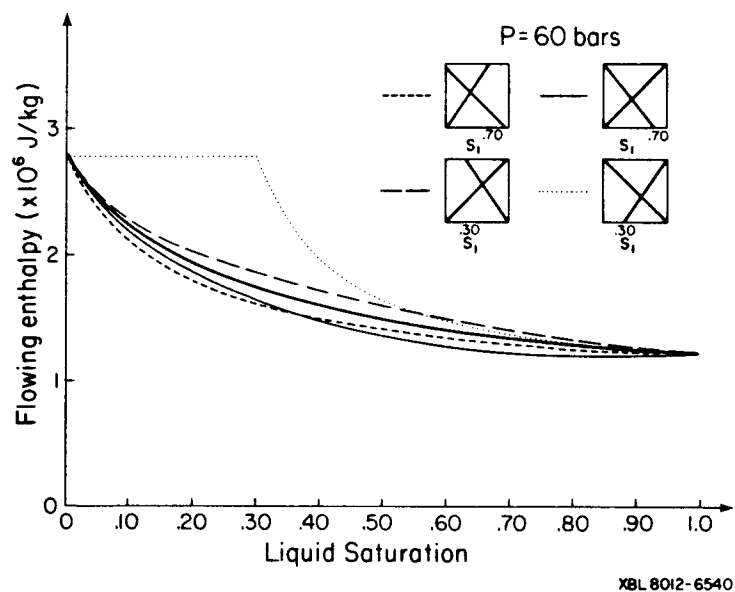


FIGURE 2. The relationship between flowing enthalpy and liquid saturation for linear relative permeability curves.

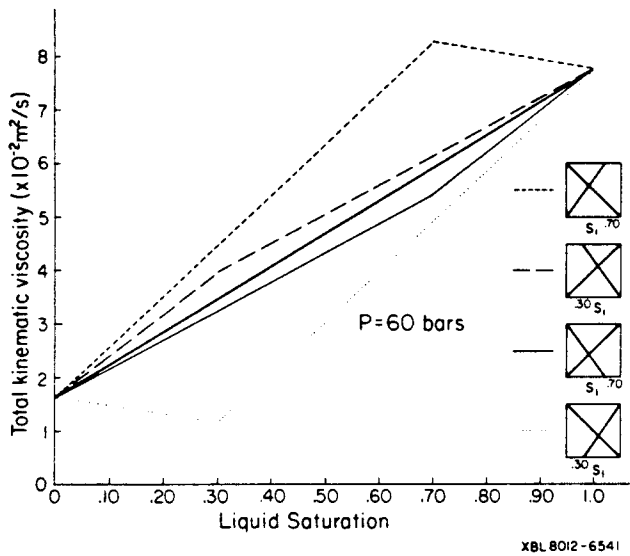


FIGURE 3. The relationship between kinematic viscosity and liquid saturation for linear relative permeability curves.

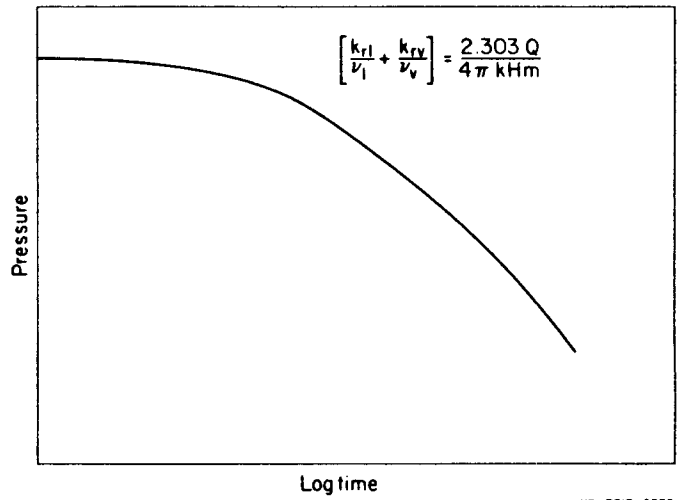


FIGURE 4. Pressure transient behavior during a well test in a two-phase reservoir.

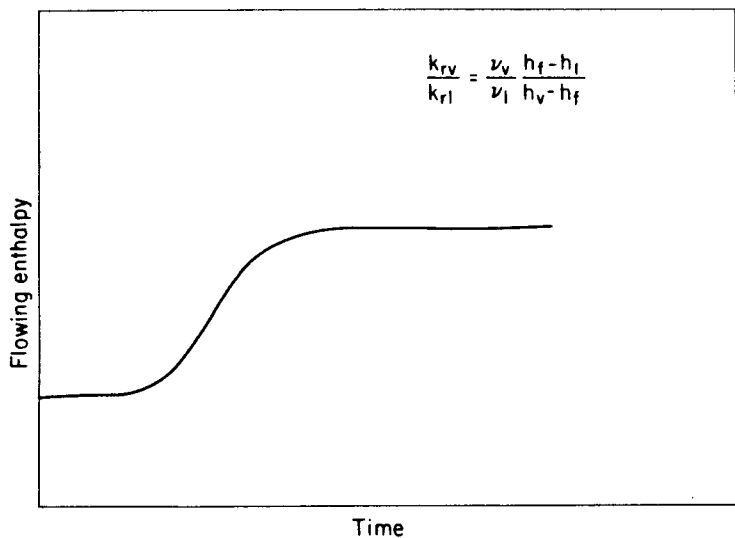


FIGURE 5. Flowing enthalpy during a well test in a two-phase reservoir.

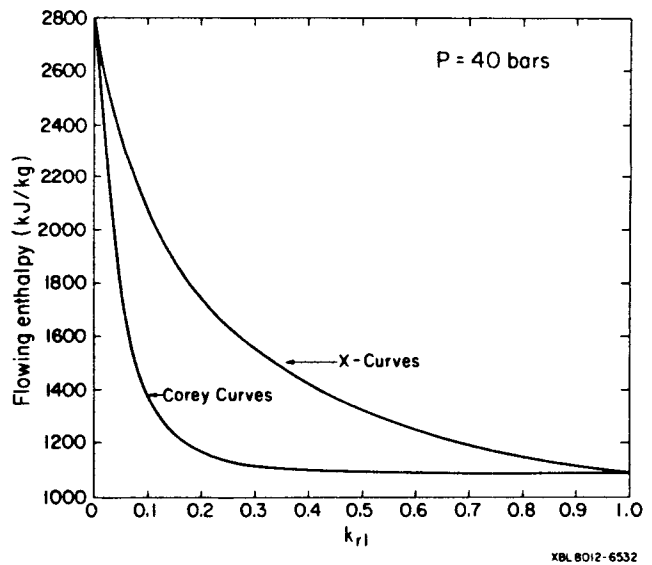


FIGURE 6. The relationship between flowing enthalpy and liquid relative permeability for Corey and "X" relative permeability curves.

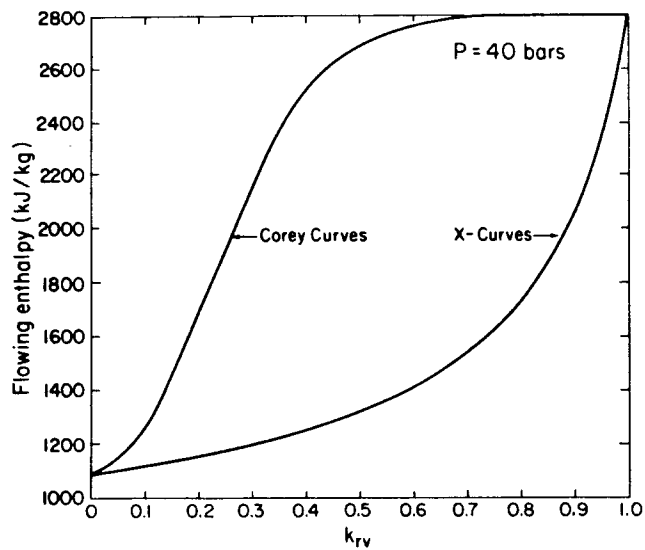


FIGURE 7. The relationship between flowing enthalpy and vapor relative permeability for Corey and "X" relative permeability curves.

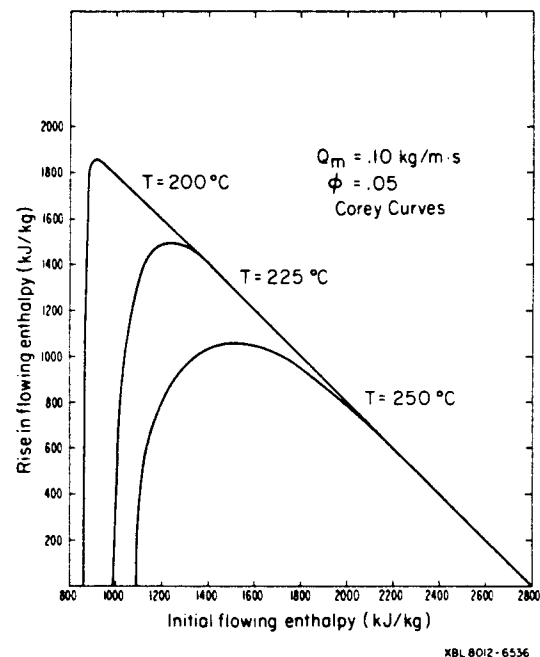


FIGURE 8. The relationship between the rise in flowing enthalpy and the initial flowing enthalpy for a porosity of $\phi = .05$.

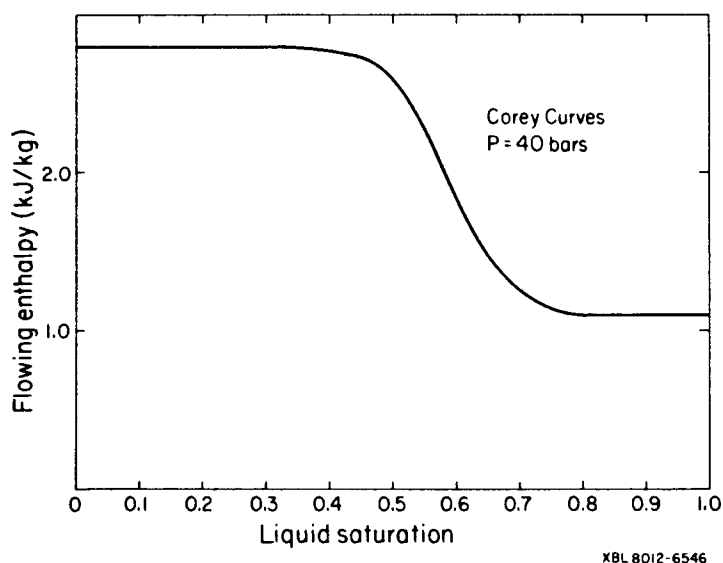


FIGURE 9. The relationship between flowing enthalpy and liquid saturation for the Corey relative permeability curves.

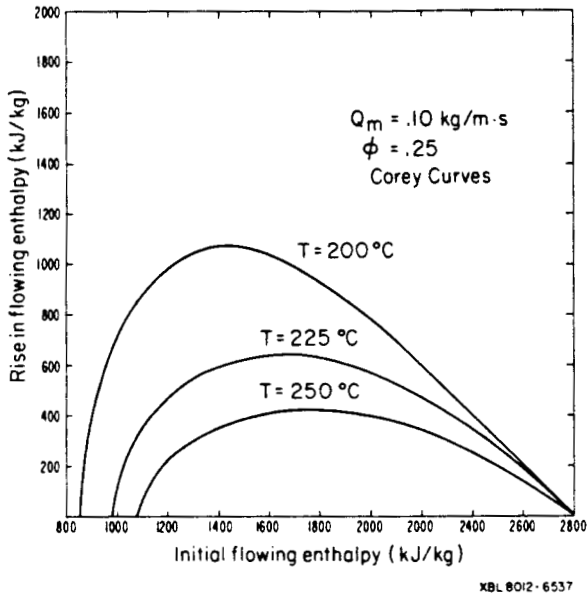


FIGURE 10. The relationship between the rise in flowing enthalpy and the initial flowing enthalpy for a porosity of $\phi = .25$.

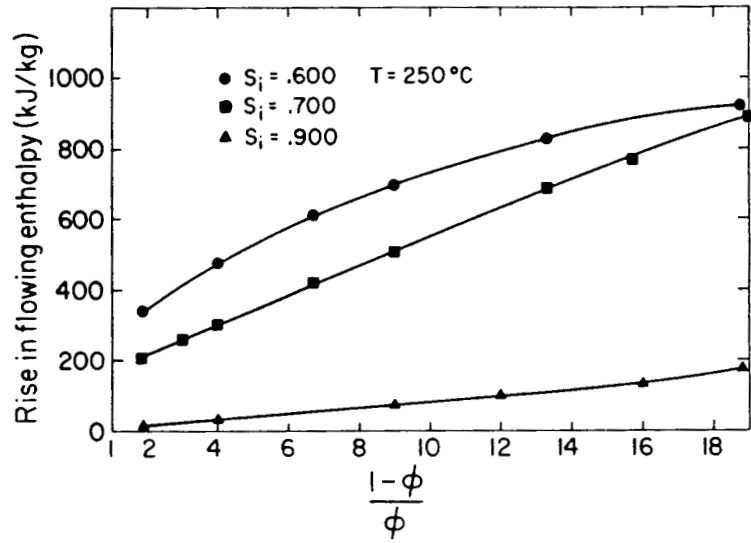


FIGURE 11. The relationship between porosity and the rise in flowing enthalpy.

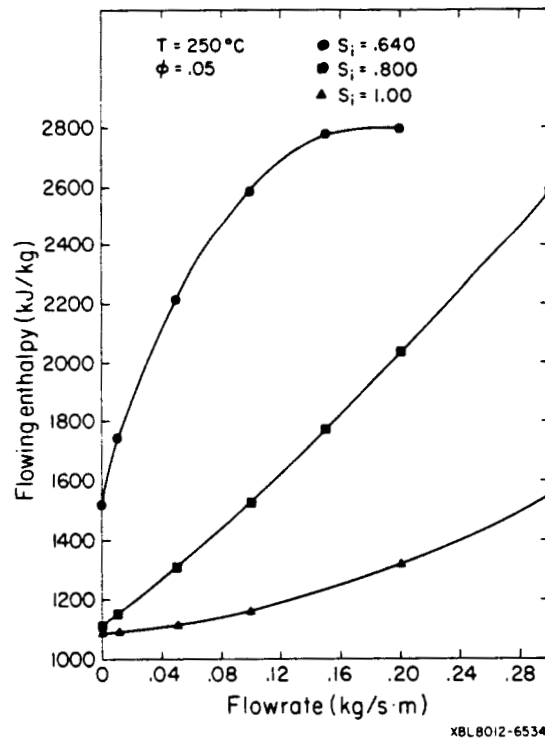


FIGURE 12. The relationship between flowrate and the rise in flowing enthalpy.

MODELLING FROM A USER'S POINT-OF-VIEW

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Introduction

In the context of this paper the 'user' includes all those involved in the management of a geothermal resource. The objective of reservoir modelling and simulation, in my view, should be to supply these 'users' with appropriate and reliable data so that they can make sound decisions, whether these be in financial or engineering fields. The scale of models would thus extend from a single well, which may require a workover to remove mineral deposition costing, say, \$30,000, to a full geothermal field development, costing more than \$100 million.

Geothermal development work can involve high risks. With the aid of modelling it should be possible to quantify risks, and, if these are considered excessive, to identify what data should be obtained to reduce them. Schemes relying on a single well are particularly hazardous. In 1974 an alfalfa drying plant was built at Broadlands next to well BR7. This well had previously been flow tested for three years, showing very reliable discharge characteristics. But when opened to supply the drying plant, the well did not perform satisfactorily and a 350 m pipeline was built to supply steam from another nearby productive well. All geothermal developments involve drilling and this, also, is a risky business. In New Zealand, over the last six years, the time to drill a 1200-1400 m investigation well shows variations of $\pm 40\%$ about the average (using the same rig and equipment). The time for workovers is even more variable, due to unforeseen downhole conditions affecting progress - an overrun of 100% would not be unexpected.

What information does the user want? Basic data will be the power-life and likely discharge characteristics of a field given certain operating conditions. For example, if we have a liquid dominated field, the design engineers will require information about changing enthalpy, gas and total flow for the system as a whole and for each individual well. There is no point in fitting a well with equipment to handle 100 t/h of separated steam if, after three years' production, it will only produce 50 t/h. Those providing finance for a scheme will require an assurance of its viability. How many years can the field sustain the projected withdrawal rate? For a well repair operation, those providing funds will want to know the chances of success and how much steam the well

might produce if the operation succeeds. These factors must be balanced against the estimated cost of the operation, which itself relies on the problem having been properly identified in the first place. In a field which has been operating for some years, the question arises: What do we do now? Do we increase production, or do nothing, or maybe manage the field by operating only selected wells. Whatever the choice, predictions of future field and well performance are required to allow the field operator to evaluate the economics of alternative schemes.

Input Data

Reliable and accurate input data are an essential part of any useful model. Problems with input data arise in three areas. Firstly, the accuracy of the raw data, and secondly, the interpretation of this data. Raw data should always be treated with considerable scepticism. Data collection-processing systems have several possible sources of error; instrument calibration, measurement procedure and data processing to name a few. Where records have been collected over a long time period, accuracy will change as different equipment, techniques and personnel become involved.

Only in exceptional circumstances are fluid conditions inside a geothermal well and in the formation outside the well in equilibrium throughout the depth of hole exposed to formation. In most wells, there are internal circulation and interzonal flow effects. The raw data must first be interpreted to tell us what is happening inside the well, then we can extend this interpretation to obtain information about the reservoir outside the well. At this stage, we must ask ourselves: Can we make any other sensible interpretation? Is the interpretation influenced by basic assumptions and does it make sense?

The third and, possibly, the most important problem area with model input is the possibility that highly significant data may be missing - either undiscovered or ignored. For example, the importance of cool inflows originating above the geothermal reservoir at Wairakei was not recognised until very recently. Measured downflows in two wells total 100 l/s, compared with total withdrawal rate of 1500 l/s. At least three other wells have comparable downflows and an unknown amount may enter the reservoir from above via natural faults and fissures.

Wairakei

During the history of investigation and production at Wairakei an enormous quantity of data has been collected and hundreds of papers written, not a few on modelling and reservoir simulation. From the field user's point-of-view, much of this work has been interesting, but of no practical value. On the total-field scale only one simulation, by Wainwright¹, has been successful in itself as a management tool. This was written in 1969 when the field had been operating for ten years and further expenditure was being considered to increase system efficiency.

The simulation used the previous six years' production data to predict steam and water flows for the following 10-15 years. Several methods were tried and the most satisfactory was found to be one in which the performance of the reservoir was projected, then the outputs of the wells calculated for these future conditions. This method can only predict well outputs if there is no major change in fluid withdrawal rate, however it does face the problem that without a prediction of future steam flow rates in some detail, no engineering progress can be made. This simulation was complicated by the fact that the high pressure wells were to be slowly derated (to increase output) in order that power station turbines would remain fully loaded. The simulation has been remarkably accurate. In 1978 the high pressure steam flow was 8% below predicted values, and intermediate pressure steam flow was marginally in excess of the prediction. The predicted steam flows were then used in a further report to assure the engineering and financial viability of this proposed 'optimisation' scheme.² Construction of the scheme was completed in 1974 and power station output was increased 11% to 162 MW(e) with no change in mass withdrawal rate from the reservoir.

Ten years after Wainwright's prediction, power station output continues to fall and again the question is: What do we do now? Many options are open. Reinjection of waste water is being considered, we could drill extra production wells or as a longer term tool we could manipulate the overall field discharge enthalpy - by shutting high enthalpy or 'dry' steam producers.

All three of the above options are presently being considered. In detailed examination of the Wairakei field, Hitchcock³ came to the conclusion that continuing rundown in output of the power station was mainly due to excess heat withdrawal from the reservoir via the high enthalpy and 'dry' steam wells. If output was to be maintained, these wells

should be shut and their contribution made up from new wells producing from the liquid levels of the reservoir. Reinjection testing at Wairakei is currently in progress. Grant has shown that provided there is no rapid return of cool injected fluid to the production wells, reinjection into the liquid reservoir should have a rapid and beneficial effect on wells producing from this level.

Broadlands

Since the first successful well was drilled at Broadlands more than \$20 million worth of usable energy (at 1c/kWh) has been used while testing the field. Most of this energy was extracted during a three year field discharge at an average rate of 60 MW(e) equivalent. This has allowed much detailed work to be done on modelling of the behaviour of the western half of the field⁵. These, and other simulations have established optimum withdrawal rates versus lifetime for this part of the field, for a no reinjection condition, but our design engineers and financiers require much more detail. Can they be assured that reinjection is viable? What are the injection well flow characteristics now, and how will they change with time? How will production well characteristics change (in detail) over the first 3-4 years of field operation?

Conclusion

These questions cannot be answered directly by modelling. However, well presented conceptual models can be used, together with the best available information to make reliable engineering decisions. Extra assurance can be built into a scheme by having a flexible design, so that, in the event of unforeseen changes, a fallback position is available without changing the overall scheme viability. The effectiveness of this approach will depend on the skill and experience, and a mutual interchange of the information among all those involved in management decisions (i.e. financiers, design engineers, reservoir engineers, modellers etc.).

One of the prime reasons for the success of the Wairakei project was the direct, on-site involvement of a small group of very competent and resourceful engineers, who followed the project through from initial investigations, to planning, construction and later operation. All understood the problems peculiar to geothermal engineering and, as a result of this, their teamwork and down-to-earth approach, there have been few major problems with the project.

For new developments today, modelling can make a useful contribution, but much detailed engineering information must still be supplied by experience and intuition. To be effective the modeller should be part of a management team which must maintain a close and continuing liaison with those involved in investigation and design. From the user's point-of-view, the ultimate tests for any model are: Does it make sense? Does it 'feel' right? and What can I do with it?

Acknowledgement

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BOILING HEAT TRANSFER FROM A DIKE

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Introduction

It is known that hot dike complexes are one type of heat sources in a volcanic geothermal reservoir. To extract energy from a geothermal reservoir, it is important to know the cooling rate of the intrusives by groundwater. With a maximum temperature of 1,200°C, the intrusives are most likely to be cooled by film boiling during the initial stages and by single-phase convection during the later stages when its temperature becomes lower than the saturated temperature corresponding to the pressure. At the Second Workshop on Geothermal Reservoir Engineering, Cheng [1] has reported that the cooling rate of a dike by free convection of single-phase groundwater can be computed according to

$$q_w = 0.444(T_w - T_\infty)^{3/2} \sqrt{\frac{k_m K \beta g C_p}{\nu x}}, \quad (1)$$

$$\bar{q}_w = 0.888(T_w - T_\infty)^{3/2} \sqrt{\frac{k_m K \beta g C_p}{\nu L}}, \quad (2)$$

and the thickness of the hot water zone is

$$\delta = 6.31 \sqrt{\frac{\mu \alpha x}{K \rho_\infty \beta g (T_w - T_\infty)}}, \quad (3)$$

where g is the gravitational acceleration; q_w and $\bar{q}_w$ are the local and the average surface heat flux; T_w and T_∞ are the temperatures of the groundwater at the surface and at a great distance from the surface; K , k_m and α are the permeability, the equivalent thermal conductivity, and thermal diffusivity of the formation; c_p , β , and ν are the specific heat, the thermal expansion coefficient, and the kinematic viscosity of the groundwater; L and x are the height of the dike and the locality on the dike measured from the bottom; ρ_∞ is the density of the groundwater at infinity.

Recently, we have obtained an analytical solution for boiling heat transfer from a vertical isothermal surface in a porous medium filled with a subcooled liquid [2,3]. In this paper we shall briefly summarize the results obtained, and carry out numerical computations of boiling heat transfer from a dike.

Film Boiling from a Vertical Plate in a Porous Medium

Consider the problem of steady cooling of an isothermal vertical surface embedded in a porous medium filled with a subcooled liquid as shown in Fig. 1. When the wall temperature T_w is sufficiently higher than the saturation temperature T_s (corresponding to its

pressure), a vapor film with thickness δ_v will form adjacent to the vertical surface. To investigate the heat transfer characteristics of this problem, Cheng and his co-worker [2,3] have made the following assumptions: (1) A distinct boundary exists between the vapor and the subcooled liquid with no mixed zone in between. (2) The interface at $y = \delta_v$ is smooth and stable, and is at a constant temperature T_s . (3) Boundary layer approximations are applicable. (4) Bousinesq approximations are invoked in the liquid phase so that density is assumed to be constant except in the buoyancy force term where density is assumed to be linearly proportional to temperature. (5) All other properties of the liquid and vapor phases and the porous medium are constant. (6) Darcy's law is applicable to both phases. It is worth noting that assumptions (1)-(5) are the usual approximations used in the classical film boiling literature. Note that as a result of the first approximation, the mathematical formulation of the problem is considerably simplified. This is because the complexity of the relative permeability no longer comes into the picture and that single-phase equations can be applied separately to the vapor and liquid phases. As a result, both the vapor and the liquid phases admit similarity solutions in terms of the dimensionless boundary layer thickness parameter $\eta_{v\delta}$ which is defined as $\eta_{v\delta} = \sqrt{Ra_{x,v}} \delta_v/x$. This parameter is an implicit function of three other dimensionless parameters: Sh , Sc , and R , where $Sh = c_{pv}(T_w - T_s)/h_{fg}$, $Sc = c_{pL}(T_s - T_\infty)/h_{fg}$,

$$R = \frac{\rho_v}{\rho_\infty} \left[\frac{\mu_L \alpha_v (\rho_\infty - \rho_v) c_{pL}}{\mu_v \alpha_L \rho_\infty \beta_L h_{fg}} \right]^{1/2}, \quad c_{pL} = k_{mL}/\rho_\infty \alpha_L \quad \text{and} \quad c_{pv} = k_{mv}/\rho_\infty \alpha_v$$

with the subscript "v" denoting quantities associated with the vapor phase while the subscript "L" denoting quantities associated with the liquid phase. The functional relationship between $\eta_{v\delta}$, Sh (a measure of degree of wall superheating), Sc (a measure of the extent of the subcooling of the surrounding fluid), and R (a property ratio) is illustrated in Fig. 2.

The local and average boiling heat transfer rates from a heated surface in a geothermal reservoir can be shown to be

$$q_w = \frac{(T_w - T_s)}{\text{erf}(\frac{\eta_{v\delta}}{2})} \sqrt{\frac{k_{mv} K (\rho_L - \rho_v) g c_{pv}}{\pi \nu_v x}}, \quad (4)$$

$$\bar{q}_w = \frac{2(T_w - T_s)}{\text{erf}(\frac{\eta_{v\delta}}{2})} \sqrt{\frac{k_{mv} K (\rho_L - \rho_v) g c_{pv}}{\pi \nu_v L}}. \quad (5)$$

Equations (4) and (5) can be rewritten in dimensionless form as

$$\frac{Nu_x}{\sqrt{Ra_{x,v}}} = \frac{1}{\sqrt{\pi} \text{erf}(\frac{\eta_{v\delta}}{2})}, \quad (6)$$

$$\frac{\bar{Nu}}{\sqrt{Ra}} = \frac{2}{\sqrt{\pi} \text{erf}(\frac{\eta_{v\delta}}{2})}, \quad (7)$$

where Nu_x and $\bar{Nu}$ are the local and average Nusselt numbers while $Ra_{x,v}$ and Ra are the Rayleigh numbers based on x and L respectively, i.e.,

$$Nu_x \equiv \frac{q_w x}{k_{m,v}(T_w - T_s)}, \quad \bar{Nu} \equiv \frac{\bar{q}_w L}{k_{m,v}(T_w - T_s)} \quad (8a,b)$$

and

$$Ra_{x,v} \equiv \frac{K(\rho_L - \rho_v)gx}{\mu_v \alpha_v}, \quad Ra \equiv \frac{K(\rho_L - \rho_v)gL}{\mu_v \alpha_v} \quad (9a,b)$$

It is convenient to multiply Eq. (6) by $\eta_{v\delta}$ and plot the quantity $Nu_x \eta_{v\delta} / \sqrt{Ra_{x,v}}$ versus $\eta_{v\delta}$ which is presented in Fig. 3. On the other hand, the quantity $Nu_x / (Ra_{x,v})$ versus Sh at $R = 0.5$ and with different values of Sc is presented in Fig. 4.

Application to Heat Transfer from a Dike

Consider a dike 100 m in height with an average surface temperature of 400°C is intruded into an aquifer (with $K = 10^{-12} \text{m}^2$, $k_{m,L} = 2.65 \text{ J/sec-K}$, and $k_{m,v} = 1.6 \text{ J/sec-K}$) at a temperature of 20°C . Suppose that the mean static pressure along the dike is at 10 atmospheric pressure and the saturated temperature corresponding to this mean pressure is 180°C . To apply the theory to this problem, we shall evaluate the properties of the vapor and liquid layers at their mean temperatures. Thus, the density, viscosity, and specific heat of vapor will be evaluated at the mean temperature of $(T_w + T_s)/2 = 290^\circ\text{C}$ while that of the liquid phase at $(T_s + T_\infty)/2 = 100^\circ\text{C}$. At these temperatures, we found that $\rho_v = 0.004 \text{ g/cc}$, $c_{pv} = 2.16 \text{ J/g-K}$, $\mu_v = 1.96 \times 10^{-4} \text{ g/cm-sec}$; $c_{pL} = 4.22 \text{ J/g-K}$, $\mu_L = 2.74 \times 10^{-3} \text{ g/cm-sec}$, $\rho_\infty = 0.9574 \text{ g/cc}$ and $\beta_{L\infty} = 4.67 \times 10^{-4}/\text{C}$, $h_{fg} = 2019 \text{ J/g}$. With these values, we obtain $Sh = 0.2364$, $Sc = 0.3323$, and $R = 0.565$, and consequently we can determine $\eta_{v\delta}$ from Fig. 2 to get $\eta_{v\delta} = 0.49$. With this value of $\eta_{v\delta}$ we obtain $Nu_x = 33.3$ at $x = 100 \text{ m}$ where $Ra_{x,v} = 258$ and $Ra_{x,L} = 425$. The vapor film boundary layer thickness can be determined from the definition of $\eta_{v\delta}$ which gives $\delta_v = 0.49x / \sqrt{Ra_{x,v}}$ and the vapor boundary layer thickness is given by $\delta_L = \frac{5x}{\sqrt{Ra_{x,L}}}$. This is plotted in Fig. 5 where it is shown that $\delta_v = 3 \text{ m}$

and $\delta_L = 24.3 \text{ m}$ at $x = 100 \text{ m}$. The vertical velocity profiles for the vapor and the liquid phases at $x = 100 \text{ m}$ are plotted in Fig. 6. It is shown that there is a velocity discontinuity at the vapor-liquid interface which is a consequence of the Darcy's law. The vertical velocity in the vapor phase is shown to be much higher than that in the liquid phase because buoyancy force is larger and viscosity is lower for vapor.

Concluding Remarks

The validity of the present theory depends critically on the assumptions of (1) the non-existence of a two-phase zone in the boundary layer, and (2) the vapor-liquid interface being stable and smooth. For the classical film boiling problems, the first assumption has been widely accepted while the second assumption is more difficult to be met in reality since bubbles near the interface may be formed (resulting in a

wavy shape) or detached (resulting in an unsteady behavior). These assumptions are certainly plausible for the corresponding problems in a porous medium. Its accuracy, however, can only be determined by future experiments.

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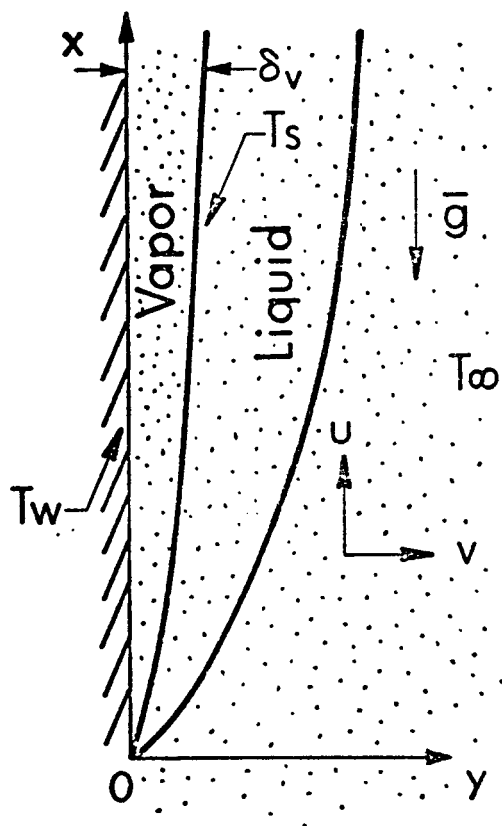


Fig. 1 Coordinate System

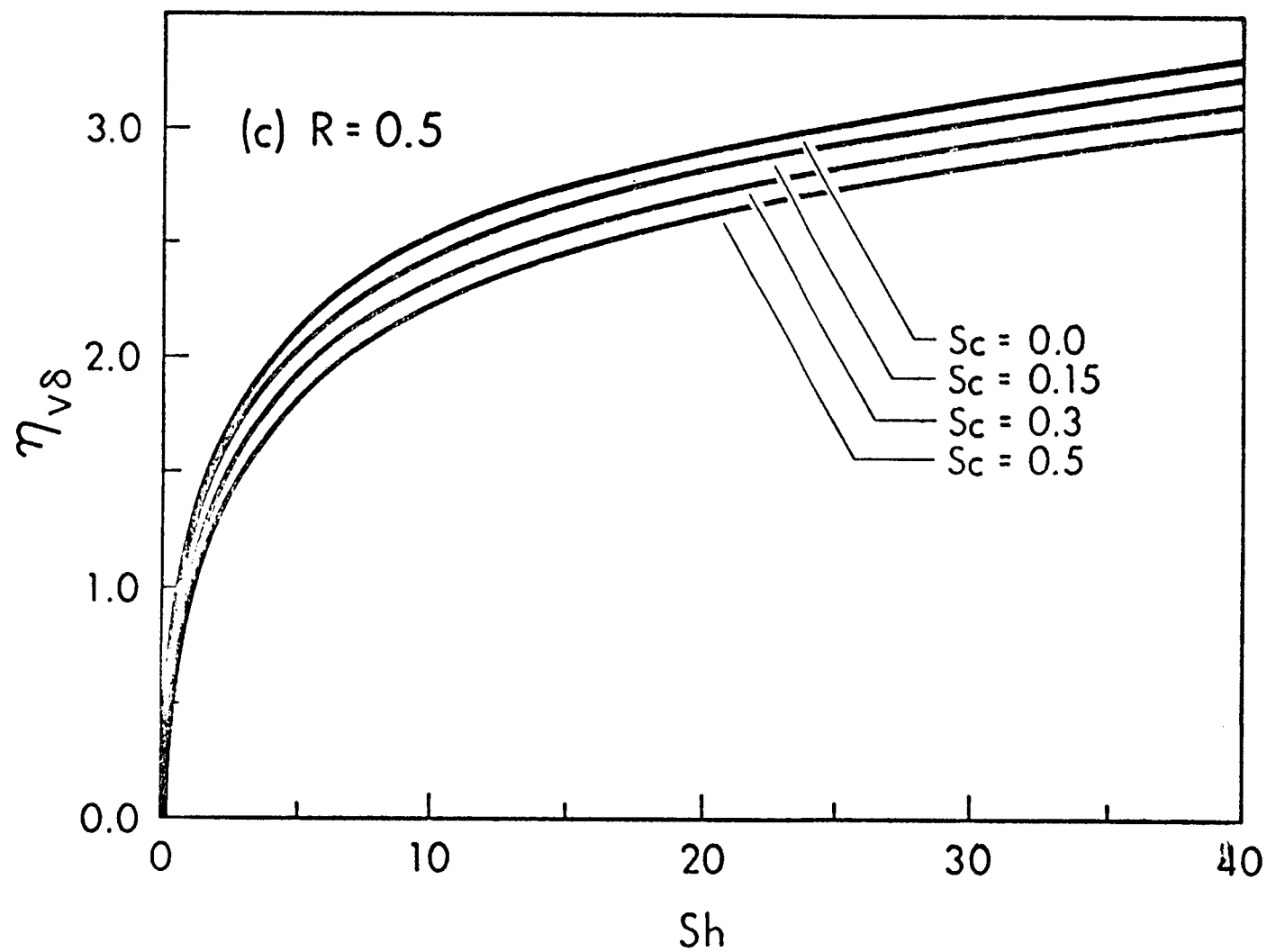


Fig. 2 $\eta_{v\delta}$ versus Sh and Sc at $R = 0.5$

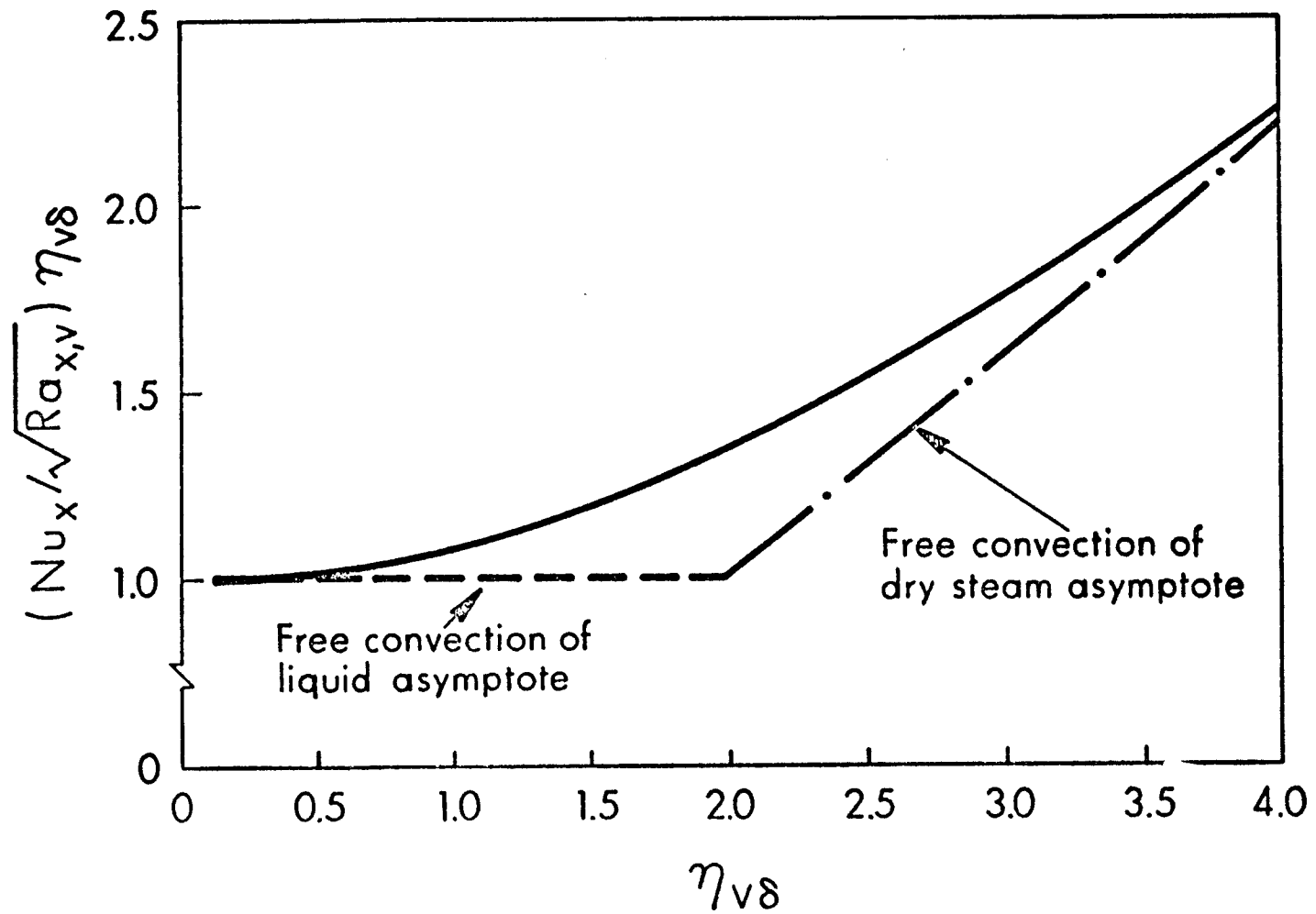


Fig. 3 Heat Transfer Rate versus $\eta_{v\delta}$

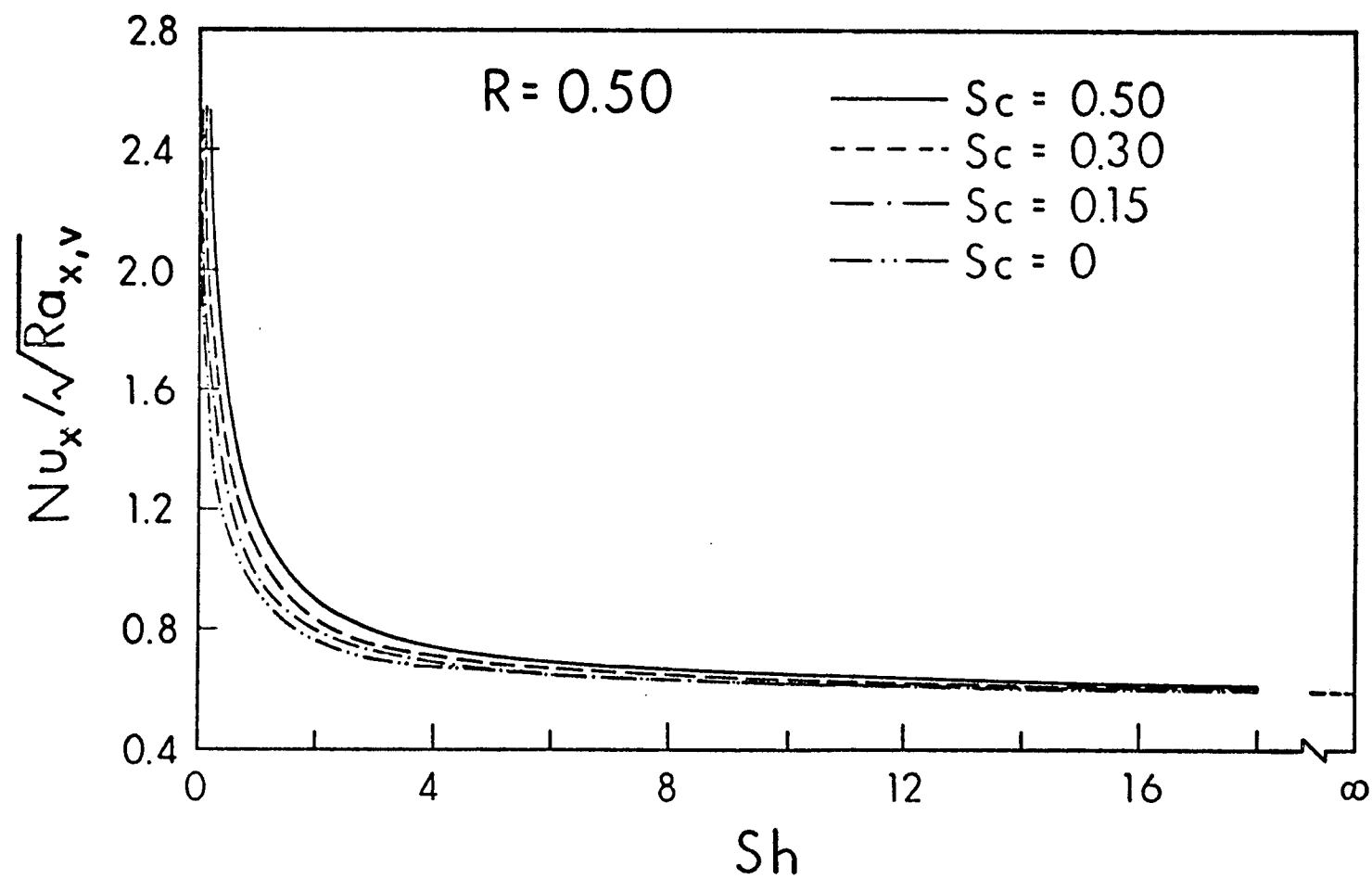


Fig. 4 Heat Transfer Rate versus Sh at Selected Values of Sc and at $R = 0.5$

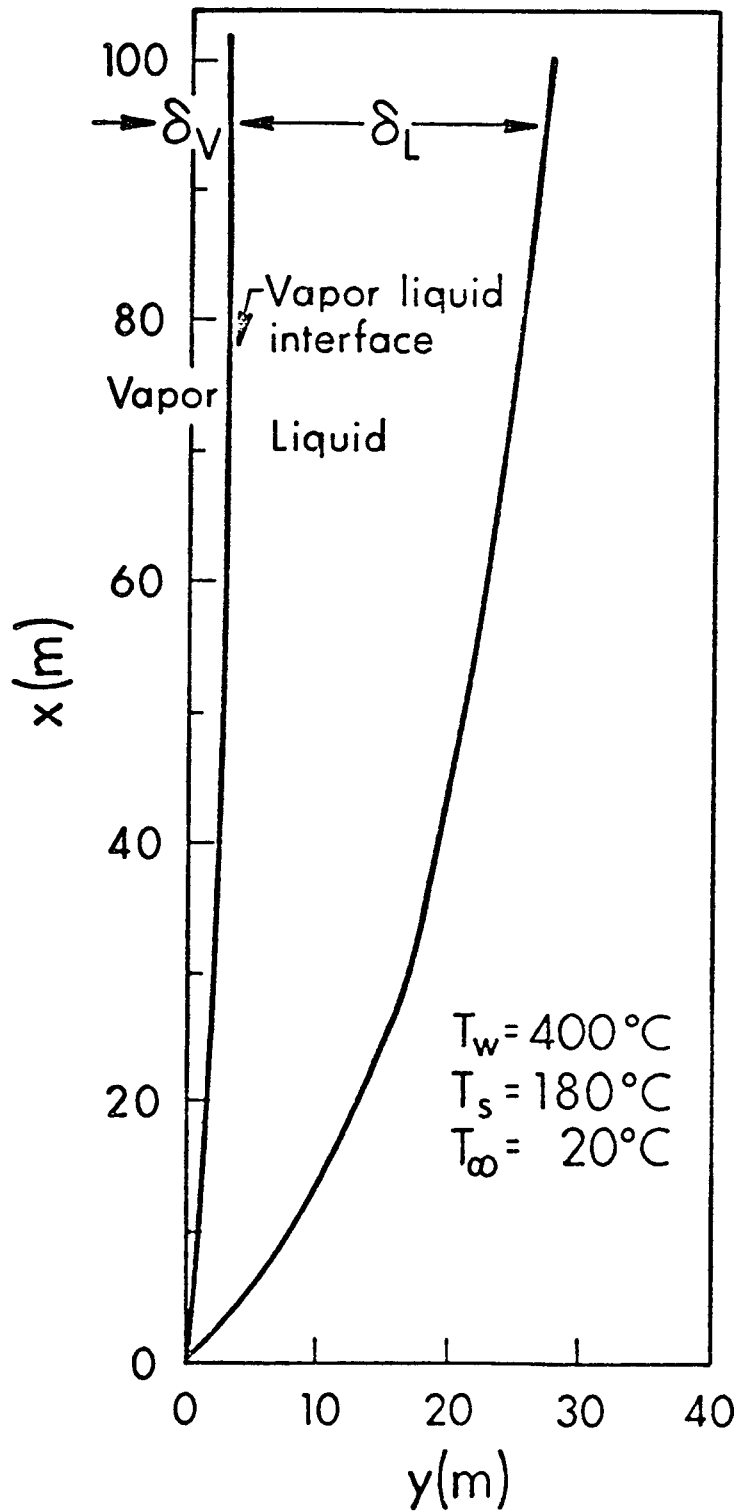


Fig. 5 Size of the Vapor Film and the Hot Water Zone

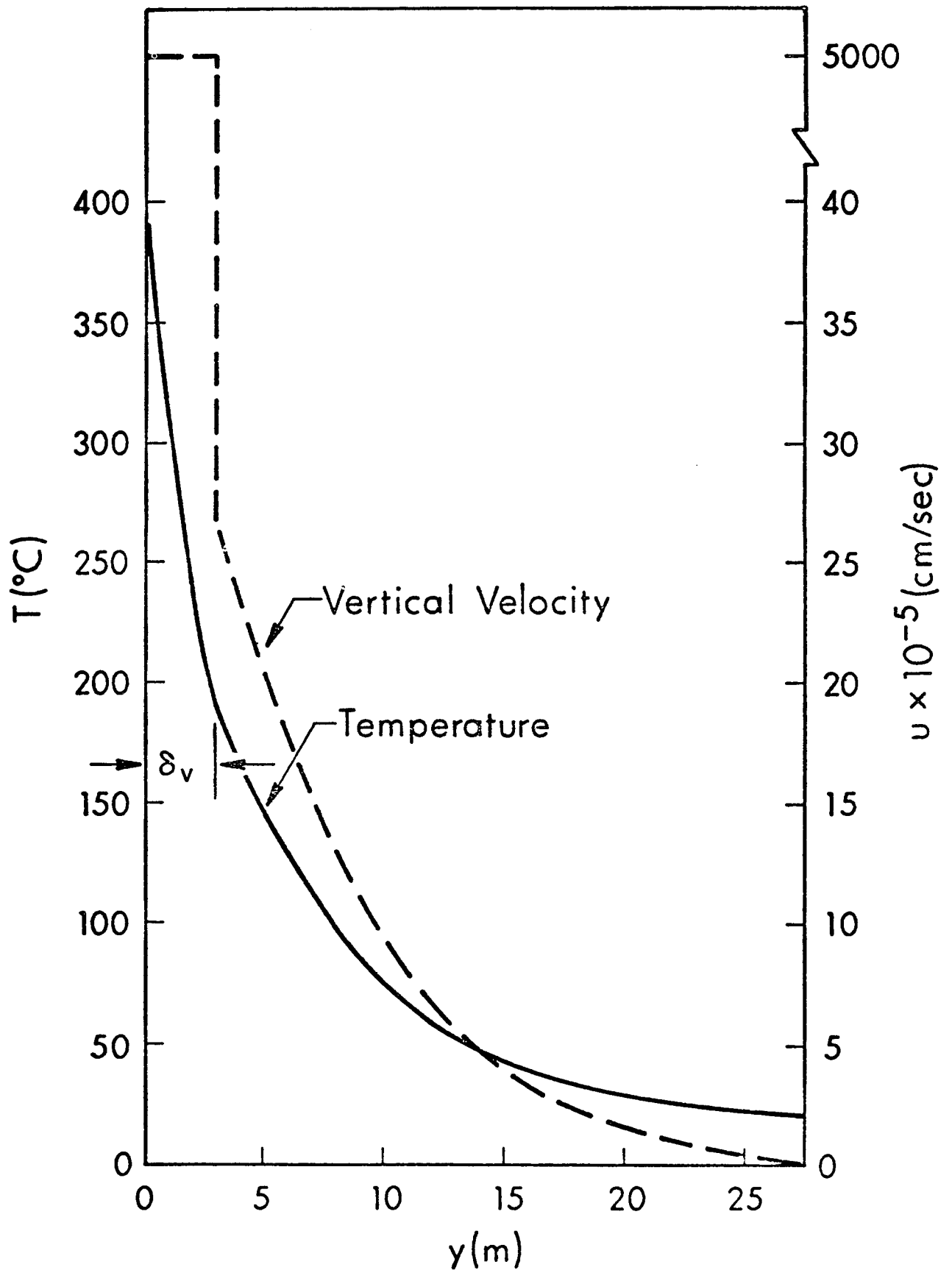


Fig. 6 Temperature and Vertical Velocity Profiles Around a Dike at $x = 100$ m

NUMERICAL CODE COMPARISON PROJECT-
A NECESSARY STEP TOWARDS CONFIDENCE IN GEOTHERMAL
RESERVOIR SIMULATORS

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Numerous computer codes capable of solving the general geothermal reservoir engineering problem involving multiphase flow of fluid and heat have been developed over the past several years. At the present time, the validity of results obtained using these simulators to model the performance and predict the response of real geothermal systems is the subject of concern both to those involved in developing and managing geothermal resources and to those involved with financing such enterprises. Do these codes accurately simulate the physical processes believed to be important? Can simulator users develop realistic conceptual models and appropriate values of input parameters to insure that numerical models of particular reservoirs yield valid results?

Experience gained in several attempts to model the Wairakei geothermal reservoir in New Zealand (Mercer and Faust 1979; Garg, Rice, and Pritchett, 1979) demonstrates that problems involved in applying these codes to real systems are significant (Sorey and Fradkin, 1979; Donaldson and Sorey, 1979), and that results obtained from various models can be quite different. A necessary first step in resolving such differences and in evaluating the usefulness of numerical simulators for geothermal reservoir analysis is the comparison of simulator results for a set of well-specified problems involving processes applicable in reservoir analysis.

Under the direction of DOE's Geothermal Reservoir Engineering Management Program (GREMP), a set of six test problems has been developed in an attempt to meet this need. The problem set covers a range of reservoir situations including single- and two-phase flow under 1, 2, and 3 dimensional conditions. Each problem has been test run to insure that the parameter specifications will yield workable solutions, and in several cases analytical solutions are available for comparison. Brief

descriptions of the problems are given below in each problem, the desired grid and time-step sizes were specified to minimize differences in results due to numerical discretization.

A Request for Proposals for the Code Comparison Project was issued in June, 1980, through DOE's San Francisco Operations Office. Proposals were accepted up until July 7, 1980 from any group possessing a numerical simulator capable of solving a minimum of two of the test problems. Four contracts were awarded effective September 1, 1980. Selection of proposals was based on technical merit and cost. While the number of groups participating was not large, the codes involved are felt to be representative of the range of numerical simulators currently being applied to geothermal reservoir analysis. In one case, a non-code developer will use a commercially available code to run five of the six test problems. Participating groups include Intercomp, Geotrans, Science Systems and Software, and Stanford University.

The basic code capabilities deemed necessary in this project included simulation of single and two-phase flow of pure water and steam in one and two dimensions. Many of the codes possess additional capabilities which may be needed in specific reservoir situations including, for example, simulation of subsidence, noncondensable gas flow, and fluids with high dissolved solids content. Details on the solution techniques and special simulator capabilities for most of the well-documented codes in use today are given by Pinder (1979) and Pritchett (1979).

The term of each contract was three months, including participation in the 1980 Stanford Workshop. Two and one half months were allotted for completion of the problems proposed for solution by each group and delivery of specified results to DOE. Preliminary comparisons and evaluations of results for each problem will be presented at the Workshop by the individuals who developed the test problems. A final report on the Code Comparison Project will be issued in early 1981.

Problem 1: 1-D Avdonin Solution

This problem involves radial flow of fluid and heat in a liquid-saturated porous media. Fluid flow is approximately steady-state and

is transported by conduction and convection. Water at 160°C is injected into a reservoir initially at 170°C , and flow occurs from a well at zero radius to an outer boundary at 1000 m. Fluid properties are held constant for comparison with the analytical solution of Avdonin (1964). Output specifications include temperature versus radial distance for a fixed time and temperature versus time at a fixed radius.

Problem 2: 1-D Well-Test Analysis

This problem involves a set of four transient well-test cases. Each case treats radial flow to a constant-discharge line sink in homogeneous porous media. In case A the fluid is single-phase liquid, in case B the fluid is a two-phase mixture with both steam and water mobile, and in case C the fluid changes from compressed liquid to a two-phase mixture as the flash front moves away from the well. An additional problem under case B conditions involves constant discharge from a one-node reservoir. For each case either an exact analytical solution or an accurate semi-analytical solution is available for comparison with numerical results. Solutions will consist of pressure, saturation, and flowing enthalpy changes as functions of time/distance squared. Relative permeability functions based on the Corey equations are to be used throughout under two-phase conditions.

Problem 3: 2-D Flow to a Well in Fracture/Block Media

This problem represents a simplification of the general problem of well testing in fractured reservoirs. A well producing at constant discharge is open to a horizontal fracture of large lateral extent. Radial flow in the fracture (treated as a high permeability porous layer) induces vertical flow from an adjacent low permeability block of finite vertical dimension. For application to vapor-dominated reservoirs, only the steam phase is mobile. Simulations with and without a boiling liquid phase in the block are to be included. Output specifications consist of well-face pressure and pressure and saturation at one point in the block as functions of time.

Problem 4: Expanding Two-phase System with Drainage

This problem involves one-dimensional vertical flow under both single and two-phase conditions. An initially hydrostatic column of liquid is disturbed by mass withdrawal at the bottom. Boiling occurs

near the top of the column and extends downward. Constant pressure/temperature specifications at the top of the column result in inflow of cold water at this boundary. The permeability distribution is non-uniform and relative permeability functions based on the Corey equations are used in the two-phase region. In principal, this problem simulates some of the dominant features in the response of a liquid-dominated reservoir to production from depth. The desired output includes pressure, temperature, and saturation variations at several depths, the discharge enthalpy history of the produced fluid, and recharge rates and cumulative recharge at the surface.

Problem 5: Flow in a 2-D Areal Reservoir

This problem involves single and two-phase flow in a two-dimensional horizontal reservoir. Mass is produced at one point in the reservoir and recharge is induced over one of the lateral boundaries. The fluid is initially all liquid with a non-uniform temperature distribution (160°C - 240°C). Two cases for the production strategy are to be simulated. In cases A and B, a well close to one corner of the field produces at constant mass for 10 years. In case B, an injection well is added near another corner of the field which injects 80°C water at constant rate after 1 year of production.

Output requirements include variations with time of pressure and temperature at selected points, discharge enthalpy history in the production well, and variations with time in total mass of steam in the reservoir. In addition, for those simulators with subgrid or near-well models, variations in the sandface pressure and saturation at the production well and sandface pressure at the injection well are to be given.

Problem 6: Flow in a 3-D Reservoir

This problem involves multi-phase flow in a three dimensional reservoir, with production from one corner grid block and constant pressure upper and lower surfaces. The fluid is initially single-phase liquid, except in one layer where an immobile steam phase exists. Initial conditions are functions of depth only, including a hydrostatic pressure distribution. The grid consists of five layers with 25 nodes in each layer. Production strategy involves a variable mass flux from one

node with a total production time of 10 years. The desired output includes pressure, temperature, and saturation at selected points and the discharge enthalpy history.

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WELL LOG INTERPRETATION OF THE CERRO PRIETO FIELD

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INTRODUCTION

The basic objective in geothermal well logging is the detection of moderate to high permeability zones containing high temperature fluids. Furthermore, identification of lithology and fluid composition will aid in regional mapping of the resource area.

Most geothermal systems are found in lithological units uncommon in petroleum exploration. To study complex lithologies, one needs calibration data which at the present time do not exist for many mineralogical units. For simpler systems, such as sedimentary type, conventional well logs may have some application.

Consider a sand-shale series type of sediments exposed to hydrothermal fluids. Because of exposure to high temperatures and as a consequence of rock-fluid interaction, the properties of the rock may undergo severe alterations. The degree of such alteration is dependent upon the rock permeability. The higher the permeability, the more surface area is available to the invading hydrothermal fluids. Thus, the nature of alteration in permeable sand is expected to be different than that in the shales.

Hydrothermal alteration may result in the formation of microfractures. It may change the chemistry of the cementation material and various metamorphic reactions may happen including dehydration and decarbonation.

To examine how these changes affect the well log responses in a sedimentary type geothermal field, we studied the well logs from the Cerro Prieto field in Mexico. A fair amount of well logs are available for the field. Copies of the logs were obtained through the Lawrence Berkeley Laboratory.

DESCRIPTION OF THE FIELD

The Cerro Prieto field is located on a plain in Mexicali Imperial rift valley, Fig. 1. It covers an area of 7400 acres. The installed capacity of the field is currently 150 MW and by 1985 plans are to boost the power output to 400 MW with the eventual goal of 1000 MW.

Among the many studies conducted on lithology, the one that relates closely to the subject of our discussion is the X-ray

diffraction data published by Elders et al.¹ From their studies, indications are that in the hydrothermally altered zones clays are found in dehydrated form and considerable reduction in rock porosity may have happened.

METHOD OF STUDY

Because of nonexistence of high temperature tools, well logs were run in the field under a pre-cooled borehole condition. The most complete suite of logs available includes ϕ_{DC} , γ -ray, DIL, SP, CNL with occasional acoustic, dipmeter and temperature logs.

The behavior of interstitial clays was scrutinized on the well log responses. Observations made were related to clay composition. The onset depth of the hydrothermally altered zone was determined through a series of crossplots.

OBSERVATIONS AND DISCUSSION

One of the significant features of the conductivity logs is the sudden drop in electrical conductivity within the hydrothermally altered zones, Fig. 2. This drop coincides with an anomalous rise in the recorded SP, Fig. 3. Using a Waxman-Smit² type model to represent the behavior of shaly sands, the reduction in conductivity may be attributed to low salinity, loss of clay surface conduction, loss of porosity or a combination of the above.

Both core data and Compensated Density Log indicate reduction of porosity in the altered zones. This in turn is reflected in the increase in formation resistivity factor. Both LL8 and ILd reflect this phenomena, Fig. 4. However, the rate of increase in LL8 is much higher than the rate observed for ILd. This difference may be caused by the difference in composition between the mud filtrate and formation water. Since R_{mf} is generally higher than R_w , the difference in response may be related to the surface conductivity effect. As it has been shown earlier,³ at low salinities, surface conductivity has a greater impact on rock conductivity.

The increase in SP may be caused by several factors such as the streaming potential, high salinity, divalent cations, and the change in the nature of clay particles.

The alteration of clays in shales seems to be limited structurally and is evident as induration effect as seen from the ϕ_{CW} and ϕ_D responses. However, the hydrogen index for such zones seems relatively unchanged since ϕ_{CN} still reads higher than ϕ_D , Fig. 5.

For shaly sand the hydrogen index in shallow and unaltered zones is relatively significant, Fig. 6, while in altered zones a reversal of the two porosity curves occurs.

Unfortunately, in no case did we see evidence of 3 porosity logs for a given well. In rare instances where both acoustic and density log data are available, the evidence of micro-fractures may be seen from the difference in responses of the two tools.

Spiderweb diagrams prepared for the wells show recognizable patterns for altered and unaltered zones. Figures 7 and 8 are examples of such comparison.

Complete lithological analyses using the well log data is not currently possible because of insufficient data. The technique discussed in this paper, however, may be used to locate hydrothermally altered zones and construct structural maps of the reservoir.

ACKNOWLEDGMENT

Financial support for this study was provided by the GLIP program of Los Alamos Scientific Laboratory.

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Fig. 1. Location of the Cerro Prieto Field

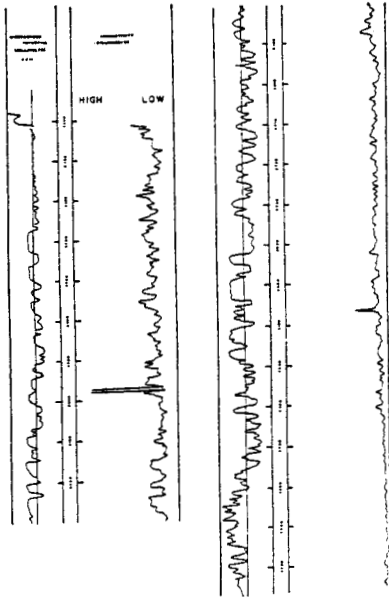


Fig. 2. Typical Conductivity Profile with Depth

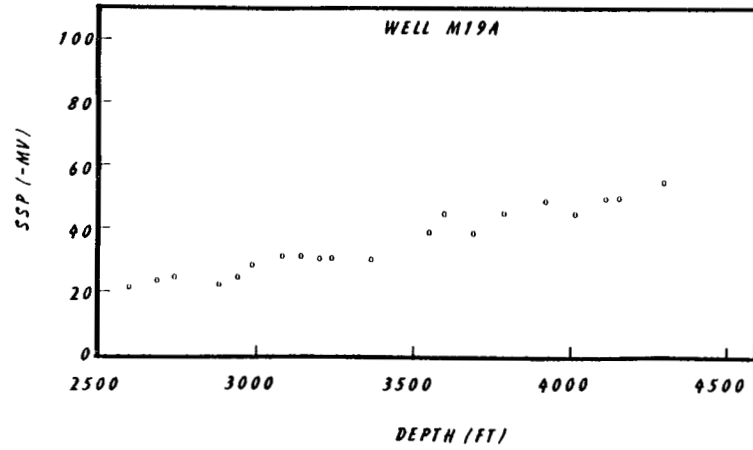


Fig. 3. Increase in SP with Depth

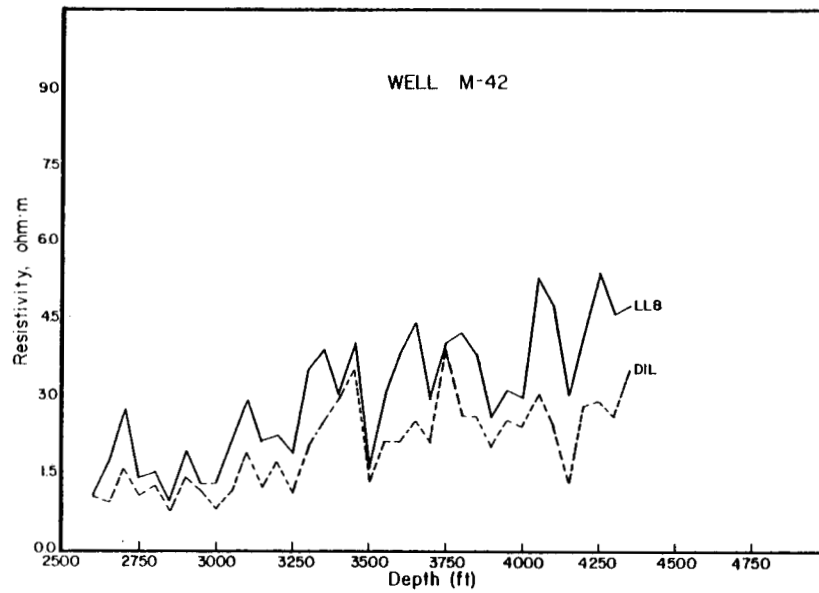


Fig. 4. Comparison of LL8 and DIL

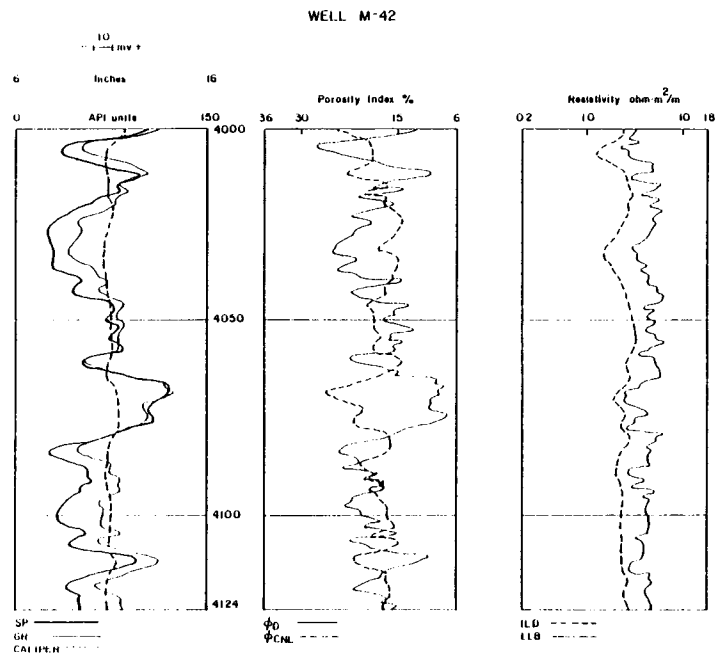


Fig. 5. ϕ_D vs. ϕ_{CNL} in an Altered Zone

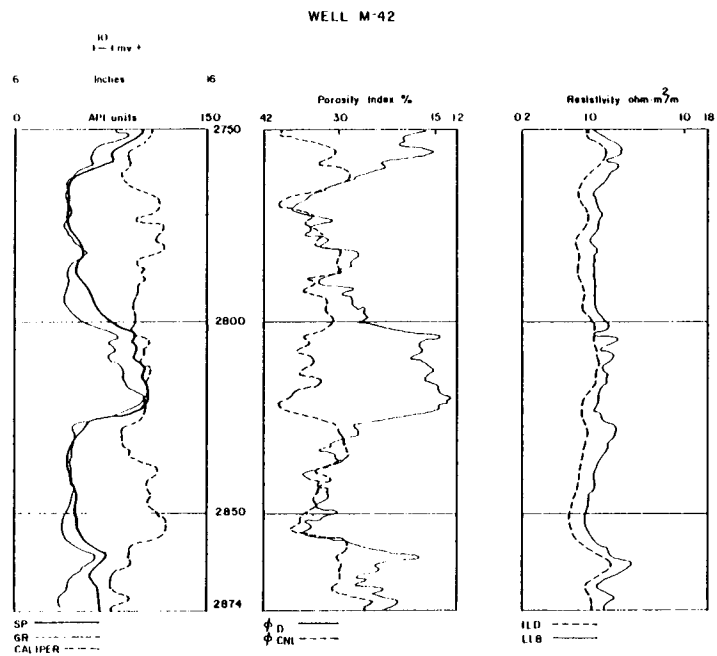


Fig. 6. ϕ_D vs. ϕ_{CNL} in an Unaltered Zone

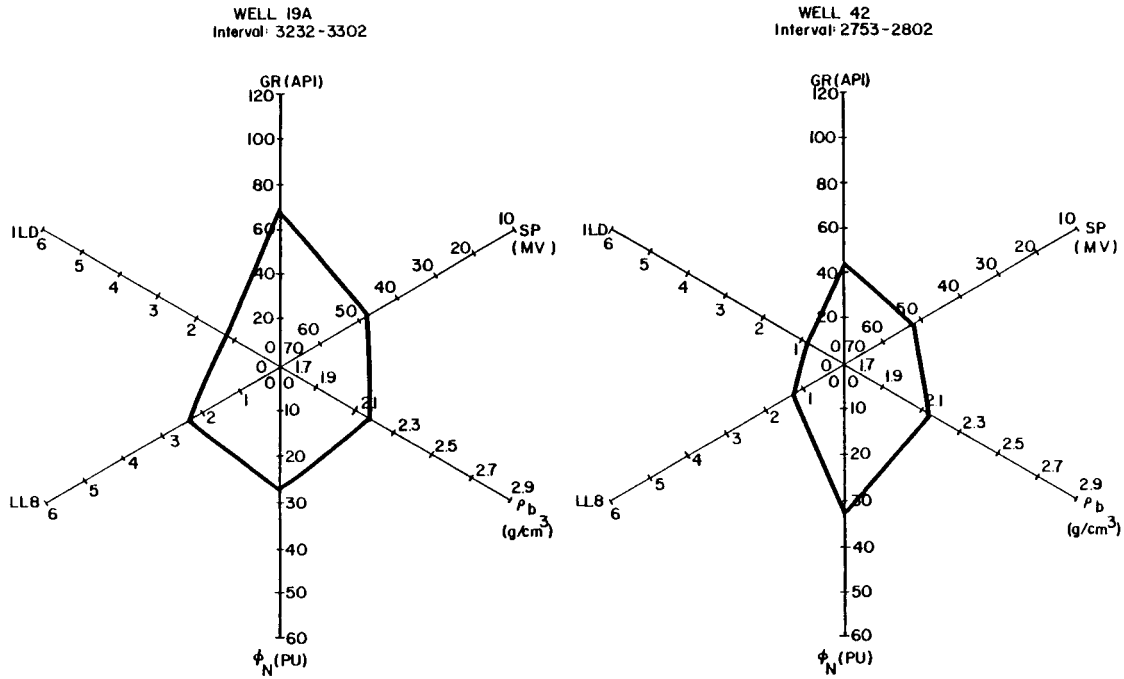


Fig. 7. Typical Spiderweb Diagram in Unaltered Zones

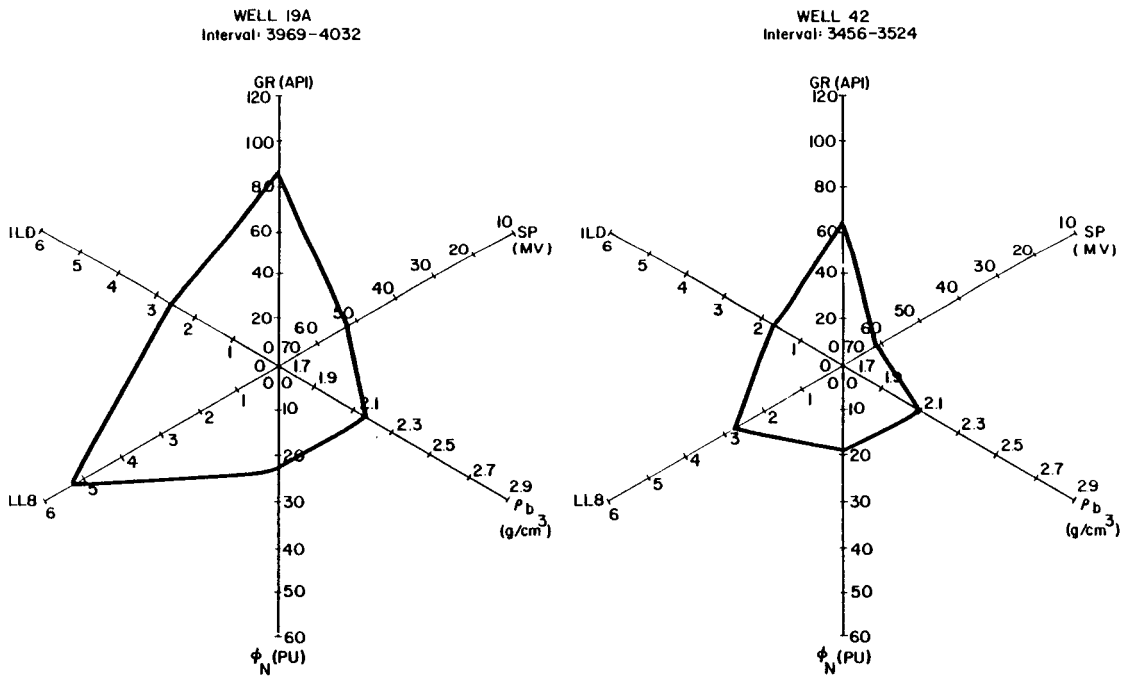


Fig. 8. Typical Spiderweb Diagrams in Altered Zones

GEOTHERMAL ENERGY EXTRACTION MODELING

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INTRODUCTION

Progress in energy extraction modeling of hydrothermal reservoirs has been achieved in two major directions. One was the development of an analytic model of heat transfer in a fractured geothermal system. The other was an experimental study of the effects of thermal stressing on rock strength and porosity.

The analytic model of linear sweep heat transfer was developed by Iregui et al (1978) and described by Hunsbedt et al (1979). This one-dimensional model calculates the water temperature as a function of time and position in the idealized geothermal system depicted in Fig. 1. Cold water enters the reservoir through a series of injection wells at one end and flows horizontally to a series of production wells at the other end. The injection and production flow rates are steady and the permeability of the formation is such that the flow is considered uniform. Reservoir pressure prevents boiling at any point in the formation. Results from the analytic model are compared with experimental data obtained from the Stanford Geothermal Program (SGP) large reservoir model, shown schematically in Fig. 2.

In fractured hydrothermal reservoirs, circulation of colder water induces tensile thermal stress at and below the rock surface. Murphy (1978) has shown analytically that such stresses have the potential to create self-driven cracks of sufficient depth and aperture to enhance energy extraction and prolong useful production life. Aside from the potential of producing self-driven cracks, thermal stressing may also influence both the mechanical and thermal properties of the rock. Changes in these properties may alter the heat transfer characteristics of the rock over the production period of a reservoir. To gain some insight into the potential significance of the effects of thermal stressing on heat transfer characteristics, an exploratory study was conducted to observe the effects of thermal stressing on rock strength and porosity.

ENERGY EXTRACTION MODELING

The linear sweep model estimates reservoir rock-to-water heat transfer by treating a collection of rock fragments as an equivalent sphere. Water

temperature-time behavior is computed from the following partial differential equations and initial and boundary conditions:

$$\frac{\partial T_f^*}{\partial x^*} + \frac{\partial T_f^*}{\partial t^*} + \frac{1}{\gamma} \frac{\partial T_r^*}{\partial t^*} = q^* \quad (1)$$

$$\frac{\partial T_r^*}{\partial t^*} = N_{tu} (T_f^* - T_r^*) \quad (2)$$

$$T_f^*(x^*, 0) = T_r^*(x^*, 0) = 1, \quad 0 \leq x^* \leq 1$$

$$T_f^*(0, t^*) = 0 \quad t^* > 0$$

where: x = distance from the inlet wells
 L = distance between inlet and production wells
 x^* = x/L
 t = time
 t^* = t/t_{re}
 t_{re} = water residence time = $L\phi/uf$
 ϕ = rock matrix porosity, uf = water velocity
 T_f^* = normalized water temp. = $\frac{T_f(x,t) - T_{injection}}{T_{initial} - T_{injection}}$
 T_r^* = normalized rock temp. = $\frac{T_r(x,t) - T_{injection}}{T_{initial} - T_{injection}}$
 γ = storage ratio = $\frac{\rho_f c_f}{\rho_r c_r} \frac{\phi}{1 - \phi}$
 ρ_f, ρ_r = water and rock density, respectively
 c_f, c_r = water and rock specific heat, respectively
 q^* = normalized external heat transfer into rock matrix = $\frac{qL}{\dot{m} c_f (T_{initial} - T_{injection})}$
 $\dot{m}$ = mass flow rate

N_{tu} = number of transfer units = t_{re}/τ_e

$$\tau_e = \frac{R_e^2}{3\alpha} (0.2 + 1/N_{Bi})$$

R_e = effective rock radius, α = thermal diffusivity

N_{Bi} = rock Biot number

These equations were solved using a LaPlace transform technique combined with a numerical inversion algorithm developed by Stehfest (1970).

The solution for the water and rock temperatures in the LaPlace space are:

$$\hat{T}_f^* = \left[\frac{q^*}{Ks^2} + \frac{1}{s} \right] \left[1 - e^{-KsX^*} \right] \quad (3)$$

$$\hat{T}_r^* = \frac{1}{s+N_{tu}} + \frac{N_{tu}}{s+N_{tu}} \left[\frac{q^*}{Ks^2} + \frac{1}{s} \right] \left[1 - e^{-KsX^*} \right] \quad (4)$$

where: $K = 1 + \frac{N_{tu}}{\gamma(s+N_{tu})}$

The water and rock temperatures as functions of time and space were obtained by the numerical inversion technique with variables of the form

$$T_f^* = f_1(N_{tu}, \gamma, q^*)$$

$$T_r^* = f_2(N_{tu}, \gamma, q^*)$$

Initial comparison of analytic and experimental data obtained from the SGP reservoir model was presented by Hunsbedt et al (1979). Further comparisons were given by Nelson and Hunsbedt (1979) incorporating data from the most recent experiment.

The comparison of experimental water temperatures with sweep model results obtained by the LaPlace transform/numerical inversion solution showed considerable disagreement for some points in the SGP model. Fig. 3 shows the experimental and predicted water temperatures as functions of time at various locations along the model centerline. It is noted that

the slope of the predicted temperature curves are generally greater than the experimental data suggest.

The sweep model was also evaluated using a finite difference solution to check the adequacy of the LaPlace transform solution. Comparison of finite difference results, also given in Fig. 3, with the LaPlace solution shows poor agreement. The finite difference technique was examined further by varying time step and mesh size, but no significant improvement in results was obtained.

The observation that the predicted temperature versus time curves are generally steeper than the experimental curves led to a closer examination of the actual behavior of the physical system and the modeling assumptions. One of the results was an observation that the temperature-time characteristic of the water entering the SGP model follows an exponential rather than a step change assumed in the analytic model. The effect of an exponential reduction in water inlet temperature was investigated using the LaPlace solution, and results are given in Fig. 4. It is noted that the slopes of the predicted curves are similar to those of the experimental data. However, a time lag is present in the predicted curves that might be related to axial heat conduction in the rock/water matrix and non-uniform heat transfer from the steel vessel. The latter effect is currently modeled by a constant heat transfer term, as shown previously in Eq. 1.

The effect of axial conduction was investigated with a finite difference solution, and resulted in a reduction of both the slope and time lag of the calculated temperature-time curves. Studies of the combined effects of axial conduction and exponential water inlet temperature reduction are not yet completed, but are expected to give predicted results which agree more closely with the experimental data. However, it is clear that the mathematical modeling of the laboratory model needs further improvement.

In attempting to model the long-term heat transfer behavior of large-scale fractured hydrothermal systems, several uncertainties in the present sweep model need to be resolved. One concerns the influence of heat transfer from the steel vessel, which releases an amount of energy comparable to that from the rock loading. Another is modeling heat transfer from the distribution of rock fragments comprising a particular geothermal reservoir heat source. Also, the potential change in rock heat transfer characteristics resulting from thermal stressing due to reservoir reinjection needs to be investigated and, if significant, incorporated in the model.

THERMAL STRESS EXPERIMENTS

To explore the effect of thermal stressing on rock strength and porosity, rectangular granite slabs were heated to 450°F. All sides of the slabs were insulated. After a uniform temperature had been achieved, the insulation on one end of the slab was quickly removed and the face quenched with a 70°F water spray. This produced tensile thermal stress on and below

the quenched face and compressive thermal stress deeper in the slab. Details of the temperature-time and transient thermal stress behavior in the slabs were reported previously by Nelson and Hunsbedt (1979).

After quenching, the slabs were cut into smaller rectangular specimens and loaded to fracture in three-point bending. It was found that specimens taken from regions of tensile thermal stress had, on average, less than one-half the strength of unquenched specimens. On the other hand, there was no loss of strength in specimens taken from regions of compressive thermal stress. Loss of strength was not due to heating alone. It was also observed that repeated tensile thermal stressing (five cycles) reduced strength to about one-third of that in unquenched rock. The reduction in strength may be due to microcracking caused by tensile thermal stress.

Porosity measurements were made on the same specimens used in the bend tests. The average porosity of unquenched specimens was 1.6%, whereas the average for specimens experiencing one and five applications of tensile thermal stress was 3.8% and 4.8%, respectively. The increase in porosity may also be a result of microcracking.

The above results were obtained from tests conducted at atmospheric pressure. Ideally, such experiments should be conducted under simulated tectonic stresses. Nevertheless, the observed reduction in rock strength and increase in porosity caused by tensile thermal stress may favor formation and growth of self-driven thermal cracks in geothermal reservoirs. It also seems plausible that tensile thermal stress may alter rock heat transfer characteristics (e.g., thermal conductivity). Further tests are underway to investigate this possibility.

FUTURE EFFORTS

Additional heat extraction experiments in the SGP large reservoir model are underway. These experiments will utilize regularly shaped, large granite blocks. This rock loading will allow a more detailed analysis of the heat transfer behavior using the one-lump parameter analytic model adapted for rocks with a known size and shape distribution. The experiments will also test the influence of the number of heat transfer units parameter, N_{tu} , on model behavior. It is anticipated that N_{tu} values will be as low as 3.0, which is well into the reservoir "heat transfer limited" region, that is, where large rock-to-water temperature differences exist. Those differences should also induce significant tensile thermal stresses in the rock.

A second major effort is the improvement of the analytical means to evaluate experimental data. The first step is to develop a finite element model to account for the heat transfer from the steel vessel of the SGP reservoir model. Removal of that component from the heat extraction data will increase the understanding and usefulness of the one-lump rock heat transfer model over the range of N_{tu} . A second step will be to evaluate experimental results with the current sweep model using the LaPlace transform solution in order to further develop the model as a simple means for

assessing heat transfer performance of fractured geothermal reservoirs. A third step will be to incorporate the results of thermal stressing experiments from the large block loading into the model to account for possible changes in heat transfer characteristics. The final step will be the development of the model to analyze the heat transfer performance of full-scale fractured hydrothermal systems, such as the Baca field in New Mexico and the Los Alamos fracturing experiment at the Site 2 location.

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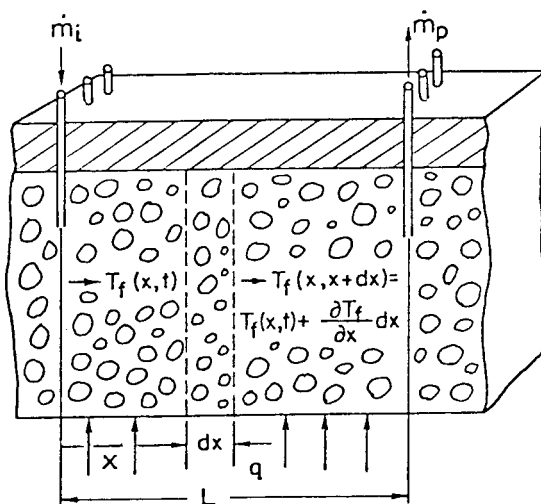
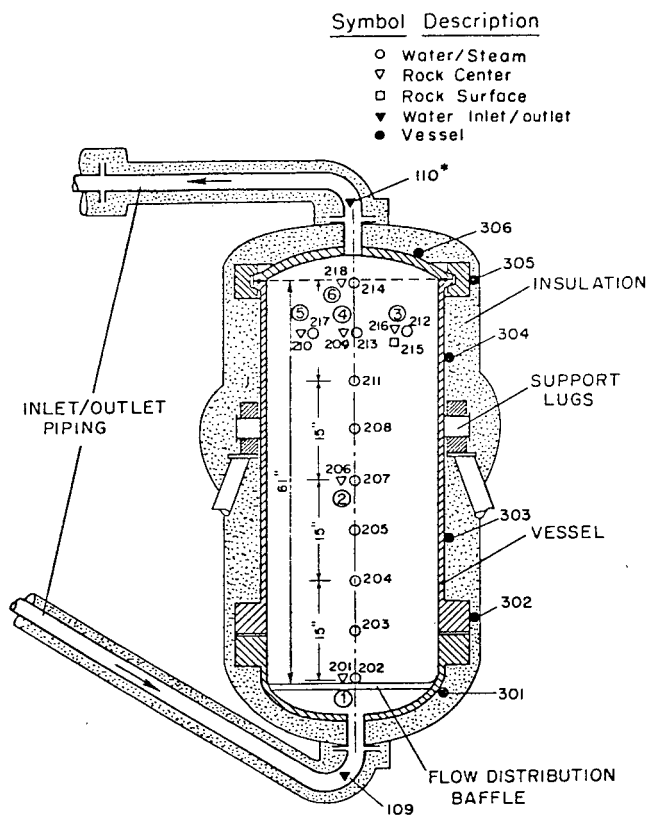


FIGURE 1. LINEAR SWEEP MODEL



• Thermocouple reference numbers

① Rock number 1

FIGURE 2. SGP RESERVOIR MODEL

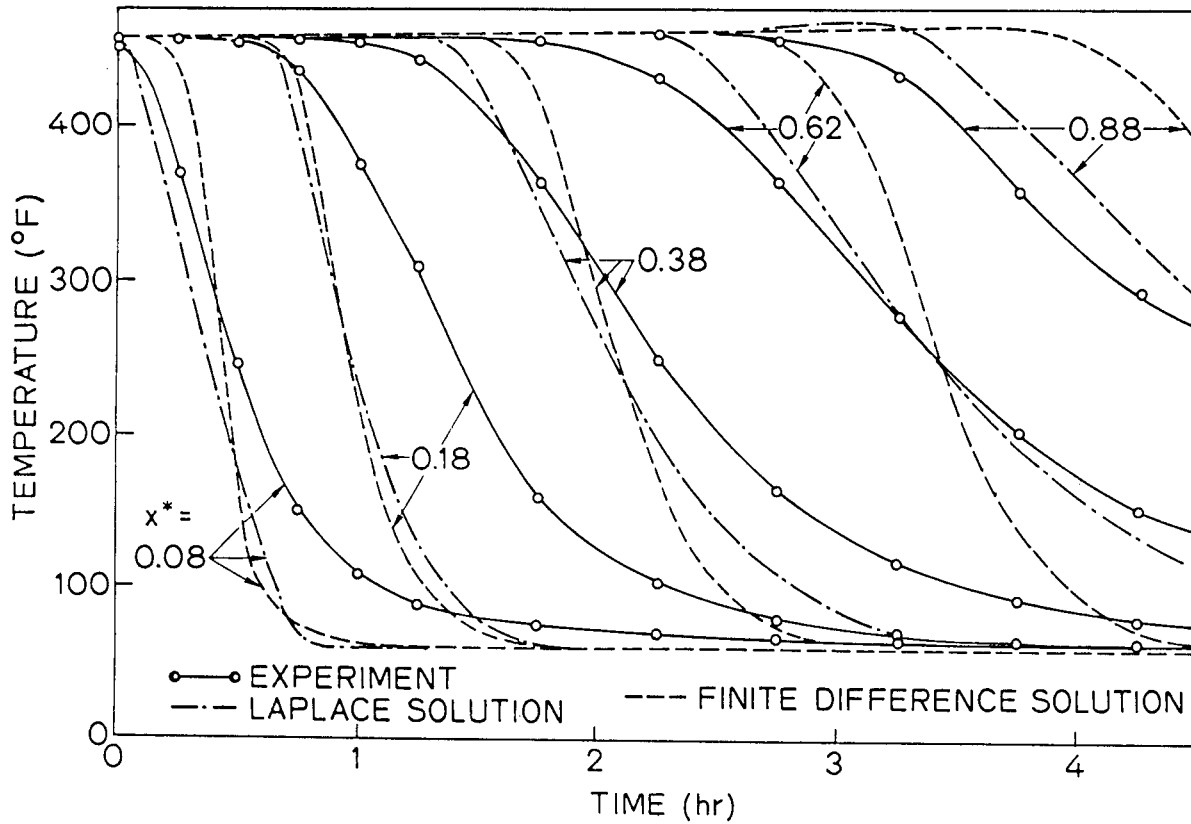


FIGURE 3. COMPARISON OF EXPERIMENTAL AND PREDICTED RESERVOIR TEMPERATURES

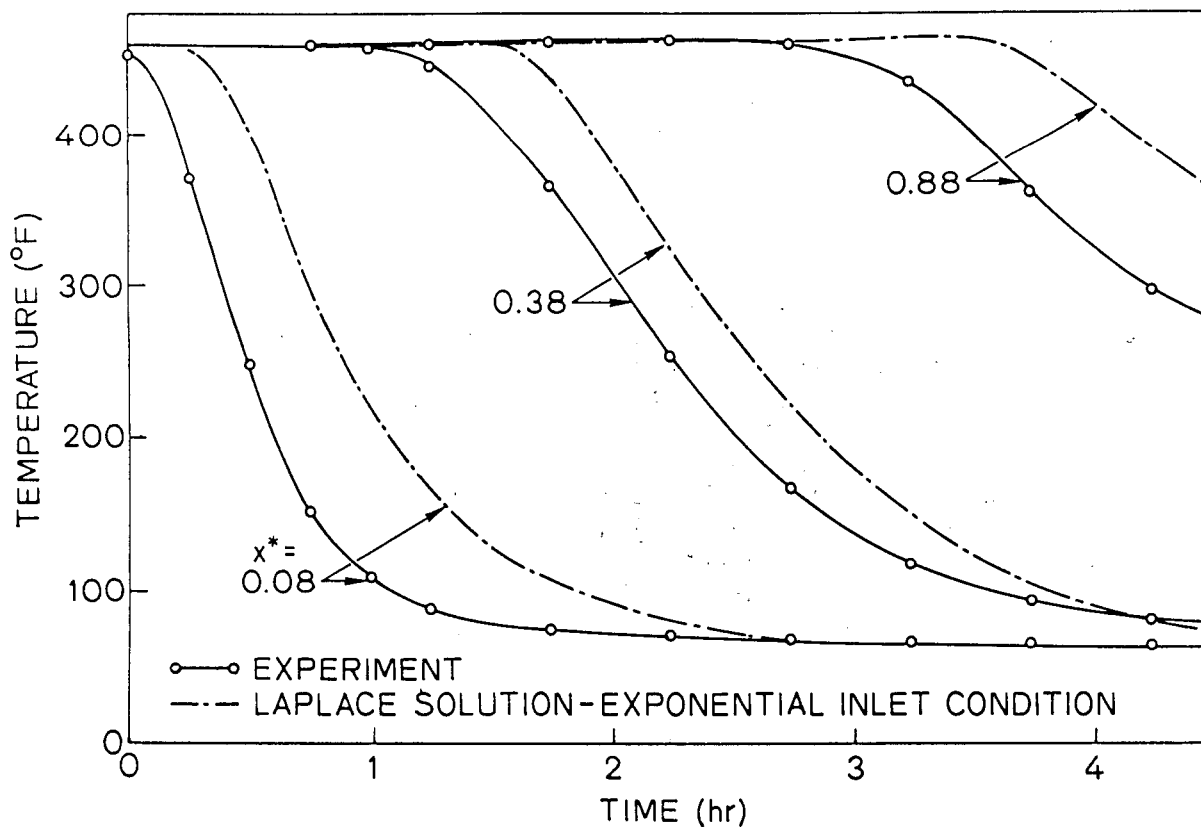


FIGURE 4. COMPARISON OF EXPERIMENTAL DATA WITH LAPLACE SOLUTION FOR AN EXPONENTIAL INLET BOUNDARY CONDITION

COMPARISON OF TWO HOT DRY ROCK GEOTHERMAL RESERVOIRS

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Two hot dry rock (HDR) geothermal energy reservoirs were created by hydraulic fracturing of granite at 2.7 to 3.0 km (9000 to 10 000 ft) at the Fenton Hill site, near the Valles Caldera in northern New Mexico. Both reservoirs are research reservoirs, in the sense that both are fairly small, generally yielding 5 Mwt or less, and are intended to serve as the basic building blocks of commercial-sized reservoirs, consisting of 10 to 15 similar fractures that would yield approximately 35 Mwt over a 10 to 20 yr period. Both research reservoirs were created in the same well-pair, with energy extraction well number 1 (EE-1) serving as the injection well, and geothermal test well number 2 (GT-2) serving as the extraction, or production, well. The first reservoir was created in the low permeability host rock by fracturing EE-1 at a depth of 2.75 km (9020 ft) where the indigenous temperature was 185°C (364°F). Reservoir performance was evaluated by a 75-day long period of closed-loop operation from January 28 to April 13, 1978. Hot water from the production well was directed to a water-to-air heat exchanger where the water was cooled to 25°C before reinjection. The relatively low power produced did not economically justify the conversion of the geoheat to beneficial usage, so it was simply dissipated to the atmosphere by this heat exchanger. The cooled water, in addition to the makeup water that was required to replace downhole losses to the rock surrounding the fracture, was then pumped down the injection well and then through the fracture system. Heat was transferred to the water by means of conduction within the nearly impervious rock contiguous to the fracture surfaces and the heated water was withdrawn by means of the production well. Results of the 75-day assessment of the first reservoir were presented by Murphy et al. (1978), Tester and Albright (1979), and Murphy and Tester (1979) but are summarized for comparison with the second reservoir below.

A second, larger reservoir was formed by extending a small, existing fracture at 2.93 km (9620 ft) in the injection well about 100 m deeper and 10°C hotter than the first reservoir. The resulting large fracture propagated upward to about 2.6 km (8600 ft) and appeared to have an inlet-to-outlet spacing of 300 m (1000 ft), more than three times that of the first fracture. Comparisons are made with the first reservoir in Table 1. Evaluation of the new reservoir was accomplished in two steps: (1) with a 23-day heat extraction experiment that began October 23, 1979, the results of which are described by Murphy (1980), and (2) a second, longer-term heat extraction experiment still in progress, which as of November 25, 1980 has been in effect for 260 days. The results of this current experiment are compared with earlier experiments below.

TABLE 1.

CHARACTERISTICS OF RESERVOIR SYSTEMS STUDIED
WITH FIRST PAIR OF WELLS

Characteristic	First Reservoir May 1977 - Jan. 1979	Second Reservoir Jan. 1979 - Present
EE-1 injection hole condition	Before recementing	After recementing
Main injection zone location in EE-1	2.75 km (9020 ft)	2.93 km (9620 ft)
Main production zone locations in GT-2	2.6 - 2.7 km (8600 - 8850 ft)	2.6 - 2.7 km (8600 - 8850 ft)
Average wellbore separation between EE-1 and GT-2 in the production interval	100 m (300 ft)	300 m (900 ft)

RESERVOIR GEOMETRIES AND FLOW PATHS

Figure 1 shows the inferred geometry of both fractures. The first fracture, whose origin was at 2.75 km in EE-1, is shown as the small vertical fracture and the new fracture is shown to the left as the larger one. Both fractures are shown as nearly vertical because the planes of hydraulic fractures are orthogonal to the minimum (least

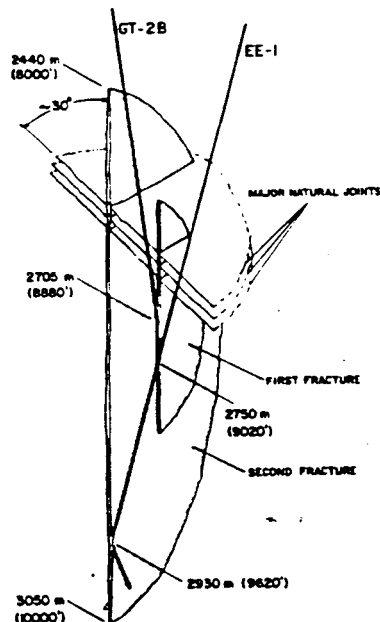


Fig. 1. Inferred reservoir geometry.

compressive) component of the tectonic earth stress. In tectonically relaxed geological settings this stress is expected to be a horizontal one at depths greater than about 1 km and, in fact, it has been shown [Murphy et al., 1977] that the minimum horizontal stress at the Fenton Hill site is only one-half the vertical overburden stress at a depth of 2.7 km. The granitic rock in which these fractures were created is fairly homogeneous and unstratified, so it is assumed that all the fractures discussed here are approximately circular in shape, rather than rectangular as is usually assumed for oil and gas reservoirs in sedimentary formations. All fracturing operations were performed with water alone; no viscosity increasing agents, loss-of-fluid agents, or proppants were added. Subsequent pumping tests suggested that, upon depressurization, the induced fractures remained partially open due to the "self-propping" of the misaligned rough surfaces produced during fracturing. The second reservoir was created by injecting a total of 1360 m³ (48 000 ft³) of water, raising the downhole pressure by 200 bars (3000 psi) above the hydrostatic level.

The manner in which the fractures are connected with the production well, GT-2, is complex and was studied with temperature drawdown and recovery measurements, wellbore flow rate measurements, visible dye and radioactive NH₄Br⁸² tracer measurements, and other logging methods. This connectivity apparently consists of a set of nonvertical natural fractures or joints with a dip of approximately 60° that intersect both the vertical fractures and the GT-2 wellbore. These joints appear to be extensions of the same ones that formed the connections between the first fracture and GT-2. The downhole temperatures and velocities of the water in the connecting joints were measured at the joint/well intersections with a combined temperature (thermistor) probe and flow rate (spinner) logging tool, which was used to determine temperature and flow rate profiles in the open hole region of GT-2. Both profiles were used to infer the depth of the connecting joints and also the relative flow rate contributions communicated by each joint.

THERMAL DRAWDOWN

During heat extraction tests of both reservoirs, the downhole temperature and flow rate tool, when not actually logging the well, was positioned at a depth of 2.6 km (8500 ft) in the production well, just above all the known producing joints that intersect the production well. In this manner the mixed mean outlet temperature of the production flow rates converging upon GT-2 was nearly continuously measured. Figure 2 shows the temporal decline of this temperature. The abrupt change in curvature for the first reservoir that occurs at day 25 is due to the doubling of the production flow rate at that time from 6 to 13 l/s (100 to 220 gpm). Despite the thermal drawdown this increase in flow rate resulted in a roughly constant power level after the first 25 days. Peak power was 5.1 MWt and the average power was about 4 MWt. The thermal decline of the first reservoir was 100°C in 75 days.

In comparison, as of November 25, 1980 the mean outlet temperature of the second reservoir had drawdown only 5°C after 260 days of heat extraction at a flow rate of 6 l/s. The initial temperature of the second reservoir was 157°C, 17°C cooler than that of the first

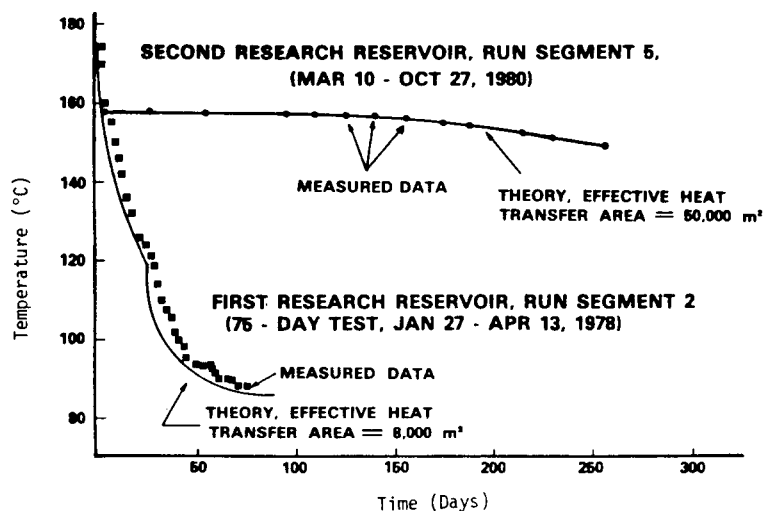


Fig. 2. Comparison of thermal drawdowns, 1st and 2nd reservoirs.

reservoir. This difference in initial temperature is due to the thermal interaction between the closely spaced reservoirs (Figure 1). As a consequence of the drawdown and subsequent thermal recovery of the first reservoir, it is estimated that the temperature of the second reservoir was disturbed by 15 to 20°C. These data, in concert with the thermal drawdown analysis models of Harlow and Pracht (1972) and McFarland and Murphy (1976), result in estimates of 8000 and 50 000 m² (86 000 and 540 000 ft²) respectively, for the effective heat transfer areas of the two reservoirs.

FLOW CHARACTERISTICS

Residence Time Studies. Reservoir volumes and dispersion characteristics were measured by injecting tracers, either the visible dye Na-fluorescein, or radioactive $\text{NH}_4\text{Br}^{62}$, in the injection well and monitoring the concentration-time behavior at the production well [Tester, Potter and Bivins, 1979]. Four injections were conducted in each reservoir and the average modal volumes are presented in Table 2, accompanied by the earlier estimate of heat transfer areas, and the fracture aperture derived from the ratio of fracture volume and area. These fracture apertures are in accord with estimates based upon self-propping caused by misaligned fracture surface roughness. Profilometer measurements on core specimens taken at 2.7 km in GT-2, that were fractured after coring, showed that, on a very fine scale, roughness asperities of 0.2 mm, typical of the rock grain size, were spaced every 0.5 mm along the face; but on a larger scale the specimens had surface waves of the order of 1 mm on a 10 mm spacing. Agreement of measured and estimated self-propped apertures during these tests is expected because fracture fluid pressures were maintained at levels below the minimum earth stress.

Flow Impedance. Flow impedance is defined as the pressure drop through the fracture system connecting the two wells, divided by the production flow rate. As shown in Fig. 3 the impedance of the first reservoir declined nearly continuously and at the end of the experiment was less than one-fifth its initial value. Even impedances as

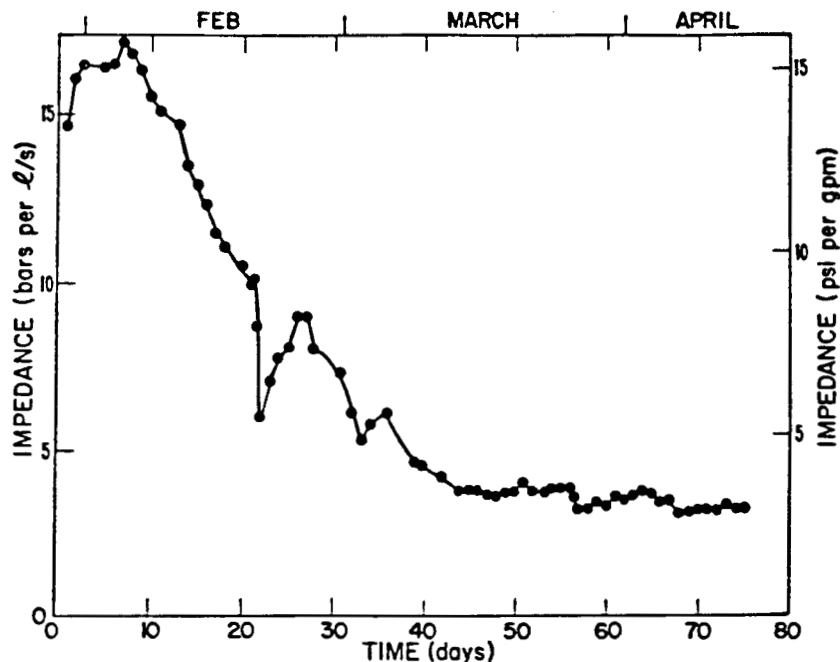


Fig. 3. Temporal variation of flow impedance, 1st reservoir.

high as the initial value, about 17 bars per l/s (16 psi/gpm) are sufficiently low for individual fractures contained in larger multiple-fracture systems of commercial size. The trend of impedance reduction is well correlated with the thermal drawdown shown in Fig. 1 and is probably associated with the partial shrinkage of fracture faces away from each other caused by cooling. This effect is particularly important near the fracture outlets, where previous flow testing had identified localized impedances associated with the joints providing communication between GT-2 and the first hydraulic fracture. In fact, temperature surveys indicated that several closed or sealed joints eventually opened to the point where they began to produce fluid.

In contrast the impedance of the second reservoir has remained essentially constant at 16 bar per l/s during both heat extraction tests; no reduction with time has been observed as occurred in the first reservoir, presumably because the thermal drawdown of the second reservoir is negligible. This rough equivalence of impedance for the two reservoirs results despite the fact that the flow paths in the new reservoir are several times longer; the distance between the inlet and outlets is 3 times longer and the heat transfer area and volume are 6 and 10 times larger, respectively.

Water Losses. Of the 68 000 m³ of water circulated during the 75-day test of the first reservoir, 1900 m³ permeated into the surrounding formation. Initially the rate of loss was high but then it diminished, so that at the end of the test the rate was only 0.13 l/s (2 gpm), or 1% of the produced flow rate. At the end of the 23-day test of the second reservoir the water loss rate once again declined, this time to a value of 1.3 l/s (20 gpm) or 20% of the produced flow rate. For comparison purposes the loss rate from the first reservoir after 23 days was 0.7 l/s (12 gpm). Therefore, the water loss rate

from the second reservoir was only twice that of the first reservoir after an equivalent period of time, despite a 6-fold increase in reservoir area and a 10-fold increase in volume. Furthermore it is emphasized that these are short-term water losses; sustained heat extraction operations over a period of years would result in additional decline of loss rates as the porosity of the surrounding rock is satisfied, [Fisher, 1977], and in fact our current testing shows that the water loss rate for the second reservoir is only 0.4 l/s (6 gpm) after 235 days.

TABLE 2
RESERVOIR SIZE ESTIMATES

Test	Effective Heat Transfer Area (m ²)	Average Modal Volume (m ³)	Average Aperture (mm)
First reservoir (75-day test)	8000	11.4	1.4
Second reservoir (23-day test)	50 000	111	2.0

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DETERMINATION OF TDS IN GEOTHERMAL SYSTEMS
BY WELL-LOG ANALYSIS

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ABSTRACT

An estimate of the chemistry of the fluid within a geothermal reservoir is required to establish the geological source and the possible environmental impact of the fluid as well as scaling and corrosion problems which might develop during production. While a detailed analysis of the chemical composition of a geothermal fluid can only be obtained from a water sample, an estimate of the total dissolved solids (TDS) in equivalent sodium chloride (NaCl) concentration can be obtained from well logs. TDS can also be useful in geological correlation between wells. TDS can be determined directly from a pulsed neutron log and a porosity log, (if the type of formation is known), or from the water resistivity, R_w , and the temperature, T . Three approaches are used to find R_w and thus TDS. The first method uses a dual induction focused log and information from the log heading. Next, R_w is found by employing an electrical log and a porosity log. The last approach utilizes the spontaneous potential log and header data. Examples are provided to illustrate the techniques described which utilize calculated values of R_w to determine TDS.

INTRODUCTION

The total dissolved solids found in geothermal fluids provide important information. From this information proper production equipment can be chosen and possible problems may be anticipated. TDS can be calculated from various combinations of well logs: (1) pulsed neutron log and a porosity log; (2) dual induction focused log; (3) an electric log and a porosity log; or (4) spontaneous potential log. The accuracy of each method depends on the estimated constants needed in each analysis and how well the assumptions underlying each method are valid.

THEORY

Using the Thermal Decay Time Log, the following equation can be written:

$$\Sigma_w = \frac{\Sigma_{\log} - \Sigma_{ma} (1 - \phi)}{\phi} \quad (1)$$

Porosity can be determined from a porosity log or from knowledge of the field. If the lithology is known, Σ_{ma} can be assumed (eg. Σ_{ma} is between 8 and 12 for a sandstone dominated reservoir). Using this approach Σ_w can be calculated at a particular depth.

If ϕ and $\Sigma_{\log}$ vary considerably over the zone of interest, a more accurate estimate of Σ_{ma} can be determined by plotting $\Sigma_{\log}$ versus ϕ . By rearranging equation 1, the following equation is obtained:

$$\Sigma_{\log} = (\Sigma_w - \Sigma_{ma})\phi + \Sigma_{ma} \quad (2)$$

This is the equation of a straight line with a slope of $(\Sigma_w - \Sigma_{ma})$ and intercept of Σ_{ma} (at $\phi = 0$). Thus, a least squares linear fit of the $(\phi, \Sigma_{\log})$ data can be used to obtain Σ_w from the intercept and slope.

Once Σ_w is determined, TDS is found from the correlation chart shown in Figure 1 (Schlumberger, 1979). This chart shows TDS as a function of Σ_w at 75°F and 200°F. The following equation describes this chart:

$$TDS = a(\Sigma_w)^2 + b(\Sigma_w) + c \quad (3)$$

where

$$a = -0.000007(T) - 0.003$$

$$b = 0.0016(T) + 2.881$$

$$c = -0.0247(T) - 63.172$$

and T is given in degrees Fahrenheit.

The next section describes the methods which calculate R_w and then TDS. The first method employs the resistivity of the flushed zone, R_{xo} , and the resistivity of the zone of interest, R_t , obtained from a dual induction focused log. The log heading provides information necessary to this analysis; the bit size used to drill each section of the well, the type of mud being circulated, the resistivity and temperature of the mud and mud filtrate (R_{mf} at T_{mf} and R_m at T_m), the depth and temperature at bottom hole (T_{BH}), and the stand off. Using Arps' equation (Arps, 1953), R_{mf} can be calculated at any depth given the temperature at that depth:

$$R_{mf2} = R_{mf1} \left(\frac{T_1 + 6.77}{T_2 + 6.77} \right) \quad (4)$$

Temperature logs are generally run in geothermal wells. If a temperature log is available it can be used to find the temperature at the depth of interest. Otherwise, knowledge of the temperature gradients with depth in a field can be utilized by working up from the bottomhole temperature. It is known that these temperatures are time-dependent, but the small changes over time should not significantly affect these results. If the depth of interest is in the constant temperature zone, it can be used. The formation resistivity factor, F, is given by:

$$F = \frac{R_t}{R_w} \quad (5)$$

or

$$F = \frac{R_{xo}}{R_{mf}} (S_{xo})^2 \quad (6)$$

Assuming a geothermal reservoir is 100% water saturated, $S_{xo} = 1$, equation 6 becomes:

$$F = \frac{R_{xo}}{R_{mf}} \quad (7)$$

Solving equations 5 and 7 an equation describing R_w is obtained:

$$R_w = \frac{R_t}{R_{xo}} R_{mf} \quad (8)$$

Using this equation, R_w can be calculated for any depth. The actual values obtained from a Dual Induction Laterolog log are a deep, medium, and shallow resistivity (R_{ID} , R_{IM} , R_S) for each depth. After reading the values from the log and calculating the ratios R_S/R_{ID} and R_{IM}/R_{ID} a chart similar to the one shown in Figure 2 (Schlumberger, 1979) can be used to obtain R_{xo}/R_t and R_t/R_{ID} . From these ratios, R_{xo} and R_t can be calculated. However, before using the correlation chart, corrections of the log data may be necessary. These corrections compensate for borehole effects and bed size.

If an analysis is desired over a zone, a plot is made of R_t versus R_{xo} for all depths in that zone. The equation which describes this plot is obtained by rearranging equation 8:

$$R_t = \frac{R_w}{R_{mf}} R_{xo} \quad (9)$$

A line can be drawn through the points which goes through the origin and has a slope of R_w/R_{mf} . R_{mf} is assumed to be constant, so R_w can be directly obtained.

The next method used to find R_w uses an electric log and a porosity log. For a given lithology, F can be calculated by:

$$F = a/\phi^m \quad (10)$$

where the constants a , and m , are lithology dependent parameters. If ϕ can be obtained from a porosity log and R_t from an electrical log, R_w can be calculated from the following equation, derived from equations 10 and 6.

$$R_w = \frac{R_t \phi^m}{a} \quad (11)$$

In many cases, the lithology is known and the appropriate values can be substituted for m and a . For a compacted formation $a = 1$ and $m = 2$, which reduces equation 11 to:

$$R_w = R_t \phi^2 \quad (12)$$

If the lithology is not well defined, the following analysis yields another procedure. R_w and F are also related by (Archie's equation):

$$S_w^n = \frac{FR_w}{R_t} \quad (13)$$

Substituting equation 10 and 13 and taking the logarithm of both sides gives:

$$n \log S_w = \log (aR_w) - m \log \phi - \log R_t \quad (14)$$

Since S_w is assumed to be 1, $n \log S_w$ will be zero. This gives:

$$\log R_t = -m \log \phi + \log (aR_w) \quad (15)$$

Assuming the lithology and salinity are constant over a zone, an indication of the constants, a and m , can be found by plotting $\log R_t$ versus $\log \phi$. The line obtained will have a slope of $-m$ and, at $\phi = 1$, the intercept will be $\log (aR_w)$. Although this does not obtain the constant, a , directly, it can be found from an independent value of R_w . For example, equation 12 could be used with average values of R_t and ϕ . This value of the constant, a , can then be used for further calculations.

The last method used to calculate R_w needs only the Spontaneous Potential Log. The static spontaneous potential value, SSP, is related to R_w by:

$$SSP = -K \log \frac{R_{mf}}{R_w} \quad (16)$$

where $K = 61 + 0.133T$ (Schlumberger, 1979). R_{mf} can be found from the log heading and T can be obtained by a temperature log or known temperature gradient. So, at any depth,

$$R_w = R_{mf} 10^{(SSP/K)} \quad (17)$$

After R_w is obtained from any of the three methods described above, TDS can be found from a nomograph for NaCl solutions such as the one shown in Figure 3 (Schlumberger, 1979). Knowing the resistivity and temperature, TDS in ppm of NaCl equivalents at 75°F can be found. This nomograph can be fitted by the following equation (Dresser, 1980):

$$\text{NaCl}_{\text{eq}} (@ 75^\circ\text{F}) = 10^x \quad (18)$$

where

$$x = \frac{3.562 - \log (R_{75} - 0.0123)}{0.955}$$

and

$$R_{75} = R_T \left(\frac{T + 6.77}{75 + 6.77} \right)$$

EXAMPLES

Because of the difficulty in obtaining data, examples are presented from one well, US Geothermal A-1, in the Geysers, California field. It was chosen because it provided the best suite of logs. However, reasonable zones were still difficult to identify and these examples are primarily for illustrative purposes. Unfortunately, no pulsed neutron log was run in this well. The first example uses a Dual Induction Laterolog, a Spontaneous Potential log, and a Temperature log. The logs were run in the fall of 1974. Twenty feet of a zone were examined, beginning at a depth of 2602 ft. From the log heading the bit size was 12½ in. with a 1.5 in. standoff. The temperature gradient was found from the temperature log (25°F/100 ft) around the depth of interest and at 2500 ft, $T = 225^\circ\text{F}$. Therefore, at 2600 ft, $T = 250^\circ\text{F}$. R_m is 11.9 $\Omega\text{-m}$ at 54°F or 2.82 $\Omega\text{-m}$ at 250°F. R_{mf} is 6.79 $\Omega\text{-m}$ at 65°F or 1.90 $\Omega\text{-m}$ at 250°F. For the given bit size and R_m no borehole correction was necessary. Values for R_{LL8} , R_{IM} , and R_{ID} were taken from the log and Figure 2 ($R_{xo}/R_m = 20$) was used to find the ratios from which R_t and R_{xo} are calculated. Table 1 presents this data and Figure 4 shows the plot of R_{xo} versus R_t . The slope of the line is $R_w/R_{mf} = 0.475$. Multiplying by R_{mf} gives $R_w = .9025$. Using Figure 3, TDS = 1840 ppm.

An independent calculation of R_w for this zone can be done using the Spontaneous Potential curve. Looking at the Spontaneous Potential log, the SSP value corresponding to this zone is -23 mV. K is found to be 94.25 and R_w is calculated to be 1.082. From Figure 3 TDS is found to be 1860 ppm.

The next example uses an Induction-Electrical log and a Compensated Neutron log run in January, 1975. Forty feet of a zone were examined beginning at a depth of 5200 ft. Table 2 lists the data and computed R_w for each depth. Figure 5 shows the plot of $\log \phi$ versus R_t . From this figure, it can be seen that most points lie together with several others being widely scattered. To help draw a reasonable line through these points, Humble's formula can be used since it obtains reliable results for most sedimentary formations. Using Humble's formula, $F = 0.62/\phi^{2.15}$ and average values of $\phi = 19\%$, and $R_t = 31 \Omega\text{-m}$, and average R_w of $1.41 \Omega\text{-m}$ is obtained. The constant, a , can then be calculated to be 0.39. By iterating on the constant, a , and R_w , a value of 0.497 for the constant, a , gives a close approximation to the average R_w calculated from Humble's formula. R_w is then calculated for each depth and an arithmetic average is determined. For this zone R_w was found to be $1.53 \Omega\text{-m}$. No temperature logs were available at this depth, so $T = 280^\circ\text{F}$ was assumed (bottomhole temperature was 285°F at 6280 ft). Using Figure 3, TDS is 980 ppm.

CONCLUSIONS

Four methods to find TDS from well logs have been presented. If a complete suite of logs is available for a given zone, several methods can be employed to obtain TDS. By using more than one method an indication of the accuracy may be determined. However, each method can be used independently so even with a minimum amount of data an estimate of TDS can be determined. However, the methods should be done statistically to successfully account for lithological differences and bad data points within a zone. These methods are dependent upon the accuracy of the constants needed, such as the resistivity of the mud filtrate and the temperature. Also, too large a borehole (greater than 14 in.) can cause the resistivity measurements to be inaccurate because of the increased borehole effects. In all methods, the lithology must be taken into account because it can significantly alter the log readings, especially from the porosity tools.

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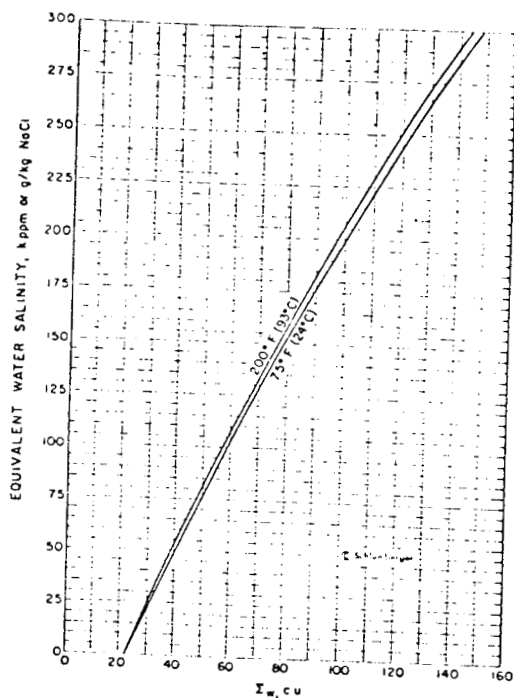


Figure 1. TDS versus Σ_w for TDT Log.

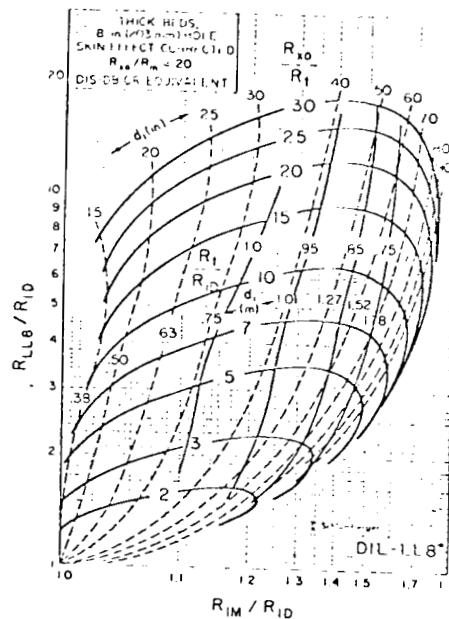


Figure 2. Solution chart
for Dual Induction-
Laterolog.

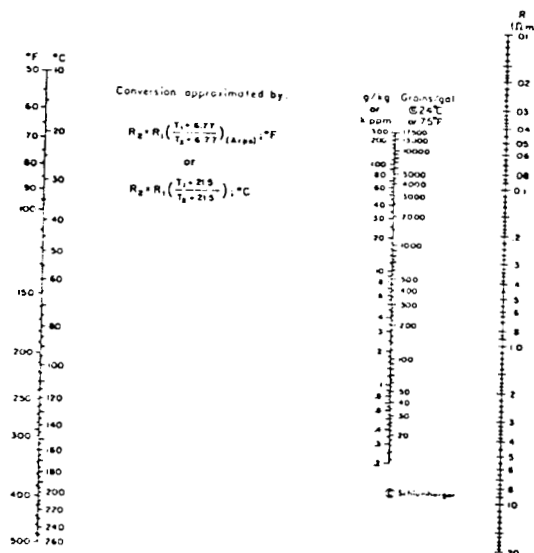


Figure 3. Resistivity Nomograph
for NaCl Solutions.

TABLE 1

Data for Example 1 - Dual Induction Laterolog.

depth (ft)	R_{LLB} (Ω -m)	R_{IM}	R_{ID}	$\frac{R_{LLB}}{R_{ID}}$	$\frac{R_{IM}}{R_{ID}}$	$\frac{R_{xo}}{R_t}$	$\frac{R_t}{R_{ID}}$	R_{xo} (Ω -m)	R_t
2602	40	28	23	1.74	1.22	2.25	0.90	46.58	20.70
2603	36	28	23	1.56	1.22	2.05	0.85	40.08	19.55
2604	34	28	23	1.47	1.22	2.00	0.84	38.64	19.32
2605	45	32	27	1.67	1.19	2.05	0.94	52.03	25.38
2606	40	31	26	1.54	1.19	1.95	0.91	46.14	23.66
2607	37	25	30	1.48	1.20	1.95	0.865	42.17	21.625
2608	44	32	27	1.62	1.185	2.00	0.93	50.22	25.11
2610	55	34	29	1.89	1.17	2.50	0.96	69.60	27.84
2611	50	32	28	1.785	1.14	2.40	0.98	65.86	27.44
2612	40	32	27	1.48	1.185	1.90	0.90	46.17	24.30
2613	35	31	26	1.35	1.19	2.00	0.84	43.68	21.84
2614	38	33	28	1.36	1.17	2.00	0.90	50.40	25.20
2615	37	32	27	1.37	1.185	2.00	0.85	45.90	22.95
2616	37	31	25	1.48	1.24	2.15	0.75	40.31	18.75
2617	35	28	23	1.59	1.22	2.05	0.85	40.07	19.55
2618	32	26	21	1.52	1.23	2.05	0.82	35.30	17.22
2619	26	21	17	1.53	1.24	2.20	0.75	26.78	12.75

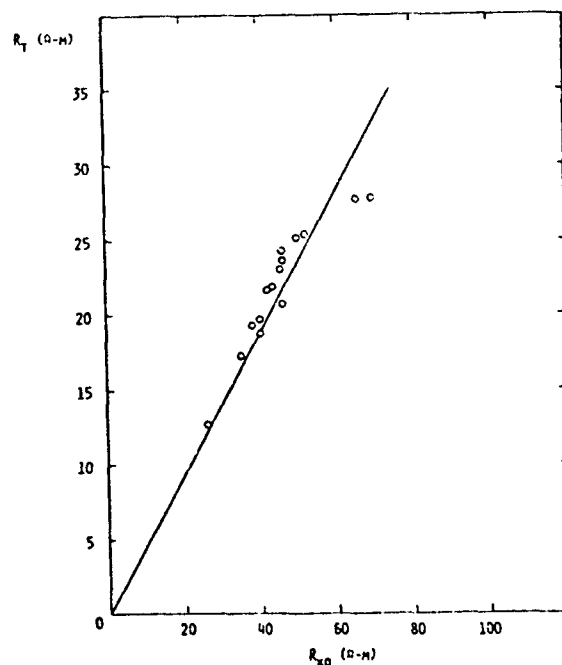


Figure 4. R_t versus R_{xo} for Example 1.

TABLE 2

Data for Example 2 - Induction-Electrical/Compensated Neutron.

depth (ft)	R_t (Ω -m)	ϕ (%)	$R_w = R_t^{2.28}/0.497$ (Ω -m)
5200	31.0	20.0	1.59
5202	35.0	19.5	1.69
5204	35.0	19.2	1.64
5206	35.0	19.0	1.60
5208	35.0	18.0	1.43
5210	40.0	20.0	2.05
5212	39.0	16.7	1.33
5214	36.0	18.0	1.45
5216	36.0	18.0	1.45
5218	36.0	18.0	1.45
5220	30.5	19.2	1.43
5222	39.5	19.8	1.98
5224	42.5	18.5	1.82
5226	40.0	18.0	1.72
5228	35.5	18.4	1.51
5230	31.0	18.2	1.28
5232	28.0	17.0	0.99
5234	25.5	17.8	1.00
5236	30.0	21.0	1.72
5238	30.5	19.0	1.39
5240	30.5	20.0	1.56

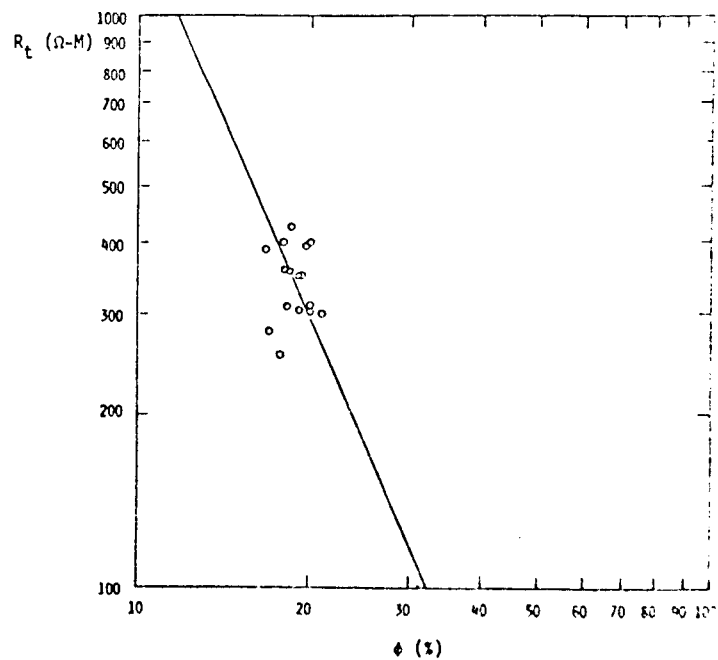


Figure 5. R_t versus ϕ for Example 2

TWO PHASE FLOW IN POROUS MEDIA AND THE CONCEPT OF RELATIVE PERMEABILITIES

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INTRODUCTION

New equations for the two phase flow of water and steam are presented. The new equations coincide with those already in use for the case of horizontal flow but are different from those for vertical flow. It is shown that the usual equations can only be valid when the two phases are flowing in separate channels, where the channel dimensions are large compared with the grain size of the porous media, and in such a case the relative permeabilities should vary only slightly with the saturation ratio. It is shown that the actual variation of relative permeabilities with saturation ratio suggests a flow model where the flow channel dimensions are of the same order of magnitude as the grain size. On this basis a new set of equations is proposed, which with the associated flow model explain relative permeabilities qualitatively. In addition they show that water can flow upwards in two phase flow where the pressure gradient is less than hydrostatic. In a simple two phase flow test it is demonstrated that this happens as predicted by the new equation set.

RELATIVE PERMEABILITIES

Relative permeabilities are permeability reduction factors, when two phases are flowing simultaneously. They are used in connection with Darcy's law, as it has been used for two phase flow, as follows:

$$\hat{v}_w = \frac{k \hat{k}_{rw}}{\mu_w} \left(- \frac{\partial p}{\partial z} - \rho_w g \right) \quad (1)$$

$$\hat{v}_s = \frac{k \hat{k}_{rs}}{\mu_s} \left(- \frac{\partial p}{\partial z} - \rho_s g \right) \quad (2)$$

The velocities, $\hat{v}_w$ and $\hat{v}_s$ are the average water and steam velocity with respect to the total seepage area. Another possibility of extending Darcy's law to include two phase flow is to use the average velocity with respect to the actual seepage area eqs. 1 and 2 would then be

$$v_w = \frac{k k_{rw}}{\mu_w} \left(- \frac{\partial p}{\partial z} - \rho_w g \right) \quad (3)$$

$$v_s = \frac{k k_{rs}}{\mu_s} \left(- \frac{\partial p}{\partial z} - \rho_s g \right) \quad (4)$$

where k_{rw} and k_{rs} are defined as follows:

$$\hat{k}_{rw} = S_w k_{rw} \quad (5)$$

$$\hat{k}_{rs} = (1-S_w) k_{rs} \quad (6)$$

Both definitions of the relative permeabilities will be used in the following discussion to avoid confusion. As can be seen from eqs. 1 and 2 the only forces acting on the two phases are the resistance force and the force of gravity. There are no interfacial forces between the two phases. The only flow model, where no forces between the phases occur is when water and steam flow in separated large channels. In such a case the relative permeabilities would only be area reduction factors defined as:

$$\hat{k}_{rw} = S_w \quad (7)$$

$$\hat{k}_{rs} = (1-S_w) \quad (8)$$

Most laboratory measurements of relative permeabilities seem to indicate that they are dependant on saturation to the power two or higher. Wyckoff and Botset (1936) investigated the flow of mixtures of liquid (water) and gas (carbon dioxide) and their results for relative permeabilities are given in fig. 1, which will be used for reference permeability curves in the following. The separate channel model is therefore not viable, as it is not in agreement with measurements. For further references see for example Chen et al. (1978) and Counsil and Ramey (1979), in which measurements of relative permeabilities for steam and water are given.

MACROSCOPIC FLOW MODEL

Since the two phases are not flowing in large separated channels, there must exist some interfacial force between them and the phases will be flowing at different velocities with some slip between them. One possibility is to use a macroscopic flow-model, in which it is envisaged that there are large bubbles of steam in water or large drops of water in steam. Here large is used in a relative sense in comparison with the grain size. If we consider for example the case of large bubbles of steam in water, Yih (1965, p. 216) gives for the velocity slip between the phases for horizontal flow as:

$$S = \frac{\hat{V}_s}{\hat{V}_w} = \frac{3\mu_w}{2\mu_s + \mu_w} \quad (9)$$

By assuming horizontal flow the slip factor is obtained from eqs. 1 and 2:

$$S = \frac{\hat{V}_s}{\hat{V}_w} = \frac{\mu_w}{\mu_s} \frac{\hat{k}_{rs}}{\hat{k}_{rw}} \quad (10)$$

By comparing eqs. 9 and 10 we obtain:

$$\frac{\hat{k}_{rs}}{\hat{k}_{rw}} = \frac{3}{\frac{\mu_s}{\mu_w} \left(2 \frac{\mu_s}{\mu_w} + 1 \right)} \quad (11)$$

Eq. 11 then gives the ratio of the relative permeabilities independent of saturation, which is clearly not in agreement with measurements as indicated by fig. 1. The macroscopic flow model is thus not viable and the flow channels must be of the same size as the grain dimensions and a microscopic flow model is more relevant. The relative permeability factors would in this case be porosity reduction factors and as indicated by most research results the permeability is a function of porosity to the third power. The relative permeabilities would then fit the experimental data in fig. 1 as shown by Irmay (1954).

MICROSCOPIC FLOW MODEL

In this model it is assumed that the water is in contact with the solid skeleton and that the steam forms channels in the water without contacting the solid skeleton. The forces per volume acting in this case would be as follows.

1) Force between solid and water:

$$\frac{V_w \mu_w}{k k_w} \quad \text{for water}$$

where k_w is a permeability reduction factor for water.

2) Force between water and steam:

$$- \frac{1}{S_w} (C_1 V_w - C_2 V_s) \quad \text{for water}$$

$$\frac{1}{1-S_w} (C_1 V_w - C_2 V_s) \quad \text{for steam}$$

where C_1 and C_2 are certain unknown constants.

3) Forces of gravity and pressure:

$$I_w = - \frac{\partial p}{\partial z} - \rho_w g \quad \text{for water}$$

$$I_s = - \frac{\partial p}{\partial z} - \rho_s g \quad \text{for steam}$$

Taking the force balance for steam and water we obtain:

$$\frac{V_w \mu_w}{k k_w} = I_w - (C_1 V_w - C_2 V_s) \frac{1}{S_w} \quad (12)$$

$$0 = I_s + (C_1 V_w - C_2 V_s) \frac{1}{1-S_w} \quad (13)$$

Inserting eq. 13 into eq. 12 and rearranging the terms gives:

$$V_w = - \frac{k k_w}{\mu_w S_w} \left(\frac{\partial p}{\partial z} + (S_w \rho_w + (1-S_w) \rho_s) g \right) \quad (15)$$

Eq. 13 then gives for the steam phase

$$V_s = \frac{1-S_w}{C_2} I_s + \alpha V_w \quad (16)$$

where α is defined as the ratio between the two constants C_1 and C_2 . Here α is the ratio between the maximum velocity of water and the mean water velocity. In a laminar flow of water and steam in a circular pipe α would be equal to 2. Eq. 16 can be rewritten by redefining the constant C_2 , as

$$V_s = \frac{k k_s}{\mu_s (1-S_w)} I_s + \alpha V_w \quad (17)$$

where k_s is some permeability reduction factor. Using the definition of I_s eq. 17 becomes

$$V_s = - \frac{k k_s}{\mu_s (1-S_w)} \left(\frac{\partial p}{\partial z} + \rho_s g \right) + \alpha V_w \quad (18)$$

by comparing eqs. 15 and 18 with eqs. 3 and 4 the relative permeabilities in the case of horizontal flow are:

$$k_w = \hat{k}_{rw} \quad (19)$$

$$k_s = \hat{k}_{rs} - \alpha \frac{\mu_s}{\mu_w} \frac{1-S_w}{S_w} \hat{k}_{rw} \quad (20)$$

If we take for example, $\alpha = 2$, $\frac{\mu_s}{\mu_w} = 1/6$ and $\hat{k}_{rw} = S_w^3$, the maximum value of the last term in eq. 20 becomes equal to 0.05, and can thus be neglected. Eq. 20 then becomes

$$k_s \approx \hat{k}_{rs} \quad (21)$$

In the case of horizontal flow eqs. 15 and 18 reduce to eqs. 3 and 4. The necessary condition to maintain upward flow of water then becomes

$$- \frac{\partial p}{\partial z} > (S_w \rho_w + (1-S_w) \rho_s) g \quad (22)$$

which can be compared with the necessary condition derived from eq. 1:

$$- \frac{\partial p}{\partial z} > \rho_w g \quad (23)$$

According to eq. 23 the pressure gradient must be greater than hydrostatic pressure in order to obtain upward flow of

water. Eq. 22, which is derived from eq. 15, allows water to flow vertically upwards, although the pressure gradient is less than hydrostatic.

FLOW TESTS

To investigate the behaviour of two phase vertical flow, a test was performed in a vertical 4" circular tube in the laboratory. The set-up is schematically shown in fig. 2.

Pressure and temperature are measured in four different levels. The steam phase and water phase are separated and measured at the top end. The flow is always upwards.

A porous gravel test medium of crushed basalt was used. The permeability was measured as being 545 Darcy. The test was not intended to show the variation of relative permeabilities with saturation so saturation was not measured, but test with porous media of other permeabilities needs to be made. The reason for completely omitting the saturation measurements in this work is the uncertainty of the known methods in use at present to measure this parameter.

The results of the tests are shown in table 1. They fall into three categories, according to the no-slip saturation, which is the saturation one would have if both water and steam were flowing with the same velocity. In the 8 first runs, S_w^0 is 2% or lower. The flow is mostly steam with very little water flow and in one case the relative permeability for water proves to be negative, which means that the water should flow downwards according to eq. 3., but in fact actually flows upwards. Otherwise the k_{rw} values behave normally, but are much higher than would be expected for these very low water saturations.

In the next five runs water and steam are flowing in more equal proportions. The k_{rw} values are all much too high, i.e. a lot more water is flowing than can be explained by eq.3.

In the next six runs there is very little or no steam. The k_{rw} values are practically equal to one as would be expected.

The test shows clearly that eqs. 3 and 4 cannot explain the results except in the six cases where the flow is almost purely water. The relative permeabilities calculated from eqs. 15 and 18 behave in accordance with theory. To demonstrate this k_{rs} is calculated, by assuming that the value of k_{rw} is equal to S_w^3 as seems to be the conclusion in the majority of cases of investigation. In these cases both S_w and k_{rw} can be calculated and the results are shown in fig. 3, and the result is quite in agreement with theory and experiments. This means that the microscopic flow model eqs. 15 and 18 fully explain the test results, whereas the macroscopic flow model (eqs. 1-4) does not.

DISCUSSION

In the literature there are two different definitions in use for relative permeability. The relative permeabilities as defined in these different ways, are related, but have very different numerical values (see eqs. 5 and 6). Careful distinction between these two is necessary especially when reporting research data. In many of the existing papers on the subject it is impossible to see whether k_{rw} and k_{rs} are being used or $\hat{k}_{rw}$ and $\hat{k}_{rs}$.

Reported laboratory tests on relative permeabilities show that they depend on saturation to the power two or higher. The eqs. 1-4 can only be valid when the fluid shear stress is transmitted directly to the solid skeleton. The relative permeability is actually a permeability reduction factor, and as it varies with saturation to the power two or higher it does not matter if the definition k or $\hat{k}$ is used, since the resulting shear stress in the water phase is always higher than if water was flowing alone with the same average velocity. From this one can conclude that a macroscopic flow model, i.e. a flow model where the water is assumed to flow more or less alone either in large channels or big droplets, does not explain the reported behaviour of the relative permeabilities.

On the other hand, if it is assumed that the gas phase is displacing the liquid phase from the pores then a microscopic flow model is envisaged. In this the steam may be flowing in more or less continuous channels or paths, but these have a cross-sectional dimension of the same order of magnitude as the pores, or less. The steam is flowing within the water, with a velocity higher than the water velocity. The resulting average velocity slip creates a shear stress between the two phases, this shear stress is transmitted through the water to the rock. It increases the velocity in the water and lessens the possibility of the heavier phase flowing downwards while the lighter phase is flowing upwards.

The microscopic model, eqs. 15 and 18, is distinctly different from the macroscopic model, eqs. 1-4, in the case of vertical flow. In the case of horizontal flow the two models yield the same equations, provided a correct definition of the relative permeabilities is used (eqs. 19 and 21). The conditions for maintaining upwards flow of water is markedly different for the two flow models (eqs. 22 and 23). This is of great importance for the calculation of geothermal convection, and it also explains the "chimney effect" of geothermal areas, i.e. a pressure level within a geothermal field that is lower than the pressure level of all surrounding aquifers. When calculating the flow towards a well, or other flows under the influence of great pressure gradients, only small differences are to be expected between the results of the two models.

Flow tests, performed in a vertical tube support the theories put forward. In a third part of the tests measured

relative permeabilities show no permeability reduction but rather an increase in permeability, and this is accepted as impossible according to all researchers, the relative permeability being always less than one for all saturations. The 1/3 of the tests mentioned is performed under such conditions that neither the steam phase nor the water phase dominates the other, i.e. neither water saturation nor steam saturation are extremely low. The resulting 2/3 of the tests behave normally with respect to the relative permeabilities.

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NOMENCLATURE

- g = Projection of the acceleration of gravity on the flow direction (m/sec^2).
- k = Permeability (Darcy)
- $k_{rw}, k_{rs}, \hat{k}_{rw}, \hat{k}_{rs}$ = Relative permeabilities for water and steam respectively.
- $\dot{m}_w, \dot{m}_s$ = Mass flow of water and steam respectively (kg/sec).
- p = Pressure (N/m^2).
- S_w = Saturation of water.
- S_w^o = No-slip saturation of water.
- S = Slip factor.
- $\hat{V}_w, \hat{V}_s, V_w, V_s$ = Mean velocity of water and steam respectively (m/sec).
- X = Mass fraction of steam.
- z = Coordinate in the flow direction (m).
- ρ_w, ρ_s = Density of water and steam respectively (kg/m^3).
- μ_w, μ_s = Dynamic viscosity of water and steam respectively ($kg/m \text{ sec}$).

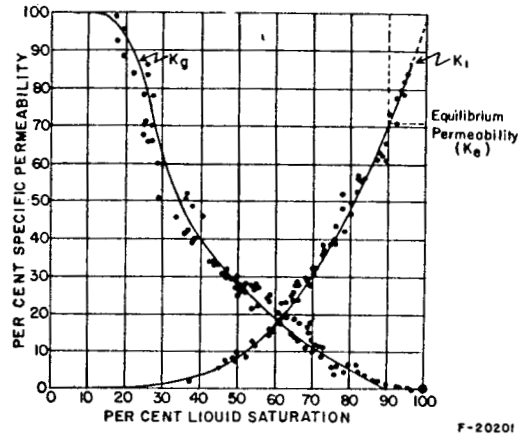


Fig. 1 Permeability - saturation relation for unconsolidated sand.
(Wyckoff and Botset (1936)).

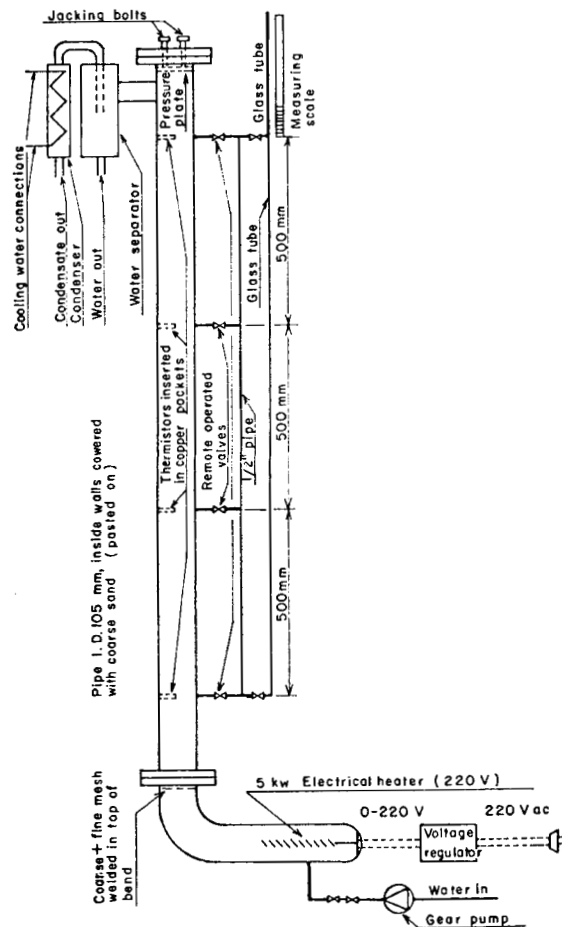


Fig. 2 Experimental setup for measuring two phase flow in porous media.

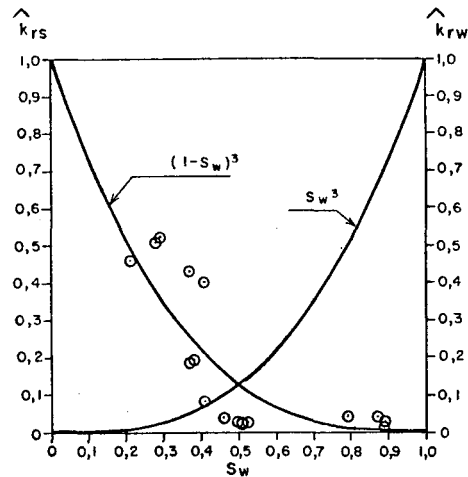


Fig. 3 Relative permeability for steam as calculated from experiments.

TABLE 1

Test no.	$\dot{m}_w$ kg/sec.	$\dot{m}_s$ kg/sec.	X %	I_w N/m ³	I_s N/m ³	S_w^0 %	$\dot{m}/I_w$ m ² . sec	Relative permeab. for water	Dominating phase in volume
1	$1.11 \cdot 10^{-3}$	$1.36 \cdot 10^{-3}$	55.1	411.2	9810.08	0.05	$0.27 \cdot 10^{-5}$	0.17	Steam
2	2.44	-	33.5	235.0	9633.85	0.13	1.04	0.66	
3	2.77	-	30.8	274.1	9673.01	0.15	1.01	0.64	
4	5.00	-	17.2	391.6	9868.82	0.32	1.28	0.81	
5	7.22	-	12.3	920.3	10319.18	0.47	0.78	0.49	
6	5.00	-	8.1	254.5	9653.43	0.75	1.96	1.24	
7	5.55	-	7.7	332.9	9731.75	0.80	1.67	1.06	
8	6.11	-	3.0	-137.1	9261.81	2.10	-4.45	-2.82	
9	8.47	-	1.0	313.3	9712.17	6.04	2.70	1.71	Water and steam
10	10.42	-	0.8	391.6	9790.50	7.82	2.67	1.69	
11	10.69	-	0.6	391.6	9790.50	10.03	2.73	1.73	
12	11.25	-	0.5	391.6	9790.50	11.00	2.87	1.82	
13	10.55	-	0.5	391.6	9790.50	11.93	2.69	1.70	
14	39.09	-	0.4	2291.0	11689.85	13.95	1.71	1.08	Water
15	34.84	-	0.4	2506.0	11905.24	16.01	1.39	0.88	
16	38.18	-	0.3	2408.0	11807.34	18.14	1.59	1.00	
17	40.00	-	0.2	2428.0	11826.92	26.25	1.65	1.04	
18	40.00	-	0.1	2526.0	11924.82	47.09	1.58	1.00	
19	38.78	-	0.0	2448.0	11846.50	100.00	1.58	1.00	

THE EFFECT OF TEMPERATURE ON THE
ABSOLUTE PERMEABILITY TO DISTILLED WATER OF
UNCONSOLIDATED SAND CORES

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INTRODUCTION

Absolute permeability is an important parameter in the evaluation of the performance of geothermal and hydrocarbon reservoirs. The primary production of oil and gas reservoirs normally is isothermal. This is not the case for geothermal reservoirs or for many enhanced oil recovery projects. In these reservoirs the temperature of the formation changes, and as a result, many of the formation properties change. Absolute permeability is an essential parameter, and it is important to study the effect of temperature on absolute permeability.

Experiments investigating the effect of temperature on absolute permeability have been carried out during the last decade. These experiments covered a range of rock types, fluids, confining pressures, and several other system parameters. It is evident that not all results are in agreement. In some cases the same observation yielded different interpretations. The investigation of the effect of temperature on the permeability to distilled water of Berea sandstones is an example of interpretation disagreement. Certain researchers claim fine sand migration causes an apparent change in the permeability, while others attribute changes to elevated temperature effects.

The work presented herein is a study of the effect of temperature on the absolute permeability to distilled water of unconsolidated sandstones at one confining pressure.

DESCRIPTION OF APPARATUS

Figure 1 presents a schematic diagram of the absolute permeability apparatus. The equipment was designed to produce the absolute permeability of a core at steady-state conditions of temperature, flowrate, and confining pressure. The apparatus consists of a coreholder, a flow system, a confining pressure system, an air bath, and a temperature-pressure-flowrate monitoring system.

The coreholder is a Hassler-sleeve type. The core is placed in a Viton tube supported by a perforated aluminum sleeve. Fine mesh screens were placed at both ends of the core to prevent sand from flowing. The end plugs are designed to ensure linear flow in the core and minimize converging flow stream lines. The pressure taps are located at the sand faces of the core.

The flow system includes an accumulator dampened pulsation pump that generates the flow of distilled water. Flowrate is controlled by a downstream needle valve, and the pore pressure is maintained by an upstream relief valve.

The confining system is pressurized by a hydraulic hand pump. An oil-water pressure vessel transmits the oil pressure to the confining water.

The air bath houses the coreholder. It is a potentiometric-controlled air bath which produces a constant temperature environment with insignificant temperature oscillations.

The monitoring system handles temperature, pressure drop across the core, and the flowrate. Temperature is measured in the flow lines upstream and downstream of the core. The coreholder temperature is measured as well. Effluent temperature is measured to convert room volumetric flowrates to run conditions. The pressure drop across the core is measured and recorded continuously during the run. Volumetric flowrates at room conditions are measured by a graduated cylinder and a timer.

PROCEDURE

The sand is sieved and washed with distilled water. Washing is done to minimize the amount of fines. Then the sand is dried at 60°C-70°C. The coreholder is packed and the dimensions of the core are measured. The core is evacuated while being confined at 2000 psig. The core is flowed after a vacuum of 1 Torr or less is established and maintained for several hours.

Several measurements of the permeability are made at a given temperature. The permeability is calculated for two or three flowrates. Then the average permeability and the errors are calculated. Two temperature cycles are carried out in every run with a run lasting about three days.

The runs are followed by a visual inspection of the core plug to ensure that no damage is evident.

SUMMARY OF RESULTS

Ottawa silica sand was used to construct the cores. In Runs No. 8 and No. 9, 150 mesh sand was used, and in Runs No. 10 and No. 11, 200 mesh sand was used. Every run consisted of two heating cycles to 300°F. A constant confining pressure set at 2000 psig was maintained throughout the runs. There was no evidence of fines migration at the downstream end of the system. In general, there were no problems in establishing steady-state conditions and measuring the absolute permeability.

Figure 2 presents the permeability at various temperatures as obtained in the described experiment. No significant change of the absolute permeability with respect to temperature and time was observed. The permeability at room temperature was reduced by about 5% after one heating and cooling cycle. The permeabilities at 250°F and 300°F were constant during the two temperature cycles. During the first heating cycle, the permeability dropped and then remained fairly constant. This suggests that upon the first heating of the sand, several things can be triggered, such as readjustment of the sand grains or a change in the characteristics of the wetting layer. The packing procedure for the core provides good reproducibility of the permeability. For all practical purposes, the two types of sands, 150 mesh and 200 mesh, produced the same permeability vs temperature behavior. About 200 pore volumes of distilled water were injected in every run, and no dependence of the permeability on time was observed. This is attributed to the initially high permeabilities of the packs, about 2500 md to 5000 md, and to the sieving and washing of the sand prior to packing.

Figure 2 also shows the experimental errors. The experimental errors were in the range of $\pm 2\%$ to 4%. The variations in measurement at a given temperature were in the range of $\pm 1\%$ to 2%.

CONCLUSIONS

The absolute permeability to distilled water of Ottawa silica sand was not dependent on the temperature level. This result agrees with much of the data in the literature. Thus far it is believed that some of the work done at Stanford University in the last few years experienced some mechanical problems that resulted in unreliable results. To expand these conclusions, several experiments will be carried out. These experiments will study a variety of consolidated sandstones as well as a range of confining pressures. The absolute permeability experimental work is leading to a continuing work on the relative permeability dependence on temperature level.

It should be emphasized that temperature level effects on capillary pressure and relative permeabilities for sandstones are still important.

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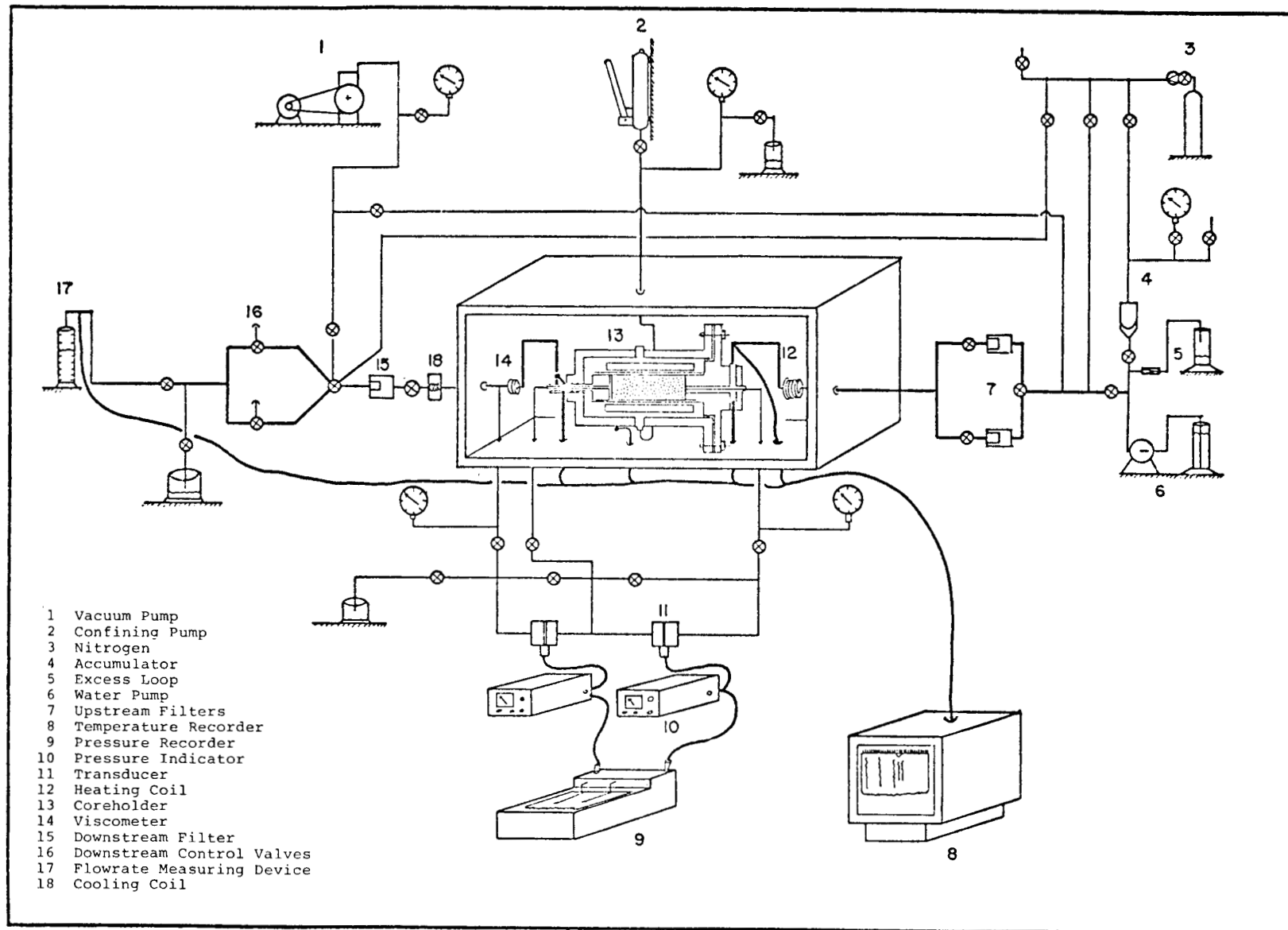


FIG. 1: SCHEMATIC DIAGRAM OF THE APPARATUS-WATER FLOW

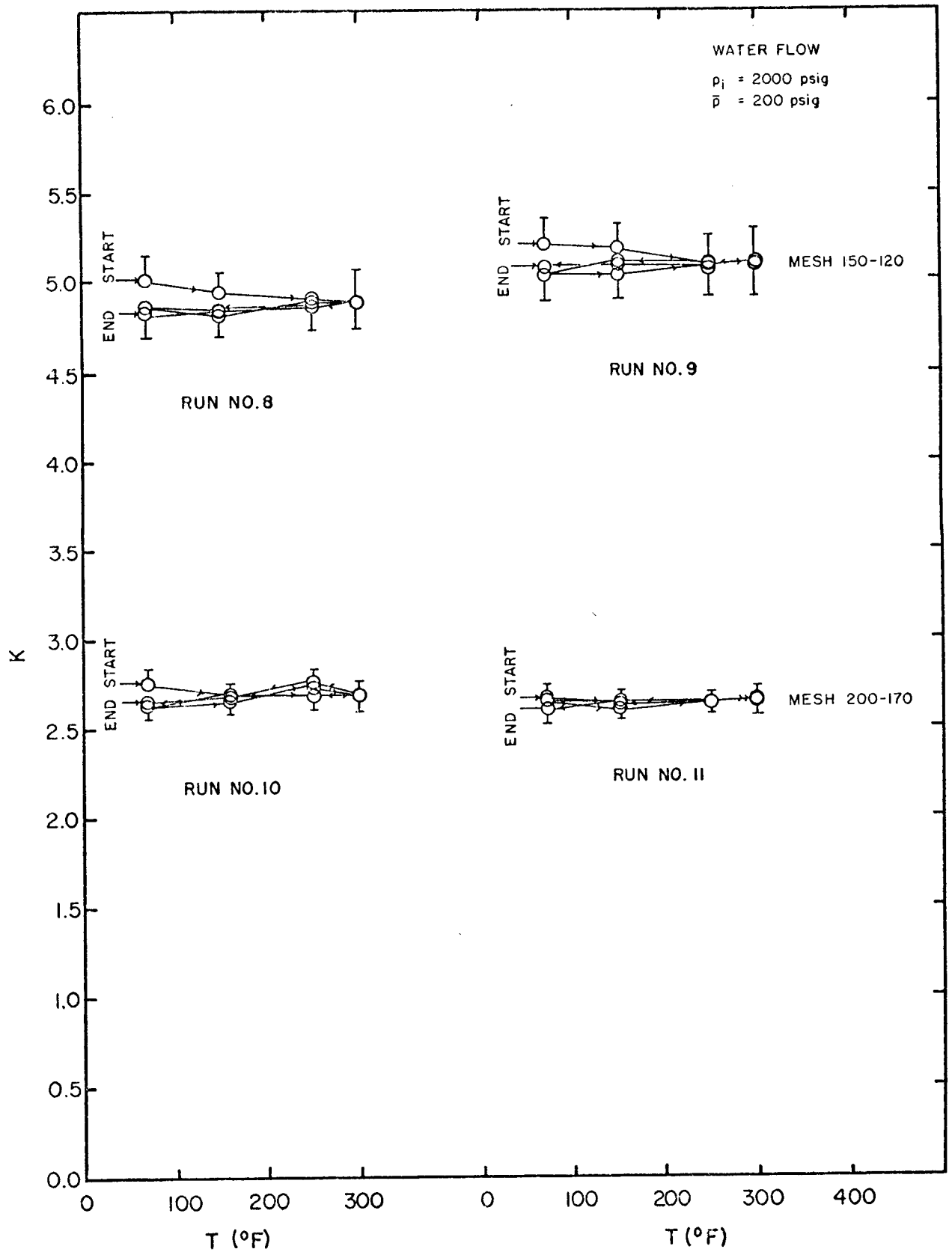


FIG. 2: DISTILLED WATER PERMEABILITY VS TEMPERATURE FOR UNCONSOLIDATED SILICA SAND CORES

LOG INTERPRETATION TECHNIQUES TO IDENTIFY PRODUCTION ZONES
IN GEOTHERMAL WELLS

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Abstract

Identification of production zones in a fractured or faulted geothermal well is quantitatively difficult. Temperature and spinner surveys along with flow tests are the techniques generally used to identify and describe these fractured zones during production testing. These techniques generally do not describe the production zones in any detail and they miss or bypass potential zones of production when fractures have been closed or plugged during the drilling process. These latter zones could possibly be stimulated (hydraulic fracturing, acidizing, explosive fracturing) and brought into production if all the fracture zones could be identified and described. Interpretation techniques using wireline logs show promise in identifying and describing fractured (open and closed) zones in geothermal wells. The strategy described in this paper on two different geothermal wells (the hot dry rock well and the Surprise Valley well) used a trial and error basis to outline and define the interpretation techniques that work best in each case. Fracture zones are identified that are both open and closed and this type of information gives a better estimation of reservoir size, flow control and reservoir life (production potential) from geothermal wells.

Introduction

Isolation of potential production zones by perforating a cemented casing is a common and routine practice in reservoir engineering for oil and gas production. Open hole and slotted casing completion techniques are used occasionally in competent formations, but lack the control and definition of the production zones. In geothermal well completions and usual geothermal reservoir engineering practice, open hole and slotted casing completions are routine. The definition of the actual production zone or zones is generally not known very well, if at all.

Isolation of potential geothermal production zones in fractured igneous rock is difficult. Detection of fractures with a single reliable logging or interpretation technique has not yet been developed. In an article, "Current Status on the Study of Naturally Fractured Reservoirs," the authors, R. Aguilers and H. H. Poolen, list eight different techniques for resolving the fracture identification problems in oil and gas reservoirs. These eight techniques of fracture identification are supported by 214 references, and 32 of these references are related to log-analysis techniques. The interpretation techniques that are useful for a specific hydrocarbon well and field are found on a trial and error basis. This is also the strategy that has been used in geothermal wells and fields.

Fracture Zone Identification

In the Geothermal Well Log Interpretation State-of-the-Art Report (LA-8211-MS) 11 logs or log interpretation techniques are discussed that might be used for the location of fractures. These logs or log interpretation techniques are:

- (1) Borehole geometry (caliper logs)
- (2) Temperature surveys
- (3) Acoustic logs (full wave sonic, amplitude waves, cycle skipping, etc.)
- (4) Porosity comparisons (sonic vs neutron vs density)
- (5) Borehole televiewer
- (6) Spontaneous potential - SP (streaming potential)
- (7) Resistivity logs
- (8) Compensated density log (correction curve)
- (9) Multiarm microresistivity logs (dipmeter)
- (10) Spectral gamma log (potassium, uranium, thorium content)
- (11) Rock strength (bulk modulus computed from sonic and density logs).

An example of the use of some of these techniques for evaluation of fractures in a hot dry well at Fenton Hill, New Mexico will be presented. Five techniques were used to define and quantify the variable termed "Frac." The techniques used were:

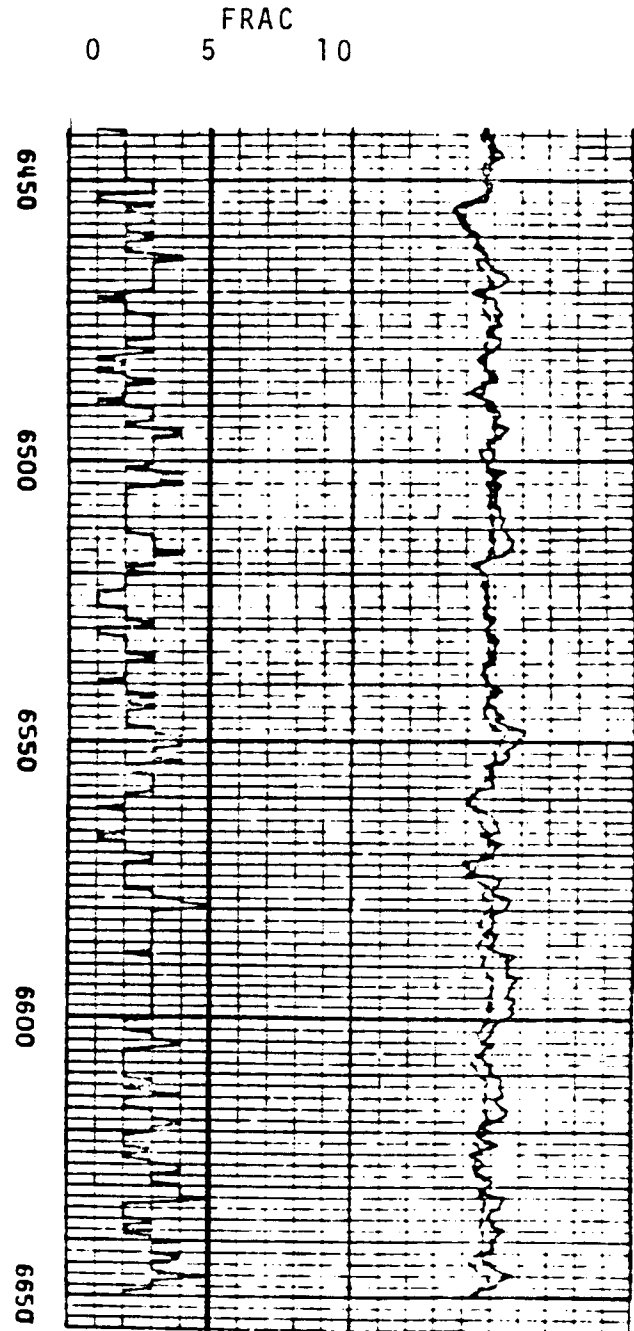
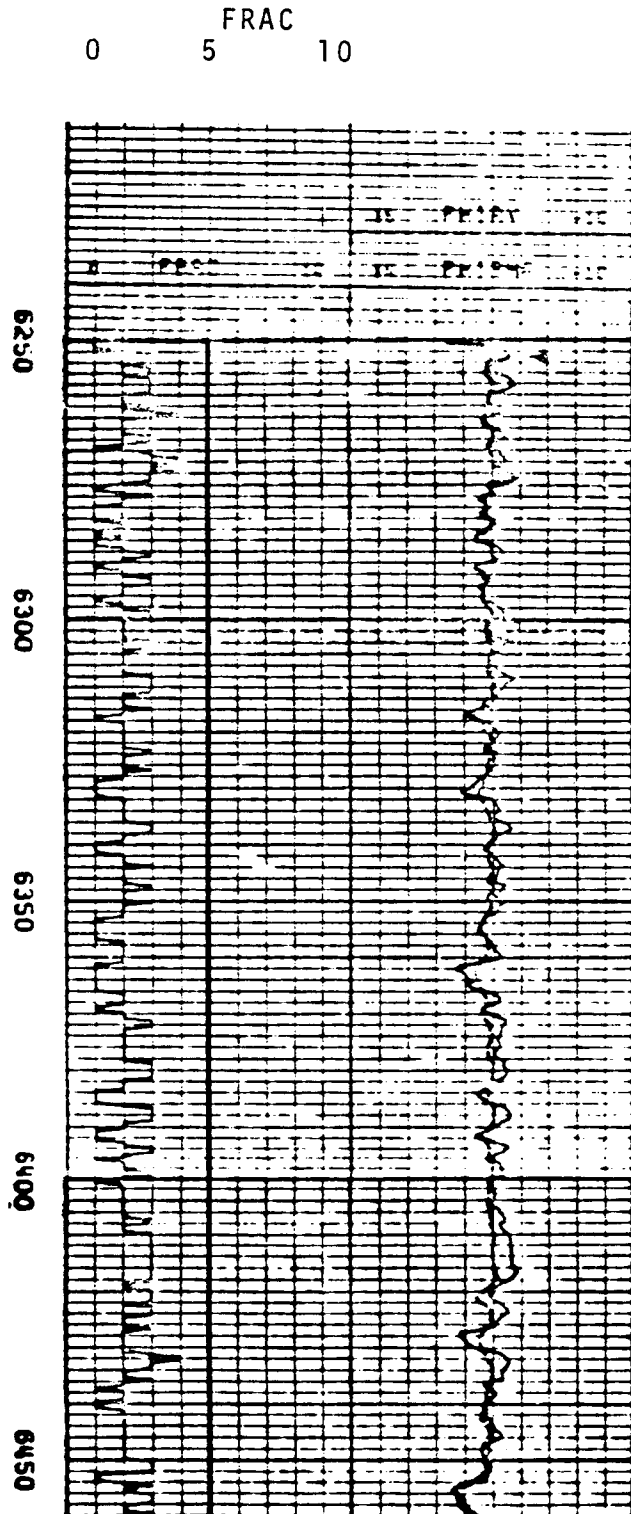


Figure 1: Fracture Detection Technique for Well GT-2.

- (1) Resistivity
- (2) Caliper (hole washout)
- (3) Correction curve for density log when borehole is in gauge (excessive correction)
- (4) Comparisons of porosity (sonic vs density vs neutron)
- (5) Rock strength (mechanical properties using sonic and density logs).

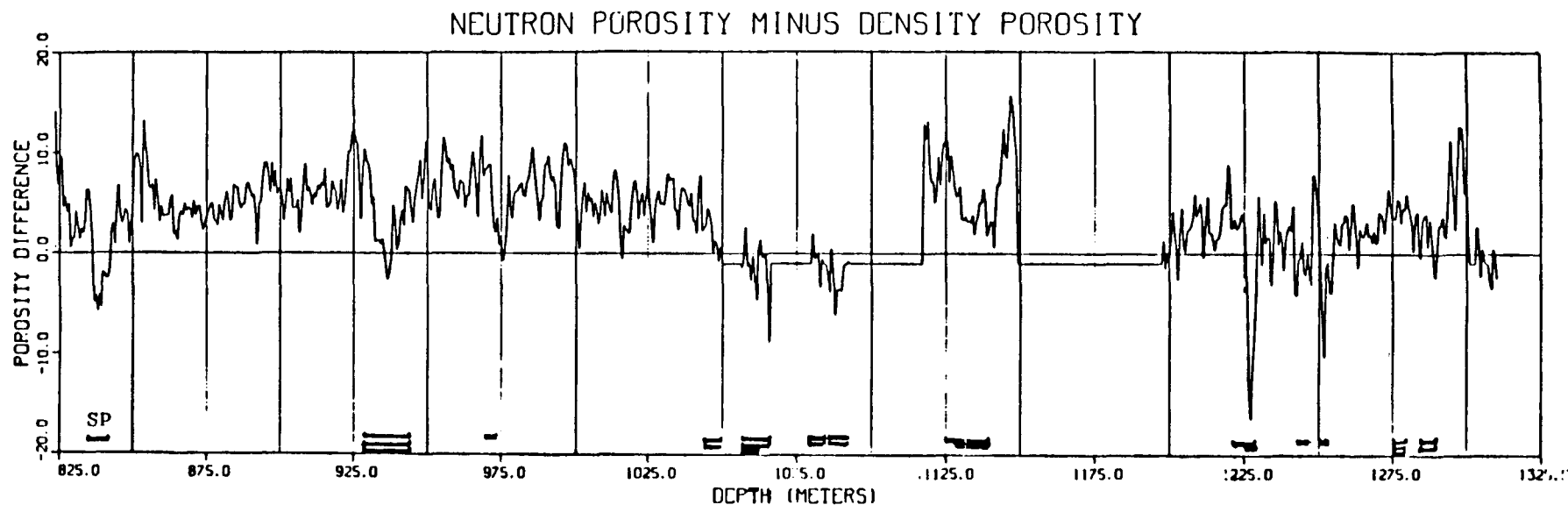
A list of each technique that indicated a fracture at a given depth was added a value of 1 to Frac. With a range of 0 to 5, the larger the value of Frac, the possibility of the existence of fractures increases. This result of the application of this method is displayed in Figure 1.

The description of the rock in the interval from 1905-2027 m (6250-6650 ft) is given by Pettitt, 1975, and Kintzinger and others, 1977, as predominantly light pink granite. The zones from Figure 1 that have values of 5 for Frac are at depths of 2006.1 m (6580 ft), 2022 m (6632 ft). These zones are fractured as described by Kintzinger (1977). We note that no estimates of permeability were made, but it is estimated that values were very low.

Another example of fracture detection is presented in the case history report on Surprise Valley, California for the Phipps No. 2 geothermal well. This well was drilled through a complex igneous lithology sequence consisting of basalt, breccia, agglomerate, volcanic ash, and welded tuff. The detailed description of the lithologic column was accomplished through the use of well cuttings and various wireline logs. The potential open and closed fractures were identified by log interpretation techniques. These are:

- (1) Spontaneous potential (SP) combined with the resistivity logs
- (2) Density response
- (3) Neutron response.

The SP deflections on the order of 10 to 15 millivolts indicated an open fracture in this well. Also the difference in the neutron porosity (ϕ_N) and the calculated density porosity [$\phi_D = (\rho_m - \rho)/(\rho_m - 1)$], where ρ_m



Difference in porosity value from the neutron log and porosity calculated from the density log. Washed out intervals are set to -1 to render them easily identifiable. The position of SP deflection is shown by bars along the bottom of the plot. One bar corresponds to a deflection greater than 5 mV; two bars, greater than 10 mV; and three, greater than 15 mV. Below 1200 meters location of the SP deflections depends on correlation of the electric logs from the original hole and the redrill and is somewhat less precise.

Figure 2. Fracture Detection Techniques for Well Phipps No. 2.

is the matrix density and ρ is the density log value, indicated open and closed fractures. The washed out intervals were determined from the caliper log and are set to -1 to render them easily identifiable. Where the porosity difference becomes negative (see Figure 2) and corresponds to a SP deflection, these indications denote zones of open fracturing. These zones should be isolated and tested for hot water production. Note that no estimates of permeability of the zones can be made from the log data.

Conclusions

Production zones of geothermal wells that are related to fractures can be identified by the use of drill cuttings and wireline logs. Each geothermal field or area has local conditions that suggest the various interpretation techniques for detecting and evaluating fracture systems. No single reliable interpretation technique for detecting and evaluating fracture systems has been developed. A trial and error approach with various logging and interpretation techniques to locate and evaluate fractures has been shown in two different geothermal fields in this paper. Production testing of the zones indicated as fractures will verify these results. If the results are positive, this type of information will yield better reservoir size definition, flow control, and estimation of production from geothermal wells.

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BENEFIT ANALYSIS FOR GEOTHERMAL LOG INTERPRETATION

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Abstract

Formation evaluation is of great importance in geothermal development because of the high capital costs and the fact that successful exploration will only pay off through a subsequent decision to construct a power plant or other utilization facility. Since much formation data is available from well logging, development of new techniques of log interpretation for application to geothermal wells is called for. An analysis of potential near-term benefits from this program and the types of formation data called for is discussed. Much useful information can be developed by adaptation of techniques used in oil and gas reservoirs, but the different demands of geothermal development from hydrocarbon production also open up new data requirements.

Introduction

Well logging for the petroleum industry first developed in the 1920's and 1930's when there was a sufficient demand for logging services to stimulate industry. Logging techniques have developed slowly over a period of decades. These techniques are sometimes unsuited to the needs of geothermal development, partly because the types of data called for are not identical to the data needs of the petroleum industry, and partly because of the different logging conditions that obtain in geothermal wells. Today, because geothermal development has barely begun, there is only limited demand to stimulate the development of specialized geothermal logging services. However, by developing the knowledge necessary to interpret the characteristics of geothermal reservoirs from log data immediately, the geothermal industry will benefit and development of geothermal resources may be accelerated. The Geothermal Log Interpretation Program at the Los Alamos Scientific Laboratory is charged with the development of log interpretation techniques to address geothermal problems. As part of this effort an assessment was made of potential benefits that might result from application of improved logging data.

Benefit Identification

The analysis focuses on development of hydrothermal resources for electric power generation. This is likely to embrace the bulk of

near-term geothermal development. Development of hot dry rock and geopressed resources, and development for geothermal non-electric applications, are not yet sufficiently advanced for a quantitative projection of their logging requirements.

Improvements in the process of geothermal development can come about in three ways. A direct reduction in the costs associated with development will produce a benefit equal to the dollars saved. This benefit may ultimately be realized as a reduction of the cost of power or as increased investment in development elsewhere, which will yield benefits indirectly. A reduction in the risk of development will produce benefits of two types: the cost of development is effectively reduced if losses are cut and development may be accelerated by increased availability of investor capital in response to the reduced risk. Finally, improved data that can aid the process of applying for and obtaining regulatory permits can allow more rapid completion of proposed power plants.

Geothermal development is highly capital intensive. Initial investment involves not only the cost of field development, but also power plant construction. Furthermore, since several production wells are required to supply a power plant, revenue may not be realized until the entire investment is made. Payout on the investment occurs over the 20 to 30 year life of the power plant, which may substantially exceed the life of individual production wells. This renders geothermal development extremely sensitive to initial risk. A large amount of capital is at risk for an extended period, and there is a substantial delay between investment and the commencement of revenues.

Reinjection is another important feature of geothermal development. Reinjection of produced brine will be required in all, or virtually all, geothermal development. The enormous quantities of brine involved make this a major factor, approximately doubling the number of wells required. In addition, the large volumes withdrawn and reinjected raise serious questions regarding the possibility of subsidence or induced seismicity. This may be a significant issue in the permitting process. This places additional value on knowledge of reservoir structure and the mechanical properties of the formation. Permeability and the pattern of flow in the reservoir also become important since reinjection may be needed to maintain productivity.

Log data can be applied to benefit a geothermal development program in a number of ways. Table I summarizes potential beneficial impacts of the development of improved techniques for geothermal logging and interpretation.

Benefit Estimate

A quantitative estimate of possible near-term benefits from research in geothermal logging and interpretation, based on development of hydrothermal areas for electricity generation in the U.S.,

was prepared for LASL. The estimate was based on a Department of Energy scenario of geothermal development and drilling costs and corrected for inflation and energy costs to 1981 dollars. Details of the scenario and cost/benefit analysis can be found in References 1, 2 and 3. Benefits were grouped into five classes of cost savings plus the benefit of earlier power-on-line. Gross benefits (no allowance for cost of logging and interpretation) in constant 1981 dollars were:

• Improved drilling success	\$175.8 x 10 ⁶
• Reduced exploratory drilling	\$ 49.5 x 10 ⁶
• Reduced flow testing	\$ 78.4 x 10 ⁶
• Reduced drilling costs	\$175.8 x 10 ⁶
• Reduced reinjection requirements	\$ 80.3 x 10 ⁶
• Scenario acceleration	\$328.6 x 10 ⁶

Drilling Success

Wells are sited on the basis of the picture of the reservoir that is built up from geophysical and geological survey data for the area and data from other wells. Obviously, the first well on a site cannot benefit from log data, but later wells may. Inter-well correlation is an established tool for revealing reservoir structure. Another application of log data which holds potential value in well siting is the use of the well log to improve or clarify the analysis of other geophysical data. Combination of seismic data with sonic log data has produced good results in the petroleum industry (Ref. 4) and might also be useful in geothermal studies. Rigby and McEuen (Ref. 5) give an example of use of resistivity log data in combination with magnetotelluric data to examine a geothermal reservoir. Development of borehole to surface and borehole to borehole techniques may also offer benefits.

Reduction of Expenditures on Unsuccessful Exploratory Wells

Decisions to abandon drilling in a poor well or to perform clean-ups, run a liner, and test a marginal well are difficult and may involve a large fraction of the total well cost. Formation temperature can be an important factor in decisions made during drilling (such as whether to continue to greater depth). Technology that could assist in estimating formation temperature away from the disturbance near the borehole would be useful (Ref. 6). Assessment of permeability is a second important concern in the decision to clean up and test a well. Location and density of fracturing can be valuable information in this context.

Reduced Well Costs

Log data are used in preparing bit and casing plans and in other drilling decisions. It is important to develop an experience base regarding lithologic identification and its relationship to drillability in the igneous and metamorphic lithologies frequently encountered in geothermal wells. Assessing porosity and degree of alteration has been found to be difficult in some areas due to uncertainties in tool response to fracturing and to hydrothermal alteration products. Determination of dominant fracture orientation might also be taken advantage of to control drilling to achieve maximum intersection of fractures. Selection of target depths can be a problem when the geologic goal is not a stratified formation. Logging during drilling to determine temperature, porosity, fractured zones encountered, etc. may be economically desirable in some geothermal areas where well costs are high.

Reduced Flow Testing

Because of the high capital investment involved in the power plant, flow testing may be prolonged, even for wells in established geothermal areas. Large production intervals, uncertainty in locating permeable zones, and heterogeneous formations may make flow test analysis difficult. In dual porosity formations (discreet major fractures together with more disseminated porosity) distinguishing porosity types can be important, as can data on fracture separation. Increased confidence in flow test analysis may allow reduced testing time or an equivalent indirect benefit.

Reduced ReInjection

Requirements for 100 percent reinjection or deep reinjection can represent a significant cost factor. Aside from these, permitting delays may also be encountered due to disputes over the reinjection plan. An effective reinjection plan is also valuable to long-term reservoir performance. Information on the hydrologic regime and in situ fluid characteristics, location of major faults and fractures, reservoir boundaries and other structural features, permeability and communication between reinjection and production areas, and mechanical properties of the reservoir rock may be of value in planning and permitting. The ability to monitor for early signs of compaction could also be of value.

Accelerated Power-On-Line

Much greater than any of the five preceding classes of cost reductions is the benefit that may accrue to the nation from time savings which can lead to an earlier start of power plant construction and earlier power-on-line. A key factor in this is the decision by a utility or other investor to commit capital for a power plant,

and this will depend on the confidence placed in whatever model or picture of the reservoir there is. Important data will include reservoir temperature and pressure, evidence of resource extent and thickness (to which log-constrained inversion of geophysical data may contribute), hydrologic evidence such as formation fluid salinities, and analysis of reservoir permeability and porosities.

Conclusion

In geothermal development the significant problems of formation analysis and log interpretation contain several shifts in emphasis from conventional practice in the search for fossil fuel resources. Significant national benefits are possible in the form of cost reductions and of more rapid development. The most obvious example is the paramount importance of temperature and temperature gradient. Other factors are introduced by the different reservoir structures, the high cost of drilling in many geothermal areas, and the high capital investment involved in the surface plant.

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Table I. Impact of Improved Interpretation and Application of Logged Data

IMPACT	ACTIVITY	REQUIREMENTS
Improved Drilling Success Rate	Exploration Development Program	Better Interaction with Other Exploratory Data, New Logging Techniques Better Knowledge of the Reservoir
Reduced Drilling Cost	Development Program and Reservoir Modeling	Preplanning Wells, Improved or More Rapid Completion, Better Selection of Total Depth
Reduced Testing Time	Assessment	Reduced Flow Testing of Production Wells Based on Greater Comparability and Relation of Logged Parameters to Production Characteristics
Improved Reinjection Program	Environmental Protection Reservoir Management	Justification for Less Than 100% Reinjection, Justification for Shallow Reinjection Better Control of Reinjection Well Clogging
Smoother Permitting	Environmental Protection	Better Control of Subsidence and Seismicity, Ability to Monitor Reservoir
Reduced Number of Exploratory Wells	Exploration	Achievement of Development Agreements Based on Fewer Wells, Reduced Investment "Up Front"
Accelerated Development	Reservoir Modeling and Assessment	Earlier Utility Commitment
Facilitation of Unitization Agreement or Other Regulations Controlling Development	Development Program	Earlier Agreement, More Equitable Allotment of Revenues or Drilling Rights
Plant Design	Plant Operation	Easier or Earlier Determination of Brine Chemistry
Improved Well Performance	Reservoir Management	Application to Selection of Completion and Well Stimulation Techniques
Extended Field Life	Reservoir Management	Reservoir Monitoring, Improved Modeling, and Reinjection Control
Location of New Resources or Resources That Would Otherwise Be Overlooked	Exploration	New Techniques and Interaction with Surface Data

EFFECT OF TEMPERATURE AND SOLUTION COMPOSITION ON THE PERMEABILITY
OF ST. PETERS SANDSTONE: ROLE OF IRON (III)

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INTRODUCTION

Understanding of the permeability of reservoir rocks at elevated temperature is becoming increasingly important both in oil field development and stimulation and in geothermal energy production. Rock properties such as permeability are often measured at ambient conditions with reservoir characteristics then based on these ambient measurements. However, rock and fluid properties may be radically altered at elevated temperatures due to the enhanced rates of mineral dissolution and growth and other geochemical processes.

A number of previous experimental studies have focused on determining the permeability of sandstones at reservoir conditions: Aruna (1976) measured permeability using water, nitrogen, oil, and 2-octanol of quartz sandstones at reservoir conditions as a function of temperature. A strong reversible decrease in permeability was noted when water was used. Rock permeability to the other fluids showed essentially no change with temperature. These results were supported by similar experimental studies of Danesh and others (1978) and Gobran and others (1980). Experiments by Piwinski and Netherton (1977) have shown decreases in permeability during continuous flow of Salton Sea brines through sandstone cores at 90°C. Read (1980) has observed decreases in permeability during dissolution studies of sand packs and cores at temperatures to 260°C.

The purpose of this study was to systematically investigate the effects of temperature and fluid composition on the permeability of quartz sandstones. We have concentrated our initial efforts on the time and flow dependence at 2 elevated temperatures (100°C, 200°C).

EXPERIMENTAL APPARATUS AND PROCEDURE

The equipment used was designed for continuous flow permeability studies to 300°C at confining pressures to 1.5 kbars. Fluid used in the experiments is pumped with a single piston metering pump with a gas-fluid separator in line to dampen pressure pulsations. Fluid is preheated to within 2°C of the experimental temperatures prior to entering the core holder. Metering valves control outflow rate which is simultaneously measured using a ball float gauge. Differential pressure is measured with a differential pressure transducer and readout. The initial system was built using stainless steel tubing and preheater in the flow line system. A second system was later built using titanium tubing and a special teflon liner for the fluid preheater.

Cores 5 cm long by 2.5 cm diameter of St. Peter Sandstone (>99% quartz) were used in these experiments. At room temperature no permeability decrease due to particle migration or clay plugging has been observed in this rock. The fluid used was boiled, distilled, deionized water. Typically the core was placed in the pressure vessel and then evacuated for several hours. The core was saturated at room temperature, and the permeability measured. The core was then reevacuated and the pressure vessel -pressure lines heated to the desired experimental temperature. Permeabilities were measured continuously through the experiment after the core was resaturated at temperature. Viscosity and density of the fluid at experimental conditions were taken from the Handbook of Chemistry and Physics (1969).

RESULTS

The first experiment was run using distilled water and the stainless steel experimental system. The results are shown in Figure 1 (curve a). The relative permeability, normalized to a reference room temperature value K_0 , drops off non-linearly with time. After 400 minutes of flow the pump was shut off. After 5 additional minutes, flow was briefly resumed for an additional measurement. This was repeated several times to determine permeability (K) during the non-flow period. The apparent permeability of the rock increases to a steady level during this period, approximately 73% of the room temperature permeability, and about 8% higher than the value measured during the flow part of the experiment. The core was then reevacuated, resaturated, and the permeability remeasured, at the same temperature. The measured permeability was equivalent to that measured at the start of the first experiment, or 95% of the room temperature permeability. This sequence demonstrates the reversibility of the measured permeability with respect to flow and resaturation. After removal of the core from the permeameter a slight reddish discoloration was noticed on the input end of the core which extended .25 cm into the core.

The results using the stainless steel system suggested that some type of plugging mechanism was responsible for the permeability decreases. The iron derived from corrosion of the steel in the flow system was considered to be a possible fouling material. To test this possibility experiments were repeated at 100°C using an inert flow system equipped with titanium and teflon. Titanium was used because of its inert properties even under extremely corrosive solution conditions (low pH, high Eh). The results of this experiment are shown on Figure 1, (curve b). Essentially no change in permeability was observed even in 400 ml of flow.

To test the system's response at even high temperature, the core was evacuated and heated to 200°C. After resaturating, approximately 400 ml of water was flowed through the core with no observed decrease in permeability. The core was reevacuated and cooled to 100°C with no apparent decrease in permeability. After cooling to 21°C the entire heating and cool-

ing permeability cycle was repeated except that the core was kept saturated the entire time. Only very slight increase (<10%) in permeability was observed during either one of these cycles. The results of these two experiments are shown on Figure 2, where permeability is plotted as a function of temperature.

As a test of the ferric iron fouling hypothesis two experiments were run in the titanium flow system using a dilute FeCl_3 solution (10PPM) at 100°C . The first solution was passed through the core with the pH of the solution (3.5) determined by the hydrolysis of the Fe^{3+} . A second experiment was subsequently run on the same core with the pH of the solution titrated with KOH to 5 prior to entry into the flow system. The permeability of the unbuffered experiment decreased slightly with time, while the permeability of the higher pH experiment decreased more sharply with flow. Figure 1, curve c shows the results of these two experiments. The pH 5 solution became slightly murky with time due to the formation colloidal $\text{Fe}(\text{OH})_3$.

DISCUSSION

The results of our experiments suggest that temperature as such has an insignificant effect on the permeability of quartz sandstones. Non-inert experimental flow through system such as those built with stainless steel will show substantial flow dependent decreases in permeability at elevated temperature due to the precipitation of colloidal ferric oxides or hydroxides in the flow channels. We believe that the ferric ion is produced during the oxidation-corrosion of the steel. Very low concentrations of Fe^{3+} (10PPM or less) can cause measureable decreases in permeability in 30 ml or less of fluid flow at 100°C .

The experiments of Reed (1980) also indicate colloid fouling since he observed strong decreases in permeability with time at elevated temperature even though his solutions (at a pH of 11) dissolved a significant amount of quartz during the experiment. We believe that the results observed by Aruna (1976), Danesh and others (1978), and Gobran and others (1980), all reflect the ferric ion plugging phenomenon which is accentuated at elevated temperature. Our observations of the significant apparent permeability increase during periods of no flow may explain the partial reversibility of previous experimental permeability vs. temperature results. These results are also in agreement with those of Piwinski and Netherton (1977) in which they related sharp decreases in permeability of cores using Salton Sea brines to precipitation of ferric hydroxide and amorphous silica.

There are at least two possible mechanisms for permeability reduction by $\text{Fe}(\text{III})$; 1) buildup of colloidal $\text{Fe}(\text{OH})_3$ on surfaces in pore throats (colloid fouling), and 2) formation of large particles of $\text{Fe}(\text{OH})_3$ which collect in pore openings. The equilibrium of pH of a $\text{Fe}(\text{III})$ - bearing solution is determined by the hydrolysis of the Fe^{3+} ion. The extent of hydrolysis and nature of the hydrolyzed species depend on the equilibrium solution pH, temperature, and total iron concentration (Baes and Mesmer, 1976). In the experiment in which the solution was

titrated to a pH of 5 before entering the core, nearly all the initial Fe(III) in solution was converted to ferric hydroxide; whereas, in the lower pH solution, more non-colloidal Fe(III) hydrolysis products were present in solution. The magnitudes of the permeability decrease for the different pH solutions shown in Figure 1 indicate that the fouling mechanism is predominantly colloidal fouling. The coagulation rate of ferric hydroxide is probably low in the very low ionic strength solutions used. However, the pH of the solution is clearly the most important factor controlling ferric hydroxide colloid formation, coagulation, and subsequent reduction in permeability. The increase in apparent permeability during static non-flow periods also suggests colloid buildup at surfaces is reversible in these systems. The results suggest a colloid fouling mechanism for permeability reduction may be important in natural systems containing Fe(III)-bearing solutions especially at elevated temperatures.

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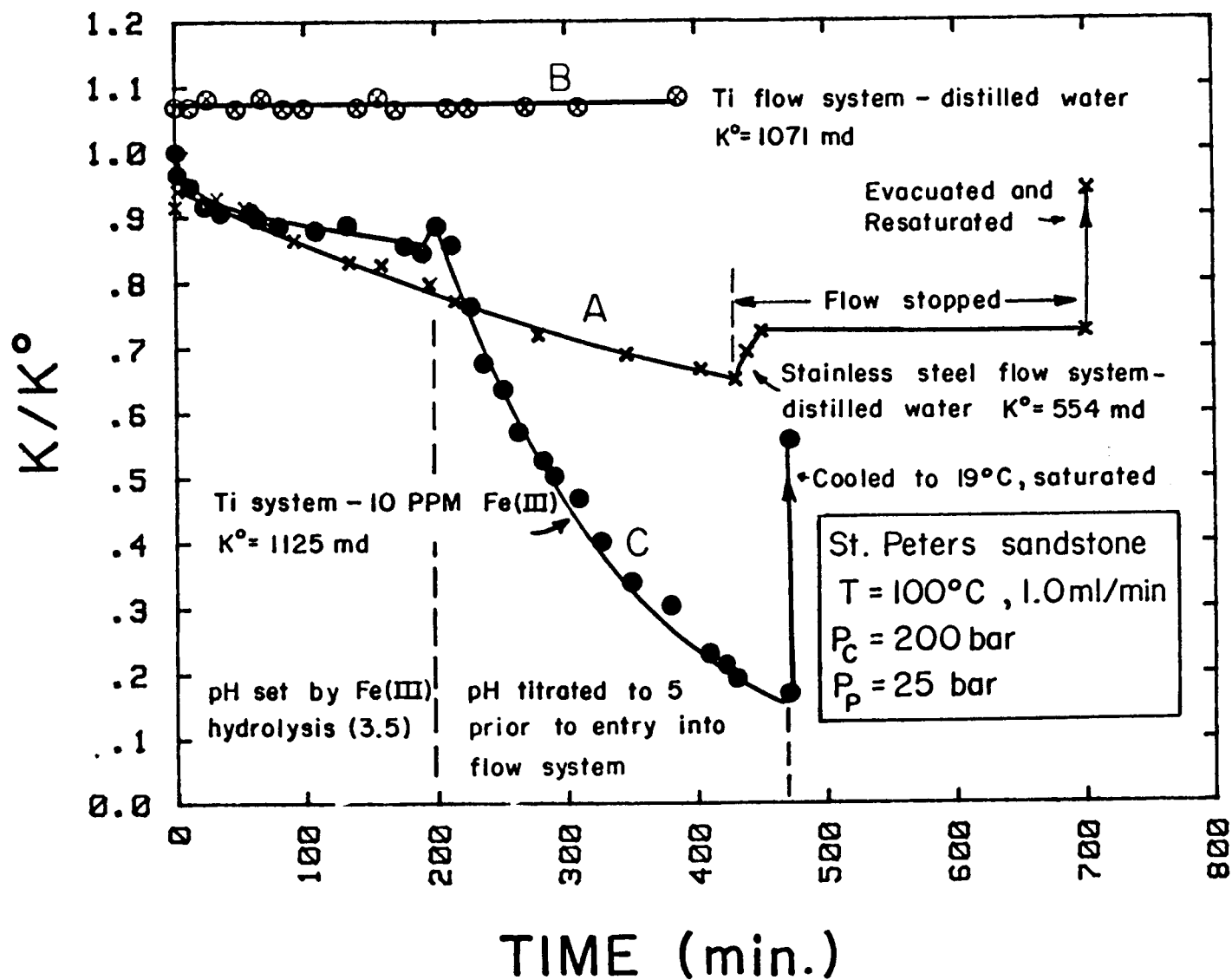


Figure 1. Normalized permeability as a function of time for St. Peters flow experiments at 100°C.

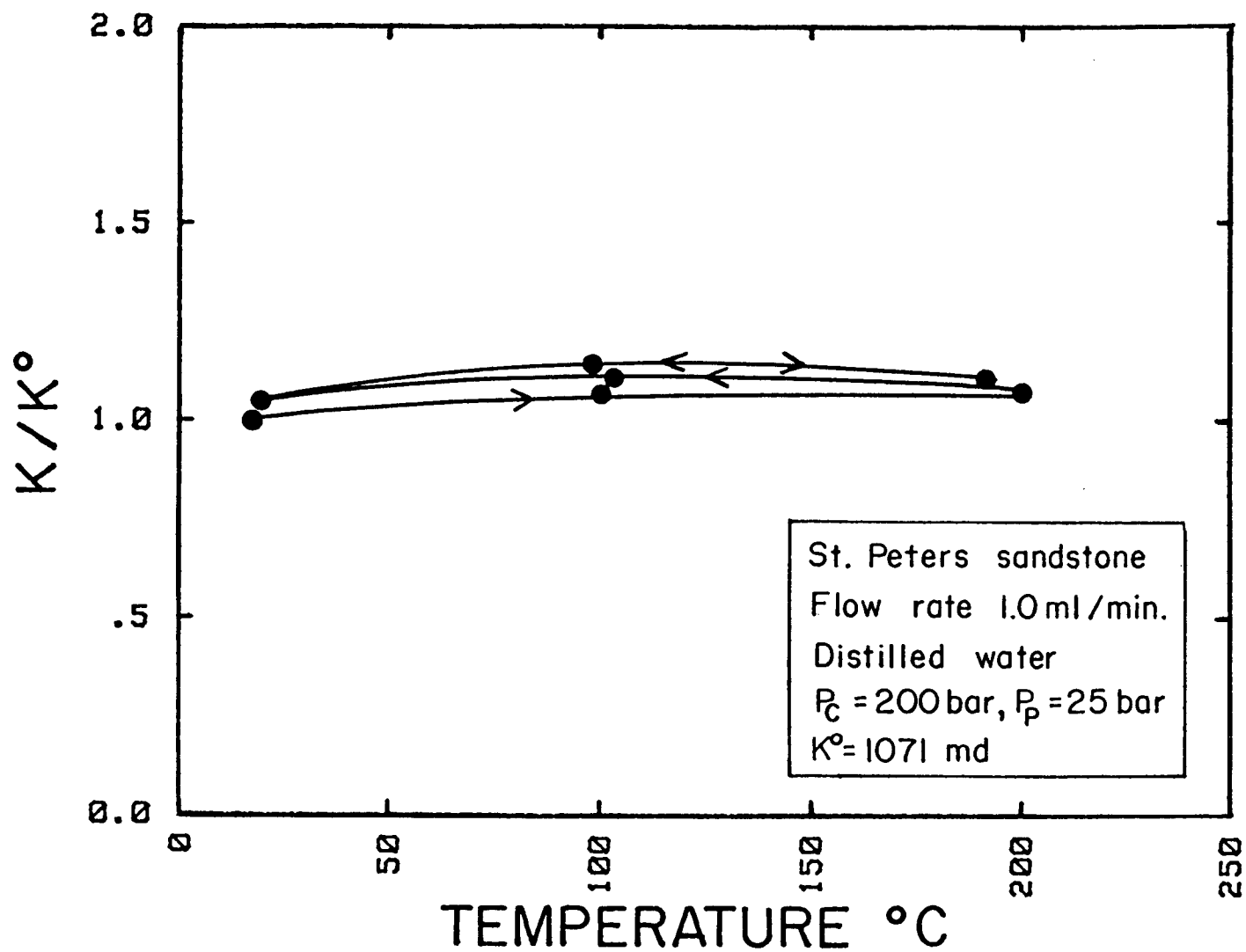


Figure 2. Normalized permeability as a function of temperature, St Peters sandstone.

TRANSIENT STEAM FLOW IN POROUS MEDIA - THEORY AND EXPERIMENT

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INTRODUCTION

A previous workshop summary (Herkehrath and Moench, 1978) described laboratory studies of transient steam flow in a porous medium. The results indicated that the time required for steam-pressure transients to propagate through the medium was as much as 30 times greater than predicted by standard noncondensable gas-flow theory. It was hypothesized that the delay in the steam pressure breakthrough was caused by adsorption of steam in the porous sample. This "adsorption lag effect" has been incorporated into the following revised model of steam flow in a porous medium.

THEORY

The steam-flow model used was basically that developed by Moench and Atkinson (1978), modified to take steam adsorption into account (Moench and Herkelrath, 1978). The equation used to describe one-dimensional, linear steam flow in a porous medium is

$$\frac{\partial}{\partial z} \left(\frac{\rho_v K}{\mu_v} \frac{\partial P}{\partial z} \right) = \phi \frac{\partial}{\partial t} (\rho_v (1-S)) + q' \quad (1)$$

in which the variables are as defined in table 1. This equation differs from the standard transient gas flow equation in that a sink or source term for steam, q' , has been added to account for adsorption or vaporization of adsorbed water. In the analysis, the Klinkenberg effect (Klinkenberg, 1941) was taken into account by assuming that the permeability was a function of pressure:

$$K = K_0 (1 + b/P) \quad (2)$$

A simplified form of the energy equation was used in the model:

$$L_v q' = H_c \left(\frac{dT}{dt} \right) \quad (3)$$

To obtain equation 3, it was assumed that temperature changes in the porous medium occur only as a result of phase changes.

In the model it was assumed that water adsorption occurs in the porous medium at steam pressures below the saturated vapor pressure. The vapor pressure of adsorbed water was assumed to be a function of the temperature and the amount of water adsorbed:

$$P = P(T,S) = P_0(T) R(S) \quad (4)$$

$P_0(T)$ represents the saturated vapor-pressure function, and $R(S)$ is the function relating the relative vapor pressure in the porous material to the fraction of the pore space which is filled by adsorbed water.

The equations were solved using the finite-difference methods developed by Moench and Atkinson (1978).

EXPERIMENTS

The steam-flow experiments were modeled after the classic transient gas-flow experiments reported by Wallick and Aronofsky (1954). The test medium used was a uniform cylindrical pack of a natural unconsolidated, fine sand. In the experiments reported here, the sample was initially evacuated at the running temperature, and then exposed to a low pressure steam source until temperature, pressure, and amount of water adsorption were constant throughout. High pressure steam was then abruptly introduced at one end ($Z=0$), and the resulting pressure transient was measured with a pressure transducer at the other end of the cylinder ($Z=L$), which was closed to provide a zero-flow boundary. Values of the parameters are shown in table 2.

Results of the experiments are summarized in figures 1 and 2. Figure 1 consists of plots of the steam pressure at $Z=L$ as a function of time since the step increase in pressure occurred at $Z=0$. When the same pressure boundary conditions were imposed using nitrogen gas as the fluid, the pressure breakthrough was 10 to 25 times faster than that shown in figure 1.

Figure 2 is a plot of the equilibrium vapor pressure in the sample as a function of the amount of water adsorption, expressed as liquid saturation. These data were obtained by exposing the sample to a known relative humidity until equilibrium was obtained, and then weighing it to determine the amount of adsorption. These results are very similar to those reported by Hsieh (1980).

To simplify the numerical calculations, the $R(S)$ function was obtained by least-squares fitting the adsorption isotherm to the empirical function

$$R(S) = 10^{-(10^{(A-S)/B})} \quad (5)$$

DISCUSSION

The empirical vapor-pressure-lowering curve obtained at 100°C was used in the model to simulate the experiments run at 100°C, 125°C and 146°C. The 100°C data were used because a complete set of data at higher temperatures was not available. However, the

results of the pressure-transient simulations were affected only by changes in slope of the vapor-pressure curve, and preliminary data indicated only a small change in the slope at increased temperature.

As shown in figure 1, agreement between theory and experiment is excellent for all the runs, thus verifying the model for the conditions of study. It should be emphasized that no fitting has been done to obtain the theoretical curves; all the parameters were measured independently.

A U.S. Geological Survey open-file report is being prepared to document these results more completely.

Table 1

Notation

A and B	= Fitting factors in relative vapor-pressure function
b	= Klinkenberg slip factor
H_c	= Heat capacity of porous medium
K	= Permeability
K_o	= Intrinsic permeability
L	= Sample length
L_v	= Latent heat of vaporization
P	= Steam pressure
$P_o(T)$	= Saturated vapor-pressure function
q'	= Rate of steam adsorption
R(S)	= Relative vapor-pressure function
S	= Liquid saturation, fractional
T	= Temperature
t	= Time
Z	= Position in sample
μ_v	= Viscosity of steam
ϕ	= Porosity
ρ_v	= Vapor density

Table 2

Values of Parameters*

A	= 8.65×10^{-3}
B	= 2.30×10^{-2}
b	= 1.4×10^5 dynes/cm ²
H _c	= 3.2×10^{-1} cal/cm ³ °C
K _o	= 3.6×10^{-8} cm ²
L	= 61.0 cm
φ	= 0.42 cm ³ /cm ³

*Remaining parameters are known properties of water at prevailing temperature and pressure

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PRESSURE IN BARS AT $Z=L$

TRANSIENT STEAM FLOW

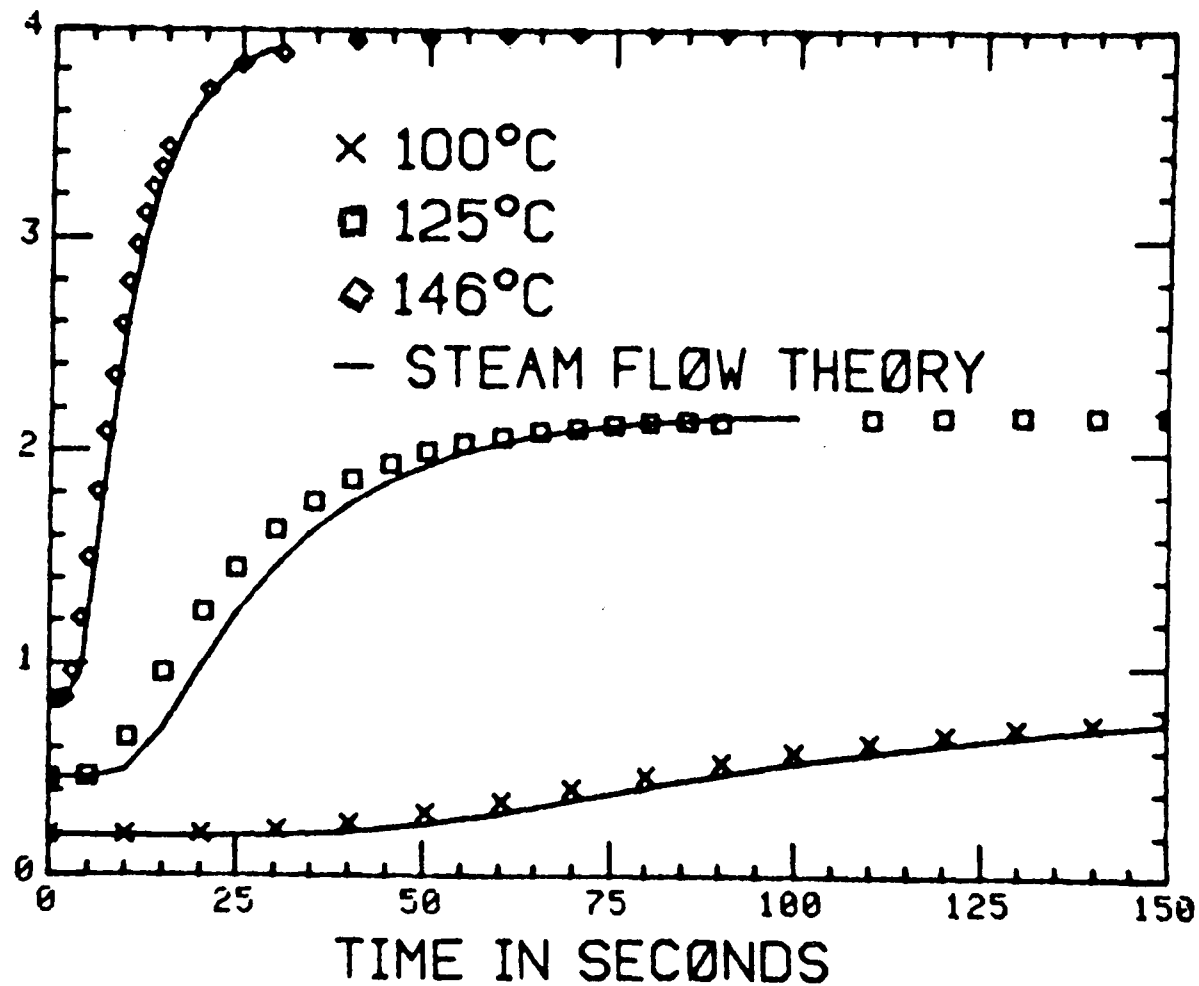
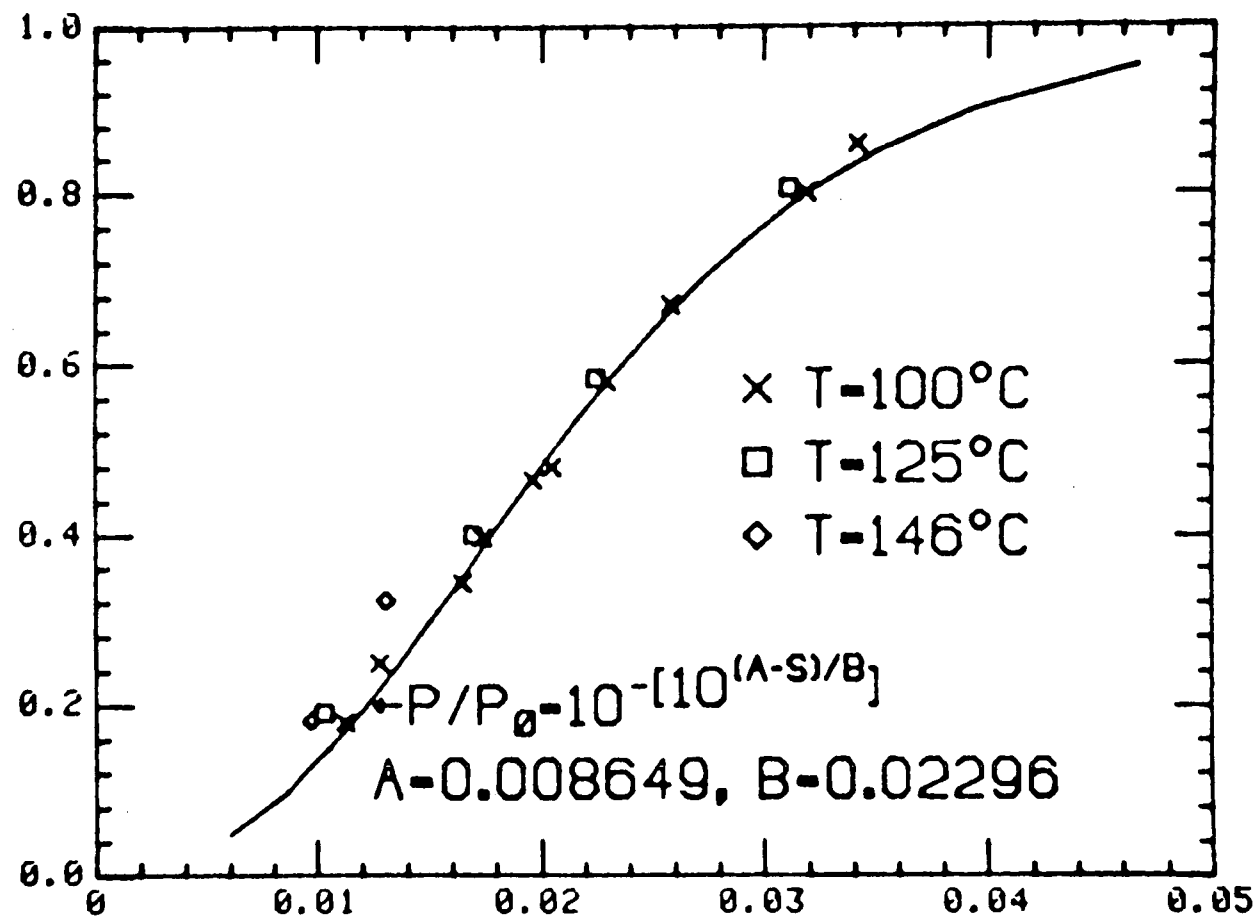


Figure 1. Steam pressure at the closed end of the porous cylinder ($Z=L$) as a function of the time since a step increase in pressure was imposed at $Z=0$. The solid lines represent computer simulations of the experiments.

RELATIVE VAPOR PRESSURE, P/P_0

VAPOR PRESSURE LOWERING



LIQUID WATER SATURATION, S , FRACTIONAL

Figure 2. Equilibrium relative vapor pressure in the porous sample as a function of the amount of water adsorption, expressed as a liquid saturation. The solid line represents the empirical equation which was used in the steam-flow simulations.

EFFECTS OF TEMPERATURE AND SATURATION ON THE VELOCITY
AND ATTENUATION OF SEISMIC WAVES IN ROCKS:
APPLICATIONS TO GEOTHERMAL RESERVOIR EVALUATION

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INTRODUCTION

In the evaluation of a geothermal resource it is critical to know the reservoir geometry, temperature, saturation, state of saturants, pore pressure, porosity and permeability. These are the parameters which will determine the production feasibility and cost effectiveness of a geothermal prospect. The increasing sophistication of seismic wave data collection and processing and recent experimental work on factors governing wave propagation in rocks has stimulated increased interest in the use of active seismic techniques to determine the in situ physical state of crustal rocks for engineering applications. In this paper we review experimental work showing how wave velocities in rocks are sensitive to parameters of interest to geothermal exploration; effective pressure, the degree of water saturation of the pores, and the bulk modulus of the pore phase. Seismic attenuation is even more sensitive to the degree of saturation and the microgeometry of the pores. Both velocity and attenuation are strongly temperature dependent and reflect thermal fracturing of the rocks at elevated temperatures. By combining data on attenuation and velocity of compressional and shear waves considerably greater constraints may be placed on the environmental state of the rocks than on the basis of P velocities alone.

WAVE PROPAGATION IN ROCKS

It is now well known that the major factor governing wave propagation in rocks is the presence of small interconnected pores and cracks within the rock. Seismic wave velocities depend on the elastic moduli and the density of the rock, and the presence of pores may alter these parameters. All pores in rock tend to lower the effective moduli and hence lower the velocity, but long narrow pores are much more effective in softening the rock than equidimensional ones. The dissipation factor Q^{-1} of seismic waves, defined as the fractional energy loss per wave cycle, is generally controlled by the interaction of the dynamic strain wave in the rock with fluids and/or gasses contained in the pores which irreversibly dissipate energy from the wave. As the presence of pores is the most important factor controlling wave propagation

in rocks, most features of wave propagation are relatively insensitive to lithology but very sensitive to the environmental conditions of the rock.

As an example the dependence of compressional (V_p) and shear (V_s) wave velocities in Berea sandstone (porosity 20%) on effective pressure and saturation is shown in Figure 1. The results indicate that pore pressure is roughly as effective in lowering velocity as confining pressure is in raising it. Both V_p and V_s increase rapidly with effective pressure at low pressure due to the closing of thin microcracks. Above about 200 bars velocities increase more slowly with pressure as most of the small aspect ratio pores have been closed. V_p is greater in fully saturated rocks than dry rocks as the fluid filled pores makes the rock stiffer in bulk compression. The shear wave velocity in contrast does not depend on the bulk modulus, only the shear modulus, and as the shear modulus of fluid is zero, saturating the pores does not increase the effective shear modulus of the sample; rather it increases its effective density and lowers the velocity. Thus when both V_p and V_s are known we may distinguish between fully saturated and dry or partially saturated rocks. This effect is particularly apparent in the velocity ratios, or Poisson's ratio (Figure 2): Dry rocks have lower ratios than saturated rocks, and for the saturated samples the ratio depends on the type of fluid present. Because steam has a much lower bulk modulus than water a steam saturated sample would behave more like a dry rock, even if small amounts of water were present. The saturation effect is present at elevated pressures.

Figures 3 and 4 show in more detail the dependence of extensional waves, a combination of pure shear and bulk compression, and shear waves on water saturation S_w . Over most of the saturation range velocities are insensitive to S_w . At $S_w < 1\%$ velocities increase rapidly with decreasing saturation. Small amounts of water weaken the rock, possibly due to chemical reactions of the water with grain boundaries. There is a small negative slope over the intermediate saturation range due to the increased effective density as the pores fill with fluids. At S_w of 95% the extensional velocities increase rapidly as the pores are becoming completely filled with water which stiffens the rock in bulk compression. There is no effect on shear, which again shows how V_p/V_s may be diagnostic of the change from fully to partially saturated rocks. Figure 4 shows that attenuation is much more sensitive to the degree of saturation than velocities. At low saturations attenuation is very low. Adding small amounts of water to completely dry rock increases attenuation drastically, to a peak at $S_w \sim 1\%$. At S_w from 2% to about 50% attenuation is roughly constant. At $S_w = 60\%$ the extensional attenuation begins to increase with further saturation due to the motion of fluid in pores which dissipate energy from the passing wave. This occurs mostly in bulk compression, hence the higher attenuation of extensional waves. In a fully saturated rock pressure induced flow within pores ceases, whereas shear induced flow between interconnected pores is maximized. At $S_w \sim 85\%$ the extensional attenuation begins to decrease and shear attenuation increases and they cross over at about 98% saturation.

WAVE ATTENUATION

Figures 5 and 6 show the dependence of compressional and shear wave attenuation on pressure and saturation in Massillon sandstone. Increasing pressure closes pores and decreases attenuation. Again attenuation is very low in dry rocks whereas in partially saturated rocks ($S_w \approx 95\%$) attenuation is significant probably due to intracrack fluid flow, with P attenuation about twice as large as S. In fully saturated rock, intercrack flow is eliminated, Q_p^{-1} is sharply lowered and again shear attenuation due to intercrack fluid flow is maximized. Figure 7 illustrates schematically how the change from partial to full saturation changes the types of pore fluid flow induced by passing strain waves which may occur within rocks and hence changes the relative amounts of attenuation in compression and shear.

In fully saturated rocks first order intercrack flow may occur only in shear, not in compression. Since the P wave is strongly affected by bulk compression it is less attenuated than an S wave. In partially saturated rock flow will occur within all pores, induced by bulk compression; whereas shear induces flow only in properly oriented pores. Consequently S attenuation is less than P. In rocks containing no liquid phase, no flow occurs and attenuation is low for all waves. Hence, the ratio of P to S attenuation may allow us to distinguish between a partially saturated and dry or fully saturated rocks.

These results suggest that we may estimate partial saturation solely from seismic data as illustrated in Figure 8, showing P and S attenuation ratios vs. P to S velocity ratios for sandstone and granite. Data for rocks separate readily into 3 fields depending on saturation: Fully saturated rocks are distinguished from dry and partially saturated rocks due to their higher V_p/V_s . Partially saturated rocks have higher P attenuation/S attenuation.

Another parameter of great interest in geothermal applications is temperature. Figure 9 shows extensional and shear velocities in a room dry Berea sandstone. Velocities increase rapidly with temperature initially due to drying. At about 160°C thermal fracturing becomes dominant causing the velocities to decrease rapidly at higher temperatures. After cooling, the sample's velocities were lower than the initial values due to the permanent thermal fracturing. Also Q first increases with temperature again due to drying (Figure 10), with a peak again at about 160°C , and with marked decrease at higher temperature due to thermal fracturing. The Q_s/Q_e ratio increases with temperature.

TWO PHASE SATURATION

Figures 11 and 12 show velocity and attenuation data at elevated temperatures and two phase saturation in Berea sandstone, Massillon sandstone, and a thermally fractured Westerly granite all taken at 150°C and 100 bars confining pressure. The velocities were measured as the pore pressure was varied to transform water to steam and back. V_p is lower in a steam saturated rock than in water saturated rock due to the lower bulk modulus of steam. In shear the behavior is more complicated. For the Berea sandstone

V_s is greater in steam saturated rock than water saturated rock due to the density effect. In granite V_s is lower in steam saturated rock than water saturated rock, caused by the stiffening of cracks with water at the high frequencies used in this experiment (1MHz). At the phase transition V_p goes through a minimum: A small amount of steam lowers the bulk modulus and sufficient water is present to raise the effective density and further lower the velocities.

Amplitudes plotted in Figure 12 provides a relative measure of attenuation. In both shear and compression, attenuation is much lower in steam saturated rock than water saturated rock. A maximum occurs in P attenuation but not in S attenuation at the phase transition where the rock is partially saturated. This is due again to intercrack flow of water which occurs mainly in bulk compression.

The examples show how velocity and attenuation may be diagnostic of whether a geothermal system contains water, steam or both. An example of field data (from McEvilly, et al., 1978) which may be interpreted on the basis of our experimental work is shown in Figure 13. Several seismic records are shown from a distant earthquake recorded over the La Primavera geothermal system in Mexico. Stations on the bottom were located outside the Caldera and show typical well developed P and S arrivals. Stations on top were located inside the caldera and they show marked changes obvious even on this unprocessed data. This is particularly evident on the third trace down. P waves are severely attenuated relative to S waves as can be seen from the smaller amplitudes and the depletion of high frequencies. As demonstrated from previously discussed experimental work, high P attenuation relative to S attenuation is diagnostic of a partially saturated rock. This may be confirmed in the field in this case as this station is located immediately adjacent to a steam vent, indicating a mixture of water and steam are present at depth.

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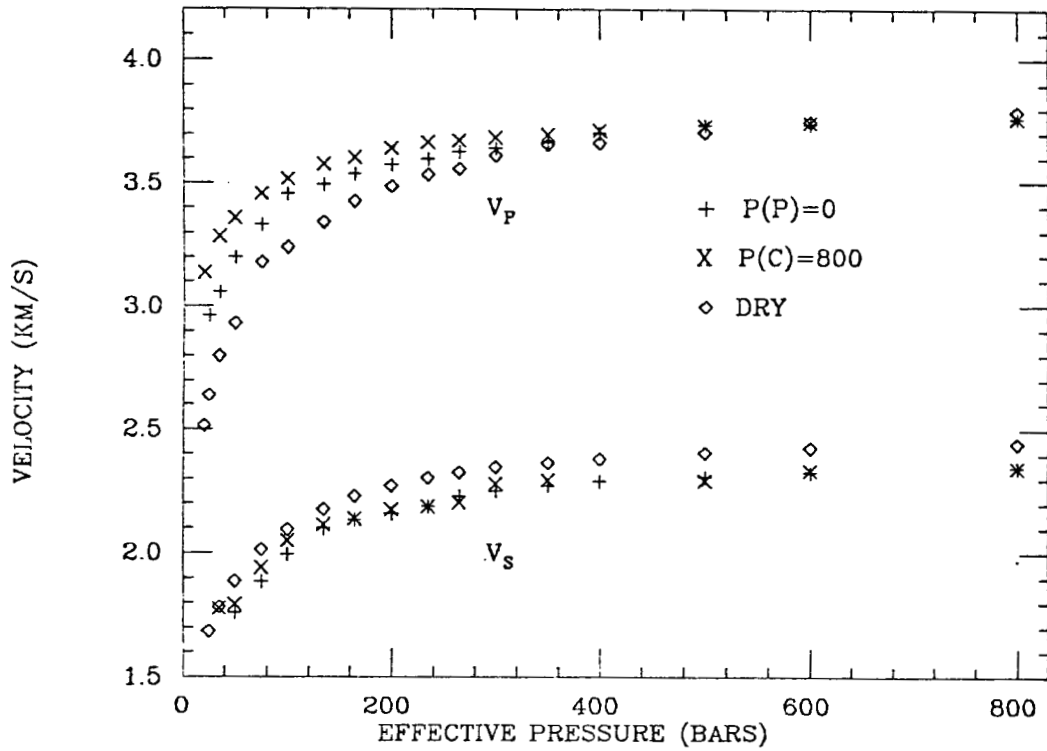


FIGURE 1

Velocity vs. Pressure and Saturation in Berea Sandstone

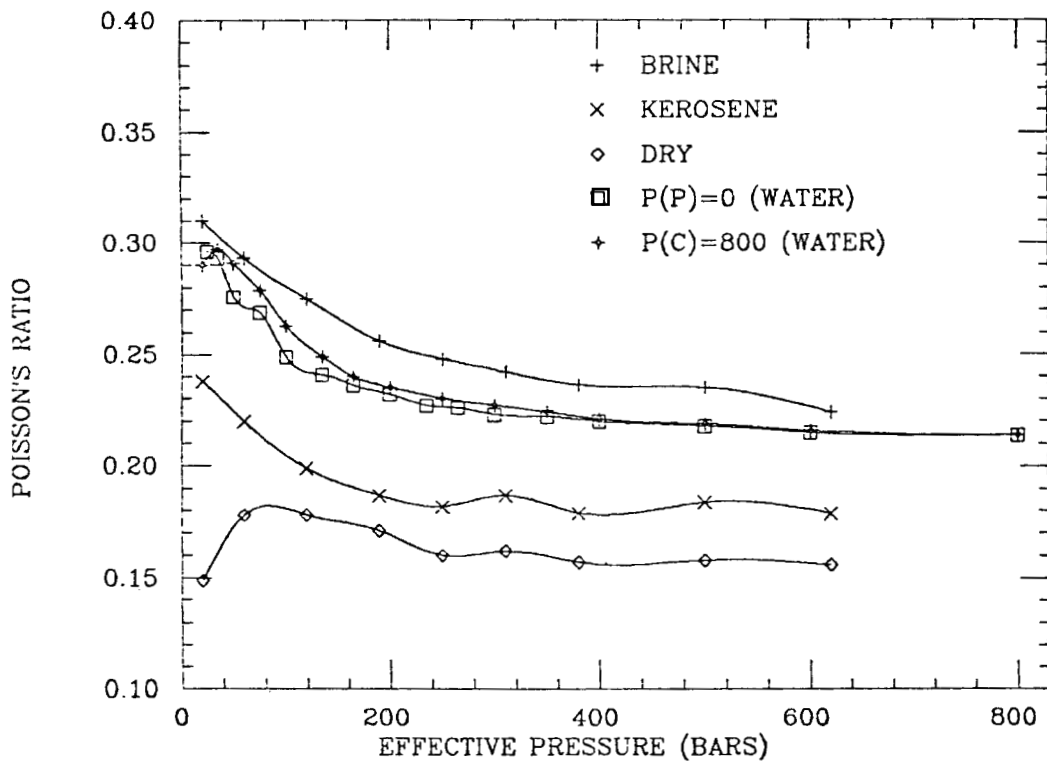


FIGURE 2

Poisson's Ratio vs. Pressure and Saturation in Berea Sandstone

Figure 5

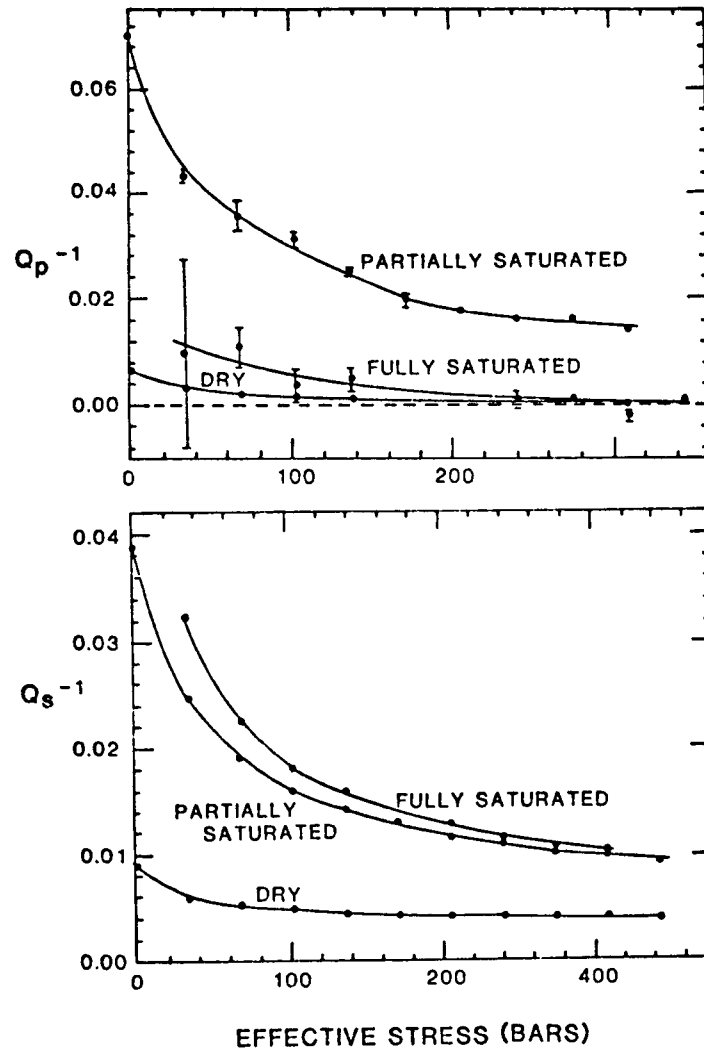


Figure 6
Attenuation vs Pressure and Saturation in
Massilon Sandstone

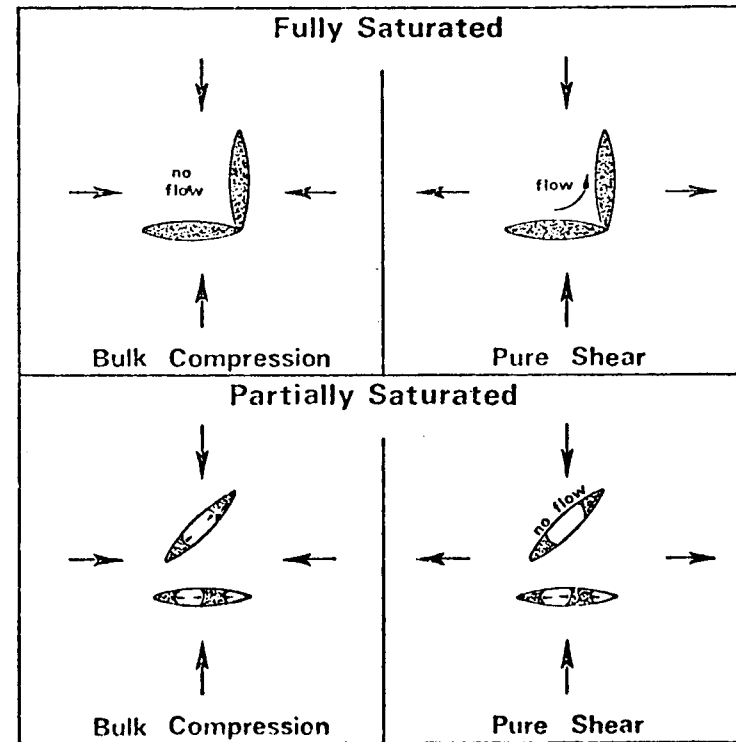


Figure 7 Fluid Flow Mechanisms in
Porous Rocks

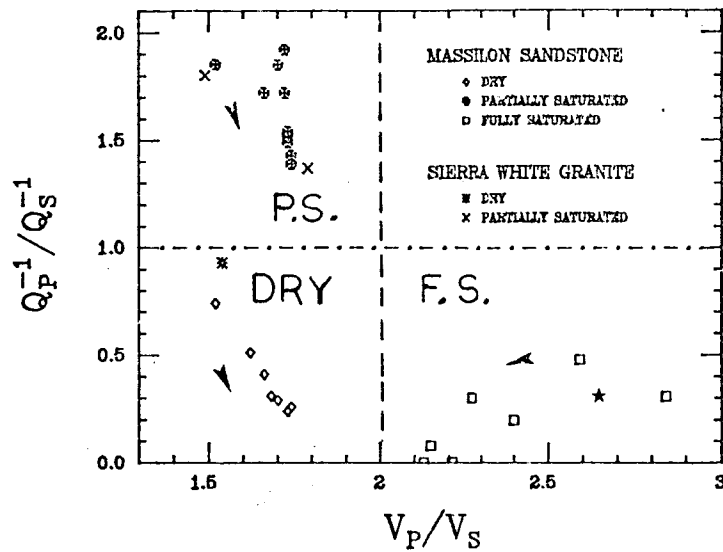


Figure 8.

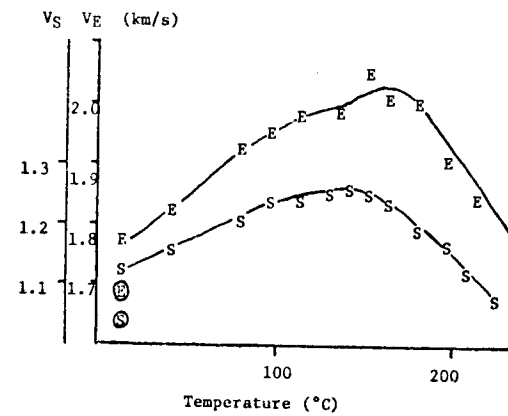


Figure 9

Velocity of E and S waves vs. temperature.

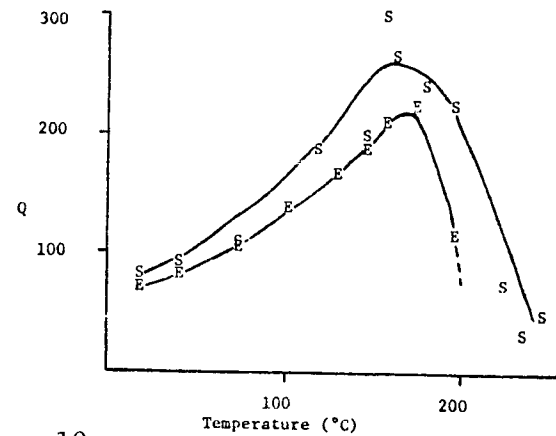


Figure 10

Attenuation of E and S waves vs. temperature.

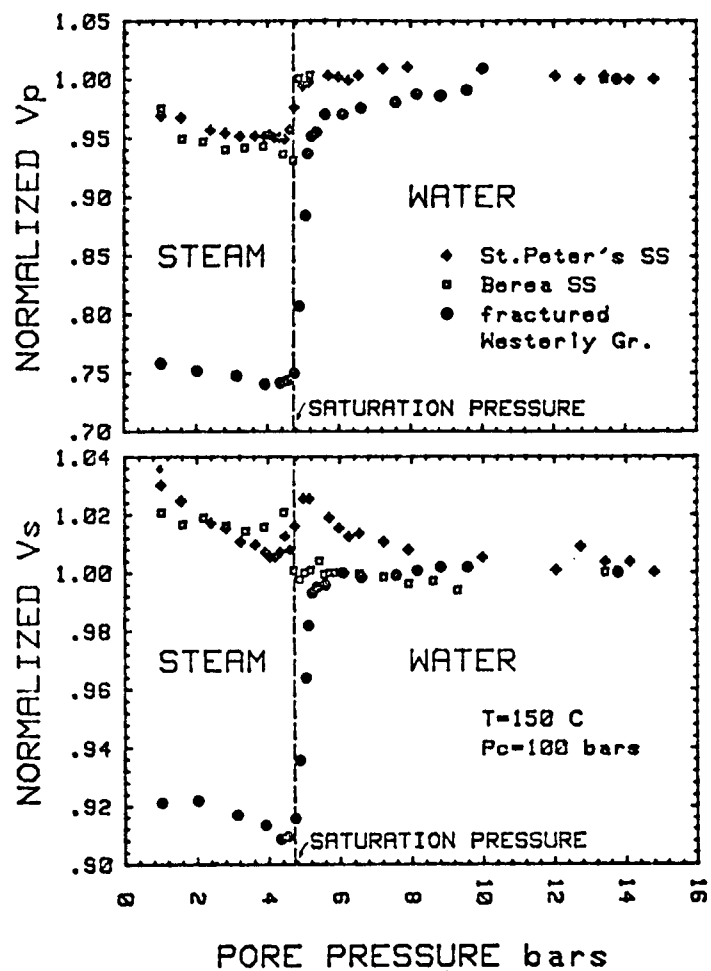


Figure 11

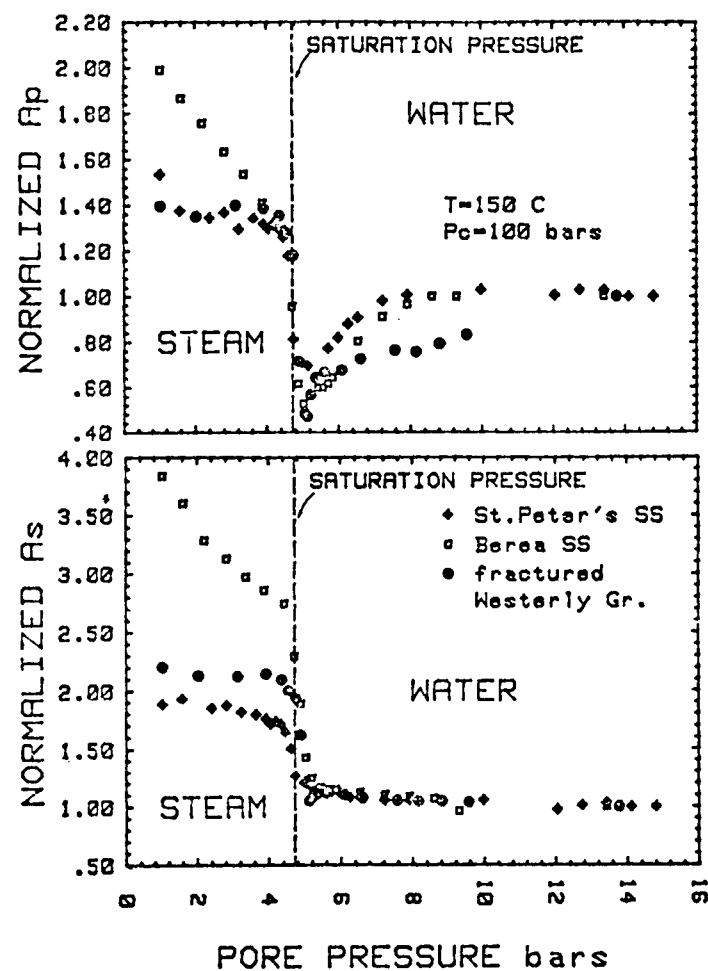


Figure 12

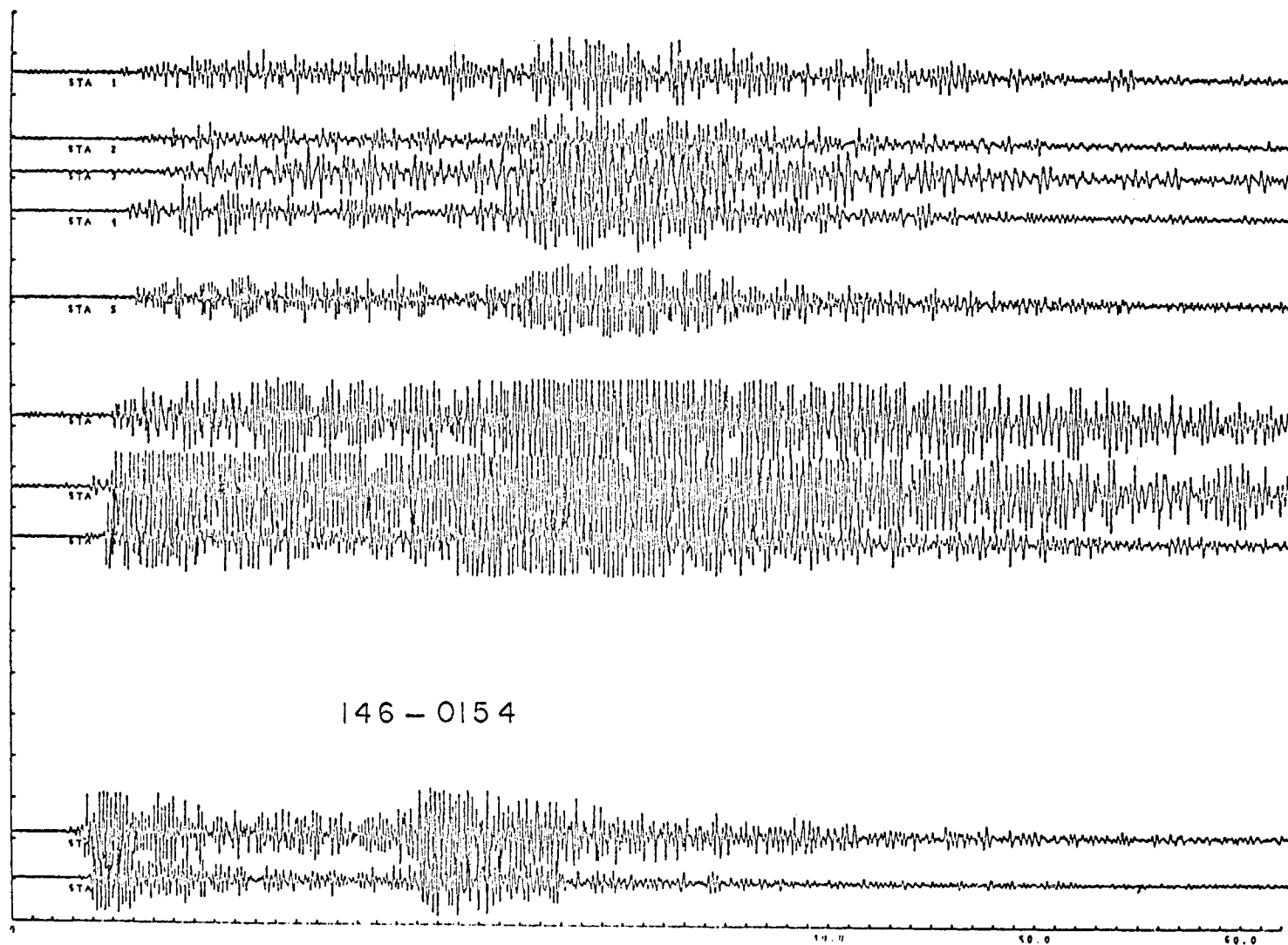


Figure 13. Seismic Records from Distant Earthquake Recorded over the La Primavera Caldera in Mexico. From McEvilly et al (1978).

RESERVOIR EXPLORATION/TESTING BY
ELASTOMECHANICAL METHODS

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Introduction

The recovery of geothermal energy for power generation invariably involves the withdrawal of very substantial amounts of heat/water from the subsurface. For example, the commercial operation of a 100 MW power plant in a liquid dominated reservoir situation will require the recovery of about 5×10^{16} J/yr of heat and a mass flow of water of about 5×10^{10} kg/yr. A number of conspicuous phenomena are associated with this rate of production. Usually there are changes in the subsurface temperature, a significant rate of lowering of the local reservoir fluid pressure and an associated lowering of the ground water surface in the production region. Moreover, there are more subtle effects such as subsidence, strain and tilt of the ground surface, changes in the local gravity field and changes in the subsurface electrical conductivity. All these phenomena represent responses of the reservoir to production and convey information on the evolution of the system. The recording of these signals can therefore be helpful in reservoir monitoring during production. Obviously, the evolutionary pressure phenomena are known to everyone engaged in reservoir engineering and the recording of reservoir pressure in available boreholes and of the groundwater level are standard tools in production monitoring. Although ground subsidence and changes in the gravity field have been recorded in a few cases, the elastomechanical phenomena have not received much attention.

The purpose of this brief note is to present a preliminary evaluation of the potential of the elastomechanical methods in practical reservoir engineering and related areas. Assuming simple relevant situations, the strength of the field signals will be estimated and compared to other ground surface data such as gravity and D.C. electrical signals that are also of interest in reservoir monitoring. Because of greater difficulty in observing surface strain, we will limit our discussion to vertical ground displacement and tilt signals.

Basic Relations

For the sake of brevity we will consider only liquid dominated reservoirs embedded in porous/permeable half-spaces that are ultrasimple in the sense that the formation can be taken to respond in bulk as a homogeneous and isotropic Hookean solid. Because of the two-phase situation, all elastic parameters are composite and will consequently have to be defined properly. Moreover, Hooke's law must be generalized to include the effects of the pore or fracture fluid (see for example, Nur and Byerlee, 1971). In the present note, where only orders of magnitude are of interest, we will circumvent a more detailed discussion of these aspects by assuming that the saturated formation has

empirically well defined effective elastic parameters. Armed with this set of quite strong but useful assumptions, we are now in the position of considering the effects listed in the introduction above.

Let the (x,y) plane of our coordinate system be placed in the surface Σ of the half-space with the z-axis vertically down. The general field point is $P = (x,y,z)$. We assume that the reservoir is in equilibrium at the onset of production at time $t = 0$. Having at a later time produced a certain mass of fluid, we can assume that the subsurface temperature field has been perturbed by an amount $T(P)$ and the subsurface fluid pressure field by $p(P)$. Clearly, since the fluid pressure vanishes in the drained formation there is a discontinuity in the pressure field at the groundwater level.

Let the formation displacement vector resulting from both perturbations be $\vec{u}(P) = (u,v,w)(P)$. Moreover, let λ and μ be the effective Lamé parameters, k the effective bulk modulus, ν the Poisson ratio and α the effective thermal expansivity of the fluid/rock systems. Since the half-space is assumed to be Hookean, the elastomechanical equations for the displacement are

$$\mu \Pi \vec{u} - (\lambda + \mu) \nabla \nabla \cdot \vec{u} = \vec{b}, \quad (1)$$

where $\Pi = -\nabla^2$ is the Laplacian operator and $\vec{b}$ is the body force density field resulting from the temperature and pressure perturbations. The boundary condition at the ground surface Σ is that of no stress. In the present case, $\vec{b}$ is a sum of two terms, one of thermoelastic origin associated with the perturbation temperature field T and a second one that results from the perturbation p of the pore pressure. Because of the discontinuity at the groundwater surface, it is convenient to split the second contribution into two parts, one associated with the perturbation pressure field in the wet formation and the other one resulting from the draining of the formations by the subsidence of the groundwater level. We have thus

$$\vec{b} = -\nabla f, \quad (2)$$

where

$$f = f_T + f_p + f_g \quad (3)$$

where the f 's are scalars and the subscript T refers to temperature, p to fluid pressure, and g to groundwater level.

On the basis of the theory of thermoelasticity (Boley and Weiner, 1960) we obtain the first factor

$$f_T = \alpha k T \quad (4)$$

There is some uncertainty as to the proper form of f_p . This factor depends quite heavily on pore/fracture geometry and connectivity. For the present purpose we will adapt the classical procedure of Biot (1941) by assuming

$$f_p = \theta p \quad (5)$$

where θ is a positive dimensionless factor quantizing the effects of the pore pressure p on the rock matrix. Clearly, this factor is less than unity, but actual values may vary within rather wide limits. Few experimental results are available. We can only quote elastomechanical data collected by Rice and Cleary (1976) from which values of $\theta = 0.2$ to 0.8 can be inferred. The lower values apply to samples of marble and granites whereas the higher values are obtained for sandstones. Along the same lines the third factor on the right of (3) can also be estimated on the basis of (5) where p is then the negative hydrostatic pore pressure in the drained rock above the groundwater level. Given $p(P)$ and $T(P)$, the problem of solving (1) for the displacement vector $\vec{u}(P)$ is now well defined.

A simple procedure of solving (1) at the above defined conditions has been presented by Bodvarsson (1976). We will refrain from discussing details of the method and quote only the result of main interest, that is, the expression for the vertical displacement component w at the ground surface Σ . Let $S = (x, y, 0)$ be a field point on Σ and $Q = (x', y', z')$ be the source point; then

$$w(S) = \int g_w(S, Q) f(Q) dv_Q \quad (6)$$

where $dv_Q = dx' dy' dz'$ and $g_w(S, P)$ is the appropriate Green's function

$$g_w(S, Q) = [(1-\nu)/\pi(\lambda+2\mu)] z' / r_{SQ}^3, \quad (7)$$

where

$$r_{SQ}^2 = (x-x')^2 + (y-y')^2 + (z')^2 \quad (8)$$

is the distance from Q to S . The tilt vector $\vec{t}(S)$ is obtained from (6) by $\vec{t} = -\nabla_h w$ where $\nabla_h = (\partial_x, \partial_y, 0)$, the horizontal gradient in Σ . This vector can thus be expressed in the same form as (6) by

$$\vec{t}(S) = \int \vec{h}(S, Q) f(Q) dv_Q \quad (9)$$

where $\vec{h} = -\nabla_h g$.

Simple Situations

To present an overview of relevant field amplitudes, we will consider ground surface displacement and tilt fields generated by temperature or pressure perturbations within bounded compact source regions. Moreover, let the average depth of the source region be rather larger than its greatest linear dimension. Obviously, this situation is best portrayed by a spherically symmetric source region of radius R placed such that the depth d of the center is a few times larger than R . In the case of the first two factors in (3) the integrals in (6) and (9) can then be quite well approximated by simple expressions. With regard to the ground surface displacement we are most interested in the maximum value w_m that is obtained at the point 0 vertically above

the center of the region. Assuming the Poisson relation $\lambda = \mu$ that applies quite well to common rock, and taking that $z' \approx r_0 Q \approx d$, we obtain on the basis of (6) and (7) that

$$w_m = (15/36\pi)\Delta V/d^2 = 0.13\Delta V/d^2 \quad (10)$$

where

$$\Delta V = (1/k) \int f dV_Q \quad (11)$$

is the total volume increment. In the particular case that f is homogeneous over a spherical region of radius R equation (10) leads to

$$w_m = (5f/9k)R^3/d^2 \quad (12)$$

A little algebra reveals that the maximum ground surface tilt is obtained at a distance $(d/2)$ from the center 0 and amounts to

$$t_m = 0.11\Delta V/d^3 \quad (13)$$

or in the spherical case

$$t_m = (0.48f/k)R^3/d^3 \quad (14)$$

As already emphasized these expressions hold for the temperature and pressure perturbations involving f_T and f_p in equation (3). Since the third factor f_g results from the lowering of the groundwater level the source region for this effect is quite different from the compact region assumed above in the case of f_T and f_p . In fact, f_g is generated by an unloading of the half-space because of the drainage of the formations above the groundwater level. This results in two effects. First, a contraction of the drained formation as indicated directly by equations (3) and (5). Second, the unloading results in an upward displacement of the ground surface due to elastic rebound of the entire half-space. The second effect can be estimated on the basis of the Bussinesq formula for the surface loaded half-space (Love, 1927). Although analytical expressions are available for the form of the drained volume (Bodvarsson, 1977), we will here assume that to the first approximation, the form is that of a disk of thickness h and a diameter D . Using (3), (5) and the Bussinesq formula in combination with Poisson's relations we obtain then upon some algebra the maximum vertical ground surface displacement that occurs at the center of the disk

$$w_m = \phi g \rho h [(\theta h/5\mu) - (3D/8\mu)] \quad (15)$$

where ϕ is the porosity, g the acceleration of gravity and ρ the density of the fluid. It is important to emphasize again that this result is based on the assumption of a compact homogeneous/isotropic half-space. The second term in (15) will dominate under such circumstances. However, the presence of unconsolidated non-Hookean surface layers would invalidate the first term in (15) and generally lead to very much greater displacements as observed in

some areas (see for example Hatton, 1970).

An estimate of the maximum ground surface tilt associated with the second term in (15) is given by

$$t_m = -3\phi g \rho h / 4\mu \quad (16)$$

Gravity and D.C. Conduction Changes

Assuming the same situation as above, the lowering of the groundwater level leads to a reduced g-field at the center of the disk of

$$\Delta g = -2\pi\gamma\phi\rho h \quad (17)$$

where $\gamma = 6.67 \times 10^{-11}$ SI is the gravitation constant.

Referring again to a temperature perturbation $T(P)$ within a compact source region, we can assume that the electrical conductivity within the region is increased by $\sigma_1(P)$ over the homogeneous half-space that has a uniform conductivity σ_0 . Moreover, let there be an impressed horizontal unidirectional, uniform electrical field E_0 that is scattered by the conductivity inhomogeneity. In the particular case that the source region is homogeneous spherical of radius R with the center at a depth d , the horizontal electrical field at the ground surface right above the center is given approximately by (Grant and West, 1965)

$$E = E_0(1-a) \quad (18)$$

where

$$a = [2\sigma_1 / (\sigma_1 + 3\sigma_0)] R^3 / d^3 \quad (19)$$

Discussion

Continued production of the magnitude referred to in the introduction may lead to average reservoir source region pressure declines of the order a few 10^5 Pa. The groundwater level may be lowered by a few tens of meters and there may be a temperature decline of the order of a few tens of centigrades. Focusing our attention on the particular case of $T = 50^\circ\text{C}$, $p = 5 \times 10^5$ Pa and assuming $k = 2 \times 10^{10}$ Pa and $\theta = 0.4$, we find that $f_T = 100$ fp. Clearly, the thermoelastic effects tend to dominate the pressure effects and thereby also the effects of the lowered groundwater level. Moreover, in conjunction with $T = 50^\circ\text{C}$ let $\alpha = 2 \times 10^{-5}/^\circ\text{C}$, $R = 300$ m and $d = 10^3$ m. Equation (10) and (13) give then the values $w_m = 15$ mm and $t_m = 12$ μrad . Referring to the same situation, let $\sigma_1 = -0.2\sigma_0$ and equation (19) gives $a = -0.004$. Assuming $\phi = 0.05$, $h = 50$ m, $\rho = 10^3$ kg/m³, we obtain from (17) $\Delta g = 10^{-6}$ m/s² = 0.1 mgal.

Vertical ground displacement can be monitored with a precision of about one mm, surface tilt with a few 10^{-1} μrad , gravity with about 10 μgal and D.C. conduction in producing geothermal areas with no better precision than perhaps one part in 100. Although the above numerical data are grossly inadequate, the results,

nevertheless, tend to indicate that in the absence of adequate bore-hole data, tilt observations at properly designed solid rock surface stations evidently offer the most appropriate method of monitoring large scale reservoir temperature evolutionary processes taking place at moderate depths.

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RADON TRANSECT STUDIES IN VAPOR- AND
LIQUID-DOMINATED GEOTHERMAL RESERVOIRS

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INTRODUCTION

Radon transect analysis involves short-term sampling of wells across a geothermal reservoir to examine structural and thermodynamic properties of the reservoir. In these studies, two natural gaseous components of the produced geofluids are measured: (1) the radioactive isotope, radon-222 which decays upon release from the host rock with a half-life of 3.83 days; and (2) the non-radioactive compound ammonia, which appears to be produced continuously in geothermal fluids. The information sought in these studies include data on the spacial and temporal behavior of the geofluids in relation to the structural and thermodynamic conditions in the reservoir. Factors that can effect the relative composition of these two natural components include their relative solubilities, partitioning functions under cycles of brine evaporation and condensation, radioactive decay (radon only), and chemical reactions (ammonia only).

The use of radon as an internal tracer of geofluid transport has been well documented (e.g., Stoker and Kruger, 1975; D'Amore and Sabroux, 1976). Kruger, Stoker, and Umaña (1977) noted the large difference in radon concentration between liquid and vapor-dominated geothermal reservoirs as well as significant variations between neighboring wells in one formation and temporally within a single well. Models of the relationships between radon concentration and flowrate have been described (e.g., Stoker and Kruger, 1975; D'Amore and Sabroux, 1976; Warren and Kruger, 1979). These models considered linear, radial, and conical flow geometry with radon release from uniformly deposited radium in the host rock flowing with the brines or steam through a reservoir of uniform properties. In the conical model of Warren and Kruger (1979), radon in vapor-dominated geothermal reservoirs is assumed to boil out with steam production at a boiling front in the reservoir, with radon decay during transport through the steam reservoir to the well plus an accumulation of radon from the reservoir rock along the transport path. Thus the radon concentration at the wellhead is dependent on a number of parameters describing the release and transport of the radon with the geofluids.

Radon concentration in geothermal fluids under steady flow conditions have been shown by Stoker and Kruger (1975) and D'Amore et al (1978) to depend on the release parameters,

$$C_s = \frac{E_m \rho_r}{\phi \rho_f} \quad (1)$$

FIGURE 3

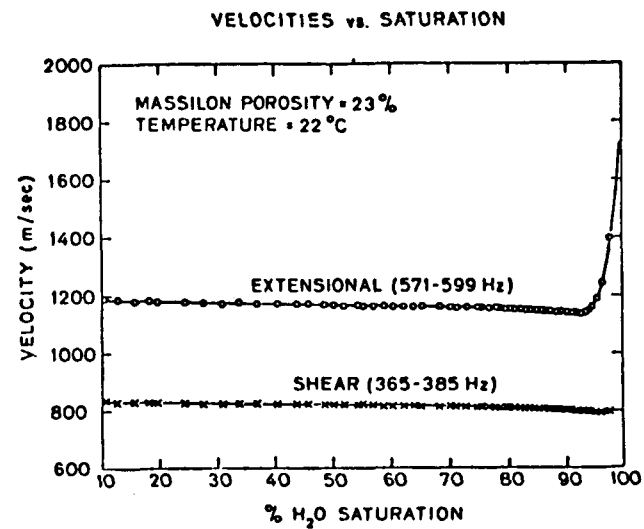
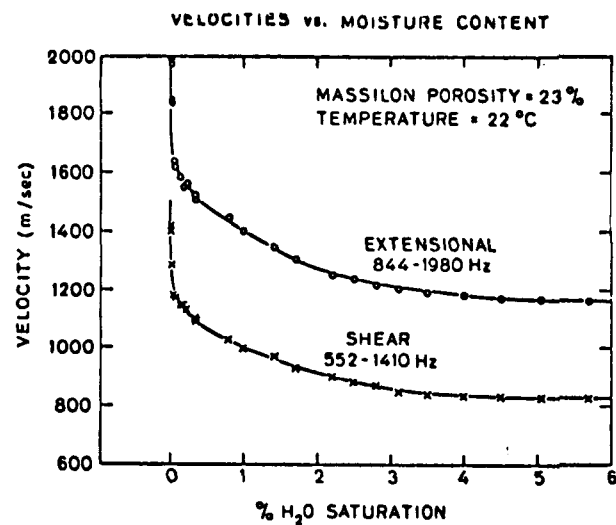
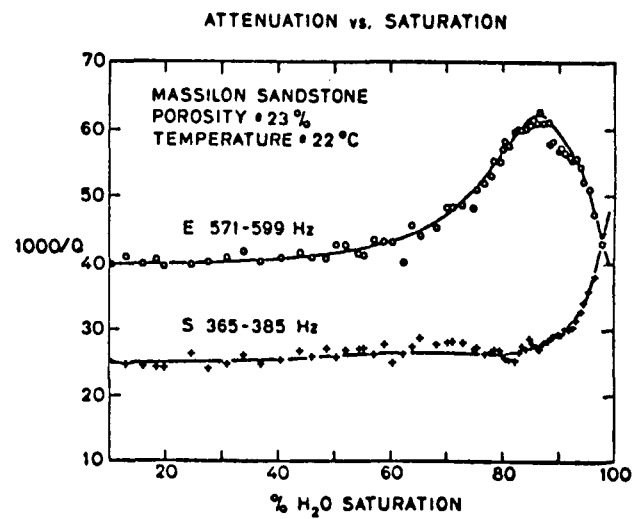
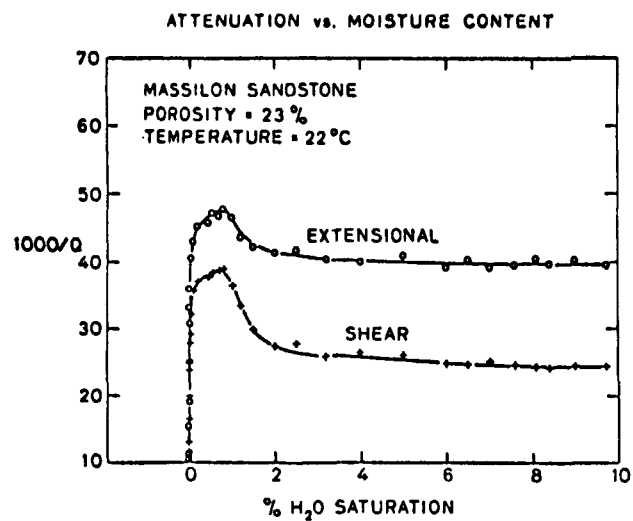


FIGURE 4



where C_s = mass concentration of radon, nCi/kg rock

F_m = emanating power, nCi/kg rock

ρ_r = rock density, kg/m³

ρ_f = fluid density, kg/m³

ϕ = porosity, m³/m³

For constant rock density at the producing pressure, the concentration of radon is expected to be inversely proportional to the fluid density. Thus the great difference in density of water and steam in pore volumes is consistent with the observed difference in radon concentration in liquid and steam geothermal fluids.

Warren and Kruger (1979) reported the results of flowrate transient experiments in vapor-dominated reservoirs. The observed transients in radon concentration following instant changes in flowrate were described by the model of boilout, transport, and radon decay and accumulation with respect to the steam phase. It was noted that the assumption of constant radon emanation during the flowrate (and pressure) change might not be valid. Macias, Semprini, and Kruger (1980) observed significant changes in radon emanation with changes in the geothermal fluid and the thermodynamic conditions in the reservoir. The method of transect analysis was developed to bridge these two types of study. In order to separate the changes due to time properties of the release and transport, during which radon is undergoing continuous radioactive decay, a non-radioactive component of the non-condensable gases is measured simultaneously. Analysis of these two components may be helpful in distinguishing between changes in radon concentration due to changes due to transport phenomena during production. This communication describes the transect analysis conducted at the vapor-dominated reservoirs at The Geysers in California and the liquid-dominated reservoirs at Cerro Prieto in Baja, California.

TRANSECT EXPERIMENTS AT THE GEYSERS

Three radon transect analyses have been completed at The Geysers; two of them (I and II) along a line of wells in the older producing zones, and the third (III) in a newer producing area across Big Geyser Creek. Ammonia measurements were also made in transects II and III.

(a) General Observations

The results of transects I and II are shown together in Fig. 1. The two experiments show similar profiles in that the radon concentration decreases from left to right along the transect, indicating either longer transport times in the right part of the field or greater accumulations in the left part of the field. Linear regression analysis of radon concentration as a function of flowrate along the transect showed a negative correlation of -0.61, indicating radon concentration to be either inversely

related to flowrate or that radon is accumulated by either increased emanation or enrichment by condensation processes.

The concentration profiles of radon and ammonia for transect II are shown in Fig. 2, in relation to the structural cross section of the reservoir. The concentration gradients of the two components appear similar, with an abrupt change at the location of the indicated faults. Although the radon-ammonia ratio is highly correlated along the transect (with a linear correlation coefficient of 0.97), the average ratio is significantly different on either side of the faults. The eight wells on the left have a mean ratio of 0.08 ± 0.01 whereas the seven wells on the right have a mean ratio of 0.15 ± 0.06 . If the ammonia concentration is conservative across the transect, the data would indicate that radon is undergoing depletion in the left part of the field and enrichment on the right part. Another way to express this difference is to assume that radon has a longer transport part on the left or that ammonia undergoes a process of greater accumulation. These two experiments have produced a number of possible processes that may be operative at this field:

- (1) a physical or chemical process for addition or depletion of ammonia with a rate constant surprisingly similar to the 3.83 day half-life of radon-222,
- (2) a common source of both components in the host rock with the concentrations dependent primarily on emanation and reservoir fluid properties,
- (3) changes in the degree of saturation of the enrichment of the non-condensable gases in various areas of the field,
- (4) enrichment processes such as condensation within the steam zone of the reservoir in which case both components would be enriched as functions of their partition coefficients.

Although possibility (1) cannot be ruled out at the present time, no physical or chemical process for ammonia with a rate constant of approximately 3.8 days is apparent. Evaluation of possibility (2) awaits further clarification of the changes in emanation with changes in reservoir properties and additional chemical information of the host rock. Possibility (3) represents enrichment processes such as the Raleigh condensation process proposed by D'Amore and Truesdell (1980), where gas components are enriched. In such processes the ammonia concentration reflects long-term enrichment while the radon concentration reflects saturation conditions. If this possibility predominates, the data would indicate that higher radon concentrations occur where greater amounts of vapor are present, suggesting a change in degree of gaseous saturation. In this case, wells in the left part of the transect are producing from shallower zones with greater vapor content. In possibility (4), condensation and vaporization cycles would concurrently enrich both concentrations, but the ammonia concentration would not be as time dependent as the radon concentration, which would reflect only the latest 10-30 days of such processes.

(b) Thermodynamic Relations

Reservoir conditions play an important part in wellhead concentrations of radon and ammonia. Downhole pressures in transect II and III vary over a significant range: from 100 to 380 psia for transect II; and from 190 to 310 psia in transect III. Equ. (1) notes the radon concentration to be inversely dependent on the fluid density. Linear regression analysis was made of the radon concentration as a function of specific volume of the reservoir fluid for the reported downhole pressures. Fig. 3 shows a correlation coefficient of 0.78 and a slope suggesting an inverse relationship between radon concentration and fluid density as given by Equ. (1). Similar results were obtained for the regression analysis of the ammonia concentration data, indicating that the ammonia is released from the formation rock by the same diffusion processes responsible for radon release.

The effect of changes in reservoir pressure on the partitioning of the two gaseous tracers between the brine and vapor phases must be considered. It is not clear whether the changes in partition coefficients of radon and ammonia between brine and steam are sufficient to result in the observed radon-ammonia ratios. Variations in emanation of radon with changes in pressure and temperature under controlled model reservoir conditions were noted by Macias, Semprini, and Kruger (1980). Further experimental data on their emanation is required to further evaluate this process.

TRANSECT EXPERIMENTS AT CERRO PRIETO

Two transect analyses have been completed at Cerro Prieto to evaluate the transects in terms of the structural features of the field and the thermodynamic conditions in a liquid-dominated reservoir. The structural features have been described by Vonder Haar and Howard (1980). The data were grouped into the four subset transects shown in Fig. 4, which cross some of the given faults and were examined for the changes in thermodynamic conditions over the field. A preliminary indication that radon concentration was related to fluid enthalpy was noted by Horne and Kruger (1979) in a study of radon emanation along the Waiora fault at Wairakei, New Zealand.

A total of 23 wells were sampled at Cerro Prieto during the two transect experiments and the enthalpy of the fluids ranged from 1230 to 2360 kJ/kg, representing a range in produced fluid mixtures from all liquid to 70% vapor at a reservoir temperature of 290°C. The corresponding wellhead radon concentrations ranged from 0.20 nCi/kg in the low enthalpy wells to 3.6 nCi/kg in the highest enthalpy well.

An analysis of the data was attempted by modifying Equ. (1) to represent the contributions to the concentration from the two fluid phases:

$$C_T = X \frac{E_v \rho_r}{\phi \rho_v} + (1-X) \frac{E_l \rho_r}{\phi \rho_l} \quad (2)$$

where X is the steam saturation. The enthalpy of the two phase mixture is given by

$$h = Xh_v + (1-X)h_l \quad (3)$$

A regression analysis of the concentration-enthalpy data, shown in Fig. 5, was made to examine the linearity between these two parameters. A linear relationship, with correlation coefficient of 0.80, is implied, but is highly influenced by the high radon-high enthalpy of well M-45. An equilibrium volumetric radon concentration of 168 nCi/m³ pore volume was estimated for the observed average radon concentration of 0.20 nCi/kg for the low enthalpy wells having production of all liquid with density of 840 kg/m³. The calculation, however, was made with the assumption that the volumetric concentration was identical for both phases, which is probably incorrect according to the observations of Macias, Semprini, and Kruger (1980) that emanation changes with pore fluid density.

The dashed lines in Fig. 5 represent reservoir temperatures of 280°C and 320°C. The regression line of the data represents a reservoir temperature of 290°C, in good agreement with Na-K-Ca geothermometer estimate given by Mahon et al (1978). Analysis of the four subset transects shown in Fig. 4 shows increased detail in examining the dependence of radon and ammonia concentrations on the enthalpy as steam saturation of the produced fluids. The correlation between radon concentration and fluid thermodynamic conditions indicate that radon monitoring may provide information on changes in the field. For example, if the relations measured to data are reliable, the data indicate a decrease in reservoir temperature in the southern area of the field with exploitation while temperatures have remained high in the eastern area. The data may also be indicating that phase separations are occurring in parts of the field such that equilibrium is achieved in both phases. Further measurements of radon should corroborate the initial suggestions that wells in the north central area flow primarily as liquid with evidence of two-phase conditions in the area of well M-27, and that flow is predominantly two-phase in the south-central area near wells M-45, M-48, and M-84.

CONCLUSIONS

Results to data are confirming the development of radon transect analysis to study the structural and thermodynamic features of vapor- and liquid-dominated geothermal reservoirs. The three experiments conducted at the vapor-dominated fields at The Geysers have raised several interesting questions concerning the source and transport of various gaseous components of the produced geofluid. Pressure variation appears to play an important role in determining the emanation of radon (and ammonia) from the formation and the transport of these gases during production may be influenced by the thermodynamic changes in the steam transporting them to the wellhead. Changes in structural regime in the old area of The Geysers may be observed by these measurements.

Measurements at Cerro Prieto are indicative of liquid-dominated reservoirs. Here, current measurements do not show that radon concentrations are influenced by structural features. The radon (and ammonia) concentration appears to be influenced primarily by the thermodynamic state of the one- or two-phase geofluid. The use of radon and ammonia as internal tracers to two-phase reservoir during production appears to be warranted.

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GAS GEOTHERMOMETRY FOR DRILLHOLE FLUIDS FROM VAPOR DOMINATED AND HOT WATER GEOTHERMAL FIELDS

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INTRODUCTION

The compositions of steam from the vapor-dominated geothermal systems of Larderello, Italy and The Geysers, California have been shown by previous investigators to vary with position in the field (Celati et al., 1973; Panichi et al., 1974; D'Amore et al., 1977; Truesdell et al., 1977; Truesdell and Nehring, 1978; Mazor, 1978). The most conspicuous chemical patterns observed in the Larderello and The Geysers vapor-dominated geothermal areas are strong increases or decreases from the center to the edges of constituents carried in the steam. The pattern of these parameters in vapor-dominated systems seem to be controlled mainly by a process of lateral steam movement and condensation (D'Amore and Truesdell, 1979; Calore et al., 1980).

The condensation process, at constant temperature and total pressure increases the partial pressure of CO_2 at the same rate as the gas/steam ratio, strongly affecting the composition of the total gas (including steam). The condensation effect should increase contents of CO_2 , H_2S , H_2 and CH_4 in the residual steam to about the same degree because their solubilities are similar. However, the general trend observed is almost constant ratios of H_2S , H_2 , CH_4 to H_2O as the $\text{CO}_2/\text{H}_2\text{O}$ ratio increases in Larderello about 5-6 times from the center to the edges at constant temperature. This means that the H_2/CO_2 , CH_4/CO_2 , and $\text{H}_2\text{S}/\text{CO}_2$ ratios decrease with increasing $\text{CO}_2/\text{H}_2\text{O}$ ratios. Apparently the only mechanism that can explain this behavior is reaction of these three gases with other gases and with reservoir minerals so that the partial pressures of these gases are buffered by temperature-dependent reactions with water and rock minerals.

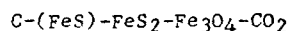
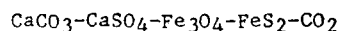
GEOTHERMOMETERS

A system of appropriate equations involving H_2O , CO_2 , H_2 , CH_4 , H_2S can be set up. Table 1 shows the equations and their equilibrium constants as functions of temperature in degrees Kelvin.

Equation 2 expresses a possible double origin for CH_4 , from carbon dioxide and from free carbon via hydrogen reduction. Free carbon as carbonaceous minerals has been found in cuttings from wells at Larderello, Cerro Prieto, and elsewhere. Hydrogen partial pressure can be calculated from the dissociation reaction of water (reaction 1), by fixing temperature and oxygen fugacity.

Equations 3 and 4 express the control of sulfur fugacity by magnetite, pyrite and oxygen fugacity and the control of H_2S partial pressure by sulfur fugacity and hydrogen partial pressure. In general, gas equilibrium equations are expressed in fugacities but at the relatively low pressures of geothermal systems these are equivalent to partial pressures. The term fugacity is retained here only for oxygen and sulfur which are not measureable in the well discharges but important in expressing reservoir conditions.

Equation 5 expresses the partial pressures of oxygen determined by two extreme oxygen buffer systems:



and equation 6 the fugacity of saturated steam. Assuming ideal gas behavior, P_{CO_2} is a function of $\text{Nl}_{\text{CO}_2}/\text{Kg}_w$ as in equation 7.

$$P_{\text{CO}_2} = P_{\text{H}_2\text{O}} (\text{Nl}_{\text{CO}_2} / \text{Kg}_w) / (55.51 \times 22.4) \quad (7)$$

where $(\text{Nl}_{\text{CO}_2} / \text{Kg}_w)$ is the gas/steam ratio as liters of CO_2 at standard conditions (STP) per kg of steam.

From equations 1 to 7 the following equations have been obtained, relating the gas composition to temperature ($^{\circ}\text{K}$) and gas/steam ratio.

$$\log (P_{\text{H}_2} / P_{\text{CO}_2}) = 4.34 - 2396/T - \log (\text{Nl}_{\text{CO}_2} / \text{Kg}_w) \quad (8)$$

$$\log (P_{\text{CH}_4} / P_{\text{CO}_2}) = 16.87 - 4318/T - 3.56 \log T - 1/2 \log (\text{Nl}_{\text{CO}_2} / \text{Kg}_w) \quad (9)$$

$$\log (P_{\text{H}_2\text{S}} / P_{\text{CO}_2}) = 7.74 - 3024/T - 0.79 \log T - \log (\text{Nl}_{\text{CO}_2} / \text{Kg}_w) \quad (10)$$

$$\log (P_{\text{H}_2} / P_{\text{CO}_2}) = 5.52 - 3406/T - 1/2 \log (\text{Nl}_{\text{CO}_2} / \text{Kg}_w) \quad (11)$$

$$\log (P_{\text{H}_2\text{S}} / P_{\text{CO}_2}) = 8.92 - 4033.5/T - 0.79 \log T - 1/2 \log (\text{Nl}_{\text{CO}_2} / \text{Kg}_w) \quad (12)$$

Equations 11 and 12 must be considered semi-empirical, because the H_2/CO_2 and $\text{H}_2\text{S}/\text{CO}_2$ parameters are arbitrarily taken as function of $(P_{\text{CO}_2})^{1/2}$ instead of P_{CO_2} equations 8 and 10.

The geothermometers have been tested on data, reported in table 2, from the Italian fields of Larderello, Travale, Bagnore, Piancastagnaio and from The Geysers, U.S.A. For the central Larderello ("classic") area, 70 samples have been ranked for increasing gas/steam ratio. Table 3 shows the temperatures computed from equations 8, 11, 9, 10 and 12. Equation 8 can be used satisfactorily for the Italian geothermal fields, except where the gas/steam ratios are very high (more than 50 liters of gas per kg of steam). Equation 9 fails for CH_4/CO_2 ratios of more than 0.05. In the Larderello and Travale fields only, reliable results can be obtained computing the average of the three temperatures calculated from equations 8, 9 and 10. The most reliable results, however, are provided by equations 10 and 12. Equation 12 indicates reasonable temperatures for all these vapor-dominated geothermal fields.

In figure 1, equation 12 is plotted at selected temperatures along with the analytical data for Larderello, The Geysers and Travale fields which exhibit a wide range of gas/steam ratios. An attempt has been made to apply equation 12 to all of Larderello geothermal field. Figure 2 shows the computed isotherms at 250, 225, and 200°C. The full circles indicate temperatures of more than 250°C. The only wells shown are those for which recent (1978-1980) data are available.

RESERVOIR TEMPERATURE EVOLUTION OF SINGLE WELLS

Well-head temperatures of single wells change with time but these temperatures are a complex function of flow rate and do not directly indicate changes in reservoir temperatures. The gas geothermometers have been applied to steam samples from wells FBN and ALR in order to define changes in both well and reservoir temperatures. Both these wells are situated in the central part of the Larderello classic area and have produced steam for about 40 years. Gas/steam ratio and dry gas composition evolve with time. As an example, the evolution of steam H_2S contents in dry gas for well ALR and of gas/steam ratios for three wells in Larderello is shown in figures 3 and 4.

In figures 5 and 6 the well-head temperature, well-bottom temperature computed by the methods described by Nathenson (1975), and the average temperature computed using H_2S , H_2 , CH_4 geothermometers (equations 8, 9, and 10) are plotted as function of time. The agreement of geothermometer temperatures with computed well-bottom temperatures is very good. The increase of temperature in the first 25 years could be related to a change in the source of steam from wetter to drier parts of the reservoir. During production, decrease of pressure causes the flashing of the liquid water to steam and a decrease of temperature (Truesdell and White, 1973).

A completely dry system will have the same temperature with exploitation and a constant decay of flow rate. The decrease of steam flow rate with time observed at Larderello is generally exponential and only a considerable amount of liquid water at starting production can explain this strong decrease in flow rate during the first years of exploitation. If the gases retain a memory of the original reservoir temperature and are not greatly influenced by the rapid decrease of temperature caused by flashing, the difference between the well-bottom temperature and that indicated by gas geothermometers should be related to the ratio of liquid water to rock in the producing reservoir. As shown in D'Amore et al. (1978) from an application of Rn^{222} as tracer, the transit time of steam in Larderello from the two-phase, vapor-dominated reservoir to the well bottom is of the order of a few days. This travel time is too short to allow significant reequilibration of gas reactions at the new temperature conditions.

In figure 7 the volume per cent of liquid water in total rock is plotted versus the difference between the reservoir temperature and well-bottom temperature affected by flashing (data from Truesdell and White, 1973). The starting temperature to plot the diagram is 240°C but the computed temperatures differences are also approximately correct for a starting temperature of about 250°C.

LIQUID WATER IN THE RESERVOIRS OF LARDERELLO AND THE GEYSERS

Table 4 shows the approximate volume per cent of liquid water in the part of the reservoir feeding the wells ALR and FBN from 1940 to 1978, computed as described by Truesdell and White (1973) from differences in temperatures given by the H_2S geothermometer (equation 12) and the well-bottom temperatures calculated according to Nathenson (1975). The differences between the bottom-hole temperatures and a constant reservoir temperature of 255°C are also given.

As the flow rate decreases, the volume per cent of liquid water in the producing reservoir decreases regularly. After a broad maximum from 1950 to 1960, the computed temperatures in reservoir and at the well bottom decrease moderately probably due to the increasing contribution of the steam directly coming from flashing of deep brine. The temperature decrease is moderate because steam temperatures are buffered by passage through the dry but still hot reservoir. Geothermometer temperatures agree with bottom-hole temperatures because the long transit time has allowed reequilibration of the gases. When the steam temperature starts to drop, chloride ion in the steam for these wells starts to increase strongly. This is consistent with a contribution of steam coming from a chlorine-rich water such as the hypothesized deep brine. The flow rate continues to decrease because of the strong exploitation in this part of the field.

It is interesting to note that the leveling off of the flow rate from its initial large values coincides with the achievement of near maximum well-bottom temperatures. Flashing of liquid from the upper condensate layer near the well bottom produces a large flow of relatively low temperature steam. When this is exhausted steam is supplied from drier parts of the reservoir at greater distances from the well. Flashing of the deep

brine produces no increase in flow because it is distant from the well bottom. Because the brine zone is saturated the steam flow path may be expected to increase more slowly and the rate of flow decline may decrease.

The calculated percentage of liquid water in the reservoir rock is shown for a number of The Geysers wells in Table 5 (data courtesy of Union Oil Co.). The temperature has been computed starting from a reservoir temperature of 247°C based on the maximum sea level pressure of 36 bars for the Sulfur Bank wells (Lipman et al., 1978), and the average depth of The Geysers wells assuming saturated steam. This temperature is consistent with the average temperature (249±10°C) computed by the H₂S geothermometer (equation 12). The computed liquid water contents in the reservoir increase with CO₂/steam ratio as would be expected with increasing condensation. The average water contents are close to 6.5 volume percent, similar to the figure of 5 per cent used by Nathenson and Muffler (1975) to calculate reserves at The Geysers.

The actual content of liquid water at The Geysers is much higher than the present content computed for wells GR1, ALR and FBN of Larderello, but of the same order of the content computed for these three wells in the early years of production. The thickness and water content of the vapor-dominated reservoir appears to differ in the two systems and it is not certain whether steam compositions at The Geysers will go through the same evolution as at Larderello.

The gas geothermometer provides indications of reservoir conditions distant from the well bottoms and allows estimates of the liquid water content of reservoir rocks. Since most steam must be produced from the vaporization of this liquid, the calculation of liquid water content allows estimates of steam reserves within a known volume of reservoir rock.

APPLICATION OF THE GEOTHERMOMETERS TO HOT-WATER FIELDS

Equation 10 has been applied to calculate the reservoir temperatures using computed H₂S/CO₂ ratios in the total fluid of samples from several wells of hot water fields.

The following parameters are used:

P _{sep}	measured pressure at separator (bars)
E _{tot}	measured enthalpy of total fluid at separator (J/g)
E _w	enthalpy of liquid water (J/g)
E _s	enthalpy of steam (J/g)
% H ₂ S	measured mole per cent of H ₂ S in the total noncondensable gas
X _{H₂S}	molar fraction of H ₂ S in total fluid (steam + liquid water)
X _w	fraction of liquid water
X _s	fraction of steam
Y	measured gas/steam ratio (moles/moles)
n	number of moles

The enthalpy balance is:

$$E_{tot} = E_w X_w + E_s (1 - X_w)$$

Using the measured P_{sep} and E_{tot}, liquid and steam enthalpies can be computed from steam tables, and then the function of liquid water X_w and steam X_s:

$$X_w = (E_{tot} - E_s) / (E_w - E_s)$$

$$X_s = 1 - X_w$$

From X_s, the measured % H₂S and the gas/steam ratio Y, the molar fraction of H₂S in total fluid, X_{H₂S}, can be computed:

$$X_{H_2S} = \frac{100}{Y \cdot X_s} \cdot \frac{100}{\% H_2S} - 1$$

For water-dominated systems it is then convenient to have an H₂S geothermometer as a function of X_{H₂S}, taking into account the solubility of this gas.

The theoretical partial pressure of H₂S is given by developing equations 1, 3, 4, 5, 6 as a function of temperature (°K)

$$\log P_{H_2S} = 10.11 - 5043.5/T - 0.79 \log T$$

By Henry's law, the partial pressure of a gas can be related to the molar fraction.

$$P_{H_2S} = X_{H_2S} \cdot K_{H_2S}T$$

Henry's law constant, K_{H_2S} , is a function of temperature (Kozintseva, 1964). Then:

$$\log X_{H_2S} = 10.11 - 5043.5/T - 0.79 \log T - \log K_{H_2S}(T)$$

The theoretical $\log X_{H_2S}$ given by the previous equation is plotted in the figure 8.

The results of these calculations are shown in table 6. The H_2S geothermometer (equation 13) appears to give results consistent with liquid-based geothermometers.

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Table 1.--Basic chemical reactions and equilibrium constants.

Reactions	Equilibrium constants	Regression coefficients			Ref
		A	B	C	
(1) $\text{H}_2\text{O}_v = \text{H}_2 + 1/2 \text{O}_2$	$\log K_1 = A_1 + B_1/T$	2.652	-12,776		a
(2) $\text{C} + \text{CO}_2 + 6\text{H}_2 = 2\text{CH}_4 + 2\text{H}_2\text{O}_v$	$\log K_2 = A_2 + B_2/T + C_2 \log T$	6.82	11,801	-7.11	b
(3) $\text{H}_2\text{S} = \text{H}_2 + 1/2 \text{S}_2$	$\log K_3 = A_3 + B_3/T + C_3 \log T$	-0.13	-4,394.5	0.79	c
(4) $1/3 \text{Fe}_3\text{O}_4 + \text{S}_2 = \text{FeS}_2 + 2/3 \text{O}_2$	$\log K_4 = A_4 + B_4/T$	-4.683	-3,796		d
(5) $f_{\text{O}_2} = f_1(T)$	$\log P_{\text{O}_2} = A_5 + B_5/T$	2.80	-20,760		
(6) $f_{\text{H}_2\text{O}} = f_2(T)$	$\log P_{\text{H}_2\text{O}} = A_6 + B_6/T$	5.451	-2,020		

References: a, Barin and Knacke (1973); b, Ellis (1957), Kubaschewski (1951); c, Holland (1965);

d, Helgeson (1969).

Table 2a. Average (and standard deviation) of volume per cent and log $P_{\text{gas}}/P_{\text{CO}_2}$ for 70 wells of the central "classic" Larderello and Serrazzano zones divided into groups according to gas/steam ratio.

									S-1	S-2	S-3
log Nl/Kg_w (avg.)	1.25	1.36	1.46	1.56	1.66	1.77	1.87	2.02	1.23	1.25	1.41
(V%) H_2	2.9 $\pm$ 0.4	2.7 $\pm$ 0.4	2.1 $\pm$ 0.4	1.8 $\pm$ 0.2	1.6 $\pm$ 0.2	1.2 $\pm$ 0.2	1.0 $\pm$ 0.3	0.8 $\pm$ 0.2	3.6 $\pm$ 0.3	3.8 $\pm$ 0.5	3.1 $\pm$ 0.2
log($P_{\text{H}_2}/P_{\text{CO}_2}$)	-1.50	-1.54	-1.65	-1.72	-1.78	-1.91	-1.99	-2.09	-1.40	-1.38	-1.46
(V%) CH_4	1.5 $\pm$ 0.3	1.4 $\pm$ 0.2	1.4 $\pm$ 0.1	1.4 $\pm$ 0.5	0.9 $\pm$ 0.4	0.6 $\pm$ 0.3	0.4 $\pm$ 0.2	0.6 $\pm$ 0.4	1.4 $\pm$ 0.1	1.7 $\pm$ 0.2	1.8 $\pm$ 0.1
log($P_{\text{CH}_4}/P_{\text{CO}_2}$)	-1.79	-1.82	-1.83	-1.83	-2.03	-2.21	-2.39	-2.21	-1.85	-1.73	-1.71
(V%) H_2S	2.5 $\pm$ 0.6	2.3 $\pm$ 0.5	1.9 $\pm$ 0.1	1.7 $\pm$ 0.3	1.4 $\pm$ 0.4	1.0 $\pm$ 0.3	0.7 $\pm$ 0.2	0.5 $\pm$ 0.3	3.2 $\pm$ 0.2	3.0 $\pm$ 0.1	3.1 $\pm$ 0.2
log($P_{\text{H}_2\text{S}}/P_{\text{CO}_2}$)	-1.57	-1.61	-1.69	-1.74	-1.84	-1.99	-2.15	-2.29	-1.45	-1.48	-1.47
(V%) CO_2	92.4 $\pm$ 1	93.0 $\pm$ 1	93.7 $\pm$ 1	94.2 $\pm$ 1	95.8 $\pm$ 1	96.7 $\pm$ 1	98.2 $\pm$ 1	97.5 $\pm$ 1	91.1	90.8	91.7

Table 2b. Carbon dioxide/steam and gas ratios for some high-temperature wells at Serrazzano, for some wells at The Geysers and for reference wells at Monte Amiata and Travale.

	G-1	G-2	G-3	G-4	G-5	G-6	G-7	G-8	G-9	A-1	A-2	T-1
log($\text{Nl}_{\text{CO}_2}/\text{Kg}_w$)	0.33	0.12	0.38	0.69	0.56	0.53	-0.73	0.64	-0.62	1.56	2.16	1.66
log($P_{\text{H}_2}/P_{\text{CO}_2}$)	-0.45	-0.87	-0.64	-0.66	-0.47	-1.21	-1.42	-0.90	-0.70	-2.44	-2.29	-2.25
log($P_{\text{CH}_4}/P_{\text{CO}_2}$)	-0.79	-0.92	-1.39	-0.96	-0.53	-1.70	-1.34	-0.73	-0.15	-1.84	-1.56	-1.58
log($P_{\text{H}_2\text{S}}/P_{\text{CO}_2}$)	-1.02	-1.16	-1.06	-1.21	-1.15	-1.56	-1.12	-1.11	-0.64	-2.97	-2.37	-1.97

Well names:	Serrazzano area, Larderello	The Geysers	Monte Amiata - Travale
	S-1 VC/10	G-1 Rorabaugh-10	A-1 Bagnore 2b
	S-2 Querciola 1	G-2 La Koma-Fame-15	A-2 Piancastagnaio 8
	S-3 Lustignano 5	G-3 DX-State-30	T-1 Travale 23/D
		G-4 Ottobone-State-15	
		G-5 Rorabaugh-7A	
		G-6 DX-27	
		G-7 CA 956	
		G-8 Aidlin 1	
		G-9 CA 1892	

Table 3. Temperatures computed by gas geothermometers (°C)

Larderello (classic area) log (NlCO ₂ /Kg _w)	T _{H₂}		T _{CH₄}		T _{H₂S}		T _{meas}
	eq. (8)	eq. (11)	eq. (9)	eq. (10)	eq. (12)		
1.22	245	250	241	235	248		108-260
1.33	253	251	243	241	249		234-252
1.43	252	246	246	243	247		229-244
1.53	256	245	250	248	247		223-245
1.64	262	244	239	249	244		206-242
1.76	260	239	230	246	238		210-222
1.86	263	237	221	240	231		201-222
2.01	269	235	239	241	226		198-233
Serrazzano							
Well VC/10	253	265	235	243	256		260
Querciola 1	258	268	246	242	255		265
Lustignano 5	268	269	253	260	262		270
M. Amiata - Travale							
Well Bagnore 2b	184	200	249	153	173		160
Piancastagnaio 8	263	233	302	248	226		210
Travale 23/D	213	218	276	239	236		240
The Geysers (table 2)							
1	264	313	286	206	256		252+
2	198	265	266	180	239		
3	248	297	240	207	255		
4	283	310	287	220	255		
5	290	323	323	214	255		
6	204	253	222	180	225		
7	96	193	204	128	214		
8	248	285	307	224	260		
9	150	225	221	133	249		247

Table 4. Reservoir temperatures computed from equation (12), well-bottom temperatures and volume percentages of liquid water in the reservoir for two wells of Larderello from 1940-1978.

Well	Year	Q _{Steam}	N CO ₂ /Kg _w	log(P _{H₂S} /P _{CO₂})	T _{H₂S}	T _{WB}	(T _{H₂S} -T _{WB})	(255-T _{WB})	V% liq. H ₂ O
FBN	1942	80-97	24	-1.59	252	215	37	40	6.1-6.5
	1951	51	26	-1.56	257	235	22	20	3.3-3.6
	1960-63	28	29	-1.65	252	248	4	7	0.7-1.2
	1970-71	18	29	-1.65	252	251	1	4	0.2-0.7
	1977-78	15	28	-1.69	248	245	3	10	0.5-1.7
ALR	1941	120	16	-1.51	252	216	36	39	5.9-6.4
	1951	38	26	-1.57	255	239	16	16	2.6-2.6
	1965-66	20	43	-1.74	251	250	1	5	0.2-0.9
	1970-71	15	28	-1.67	249	247	2	8	0.4-1.3
	1977-78	10	25	-1.71	246	247	0	8	0 -1.3

Table 5. Reservoir temperatures computed from equation (12), well-bottom temperatures and percentage of liquid water in the reservoir for nine wells at The Geysers in 1977.

Sample	$\text{NlCO}_2/\text{Kg}_w$	$\log(\text{PH}_2\text{S}/\text{PCO}_2)$	$\text{T}_{\text{H}_2\text{S}} \text{ } ^\circ\text{C}$	$\text{T}_{\text{WB}} \text{ } ^\circ\text{C}$	$(\text{V}\%)_{\text{liq. w 0.5}}$
e	0.79	-1.01	241	232	2.4
a	1.10	-0.95	250	220	4.5
f	1.34	-0.99	251	207	6.5
c	1.53	-1.37	227	207	6.5
b	1.58	-0.98	254	207	6.5
d	1.76	-1.04	251	204	7.0
g	2.08	-1.36	232	204	7.0
h	2.08	-1.22	241	214	5.5
i	2.73	-1.06	257	179	11.1

Table 6 Reservoir temperatures of water-dominated geothermal systems calculated from equation (10) compared with measured temperatures and temperatures from other geothermometers. Data from Truesdell and Singers (1971) except for Cerro Prieto (Nehring and Fausto, 1979) and Namafjall (Arnorsson, 1974).

Well	Temperatures				H_2S	SiO_2
	Na-K-Ca	Na-K	Measured	Maximum		
Cerro Prieto 8	273	278	295	340	298	270
27	268	277	284		312	279
35	287	301	299		291	299
21A	283	301	279		301	280
20	258	262	243		289	256
Wairakei 20	254	262	260	270	231	246
Broadlands 2	297	287	287	307	265(290)	261
Tauhara 1	259	257			248	248
Rotakawa 1	259	255			247	254
Kawerau 8	282	258	260		291	282
Orakeikorakei 3	245	242	237		233(232)	234
Kizildere 1A	243	193		210	216	199
Matsao E205	234	248	240	300	290	245
Otake 7	230	212	195		180(201)	217
Hveragerdi G7	217	193			211(22)	222
4	187	165			219	200
Reykjanes 8	240	235	270		225(233)	251-256
Namafjall 4	237	256	280	290	290	252-207
5	221	237	250		278	264-243
6	245	257	270		306	264-243
7	247	265	290		317	280-243
8	236	257	275		277	241
9	244	266	260		295	254-259
Tatio 2	291	213	226	260	206	218

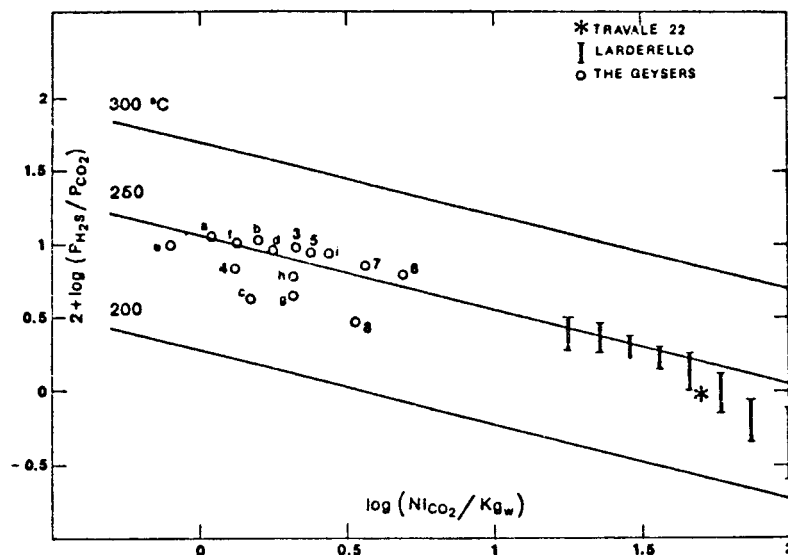


Figure 1

Figure 1. Application of equation 12 to Larderello, Travale, and The Geysers. Actual H_2S/CO_2 ratios (as $\log(P_{H_2S}/P_{CO_2} + 2)$) are plotted vs. gas/steam ratios. Continuous lines show predicted values at selected temperatures.

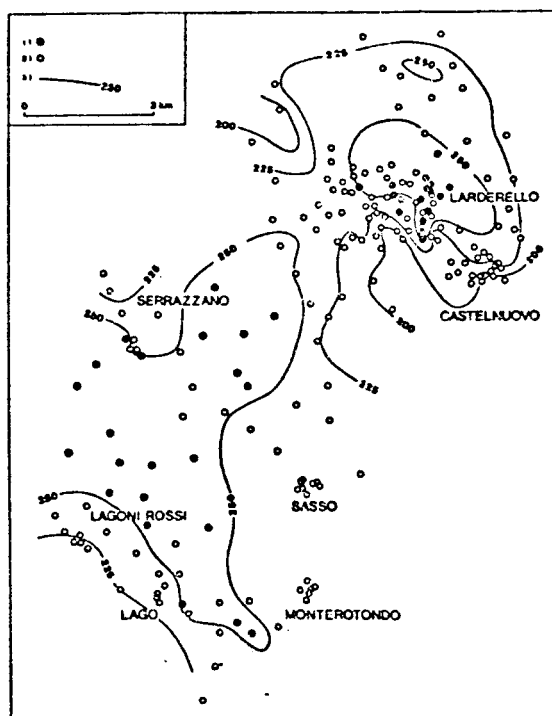


Figure 2

Figure 2. Application of equation 12 to all of Larderello field.
 (1) computed T greater than 250°C
 (2) computed T less than or equal to 250°C
 (3) computed isotherms at 250, 225 and 200°C

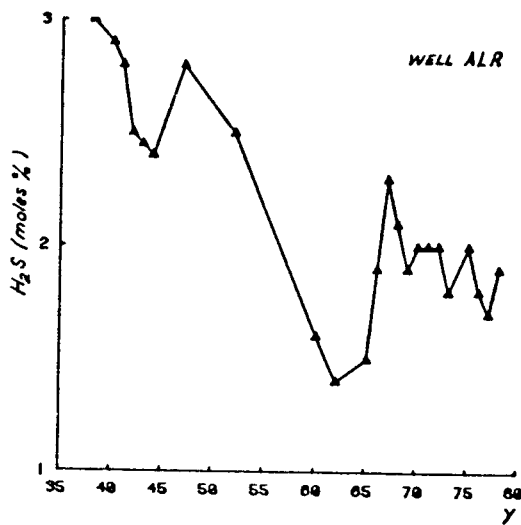


Figure 3

Figure 3. Evolution of H_2S percentage in the dry gas is plotted vs. time (years) for well ALR.

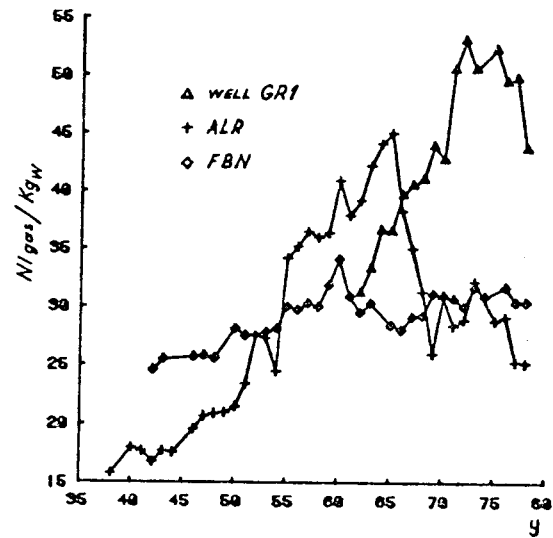


Figure 4

Figure 4. Change with time of gas/steam ratio (N_{lgas}/Kg steam) for three Larderello wells.

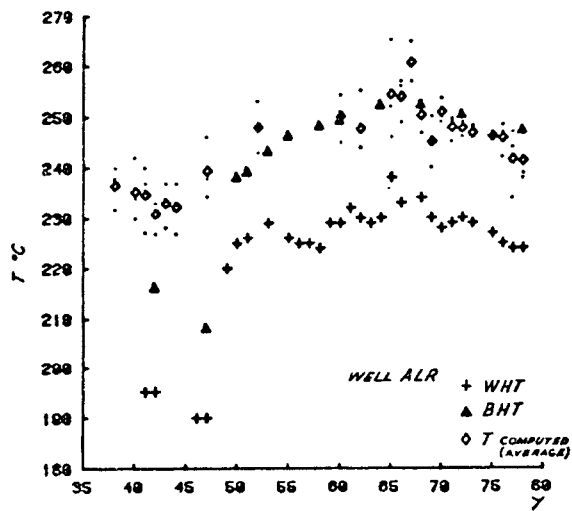


Figure 5

Figure 5. Evolution with time of well-head temperature (crosses), well-bottom temperature (triangles), and average reservoir temperature computed using H_2S , H_2 , CH_4 geothermometers (diamonds) for well ALR.

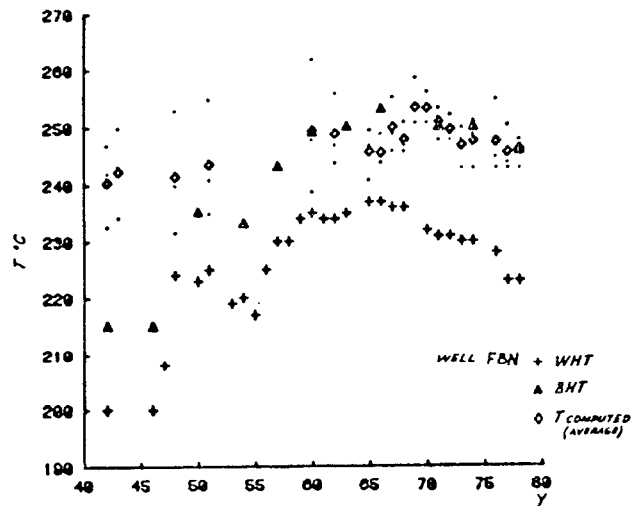


Figure 6

Figure 6. Same as Figure 5, for well FBN.

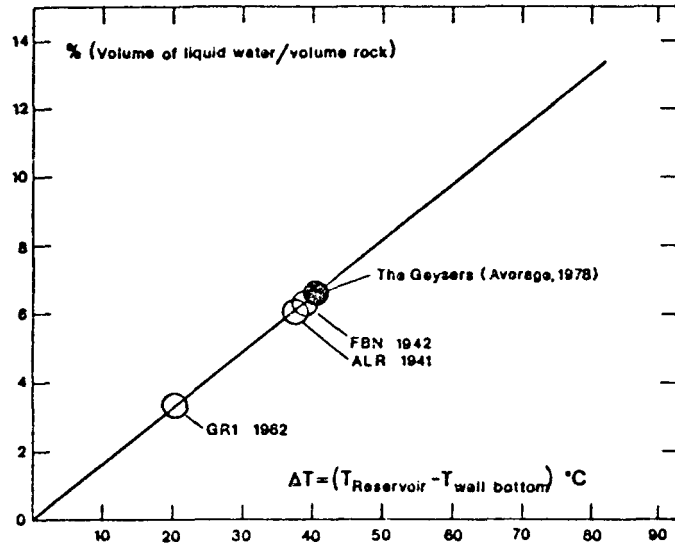


Figure 7

Figure 7. Computed volume per cent of liquid water in total rock plotted vs. the difference between the reservoir and the well-bottom temperatures. Starting production conditions are located on the diagram for 3 wells at Larderello.

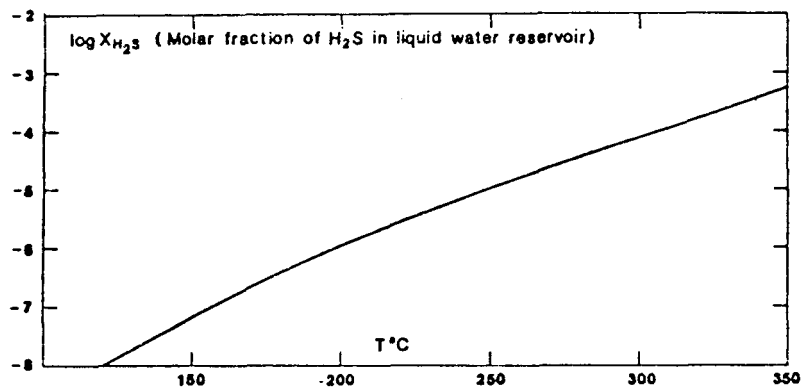


Figure 8

Figure 8. Computed molar fraction of H_2S in liquid water reservoir as function of temperature used as geothermometer for water-dominated geothermal systems (Table 6).

HYDROTHERMAL ALTERATION MINERALS OF THE GEYSERS STEAM FIELD,
CALIFORNIA AND THEIR POTENTIAL USE IN EXPLORATION

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INTRODUCTION

Little information has been published on the hydrothermal alteration minerals occurring at depth in the Geysers steam field, California. Steiner (1958) reported the occurrence of wairakite from a well; McNitt (1964) identified pyrite, sericite, calcite, quartz, siderite, apatite and chlorite in cores of Franciscan graywacke and greenstone. Recently, Union Oil Geothermal Division furnished a set of well cores from the cap rock overlying the steam reservoir for geophysical studies (Lockner *et al.*, 1980); sample localities are shown in Figure 1. Cores of meta-graywacke and greenstone from 4 wells---Thermal 10 (TH10), Lakoma Fame 6 (LF6), D & V 1 (DV1) and Horner State (HS1)---were compared to unaltered Franciscan metagraywacke (GP5) from surface exposures (Table 1). Several previously unreported alteration minerals were found in the cored rocks, including epidote, tremolite-actinolite, prehnite and tourmaline. This note describes the observed alteration minerals and some of the factors that controlled their growth.

SAMPLE DESCRIPTIONS

GP5 -- Outcrops of Franciscan rock in the Geysers area consist of massive, fine-grained metagraywacke with the mineral assemblage quartz + albite + chlorite + phengite + pumpellyite + sphene + calcite. GP5 contains some relict detrital epidote, that occurs as rounded grains or as part of schistose metamorphic rock fragments. These partly altered relics are readily distinguished from the hydrothermal epidote of some cores.

HS1 -- The Horner State well is located near the northern limit of drilling operations in the Geysers steam field (Fig. 1). Metagraywacke at 1478 m depth is nearly identical to GP5, except for the presence in HS1 of narrow veins of calcite + pyrite. Although calcite is associated with both the initial, Franciscan metamorphism and later hydrothermal activity, pyrite is exclusively a hydrothermal mineral. Therefore, these veins are correlated with events related to the steam field.

DV1 -- In contrast to the texturally unmodified GP5 and HS1 metagraywackes, the DV1 core is a semischist with partial segregation of quartzofeldspathic and chlorite-rich layers. Some of the quartzose layers have been fragmented and the pieces randomly oriented in the chloritic bands. This fragmented, schistose texture probably originated during Franciscan metamorphism and defor-

mation; the veins associated with the hydrothermal events in DV1 cut across all the deformation features.

A large number of hydrothermal vein minerals occur in DV1 (Table 1); calcite alone is notably absent. One set of veins contains the assemblage epidote + calcic amphibole + chlorite + adularia + pyrite. Chlorite generally lines the walls of such veins, and euhedral epidote and adularia extend into the veins from the margins. The pale green calcic amphibole is probably tremolite or actinolite in composition. Wider veins in DV1, that cross-cut the epidote and actinolite-bearing veins, consist of coarse-grained adularia + quartz + pyrite + prehnite + chlorite. The prehnite in the large veins is an interstitial mineral and the quartz occurs as euhedral crystals that are enveloped by coarse-grained, anhedral adularia.

Other than vein development, the DV1 metagraywacke exhibits few effects of hydrothermal alteration. Minor amounts of epidote and actinolite are found in the wall rock adjacent to the epidote-bearing veins. DV1 also contains a considerable amount of green, blue-green, or brown tourmaline that has apparently crystallized in response to the hydrothermal activity. The tourmaline occurs as aggregates of irregularly shaped to tabular crystals in the chlorite-rich bands.

TH10 -- This metagraywacke also shows a high degree of textural reconstitution, in this case owing to recrystallization during hydrothermal alteration rather than to deformation accompanying Franciscan metamorphism. In places this alteration has destroyed the sedimentary fabric, producing a fine-grained, non-foliated mosaic of quartz + feldspar + chlorite + white mica. The alteration is characterized by the introduction of potassium and sulfur, and the loss of sodium. All feldspars in TH10, that previously had been albitized during Franciscan metamorphism, have been replaced by adularia with a tile-like texture identical to that of the adularia at Wairakei, New Zealand (Steiner, 1970). Extensive pyrite mineralization also has taken place, with sulfides concentrated in some shale and volcanic rock fragments and in the metagraywacke matrix.

TH10 is extensively cut by veins whose mineral assemblages differ from DV1 in the absence of epidote and actinolite and the presence of calcite (Table 1). An early generation of narrow, laminar veins consists of alternating layers of fine-grained quartz and chlorite. Later, wider veins composed principally of quartz + adularia + pyrite are similar to veins in DV1. Minor, interstitial prehnite in these younger veins is partly replaced by calcite; in places the vein walls are lined with chlorite.

LF6 -- Greenstone samples from 2 depths were examined from the Lakoma Fame well. At the deeper, 969 m level, the rock was originally an aphanitic metabasalt with scattered small plagioclase laths and scarce relict pyroxene phenocrysts. The igneous

minerals were replaced by the assemblage albite + chlorite + sphene + white mica during Franciscan metamorphism. Narrow veins of albite + chlorite may also be correlated with the early Franciscan metamorphism, for the following reasons: 1) the albite-bearing veins are cut by veins clearly associated with the steam field; and 2) the characteristic feldspar of the hydrothermal veins is adularia rather than albite. Later veins consist principally of coarse-grained chlorite + adularia + pyrite. Neither calcite, quartz, nor epidote was positively identified in this rock. Other than vein formation, this greenstone shows no evidence of hydrothermal alteration.

Greenstone at the 922-927 m level in LF6 is considerably coarser-grained and contains many more pyroxene phenocrysts than the greenstone at greater depth. The 922 m rock also has larger veins that contain calcite, epidote, and actinolite in addition to pyrite, adularia, and chlorite (Table 1). The calcite is a late vein mineral that fills the centers of some veins and cuts across minerals such as epidote and adularia. Minor amounts of epidote have also crystallized within the greenstone wall rock.

CONTROLS ON MINERAL DISTRIBUTION

Because of the limited number of cores examined here, generalizations about mineral distribution and the controls of mineral occurrence cannot be made. However, variations in mineral assemblages have been observed at different depths and locations within the Geysers steam field. The observed distributions may have been influenced by the following factors:

1) Temperature. The crystallization of epidote and actinolite in the cores may be most strongly controlled by temperature. In other geothermal fields, epidote and actinolite occur at temperatures above about 220°C. According to White *et al.* (1971), temperatures within the steam reservoir at the Geysers are relatively uniform at 240°C. The epidote- and actinolite-bearing core DV1 was located just above the steam reservoir, where temperatures near 240°C may also have prevailed. Similar temperatures may have existed at depth in the Lakoma Fame well. Reduced temperatures at the shallow depths (100 m) of the TH10 core may explain the absence of epidote and actinolite from that thoroughly recrystallized metagraywacke.

Cored metagraywacke from the Horner State well was obtained at the greatest depth of all examined cores, yet HS1 displays the least development of veining and no wall rock alteration. This well may have been drilled into low-temperature rock lying outside the influence of the steam reservoir.

2) Pressure. According to Browne (1978), pressure has little direct effect on hydrothermal alteration. However, changes in fluid pressure, such as those produced by boiling, may alter the fluid composition and thus promote crystallization of certain

vein minerals. Boiling and subsequent loss of CO_2 may have resulted in the deposition of calcite, quartz and adularia in some cores. In contrast, non-boiling of the hydrothermal fluid at DV1 is a possible explanation for the absence of calcite from that core.

3) Permeability. Permeability is an important factor in the amount of rock alteration attained within a geothermal field. In rocks of low permeability, interaction between the rock and a hydrothermal fluid is slight and equilibrium is certainly not attained. At the Ohaki-Broadlands geothermal area in New Zealand, the replacement of plagioclase by adularia in the reservoir rocks is roughly correlated with an increase in the measured well permeability (Browne, 1970). Of the Geysers cores studied, TH10 may have been the most permeable; the abundance of pyrite and adularia indicate that a significant amount of chemical exchange has taken place. In contrast, LF6 and DV1 show little rock alteration, most of which is concentrated near veins.

4) Rock Type. At low temperatures, the composition of the reservoir and cap rocks may influence the alteration minerals observed (Browne, 1978). The concentration of chlorite, calcic amphibole, and epidote along the vein walls suggest that some of the iron and magnesium required for their crystallization was provided by the host rock, through exchange reactions with the hydrothermal fluid. Had other rock types of different compositions been present, different vein minerals might have formed.

POTENTIAL USE OF ALTERATION MINERALS IN EXPLORATION

Unlike hot-water systems, the mineral relationships of vapor-dominated geothermal systems have not been investigated in any detail (White, 1970). However, of the above parameters, the relationships between temperature and mineral occurrence may prove useful in evaluating the steam-producing potential of different wells. In particular, the occurrence of epidote and actinolite in cap rocks of various compositions indicates that temperatures approaching those of the steam reservoir have been attained. Similarly, the borders of vapor-dominated systems may be identified by the absence of high-temperature mineral assemblages even at great depth. Knowledge of the permeability of the caprock may prove important in evaluating the effectiveness of the seal that produces a vapor-dominated system.

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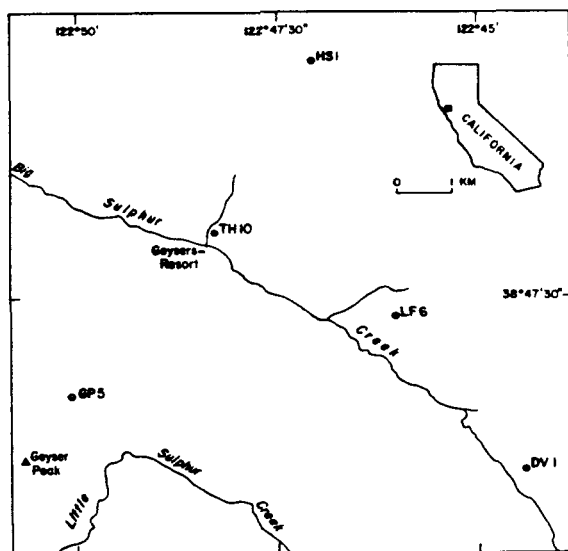


Figure 1.

Sites of wells and sampling areas at
The Geysers

Mineral	GP5	HSI-1478M		TH10-100M		922-927M		LF6 969M		DVI-1260M	
		Rock	Vein	Rock	Vein	Rock	Vein	Rock	Vein	Rock	Vein
Quartz	X	X	X	X	X		X			X	X
Albite	X	X				X	X	X	X	X	
Chlorite	X	X		X	X	X	X	X	X	X	X
White mica	X	X		X	X	X		X	X	X	
Sphene	X	X		X		X		X		X	
Pumpellyite	X	?									
Adularia				X	X		X		X		X
Pyrite			X	X	X		X		X		X
Calcite	X	X	X		X		X				
Prehnite					X						X
Epidote						X	X			X	X
Amphibole							X			X	X
Tourmaline										X	

Table I

Alteration minerals in the various rocks

GEOCHEMICAL BEHAVIOR OF THE SECOND HOT DRY ROCK GEOTHERMAL
RESERVOIR AT FENTON HILL, NEW MEXICO

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INTRODUCTION

Characteristics of a Hot Dry Rock (HDR) geothermal reservoir were deduced by matching a geochemistry model which incorporates rock dissolution and displacement of an indigenous pore-fluid to chemical analyses of recirculating geothermal fluid. Two reservoirs were created between a pair of wells by hydraulic fracturing. The geometry of these reservoir systems, as well as operational conditions during flow experiments and general heat extraction and water loss performance are described in a preceeding paper by Murphy et al.(1). The first of the reservoirs was evaluated by a 75-day flow test designated as Segment 2. Subsequent operations required the cementing of the injection well to stop a leak behind the casing, and this cementing operation closed the connection to the first reservoir. The second, larger reservoir was evaluated with two flow tests -- the first had a duration of 24 days and is called Segment 4 and the second, called Segment 5, will end on December 19, 1980 after 284 days of operation. Descriptions of the fluid geochemistry in the first reservoir have already been presented by Grigsby and Tester(2), and a preliminary analysis of the Segment 4 test has also been published(3). Present discussion will be mainly concerned with the geochemistry of the second reservoir. Of particular interest in a HDR geothermal reservoir is the relationship between the mixed-mean temperature of the geothermal fluid as measured with a downhole thermistor and the temperatures given by the silica and the Na-K-Ca geochemical thermometers. As will be shown, the temperatures predicted by applying the chemical geothermometers directly to the produced fluid composition at a given time do not represent the true current reservoir temperature.

GEOCHEMISTRY

Fluid samples were analyzed for pH, Eh, conductivity, SiO_2 , Na^+ , K^+ , Ca^{++} , Li^+ , B, $\text{SO}_4^{=}$, Cl^- , HCO_3^- , and F^- and samples of the gas dissolved in the liquid were analyzed for H_2 , N_2 , O_2 , CO_2 , H_2S and Rn. The data for SiO_2 and Cl^- are plotted vs time for Segments 4 and 5 in Figures 1 and 2 to illustrate the behavior of the system. The rapid decline in both silica and chloride shown in the first eight days in Fig. 1 is due to open-loop operation when the produced fluid was discarded rather than re-injected. After closed-loop operation was established in day 8, the produced fluid is re-injected and the silica and chloride concentrations rapidly attained steady-state levels. The graphs in Fig. 2 also show decline from the high initial concentrations

to steady-state levels, however, due to the absence of a long period of open-loop operation in the Segment 5 test, steady-state conditions were reached much more rapidly.

Two types of behavior are discernable from analysis of the fluid chemistry. In the first, the concentration of an aqueous species is fixed by mineral-water equilibria. An example of this is the quartz-water system which fixes the silica concentrations in solution. On the other hand certain species like Cl^- and B, do not result from equilibrium with any known mineral in the rock. The constant ratio of boron to chloride(3) suggests that these species are present in the rock as interstitial salts or pore-fluid. When a flow experiment is initiated in a fracture, some of this pore-fluid is displaced immediately, resulting in the high initial concentrations of Cl^- observed in Figs. 1 and 2. Long-term circulation will eventually sweep the fluid from the rock pores and microcracks that are connected to the main flow system. The dissolved ions in the pore-fluid will maintain a constant ratio in the fluid produced at the surface when the effects of addition of different species concentrations in the make-up water are accounted for. These ratios in the pore-fluid are most easily seen by plotting the nondimensional concentration $\langle C \rangle$ defined as

$$\langle C \rangle \equiv \frac{C^\infty - C}{C^\infty - C_m}$$

for several dissolved species vs. time where C^∞ is the concentration of a given species in the pore fluid, C_m is the concentration in the make-up fluid, and C is the concentration of that species in the produced fluid at time t . Plots of $\langle C \rangle$ vs. time for sodium, potassium, chloride, and boron for the Segment 4 test are shown in Fig. 3. Values for C^∞ for each of these curves are simply the measured concentrations of these species in the earliest samples taken at the production well during the start of a flow experiment. The values for C_m are the measured concentrations in the makeup fluid.

MODELING

It was found from the results of the Segment 2 test(4) that the geochemical behavior of the early system could be adequately described by two parallel flow paths at different temperatures. Such a model is shown schematically in Fig. 4. The changes in concentration of a chemical species resulting from mineral dissolution or pore-fluid displacement in both flow paths are derived by writing a mass balance on each species and on the total mass in the system. Many of the terms used in the model to account for the rate of dissolution or displacement in the separate flow paths are not directly measurable; therefore, the unknown parameters are lumped into two temperature dependent parameters. These parameters are adjusted within reasonable limits to match the actual behavior measured under open- or closed-loop experimental conditions. Comparisons of the best-fit solutions obtained for the data from Segment 4 are shown in Fig. 5. The close fit of the calculations with the actual data suggests that a simple model with two parallel paths is sufficient at the present time to describe pore-fluid displacement in the reservoir.

GEOOTHERMOMETRY

If two parallel flow paths at different temperatures and residence times are conducting fluid through the reservoir, the produced fluid compositions will result from the combination of reaction rates, residence times and flow rates in each of the flow paths. Estimates of the flow split between the paths can be made by considering a species such as Cl^- which does not result from mineral-water reactions in the reservoir. From the closed-loop portion of the Segment 4 test, ~92.5% of the fluid passes through the main fracture system while the other 7.5% passes through the secondary path. Because there will be insignificant thermal drawdown and long contact times between fluid and rock, the fluid passing through this secondary flow path will truly reflect the mean rock temperature in this path. The quartz geothermometer(5) and the Na-K-Ca geothermometer(6) temperatures have been calculated for the fluid produced during Segments 4 and 5. Graphs of these temperatures as well as the downhole measured temperatures are shown in Fig. 6. Since no thermal drawdown was measured in the Segment 4 test, it is not surprising that no decline in geothermometer temperature is seen in Fig. 6a. There is, however, measurable decline in downhole temperature in the Segment 5 test. This temperature decline is observed in the quartz geothermometer; however, no similar decline is seen in the Na-K-Ca geothermometer. In addition, the Na-K-Ca geothermometer is affected significantly less during the open-loop portion of Segment 4 than is the quartz geothermometer. This insensitivity of the Na-K-Ca geothermometer to reservoir temperature decline and to changes in inlet fluid composition during a test is due to the constant Na/K ratio in the pore-fluid which is displaced from the secondary flow path. This Na/K ratio is fixed by equilibrium with the feldspars at the initial rock temperature (~190°C) and dilution of the pore-fluid with fresh water does not affect the Na/K ratio in the produced fluid. Because re-equilibration of this geothermometer is extremely slow (see, for example, ref 7) the Na-K-Ca geothermometer reflects the initial rock temperature rather than changes in the reservoir temperature due to heat extraction.

The quartz geothermometer, on the other hand, is affected by changes in temperature in the main flow path as well as changes in the inlet fluid composition. This is seen in the first eight days of the Segment 4 test (Fig. 6a) as well as in three periods of open-loop circulation at about days 102, 110 and 230 in the Segment 5 test (Fig. 6b). The sudden change in inlet fluid composition in the Segment 5 test exceeded the ability of the main flow path to dissolve quartz and thus raise the silica concentration in the produced fluid. Re-establishing the closed-loop mode resulted in a rapid rise in the silica concentration back to the pre-open-loop levels. Interpretation of this response and of the application of the quartz geothermometer to the HDR system are in progress, however, incomplete knowledge of the temperature dependence of the rate of dissolution of quartz has hampered further development of the analysis.

CONCLUSIONS

The results of three major heat-extraction experiments conducted in two hot dry rock geothermal reservoirs indicate that the fluid chemistry is largely influenced by the interstitial fluid contained in the reservoir rock. This fluid is slowly removed by the circulation of relatively fresh water through the fracture systems until the level of dissolved species is ultimately fixed by rock-water equilibrium. Because the sodium and potassium observed in the system were contributed by the pore-fluid, the Na-K-Ca geothermometer was insensitive to changes in the rock temperatures. The quartz geothermometer does reflect the changes in reservoir temperature, however the concentration of silica in solution must be adjusted for the effect of mixing of small amounts of silica-saturated pore-fluid with fluid which has passed through the main flow path. When the pore-fluid contribution is subtracted, the resulting concentration of silica in the produced fluid can be modeled with a kinetic model to determine the actual temperature of the reservoir rock.

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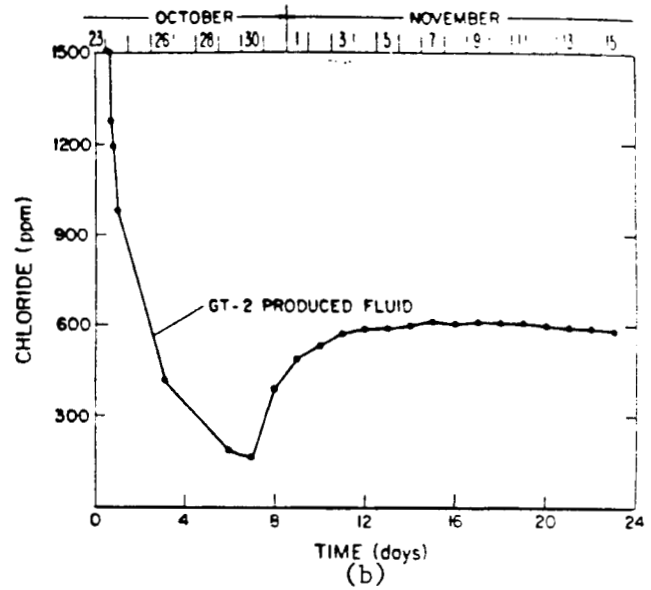
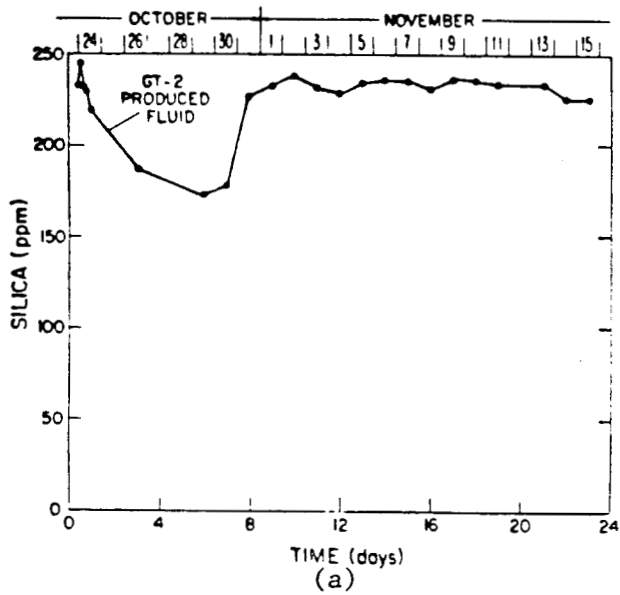


Figure 1 Silica (a) and chloride (b) variations with time in the Segment 4 test.

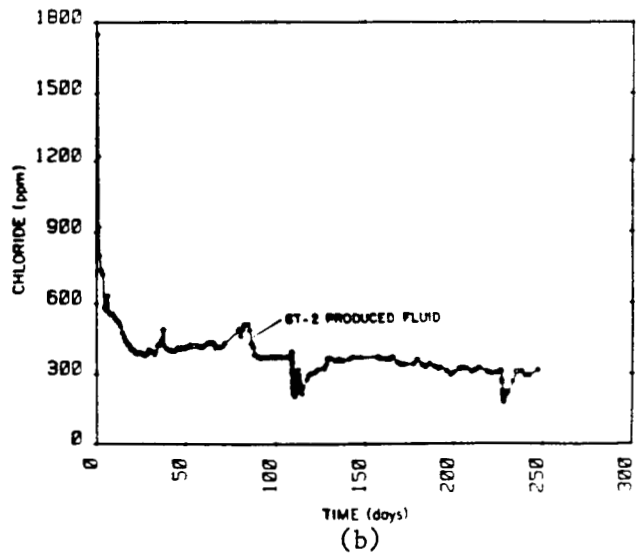
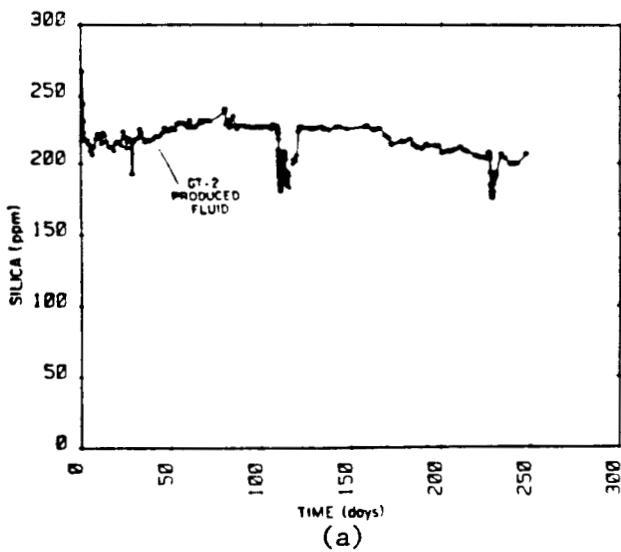


Figure 2 Silica (a) and chloride (b) variations with time in the Segment 5 test.

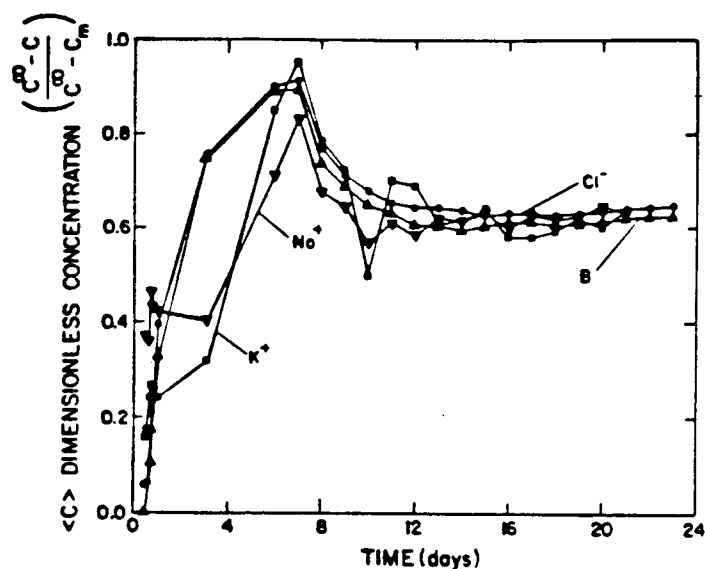


Figure 3 Nondimensional concentrations of Na^+ , K^+ , Cl^- and B in the produced fluid from the Segment 4 test.

SCHEMATIC OF FENTON HILL SYSTEM

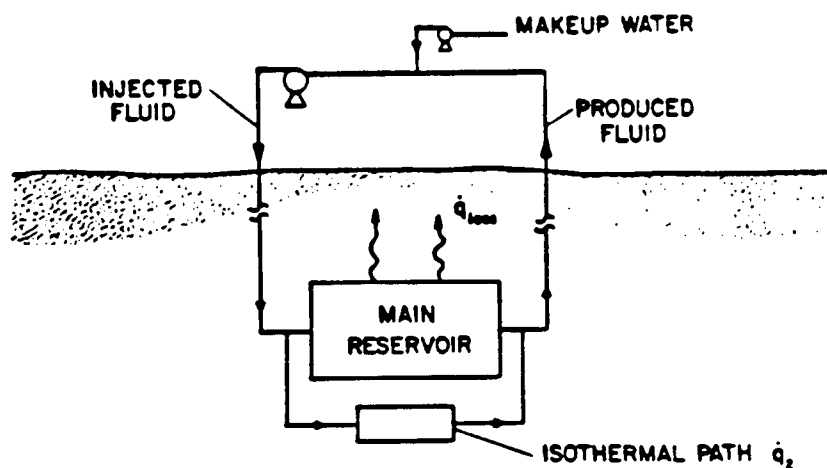


Figure 4 Schematic of the parallel-path model for the Fenton Hill System. The main reservoir consists of the short-residence time fracture system while the isothermal or secondary path has a long residence time.

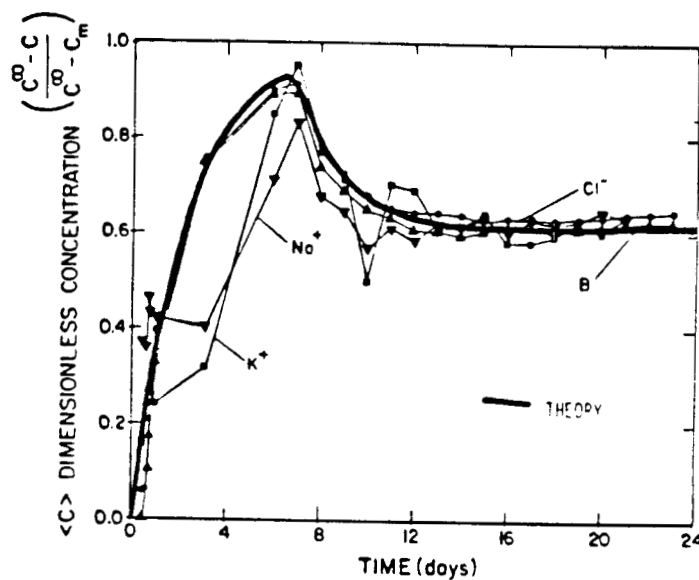


Figure 5 Theoretical fit to the experimental data for the pore-fluid displacement model.

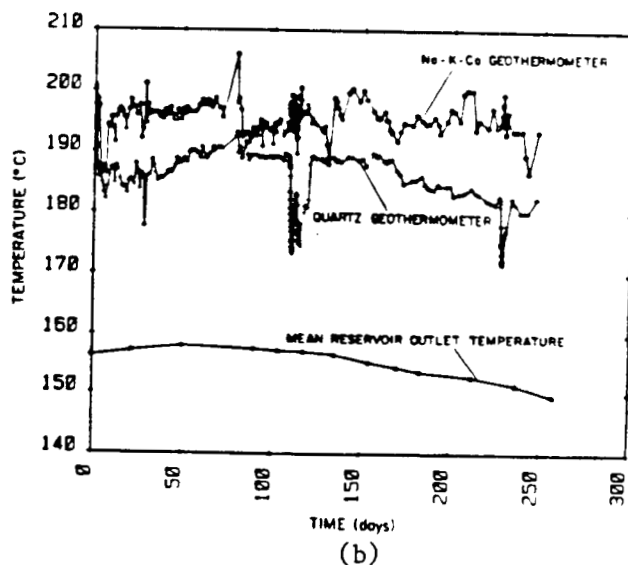
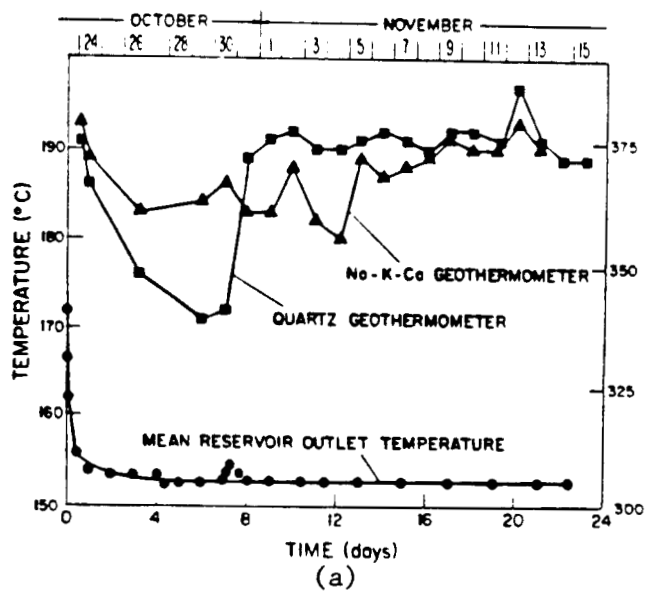


Figure 6 Comparison of the Na-K-Ca geothermometer and quartz geothermometer temperatures to the measured downhole reservoir outlet temperature for Segment 4 (a) and Segment 5 (b).

GEOTHERMAL RESERVOIR INSURANCE PROGRAM: EVALUATION
OF ALTERNATIVES AND ASSESSMENT OF NEEDS

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A significant part of a recent workshop sponsored by the Electric Power Research Institute (EPRI 1978) was devoted to the question of the risks of geothermal development and the need for a geothermal reservoir insurance program. In this workshop, several viewpoints regarding the adequacy of the available measures for reducing financial risks to the developers and users of geothermal energy were discussed. The main point of agreement among the authors was the existence of risk in geothermal development, and that some method for reducing the financial risks to the developers and users of geothermal energy was necessary for accelerated development of this resource.

Several schemes were suggested to reduce the financial risks to the users of geothermal energy and the financial institutions responsible for extending loans for geothermal industrial projects.

The suggested schemes included the following (Aidlin 1978; Falick 1978):

- contractual arrangements between the resource company and the user that would place the risk of reservoir loss on the supplier, or apportions the risk between the supplier and user
- enactment of state legislation that would require regulatory agencies such as the Public Utilities Commission (PUC) to treat, for tariff base purposes, the first power plant as an R&D facility eligible for accelerated depreciation
- construction of "turn-key" power plants built by companies willing to assume financial risk in exchange for a guaranteed rate of return generated through the sale of electricity to utilities
- use of the existing Geothermal Loan Guarantee Program that allows a participating utility to repay the debt through government assistance
- encouragement of private industry to provide coverage for the risks of geothermal development.

Each of these suggested methods has its advantages and disadvantages and each covers risks to certain users with the possible exclusion of others, resulting in different groups having widely divergent views on the relative attractiveness and feasibility of one scheme versus another.

In addition, each scheme is accompanied by either direct or indirect costs to the potential end user whose views would be represented either by public interest groups or regulatory agencies mandated with protecting the public interest, and each is accompanied by a multitude of direct and indirect implications which are not totally known at this time.

In view of the inadequacies of the above schemes and uncertainties regarding their effectiveness in providing the necessary incentives for an accelerated pace of development, recent legislation (U.S. Congressional Record, 1979) directs the Department of Energy to consider initiating a government-sponsored insurance program that would supplement the policies that may be offered by the private insurance industry.

In this paper we present some thoughts on a study that would help in laying the groundwork for drafting regulations for the geothermal reservoir insurance program. The objectives of this study would be

- 1) to assess the likelihood and the financial consequences of premature depletion of reservoirs
- 2) to evaluate the advantages and shortcomings of alternative schemes for reducing the financial risks of geothermal development
- 3) to assess the need for government-sponsored reservoir insurance programs, and
- 4) to delineate the areas and conditions under which a reservoir insurance program would be most useful in promoting national goals.

In view of the importance of the government-funded reservoir insurance program and the complex nature of the problem, four issues must be considered in defining the scope and objectives of this study. First, the goals and expectations of the government must be specifically defined and a procedure be developed to allow for measuring the achievement of these goals. Second, the reservoir-related risk should be assessed and a framework should be developed for resolution of differences among the views expressed by segments of the industry on the likelihood of premature reservoir depletion and the financial consequences of such events. Third, given the diversity of opinion among interest groups, it is important that the viewpoints of various segments of industry and the public be sought and incorporated into the study. Fourth, the study should avoid recommending a policy that would be "optimal" from an overall point of view yet would involve so many compromises that no group would consider it beneficial. With these points in mind, we propose the following four steps.

DEFINING THE GOALS OF THE GEOTHERMAL DEVELOPMENT PROGRAM

An important first step is defining the specific short-term and long-term goals of the geothermal development program. A series of attributes (measures) should be defined to serve as proxies for those goals, and proper scales should be constructed to measure the level of achievement of the objectives of the program.

The development of objectives and the measure of their achievement can be accomplished by:

- establishing general objectives
- breaking the general objectives into subobjectives
- establishing measures to define the level of achievement of the subobjectives.

The most direct means for generating objectives are a careful study of policy documents and dialogues with decision makers who often act on their perceptions of society's needs and the affected parties.

Measures can often be structured in a meaningful way by use of a hierarchy. A hierarchy provides a means for subdividing a general objective into lower level measures of more detail. These lower level measures are in turn subdivided into more detailed measures until a level of detail is reached such that the lowest level of the hierarchy consists of specific, well-defined measures that can be reasonably quantified.

Use of a hierarchy ensures that the final set of measures will be comprehensive and complete. It also assists in quantifying the effects of uncertainty in lower-level measures on the overall program goals.

ASSESSING THE RISK OF PREMATURE RESERVOIR DEPLETION

The objectives of this step are (1) to assess the likelihood of premature depletion of several reservoirs for which adequate information is available (under different production scenarios), and (2) to estimate the financial consequences of such failures.

The characteristics of reservoirs and brine, and their spatial and temporal variations, have a significant effect on the reliability of the resource. Since a power plant or other facilities using geothermal energy may become inoperable if the pressure and temperature of the heat source and the flow rate drop below certain levels, the likelihood and magnitude of decline of these parameters over time and the variation of the physical parameters over space should be estimated.

Important physical parameters, including storability, transmissivity, and the location of the producing fracture, can be estimated by well logging and well tests.

In estimating the appropriate flow rate (when the fluid is reinjected), it is important to estimate the "breakthrough" time rather than the rate of decline of temperature after breakthrough when the user facility is a power plant.

To estimate variations of the fluid characteristics over time, one or more of the available dynamic reservoir models can be used to predict reservoir behavior as a function of its physical parameters and flow rate. Once the model(s) that best describes the reservoir has been selected, the probability distribution over breakthrough time can be estimated.

The probability distribution over the input parameters can be assessed (see Tversky and Kahneman, 1974, for a treatise on several probability assessment procedures), and for each production scenario, a combination of input parameters will give a point on the distribution of the output parameter.

Different failure times have different economic consequences which can be computed by standard cost accounting methods and can include penalties for loss of goodwill, etc. Combining the economic model with the failure probability model completes the risk analysis.

This analysis will serve three purposes: (1) it provides examples of the levels of risk involved in geothermal development; (2) it gives a procedure for reservoir risk assessment that can be used as a framework for risk assignment by the insurance industry and financial community; and (3) it can help resolve different viewpoints among segments of industry on issues related to reservoir risk, the relationship between reservoir failure and production policy.

EVALUATING ALTERNATIVE SCHEMES

This step involves a detailed analysis of various options available to developers and users of geothermal energy. The objective of this task is to evaluate not only existing options, but also the feasibility of alternative measures to reduce the risks of geothermal energy.

In addition to evaluating programs offered by the insurance industry, this step involves an analysis of the limitations, scope, and potential of the Geothermal Loan Guarantee Program. The analysis will incorporate the experience of the banking industry with that program. This step also includes an analysis of the differences between geothermal energy and other segments of the extraction industry from the viewpoint of the banking industry to account for the reluctance of bankers to extend loans to the developers of geothermal energy. One possible explanation for this reluctance is the uncertainty associated with estimations of proven reserves of geothermal reservoirs (Manderbach, 1978). However, it is important that this issue be systematically addressed.

It has been suggested that contracts between the developers and users of geothermal energy be designed in such a way that financial risks on the part of the users are reduced (Aidlin, 1978). Since this scheme still proposes that a portion of the risks be accepted by the utilities, the desirability of such a scheme from the viewpoint of the utility industry should be investigated. The confidence of the utility industry in the guarantees extended by smaller resource companies should be also evaluated.

A series of interviews with regulatory agencies can help ascertain the feasibility of suggested schemes such as allowing utility companies to recover plant costs through the rate structure by accelerated depreciation of power plants.

ACHIEVING CONSENSUS AND RECOMMENDING GUIDELINES

The objective of this step is to lay the groundwork for drafting regulations by determining the extent and mode of government involvement

that would best achieve national energy goals. The success of such a program would hinge on its ability to reflect not only national energy policy, but also the interests of the industries that would be directly affected by the reservoir insurance program. Moreover, associated issues such as the necessity of additional government personnel and the safeguards required for implementation of the program should be carefully assessed, and the advantages and disadvantages of the program regarding incentives for private industry should be evaluated.

A wide gap separates the viewpoints of interested parties at this time. An objective of this task is to facilitate the exchange of information among interested industries to achieve a common understanding regarding the extent of government involvement that would best achieve national goals without creating a huge bureaucracy or complex and unenforceable regulations. To achieve these objectives we suggest the following procedure:

1. Dissemination of a document summarizing the findings of the first three steps. Comments by recipients of the document be incorporated in a revised version, and the differences of viewpoint be outlined.
2. A smaller group, including experts in government, banking and insurance industries, public interest groups, and developers and users of geothermal energy, be selected for receipt of the revised document. The viewpoints and judgments of this group on the issues discussed in the document, as well as on the existing gap between the needed risk-reducing measures and the available programs be aggregated.

The aggregation procedure can rely on one or several of the following techniques: (1) a dialectic forum for discussion of issues, (2) a procedure that would rely mainly on questionnaires such as the Delphi technique (3) the MAPS Design Technology (Multivariate Analysis, Participation, and Structure) that clusters ideas and issues in a form suitable for a strategic planning design, and (4) multiattribute decision analysis techniques (Keeney and Raiffa, 1976), by which the preferences and values of the differing groups will be assessed.

The objective of this subtask is not to achieve a consensus, but to clarify issues and viewpoints and to bring the viewpoints of the different sectors closer to each other. An attempt should be made, however (through smaller groups if necessary), to achieve a consensus among the representatives of the same industry.

3. In this step, a smaller group would be invited to a panel discussion to resolve the differences in viewpoints, if any, and to arrive at a consensus on the gaps between the needed programs and existing alternatives, and the most fruitful means of government involvement for bridging this gap.

The end result of this task will be a series of recommendations to the DOE that would serve as the framework for the geothermal reservoir insurance program.

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MODELING THE RISKS OF GEOTHERMAL DEVELOPMENT

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INTRODUCTION

Geothermal energy has emerged as a promising energy source in recent years and has received serious attention from developers and potential users. Despite the advantages of this resource, such as potential cost competitiveness, reliability, public acceptance, etc., the commercial development and use of geothermal energy has been slow. Impediments to the development of this resource include technical, financial, environmental and regulatory uncertainties. Since geothermal power is unique in that the generation facility is tied to a single fuel at a single site, these uncertainties are of particular concern to utility companies.

The areas of uncertainty and potential risks are well known (see for example EPRI 1978, and Woodward-Clyde Consultants 1980). This paper presents a method for quantifying the relevant uncertainties and a framework for aggregating the risks through the use of submodels. The objective submodels can be combined with subjective probabilities (when sufficient data is not available) to yield a probability distribution over a single criterion (levelized busbar cost) that can be used to compare the desirability of geothermal power development with respect to other alternatives.

THE COMPONENTS OF COST

Figure 1 summarizes the components of busbar cost. The components of capital and operating costs are self-explanatory. The costs associated with plant shutdowns are those which only occur if the plant becomes essentially "inoperable", for whatever reasons, prior to its design life. These consist of the opportunity cost of unavailability of power, the "write-off costs" for the plant, and the cost of any additional losses.

THE RISK MODEL

The uncertainties can be divided into two broad categories. The first category affects capital and O&M costs of an operating plant as well as the project schedule. The second category of uncertainties has a low probability of occurrence but can result in the plant becoming inoperable, thus significantly impacting costs. Among events in the second category are damage from a major earthquake, marked changes in existing regulations, and major plant or reservoir-induced environmental impacts.

Figure 2 illustrates how different kinds of uncertainties can be integrated into an aggregated risk model. The model consists of various submodels that relate the endogenous and exogenous uncertainties to major

major cost components, including the plant shut-down costs. The submodels may be objective (when adequate information and quantitative relationships are available), or subjective (when adequate information is not available, or when the existing information is interpreted differently by different experts). The output of the various submodels is integrated to yield the effect of several sources of uncertainty on a major cost component.

The cost aggregation and accounting model is the focal point of the model. It functions both as a means for integrating the various probabilistic cost components, and to account for financial and economic uncertainties that affect these costs. The last step of the analysis incorporates the uncertainties associated with the contractual arrangement between the utility and the resource company. The submodels are described in more detail in a recent study (Woodward-Clyde 1980).

The advantages of this aggregated approach include the following:

- endogenous and exogenous uncertainties are explicitly addressed,
- the model provides useful intermediate as well as final information for decision making,
- the output is in the form of probability distributions,
- the effect of changes in assumptions on the model output can be easily evaluated, and
- the effects of uncertainty from many diverse sources are aggregated in a unified model.

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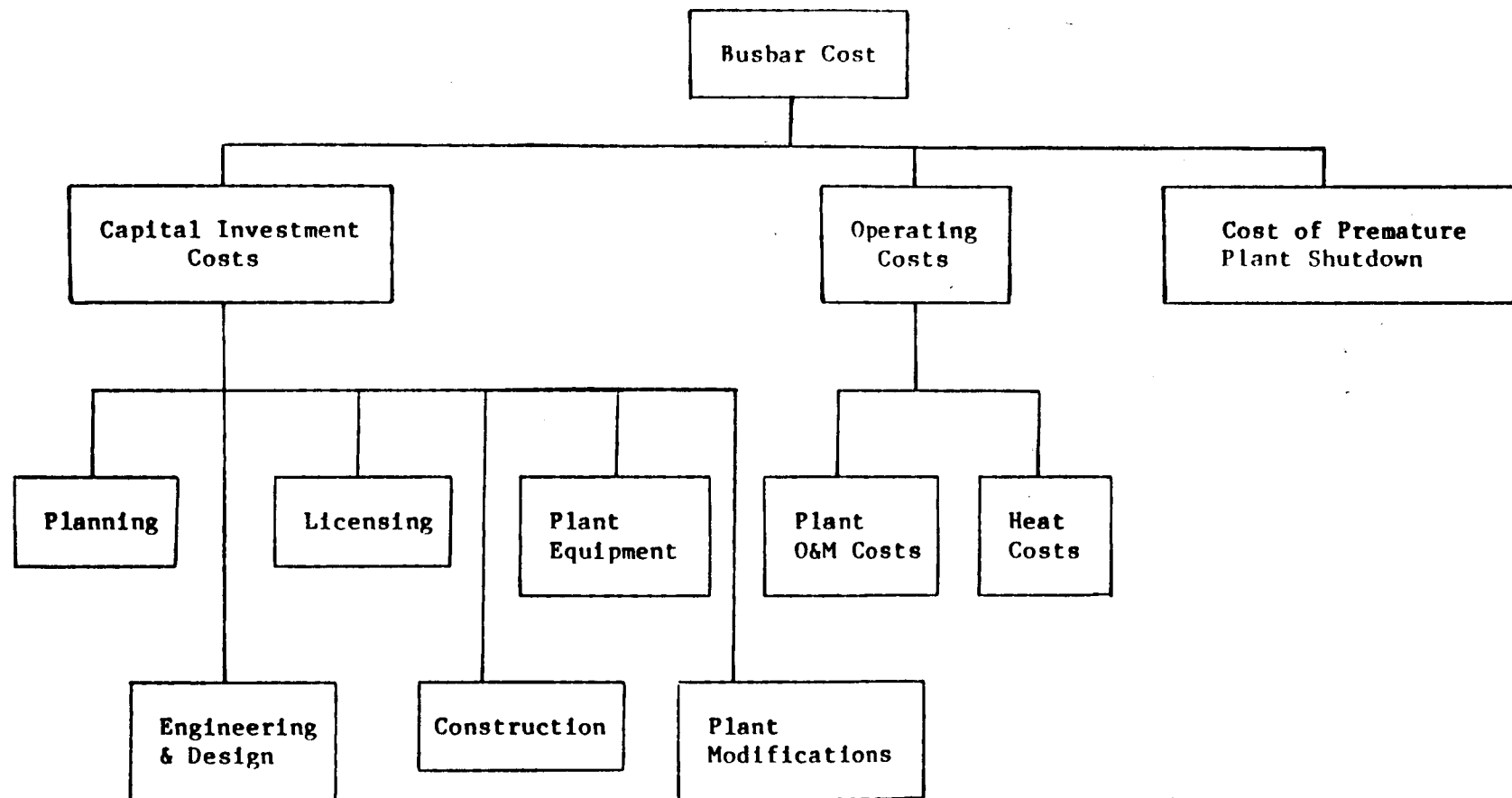


Figure 1. COMPONENTS OF BUSBAR COST

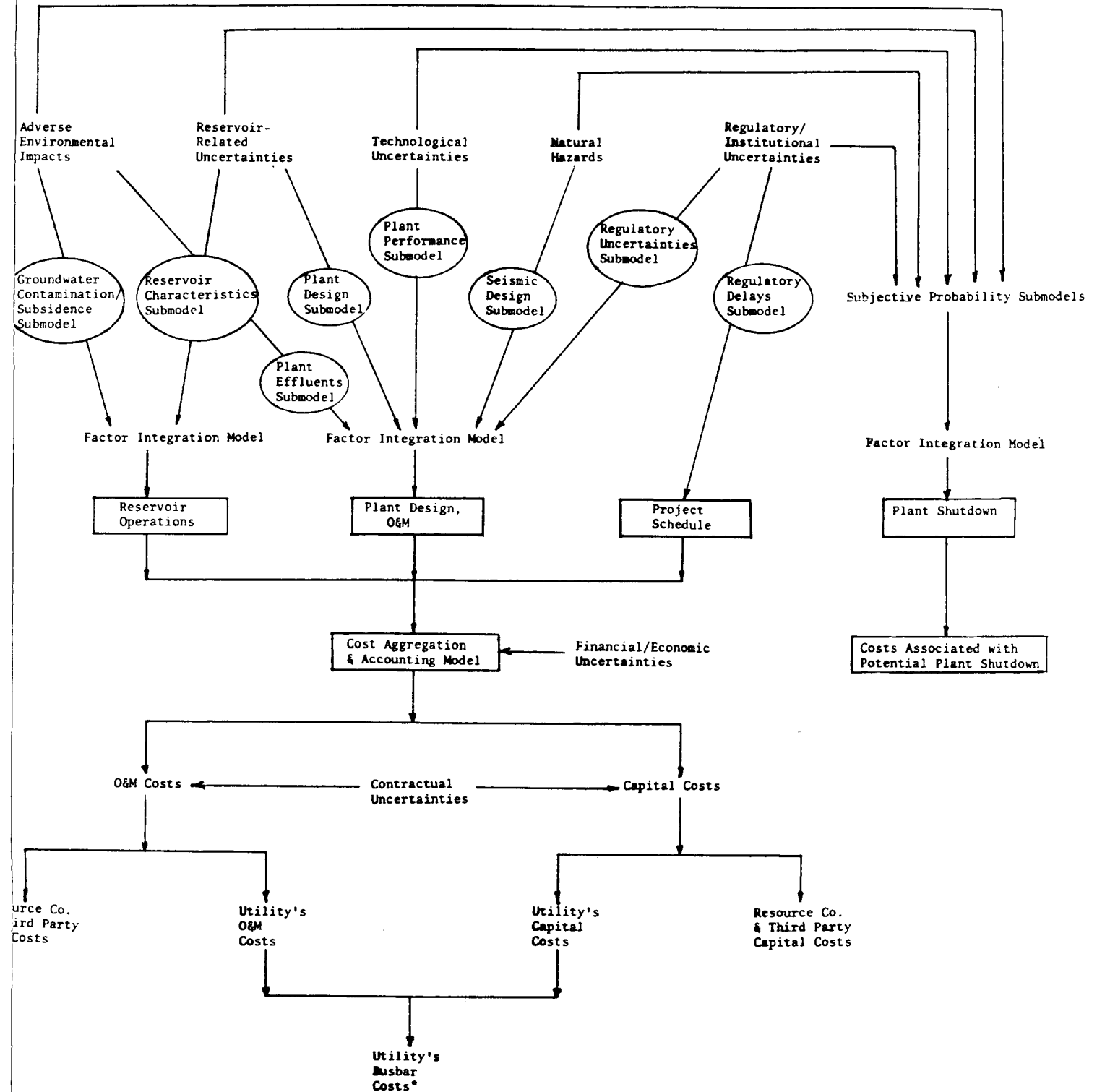


Figure 2. Conceptual Risk Assessment Model

*Does not include costs associated with potential plant shutdown

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