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PRESSURE-TEMPERATURE-SPINNER SURVEY IN A WELL AT THE GEYSERS

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ABSTRACT

This paper presents results from a flowing pressure-temperature-spinner log run in a well drilled by GEO Operator Corporation (GEOOC) at The Geysers. Analysis and interpretation of the log data are also presented. The data indicated superheated steam with a temperature of 600°F (316°C) and an enthalpy of 1316 BTU/lbm (725 cal/gm) entered the wellbore below 8000 feet (2438 meters). This temperature and enthalpy is much higher than most Geysers steam wells which produce steam at or below 475°F (246°C) and 1240 BTU/lbm (683 CAL/gm). The high temperature and enthalpy are even more puzzling since static pressure and temperature measurements conducted with Kuster type instruments six months later, indicate a "normal" vapor-dominated system existing at 475°F (246°C) and 500 psia (35 Kg/cm^2). Conceptual reservoir models which can explain these unusual thermodynamic conditions are presented.

INTRODUCTION

The purpose of this paper is threefold: (1) to describe the pressure-temperature-spinner survey run by GEO Operator Corporation (GEOOC), a wholly owned subsidiary of Geothermal Resources International, Inc., in a well at The Geysers; (2) to present and analyze the data obtained; and (3) to describe several conceptual models which can account for the observed thermodynamic behavior.

The activities of GEOOC personnel at The Geysers are currently focused in two separate areas. GEOOC leases and operates the Unit 15 steam field located in the southwest portion of The Geysers, providing steam to the Pacific Gas and Electric Unit 15. GEOOC is also exploring and developing the northwest area of The Geysers (see Figure 1). In this northwest Geysers area, a 130 MWg power plant is being constructed by Central California Power Agency No. 1, which GEOOC has dedicated approximately 1495 acres to and is under contract to supply steam. GEOOC is also actively drilling step-out wells from this proven acreage.

In 1984, GEOOC drilled a successful step-out well in the northwest Geysers area. Results from a standard flow test of 56 hours conducted upon completion of drilling were: a flowrate of 158,000 lbs/hr at a flowline pressure of 153 psia, and a flowline temperature of 405°F. During the last 5 hours of flow, a pressure-temperature-spinner log was successfully run to the total depth of the well.

The purpose of the pressure-temperature-spinner log was: (1) to identify the location and relative productive size of steam entries, and (2) to measure the flowing pressure and temperature profile. Both of these objectives were met, with details of the results being presented herein. It was determined that steam with a temperature of 600°F and an enthalpy of 1316 BTU/lbm was entering the wellbore below 8000 feet.

Following completion of the logging and flow testing, the well was shut-in and the wellbore filled with gas (primarily nitrogen) to preserve the integrity of the wellbore, miti-

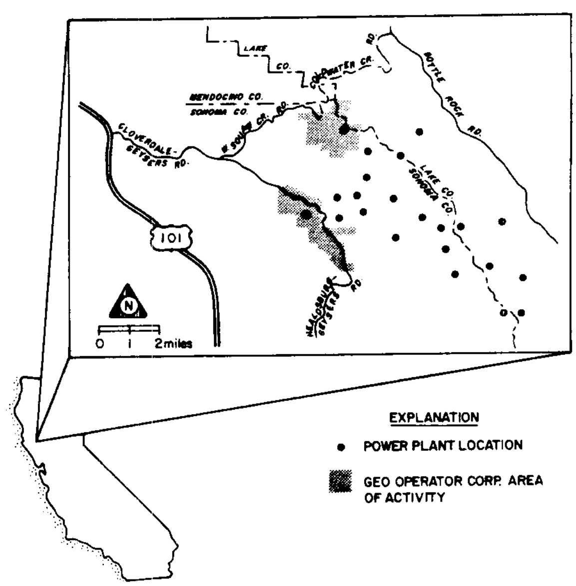

FIGURE 1. GEO Operator Corporation areas of activity at The Geysers, California.

gate any potential corrosion and prevent release of steam to the atmosphere. It was not possible to record a conventional buildup when the well was shut-in.

Approximately six months after being shut-in, a pressure-temperature survey was run utilizing conventional Kuster tools. A static pressure of 500 psia and a temperature of 475°F was measured at approximately sea level, typical of vapor-dominated systems and in particular The Geysers reservoir.

The high temperatures encountered in this well during flowing conditions is the primary subject of this paper. Geological, geochemical, and pressure transient data and analysis have not yet been incorporated in this work.

DESCRIPTION OF THE PRESSURE-TEMPERATURE-SPINNER TOOL AND RESULTS

The pressure-temperature-spinner tool was manufactured by Hot Hole Instruments (HHI) of Los Alamos, New Mexico. The tool simultaneously monitors pressure, temperature, spinner revolutions per second (RPS) and internal tool temperature. The sensitive tool electronics are insulated from the high temperature geothermal environment with a Dewar filled with an eutectic fluid. This insulation system allows the tool to be utilized in a high temperature environment for approximately four hours, after which time the tool must be pulled and allowed to cool. Individual signals from the four measurements are sent to the surface once every two seconds via a high temperature single conductor electrical line. Data is received, processed and recorded at the surface with conventional logging equipment. Product information sheets provided by HHI state that the tool is 13 feet long, 3 inches in diameter and weighs 170 pounds. The stated accuracy is 0.2% of full scale, with a resolution of 0.2 psi.

Results from the logging run made with this tool are presented in Figure 2, which is a reduced copy of the actual log. The data in Figure 2 was obtained as the tool was being pulled up from the bottom of the well. Log data obtained while lowering the tool are not

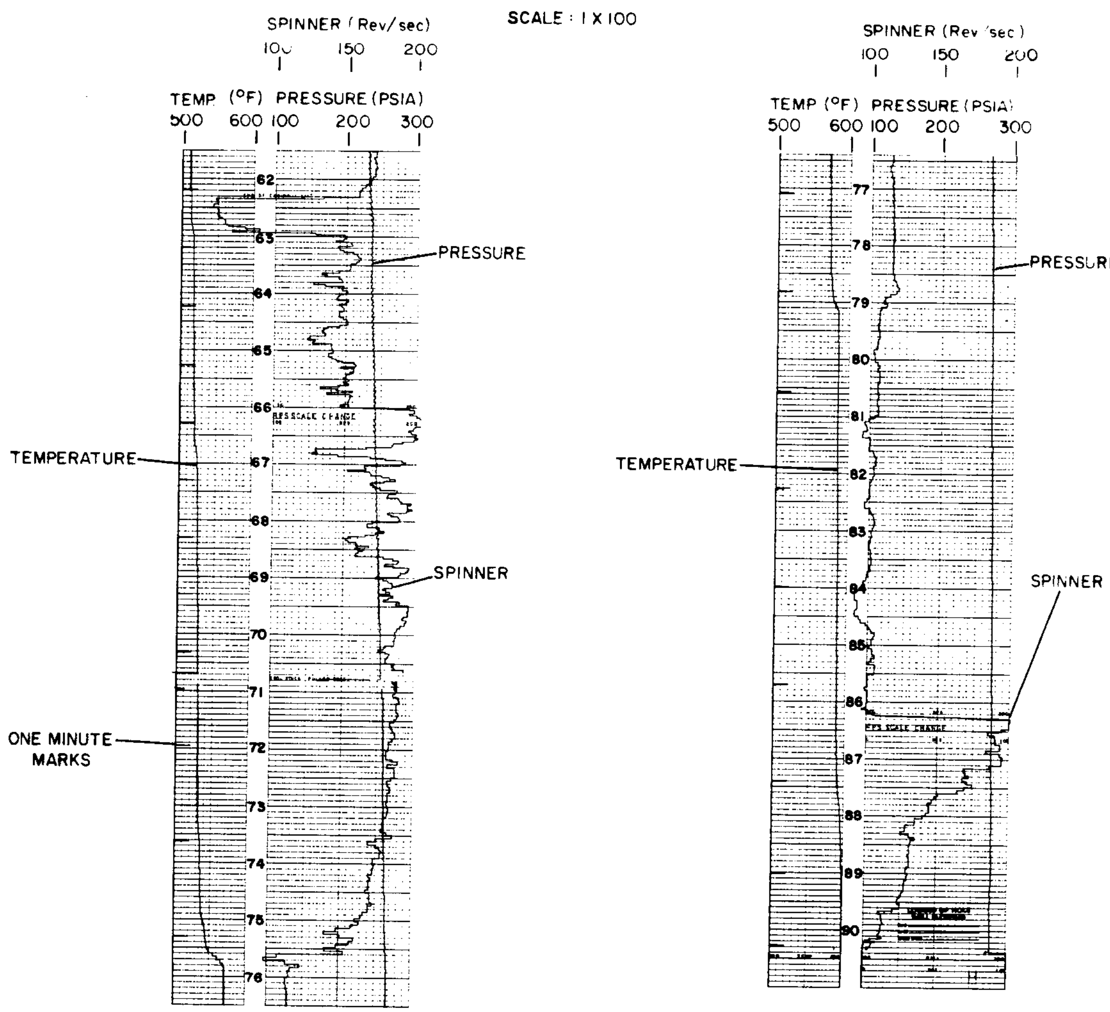

FIGURE 2. Section of the actual well log from 6200 ft.to 9030 ft.

presented as it was essentially identical. The log is not compensated for the stretch or thermal expansion of the electrical cable.

The step-like nature of the log data can be explained as follows. The logging speed was normally between 150 feet per minute and 200 feet per minute (note one minute time marks on left side of log). As previously stated, one signal for each measurement is transmitted to the surface once every two seconds. At a logging speed of 200 feet per minute, this means a measurement is being recorded once every 6.7 feet of vertical depth, which is the vertical length of each step.

The jagged nature of the spinner data is due to irregularities in the open-hole diameter caused by wash-outs and tight spots, in addition to the turbulent flow regime of the steam.

The pressure and temperature measurements recorded at the surface agreed with wellhead measurements made manually by GEOOC field operators. Manual measurements, made with conventional equipment, of pressure and temperature at the time of the logging were 154 psia and 405°F, respectively. Additionally, data from other wells in which this logging tool was used compare favorably with data obtained from tools of competitors run in the same well. For these reasons, the log data reported herein can confidently be accepted as accurate.

ANALYSIS OF SPINNER DATA

Data from the spinner portion of the log have been interpreted to determine where steam is entering the wellbore, and the relative productive size of each such entry (see Figure 3). Interpretation of this nature is possible because changes in the spinner rotational speed (RPS) are related to changes in the velocity of steam in the wellbore. When additional steam enters the wellbore at an open fracture, the steam velocity increases due to increased mass flowing through the unchanged cross-sectional area. Thus, zones where spinner RPS increase are identified as steam entries. The relative productive size of each steam entry can be estimated by assuming a linear relationship between spinner RPS and steam mass rate. The percent contribution for each entry identified has been calculated in this manner, and is shown in Figure 3.

Steam entries can be detected and their relative size estimated from measurements made at the surface during drilling. These measurements include:

1) increases in the injection pressure necessary to circulate the drilling fluid (air), caused by increased friction losses in the annulus due to the increased steam flow;

2) temperature increases in the flow line as a result of increased steam flow;

3) changes in the chemical composition of the returning fluid (air and steam);

4) drilling breaks, i.e., rapid changes in the rate of penetration;

5) flow measurements made with orifice plates and/or pitot tubes. These measurements require extensive, costly rig time and are usually only conducted upon completion of a well.

The entries detected with these methods are shown in Figure 3. In this particular well there is very good agreement between the entries detected at the surface and those detected with the log.

In higher flowrate wells, good agreement between log data and surface data would not be expected. Entries deep in high flowrate wells are often undetected as they are masked by the shallower entries. In such cases, use of a pressure-temperature-spinner log can identify the location and relative productivity of the deep steam entries.

One final point is made regarding the data presented in Figure 3. The steam entries are essentially clustered into two groups, with each group producing approximately 50% of the steam flow. One group is centered at about

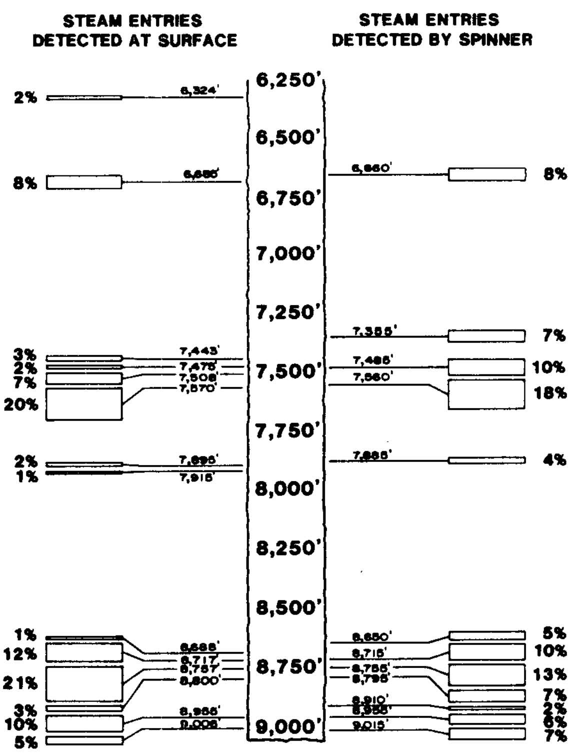

FIGURE 3. Reduced spinner data.

7500 feet, while the other group is centered at about 8800 feet. The temperature and enthalpy of the steam in these two groups is surprisingly different, as will be seen in later sections.

ANALYSIS OF PRESSURE DATA

Pressure data from the log are presented in Figure 4(b). Casing and open-hole diameters are shown alongside in Figure 4(a). As expected, the frictional losses are greatest in the 11-3/4-inch liner.

Also shown in Figure 4(b) are pressure profiles calculated from wellhead flow conditions using two relatively simple calculations. The Fritzche equation (King, 1967), normally used for calculating friction losses in horizontal pipeline flow, was modified to include pressure changes due to the piezometric head of steam. The other profile was calculated using a method published by Economides (1979) in a past Stanford workshop. Both methods can easily be run on hand-held calculators, and yield results within 10% of measured values.

ANALYSIS OF TEMPERATURE DATA

Data from the temperature portion of the log have been reduced and are presented in Figure 4(c). Since the steam in the wellbore is superheated, the pressure data from Figure 4(b) is used in conjunction with the temperature data to obtain the enthalpy which is also shown in Figure 4(c). A steam properties computer program was used to calculate these enthalpies. Two features on Figure 4(c) deserve mention. The sudden temperature and enthalpy change of the steam which occurs between 7500 feet and 8000 feet, and the high temperature and enthalpy of the steam entering the wellbore below 8000 feet.

The sudden temperature and enthalpy change can be explained as follows. The steam entering the wellbore below 8000 feet has an enthalpy of about 1310 BTU/lbm. The steam entering the wellbore above 8000 feet is "typical" Geysers steam, that is, its enthalpy is about 1205 BTU/lbm. The shallow steam cools the hotter steam from below and produces a mixture with an enthalpy of about 1257 BTU/lbm.

Wellbore heat losses for the flowing conditions present during logging were calculated using the method published by Ramey (1964). The data used in the calculations and subsequent results are presented in the Appendix. Wellbore heat losses were calculated to be 93,464,000 BTUs per day or 25 BTU per pound of steam. Kinetic energy changes have been neglected. Subtracting the 25 BTU/lbm heat loss from the previously calculated enthalpy of 1257 BTU/lbm means steam with an enthalpy of 1232 BTU/lbm should have been measured at the surface. The actual enthalpy measured at the surface with the pressure-temperature-spinner tool was 1227 BTU/lbm. The difference is attributed to the inaccuracy of determining the percent steam flow from each zone, and/or the possibility that the steam entering the wellbore above 8000 feet has an enthalpy lower than 1205 BTU/lbm.

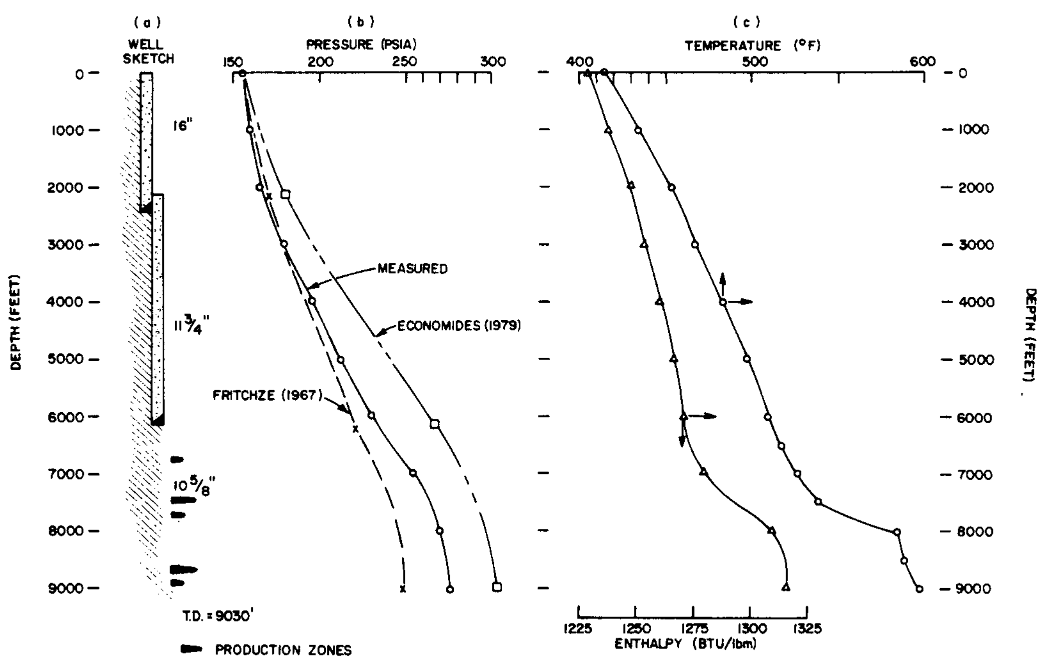

FIGURE 4. Reduced flowing pressure and temperature data.

This explanation of higher temperature and enthalpy steam entering the wellbore below 8000 feet and being cooled by a shallower steam entry is also supported by temperature measurements made during drilling. Downhole temperatures were routinely measured while taking directional surveys during the drilling process. These data are listed in Table 1. The measured temperatures were considerably higher once drilling proceeded past 8000 feet, supporting the concept of higher rock and steam temperatures below 8000 feet.

TABLE 1

Summary of Temperatures Measured during Drilling

Drilled Depth (feet)	Temperatures Measured during Directional Surveys (°F)	Flow Line Temperature of Returning Fluid (Air and Steam) (°F)
6347	209	175
6625	217	150
7194	330	167
7347	351	200
7630	452	205
7736	370	210
7975	364	212
8137	530	220
8348	550	207
8716	548	210
8825	560	227
8923	577	230
9030	N/A	231

The source of this deeper, high temperature and enthalpy steam is difficult to explain as it is unusual for vapor-dominated systems to produce steam of this nature. Before this is discussed further, it is appropriate to first consider the static pressure and temperature measurements made in the well.

STATIC PRESSURE AND TEMPERATURE DATA AND ANALYSIS

The static pressure and temperature data add a puzzling contrast to the flowing pressures and temperatures previously discussed. A static pressure and temperature survey was run in the well approximately six months after completion of the pressure-temperature-spinner log. The well was completely shut-in for the six month period. Data from this survey is typical of a static well in The Geysers. A temperature and pressure of about 475°F and 500 psia, respectively, were recorded near sea level (see Figure 5). Unfortunately, the tools would not go below 8100 feet, presumably due to a bridge or ledge in the open-hole section of the wellbore. Pressures and temperatures above 4000 feet are indicative of the gas filling the wellbore, steam exists below about 4000 feet.

The pressure gradient between the last two pressure measurements, at 8000 feet and 8100 feet, is 0.370 psi/ft indicating a static water column exists. This may only be condensate which has accumulated on top of an impermeable bridge in the well. Accumulation of condensate at the bottom of other Geysers wells has been previously reported by Lipman et al. (1978). However, it could also indicate the top of a liquid-dominated region. If an impermeable bridge exists at 8100 feet, it would isolate the deeper, hotter zone from wellbore. This would account for the difference between flowing and static temperature measurements. Further testing will be necessary to determine if such a bridge exists.

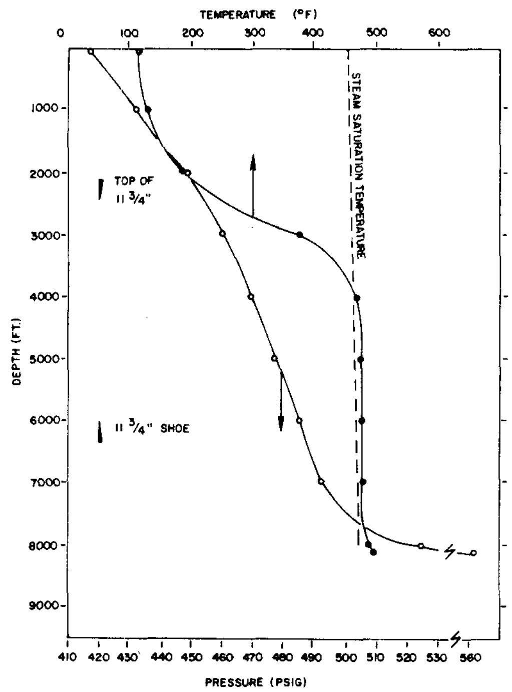

FIGURE 5. Static temperature and pressure survey conducted after 6-month shut-in.

DISCUSSION

Downhole measurements made during the flowing conditions previously described indicate steam with a temperature and enthalpy considerably greater than previously reported for The Geysers is entering the subject well below 8000 feet. Previously published data from wells at The Geysers indicate a vapor-dominated system existing at about 475°F and 514 psia (Lipman et al., 1978). James (1968) convincingly argued that vapor-dominated systems must exist at this pressure and temperature, which is essentially at the maximum enthalpy of dry saturated steam. Production of steam from a reservoir of this type, assuming isothermal expansion from 500 psia to 250 psia in the reservoir results in steam with a maximum temperature of 475°F and enthalpy of 1240 BTU/lbm being delivered to the wellbore (after Truesdell and White, 1973). Assuming no heat loss in flow up the wellbore (isoenthalpic expansion), a maximum temperature of 450°F and the same enthalpy of 1240 BTU/lbm would be expected at the surface (see Figure 6). However, decompression and flow through the reservoir probably does not occur along a perfectly isothermal path, but along some path between isothermal and isoenthalpic. Flow up the wellbore definitely is not isoenthalpic - heat losses to the cooler earth results in a 5 to 25 BTU/lbm loss. Thus, wells at The Geysers typically produce steam with an enthalpy at the surface of 1220 BTU/lbm or less as shown by the shaded area in Figure 6.

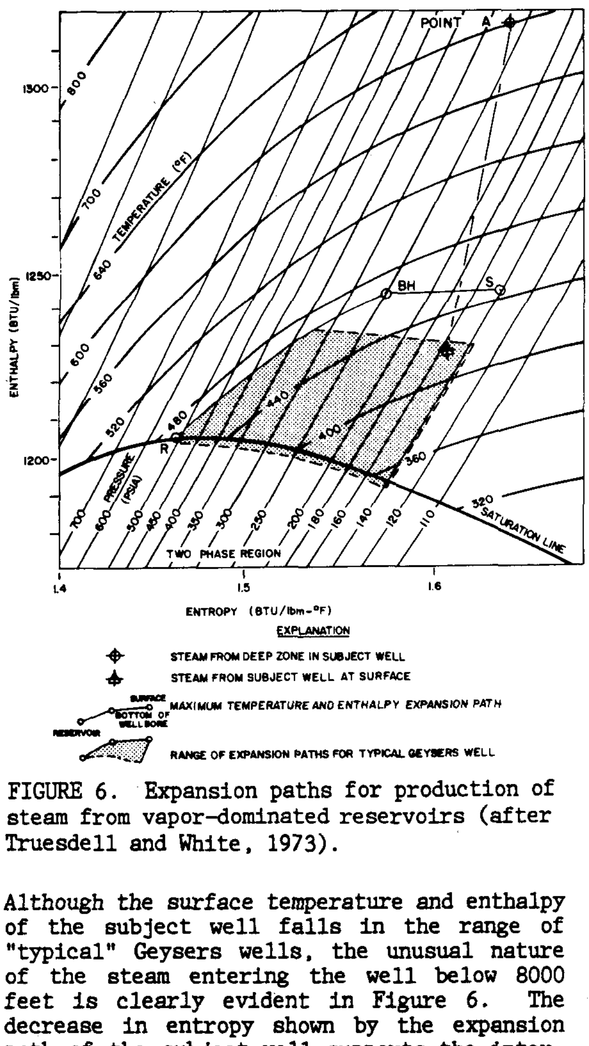

FIGURE 6. Expansion paths for production of steam from vapor-dominated reservoirs (after Truesdell and White, 1973).

Although the surface temperature and enthalpy of the subject well falls in the range of "typical" Geysers wells, the unusual nature of the steam entering the well below 8000 feet is clearly evident in Figure 6. The decrease in entropy shown by the expansion path of the subject well supports the interpretation that mixing of steam from two different zones is occurring. Flow from two different zones raises an interesting possibility. The deep, hotter steam mixes with shallower, "typical" Geysers steam to produce an enthalpy at the surface which is only slightly higher than normal Geysers wells. It is therefore possible that other Geysers wells with a surface enthalpy greater than 1220 BTU/lbm may be producing steam from two distinctly different zones. Flowing downhole temperature measurements would be necessary to detect such deeper, high temperature zones.

Since 600°F steam is entering the subject well at depth, rocks with a temperature of at least 600°F must be in contact with the reservoir fluids. Yet this temperature exceeds previous temperature measurements made at The Geysers (Lipman et al., 1978; Thomas et al., 1979) by at least 100°F. What production mechanisms can account for these high steam temperatures? What is the original state of this steam and where is it located in relation to the "typical" Geysers reservoir? Several different conceptual models which can answer these questions are presented next.

CONCEPTUAL MODELS

The conceptual models presented herein attempt to explain the thermodynamic behavior encountered. Work to include geochemical and geological studies, which will be necessary to fully understand this well and the reservoir it produces from, are underway.

The conceptual models must include a "typical" Geysers vapor-dominated system existing to a depth of about 8000 feet. This is necessary to explain the temperatures and pressures measured during static conditions, and to account for the measurements made during drilling prior to 8000 feet. Below 8000 feet, transition to a high temperature region must rapidly occur. This requires a sudden increase in the temperature gradient from less than 1°F/100 feet to about 10°F/100 feet to obtain temperatures of 600°F in 1000 feet. The pressure gradient may be that of a static steam column, or a hot water column depending on whether or not an impermeable bridge in the well at 8100 feet. If an impermeable bridge exists, a static steam gradient below 8100 feet is possible. However, if the bridge does not exist, the last two static pressure measurements indicate the start of a liquid-dominated system. Further testing of the well is necessary to determine if the impermeable bridge exists.

Vapor-Dominated System with Local Heat Source

The first model considers a localized heat source which acts like a furnace and supplies heat to produce 600°F steam from 475°F steam (see Figure 7). The heat source would likely be a local intrusion of magmatic material, such as a dike or pluton. Drilling and completing a new well acts as a stimuli which creates a new fracture flow path or paths through the previous hot dry impermeable rock. Fluid originates at 475°F and is superheated to 600°F as it flows through the hotter rock to the wellbore. Envisioned on the Mollier diagram shown in Figure 6, steam originates at 475°F (maximum enthalpy of dry saturated steam) and expands along a path much steeper than isothermal to reach Point A. A path steeper than isothermal is possible due to heat transfer from 600°F rocks. Note that the well can be outside the hot dry rock area and still produce 600°F steam as long as the fractures go through the hot dry rock. The existence of very hot dry rocks near productive wells have been noted in the Latera Field in Italy (Cavarretta et al., 1985). Static temperatures as high as 650°F at 9100 feet have been measured in dry holes near productive wells.

When the well is static, cooler, shallower steam flows down the well masking the higher temperatures below 8100 feet. This simple model is consistent with the temperatures encountered, is physically possible, but does not seem very probable.

Liquid-Dominated System below the Vapor-Dominated System

In the second model, we consider a liquid-dominated system located just below the vapor-dominated system, but isolated due to an impermeable section. The two sections were at one time connected, but the liquid-dominated system sealed itself due to mineral deposition. Fournier (1983) has hypothesized that such a system could exist at depth, but never be detected since it is self-sealed. The impermeable section permits a very high temperature gradient to exist between the vapor-dominated system and the liquid-dominated system (see Figure 8). The subject well penetrates the seal and produces water which is flashed to dryness while flowing to the wellbore. Low permeability and high pressure drops would be necessary to flash the liquid to complete dryness. Additionally, the fluid in the liquid-dominated system must be high (greater than 25%) in salt content to raise the boiling point of water to about 600°F (Truesdell and White, 1973). In effect the salt raises the saturation line shown on the Mollier diagram in Figure 6. Thus, brine exists at 600°F and 514 psia, then boils when decompressed to produce 600°F steam. If pure water existed in the liquid-dominated system, and the pressure at its free surface is 514 psia, the level would have to drop about 3000 feet to obtain the pressure corresponding to a saturation temperature of 600°F. This is calculated as follows:

Saturation pressure for 600°F - pressure at top of water surface ÷ pressure gradient = depth of 600°F water.

$$(1550 \text{ psia} - 514 \text{ psia}) \div .323 \text{ psi/foot} = 3100 \text{ feet}$$

A standing liquid column and/or flooding of the vapor-dominated system has not occurred because the liquid-dominated system is under-pressured relative to hydrostatic, hence, the pressure at the free surface of the water is 514 psia.

The problem with this model is that it seems unlikely that water could flash to dryness prior to entering the wellbore (James, 1968; Truesdell and White, 1973). Additionally, the effect of noncondensible gases, which are known to exist, would be to lower the boiling point of water. Once geochemical data is incorporated with this work, it should be possible to verify the validity of this model.

Fossil Liquid-Dominated System

The last conceptual model is an extension of the previous one. In this model, the liquid-dominated system has boiled to dryness, leaving behind superheated steam existing in the fractures and major voids. Liquid water remains adsorbed to the rocks and held in any existing small pores and fracture interstices. The ability of water to exist on rock at higher temperatures than saturation has been confirmed by laboratory work (Hsieh and Ramey, 1981; Herkelrath et al., 1983), however, their work was conducted at temperatures considerably lower than 600°F. The fossil liquid-dominated system would allow the high temperature gradients necessary for rock temperatures to reach 600°F.

The nature of the connection between the vapor-dominated system and the fossil liquid-dominated system could be physical or evolutionary. A physical barrier, such as an impermeable region, may exist which separates the two regions and prevents them from mixing to create more uniform temperature gradients. However, the boundary between the zones may be due to the evolution of the vapor-dominated system over time (Walters, M. A., personal communication). Recent work by Pruess (1985) has quantified the evolution of a vapor-dominated system from a liquid-dominated system as proposed by James (1968) and later Truesdell and White (1973). It seems possible that this northwest area of The Geysers could still be evolving into the "typical" Geysers reservoir. Hence, the deeper, hotter zone has not yet cooled down. The high temperature gradient could be due to the slow nature of the evolutionary process, especially if an area of reduced permeability is present.

Stated another way, heat transfer into this area by conduction has been greater than heat transfer out by convection, causing increased temperature. This heat transfer imbalance is probably caused by the better insulation resulting from the greater depth of the steam reservoir in this area. Pressure has not increased because the hotter zone is in communication with the typical Geysers zone.

A similar evolution process appears to be occurring in Hawaii. It has been hypothesized that the Puna Geothermal System, an apparent liquid-dominated system, is in the process of boiling to form a vapor-dominated system (Iovenitti and D'Olier, 1985). Fluids with temperatures as high as 650°F have been produced from this system.

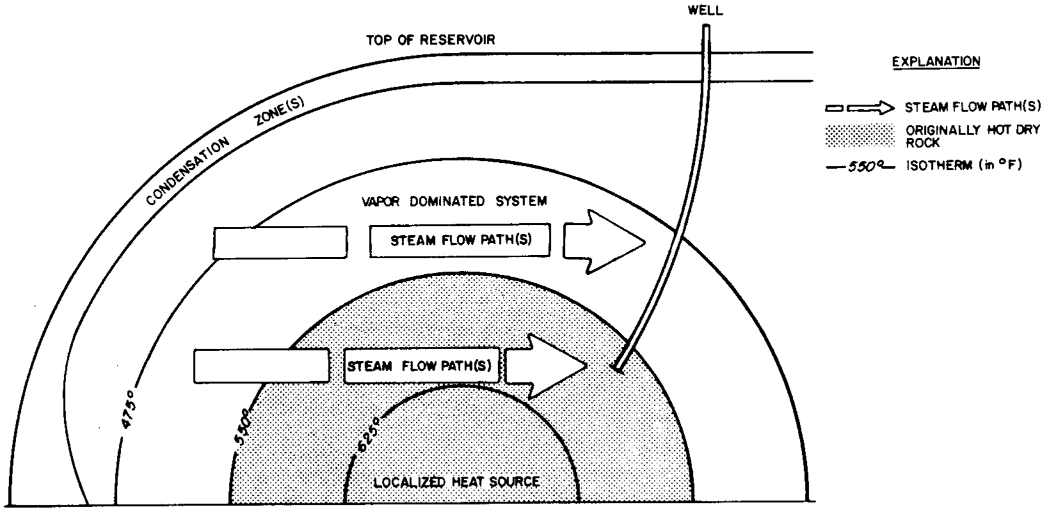

FIGURE 7. Drilling well causes new permeable fracture through previously hot dry rock. Localized heat source adds heat to steam as it flows to well.

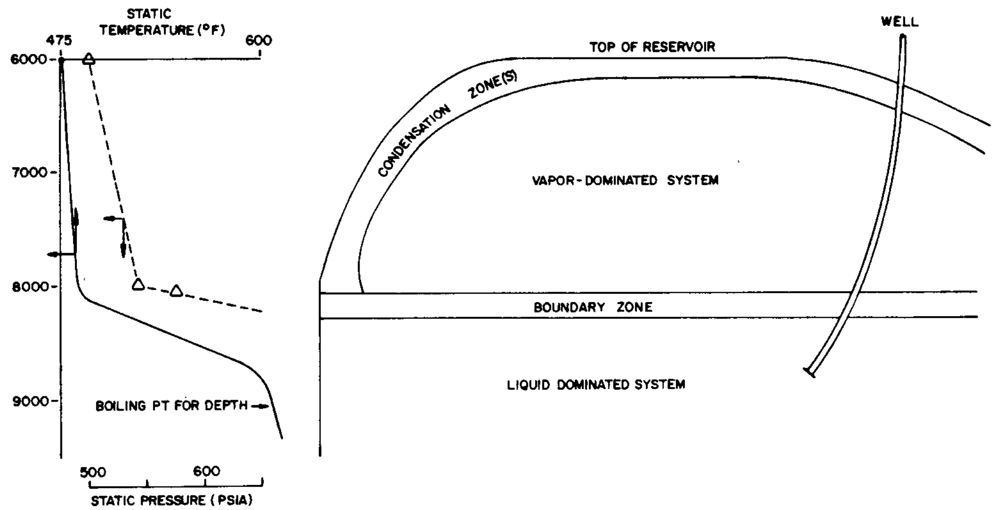

FIGURE 8. Well penetrates liquid-dominated system with high (+25%) salt content, previously sealed from vapor-dominated system.

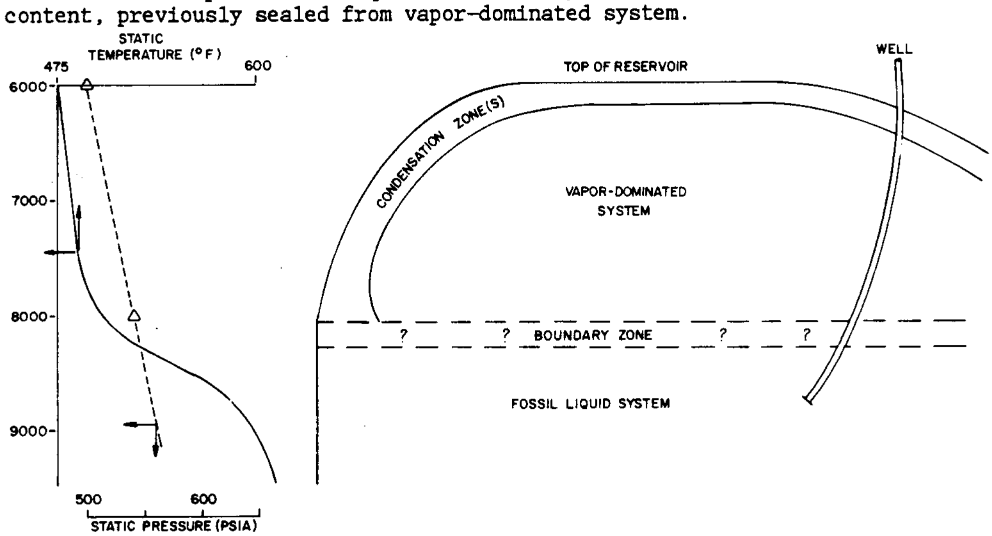

FIGURE 9. Well penetrates fossil liquid-dominated system which has evolved to high temperature vapor-dominated system.

CONCLUSIONS

1) Two separate and thermodynamically distinct zones are feeding the well described in this paper. The shallow zone supplies typical Geysers steam with a temperature less than 475°F. The deeper zone supplies steam at a temperature of about 600°F. Conceptual models of reservoirs which can produce 600°F steam have been presented.

It is possible that other wells at The Geysers are producing steam at depth with temperatures that approach 600°F, but is being masked by cooler, shallower steam and cannot be detected at the surface. Use of downhole logging tools are necessary to detect such deeper, high temperature zones.

2) The spinner data obtained from the log agrees well with conventional methods of detecting steam entries. Hence, conventional methods for detecting and quantifying steam entries can be used with more confidence in average flowrate wells (100,000 to 180,000 lbs/hr).

3) The thermodynamic data and analysis presented in this paper must be integrated with geochemical and geological studies to more precisely and fully explain the high temperatures and enthalpies encountered, and the reservoir from which they are being produced.

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APPENDIX - WELLBORE HEATLOSS CALCULATION

Nomenclature

a - geothermal gradient, $^{o}F/ft$
K - earth thermal conductivity, BTU/day ^{o}F ft
K_{cem} - cement thermal conductivity, BTU/day ^{o}F ft
Q - heat loss rate, BTU/day
r_i - inside radius of casing, ft
r_h - radius of hole, ft
r_o - outside radius of casing, ft
t - time from start of flow, days
T_e - temperature of earth at top of section, ^{o}F
T_s - temperature of steam at top of section, ^{o}F
U - overall heat transfer coefficient, BTU/day ft^2 ^{o}F
Z - depth change, ft

Heat loss for cased sections of well (Ramey, 1964)

$$Q = \frac{2 \pi r_i U K}{K + r_i U f(t)} [(T_s - T_e) Z - 0.5 a Z^2]$$

Heat loss for open hole sections of well (Ramey, 1964)

$$Q = \frac{2 \pi K}{f(t)} (T_s - T_e) Z - 0.5 a Z^2)$$

Overall heat transfer coefficient (Willhite, 1967)

$$U = [r_o (\ln (r_h/r_o))/K_{cem}]^{-1}$$

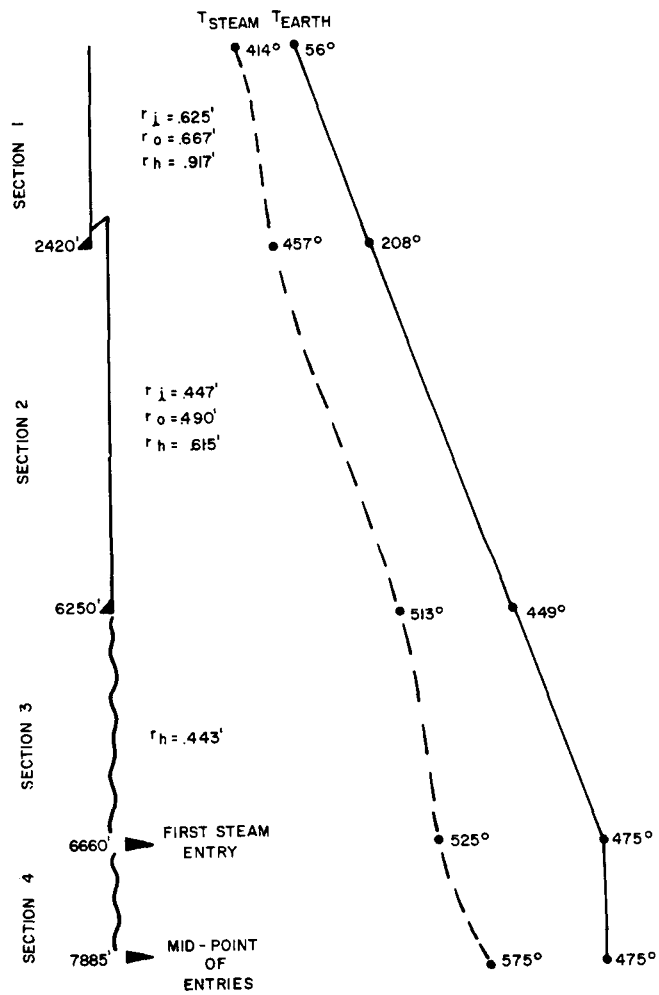
Transient heat-conduction time function for earth (Ramey, 1964)

$$f(t) = \ln (2 \sqrt{.96t} / r_h) - .29$$

Values used for calculations

t - 8 days
K - 42.4 BTU/ft day ^{o}F
K_{cem} - 7 BTU/ft day ^{o}F
Well Flowrate - 158,000 lbs/hr

HEATLOSS SCHEMATIC



SUMMARY OF CALCULATIONS

Section	Z	T_s	T_e	f(t)	U	1000 BTU/day	BTU/lbm
1	2420	414	56	1.51	33.0	50,947	13.4
2	3830	457	208	1.91	62.9	38,353	10.1
3	410	513	449	2.24	∞	2,492	0.7
4	1225	525	475	2.24	∞	1,672	0.5
					TOTALS	93,464	24.7