DOWNHOLE ENTHALPY AND SUPERHEAT EVOLUTION OF GEYSERS STEAM WELLS

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ABSTRACT

A Pressure-Temperature-Spinner (P/T/S) logging program, conducted over a 3 year period, documents a spatial and temporal evolution of both enthalpy and superheat in the Units 13 and 16 areas at The Geysers. Wells producing from the more depleted reservoir area in the southern part of Unit 13 exhibit a greater downhole superheat (up to 80°F), and wellbore enthalpy (1,230 Btu/lb) than those producing in less disturbed portions of the reservoir. Further, downhole enthalpy calculations from a single well clearly show that the enthalpy at depth is increasing with time. Finally, the combination of high permeability, reduced pressure and increasing superheated wellbore conditions identifies the southern portion of Unit 13 as an appropriate injection target.

INTRODUCTION

Calpine Corporation periodically conducts P/T/S surveys in order to monitor changes in the producing characteristics of the reservoir supplying steam to Units 13 and 16. These data are essential in overall steam forecast and reserve estimates as they are useful in understanding reservoir behavior. They also serves as the basis for the development of conceptual models used in lumped parameter and numerical simulation analysis, important aids in reservoir management.

The baseline logging program was initiated in 1986 on designated steam wells throughout the Calpine leases. Results of some of those surveys were documented by Enedy (1988). During the baseline survey program, the P/T/S tool provided reliable downhole information such as steam entry location and magnitude, wellbore heat loss, pressure drop due to friction, and maximum rock temperature.

In addition, the enthalpy was accurately calculated from wellbore pressure and temperature of single phase steam or water conditions in wells ranging from initial or virgin shut-in reservoir pressures and temperatures to the highly depleted (less than 240 psig shut-in pressure). Little depletion was revealed in reservoir rock temperatures, measured below the steam entries in the more mature areas of the field. The flowing shallow steam was cooler than the deeper rock.

For most of the surveyed wells with a sufficient deadleg (300 to 1,000 feet below the bottom most steam entry), a maximum rock temperature of 463°F was observed at total depth regardless of whatever deadleg was filled with liquid or vapor. James (1968) reported maximum rock temperatures of 464°F at the Wairakei field. Surveyed wells that bottomed within 100 feet of the deepest steam entry had lower maximum observed downhole temperatures of 440 to 450°F. These values were influenced by steam and/or flashing liquid in the short deadleg.

The purpose of this paper is to discuss the downhole superheat and enthalpy measurements taken during several years of P/T/S logging and explain the observed trends.

An area currently being targeted for an injection well is shown to be producing steam at a relatively high downhole superheat, verifying that this portion of the reservoir could benefit from increased water injection.

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Detailed descriptions of the P/T/S logging tools are provided by Enedy (1988), Davarzani (1988), Davarzani and Sloan (1987), Dennis, Kolar and Lawton (1987) and Drenick (1987).

SUPERHEAT EVOLUTION

Figure 1 shows the location of wells in the Units 13 and 16 areas, described herein, which exhibit the evolution of superheat and enthalpy. These locations range from a highly depleted area near well B (adjacent to the proposed injection site) to the essentially virgin area east of well D.

Figure 2 illustrates superheat (°F) versus depth for wells A, B, and C. Since the vertical pressure distribution is similar for all three wells, an enthalpy-depth plot would produce, in each case, a similar curve.

Well C had been on production for about 8 months at the time it was logged. This well's approximately saturated condition (ie. low superheat) typifies a well in a relatively undepleted area of the reservoir. The calculated enthalpy is approximately that of saturated steam.

Also shown on Figure 2 is well A, which was first logged in 1986 and then again in 1988. In 1986, after 6 years of production, well A already showed signs of elevated superheat - approximately 20°F. However, 2 years later (after 8 years of production), under similar flowing conditions, well A exhibited an additional 20°F rise in superheat for a total increase of 40°F above saturated conditions. The measured downhole flowing pressure also dropped about 44 psi in the same period. This trend of increasing superheat was observed both at Larderello and Wairakei by James (1968) and Bixley (1986).

The superheat versus depth curve for well B further supports the observation that the rate of escalation in superheat is indirectly dependent on rate of mass with-

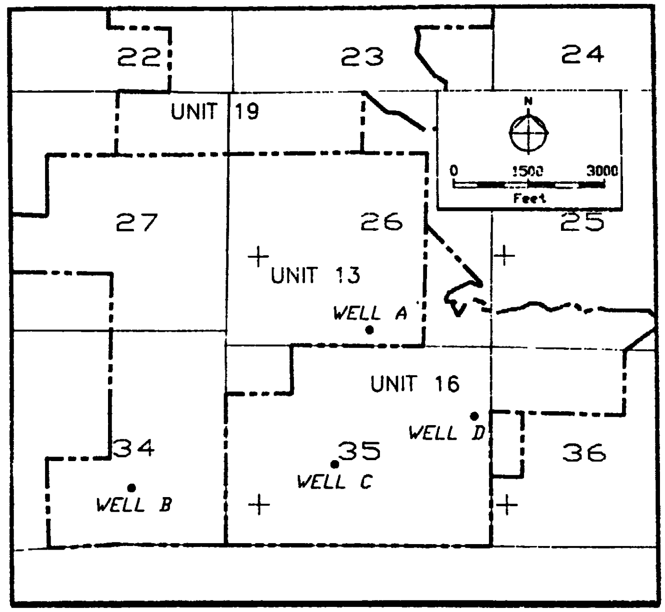


Figure 1. Well location map indicates midpoint of steam entries for subject wells in the Units 13 and 16 areas.

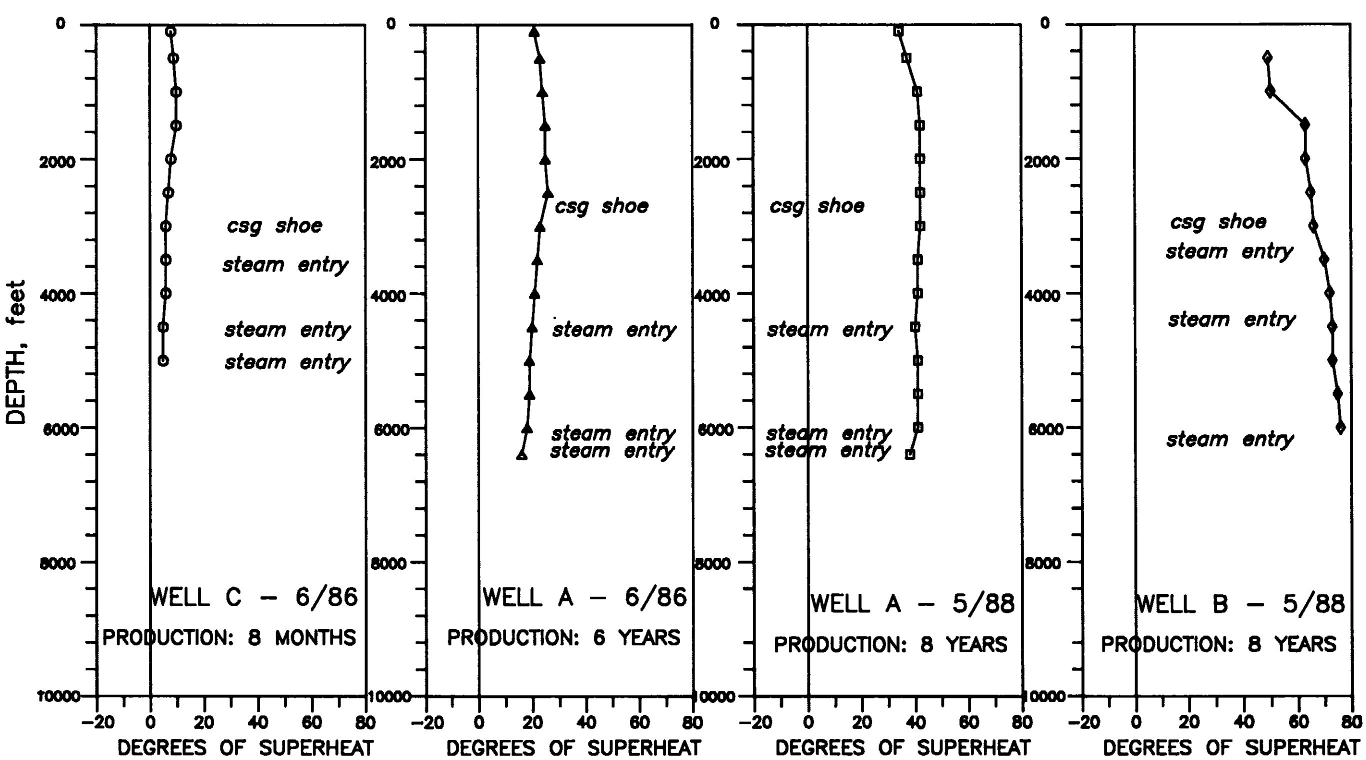


Figure 2. Evolution of superheat vs. depth over time. Increasing superheat trend is observed as reservoir becomes more depleted.

drawal from the reservoir. Well B, on production for 8 years, is completed in an area of high mass withdrawal and high pressure decline. Superheat values at 5,000 feet approach 80°F.

The high permeability, low pressure, high superheat area surrounding well B is targeted for an injection well based on the results of the P/T/S surveys and geochemical data. Beall, Enedy and Box (this volume) concluded from a tracer study that reservoir steam supplying Well B carries a component of injection derived steam. The injection component has been drawn into this segment of the reservoir from a distant but unknown injection source.

Migration of the injection derived steam into the well B area is a result of the pressure sink created by the long term production of initially very prolific wells. The combination of high permeability, high superheat (80°F at 5,000 feet) and low reservoir pressure indicate at present a low (or nonexistent) liquid fraction in this portion of the reservoir. These factors suggest a high potential for injection into this area to sustain reservoir pressure and productivity.

ENTHALPY EVOLUTION

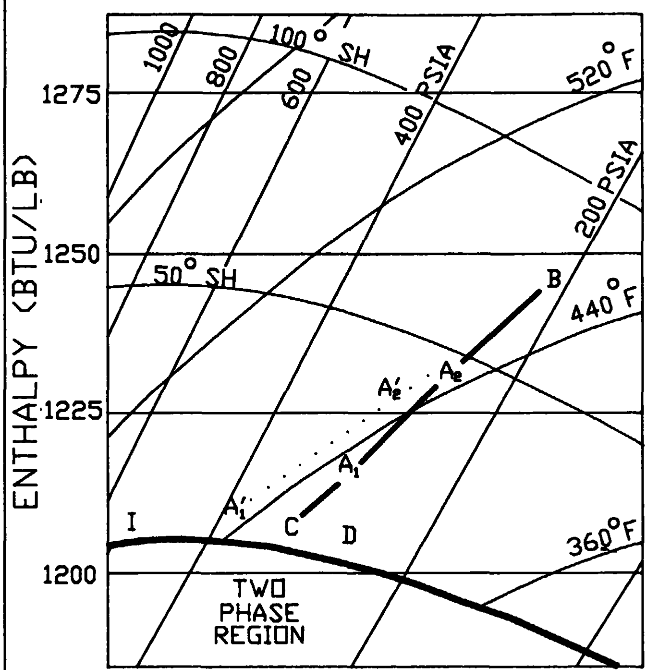
Figure 3 is a modified Mollier diagram (without entropy) that shows flowing steam enthalpy for wells at The Geysers. It traces the evolution of calculated enthalpy. Line C-B exhibits a rising enthalpy and superheat trend from estimated initial conditions through a survey taken after 8 years of production. Note that the path is not isothermal but actually reveals a somewhat increasing trend in temperature. Also, the line falls within the "normal" Geysers range of enthalpies discussed by James (1968) and Truesdell and White (1973). The 40 Btu/lb difference in enthalpies of wells B and C further illustrates that wellbore enthalpy and superheat increase as the reservoir pressure declines and the liquid fraction becomes depleted.

Well C was logged only 8 months after unit start-up while Well B was logged after 8 years of production. Since the overall reservoir characteristics of these two wells are similar (ie. permeability, initial deliverability, shallow steam entries, low gas, etc), it is conceivable that in time well C's enthalpy and superheat values will be equivalent to those of well B.

Well B, located within one of the lowest pressure sinks at The Geysers, shows one of the highest enthalpy values. The increase in enthalpy in a highly depleted area of the reservoir is an indication that it is "drying out" (ie. the liquid fraction of the reserves is boiling away and steam is being heated by the dry hot rock.) As the boiling front moves farther from the wellbore, the steam travels through a longer, more tortuous path to reach the wellbore. This results in higher steam superheat and enthalpy values observed in the wellbore over the time the

MODIFIED MOLLIER DIAGRAM

FLOWING STEAM ENTHALPY
FOR WELLS AT THE GEYSERS



LEGEND

NOTE: ALL DATA AT 5000' DEPTH

ENTHALPY OVER TIME FOR WELL A
FLOWING 88 KLB/HR
A_1 - 6 YRS
A_2 - 8 YRS

ENTHALPY AT VARIOUS FLOWRATES
FOR WELL A
A'_1 - BLEED
A'_2 - 48 KLB/HR

B - ENTHALPY FOR WELL B - 8 YRS

C - ENTHALPY FOR WELL C - 8 MOS

D - ENTHALPY FOR WELL D - 8 MOS

I - ENTHALPY AT INITIAL RESERVOIR CONDITIONS

Figure 3. Increasing enthalpy trend (at 5,000 ft. depth) is linear for a "typical" southeast well as reservoir becomes more depleted. Well D shows initial conditions of a "wet" well. Well A exhibits an essentially isothermal pressure increase as its flowrate was reduced (Line A_2-A'_1).

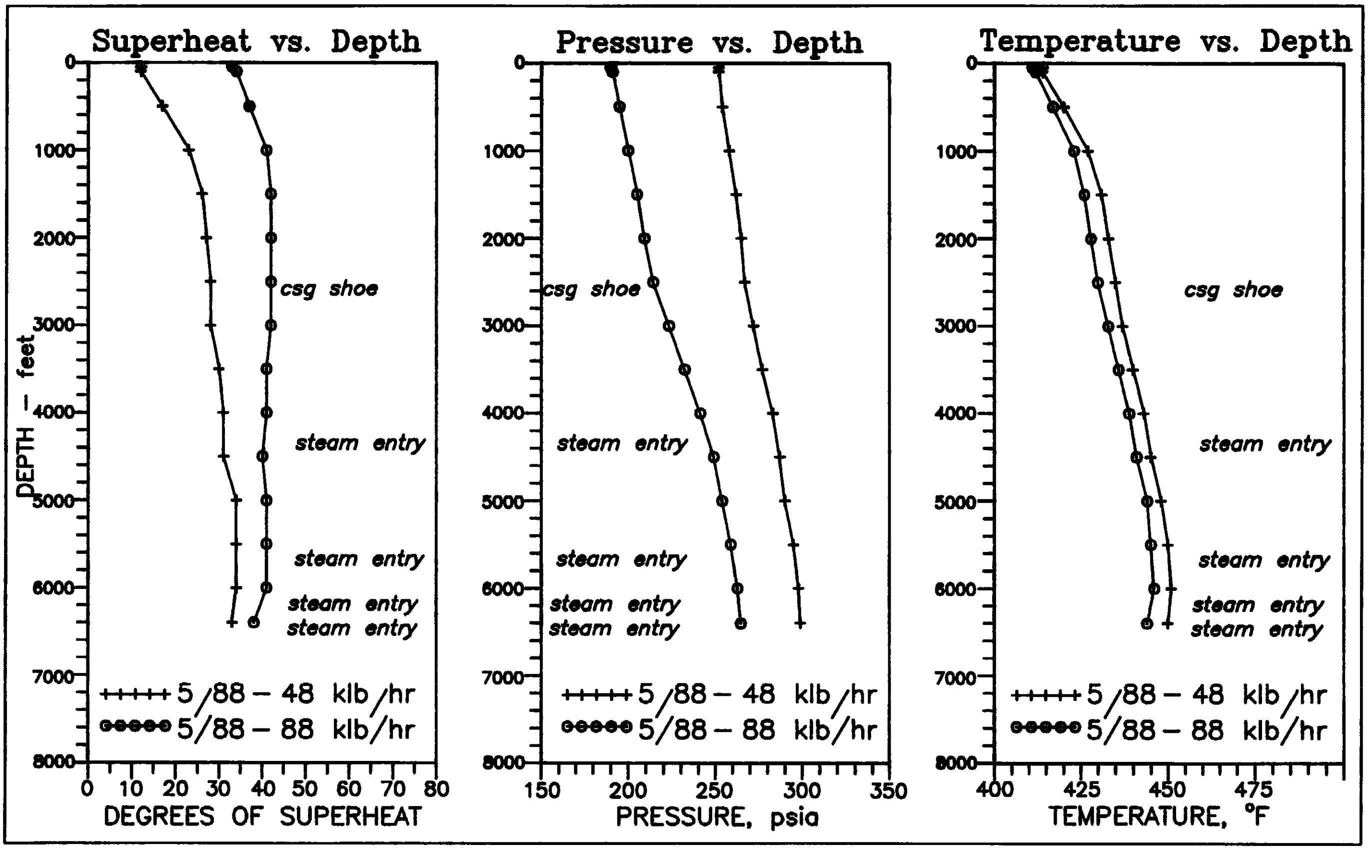


Figure 4. Comparison of superheat, pressure and temperature vs. depth for well A at full flow (88 klb/hr) and half flow (48 k lb/hr). Well A exhibits an increase in superheat gradient controlled by a decrease in the pressure gradient at the lower flow rate.

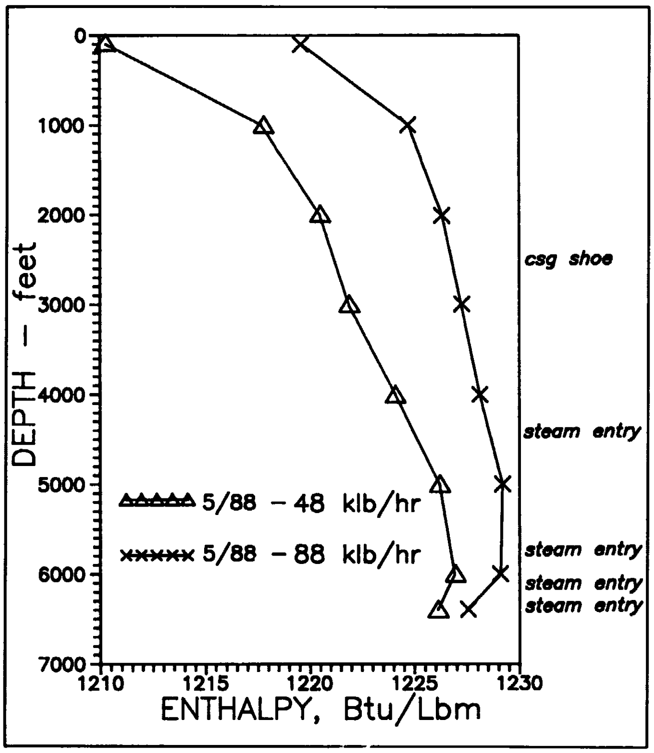


Figure 5. Comparison of enthalpy vs. depth for well A at full flow (88 klb/hrs) and half flow (48 klb/hr). Well A exhibited an increase in enthalpy gradient and higher heat loss in the cased portion of the wellbore as its flowrate was reduced.

well is produced. However, these values will not exceed the maximum enthalpy at a given rock temperature (James, 1968). This also assumes that the source of the steam does not change dramatically.

An efficient use of this excess enthalpy is to boil injected condensate or fresh water in the reservoir and effectively increase the mass of steam available for production. Increased injection has consequently been recommended for this portion of the field.

Well D on Figure 3 was logged after 8 months of production and is also in an area exhibiting an isotopic shift due to injected condensate. The lower temperature and saturated conditions are typical for an area near a reinjection point.

ENTHALPY AND SUPERHEAT AT VARIOUS FLOW RATES

It has long been observed that reducing a well to bleed flow rate often reduces the enthalpy and superheat of that well at the surface. In order to ascertain what occurs at depth, well A was logged at multiple flow rates during the June, 1988 survey. The superheat, pressure, and temperature profiles at two flow rates (full and half flow) are shown on Figure 4. The corresponding enthalpy-depth relationships are shown on Figure 5.

As the flow rate was reduced the well exhibited the following:

1. An essentially isothermal pressure increase in the open hole section of the wellbore (i.e. line A_2-A'_1 on Figure 3).
2. A decrease in the pressure gradient (throughout the wellbore) due to a smaller friction drop at the reduced flow rate (Figure 4).
3. An increase in superheat and enthalpy gradients (throughout the wellbore). This effect is controlled by a decrease in the pressure gradient at the lower flow rate (Figures 4 and 5).
4. Higher heat loss (Btu/lb) in the casing (especially in the top 1,000 feet). Note that at the lower flow rate, the wellhead enthalpy and superheat measurements do not reflect the reservoir (steam entry) values (Figure 5).
5. Near-saturated conditions at the surface (A'_1 on Figure 3).

CONCLUSIONS

To summarize, downhole pressures and temperatures obtained from P/T/S surveys have been used to monitor dynamic wellbore conditions over time. The surveys show that:

1. As mass depletion increases to the point at which the reservoir begins to dry out (ie. liquid fraction is boiled away), downhole enthalpy and superheat also increase.
2. Decreasing the flow rate effectively reduces both the downhole and surface enthalpy and superheat values.

Based on the results of this study and supporting geochemical information, we have targeted the area of the reservoir with the lowest pressure and exhibiting the highest superheat values for supplemental injection. Finally, future enthalpy and superheat trends can be predicted for northern Unit 13 and Unit 16 wells using data from the P/T/S monitoring program.

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