TRANSIENT PRESSURE TESTING

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ABSTRACT

The use of transient pressure testing has been sucessfully applied to the Tongonan geothermal field, byte, Philippines. Both pressure falloff and pressure buildup testa have been performed using Kuster downhole pressure instruments.

The data has been analyzed using log-log and semi-log methods, normally in combination. The application of these oilfield aethods to geothermal fields has limitations mainly due to the difficulty of determining in-situ reservoir rock and fluid properties. These include the porosity of the rock, the vertical extent of the producing sone and the fluid saturation.

Examples of the use of transient pressure analysis methods are illustrated.

INTRODUCTION

Using Kuster downhole instruments pressure transients at the Tongonan geothermal field have been successfully monitored. Both pressure buildup and falloff tests have been employed to obtain information about the reservoir properties around each well.

The data have been analyzed using accepted reservoir engineering techniques.

ANALYSIS METHODS USED

Most of the methods developed in reservoir engineering for analyzing mll tests are based on the hypothesis that the fluid flow is radial and isothermal and that the reservoir can be schematized as a porous, homogeneous isotropic medium of constant thickness.

The pressure gradients and fluid compressibility in the reservoir are assumed to be small, the gravity effects negligible, and the fluid viscosity constant.

In geothermal wells vith a two phase feed these assumption. are not generally true.

The aethods of analysis fall into two broad categories: semi-log and log-log methods.

Semi-log methods

The two main semi-log methods employed are the Horner method (Homer, 1951; Thomas, 1953) and that proposed by Miller, Dyes and Hutchinson (MDH, 1950). Both were originally developed for analysis of pressure buildup but can be applied directly to falloff data.

The MDH method is the easier to apply because no determination of injection/ production time is required. Provided the reservoir acts as if infinite in extent, or if tho production time is greater than twice the shut in time, then the MDH method is sufficient for determining reservoir properties.

(Earlougher, 1977). If this is not the came than the Horner method must be used.

Log-log aethods

The type curve matching method (Ramey, 1970, Earlougher et.al, 1973) generally provides a direct evaluation of transmissivity, skin factor and hydraulic diffusivity. However, the matching process seldom provides a clear result owing to the similar shape of the standard curves. The situation has been improved recently by a new method (Garcia-Rivera and Raghavan, 1979) of obtaining a value for the dimensionless storage coefficient (C_D). This gives a greater degree of confidence in the curve match obtained. Thio method was developed for oil wells but has proved to be effective in recent analyses carried out on wells in the Tongonan geothermal field.

Some wells have shown characteristics indicating that they intersect fractures. In these cases the curve matching methods of Gringarten et.al, (1975) have been used.

Limitations

The major limitations on these methods in a geothermal situation are due to the difficulty of determining in-situ rock and fluid properties. This means that a rigorous analysis cannot be attempted.

The unknown rock properties include the porosity-compressibility product and the vertical thickness of the producing layer. To evaluate reservoir permeability (k) these parameters must be known.

Unknown fluid properties include the viscosity, saturatlon and enthalpy. These properties can be evaluated under discharging conditions but their relationship to the in-situ properties is assumed rather than known.

Grant (1978) has determined methods of obtaining the porosity-compressibility (ϕc_t) product for two phase steam water mixtures, while Grant and Sorey (1979) have presented a method of obtaining a total fluid viscosity (μ_t). Both methods have been used, but by using hydraulic diffusivity rather than permeability as a parameter for comparison, the need to calculate a porosity-compressibility product is overcame. This is particularly important when comparing single phase wells with two phase wells.

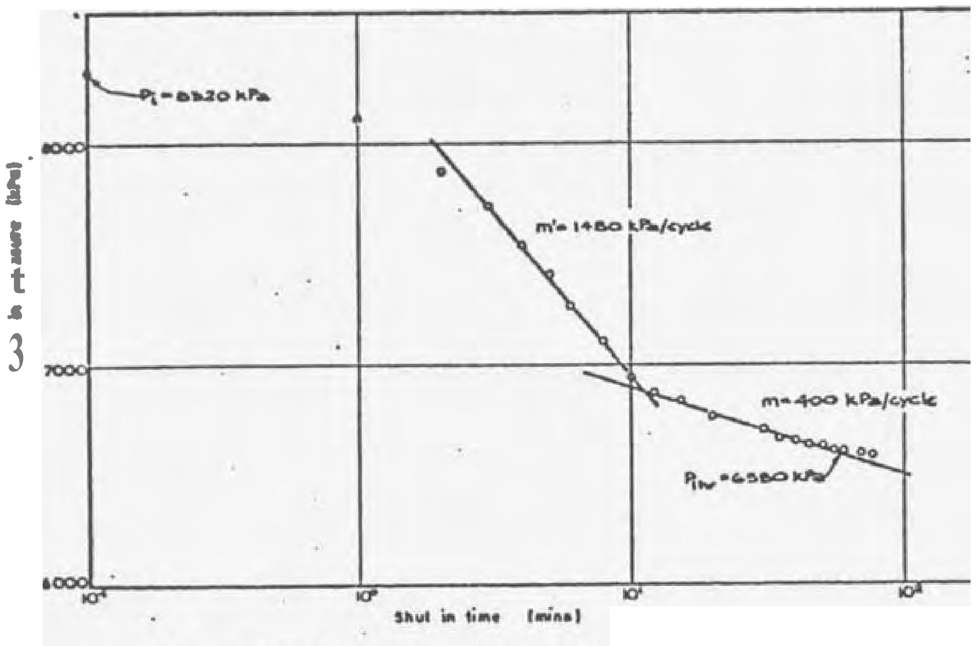
These limitations mean that the amount of information obtainable from geothermal wells is substantially less than fraa oil wells. For example a Homer or MDH plot will give only a value of transmissivity in a geothermal well whereas in an oil well values for permeability, skin factor, hydraulic diffusivity, and average reservoir pressure can also be obtained. This is because the in-situ rock and fluid properties are known with a greater degree of confidence.

RESULTS

A number of results from various well8 8re presented to show how the various techniques are applied and to indicate the difficulties that can be encountered.

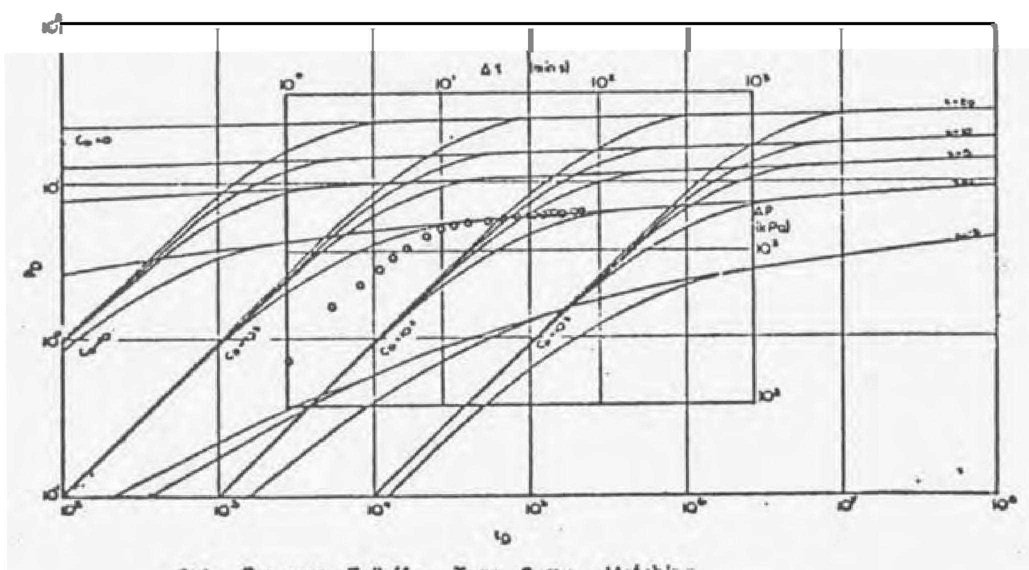
Well 214

This is a deep (1990 m) production well producing a steam-water mixture. On completion, the falloff in pressure was monitored after injection of water for about 15 hours. The data were analyzed by the MDH method and the Ramey curve matching technique, incorporating the method of Garcia-Rivera and Raghavan. The plots are shown in Figs 1 and 2.



214 Pressure Falloff (MDH Plot)

Fig 1

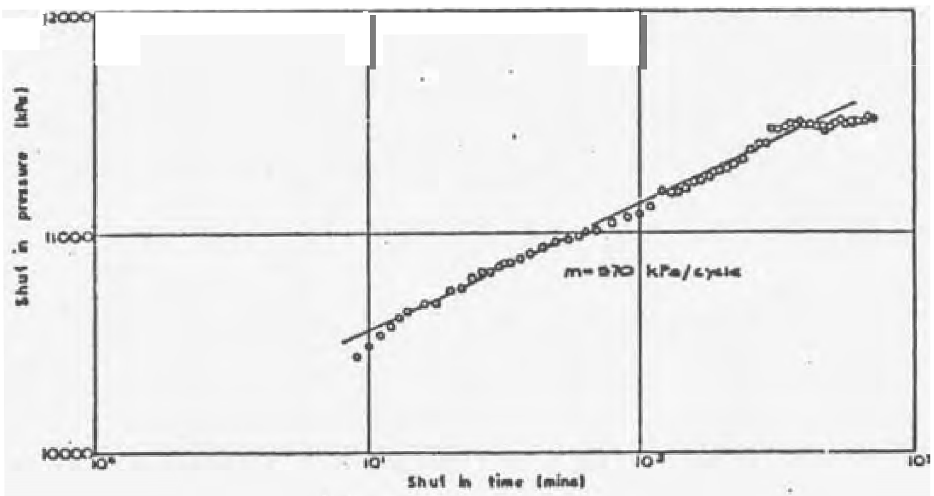


214 Pressure Falloff — Type Curve Matching

Fig 2

The analysis gave a transmissivity = 3.5 d-m, skin factor = -0.1 and a hydraulic diffusivity = 1690 m^2/hr.

The well was then allowed to heat up before it went on discharge for output testing. It was on discharge for 110 days and when shut in the pressure recovery (buildup) was monitored. This was analyzed by the MDH method. The log-log method was not used because the early time data were not monitored. This plot is shown in Fig 3.



214 Pressure Buildup (MDH Plot) Fig 3

The analysis indicated a transmissivity of 4 d-m.

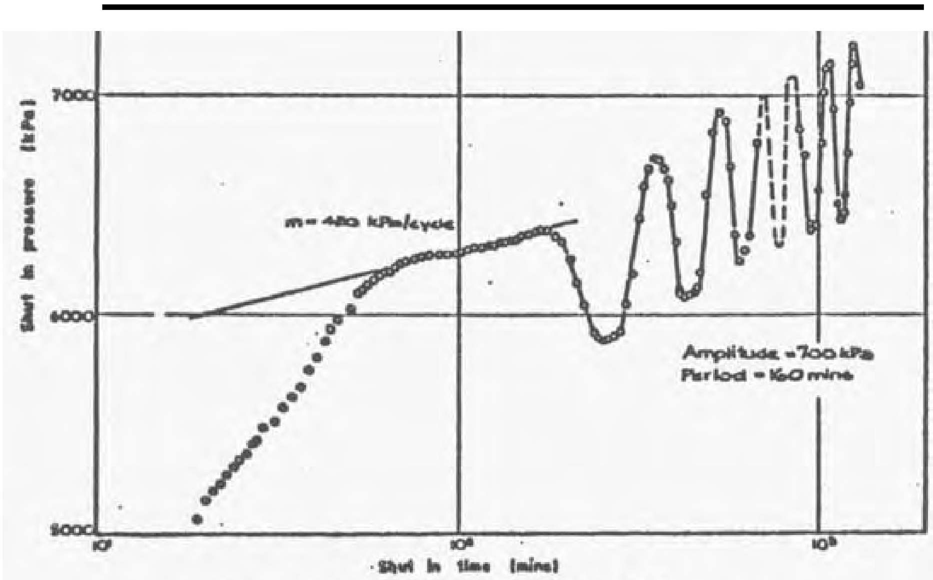
The indications are, therefore, that the transmissivity had not changed significantly during discharge.

The pressure buildup indicates a constant pressure boundary which could be interpreted as the boundary between a two phase and single phase area of the reservoir. This implies that 214 feeds from a single phase aquifer with flashing occurring in the rock. The fast recover- time of 5 hours is also indicative of a single rather than two phase reservoir.

Well 401

well 401 was the first deep well (1940 m) drilled in the Tongonan field and produces a high enthalpy (2200 kJ/kg) two phase fluid. It was used to supply steam to the 3 MW power station for 18 months and then underwent an output test for 172 days. On shut in the pressure buildup was monitored and the MDH plot is shown in Fig 4.

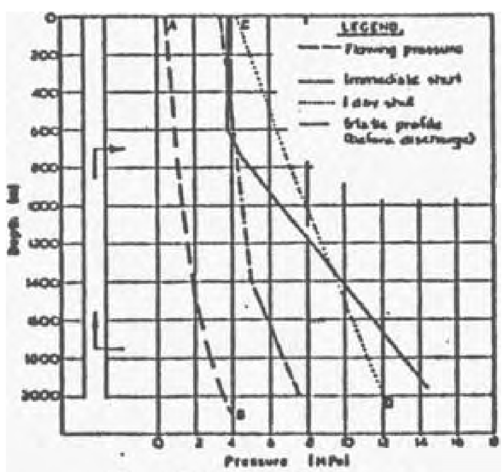
For the first three hours the well recovered normally and enough data was obtained to calculate a transmissivity of 4.5 d-m. The shape of the plot indicates either high wellbore storage or wellbore damage (i.e. positive skin factor).



401 Pressure Buildup (MDH Plot)

Fig 4

After this time the wall started to cycle with a constant period and amplitude which is indicative of two permeable zones. The explanation for this *is* illustrated in Fig 5.

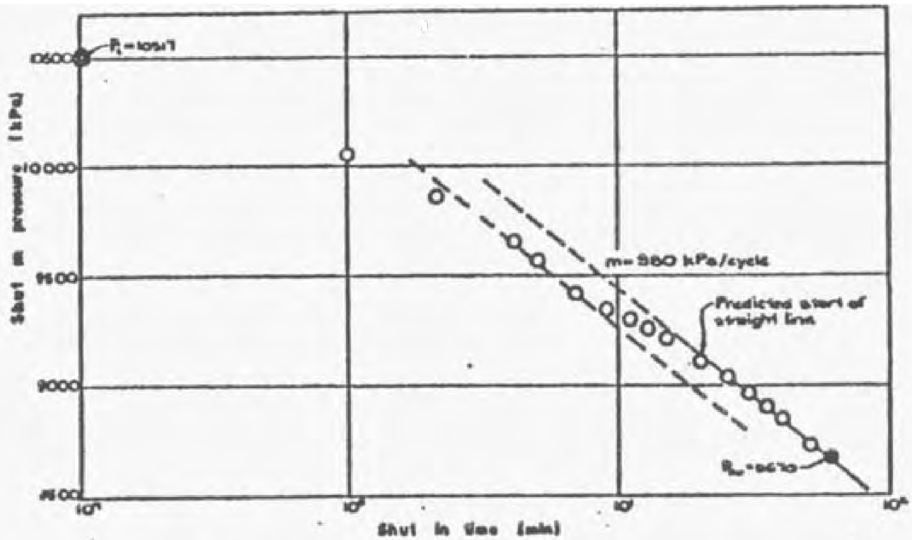


401 Pressure Profiles Fig 5

under flowing conditions the pressure profile in the well is similar to AB. After shut in the pressure recovers to the profile CD at which point a flow out of the well at the top permeable tone will occur, with flow into the well at the bottom permeable zone. After a period of time the pressure drawdown is such that the flow out the top ceases, causing the flow in the well to cease. It then starts to recover and *the* same cycle occurs.

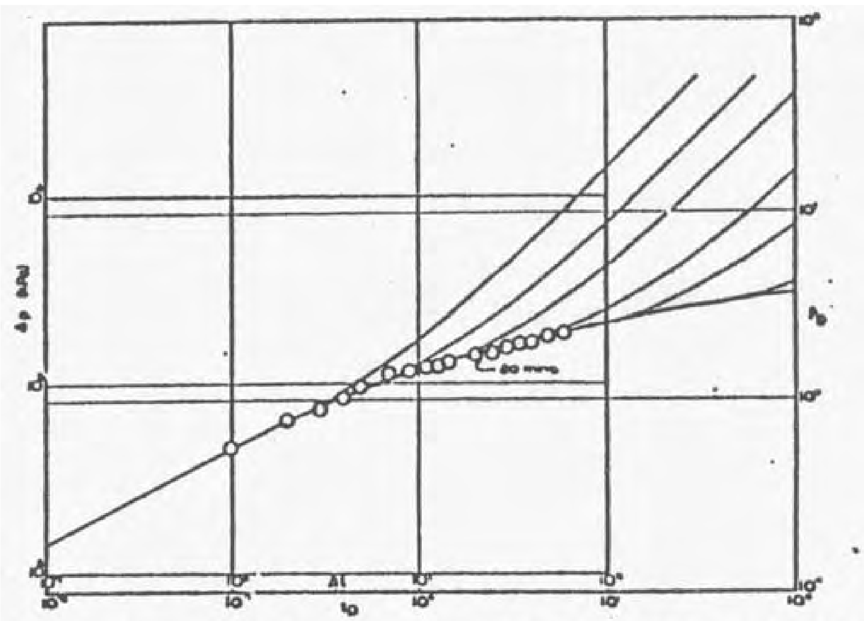
Well 103

This well is a medium (1400 m) depth production well producing a two phase fluid. On completion the falloff was monitored after injection of water for about 3 hours and the data analyzed by the MDH method (Pig 6). The plot shows the characterlotics of a naturally fractured reservoir and so the appropriate log-log curve matching method was used. (Fig 7).



103 Pressure Falloff – MDH Plot

Fig 6



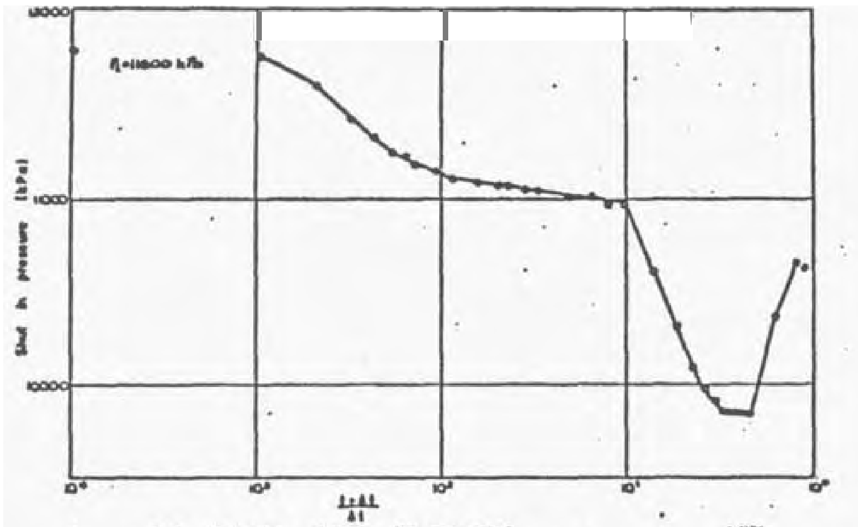
103 Pressure Falloff – Uniform Flux Fracture Curve Analysis

Fig 7

The analyses indicated a transmissivity of about 1 d-m. Due to a lack of data on in-situ rock properties the analysis cannot be taken further,

Well 215

This is a deep (1560 m) production well which has not been discharged to date. *On* completion a falloff test was run after injection of water for approximately **15** hours. **As** the time of interest **is** of the **same** order or greater than the injection time the Horner method has been **used.** (Pig *8).*



215 Pressure Falloff (Horner Plot)

Fig 8

The recovery **is** normal **for** about *80* mins but then the pressure suddenly decreases. This has been noted in other wells (Grant et.al, 1979), for example Kawerau 22. The effect is due to hot fluid flowing down the well and heating the cooler water column, This causes the density to decrease which reduces the downhole pressure. In **215** this occurred **over a** six hour **period** and **the** change in pressure corresponds to a change in the average column temperature from 130°C to 225°C. From subsequent temperature surveys the temperature **of** the hot fluid is about 260°C. The lowering of pressure stops the lower zone accepting fluid while the upper zone still flows. This causes the water column to increase until the downhole pressure is great enough for the lower zone to start accepting fluid again.

As the well has not been discharged the fluid propertfes are **not known.** The analysis is, therefore, incomplete and no value of transmissivity **has** been calculated.

DISCUSSION

The well tests illustrated here show a wide cross section of results obtained from Tongonan. Most of the analyses have been straightforward but others have required more careful interpretation.

These tests have an important part to play in field management by providing a method of gauging changes or instability in performance. For example 401 shows no instability on discharge but it is obvious from the pressure buildup test that the potential for instability is there. Also 215 is to be used as a monitor well during long term discharge studies. If, however, its response is complicated by its own inherent instability it would not seem to be a good choice for this application.

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