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WELL TESTING IN A LIQUID DOMINATED TWO PHASE RESERVOIR

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ABSTRACT

The Tongonan Geothermal Field, Leyte, Philippines is a good example of a liquid dominated geothermal system with extensive two phase conditions. This paper outlines the history of one well and a variety of test procedures including transient pressure testing methods, successfully used to identify characteristics of the reservoir and geothermal fluid adjacent to the well when flashing occurs within the rock as well as the wellbore. The effects of an experimental injection treatment are discussed.

TONGONAN GEOTHERMAL FIELD

Exploration and more recently development of a geothermal resource in Leyte, Philippines, has been in progress since 1973. Exploratory drilling (300 to 600 metre wells) commenced in 1974 and was completed in 1976 when delineation and development drilling began. Fifteen successful producing wells have been completed to May 1979 and two disposal wells have been drilled. Of the eleven production wells for which initial testing is completed the mean steam flow after three months testing is 25 kg/s (90 t/hr) per well at 1 MPa wellhead pressure.

Steam from the first development well was used less than nine months after spud, to generate the first commercial geothermal power in the Philippines. A 3 MW non-condensing turbo-generator was used for this purpose and to provide pilot plant facilities prior to subsequent field development. A 112 MW plant is under design and is expected on line late 1981 as the first stage of what could be a 400 MW ultimate field development.

Two phase conditions are believed to occur over a considerable portion of the identified field between 4 sq km and 7 sq km area. The test data introduced in this paper refers to a typical well drilled into the two phase part of the system.

INTRODUCTION

Pressure transient analysis techniques are routinely used in petroleum wells for the determination of reservoir parameters. These techniques have allowed an understanding of reservoir and well behaviour and have presented methods of quantifying and monitoring changes in skin, storage, transmissivity and permeability.

For testing geothermal wells, procedures initially concentrated on empirical methods (James 1970) for determining individual well and field potential, but provided little information on the reservoir. Pressure transient methods were first applied successfully in vapour dominated systems where gas reservoir methods were found to be suitable for analysing steam reservoirs. (Brigham and Morrow 1973). Wellhead readings were used which eliminated the need for downhole instrumentation with its consequent measurement difficulties. In liquid dominated systems transient well testing is frequently more difficult especially if two phase conditions exist in the formation. Recent workers have shown the use of these techniques when no flashing occurs (Witherspoon et al 1976), and when flashing occurs only in the wellbore (Gringarten 1978). Two rate flow tests have also been analysed (Riviera and Ramey 1977). Grant (1978) compared pressure transients in two phase conditions with single phase and gave examples of transient pressure testing in a liquid dominated two phase reservoir. This paper reviews the testing of a well in a similar field, but without large amounts of gas.

DRILLING SUMMARY

The well was spudded on 13 August 1978 and completed to 1801 metres on 16 October 1978. Production casing had been set at 618 metres and an 8½" diameter open hole drilled to total depth. The encountered lithologies comprised andesite lavas, breccias, tuffs and intercalated fine black shales or volcaniclastics. Below about 1600 metres the well intersected plutonic intrusives and was terminated in rocks of granitic composition. A silicified andesite was found at

213 to 222 metres, the well came under pressure between 232 and 245 metres and flowed gas (CO_2/H_2S). In the production hole circulation losses were encountered at 722 metres and continued intermittently to 1018 metres. A further partial circulation loss occurred at 1171 metres depth.

COMPLETION TESTS

The completion method used on this well was a 7 5/8" diameter slotted liner squatted on bottom and landed with a J slot adapter. The hole was washed after installing the liner. Three successful temperature profiles (Fig.3 a,b) were run while pumping cold water into the well and they indicated that most of the flow was leaving the well between 850 and 1080 metres. A multirate injection test was then performed with a pressure gauge at 900 metres and pumping rates up to 26.5 kg/s (10 bbl/min). This indicated the injectivity of the well was 36 kg/s-MPa which is about average for wells at Tongonan. The injectivity test was performed to gauge the apparent permeability of the well on completion prior to thermal recovery and discharge. Best results are obtained when the pressure gauge is located adjacent to the major loss zone in the well as indicated by the previous temperature profiles.

WELL STIMULATION

An attempt was made to stimulate the injectivity (injection rate, pressure change quotient) of the well with a series of injection tests. These tests followed on the previous injectivity test. The second test comprised pumping at five rates up to 50.4 kg/s (19 bbl/min). Downhole pressures were measured with increasing and decreasing flow rates. The well was then quenched at a variety of flow rates for eight hours. The second injection test was then repeated with four pumping rates up to 45 kg/s (17 bbl/min). A substantial improvement in injectivity was noted and the initial test was repeated to determine any permanent benefit from the tests. No wellhead pressure was recorded during any part of these tests.

TABLE 1 - INJECTIVITY TESTS

Test	Injectivity	Max. Pump Rate
1	36 kg/s MPa	26.5 kg/s
2	39 kg/s MPa	50.4 kg/s
3	73 kg/s MPa	45.0 kg/s
4	59 kg/s MPa	26.5 kg/s

The results, tabulated in table 1, indicated that there was a marginal improvement in injectivity by doubling the pumping rate. Injectivity doubled between the first and third tests after quenching the well for eight hours, suggesting greater benefit gained from quenching time than injection pressures. The fourth test was performed shortly afterwards and at lower injection rates. The injectivity was lower than in the third test, but nearly two thirds higher than the result of the first test. This suggests that some permanent benefit to well permeability is gained from injection testing, but not all the enhanced permeability can be considered permanently retained. Evaluation of pressure falloff after each injection test suggested no significant increases in permeability were occurring but a decrease in skin effect was seen.

In conclusion, positive benefit was gained by water injection and created increases in injectivity. Curve matching techniques suggested the skin effect had disappeared by the end of the injection and falloff tests, but the transmissivity was little changed.

FALLOFF ANALYSIS

The pressure transients during the falloff after each injection test were monitored and the pertinent results are noted here. Fluid conditions in the reservoir some distance away from the well are assumed to control the pressures at the well hence the fluid characteristics used in this assessment are for the two phase reservoir, not the injection fluid. This assumption should be valid for early tests. For the first test a "Horner" analysis indicated a transmissivity of 9.0 darcy-metres. A type curve match gave a similar transmissivity kh = 10.3 darcy-metres and indicated permeability k = 4.1 darcy, thickness = 2.5 metres and a slightly positive skin. The skin was then calculated to be 1.3. Wellbore storage was observed to be the predominant effect after shut in although the well had a small positive skin effect on well completion.

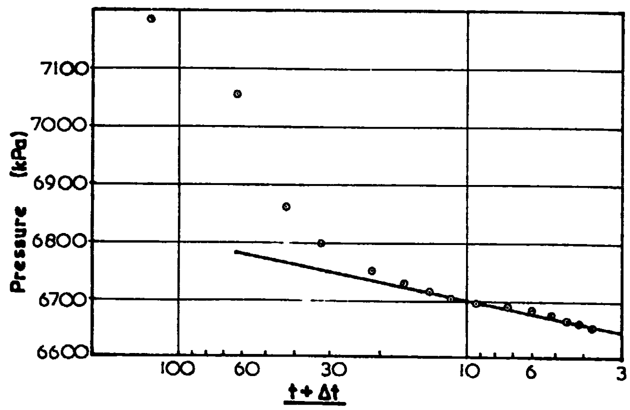

Figure 1 PRESSURE FALLOFF - HORNER PLOT.

THERMAL RECOVERY

Between the finish of the completion tests and the commencement of the output test the well was allowed to heat up. During this period the well was briefly discharged on three occasions to clear drilling debris and mud from the well, collect samples of fluids and ejecta, and to encourage hotter fluids to replace the cold fluids pumped into the well during completion. These discharges also allowed the output of the well to be estimated to enable sizing of the output test equipment. The pertinent aspects of the thermal

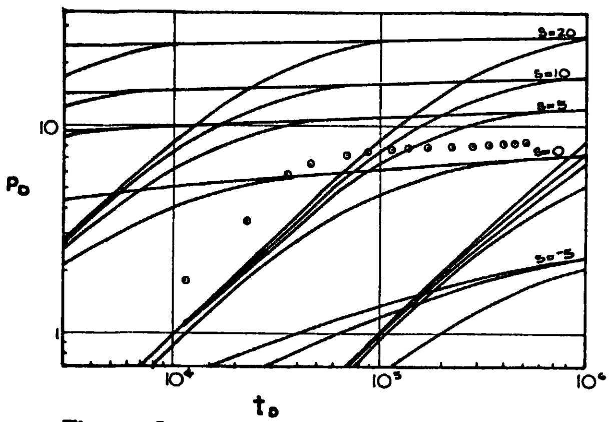

Figure 2 PRESSURE FALLOFF – CURVE MATCH.

recovery of the well were a temperature maximum adjacent to a drilling loss zone at 730 metres, and apparent flow down the well originating from about 910 metres (Fig.3, e). The well had an increasing temperature gradient to the bottom of the well. The temperature in the well increased until the cooler down flow in the well disappeared fifty three days after completion, being replaced by an upflow. The well then had increasing temperatures over its entire length to a maximum of 317^{o}C at 1745 metres. Evaluation of the pressure gradient changes over this period indicated that the well was pressure controlled from about 700 metres to 900 metres and that the apparent water level in the reservoir was about 150 metres below surface. The well developed a natural wellhead pressure, due to gas inflow, of 5.0 MPa.

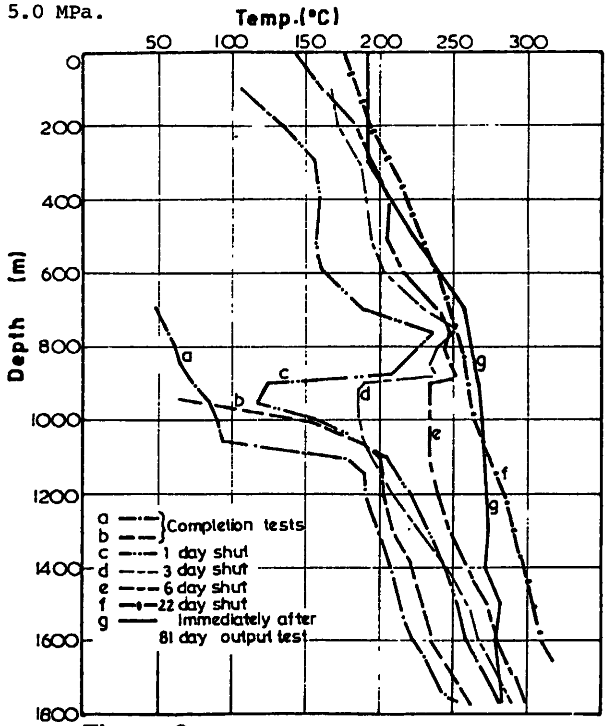

Figure 3 TEMPERATURE PLOTS

OUTPUT TESTING

The well was discharged continuously for a period of 81 days with minor halts to repair surface equipment and change backpressure orifice plates in the discharge line. The testing was via a horizontal discharge line from the well fitted with fluid sampling points, pressure tappings and provision for backpressuring the well through use of orifice plates. The flow rate is measured using James' Lip Pressure measurement system which consists of pressure measurement at the end of the discharge tube and a silencer to separate the steam and water flows. The water flow is measured over a weir.

The well was discharged without restriction for twenty seven days to stabilise the well's output after the initial peak on opening. The well was then run for seven, nine and five days with chokes of 113 mm, 87 mm and 76 mm diameter. This was followed by a full bore discharge for a further thirty three days before shut in. The well output illustrated in Fig. 4 revealed from the changes in output with wellhead pressure that the well is predominantly wellbore controlled and that the maximum discharging pressure is about 4.0 MPa. The discharge enthalpy of 1380 kJ/kg was in excess of the specific enthalpy of fluid at the maximum temperature recorded in the well at the production zone level. The majority of the production is believed to come from 910 to 1050 metres with further feed zones at 1400 metres and bottomhole. The production temperature at shut in was 218^{o}C.

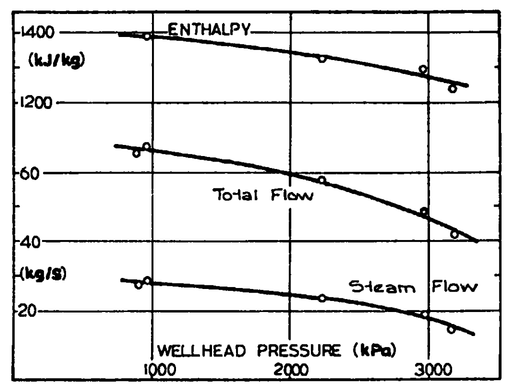

Figure 4 OUTPUT CURVES

PRESSURE BUILDUP ANALYSIS

Following completion of the eighty one day output test the pressure buildup was monitored using successive pressure logs with a Kuster KPG pressure gauge. The gauge was lowered between the probable production zones at 1200 m. Because of complex density changes down the well, bottomhole pressure measurement is not suitable for monitoring wells when boiling occurs in the well or formation. Knowledge of the reservoir parameters in the vicinity of the well is obtainable if the standard petroleum engineering techniques of analysis are modified to account for two phase conditions within the rock. Grant (1978) has presented methods of analysis which take into account the phase change and the resultant much greater compressibility of the steam water mixture. Grant and Sorey have provided a satisfactory method of estimating well parameters in two phase flow using single phase pressure transient theory. Initial estimate of reservoir parameters is from log-log analysis of pressure buildup.

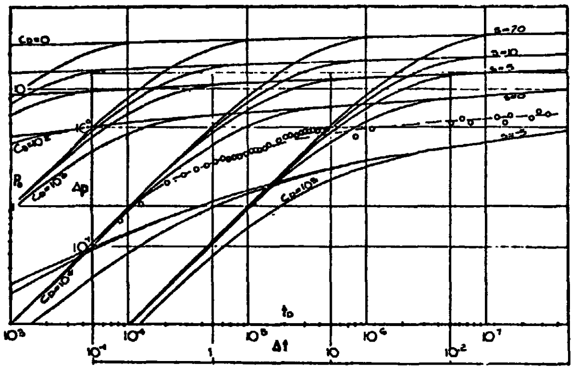

Figure 5 PRESSURE BUILDUP- CURVE MATCH

The match point is $P_D = 1$ $P = 240$ kPa
$t_D = 10^6$ $t = 18$ hours
$C_D = 10^4$, and the skin is slightly negative, $s \approx -3$. The two phase parameters are derived using the method of Grant and Sorey (1979). The discharge enthalpy was 1380 kJ/kg, compared to a production zone temperature of 281°C (liquid water 1243 kJ/kg). This gives the vapour fraction in the flow, at reservoir conditions as 0.087. The specific volume of the water-steam mixture is $0.087\nu_s + 0.913\nu_w = .00384$ m^3/kg. With a standard specific volume for liquid water at surface of 0.00104, this gives B = 3.69. The relative permeabilities are found from

$$\frac{K_{rw}}{K_{rs}} = \frac{\mu_w \nu_w}{\mu_s \nu_s} \; \frac{h_s - h_t}{h_f - h_w} = 2.35$$

Assuming the "fracture-flow" relation $K_{rw} + K_{rs} = 1$, we obtain $K_{rw} = 0.721$, $K_{rs} = 0.279$. Then the viscosity of the flowing fluid

$$\frac{1}{\mu_t} = \frac{K_{rw}}{\mu_w} + \frac{K_{rs}}{\mu_s} \; ; \; \mu_t = 44.74 \times 10^{-6} \quad \text{Pa.s}$$

The compressibility, for rock of volumetric heat capacity 2.5 mJ/m^3 °C, is approximated by

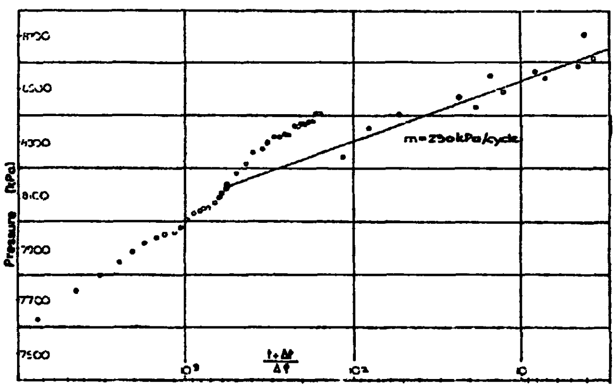

Figure 6 PRESSURE BUILDUP—HORNER PLOT

$\phi C_t = 50\ (T/100)^{-7} = 3.61 \times 10^{-4}$ kPa^{-1}
Substituting into the values for the log-log match point gives, for a flow of 66.5 kg/s
kh = 7.3 darcy-metres, k = 2.9 darcy.
Semilog methods, where possible, are preferable. From Fig. 6 a slope 230 kPa/cycle is found. This gives kh = 8.7 darcy-metres in good agreement with the log-log fit. The skin effect was calculated to be -2.9 which is also in agreement with the curve fit chosen in Fig. 5.

SUMMARY OF RESULTS AND ANALYSES

1. Initially moderate injectivity on completion, 36 kg/s-MPa, and slight skin damage.
2. Injectivity improved by high rate injection test, skin damage disappears and transmissivity remains about the same 10 darcy-metres.
3. Increasing temperatures over entire hole depth to a maximum of 317°C. Gradient typically following boiling point for depth profile.
4. Reservoir pressure 12.3 MPa at 1700 metres. Natural wellhead pressure, 2.0 to 5.0 MPa due to gas.
5. Well is located in two phase part of reservoir.
6. Output at 1 MPa wellhead pressure, 66 kg/s total flow, 24 kg/s steam flow. Well output controlled by wellhead and wellbore pressure losses.
7. Power Potential 10 MW$_{(e)}$.
8. Producing Zones 910-1050 m, 1400 m, 1700-1755 m.
9. Good agreement between semilog and log-log pressure buildup analyses. Transmissivity about 8.5 darcy-metres, permeability about 3 darcy. These results agree with pressure falloff analyses at well completion.
10. Well appears to be slightly stimulated (negative skin) after flowing 81 days.

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