Build-Up and Back-Pressure Tests on Italian Geothermal Wells

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ABSTRACT

Build-up curves of some Italian geothermal fields (Larderello, Travale, Mt. Amiata) analyzed with oil-well test methods reveal:

Transmissivity (*hk*) values ranging between 1 and 200 Darcy-meters. Transmissivity values obtained with different methods are consistent with one another.
Generally negative skin effect coefficients.
Well-bore storage coefficients which are usually higher than those calculated on the basis of well volume and fluid properties.
Complex boundary effects and formation heterogeneities.

For most of the high productivity wells, back-pressure curves reveal the existence of a non-Darcy flow in the reservoir.

The *hk* values thus obtained are compatible with the results of build-up tests.

INTRODUCTION

Back-pressure and build-up tests have been carried out in Italian geothermal fields for the past twenty years in order to determine the best exploitation conditions and the shut-in pressures.

This paper gives the results of the analysis of the data obtained from these tests, according to criteria developed for oil reservoir engineering. The majority of the data already existed and the remainder were obtained from measurements made for this purpose in these last few years.

As the models used in oil reservoir engineering are based on hypotheses, some of which cannot be directly transferred to geothermal fields, this work also aims at checking their validity.

It has been shown that in Italian geothermal fields the fluid flow mainly takes place in fractures. Matrix permeability from direct analysis of the cores is less than 10^{-4} Darcy and there are wells which have not crossed fractured layers and consequently are completely nonproductive.

The fracture distribution is very difficult to determine. Very often these fractures are found near the contact between the potential reservoir and the cap-rock formations where, at least in the case of Larderello, a quite continuous fractured horizon seems to extend over almost all the field (Celati et al., 1975).

It is thought that the fracturation takes no preferential direction in the upper part of the potential reservoir and therefore an isotropic medium model can be justified here in large part. In the lower part of these formations fracturation is not so common, and the direction is expected to be mainly vertical. In this situation a "thickness of the permeable layer" could have no definite meaning. The fact that there are highly productive wells at a relatively short distance from nonproductive wells suggests strong lateral heterogeneities.

Strong heterogeneities in the electrical properties of the rocks were also revealed by the magnetotelluric prospecting survey in Travale field (Celati et al., 1973). A first analysis showed that these results could be connected with the distribution of the fractures.

Most of the wells under study in this paper produce superheated steam with generally small quantities of gas (1 to 10%; mainly CO_2). These wells are in zones which have been subjected to drainage over a long period, with the result that the methods used in gas wells can also be said to apply in their case.

Although there are plenty of reliable data available they are affected by the industrial requirements of the running of the field. Normally the tests are performed a few days after the wells have gone into production and are very rarely repeated after the wells have been connected to the power plants.

In the case of the older data there are often doubts as to the production conditions in the period before shut-in. The pressure at the moment when the valve is completely closed is not always known. The first pressure values are sometimes read after a few minutes; usually a long period of time is needed for closing the valve (10 to 30 minutes)

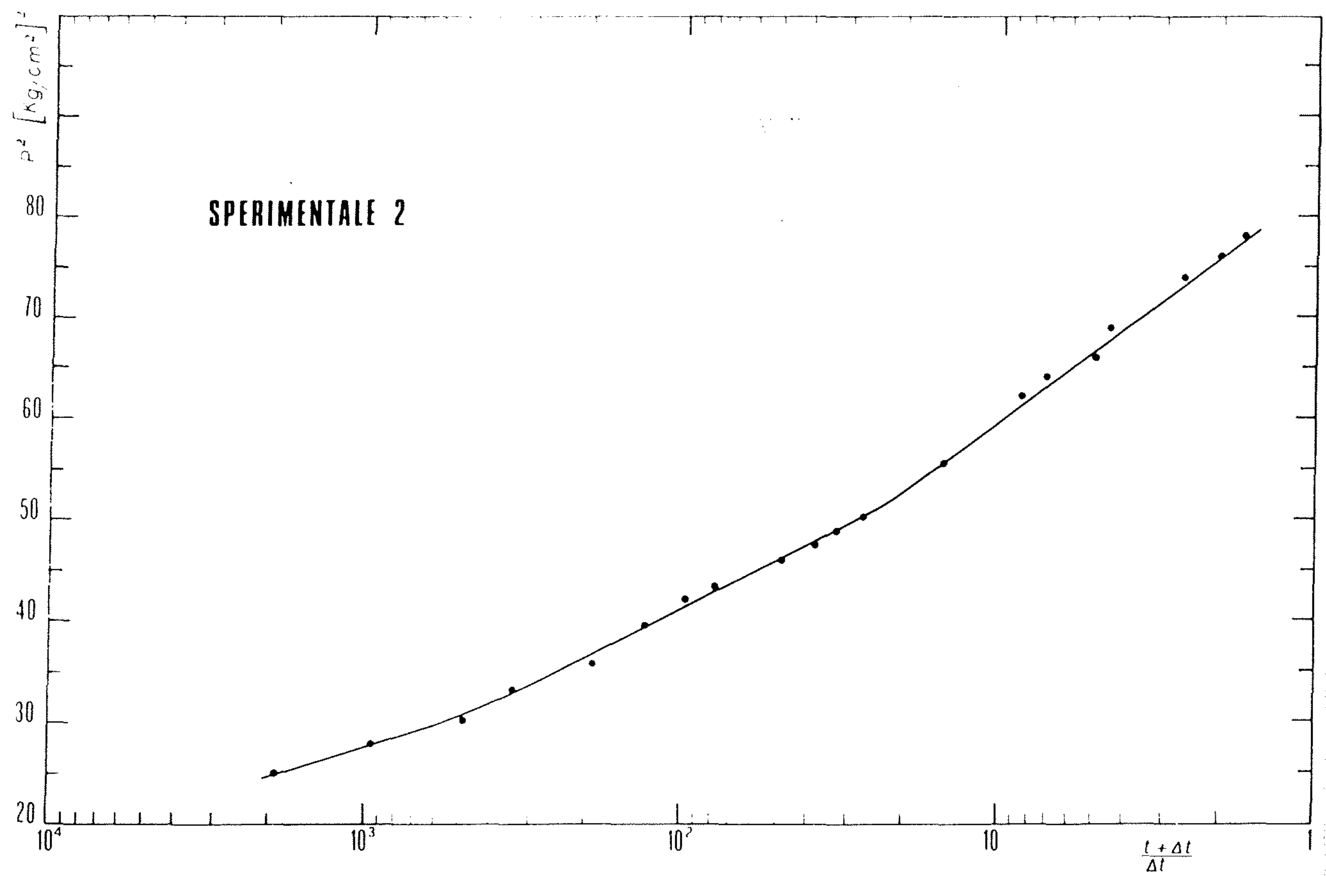

Figure 1. Pressure build-up for Sperimentale 2 steam well, Larderello.

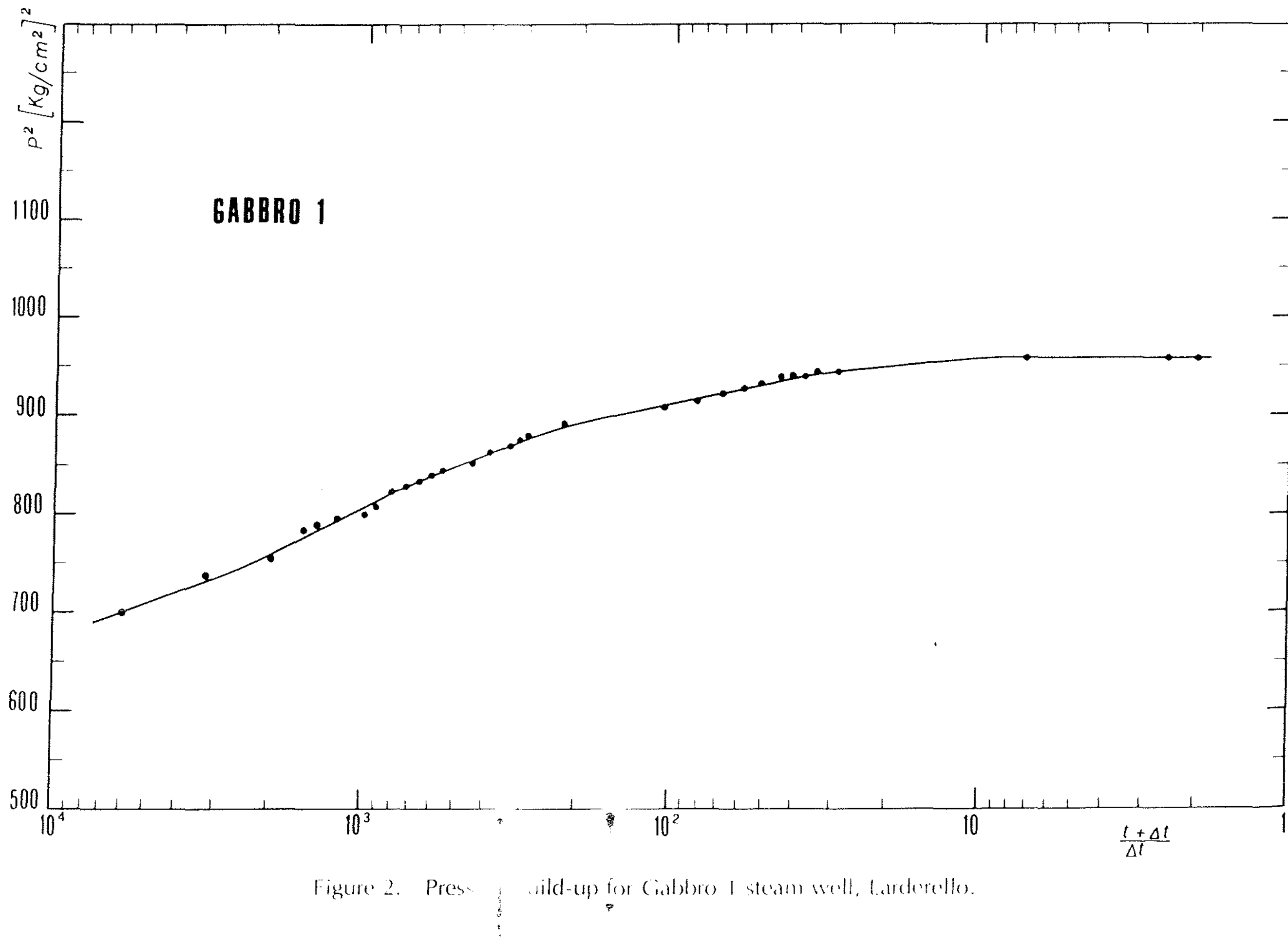

Figure 2. Press... ...uild-up for Gabbro 1 steam well, Larderello.

The isochronic method has never been used, but a good stabilization has usually been attained in determining the back-pressure curves. This paper gives a discussion of the test results and the problems arising from their interpretation.

ANALYSIS METHODS USED

Most of the methods developed in oil reservoir engineering for analyzing well 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 in the reservoir are also assumed to be small, the gravity effects negligible, and the fluid viscosity constant.

Build-Up Analysis

The existing analysis methods have in general been developed for fluids with small compressibility. In our case, where the fluid is steam which is often superheated, the vapor flow has been assumed and dealt with both as an equivalent liquid flow according to the method suggested by Matthews and Russell and using the pressure-squared form (Matthews and Russell, 1967).

The conventional semilogarithmic plot by Horner (Figs. 1, 2, 3, 4) was used in determining the *hk* (thickness·permeability) values, but we were unable to evaluate the permeability *k*, as a meaningful value of *h* was impossible to determine. With this method the skin effect cannot be defined with precision as *k* and ϕ are unknown.

The type-curve matching method generally provides a direct evaluation of the hydraulic diffusivity, $k/\phi\mu c_t$, and the skin effect. However, more than one matching is often obtained from these methods mainly because there are not enough successive measurements immediately after well shut-in. Consequently, one single value for hydraulic diffusivity cannot be determined.

With regard to the dimensionless pressure, on the other hand, the imprecision in fitting, and consequently in determining *hk*, is small.

The theoretical studies on transient fluid flow and well test analysis over the last few years also permit an analysis of the data referring to the period before the conventional straight line, on a semilog plot, is reached. Thus the factors influencing the first period of pressure build-up, such as well-bore storage and skin effect, may be evaluated.

Type curves are also available for analyzing fractured wells. These curves also permit us to identify the section of the pressure build-up curve where well-bore storage is the controlling effect (slope 1 of the log-log type curve), the eventual linear flow periods (lying on a straight line of slope 1/2) which occur at early times in fractured wells, and the beginning of a proper straight line on a conventional semilogarithmic plot.

Type curves from Agarwal, Al Hussainy, and Ramey (1970) for wells drilled in infinite reservoirs with well-bore

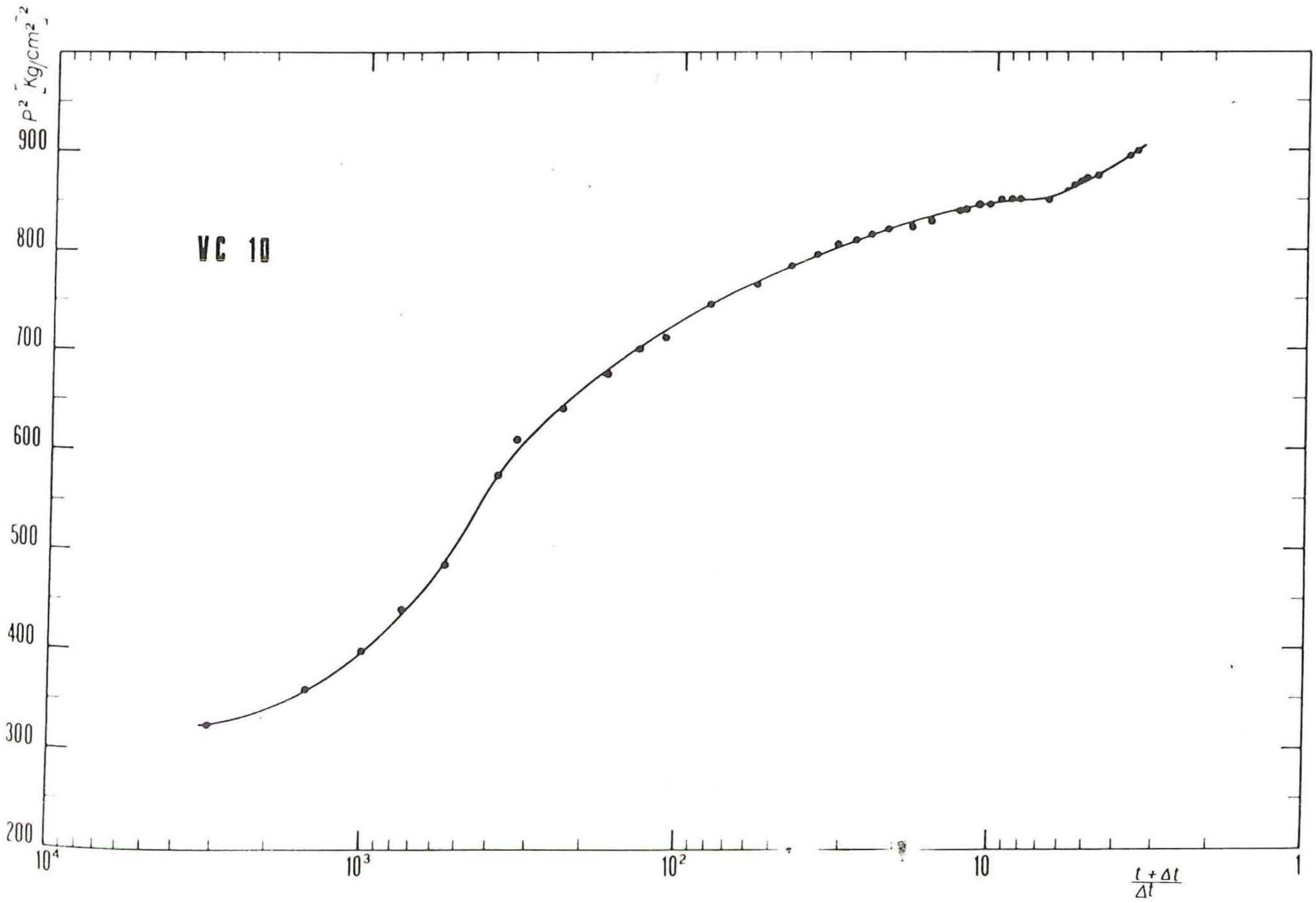

Figure 3. Pressure build-up for VC 10 steam well, Larderello.

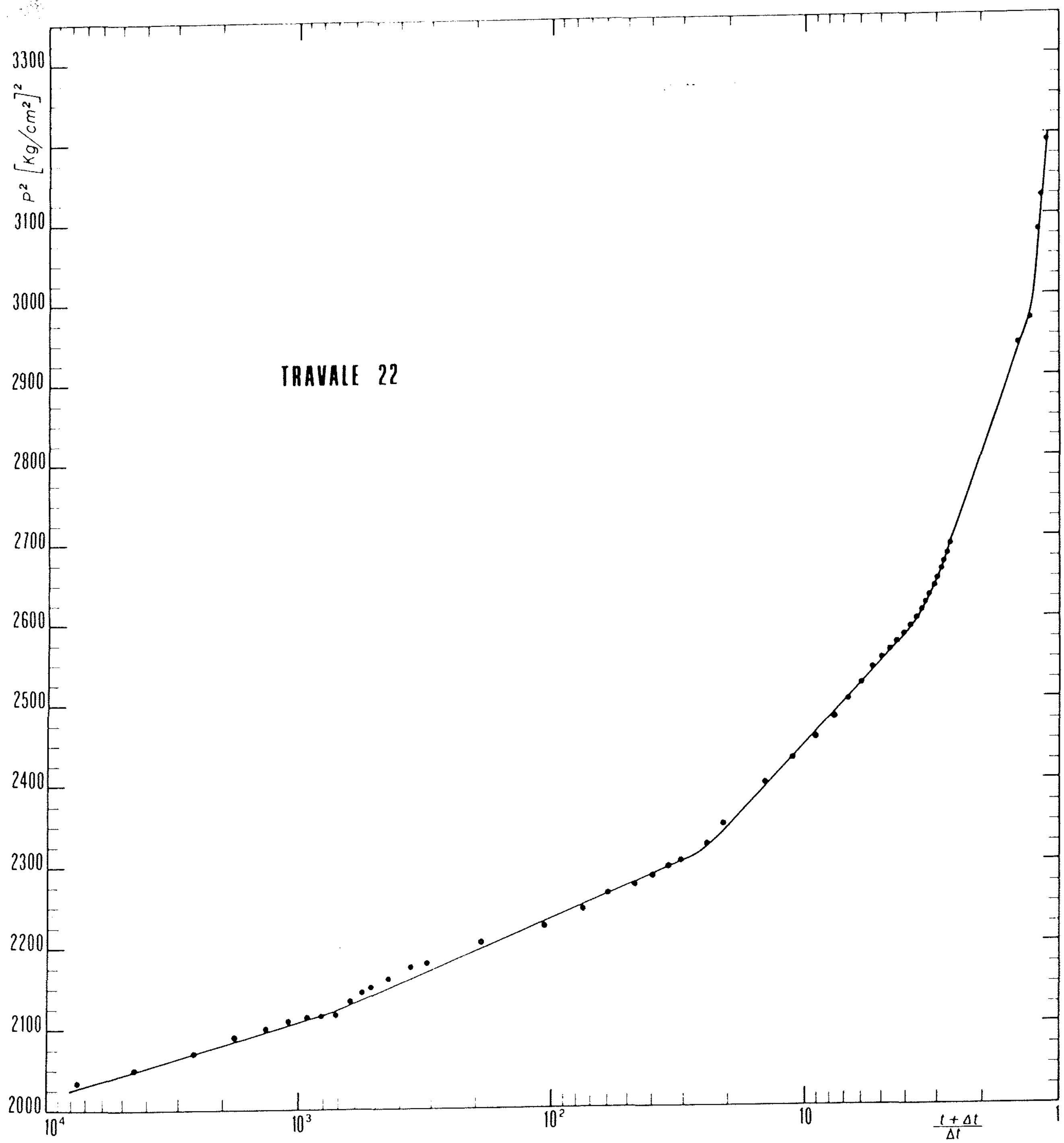

Figure 4. Pressure build-up for Travale 22 steam well, Travale.

storage and skin effect were used (Fig. 5).

In these curves dimensionless pressure

$$p_D = \frac{2\pi hk}{q\mu}(p_i - p_{wf}) = \frac{\pi hkM}{G\mu zRT}(p_i^2 - p_{wf}^2) \qquad (1)$$

vs dimensionless time

$$t_D = \frac{kt}{\phi\mu C_t r_w^2} \qquad (2)$$

are displayed in a log-log plot with different values of dimensionless storage constant

$$C_D = \frac{C}{2\pi r_w^2 h\phi C_t} \qquad (3)$$

and skin effect as parameters. (See Table 1 for the nomenclature of all mathematical expressions in this paper.)

These curves, relative to the drawdowns, can be applied, according to Agarwal, Al Hussainy, and Ramey (1970), to build-up analysis provided that the time since shut-in is small compared to the flow time.

As wellhead shut-in pressure is used, the flow pressure

Table 1. Nomenclature of mathematical expressions.

C_t	Total compressibility
C	Well-bore storage constant
C_D	Dimensionless storage constant
C_p	Performance coefficient
G	Mass production rate
h	Permeable formation thickness
k	Permeability
L	Fracture half length
M	Molecular weight
p	Pressure
p_D	Dimensionless pressure
p_i	Initial reservoir pressure
p_e	Static well pressure
p_{wf}	Flowing well pressure
p_{ws}	Well pressure after shut-in
q	Volumetric production rate (reservoir conditions)
r	Radius
r_e	Exterior boundary radius
r_w	Wellbore radius
R	Gas law constant
S	Skin factor
t	Time of flowing
t_D	Dimensionless time
T	Absolute temperature
v	Apparent velocity
V_w	Wellbore storage volume
x_e	Side length of the square reservoir
x_f	Fracture length
z	Compressibility factor
β	Turbulence factor
Δt	Shut-in time
ϕ	Porosity
μ	Viscosity

has been assumed to be equal to that measured at the instant the valve was closed (Ramey, 1970). From the matching hk, S, $k/\phi\mu C_t$, and C can be obtained.

When we can clearly identify the pressure build-up section, totally dependent on well-bore storage, C can be determined a priori

$$C = \frac{q\Delta t}{\Delta p} \tag{4}$$

but C_D cannot be determined as the value of $h\phi$ is unknown.

Therefore a previously calculated C_D value cannot be used in identifying the family of curves on which matching is to be applied.

The C value can be obtained from

$$C = 2\pi \frac{hk}{\mu} C_D \frac{t}{t_D} \tag{5}$$

where t and t_D are corresponding values in matching, even when slope 1 section is missing.

The C value can also be calculated from

$$C = V_w C_t \tag{6}$$

In short-time well test analysis the curves given by Earlougher and Kersch (1970) were also used. These consist of a log-log plot of $p_D C_D/t_D$ versus t_D/C_D with $C_D e^{2S}$ as parameter (Fig. 6). In this case matching takes place between the type-curve and the graph $\Delta p/\Delta t$ versus Δt. C, hk, and S in theory can be determined from matching.

Matching should be carried out, estimating C from the well volume and using this to locate the horizontal asymptote on the data plot. In our case S could not be obtained from the parameter $C_D e^{2S}$ as $h\phi$ was unknown.

Also used for the analysis were the type curves for vertically fractured wells, relative to both uniform flux fractures and infinite conductivity fractures, taken from Gringarten, Ramey, and Raghavan (1972) (Figs. 7, 8).

The authors point out that the first is suitable for analyzing wells with natural fractures and the second for analyzing hydraulically fractured wells. The curves are valid in the case of plane fractures in infinite reservoirs or in closed square reservoirs. In the latter, if enough long-time data are available, the match also gives the ratio between the side of the reservoir and the length of the fracture.

Dimensionless quantities are defined as

$$p_D = \frac{2\pi hk}{q\mu}(p_i - p_{wf}) = \frac{\pi hkM}{G\mu zRT}(p_i^2 - p_{wf}^2) \tag{7}$$

$$t_{DL} = \frac{kt}{\phi\mu C_t L^2} \tag{8}$$

$$C_{DL} = \frac{C}{2\pi\phi h C_t L^2} \tag{9}$$

and therefore C can again be calculated from Equation (5).

For very early-time data interpretation Ramey (unpub. data) gave us type curves for vertically fractured wells with well-bore storage (Fig. 9). These curves were also used in our study.

Back-Pressure Curves

As no bottom-hole pressure curves of this type are available at the moment they were calculated by the method described by Rumi (1967). Pressure-squared difference was plotted versus the production rate on a log-log scale. The plot allows us to determine the performance coefficient C_p and the exponent n according to the formula

$$G = C_p(p_e^2 - p_{wf}^2)^n \tag{10}$$

The exponent n varies between 1, for laminar flow, and 0.5 for completely turbulent flow. Where the value of n indicates the presence of turbulent flow, Forchheimer's equation

$$\frac{dp}{dr} = \frac{\mu}{k} v + \beta\rho v^2 \tag{11}$$

leads us to expect a relationship between pressure and flow rate of the type (Govier, 1965)

$$p_e^2 - p_{wf}^2 = aG + bG^2 \tag{12}$$

where

$$a = \frac{\mu \ln \frac{r_e}{r_w}}{\pi hk} \frac{zRT}{M} \tag{13}$$

$$b = \frac{\beta}{h^2} \frac{zRT}{M} \left(\frac{1}{r_w} - \frac{1}{r_e}\right). \tag{14}$$

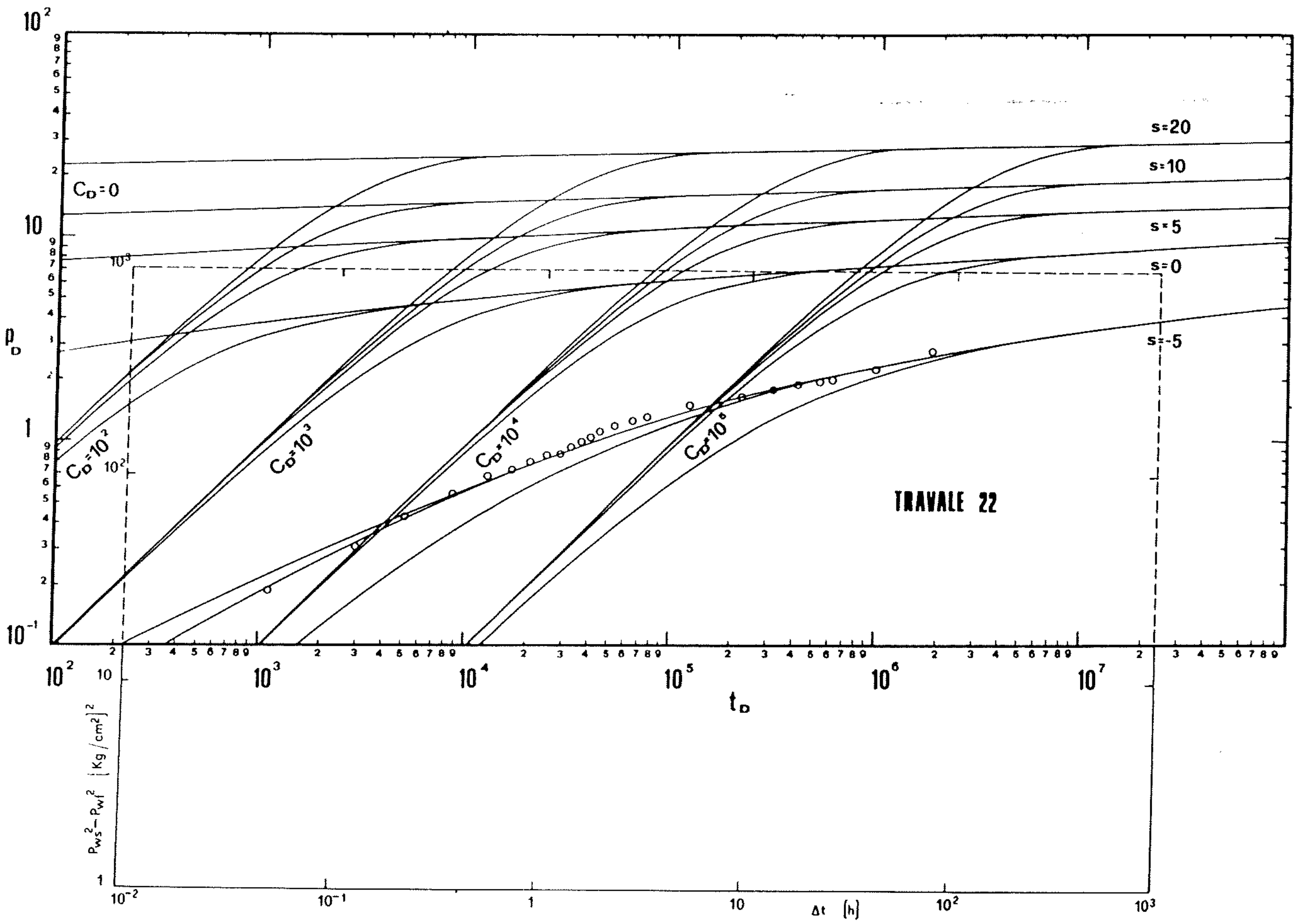

Figure 5. Type-curve matching for wells with wellbore storage and skin effect (Agarwal, Al Hussainy, and Ramey, 1970).

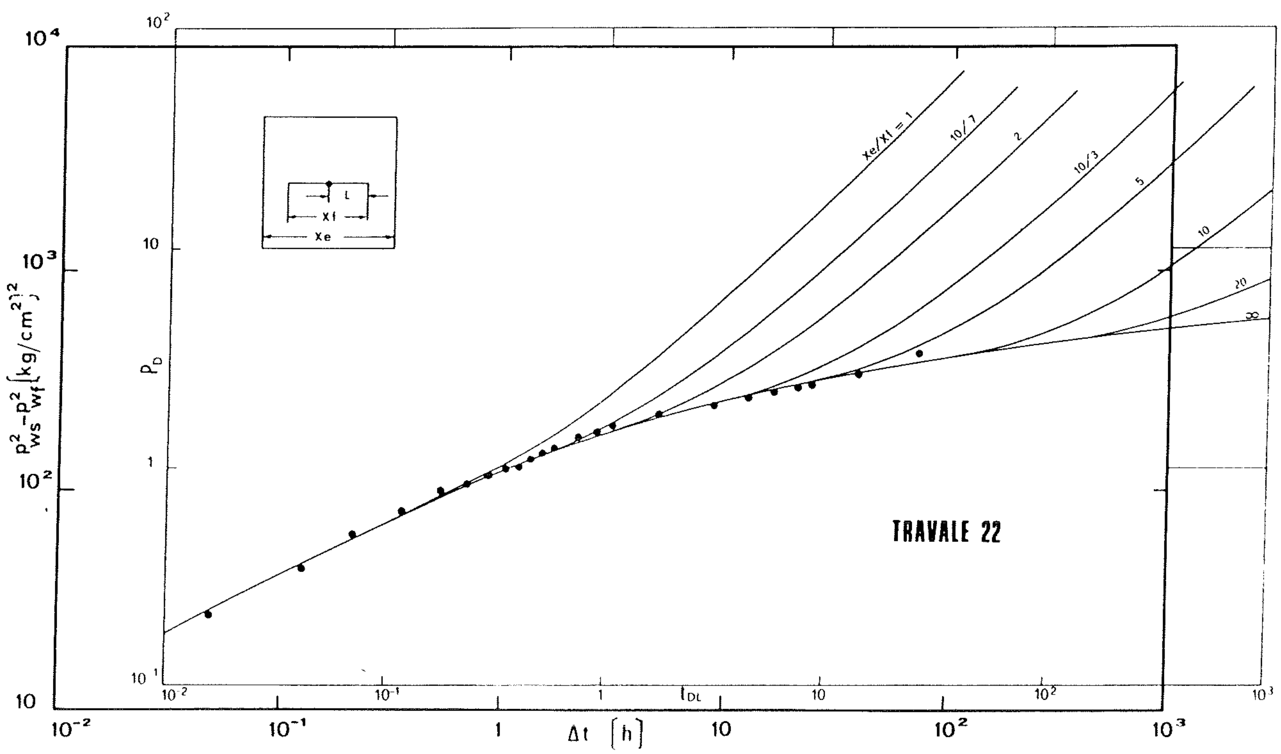

Figure 6. Type-curve matching according to Earlougher and Kersch (1970).

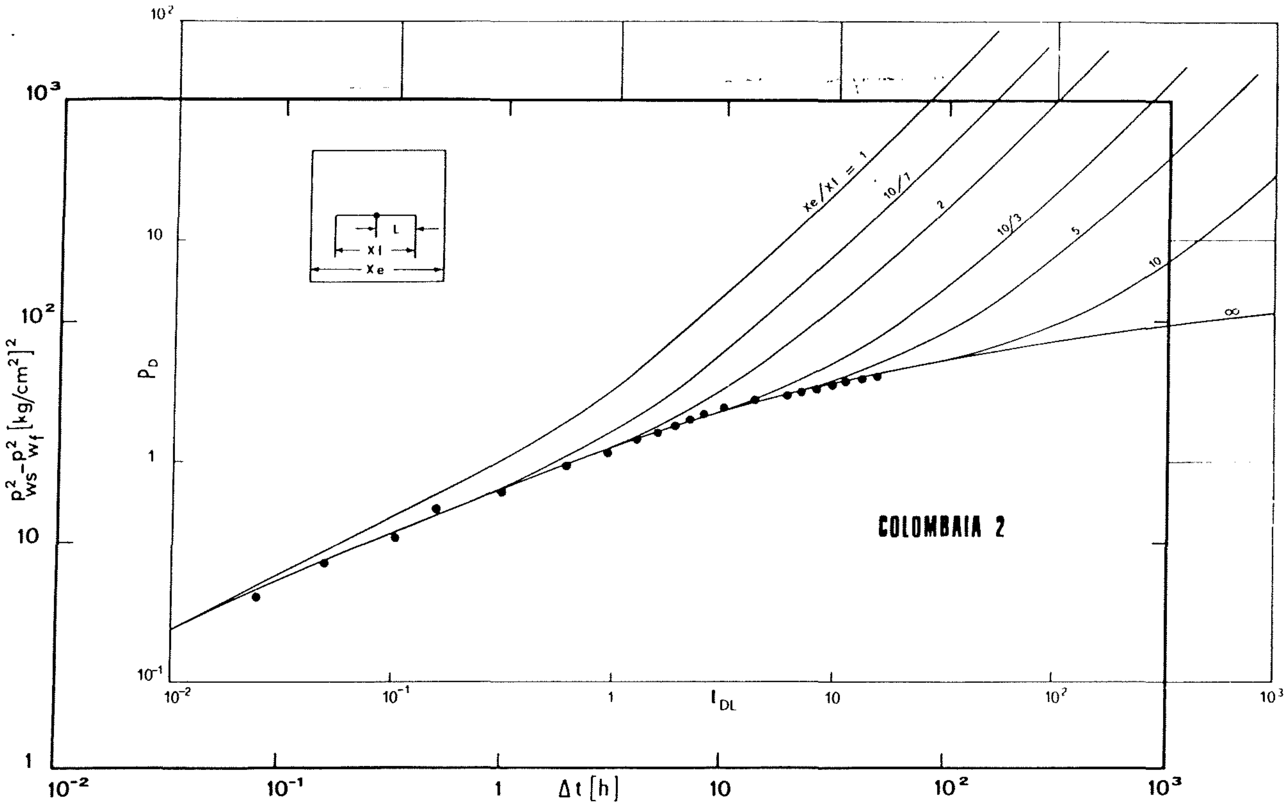

Figure 7. Type-curve matching for vertically fractured wells, uniform flux case.

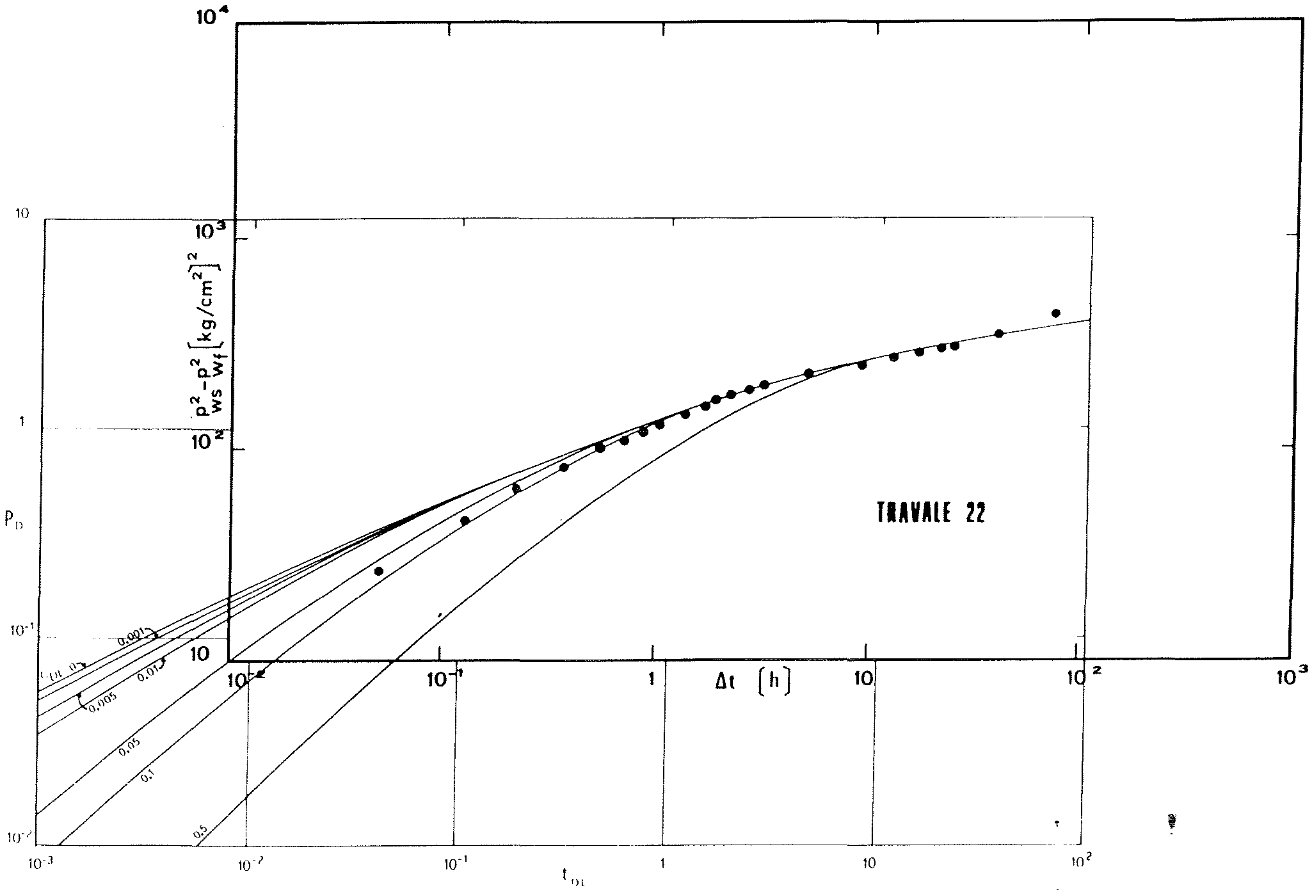

Figure 8. Type-curve matching for vertically fractured wells, infinite conductivity case.

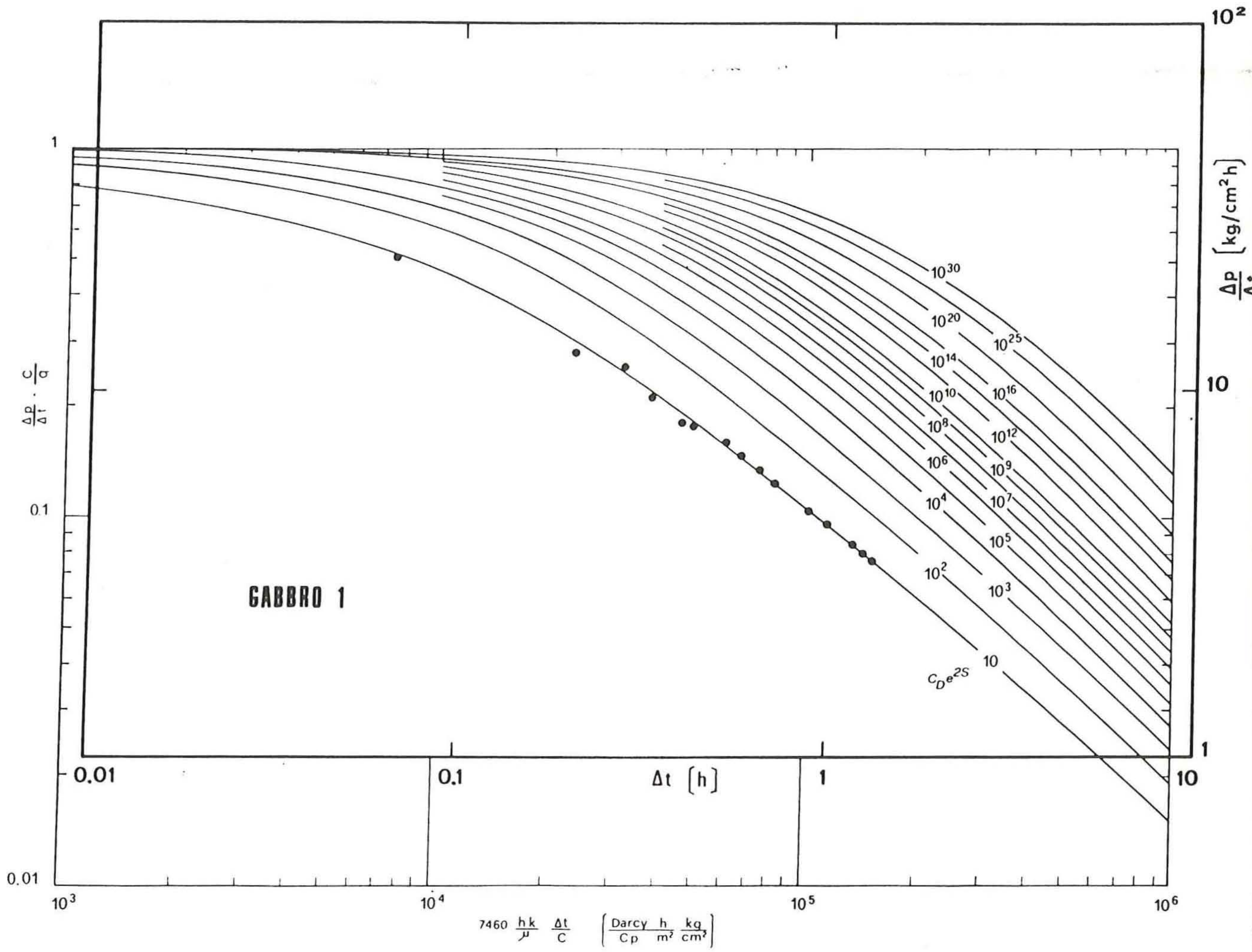

Figure 9. Type-curve matching for vertically fractured wells with wellbore storage.

We can determine a and b by fitting the experimental data and hk can be thus obtained from the value of a. There is considerable uncertainty as to the estimation of the r_e/r_w ratio.

RESULTS

Although a great number of wells were examined, they are not representative of all Italian geothermal wells; they were not chosen according to statistical criteria but by the relative availability of the data.

Transmissivity

Most hk values range between 0.5 and more than 100 Darcy-meters. Sometimes the data can be interpreted by different methods. In this case the values of hk obtained are in agreement with one another. (Deviation is generally within 30%.)

We think that the difference obtained from methods based on the same hypothesis are mainly due to reservoir heterogeneity: in fact early-time measurements are affected by transmissivity near the well which would generally differ from that at a certain distance from the well.

Despite the fact that errors in p_{wf} have a great influence on the behavior of the Δp versus Δt curve in its first portion, the hk value from type-curve matching does not change to an appreciable extent if shut-in time is long enough.

Several times the proper straight line section of the semilogarithmic plot was difficult to identify even with the help of the type curve.

In some wells (Fig. 4) the Horner plot shows several sections with ever-increasing slopes (slope ratios 2 to 4). The increase in slope could be explained by the existence of one or more linear barrier faults or of layering. This is often confirmed by the geological reconstruction.

Hydraulic Diffusivity

The values of $k/\phi\mu C_t$ were obtained by matching with the type curves given by Agarwal, Al Hussainy, and Ramey (1970) for an infinite reservoir with wellbore storage and skin effect.

Due to the lack of precision in the initial data and the impossibility of determining the value of C_D beforehand, the match can sometimes be carried out on more than one type curve (Fig. 11) and the uncertainty in diffusivity is more than one order of magnitude.

$k/\phi\mu C_t$ ranges from 10 to 10^5 m²/hr with values more often between 10^3 and 10^4. (An interference test run in

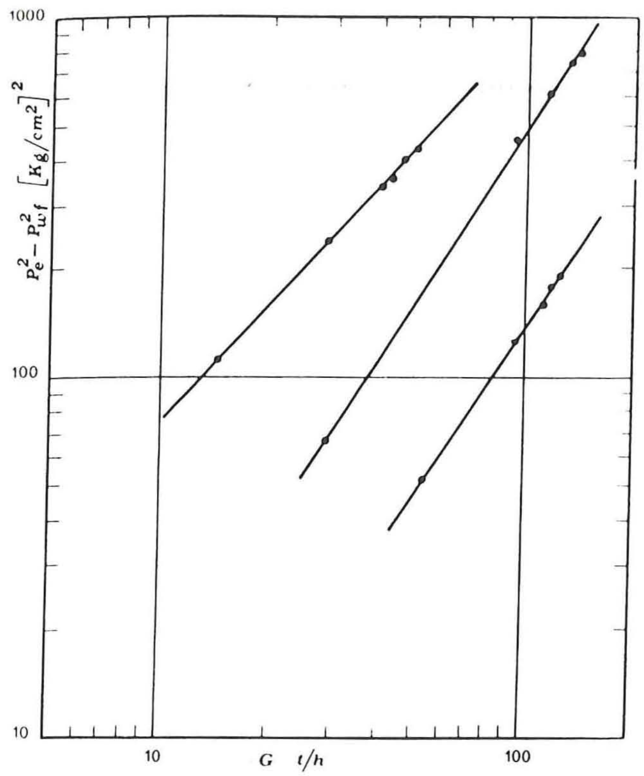

Figure 10. Performance curves for three steam wells in Larderello.

Alfina field gave a value of about 2.5×10^3 m^2/hr for the hydraulic diffusivity.) This value dispersion may be a result of the inadequacy of the model based on the homogeneity and isotropy of the reservoir. In many cases, in fact, a suitable match can also be obtained with the type curves for fractured wells.

$k/\phi\mu C_t L^2$ Ratio

Using the type curves for vertically fractured wells $k/\phi\mu C_t L^2 = t_D/t$ was evaluated where matching was possible. The resulting values ranged from 1 to some tens of hours^{-1} (By assuming for $k/\phi\mu C_t$ the values most frequently met with, the L of the semifractures then ranges between 10 and 100 m.)

Although the wells under study draw their fluid from a fractured reservoir, matching with type curves for fractured wells can only be applied for 70% of them.

It is thought that the analysis methods for nonfractured wells are the most suitable for wells whose permeability is due to small isotropically distributed fractures. With this match the boundary effect was rarely seen and the x_e/x_f ratio could not be evaluated. In a very few cases only finite values of more than 10 were found.

In several cases matching was also possible with type curves for horizontally fractured wells (Gringarten, Ramey, and Raghavan, 1972), but this generally occurs with type curves which are very similar in shape to those for vertically fractured wells. It is thus impossible to distinguish between the two types of fracture.

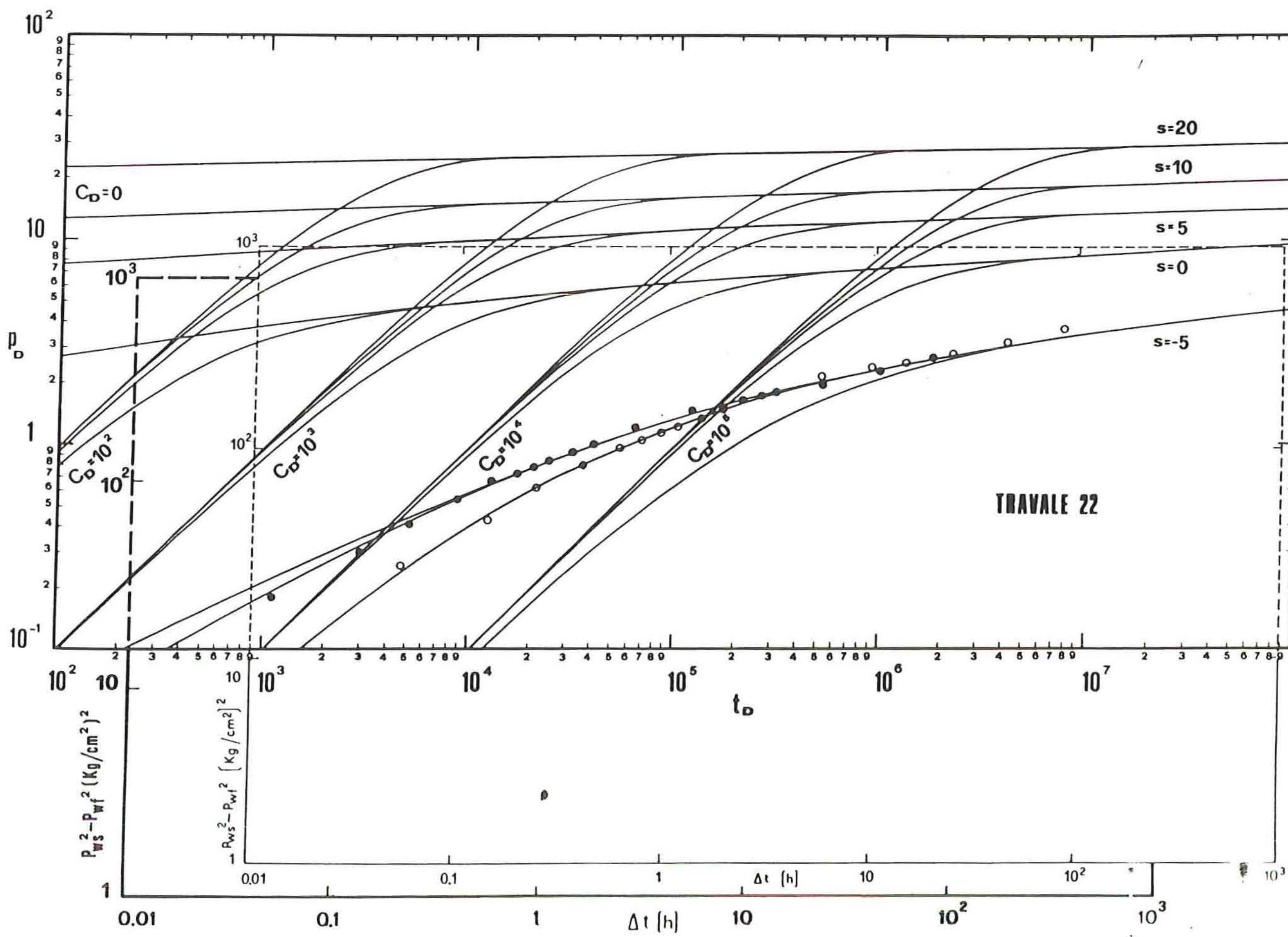

Figure 11. Matching of two type curves with the same data.

Skin Factor

The skin factor was evaluated with the type curves given by Agarwal, Al Hussainy, and Ramey; Earlougher and Kersch; and with Horner's method. The S value obtained from the last two methods is somewhat doubtful as the $h\phi$ product or the k/ϕ ratio must be estimated.

However, the values of S obtained in this way differ only by a few units from the more reliable values obtained from the curves after Agarwal, Al Hussainy, and Ramey. Almost all the latter values ranged between 0 and -5. This seems in accordance with the fact that the wells produce from natural fractures.

It must be noted that no stimulation (acidization, hydraulic fracturing, and so on) occurred.

Well-bore Storage Constant

The values of C calculated with $C = V_w C_t$ range between 1 and 10 m^3/atm, while the values of $C = q\Delta t/\Delta p$ calculated when Δp is proportional to Δt, range between 20 and 500 m^3/atm.

When applying the Earlougher curves, as matching is impossible with horizontal sliding only, curve matching was obtained by leaving out the initial position of the asymptote, and C was then calculated.

Although C_D may sometimes vary by some orders of magnitude, this inaccuracy does not apply to the values of C as a result of the simultaneous variation in t_D.

The values of C obtained from the well volume are always at least one order of magnitude below those obtained from other methods. This may be attributed to the presence of natural cavities or vapor condensation phenomena after well shut-in. In support of this second hypothesis we might add that the only well producing incondensible gases gave the same C value with the different methods.

Shut-in Pressure

Horner's semilogarithmic plot hardly ever shows one single straight section for long times. In some cases the slopes increase (continuously or discontinuously); in others they decrease (Figs. 1 to 4). However, there is always difficulty in obtaining shut-in pressure at $\Delta t = \infty$.

Our present lack of knowledge on some aspects of the phenomena involved, the difficulty in defining the geometry of the system, and boundary conditions all combine to prevent us transferring the methods of determining static pressure used in oil reservoir engineering to the geothermal field.

Back-pressure Curves

The analysis of the back-pressure curves was confined to the wells with highest flow rate in order to get as close as possible to adiabatic flow conditions. Wells with long open hole sections were not considered in order to avoid inaccuracy on the friction factor.

The values of the exponent n of the performance curves range between 0.6 and 0.9 and reveal the presence of turbulent flow in the formation.

The values of hk obtained from Equation (13), correcting r_w for skin effect, differ at the most by a factor of 2. This discrepancy may be partly justified by the uncertainty as to the value of r_e.

CONCLUSIONS

The analysis performed on 40 geothermal wells reveals:

1. Consistency between the results from the methods of analysis used.
2. Type curves based on simple models fit field data.
3. No change in hk value and skin factors has been revealed when build-up tests have been repeated on the same well.
4. The results for hk, skin, and storage are in agreement with what we can expect from geological knowledge.
5. Short-time data and proper straight-line sections of build-up tests can be analyzed, whereas long-time data are not yet easily explained.

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