

SOME MISMATCHES OCCURRED WHEN SIMULATING FRACTURED RESERVOIRS AS HOMOGENEOUS POROUS MEDIA

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ABSTRACT

The understanding of transport processes that occur in naturally fractured geothermal systems is far from being complete. Often, evaluation and numerical simulations of fractured geothermal reservoirs, are carried out by assuming equivalent porous media and homogeneous petrophysical properties within big matrix blocks. The purpose of this paper, is to present a comparison between results obtained from numerical studies of a naturally fractured reservoir treated as a simple porous medium and the simulation of some real aspects of the fractured reservoir. A general conclusion outlines the great practical importance of considering even approximately, the true nature of such systems. Our results show that the homogeneous simplified evaluation of the energy resource in a fractured system, could result in unrealistic estimates of the reservoir capacity to generate electricity.

INTRODUCTION

Since early this century, began the scientific study of geological systems containing some kind of fluid in fractured rocks. Thirty-five years ago it was introduced, for the first time, the double porosity concept for the better comprehension of such systems. However, the understanding of transport processes occurring in naturally fractured geothermal reservoirs is still far from being completed. The main problem is the difficulty to represent the dimensions and spatial distribution of fractures. In these media, mass and energy flows occur with phase changes, in places where distribution and heterogeneity of petrophysical parameters have an enormous importance in the local behavior of the reservoir.

This work originates in the practical experience obtained during the evaluation of different fractured hydrothermal Mexican systems, such as Los Azufres, Los Humeros, La Primavera and Las Tres Virgenes. These geothermal reservoirs show an essential characteristic: most of the

good producer wells intersect conductive faults or they are completed at the vicinity of intensely fractured regions related to faults. In those fields, most useful wells have crossed, at different depths, zones of high permeability ($\sim 10^{-10} \text{ m}^2$), which does not correspond to fresh volcanic rock permeability ($\sim 10^{-18} \text{ m}^2$), neither to fracture permeability ($\sim 10^{-13} \text{ m}^2$). The contrast in values affects the behavior of the reservoir and the immediate response of the wells. Several phenomena detected in these systems, can neither be explained nor reproduced if only single porosity is considered. For example, abrupt changes of pressure of various dozens of bars between the well and the reservoir are observed. Zones exist under compressed liquid thermodynamic conditions, having wells producing high quality steam in the formation. In these zones a great enthalpy difference exists between well's feed point and the reservoir. Continuous fluid production was also observed in some wells that remain in quasi-stationary state for years, maintaining concentrations of non-condensable gases practically constant. Volcanic fractured rock forming these systems is anisotropic and there is coexistence of high permeability zones with very low or null permeability regions.

The routine procedure to evaluate the recoverable fraction of heat and the longevity of the reservoir subject to different scenarios of exploitation, is carried out by numeric simulations which serve as technical supports to justify the investment. Calculations and mathematical modelling are the only available low cost techniques, that allows to the prediction of the reservoir behavior, under different exploitation conditions. The inherent difficulty to the understanding of the flow mechanisms in fractured geothermal systems, is not minor or secondary matter. In this document we show that the simplified evaluation of the energy resource in a fractured system, could drive to unrealistic estimates of the reservoir capacity to generate electricity. Our conclusions are related to a very practical issue: the final cost of the project.

SINGLE POROSITY MEDIA AND FRACTURED VOLCANIC SYSTEMS

There are essential differences between fractured reservoirs with faults and simple porous media: non fractured volcanic reservoirs have never been found. Single porosity systems of volcanic origin do not exist. The genesis of a volcanic system occurs by pyroclastic eruptions, magma flows, cooling and solidification of lava, tectonics, seismicity, resurgence, creation of faults and intense fracturing. In this natural scenery remains trapped the water, originating a hydrothermal system. Because of the different internal geometry and topology of the fractured rock, the thermodynamical functions abruptly change their values, introducing discontinuities in their gradients at the boundaries between the solid matrix and each fracture and fault.

The detected changes could have a wide variety of forms and behavior. These changes do not occur only in the pressure and temperature, but they are also reflected in abrupt variations of mass and energy flows, in the distribution of steam and on the behavior of non-condensable gases. In a single porosity medium, nothing of this occurs. In the matrix there is primary porosity and the thermodynamical properties vary continuously and smoothly; fluid transport in the small pores obeys Darcy's law and phase changes occur gradually. In fractured media things get more complicated because of the impossibility to perform direct measurements of key parameters. To put in context and better explain our discussion, we briefly expose two approaches to model fractured reservoirs.

Double Porosity Model

Double porosity media are a classical topic in the literature on fractured reservoirs. The first models for slightly compressible liquid and pseudo-steady state matrix-flow, appeared in the 60's (Barenblatt et al., 1960; Warren & Root, 1963). Subsequently in the 70's and 80's the transient matrix-fracture flow and the effect of conductive faults were considered (de Swaan, 1976; Cinco Ley & Meng, 1988). Similar problems of double porosity were studied in geothermal reservoirs but, due to phase change and non-linearities in the basic equations, analytic solutions are very scarce (Pritchett & Garg, 1990; Zimmerman et al, 1993). Double porosity in fractured geothermal media, was generalized and solved numerically by means of the MINC (Multiple Interacting Continua) concept by Pruess and Narasimhan (1985).

The concept of "double porosity" assumes that fluid diffusivity is higher in the fractures than in the matrix blocks. In this study a transient matrix-fractures transfer of heat and mass is considered. An essential feature of this double porosity model is the possibility to perform a

detailed numerical treatment of the interporosity flow between both media. A limit situation to the application of the MINC method appears when the fracture spacing is too large, because the method assumes that the thermodynamic variables inside the matrix only depend on the distance to the next fracture (Pruess & Narasimhan, 1985). In some cases, the matrix blocks are traversed by faults and are frequently exposed to non uniform boundary conditions, because of alternate injection of liquid at minor temperature during long time.

Triple Porosity Model

In order to explain empirically the behavior of the aforementioned Mexican reservoirs, based on systematic observations, we introduced recently a triple porosity / permeability concept (Suárez & Samaniego, 1995), which is applicable to fractured systems traversed by penetrating, open faults. Under this concept the intensity of fracturing is very high near the fault, intermediate in the fractured medium and very low or null in the matrix blocks. In these media an abrupt permeability contrast exists among matrix, fractures and faults. The evidence strongly suggest that fluid transport in this type of systems occurs in four stages (Fig. 1):

Matrix → {micro + fractures} → Fault → WELL

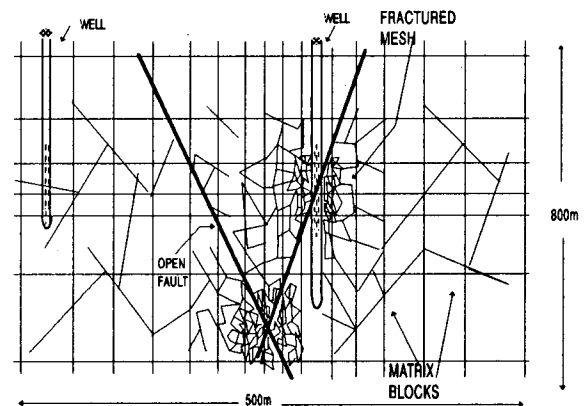


FIGURE 1.- TRIPLE POROSITY MODEL

Experimental data show that matrix blocks are very small in the vicinity of the fault, with fractures separated a few centimeters each other (Fig. 2). The matrix blocks are very big far from the fault where only distant and isolated fractures can be found. Our "triple porosity" idea, considers that fluid diffusivity attains its maximum value within the fault; it is higher in the fractures than in the matrix and flow toward the wells occurs in such a way that the initial response in the extraction zone is detected immediately in the fault, then it is noticed in the fractured

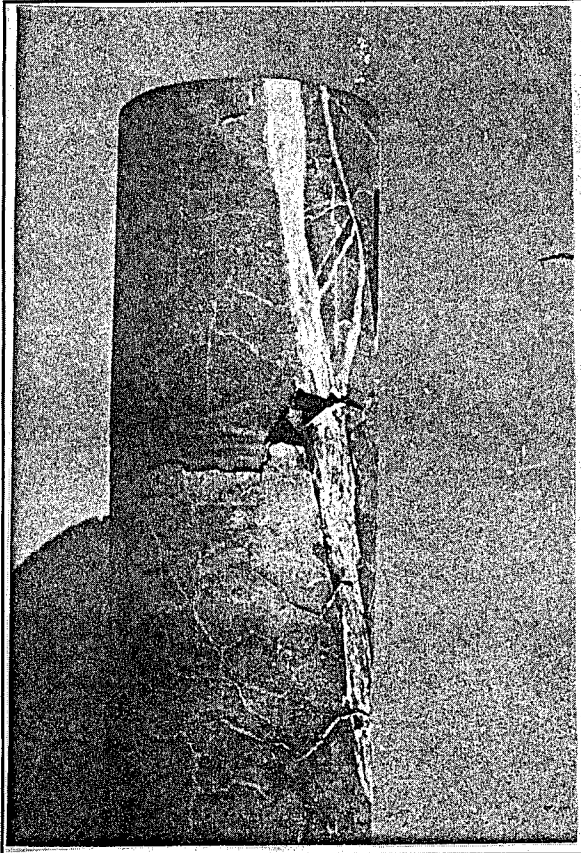


FIG. 2.- FRACTURED CORE OF ANDESITES.

network and later in the rock matrix. Matrix, fractures and fault are three interacting continua clearly distinguishable by their respective petrophysical parameters. Mass & energy interaction is carried out through special transport functions that depend on the form and size of the blocks, on the intensity of fracturing and on the communication with the fault. The local transfer as mentioned is transient involving, many factors including tortuosity and roughness.

GENERAL EQUATIONS

Mathematical description of flow through porous media with different porosities: single (SP), double (DP) and triple (TP), obeys approximately well the same differential equations. The difference between each one resides in the dimension and number of equations of the problem. SP requires one equation for mass and one for heat. DP requires a couple of equations for each medium. TP, formed by three interconnected continua, requires three pairs of equations.

In any of these three cases, the transient flow of mass and energy is theoretically described by two well known pseudo-tensorial equations:

$$\frac{\partial(\rho_j \phi_j)}{\partial t} + \text{div}(\rho_j \vec{v}_j) = q_{ij} \quad \dots [1] \text{ (Mass)};$$

$$\frac{\partial e_j}{\partial t} + \text{div}(\rho_j h_j \vec{v}_j - \mathbf{K}_j \cdot \vec{\nabla} T_j) = q_{ij} h_j \quad \dots [2] \text{ (Heat)}$$

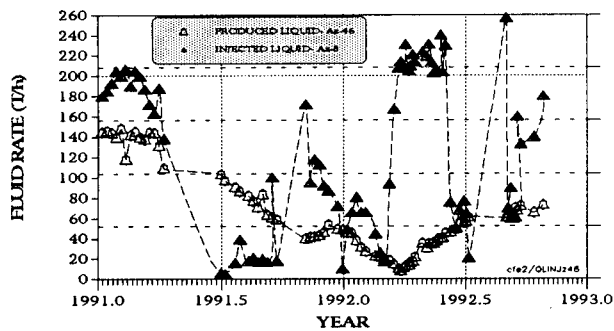
Subindex $j = \mathbf{m}$ (atrix), \mathbf{f} (racture), \mathbf{F} (ault), represents the respective equation for each medium. This gives a total of two, four or six scalar equations. Nomenclature is common: ρ_j is density, ϕ_j porosity, v_j fluid speed, e_j is total energy [rock+fluid], h_j specific fluid enthalpy, \mathbf{K}_j is the thermal conductivity tensor and T_j is the temperature in each medium. All terms are functions of time and space. The parameter q_{ij} represents the mutual exchange of fluid among media. From the mathematical modeling point of view, the non-linearity of the processes involved makes impossible their exact or analytic solution.

FLUID TRANSPORT THROUGH FAULTS

Figure 2 shows a 10 cm diameter core, crossed by one sealed fault of the Los Azufres geothermal field, at 2679 m depth. In the picture it is clearly observed an intense network of fractures, having a common stress origin and surrounding the main structure. The fault itself, has a width of 1.5 cm. Fractures present an average opening of 0.1 cm. The location of non producing wells in the same field, suggests that fissuring diminish when the distance to faults increases at any depth. Other cores of the same well not crossing the fault, show a total absence of fractures. This fact demonstrates that far from the fault, the matrix blocks increase their size and fractures become ever more spaced (Fig. 1).

In 1991, liquid injection in well Az-8 of the same reservoir went down from 200 T/h to 10 T/h (Fig.3). During the same period produced liquid at well Az-46, located to the East at 1290 m distance, diminished. Faults oriented E-W communicate both zones. In February 1992 injection in Az-8 was rapidly incremented from 10 to 225 T/h. At that moment, produced liquid at Az-46 had a minimum value of 8 T/h. Liquid injected in Az-8 delayed approximately 21 days to arrive to the production zone. The injection well is completed 1330 m deeper than the production well. Total distance between both wells is equal to 2620 m. Average flow speed between both zones is about 124.8 m/day or $1.44 \cdot 10^{-3}$ m/s. Assuming that flow takes place in a plane defined by both wells, a pressure gradient of 0.054 bar/m was estimated. From Darcy's law it is inferred a global permeability of $1.16 \cdot 10^{-11} \text{ m}^2$ (~11 darcy). This value was obtained under the assumption of zero tortuosity and two-dimensional transport. The actual vectorial distance between both wells must be higher. We deduce that velocity and permeability inside that zone correspond to the transport of liquid through faults and fractures.

Fig. 3.- INJECTION & PRODUCED LIQUID at WELL Az-46



NUMERICAL COMPARISON BETWEEN SINGLE POROSITY AND FRACTURED MEDIA

The three models previously discussed were applied to the simulation of the southern sector of the Los Azufres field, Mexico, using real reservoir data. This sector presents essential aspects for modeling (Suárez et al, 1992): wide and rich production history, simultaneous reinjection since the beginning of exploitation, fluid extraction is concentrated in a strait corridor with penetrating faults and intense fracturing. Models were numerically solved with MULKOM's code (Pruess, 1988) for three different 3-D problems related to the same sector, varying the details of its geometry. Simulation's objective in all cases, was to reproduce the first eleven years of reservoir's exploitation.

The first problem consisted of simulating a single porous medium without fractures. A mesh of 115 horizontal elements was created, with 7 vertical stratum, for a total of 805 elements. Each of the 23 producing wells were located in a single element (Fig. 4).

The following problem consisted in the evaluation of the same zone considering double porosity and employing MINC method. This technique, applied to the same previous mesh, would generate a minimum of 8000 elements, complicating unnecessarily the problem. The extraction of fluid in that zone is 75% concentrated in a corridor defined by faults oriented W-E. Wells outside this area seem not to be affected by extraction in the corridor. We proceeded then to simulate by DP only that portion by creating a system of three parallel fractures penetrating up to layer D (Fig. 4). Each original matrix block was partitioned into five nested volume elements, this DP model generated a mesh of 116 elements per fracture. The corridor's lateral walls were supposed impervious; this simplification allowed to eliminate elements and wells outside the principal volume.

The third model considered triple porosity inside the same corridor, simulating the fault's width until a zone of direct influence of 1 meter wide. The fractured network

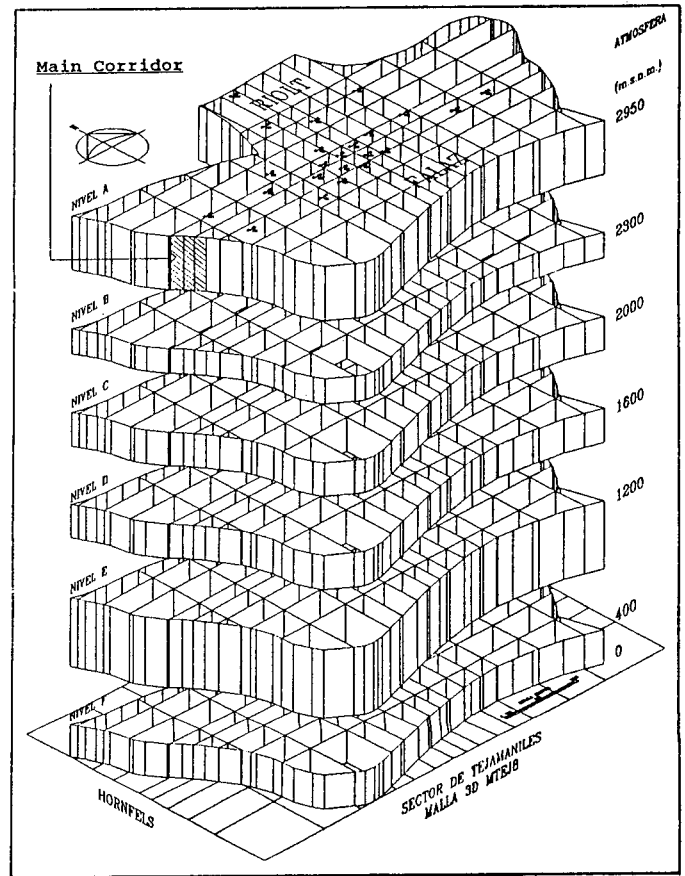


FIG. 4.- 3-D MESH USED FOR SIMULATIONS

is very intense in the immediate vicinity of the fault inside a 5 m radius. There is a transition zone of 10 m, with less fractures and minor permeability, connected to regular matrix blocks at growing distances up to 400 m of total width. The so defined corridor is horizontally closed; it only admits fluid and heat from vertical profound stratum. A mesh of 241 elements with 15 active wells was processed. This experiment showed that it is possible to reduce the number of elements in a fractured mesh, without losing essential attributes of the real medium.

An essential difficulty found in the simulation of this type of fractured media, was the representation of the fluid rate distribution among the three media. Strictly speaking, a geological fault is a deep open channel having porosity values close to 100% and extremely high hydraulic conductivity. Flow occurs in a two-dimensional space defined through the fault's plane; tortuosity is insignificant and only the walls' roughness could have importance in the transport. Flow inside the fractured mesh is 3-D and tortuosity could be important. Wells presenting high flow rates have to distribute their production among matrix, fractures and the fault, defining a fault's zone of influence. A key unknown is the percentage of fluid rate corresponding to each portion of the system.

TABLE 1.- SOME KEY RESERVOIR PARAMETERS USED IN THE SIMULATIONS.

STRATA	Rock Density (kg/m ³)	Porosity (%)	Permeability (W - E) k _x (m ²)	Permeability (N - S) k _y (m ²)	Vertical Permeability k _z (m ²)	Thermal Conductivity (W/m/°C)
CAPROCK	2251	0.1	10 ⁻¹⁷	10 ⁻¹⁸	10 ⁻²⁵	0.18
NIV_B	2355	11.9	248·10 ⁻¹⁵	10 ⁻¹⁶	248·10 ⁻¹⁵	1.93
NIV_C	2434	8.3	48·10 ⁻¹⁵	10 ⁻¹⁷	48·10 ⁻¹⁵	2.09
NIV_D	2528	5.5	7.4·10 ⁻¹⁵	10 ⁻¹⁸	7.4·10 ⁻¹⁵	1.62
NIV_E	2677	2.9	10 ⁻¹⁵	10 ⁻¹⁸	10 ⁻¹⁵	1.69
NIV_F	2900	1.0	10 ⁻²⁵	10 ⁻²⁵	10 ⁻¹⁹	2.01
FRACTURE	2000	50.0	5.5·10 ⁻¹³	10 ⁻¹⁷	5·10 ⁻¹³	1.93
FAULT	1528	80.0	1.5·10 ⁻⁹	10 ⁻¹⁸	10 ⁻¹²	1.62

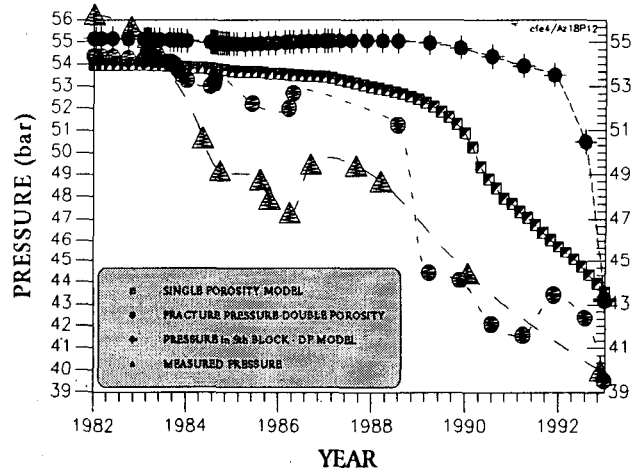
In our DP and TP models we assigned by trial and error, a mass rate extraction proportionally distributed in each medium. Another practical aspect is the importance of detailing the production and injection history, because a coarse averaged history could mask the true response of the fractured medium. In our treatment we considered time steps between two days and 30 days, depending on the rapidity of mass rate changes. We did various series of numerical experiments employing known reservoir parameters (Table 1). Unknown property values were obtained by trial and error when fitting system's initial state and during the history matching of the field. Permeability distribution has a tensorial nature and was obtained from several sources (pressure tests, core measurements, experiments); its decrement is exponential with depth in non fractured zones. Specific heat of saturated rock is homogeneous and equal to 1165 J/kg/°C.

DISCUSSION OF RESULTS

At Los Azufres, thirty-nine reservoir pressure measurements were made in several wells, at different dates during the period 1982-1993. Enough data are available to compare with calculated values. Observed enthalpy in some selected wells, differs a maximum of 4% between wellhead and bottomhole. Fluid entering wells Az-18, 33 and 46 is two-phase at the feeding point. Measured enthalpy is supposed to represent enthalpy in the fractured zone at well's neighborhood. Figure 5 shows a comparison between SP and DP pressures at Az-18 production zone. It is observed that the pressure curve calculated with SP underestimates the measured pressure decline for the reservoir. Pressure oscillations are observed in the fracture. This behavior is absent in the SP

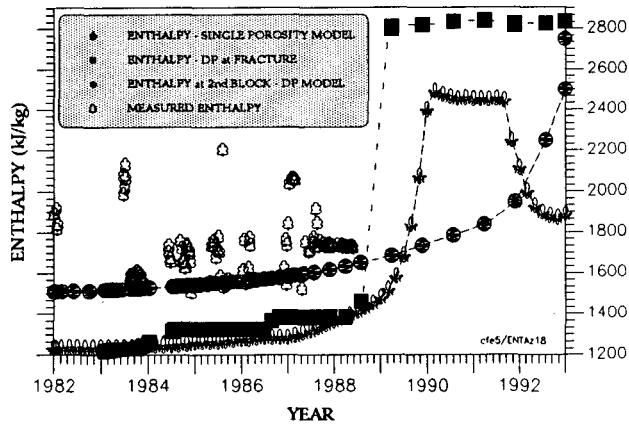
case. Fluctuations reflect the complex history of liquid injection (Fig. 2). At the 5th matrix block in the DP model, the pressure curve is almost parallel to SP curve, since the beginning until 1989. In that year fluid extraction was incremented.

Fig. 5.- COMPARED PRESSURES at Well Az-18



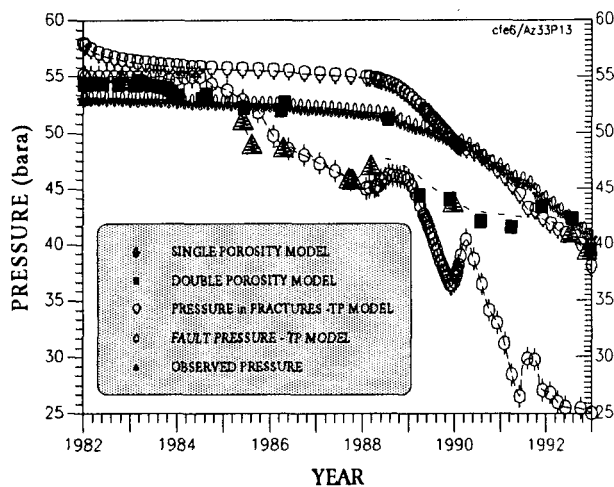
Enthalpy incremented smoothly from 1600 kJ/kg in 1983 to 2200 kJ/kg in 1992 (Fig. 6). For first years, the SP model underestimates enthalpy evolution, then it increases abruptly, over-estimating measured values. After that, enthalpy falls abruptly, reflecting the arrival of more liquid. The DP model reproduces quite well the real evolution. This match was achieved taking into account simultaneous contribution of fluid from fractures and nearest matrix block. TP model was unnecessary to reproduce this behavior.

Fig. 6.- COMPARED ENTHALPIES at WELL Az-18



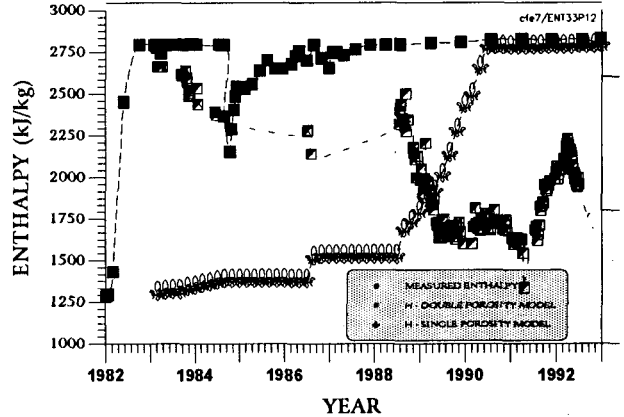
Another interesting example comes from well Az-33 located in the same field's sector. Its evolution was analyzed using the three models. Fault pressures calculated by TP model reproduced, reasonably well, the measured pressures until 1989 (Fig. 7). From then on, depression in the fault is higher than measured values, almost doubling real pressure decrement in 1992. This result shows a typical behavior when extracting fluid directly from a fault. In reality, mass rate must be simultaneously distributed somehow among fractures and block matrix surrounding the fault. The pressure is higher at the beginning because initial pressures in fault, fractures and matrix are different. In 1988, fluid extraction was incremented to feed a 50 MWe power plant. As soon as the fault feeds several wells, its global mass rate increased. This explains the abrupt fault's depression in TP model. Nevertheless, in the fractured mesh and in matrix blocks, there is enough fluid and depression is lower. We conclude that the well's feeding zone receives fluid mass from different media at different thermodynamic conditions. Table 2 introduces a summary of comparative values.

Fig. 7.- COMPARED PRESSURES at WELL Az-33



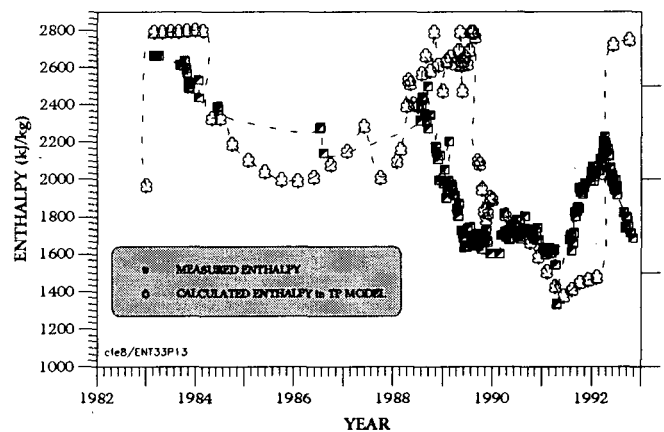
For this problem, the three models reproduce quite well the final pressure, but not the enthalpy. Fig. 8 compares real enthalpy with values calculated by SP and DP models. In both cases real behavior was not reproduced. DP liquid enthalpy started at 1250 kJ/kg, but incremented soon. Fluid in the fractures evolved toward steam dominated.

Fig. 8.- COMPARED ENTHALPIES SP-DP at WELL Az-33



The TP model reproduces reasonable well general enthalpy changes (Fig. 9). This match was obtained by superposing the evolution of various zones of the TP medium. The first part of the curve corresponds to fluid extracted in the fault; the second portion, to the fractured network and the third part corresponds to fluid in the matrix-fractures interface. The triple porosity mechanism

Fig. 9.- COMPARED ENTHALPIES SP-TP at WELL Az-33



explains why, when extraction starts up, pressure differences are introduced between the reservoir and the well's feeding point. Pressure gradients induce the creation of a boiling front starting at matrix-fractures interface. Apparently a parallel mechanism of phase segregation appears, allowing the migration of more vapor toward the well, even if the reservoir's natural state corresponds to compressed liquid.

TABLE 2.- SOME FINAL RESULTS COMPARING MEASURED AND CALCULATED VALUES AT WELLS AZ-18 & AZ-33.

Well Az-18	P _{initial} (bar)	P _{final} (bar)	ΔP (bar)	T _{initial} (°C)	T _{final} (°C)
Single Porosity	54	43.5	10.5	269	255
Double Porosity	54.5	39.5	15	269	264
Measured	56.3	40	16.3	271@	?
Well Az-33	P _{initial} (bar)	P _{final} (bar)	ΔP (bar)	T _{initial} (°C)	T _{final} (°C)
Single Porosity	53	40.7	12.3	268	252
Double Porosity	54	40	14	269	264
Triple Porosity	55	38	17	270	253
Measured	55	39	16	270@	?

(@) Assuming that fluid was 2-phase.

As last example, we show the evolution in time of the spatial distribution of pressure, temperature and steam saturation around another well intersecting the same fault, approximately at 800 meters depth. In the following graphs several curves, calculated with the triple porosity model, are shown simultaneously at several depths in the three media. In figures 10 and 11, it is observed that the measured values of pressure and temperature, correspond to some kind of average values among the fault, the fractures and the matrix. The lowest values are in the fault, while the highest are in the matrix and in deep zones far from the feeding point. Figure 12 shows that steam is distributed in a complicated form among the three media. In the fault high quality vapor takes place very quickly. This phenomenon coexists with zones containing less vapor and even, matrix blocks and profound zones could remain in compressed liquid state.

Fig. 10.- PRESSURES At FAULT's NEIGHBORHOOD

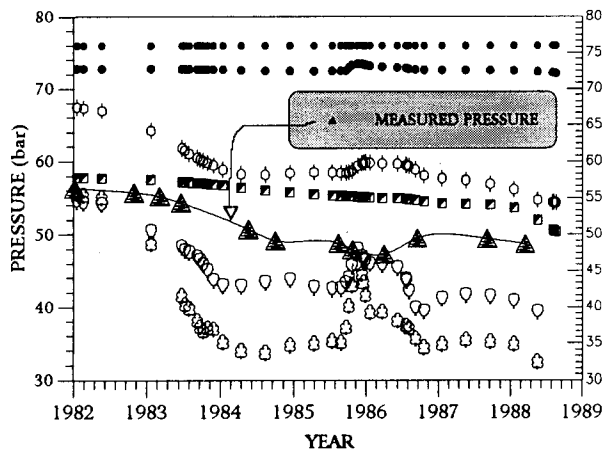


Fig. 11.- TEMPERATURES At FAULT's NEIGHBORHOOD

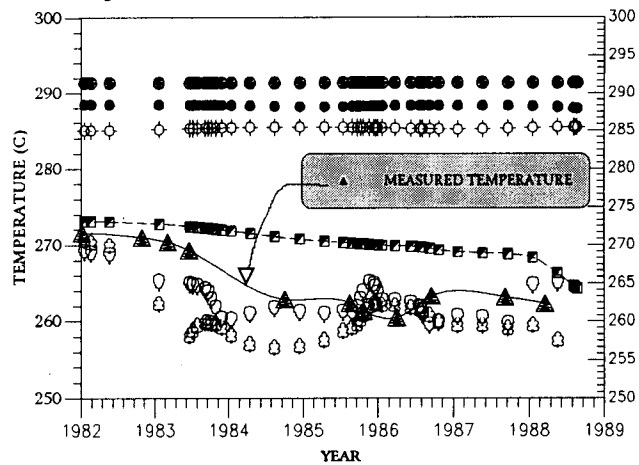
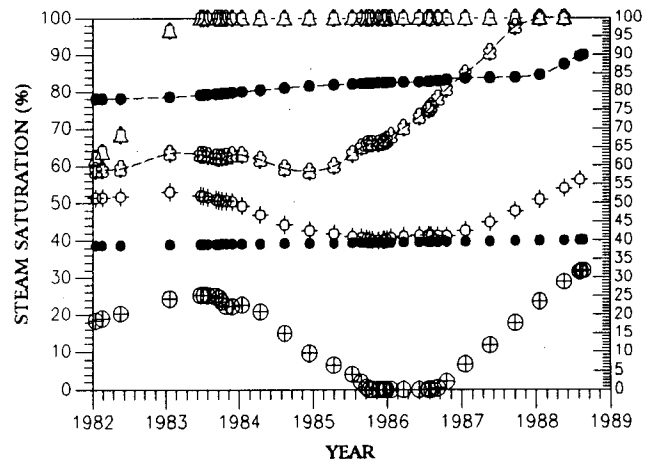


Fig. 12.- STEAM DISTRIBUTION At FAULT's NEIGHBORHOOD



CONCLUSIONS

From the results of this study, the following conclusions are extracted.

-In the simulation of a geothermal fractured reservoir as a single porosity medium, there is a clear tendency to underestimate the real pressure fall off in production zones.

-Under these conditions, making long term extrapolations about the behavior of production zones, could drive to overestimate the planned capacity of a geothermal power plant, because the natural longevity of wells, could be shorter.

-Detailed simulations using Double or Triple Porosity modeling, are not exempt of difficulties. If the behavior of the fault is the only considered aspect, there will be a tendency to exaggerate the pressure fall off.

-A realistic analysis should take into account the simultaneous contribution of the fault, the fractured mesh and some matrix blocks in the zone of influence of the conductive fault.

-Evolution of production enthalpy could become very complicated in wells subjected to intensive long term injection. The matching of this behavior can be achieved only if double or, better, triple porosity models are considered. Single porosity not always give bad results, but it fails systematically when reproducing reinjection effects in fractured zones.

-Simulating fluid extraction from faults, requires simultaneous extraction from distinct producing strata at different thermodynamic conditions. In the examples presented, the best enthalpy fitting was obtained with double and triple porosity models.

-Real pressure fluctuations are originated by the production/injection history of the analysed field. Pressure oscillations were numerically detected in fractures and in the fault. This phenomenon is absent in the matrix blocks and in single porosity modeling.

-Including details of faults and fractures in a simulation, results in an increase of the number of matching possibilities.

-Mathematical models can only represent some portion of reality. For any complex fractured system, an idealized equivalent system will always exist containing the principal features of some part of the phenomenon, in some portion of the space, during certain time.

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