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REINJECTED WATER RETURN AT MIRAVALLES GEOTHERMAL RESERVOIR, COSTA RICA: NUMERICAL MODELLING AND OBSERVATIONS

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ABSTRACT

The first 55 MW power plant at Miravalles started operation in March, 1994. During the first few months of production, a gradual increase in chloride content was observed in some production wells. The cause was assumed to be a rapid return of injectate from two injection wells located fairly near to the main production area. A tracer test was performed and showed a relatively rapid breakthrough, confirming the assumption made. Numerical modeling was then carried out to try to reproduce the observed behavior. The reservoir was modelled with an idealized three-dimensional network of fractures embedded into a low permeability matrix. The "two waters" feature of TOUGH2 simulator was used. The numerical simulation showed good agreement with observations. A "porous medium" model with equivalent hydraulic characteristics was unable to reproduce the observations. The fractured model, when applied to investigate the mid and long term expected behavior, indicated a reservoir cooling risk associated to the present injection scheme. Work is currently underway to modify this scheme.

INTRODUCTION

Miravalles geothermal field is located in the northwestern part of Costa Rica, some 150 km from the capital city of San Jose. After the first 55 MW power plant came into operation , in March 1994, a 5 MW back-pressure unit was put on line, to use the available excess steam from the well field, in November 1994. A second 55 MW unit is under construction and it is expected to start operation in the second half of 1997 (Mainieri and Robles, 1995). In 1995 a feasibility study for one or two additional 25-30 MW units was carried out (ELC, 1995), looking for a more intensive exploitation of the available resource.

All separated brine at Miravalles is reinjected but some observations indicated a relatively rapid return of injectate towards the main extraction area during the first year of exploitation. Considering the installation of future units, a review of the present injection scheme was undertaken. The work presented in this paper is part of that effort whose final result was the recommendation to modify the present injection scheme by concentrating the brine disposal in the southern field sector. This is expected to decrease or eliminate the risk of reservoir cooling in the mid to long term.

FIELD CHARACTERISTICS

The geothermal field is located in the southern slope of Miravalles volcano, within a caldera affected by strong neotectonic phenomena. The proven extension of the commercially exploitable reservoir is 15 km^2 and 12 km^2 more are presently classified as area of probable expansion. The reservoir top is at about 700 m, getting deeper gradually to the south and rather abruptly to the west. The estimated thickness of the reservoir is estimated in 800-1000 m.

The maximum temperature (255°C) occurs in the northeastern part of the field, in correspondence with the assumed zone of hot recharge of the system. Temperature gradually decreases towards the south, along preferential flow paths formed by a north-south fault system, reaching 230°C in the southernmost productive wells (see Figure 1).

The high reservoir permeability (transmissivity values between 60 and 140 D.m) is mainly related to intensive fracturing of volcanic rock formations. The feed zones of the best productive and/or injection wells appear to correspond to intersections with important fractured layers of limited thickness and very high permeability (productivity indexes > 15 kg/s/bar) or with major fault structures of the field.

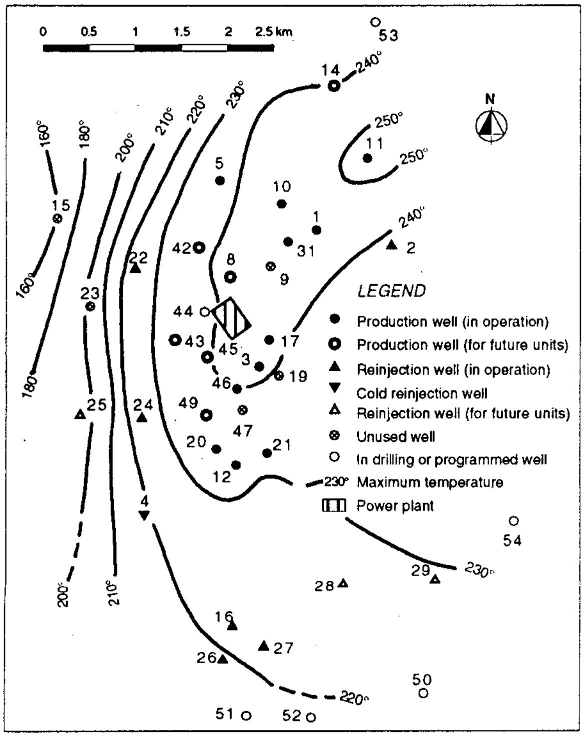

Figure 1. Location Map and Reservoir Temperature

The reservoir is of the liquid-dominated type. In the initial state, only thin two-phase caps in the shallower parts of the reservoir migth have existed in an otherwise liquid-filled medium. The geothermal fluids are of Na-Cl type, with a T.D.S. of 5300 ppm at at reservoir conditions. The average NCG content is of about 0.8% by weight in the steam separated at 7 bar a.

Up to now, 35 wells have been drilled, most of which are good producers. Some wells indicated as "reinjection wells" in Figure 1 are actually good to excellent producers (PGM-22, 24, 28, 29), they are, however, utilized or foreseen for injection due to their peripheral location with respect to the main extraction area. In particular, wells PGM-28 and PGM-29 could be utilized as producers for a new unit in the southeastern sector of the field if moving of injection further to the south proves to be feasible.

Deliverability of productive wells is in the range of 40 to 250 kg/s of total mass, with an enthalpy between 980 and 1150 kJ/kg, resulting in a power production between 3 and 15 MW (average 9.5 MW per well) with a single-flash condensing unit. Absorption capacity of injection wells varies between 100 and 350 kg/s.

The current exploitation scheme is summarized in Table 1. The term "satellite" refers to separation stations common to a group of production wells. .

Table 1. Present Exploitation Scheme (55 + 5 MW)

Satellite	Production Wells	Reinjection Wells	Prod./Reinj. *)
-	PGM-11	PGM-2	5%
1	PGM-1 PGM-5 PGM-10 PGM-31	PGM-22	25%
2	PGM-3 PGM-17 PGM-46	PGM-24	40%
3	PGM-12 PGM-20 PGM-21	PGM-16 PGM-26 PGM-27	30%

Note *) : **Percentage of total steam supply to the plant, and of total reinjected water (average value)**

From each station a reinjection line conveys the brine to one or a few injection wells. The total deliverability of wells currently connected to the system exceeds the requirements of installed units. Indicated values for production and reinjection refer to the average contribution to the total steam supplied to the plant and to the total amount of injectate.

FIELD BEHAVIOR UNDER EXPLOITATION AND CHEMICAL MONITORING

From the thermodynamic point of view, field monitoring during the first year of exploitation has shown the following:

. gradual and moderate decrease of reservoir pressure of about 2 bar/year;

. constant to slightly increasing discharged fluid enthalpy, interpreted as the result of development of two-phase caps in the uppermost layers of the reservoir. The observed increase is in the range of 50 to 100 kJ/kg;

. practically constant deliverability of production wells;

. constant to slightly increasing absorption capacity of injection wells.

The chloride content of separated brine is being monitored in all production wells in order to identify evolution trends in reservoir fluid (Yock and Acuña,

1995). Chloride ion was selected based on the following considerations:
. it is not affected by deposition processes;
. it is the predominant ion species in Miravalles fluid;
. the analysis method is easy, fast and inexpensive.

The observed evolution, in a few selected wells, is shown in Figure 2. The wells can be subdivided into three categories (see Figure 3), namely:

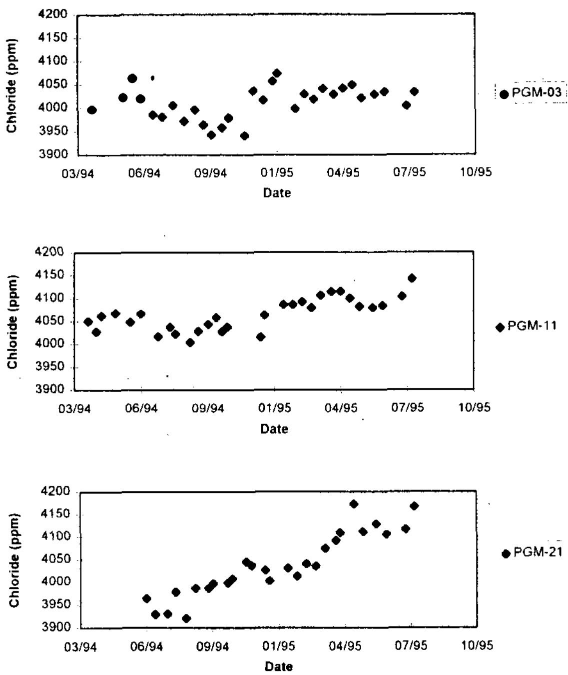

Figure 2. Chloride Content Evolution in Selected Wells

. wells with practically constant chloride content, showing oscillations within the range of accuracy of measurements: PGM-1, 31, 3, 17;
. wells with slight to moderate increasing tendency in chloride content: PGM-11;
. wells with moderate to high increasing tendency in chloride content: PGM-5, 10, 12, 20, 21.

The increasing trend is fairly constant in all wells affected by this phenomenon, and it is believed to be related to return of injectate to the central part of the field. In fact, the chloride content of injectate is 15-18% higher than reservoir fluid due to separation of the steam phase (at a pressure of about 7 bar). A 5% increase in chloride content in the produced fluid could therefore be explained by the mixing of the original reservoir fluid with about 17-22% of injectate. Due to their location at a relatively short distance, massive injection in wells PGM-22 and PGM-24 appears to be the probable cause.

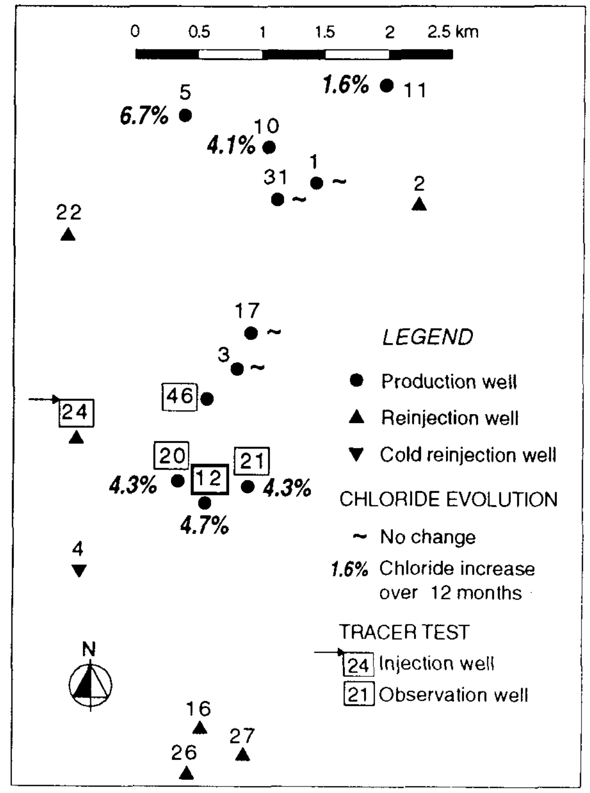

Figure 3. Evolution of Chloride Content and Tracer Test Arrangement

That explanation, however, does not appear to be applicable to PGM-11 that is located rather far away from the injection sectors. Other processes like enrichment by boiling and/or inflow of higher temperature fluid could be responsible for the evolution of well PGM-11, located in the hottest part of the field, close to the assumed hot recharge area.

TRACER TEST

In order to obtain additional information about the degree of hydraulic connection between the western injection area and the production sector, a tracer test was carried out. This test started on February 2, 1995 (Yock et al., 1995). Radioactive tracer I^{131} (half life period 8 days, calibrated activity 74 GBq) was injected in well PGM-24, and production wells PGM-12, PGM-20, PGM-21 and PGM-46 were monitored daily during 45 days. The water samples were analyzed with a liquid scintillometer, type Packard 1900 TR, with counting periods of 200 minutes.

Figure 4 summarizes the obtained results for wells PGM-12 and PGM-46, where a peak is observed after 35 and 30 days respectively, that defines the breakthrough of injected tracer in those wells. Before this time, a weak transient increase is observed

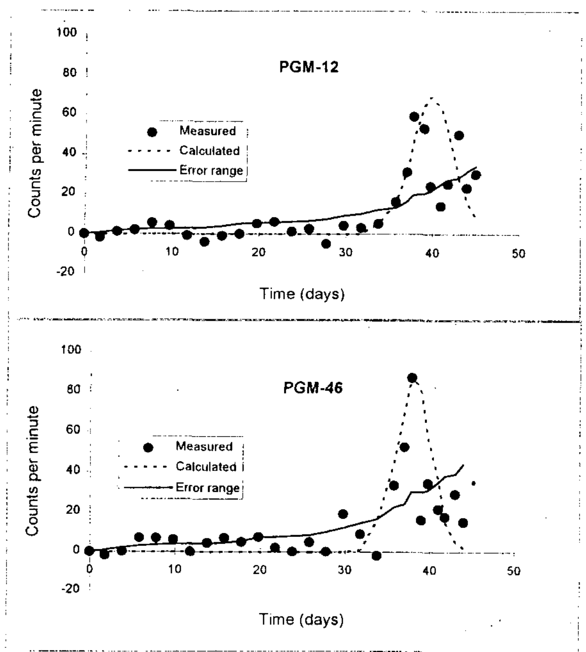

Figure 4. Tracer Test Results

between 6 and 11 days in both wells, however, due to the weakness of the signal, this cannot be interpreted with certainty as an early arrival through a secondary connection. On the other hand, wells PGM-20 and PGM-21 also showed a moderate increase of sample activity at similar times (about 30 days from injection), although it is mostly below the uncertainty level of the test, and is therefore discarded as an evidence of breakthrough.

It is worth to mention that PGM-12 and PGM-46, which showed the best evidence of tracer breakthrough, have open permeable zones at a shallower depth with respect to other monitored wells: it appears, therefore, that the hydraulic connection is related to shallow feed zones , although this hypothesis deserves further investigation.

A preliminary attempt to match the observed data with a simple model based on radial geometry and a porous medium resulted in the curves shown also in Figure 4. The parameter values required to obtain in both cases an acceptable match are very similar, namely:

. velocity of convective flow about 1.2 m/hr
. dispersion coefficient between 0.005 and 0.007 m^2/s
. combined mass parameter between 12000 and 12500 cpm.m (counts per minute - meter)

The resulting flow velocity falls in the lower end of the range reported for other fracture dominated reservoirs. For example the reported values for Dixie Valley (Benoit, 1995) are in the range 0.2-5 m/hr. The interpretation of the dispersion coefficient is not straightforward, due to the application of a porous medium model to a fractured domain. The estimated Peclet numbers are 540 for PGM-12 and 730 for PGM-46. These values indicate low dispersion. This suggests that the tracer moved as a relatively sharp front through the formation, as it has to be expected for highly channeled flow in a fractured reservoir.

MODELLING STUDIES

Numerical Model

In the frame of the feasibility study for an expansion of the installed capacity (ELC, 1995), a new numerical model for Miravalles was implemented. TOUGH2 (Pruess, 1991) code was used. The mesh is three-dimensional, with an horizontally irregular geometry (see Figure 5) and a vertical discretization consisting of 5 layers with decreasing thickness towards the reservoir top. The reservoir bottom is set homogeneously at 1200 m.b.s.l., whereas geometry of the reservoir top is modeled by removing shallower layers were necessary to try to match reservoir thickness. Thus, the uppermost layer for different parts of the model is located at a depth between 100 m.a.s.l and 600 m.b.s.l.

To take into account the conductive heat loss through the cap-rock, the uppermost blocks are connected to an impermeable block at constant temperature that acts basically as a heat sink. The selected geometry allows to maintain the total number of blocks within reasonable limits for a preliminary study (146 blocks), and puts together, in a single block, wells that belong to the same "satellite", where appropriate.

Mass sources and sinks are located where necessary in order to simulate the dynamic conditions of natural recharge-discharge. The amount of fluid flowing through the system has been evaluated through study of the natural state of the reservoir, trying to match the observed temperature and pressure distribution.

The permeability distribution of the model is schematically shown in Figure 5, where the resulting transmissivity value for each block "column" is

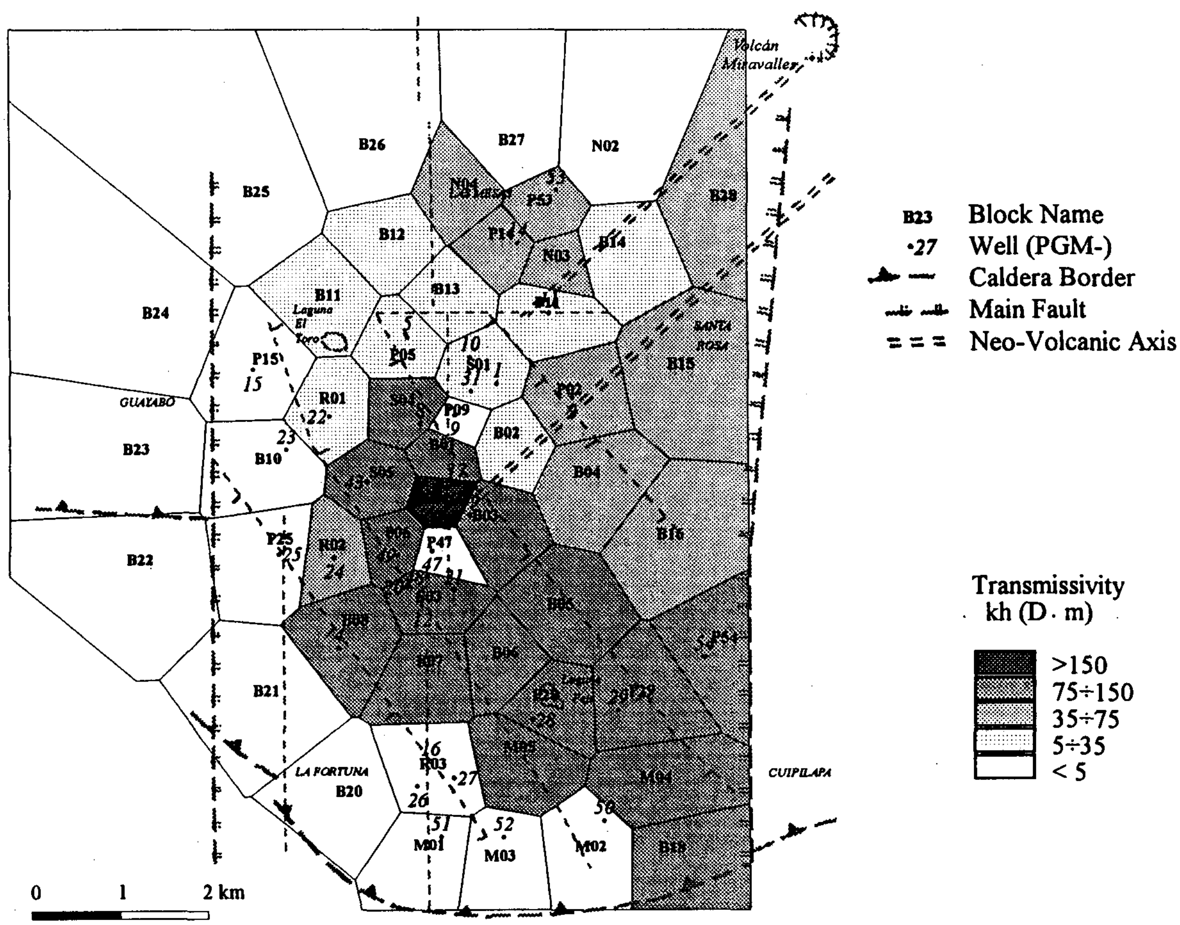

Figure 5. Numerical Model : Mesh and Transmissivity Distribution

presented. The highest transmissivity is located in the southern and southeastern sectors.

Return of Reinjected Water

Distribution of injected fluid in the reservoir and return velocity towards the central extraction sector have been investigated. Different chemical characteristics for reinjected and reservoir fluid were assumed (the simulator TOUGH2 allows for the definition of two different "types" of water). Based on reported produced and injected mass rates during 1994 for Miravalles, the content of injectate in extraction blocks, have been compared for two different models:

. a basic porous medium model with a porosity value of 10%;

. a fractured medium model, with a secondary mesh generated with the MINC method (Pruess, 1983). The idealized three-dimensional fracture system has constant fracture distance of 250 m in the three directions. The matrix has a low permeability (0.1 mD), and acts essentially as storage for reservoir fluid that flows only to fractures of its own block. Circulation between blocks occurs only through fractures. The equivalent permeability of the total system corresponds to the basic porous medium case.

Figure 6 shows the results for some extraction blocks. The porous medium model does not show any significant content of injectate after 8 months of exploitation. On the other hand, the fractured medium model shows an important return of injectate. Extrapolating the results to 1 year, a fraction of injectate of about 15% and 10% is estimated for the extraction blocks of well PGM-5 (P5) and Satellite 3 (PGM-12, PGM-20, PGM-21, block S3) respectively. Taking into account the strong idealization of the model, these values are in reasonable agreement with field observations: an increase of 4% in chloride content would correspond to a mixing of reservoir water with 15-20% of Cl-enriched injectate.

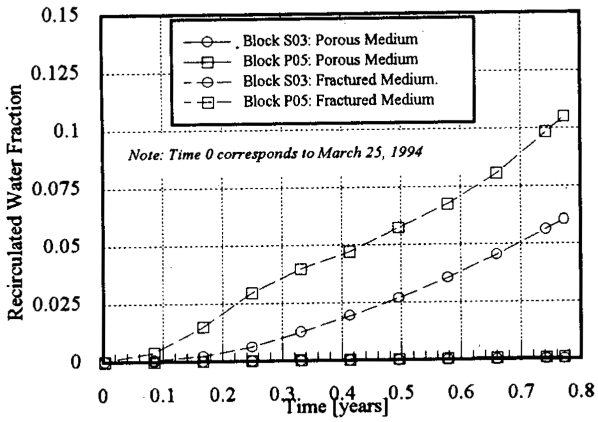

Figure 6. Numerical Model Results: Fraction of recirculated water in extracted fluid

Evaluation of Alternative Reinjection Strategies

The above described simulation suggests that for the reservoir mid and long term behavior, a fractured model (even if oversimplifies the actual fracture network) is likely to give more realistic results than a porous medium model.

Taking into account the expected increase in installed capacity of the field, the model was applied to evaluate the mid to long term cooling risk. Figure 7 presents the currently adopted reinjection strategy (Scheme A) and an alternative strategy (Scheme B), which foresees the abandonment of injection wells PGM-22 and PGM-24 and the concentration of injection in the southern field sector.

It was assumed that this change would be effective when the second 55 MW unit starts operation (mid of 1997). The model assumes fluid extraction distributed at different depths, according to known characteristics of existing wells. The steam production of each block is kept constant throughout the entire simulated period (i.e. make-up wells are assumed to be located in the same area as present wells). Injection is assumed to take place in the deeper part of the reservoir (below 300 m.b.s.l.), distributed in two lower layers of the model: injection

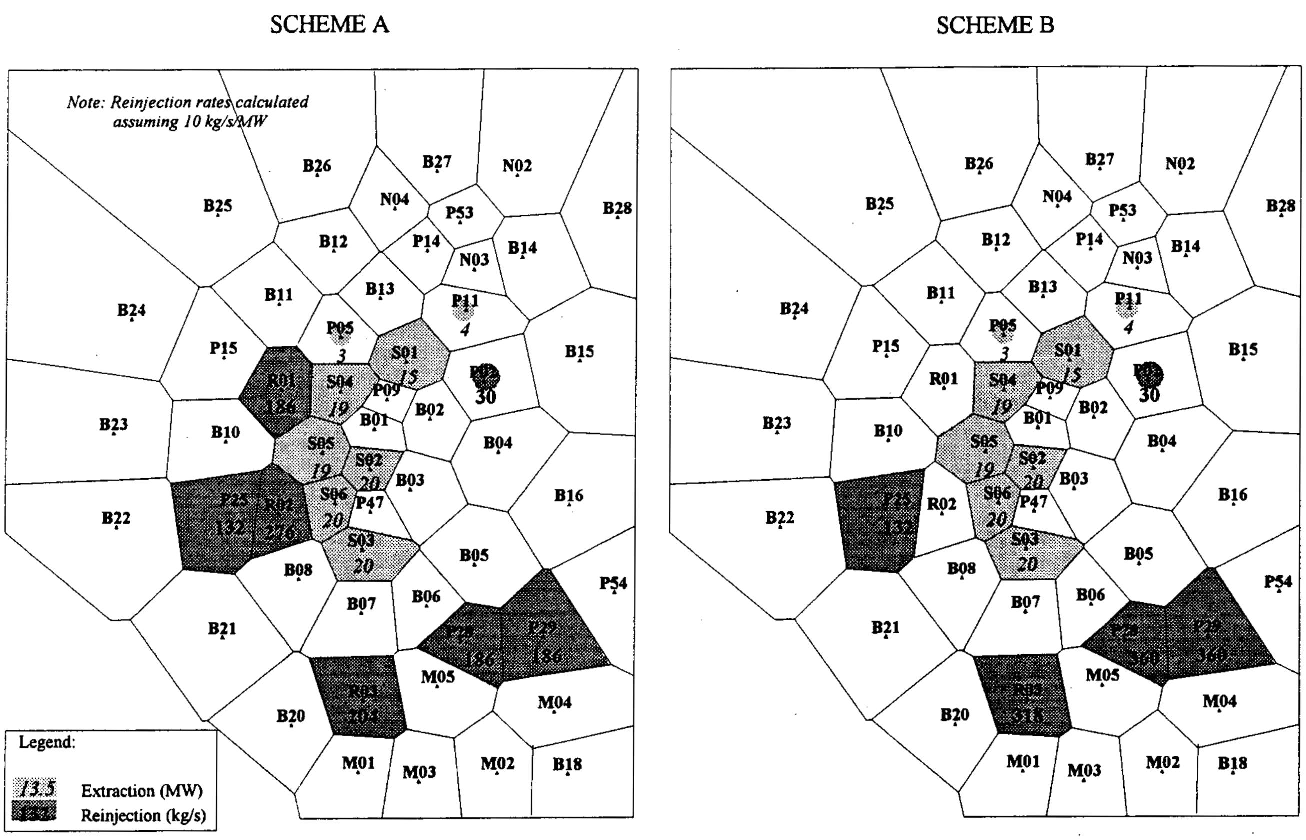

Figure 7. Numerical Model: Alternative Exploitation Schemes

rate varies as a function of enthalpy of extracted fluid.

Reservoir cooling is reflected by the evolution of discharge enthalpy of extraction blocks shown in Figure 8. The reported data are averaged values for the block "columns". Blocks S1 to S6 correspond to Satellites 1 to 6, each one including two or three production wells (see Figure 5). The comparison of obtained results relevant to the two injection schemes shows that, with the exception of the southernmost satellite S3, enthalpy evolution is positively affected by reduction of injection in the western field sector. Only satellite S1 appears relatively unaffected by return of injectate, regardless of the adopted scheme, with a clear tendency to higher discharge enthalpy with time.

In spite of the relatively small differences in absolute values of discharge enthalpy (50 to 100 kJ/kg), enthalpy decrease, combined with reservoir pressure decrease induced by exploitation, has dramatic consequences on deliverabiliy of wells. In fact, using a wellbore simulator, it results that the expected evolution of steam deliverability of wells is significantly worse with Scheme A.

Apart from an additional loss of average well production (see Figure 9), particularly in the mid term, it results that many wells of Satellites 4, 5 and 6 could be unable to maintain production at the prescribed wellhead pressure, so they would have to be eventually abandoned. On the other hand, the concentration of injection in the south (Scheme B), would probably limit this kind of risk to the southernmost Satellite 3.

It is also important to take into account that a possible reservoir cooling, caused by the present reinjection scheme, would strongly limit the available area for future make-up wells.

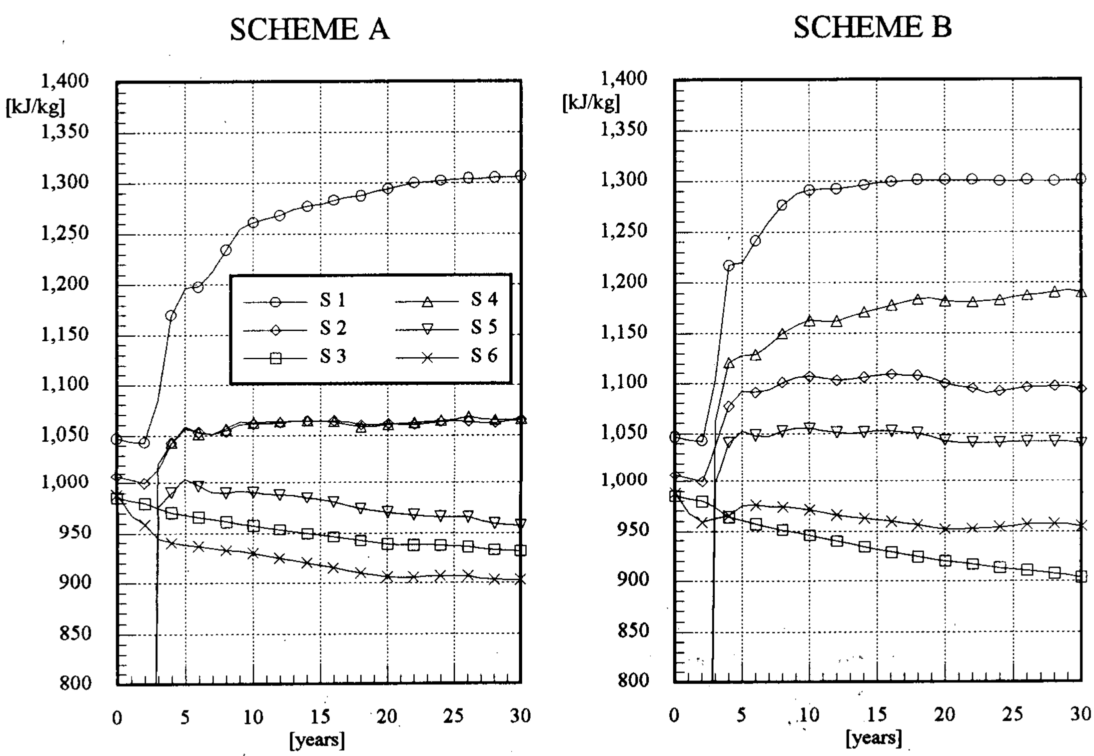

Figure 8. Numerical Model Results: Evolution of Discharge Enthalpy

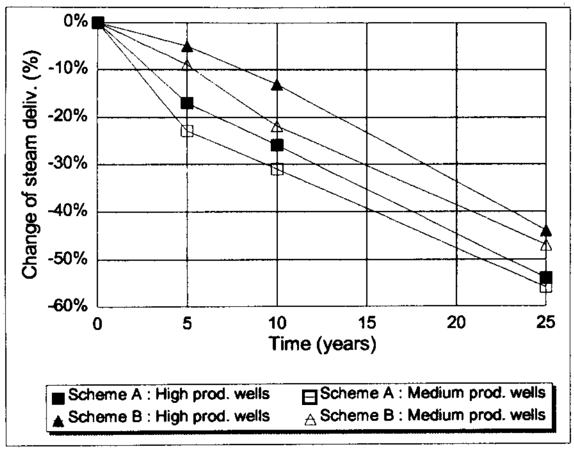

Figure 9. Numerical Model Results: Average Steam Deliverability of Production Wells

In the porous medium model, the expected evolution is by far more favorable, both in terms of enthalpy evolution and steam deliverability (10% average loss after 30 years). In this case, the difference between injection alternatives appears to be rather limited. It is, therefore, evident that the use of a porous medium model would lead to results that are likely to be too optimistic.

CONCLUSIONS

Chemical monitoring of Miravalles production wells shows a rather widespread progressive increase of the chloride content of the fluid, which is interpreted as a consequence of increasing fraction of injectate in the produced fluid.

The relatively rapid return of injectate towards the extraction sector is believed to be related to the existence of preferential flow paths (fractures) in the reservoir. The problem is of particular concern for injection wells PGM-22 and PGM-24, which are relatively close to the main production wells: a tracer test confirmed the existence of a good hydraulic connection between PGM-24 and some wells in the central part of the field.

In order to obtain reasonable agreement between simulation and observations, a highly idealized fractured medium proved to be a better choice than a classical "porous medium".

Results of the modelling study performed should be considered in a rather qualitative way because history matching is limited by the short exploitation period at Miravalles. The results, however, show the risk of cooling of important portions of the reservoir in the mid to long term with the currently adopted injection scheme.

Those results, when combined with field tests and observations, point out the necessity of careful monitoring of reservoir evolution and adoption of a safer injection strategy for the mid and long term conservation of the resource

An alternative strategy, based on the concentration of injection in the southern field sector, appears to be more adequate, strongly mitigating the risk of a negative evolution of the deliverability of wells. Work is presently underway to implement this injection strategy.

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