Proceedings 18th NZ Geothermal Workshop 1996

PRELIMINARY REINJECTION TRIALS IN THE OLKARIA NORTH EAST FIELD

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SUMMARY- Reinjection of waste brine from Olkaria Geotlieriiial Field (EPF & NE) has been proposed. Tracer, injection , reinjection and Interference tests have been undertaken to investigate the viability of this proposal for waste disposal as a mitigation to enviromental pollution through surface disposal as well as enhancing reservoir performance through extra heat recovery and reservoir pressure maintenace. The sites for the proposed reinjection wells have been selected and several wells have been drilled or identified from non producers.

1. INTRODUCTION

Reinjection of waste brine from geothermal power plant whose reservoir produce water or water/ steam mixture remains as one of the most important problems facing reservoir engineers. Considering the cost and benefits, reinjection is tlie most readily available alternative to surface disposal of geothermal waste water.

The wells in Olkaria NE geothermal field tap from a high temperature (240-340°C), low gas liquid dominated reservoir. The wells deliver at tlie well head a two-phase mixture of mainly steam and water. After tlie separation, the water is directed to conditioning ponds before reinjection into OW-R2 & R3. Before these wells were drilled, waste water from wells under short term discharge tests was disposed off into conditioning ponds. The water in these ponds would be contained through evaporation and seepage into tlie ground.

For the selection of optimal reinjection scheme for the intended 64 Mwe power plant, tlie critical questions that had to be answered were where to reinject (how far) and how much to reinject (flow rates) within or outside tlie main reservoir. These questions are answered by interpretation of flow patterns in the reservoir, geological descriptions and pressure interference interpretation. The other problem that need to be addressed is Iiow to obtain reliable and consistent injectivity in the reinjection wells since the chemicals dissolved in the waste water have a tendency to precipitate in the well and in tlie formation and block further injection. Redrilling reinjection wells is an expensive proposition. This is solved by understanding tlie chemistry of the separated brine especially silica and the reservoir temperatures at injection depths. The reinjection scheme for the North East is designed with the pliilosopliy that aim at addressing the raised problems.

The radial distribution of injected fluid is very unlikely considering the fractured nature of geothermal reservoir, and therefore fracture flow (channeling) is the most likely occurreiice and must be investigated and identified on time. Failure to acknowledge this could lead to the danger of fast breakthrough with a disastrous effect on the reservoir by quenching on otherwise good producing wells. Various tests described below have been undertaken or are currently in progress to try and investigate various aspects related to injection.

Several tests and siniulation work have been. undertaken in tlie EPF and the results are briefly reviewed in this paper to highlight major aspects related to reinjection that may help in predicting what could happen in the NE on implementation of the proposed reinjection.

The reinjection is expected to reap benefits which include ; sustenance of the reservoir pressure wliicli depletes with time due to fluid abstraction, effective waste brine disposal to mitigate environmental pollution, and prolong tlie life of the field by recovery of more heat from the water-depleted hot rock.

2. GEOLOGY

The Olkaria NE is characterized by high ground consisting mainly of pyroclastics and rhyolites from various volcanic centres in this area and Longonot. Poor sample recovery and extensive alteration in some horizons makes a stratigraphic correlation difficult. However, in this area, the top to about 1700 m.a.s.l. is predominantly rhyolites and pyroclastics (KPC and GENZL, 1988). The rocks encountered downhole include: pyroclastics, tuffs, rhyolites, trachytes, basalts and minor intrusives. The permeability in this region is associated with fractures, contact zones between lava units and tuffs. The major visible faults that control fluid flow in this region are the Olkaria Fault Zone trending in a ENE-WSW direction, and the Ololbutot Fault trending in a north-south direction. Other concealed faults are inferred from drill cuttings and cores recovered from the wells and stratigraphic correlation.

The wells in this area are drilled to depths between 1800-2500m with an average depth of 2200m. The $9^5/_8$" casing is set between 600-800m depth. The wells generally intersect permeable zones between 1350-900 m.a.s.l, where temperature recovery indicates near two-phase condition. Deeper permeability is encountered in the liquid zones between 800-350 m.a.s.l. Some deeper well intersect permeable zones at -50 m.a.s.l.

3. LOCAL HYDROLOGY

The hydrology of the area is complex, incorporating surface and subsurface cold water system and geothermally induced flows.

The geothermal resource in Olkaria field is recharged by an estimated 150 million m^3 of annual rainfall wliicli permeates in a north to south direction through faults and fractures (Bödvarsson, 1993). Fluid flow within the geothermal reservoir is dominated by convection wliicli result to two major upflows that have been identified on either side of the fracture zone east of the Olkaria peak. near wells OW-302 and OW-716 area (Fig. 1). Boiling fluids from these two upflow zones flow laterally along the Olkaria fault and mix with cooler water flowing southward along the central zone bounded by the Ololbutot fracture zone in the east and a parallel fracture zone in the west running through the Olkaria peak.

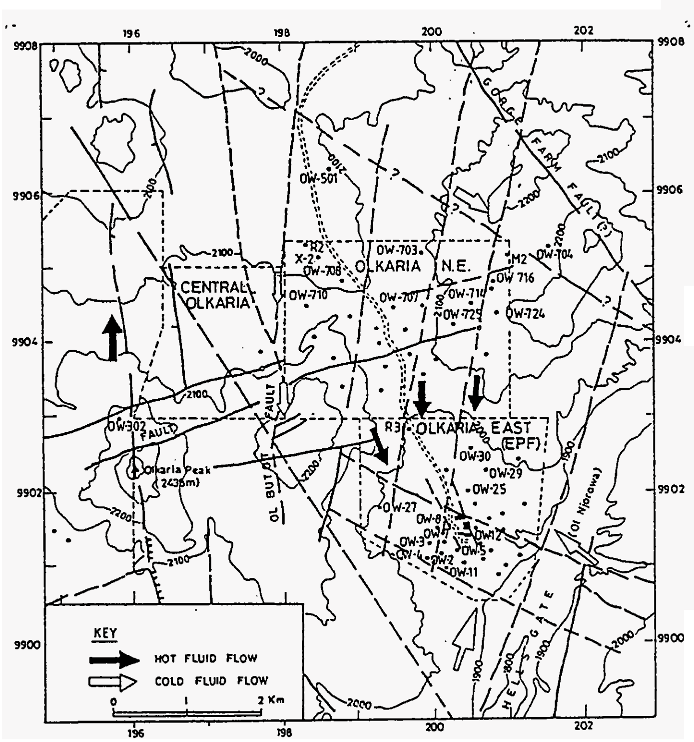

Fig.1 Map showing major hydrological features and wells location

The other major feature of the local hydrology is lake Naivasha which is located 15 km north of Olkaria N.E. It remains uncertain whether there is a direct hydraulic link between the lake and the geothermal reservoir and with a complex subsurface hydrology conclusive evidence remains elusive.

4. WORKING MODEL FOR EASTERN PRODUCTION FIELD (EPF) & NORTH EAST

Figure 2 shows the current working model for the two geothermal fields based upon interpretation of the data available from the fields.

An upflow exists under Olkaria **NE** field and possibly it occurs along a part of Olkaria fault. EPF is possibly on the outflow of the upflow from NE as is indicated by excessive enthalpy relative to quartz geothermometer recorded in the EPF wells, lateral flows into some wells, and such features as higher CO_2 in the **NE** fluids implying that the fluids are less boiled compared to EPF. Wells to the north east end of the **NE,** show higher N_2 indicating leakage of surface waters into the system, this is possibly recharge along the inferred Gorge farm fault (Fig. 2). In EPF and **NE** Olkaria, a continuous basaltic lava formation occurring at elevations varying between 1500-1000 m.a.s.l. appears to be the constraining formation capping the steam below it. In Olkaria **NE,** this formation is at slightly lower elevation compared to EPF implying possibly that the buried Olkaria fault has a downthrow to the north (KPC, 1994).

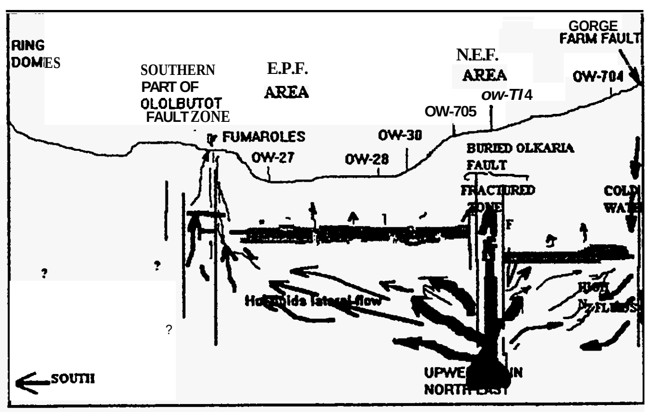

Fig. 2 - A x-section through EPF and NE fields

5. SUMMARY OF REINJECTION RESULTS FROM SIMULATION STUDIES

The main objectives of the simulation studies conducted for the North East field (Bodvarsson, 1993) were to investigate the generating capacity of Olkaria **NE,** the effects of reinjection on individual wells performance as well as on the entire reservoir behavior and the degree of interference between the reservoirs in the Olkaria East and Olkaria **NE.**

All the water from the western sector was assumed to be injected in OW-703 and wells in the eastern sector injected into OW-704. These injector wells were assumed to be in hydrological communication with the geothermal reservoir. The porous medium approximation was employed in the simulation work. The simulation results gave the following indications:

- that reinjection would help maintain reservoir pressure (especially in deeper parts of the reservoir), keep the average fluid enthalpies low and generally reduce the number of replacement wells needed. The wells in the eastern sector may be more susceptible to cooling due to return of reinjected water, whereas wells in the western sector may be cooled by natural cold water recharge.

- The pressure decline prediction was estimated to be between 10 and 15 bars depending on the reservoir layers after 30 years of production of 64 MWe.

- Full scale reinjection would help in reducing the number of replacement wells by approximately eight (8) wells during 30 years of production.

Earlier, simulation work had been undertaken (Bödvarsson and Pruess, 1988) for the EPF. One of the main objective **of this** work was to update the existing three-dimensional exploitation model using the extra data available; apply the model to investigate how the power plant output would decline with time until replacement wells became available; determine how many replacement wells would be required to bring the plant back to capacity; and predict the future performance of the reservoir with and without reinjection.

Results fiom the simulation using flow rates between 10 and 40 kg/s of reinjected water into OW-03 predicted significant mobility effects in the neighbouring wells OW-5 ,7 and 8. No observable changes were predicted for OW-02 and 11.

6. TRACER AND FLUID INJECTION IN OW-03 AND OW-704

Fluorescein dye was injected **as** a tracer slug into OW-03. Prior to injection of the tracer, 134770 m^3 of lake water at ambient temperature had been injected for a total of 45 days. The tracer test **was** conducted for a period of 172 days with an average injection rate of 100 t/hr.

Early returns were recorded in OW-02, 4 **,** 7 and OW-11. Tracer tests revealed moderate tracer return speeds of less than 5 m/ hr (Ambusso, 1993). No observable changes were recorded in OW-07 and OW-08. These results were the exact opposite of what had been predicted in the Numerical Simulation Studies sited above. During the six months of the test, marked improvement in production from the wells near the injection well were recorded. For exaniple, OW-04 had severe cycling problem during discharge with a rated output of 1 MWe. Upon injection, the well cyclicity greatly reduced and could sustain discharge throughout which had not been experienced before. The steam output rose to 2.2 MWe and occasionally rose to 3 MWe (Ambusso, 1993).

Reinjection of hot brine (150 C) into OW-03 from OW-27 separator, at a rate of 20 t/hr has been implemented since late May this year. More brine (10 t/hr) for reinjection into this well will be available once the replacement wells OW-31 and OW-33 are connected to the power plant. Plans are at advanced stage to *start* reinjection of 200 t/hr of cold water from infiltration ponds into OW-12 which was previously a producer. Proposal on reinjection of separated brine from OW-29 and OW-30 separator into OW-25 (previously a producer) is under consideration. Successful implementation of these reinjection plans will lead to about *55%* reinjection of fluids currently being abstracted in the EPF.

Results from the monitoring of short and long term effects of these reinjection schemes in injector and adjacent production wells, and the overall reservoir perfomance will determine whether any major changes will need to be adopted.

Tracer and injection tests were performed in the North East Field in order to reduce the uncertainty in engineering design and determine the suitability of OW-704 as a reinjection well for the waste brine during production (Karingithi, 1994). 250 kg sodium fluorescein dye was dissolved into 4000 litres of water and injected into OW-704 **as** a slug. Tracer returns were observed in OW-M2 which is 580m deep and 620m **fkom** OW-704 and OW-716 which is 900m from OW-714 (Fig. 1). Tracer return velocities of **0.31m/hr** and 1.3m/hr were observed in both wells respectively. Other wells on discharge **,** OW-714 and OW-725 did not show any tracer returns. Another chemical tracer, Potassium iodide, was later injected in OW-704 for long term monitoring.

7. INTERFERENCE TESTS IN THE NORTH EAST

A multi-well interference test was conducted in the eastern sector of the **NE** geothermal field from November 1993 to April 1994. OW-714, OW-716 and OW-724 were used as producer wells and OW-707 and OW-724 were used **as** monitoring wells. Preliminary test drawdown data indicated the existence of lateral communication between wells. **A** pressure drawdown of 0.2 bars was observed in OW-707 after 125 days and 0.47 bars in OW-724 after 104 days (Kagiri, 1993). Pressure support boundaries were also inferred from the test results. Monitoring of the test **has** been going on. **A** check of the pressure drawdown in OW-707 after another 365 days showed a further 3 psi (0.2 bars) pressure drop. Earlier analysis of shut-in pressure buildup (Kagiri, 1993) for several **NE** wells showed rapid pressure recovery in some wells which gives further credence to possible existence of pressure support boundaries.

8. CHANGE IN REINJECTION STRATEGY FOR THE NORTH EAST

The initial proposed and designed reinjection scheme for the **NE** was to use OW-704 as the reinjection well with a facility to divert the waters into OW-703. Short term injectivity tests in OW-704 had been conducted and found that the well could take all the water froin the North East field by pumping to the extent that it had been necessary to provide for only one other reinjection well less than 1200m deep.

The Olkaria NE field comprises of higldlow grounds and therefore some wells sited in this field have altitude variations of upto 200m. The altitude difference between the low lying wells which is also to be the site of the conditioning pond prior to injection, and OW-704 is 108m (approximately 11 bars water pressure). This design posed serious operational problem related to the cost of pumping uphill 227 kg/s of waste brine. The pumps for this capacity were rated to a total power requirement of 500 kW. For a reliable system that had standby pumps, the total capital cost was estimated at US Dollar 272,000 (Ouma, 1992)

An alternative reinjection scheme was proposed that gave priority to reinjection by gravity and aimed at trying to use tlie reinjected brine in reservoir pressure sustenance and heat recovery from the rocks, to prolong the life of both Olkaria East and the North East once production commenced. These proposals resulted to tlie drilling of reinjection wells OW-R2 and OW-R3.

8.1 Well OW-R2

This well is located in the north western side of the Olkaria **NE.** It lies on the edge of the field defined by resistivity boundary of less than 30 ohms (Onacha pers. comm) and can therefore be referred to **as** an edge field reinjection well. The well is located at an elevation 1971.05 m.a.s.l. It was drilled to a total depth of 2201m and the $9^5/_8$ " casing set at 695m. The permeable zones inferred from water loss test and temperature recovery profile are located between 850-1050m, 1150-1250m, and 1850-1950m. The estimated periiieability thickness product is 0.77 Dm. The permeability for most NE well lies between 0.4-10 Dm. The average injectivity value for the well is 2 kg/s/bar. The major loss zone in the well is between 1000-1200m (Fig. 3). Temperatures in this zone after 33 days recovery **was** 218-240 degree C. More days of recovery could achieve slightly higher temperatures. The injectivity value is on tlie lower side when compared to other wells in tlus field which generally have values above 3 kg/s/bar. The static water level in the well is at 400m. The well is drilled 700m from the nearest production well (OW-710).

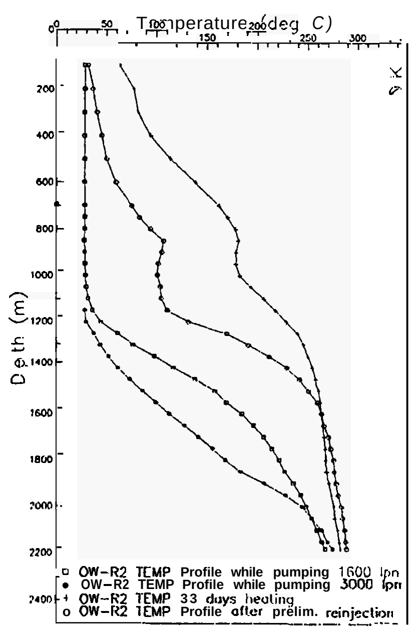

Fig. 3 OW–R2 Downhole temperature profiles

Reinjection of conditioned brine at an average rate of 80t/hr and temperatures of 40 C was conducted for a period of 400 days. Water level **was** monitored occasionally and it **was** found that the water level rose **by** about 35m which was 3.5 bars pressure. Some days after the **start** of reinjection test, the well developed a blockage and therefore no measurements could be taken below 750m.

8.2 Well OW-R3

The well is located in the buffer zone between the North East and the EPF. The well is therefore an "infield" reinjection well. Most future replacement wells for the EPF power station are targeted within this region. The well is located at an elevation of 1980.49 m.a.s.l. and was drilled to a total depth of 2200m with production casing set at 705.61m. Periiieable zones are inferred between 800-1200m, 1300-1500m, 1700-1800m and below 2000m. It has a permeability thickness product of 1.41 Dm and injectivity value of 1.27 kg/s/bar at low pumping rates. At higher injection rates, the well injectivity increases to 6.25 **kg/s/bar**. Comparing the profile after 32 days recovery (Fig. 4) and that when the well was drilled to 714m, it is evident that the well had not yet fully recovered. The intermediate temperature profile (Fig. 4) follows the BPD curve which is a common feature for most of the wells in the **NE.** From this profiles, it is obvious that any injection zone below 800m is above 250 C which will be favourable for reheating tlie reinjected brine as it moves within the reservoir . The static water level is at 400m depth. Reinjection of separated brine into this well at 47 C started recently.

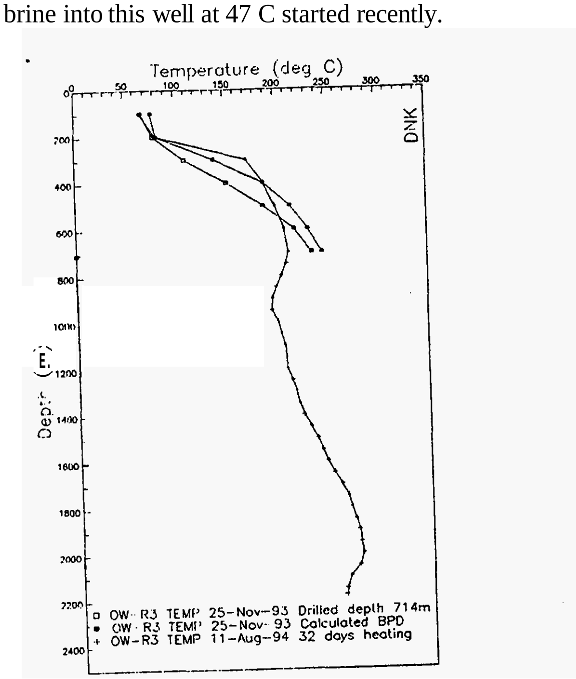

Fig. 4 OW--R3 Downhole temperature profiles

8.3 Well OW-704

The well was drilled **as** an appraisal well on the northerly end of the **NE** field to investigate the extend of tlie reservoir in that direction. It was drilled to 2005.7m and cased deep to a depth of 886m. The well is situated at an elevation of 2176 m.a.s.l. Downhole temperatures after completion confirmed that the well was **in** the boundary of the reservoir by having a temperature inversion at 1550m (Fig. 5). This temperature reversal is due to cold recharge from tlie north (KPC, 1988). Injection tests at low pump rates gave an average injectivity of 6 kg/s/bar and transmissivity of 1.9×10^{-8} m^3/Pas. At higher pumping rates, the transmissivity increased by an order of magnitude.(Bödvarsson, 1993). The permeable zones are located at between 950-1100m and 1500-1600m. The wafer level in the well at static condition was at 500m. At high injection rate of 438 t/hr during short term test and at a rate of 230 t/hr , for long term injection, the water level rose by less than 100m (Fig 5).

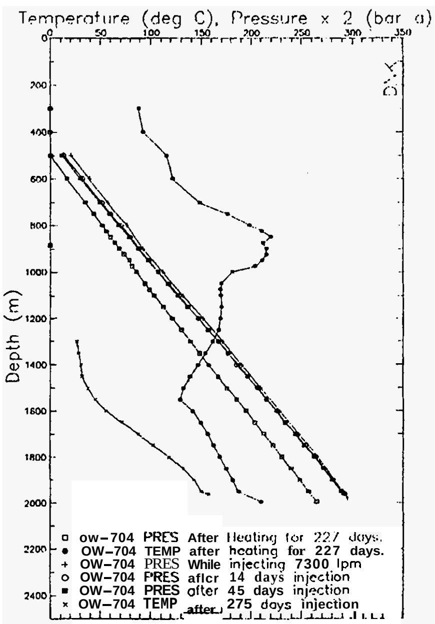

Fig. **5** OW-704 Downhole temperature and **pressure** profiles

Injection of the lake wafer at an average of 230 t/hr has been going on since November, 1993. Tracer test discussed above was conducted during this period. Another chemical tracer potassium iodide has already been introduced for long term monitoring.

9.DISCUSSION

A successful reinjection is **as** a result of integration of all reservoir and well data available, followed **by** accurate interpretation of the data thereof before the test is implemented. These data will include the geological descriptions, fluid chemistry, reservoir temperature, flow patterns in the reservoir and the pressure interference interpretation.

Numerical simulation studies act **as** bridge in connecting and incorporating all the data to predict the future performance of the reservoir under different exploitation scenarios. **Good** predictions from these studies that relate well with what is actually realized during tlie physical exploitation will largely depend on liow accurate the data is; and our knowledge of tlie subsurface reservoir, i.e. its fracture pattern and permeability distribution and the reservoir fluid thermodynamic state.

The tracer and injection tests in the **NE** gave similar results to those from the EPF. Tracer returns were observed in OW-M2 and OW-716 though there was only a small pressure gradient stimulation between the two regions. During large scale production, the resulting mass withdrawal could lead to large pressure gradients between the producing reservoir and zones of reinjection. Consequently this could lead to rapid fluid returns that will be undesirable. The **NE** is characterized by many concealed structures whose nature and influence on reservoir behavior is not well understood. Pressure buildup during shut-in manifest possible existence ***of*** pressure support boundaries. Interference tests results have given qualitative indications of pressure connection between some wells and pressure support boundaries were inferred. The 1993 update simulation studies showed that the **wells** in the eastern sector of the field will be susceptible to cooling due to returns of reinjected water while those in the western sector may be susceptible to cooling through natural cold water recharge. These tests and simulation work show that there are possible detrimental effects that could result from the expected reinjection.

The question on where to reinject has been addressed after considering the benefits that will accrue from those sites and this lead to the drilling of OW-R2 and OW-R3 to supplement reinjection in OW-704 and other possible candidate wells OW-703 and OW-501. We consider the first three **wells** as the available options, then tlie question is liow much to reinject in each well and under what conditions (temperature) ?. The engineering design of the reinjection system for the **NE** power plant considers cold reinjection of waste brine from the conditioning ponds at 40 C. This temperature is necessary to allow amorphous silica to precipitate before reinjection. At this reinjection temperature, it is proven that possible effects of silica scaling in the casing and in the reinjection well are eliminated.

Heat-up temperature profiles in OW-R2 and OW-R3 indicated temperature more than 230 C at the major loss zones. It can be assumed that the reinjected fluids will be sufficiently reheated to reservoir temperature as they migrate towards the production field. This will only be possible if and only if, the fluid residence time in the reservoir is large and the heat sweep area is sufficient enough for maximum fluid/rock interaction.

If the reinjection scenarios were to change **as** floated in several forums including the Board ***Of*** Consultant meeting (BOC, 1994), **i.e.** hot reinjection into OW-R3, the risk of fast cold premature returns will be minimized. At tlie separation conditions of 6.0 bara pressure, the brine temperature will be 159 C. Coupled with high pH levels of 9 and short transit time between the separation point and the reservoir reinjection zones, favourable results may be realized.

The volumes to be injected in each well will primarily depend on the well capacity, ability to sustain this capacity, injection temperature and the economics of tlie surface fluid gathering system.

The reinjection scenario simulated in the update studies for the **NE** varies significantly with the current status where other wells OW-R2 and OW-R3 will be included in the reinjection **of** the water. The volumes to be reinjected in each sector will vary significantly and therefore observed return effects may lag for longer periods than predicted before. If result from reinjection into OW-03 is anything to go by, then the porous medium model approximation for the entire NE reservoir is bound to fail. The series **of** tests conducted in the EPF and NE indicate complex permeability distribution thus invalidating the above model. Earlier predictions from simulation studies for reinjection into OW-R3 contradicted results from the short term tests conducted as far as mobility effects in the neigbouring wells were concerned.

Proposed reinjection of cold water into OW-12 in the EPF is expected to provide extra steam into the already dry wells in its neigbourhood. It is assumed that the cold reinjected fluids will migrate downward through gravity, and once in contact with hot rock, will get heated and through buoyancy forces ascend as a hot plume of fluid towards the production wells.

Therefore, from the foregoing discussion, it is clear that despite the availability of all possible information, and rigorous interpretation of the data, there is no possible way **of** predicting what will actually happen during the long term reinjection strategy. Therefore **,** for any designed reinjection programme, however well it is designed, it will only prove its worth by monitoring its overall long teriii performance. It is therefore very important to input appropriate measures to monitor the wells (reinjection and producing) and reservoir behavior during reinjection and to effect the necessary changes for optimum performance of power plant during its life span.

10. CONCLUSION

The various tests conducted in this field indicate the reinjection of waste brine for enviromental protection and reservoir management. The tests give an insight as to the nature of the Olkaria reservoir. The reinjection and the tracer tests in the EPF prove the existence of channels through which rapid fluid movements can be realized.
These tests show that a well designed reinjection of cold/hot fluid could lead to greater sustenance of production and reduction of cyclicity in wells; while improving overall well energy throughput and causing increase in steam flow can lead to increase in cyclicity which is a non-desirable effect. For the proposed NE steamfield design, some wells will share the separation equipment and if this effect is experienced it could pose a serious problem during production from the wells. The tests have shown that reinjection into the central area of the EPF could achieve the desired results.

To implement these reinjection stratergies, monitoring **of** critical parameters related to the reservoir and optimum field performance will be paramount.

11. ACKNOWLEDGEMENTS

I thank the KPC staff who helped in editing this script. Appreciation to the KPC management for approving publication of this paper.

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