

## RESULTS OF INJECTION AND TRACER TESTS IN OLKARIA EAST GEOTHERMAL FIELD.

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### ABSTRACT

This paper presents results of a six month Injection and Tracer test done in Olkaria East Geothermal Field. The Injection tests show that commencement of injection prior to onset of large drawdown in the reservoir leads to greater sustenance of well production and can reduce well cycling which is a common feature of wells in Olkaria East Field. For cases where injection is started after some drawdown has occurred in the reservoir, injection while leading to improvement of well output can also lead to increase in well cycling which is a non desirable side effect. Tracer tests reveal slow rate of fluid migration ( $< 5$  m/hr). However estimates of the cumulative tracer returns over the period of injection is at least 31% which is large and reveals the danger of late time thermal drawdown and possible loss of production. It is shown in the discussion that the two sets of results are consistent with a reservoir where high permeability occurs along contact surfaces which act as horizontal "fractures" while the formations between the "fractures" have low permeability. This type of fracture system will lead to channeled flow of injected fluid and therefore greater thermal depletion along the fractures while formations further from the fracture would still be at higher temperature. In an attempt to try and achieve a more uniform thermal depletion in the reservoir, it is proposed that continuous injection be done for short periods (-2 years) and this be followed by recovery periods of the nearly the same length of time before resumption of injection again.

### INTRODUCTION.

A joint Injection and Tracer test was done in Olkaria East Field between April and September 1993 to determine the effect of injection on the performance of production wells and to evaluate the possibility of implementing long term injection programmes in the field. This sector of Olkaria field has been exploited for power generation for over ten years now and most parts of the field have experienced pressure drawdown of about ten (10) bars. This has lead to the enlargement of an originally thin steam dominated zone in the upper part of the reservoir and to development of two phase conditions in the lower sections. Total steam production from the entire field has declined at an average rate of 4-5% per year while most wells have also experienced an enthalpy rise over this period with a number of wells in the field center discharging saturated and slightly superheated steam

(Ambusso and Karingithi, 1993). Temperature changes in the field center have dropped by between 5 and 15°C as deduced from short shut-in tests and regular downhole surveys. Because of this injection is considered an attractive way of extracting the high energy reserves in the reservoir and has the possibility of restoring some of the lost production or at least reducing the rate of decline in steam production. The tests discussed in this paper were aimed at determining a suitable injection strategy that would lead to efficient extraction and utilization of the energy reserves while avoiding some of the detrimental effects that have been reported in several injection projects worldwide.

Though it is intended that injection be done in parts close to the field center where largest drawdown have been experienced, no wells were immediately available there and OW-3 which is a non-commercial well to the south west of the field was selected as an injector well. This well has been used for pressure monitoring in the field and is known to be in communication with the reservoir having itself experienced a pressure drop of about twelve (12) bars. A number of production wells are within a few hundred meters of this well and it was therefore considered suitable for the preliminary tests. Fig 1 shows a layout of the wells in the field.

### TEST DESCRIPTION.

A total of 413542 cubic meters of water at ambient conditions (18°C) was injected over the period of the test which in all took 172 days giving an average injection rate of about 100 cubic meters per hour. The total amount of water injected during the test is almost twice the amount of steam withdrawn per month from the whole field while the average injection rate is close to half the mass withdrawal rate by the wells around OW-3.

As a method of evaluating effects of injected fluid on the production wells all output parameters of the wells around OW-3 were continuously monitored during the period of injection and shortly after to asses the rate of return to normal after stoppage of injection. The parameters selected for this purpose were steam and water flowrates, and discharge enthalpy. The overall variation of the three parameters with time (cycling) also formed an important part of the tests. Due to fluctuation in well output for most wells it was found necessary to compute average values from data collected in five (5) minute intervals for 2 to 3 hours

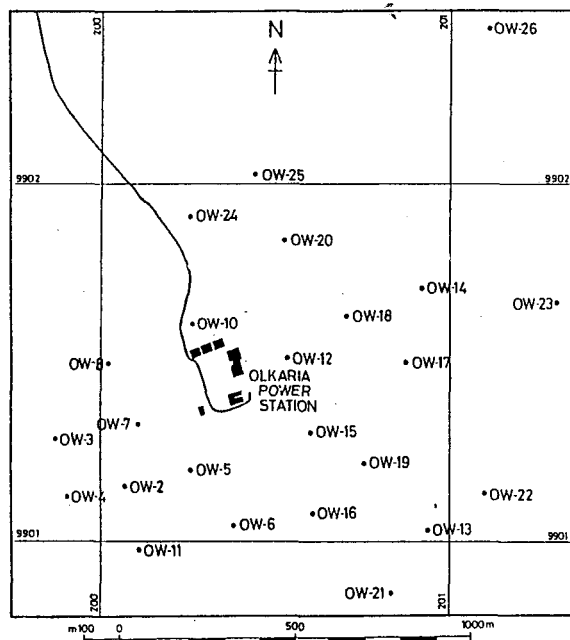


Fig.1 Well sites

either once a week or once a fortnight. These values were then plotted against time and changes noted. For wells with steady flowrates daily spot readings were found to be sufficient. For wells connected to the power plant steam flow was determined from pressure drop across orifice plates on the steam line. The pressure drop across the orifice plates was also recorded on charts that were fixed on the steam line which also indicated variations in steam flow. Water flow was measured by a weir-box and corrected for flushing to the atmosphere. One well, OW-4 which shares a production separator with OW-2 and with which it produces alternately was blowing to atmosphere and the James lip pressure method was used for output computations.

For the Tracer test Fluorescein Sodium a chemical that is known to undergo thermal degradation at elevated temperatures was used. However this degradation is known to take place exponentially (Adams and Davies, 1991) and large amount of the tracer was used so as to compensate for the effects of temperature. One hundred and twenty five (125) Kilograms of the tracer was introduced in OW-3 after forty five (45) days of injection. This was done over a 1¼ hour period with the water flow stopped and therefore effectively represents a slug. A multipurpose Perkin-Elmer fluorimeter with a sensitivity of  $10^{-14}$  mole/ liter was used to detect the tracer in brine samples. However the lowest sensitivity had to be raised to  $10^{-9}$  mole/liter as a number of wells had background fluorescence at this level presumably due to fine suspensions.

Three samples per day were collected and analysed during the first month after introducing the tracer. The frequency was later reduced to one sample per day for the next two months. For all wells samples were collected from the weir-box except OW-8 which shares

a separator with OW-7. Samples for OW-8 were collected from the two phase line. For OW-7 which was blowing through the well silencer and not connected to the plant it was not possible to determine independent tracer level as the water flow at the weirbox was for the two wells (with OW-8). It was however still possible to determine the first arrival time as Fluorescein was detected first at the weir-box while the tracer was detected in samples from the two phase line at a later time.

Due to strong tracer returns and notable changes in well output for a number of wells during the injection period, it was decided in the course of the tests to determine changes in brine chemistry as these were likely to show dilution trends with time. The comparatively inert and easy to analyze chloride was selected and its concentration was determined alongside the Fluorescein. This data as shown below proved useful in tracing the fluid returns as two wells OW-2 and OW-4 showed what seemed to be clear dilution trends.

Pressure Transient tests that were planned to be done at various stages of injection were abandoned due to difficulty in maintaining steady injection rates. However regular downhole surveys were done throughout the injection period and shortly after. Temperature information from these surveys did prove useful for purposes of identifying water loss zones. These profiles also provided a suitable method for evaluating the extent of thermal depletion as the injection well being the point of cold water entry should basically represent the extreme case as far as heat extraction by the injected fluid is concerned and temperature recovery trends are important in this aspect.

## RESULTS

Results are presented for those wells that did show changes in output that can be attributed to injection and those that did receive significant amount of the tracer. This is done separately for injection and tracer tests before the two sets of results are integrated into one and the overall conclusion from the two sets discussed in the next section.

### Injection tests

OW-2 which is 216.7 meters from OW-3 was the first well to show change in output parameters which occurred within the first month of injection. The water flow which hitherto had only small fluctuations started having surges which exceeded ten (10) tonnes/ hour an amount that was nearly twice the highest recorded water flowrate over the past three years. The surges increased both in magnitude and frequency throughout the injection period. These surges in water flow were accompanied with reduction in steam flow. Figures 2 shows daily water readings for OW-2 during the injection period. It is clear from the graph that the surges increased throughout the injection period.

Figure 3 shows the average steam and water flow for OW-2 from monitoring data collected every fortnight. The figure shows that the average water flow increased progressively throughout the injection period before falling gradually shortly after injection

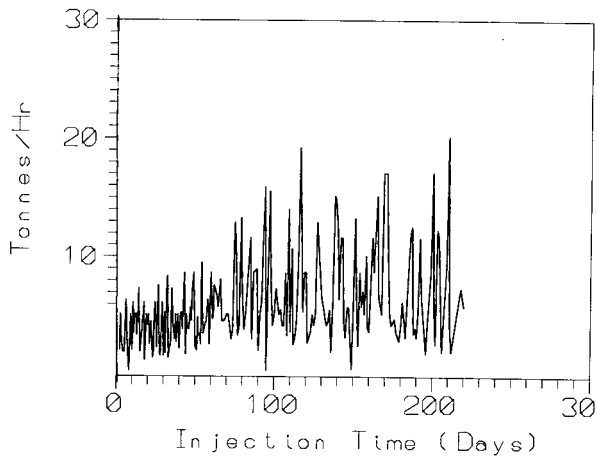


Fig. 2 OW-2 Daily Water Flow

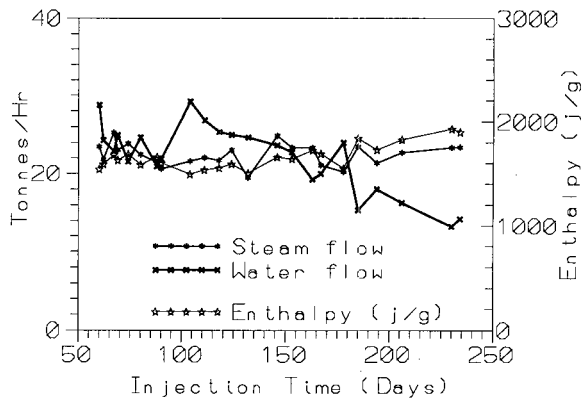


Fig. 4 OW-4 Average Output Values

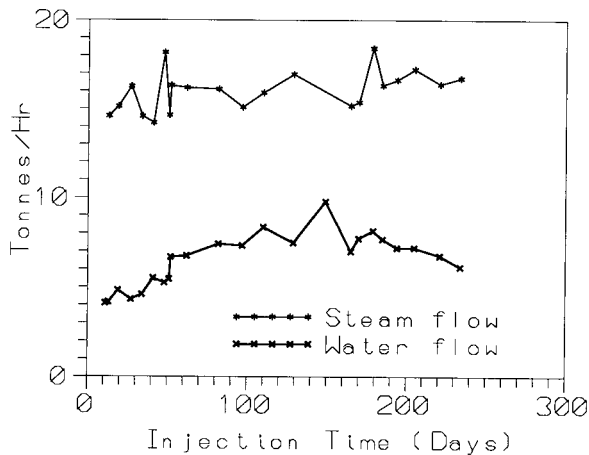


Fig. 3 OW-2 Average Output Values

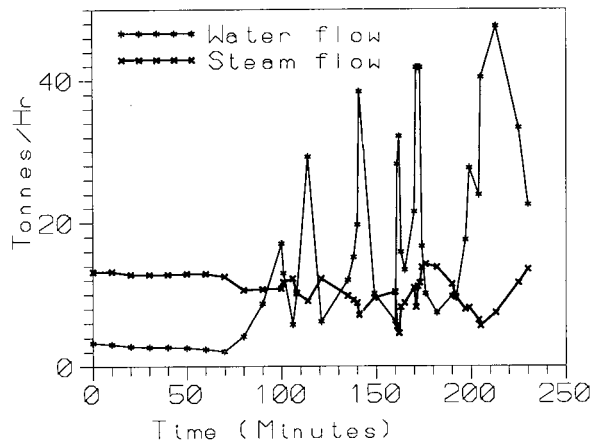


Fig. 5 OW-4 Output in 1988

was stopped. The surges in water flow did not show any reduced frequency but the highest readings were subsequently lower than those recorded during the injection time. The steam flow on the other hand remained unchanged during the injection period. This shows that the main effect of injection is to cause an increase in water flow.

Figure 4 shows average steam and water flow, and enthalpy for OW-4 during the injection period and shortly after. This well is 185 meters from OW-3 and was only opened for discharge through the atmospheric silencer with injection in progress. The figure shows that steam and water flow were unchanged throughout the injection period but the water flow dropped after injection was stopped. This is also reflected in the increase in enthalpy after injection. This behavior shows that as in the case of OW-2 the injected water goes largely to increase the water flow. Another notable feature of this well over the injection period was the reduction in cyclicity. This well is known from previous discharge tests to be cyclic with periodic variations in water flow. However during the injection period there was notable stability in all output parameters which in all cases were higher than those recorded during the earlier tests. Figure 5 and 6 show steam and water flow over monitoring periods during discharge tests in 1988 and during the

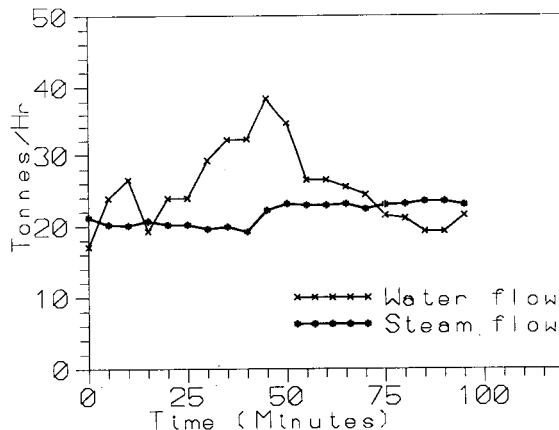


Fig. 6 OW-4 Output during injection (118 days of injection)

just concluded injection tests respectively. In both cases the lip pressure pipe was 5 inches. The increased production and higher stability show that the well output was boosted by the injected fluid.

Figure 7 shows daily water flow for OW-11 which is 438 m from OW-3. The initial increase in water flow

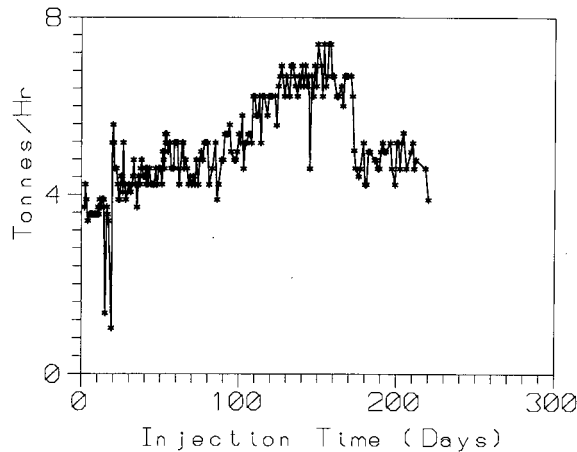


Fig. 7 OW-11 Water Flow (T/Hr)

after 20 days is due to weir-box cleaning and is therefore not real. There is a systematic increase in water flow after about ninety (90) days of injection before the flow stabilizes about a month later. Steam flow over this period was constant and no changes in flowrate or cycling as in the case of OW-2 was observed. This increase in flow can only be attributed to return of the injected fluid. This late increase in water flow is followed by a rapid and almost immediate decline in water flow after injection.

No other wells showed changes in output due to injection. Most notable among these wells is OW-5 which being 374 meters from the injection well is closer than OW-11 which had did show significant increase in water flow. This negative result has to do with the shallow depth of the well (901 meters) and is discussed below.

#### Tracer tests.

Tracer return profile for OW-4 is shown on figure 8 while figure 9 shows profiles for OW-2 and OW-7 (& OW-8). The strongest tracer return was recorded in OW-4 whose tracer concentration at the peaks was five hundred times higher than those for OW-2 and OW-7 and the strong green colour of the Fluorescein Sodium was visible at the weir-box during most of the test period. The first arrival times are 106 hours for OW-2, 88 hours for OW-4 and 98 hours for OW-7. The tracer speeds from these arrival times are 2 meters per hour for OW-2 and 2.1 meters per hour for OW-4 and OW-7. These tracer speeds are moderate as compared to speeds reported for other fields in the world.

The tracer return profile for OW-2 does not have the classical build up to the peak as for OW-4 but still does have a number of important interpretive features. However given the strong effects of injection reported above a stronger tracer return should have been expected. That this was not so does show that the tracer could have suffered thermal degradation and stronger tracer returns should be observed otherwise. However taken as it is the short return time and the extended peak show the existence of short circuit paths between the well and OW-3 and that there is substantial mixing along the path respectively. The obvious tail does show that there is tracer

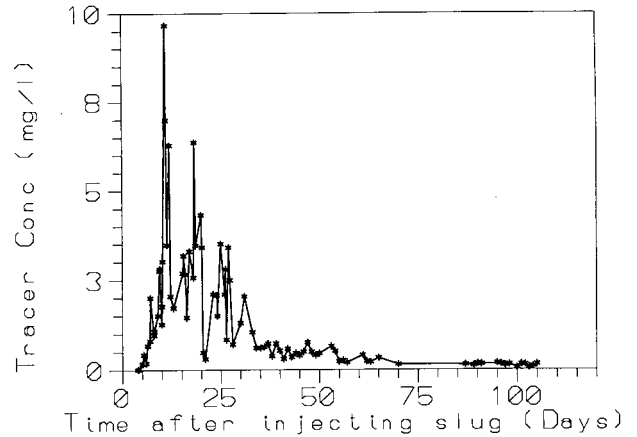


Fig. 8 Tracer Profile for OW-4

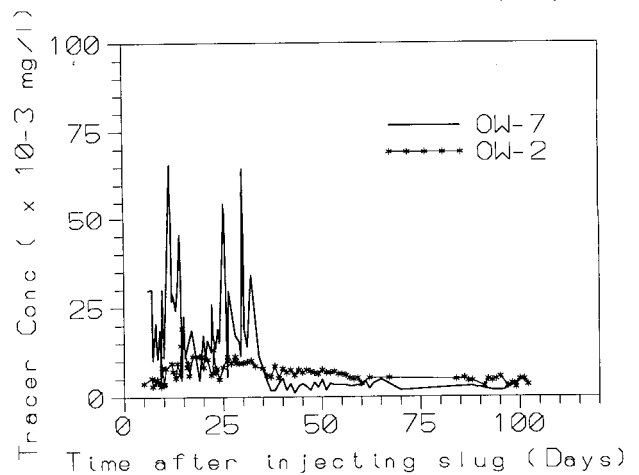


Fig. 9 Tracer Profile

dispersion/retention along the return path. This shows that the fracture(s) transmitting the fluid is (are) small and that the formation does have high permeability. Only 120 grammes of the tracer or .1 % of the total injected tracer was recovered in this well over a period of about 100 days.

For OW-4 three classical peaks in a declining manner were observed and a tail at lower concentration was observed after the last peak. The profile shows that there are several return paths between this well and OW-3. However the lower tracer concentration at the tail shows that only a small proportion of the tracer is either dispersed or retained as most of the tracer returned during the peaks. Further more the tracer build to the first peak after first arrival takes along time while the peaks are rather sharp. These return characteristics do show greater tracer spread rather than mixing as the later property would lead to a prolonged or extended peak. The low tracer concentration at the tail does indicate lower formation permeability as otherwise a significant level of tracer should have been retained. 38 kgs or 30 % of the total tracer injected was recovered in this well over a period of about 100 days. This amount of tracer is large and indicates large injection fluid returns and does show the potential for rapid thermal depletion even though

tracer speeds were low.

The return profile for OW-7 is very fluctuate. This variation was because the water flow at the weir-box was combined with that from OW-8 a well with a variable water flow and only had low levels of tracer at a latter time. The total, amount of tracer recovered from this well was estimated to be 160 grammes.

### Chloride

Figure 10 shows the daily weir-box chloride concentration for OW-2 and OW-4 the two wells that showed chloride change during injection. The dilution trends are different as OW-2 shows a gradual linear dilution trend while OW-4 shows a 'step' change in chloride concentration. The former shows that there was a gradual increase in the proportion of injected fluid in the final discharge throughout the injection period while the step change observed for OW-4 shows that the proportion of injected fluid in the final discharge remained constant throughout the injection period. The trend shown by OW-2 is reminiscent of a diffusion type process such as would occur in gradual temperature decline as observed in cases of fluid transmission through a fracture at high temperature with heat being transferred to the fracture conductively. This trend is suggestive of fracture-matrix interaction where there is fluid contribution from the matrix to the fracture with the fluid from the matrix either diminishing continuously or itself undergoing dilution. For the case of OW-4 the step change does show absence of continuous fluid contribution by the matrix and possibly existence of different return paths for the injected and resident reservoir fluid to the production well. This could also imply that mixing of the two species of fluid occurs near the production well.

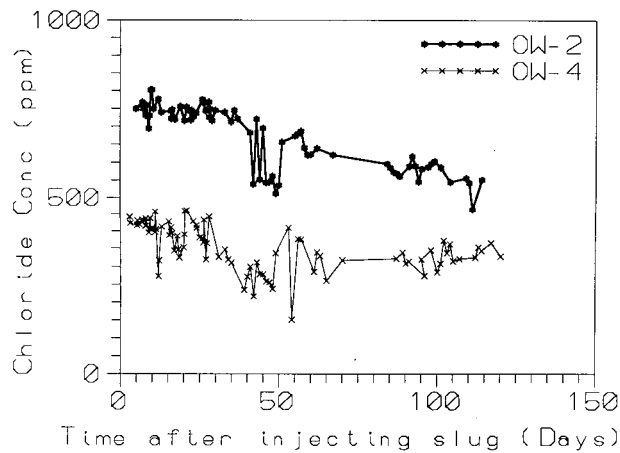


Fig. 10 Chloride (OW-2 and OW-4)

It is possible to estimate the proportion of injected fluid in the final discharge in both cases by assuming simple single stage mixing between the injected fluid whose chloride concentration was about 95 ppm and the liquid phase of the resident reservoir fluid. These estimates give the proportion of injected fluid in the total discharge as 3.5 % and 18 % for OW-2 and OW-4 respectively. Further refinements taking into account the chloride variation in the field, fracture and other formation properties need to be applied to this data to

obtain more reliable estimates of proportion of injected fluid in the final discharge from this data.

### Down hole surveys.

Figure 11 shows temperature profiles taken in OW-3 during the injection tests and shortly after. Also included is a profile taken in the well before injection. The profiles during injection show high temperature readings (35<sup>0</sup> C) and implies that the upper parts of the well could have been discharging during injection. This is supported by the profiles taken after injection which show rapid recovery of the upper parts of the well. The main parts of water loss from the profiles were below 850 m depth. This deep level of water entry explains partially the negative results observed in OW-5 whose total depth is only 910 meters. The temperature recovery even for parts that are within the main loss zones is significant and does show that the effect of injection in the reservoir parts beyond OW-3 are less than those in the well.

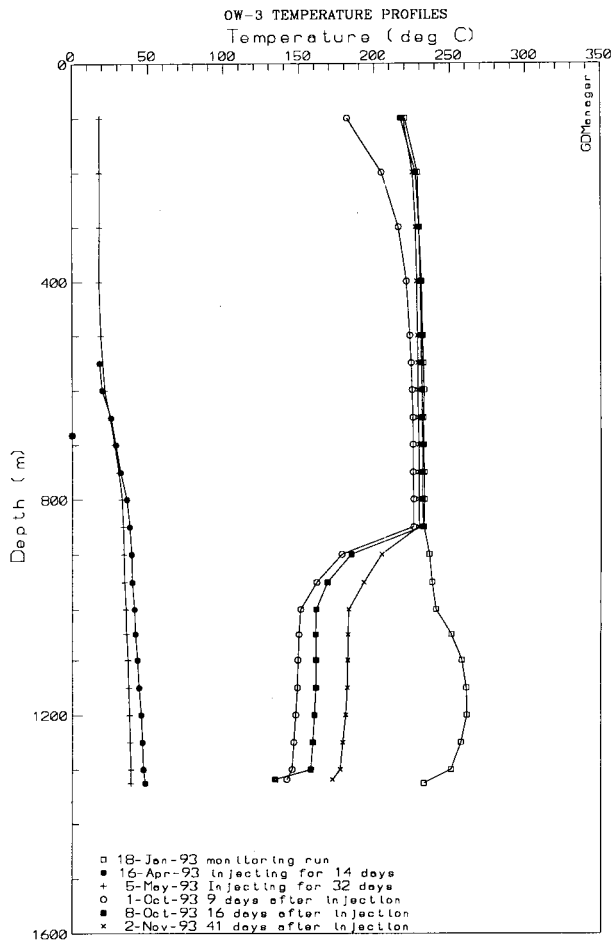


Fig. 11

### DISCUSSION

The results of injection and tracer tests show that the principal directions of fluid migration is southwards with smaller proportions migrating to the north. These are the directions of low pressure potential as these zones have undergone depletion due to production. It

however does seem necessary to invoke a high permeability channel between OW-4 and the injection well given the high level of tracer return in the well. The most important part of the tests are the results of injection tests as these show directly the effect of injected fluid on well performance. However there are some aspects of the tracer tests that have important bearing on the reservoir structure and these are evaluated first before making an assessment of injection strategy.

For all the wells where tracer returns were recorded the tracer speeds were low. However the total tracer returns are large being at least 31% of the injected tracer for all wells. Another aspect of the tracer profiles is the sharp peaks seen in OW-4 that show less mixing of the fluid but a gradual build up to the peak indicates tracer spread. A fracture characteristic that adequately accounts for these features is one where large horizontal fractures are the ones transmitting fluid while the surrounding formations have low permeability. Such fractures would give low tracer speeds due to their large size and fluid flow in them would be radial and speed should decrease inversely with distance. The returns would still be large as the injected fluid would nearly all be transmitted to the production wells. This is supported by the geological structure of the wells which show nearly similar lithologies of the wells (Noble and Ojiambo, 1976). This structure is the cause of the mainly lateral permeability known to exist in this part of the Field.

As for the effects of the injected fluid on well performance the most significant was the increase in water flow. Except for OW-4 (see next paragraph), for the other wells steam flow was not affected by the injection and does show that only the mobility of the liquid phase was increased by injection. That steam is unaffected by injection could be because of the two phase nature of the reservoir where pressure is governed by temperature which changes very slowly even on injection. However it is possible some of the injected could have been boiled and returned as steam. It would be difficult to increase the steam flow as significant proportion of the injected fluid would have to boil so as to increase the pressure and steam phase mobility in the reservoir. This can be achieved to some extent in the field center which is steam dominated and a higher proportion of the injected fluid could be boiled. Higher Injection temperature would lead to better results.

For OW-4 the effect of injection was not only an increase in total flow but also low cycling compared to what was seen in the well during discharge tests. The steam flow during this period was also higher than those during the tests. This does show that production was sustained as the well was able to maintain production most of the time. There also seems to be an advantage in opening the well with injection in progress as the zone around the well was still at a

higher pressure potential. Thus the injected fluid goes to sustain the fluid flow rather than first restore then sustain flow as was the case for the other wells. This indeed seems to be the case with OW-2 where increase in instability was noted. This can be attributed to premature return of injected fluid and could be reduced by injecting at higher temperature.

The recovery trends after injection do show that the effects of injection are reversible provided the injection periods are short. This is true for the production trends in OW-2 and OW-4 and in the injection well itself where temperature measurements have shown significant recovery. However due to channeled flow along fractures, thermal depletion along the return path can still be large while formations beyond the fractures could still be at high temperature. This non uniform extraction of heat along the fractures can lead to enthalpy reduction and loss in output. Allowing for a recovery time as was done for the above tests will lead to better redistribution of heat from the hotter formation to the cooler fractures. This will lead to more uniform heat extraction without risking loss of production. Further tests will be necessary to establish the safe lengths of injection and recovery that will be applied. However in the central parts of the field longer periods of injection could be used as there are several production wells.

#### CONCLUSION.

From the foregoing results and discussions injection into OW-3 is feasible and the effects of injection over short periods on well output do not show severe thermal degradation. The advantage of increased well output for OW-4 and reduced cycling do outweigh the small disadvantage of increased cycling seen in OW-2. Further more the cycling does not lead to loss in steam production and could be reduced by injecting water at higher temperature. The results also show that injecting in the field center which is steam dominated could lead to better results. However as in the case OW-3 continuous injection should be over short periods and be followed with 'recovery' periods for about the same length of time before resumption of injection again.

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