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A SUMMARY OF MODELING STUDIES OF THE EAST OLKARIA GEOTHERMAL FIELD, KENYA

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ABSTRACT

A detailed three-dimensional well-by-well model of the East Olkaria geothermal field in Kenya has been developed. The model matches reasonably well the flow rate and enthalpy data from all wells, as well as the overall pressure decline in the reservoir. The model is used to predict the generating capacity of the field, well decline, enthalpy behavior, the number of make-up wells needed and the effects of injection on well performance and overall reservoir depletion.

INTRODUCTION

Geothermal exploration of the Olkaria geothermal field in Kenya started in the 1950s; by 1958 two exploration wells (X-1 and X-2) had been drilled in the area (Noble and Ojiambo, 1975). The lack of productivity of the wells and intensive development of hydropower delayed further development of the area until the early 1970s. At that time the Kenyan government received financial support from the United Nations (UN) to undertake an extensive exploration project; a feasibility study was carried out in 1976 after six additional wells had been drilled and tested. The study concluded that development at Olkaria for power production was feasible (United Nations, 1976).

During the last decade, production drilling has been carried out in the eastern part of the field (East Olkaria) and a power plant with three 15 MW_e units has been constructed. The first unit came on line in July 1981, the second one in December 1982, and the third unit started power production earlier this year (1985).

Numerical modeling studies have been used to aid in the development of the field. Bodvarsson (1980), Bodvarsson and Pruess (1981), and Bodvarsson et al. (1982) have used numerical modeling techniques to investigate the effects of vertical and horizontal permeabilities on the generating capacity of the Olkaria field, and also have investigated the effects of exploiting aquifers at different depths. The results of these simulation studies indicate that the present wellfield area (East Olkaria) is well capable of providing steam for 45 MW_e power production.

The primary objective of the present work is to develop a numerical model of the Olkaria field that can be used to predict with confidence the future behavior of producing wells, the effects of reinjection, and the overall depletion of the reservoir. The model is fully three-dimensional, with all existing wells represented individually (well-by-well model). This allows for history matching of flow rate and enthalpy data from all wells, as well as the average reservoir pressure decline. Using this model we predict future flow rate decline of the existing wells, the appropriate well spacing, the generating capacity of the East Olkaria field, effects of injection on field performance, and the number of development wells needed. A more detailed description of this work is given by Bodvarsson et al. (1985a,b).

OLKARIA GEOTHERMAL FIELD

The Olkaria geothermal field in Kenya is located in the Great Rift Valley, about 100 km northwest of Nairobi (Fig.1). The areal extent of the geothermal field has been estimated at about 50 km^2 based on shallow temperature gradients and the occurrence of fumaroles (Noble and Ojiambo, 1975). Resistivity surveys have indicated a larger anomaly, some 80 km^2 in areal extent (United Nations, 1976). Natural heat losses from the field amount to some 400 MW_t (Glover, 1972).

To date, 25 wells have been drilled in the present production area in the eastern part of the Olkaria field; 22 are supplying steam to the power plant (Fig. 2). Figure 2 also shows the locations of exploration holes in other areas of the field. Data from the wells have identified the presence of a thin steam layer (50-150 m thick) overlying a thick liquid-dominated two-phase reservoir (Fig. 3). The rocks encountered are volcanic, with basaltic rocks dominating at 500-700 m depth and acting as a caprock to the system. The reservoir rocks consist primarily of fine-grained lavas and tuffs (KPC, 1981a, 1982a, 1983a, 1984a; Browne, 1981). Fluid flow is concentrated along contraction joints in the lavas, scoria zones, and lava contacts (KPC, 1984b). Most of the wells have multiple feed points, often with internal flow between feed points in the steam zone and underlying liquid-dominated zone (e.g., KPC, 1984b).

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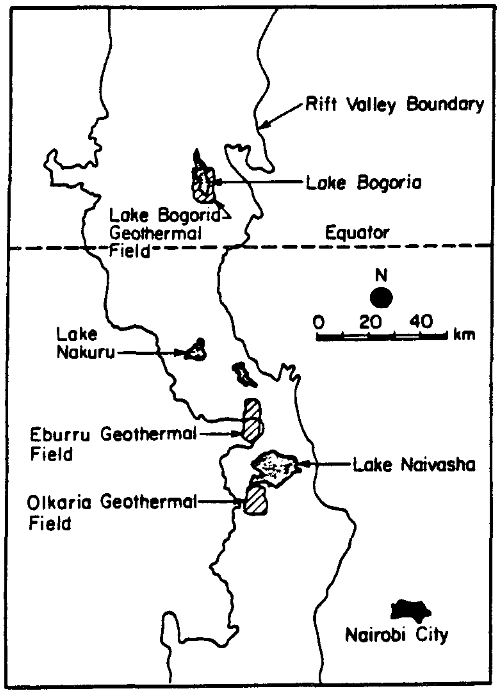

Figure 1. Location of the Olkaria geothermal field in the Rift Valley (from Svanbjornsson et al., 1983).

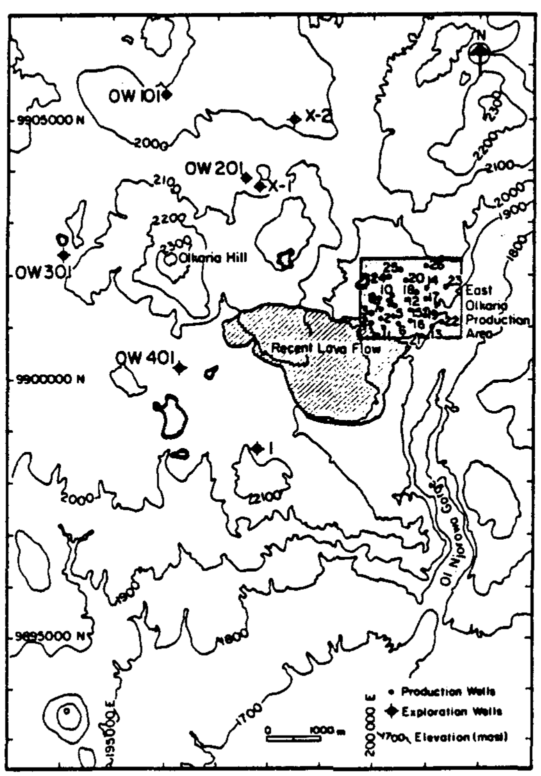

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Figure 2. Well locations at Olkaria (from KPC, 1984c).

The reservoir fluids are of the sodium-chloride type with only about 200-700 ppm of chloride. Non-condensible gas content is small (approximately 50 millimoles per kg steam). The chloride concentration increases both with depth and from south to north. This, along with a pronounced pressure decrease (11 bar/km) from north to south strongly suggests the presence of an upflow zone north of the present well field (Fig. 3). A detailed description of the conceptual model shown in Figure 3 is given elsewhere (KPC, 1982b, 1984b).

The large areal extent of the geothermal system at Olkaria (~80 km^2) and the large thickness of the reservoir (~2000 m) suggest a large power potential of the resource. The generating capacity of the resource has been estimated to be 500-1000 MW_e for a production period of 30 years (KPC, 1981b). However, the rather low average reservoir permeability (1-10 md) may make it impractical to recover more than a fraction of the energy in-place. For reliable estimates of the energy that can be economically extracted, numerical simulation studies are required.

The work presented in this report is based upon data collected by various experts from Kenya Power Co. (KPC), and their consultants. Key references include numerous reports by KPC experts, status reports prepared by Virkir, and Merz and McLellan, and overview reports by Waruingi (1982), Svanbjornsson et al. (1983) and KPC (1984c).

HISTORY MATCH OF WELL PERFORMANCE

The primary data used for the history match of the Olkaria wells are the flow rate and enthalpy data. Flow testing of some of the early wells started in 1975 on a rather small scale; more significant fluid extraction began in mid-1977. We neglect the small fluid mass extracted before July 1977. From July 1977 until the end of 1983 (the simulation period) wells 2-23 were tested periodically; wells 2, 5-7, 10-12 were continuously produced after the first 15 MW_e unit came on line in 1981, and wells 13-19 after the second unit came on line (August 1982). In the simulations we model the actual flow history of each well. The simulations are carried out using the two-phase, three-dimensional simulator MULKOM (Pruess, 1982).

One major approximation in our simulations is the use of a porous medium model for the fractured rocks at Olkaria. A porous medium model is used because of the limited fracture data available, and the lower computational cost involved. As we will illustrate in a later section, the porous medium model matches well the observed data.

Computational Approach

Figure 4 shows an areal view of the integral finite difference grid used in the history match simulations; the grid was later extended in all directions for the prediction studies. In developing the grid shown in Figure 4, the surface locations of wells 2 through 26 were used as nodal points (represented by the dots). In order to

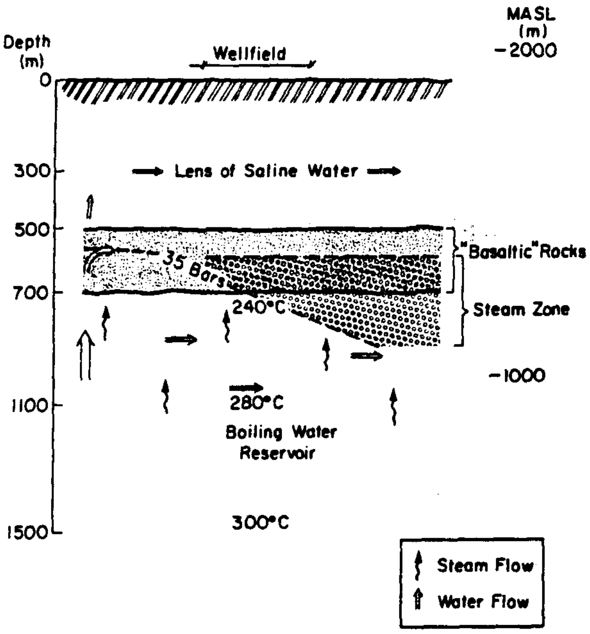

Figure 3. Schematic N-S section through the Olkaria geothermal reservoir (from KPC, 1984b).

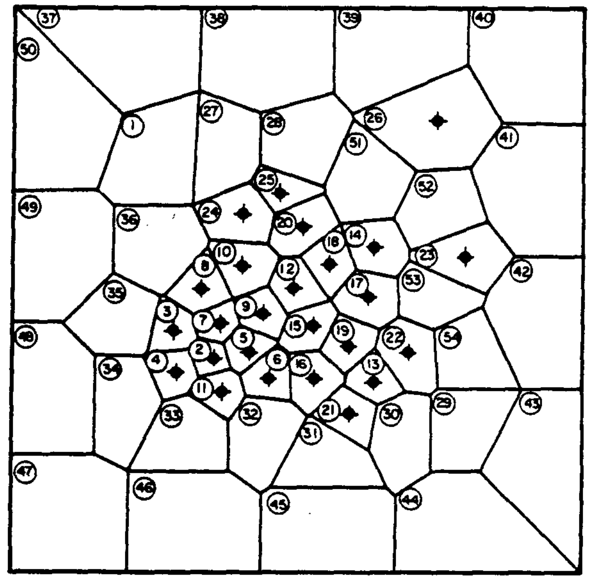

Figure 4. Mesh used for history match.

represent the wells more realistically a radial mesh was embedded into all of the well elements. The outer elements provide recharge to the wellfield.

In order to determine the appropriate vertical dimension of our model, we considered the locations and relative strengths of feed zones for all of the wells (Fig. 5). The figure shows that most of the wells are cased to a depth of about 500-600 m; well 19 is cased through the steam zone (at a depth of 600-750 m). Most of the wells have 2 or 3 feed zones; often one of the feed zones is located in the steam zone. The presence of the steam zone makes a three-dimensional model necessary, and it was decided to use a three-layer model. The top layer (100 m thick) represents the steam zone; two layers of 250 and 500 m thickness, respectively, represent the underlying liquid zone. The bottom of the reservoir was assumed to be at a depth of 1500 m, which is the depth to the deepest major feed zone (well 19). Note that by neglecting recharge from greater depth the results should be somewhat conservative.

Flow into a well is allowed through all layers in which the well has one or more feed points. We do not prescribe the flow from each layer, but calculate it based upon the following deliverability model (Pruess et al., 1984):

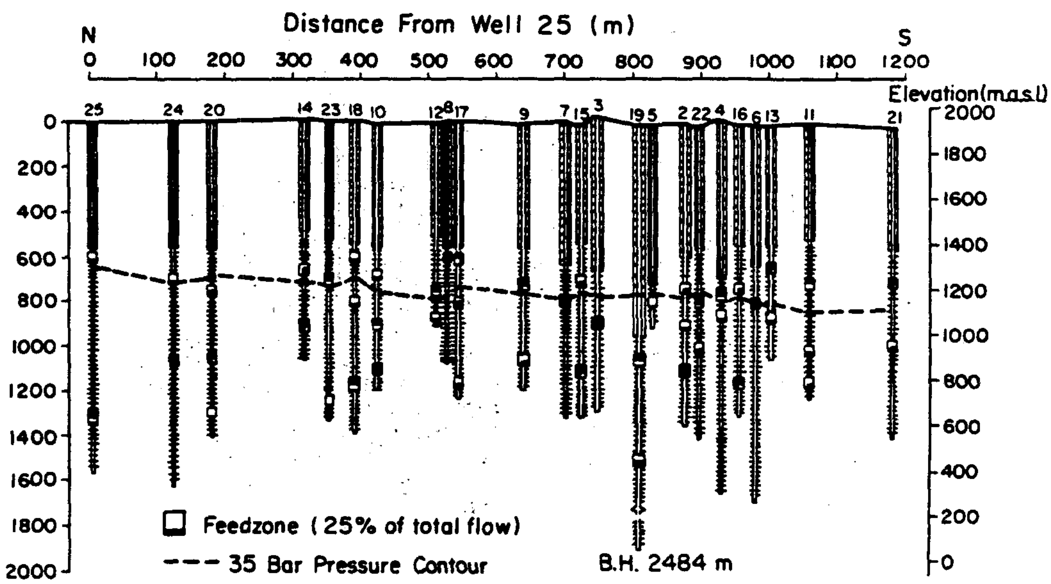

Figure 5. Major feed points in wells.

$$q = \sum_{\beta = \text{liquid, vapor}} \frac{k_{r_\beta}}{\mu_\beta} \cdot \rho_\beta \cdot PI \cdot (p_\beta - p_{wb})$$

where k_{r_β}, μ_β, ρ_β and p_β are relative permeability, viscosity, density and pressure of the β-phase, respectively. PI is the productivity index and p_{wb} is the flowing well pressure opposite the feed zone. Values of p_{wb} are obtained from pressure profiles of flowing wells; average values used for the steam zone and the upper and lower liquid zones are 8, 12, and 22 bars, respectively. The total flow rate from a well is simply the sum of the flow rates from all connected layers.

In order to obtain a reasonable match with observed flow rates and enthalpies of the wells, numerous iterations were necessary. The parameters adjusted during the iteration process were the productivity indices, permeability, and porosity. Although the effects of these parameters are coupled, each of them affects the flow rates and enthalpies in a very different way. The productivity index mostly affects the flow rate at relatively early time; consequently, we use this parameter to fix the initial rate from a layer. For the time scale of interest here (months or years), the permeability primarily controls the flow rate decline with time, and the porosity controls the enthalpy transients.

Simulation Results

After numerous iterations we obtained reasonable matches with flow rate and enthalpy transients for all of the wells. As an example, Figure 6 shows the match obtained for well 11. The enthalpy data is in the upper half of the figure, with the flow rate data occupying the lower part; the solid lines represent the measured values. The match between the observed and calculated values is reasonable, especially if one considers the approximate nature of flow rate and enthalpy measurements. In general, our matches for all wells are within 100-200 kJ/kg for the enthalpy and 1-2 kg/s for the flow rate (Bodvarsson et al., 1985a). The average calculated enthalpy of the produced fluids from all wells and the cumulative mass extracted also show good agreement with the measured values.

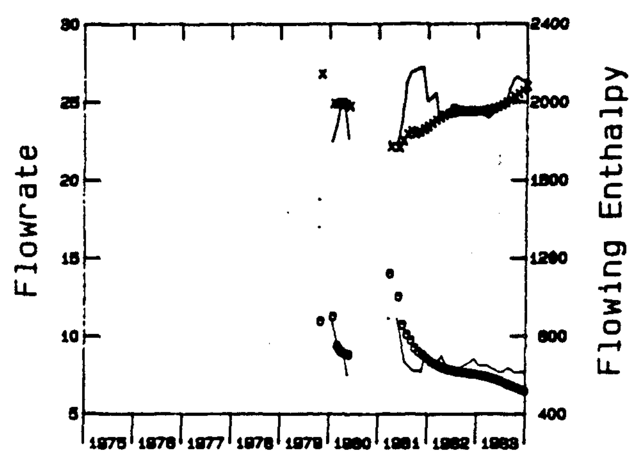

Figure 6. History match for well 11 at the Olkaria field.

In general, the flow rate decline of the wells is mostly due to phase mobility effects; i.e., changes in vapor saturation in the producing elements. Because the density of vapor is smaller than that of liquid, an increase in vapor saturation will cause a flow rate decline, even though the element pressure may change very little. Therefore, when a well is put on line and boiling starts in its vicinity, causing increases in vapor saturations, the enthalpy generally rises and the flow rate declines. At the end of the simulation period (end of 1983), most of the wells have reached quasi-steady conditions, with a rather gradual enthalpy rise and flow rate decline. In comparison to other geothermal fields, the enthalpy rise for the Olkaria wells is large, primarily because of low reservoir porosities and permeabilities.

By calibrating the model to field data we determine the effective porosity and permeability distribution in the reservoirs. In both the upper and lower liquid zones an average porosity of 2% is obtained, with variations ranging from 0.25 to 6%. Note that due to lack of enthalpy variations in fluids coming from the steam zone, we are not able to estimate the effective porosity in that zone. It should also be noted that the porosities determined represent the fracture porosity of Olkaria rocks rather than the matrix porosity. Average matrix porosities of Olkaria rocks vary from 8 to 16% depending on the rock type and depth (Mwangi and Muchemi, 1984). Our modeling results indicate that average permeabilities of the steam, upper liquid and lower liquid zones, are 7.5, 4.0, and 3.5 md, respectively. Variations in the permeability range from 0.25 to 25 md, with no apparent spatial trends, except for a distinct high permeability anomaly in the lower liquid zone, extending N-S through wells 12, 15 and 16. These permeability values are somewhat higher than those inferred from well tests of individual wells. However, the well test data are somewhat questionable as they do not correlate well with well outputs.

The percentage of flow from different layers is compared to estimates made by KPC (1984b), and for many wells the agreement is quite good. Our simulation results indicate that about 60% of the produced fluids come from the liquid zone, and only about 40% from the steam zone. The basis of this estimate is the enthalpy variations in the wells, which clearly suggest significant inflow of low enthalpy fluids from the liquid zone at early times. Later on, the enthalpy of most wells increases rapidly due to boiling in feeds in the liquid zone. The relatively high inflow rate from the liquid zone supports deep drilling, as opposed to shallow drilling; i.e., completing the wells only in the steam zone.

From the well-by-well model, we obtain estimates for the downhole pressure and vapor saturation transients in each flowing well. Figure 7 shows these data for the upper liquid feed of well 12.

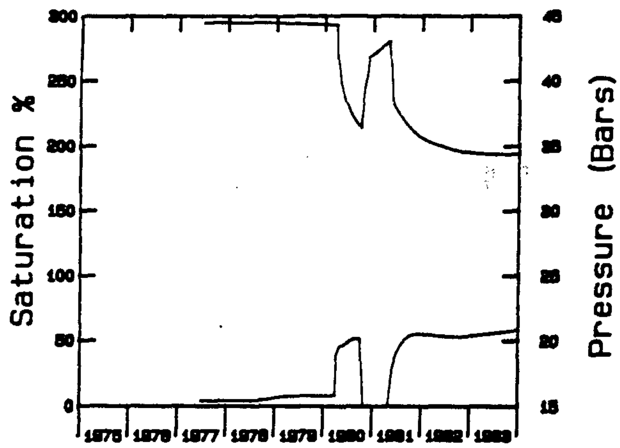

Figure 7. Pressure and vapor saturation changes with time for history match - well 12, upper liquid zone.

The lower curve represents the vapor saturation and the upper curve the pressure transients. The well had a short flow test in 1980, but was connected to Unit 1 in 1981. The figure clearly shows the pressure drop and vapor saturation rise due to exploitation. Note the over-recovery in the vapor saturation after the initial flow test due to heat mining, which is consistant with theoretical results (Sorey et al., 1980).

The actual pressure drawdown in the reservoir must be compared to calculated pressure data from non-producing ("observation") wells. The simulation results predict very small pressure drawdowns in the field to date (1984), or on the average, 4, 2 and 1 bars in the steam, upper liquid, and lower liquid zones, respectively. This small calculated pressure decline has been verified by field measurements (Haukwa, 1984).

Figure 8 shows the vapor saturation distribution in the upper liquid zone at the end of 1983. The figure shows that the vapor saturation changes do not extend far outside the wellfield area because of the high compressibility of two-phase mixtures. Over most of the wellfield the vapor saturation has increased from 10 to 50%, with local maxima around the producing wells.

PERFORMANCE PREDICITONS

From the history match we obtain a model that can be used to predict the response of the reservoir and individual wells to various exploitation schemes. At present the main interest at Olkaria is to investigate the reservoir response to power productions of 45 and 105 MW_e, to study the effects of injection, and to determine proper well spacing for future drilling. The following scenarios are studied:

(1) 45 MW_e power production with future ("development") wells at a density of 11 wells/km^2.

(2) 45 MW_e power production with development wells at a density of 20 wells/km^2.

(3) 105 MW_e power production with development wells at a density of 11 wells/km^2.

(4) 45 MW_e power production with 40% reinjection and development well density of 11 wells/km^2.

(5) 45 MW_e power production with 100% reinjection and development well density of 11 wells/km^2.

For the history match, the model was calibrated against 6.5 years of data (July 1977 - December 1983). As a general rule one should not expect to be able to predict the behavior into the future with confidence for more that the calibration time, i.e., approximately to the year 1990. However, it is useful to compare predictions for different scenarios for a longer timespan, and therefore we have calculated the various cases for a period of 30 years, to the year 2015.

Because of the long performance prediction period and the high production rates, the mesh used for the history match (Fig. 4) had to be extended to accommodate an expanding wellfield. The extended mesh includes the old one as the central part, and covers an area of 8 x 12 km^2. The grid is extended further to the north than in the other directions, because of available drilling area there; we also assume that some of the future wells will be drilled to the west. Reservoir conditions and parameters are believed to show little lateral variation over the area covered by the extended mesh. Therefore, outside the wellfield we use the average permeability and porosity values obtained for the wellfield from the history match.

When a constant electrical power production is desired, appropriate constraints must be placed on the steam rate at the separators. Following Bodvarsson et al. (1982) and Bodvarsson and Pruess (1981), the steam rate from a well at the separators is calculated assuming iso-enthalpic flow up the well. When the total steam rate of the existing wells falls below that required (e.g., 125 kg/s for 45 MW_e), additional development wells outside the present wellfield are automatically added during the course of the simulation.

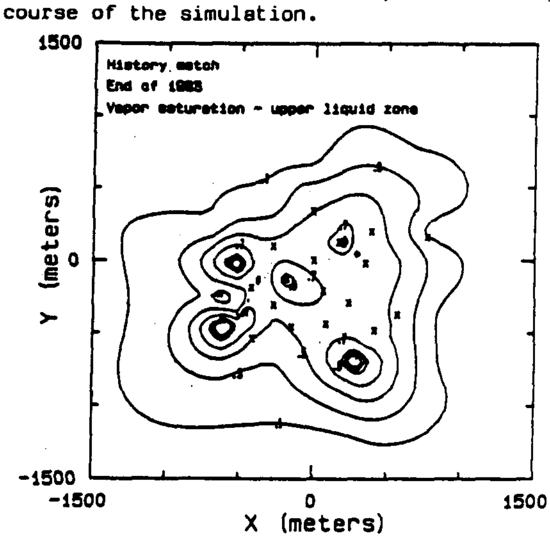

Figure 8. Vapor saturation distribution in the upper liquid zone at end of 1983.

45 MW_e Power Production

Two cases are considered, 11 and 20 wells per km^2. The results of both cases show that the readily available drilling area in East Olkaria is sufficient for power production of 45 MW_e for 30 years. The total new development area needed is approximately 2 km^2, bringing the total wellfield area to 4 km^2 by the year 2015. Within the next decade all of the existing production wells will become pure steam producers, thus continuing the present trend (average enthalpies have increased from 1900 to 2400 kJ/kg during the last six years). The rapid enthalpy rise is primarily due to the low effective porosities and permeabilities at Olkaria. Figure 9 shows the vapor saturation distribution in the upper liquid zone at the end of 2015. The pure vapor zone extends farthest to the north because most of the development wells are sited north of the present wellfields; note also the rather small areal extent of the disturbance (2-3 km radius) after 30 years of 45 MW_e power production.

The results for the two cases with well spacings of 11 and 20 wells per km^2 are very similar. Basically the same areal extent of the wellfield is required and the enthalpy behavior of the wells is similar. The similar results can be explained when one considers that the wellfield boils dry rather quickly and the flow from the wells is limited by the recharge from the outside. Since the permeability of the outside rocks is low, the fluid flow to the wellfield is the limiting factor. However, a large difference emerges when one considers the number of development wells needed to maintain 45 MW_e power production. Figure 10 shows that 24 and 40 additional wells are needed for well densities of 11 and 20 wells per km^2, respectively. These results strongly suggest that the present well density at Olkaria of 20 wells per km^2 is far too high. Although drilling wells with relatively small well spacing appears to be advantageous in the short term, in the long run, larger well spacing is predicted to provide similar steam flow with considerable economic benefits.

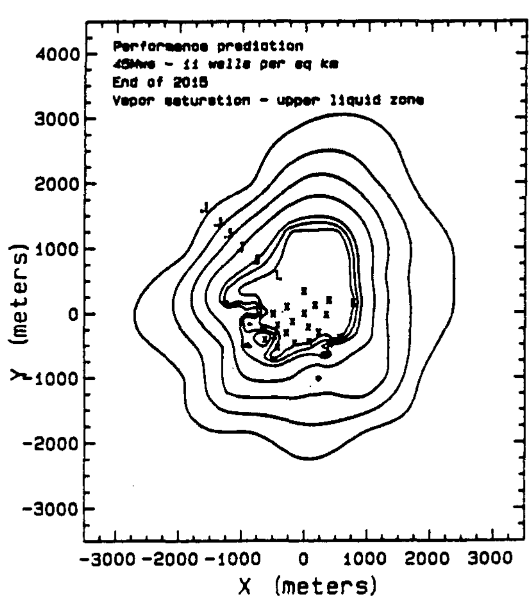

Figure 9. Vapor saturation distribution in the upper liquid zone at end of 2015.

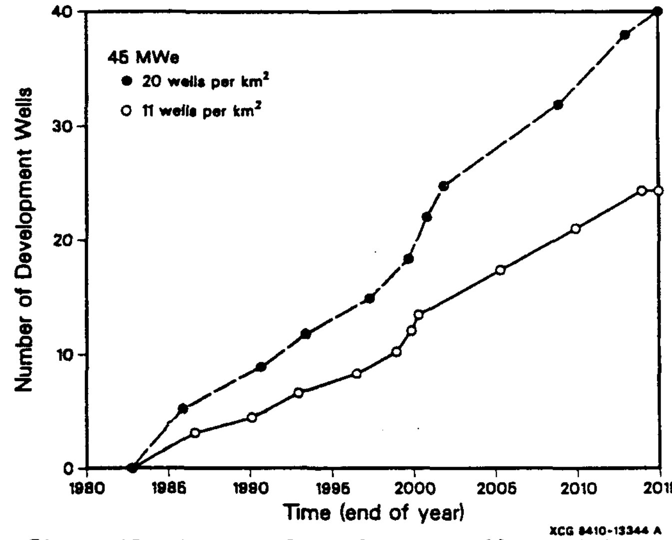

Figure 10. Number of development wells needed to maintain 45 MWe using different well spacing and with 100% injection.

Other Cases Studied

Due to space limitations, it is not possible to describe the results obtained for cases involving 105 MW_e power production or cases with reinjection. For those results and more detailed information on all the simulation studies the reader is referred to Bodvarsson et al. (1985a,b).

CONCLUSIONS

A detailed 3-dimensional model of the East Olkaria field that includes descriptions of individual wells has been developed. The model matches reasonably well the flow rate and enthalpy history of all Olkaria wells. The results of the simulation studies indicate that:

(1) Effective porosities of the liquid zone are low, on the average 2%. These porosities represent the average fracture porosities of Olkaria rocks. Average permeabilties are estimated to be 7.5, 4.0 and 3.5 md for the steam, upper liquid and lower liquid zones, respectively.

(2) Our results indicate that 60% of the produced fluid come from the liquid zone and 40% from the steam zone. This suppports deep drilling with substantial open intervals for flow from the liquid dominated zone.

(3) Well densities at Olkaria (20 wells/km^2) are too high; for future wells a well density of 11 wells/km^2 is recommended.

(4) The present wellfield area (East Olkaria) can easily handle power production of 45 MW_e for 30 years; the wellfield must be extended by some 2 km^2.

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