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Deliverability and its Effect on Geothermal Power Costs

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Abstract

The deliverability of liquid-dominated geothermal reservoirs is presented in terms of reservoir performance, and wellbore performance. Water influx modeling is used to match the performance of Wairakei in New Zealand, and Ahuachapan in El Salvador. The inflow performance is given in terms of a linear productivity index for liquid-only flow, and a solution-gas drive relationship for two-phase flow. A 9-5/8" production well is assumed, flowing 250°C water from 900 m depth, with a wellhead pressure of 100 psia. A Geothermal Development Model, that couples reservoir deliverability and power plant performance, and assigns costs to both, is used to illustrate how the development cost of geothermal electric power projects can be estimated.

Introduction

The performance of reservoir/wellbore systems is perhaps the major cause of uncertainty in geothermal field development decisions, at least in comparison to the performance of surface facilities and power plants. Because of this uncertainty it is difficult to optimize the development of liquid-dominated resources for electric power production. This may be the reason why issues of geothermal resource exploitation and power plant operations tend to be dealt with separately in the literature. In this paper, we couple the reservoir and economical issues in a Geothermal Development Model, and consider the effect of deliverability on the cost of geothermal electric power from liquid-dominated resources. The overall performance of a reservoir/wellbore system with time is what we call deliverability. It has three components: reservoir performance, inflow performance, and wellbore performance.

Reservoir Performance

A reservoir model describes the change in reservoir pressure as a function of fluid production. The reservoir models available range from simple decline curves, through lumped-parameter models, to distributed-parameter models. Grant (1983) has reviewed these for geothermal uses. Figure 1 shows the drawdown in reservoir pressure versus cumulative mass withdrawal for three liquid-dominated reservoirs: Ahuachapan, Svartsengi, and Wairakei. These data were taken from Vides (1982) and Quintanilla (1983) for Ahuachapan, and from Gudmundsson et al. (1985) and Stacey and Thain (1983) for Svartsengi and Wairakei, respectively. Figure 1 shows that the drawdown in the three reservoirs is similar. The Wairakei reservoir is known to be larger than the others. In terms of surface area, it is reported to be about 15 km^2 (Donaldson and Grant, 1978), while Ahuachapan and Svartsengi are likely to be in the range 5-10 km^2. Figure 1 suggests that Svartsengi is the smallest of the three; it shows greater drawdown at lower levels of production. Through 1982, the average rate of fluid production from Wairakei was about 1500 kg/s; the rate at Ahuachapan was about 600 kg/s through 1983; from Svartsengi the average rate was about 150 kg/s, currently it is about 300 kg/s. The three fields are reaching nearly the same level of drawdown as cumulative mass production increases. The long-term drawdown appears to be about 3 MPa, although the drawdown in the two smaller fields has not leveled off as much as Wairakei. We observe that these geothermal liquid-dominated reservoirs exhibit a similar drawdown characteristic; their overall uniform behavior suggests they can be modeled using similar reservoir engineering techniques. The Wairakei, Ahuachapan, and Svartsengi reservoirs have a steam/vapor-dominated zone above the main liquid-dominated zone; see Donaldson and Grant (1981), Rivera-R. et al. (1983), and Gudmundsson and Thorhallsson (1986) for details, respectively.

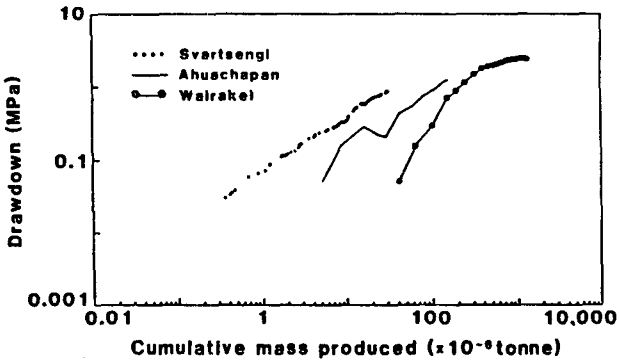

Figure 1. Drawdown in reservoir pressure in three liquid-dominate reservoirs.

We elected to use a lumped-parameter model with water influx to study the performance of the three liquid-dominated reservoirs; specifically, the simplified method of Hurst (1958). This method was used by Olsen (1984) and Gudmundsson and Olsen (1985) to match the production history of the Svartsengi reservoir. Marcou (1985) extended this work to include Ahuachapan and Wairakei - the latter match will be discussed here. We assumed the reservoir to be radial and finite, and the supporting aquifer to be radial and infinite. In water influx modeling we focus on fluid flow across the boundary between the hot reservoir and surrounding warm aquifers. The reservoir is taken to have homogeneous properties and uniform pressure. The model equation is given in terms of the warm aquifer physical properties; the permeability-thickness product of the reservoir and aquifer are taken to be equal; the compressibility of the reservoir and aquifer provide the main contrast in properties. In a general way, the pressure response of the reservoir is dominated by the flow of water into the main reservoir volume from surrounding aquifers. If there was no fluid flowing into the reservoir, it could be modeled as a constant volume tank under decompression or drainage. There are three constants used in the Hurst (1958) simplified method

$$A = \frac{\mu_a}{2 \pi k h \rho_a}$$

$$B = \frac{k}{\phi \mu_a c_a r_r^2}$$

$$C = \frac{2 c_a}{c_r}$$

where the symbols have the usual meaning, and the subscripts a and r stand for aquifer and reservoir, respectively. Grant et al. (1982) showed that for typical geothermal reservoir conditions, the compressibility of liquid water is of the order of 10^{-9} Pa^{-1}, steam vapor 10^{-7} Pa^{-1}, and a two-phase mixture 10^{-6} Pa^{-1}. This range of several orders of magnitudes affects greatly the pressure response of geothermal reservoirs, particularly when two-phase zones are present.

We matched the Wairakei data using 3 years, 6 years, 12 years, and 25 years of production history. The match parameters obtained from the partial data sets were then used to predict the drawdown in reservoir pressure for the 25 years of history. Our matches are shown in Figure 2. We wanted to test the forecasting ability of the model. Using the first three years of history, the model overpredicts the drawdown; using six years or more the match between model and actual drawdown was reasonable. That is, using six years of production history, we were able to forecast the next twenty years of drawdown with reasonable success. The following values of model constants were obtained from the full match: $A = 6.7 \times 10^2$ pa.s/kg; $B = 9.3 \times 10^8$ s^{-1}; $C = 0.19$. For an aquifer compressibility of 2.4×10^{-9} Pa^{-1}, the reservoir compressibility becomes 2.6×10^{-8} Pa^{-1}. It appears from this result that boiling in the two-phase zones does not significantly influence the compressibility of the Wairakei reservoir.

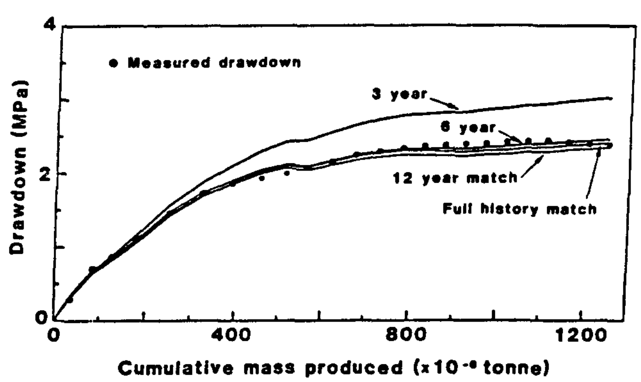

Figure 2. History match and forecast of drawdown for Wairakei.

Inflow Performance

The relationship between reservoir pressure and wellbore flowing pressure we call inflow performance. In general, the mass flowrate w increases with increasing difference between the two pressures, as expressed by the relationship

$$w = J\,(p_r - p_{wf})$$

where J is a constant called the productivity index. This equation usually applies for single-phase laminar flow into the wellbore; single-phase Darcy-type flow. In the case of geothermal wells, the well flowing pressure p_{wf} ought to be measured at the depth of the well's main feedzone fracture. The linear productivity index has been used by Gudmundsson (1984) in the calculation of output curves of geothermal wells with single-phase feedzones, using a wellbore simulator. We use it here for single-phase flow from the reservoir into the wellbore; when the well flowing pressure p_{wf} is greater than the saturation pressure p_{sat} of water. Figure 3 shows that inflow performance of well Utah State 14-2 in the Roosevelt Hot Springs geothermal area. The data were taken from Butz and Plooster (1979), and Butz (1980); see also Menzies (1982). The productivity index of this well was determined to be about 40 tonne/hr.MPa (600 lb/hr.psi), which is an average-kind of a well. A more productive well is well 12 in the Svartsengi field, which was reported by Gudmundsson (1984b) to have a productivity index of about 100 tonne/hr.MPa (1500 lb/hr.psi). We note that the productivity index is the inverse slope of the line above p_{sat} in Figure 3. A larger productivity index, therefore, means that a greater flowrate is achieved for the same pressure drive. Furthermore, the advantage of increased casing size is greater for wells with a large productivity index.

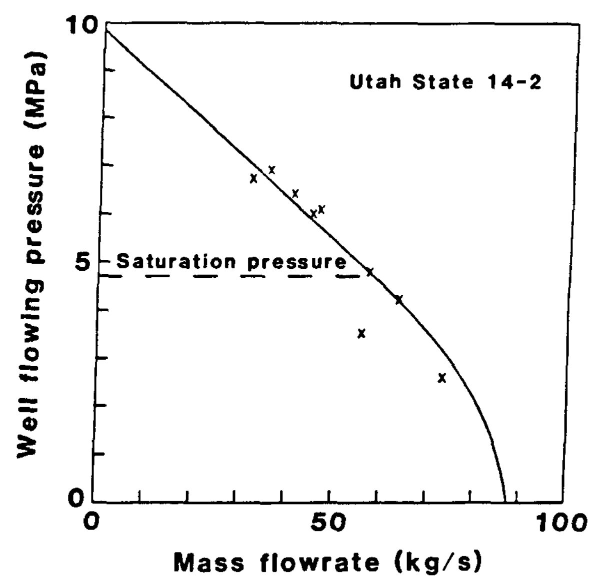

Figure 3. Inflow performance of well Utah State 14-2.

At relatively high flowrates, and when a steam/water mixture flows from the reservoir into the wellbore, the relationship between mass flowrate w and driving pressure $(p_r - p_{wf})$, is likely to become non-linear. This problem was investigated by Vogel (1968) for solution-gas drive reservoirs in the petroleum industry; Menzies (1982) considered a similar problem of steam/water flow in fractures, including the effect of heat transfer from the rock to two-phase mixture. The Vogel-method was used in our work because of its simplicity.

The Vogel (1968) inflow performance curve is an empirical relationship, obtained for the situation where gas is coming out of solution; the flow of oil from its bubble point to increasing gas/oil ratio. We decided to apply the Vogel (1968) relationship to only the two-phase flow part of the geothermal inflow performance curve. For this situation the relationship takes the form

$$\frac{\Delta w}{\Delta w_{max}} = 1.0 - 0.2 \left[\frac{p_{wf}}{p_{sat}} \right] - 0.8 \left[\frac{p_{wf}}{p_{sat}} \right]^2$$

The Δw is the incremental mass flowrate we achieve by lowering the well flowing pressure below the fluid's saturation pressure. The Δw_{max} is what would ideally be achieved if the well flowing pressure be became negligible; in other words, if there was negligible pressure drop in the wellbore. The square term in the modified Vogel (1968) relationship takes into account turbulent losses and other non-linear effects. The inflow performance below the saturation pressure in Figure 3 is a solution-gas-type relationship. We see that the inflow performance of well Utah State 14-2 can be matched with a linear productivity index at pressures above the saturation presure, and a combined linear and non-linear relationship at lower pressures.

Wellbore Performance

We considered wells that produce steam/water mixtures at the wellhead. In the main they will have liquid water feedzones; in some cases the fluid will be two-phase, as in Figure 3 when the well flowing pressure falls below the saturation pressure. Wellbore performance concerns the pressure drop from the bottom or main feedzones to the wellhead. This performance depends on many variables, including: fluid enthalpy, reservoir pressure, well diameter and depth, and wellhead pressure. Ambastha and Gudmundsson (1986) present flowing pressure and temperature profiles in 10 two-phase geothermal wells; they also match the data using a wellbore simulator based on the Orkiszewski (1967) pressure drop correlations. Such a simulator can be used to construct performance curves for two-phase geothermal wells. Butz and Plooster (1979) and Butz (1980) have published performance curves for well Utah State 14-2. The curves are based on a fluid enthalpy of 1100 kJ/kg (liquid water at 250°C), a reservoir pressure of about 9.7 MPa (1430 psia) at a depth of 900 m, and a wellhead pressure of 0.69 MPa (100 psia). We present these curves in Figure 4 as wellbore performance curves for a 9-5/8" and 13-3/8" casing from 900 m depth to surface. The wellbore performance curves are independent of inflow performance and reservoir performance; when we couple them, however, we obtain the reservoir/wellbore system deliverability.

Geothermal Development Model

Decision making about geothermal developments deals with objectives, choices, and constraints. To optimize this decision making process, we need a model that includes both the physical and economic features of development. We have made such a model from the point

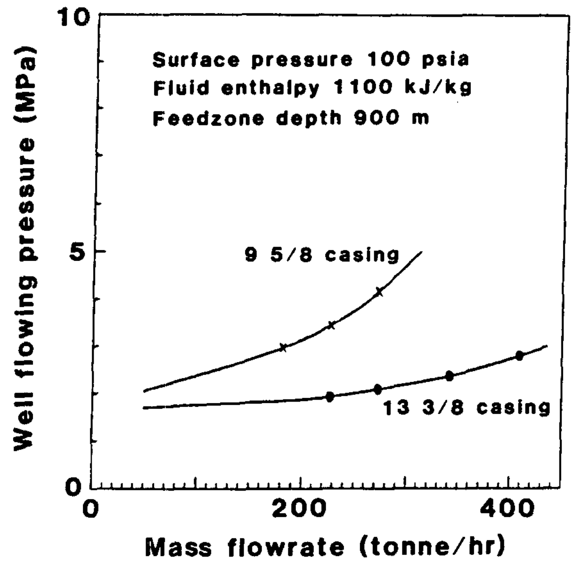

Figure 4. Wellbore performance of 9 5/8" and 13 3/8" wells.

of view of reservoir engineering, to study the effect of deliverability on electric power costs. The elements of the Geothermal Development Model are shown in Figure 5. Several physical models or features can be selected for each of these elements; similarly, different problems can be investigated: (1) reservoir can be modeled using decline curves, lumped-parameter models, or distributed-parameter models, (2) wellbore flow can be modeled using generalized, or flow pattern specific two-phase flow models, (3) surface facilities can have separators at each wellhead, or a central separator station (4) wellhead units and a central station are typical power plant choices (5) spent fluids can be disposed of at the surface or injected back into the reservoir, with or without chemical treatment. And, for whatever choices we make, there are associated costs, and constraints.

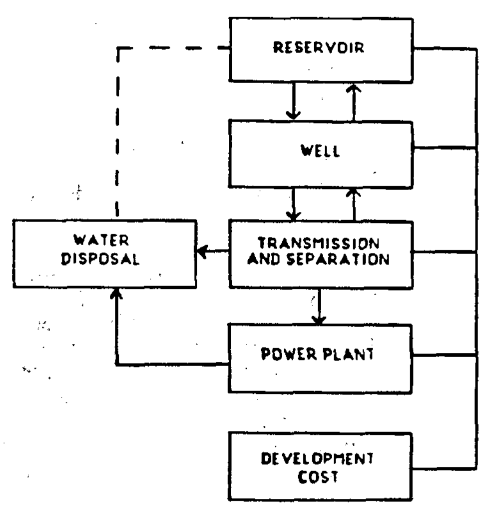

Figure 5. Elements of geothermal development model.

Above we presented the main features of the reservoir, inflow, and wellbore performances used. The following are a few details needed to complete the coupling of the individual performances to get the reservoir/wellbore system deliverability. We decided to use a 9-5/8" wellbore casing. The inflow performance curve in Figure 3, the 9-5/8" wellbore casing performance curve in Figure 4, intersect at a total flowrate of 220 tonne/hr (60 kg/s). This flowrate then, is the initial flowrate from a well like Utah State 14-2, for a wellhead pressure of 0.69 MPa (100 psia). With decreasing reservoir pressure, this flowrate will also decrease, because the inflow performance curve will move down in parallel with the initial curve, because it is constrained to go through the current reservoir pressure. We determined the deliverability of our typical well to follow the approximate relationship

$$w = 30p_r - 60$$

where w is mixture flowrate (kg/s) and p_r the average reservoir pressure (MPa). We used this equation in the development model to determine how many wells are needed at start-up, and when new wells are needed.

For a mixture enthalpy of 1100 kJ/kg and a separator pressure of 0.69 MPa, the mass fraction of steam is 22 percent. We reviewed a number of publications on geothermal electric power plants to obtain a value for the conversion efficiency of steam to electric power (see Marcou, 1985). We found that the following value were representative: condenser plants 8 tonne/hr.MW and back-pressure plants 15 tonne/hr.MW. We assumed negligible pressure loss from the wellhead to power plant. It follows that a well like Utah State 14-2 can generate about 6 MW of electric power initially. The average capacity of wells in liquid-dominated reservoirs worldwide is about 5 MW.

We divided the total cost of development into steamfield costs and power plant costs. Again, we reviewed a number of publications on geothermal electric power developments. The studies reviewed indicated that steamfield costs range from 25 to 50 percent of total development cost. Two of the references are reports by Holt and Ghormley (1976) and Southan et al. (1983). We decided to select typical cost values for use in the development model. The intial investment cost of central power plants was taken as 1.3 M$ per installed MW. This is cost in 1984 dollars, and includes expenses during construction. The initial investment cost of condenser wellhead units was taken as 0.7 M$ per MW. The cost of backpressure wellhead units was taken as 0.5 M$ per MW. We used an annual cost of 0.03 M$/year per MW for central plants, 0.06 M$/year per MW for condenser wellhead units, and 0.03 M$/year per MW for backpressure wellhead units. The wellhead units were assumed 5 MW in capacity. The investment cost values used in the development model can be thought of as total cost at start-up.

Steamfield costs include production wells, separators, pipelines, and injection wells; that is, the total cost of delivering steam to a power plant. We lumped these costs into one value and assigned them to a production well. In other words, we assumed that total steamfield costs are proportional to the number of production wells. We selected 2.2 M$ per production well as a representative value. The annual steamfield expenses we estimated 0.3 M$/year per production well. Note that the cost of injection wells, for example, is included in this cost value; we are simply using the production wells as our yardstick. Like the power plant costs, the steamfield costs ought to be thought of as the total cost at start-up.

A project life of 25 years and a discount rate of 10 percent were selected for our study. Costs were discounted to find their net present value at the start of the project.

For a project involving a central plant, the total development cost was arrived at as follows. The initial plant investment cost, plus the sum of the discounted annual plant cost, were added to the initial steamfield investment cost, plus the discounted annual steamfield costs. In addition, as the deliverability of each well declines with time, more wells need to be drilled to maintain steam production. The cost of the additional wells was discounted to present value along with their annual steamfield costs. For a project involving a wellhead unit, the plants and wells were installed at the same time in pairs. Wells and wellhead plants added after the first year of the project, were discounted to the first year; that is, their investment and annual costs.

The steamfield was assumed to operate every day of the year; at 100 percent capacity. The power plant was assumed to be operated at 80 percent capacity. Therefore, the drawdown in reservoir pressure was calculated assuming the wells were on-line all the time; the cost of electricity was calculated assuming the power plant was on-line 80 percent of the time.

Results and Discussion

The general form of our results is shown in Figure 6. The total cost of project development in million dollars, based on net present value at start-up, is plotted against generation level or installed electric power in megawatts. Consider the nature of this curve. Point A is a 50 MW power project, and point B a 150 MW project. The net present value development cost of the 50 MW project is 100 M$, while the 150 MW project costs almost 450 M$ (447 M$), which give 2000 $/kW and about 3000 $/kW as specific costs, respectively. Figure 6 happens to be based on Ahuachapan match parameters and 5 MW wellhead plants with condensers. The slope of the curve in Figure 6 gives the energy cost from different size developments. For example, at point A the gradient corresponds to a levalized energy cost of 31 mills/kWh, at point B it is 83 mills/kWh, and at point C (90 MW plant) it is 47 mills/kWh. We distinguish between the average and marginal cost. The average cost of energy is found from the slope of a line connecting some point on the curve with the origin. The marginal cost is found from the slope of the tangent to some point on the curve. At point A both the average and marginal costs are the same. At point B, however, the average cost is 47 mills/kWh, but the marginal cost 83 mills/kWh.

Why does the marginal cost of energy increase with generation level? The main reason, we think, is that the flowrate of the production wells decreases more rapidly at high generation levels than low, but also because we assumed no economy of scale in power plant costs. To illustrate this point: 11 wells are required for the 50 MW project in Figure 6, yet 78 wells are requried for the 150 MW project. Therefore, while the generation level tripled, the required number of wells (over the life of the project) increased about seven times. Neither did we lower the cost associated with production wells with time; that is, we assumed the same ratio of injection to production wells at start-up and later. We are forced to conclude that geothermal power developments shown dis-economy of scale when steamfield costs and power plant costs are coupled

The Geothermal Development Model can be used to study any number of reservoir/wellbore deliverability and

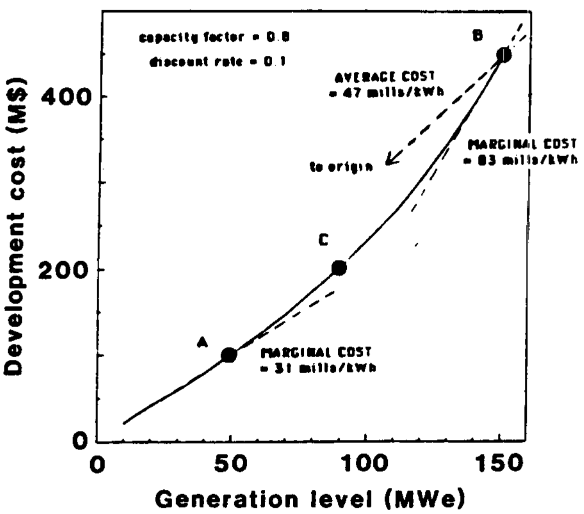

Figure 6. General form of results from development model.

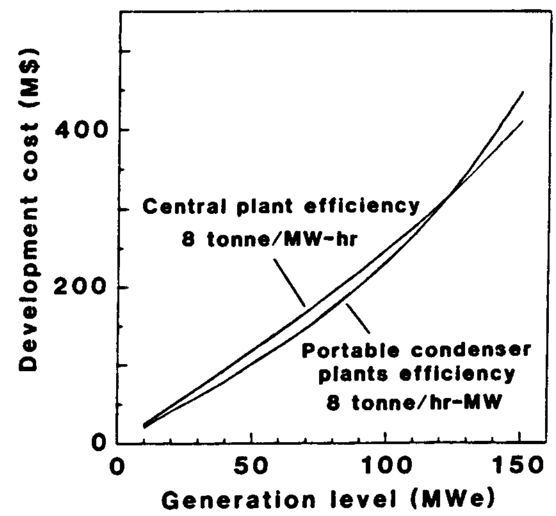

Figure 7. Effect of plant choice on development cost for Ahuachapan match parameters.

power project scenarios. We used the reservoir and economic parameters already discussed, to study the effect of different reservoirs, different power plant choices, and different wellfield operations. In the last of these, we contrasted the effect of constant wellhead pressure production, against constant flowrate production (choked wells). We found that lower development costs were achieved in the constant wellhead pressure case. In our study of different power plant choices, we found the backpressure option was in all cases much more expensive than the condenser option; the reason being the large difference in their conversion efficiency from thermal to electric power.

Figure 7 shows the effect of different types of power plants; that of wellhead units with condensers (same as Figure 6), and a central power station (with condensers). We used the reservoir match parameters for Ahuachapan. At low generation levels the wellhead option costs less, but at high generation level it costs more. This results comes about due to the constraint of having each wellhead unit hooked up to just one well. At high generation levels the flowrate of the wells declines much more than at low generation levels. Each of the wellhead units is generating below what it is capable of generating, resulting in over-installed capacity. In the central plant scenario, on the other hand, the installed capacity is always the same, because make-up wells can be connected to the plant as required. We did the same calculation using match parameters from the Wairakei reservoir. Unlike that shown in Figure 7, the cental power plant option costs more at all generation levels, because the reservoir/wellbore deliverability does not decline as much as at Ahuachapan.

The scenario of different size reservoirs for the same type of power plant project, is shown in Figure 8. Using the deliverability of Ahuachapan and Wairakei, we calculated the development cost for wellhead units with condensers. The message of Figure 8 is that there is a great cost advantage in having a large reservoir over that of having a medium or small reservoir. This advantage becomes more pronounced with increasing generation level. At 150 MW the Ahuachapan option has a marginal energy cost of 83 mills/kWh, while the Wairakei option has a marginal cost of 40 mills/kWh.

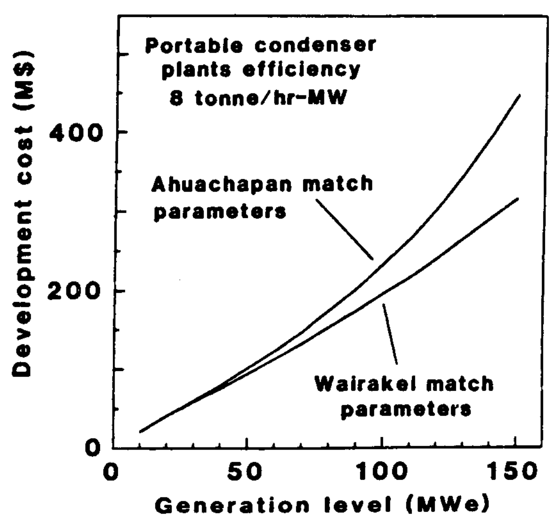

Figure 8. Effect of reservoir/wellbore deliverability on development cost for wellhead condenser plants.

Conclusions

- The production histories of the liquid-dominated Ahuachapan, Svartsengi, and Wairakei reservoirs, were successfully matched using the radial form of Hurst's simplified water influx method. In the case of Wairakei, for example, six years of production data were sufficient to match the full twenty-five years of history.
- The deliverability of reservoir/wellbore systems consists of reservoir performance, inflow performance, and wellbore performance. Methods and data are available to model the deliverability of liquid-dominated geothermal reservoirs. The methods selected here were intentionally kept simple, so there is ample scope for improvements.

- The Geothermal Development Model can be used to study the effect of reservoir/wellbore deliverability and different power plant schemes on the economics of geothermal electric power. With model refinements, it ought to be possible to optimize geothermal field developments.
- The cost of geothermal electric power and energy increases more rapidly than linearly with the size of development; there exists a dis-economy of scale in geothermal power developments. This effect is especially true for large developments and small and medium sized reservoirs.

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Enhancement of Steam Phase Relative Permeability Due to Phase Transformation Effects in Porous Media

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An experimental study of two-phase concurrent flow of steam and water conducted (Verma et al., 1985) and a set of relative permeability curves was obtained. These curves were compared with semi-empirical results (Brooks and Corey, 1964) and experimental results obtained by other investigators (Johnson et al., 1959, and Osoba et al., 1951) for two-phase, two-component flow (oil/gas; gas/water; gas/oil). It was found that while the wetting phase relative permeabilities were in good agreement, the relative permeability for the steam phase was considerably higher than the relative permeabilities of the non-wetting phase (oil in oil/water and non-condensing gas in gas/oil or gas/water) in two-component systems (Figs. 1 and 2). This enhancement of steam relative permeability is attributed to phase transformation effects at the pore level in flow channels.

There are two separate mechanisms by which phase transformation affected relative permeability curves (1) phase transformation in converging-diverging flow channels with hydrophilic walls can cause an enhancement of steam phase relative permeability; and (2) phase transformation along the interface of a stagnant phase and the phase flowing around it controls the irreducible phase saturation of the stagnant phase (Verma, 1986).

A pore level model was considered to study the first mechanism. In this model a pore space, shown in Figure 3, is idealized as a torroidal flow channel (Fig. 4) with a throat radius r_t and pore body radius r_b. Flow of steam and water through the throat portion of a pore was modeled using the MULKOM simulator (Pruess, 1983). The results indicate that when steam encounters a pore throat of a highly constricted flow channel (i.e., $\frac{r_t}{r_b} << 1$) in high conductivity solid, a fraction of the flowing steam condenses upstream from the constriction, depositing its latent heat of condensation. This heat is conducted through the solid grains around the pore throat, and evaporation takes place downstream. Therefore, for a given bulk flow quality, a smaller fraction of steam actually flows through the throat segments. Since steam has much higher kinematic viscosity than liquid water, and since the throat segments are the primary contributors to the overall flow resistance in the flow channels, the phase transformation effects reduce the overall resistance to steam flow along channels with varying cross sections. This pore-level effect manifests itself as relative permeability enhancement on a macroscopic level. However, our numerical studies indicate that for typical pores found in sandstone this effect is negligible.

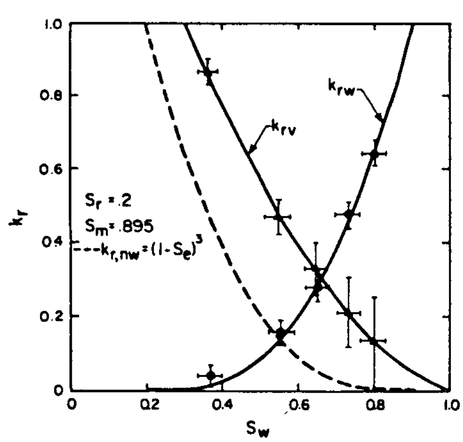

Figure 1. Relative permeability curves. Data points indicate the experimental results; the solid lines indicate the best fit. The broken curve is the relative permeability of the nonwetting phase according to the data of Brooks and Corey (1964).

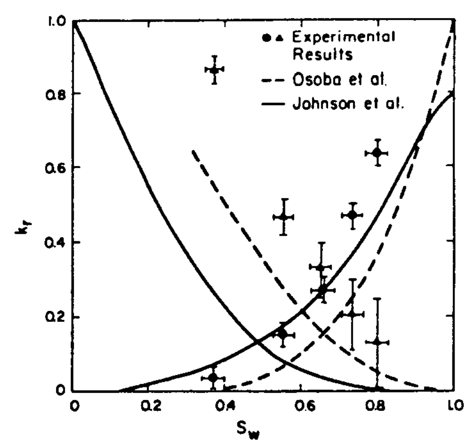

Figure 2. Comparison of our experimental results with those of Johnson et al. (1959) for oil-water and Osaba et al. (1951) for oil-gas. The wetting phase relative permeabilities compare well, but the steam phase relative permeabilities are higher than nonwetting phase relative permeabilities obtained by other investigators.

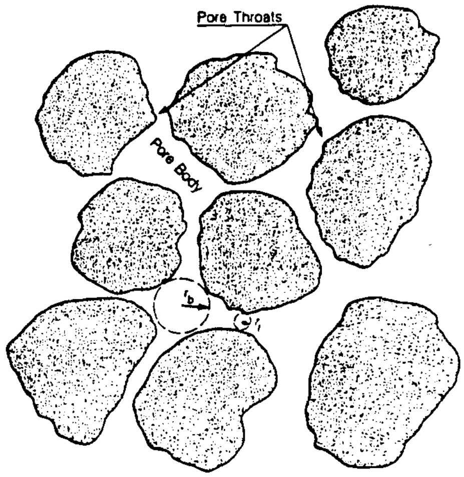

Figure 3. Schematic of pore space showing pore bodies and the throats connecting them.

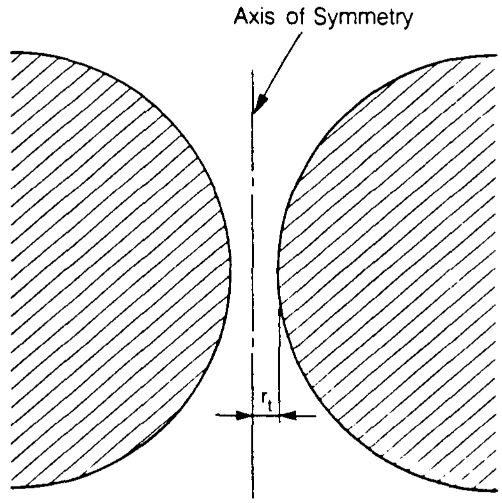

Figure 4. Idealized representation of a pore throat as a torroidal flow channel.

The second effect was studied by applying thermodynamic stability criteria to stagnant phases in pore space. Our study indicates that: (1) irreducible phase saturation for the steam phase will be negligible small when the liquid phase is flowing in the direction of lower thermodynamic pressure and temperature; and (2) irreducible phase saturation for the liquid phase will generally be negligible when steam is flowing in the direction of lower thermodynamic pressure and higher temperature. Detailed derivation of these results is given in a forthcoming report (Verma, 1986).

We conclude that the enhancement of steam relative permeability observed in our experiment is due to a reduction in irreducible steam phase saturation in comparison to the irreducible phase saturations for the non-wetting phase in the oil-water and oil-gas experiments with which we have compared our results.

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