Two-Phase Wells

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Introduction

The output of two-phase geothermal wells consists of steam vapor and liquid water at some wellhead pressure. Typically, this two-phase mixture is piped to a separator to produce steam for electric power generation. The liquid water separated from the steam is disposed of at the surface or injected back into the reservoir. The rate and pressure of the steam produced by individual wells is an important parameter in the feasibility of geothermal electric power developments.

A paper on the output behavior of two-phase geothermal wells is that of James (1970). It deals with the measurement of flow and enthalpy, the maximum flow and wellhead pressure of wells in liquid-dominated reservoirs, the effect of casing diameter on output, and the realization that water flows into geothermal wells through fractures. These technical issues remain of great importance in the geothermal industry. Recently James, (1983) considered the effect of long term production on the output curve of two-phase wells

Sudies of two-phase flow in geothermal wellbores are those of Gould (1974) and Nathenson (1974). Both provide a good introduction to two-phase wellbore flow. The Gould (1974) study was based on methods developed in the petroleum industry, and the applications considered were wellbore deposition and deliverability calculations. The Nathenson (1974) study considered homogeneous wellbore flow and coupled it to porous media flow in the reservoir. The problems investigated by Nathenson (1974) were deliverability and wellbore deposition. He also considered the effect of reservoir permeability on output and the useful energy (available energy) produced by typical wells for electric power generation. Upadhyay and others (1977) developed a wellbore simulator and compared calculated and observed pressure drops in two-phase geothermal wells. Several similar studies have since been carried out, including that of Gudmundsson and others (1984). Typical uses of wellbore models in the development of geothermal resources have been reported by Miller and Harrison (1985).

Typical Wells

Geothermal wells have flowrates that are an order of magnitude greater than the flow of most oil and gas wells. A typical geothermal well produces at steam/water rates sufficient to generate about 5 MW of electrical power. This assumption can be verified by using wellfield data made available to the Geothermal Resources Council for the 1985 International Symposium on Geothermal Energy. The average electric power capacity of wells in 12 fields worldwide are shown in Table 1 and Figure 1. Fields having fewer than 5 production wells were omitted, so were all wellfield data from Japan. It seems that geothermal wells in Japan have noticeably less output than wells elsewhere in the world, either because the Japanese fields were overexploited, or perhaps many of the wells are used for injection purposes. The data reported to the Geothermal Resources Council were total mass flowrate and mixture enthalpy for all wells drilled in a given geothermal field. Non-productive wells and injection wells were included when adding the total number of wells drilled in a field. The average capacity of these wells was estimated by assuming that the thermal power produced could be converted into electric power with an efficiency of 10 percent.

Table 1. Average electric power capacity of wells in geothermal fields worldwide.

Field, Country	Wells	Capacity (MWe)
Svartsengi, Iceland	11	10.4
Mokai, New Zealand	5	10.0
Tongonan, Philippines	52	7.5
Miravalles, Costa Rica	5	6.6
Broadlands, New Zealand	45	5.8
Tiwi, Philippines	90	5.3
Palinpinon, Philippines	51	4.6
Bacon-Manito, Philippines	19	4.5
Kizildere, Turkey	16	4.4
Mak-Ban, Philippines	83	4.2
Wairakei, New Zealand	120	3.0
Krafla, Iceland	24	1.6
Total	521	—

Two-phase geothermal wells can have a liquid only or a steam-water feedzone. When liquid water flows into a geothermal well, the water will remain liquid up the wellbore until reaching a depth where the pressure is the same as the saturation pressure. At this depth the liquid water will start to flash to form steam. It will continue to flash until reaching the wellhead, surface pipeline, and eventually the steam-water separator. If the flowrate and total mixture enthalpy of such a

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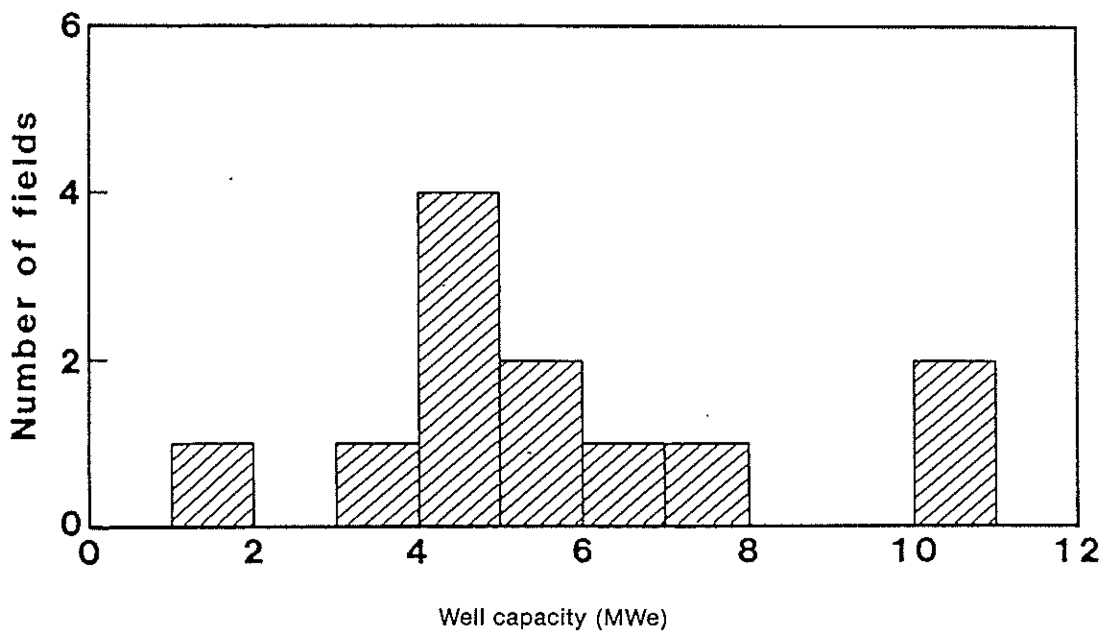

Figure 1. Average capacity of wells in geothermal fields worldwide.

well were measured, the results could be plotted as shown in Figure 2. This figure shows an output test on well 1 in the Miravalles field in Costa Rica (Gudmundsson and others, 1984). The total mixture flowrate and enthalpy were measured at several wellhead pressures. The mass flowrate shows the typical behavior of two-phase wells that have a liquid only feed. At low wellhead pressures the flowrate is the highest, and as the wellhead pressure increases the flowrate becomes less. The mixture enthalpy, however, remains constant. Although the measured enthalpy ranges from 970 to 990 kJ/kg, the values must be interpreted as resulting from the same liquid feed. Experience has shown that under the best of conditions the enthalpy of two-phase geothermal mixtures cannot be measured more accurately than 20 kJ/kg above or below the true value (Grant and others, 1982). Liquid water at 225 to 230°C has the enthalpy values measured. That is, the water that flows into well 1 in Miravalles must be in this temperature range.

The situation where a two-phase mixture flows into the wellbore is different from the case where the feed is liquid only. The two-phase feed can result from several reservoir-wellbore flow conditions: it could be liquid water that flashes as it flows toward the wellbore, it could be that the overall fluid state in the reservoir is two-phase or, the well could have two feedzones one of which has liquid feed and the other steam. For whatever reason a geothermal well receives a mixture of steam and water, the end result is that the mixture enthalpy may now depend on wellhead pressure. This behavior is shown in Figure 3 for well 2 in the Los Azufres field in Mexico (Molinar, 1985). The mass flowrate decreases with increasing wellhead pressure just as in Figure 2. However, instead of the mixture enthalpy remaining constant, it now decreases with increasing wellhead pressure. Another example of this kind of behavior has been presented by Menzies and

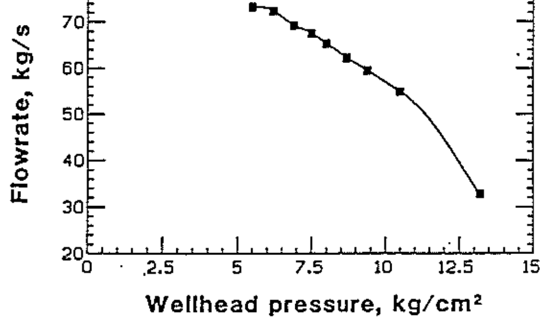

Figure 2. Output curve and enthalpy of well 1 in Miravalles field, Costa Rica.

others (1982) for well 403 in the Tongonan field in the Philippines.

The output curve of a geothermal well shows the flowrate, enthalpy, and wellhead pressure at the time of measurement. After a few months or years of production the downhole conditions are likely to change due to reservoir drawdown. It follows that the output curve of geothermal wells will change with time. The rate of change will depend on the overall reservoir-wellbore system. Examples of this behavior have been reported by Stefansson and Steingrimsson (1980) for well 11 in the Namafjall field and well 12 in the Krafla field in Iceland, and by Grant and Glover (1984) for well 21 in the Broadlands field in New Zealand. The first year output behavior of well 12 in the Krafla field is shown in Figure 4. It shows that after one week of discharge the well was producing steam only. Although not shown on the figure, the steam flowrate was found to be independent of wellhead pressure. This behavior indicates that the rate of flow was determined by the steam pressure drop through the reservoir.

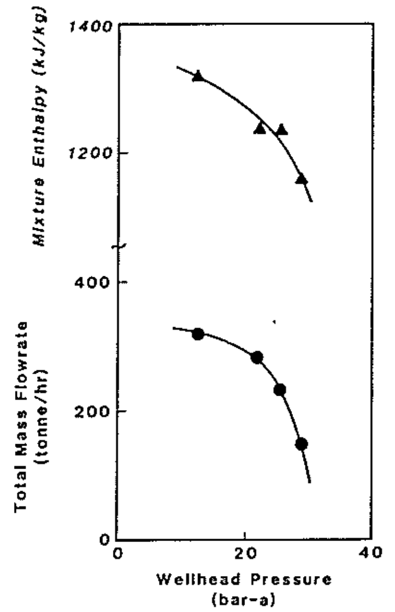

Figure 3. Output curve and enthalpy of well 2 in Los Azufres field, Mexico.

Casing Design

The output of two-phase geothermal wells is determined primarily by the feedzone permeability, fluid enthalpy, and wellbore diameter. Other factors include fluid chemistry, and well depth and roughness. For a given geothermal resource, therefore, the casing design is the only factor that can be optimized. It was demonstrated by Budd (1973) that the well diameter and feedzone depth in vapor-dominated reservoirs determines the rate of steam flow to the surface. In the case of liquid-dominated reservoirs, however, this output behavior has not been demonstrated in the field until more recently (Gudmundsson and others, 1981).

The Svartsengi field in Iceland is a typical liquid-dominated reservoir containing water at 235-240°C. The wells have liquid feed and flashing starts up the wellbore at depths of 200-400 m. It was found that calcium carbonate deposits formed in the wellbore where the flashing started. These deposits have to be cleaned out by drilling (reaming) about once per year. The early deep wells in Svartsengi had a 9-⅝ in. production casing down to about 600 m depth. To try to cut down on the frequency of wellbore cleaning, it was decided to increase the size of the production casing of all new wells to 13-⅜ in. The total depth of these wells is in the range 1000-1600 m. At standard operating conditions the output of the 9-⅝ in. wells is about 60 kg/s of steam-water mixture. However, the 13-⅜ in. wells produce at least double that amount. It seems that the increase in flow is directly proportional to the cross-sectional area of the wellbore. The output curves of the 9-⅝ in. and 13-⅜ in. wells in the Svartsengi field are shown in Figure 5. The wells are closely spaced at about 200 m and produce from similar depths. The Svartsengi reservoir must be highly permeable for the wellbore to have so much effect on the output.

The wells in the Svartsengi field have a production casing of a uniform diameter, either 9-⅝ in. or 13-⅜ in. At greater depth the wells have a 7 or a 9-⅝ in. slotted liner, respectively. Geothermal wells can also be of stepped design where several production casing diameters are used in the same well. Bilicki and others (1982) studied the theoretical effect of stepped casing design on the output of a typical well at Brawley in the Imperial Valley, U.S.A. Their casing designs are shown in Figure 6. The reservoir

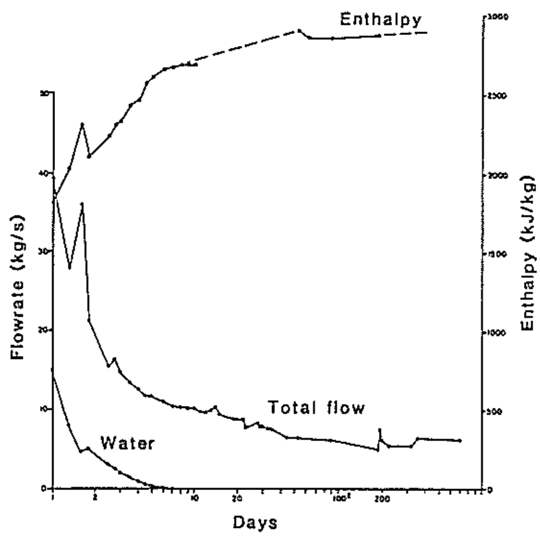

Figure 4. First year of flowrate and enthalpy of well 12 in Krafla field, Iceland.

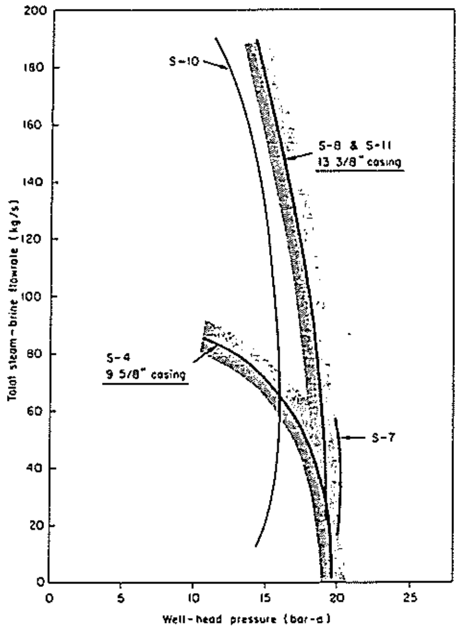

Figure 5. Output curves of wells in Svartsengi field, Iceland.

temperature was assumed 250°C, the total dissolved solids 15 wt. %, the reservoir pressure 24.2 MPa, and the laminar flow productivity index 0.0182 kg/s.MPa. The uniform wellbore diameter shown corresponds to 7-⅝ in. casing, and the two larger diameters in the stepped well correspond most likely to 11-¾ in. and 20 in. casing. The calculated output curves of the two wells are shown in Figure 7. They show that if wells were operated at a wellhead pressure of 0.9 MPa (900 kPa), the stepped well is capable of delivering nearly 2.5 times as much flow as the uniform well.

Discharge Analysis

The output curve of a two-phase geothermal wells with a liquid feed can be estimated using the discharge analysis method presented by Gudmundsson (1984). The discharge analysis method is based on three key elements. The first of these is having a wellbore simulator for two-phase geothermal wells. This makes it possible to calculate down-hole flowing pressures corresponding to measured wellhead conditions. The simulator must have the capability to start the calculations from both the wellhead and wellbottom.

The second key element is the concept of inflow performance; that is, the flow of fluid from the reservoir and into the wellbore. If the flow is laminar (Darcy flow) the well known oil and gas industry productivity index can be used:

$$P.I. = \frac{w}{\bar{p} - p_{wf}}$$

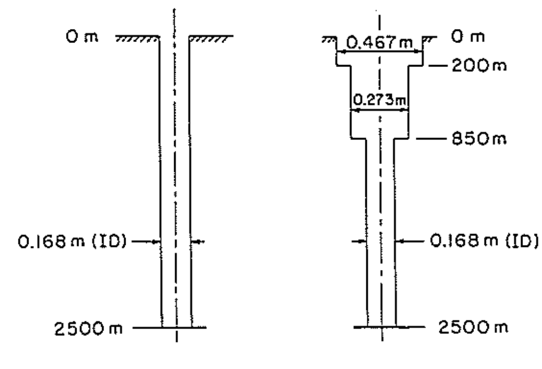

Figure 6. Casing design for uniform and stepped wells in a Brawley-type reservoir.

where w represents the total flowrate and $\bar{p}$ and p_{wf} the average reservoir pressure (static λ The productivity index ~~feedzone~~ is assumed to stay constant not only with flowrate ~~pressure)~~ but also with time. However, the average reservoir pressure can change with time. The wells are assumed to have reached steady flowing conditions when measured. Also, the method refers to the well discharge curve at the end of the output measurement used. λ*

If the rate of flow from the reservoir and into the wellbore is large, or the feedzone fracture is narrow, the flow may become turbulent. In this case the productivity index should not be used. Other inflow functions are more appropriate when the flow is partly or fully turbulent. For example the two constant equation (Nind, 1981):

$$\Delta p = \alpha \cdot w \cancel{+} \beta \cdot w^2 \qquad \lambda^{+}$$

where the two terms on the right hand side represent the laminar and turbulent contribution to the pressure drop, respectively. The pressure drop ~~Δp~~ is that from the average reservoir pressure to the well flowing pressure. At least two output measurements are required to determine the constants ~~α~~ and β. $\lambda^{\Delta p}$ λ^{α}

The third key element in the discharge analysis method is knowing the pressure at the depth of the pivot point. The pivot point pressure represents the static reservoir pressure at the main feedzone of the well, denoted by $\bar{p}$. To obtain the pivot point pressure, at least two pressure surveys must be made in the well during warm-up. The pivot point depth is the only point in the well where the pressure remains constant during warm-up (Grant and others, 1983). In wells with one major feedzone the pivot point and the feedzone are at the same depth. In wells with two major feedzones the pivot point will be located between the feedzones according to the lever rule; the point being closer to the higher productivity index feedzone.

The following data are required in the discharge analysis method:

(a) One output (discharge) measurement giving total mixture enthalpy. The fluid chemistry should also be included to obtain the liquid density and the amount of non-condensable gases.

* feedzone pressure) and wellbottom flowing pressure, respectively.

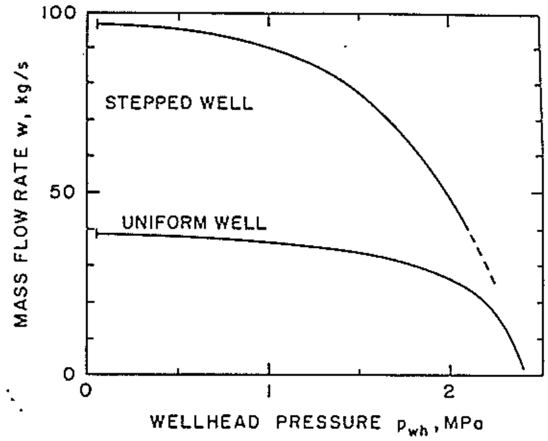

Figure 7. Output curves for uniform and stepped wells in a Brawley-type reservoir.

(b) Two pressure profiles in the static well during warm-up to determine the pivot point that represents the average reservoir pressure at that depth.

(c) Well and casing design for depth, diameter, and roughness.

The following calculations are carried out in the discharge analysis method using a wellbore simulator:

(a) Starting from the wellhead, calculate the flowing pressure profile down to the depth of the pivot point. This gives p_{wf}, the flowing wellbore pressure.

(b) Calculate productivity index using the measured flowrate w and the pressure values $\bar{p}$ and p_{wf} already obtained.

(c) Using the productivity index determined, calculate the flowing wellbore pressure for some new flowrate; higher or lower.

(d) Starting from the depth of the pivot point and using the new wellbore flowing pressure, calculate the pressure (and temperature) profile to the wellhead. This gives a new wellhead pressure.

Repeating steps (c) and (d) of the calculations, it becomes possible to determine the wellhead pressure at different flowrates, and to construct an output curve.

Output data from well 12 in the Svartsengi field in Iceland can be used to illustrate the discharge analysis method. Pressure surveys were taken in well 12 before it was discharged for the first time, after 10 days and 3 months of warm-up. The pressure profiles in Figure 8 are shown to intersect in the depth range 1000-1200 m (Gudmundsson, 1984). This intersection is called the pivot point and represents the pressure controlling depth of the well. Well 12 was discharged for a few weeks and the massflow stabilized at 42 kg/s and a wellhead pressure of 1500 kPa. The steam-brine enthalpy was measured 1000 kJ/kg, which corresponds to a liquid water temperature of 232° C.

The pivot point pressure (average reservoir pressure $\bar{p}$) was taken as 1279 psia at 3936 ft. depth. The casing inside diameter was 1.0521 ft. to 607 m and the open hole (barefoot) diameter 1.0208 ft. to the bottom at 1477 m. The total flowrate was taken as 330,000 lb/hr at 220 psia wellhead pressure and the mixture enthalpy as 429 Btu/lb.

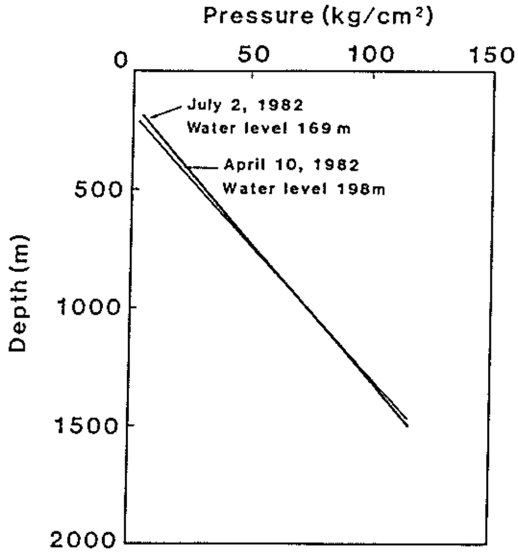

Figure 8. Pressure profiles during warm-up in well 12 in the Svartsengi field, Iceland.

Using a state-of-the-art wellbore simulator (Ortiz-R., 1983), the flowing pressure at the pivot point was calculated p_{wf} = 1050 psia. For the given flowrate w (lb/hr) and average reservoir pressure $\bar{p}$, the productivity index was determined P.I. = 1456 lb/hr.psi. The wellhead pressure was then calculated for a range of flowrates. The results of the wellbore simulation calculations for well 12; are shown in Figure 9. In addition to the estimated output (discharge) curve, the pressures assumed and calculated downhole are also shown. These are the reservoir, feedzone, and flashing pressures. Note that the flashing pressure is the saturation pressure corresponding to the enthalpy of the geothermal fluid. What the figure shows is that the potential pressure drop dominates the discharge behavior of the well. Friction losses contribute some pressure drop in the two-phase region, but only above 600,000-800,000 lb/hr flowrate.

Deliverability

The production of steam and water from a geothermal reservoir is a series problem. That is, it depends on the reservoir pressure, the flow of fluid through the feedzone into the well, and then up the wellbore to the surface. These three elements of deliverability are called reservoir, inflow, and wellbore performance, respectively. An output test of a geothermal well gives the deliverability at the time of testing. After a few years of production the deliverability is likely to change because of drawdown in reservoir

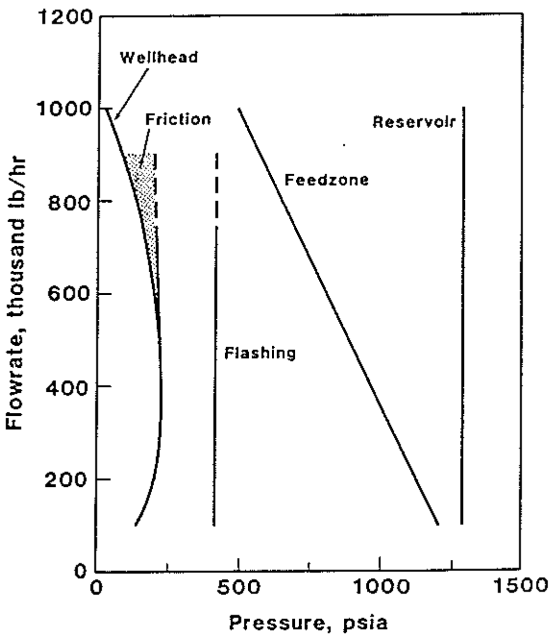

Figure 9. Output curve and downhole pressures in well 12 in Svartsengi field, Iceland.

pressure. The prediction of reservoir pressure with time is the subject of reservoir modeling, and will not be discussed here.

The flow behavior of a typical geothermal reservoir-wellbore system is shown in Figure 10 (Marcou, 1985). The family of curves that go from high to low wellbore flowing pressure p_{wf} are the inflow performance. The highest curve, for example, is the inflow performance before any reservoir pressure drawdown has occurred. The figure shows an initial reservoir pressure of 9 MPa at zero flowrate. With time the reservoir pressure falls and so does the mass flowrate. The inflow performance curves in Figure 10 are composed of two forms of flow behavior, depending upon whether the flowing pressure is above or below the saturation pressure of the geothermal fluid. The saturation pressure is the pressure at which liquid water at a given temperature will start to boil. For the liquid-dominated reservoir conditions used in Figure 10, the saturation pressure is between 4 and 5 MPa (corresponding to reservoir temperature in the range 250 to 260°C). Above the saturation pressure a linear relationship was assumed between the mass flowrate w and well flow pressure p_{wf}; that is, a laminar flow productivity index as used in the discharge analysis example above. Below the saturation pressure, however, the slope of the inflow performance curve was assumed to becomes more and more negative. This indicates that when a steam-water mixture enters the wellbore, the resistance to flow is greater than for liquid-only flow at the same mass flowrate. In the petroleum industry, a solution-gas drive reservoir is not unlike a geothermal steam-water flashing reservoir. The empirical inflow performance relationship of Vogel (1968) was used to construct the below saturation pressure part of the family of curves in Figure 10. This kind of geothermal inflow performance curve has been matched with success to downhole data from well 14-2 in the Roosevelt Hot Springs field in Utah (Marcou, 1985). The method does not take into consideration the gain in mixture enthalpy that occurs when flashing takes place in the reservoir, as discussed by Menzies and others (1982).

The two curves in Figure 10 that cut across the family of inflow performance curves, are the wellbore performance curves of 9-⅝ in. and 13-⅜ in. production casing, for a given set of wellhead conditions. These curves are also called casing performance curves. They were constructed assuming 1100 kJ/kg enthalpy liquid water flowing from a depth of 900 m to a constant wellhead pressure of 690 kPa (100 psia). This mixture enthalpy corresponds to that of liquid water in the temperature range 250 to 255°C. A wellbore simulator was used to calculate the well flowing pressure at 900 m depth at different mass flowrates for a constant wellhead pressure, such as would be in a situation where steam is separated at or above some constant pipeline (steam turbine inlet) pressure. The mass flowrate of steam and water from the geothermal reservoir-wellbore system shown in Figure 10, is determined by the intersection of the inflow and wellbore performance curves. For example, the highest pressure inflow curve intersect the 9-⅝ in. and 13-⅜ in. wellbore curves at 220 and 260 tonne/hr flowrates, respectively. In this way the mixture flowrate at the wellhead can be determined with time as the inflow performance curves become lower.

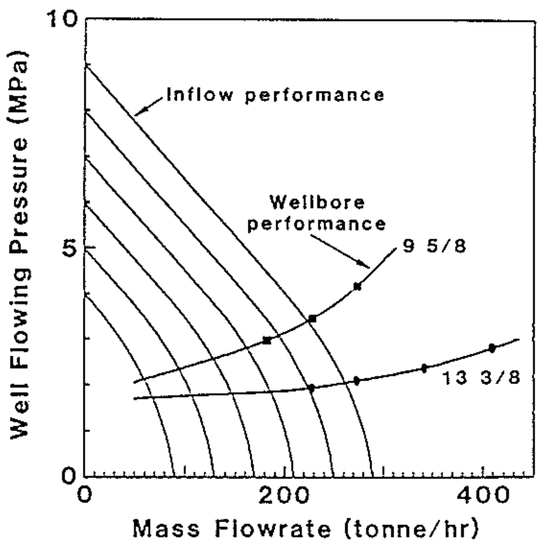

Figure 10. Deliverability behavior of a typical liquid-dominated reservoir-wellbore system.

The slopes of the inflow and wellbore performance curves in Figure 10 are such that increasing the casing diameter from 9-⅝ in. to 13-⅜ in. increases the mass flowrate by only 18 percent (from 61 to 72 kg/s). This increase is much less than that demonstrated in the Svartsengi field in Iceland and shown in Figure 5. The reason for this is that the inflow performance used in Figure 10 is that of a typical geothermal well, using well 14-2 in the Roosevelt Hot Springs field as an example. The wells in the Svartsengi field, however, attain much greater production rates because of higher reservoir and feedzone permeability. The linear productivity index corresponding to the inflow performance in Figure 10 is about 40 percent of that reported for well 12 in the Svartsengi field above. A higher productivity index means that the well flowing pressure shown in Figure 10 falls less rapidly with increasing mass flowrate. Therefore, it will intersect the wellbore performance curves at a higher flowrate.

Summary

(a) Typical two-phase geothermal wells produce sufficient steam to generate about 5 MW of electric power.

(b) Two-phase mixtures with excess enthalpy can flow into the wellbore. The steam fraction of such wells at the wellhead can range from that of liquid feed-zone wells, to dry or even superheated steam wells.

(c) Larger diameter casing allows greater production rates in typical geothermal fields. Under favorable reservoir conditions the rate of production is proportional to the casing cross sectional area.

(d) Discharge analysis is a method to estimate the output curve of two-phase liquid feed wells from the minimum of data.

(e) The deliverability of steam and water from a geothermal system depends on coupling of the reservoir, inflow, and wellbore performances.

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