A METHOD TO RECOVER USEFUL GEOTHERMAL-RESERVOIR PARAMETERS FROM PRODUCTION CHARACTERISTIC CURVES.
(2) HOT WATER RESERVORIES.

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ABSTRACT
In this paper we develop and demonstrate a method to estimate the reservoir pressure, a mass productivity index, and a thermal power productivity index for vertical water-fed geothermal wells, from its production characteristic (also called output) curves. In addition, the method allows to estimate the radius of influence of the well, provided that a value of the reservoir transmissivity is available. The basic structure of the present method is: first, the measured wellhead mass flowrate; and pressures are transformed to downhole conditions by means of a numerical simulator; then, the computed downhole variables are fitted to a simple radial model that predicts the sandface flowrate in terms of the flowing pressure. For demonstration, the method was applied to several wells from the Cerro Prieto geothermal field. We found very good agreement of the model with this ample set of field data.

INTRODUCTION
Production characteristic curves, also called output curves, are routinely determined for most geothermal wells. These curves relate mass flowrate at the wellhead with the corresponding wellhead pressure. Their normal uses include gathering qualitative information about reservoir properties (e.g. relative values of reservoir pressure, temperature or gas content, reservoir permeability) and about effects of scaling in the wellbore (e.g. Grant et. al., 1982); estimating discharge enthalpy from the maximum discharging pressure (James, 1970, 1980 a,b); and, of course, predicting mass flow rates for given wellhead pressures and vice-versa.

Output curves contain mixed information about both the reservoir and the intervening wellbore. As pointed out, only qualitative information about the reservoir is usually recovered from these curves. The sole exception to this, James' maximum discharging pressure method to estimate discharge enthalpy, is based on the fact that at low flowrates resistive wellbore effects are unimportant; that is, in this case the wellbore and reservoir information are already separated.

In this paper we develop and demonstrate, via field examples, a method to recover important quantitative information about the reservoir from output characteristic curves of water-fed wells. In a companion paper (Iglesias et. al., these Proceedings), we describe and demonstrate a similar method for steam-wells. The method is based on unscrambling the wellbore and reservoir contributions to the output curves, by means of a wellbore flow numerical simulator, and then fitting these results to a simple radial model of the reservoir flow. The reservoir information retrievable with our method can alternatively be obtained by traditional methods, which require bottomhole measurements. These measurements are difficult to take in high temperature wells which, more often than not, contain corrosive fluids. Moreover, the method presented in this paper uses as input data characteristic curves that have to be determined, anyway, for other uses. Our method is, therefore, an efficient way for retrieving important reservoir information from usually available wellhead data, without resorting to more difficult bottomhole measurements. No previous similar work is known to the authors.

METHOD
The method presented here requires production characteristic curves as input data. These data are converted to the corresponding bottomhole quantities by means of a wellbore flow numerical simulator. Then, the computed bottomhole quantities are fitted with a simple model that predicts the sandface flowrate as a function of the bottomhole flowing pressure. The fit provides estimates of the reservoir pressure $p_r$, and the productivity index $J$ of the well. If estimates of the reservoir transmissivity $(k_h/u)$ are available, the radius of influence of the well can also be estimated.

Output characteristic curves are recorded during production tests. During these tests, the
wells are typically flown through several orifices of varying diameters. For each orifice the flow is maintained until stable or quasistable conditions are reached. At this point, the mass flowrate and the corresponding wellhead pressure are recorded. Liquid-fed wells in high enthalpy fields usually produce mixtures of water and steam at the surface. In this type of well the data recorded are the steam and water flowrates, and the wellhead pressure. After recording the data, the flow is diverted through another orifice of different diameter, and the process restarts. Thus, for high-enthalpy water-fed wells production tests provide two related curves: water and steam flowrates versus wellhead pressures. These constitute the raw data of the method presented here.

The wellbore numerical model (WELFLO) used in this work is described by Goyal et. al (1980) and references therein. WELFLO is a finite difference, one dimensional, multiphase, steady-state geothermal wellbore flow simulator appropriate for vertical multidiameter wells. It has been extensively validated against field data (Goyal et. al , 1980; Arellano, 1983). Two features of this code make it adequate for the problem at hand. First, the capability to compute bottomhole conditions from wellhead input variables, as needed. Second, the assumption of steady-state flow in the wellbore. This assumption is required because the stable or quasi-stable conditions attained during the production test allow wellbore transients to die out. The input variables of WELFLO are the geometry of the well (lenghts, diameters, extent of open or ranurated interval), total mass flowrate, wellhead pressure, and wellhead total specific flowing enthalpy. Conductive heat losses to the wellbore walls are unimportant in steady-state flow (Goyal et. al., 1980; Gould, 1974) and were neglected in our calculations.

Our method requires to transform each and every measured data point of the characteristic curve to the corresponding bottomhole conditions. Of the complete set of bottomhole variables computed by means of WELFLO, we require only the flowing pressure and the total mass flowrate (which equals the wellhead flowrate, due to the steady state conditions of the flow in the bore). Errors of the wellhead input quantities affect the bottomhole flowing pressures (BHP's) computed by means of WELFLO in different fashions, as follows (Goyal et. al., 1980). Computed BHP's are relatively insensitive to errors of the wellhead total mass flowrate. Errors of wellhead pressures have effects of the same order of magnitude on computed BHP's. Input enthalpies greater than the true value decrease calculated BHP's in approximate proportion to the error. Finally, computed BHP's are very sensitive to negative errors of the input enthalpy.

Once the output characteristic curves are recorded, little can be done with respect to the errors of the mass flowrates and of the corresponding wellhead pressures. Fortunately, this is not the case for the flowing total specific enthalpy, the most sensitive quantity with regard to BHP's. The individual specific enthalpies corresponding to each data point of the characteristic curve are computed from the related water and steam flowrates and known separation pressure. These individual enthalpies are affected by the random errors of the measured water and steam flowrates. Now, for liquid-fed geothermal wells the flowing total specific enthalpy is constant and independent of wellhead pressure or mass flowrate (e.g. Grant et. al., 1982). Therefore, we take the arithmetic mean h_r, which is the best statistical estimate of the true value in a set of random measures, as the value of the constant flowing specific enthalpy h_r. This approach minimizes the errors of the computed BHP's. As a further precaution, we check the set of individual enthalpies for possible correlations with wellhead pressures or mass flowrates. The existence of such correlations may indicate two-phase flow in the reservoir, which in turn would invalidate the present analysis.

For the flow in the reservoir we chose a simple model suggested by experience: radial, horizontal, isothermal flow of a liquid through a porous, homogeneous, confined, cylindrical reservoir of constant thickness. If the outer boundary condition is constant pressure, then steady state can be achieved. In that case the mass flowrate is given by

$$W = \frac{\alpha k h}{v} \ln \left( \frac{r_e}{r_w} \right)$$

the well-known expression of Darcy’s Law for steady-state radial flow, in massic form. Here \(\alpha\) is a constant to accommodate different systems of units (nomenclature at the end of the paper). This steady-state model can approximate three situations of interest, with the restrictions commented below. (a) Infinite acting period, i.e. no boundary effects are felt during the time period \(\Delta t\) over which the output production data were collected; in this case \(\Delta t\) must be smaller than the time scale associated with the outward movement of the pressure perturbation in the reservoir, for equation (1) to a valid approximation. (b) Constant pressure outer boundary condition, which may arise from the existence of a strong radial recharge some distance away from the well; equation (1) is valid with no restrictions on \(\Delta t\). (c) Finite reservoir, no-flow condition at \(r = r_e\); approximation (1) is valid when \(\Delta t\) is smaller than the time scale associated with the decrease of \(p_e\).

If the reservoir flow model summarized by (1) is valid for a given set of output data (production characteristic curve), a plot of the computed sandface flowrates versus the corresponding flowing pressures should give a straight line. From (1) the intercept of this line is

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The reservoir pressure is then easily computed from
\[ p_e = -(a/b) \]  

A massic productivity index is naturally defined as
\[ J_m = W/(p_e - p_{wf}) \]  

Then, from (1), (3) and (5)
\[ J_m = -b. \]  

In geothermal applications a quantity of great interest is the thermal power of a given well. In analogy to (51), a useful power productivity index may be defined as
\[ J_p = h_J P T_m \]  

for water-fed wells. In definition (6) we have used \( h_J \), the total specific flowing enthalpy, which is constant and independent of wellhead pressure and total mass flowrate, as mentioned. In practice, we estimate \( h_J \) by \( h_T \), the total specific flowing enthalpy averaged over the characteristic curve, to minimize errors.

Finally, if the reservoir transmissivity \((kh/\mu)\) is known, the radius of influence of the well can be estimated from (6) as
\[ r_e = r_w \exp(\alpha kh)/(u \cdot J), \]  

where we have replaced \( v \) with the specific volume of the liquid at reservoir conditions. In practice we estimate \( v \) by the specific volume of saturated water at the computed bottomhole temperature.

Estimates of \( r_e \) by this method are affected by the existence of a non-zero skin. This is because the permeability \( k \) in equation (8) represents the permeability "seen" by the well, which is not the reservoir permeability if there is a non-zero skin. In this case \( k \) should be replaced by the composite permeability
\[ \bar{k} = \ln(r_e/r_w)/(\ln(r_e/r_w) + \ln(r_e/r_s)/\bar{k}) \]  

Taking \((r_e/r_w) \approx 1 + \epsilon\), with \( \epsilon \ll 1 \) as usually assumed, it is easy to show from (9) that

\[ \epsilon < k \]  

whether the skin is positive or negative. Expression (10) implies that (8) overestimates \( r_e \) if the reservoir permeability (e.g. as obtained from pressure tests) is used, when a non-zero skin exists. Given the exponential form of (8), these errors may be important.

FIELD VALIDATION

For validation purposes we have applied our method to 5 wells from the Cerro Prieto geothermal field. Figure 1 shows their location.
results are summarized in Table 1. The excellent fits, evidenced by the high correlation coefficients, are strong evidence of the validity of the method presented here.

The inferred reservoir pressures agree with the measured shutin, or nearly shutin, downhole pressures to better than 17% in average. The agreement is good, considering the uncertainties involved, and the usual errors associated with alternative methods to estimate reservoir pressures. The uncertainties include errors in the measured or assumed input quantities of the

As another check on our method, we have compared the inferred reservoir pressures with measured shutin (or nearly shutin) downhole pressures. These results are shown in Table 2. The measured downhole pressures $p_{\text{meas}}$ were corrected to the corresponding bottomhole depths by addition of the hydrostatic heads due to the differences of depth. Saturated liquid densities at the computed downhole temperatures were used in these calculations.

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### Table 1. Results of the method applied to hot water wells from the Gerro Prieto geothermal field.

<table>
<thead>
<tr>
<th>Well</th>
<th>Correlation Coefficient $r$</th>
<th>$P_e$ (bar)</th>
<th>$J_p$ (ton/hr)</th>
<th>$h_i$ (MJ/ton)</th>
<th>$J_p^*$ (MW/bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>M-110</td>
<td>-0.9958</td>
<td>175.1</td>
<td>6.64</td>
<td>1411.1</td>
<td>2.60</td>
</tr>
<tr>
<td>E-2</td>
<td>-0.9810</td>
<td>212.1</td>
<td>3.53</td>
<td>1484.3</td>
<td>1.46</td>
</tr>
<tr>
<td>M-93</td>
<td>-0.9683</td>
<td>266.5</td>
<td>2.79</td>
<td>1332.5</td>
<td>1.03</td>
</tr>
<tr>
<td>M-109</td>
<td>-0.8737</td>
<td>316.0</td>
<td>2.53</td>
<td>1323.0</td>
<td>0.93</td>
</tr>
<tr>
<td>M-102</td>
<td>-0.9718</td>
<td>235.9</td>
<td>1.50</td>
<td>1488.1</td>
<td>0.62</td>
</tr>
</tbody>
</table>

*Expressed in thermal MW per bar.
method, errors in the measured downhole pressures, and whether the measured downhole pressures represent reservoir pressures. As discussed in the previous section, errors in input variables of the method such as wellhead pressures, flowrates and enthalpies, or in the assumed inside diameters of the wells (possibly arising from scale deposits), might originate percentual errors of the order of magnitude shown in Table 2. On the other side, the measured shutin pressures, just like any other kind of measurement, are affected by instrumental and human errors. Finally, downhole pressure measurements may not represent true reservoir pressures, on two counts. First, it is often difficult to assess whether the shutin time has been long enough for equilibration. And second, geothermal shutin downhole profiles do not necessarily reflect reservoir pressure, except at the precise depth corresponding to feed points, even if shutin times are long enough (Grant, 1979; Grant et al., 1981).

The inferred reservoir pressures shown in Table 2 appear to be systematically greater than the (corrected) measured pressures. This may be a random effect, masked by the relatively small size of the sample (3 cases), with the errors caused by the reasons discussed in the last paragraph. Alternatively, it may be a truly systematic effect introduced by the method presented here. More field data will be processed to solve this question.
Table 2. Inferred reservoir pressures vs. measured shut-in (or nearly shut-in) downhole pressures.

<table>
<thead>
<tr>
<th>Well</th>
<th>P&lt;sub&gt;meas&lt;/sub&gt; (bar)</th>
<th>Depth (m)</th>
<th>Conditions</th>
<th>P&lt;sub&gt;corr&lt;/sub&gt;* (bar)</th>
<th>P&lt;sub&gt;e&lt;/sub&gt; (bar)</th>
<th>Depth (m)</th>
<th>(P&lt;sub&gt;e&lt;/sub&gt; - P&lt;sub&gt;corr&lt;/sub&gt;)/P&lt;sub&gt;e&lt;/sub&gt; (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>M-110</td>
<td>163</td>
<td>1843</td>
<td>shut-in</td>
<td>163.7</td>
<td>175.1</td>
<td>1854</td>
<td>+6.5</td>
</tr>
<tr>
<td>E-2</td>
<td>166.5</td>
<td>1762</td>
<td>flowing by $# = 1''$ orifice</td>
<td>178.1</td>
<td>212.1</td>
<td>1946</td>
<td>+16.0</td>
</tr>
<tr>
<td>M-93</td>
<td>235</td>
<td>2553</td>
<td>flowing by $# = 1''$ orifice</td>
<td>235.3</td>
<td>266.5</td>
<td>2558</td>
<td>+11.7</td>
</tr>
<tr>
<td>M-109</td>
<td>223</td>
<td>2385</td>
<td>flowing by $# = 1/4''$ orifice</td>
<td>223.6</td>
<td>316.0</td>
<td>2395</td>
<td>+29.2</td>
</tr>
<tr>
<td>M-102</td>
<td>184</td>
<td>1900</td>
<td>shut-in</td>
<td>189.6</td>
<td>235.9</td>
<td>1990</td>
<td>+19.6</td>
</tr>
</tbody>
</table>

*P<sub>corr</sub> = P<sub>meas</sub> corrected to bottomhole depth (see text).

SUMMARY AND CONCLUSIONS

We have developed and demonstrated a method to retrieve the reservoir pressure $P_e$, a mass productivity index $J_m$, and a thermal power productivity index $J_p$ corresponding to vertical water-fed wells from its production characteristic curves. If an estimate of the reservoir transmissivity $(k_h/\mu)$ is available, our method provides a way to estimate the radius of influence of the well.

We have successfully validated the method against an ample set of field data. The quality of the agreement is very good.

The main advantages of the method are as follows: It provides a way for retrieving important reservoir information from usually available production characteristic curves; no extra measurements are needed. Unlike traditional methods that require significantly more difficult bottomhole measurements to evaluate the reservoir pressure and the productivity index, the present method works from more easily taken wellhead measurements. Finally, the method provides important information concerning the two main aspects of geothermal resource utilization: mass and heat production.

A distinctive feature of the method described in this paper is that it combines two of the most important aspects of the geothermal resource, namely, mass and heat production. This useful feature is illustrated by the results presented in Table 1: reservoir pressures and mass productivity indexes on the one hand, and enthalpies on the other, are combined in a single parameter, the power productivity index.

The results of Table 1 show that the mass productivity indexes are mostly independent of both the reservoir pressure and the specific enthalpies. These results also show that the specific enthalpies of the wells are rather independent of the corresponding reservoir pressure. Finally, there is a strong correlation (linear correlation coefficient = +0.9969) between $J_m$ and $J_p$. If representative of the whole field, these results indicate that in Cerro Prieto the controlling factor for mass and heat production is reservoir transmissivity.

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NOMENCLATURE

- $a$: Intercept of straight line (ton hr<sup>-1</sup>)
- $b$: Slope of straight line (ton hr<sup>-1</sup>/bar<sup>-1</sup>)
- $h$: Reservoir thickness (m)
- $h_T$: Flowing total specific enthalpy (MJ ton<sup>-1</sup>)
- $h_{T_a}$: Flowing total specific enthalpy averaged over characteristic curve (MJ ton<sup>-1</sup>)
- $J_m$: Mass productivity index (ton hr<sup>-1</sup>/bar<sup>-1</sup>)
- $J_p$: Thermal power productivity index (MW bar<sup>-1</sup>)
- $k_s$: Permeability of skin zone (md)
- $k$: Composite permeability seen by the well when there is a non-zero skin (md)
- $
u$: Permeability (md)
pe: Reservoir pressure (bar)

Pwf: Sandface flowing pressure (bar)

Pmeas : Measured shutin pressure (bar)

Pcorr: Pmeas corrected to bottomhole depth (bar)

r_e: Radius of influence of the well (m)

r_w: Wellbore radius (m)

r_s: Radius of the skin zone (m)

v: Specific volume of liquid water (m³ kg⁻¹)

W: Mass flowrate (ton hr⁻¹)

α: Constant to accommodate different systems of units

μ: Viscosity (cp)

ν: Kinematic viscosity (m² s⁻¹)

REFERENCES


