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Pressure Depletion Calculations for Liquid Geothermal Reservoirs

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ABSTRACT

One of the key problems in geothermal field management is to determine how many wells will be needed, and when in the project lifetime the new wells will come on-line. To make this determination requires an estimate of the field depletion.

Methods used for approximating the field behavior are discussed, and examples are provided using data from some liquid-dominated reservoirs in the U.S. and abroad. The calculated decline curves are compared to a few cases for which field production data is available.

INTRODUCTION

This paper considers the depletion of a single phase, liquid geothermal reservoir producing from wells in two-phase flow. While there are other cases of interest (two-phase reservoir, vapor-dominated reservoir, downhole pumps, etc), we will limit our comments to the case described above.

An estimate of reservoir depletion (decreasing production) is important to geothermal developers, lenders, and field engineers. Depletion estimates provide the necessary data to determine how many wells must be drilled; when the wells will be needed to support production; and (in some cases) where the most desirable well locations are in the field. Drilling schedules and well locations (because of cost and lease-related factors) are the most important field-management decisions to be made for a geothermal project, because the drilling is usually the most costly field item. Occasionally gathering systems are comparable in cost, but for most projects drilling costs are paramount. For that reason, it is of great importance - financially as well as technically - to minimize the initial number of production and injection wells, and to maximize the time until new (makeup) wells must be drilled. This strategy maximizes the return on investment by "pushing" the well costs out into a higher discounted time frame.

Reservoir depletion estimates, and an estimated or updated drilling schedule, are needed both prior to power plant startup and after production is underway. The pre-production estimates are crucial to both developers and lenders in making financial appraisals of a project. Continued estimates are required after the power plant has been in operation to both verify the pre-production estimates and to take into account changes that have occurred. For example, the actual location and production of newly drilled wells can vary substantially from estimates made before drilling.

In the remainder of this paper the methodology, data, and calculational tools are explained; and examples are given of field depletion for a case prior to power plant startup; and for a case of a field that has been in production for about 7 years. In both cases the data is still proprietary, and some of the quantitative information can not be provided at this time. The field locations and well names must also remain anonymous.

METHODOLOGY

We are concerned here only with the case of a liquid reservoir producing from two-phase wellbores. Some of the methods and calculations can be simplified or altered for application to other possible cases.

The general approach is to use a wellfield pressure simulator to estimate reservoir/wellbore conditions, and a two-phase wellbore simulator to estimate wellhead conditions. The power plant design criteria impose constraints on the wellhead conditions (the required power plant inlet pressure and enthalpy usually have a relatively narrow design range for maximum power plant efficiency), but the reservoir also imposes constraints on the wellhead conditions (well productivity and reservoir enthalpy can vary substantially over the field), and interference and depletion results in reservoir pressures that decrease with time. In the examples given below the calculations are done for reservoir enthalpy that does not vary from well to well; however, the variation in field enthalpy must be taken into account when the data is available. This can be done by using well test data and exploratory temperature profiles if they are available. The variation in enthalpy is most important for the calculation of the wellhead conditions from downhole values, since the wellbore simulator is most sensitive to variations in enthalpy.

The primary emphasis in this report is on the pressure depletion (and associated production decline) when the field feeds a power plant at (approximately) constant pressure. The constant pressure constraint results in well production declines, and for the case of two-phase wellbore flow, the wellhead conditions are not a linear function of the reservoir drawdown (pressure depletion). Therefore, a combination of reservoir and wellbore simulation is needed to accurately estimate the field decline during production and to accurately estimate the corresponding drilling demands to meet the minimum power plant requirements. For reservoirs that remain single phase, and have relatively small amounts of dissolved gases, the downhole wellbore enthalpy is often approximately constant over time periods of a few years. This allows the initial declines to be calculated with a minimum of effort and cost through the use of pressure simulators using linear superposition of analytical solutions. Long term field declines require the use of more detailed hydrothermal simulation using discrete simulators that calculate both pressure and enthalpy changes, and take into account the change in reservoir (wellbore) enthalpy with time. The methodology is summarized in Table 1, below.

Table 1. Summary of Methodology

- Use measured well test data and downhole productivity curve to calibrate a wellfield pressure simulator.

- Use measured downhole and wellhead productivity curves and flowing wellbore profiles to calibrate two-phase wellbore simulator.

- Use measured reservoir enthalpy and calculated reservoir pressure from wellfield simulator to calculate wellhead conditions.

- Through parametric study determine when the wellfield pressure will decline below the required minimum for power plant needs.

- Add a well (or wells), lower the flowrates in the new wellfield and continue the calculation.

THE SIMULATORS

The calculations shown below have been done using commercially available wellfield and wellbore simulators (ref 1). The programs run on an IBM PC microcomputer and provide cost effective tools for reservoir engineers involved in well testing and field simulation.

The pressure simulator - MRMW Version 3.0 - uses linear superposition to calculate the wellfield pressure (ref 2). Several model options are available, and the program also has options to allow type-curve matching of production or injection well test data, can be used for interference test analysis, and can generate dimensionless type curves.

The wellbore simulator - WELF Version 3.0 - is a steady state, two-phase simulator that includes options for variable wellbore diameters, heat losses, and large fluid TDS (ref 3).

Both simulators return the calculated values within seconds, and allow numerous numerical studies to be done quickly and easily.

DATA

Two examples are included and are summarized in Table 2, below.

Table 2. Examples used in calculations

<u>Case 1</u> - US field not yet in production

A) Injection outside the field
B) Power plant requirement = 2.5×10^6 #/hr
C) Minimum wellhead pressure = 200 psi
D) Maximum flashpoint (bubble point) depth is above production string
E) 8 production wells and 3 injection wells at plant startup

<u>Case 2</u> - Overseas field with seven years of Production

A) Injection inside the field
B) Power plant requirement = 3200 Tonnes/hr (7×10^6 #/hr)
C) Currently 13 production wells and 16 injection wells

The first case to be considered is a wellfield that was in the planning stage when these calculations were made. The initial wellfield pattern, including eight production wells and three injection wells, is shown in Figure 1. The proposed injection is defined to be outside the producing field, and is constrained by current lease positions. The power plant requires 2.5×10^6 lb/hr of fluid at the minimum reservoir enthalpy. Production and interference well test data were used to estimate the average reservoir parameters using the pressure simulator described above. The wellhead and downhole production curves are shown in Figure 2. As seen in Figure 2, the reservoir pressure is non-linear with respect to flowrate. Ideal Darcy flow produces a sandface productivity curve that is a straight line. However, many geothermal wells - particularly those producing with two-phase wellbore flow - have non-Darcy downhole productivity curves. This type of non-linearity requires care in applying well test analysis results to pressure depletion applications. Typically the reservoir and wellbore parameters are obtained from production tests where the well is flowed at nearly its maximum rate.

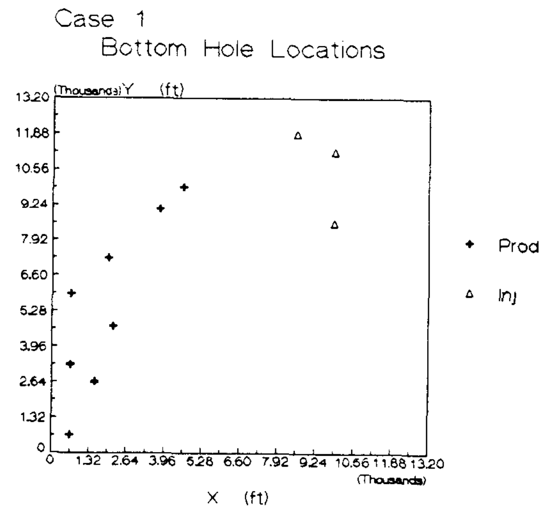

Figure 1. The initial wellfield showing bottomhole locations of the production and injection wells.

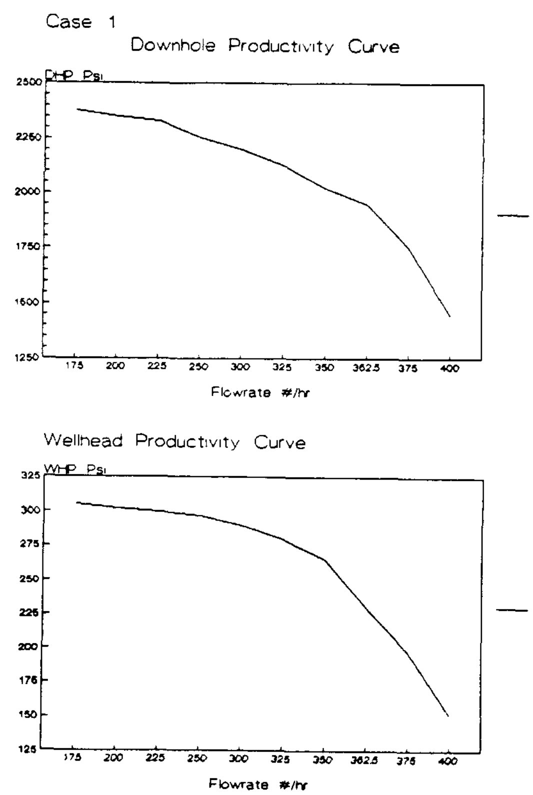

Figure 2. The downhole and wellhead productivity curves for Case 1.

As shown in Figure 3, the non-Darcy effects are a maximum at high flowrates. Typically, if a test is conducted at a single flowrate, the non-Darcy effect is interpreted as a large skin effect. The apparent skin factor can be written as

$$S_a = S_d + S_{pp} + Dq^{n-1} \qquad (1)$$

where

Sa is the apparent skin effect from well test data

Sd is the true skin due to sandface damage

Spp is a pseudoskin due to a partially penetrating well

Dq^{n-1} is the non-Darcy flow effect expressed as an exponential term (D is an empirically determined constant and q is the total mass flowrate).

Usually non-Darcy flow is approximated by an equation based on the modifications to Darcy's law shown in equation (2).

$$q + Dq^2 = K \frac{dp}{dx} \qquad (2)$$

For many geothermal wells the non-Darcy exponent in Equation (1) that is required to match the productivity data from well test measurements is between 1 and 5.

The importance of the non-Darcy effect in pressure depletion calculations is apparent from Figure 3. If a well test is analyzed with data for one flowrate and a large apparent skin factor is obtained, then when that large (constant) skin is used in the pressure depletion calculations, the late time depletion (at lower flowrates) will be vastly over-estimated, since the apparent skin factor should decrease as the flowrates in the field decline. The pressure simulator referred to in Reference 1 includes the effects of non-Darcy flow.

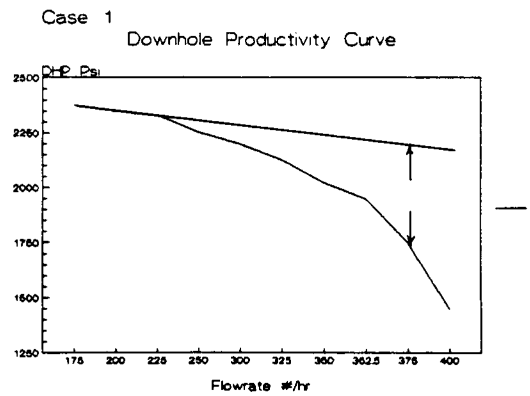

Figure 3. Demonstration of non-Darcy flow component at high flowrate.

For Case 1 the power plant inlet design pressure requires that the wellhead pressures downstream of a wellhead choke remain greater than 200 psia. Figure 4 shows 3 wellbore profiles from flowing, downhole, pressure measurements. Downhole, flowing pressure and temperature measurements are essential for complete and accurate interpretation of two-phase well test data. The casing shoe limits the depth that the flash point can be allowed to reach while maintaining a single-phase liquid reservoir. For the Case 1 wellfield it is critical that the reservoir remains single-phase in order to maintain an approximately constant wellhead enthalpy, and to maintain the single-phase productivity.

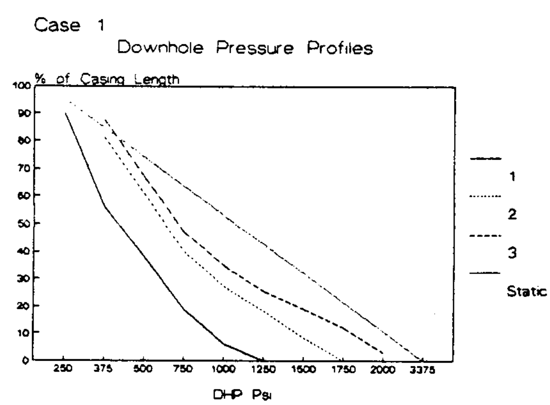

Figure 4. The downhole pressure profiles for the static well and for three different flowrates.

The second case to be considered is a wellfield that has been producing power at a constant rate for about 7 years. The wellfield (reservoir) pressure is shown in Figure 5. There are currently 13 production wells and 16 injection wells in use. The injection wells are inside the wellfield. The power plant requires about 3200 Tonnes/hr (7 x 10^6 lbs/hr).

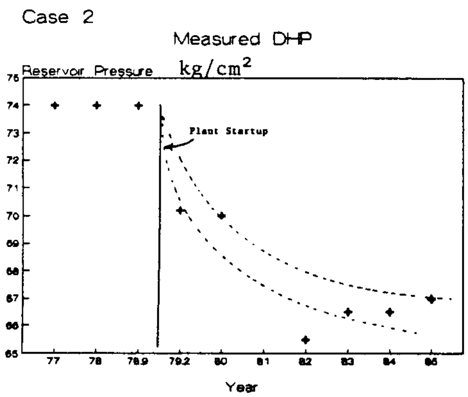

Figure 5. Downhole pressures as a function of time for Case 2.

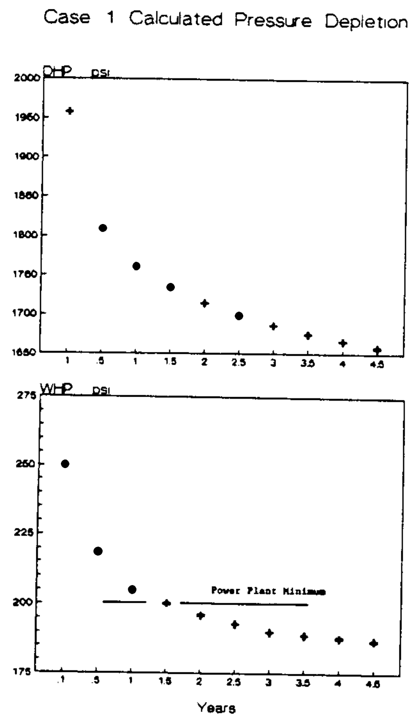

Figure 6. Calculated pressure at an average well when the wellfield delivers to the powerplant.

CALCULATIONS

The productivity curves and wellbore profiles for Case 1 shown above were obtained from well tests during which a single production/injection well-pair was flowing. When the wellfield is brought on-line for power production the interference effects between wells result in substantially larger drawdowns than measured from individual (doublet) tests. For Case 1 where the field had not yet been drilled, a test with all wells flowing was not possible. The only way to estimate the drawdowns and adequacy of the planned wellfield is through simulation.

Figure 6 shows the calculated average wellfield production decline for the Case 1 (the initial wellfield pattern is shown in Figure 1). The depletion (decline) curve in Figure 6 shows the typical steep startup decline that is characteristic of liquid reservoirs. This startup decline was also shown in the data for Case 1. The calculation for Case 1 was stopped at about 5 years, since the data and methodology do not warrant further predictions.

The power plant requirement of 2.5 x 10^6 #/hr sets the average initial well flowrate, and shows that eight wells constitute a 25% excess capacity at plant startup. The calculation also shows that a make up well would be needed within 1/1-2 years from startup for this case. Although additional calculations are not shown in Figure 6, it is clear that when production and injection makeup wells are added at 1-1/2 years, the average well flow is reduced about 11% with a corresponding increase in wellhead pressure. The depletion calculations can then be continued from that point with the new wellfield pattern and flowrates as input to the calculation.

Several wells have been added since startup in our second example, Case 2, over the past 7 years. The field decline and schedule of drilling have been used to obtain the average reservoir parameters for the field, and are currently being used to study certain key reservoir management problems.

SUMMARY

The need and uses for depletion analysis of liquid geothermal reservoirs was outlined. The importance of the drilling schedule on economic appraisals of a project were reviewed. The types of data, and subsequent methodology that can be used to make pressure depletion calculations, was described. Commercially available microcomputer simulators make the parameter studies fast and cheap. Data was shown for a field that has produced for several years to provide a measured example of reservoir pressure decline in a liquid reservoir producing from two-phase wellbores.

REFERENCES

1. User Manuals for MRMW and WELF describe the simulators, BG Software, Oakland CA.

2. R.C. Erlougher Jr. SPE Monograph "Advances in Well Testing", 1977.

3. Basic descriptions of some wellbore models are given in the following list:

M. Natenson, Jour. Research U.S. Geol. Survey, Vol 2 No 6, 1974;

P. Atkinson, H. Ramey Jr, SPE Paper 6792, 1977

C. Miller, LBL report #10910, 1980.