Proceedings World Geothermal Congress 2000
Kyushu - Tohoku, Japan, May 28 - June 10, 2000

GEOTHERMAL RESOURCE PROVING CRITERIA

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Key Words: geothermal, resource proving, resource definition, reserves.

ABSTRACT

The great expansion of geothermal development, and in the number of geothermal developers, during the 1990s, led to the need to formally define geothermal reserves. Such definition occurs at a project milestone, such as bank finance approval, or to enable an oil company to add reserves to its assets, or when a project is sold; as well as the more obvious traditional need to size a power station. At the same time technology and experience has grown rapidly.

The development of reservoir simulation has been spurred by both software development and practical experience. It is now the case that reservoir simulation provides in most cases a reliable and proven technology for resource assessment, and is clearly superior to lumped-parameter estimates such as stored heat, and the cost of reservoir simulation is now reasonable. The superiority is so clear that it is difficult to justify the use of any other method to provide an estimate to the reserves available from a geothermal resource. Possible exceptions include small projects using only part of a resource.

1. INTRODUCTION

1.1 What are geothermal reserves?

The object of geothermal exploration and development is, in nearly all cases, the generation of electric power. The capacity of a field is therefore best measured in its total cumulative ability to supply power. Recently the World Petroleum Congresses and the Society of Petroleum Engineers agreed a standard. (SPE 1997) Their definition begins:

> “Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward…”

Degrees of uncertainty can be denoted by classification as proven or unproven, and unproven is further subdivided into probable and possible. Some stock exchanges (eg Australia) have rules governing the reserves definitions for mining companies. These rules for both mining and petroleum are not completely prescriptive but tend to refer to professional practice, to allow for the changes in technology with time.

It seems logical to follow a similar approach to geothermal reserves. The crucial constraint is to methods that are commercial, and fields that are known. The reserves will change with time, depending on changing technology and economics. For example, no reserves can yet be assigned to an HDR or fracturing project, since these techniques have never been commercial; but some fields with temperatures formerly regarded as too low would now have reserves for electricity generation, due to the now wide-spread commercial use of binary plant.

1.2 Reserve proving methods

A number of methods have been used over the years to estimate the total amount of steam or heat available from a geothermal field. These methods include:

- ❑ Stored heat
- ❑ Total well flow
- ❑ Areal estimates (power density)
- ❑ Decline analyses
- ❑ Lumped-parameter models
- ❑ Reservoir simulation

The first five of these are now reviewed, before considering simulation.

2. SIMPLE METHODS

2.1 Stored heat

This is the oldest method. Its theoretical basis is simple: use the isotherms to estimate the total amount of heat contained within the reservoir (Muffler & Cataldi 1978). Then the fraction that can be recovered is estimated.

This method has significant weaknesses. There is little experimental evidence to validate the recovery factor used. It is also very easy to include within the rock volume, regions of low permeability that in practice will not contribute to the producible reserves. For these reasons stored heat often leads to overestimates of field capacity, sometimes by large multiples.

2.2 Total well flow

In the absence of any other knowledge, the total flow of the drilled wells has sometimes been taken as the field capacity. This is clearly incorrect.

The field reserves are (by whatever method) the amount of fluid or steam in the resource. The total flow of the wells is simply the current ability to deliver fluid. Drilling more wells would increase the flow but not alter at all the reserves.

This criterion is sometimes still used as a partial criterion, ie requiring a demonstrated ability to deliver fluid, by requiring drilled wells to have some minimum total flow. This still confuses the issue of reserves with deliverability. *Provided that there is permeability, and drilling has shown the ability to drill productive wells*, total well flow is simply a matter of drilling, and unrelated to reserves.

The SPE/WPC definition similarly addresses this issue:

> “..the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir.”

2.3 Areal estimates

Resource assessment based on area has a long history in petroleum. It is usually expressed as an allowable flow per unit surface area, or an allowable well density. Often these estimates are based upon a simple reservoir model based upon a drainage area per well, and calculated rundown (or decline in well flow rate) dependent on the drainage area.

An alternative in geothermal is expressed as power density – number of megawatts generated per unit area of reservoir. Such a figure, usually 10-20 MW/km^2 is often used in the early days of exploration, to give preliminary estimates of the field capacity.

The amount of heat in the reservoir is proportional to the temperature, so this estimate should depend on reservoir temperature. Figure 1 shows values based on observed performance for a number of fields, and indicates that power density for most fields ranges from 8 MW/km^2 at 230°C to up to 30 MW/km^2 at 300°C.

2.4 Decline analyses

This method fits the history of flow from a well or group of wells to one of a family of standard curves. Ideally the flow should be at constant wellhead pressure, but usually pressure varies and flow is adjusted to compensate. The standard curve is then used to predict future flow and hence total cumulative production. The method derives from petroleum practice, and is applicable to a group of wells that are not subject to any change in management, or change in number. The method was previously used at The Geysers as means of resource assessment, and apparently is still used.

A limitation of the method often overlooked is that it applies to a constant number of wells. If more wells are added the decline rate increases; see for example Goyal & Box (1990) , and the Appendix. It is also the case that the reserves proven by this method are the reserves of the entire drainage area of the wells. Additional drilling adds deliverability, but does not add to the reserves unless it penetrates a new unperturbed area of the reservoir.

It is also used more frequently, and used today, as a means of projecting well flow for a few years, in order to monitor rundown and predict makeup drilling requirements. In this it is similar to the simple spreadsheet models described in the next section.

2.5 Lumped-parameter models

There are reservoir models using a single block or "lump" to represent a reservoir. They are the simplest case of reservoir simulation. They were extensively used before reliable simulation codes became available. Now they are used for local projection of well performance, say for a small isolated group of wells, or short-term field predictions.

Such simple models, typically implemented on spreadsheets, can provide good estimates over a few years, and are often by far the best method of making short-term incremental decisions about field management. But over the longer term they cannot represent the actual behaviour of an entire field with the same accuracy as a simulation, as such simple models cannot include the effect of factors not local to the area or time of the simple model. Distant parts of the reservoir, and the reservoir boundaries, control the long-term behaviour.

3. RESERVOIR SIMULATION

3.1 Introduction

The process of reservoir simulation is the construction of a detailed numerical model of a reservoir, and calculation of the past and future flows of geothermal fluid, using a standard simulation code. The structure is specified on the basis of known geological and geophysical structure, and upon the results of drilling. Those results include the geological logging, downhole pressure and temperature, and permeability as indicated by well tests.

The form of the model is then validated by either one or two steps:

- ❑ Natural state matching
- ❑ History matching

These two matching processes constrain the reservoir model. Natural state matching should always be done, and history matching also done, if there is any history to match. Because it is more constrained, a model is better when there is a history match, but even the natural state match alone provides significant definition of the reservoir.

3.2 Natural state matching

Prior to exploitation, the reservoir has a natural state: a distribution of fluid, pressure and temperature, and a natural flow of fluid into the reservoir from beneath and to ultimate surface discharge. The natural state matching uses the model, run to a quasi-steady state, to reproduce the pressure and temperature distribution. The natural influx is specified at the base of the model, and the quasi-steady state must match the surface discharge, and the pressure and temperature distribution, to the extent it is known from drilling. The model structure, primarily permeability, is adjusted until a match is obtained.

For a liquid-dominated reservoir, natural state matching strongly constrains the model. The temperature distribution is produced by a balance of convective heat upflow, conductive and convective losses at the sides, and surface discharge. To get the temperature distribution correct requires getting the pattern of flow through the reservoir largely correct.

There is normally a natural pressure gradient in the reservoir. There may be a lateral gradient, or a vertical gradient significantly different from hydrostatic. In each case the gradient is produced by the natural flow, and matching constrains permeability, horizontal or vertical.

For a vapour-dominated reservoir natural state matching is far less informative. The reservoir is basically a permeable box with sealed (or nearly sealed) boundaries, and steam expands into all permeable regions, with little contrast in pressure or temperature within the reservoir. In some cases there may be measurable pressure gradients across the field, which provide some information to constrain a natural state simulation.

In both cases the natural state matching constrains the distribution of permeability. Porosity is not constrained, since it only enters into the dynamic heat and mass balance, and does not affect steady-state fluxes of heat and mass.

3.3 History matching

If there is any history of discharge, then this history must also be matched. This matching provides additional constraints, as there is now a non-steady flow in the reservoir, and pressure drawdown draws fluid in directions different from the natural flow. Even if there is only a short history of well-testing, it can be valuable to match this. If nothing else, it will test how the chosen structure matches individual well performance. If there is a systematic bias, this may indicate a systematic bias in the assumed permeability structure.

4. DISCUSSION

4.1 Lack of calibration

Despite a large number of publications presenting the assessment of a particular field, there is very little published material that compares later performance with a field assessment, except for the work of Bodvarsson et al. (1989). And of course the large number of successful projects demonstrate that the assessment in these particular fields was correct. However no method of resource assessment has been properly calibrated against actual performance of actual fields.

4.2 Resources over-estimated

There are a number of projects around the world with plant operating below capacity.

The case of The Geysers is well known, and this experience has discredited the use of decline analyses as a means of resource assessment. (Decline analyses remain useful for projecting well performance.)

In most other cases of over-sizing the project was started at a time when resource assessment must have been on the basis of stored heat. In some projects operating below capacity, the final plant sizing decision was made on criteria other than resource assessment (usually a desire to gain from economies of scale on turbines), and so subsequent performance does not necessarily imply faulty initial assessment.

The stored heat method contains many factors subject to subjective assessment. The most important of these is the recovery factor. There is very little experimental or field evidence to support values chosen, and consequently the value chosen is arbitrary. In some projects at least overly high values have been used.

In addition, the depth of the reservoir is often a difficult parameter. Permeability normally decreases with depth (Bottomley & Grant 1998), and so how much stored heat can be attributed to hot regions below the top of the reservoir is also somewhat difficult.

The use of power density is superior to stored heat as a means of preliminary field sizing as it involves fewer assumptions about the reservoir. Only productive reservoir area and average temperature need to be estimated.

4.3 Resources successfully estimated

There are considerably more successful projects, which have either been assessed correctly, or under-assessed and extended. In larger fields the normal practice has been for some time to develop by stages. In all such projects except The Geysers simulation has been used at the later stages to manage the process of field expansion.

In smaller fields where only a single unit has ever been built, and continues to operate at full load, there has been an accurate assessment of field size.

Little if any is published from this large base of experience to provide a quantitative check on resource assessment (eg: if stored heat was used, what recovery factor was actually achieved?).

Overall these successes provide good support to the principles of reservoir engineering used, as clearly the methods must be physically realistic even if numerical calibration is lacking.

4.4 Superiority of simulation: avoiding unnecessary assumptions

Sometimes known complicating factors are accommodated by downgrading regions of the reservoir that are less permeable or less well known. But this is simply introducing structure into the conceptual model.

The use of a simulation model has the great advantage that it avoids the use of unnecessary assumptions. Suppose a reservoir has a region of poor permeability. In a stored heat assessment such a region is usually included, and then a judgement made about adjusting the recovery factor.

If there is some information indicating poor permeability, a simulation explicitly representing such a region avoids the judgement in favour of explicitly calculating whether sufficient pressure gradient will develop to draw fluid. Similarly making judgements about a fractured reservoir can be avoided. If there is information to indicate that significant volumes of matrix rock may be inaccessible, it is better practice to use a fractured reservoir simulator, incorporating the best estimates of fracture spacing and other parameters.

And the problems of how useful the hot rock at the bottom of the reservoir may be are best solved by modelling this explicitly, as a region of lower permeability, rather than making an informed judgement to include or exclude volume. Similarly errors based on decline analyses and varying numbers of wells are automatically avoided when the flow and pressure history is matched, and the number of wells explicitly modelled.

4.5 Conclusion

Bodvarsson et al. (1989) provide a comparison and validation of reservoir simulation for Olkaria. Simulation predictions made earlier are compared against actual later performance. The simulation performed well.

The cost of reservoir simulation is now relatively small – a few tens of thousands of dollars (US) to a few hundred thousand. Set against the money that would be wasted by a decision to oversize, it is clear that even a small increase in confidence is worth the expenditure.

Only for a small development, where the commitment is to a project clearly smaller than the resource capacity, is there no economic benefit to the better definition of reserves.

This case normally arises in the first stage development of a field that is clearly significantly larger, so that negligible risk attaches to the sizing of the first unit. If the first unit is pressing against the possible field size then a simulation is essential.

It is therefore concluded that the normal method for providing an estimate of resource capacity should be by reservoir simulation. For initial field exploration, where only rough estimates are needed, power density is preferable to stored heat, but simulation is preferable to both for development decisions.

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APPENDIX: Simple box model and reservoir decline.

Consider a simple box model, of a reservoir containing a mass M of fluid, and where this mass is proportional to the pressure P, ie $M = SP$. The reservoir might be gas, or liquid with a free surface, provided there is a linear relation between mass and pressure. Let each well be modelled as a simple leak through constant resistance R, and operating pressure P_o. Flow of each well is $W = (P-P_o)/R$. Then if there are n wells, conservation of mass gives

$$\frac{dM}{dt} = S\frac{dP}{dt} = -nW = -(n/R)(P-P_o)$$

This then gives for the pressure, with initial pressure P_i:

$$P = P_o + (P_i - P_o)exp(-nt/RS)$$

This is an exponential decline with time, with the exponent proportional to the number of wells. Flow of a single well follows a similar exponential form, declining exponentially from its initial value $W_i = .(P_i-P_o)/R$:

$$W = W_i exp(-nt/RS)$$

Cumulative withdrawal is also exponential from the initial mass M_i:

$$M = M_i - S(P_i-P_o)(1- exp(-nt/RS))$$

Both pressure and well flow are linear functions of cumulative withdrawal. Well flow declines exponentially with time if operating pressure and the number of wells is kept constant.

FIGURE

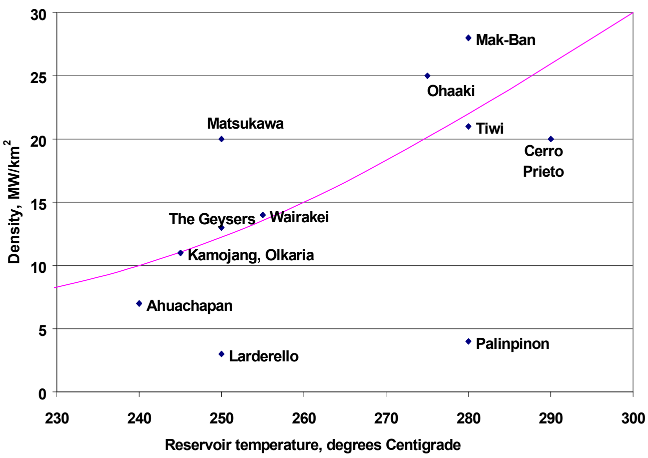

Figure 1. Power density of developed geothermal fields, after Grant (1996)

Note: Ohaaki assessed at 80MW (Grant, 1979).