The End Point of Geothermal Developments: Modelling Depletion of Geothermal Resources

J V Lawless
*A W Clotworthy; *G Ussher
Sinclair Knight Merz
PO Box 9806, Newmarket, Auckland, New Zealand: JLawless@skm.co.nz

Any finite quantification of the “capacity” of a geothermal resource implicitly involves a start point and an end point for energy extraction. The issue addressed in this paper is: at what time and why does energy extraction cease from a geothermal resource, and what are the implications for resource assessment?

The point of cessation can be referred to as the “end point” and the reason for cessation as the “failure mode”. The objective of this paper is to define the various ways that geothermal energy extraction development can be quantified and might have to cease, and then look at to what extent these can be built into predictive models. Useful insights can be gained from experience in “conventional” geothermal projects based on high temperature naturally convective systems with long operating histories, in excess of 50 years in some cases. This study is theoretical in the sense that to date, no whole geothermal power schemes anywhere have been decommissioned due to the resource reaching the end point and failing (though individual plants have ceased to operate). However, this will eventually be the case.

These issues will became increasingly important in Australia as projects move from Inferred Resource estimates to higher Resource and Reserve categories.

Stored Heat Estimates

In a simple stored heat estimate with no natural heat or fluid recharge over the project lifetime, the implicit assumption is that the project will cease when all of the available energy has been extracted. So the “failure mode” is a temperature decline. This is implicit in all of the Inferred Resource estimates that have been public in Australia so far, since they are all based on stored heat estimates.

In many of those assessments the “cut off temperature” which represents the minimum isotherm for defining the resource volume is based on an assumed power plant inlet temperature, and the “base temperature” which the available energy is referenced to is based on the plant rejection temperature. But even those apparently straightforward assumptions can be significant oversimplifications.

In a system with reinjection, practically speaking energy extraction will have to cease when the fluid coming out of the production wells drops below the minimum inlet temperature requirement of the power plant. But at that time there will be a temperature and pressure gradient laterally through the reservoir from the reinjection to the production wells, so the average resource temperature at that time will be less than the power plant inlet temperature. That average temperature should more logically be the cut off temperature for the stored heat assessment.

The next level of refinement is to consider that because of the change in water viscosity with temperature, the lateral pressure and therefore temperature gradient between the reinjection and productions wells will definitely not be linear, which means the fraction of the resource volume from which energy can usefully be extracted is not just a simple proportion. That could readily be addressed by a dynamic reservoir model, provided suitable data on the formation properties are available for calibration.

A related consideration which has arisen in one recent resource estimate is that the, use of a “cut-off isotherm” may not be the most appropriate method to apply to a series of vertically stacked sedimentary aquifers or horizontally fractured granite, in which heat flow is conductive and not convective, i.e. temperature is stratified, low at the top and high at the bottom, so wells at different depths or wells with multiple feed zones may produce fluid with a wide range of temperatures.

In such a system there could be the freedom to set the cut-off temperature at such a level, which ensures that the mixed geothermal fluid produced at the well head remains above the power plant temperature. Adoption of this approach could mean that the cut-off temperature to define the geothermal reservoir is lower than the power plant inlet temperature. The adoption of a lower cut-off isotherm could be beneficial in situations where the benefits of increasing the total volume outweigh a modest decrease in the temperature of the fluid produced.

Further considerations to take into account are: heat loss up production wells, which could be considerable where wells are deep and flow rates small; heat loss between the wells and power plant; heat loss between the separators (if any) and power plant and reinjection wells; and heat gain down the reinjection wells. There are also power systems aspects to consider such as process and thermodynamic issues as well as parasitic pumping etc. loads. Site-specific ambient temperatures and humidity will dictate practical cooling options.

Furthermore, if the production temperature declines over the lifetime of the project which is what would be expected in a heat mining operation and is therefore implicit in a stored heat estimate, the power plant efficiency would also drop and the production pumping requirements will change as the fluid density and viscosity changes. That would be exacerbated by reservoir pressure changes. All of these factors can and ideally should be modelled as resource assessments become more accurate, even when just using a stored heat approach.

Dynamic Resource Estimates

An alternative approach is to assume that a certain rate of extraction is indefinitely physically sustainable on a human time scale, in which case the field “capacity” is better expressed as MWth or MWe (making suitable assumptions as to conversion efficiency) rather than PJthermal or MWthermal-years in place and recoverable. This appears to be the case with fields such as Wairakei in New Zealand, where reservoir modelling predicts that extraction will be physically sustainably for at least 100 years – which is perhaps simply an expression of the fact that our perception of the “resource” is too limited in that it does not include the deeper heat source. But even there other factors may come into play which could mean the project cannot in fact sustain output for all of that period.

Based on practical experience of geothermal systems that have been exploited for a long period of time, there are other possible failure modes as follows.

With dynamic reservoir simulation, which is the most common means of assessing appropriate capacity in advanced existing conventional schemes without pumping, the “failure mode” is often predicted to be pressure decline rather than simply temperature decline. In a single phase (liquid) reservoir, pressure decline will be due to draw down in liquid pressure, as in a groundwater aquifer. In a two-phase reservoir such as Wairakei in New Zealand, Cerro Prieto in Mexico, or many of the other high temperature “conventional” projects worldwide which have been exploited, pressure draw down will to some extent be buffered by boiling, but if wells tap two-phase zones, pressures will be linked to temperatures, so can decline if cool water invades the reservoir (as has happened at Ohaaki for example).

In a dry steam system such as The Geysers in California pressure decline can be due to the reservoir drying out. Water loss within EGS projects is an obvious parallel though of a different origin.

Pressure decline has two important consequences. Initially it will cause declines in well mass output (though that may be compensated for by rising enthalpy if boiling occurs so the available energy output actually increases). It is also possible that pressures may eventually fall to the point where steam turbines become inoperable. In both cases considerable unrecovered thermal energy may remain within the reservoir.

To some extent these effects can be countered by drilling make up wells or adopting pumping, but a point of no return may be reached at which drilling further wells is not considered economic.

Linked to and synergistic with reservoir pressure declines, there can be incursion of groundwater, either laterally or from above. This has been well documented and studied in New Zealand resources such as Wairakei, Ohaaki and Kawerau as well as in some fields in the Philippines. As well as chemical monitoring of well production physical and chemical parameters, repeat micro-gravity measurements are an appropriate tool for tracking fluid movements.

Incursion of cool ground waters may be severely detrimental by reducing well enthalpies, as at Ohaaki. But it can also causing undesirable chemical effects such as scaling and corrosion. The ground water above and around high temperature geothermal systems may be high in species such as bicarbonate and sulphate and of low pH, developed by separation, absorbtion and oxidation of gas phases. Wells have failed in New Zealand fields due to external corrosion by such secondary fluids. They can also contribute to scaling in production wells by anhydrite from the admixed sulphate and/or more commonly calcite from the bicarbonate.

Premature reinjection returns to production wells are also a common limiting factor in some developments, and can leading to a low % energy recovery though not usually total failure of the project.

Excessive environmental effects on the surface are another factor that can limit geothermal energy extraction well before thermal energy depletion. At Wairakei in New Zealand for example, many years of geothermal fluid extraction with very limited reinjection have caused severe localised surface subsidence (possibly up to 21m) and increases in thermal activity including hydrothermal eruptions. The possibility of such effects extending into populated areas has been a constraint on further development. At Rotorua, power generation is effectively precluded because of concerns over effects on thermal activity which is crucial to the tourist industry.

Ability to Predict Failure Modes and Model End Points

The ability to predict what will be the failure mode of a geothermal project and hence its end point for resource estimation varies both according to the nature of the reservoir and the amount of knowledge available. At an early (pre-drilling) stage stored heat with its implicit assumption of temperature depletion is the most appropriate tool.

Once exploration wells are drilled and tested, stored heat estimates can be refined, but data may start to become apparent which indicate other possible end points, such as premature reinjection returns. At this stage such effects can be qualitatively modelled by analogies and dynamic reservoir simulation, but probably as a series of "what if" scenarios rather than a definitive quantitative prediction. To do so will require more attention is paid to permeability data than has been typically the case so far.

It is only once some production history becomes available either through operation of a small scale initial power generation scheme or long term well testing, that dynamic reservoir simulation can really come into its own and can be used to give reliable forward predictions.

Implications for Resource Estimation

The methodology for meaningful resource and reserves estimates will change over time as projects become more advanced. While stored heat estimates are adequate for Inferred Resource estimates, more advanced projects and higher resource categories should take into account other possible end points and adjust the estimates accordingly, in many instances most particularly through numerical reservoir simulation.

In many cases this approach will cause the later resource estimate to be lower than the initial ones – though strictly speaking that should not be so if the risks and uncertainties have been considered properly in the initial estimates. That is not always necessarily the case however. At Wairakei for example a significant stimulation of heat and fluid recharge has occurred which has increased the resource available.