Optimisation of Geothermal Resource Economics

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INTRODUCTION

This talk covers optimisation of the cost of electric power from Hot Dry Rock (HDR) systems, otherwise known as Enhanced Geothermal Systems (EGS). These systems are hydraulically tight reservoirs whose permeability has been enhanced by hydraulic stimulation. An EGS "unit" in this talk refers to an injection well and the neighbouring production wells that derive fluid from it; for example, a doublet, triplet, five-spot, etc. The reservoir is assumed to be developed in the basement rock rather than in any sedimentary overburden. Most of the parameters in this exercise reflect the conditions encountered at the U.S.A. Desert Peak EGS project and the costs reflect 2006 U.S. dollars, but the conclusions reached here regarding optimisation should be applicable, at least qualitatively, to any EGS project today.

Optimisation of geothermal resource economics calls for minimising the levelised cost of power (¢ per kilowatt-hour) over the project life. Minimising the levelised cost, in turn, requires minimising the capital cost of project development ($ per kilowatt-hour installed) as well as the operations-and-maintenance (O&M) cost (¢ per kilowatt-hour generated). The approach taken here is as follows: (a) using numerical simulation of an idealised reservoir to estimate power generation over time for various system configurations (number and spacing of wells, assumptions about stimulation effectiveness, etc.); (b) estimating the levelised power cost for each configuration, based on capital cost, O&M cost, cost of money and inflation rate; (c) determining the sensitivity of levelised cost to the cost components, interest and inflation rates, and resource characteristics (pumping rate, reservoir properties, depth to the reservoir, etc.); and (d) based on this sensitivity analysis and certain issues of site characteristics, identifying the practical steps that could be taken towards economic optimisation.

LESSONS FROM RESERVOIR MODELLING

From the forecast of the production rate and temperature from the reservoir model, the net power generation versus time was calculated, for each well geometry, after subtracting the parasitic power needed by injection and production pumps. For each combination of assumed geometry, injector-producer spacing, stimulated thickness, enhancement level (fracture spacing and permeability) and production rate, three criteria of performance were computed: (a) net generation profile (net generation versus time over project life), (b) net power produced per unit injection rate, and (c) fraction of in-place heat energy recovered.

This numerical simulation study led to the following conclusions relevant to optimisation of resource economics:

- Cooling rate at production wells is not an adequate criterion for measuring the effectiveness of an EGS power project; net generation profile and reservoir heat recovery factor are more appropriate criteria;
- Improving permeability, without improving the matrix-to-fracture heat transfer area (that is, reducing the fracture spacing), has little benefit in heat recovery or net generation;

- The net generation profile can be improved (that is, the decline rate can be reduced) by curtailing the throughput without significantly affecting average generation over the project life;
- Increasing the stimulated volume increases the generation level without significantly affecting the shape of the generation profile; and
- For a given state of stimulation (that is, fracture spacing and permeability) average net generation increases linearly with stimulated volume and is nearly independent of well geometry.

LESSONS FROM ECONOMIC MODELLING

We have estimated the drilling cost based on a statistical correlation with depth, and the stimulation cost based on the experience of the European EGS project at Soultz-sous-Forêts and Geodynamic Ltds' EGS project at Cooper Basin, Australia. For the power plant and surface facilities cost and the O&M cost, we have used the typical range of values in the geothermal industry. The uncertain variables in this analysis (capital costs of drilling, stimulation, power plant and surface facilities, O&M cost, interest rate and inflation rate) were subjected to Monte Carlo sampling and used in a probabilistic assessment of the levelised power cost. The capital cost was amortised over the project life at the interest rate, and O&M cost was increased at the inflation rate over the project life. The annual capital-plus-interest payment and O&M cost were discounted to their present value using the inflation rate. The mean levelised power cost versus stimulated volume per EGS unit was thus estimated for all configurations and stimulated volumes considered.

The economic analysis resulted in the following conclusions relevant to economic optimisation:

- Levelised power cost declines with increasing stimulated volume, and for any configuration, with the repeating of contiguous EGS units;
- The lowest possible cost of power at Desert Peak was estimated at 5.43¢ per kWh, ignoring certain uniquely site-specific and/or atypical costs of exploration, infrastructure development (such as roads and the transmission line), regulatory compliance, environmental impact mitigation, royalties, and taxes;
- Levelised power cost is most sensitive to O&M cost, followed by power plant/surface facilities cost, drilling cost per well and interest/inflation rates, in that order. It is insensitive to stimulation cost but very sensitive to the effectiveness of stimulation;
- Improvements in geothermal pump technology in the future could allow increasing the maximum practicable pumping rate from a well (currently 200 R/s), thus reducing the levelised power cost; a plausible 50% improvement in the pumping rate can reduce the levelised cost to 5¢/kWh;
- The effectiveness of stimulation in creating closely-spaced fractures and the desired reservoir characteristics (uniform, isotropic and sub-horizontal) reduces the risk of cooling of the produced fluid. The levelised power cost is sensitive to cooling rate (approximately 0.5¢/kWh increase per °C cooling per year); and
- Reservoir depth determines drilling cost, energy reserves and well productivity, while the effectiveness of stimulation, which is dependent on the lithology and in-situ stress condition at this site, determines cooling. Therefore, the levelised cost can be very sensitive to site characteristics.

CONSIDERATION OF CERTAIN SITE CHARACTERISTICS

It is obvious that the higher the temperature gradient at a site the more attractive the resource economics is likely to be. Site selection is often based on regional heat flow distribution and drilling of relatively shallow exploration wells. However, the temperature gradient measured at relatively shallow depths cannot necessarily be extrapolated downward indefinitely because of intervening geological issues such as the thickness of sediment cover on the basement, radioactive heat generation rate in the basement or the presence of natural convection cells. These issues are reviewed in this talk.

While energy reserves per unit area at any site increases with depth, net MW production capacity per well does not necessarily increase with depth. This issue arises from the fact that up to the depth where the temperature reaches 190 °C, which is the temperature limit for pumps available today, the capacity of a pumped well would increase with depth. Below this depth a well will have to be self-flowed and its capacity would actually be less; this would be true up to the depth where the temperature reaches about 220 °C. Above this temperature level no generalisation is possible about well capacity. Considering the well capacity and cost of drilling versus well depth, an optimum drilling depth may be defined at a site; this optimum drilling depth can be either the depth at which the well capacity is maximised or the drilling cost per MW well capacity minimised.

CONCLUSIONS

Based on numerical modelling of an idealised reservoir, economic analysis, and practical considerations of certain site characteristics, we conclude that the following steps can be taken towards optimising the economics of an EGS project; the steps are presented below in decreasing order of their importance:

- Reduce the operations and maintenance cost;
- Reduce the power plant cost;
- Choose the site with the highest possible vertical temperature gradient and/or the thickest possible sedimentary cover on the basement;
- Choose the drilling depth that maximises MW well capacity per unit drilling cost rather than reaches the hottest resource;
- Create the largest possible stimulated volume per well;
- Improve stimulation effectiveness, and in particular, reduce the fracture spacing and heterogeneity in the hydraulic characteristics of the stimulated volume;
- Pump the production wells, if possible, taking advantage of the evolving improvements in pump technology;
- Develop multiple contiguous EGS units to benefit from the economy of scale; and
- Through reservoir modelling optimise well spacing and injection rates that minimise the rate of decline in net generation with time.