Ensuring Resource Adequacy for a Commercial Geothermal Project

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ABSTRACT

This paper reviews the available approaches to ensuring resource adequacy for a commercial geothermal project, particularly from the viewpoint of investors who are familiar with investment in the petroleum and mining industries. Adequacy of the resource quality and well productivity or injectivity can be readily ensured through drilling and testing of wells. However, establishing the adequacy of recoverable energy reserves for a project can be challenging because of the inherent weakness in the concept of "reserves" in the geothermal context as opposed to oil, gas or mining projects. The concept of reserves and the approaches to reserve estimation in the petroleum and geothermal industries are compared and contrasted. Another aspect of resource adequacy assessment for a commercial geothermal project, namely, forecasting of reservoir performance is reviewed. The review shows that the perceived resource adequacy risk can be covered for a commercial project in several possible ways.

Introduction

Development of a commercial geothermal project is technically feasible only if the resource quality and quantity as well as the forecast of long-term performance of the reservoir are acceptable. The resource quality issues, such as, temperature (or enthalpy), pressure, fluid chemistry, etc. are readily resolved through drilling and testing of wells. One aspect of resource quantity, namely, well productivity and injectivity, is also unequivocally resolved by drilling and well testing. The resolution of another important aspect of resource quantity, namely, available reserves, is less straight forward. Forecasting of long-term performance of the reservoir as well as estimation of reserves become increasingly more reliable as the reservoir is exploited. This paper addresses the intertwined issues of reserve estimation and forecasting of reservoir performance in ensuring resource adequacy of a commercial geothermal project, particularly before any significant production has taken place.

Limitations in the Concept of Reserves

The concept of reserves as applied to commercial geothermal projects has some inherent weaknesses that tend to portray an undue sense of resource risk in the minds of investors, particularly those who are relatively new to the geothermal industry. Since many such investors are familiar with investments in oil, gas or mining projects, the differences between such projects and a geothermal project should be considered. As shown below, this perceived risk can be mitigated for any given geothermal project; but first let us review the weaknesses in the concept of geothermal reserves.

At the outset it should be noted that, unlike oil, gas or minerals, geothermal resource is not a material; it is energy, as are solar and wind resources. Hot water or steam produced from a geothermal reservoir is merely the medium that transports heat from the reservoir to the power plant and is injected back into the reservoir after heat is extracted from it. As such, a geothermal project, like a solar or wind project, calls for the estimation of energy generation capacity (expressed as BTU-per-hour or kilowatt), not reserves per se (expressed as barrels, cubic feet or tons). There is another fundamental difference between a geothermal project on one hand and oil, gas or mining projects on the other, namely, that a geothermal reservoir is an open system while an oil or gas reservoir or an ore body is confined. Figure 1a, overleaf, is a schematic representation of an oil reservoir illustrating its closed nature, the resource being completely enclosed within the lateral boundaries and the cap rock, both of which are impermeable, and the oil-water contact, which is effectively a movable horizontal fluid barrier. Well established exploration tools (such as, seismic reflection and refraction surveys), drilling results and stratigraphic correlation allow relatively confident definition of the impermeable boundaries, while analyses of well logs and cores allow assessment of the relevant reservoir properties (such as, thickness, porosity and water saturation) and definition of the oil-water contact. Therefore, the estimation of the oil-in-place is a relatively straightforward exercise.

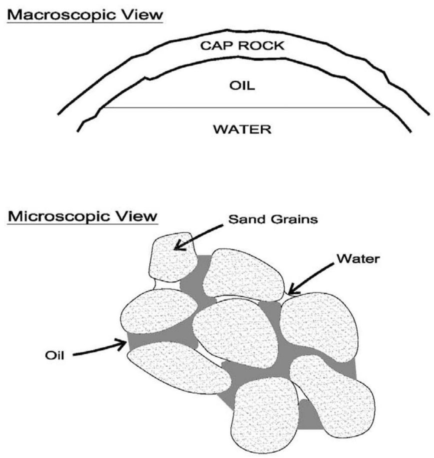

Figure 1. Schematic representation of an oil reservoir.

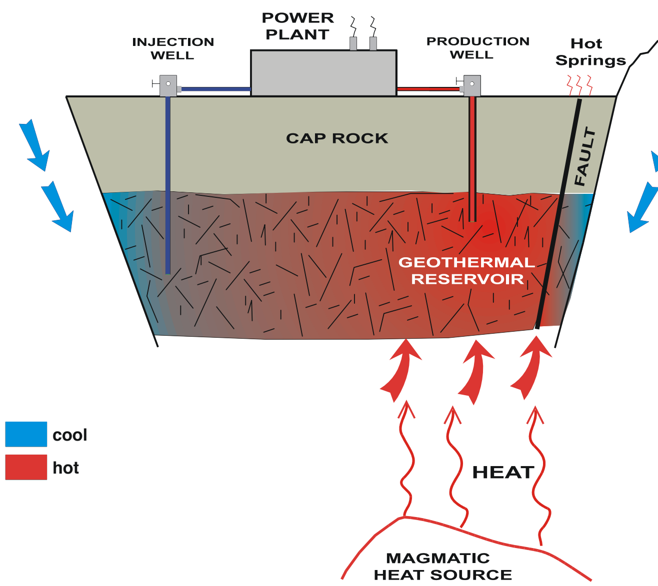

Figure 2. Schematic representation of a geothermal system.

Figure 2 is a typical schematic representation of a geothermal system illustrating its open nature. As Figure 2 indicates, a geothermal reservoir is essentially a plume of hot water and/or steam in a vast subsurface system of relatively cool water. The only commonly-encountered impermeable boundary to a geothermal system is a cap rock that prevents complete dissipation of the rising plume of hot water into the groundwater system. Sometimes incomplete lateral boundaries also occur. The cap rock is generally breached at places; otherwise hot springs or fumaroles would be rare occurrences. Since a geothermal reservoir is not a confined system, the concept of reserves is awkward in this context. The fluid inflow into a geothermal reservoir, whether hot fluid recharge from below or cool water influx from shallower depths, is balanced by fluid outflow from the system as hot springs, fumaroles, leakage into groundwater aquifers, etc. (Figure 2). This inflow and outflow of fluids also involve corresponding inflow and outflow of convective heat. Conductive heat inflow from the bottom of the reservoir plus convective heat inflow with the fluids are balanced by conductive heat loss from the top of the reservoir and convective heat loss through fluid discharge. The combined rate of this conductive and convective heat energy inflow into a geothermal reservoir represents the extent of truly renewable energy production rate possible from the reservoir. On the other hand, the stored heat within the reservoir, which remains constant until exploitation starts, is the maximum reserve of heat that can be potentially be “mined” from the reservoir, the rate of this heat mining being dependent on the assumed project life.

The heat energy generation rate possible from a geothermal reservoir is the sum of the renewable energy production rate and the planned rate of exploitation of the “minable” heat resource (Sanyal, 2004). While the gross extent of this “minable” heat resource can be estimated from exploration and drilling results, the extent of the renewable heat production capacity cannot be estimated with confidence until the geothermal reservoir has been produced for a prolonged period. Therefore, it is customary to ignore the renewable portion in estimating the resource adequacy for a geothermal project. But does this practice underestimate reserves? As discussed below, it generally does.

Wisian et al (2001) utilized surface heat flow distribution data to establish that an existing geothermal power plant typically has about ten times the energy output equivalent of the conductive heat loss rate from the geothermal system. Sanyal (2004) utilized results of numerical simulation of reservoirs to establish that geothermal power plants tend to have 5 to 45 times the energy output equivalent of the convective recharge rate into the reservoir. Therefore, the renewable component of geothermal reserves is usually minor. However, there are geothermal reservoirs that have shown an increasing renewable component as the installed plant capacity has been expanded. Unfortunately, how high the renewable fraction in the reserves may rise in such cases can be truly known only when either the reservoir is depleted or any further expansion of the plant capacity causes undue resource degradation.

In the petroleum industry, estimating oil-in-place is not only straightforward on the macroscopic scale (Figure 1a) but also on the microscopic scale (Figure 1b). Availability of various well logs, whole cores and sidewall cores in the petroleum industry allow the thickness of the permeable layers, reservoir porosity, and water saturation to be determined with fair accuracy. Thus oil-in-place can be estimated with reasonable confidence. On the contrary, in the geothermal industry, there is little possibility of quantitative application of well logs or core analyses towards estimating reservoir properties; therefore, estimating heat energy-in-place is a less accurate exercise.

While it is relatively straightforward to estimate the potentially “minable” portion of the heat-in-place in the reservoir, estimation of the fraction of this heat that can be recovered (the so called recovery factor) is not possible until prolonged production has taken place from the reservoir. In theory, one could estimate the recovery factor by numerical simulation of the system before it is exploited; but not being calibrated against any exploitation history renders such an estimate rather unreliable. Therefore, the general practice is to assume a recovery factor based on experience. The same practice of empirical assumption of a recovery factor in the absence of production history is routine in the petroleum industry. However, in the petroleum industry such an assumption would be based on accumulated statistical records from similar fields in the same sedimentary basin. Unfortunately, such statistical records are essentially nonexistent in the geothermal industry, the number of wells drilled and reservoirs exploited in the geothermal industry being a minuscule fraction of those in the petroleum industry.

A geothermal project may not be based on an entire reservoir but on a specific leasehold that shares the same reservoir with other leaseholds. In such a case the reserves under a specific leasehold would be dependent on how the neighboring leaseholds are going to be exploited, a fact that may not be known *a priori* given the competitive nature of leasing. A unique estimate of reserves under the leasehold in this case is difficult.

Finally, there is a common misperception that a high well productivity implies large reserves, and vice versa. But there is no theoretical or empirical correlation between well productivity and reserves. This is unfortunate because well productivity is readily measurable while reserves generally cannot be estimated accurately.

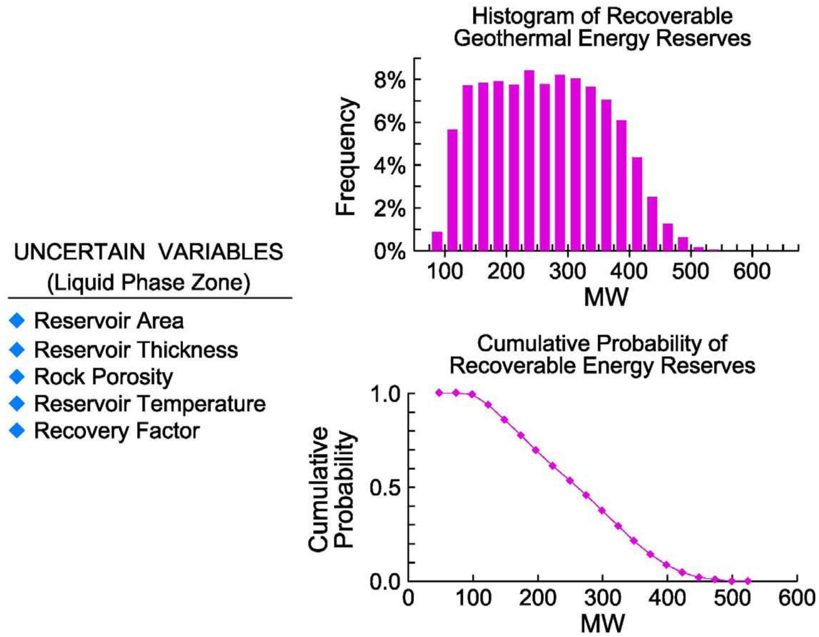

Figure 3. An example of volumetric estimation of reserves (Mahanagdon Reservoir, The Philippines).

Reserve Estimation for a Commercial Project

Several methods of geothermal reserve estimation of varying degrees of reliability are available. These fall in two categories (Sanyal and Sarmiento, 2005): (1) methods that do not depend on the production history of the field, and (2) methods that require some production history from the field. In the former category belong empirical methods and volumetric reserve estimation; in the latter category lie decline curve analysis, "lumped parameter" modeling, and numerical reservoir simulation. Sanyal and Sarmiento (2005) review these methods.

If the reservoir has not yet been exploited, volumetric reserve estimation is the only reasonable approach, in which the reservoir volume is defined from the estimates of reservoir area and thickness based on exploration and drilling results. An average temperature within the reservoir is estimated from drilling and well testing results. From the estimates of reservoir volume and temperature, the stored heat above a reference temperature level (typically the ambient temperature or temperature of the injected water) is estimated. Then, assuming a recovery factor, the amount of recoverable heat is calculated. Electrical energy reserves are estimated from the recoverable heat reserves assuming an appropriate energy conversion efficiency. For a given project life and an assumed power plant capacity factor, the MW capacity for the leasehold can then be derived. To account for the uncertainties in the required parameters, such as, reservoir area, thickness, temperature, etc., volumetric reserve estimation is often conducted as a probabilistic exercise. Figure 3 presents an example of the histogram and cumulative probability distribution of MW capacity of a geothermal field in the Philippines obtained by volumetric reserve estimation (Sanyal and Sermiento, 2005). An investor would typically require a cumulative probability of at least 90% that the proposed plant capacity can be supported for the project life by resource production from the leasehold.

If some production history from the reservoir is available, numerical simulation of the reservoir would be the best approach to reserve estimation. In this approach the reservoir is not treated as a single "tank" as in volumetric reserve estimation or in "lumped-parameter" modeling; instead, it is discretized into a large number of grid blocks so that the spatial variations in reservoir geometry and rock and fluid properties can be taken into account. Figure 4, overleaf, illustrates a reservoir simulation grid used for numerical simulation of the Beowawe reservoir in Nevada (Butler *et al,* 2001). Unlike volumetric reserve estimation, numerical simulation considers mass and heat recharge and discharge as well as the physics of fluid flow and heat transfer, and in some cases certain other physical phenomena (such as, mass transfer) that can affect reservoir performance. Therefore, numerical simulation is a tool that is useful for both reserve estimation and forecasting of reservoir performance. If the numerical simulation model is (a) based on a sound conceptual (hydrogeologic) model and adequate empirical data on rock and fluid characteristics, (b) constructed in sufficient detail, and (c) adequately calibrated against both the pre-exploitation state of the reservoir and observed reservoir performance under exploitation, then it can serve as the most reliable tool available for both reserve estimation and reservoir performance prediction.

The process of reserve estimation is by and large standardized in the petroleum industry. But standardization of the process of reserve estimation of commercial geothermal

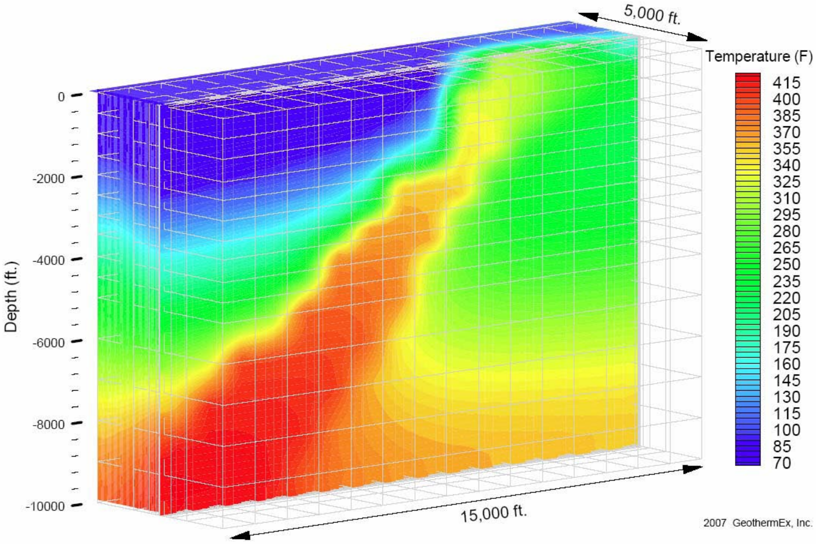

Figure 4. An example of a numerical simulation model (Beowawe Reservoir, Nevada).

properties has not attracted interest of the investors because of the limitations in the very concept of geothermal reserves as indicated above. In fact, one can argue that such attempts can be detrimental to the interests of either the developer or the lender or both. For example, at the Steamboat field in Nevada the volumetric reserve estimation approach would have indicated a substantially smaller development potential than has actually been sustained already for two decades because the field is subject to robust natural recharge. Any standardized reserve estimation approach, which would logically have been volumetric reserve estimation, would have stifled commercial development of this field; and as such would have been detrimental to the interest of the developer. At the other extreme, at The Geysers field in California many power plants, with a total capacity of nearly 2,000 MW, were installed by 1989 based on a standardized reserve estimation method akin to the "power density" approach (Grant, 2000). The performance of the field since then has clearly demonstrated that the field was vastly overdeveloped, leading to a substantial curtailment in the return expected by the investors. It should be noted that at The Geysers, volumetric reserve estimation would have been futile because the water saturation, which largely determines the reserves in a steam reservoir, was unknown. The industry experience shows that the only reasonable approach to reserve estimation for a commercial project is one that that is appropriately flexible and judiciously applied to a specific site with due regard to the available resource information and the cumulative experience gained from similar fields in the same geologic province.

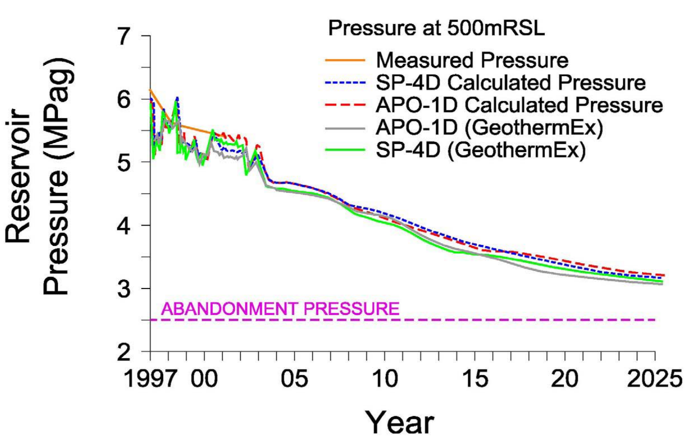

Figure 5. An example of forecasting reservoir pressure from numerical simulation (Mt. Apo Field, The Philippines).

Forecasting Reservoir Performance for a Commercial Geothermal Project

There are primarily three aspects of long-term reservoir performance that affect the resource adequacy for a commercial geothermal project; these are: (a) cooling (or enthalpy decline) of the produced fluid, (b) pressure decline and consequent decline in well productivity, and (c) increase in the non-condensable gas content in the produced fluid. All these aspects of reservoir performance can be handled best through numerical simulation (Sanyal and Sarmiento, 2005). Figure 5 shows an example, from the Mt. Apo field in the Philippines, of a forecast of reservoir pressure as a function of time using reservoir simulation. This figure shows pressure forecasts made using several different models and scenarios, all of which gave similar results. This implies that the uncertainty in these forecasts was relatively small. Figure 6 illustrates the forecasting of reservoir enthalpy, fluid production rate and non-condensable gas content in the produced fluid over time from the Uenotai field in Japan (Butler et al, 2005). Figure 6 shows good matches between the observed and computed values of enthalpy, flow rate and gas content over the six-year calibration period (1996 to 2002) implying a well-calibrated model. Therefore, the forecasts shown in this figure beyond 2002 can be considered reliable. Although not illustrated here, it should be noted that before calibrating the simulation model against the production history, it must be first calibrated against the pre-exploitation condition of the reservoir, at least the distribution of temperature and pressure within it.

Figure 6 illustrates how the resource adequacy for a commercial geothermal project can be ensured through numerical reservoir simulation. As of 2000, after 6 years of production, enthalpy had not declined, flow rate had established a significant decline trend and gas content had been going up steadily. At the rate of increase in gas content seen up to 2002, the power plant would have reached its design limit for gas content in a few years leading to an increasing loss of power conversion efficiency. This ominous trend together with the relatively rapid decline trend in the production rate of fluids seen up to 2002 cast serious doubt about the ability of this project to remain commercially operable for long. But as Figure 6 shows, reservoir performance forecast through simulation clearly established that the project would remain commercially viable through the project life (to 2022) because: (a) enthalpy would remain nearly constant; (b) fluid productivity decline rate would ease with time and flow rate would become nearly

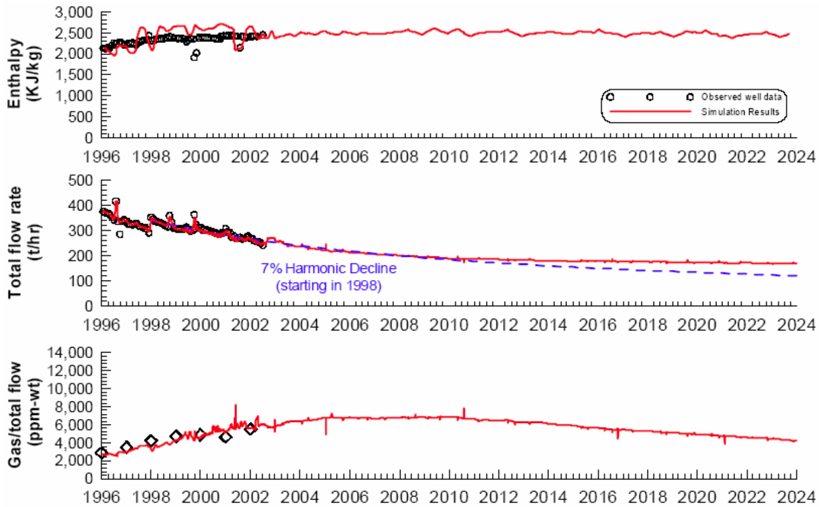

Figure 6. Example of forecasting enthalpy, total flow rate and gas contents from numerical simulation (Uenotai Reservoir, Japan).

constant after 2010; and (c) the increasing trend in gas content would end in a few years and the plant design limit would not be reached. By 2006, the forecasts made in 2003 have proven correct and the resource adequacy firmly established.

Covering the Resource Adequacy Risk

Finally, it should be noted that several obvious ways are available to cover the resource adequacy risk in a commercial geothermal project; the most important of these being as follows:

a) In the early 1980s, at least one insurance company had introduced insurance policies to cover geothermal reservoir risk. Unfortunately, the premiums proved unattractively high for the economic climate of the time, and these policies did not catch on. Given the more favorable power prices available today it is worthwhile reconsidering the concept of geothermal reservoir insurance.

b) For a new geothermal field without any exploitation history, one should heed the accumulated project experience in similar fields in the same geologic province. Although in such a situation no production history would be available with which to calibrate a numerical simulation model, sensitivity studies based even on an un-calibrated model can be helpful in the assessment of reserve adequacy.

c) An adequate lease area should be secured to ensure the availability of sufficient productive ground and minimal interference from any competing development. Volumetric reserve estimation supplemented by well interference testing and numerical modeling can help in this exercise.

d) The leasehold should be developed in relatively small, incremental steps of power capacity development. This, in fact, is the prevailing practice; a field with an estimated reserve of several hundred MW would typically be developed in phases, with each phase representing a 30 MW or 50 MW development. As each phase demonstrates sustainability the next phase is initiated.

e) If some production history exists, a calibrated numerical simulation model can be used as an efficient tool in forecasting reservoir performance under various plausible scenarios, from which the least risky development scheme can be determined.

f) It should be recognized that all conclusions arrived at above apply only to conventional "hydrothermal" projects. In the case of enhanced geothermal (or hot fractured rock) project there is no simple way to estimate reserves. Therefore, any standardized approach to reserve estimation would lead to major uncertainties for both the developer and financier. There is no general approach to estimating reserves for an EGS or HFR project because the estimation of a recovery factor is far from well established and there are no case histories from which to learn lessons.

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