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ONE DISCIPLINE, TWO ARENAS - RESERVOIR ENGINEERING IN GEOTHERMAL AND PETROLEUM INDUSTRIES

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ABSTRACT

The similarities and differences in reservoir engineering in the geothermal and petroleum industries are not familiar to many. This unfamiliarity frequently leads to aberrant perception of the risks and rewards of geothermal development in the minds of developers and financiers who are accustomed to the petroleum industry but are new to geothermal. This paper is a comparative survey of the state-of-the-art of reservoir engineering in the two industries.

This survey leads to the following conclusions. First, compared to petroleum, geothermal reservoir engineering is more challenging in that conceptual modeling has more complexity, parameter estimation has more limitations, and volumetric reserve estimation has more uncertainty. However, the saving grace of geothermal reservoir engineering is numerical simulation, which allows one to overcome the above limitations and produce estimates of reserves and forecasts of reservoir and well behavior that are at least as reliable as in the petroleum industry. Second, the term "reserves" in the geothermal industry has no standard definition, and in fact is a misnomer compared to the usage in the petroleum industry. Third, unlike in the petroleum industry, reservoir engineering and geoscience are intricately intertwined in geothermal. Finally, empirical knowledge about the nature of geothermal reservoirs is minimal and the body of literature on geothermal case histories is minuscule compared to petroleum. This imposes a higher premium on the practical experience of the engineer in geothermal reservoir engineering.

INTRODUCTION

Reservoir engineering as a distinct discipline had a hazy beginning in the petroleum industry in the 1930s, whereas the entry of reservoir engineering in the geothermal industry can be precisely dated to 1969 (Whiting and Ramey, 1969). By the mid 1970s geothermal reservoir engineering was an established discipline, the Second U.N. Symposium on the Development and Use of Geothermal Resources in 1975 being the first presentation of a multitude of papers on geothermal reservoir engineering at a single forum. Since then, several hundred papers have appeared in the literature marking the advance of the state-of-the-art of geothermal reservoir engineering.

Over the last three decades geothermal reservoir engineering has evolved and diverged from its petroleum counterpart. Today, many individuals in both petroleum and geothermal industries are unaware of the similarities and differences between reservoir engineering in the two industries. This unfamiliarity frequently leads to aberrant perception of the risks and rewards of geothermal development in the minds of developers and financiers who are accustomed to the petroleum industry but are new to geothermal. Such parties often consider geothermal reservoir engineering to be inherently less reliable than its petroleum counterpart. This perception is born of the contrast between the familiar and tangible nature of petroleum and the seemingly exotic and nebulous aspects of geothermal energy, being associated with such disquieting images as violent volcanoes, gushing geysers and seeping sulfurous gases. On the other hand, a greater and abiding faith in petroleum reservoir engineering prompts certain parties to believe that petroleum reservoir engineering can be readily applied, unaltered, to geothermal. Neither view is reasonable. The author has had the privilege of working in both industries and discussing these differences with numerous interested individuals and institutions over the years. This paper is a survey of the differences in the state-of-the-art of the same discipline of reservoir engineering applied in two distinct arenas: petroleum and geothermal.

CONCEPTUAL MODELING

A pivotal distinction between petroleum and geothermal reservoirs is that a geothermal system cannot be static, for a static fluid reservoir must cool down. Migrating petroleum, on the other hand, is trapped in structural or stratigraphic "traps" forming static pools. A geothermal system represents structurally-controlled convection, with dynamic equilibrium existing between mass and heat flow into and out of the reservoir. Therefore, the definition of the heat and fluid sources and discharge areas of the system, and the tortuous flow paths in between, poses a significant extra hurdle in geothermal reservoir engineering.

A geothermal reservoir typically lacks a well-defined structure or physical boundary. Petroleum reservoirs occur in sedimentary rocks that have clear stratification and regular structures, whereas most geothermal resources occur in igneous or metamorphic rocks, with fewer and more poorly defined stratigraphic horizons and more complex and heterogeneous structures or no discernable structure at all (as in randomly fractured granite). The boundaries of a petroleum reservoir are unequivocally defined by the structural or stratigraphic trap and the oil-water or gas-water contact. The boundaries of a geothermal resource are often somewhat arbitrary, being defined by the contour of the lowest commercially attractive temperature within a larger flow system. Thus, a geothermal reservoir is often described as a "plume" of hot water, emanating from a hot recharge source, existing within and in dynamic equilibrium with a larger flow regime. For this reason, one speaks more often of a geothermal "system" or "resource" than of a geothermal reservoir. A geothermal reservoir does have a "cap rock" albeit often ill-defined; otherwise the hot geothermal fluid, being less dense than the surrounding cooler water, would escape due to buoyancy. But the cap rock is usually leaky, otherwise the system would be static and hence, would cool down. The very nature of the geothermal reservoir thus looms as a formidable challenge in reservoir definition.

In the petroleum industry the geologist and the reservoir engineer typically play their professional roles independently of each other; the geologist defines the structure and boundaries of the gross reservoir while the reservoir engineer deals with the pore space and the fluids in it. In the geothermal industry the geoscientists (geologist, geochemist and geophysicist) and the reservoir engineer ideally work hand-in-hand to develop a conceptual model of the system. In fact, as discussed later, the conceptual model typically needs verification and improvement through numerical simulation of the pre-exploitation state of the system. Geoscience and reservoir engineering are thus intricately intertwined in the geothermal industry, a consequence of the dynamic and unconfined nature of the reservoir and the fact that the bulk of the thermal energy resides not in the pore fluids but in the rock itself, a point elaborated below.

Surface geological investigations are essential in defining a geothermal system, irrespective of depth, compared to a petroleum field because geothermal fluids typically discharge at or close to the ground surface, giving rise to hot springs, fumaroles, gas vents, altered rock outcrops, etc. Geothermal systems without any surface manifestations ("blind anomalies") are relatively rare. Geochemical exploration of hot springs and fumaroles, and monitoring of the chemistry of the fluids produced from wells, are far more critical aids in reservoir definition in the geothermal industry than in petroleum. Seismic reflection and refraction surveys, which are quintessential exploration tools in the petroleum industry, are neither commonplace nor convincingly effective in geothermal. On the other hand, electrical resistivity and heat flow surveys are invaluable in reservoir definition in the geothermal industry but not in petroleum. Gravity and magnetic surveys have limited but comparable utility in reservoir definition in both arenas. Well-to-well correlation of logs is a routine and rewarding means of revealing the geologic structure of a petroleum reservoir; but in geothermal this effort yields only modest success because of a general lack of well-defined stratification. Geological correlation based on micropaleontology is ruled out for geothermal because of the absence of fossils.

The pore-space geometry is more varied, and generally more intractable, in geothermal compared to petroleum. It is often debatable to what extent a specific geothermal reservoir is best represented as a purely porous medium (intergranular porosity model), purely fractured medium, or a case in between (the so-called double-porosity model of the petroleum industry). The familiar class of geothermal reservoirs associated with a single fault or rift zone have no counterpart in the petroleum industry. In fact, faults are unbreachable barriers to flow in the petroleum context while in geothermal they often represent fluid flow conduits and are not impervious to heat conduction.

PARAMETER ESTIMATION

Unlike the case of petroleum reservoirs, there is a paucity of well logging techniques with which to estimate the porosity or assess the lithology of a geothermal reservoir. Conventional well logs are calibrated for lithologies encountered in oil and gas fields, namely, sandstone, limestone and dolomite. With a few exceptions, geothermal systems are hosted in igneous and metamorphic lithologies, for which well log responses are not calibrated. Calibration of well logs in the geothermal industry is frustrated by the fact that geothermal lithologies are highly variable in their chemical composition. Sandstone, limestone and dolomite have standard chemical compositions: S_iO_2, $CaCO_3$, and Ca (Mg) CO_3, respectively. But no two igneous or metamorphic rocks ever possess exactly the same mineral constituents or chemical composition. Development of well logging “test pits” for geothermal lithologies (granite, basalt, etc.) by the U.S. Department of Energy, following the practice in the petroleum industry, has proven futile in spawning a quantitative logging practice in the geothermal industry. Although this shortfall in well logging is a manifest source of uncertainty, it has a surprisingly minuscule overall impact on geothermal reservoir assessment.

Unless a geothermal reservoir produces only water (implying nearly 100% water saturation), there is no reliable means of estimating the water saturation in the reservoir; even a reservoir that produces only steam may harbor high water saturation. Unlike in the petroleum industry, no established well logging or core analysis technique exists with which to estimate water saturation in geothermal reservoirs; electrical resistivity and pulsed neutron logs are ineffective in distinguishing between steam-filled and water-filled zones. This is not surprising considering that the porosity in a geothermal reservoir is on the order of only 3 to 5%, and rock density is about 2.7 times that of water and two orders of magnitude higher than that of steam. Derivation of reservoir water saturation from the geochemical characteristics of the produced fluids has proven unsuccessful, at least quantitatively. Therefore, the distribution of water saturation in a geothermal reservoir can only be deciphered by trial-and-error numerical modeling of the reservoir. This limitation combined with the uncertainty in porosity estimation is a drawback, but not an insurmountable obstacle, in the assessment of two-phase geothermal systems.

In contrast to petroleum reservoirs, core analysis offers little aid in estimating either the absolute permeability value or relative permeability characteristics of a geothermal reservoir. In fact, even retrieval of representative core samples from a geothermal reservoir is fraught with difficulty because of the fractured nature of the vast majority of geothermal rocks. If the core falls apart at the fractures, the permeability of the remaining rock fragments would be much lower than that of the whole rock. If the core remains intact, stress release upon coring may cause an artificial increase in the fracture permeability of the rock. Furthermore, the petrophysical properties of fractured core samples are likely to be stress-sensitive. This unavailability of representative core samples and the inability to reproduce the precise *in-situ* stress conditions in the laboratory preclude any quantitative analysis of cores from most geothermal reservoirs for estimating porosity, permeability or relative permeability characteristics. Although the well-known “Corey” relative permeability curves from the petroleum industry, or other similar correlations, have been readily adapted for geothermal application, their utility is constrained by the absence of reliable estimates of the "irreducible" water saturation or "critical" steam saturation. Attempts have been made to estimate steam/water relative permeability characteristics from production records (Horne and Ramey, 1978), but the utility of the approach has been limited by the inability to estimate reservoir water saturation. This constrains the level of confidence in the forecast of production characteristics of a geothermal reservoir.

Well-to-well tracer tests in a geothermal reservoir usually lack the quantitative utility of such tests in a petroleum reservoir. The absence of stratification and more pervasive heterogeneity of the pore structure in a geothermal system plague quantitative interpretation of tracer test data. Even if the tracer data can be interpreted to quantify certain hydraulic aspects of a geothermal reservoir without a shadow of non-uniqueness, an accurate assessment of the heat transfer characteristics of the reservoir, which is crucial in geothermal reservoir engineering, cannot be guaranteed. Therefore, the reservoir engineer resorts to numerical simulation for rigorous quantitative analysis of geothermal tracer test data rather than relying upon analytical solutions as is common in the petroleum industry. In recent years tracer testing has seen promising innovations unique to the geothermal industry (Adams, 1995).

Drill stem testing and single-well tracer testing, which can be utilized to define the productivity characteristics of multi-zone petroleum wells, are not readily applicable to geothermal wells. However, both single-well pressure transient tests (build-up, drawdown, multi-rate, etc.) and well-to-well pressure interference tests can usually be used to define the hydraulic properties of geothermal reservoirs as effectively as for petroleum reservoirs, particularly if the reservoir contains a single-phase fluid (for example, Sanyal, *et al*, 2000). The non-isothermal nature of a geothermal reservoir can occasionally undermine the accuracy of such tests, particularly for injection wells. While the petroleum literature is replete with solutions of the Diffusivity Equation for myriad reservoir geometries, only the Line Source solution for an infinite-acting system (with superposition in time or space, when needed) is usually applicable to a geothermal reservoir because of its unconfined nature. For wells producing from a single fracture, one of the vertical fracture solutions (Ramey, 1976) may prove useful, particularly for short-term well testing. In many geothermal reservoirs, the flow to a wellbore is likely to be "spherical" in nature rather than radial or linear as assumed in petroleum well testing. If the reservoir hosts a two-phase fluid, pressure transient tests in both petroleum and geothermal production wells suffer from similar, significant limitations. If the pressure and saturation changes are small, the standard equations for transient pressure testing can be applied to a two-phase geothermal reservoir by using a "two-phase compressibility" (Grant and Sorey, 1979). Testing of a two-phase geothermal well is further complicated by the impact of heat transfer (such as caused by injection) on reservoir steam saturation (Garg, 1980; Aydelotte, 1980).

Except for a rare few geothermal reservoirs with stratification, the concept of "net thickness" (h) of the petroleum industry is not meaningful for geothermal. Therefore, while the permeability-thickness product ("kh" or the "transmissibility" of the petroleum industry) and storativity ("$\phi c_t h$") of a geothermal reservoir can be derived from pressure transient tests, unique values of permeability (k) or porosity (ϕ) remain elusive. Again, permeability and porosity can only be established with any confidence from trial-and-error numerical simulation of the reservoir. The concept of skin factor of the petroleum industry, which is ill-adapted in the geothermal context, implies that a damaged well should display a positive value of skin factor while a stimulated well (particularly a well intersecting a fracture) a negative value. Geothermal wells rarely show a positive skin factor, for a well flows primarily because it intersects one or more fractures in an otherwise tight rock. Therefore, even a damaged geothermal well usually displays a negative skin factor because some of the fractures intersecting the well may be partially or totally clogged (by drill cuttings, mud or lost-circulation material) leaving yet others open to flow.

Compared to the petroleum industry, flow metering in the geothermal industry is not standardized, and therefore, tends to be less reliable. Flow metering of a two-phase geothermal well is tolerably accurate when a separator is used, but still generally not as accurate as in the petroleum industry. Furthermore, more than one geothermal production wells are sometimes connected to a single separator, precluding routine, accurate metering of individual well flows. Flow metering of two-phase geothermal wells often utilizes an orifice plate, sometimes along with a weir box, rather than a separator, the flow rate and enthalpy being calculated from empirical correlations. Alternatively, two-phase geothermal wells are metered using a "critical flow tube" and the so-called James correlation (James, 1965). Yet another alternative is the "tracer dilution" technique for geothermal flow metering (Hirtz and Lovekin, 1995). The last three approaches, which forego the use of a separator, often result in significant metering uncertainty for two-phase production wells.

Deliverability, injectivity and isochronal tests, and the concepts of productivity and injectivity indexes, of the petroleum industry have also become fashionable in the geothermal industry. However, instead of volumetric flow rates for petroleum wells, mass flow rates are reported for all but very low temperature geothermal wells because the volumetric flow rate of a geothermal fluid, particularly when it is two-phase, is an acutely sensitive function of temperature and pressure. The use of mass rates obviates the need for the "formation volume factor" of the petroleum industry.

The plethora of cased hole, "production" logs familiar in the petroleum industry are generally unavailable in geothermal. Interpretation of temperature, pressure and spinner logs is inherently more difficult for geothermal wells than petroleum due to one or more of a host of insidious complications: presence of multiple production zones with varying enthalpies and/or hydraulic heads giving rise to cross-flow between zones or oscillations in the flow rate and enthalpy, wellbore heat loss (particularly to active cool aquifers above the reservoir), gas build-up or natural convection under static condition, scaling or corrosion in the wellbore affecting the pressure drop characteristics, and so on.

Petroleum reservoir engineering requires PVT data derived in the laboratory from reservoir hydrocarbon samples, or approximated from a variety of empirical correlations. Thanks to the standard steam tables, accurate values of physical properties of steam and water are always at the disposal of the geothermal reservoir engineer. The dissolved salts (mainly NaCl) are taken into account using well-established correlations for geothermal brines, while the dissolved gases (mainly CO_2 and H_2S) are dealt with by using standard equations of state. Therefore, geothermal fluids are more readily and accurately characterized than petroleum even as the geothermal reservoir defies simple characterization to which the petroleum reservoir is eminently amenable.

ESTIMATION OF RESERVES

In the estimation of reserves, there exists a fundamental difference between the two industries. While petroleum engineering calls for an estimation of the volume of hydrocarbon in the reservoir pore space, geothermal engineering seeks to estimate the amount of thermal energy stored, not only in the fluid (in the pores and fractures) but also in the rock. In geothermal engineering, neither porosity nor water saturation has a major impact on reserve estimation because 80% to 95% of the *in-situ* thermal energy resides in the rock matrix. The critical step in the estimation of stored thermal energy is the definition of the temperature distribution within the reservoir based on interpretation of temperature logs recorded in wells and guided by an appropriate conceptual model of the geothermal system; this is akin to defining the distribution of the product of porosity and water saturation for petroleum reserve estimation. As discussed before, definition of the boundary, whether physical or representing the contour of a "cut off" temperature, is more challenging in the case of a geothermal reservoir than a petroleum reservoir, where the physical boundary and oil-water (or gas-water) contact are more tangible and more amenable to definition. Therefore, "reservoir limit test" of petroleum engineering has little practical significance in geothermal.

The next step in volumetric reserve estimation is the assumption of a "recovery factor": the recoverable fraction of the hydrocarbon-in-place in petroleum engineering, and the recoverable fraction of the in-place thermal energy in geothermal. Unfortunately, few long-term case histories of geothermal projects are available; therefore, no empirical correlations exist from which to estimate the recovery factor for "volumetric" reserve estimation as is routine in the petroleum industry. The recovery factor in geothermal reserve estimation is assumed based solely on experience, and therefore, is more arbitrary than in petroleum reserve estimation. The final step in geothermal reserve estimation is to apply a thermal-to-electrical energy conversion factor to the estimated thermal energy reserves; this factor, of course, has no parallel in petroleum reserve estimation.

The term "reserves" is a misnomer in the geothermal industry, where reserves are presented in terms of the available power capacity (in megawatts) for an assumed power plant life, rather than in terms of the amount of energy (megawatt-years). In other words, "reserves" in the geothermal context represent an energy production rate (akin to barrels per day or MMSCF per day in the petroleum industry) rather than reserves comparable to barrels or MMSCF of petroleum reserves. With the current fashion of labeling geothermal energy as "renewable," the concept of volumetric reserve estimation courts contradiction. The "reserves" of a truly renewable resource is, by definition, limitless; for example, no attempt is made to estimate wind or solar energy reserves. However, in the context of the power generation rate, the amount of a renewable energy resource is best defined as the maximum rate of natural replenishment of energy, rather than the amount of energy contained in any given volume. A geothermal reservoir is not renewable within the 25 to 30 year life span of a geothermal power plant, unless the plant capacity is small enough in comparison to the rate of natural recharge of hot fluids, which can only be estimated by trial-and-error numerical modeling of the initial state. To complicate matters, upon exploitation this rate of recharge may increase; the extent of any such increase can only be assessed by trial-and-error numerical simulation of the production/injection history of a field. In the author's experience, natural energy recharge rate never amounts to more than a modest fraction of the energy extraction rate in most commercially exploited geothermal fields. Volumetric reserve estimation, failing to take into account the natural recharge, may thus be considered pessimistic. However, given the uncertainty in the recovery factor used in this process, neglecting natural recharge hardly affects the accuracy of such reserve estimation.

Mimicking the practice in the petroleum industry, geothermal energy reserves are occasionally presented under the categories of "proved", "probable" and "possible." However, unlike in the petroleum industry, these terms lack standard definition in the geothermal context; attempts to standardize them have proven futile. This situation stems from the fact that unlike the case of petroleum, volumetric estimation of geothermal reserves is inherently uncertain, and therefore, classification into three reserves categories to reflect the associated uncertainty is deemed superfluous. For all practical purposes, the "proved" reserves in the case of a geothermal project is the best estimate of the reserves, based on all available data, discounted for the underlying uncertainty. How, and how much, to discount remains a matter of choice without the slightest hint of an industry-wide consensus. This nebulous discounting process is dictated more by how risk averse the developer is than by scientific or engineering principles, and may even strain ethical principles in the heat of competition for market share or bargaining between the buyer and seller.

The materials balance approach to reserve estimation used in the petroleum industry had been extended to a materials-and-energy balance approach early in the history of the geothermal industry (Whiting and Ramey, 1969). This latter approach, labeled "lumped-parameter modeling" in the 1970s, was seen as a promising means of reserve estimation that is more accurate than volumetric reserve estimation but not as rigorous as numerical simulation. Unfortunately, this approach soon proved to be deficient because of the unconfined, dynamic and heterogeneous nature of geothermal reservoirs. Lumped-parameter modeling has all but disappeared from the geothermal scene. Therefore, numerical simulation, although it involves an order of magnitude more effort, remains the sole means of improving upon volumetric reserve estimation in the geothermal industry.

The p/z method of reserve estimation for gas reservoirs has been applied to steam fields (for example, Brigham and Morrow, 1977; Sanyal, *et al*, 1989). However, these applications have proved unsatisfactory except when the methodology could be ingeniously modified for a site-specific application (for example, Brigham and Neri, 1979). Decline curve analysis of the petroleum industry offers a convenient tool for the near-term projection of productivities of geothermal steam wells (Sanyal, *et al*, 1989) and even for two-phase wells in many cases. Experience shows the decline trend for geothermal wells to range from exponential to harmonic, compared to the wider range of exponential to hyperbolic for petroleum wells. Most steam or high-steam fraction wells appear to decline with a harmonic trend, akin to partial water-drive gas wells.

NUMERICAL MODELING

Except for the special case of thermal recovery, all aspects of petroleum reservoir engineering are concerned with an isothermal reservoir, whereas a geothermal reservoir is anything but isothermal. Therefore, for modeling a geothermal reservoir, one must solve a set of simultaneous partial differential equations involving both fluid flow and heat transfer, while in modeling a petroleum reservoir, only fluid flow needs be considered. However, numerical modeling of a geothermal system never involves the higher-order complexity of "compositional" modeling as is required for reservoirs with high API gravity petroleum.

Most of the concepts, qualitative and quantitative, associated with the performance of a petroleum reservoir are also applicable to a greater or lesser extent to a geothermal reservoir. Drive mechanisms, such as, solution gas drive, gas cap drive and water drive of the petroleum reservoir have their counterparts in geothermal although the associated terminology has not entered the geothermal lexicon. A "steam cap" sometimes develops in an exploited reservoir, but a distinct "steam-water contact" can rarely be defined compared to the sharp gas-oil contact in a petroleum reservoir. As regards the displacement of geothermal fluids by injected cool water, the concepts of "sweep efficiency" and "vertical conformance", as used in petroleum engineering, are awkward to apply to all but a few geothermal reservoirs with intergranular porosity; as to what is being swept, the geothermal reservoir engineer is more interested in heat than fluids. The relative permeability characteristics play the same crucial role in both geothermal and petroleum reservoirs. Unlike in petroleum reservoir engineering, capillary pressure characteristics are, however, not important in geothermal, nor does the additional complication of three-phase (oil-gas-water) relative permeability relations burden geothermal reservoir engineering. The problems of immiscible displacement, a preoccupation of the petroleum reservoir engineer, is absent in geothermal while *in-situ* boiling of the "irreducible" water saturation is a phenomenon unique to geothermal and thermal oil recovery. Patterned injection (five-spot, line drive, etc.) of petroleum industry is not a practice in geothermal. Finally, because the geothermal fluid is single-component, "retrograde condensation" is ruled out in a geothermal reservoir.

For solution of the partial differential equations involving fluid and heat flow in a geothermal system, the finite-difference schemes and solution techniques used are comparable to, and in some aspects perhaps more advanced than, those prevalent in the petroleum industry. The basic process of construction of geothermal and petroleum numerical simulation models is similar. However, the numerical model of a geothermal reservoir must include a far larger volume of the subsurface than just the reservoir itself. This is an obvious necessity if the reservoir has no physical boundaries. Even where physical boundaries exist, such as a cap rock or a barrier fault, fluid flow is impeded or prevented across it but not heat conduction. The conductive heat sources and sinks, such as a hot and impermeable basement below the reservoir or the atmosphere above the ground surface must be included in the model in one fashion or another. The convective heat and fluid sources, such as a hot "upflow" zone from below the reservoir or percolation of cooler ground water down to the reservoir must likewise be included in the model (see for example, Butler, *et al*, 2001). Either the potential or the strength of each heat or fluid source must also be specified as appropriate. In contrast, the simulation model for a petroleum reservoir does not include any subsurface volume outside its physical boundaries, the water influx from below the oil-water contact being handled through various analytical formulations. Therefore, the numerical model of a geothermal reservoir must involve a much higher number of grid blocks than a petroleum reservoir model of comparable resolution.

The first step in the calibration of the numerical reservoir model is profoundly different between the two industries. In petroleum reservoir modeling, one needs only to "initialize" the model for a few tens of simulated years of pre-exploitation condition, primarily to ensure a stable oil-water, oil-gas or gas-water contact. In geothermal reservoir modeling, an exacting step of "initial state" (that is, pre-exploitation) modeling for a simulated geological time of several tens of thousands of years is deemed essential. Figure 1 shows a flow chart of this process.

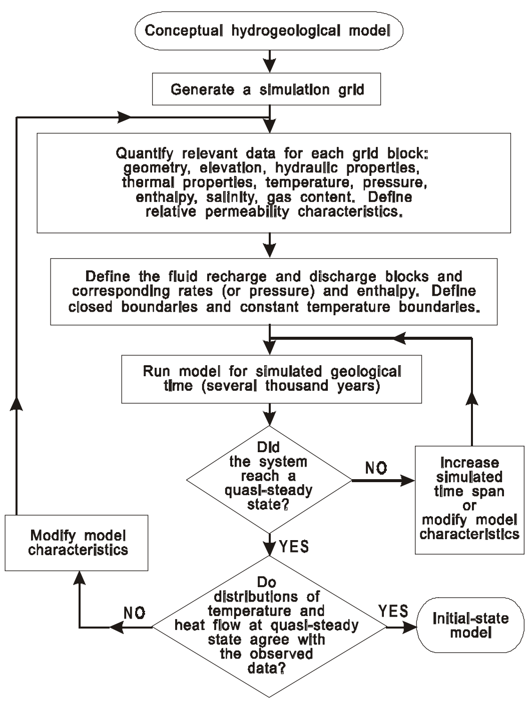

Figure 1. Flow Chart of Numerical Simulation of The Initial State

In initial-state modeling, the known and calculated initial distributions of temperature, pressure and enthalpy within the reservoir are matched by trial-and-error modification of the model, verifying, and usually improving in the process, the conceptual model of the geothermal system. Two aspects of the conceptual model are largely guessed during model construction, and verified and improved, during initial-state modeling: (a) location and characteristics of the fluid sources and sinks, and (b) distribution of the petrophysical properties (particularly permeability). This elaborate step of model calibration is superfluous for petroleum reservoirs because of their isothermal, static and confined nature, and the availability of direct estimates of petrophysical properties.

The "history matching" phase of model calibration is similar in both industries, the reservoir pressure being the common parameter matched in both. Steam/water ratio (or enthalpy) on the one hand, and gas/oil or oil/water ratio on the other, are also matched in this phase of calibration. For a single-phase geothermal reservoir, this second parameter to be matched becomes the temperature of the produced water or the superheat of the produced steam, as the case may be. The reservoir parameters that are varied in the trial-and-error history matching process are essentially identical in the two industries. One or more of several other parameters, unique to geothermal are occasionally matched as part of the history matching process: concentration of non-condensable gases in the produced steam, concentration of dissolved solids (or the chloride ion) in the produced water, and heat flow distribution at the ground surface (for example, Butler, *et al*, 2001; Mainieri, *et al*, 2002). On rare occasions, this phase may involve history matching of changes in gravity (measured at the surface) or chemical characteristics of the produced water (such as, pH, mineral content, etc.). These latter aspects of history matching (for example, Tokita, *et al*, 2000; Xu, *et al*, 2001), which are at the cutting edge of application of geothermal reservoir simulation, are clearly beyond the practice in the petroleum industry.

The approach to reservoir behavior forecasting using the calibrated model is virtually the same in the two industries. In petroleum reservoir engineering there is a rule of thumb that a reservoir behavior forecast is valid for a period no longer than the number of years of history used to calibrate the model. However, more often than not, the geothermal reservoir engineer has the unenviable burden of forecasting reservoir behavior for 25 to 30 years even though the available production history may not amount to more than a few days or weeks of well tests. This predicament stems from the custom of amortizing geothermal power plants for 25 to 30 years; a developer or investor requires the assurance of favorable reservoir performance over that length of time. Therefore, the reliability of forecasts from geothermal simulation is intrinsically low for new projects. To cover this risk, it is customary to ensure that the capacity of the plant to be installed is significantly smaller than that indicated to be sustainable by volumetric reserve estimation, or numerical modeling even in the absence of sufficient production history. In other words, a "safety margin" is included in determining the capacity of a project in an unexploited geothermal field. However, for established geothermal projects with several years of history, forecasting is equally as reliable as in the petroleum industry, and is routinely relied upon for project management or expansion.

Notwithstanding the myriad limitations of geothermal conceptual modeling and parameter estimation discussed above, numerical simulation of geothermal reservoirs has proven to be an outstandingly effective tool. This seeming contradiction can be resolved as follows. As regards conceptual modeling that forms the basis of numerical modeling, geothermal enjoys two redeeming features not available in petroleum reservoir definition: (a) geochemical studies add a reliable dimension of reinforcement; and (b) initial-state modeling allows quantitative verification and refinement of the conceptual model. As regards parameter estimation, geothermal enjoys two enormous advantages over petroleum: (a) the bulk of the thermal energy being stored in the rock, uncertainties in the estimation of the petrophysical properties have less impact on the performance of the reservoir; and (b) water and steam properties are defined with a level of exactitude not possible for petroleum, which is a mixture of many different hydrocarbons. These advantages tend to mitigate the limitations in geothermal modeling. Finally, the absence of the problem of fluid immiscibility makes geothermal reservoir simulation theoretically simpler and less dependent on empirical concepts.

The forecast from numerical simulation compares favorably with the actual performance of the field in most geothermal projects if the operating scenario assumed in forecasting is adhered to (O'Sullivan, *et al*, 2001). In most fields, it is difficult to strictly compare simulation forecast with observed well behavior because the production/injection plan assumed to make the forecast may have been changed after the forecast was made. The attached Figure 2 (concerning The Geysers geothermal field, California) shows a good example of the validity of geothermal simulation forecasts.

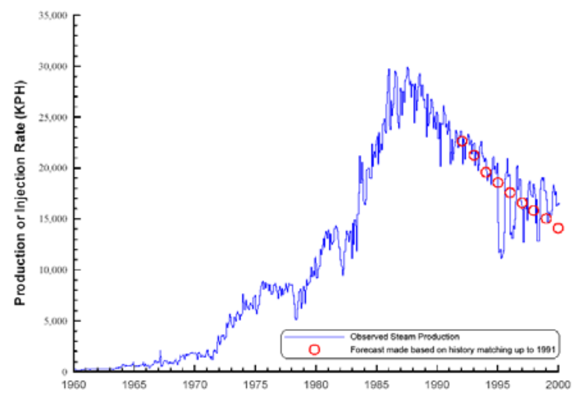

Figure 2. Historical and Projected Fieldwide Production, The Geysers Field

The continuous curve in Figure 2 shows the steam production rate history of the field for a 40 year period; the production rate has the unit of kilopounds per hour ("KPH"), 15 KPH being equivalent to 1 MW. The large fluctuations in the production rate reflect the seasonal variation in generation in this field; in the winter, when hydroelectric power is plentiful, geothermal power generation is curtailed. At its peak (in 1989) the field generated over 2,000 MW; the present production level is about 1,000 MW. This entire field with several hundred active wells was modeled in 1991 and a long-term forecast was made by Pham and Menzies (1993) of the declining production rate shown by circles in Figure 2. In Figure 2, the match between the observed and forecast rates is reasonable between 1992 and 1998. However, after 1998 the forecast rates are lower than observed because the operator began injecting large amounts of treated municipal wastewater into the field, which was not contemplated when the forecast was made in 1991.

Finally, the numerical wellbore simulation approach is essentially the same in both industries as regards the calculation of hydrostatic, frictional and acceleration pressure gradients; the acceleration gradient is calculated using one of the many correlations in vogue in both industries. However, geothermal wellbore simulation is more involved, for it must also take into account the thermodynamics and wellbore heat loss, which are generally not issues in the petroleum industry (Gould, 1974). As in the petroleum industry, coupled reservoir and wellbore simulation is used for forecasting geothermal well behavior under various plausible production/injection scenarios.

CONCLUSIONS

1. Compared to petroleum, geothermal reservoir engineering is more challenging in that (a) conceptual modeling has more complexity, (b) parameter estimation has more limitations, and (c) volumetric reserve estimation has more uncertainty. However, the saving grace of geothermal reservoir engineering is numerical simulation, which allows one to overcome the above limitations and produce estimates of reserves and forecasts of reservoir and well behavior that are at least as reliable as in the petroleum industry.

2. The term "reserves" in the geothermal industry has no standard definition, and in fact is a misnomer compared to the usage in the petroleum industry.

3. Unlike in the petroleum industry, reservoir engineering and geoscience are intricately intertwined in the geothermal industry.

4. Compared to petroleum reservoirs, empirical knowledge about the nature of geothermal reservoirs is minimal since petroleum wells outnumber geothermal wells by many orders of magnitude, and the body of literature on geothermal case histories is minuscule. This imposes a higher premium on the practical experience of the engineer in geothermal reservoir engineering.

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