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Geothermal Power Capacity of Wells in Non-Convective Sedimentary Formations

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ABSTRACT

Many sedimentary formations, including some that contain oil or gas, may be hot enough to serve as commercial geothermal reservoirs. Unlike conventional geothermal reservoirs which generally occur in fractured formations, these reservoirs have intergranular porosity, which allows relatively easy estimation of the hydraulic characteristics of a well from cores and well logs. Using these estimates, the well's power capacity can be estimated for various well production options (such as, pumped or self-flowing) and power generation technology options (such as, binary, flash or hybrid).

The sedimentary formations considered here are not convective systems as is the case for conventional geothermal systems; instead these systems show a conductive temperature gradient. These systems have certain advantages and disadvantages in development compared to conventional, convective geothermal systems. Using the estimated hydraulic characteristics (reservoir flow and storage capacities, and wellbore skin factor), the power capacity of a well in such a system can be estimated from: (a) modeling the well's productivity index as a function of time taking into account the pressure interference between wells; (b) estimation of the flow rate available from the well by downhole pumping and/or self-flowing, taking into account the wellbore heat loss; and (c) estimation of the power capacity for various generation technologies. From the estimation of the power capacity of a well as a function of time, the levelized cost of power over the life of the project can be estimated.

The levelized cost of power is sensitive to reservoir flow capacity (kh) and temperature; it can be very sensitive to drilling depth because drilling cost and temperature increase with depth, while reservoir porosity, reservoir permeability and net sand fraction decrease with depth. For a given reservoir depth, the lower the resource temperature the more sensitive the levelized power cost to reservoir kh.

1. INTRODUCTION

Conventional geothermal reservoirs typically occur in hard rock (igneous or volcanic) and much less commonly in sedimentary formations. One prominent exception is the Imperial Valley of California, where nearly 600 MW of geothermal power capacity already exists and another 100 MW capacity is being added. But even when they occur in sedimentary formations, conventional geothermal reservoirs are characterized by hydrothermal convection within the reservoir, which requires the existence of some vertical permeability and a cap rock. The presence of hydrothermal convection in such a reservoir is identified by an isothermal temperature-versus-depth profile below the cap rock; above the cap rock temperature increases linearly with depth. Figure 1 schematically defines a "conductive" and a "convective" system based on the vertical temperature profile.

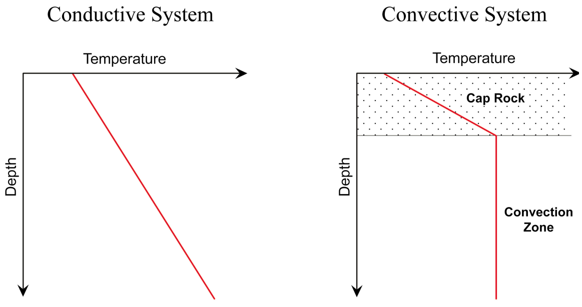

Figure 1: A matter of definition.

Most sedimentary basins have little vertical permeability because of the presence of impermeable shale layers sandwiched between permeable sandstone layers. In such systems natural hydrothermal convection is absent and the temperature increases linearly with depth without reaching an isothermal temperature profile. For example, Figure 2 shows a linear temperature profile with depth (based on discrete data from abandoned wells) in a sedimentary basin in Southern Louisiana, where convective systems do not exist.

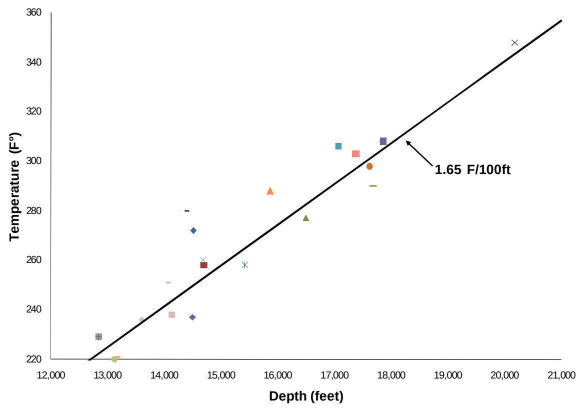

Figure 2: Temperature versus depth of abandoned wells in an area of the U.S. Gulf Coast.

Figure 2 shows that at depth the temperature in such non-convective systems can reach levels attractive for power generation. Even though such a system does not have significant vertical permeability, a well in such a basin can penetrate a sufficient number of sand layers to achieve enough reservoir flow capacity to allow commercially attractive flow rates. The flow capacity of a reservoir is usually represented by the parameter kh, where k is reservoir permeability and h is the cumulative thickness of the sand layers penetrated by the well. Production of geothermal water from such non-convective sedimentary basins has been receiving attention in the last few years in some areas, particularly, Australia and the U.S. Gulf Coast, where petroleum wells in the non-sedimentary basins often display high temperatures.

2. NON-CONVECTIVE SEDIMENTARY SYSTEMS VS. CONVENTIONAL GEOTHERMAL SYSTEMS

Such non-convective, sedimentary geothermal reservoirs generally have "intergranular" porosity, which allows relatively easy estimation of the hydraulic characteristics of a well from well logs and cores. Conventional convective geothermal reservoirs in hard fractured rock, on the other hand, do not allow such ready estimation of porosity from well logs or cores. Furthermore, permeability in sedimentary intergranular rocks estimated from cores can be statistically correlated to porosity; usually the logarithm of permeability can be correlated as a linear function of porosity. This is rarely possible for a non-sedimentary formation. In sedimentary intergranular formations, the net sand ("h") can also be readily estimated from well logs. Once porosity (Ø), permeability (k) and net thickness (h) versus depth are estimated from well logs and cores, the reservoir flow and storage capacities can be computed.

As for conventional geothermal systems, the "skin factor" of the well can be estimated from well testing. When the estimates of Ø, k and h are available, the "productivity index" (PI) of a well can be calculated and compared with direct measurements of PI from well testing. It should be noted that PI of a well is also a function of time and the extent of interference between wells, as discussed below (from Sanyal, *et al*, 2005).

There are several differences between the characteristics of a non-convective sedimentary system and a conventional convective geothermal system that can adversely affect the power available and the economics of development of the former. For example, the lack of vertical permeability in a non-convective sedimentary system may preclude significant natural recharge of hot fluids as is expected in a conventional geothermal system. Other undesirable characteristics of some non-convective sedimentary systems include: (a) lenticular nature of the sand layers reducing the effective flow capacity of the reservoir; (b) the presence of "growth" faults that can sharply reduce the reservoir volume that can be tapped by a group of wells; and (c) the poorly-consolidated nature of the formation often causes sand production in the wells, resulting in damage to the pumps and plugging of wells.

3. DETERMINATION OF INITIAL WELL PRODUCTIVITY CHARACTERISTICS

The productive capacity of a geothermal well can be quantified by the parameter Productivity Index (PI), which is defined as the total mass flow rate (w) per unit pressure drawdown, that is,

$$PI = w / \Delta p \tag{1}$$

Here we have defined as:

$$\Delta p = p_i - p \tag{2}$$

Where p_i is initial static pressure in the reservoir and p is flowing bottom hole pressure at the well, which will decline with time if the well is produced at a constant rate w. It should be noted that in the petroleum industry, PI is defined in terms of the volumetric rather than mass flow rate and Δp is defined as $(\bar{p} - p)$, where $\bar{p}$ is average static reservoir pressure. The flowing bottomhole pressure (and consequently PI) of a well flowing at a constant rate declines with time. This decline trend in PI is a function of the hydraulic properties and boundary conditions of the reservoir, and interference effect between wells (if more than one well is active). For such estimation it is customary to utilize the so-called Line-Source Solution of the partial differential equation describing transient pressure behavior in a porous medium filled with a single-phase liquid (Earlougher, 1977). This solution gives the production rate from a single well in an infinite system as:

$$w = \frac{2\pi(kh)\rho(\Delta p)}{\mu\, p_D} \tag{3}$$

where
- kh = reservoir flow capacity,
- ρ = fluid density,
- μ = fluid viscosity, and
- p_D = a dimensionless variable that is a function of time.

In equation (3), p_D is given by:

$$p_D = -\frac{1}{2} \mathrm{Ei}\left(\frac{-r_D^{\,2}}{4t_D}\right) \tag{4}$$

where
- t_D = dimensionless time = $\dfrac{(kh)t}{(\phi c_t h)\mu r_w^{\,2}}$
- $\phi c_t h$ = reservoir storage capacity,
- c_t = total compressibility of rock and fluid,
- ϕ = reservoir porosity,
- r_D = dimensionless radius, = r/r_w,
- r = distance between the "line source" and the point at which the pressure is being considered (equal to wellbore radius if flowing wellbore pressure is being considered),
- r_w = wellbore radius, and
- t = time.

In equation (4), Ei represents the Exponential Integral, defined by

$$Ei(-x) = -\int_x^\infty \frac{e^{-u}}{u}\, du \tag{5}$$

Equation (3) is true if wellbore skin factor is zero, that is, the wellbore flow efficiency is 100%, the well being neither damaged nor stimulated. If skin factor is positive (that is, the wellbore is damaged), for the same flow rate w, there will be an additional pressure drop given by:

$$\Delta p_{skin} = \frac{w\mu}{2\pi(kh)\rho} \cdot s \tag{6}$$

Productive geothermal wells usually display a negative skin factor, which implies a "stimulated" well (that is, the wellbore flow efficiency is greater than 100%), because such wells intersect open fractures. A negative skin factor of significant consequence is uncommon in non-convective sedimentary systems.

Figure 3 is an example of computed PI as a function of time for the entire range of kh and skin factor encountered in such systems. This figure shows that PI declines with time, but the rate of decline slows down with time. Since Figure 3 covers the entire range of kh and skin factors values typical of non-convective sedimentary formations, PI of wells in such systems should range from about 2 to 30 l/s/bar.

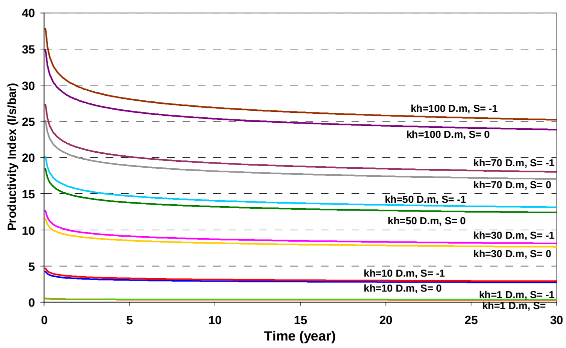

Figure 3: Calculated productivity index versus time.

Figure 4 presents a set of computed graphs of the net MW power capacity of a well as a function of temperature and PI; the details of this computation are discussed later. In Figure 4 the wells are assumed to be pumped if the temperature is less than 190°C, which is the temperature limit for today's pumps, and self-flowed at higher temperatures.

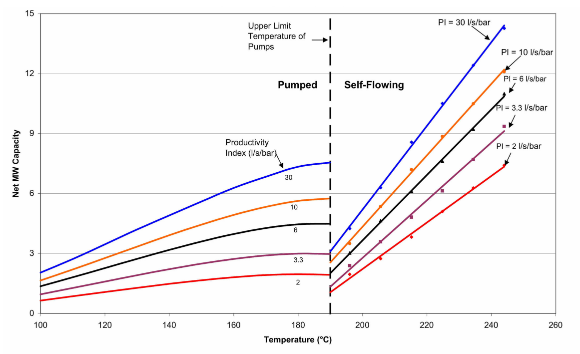

Figure 4: MW (net) capacity of a well versus temperature (from Sanyal, et al, 2007).

4. DECLINE IN WELL PRODUCTIVITY WITH TIME AND DUE TO WELL INTERFERENCE

From equations (1) through (6) it is seen that the PI of a well flowing by itself, as defined here, is independent of production rate, and can be calculated as a function of time. The PI of a well declines with time, but the decline rate lessens continuously, and after a few months of flow PI levels off substantially. If more than one well produces from the same reservoir, there will be interference between the wells, reducing the PIs of all wells. From equations (1) through (6) it is possible to calculate the pressure drawdown at a well, and therefore its PI, in response to both its own production plus the interference effect of simultaneous production from other wells in the field; this is accomplished by the mathematical process of "superposition in space" of the Line-Source Solution (Earlougher, 1977), as described below.

If n wells produce simultaneously, the PI of a well will decline with time according to:

$$PI = \frac{2\pi(kh)\rho w}{\mu\left[\sum_{i=1}^{n} w_i p_{Di}(t,r_i) + ws\right]} \qquad (7)$$

and, from (4),

$$p_{Di}(t,r_i) = -\frac{1}{2}Ei\left(\frac{-(\phi c_t h)\mu r_i^2}{4(kh)t}\right), \qquad (8)$$

where w_i is flow rate of well i and r_i is its distance from the subject well (i=1,….n).

Equations (7) and (8) show that if all wells flow at the same rate, PI becomes independent of flow rate:

$$PI = \frac{2\pi(kh)\rho}{\mu\left[\sum_{i=1}^{n} p_{Di}(t,r_i) + s\right]} \qquad (9)$$

Similarly, the mathematical process of "superposition in time" of the Line-Source Solution (Earlougher, 1977) can be used to calculate the pressure drawdown and PI when flow rate changes with time.

In addition to flow rate, skin factor, and diameter of the production well whose PI is being considered, the calculation requires the distance to and flow rate from (or injection into) each neighboring active well and estimates of several reservoir parameters. The main input parameters are: viscosity and specific volume of the reservoir fluid; reservoir flow capacity; reservoir storage capacity; and initial reservoir pressure. Initial reservoir pressure can be approximated from reservoir depth assuming hydrostatic condition; that is, the water level in a static well is at ground elevation. Thus, it is possible to estimate the range of PI of wells as a function of time taking into account interference between wells. Figure 5 shows the estimated PI values of a well (RRGE-1) at the Raft River geothermal field (Sanyal, *et al*. 2005) as a function of both time and how many producing wells (at what distances from the subject well) are interfering with each other. Although the Raft River reservoir is not sedimentary, it illustrates the sensitivity of PI to time and well interference; the impact of well interference on the PI is rather strong in this field.

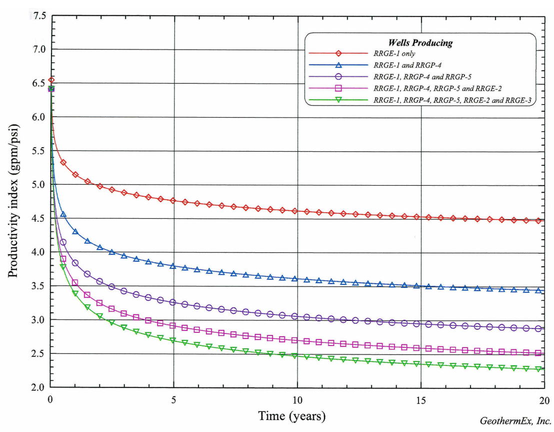

Figure 5: Effect of well interference on productivity (from Sanyal, et al, 2005).

5. PRODUCTION RATE AVAILABLE FROM A PUMPED WELL

In a pumped well, the water level must lie above the pump intake to avoid pump cavitation. For any given pump setting depth, the maximum available pressure drawdown (Δp) in a pumped well without the risk of cavitation can be estimated from:

$$\Delta p = p_i - (h-h_p)G - p_{sat} - p_{gas} - p_{suc} - p_{fr} - p_{sm}, \qquad (10)$$

where
- p_i = initial static reservoir pressure,
- h = depth to production zone,
- h_p = pump setting depth,
- G = hydrostatic gradient at production temperature,
- p_{sat} = fluid saturation pressure at production temperature,
- p_{gas} = gas partial pressure,
- p_{suc} = net positive suction head required by the pump,
- p_{fr} = pressure loss due to friction in well between h and h_p, and
- p_{sm} = additional safety margin to ensure cavitation does not occur at pump intake.

The pressure loss due to friction (p_{fr}) in equation (10) can be calculated as follows:

$$p_{fr} = \frac{f\rho v^2}{2g_c d}\left(h - h_p\right), \qquad (11)$$

where
- f = Moody friction factor,
- v = fluid velocity in well,
- ρ = fluid density,
- d = internal diameter of the wellbore, and
- g_c = gravitational unit conversion factor.

The maximum available pressure drawdown can be calculated from equations (10) and (11). The pump can be set as deep as 500 m if a line shaft pump is used, but if an electric submersible pump is used it can be set considerably deeper (but for all practical purposes, no deeper than 1,100 m).

From the calculated value of the PI of a well and maximum allowable pressure drawdown, one can calculate, as a function of time, the maximum available production rate (w) given by:

$$w = (PI) \cdot (\Delta p). \qquad (12)$$

The net power available from the production rate of w can be estimated as shown below.

6. POWER CAPACITY AVAILABLE FROM A PUMPED WELL

It is possible to estimate the kilowatt capacity available from a given fluid supply rate, from:

$$\text{Electrical energy per kg of fluid} = e \cdot W_{max}, \qquad (13)$$

where
- e = utilization efficiency of the power plant, and
- W_{max} = maximum thermodynamically available work per lb of fluid.

W in equation (13) is derived from the First and Second Laws of Thermodynamics:

$$dq = c_p dT \text{ and} \qquad (14)$$

$$dW_{max} = dq(1-T_o/T), \qquad (15)$$

where
- c_p = specific heat of water,
- T = resource temperature, and
- T_o = rejection temperature.

For calculation of power capacity, T_o can be assumed to be the average ambient temperature. For efficient power generation from a resource at this temperature range, the binary-cycle technology is likely to be used; for modern binary power plants, a value of about 0.45 can be assumed for utilization efficiency. From the above equations the fluid requirement per MW (gross) generation, not counting the parasitic load of production and injection pumps and power plant auxiliaries, can be estimated.

To estimate the net power capacity of a well, the power required for pumping must be subtracted from the gross power available from the pumped well. The power required by a pump operating at the maximum allowable drawdown condition is given by:

$$\text{Pumping power} = (w.H/E_p + h_p.L)/E_m, \qquad (16)$$

where
- H = total delivered head,
- L = shaft horsepower loss per unit length,
- E_p = pump efficiency, and
- E_m = motor efficiency.

In equation (16), H is given by:

$$H = (p_d - p_{sat} - p_{gas} - p_{sm})/G + h_p, \qquad (17)$$

where p_d = pump discharge pressure.

Besides the parasitic power needed for the production pump, the power for the injection pump and plant parasitics needs to be subtracted from the above-estimated net power to arrive at the true net power available from the well.

Figure 6 shows an example of the computed true net MW power capacity available from a well as a function of the pump setting depth and years of operation.

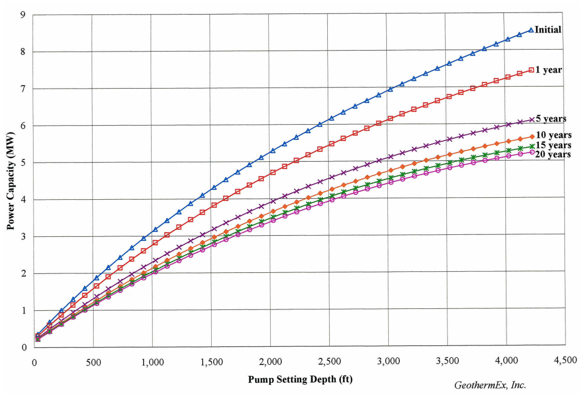

Figure 6: Net power capacity versus pump setting depth of a well versus time.

7. POWER CAPACITY AVAILABLE FROM A SELF-FLOWING WELL

As stated before, if reservoir temperature is higher than about 190°C, the wells will need to be self-flowing. Therefore, we have also considered the feasibility of self-flowing of wells tapping a reservoir hotter than 190°C (Figure 4). This flow behavior analysis has been conducted by numerical wellbore simulation based on the estimated stabilized PI of the well. Numerical wellbore simulation allows the estimation of wellhead power capacity versus flowing wellhead pressure taking into account hydrostatic, frictional and acceleration pressure gradients, wellbore heat loss, phase change, steam separator pressure, and steam required by the power plant per MW.

8. ECONOMIC CONSIDERATIONS

Economics of geothermal power generation in a non-convective sedimentary basin is sensitive to depth. As depth increases so does temperature, usually linearly (for example, see Figure 2), and therefore, heat content per unit mass of reservoir fluid becomes higher. However, in such basins, porosity tends to decline with depth almost linearly; for example, Figure 7 presents the porosity versus depth correlation from wells in a sedimentary basin in South Louisiana.

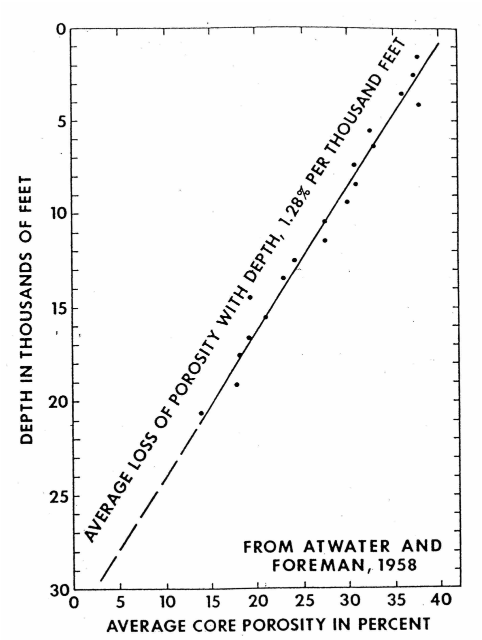

Figure 7: Average core porosity versus depth, South Louisiana wells (from Jones, 1975).

This figure shows a 1.28% loss in porosity per 1,000 ft depth. If porosity declines, permeability would too. Furthermore, the net sand fraction also declines with depth in many sedimentary basins. This implies that reservoir flow capacity and storage capacity are likely to decline with depth, which, in turn, would cause the well PI to decline with depth. However, increasing temperature with depth would tend to lessen these negative impacts on the power capacity of a well.

Drilling cost is another variable very sensitive to depth. Figure 8 is a statistical correlation of drilling cost of a well versus its depth (GeothermEx, 2004). By estimating the available net power capacity versus depth following the discussion above and taking into account the corresponding drilling cost (Figure 8), it is possible to arrive at an optimum depth range for exploiting such a system.

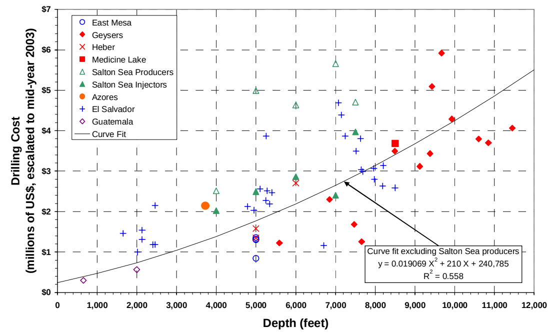

Figure 8: Correlation of drilling cost versus well depth (from GeothermEx, 2004).

Figure 9 shows our estimation of the net power capacity available as a function of reservoir temperature and depth in a sedimentary basin, where wells are to be pumped using submersible pumps. It is obvious that net power capacity is a function of temperature, and consequently, of well depth; the sensitivity of net power capacity to temperature and kh increases as we approach higher temperatures and higher kh.

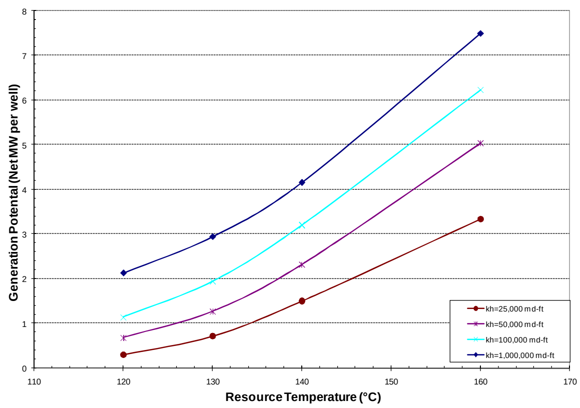

Figure 9: Generation potential of pumped wells.

Figure 10 shows our estimation of the levelized cost of geothermal power in a sedimentary basin over the project life as a function of reservoir temperature and kh. The following parameters have been assumed for this estimation: production well cost of 5M$; injection well cost of 3M$; production to injection well ratio of1; plant cost of 2500 $/kW-gross, and operating cost of 25 $/kW-hr net.

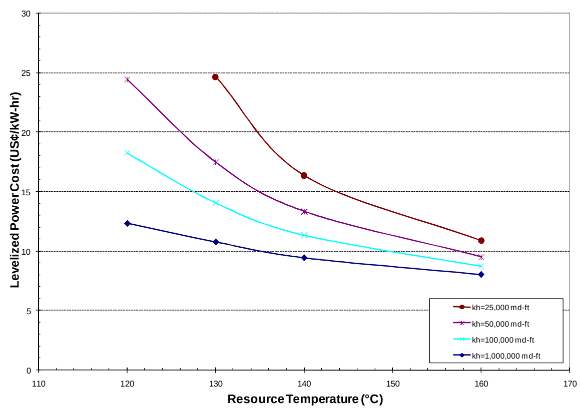

Figure 10: Levelized power cost vs. temperature and kh.

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In Figure 10 we have kept the drilling cost constant, and independent of temperature, because in this case the variation in temperature reflects lateral variation in temperature within this large basin rather than increasing temperature with depth. Figure 10 shows that within this basin the levelized cost becomes increasingly more sensitive at lower temperatures (but at similar depth levels) as well as lower kh.

9. CONCLUSIONS

1. Unlike conventional geothermal systems, non-convective sedimentary systems allow ready estimation of the fundamental hydraulic characteristics (porosity, permeability and net thickness) from well logs and cores, even before any wells have been flow tested.

2. The lack of vertical permeability in a non-convective sedimentary system may preclude significant natural recharge of hot fluids as expected in a conventional geothermal system; this may limit resource recovery over time.

3. Lenticular nature of the sand layers and/or the presence of "growth" faults in non-convective sedimentary systems may limit the effective flow capacity and volume of the reservoir to be exploited.

4. The poorly-consolidated nature of the formation often causes sand production in wells, resulting in damage to the pumps and plugging of wells.

5. From the estimates of the hydraulic characteristics of the reservoir derived from well logs and cores, and well characteristics from well tests, the productivity index of a well in such a system can be calculated as a function of time, taking into account the interference between wells.

6. From the estimated PI characteristics, the net power capacity of a well as a function of time can be calculated for either pumped or self-flowing wells and for any generation technology.

7. The economics of power production from a non-convective sedimentary system can be very sensitive to drilling depth because drilling cost and reservoir temperature increase with depth while reservoir porosity, permeability and net sand fraction typically decline with depth.

8. The levelized cost of power over the plant life is very sensitive to reservoir temperature and kh. Higher the temperature and kh, the lower the levelized cost.

9. For a given reservoir depth, the lower the resource temperature, the more sensitive is the levelized power cost to reservoir kh.

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