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An Analysis of Power Generation Prospects from Enhanced Geothermal Systems

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ABSTRACT

This paper presents an analysis of power generation prospects from Enhanced Geothermal Systems (EGS), specifically, reservoirs with subcommercial permeability enhanced by hydraulic stimulation. EGS is also known as "hot dry" or "hot fractured rock" systems. The performance under consideration here is the net electrical power delivered as a function of time over the 20-to-30 year life of a power plant. Although the parameters in this exercise generally reflect conditions encountered at the Desert Peak EGS project in the State of Nevada, United States, the conclusions are applicable, at least qualitatively, to any EGS project.

The analysis relies on numerical simulation of three types of EGS set-ups: (a) doublet (an injection and production well pair), (b) triplet (an injector flanked by a production well on each side), and (c) five-spot (an injector at the center and a production well at each corner of a square). Desert Peak EGS site is a low-permeability fringe of a hydrothermal system with a temperature of 210°C and pre-enhancement porosity and permeability values of 2% and 1 millidarcy, respectively. The stimulated volume within the system is modeled as a double-porosity system (that is, matrix blocks separated by fractures), and the hydraulic characteristics of the reservoir are assumed to remain constant following enhancement. The assumed thickness of the stimulated zone was varied from 150 to 1,200m, and a range of fracture spacings (from 0.33 to 300m) and fracture permeabilities (from 1 to 100 millidarcy) following enhancement was considered. The spacing between the injector and producers was also varied.

The injection water temperature was assumed to be 82°C. The injection rate was dictated, through reservoir simulation, by the production rate assigned; production wells were allowed a maximum drawdown of 3.4 MPa and the injection well was limited to a maximum pressure buildup of 6.9 MPa. From the forecast of the production temperature, the gross power available per unit produced mass was calculated as a function of time from the First and Second Laws of Thermodynamics; from this, the net power available 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 and correlated to the above variables: (a) net generation profile (generation versus time), (b) net power produced per unit injection rate, and (c) fraction of in-place heat energy recovered.

1. INTRODUCTION

This paper presents an analysis of the performance of Enhanced Geothermal Systems (EGS), specifically, reservoirs with subcommercial permeability enhanced by hydraulic stimulation, thermal energy being recovered by conventional injection and production wells. EGS is also known as "hot dry rock" or "hot fractured rock" systems. The net electric power delivered by such a system over the long term is the focus of this performance analysis. Most of the parameters used in this exercise reflects conditions encountered at Desert Peak in the State of Nevada (United States), where an EGS project is under development (Robertson-Tait and Morris, 2003).

Performance of such systems is typically judged by the cooling trend of the produced water, with faster cooling rates representing less attractive performance. However, from a practical viewpoint, we believe that the net electric power capacity available from such a system versus time, herein termed the "net generation profile," is a more appropriate and comprehensive criterion of performance. The flatter the net generation profile the more attractive the prospect. At least two other criteria of performance, estimated as functions of time, can also effectively complement the net power capacity criterion. These are the fraction of in-place thermal energy recovered from the reservoir and the net power produced per unit injection rate. The goal of this study is to assess these performance criteria through sensitivity analysis using a numerical simulation approach. In numerical simulation, we have assumed that after stimulation, the fracture characteristics remain unchanged over the project life. While enhancement of fractures with time due to thermal contraction of rock is possible, gradual closing of fractures or degradation of fractures due to scaling is equally possible. Therefore, a fracture system that is invariant with time was considered a reasonable compromise for this exercise.

Preliminary results of this study have been presented in Butler, et al (2004); this paper presents further analysis and refinement.

2. THE NUMERICAL MODEL

To study of the performance of a hypothetical EGS project, a three-dimensional, double-porosity, finite-difference numerical model of the reservoir was developed. To reduce boundary affects, a large area (3,658m-by-3,658m) was modeled and steady-state peripheral aquifers were attached to the top 5 layers. The permeability of these aquifers was set at 10% of the reservoir permeability. Most of the remaining parameters were based on the site-specific conditions at Desert Peak. The model extended vertically from a depth of 1,219m to 2,743m below the ground surface, and the average initial temperature of the reservoir was 210°C.

Figure 1 shows the grid system used in simulation. Grid spacing increases from 30.4m in the central part of the model to 731.5m towards the edges. To reduce grid orientation effects, a 9-point finite differencing scheme was used. The reservoir is divided into eight 152.4m layers underlain by a 305m layer representing the lower-permeability basement rock. This 25-by-25-by-9 grid system, shown in Figure 1, results in a total of 5,625 matrix blocks and 5,625 fracture blocks.

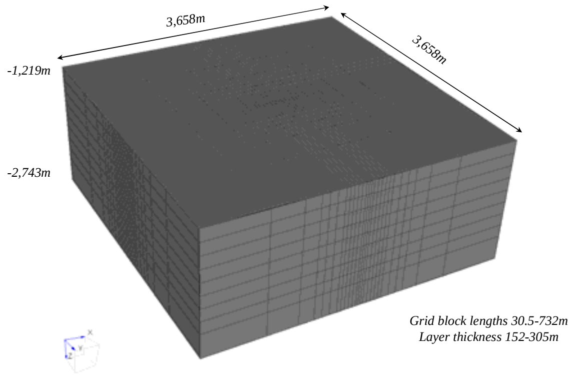

Figure 1. The basic grid system used

The horizontal permeability in the fracture system was set to 1 md with a porosity of 2%, based on conditions encountered at the Desert Peak EGS project area. Based on this low permeability, a pre-stimulation fracture spacing of 305m was chosen. Vertical permeability was assumed to be 10% of the horizontal permeability. Since the production and injection wells in this model are open to the top 8 layers, the modeling results are not highly dependent on vertical permeability. Matrix porosity was assumed to be 2% and matrix permeability was assumed to be two orders of magnitude lower than the fracture permeability.

The injection water temperature was assumed to be 82°C, which is the temperature of the separated water available from the existing Desert Peak power plant located in the permeable area of the field. The injection rate was dictated, through reservoir simulation, by the production rate assigned to the producers. Downhole injection pressure buildup was limited to 6.9 MPa, implying a maximum injection wellhead pressure of about 5.5 MPa. Based on current pump technology, production wells were limited to a maximum flow rate of 126 liters per second. Higher flow rates are possible from commercially available downhole pumps, but pump efficiencies worsen rapidly above this flow rate. Production well drawdown was limited to 3.4 MPa based on our observation that the parasitic load relative to gross generation ratio starts to become prohibitive above this value.

For each combination of assumed geometry, injector-producer spacing, stimulated thickness, and enhancement level (fracture spacing and permeability), the maximum initial net capacity, as well as the decline trend in net generation versus time ("net generation profile") were estimated for a project life of 30 years.

This power capacity calculation utilized the First and Second Laws of Thermodynamics to estimate the maximum available work per unit fluid mass, that is,

First Law of Thermodynamics:

$$dq = c_f dT \qquad (1)$$

and

Second Law of Thermodynamics:

$$dW = dq(1 - T_o / T)\ , \qquad (2)$$

where q is heat, T is absolute temperature of produced water, T_o is absolute temperature of rejection and c_f is average specific heat of water.

Gross power available is then calculated from the production rate, assuming a rejection temperature of 15.6°C and using an utilization efficiency factor of 0.45. This utilization efficiency (fraction of available work converted to electrical power) is typical for modern generation facilities. The net power available versus time was then calculated, for each scenario, after subtracting the parasitic power needed by injection and production pumps.

3. MODELING RESULTS

The first injector-producer geometry to be studied was a "five-spot" with four producers at the corners of a 914m-by-914m square and an injector at the center. This geometry is a classical configuration in the oil industry; of the injector-producer geometries considered, this configuration has the highest production-to-injection well ratio and best sweep efficiency. The geometry of this five-spot, including the area of enhanced permeability and fracture spacing, that is, the stimulated zone, is shown in Figure 2.

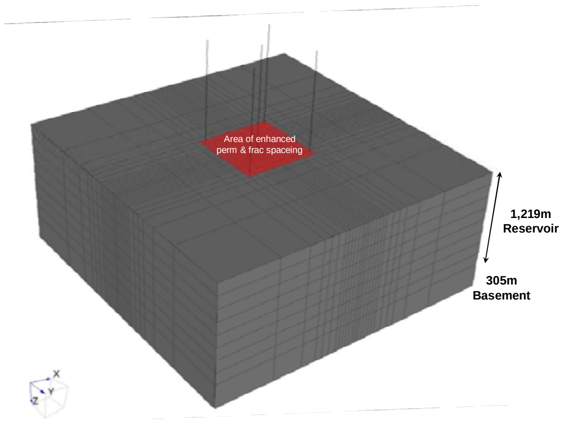

Figure 2. Grid system with a 914m-by-914m Five-Spot

Other well geometries considered were a triplet (an injector flanked by a producer on each side) and a doublet (an injector-producer pair). For each geometry, a range of dimensions was considered. Simulation runs were made using these geometries with the thickness of the stimulated zone varying from 152m to 1,219m, and with a range of fracture spacings (from 0.30m to 305m) and fracture permeabilities (from 1 to 100 millidarcy). A large number of simulation runs were made; only a few representative examples are discussed in this paper.

The "base case" run considers an un-stimulated reservoir, represented here by an extremely wide fracture spacing of 305m. Calculated gross and net generation, production temperature, total production rate (from 4 wells), and injection rate, as functions of time for 30 years, are shown in Figure 3.

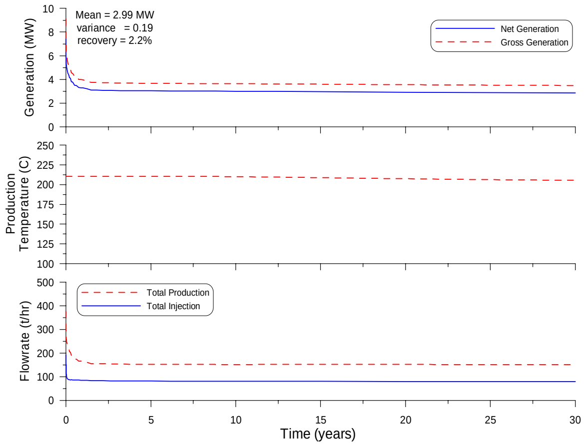

Figure 3. Results for the base case (914m-by-914m Five-Spot with horizontal permeability of 1 md and fracture spacing of 305m)

These results indicate the base case system is capable of supporting 3 MW of net generation. Temperature decline over 30 years is insignificant due to the very low flow rates involved. The production rate is about 19.8 kg/s more than the injection rate, indicating substantial fluid gain from the reservoir. The net generation profile is attractive because it is very flat, the variance over 30 years being only 0.19 MW around a mean of 2.99 MW. However, a generation level of 3 MW from 5 wells makes this un-stimulated reservoir patently uneconomic. The heat recovery is a very low 2.2%.

Figure 4 shows the results for the case where the horizontal permeability of two production layers in the 5-spot model (from -1,372m to -1,676m) is increased by a factor of ten but there is no change in fracture spacing (that is, matrix-fracture heat transfer area) from the base case, the fracture spacing still being 305m.

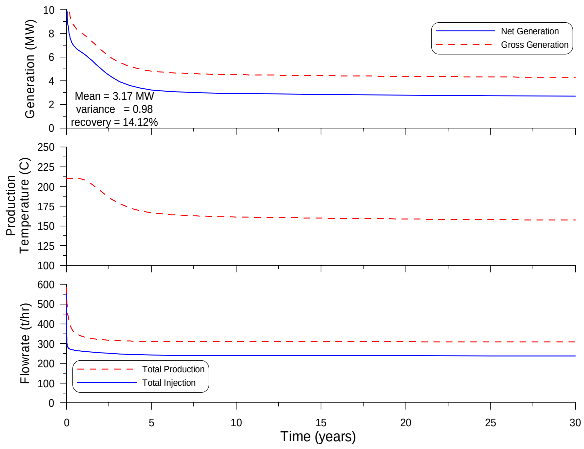

Figure 4. Results for a 914m-by-914m Five-Spot with horizontal permeability of 10 md and fracture spacing of 305m, with 305m stimulation thickness

These results show that higher permeabilities allow for higher flow rates, which, in turn, result in higher temperature decline and higher parasitic losses. The overall result is a system that is capable of supporting about the same generation level as the base case. The net generation profile is less attractive (3.17 MW mean with 0.98 MW variance) but the heat recovery factor is higher than in the base case (14.12%). With higher reservoir permeability, the total capacity of the 4 production wells is closer to the injection well capacity, resulting in relatively less fluid gain compared to the base case. This case is less attractive than the base case in the sense that almost 3 times the throughput is required for approximately the same generation capacity. A higher throughput results in higher surface facilities cost and higher injection capacity requirements.

If the stimulation process results in both a ten-fold increase in permeability as well as a ten-fold decrease in fracture spacing, a more favorable result is obtained as shown in Figure 5. In this case, both net generation capacity and heat recovery for a 914m-by-914m five-spot were more than double; the net generation profile was improved (6.49 ±0.38 MW) and recovery factor was higher (29.4%), but the injection rate per MW remained nearly the same compared to the base case.

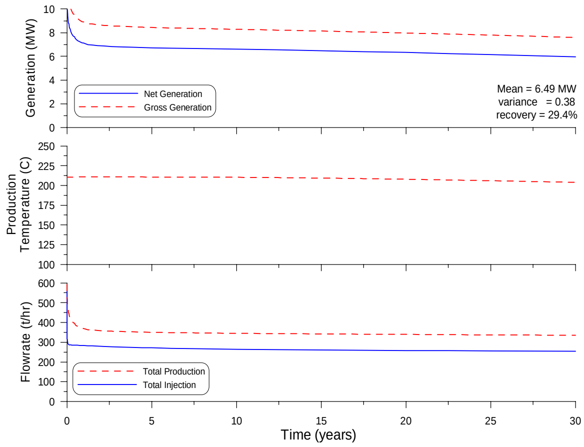

Figure 5. Results for a 914m-by-914m Five-Spot with horizontal permeability of 10 md and fracture spacing of 30.5m, with 304.8m stimulation thickness

These results illustrate that if stimulation results in increased permeability with minimal increase in heat transfer surface there is little practical benefit. If both the permeability and heat transfer area can be increased, the performance of the system can be significantly improved.

It is likely that any stimulation process that is capable of increasing the heat transfer area will also increase the permeability by a relatively large magnitude. To model such a system, the permeability of the stimulated zone was assumed to be two orders of magnitude higher than the base case permeability and the fracture spacing was decreased by one order of magnitude. Such a system is capable of supporting much higher flow rates and therefore higher initial generation levels as shown in Figure 6 for a production rate of 500kg/s. Figure 6 shows that the high throughput results in a steep rate of temperature decline, and calculations indicate that net generation would drop to zero by year 20. In other words, the net generation profile is unacceptably poor. Due to the high level of stimulated permeability, the flow capacity of the injection well increases to the level where nearly all of the produced fluid can be injected. Thus, increasing permeability and decreasing fracture spacing in this case do not lead to an attractive production scenario.

In all of the systems described above (Figures 3 to 6) the production wells are produced at their maximum flow rate based on pump capacity or drawdown limit. By reducing the production rates, lower temperature decline rates and lower parasitic losses should be obtained. To test this concept, the high permeability and close fracture-spacing model, considered in Figure 6, was re-run with a lower production limit on each production well (126 kg/s). The results from this simulation run are shown in Figure 7.

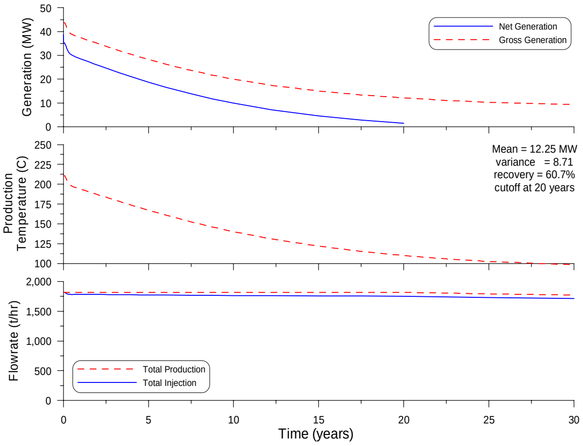

Figure 6. Results for a 914m-by-914m Five-Spot with horizontal permeability of 100 md and fracture spacing of 30.5m, with 304.8m stimulation thickness

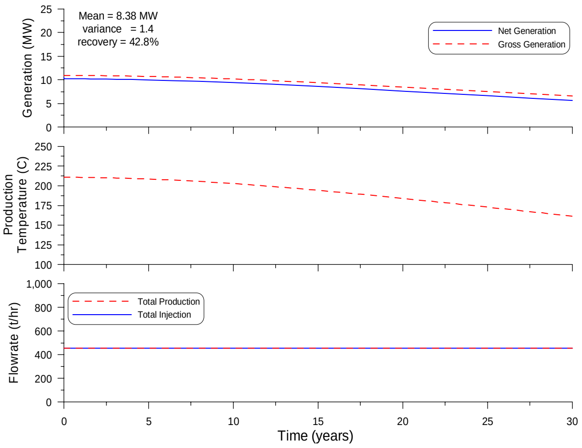

Figure 7. Results for a 914m-by-914m Five-Spot with horizontal permeability of 100 md, fracture spacing of 30.5m, 305m stimulation thickness, and 126 kg/s production limit per well

These results illustrate that reducing the production rate results in a more commercially attractive generation profile (lower variance relative to the mean). Heat recovery is lower than in the previous case, but due to reduced parasitic loads and longer project life, the net MW-hours supplied by the system is higher than for the system considered in Figure 6. The above discussion shows that important criteria in judging the performance of EGS projects are not only the maximum generation level, cooling rate, and heat recovery but also the net generation profile over time. In addition, the injection rate required per net MW is seen to be an important practical criterion.

Figures 8 and 9 shows the grid geometry used for a doublet and a triplet respectively. For each geometry, a range of dimensions, stimulated thickness, fracture spacing and fracture domain permeability values were considered and simulation results were plotted and analyzed as for the five-spot cases illustrated above.

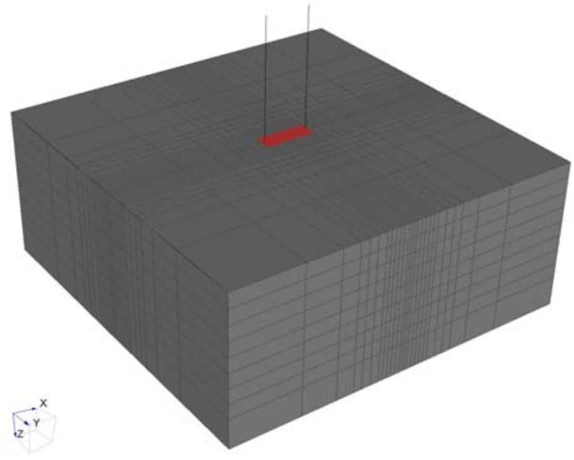

Figure 8. Grid system with a 503m-by-183m doublet

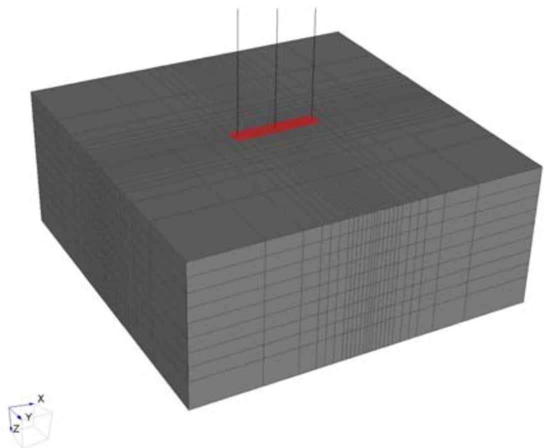

Figure 9. Grid system with a 914m-by-183m triplet

4. CORRELATION OF RESULTS

The results of a vast number of simulation runs were analyzed to develop correlations of practical consequence and at least qualitatively applicable to any EGS project. Several empirical correlations were possible for the three basic geometries of various dimensions, each with a range of values of fracture spacing and fracture domain permeability. The average net generation results were grouped to discern the inherent patterns. One such grouping, where the permeability in the stimulation zone is increased to 100 md and fracture spacing reduced to 3.05m, is shown in Figure 10. From Figure 10 it appears that the average net generation is a linear function of the stimulated thickness for all geometries.

As expected, geometries with higher producer-to-injector ratios and larger stimulation areas and thicknesses are capable of supporting higher generation levels. To arrive at such a correlation, in stimulation cases that displayed high temperature decline rates, the production rate was reduced until an acceptable generation profile could be obtained by trial and error. A mean generation capacity level with less than 15% variance over a 30-year project life was considered an acceptable generation profile.

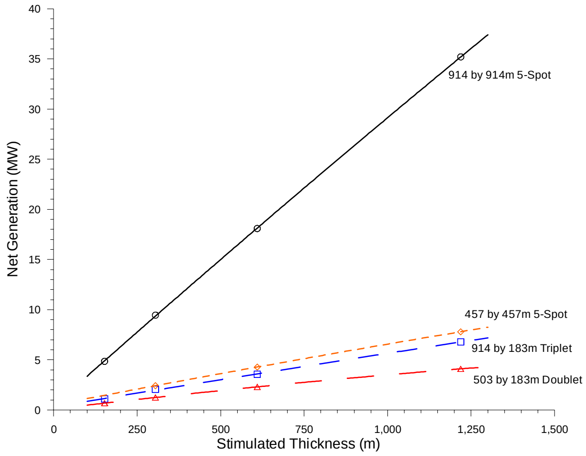

Figure 10. Average net generation versus stimulated thickness for a stimulation zone permeability of 100 md and 3.05m fracture spacing

If the production rate is reduced until the net generation becomes relatively flat, net generation as a function of stimulated volume is essentially independent of the system geometry, as shown in Figure 11 for a stimulation zone with 100 md horizontal permeability and 3.05m fracture spacing. This fact is of major practical import in that the fundamental difference between developing an EGS project and a conventional geothermal project is the major additional cost of creating a substantial stimulated volume.

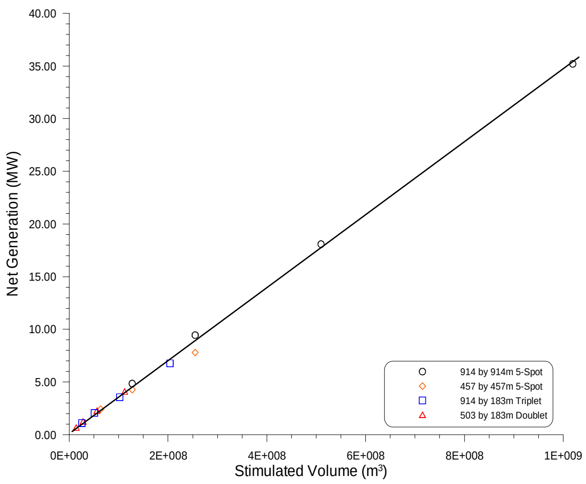

Figure 11. Average net generation versus stimulation volume for a stimulation zone of 100 md permeability and 3.05m fracture spacing

The results shown above demonstrate that as the stimulation volume increases, higher flow rates, and therefore higher generation levels, become possible. However, at high flow rates, temperature decline becomes the controlling factor. Since temperature decline is related to the stimulated volume (that is, in-situ heat reserves), the generation capacity that can be supported by an EGS project is dependant primarily on the volume of stimulated rock, the geometry of this stimulated volume having only a secondary impact on the generation capacity.

Although Figure 11 implies that average net generation is a function of stimulated volume only, the generation is supported by only 2 wells in a doublet, 3 wells in a triplet, and 5 wells in a 5-spot. Therefore, average MW level achieved per well is another important economic criterion; Figure 12 shows the average MW per well as a function of the stimulated volume for several well geometries.

In all of the geometries studied, the properties within the stimulated area were uniform. In practice, the enhancement in permeability (and fracture spacing) is not expected to be uniform. Results shown in Figure 11 suggest that this may not be as problematic as one might imagine. If the effective volume of a complex and non-uniform stimulation zone can be estimated, the generation capacity of the system can be approximated.

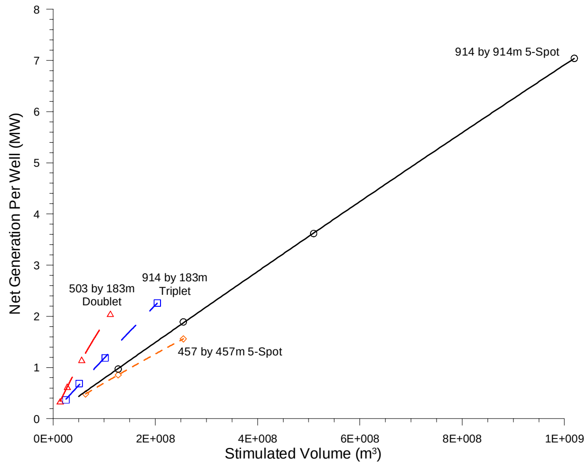

Figure 12. Average net generation per well versus stimulation volume for a stimulation zone of 100 md permeability and 3.05m fracture spacing

A single linear trend is obtained on a plot of average net generation (with a variance less than 15% of the mean over project life) versus stimulated volume for a range of well geometries, fracture spacing and permeabilities; this is shown in Figure 13. Even through there is more data scatter in Figure 13 than in Figure 11, which is for a specific combination of fracture spacing and permeability, the linearity of the data trend in Figure 13 is remarkable.

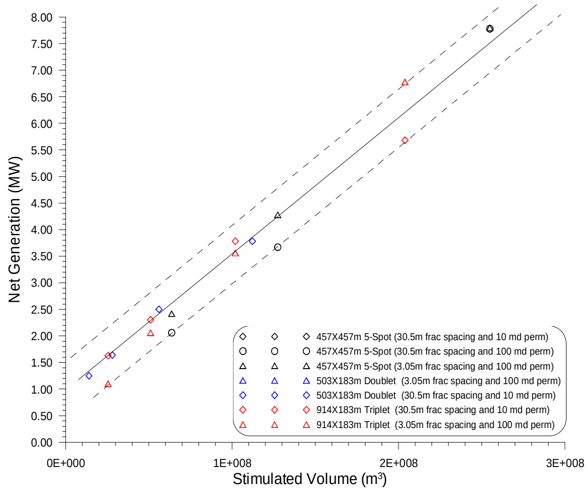

Figure 13. Average net generation versus stimulation volume for a range of geometries, fracture spacing, and permeabilities

Recovery factor (that is, the fraction of heat-in-place in the stimulated volume recovered over the 30-year project life) was correlated to well geometry, spatial dimensions, fracture spacing, and fracture domain permeability. For any given well geometry, recovery factor was found to be correlateable to production rate for any given stimulation thickness, irrespective of fracture spacing and permeability. Figure 14 shows, for a 457m-by-457m five-spot the estimated value of recovery factor as a function of production rate and stimulated thickness. This figure shows the correlation to be essentially independent of fracture spacing and permeability.

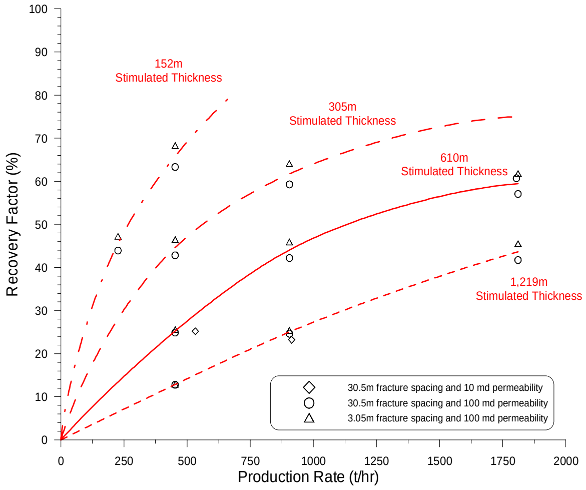

Figure 14. Recovery factor versus production rate for a range of stimulation thickness (457-by-457m 5-Spot)

Finally, recovery factor was correlated to stimulated volume for the optimized production rate (that caused less than 15% variance from the mean net generation over project life) irrespective of well geometry, fracture spacing, and fracture permeability; Figure 15 shows the results. For a stimulation volume less than about 10^8 cubic meters, recovery factor appears to decline as a function of stimulated volume. Above a stimulated volume of 10^8 cubic meters, the recovery factor remains in the range of 0.4 to 0.5 irrespective of stimulated volume, well geometry, fracture spacing, and permeability.

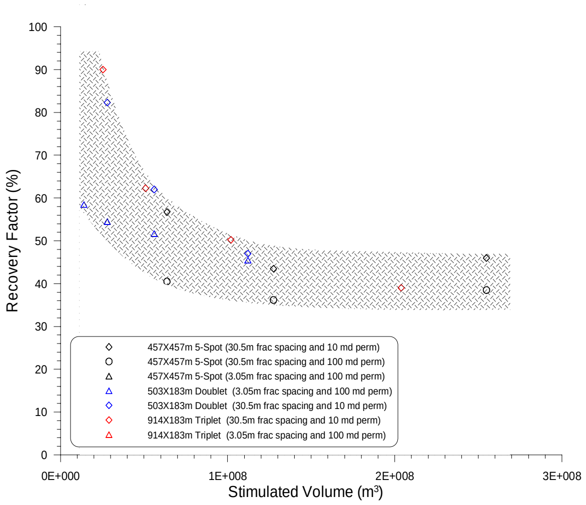

Figure 15. Recovery factor verses stimulation volume for a range of well geometries, fracture spacing, and permeabilities considered

This range of recovery factor can also be deduced from the earlier correlation of net generation to stimulated volume (Figure 13). The linear trend in Figure 13 implies a net generation of $2.6X10^{-2}$ Watts per cubic meter. For the Desert Peak project, the reservoir temperature and average ambient temperature are 210°C and 15°C respectively. Therefore, assuming a typical volumetric specific heat value of 2,00kJ/m^3/°C, the heat-in-place with respect to ambient temperature is $5.27X10^5$ kJ/m^3, or $1.46X10^5$ Watt-hour/m^3. For a 30-year project, this heat –in-place implies a capacity of 0.556 Watts per m^3. Assigning a reasonable thermal-to-electrical conversion rate of 10%, the power available is 0.056 W_e per m^3. Therefore, from Figure 13, recovery factor is $2.6X10^{-2}$/0.056 or 0.46, which is the average of the 0.4 to 0.5 range of recovery factor seen in Figure 15.

CONCLUSIONS

- Cooling rate at production wells is not an adequate criterion for measuring the effectiveness of an EGS power project; net generation profile versus time and reservoir heat recovery factor are the most appropriate criteria.
- Improving permeability, without improving matrix-to-fracture heat transfer area (that is, reducing fracture spacing), has little benefit in heat recovery or net generation.
- The net generation profile can be improved by reducing the throughput without significantly affecting average generation over the life of the project.
- Increasing stimulation volume increases generation level without significantly affecting the shape of the generation profile.
- For a given state of stimulation (that is, fracture spacing and permeability) average net generation versus stimulated volume can be described by a linear correlation that is independent of well geometry.
- Recovery factor can be reasonably correlated to stimulation volume, irrespective of well geometry, fracture spacing and fracture domain permeability.
- Except when the stimulated volume is small, recovery factor is nearly independent of well geometry, stimulated volume, fracture spacing and fracture domain permeability; it lies in the range of 0.4 to 0.5.

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