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A NUMERICAL SIMULATION STUDY OF THE PERFORMANCE OF ENHANCED GEOTHERMAL SYSTEMS

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ABSTRACT

This paper presents the results of a numerical simulation study of the performance of Enhanced Geothermal Systems (EGS), specifically, reservoirs with subcommercial permeability enhanced by hydraulic stimulation. The performance under consideration here is the net electrical power delivered as a function of time and the parameters in this exercise reflect conditions encountered at the Desert Peak EGS project in Nevada.

Three well geometries are considered: (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). The injector and producers communicate through a double-porosity reservoir with a thickness of 4,000 feet and at a temperature of 410°F. After enhancement by stimulation, the hydraulic characteristics of the reservoir are assumed to remain constant. The thickness of the stimulated zone was varied from 500 to 4,000 feet, and a range of fracture spacings (from 1 to 1,000 feet) and fracture permeabilities (from 1 to 100 millidarcy) following enhancement were considered. The spacing between the injector and producers was varied over a wide range.

The injection water temperature was assumed to be 180°F, which is the temperature of the separated brine available from the existing Desert Peak power plant. The injection rate was dictated, through reservoir simulation, by the production rate assigned to the producers. Production wells were allowed a maximum drawdown of 500 psi and the injection well was limited to a maximum pressure buildup of 1,000 psi.

From the forecast of the production rate and temperature, the gross power available 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 scenario, after subtracting the parasitic power needed by injection and production pumps. For each combination of assumed geometry, injector-producer spacing, stimulated thickness, and enhancement level (fracture spacing and permeability), the net power generation capacity versus time ("net generation profile") was calculated.

For each case, the mean and variance of the net generation over 30 years, net power produced per unit injection rate, and the fraction of the in-place heat energy recovered were estimated. The results indicate that power generation from an enhanced geothermal system, such as at Desert Peak, should be technically feasible under a variety of development scenarios.

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 an otherwise conventional injection/production well set-up. The net electric power delivered by such a system is the focus of this performance analysis. Most of the parameters used in this exercise reflects conditions encountered at Desert Peak in Nevada, where an EGS project is under development by Ormat Nevada Inc. with financial support from the U.S. Department of Energy.

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 is a more appropriate and comprehensive criterion of performance. 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 to 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.

THE NUMERICAL MODEL

To study of the performance of a hypothetical EGS project, a three-dimensional, double-porosity numerical model of the reservoir was developed using TETRAD, a commercially available simulation software package that has been widely used in the geothermal industry. To reduce boundary effects, a large 12,000-by-12,000 ft. area is incorporated and steady-state peripheral aquifers are 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 extends vertically from a depth of 4,000 to 9,000 ft. below the ground surface, and the average initial temperature of the reservoir is 410°F.

Figure 1 shows the grid system used in simulation. Grid spacing increases from 100 ft in the center part of the model to 2,400 ft. towards the edges. To reduce grid orientation effects, a 9-point finite differencing scheme is used. The reservoir is divided into eight 500 ft. layers underlain by a 1,000 ft. 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.

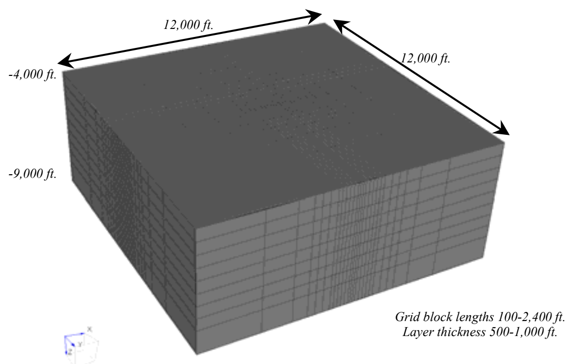

Figure 1. 3-D dual-porosity grid system used to study EGS performance.

The horizontal permeability in the fracture system was set to 1 md (or 4,000 md-ft of permeability-thickness product) 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 1,000 ft. was chosen. Vertical permeability is 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 is assumed to be 2% and matrix permeability is assumed to be two orders of magnitude lower than the fracture permeability.

The injection water temperature was assumed to be 180°F, which is the temperature of the separated water available from the existing Desert Peak power plant. The injection rate was dictated, through reservoir simulation, by the production rate assigned to the producers. Downhole injection pressure buildup was limited to 1,000 psi, implying a maximum injection wellhead pressure of about 800 psi. Based on current pump technology, production wells were limited to a maximum flow rate of 2,000 gallons per minute. Higher flow rates are possible from commercially available downhole pumps, but pump efficiencies fall rapidly above this flow rate. Production well drawdown was limited to 500 psi, based on the 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 declining net generation versus time were estimated for a project life of 30 years. For the purpose of this paper, this forecast of net generation versus time is termed “net generation profile.”

This power capacity calculation utilized the First and Second Laws of Thermodynamics to estimate an available work per unit fluid mass as shown below:

First Law of Thermodynamics:

$$dq = c_f dT \text{ and} \tag{1}$$

Second Law of Thermodynamics:

$$dW = dq(1 - T_o / T) \, , \tag{2}$$

where T = absolute temperature of produced water,
T_o = absolute temperature of rejection and
c_f = average specific heat

Gross power available is then calculated by assuming a rejection temperature of 60°F, multiplying the available work per unit fluid mass by the production rate, and using an utilization efficiency factor of 0.45. This utilization efficiency (fraction of available work converted to electrical power) is typical for binary 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.

MODELING RESULTS

The first injector-producer geometry to be studied was a "5-spot" with four producers at the corners of a 3,000-by-3,000 ft. 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 5-spot, including the area of enhanced permeability and fracture spacing, that is, the stimulated zone is shown in Figure 2.

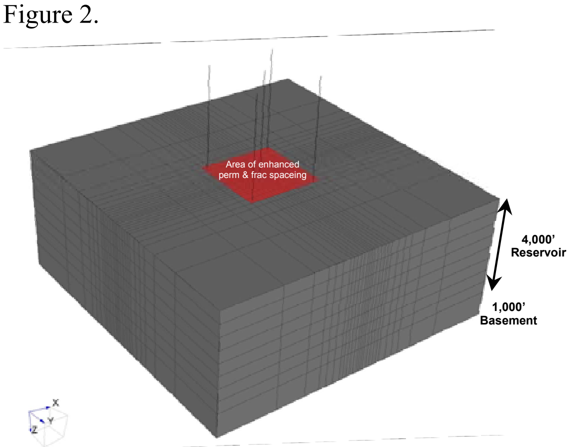

Figure 2. 3,000-by-3,000 ft. 5-spot grid system.

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, and with the thickness of the stimulated zone varying from 500 to 4,000 feet with a range of fracture spacings (from 1 to 1,000 feet) and fracture permeabilities (from 1 to 100 millidarcy). A large number of simulation runs were made; only a few examples are discussed in this paper.

The "base case" run considers an un-stimulated reservoir, represented here by an extremely wide fracture spacing of 1,000 ft. 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.

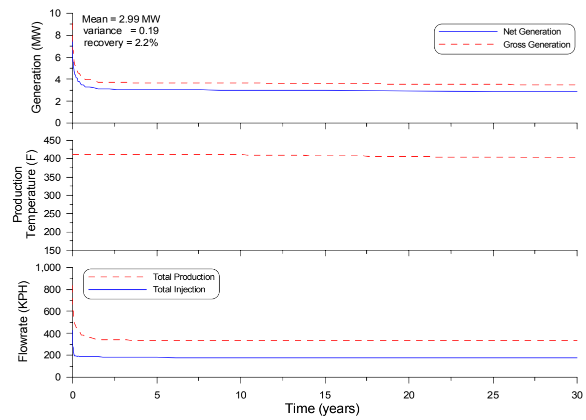

Figure 3. Results for the base case (3,000-by-3,000 ft. 5-spot with horizontal permeability of 1 md and fracture spacing of 1,000 ft.)

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 157,000 lbs/hour 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 -4,500 to -5,500 ft) is increased by a factor of ten but there is no change in the fracture spacing (that is, matrix-fracture heat transfer area) from the base case, the fracture spacing still being 1,000 ft.

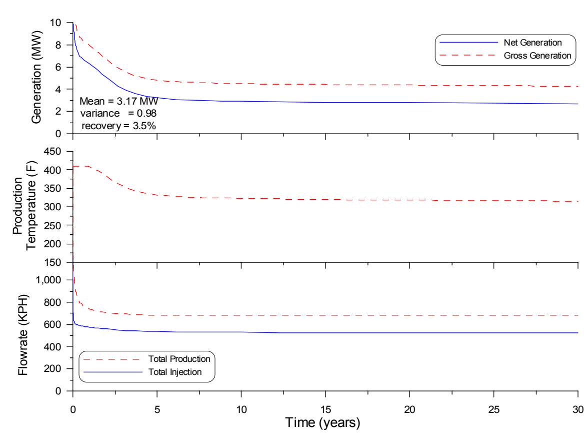

Figure 4. Results for a 3,000-by-3,000 ft. 5-spot with horizontal permeability of 10 md and fracture spacing of 1,000 ft., with 1,000 ft. stimulation thickness.

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 the base case (3.5%). 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. Higher throughput results in higher surface facility 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 (*i.e.,* increased heat transfer area), a more favorable result is obtained as shown in Figure 5. In this case, net generation capacity and heat recovery for a 3,000-by-3,000 ft. 5-spot were more than doubled, the net generation profile was improved (6.49 ±0.38 MW), but the injection rate per MW remained nearly the same compared to the base case.

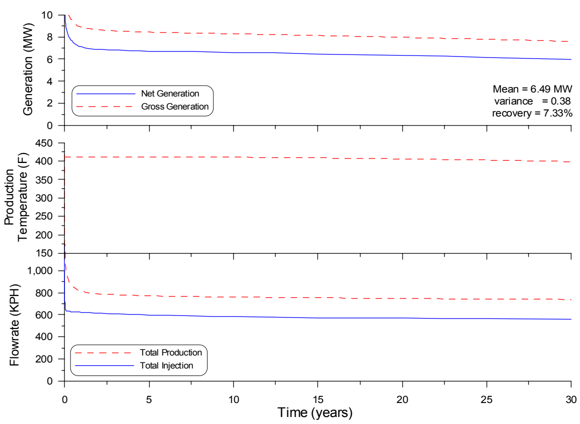

Figure 5. Results for a 3,000-by-3,000 ft. 5-spot with horizontal permeability of 10 md and fracture spacing of 100 ft., with 1,000 ft. stimulation thickness.

These results illustrate that if stimulation results in increased permeability with minimal increase in heat transfer surface (such as shown in Figure 4) there is little practical benefit. If both the permeability and heat transfer 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 this type of 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.

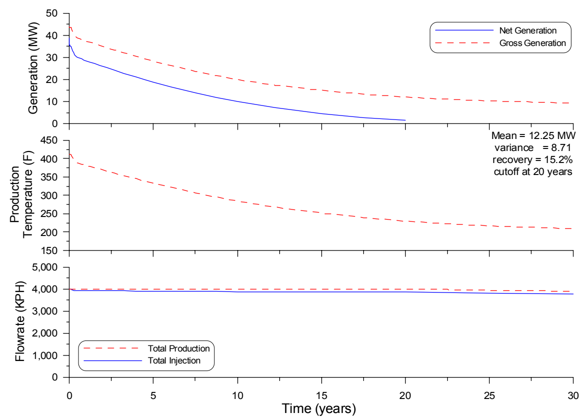

Figure 6. Results for a 3,000-by-3,000 ft. 5-spot with horizontal permeability of 100 md and fracture spacing of 100 ft., with 1,000 ft. stimulation thickness.

However, these high throughputs result in steep temperature decline rates, 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 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 (Figure 3 to 6) the production wells are produced at their maximum flow rate based on pump capacity or drawdown limit. There is no reason that smaller pumps could not be installed in these wells. By reducing the production rates, lower temperature decline rates and lower parasitic losses should be obtained. To test this concept, the high permeability model, shown in Figure 6, was re-run with a lower production limit on each production well of 250,000 pounds per hour (approximately 500 gallons per minute). The results from this simulation run are shown in Figure 7.

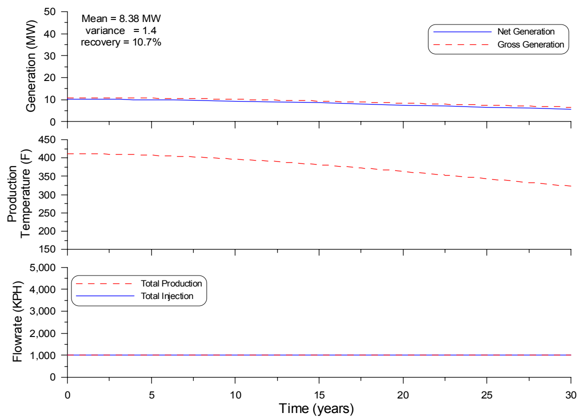

Figure 7. Results for a 3,000-by-3,000 ft. 5-spot with horizontal permeability of 100 md and fracture spacing of 100 ft., with 1,000 ft. stimulation thickness, and 250,000 pounds per hour flow limit.

These results illustrate that reducing the production rate results in a more commercially attractive generation profile (lower variance). 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 shown in Figure 6. The above discussion shows that important criteria in judging the performance of EGS projects are not only the net 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 was considered and simulation results were plotted and analyzed as for the 5-spot cases illustrated above.

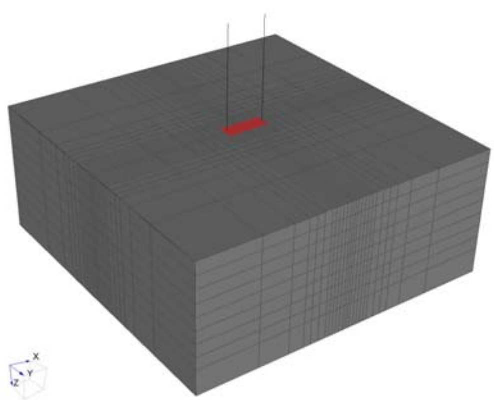

Figure 8. 1,650-by-600 ft. doublet grid system.

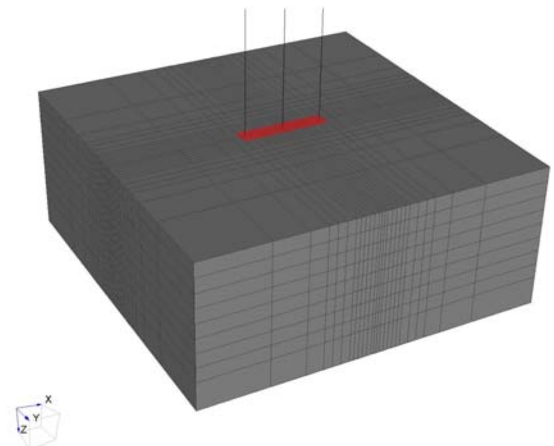

Figure 9. 3,000-by-600 ft. triplet grid system.

To aid in understanding the large number of simulation results obtained for the three basic geometries, the average net generation results were grouped to display the inherent patterns. One such grouping, where the permeability in the stimulation zone is increased to 10 md and fracture spacing reduced to 100 ft., 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.

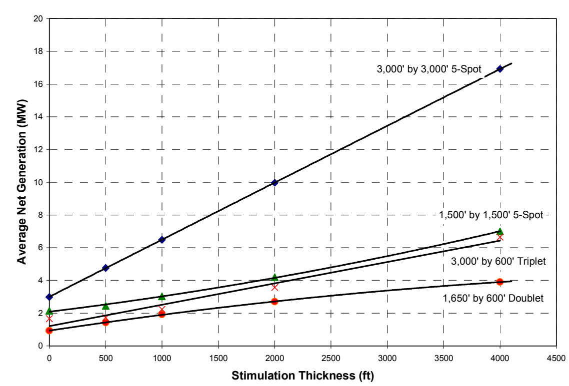

Figure 10. Average net generation versus stimulation thickness for a stimulation zone permeability of 100 md and 100 ft. fracture spacing

As expected, geometries with higher producer-to-injector ratios and larger stimulation areas and thicknesses are capable of supporting higher generation levels. In stimulation cases that displayed high temperature decline rates, the production rates were reduced so that more favorable generation profiles were obtained.

The average 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 100 ft. 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.

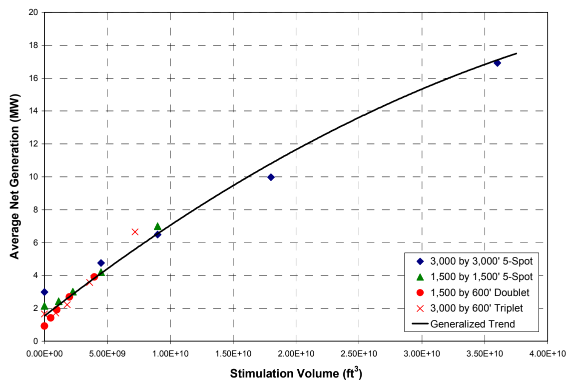

Figure 11. Average net generation versus stimulation volume for a stimulation zone of 100 md and 100 ft. fracture spacing.

The results shown above demonstrate that as the stimulation volume increases, higher flow rates, and therefore higher generation levels, are possible. However, at high flow rates, temperature decline becomes the controlling factor. Since temperature decline is related to the stimulated volume (*i.e.,* in-situ heat reserves), the generation capacity that can be supported an EGS project is directly related to the volume of stimulated rock, the geometry of this stimulated volume having little 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 economical 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.

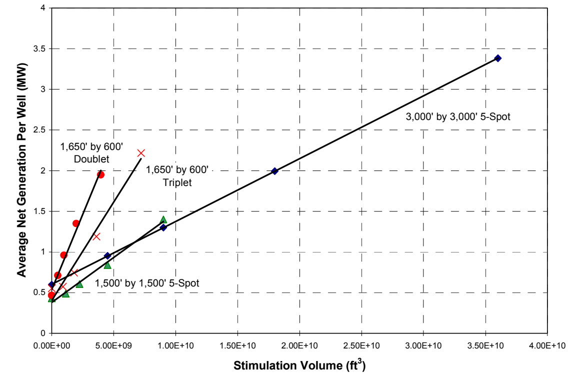

Figure 12. Average net generation per well for a stimulation zone of 100 md and 100 ft. fracture spacing.

CONCLUSIONS

- Cooling rate at production wells is not an adequate criterion for measuring the success of an EGS project. Net generation versus time and reservoir heat recovery factor are the appropriate criteria to judge the effectiveness of an EGS project.
- Improving permeability, without improving matrix to fracture heat transfer area (that is, reducing fracture spacing), has little benefit in heat recovery or net generation.
- Net generation profiles 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.
- Average net generation versus stimulation volume can be described by a simple correlation that is independent of well geometry.

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