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Enhanced Geothermal Systems (EGS) with CO_2 as Heat Transmission Fluid - A Scheme for Combining Recovery of Renewable Energy with Geologic Storage of CO_2

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ABSTRACT

It has been suggested that enhanced geothermal systems (EGS) may be operated with supercritical CO_2 instead of water as heat transmission fluid (D.W. Brown, 2000). Such a scheme could combine recovery of geothermal energy with simultaneous geologic storage of CO_2, a greenhouse gas. At geothermal temperature and pressure conditions of interest, the flow and heat transfer behavior of CO_2 would be considerably different from water, and chemical interactions between CO_2 and reservoir rocks would also be quite different from aqueous fluids.

This paper summarizes our research to date into fluid flow and heat transfer aspects of operating EGS with CO_2. (Chemical aspects of EGS with CO_2 are discussed in a companion paper; Xu and Pruess, 2010.) Our modeling studies indicate that CO_2 would achieve heat extraction at larger rates than aqueous fluids. The development of an EGS-CO2 reservoir would require replacement of the pore water by CO_2 through persistent injection. We find that in a fractured reservoir, CO_2 breakthrough at production wells would occur rapidly, within a few weeks of starting CO_2 injection. Subsequently a two-phase water-CO_2 mixture would be produced for a few years, followed by production of a single phase of supercritical CO_2. Even after single-phase production conditions are reached, significant dissolved water concentrations will persist in the CO_2 stream for many years. The presence of dissolved water in the production stream has negligible impact on mass flow and heat transfer rates.

1. INTRODUCTION

The resource base of geothermal energy is very large. The inventory of geothermal energy in the conterminous U.S. down to drilling-accessible depths of 6.5 km has been estimated as over 600,000 EJ (Exajoule; 1 EJ = 10^{18} Joule), which corresponds to 6,000 times the current primary energy consumption in the U.S. of about 100 EJ annually (MIT, 2006). In spite of this abundant and renewable resource, geothermal energy currently contributes only 0.3% of primary energy consumption in the U.S. This is because commercial extraction of geothermal energy is limited to the few very highest-grade "hydrothermal" resources, in which significant fluid circulation occurs naturally through well-connected fracture networks. Efforts are underway in many countries to develop "enhanced (or engineered) geothermal systems" (EGS) that tap into the much larger resource base of hot rocks with inadequate permeability and fluid circulation, by (i) drilling boreholes to depths of 3-5 kilometers or more, (ii) injecting water at high pressure to enhance natural rock fractures and generate new ones (stimulation), and (iii) extracting thermal energy by circulating water through a system of injection and production wells. Significant technical advances must be made to make EGS commercially viable (MIT, 2006), including (1) increasing the size of the stimulated reservoir volume, (2) lowering reservoir impedance to improve rates of fluid flow and heat extraction, (3) controlling precipitation and dissolution of rock minerals, to avoid the twin problems of formation plugging on the one hand, short-circuiting flow paths on the other, (4) reducing water losses from the circulation system, (5) reducing the "parasitic" power requirements of the water circulation system, and (6) reducing the cost of deep boreholes. Several of these challenges relate to the physical and chemical properties of water as a heat transmission fluid, including the large viscosity of cold injected water, and the fact that water is an ionic solvent that strongly interacts with rock minerals at geothermal temperatures.

The challenges of water-based EGS may yet be overcome by future technological advances. However, one problem with water is that it is a scarce and precious commodity in many regions. As a potential game-changing alternative, D.W. Brown (2000) proposed to operate EGS with supercritical CO_2 instead of water as heat transmission fluid. Brown pointed out that CO_2 has attractive properties as an operating fluid for EGS, and EGS-CO_2 reservoirs could provide storage of greenhouse gases as ancillary benefit. Favorable properties of CO_2 emphasized by Brown include the following:

- Large expansivity of CO_2 would generate large density differences between the cold CO_2 in the injection well and the hot CO_2 in the production well, and would provide buoyancy force that would reduce the power consumption of the fluid circulation system;
- Lower viscosity of CO_2 would yield larger flow velocities for a given pressure gradient; and
- CO_2 would be much less effective as a solvent for minerals in the host rock, which would reduce or eliminate scaling problems, such as silica dissolution and precipitation in water-based systems.

Research aimed at developing a quantitative understanding of potential advantages and disadvantages of operating EGS with CO_2 has begun only recently (Pruess and Azaroual, 2006; Pruess, 2006, 2008; Merkel, 2006; Azaroual et al., 2007; Atrens et al., 2008, 2009). The present paper discusses recent advances in assessing the potential of EGS-CO_2 technology.

2. RESERVOIR HEAT EXTRACTION

Using numerical simulation, we have studied the performance of CO_2 as a heat transmission fluid for fractured EGS reservoirs for a range of temperature and pressure conditions, and have made comparisons with water as a transport medium for thermal energy. For a given effective pressure gradient, fluid mass flux is proportional to the mobility m = ρ/μ (ρ = fluid density, μ = viscosity), which for CO_2 has a very different dependence on temperature and pressure conditions than for water (Pruess, 2006). For most T, P-conditions, CO_2 is considerably more mobile than water, so that, for a given pressure gradient, it would flow at larger mass rates than water. The mobility of water is significantly reduced at the colder injection temperatures, whereas for CO_2 the mobility contrast between hot and cold temperatures is small. The relative performance of CO_2 and water as heat transmission fluids shows significant dependence on temperature and pressure conditions (Pruess, 2006, 2008).

We have performed numerical simulations for a hypothetical fractured reservoir with parameters patterned after the European EGS experiment at Soultz/France (Gérard et al., 2006). The EGS reservoir was modeled as a fractured system with three orthogonal fracture sets at D = 50 m spacing. Matrix blocks were assumed impermeable, and the method of "multiple interacting continua" (MINC; Pruess and Narasimhan, 1985) was used to represent matrix-to-fracture heat transfer. For simplicity, a five-spot pattern was assumed for injection and production wells, which allows to limit the model to a 1/8 symmetry domain (Fig. 1). All simulation results will be reported on a full-well basis. Reservoir thickness was assumed as 305 m, so that the reservoir volume per injector-producer pair was 0.3 km^3. Fluid circulation was induced by specifying a certain pressure drop, typically 20 bar, between the injection and production sides of the reservoir. Mass flow and heat transport were monitored and compared for an "all CO_2" and an "all water" system. The simulations were done with our general-purpose simulator TOUGH2 (Pruess, 2004), augmented with a special fluid property module "ECO2N" to provide fluid properties for water and supercritical CO_2 (Pruess and Spycher, 2007). The ECO2N fluid property module has an upper temperature limit of 110^{o}C, because it uses a non-iterative model for partitioning of CO_2 and water between aqueous and CO_2-rich phases (Spycher and Pruess, 2005). In the present example, we consider systems of either pure CO_2 or pure water so that there is no phase partitioning, and the temperature limit can be removed. Simulations considering both H_2O and CO_2 in the reservoir are presented later in this paper, using an extension of the phase partitioning model to higher temperatures.

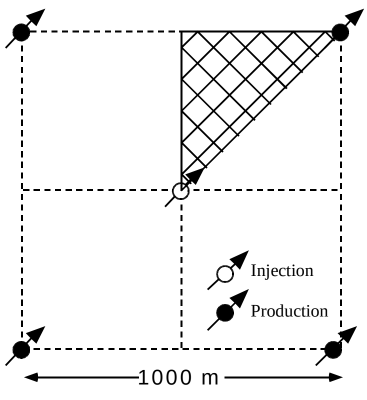

Figure 1: Five-spot well pattern with computational grid for modeling a 1/8 symmetry domain.

2.1 2-D Simulations

Simulations were carried out in 2-D flow geometry for initial reservoir temperatures in the range of 120-240^{o}C. Heat extraction rates with CO_2 were found to exceed those for water by 40-90%, with the advantage of CO_2 becoming greater at lower reservoir temperature (Pruess, 2006). This behavior occurs because fluid mobility m = ρ/μ for water decreases strongly with decreasing temperature, while for CO_2 the temperature dependence of mobility is much weaker. The heat extraction studies in (Pruess, 2006) compared CO_2 with water; they likely underestimate the advantage of CO_2, because in practice, water-based EGS reservoirs will operate with brine, which is more viscous than fresh water.

In an earlier comparison of heat extraction for CO_2 and water-based systems, we had considered a linear flow system instead of a five-spot, and had found only a modestly larger heat extraction rate for CO_2 as compared to water (approximately 15% larger; Pruess and Azaroual, 2006). The large differences in relative heat extraction performance between the linear system and the five-spot seem surprising, in view of the fact that the thermodynamic conditions for the reservoir and the injected fluid were the same in both problems. However, the differences can be readily understood from the different flow geometries. Indeed, for a water reservoir operated in five-spot geometry, much of the pressure drop available for pushing fluid from the injection to the production well is used up by the highly viscous cold water surrounding the injection point. The radial flow geometry around the injection well in the five-spot problem amplifies this "mobility block" for water, making the relative advantage of CO_2 larger than in the linear system.

2.2 3-D Flow Effects

Density differences between cold fluid in and around the injection well and hot reservoir fluid are much larger for CO_2 than for water. In addition to generating much larger overpressures at the production well in a CO_2-based system, this gives rise to two related 3-D effects in EGS operated with CO_2, (1) for a vertical injection well with a sizeable open interval, pressure differences between injection and production sides will increase with depth, as will outflow rates per unit reservoir thickness, and (2) cold injected fluid will be subject to negative buoyancy in the reservoir, and will tend to slump downward. If both injection and production are made over the entire permeable interval, these effects will promote rapid thermal breakthrough near the bottom of the reservoir. This is apparent in Fig. 2, which shows production flow rates and temperatures for a 3-D version of the five-spot problem discussed above, in which the reservoir thickness of 305 m was divided into 6 layers, and fluid injection and production were made over the entire open interval (Pruess, 2008). The (bottom) layer 6 starts out with the largest flow rate, and shows the strongest increase over time due to a self-enhancement mechanism: as the reservoir cools the mobility of CO_2 increases, providing a positive feedback between reservoir cooling and flow. This leads to rapid thermal breakthrough in the deeper parts of the reservoir (Fig. 2, bottom). The unfavorable heat extraction behavior observed when all reservoir layers are open in both injection and production well is evident from Fig. 3, which shows total net heat extraction and mass flow rates, summed over all layers of the production well. Heat extraction rates begin a significant decline after about 8 years, coincident with an increase in mass flow that is entirely due to the increased mobility of colder CO_2.

Premature breakthrough of cold injected fluid can be avoided by restricting production to a shallower depth interval. Fig. 4 shows net heat extraction and mass production rates for a scheme in which injection is made in all six layers, just as in the previous case, while the production well is open only in the topmost layer. It is seen that this indeed avoids early thermal breakthrough of injected fluid, leading to a nearly constant heat extraction rate for 25 years, followed by a slow decline that is a consequence of overall thermal depletion of the reservoir, not of premature thermal breakthrough.

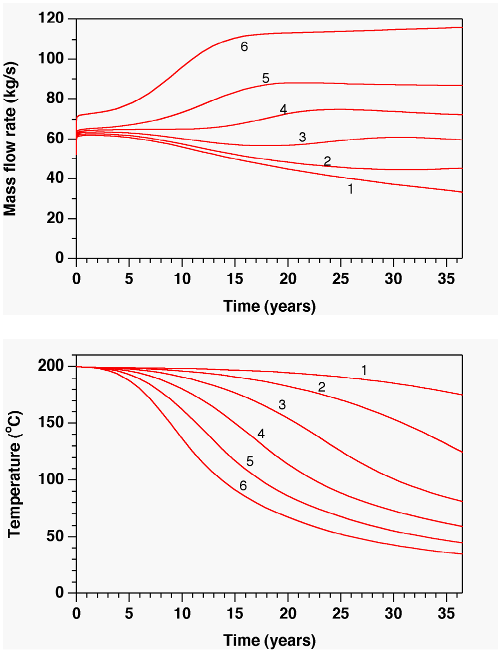

Figure 2: Production rates (top) and temperatures (bottom) in the different reservoir layers (1-top, 6-bottom) for a CO_2-EGS with injection and production wells open in all layers. Increased mass flow in deeper layers generates more rapid cooling.

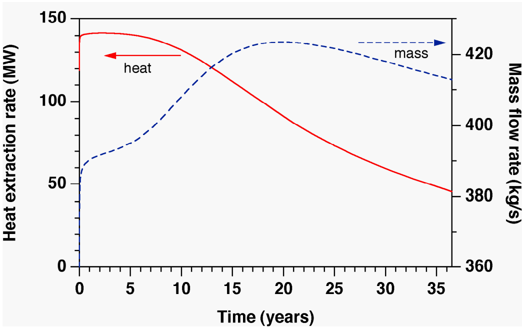

Figure 3: Total heat extraction and mass production rates from a CO_2 production well open in all six layers of a 200°C reservoir.

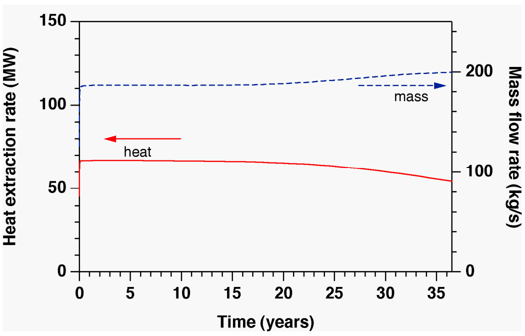

Figure 4: Heat extraction and mass production rates from a production well that is open only in the topmost 50 m thick interval of a 200°C CO2 reservoir.

3. EGS RESERVOIR DEVELOPMENT

The EGS heat transfer studies summarized above have demonstrated significant advantages of EGS operated with CO_2 as compared to water. The important question then becomes: can we actually "make" an EGS-CO_2 reservoir? EGS would be developed in formations that typically will be water saturated, and the hydraulic and chemical stimulation that would be conducted will introduce additional aqueous fluids. If EGS are to be operated with CO_2, stimulation would need to be followed by an additional step of reservoir development, in which CO_2 would be injected over a period of time to displace and essentially remove the resident water, at least from the central zone of the stimulated volume. Removal of water would occur through (1) immiscible displacement of aqueous phase by the supercritical CO_2-rich phase, and (2) dissolution of water into the flowing CO_2 stream. The initial phase of EGS-CO_2 reservoir development would likely lead to enhanced chemical reactivity, due to the presence of water-CO_2 mixtures (Fouillac et al., 2004; Xu and Pruess, 2010). Rock-fluid chemical interactions are ignored in the present study.

CO_2 injection and associated reservoir pressurization would generate a production fluid stream that initially would be single-phase aqueous, then would transition to two-phase water-CO_2 mixtures, and eventually would dry out to produce a single supercritical CO_2 phase. This phase will contain some dissolved water that may be chemically active. Note that produced water should be disposed of, not reinjected, in order to convert the EGS pore fluid to CO_2. We present here a quantitative analyses of the EGS-CO_2 reservoir development process, using newly developed modeling capabilities that accurately describe the partitioning of water and CO_2 between aqueous and CO_2-rich phases for the entire range of relevant temperature and pressure conditions (Spycher and Pruess, 2009).

The process considered is injection of CO_2 into an initially water-saturated fractured reservoir at temperature and pressure conditions of (T, P) = (200°C, 200 bar). Injection temperature is 20°C with a (downhole) overpressure of 10 bar relative to original reservoir pressure of 200 bar, while fluid production occurs against a downhole pressure of (200-10) = 190 bar. A key aspect of the behavior of the flow system is two-phase flow of water-CO_2 mixtures in both fractures and matrix rock, driven by externally imposed pressure gradients, as well as by gradients of capillary pressure that evolve in response to increasing gas saturations from CO_2 injection. We model this process by considering a rock matrix with finite albeit small permeability of k_m = 1.9×10^{-18} m^2, typical for tight intact reservoir rocks such as granite, graywacke, or welded tuff. Information on interfacial tension and capillary pressures between CO_2 and water is available only for temperatures below 125°C (Bachu and Bennion, 2007; Chiquet et al., 2007). For the simulations performed here, we base the strength of capillary pressure on a CO_2-water interfacial tension of γ = 0.028 N/m, as measured for T = 50°C, P = 200 bar (Chiquet et al., 2007). In response to continuous injection of pure supercritical CO_2, parts of the flow system dry out, necessitating a consistent treatment of capillary pressure as liquid saturation S_l ==> 0. We use the approach proposed by Webb (2000) to modify the van Genuchten (1980) capillary pressure function in the dry region, imposing a limiting strength of P_{cap} = - 1000 bar as S_l ==> 0.

3.1 Results

Simulation results are given in Figs. 5-7. Initial fluid production in response to CO_2 injection is single-phase water. Breakthrough of CO_2 at the production well occurs after 46 days, and subsequently a two-phase water-CO_2 mixture is produced. Over time the rate of gas production increases, while aqueous phase production declines, reflecting relative permeability effects as gas saturations in the reservoir increase from continuous CO_2 injection. After 3.9 years of CO_2 injection aqueous phase production ceases, and subsequently a single-phase stream of supercritical CO_2 is produced. At the time when aqueous phase ceases to be produced, the produced CO_2 includes approximately 6.4% by weight of dissolved water (Fig. 6). The water content in the produced fluid declines fairly rapidly afterwards, due to partial reservoir dry-out in the fractures, dropping below 1% after 7.4 years, and below 0.1% after 17.1 years, while at the end of the simulation, after 36.5 years, the water content in produced CO_2 is 0.012%. However, at this time almost half of the initial water inventory in the reservoir still remains in place inside the low-permeability matrix blocks.

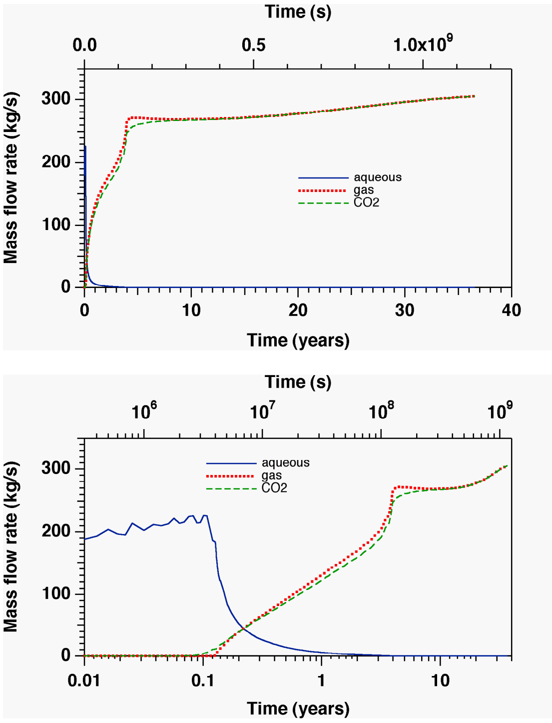

Figure 5: Simulated production behavior of the EGS system in response to injection of pure CO_2 at constant downhole pressure of 210 bar on linear (top) and logarithmic time scales (bottom).

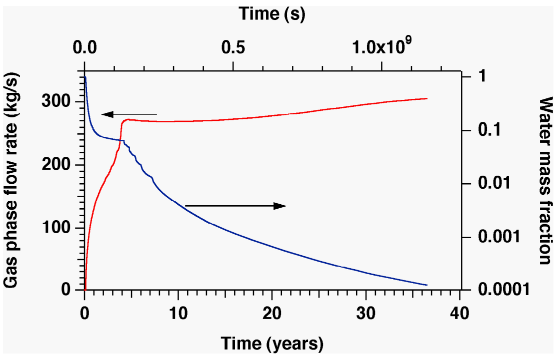

Figure 6: Simulated rate and composition of produced fluid.

It is of interest to compare heat extraction for the present case of an initially water-saturated EGS with permeable matrix blocks to the results obtained previously for a system initialized with all CO_2 and impermeable rock matrix. Fig. 7 shows that significant differences occur only during the early time period when CO_2-water mixtures are produced. After the production stream dries out, heat extraction rates for the two systems are almost identical.

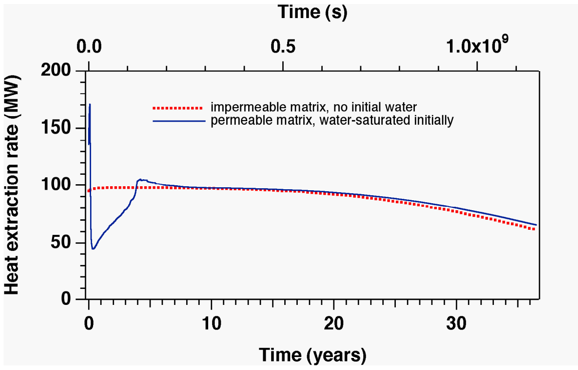

Figure 7: Comparing heat extraction rates for a realistic EGS-CO_2 system starting from water-saturated conditions with a system initialized as all CO_2.

We have performed limited sensitivity studies, varying parameters such as strength of capillary pressure, and matrix porosity and permeability. We also did a simulation that included molecular diffusion of water dissolved in CO_2, and CO_2 dissolved in water. These problem variations did affect quantitative details of reservoir production behavior, but had only small effects on heat extraction rates and the water content of produced CO_2.

Electric power generation from EGS operated with CO_2 could use binary cycle technology, or alternatively could directly feed the produced CO_2 stream to a turbine, thereby avoiding capital and operating expenses, and heat losses, of a heat exchanger (Atrens et al., 2009). Our simulations suggest that significant concentrations of dissolved water would persist in the CO_2 production stream for many years. At the assumed injection temperature of 20^{o}C, water solubility in CO_2 is approximately 0.1% (Spycher et al., 2003), which will be exceeded in the production stream of our reference case for 17.1 years (Fig. 6). If the CO_2 is to be directly fed to the turbine, it will be necessary to dry the produced fluid upstream of the turbine, to avoid corrosion from water condensation and carbonic acid formation at the low-P, low-T side of the turbine.

4. CO_2 USE AND STORAGE

The CO_2 inventory of the EGS reservoir discussed in the previous section reaches 1.19 Mt (Megatonnes) after 5 years, and 3.14 Mt after 36.5 years (full-well basis). Thermal power production is 75 MW(th) on average, which translates into approximately 13 MWe electric power, based on typical utilization efficiencies and thermodynamics (Sanyal and Butler, 2005). For 1,000 MWe of installed EGS-CO_2 electric power capacity, CO_2 inventory would be 91.5 Mt after 5 years, 241.5 Mt after 36.5 years.

EGS water circulation tests carried out over periods of months to almost one year suggest that long-term fluid losses may amount to approximately 5% of injection (Duchane, 1993). For the reference case reported above, a mass flow of approximately 22 kg/s of CO_2 will be required per MW electric power (Pruess, 2006). At an estimated 5% fluid loss rate, CO_2 loss will then be approximately 1 kg/s per MWe, or 1 t/s per 1,000 MWe.

For a perspective on these numbers, we note that a 1,000 MWe coal-fired power plant generates approximately 1/3 t/s of CO_2, or 10 Mt/yr (Hitchon, 1996). The CO_2 inventory after 36.5 years of 1,000 MWe of EGS-CO_2 power generation would amount to the emissions from a 1,000 MWE coal-fired plant over a 24 year period. The CO_2 loss rate of 1 t/s for 1,000 MWe of EGS-CO_2 equals the emissions from 3,000 MWe of coal-fired generation. While these estimates are rough, they suggest a very large potential for CO_2 storage from EGS with CO_2.

Whether CO_2 lost equals CO_2 stored will require thorough scrutiny before practical implementation of EGS with CO_2 could be considered. Efficient CO_2 storage seems quite realistic in our view because escaping CO_2 would react rapidly with formation minerals in the aqueous high-temperature environments surrounding an EGS reservoir, making self-sealing of the reservoir likely (Fouillac et al., 2004; Xu and Pruess, 2010).

5. CONCLUDING REMARKS

Quantitative assessment of the potential for operating EGS with CO_2 instead of water is in the early stages. Studies to date suggest that EGS operated with CO_2 may have significant advantages over water-based systems, including larger heat extraction rates, and more favorable wellbore hydraulics (Pruess, 2006). It is expected that rock-fluid interactions may also be more favorable for EGS with CO_2 than with water, but little information is available about chemical interactions between supercritical CO_2 and rock minerals. Studies of geochemical interactions in EGS-CO2 are presented in a companion paper at this congress (Xu and Pruess, 2010). EGS with CO_2 has sufficiently attractive features to warrant continued exploration, and interest in this concept is growing. For a realistic assessment it will be necessary to go beyond theoretical estimations and paper studies, and begin to design, implement, and analyze practical tests in the laboratory and the field.

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