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DGS High Capacity, Single Well, Full Hydraulic Circuit Technology Refinements for EGS

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ABSTRACT

An innovative method that extracts global scale energy from HDR while eliminating geothermal's fundamental problems obsolesces current EGS approaches. Called "DGS," the single vertical well format features complete control over reservoir hydraulics, heat recovery, and production of 50 MW from the top 1/5th thermal gradient rock anywhere in the world. Based on downhole construction materials and procedures known to the developers for decades, DGS works by installing flow diverters in engineered reservoirs that cause heat-carrying fluid to travel across 60M square feet (630 hectares) of accessible subsurface rockfaces. The diverters are installed in a manner effecting hydraulic channel definition in the reservoir, where sweep efficiency is controllable, enabling more than 90% heat recovery. Set in deeper, hotter strata, generally 2X that of traditional EGS, high rock overburden mitigates natural fracture presence and connectivity, eliminating the traditional ever-present problems of excessive water loss and seismicity potential. DGS coauthors also present in their paper the system's high-temperature proppant carrying fluid, specific means of reservoir diverter construction, novel multi-set thermally compliant packer system, and methods of energy recovery optimization.

1. INTRODUCTION

There are three non-emitting baseload energy sources: nuclear, hydroelectric, and, potentially the largest, geothermal. Where environmental controversies and weather dependencies are well-known aspects of nuclear and hydro generation, geothermal is effectively devoid of such issues. However, naturally occurring hydrothermal resources ultimately depend on the very rare coincidence of substantial amounts of heat, fluids, and permeability in reservoirs. Current knowledge suggests that this coincidence from an economic perspective should be more frequent. Potentially substantive energy from naturally occurring marginal hydrothermal systems then involves a human intervention to emulate hydrothermal reservoirs in hot rocks for commercial use. This alternative is known as Enhanced Geothermal Systems (EGS).

EGS reservoirs are made by drilling and fracturing hot rock sufficiently to enable fluid flow between injectors and producer wells. The fluid flows along permeable pathways, picking up in situ heat and exiting the reservoir via production wells. At the surface, the fluid passes through a power plant where electricity is generated. Upon leaving the power plant, the liquid is returned to the reservoir through injection wells to complete the circulation loop. If the plant uses a closed-loop binary cycle to generate electricity, none of the fluids vent into the atmosphere. The plant will have little to no greenhouse gas emissions other than vapor from water that may be used for cooling (www.energy.gov Geothermal Technologies Office – GTO).

However, this alternative and seemingly viable energy source is virtually nonexistent in global energy markets due to several technical and economic challenges in addition to the burdens of duplicative drilling requirements, well-known water losses, and low energy output.

Very often, less than 1/10th of the available energy is recovered from EGS production. EGS efforts to artificially produce massive steam volumes have failed because such developments do not access or transfer adequate heat from the subsurface. More specifically, developers cannot adequately control the heat-carrying water's flow direction, speed, or thoroughness. Consequently, "hydraulic short-circuiting," where injection waters frequently find the path of least resistance, missing the desired route altogether or prematurely exiting the heating process and excessively cooling the short-circuited route.

A new Full Thermo-Hydraulic Geocircuit™ System called "DGS" is based on 40-year-old practices and expertise. The system creates extensive reservoir systems in deep hot rocks found almost anywhere. DGS operating temperatures may exceed 371°C (700°F), and water heating surface area may exceed 550 hectares (1400 acres) at <10 km depths. More importantly, the technology creates controlled hydraulic channels in impermeable hot rock that direct water flows across all the hot rock surfaces. The hydraulic channeling effect is analogous to lining or installing levees on riverbanks, confining flows where they can be helpful. The heat transfer efficiency of a DGS installation thereby approaches 100%. Based on a high-efficiency hydraulic and thermal sweep, 50 MW wells may be reliably installed, and geothermal may be globally scaled. DGS Technology is economically deployable now at 35 MW levels.

2. TRADITIONAL EGS CHALLENGES

Conventional EGS developments are attempted in relatively shallow HDR to collect heat from natural, augmented, and induced fracture systems. EGS comprises two subsystems: wells (injection and production), reservoirs, and the surface power plant operation.

The reservoir subsystem is developed by drilling wells into hot crystalline sediments, generally at <3 km (~9900 ft) depths and connecting the wells through hydraulic fracturing. Water or other heat-carrying fluid is pumped through injection wells into the reservoir, where heating is intended by substantial contact with the hot rock before recovery through one or more production wells, Figure 1.

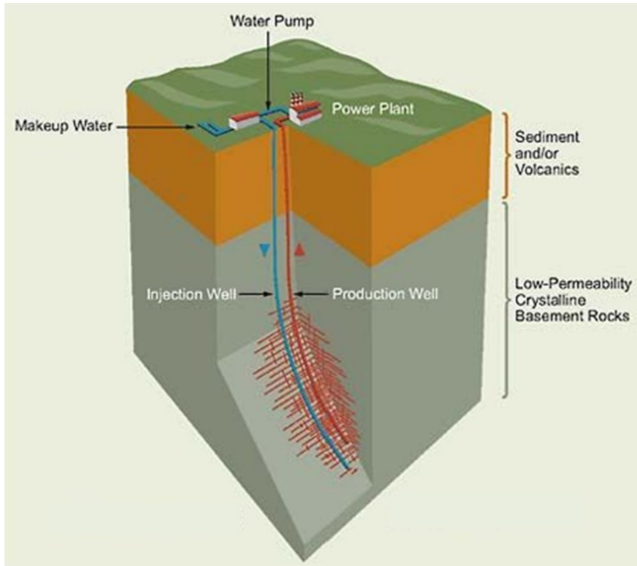

Figure 1: Two well-shallow EGS layout

2.1 EGS developmental challenges include (Pollack et al., 2021):

A. Scarcity of connected natural fracture networks, particularly in deeper, hotter intervals where occurrences of natural fractures declines
B. Doubled problematic drilling and doubled drilling costs of a two+ well system
   - Per MW drilling cost is 3X to 6X over other approaches
   - Doubled well integrity issues
   - Doubled lost circulation inevitabilities
   - Lost or stuck downhole equipment
C. Induced seismic tremors or quakes
D. Injectivity issues
   - Misdirected connectivity between injection and recovery leading to lost production, wasted injection energy, and water loss
   - Commercially insufficient injectivity potential
   - Parasitic injection loads
   - Concentrated flow path, or hydraulic/thermal “short-circuiting,” leading to an early thermal breakthrough, Figure 2
E. Low energy output due to limited non-vertical heat access and inadequate reservoir-stage volumes

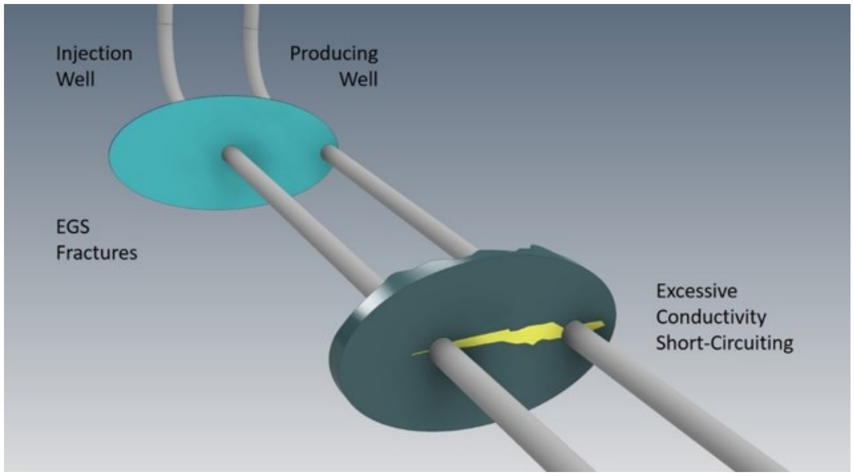

Figure 2: 6 to 10% actual heat recovery potential due to a single well-reservoir recovery point causing hydraulic and thermal short-circuiting

2.2 Solutions to EGS challenges

The new DGS Technology's depths, conditions, and practices are the opposite of traditional geothermal. Long-running emphases and issues with (A) excessively costly multiple directional wells and drilling problem incidences, (B) controlled reservoir creation, (C) injectivity wastes, and (D) low energy recovery are resolved by:

A. Drilling a *single* vertical well to access maximum heat while cutting drilling costs by 75% and placing emphasis on deeper, more stable, and predictable strata
B. Fracturing and producing from deeper, hotter strata where fissures shrink with increased overburden by recrystallization, thereby disconnecting natural fracture systems and reducing permeability and uncontrolled fracture propagation
C. Transcending traditional injectivity concerns by, instead, circulating in massive, highly conductive reservoirs having well-defined circulating conditions, negative injection/circulation pressures, and a crystalline bonding water loss elimination program that begins with the fracturing process and continues as part of the production operations
D. Creating some 20 MHF reservoirs providing 60+ million square feet of 150°C to 400+°C (300° to 750+°F) HDR surface area with well-defined hydraulic pathways enabling 90+% hydraulic and thermal sweep efficiencies

3. NEW FULL THERMO-HYDRAULIC GEOCIRCUIT SYSTEM (DGS)

DGS Technology (See Figure 3 on the next page) is described as a closed, vertically stacked series of vastly propped fractured reservoirs made in deeper, hotter, more stable hot rock–*Earth's most abundant resource*. The new technology incorporates the best attributes of legacy geothermal systems, such as the high output potential of hydrothermal and the low risks of closed loops, while designing out the traditional drawbacks of unsustainable water losses or the increased risks inherent to the exploration of economic, natural fracture systems.

The system's highly conductive hydraulically fractured reservoirs are bifurcated by an impervious lens, or barrier that causes circulating work fluids to flow great distances away from the wellbore, thereby picking up substantial heat. The fluid then turns 180° around the end of the diverting barrier, collecting additional heat while flowing on the opposite side of the barrier and towards re-entering the well. The barrier can be made of multiple material types.

Downhole, the working fluid outlets, and inlets in the wellbore are separated by proprietary isolation equipment installed between the production tubing and well casing.

Some 20 reservoir stages, each with lengths upwards of one mile, may be constructed, creating 550 hectares (60,000,000 square feet) of reservoir surface area in formation temperatures of 150°C to 400+°C (300°F to 750+°F). The performance potential of DGS is extraordinary. Based on massive resource surface area and the creation of high sweep efficiencies, DGS is the sole means by which 50 MW may be reliably brought to the wellhead, levels some 10X to 30X over alternatives. A full-scale DGS installation will produce a gross 50 MW at approximately 400°F and 2500 GPM at the wellhead.

The DGS system can achieve 1 GW hourly production from approximately 1150 hectares (2800 acres) and produce 10+% global Total Energy by 2050 with suitable investment and infrastructure.

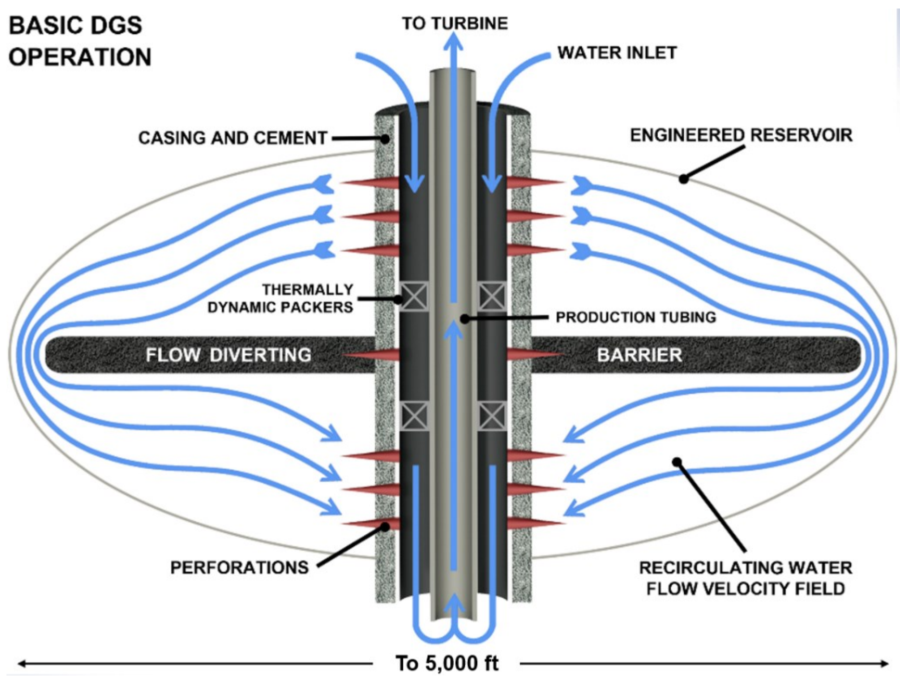

Figure 3: Basic single-stage DGS operation: (1) Pump water down the casing-tubing annulus, (2) Water is diverted through upper perforations into the fractured reservoir, (3) Guided by a barrier structure, water collects heat as it travels across the hot reservoir rock, (4) Superheated steam enters the well through lower perforations and flows up the tubing to a turbine, and (5) water is recycled back to the well

Below is a six-point summary of DGS Full GeoCircuit™ refinements to traditional EGS:

1. A single vertical well performs both injection and recovery functions, offering the most economical drilling-enthalpy approach; traditional directional wells twice add 160+% to the costs
2. DTS Technology harvests virtually unlimited, deeper, more stable HDR.
   - 10+% of Earth's land area overlies 5 MW / km heat
   - Emphasis on the most stable of geology, mitigating problematic drilling, stimulation, and production
3. Controlled massive reservoir creation, including determination of all fracture dimensions, the communication of separate fractures, controlled leakoff in the fracture, and fracture conductivity
4. Extreme-length heat recovery flow paths approaching 40 miles
5. Coplanar well-reservoir arrangement, allowing for well-defined reservoir boundaries and tunable, high-efficiency hydraulic and thermal sweep functions
6. Near zero renewable energy surface land use with wellheads and plant integral

4. DETAILS OF FIVE DGS COMPONENTS

DGS Technology consists of five distinct, but synergistic elements: (1) Dimensionally controlled propped hydraulic fractures, (2) High-temperature fracture fluid (>350°C), (3) Engineered bifurcating flow diverters constructed in the fractures, defining precise hydraulic pathways, (4) Thermally variable production packer assemblies, and (5) Full-fracture volume sweep capability approaching 100% energy recovery.

4.1 Controlled reservoir creation

Proficient geothermal production emanates from fracture planning and subsequent efficient placement of high-temperature proppant in the fracture. Fracture geometry planning begins with understanding the resource rock's tensile failure properties rock. The control of fracture, height, width, and length is determined by pumping rate, pressure, and stable high-temperature fracturing fluid viscosity. The high-temperature fracturing fluid is also required to place high-temperature proppants, thus assuring high fracture conductivity. The fracturing variable that is not controllable is fracture azimuth, but with a reliably vertical orientation because of its perpendicularity to the formation's lease principal stress, as shown in Figure 4.

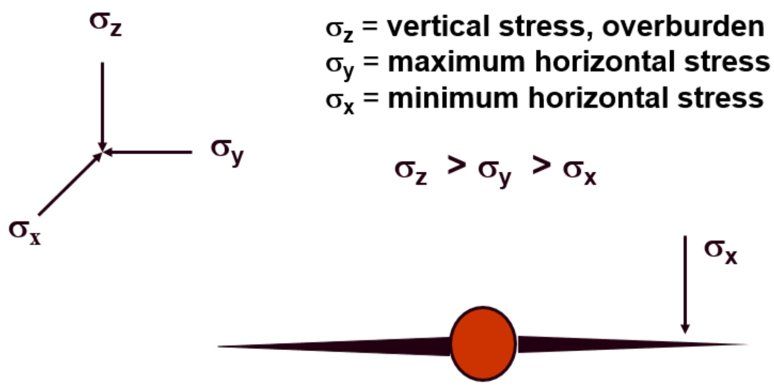

Figure 4: Vertical fracture perpendicular to the least principal stress, σ_x

The fracture dimensions, height, width, and length obtained in each rock system are different, indicating that material properties anisotropy affects the resultant stress shadows and, thus, the pattern of fracture development. The detailed design of hydraulic fracture treatments requires detailed information on the in-situ stresses. An engineer must know the magnitude of the minimum in-situ stress for the pay zone and over- and underlying zones and, in some cases, must know the direction for the principal stresses (Economides et al., 2000). The equilibrium fracture height concept provides a simple and reasonable contrast between the target layer and the over- and under-burden strata (Simonson et al., 1978).

Factors that influence fracture geometry, height, width, and length (Figure 5) include the insitu rock stresses (σ_x, σ_y, and σ_z), rock properties (Young's Modulus [E], Poisson's ratio [v], etc., and reservoir pressure. Frac design models apply these variables using a material balance and associated fluid efficiency (C_{eff}), which is a function of three fluid loss values C_w – wall building, C_c – compressibility, and C_v – viscosity, all pretty much negligible in impermeable rock. Thus, the fracture dimensions are controlled by the following:

Height (h) ft $\cong$ pumping rate x fracturing fluid viscosity / larger height limits length

Width (w_f) ft $\cong$ rate x viscosity

Length (L) ft $\cong$ working fluid volume $\pm(\Delta H + \Delta W)$

Fracture Conductivity (FC) md-ft) = $w_f k_f$, where k_f is the permeability (md) of the proppant bed.

Dimensionless Conductivity (C_{fD}) = FC /πk L_f, where k = formation permeability (md) and L_f = propped fracture length (ft)

Note: $10 \le C_{fD} \le 100$ Optimum Range (Economides, et al., 2002)

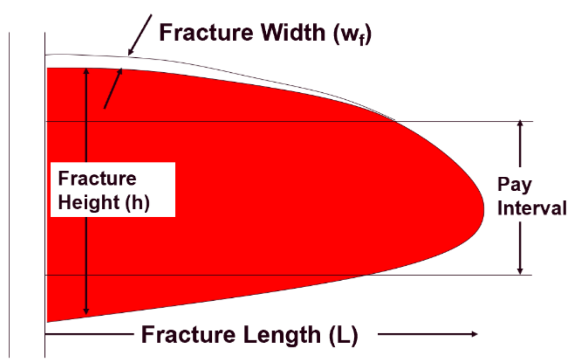

Figure 5: Fracture geometry

4.1.1 High-temperature proppant

A proppant is a solid material, typically sand, treated sand, or manufactured ceramic materials, designed to keep an induced hydraulic fracture open during or following a fracturing treatment. Proppants are added to a fracturing fluid at a concentration generally of 2.0 lb/gal, varying depending on the application. The propping material must bear the formation closure pressure, or minimum horizontal stress, equal to the frac (gradient x depth) minus bottom hole flowing or injection pressure. Should proppant strength be insufficient and crushing occurs, fracture conductivity, critical to the success of the reservoir, will be considerably diminished.

Successful fracture stimulation requires dramatic technical improvements to traditional proppants to create productive, sustainable reservoirs in higher-temperature geothermal environments. Common to the production of hydrocarbons, the use of proppants in commercial geothermal projects, as well as any developmental research for use in such deleterious aqueous environments, has been extremely limited (Jones et al., 2014). The means to improve proppants for high-temperature geothermal well applications include, for example, increased standards and materials properties consisting of:

- Mono-sphere, single particle sizing, and perfect roundness and sphericity
- Ceramic substrates encapsulated by various external coatings
- Metals, including corrosion-resistant alloys
- High-strength glasses

4.2 High-temperature fracturing fluid

A high-temperature fracturing fluid with thermally stable viscosity enables the creation of hydraulic fractures in high pressure and high temperature (>200°C or 392°F) conditions. In addition to transmitting hydraulic pressure to the formation, a non-viscosity thinning fluid must also efficiently transport proppant particles having size and density adequate to create and sustain highly conductive reservoirs.

One ideal non-organic, high-temperature fluid for highly conductive fracture creation is the authors' chemically three-dimensional "DTS ProGel," which is derived from sodium silicate Na_2SiO_3. The gel has known functional capability with high-temperature proppants to 350+°C (660°F) and has higher temperature potential. DTS ProGel is a completely environmentally friendly, low-cost, inorganic hybrid gel made with any salinity water Figure 6 (McDonald, M., 2016).

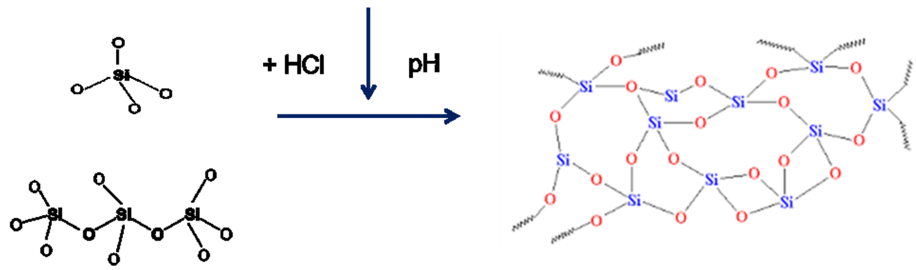

Figure 6: Sodium silicate polymerization

Figure 7 illustrates that the gel exclusively has high stability performance at temperature, in stark contrast to conventional viscosifiers having thermal limitations of 175°C (350°F). The DTS fluid shows constancy at 200°C (392°F). Furthermore, the gel has an estimated upper limit of 500°C.

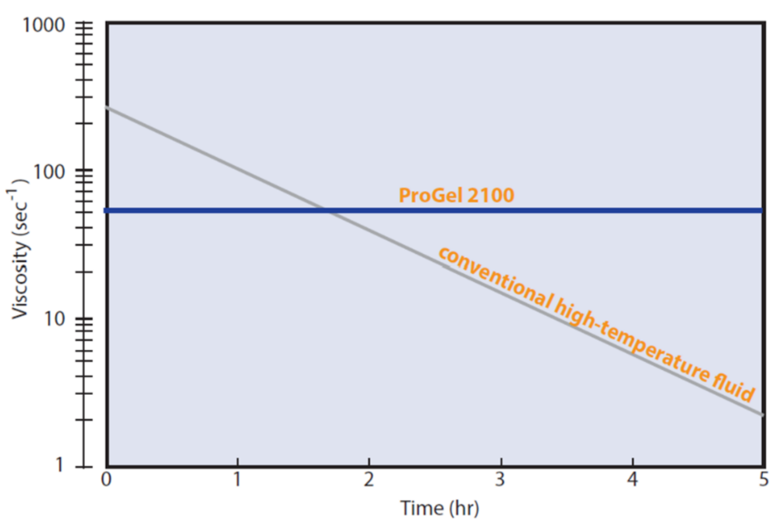

Figure 7: Viscosity comparison of 5% by weight ProGel compared to a 120 lb/Mgal crosslinked organic polymer at 200°C (392°F)

The author first applied a Na_2SiO_3 fracturing fluid derivative in 1980 in seven hydrothermal steam wells in Nigorikawa Geothermal Field, SW Hokkaido, Japan Figure 8. (Katagiri, K., et al., 1983 and Liu, S., et al., 2020).

Figure 8: Frac spread at a Nigorikawa Geothermal Field well

4.3 Fluid diverting barrier construction

There are eight diverting lens-barrier construction methods to effect well-defined, controllable horizontal flow pathways for the DTS system. One construction approach places impermeable barrier material along the middle elevation of the propped fracture. Fluid in a high-temperature fracture has a density gradient that can be enhanced by pumping a higher-density fluid along the bottom one-third of the reservoir. A sealant, the density approximately matched to the mean of the reservoir's fluid contents, en pumped along the interface of the higher and lower density layers, thereby maintaining the desired placement elevation. The addition of aggregate-type fillers to a tail-in sealing material enhances near-wellbore permanency. There are five material families, including organics, cementitious, and elastomeric products, applicable to this and several other construction approaches. Figure 9 (Rensvold, R., et al., 1975 and Liu, S., et al., 2020).

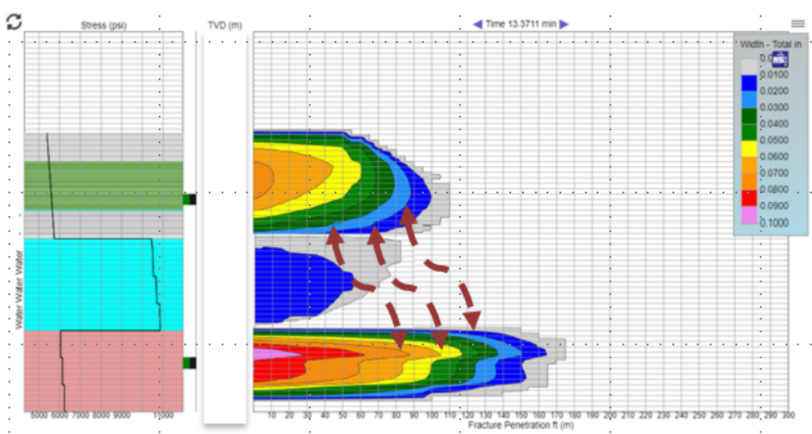

Figure 9: Modeling of an alternative barrier construction method, intersecting fractures around an impermeable barrier lens, per NSI StimPlan

4.4 Isolation tools, packer issues

High temperatures and wide thermal variations impose extreme stresses in the form of substantial length changes (of several feet) to these tubular assemblies that suspend isolation packers. Such stresses can cause tubing and packer damage and unseating of packers:

- Ballooning and reverse ballooning, defined as contradictory tension/compression stresses
- Temperature effects shortening or lengthening of the tubular string
- Piston effect of packer elements, surging or swabbing
- Tubular helical buckling (Lubinski, A., et al., 1962)

A thermally compliant solution requires sealing by multiple elastically biased, self-adjusting, non-elastomeric elements. The DTS Isolation device is actuated by heat, its seal members then mimic cement 'touching' pressure loss. The tool is deployable in high quantities, where 40 or more can be set simultaneously.

Figure 10: Novel DTS Isolation Device

4.5 Full-fracture fluid sweep capability approaching 100% energy recovery

The DGS hydraulic circuit design enables control over hydraulic and heat sweep efficiencies. Control inputs include circulation rate changes, where the flow rate may be caused to become turbulent, where fluids seek relief vertically, thereby sweeping the entirety of reservoir height. Other hydrological adjustments include fluid elevation level changes, variations to inlet and outlet elevations, fluid density alterations, and changes in flow direction. (Multiphysics, C., 1998).

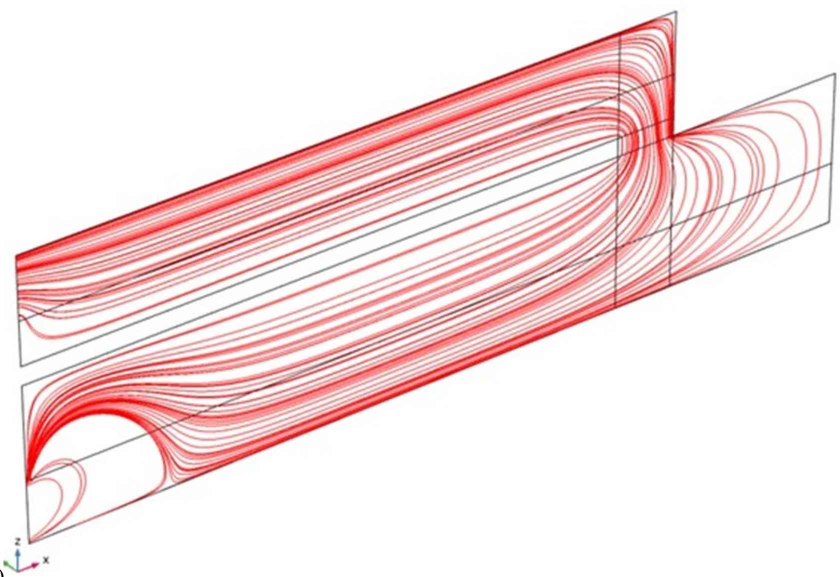

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Figure 11: Streamlined velocity profile is seen in a one-quarter reservoir system view

5.0 SUMMARY & CONCLUSIONS

DGS creates extensive reservoir surface area in deep hot rocks found most anywhere. Operating temperatures may exceed 370°C (700°F), and water heating surface area may exceed 550 hectares (1400 acres). More importantly, the technology creates controlled hydraulic channels that direct water flows across the entirety of the hot rock surfaces. The hydraulic and thermal channeling effect is analogous to lining or installing levees on riverbanks, confining flows to where they can be useful. The heat transfer efficiency of a DGS installation thereby approaches 100%. Such energy extraction efficiency from a system of massive reservoirs is the basis that geothermal energy can truly be globally scaled.

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