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Deep Single Well EGS Method for Highly Elevated Power and Four Well, 216 GWh Seasonal Storage Capacity

Jeffery A. Spray and Shailesh Gupta

DTS Technologies, LLC, 12755 Ashford Hills Drive, Houston, TX, 77077

jaspray@earthlink.net

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ABSTRACT

Despite geothermal's potential abundance and the introduction of multi-well enhanced systems (EGS) 50 years ago, both remain as potential power. Through an innovative reconfiguring of EGS in HDR, this paper presents fundamental refinements and substantive baseload production levels making HDR geothermal highly scalable, even to climate impact levels. One novel application of the reconfigured EGS includes grouping four wells' early production into single or paired plants, supplying three months, 30 MWe per well seasonal and replenishable energy storage.

The paper's objective is to demonstrate realizable long-term clean energy abundance by use of the innovative Deep Geothermal System, or "DGS" method, as supported by decades of subsystem field experience and by recent simulation-based design, performance evaluation, and optimization.

DGS reconfigures the traditionally redundant directional or horizontal drilling of multi-well EGS into one substantially deeper vertical well, thereby accessing 50% higher average heat and maximizing per-MW drilling investment. DGS drilling trajectory is done in a manner that is co-planar with its subsequently induced fracture-reservoir-circuits, enabling full hydraulic communication along the entire well-fracture heights.

Long-length flow diverters are constructed horizontally in the fractures, bifurcating them and doubling heat-collecting flow length. The diverters guide flow away and back to the well, superheating fluids over 45 hours' exposure at depths and heat levels double or more that of traditional practice. Tuning of the co-planar hydraulics, in concert with strategic placement of the diverter, enables full control over reservoir's hydraulic behavior and heat extraction from some 560 hectares (1380 acres) of total system geothermic rockface having 150°C to 400°C and higher heat.

Simulation by Computational Fluid Dynamics (CFD) and conjugate heat transfer analyses predicted well production temperatures and output over various rock thermal gradients, fracture dimensions, separation, inlet temperatures, and flow rates. Analyses also showed high-early per well baseload nearing 120MWt by fully sweeping an optimized count of 15 massive, highly separated reservoirs. Net early well output exceeds 30 MWe, as no parasitic injection or significant cooling loads are required in the vacuum driven DGS surface inlet.

Analytical work also revealed a roughly optimal 335-meter reservoir separation enabling high level baseload heat replenishment while balancing the practical aspects of overall installation design, deep well construction, economics, and sustainability. A 15 to 20 MWe range baseload output occurring for some 20 years was also shown prior to entering steady state production.

Extension of the analytical work further revealed DGS' ability to deliver 30 MWe as baseload stored energy delivery on a three-month seasonal basis. Thermal recovery occurring for the balance of the year ranged from 92% to in excess of 98%, depending on well spacing and effective rock volumes.

The innovative DGS single well HDR geothermal method is not only novel, but revolutionary. DGS technology obsolesces orders more costly and less productive EGS designs requiring two or more wells per location-output. Geothermal's promises are shown realizable by the type of work presented in the paper – and in new ways.

1. INTRODUCTION

The still burgeoning EGS is not at fault for geothermal's effective power market absence. At fault, is the stark scarcity of three critical natural factors needed that also define natural geothermal's condition: heat, permeability, and water. Incidentally, EGS, i.e., enhancement by hydraulic stimulation, was merely a response to commonly low natural permeability and elusive water supplies.

Adding to this paper's opening, EGS has long suffered other significant issues, some directly addressable by analysis, some indirectly benefitting by it. Included here are: A) redundant drilling cost, B) low power output, C) baseload inability, D) parasitic injection and cooling costs, E) water losses, and F) seismicity risks. Reasons for each traditional problem and their general solutions follow:

A. Redundant drilling's excessive cost results from the traditional necessity to install two or three separate directional or horizontal wells per producing site. Generally, one production well and one or two injectors are made. The issue of excess becomes significant, as when combined, drilling a total of 11 km or more may be required per site, even though the target depth may be only 2.5 km. It should be noted that recent advances in PDC bit design and field practices have increased high strength rock drilling penetration rates by many orders, dramatically improving upon the traditionally gating problem. However, it should also be noted that such advances and their overall impacts have been conducted in carefully selected geologic conditions.

The ideal solution reduces well count to one and reorients horizontal type trajectories to vertical, where vastly more heat can be accessed, in some cases 3X higher bottomhole temperature and 60% more total heat is accessed, given the same overall drilled length.

B. Low power output has historically been attributed to low injection rates, fracture crossflow, and water loss. Although these issues are improving through very careful planning and site selection, the above mentioned cantilever-type configuration and its fundamental hydraulic extractive contradictions remain. The conventional EGS arrangement essentially consists of single plane fracture-reservoir surface area penetrated perpendicularly by effectively single point wellbores, the latter being miniscule in surface or transmissive area by comparison. Although slightly more involved, the wellbore piercings are ultimately mere pinpoints relative to the larger fracture surface area. On this basis, and even though high injection rates could flood fracture volumes, heat carrying flow simply wants to take the least resistant, narrowest possible path. Instead of thoroughly contacting reservoir rockfaces, a short-circuit channel occurs as quickly as possible towards the production well. The result is a highly limited “sweeping” exploitation of the system. EGS’s early production phases do show longer heating and operating cycles, as cooler and denser injection fluids sink and displace their opposites, thus temporarily delaying the narrow channeling effects. However, upon cooling the rock by commercial level use, the short-circuited pathway ultimately dominates. See **Figure-1**.

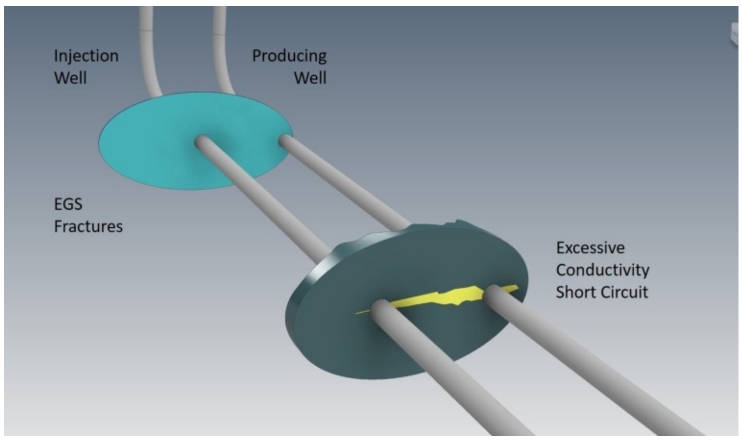

Figure 1: Hydraulic and thermal short-circuiting common to limited well-reservoir EGS connectivity. Not fully sweeping the fractures, flow along the least resistance follows at high injection rates or as the system cools.

The ideal solution is the opposite of the traditional well-fracture perpendicularity scheme─one that instead is a co-planar arrangement, fully complementing and providing free well-reservoir hydraulic communication along their shared 120+m fracture height. In stark contrast with legacy designs, where only a relative few well perforations supply the fracture along one generally horizontal channel, the innovative and preferred full communication approach provides such conduits by the several hundred’s or more. Further, their placement, quantities, and individual geometries are tunable for discrete optimization purposes. See **Figure-2**.

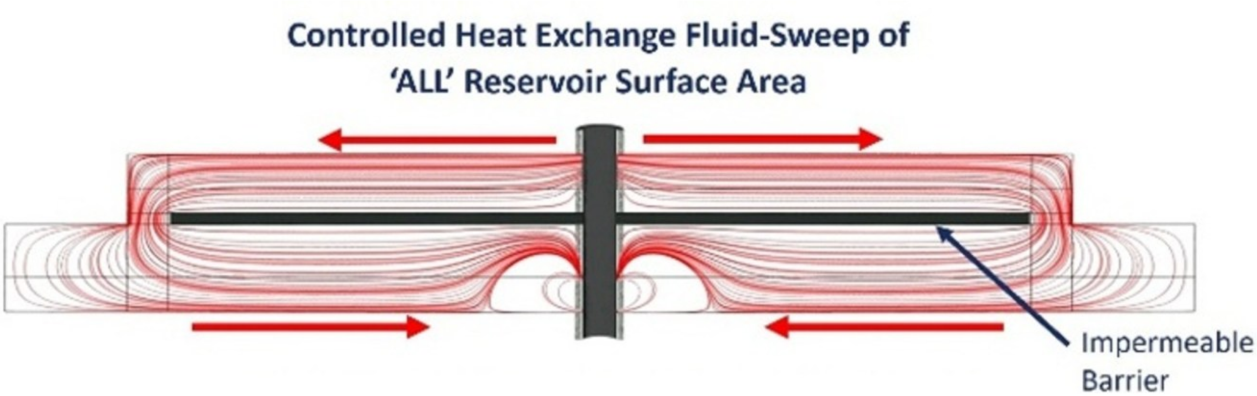

Figure 2: Preferred co-planar well-fracture arrangement approaches 100% thermo-hydraulic recovery, as tuned by perforation geometry and placement. Note deliberately altered perforation placement indicating detailed control over sweep.

C. Baseload inability stems simply from insufficient heat replenishment due to several factors. First, the mentioned limited effective rock surface area contact problem leads developers to oversupply fracture size and quantities. Oversizing leads to economic or seismicity constraints, while excessive fracture quantities come at the expense of critically needed reservoir separation for reheating purposes. Indeed, current practices of fracturing at roughly 20m intervals, borrowed from oil and gas, leave vastly insufficient replenished rock volumes. The reality is that baseload heat replenishment separation ideally requires **15X** or greater distance over current practice. However, upon correcting conventional EGS separation distance, a contradiction occurs in that only four to seven fractures are placeable along even 1 km – 2km length horizontal laterals, far fewer than the 50+ quantities of current designs.

The ideal solution is a physically fundamental one, where baseload related fracture-reservoir separation and feeder rock volumes are increased by some 12X to 16X, or 330m to 450m, respectively, and into ever hotter geology.

D. Major parasitic loads, particularly reinjection and cooling, consume approximately 30% and an additional 15% of gross power output, respectively. Injection work approaches or exceeds 16 MPa and 125 l/sec. Consuming additional gross power, cooling is traditionally required to condense reinjection fluids, ORC gases, or both.

The ideal solution first eliminates the need for reinjection work. This is accomplished by increasing the hydrostatic and circulating density differential between denser, cooler annular inlet fluid and a lighter heated fluid present in the production tubing. The density differential improves as a function of increased vertical depth and corresponding temperature elevation, while both also dramatically reducing viscosity to only 14% that of ambient. Such improved conditions enable HDR system self-circulation, thus obsolescing the need for injection work and cooling losses. Second, a strong annular vacuum created by the annulus-tubing fluid column weight differences acts to pull inlet fluids in and downward, thus integrating the condensing process. Third, maintaining high temperature baseload enables use of 3X more productive flash conversion turbines, thereby eliminating the cooling needs of ORC's.

E. Water loss, occurs due to the presence of connected natural fracture systems (generally attributable to a lack of depth), geologic faults, and as exacerbated by injection pressures.

The ideal solution, beyond robust site selection practice, is increased vertical stimulation depth (starting at 3000m or deeper and continuing indefinitely), where increased rock weight closes and disconnects natural fracture systems and their fluid transport potential.

F. Seismicity risk and its mitigation occurs according the mechanisms outlined in "E".

2. THE DTS-EGS SOLUTION

The DTS Geothermal System (*DGS*) is a reconfiguration and streamlining of traditional and burgeoning multi-well EGS schemes. The reconfiguring reverts to a single well and to EGS's original *vertical* trajectory and deeper drilling approach, where 2X to 5X greater total heat is accessed over the same drilled length. As earlier outlined, reconfiguration to the vertical also means that the hydraulic connection between the generally vertical well and vertically oriented fracture heights are fully aligned, working in concert to more completely contact, refill, and thermo-hydraulically sweep all HDR face area.

Here, streamlining means that the DGS arrangement produces *more energy by use of the single well than are capable by two, three or more wells traditionally*. No longer needed are the expenses or hydraulic limitations resulting from multiple injector and production wells and parasitic operations occurring at each site.

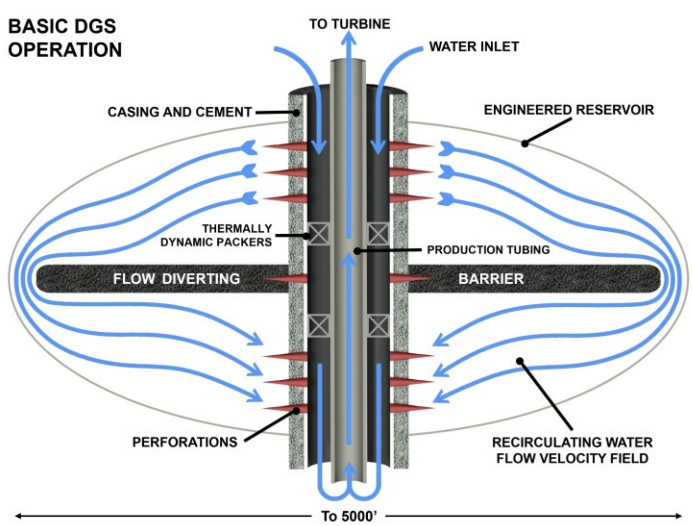

Figure 3: DGS operational schematic: A) Water flows through the casing-tubing annulus on vacuum. B) Water is diverted through perforations into the fracture-reservoir. C) Guided by the barrier structure, the water collects heat as it travels across the hot reservoir and back. D) Superheated, the water re-enters the well, flowing to the surface via production tubing. Multiple stages are constructed.

The innovative DGS system is described as a full fluidically connected vertical well and induced, propped fracture arrangement. Flowing without the need for injection pressure, fluids are introduced at the surface through the well annulus. Isolating packers then direct the fluids into a fracture-reservoir-circuits, each horizontally bifurcated by long length flow diverting structures.

The DGS flow diverting "barrier" construction is derived from water conformance, or water control methods practiced for decades in oil, gas, geothermal, and other fields. DGS barrier construction includes eight alternative means and may consist of various materials from at least five chemical classes, including silicate, elastomeric, and cementitious types. Flow barriers may also be created using the reservoir's native rock or by use of resorted proppants. The diverter's construction process has advantages over conventional fluid conformance requirements in that its placement only needs to concern partially sealing a narrow fracture width, not plugging 360^o circumferentially around the well, as is critical in O&G, for example.

Once heat carrying fluids have entered the reservoir, the diverter guides them upwards of 750 meters (2500 ft.) away from the well along the bifurcated reservoir's upper area and then back, re-entering the well through the lower circuit-half's numerous perforations. After repeating through a series of some 15 massive reservoir-circuits, superheated or even supercritical fluid is directed to the surface through production tubing, **Figure-3**.

3. CFD/CHT MODELING APPROACH AND OBJECTIVES

To produce long-term utility scale baseload from an HDR well, three outsized geologic and engineered components are required: exceptional heat, ranging 150^{o}C to 500^{o}C (300^{o}F – 900^{o}F), occurring through a 3km to 10km depth interval; feed rock volume and fracture rockface surface area massiveness of 4.67km^3 and 550 hectares (1.12mi.^{3} and 60MM ft^2), and most importantly; a controllable high efficacy, high circulation rate hydraulic-rockface conductivity and heat sweeping extraction process providing >90% heat recovery to >80 l/s / 1300 GPM circulation).

Determining performance of the innovative DGS method first emphasized maximizing gross baseload power. Work additionally incorporated detailed longevity-decline behavior, subsystem efficacy, practical drilling, construction, and economic considerations, and overall basic order design optimization. Other considerations and objectives were:

- Maximized output based on practicable self-circulating flow rates and known reachable and operable depths and temperatures
- Optimal reservoir separation distance as concerns long term baseload-decline
- Steady state output levels and time to steady state
- Optimal and practicable well construction vs. overall output
- Circulating pressure loss determination, accounting for fluid density and viscosity reductions.
- Validation of self-circulating capability, mitigating injection and cooling parasitics.

A range of system design and model input assumptions, both potentially detrimental or enhancing to output, were integral to the simulation program. Among the disadvantageous assumptions are reservoir symmetry, uniform hydraulic conductivity, and controlled stratified hydraulic behavior. By contrast, unutilized example inputs capable of increasing productivity and/or system longevity include increasing rock thermal coefficient (potentially doubling or more), increasing circulating fluid heat capacity, and substantially lowering fluid input temperature, the latter two each providing proportionate increases early in power output.

Figure 4: Computational mesh representing ¼ DGS reservoir and rock volume. Flow diverting barrier, also in white.

3.1 Model Visuals

Figure-4 represents a typical computational mesh used for the CFD analyses of the basic DGS configuration illustrated in Figure-3. Simulations were conducted using STAR-CCM+ (Siemens 2023), which solves governing equations for mass, momentum, and energy conservation for water flow in the HDR fracture and energy conservation in the rock. **Figure-5** shows example water temperature rise contours as it travels through a fracture-quarter, while **Figure-6** shows typical operational temperature contours in the rock. **Figure-7** provides a simplified DGS well layout with dimensions.

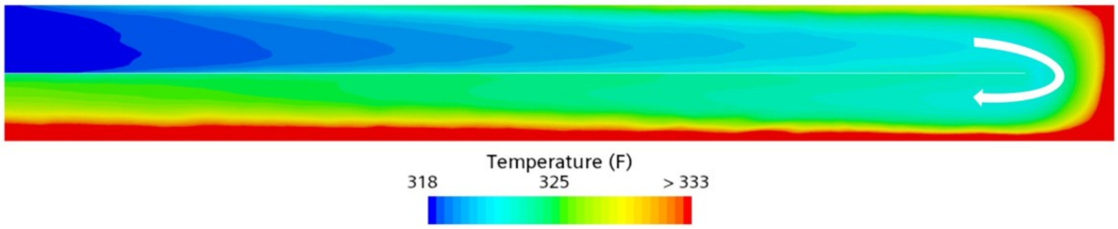

Figure 5: 1/4 view of a water heating profile through a lower temperature reservoir-stage.

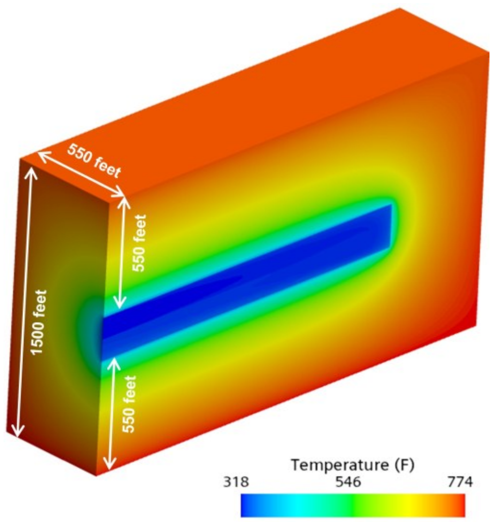

Figure 6: Example higher temperature rock contours with affecting beyond 500 feet radially.

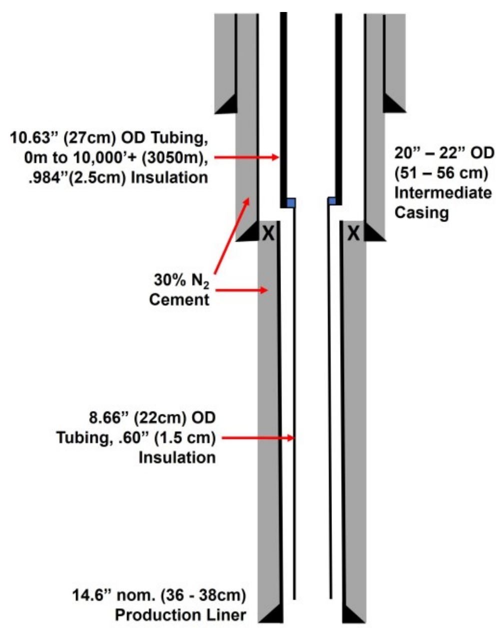

Figure 7: Deep, large diameter DGS well scheme, minus 4000’ open bottomhole. Design stays within 80% of record sets.

Figure-7 provides a simplified DGS well layout and dimensions. **Figure-8** shows a nearly full, 14 stage reservoir DGS system, created using imperial dimensions, and where each reservoir is separated by 335m (1100').

Figure 8: Nearly full, 14-stage DGS installation with additional description.

General comments. Some general parametric simulation results show that output temperature increases only slightly by increasing reservoir height.

Increases in reservoir separation also result in higher temperatures, but reduces the number of placeable reservoirs within the same depth interval. A 15 fracture quantity system optimum was then found based on parametric thermal analysis.

Once reservoir behavior was understood, heat contribution from the cased hole interval from 0' to 10,000' depth was modeled. Modeling of the cemented liner sections separating the generally optimal 15 reservoir stages followed, finally arriving at the baseload production of the system shown in **Table-1**.

3.2 System Components and Dimensions

Their dimensional ranges and sample sizes presented from surface to total depth and according to process step follow:

- Harvested HDR interval – 3050m to 10,360m (10,000' to 34,000') vertical depth
- Telescopic surface and intermediate casings – 0m to 910m and 0m to 3050m (0' – 3000' and 0' to 10,000').
    - Smallest ID = 47cm to 50.8cm (18.5" to 20")
    - Mean foamed cement TC = .6 W/m·k

- Induced reservoirs
  - Half length: 760m (2500’)
  - Height: 90m to 120m (300’ – 400’)
  - Widths: 3.2mm to 12.7mm (.125” – .500”)
  - Modeled reservoir sample sizes: 3 – 4
  - Original and final count: 20 and 15
- Flow diverting barrier half-length – 670m (2200’)
- Production liner reservoir separations throughout 3050m to 9570m (10,000’ – 31,400’) depth.
  - Quantity: 14 - 15
  - Vertical separation distance between reservoirs: 175m to 335m (572’ – 1100’).
  - Final ID: 35 cm (13.7”)
  - Mean natural rock temperature: 330^{o}C (625^{o}F)
  - Total of heat contributing lengths: 4700m (15,400’)
- Below completion openhole interval – 9570m to 10,790m (31,400’ – 35,400’).
- Production tubing – tapered
  - Upper zone ID: 24.1 cm (9.5”), OD tubing-casing annular volume = 165.3 l/m (13.3 Gal/ft).
  - Lower zone ID: 18.8 cm (7.4”), OD tubing-casing annular volume = 135.4 l/m (10.9 Gal/ft).
  - Insulation radial thickness adder: 1.45 cm to 4.24 cm (.57” to 1.67”).

3.3 Primary Model Variables

- Heat carrying fluid inlet temperature range: 93^{o}C to 149^{o}C (200^{o}F – 300^{o}F).
- Circulating rates: 32 l/s to 83 l/s (500 GPM – 1328 GPM).
- Rock thermal gradient(s): 45.6^{o}C/km to 54.7^{o}C /km (.025^{o}/ft. – .030^{o}/ft.).

Fixed Inputs

- Rock thermal coefficient: 2.2 W/mk, average western US granites, discounted for depth >325^{o}C.
- Carbon steel, cement TC = standard API grade materials and properties.
- Carrying fluid = fresh water, properties per https://webbook.nist.gov/chemistry/fluid/.

3.4 Component and System Analyses

3.4.A1 Analysis of the Fracture-Reservoirs

- Range of full rockface surface area, per stage: 28 to 37 hectares (3MM ft^2 – 4MM ft^2).
- Total flow distance, each stage: 3050m (10,000’)
- Range of flow velocity: .152 m/s to .51 m/s (.499 ft/s – 1.67 ft/s).
- Range of flow time, per stage: 64 min. to 167 min.
- Range of reservoir-stage temperature: 121^{o}C to 500^{o}C (250^{o}F – 930^{o}F).
- Range or inlet water temperature: 99^{o}C to 159^{o}C (210^{o}F to 318^{o}F).

3.4.A2. Mathematical Basis

Heat Transfer Rate, T1 to T2:

$$Q\ (W) = m * Cp * (T2-T1) \tag{1}$$

where m = water mass flow rate, kg/s, Cp = specific heat capacity of the water, J/kg^{o}C, T2-T1 = mean water T at reservoir inlet/outlet, K

Heat Transfer Rate, rock to water:

$$Q = h * A * (Trock-Tw) \tag{2}$$

Where h = effective heat transfer coefficient (function of water density, and viscosity, as affected by temperature and pressure), W/m^{2}K (rock/water interface convection, water conduction and convection), A = water/rock interface surface area, m^2, $Trock$ = temperature of rock-to-water contact, K, Tw = temperature of water-to-rock contact, K

3.4.A3 Results

- The final per stage range of temperature increase to the heat carrying fluid’s entry to exit: .89^{o}C to 14.8^{o}C (5.3^{o}F to 30.4^{o}F).
- Changes to the fracture’s X and Y dimensions ≈ 0.33:0.10 changed heat.
- Changes to Z width dimension increased heat at approximately 1.0:.3.0

3.4.A4 Analysis of Fracture-Reservoir Spacing

A fourth reservoir was added underneath an originally three-reservoir analytical sample count and located across an 1830m (6000') interval of project HDR. The original 335m (1100') reservoir separation was consequently reduced to 175m (572'). The change led to a top-down output reduction of the upper three reservoirs output of 8.4%, 12.4%, and 13.8%. The overall interval output increased 5.4°C (9.7°F), 22%, or 3:2. It was subsequently estimated that reciprocal effects with respect to individual reservoir stage contribution would occur when separation is increased proportionately.

3.4.B1 Analysis Of The Upper Cased Hole Interval Insulative Properties, Inputs

- Ground surface temperature: 21.1°C (70°F)
- Range of rock temperature at 3050m (10,000') depth: 121°C to 159°C (250°F - 320°F).
- Annular flow velocity: .348 m/s (1.14 ft/sec)
- Computational determination of the composite thermal coefficient of steel casings and cement layers

3.4.B2 Mathematical Basis

Repeats fundamental flow and transfer properties in (1) and (2), adjusted for geometry.

3.4.B3 Resulting Temperatures at 3050m Depth

- 93°C (200°F) fluid inlet at surface: 1.1°C (2°F)
- 149°C (300°F) fluid inlet at surface: -.34°C (-.6°F)

3.4.C1 Analysis of Heat Contributions of the Lower Hole Liner Sections

- The four bottommost 1100' sections were analyzed, other's results were extrapolated
- Total component lengths = 4700m (15,400') of average 330°C (625°F) rock
- Casing cement TC = .9W/mk
- Uninsulated production tubing present

3.4.C2 Mathematical Basis

Repeats fundamental flow and transfer properties in (1) and (2), adjusting for geometry.

3.4.C3 Results

- Employment of the program's lowest circulation rate, 31 l/s (500 GPM), produced a maximum 20.1°C (36°F) net heat, 11% of that mid-program's system total addition. Scenario output in = 4.9 MWt.
- Presence of an under- or overlying reservoir affected area heat transfer by 45%. The hottest liner intervals added 1.3°C to 1.4°C (2.3°F – 2.5°F) when confined, and 1.9°C to 2.0°C (3.4°F – 3.6°F) open ended.
- Use of 99°C (210°F) fluid inlet subsequently produced a stable 11.2°C (20°F) addition overall, even upon doubling of the circulation rate.

3.4.D1 Analysis Of The Production Tubing Assembly, Uninsulated and Insulated

- Thermal losses radially through uninsulated and insulated production tubing were determined
- Tapered assembly consisting of 27.3 cm (10.75") OD upper and 21.9 cm (8.625") OD lower zone
- Two insulation thicknesses: .057", 1.67"

3.4.D2 Mathematical Basis

Repeats corresponding basis expressed in 'A', adjusting for composite materials and properties.

3.4.D3 Results

- Heated fluids traveling up the tubing lose the equivalent of 46% of the heat added by the corresponding cased hole interval contribution discussed in 'C'.
- Addition of .057" thickness .06 W/mk insulating layer reduces losses by 84.2% to 90.3%.
- Addition of 1.67" thickness .06 W/mk insulating layer reduces losses by 91% to 94%.

3.4.E1 Analysis Of The Bottom Openhole Interval

- Interval consisting of 4000' wellbore with modeled average 440°C to 532°C (825°F – 990°F) rock.

3.4.E2 Mathematical Basis – Repeats and adjusts 'A'

3.4.E3 Results

- Despite the nominally extreme rock temperature, only 2.7°C (4.8°F) contribution is made, limited to 0.8 MW, in part, owing to the system's elevated temperatures overall.
- A 2.7°C (4.8°F) contribution = 1.4% of the study's final output.
- Exploitation of the interval type is economically producible and additive to output at 1/3 the cost of full D&C.

3.4.F. Summary of the Full DGS Installation's Thermal Performance

- Peak, 10-yr average, and steady state outputs = 111.5 MWt, 49.1 MWt and 27.9 MWt.
- Time to steady state: 20 to 30 years
- Baseload energy contribution by each component
    - Induced reservoirs 88%
    - 4700m (15,400') cased hole intervals 11%
    - 1220m (4000') openhole interval 1.4%
    - 3050m (10,000') upper cased hole -.8%

3.5 Hand Calculations, Integration of Prior DGS and AGS Analyses, and Other

Towards the DGS system's potential for self-circulation and injection parasitic mitigation, calculations for perforation pressure drop was performed by using Darcy-Weisbach and the Blasius friction factor. Owing to six non-tortuous SPF, losses were near zero.

Further towards the system's potential for self-circulation and parasitics mitigation, calculations for bottomhole hydrostatic pressures were made by the simple field formula:

$$P = (d * w) / 19.52 \tag{3}$$

where d = depth, w = fluid weight

Use of the mean densities of progressively heated water showed a pressure differential of 24 MPa (3483-psi) at the wellhead at the highest early production temperature modeled (450°C). Releasing pressure at the surface creates an annular drawdown potential of 3440m (11,300 ft.) with associated high vacuum. Circulation losses through the high conductivity propped fractures were surprisingly only 36-psi each, even through the upper stages flowing cooler, more viscous fluid. The low resistance gradually halved upon the system's reaching full temperature and 86% viscosity reduction. Annular volumes also adequately minimized losses throughout, with the larger upper diameters at effectively zero. Losses through the production tubing were negligible.

In total, approximately 600-psi are consumed through 82 l/s (1300 GPM) high temperature operating circulation. Sufficient self-circulating rates continue to an average system temperature of approximately 215°C (420°F). Operating temperatures below these levels are benefitted by use of production side pumping, so as to maintain intended annular and wellhead behaviors.

3.5.1 Incorporation of Earlier Modeling Work

I. The technology developing company commissioned an initial bifurcated reservoir heat transfer and hydraulics study titled, "Vertical EGS Modeling and Simulation" in 2022. The current study verified the heating results of the first. The 2022 effort also produced the fundamental and tunable hydraulic flow field coverage represented earlier in Figure-2. This effectively full coverage result was based on a first ever flow rate estimation intended to produce both large production volumes and the effect of full hydraulic sweep. A 90%+ coverage was gained by the first attempt. The image also shows correctable flowline shapes that were deliberately manipulated by positioning of the inlet and outlet perforations.

II. Prior to the initial DGS study, the developing company also commissioned "Numerical Steady State Solutions for 20,000 ft. Wells Completed With Graphite vs. Cement" and "Steady State Parametric Study Over Injection Flow Rate" analytical simulations of a most basic AGS design: a cased or uncased wellbore and production tubing. These revealed a slightly more than 30% improvement to heat delivery due to the substitution of standard insulative well cement with relatively hyper-conductive graphite (200X greater TC) constructed as a voidless thermal circuit. The program results also revealed very highly accelerated bottomhole and system temperature degradation (>50%) virtually overnight by circulating even a modest 32 l/s (500 GPM). In this example, the higher level well construction's thermal conductivity outpaced the rock's limited surface area ability to maintain wellbore heat. It follows that lower temperature annular fluids, even thousands of feet away will cause such accelerated heat influx elsewhere, and to the point of practical overall system depletion. Such is the basis for a strong, however contrary preference towards well construction materials that are more insulative than conductive, as discussed in the conclusions section.

The Extended Economic Viability of Lower Geothermal Gradient Lands

Analyses resulting from developmental inquiries under geographic areas having substantially less than the technology's ideal targeted heat potential revealed a linear reduction concerning output and corresponding economic returns. Especially when utilized on a flex basis, even in 60th percentile gradient heat, DGS still demonstrated economic attractiveness, thus doubling e.g., US land viability to 20% - 30%.

4. MODELING CONCLUSIONS

Figure-9 and **Table-1** illustrate the temperature a full DGS System as a function of time, circulation rate, and inlet temperature towards a steady state performance.

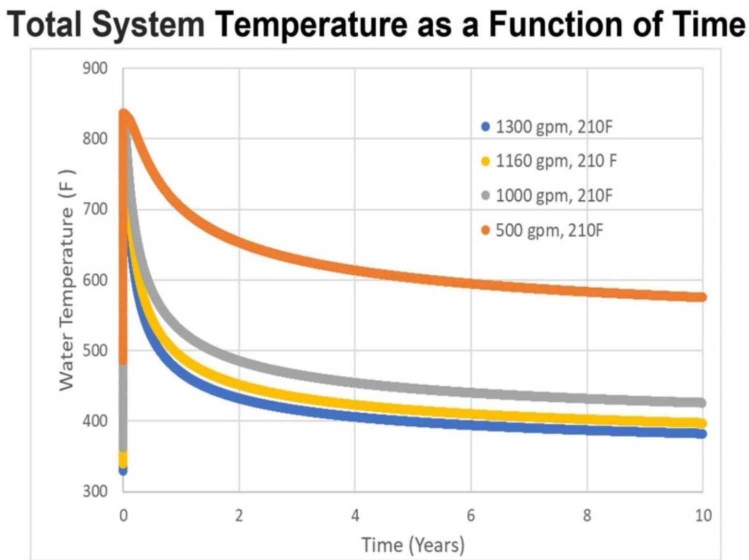

Figure 9: Model output and decline behaviors over 10 years; steady state occurring between years 20 – 30.

Table 1: Production profiles of the generally optimized full 15 stage DGS modeling results across four circulation rates.

	Peak, Mean, and Steady State MWt							
Flow Rate (GPM)	**Peak**	**1 year**	**2 year**	**3 year**	**4 year**	**5 year**	**10 year**	**Steady State**
500	44.5	39.6	36.4	34.4	33.2	32.2	29.4	21.1
1000	87.9	57.6	49.6	45.7	43.2	41.4	36.8	27.3
1160	100.4	61.2	52.1	47.8	44.7	43.1	37.9	27.9
1300	111.5	63.3	53.5	49.0	46.0	44.0	38.8	27.9

4.1 To the Project Objective: Determining Maximum Practicable Output by the System

The simple approach to maximizing both peak and long term output, and therefore financial returns, is by full out operation of the system. The resulting 110 MWt early production and 20 year 50 MWt average are world class for geothermal output, the latter output still some 4.5X higher than mean hydrothermal production worldwide. The DGS method's demonstration of higher end hydrothermal economic qualities, but in a highly repeatable and ubiquitous HDR form, reduces the DGS per-MW CAPEX and OPEX to a most economic power source status. System performance was analyzed with reasonable input assumptions and was conducted without the need of parasitic injection and cooling loads.

4.2 The Requirements for Meaningful Geothermal Energy Production

Achieving 100+ MWt baseload power from HDR requires upper to extreme level inputs in all respects:

4.2.1 System Massiveness

Exceptional drill depths to some 10 km – first accesses exceptional heat, with DGS production starting temperature of 160^{o}C, progressing to nearly 500^{o}C. The producing interval's height, in excess of 7 km, allows the optimal count of 15 reservoirs, 330m heat replenishing reservoir separation, and extraction from 6 km of cased hole and openhole intervals as augmenting heat contribution. Ever increasing depth furthermore also improves rock uniformity and predictability. Per well rock surface area totals 550 hectares. The lower heating interval volume is comprised of 4.67 km^3, the neutral/heat maintaining upper interval is 1.7 km^3.

System fluid volume, driven by depth X maximized fracture dimensions X high porosity proppant X large well diameter = 14,150m^3. Per cycle circulation time is 45+ hours. If considered as energy storage, each well holds 111 MWt for a minimum 45 hours and >100 MWt for 3.4 months.

The viability of geothermal as a significant power source is reliant on duplicating and enhancing such threshold level mass energy.

4.2.2 Gradual Heating

An extended benefit of massive production area and long circulation times is the capability of conservative extraction locally, i.e., low incremental heat addition for the purpose of longer term sustainability. Closely matching inlet fluid and rock temperatures can be optimized to provide two+ decades long high level output before entering steady-state status. The relative fluid-to-rock temperature indicated by CFD-CHT ranges from 1.6% inlet fluid to rock differential early in the heat transfer process, to only 3.5% differential at the ending highest temperatures.

4.2.3 Low Velocity / High Circulation Rate Heat Transferring Fluid Flows

Analyses revealed that doubling fracture volume increases per stage added heat by 60%. A roughly optimal and practicable .152 m/s (.499 ft/s) was determined, producing similar output even though the circulation rate varied as much as thirty percent (shown in **Figure-9**). Although fracture volume could practically be augmented by 20% by increasing its height, such refinement was not performed.

4.2.4 Thermo-Hydraulic Sweep Effectiveness

Orders more efficacy over traditional EGS capability is needed, to levels approaching 100% rock coverage, flow uniformity, and continuity of operation. A corresponding degree of discrete level flow control is also needed, including tuning of perforation diameter, quantity, and placement capabilities indicated by the DGS.

4.2.5 Heat Preservation

Is high in impact, both during and subsequent to the heating process. Insulated vs. uninsulated lower area production tubing eliminated approximately 90% of heat losses, or some 6.5% of overall output. A rough order calculation for the upper interval's tubing and casing insulative contributions amount to an additional 30% in potential loss.

4.2.6 Integrated Contributions and a Contrary Finding

The design's substantial length also provides 5900m (19,350') of cased hole and 1220m (4000') openhole well sections (as AGS) that add heat on the order of 11% overall. Although any addition is welcomed, it must be able to contribute long-term. Because of AGS's limited heating area, it effectively cools much faster than do the fracture components. Consequently, heat may actually lost through the AGS-well sections in the same manner describing tubing and surface casing losses above. Although AGS developers seek to amplify well materials conduction, such development is counter-productive over the long term here, a contrary finding.

5. APPLICATION AS SEASONAL ENERGY STORAGE

With BESS and similar devices most commonly providing service for 4 – 8 hours, calls for increased energy storage longevity are endless, evolving well beyond hours or even days, to seasonal levels. Although primarily intended as a clean power source, the indicated DGS output and economic attributes show attractiveness for use also in green H_2 production, gas decarbonization, CCS, and as a multi-month baseload energy storage method.

Extension of the modeling's data at 1300 GPM circulation indicate that the high early output of the DGS design can be utilized to operate at an average 30 MWe flash conversion baseload output level for three months. Thermal recovery to very nearly to original peak rock temperatures occurs over the next nine months to timely recommence subsequent seasons. Referring again to **Figure-9**, production temperatures are shown across various circulation rates over ten years. Plot' congestion is seen in the first half of Year-1 as most circulation regimes maintain exceptional thermal levels, although while declining rapidly. Seen are the 1000 – 1300 GPM scenarios maintaining average of 500^{o}F as the period's lower end production temperature through the first year of operation.

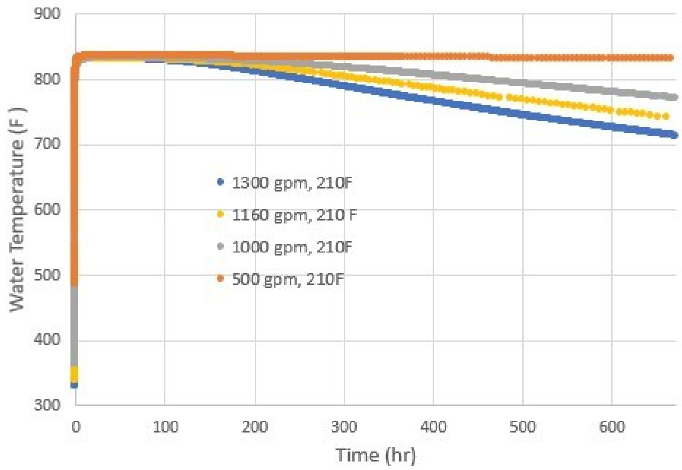

Figure 10: 29-day model decline detail of water temperature.

A more detailed, 29-day baseload water temperature graphic is shown as **Figure-10**, indicating initial decline behavior. From these and other model data, a variety of three-month performance curves were generated (**Figure-11**). The system's early and recovered production temperatures are found applicable for corresponding seasonal power output. The study's optimal 1300 GPM circulating rate, as seen in Figure-11, shows conditions for an average 29.5 MWe production through three months, totaling 62,730 MWh per well. Connecting four wells' production as a 70 MW to 100 MW production facility yields 250,920 MWh seasonal output, an amount exceeding the paper's original titular intent.

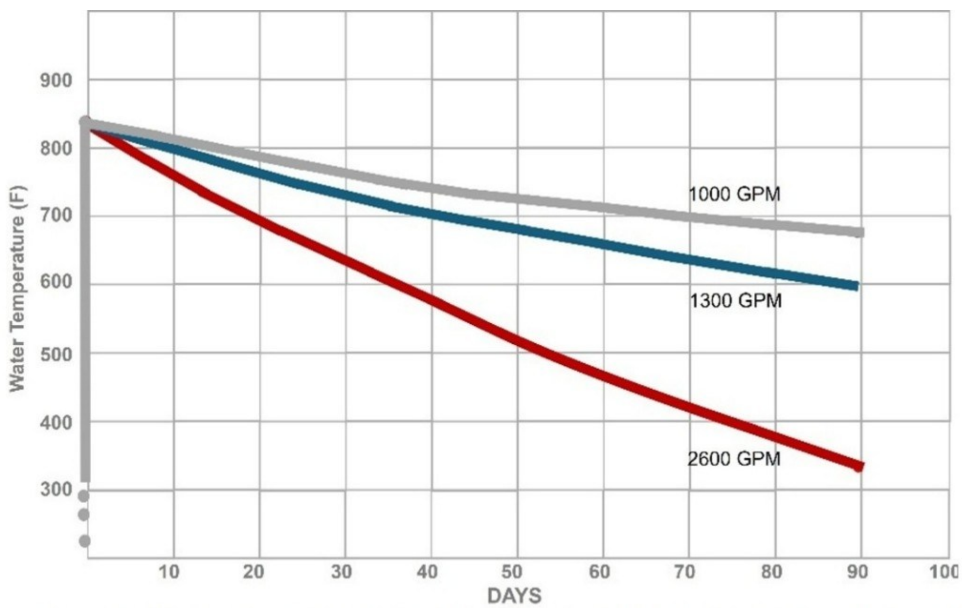

Figure 11: 90-day plots of model's water temperature at 1000 and 1300 GPM. The 2600 GPM curve is per extension.

Figure-12 shows a nine-month shutdown and recovery period returning 92% – 97% of the original rock T, as driven only by well spacing and rudimentary traditional EGS efficiencies. Repeating the Section 3.1 comments regarding the critical heat replenishment function of substantial spacing per se, a 5.5% difference in recovery is shown, a significant amount when considering decline economics year over year.

Subsequently, incorporation of the DGS' effective 4.67km^3 rock volume, considered exceptionally large, refined and elevated the results to 98.5% for the upper case, 96.4% for the base case, 93.3%, in the small volume-recovery case (**Figure-13**).

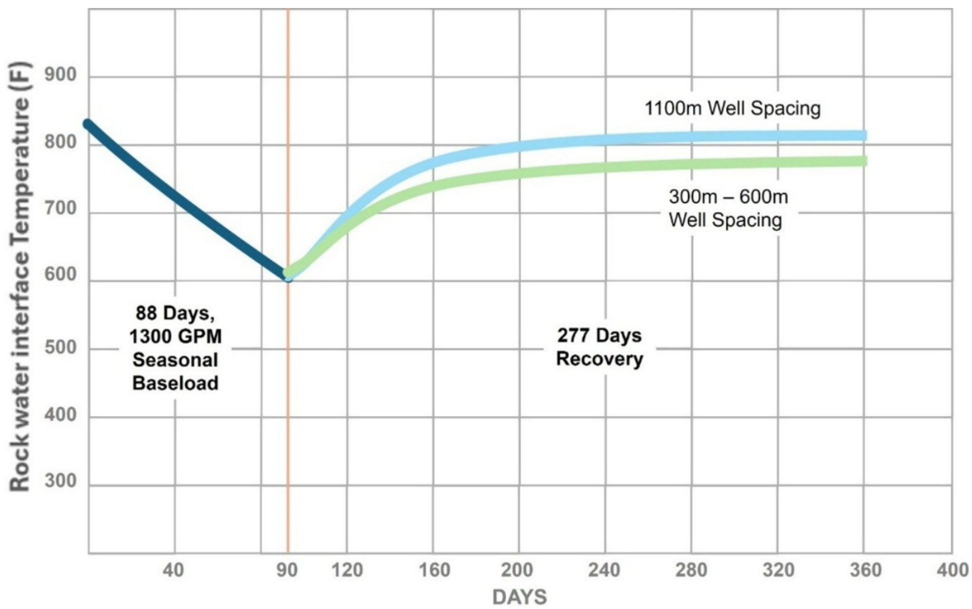

Figure 12: Rock-water thermal recovery to 92% and 97% based on EGS type well spacing.

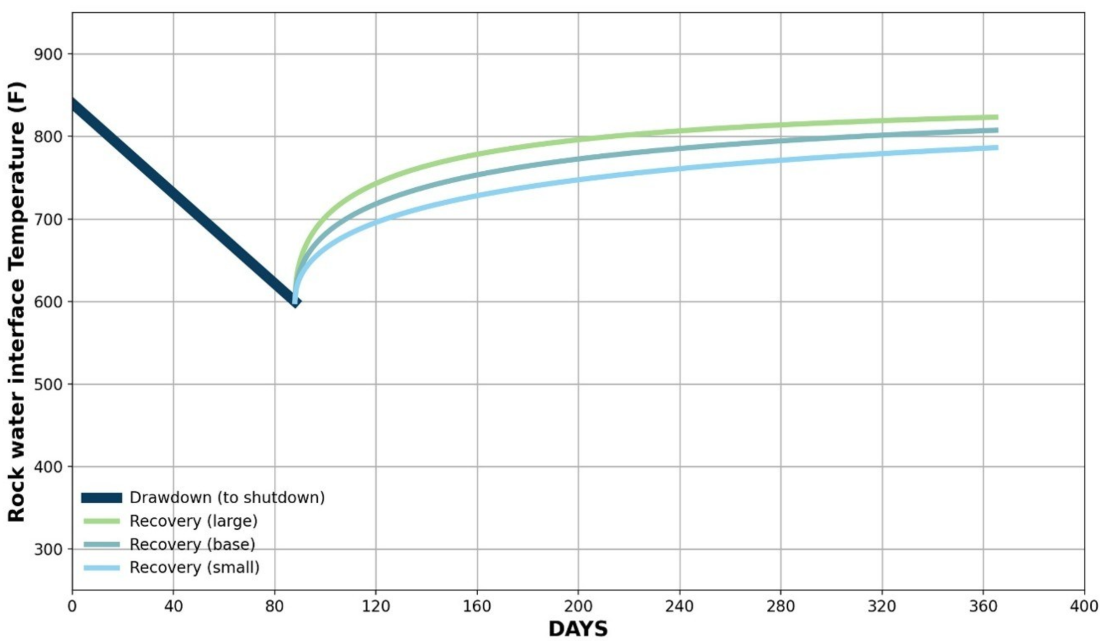

Figure 13: 1300 GPM, 30 MWe 88-day baseload seasonal rock-water interface temperature levels with offseason recovery ranging 93% to 98.5% upon adding 4.67 km3 effective DGS rock volume.

4.1 Seasonal Storage Summary

Section outlines two areas:

Technical Outline

- A four well DGS production installation is shown capable of producing in excess of 250,000 seasonal MWh
- The core of unconventional geothermic heat extraction and recovery is in terms of 100's of meters spacing per se
    - Fracture spacing
    - Well spacing
        - Massive rock volume is tantamount to extensive well spacing
- 12.5% higher water-rockface recovery efficiencies were seen over conventional EGS models, owing to augmented fracture spacing
- Extensive spacing requirements related to thermal recovery transcend four-well production facility designs, with preference towards single or paired e.g., 30 MW installations.

- The effective 4.67km^3 DGS' rock volume is among the highest normally calculated in the space
- Extensive spacing related heat replenishment both extends thermal decline schedules (to potentially 2% annually vs. 45% first year), while augmenting prospective stored energy based revenues.
- No output level optimization has been performed

Pragmatic & Economic

- Three months, 30 MWe baseload per well viability
- The DGS storage energy is internally generated and without parasitic loads
- There are no storage or efficiency losses, excepting some possible water leakoff
- Actual cost is baseload based at $3k/kw vs. four to eight hour partial $1k/1kw, actual = X 6 or X 3
- Mean seasonal power pricing may equal yearly revenues, halve labor cost

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