Proceedings World Geothermal Congress 2026
Calgary, Canada, June 8 – 11, 2026

Optimizing EGS Well Development Strategies for Reservoir Temperature Decline Sensitivities

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Keywords: development planning, EGS, techno-economic sensitivity

INTRODUCTION

Enhanced Geothermal Systems (EGS) have the potential to deliver scalable, low-carbon, baseload electricity by harnessing heat from hot dry rock formations. Despite significant advances in drilling and stimulation technologies, the economic viability of EGS projects remains strongly dependent on the subsurface performance and the strategies employed for long-term field development. A critical challenge lies in managing thermal decline within the reservoir while maintaining sufficient plant utilization and minimizing the number of high-cost wells. This study introduces a development optimization workflow that addresses these challenges during the early phases of project evaluation.

1 BACKGROUND

The thermal energy available from a geothermal production well is controlled by two fundamental parameters: the flowing temperature of the produced fluid and the volumetric flowrate delivered to the surface. These variables combine to define the enthalpy content of the brine at the wellhead, which in turn determines how much energy can be transferred to a binary Organic Rankine Cycle (ORC) power plant. Figure 1 illustrates this relationship, showing thermal power output as a function of both flowrate and temperature. At high temperatures, relatively modest flowrates can sustain multi-megawatt output, whereas at lower temperatures, disproportionately higher flowrates are required to achieve the same energy delivery.

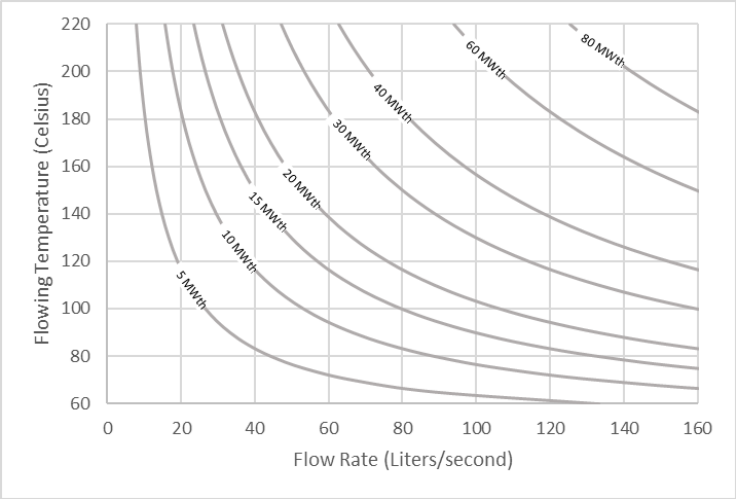


Figure 1. Example relationship between flowing temperature, flowrate, and thermal power output for a geothermal production well. As reservoir temperatures cool, higher flowrates are required to maintain equivalent thermal delivery to the ORC.

This relationship has direct implications for long-term field management. As reservoir temperatures decline over time, sustaining power output requires progressively greater pumping rates. However, increasing flowrates accelerates thermal drawdown and raises parasitic pumping demands, eroding project economics. One mitigation strategy is to reduce flowrates proactively as reservoir temperatures decline. By reducing production, the energy density of the produced brine is preserved, slowing the rate of cooling and extending the productive life of the reservoir. Figure 2 shows an example relationship of flowrate and thermal decline.

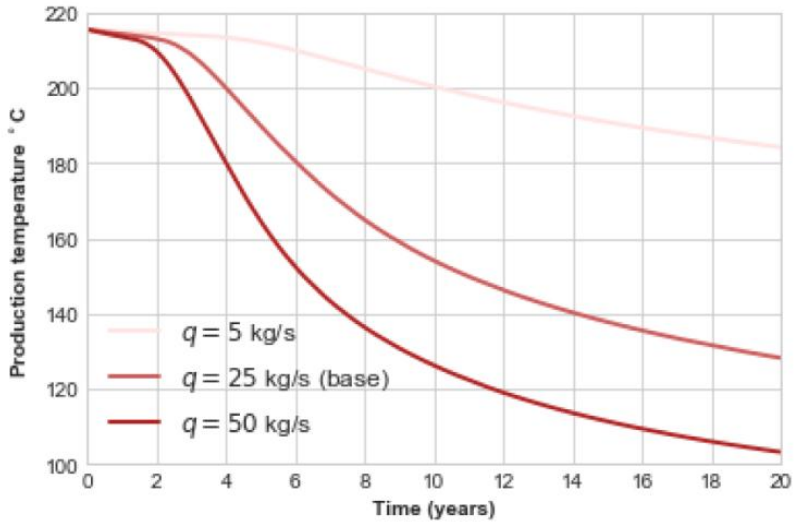


Figure 2. Example modelled temperature decline curve for various flow rates (from Janiga et al, 2022).

In a development scenario, multiple production wells contribute simultaneously to the ORC plant. The mixed stream delivered to the facility represents a blend of individual well contributions. If one or more wells are producing relatively cold fluid, the combined temperature drops, reducing the thermodynamic efficiency of the ORC conversion cycle. Because ORC efficiency is temperature dependent, maintaining a high blended production temperature is critical for maximizing electricity output per unit of thermal energy extracted.

For early phase EGS projects that are establishing scenarios for drilling costs and net power production, thermal decline type curves and flowrate decline management assumptions can be used to optimize the drilling schedule for a target plant capacity. The considerations of balancing flowrate, reservoir cooling, and plant utilization provide a framework to explore trade-offs between drilling costs and power production.

2 METHODOLOGY

The workflow utilizes thermal decline type curves with flowrate adjustments and well scheduling to optimize system design for a binary Organic Rankine Cycle (ORC) power plant. The central objective is to maintain high plant capacity utilization by maximizing the blended production temperature and minimizing total system flowrate supplied to the plant. As reservoir temperatures decline, individual well flowrates can be reduced in order to preserve produced energy density, slow thermal drawdown, and extend well life (Figure 3). Key system constraints, such as maximum and minimum bounds on total flowrates, can be explicitly incorporated to ensure realistic operational strategies.

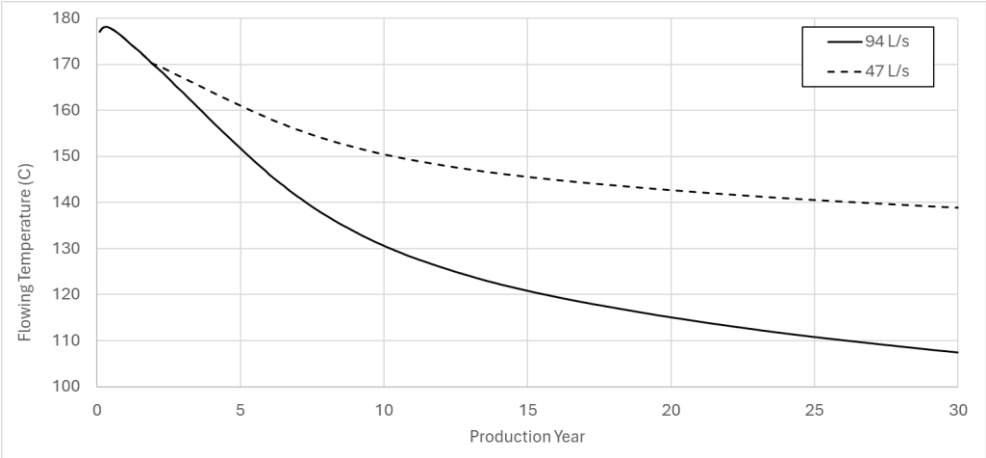


Figure 3. The temperature decline for an individual production can be adjusted by scaling the drawdown relative to the reduction in flowrate. This example shows temperature decline for a constant flowrate of 94 L/s (i.e. type curve) and the modified temperature decline when the flowrate is reduced to 47 L/s after 2 years of production.

Starting from the type well depletion curve with a constant flowrate, wells are added to the drilling schedule and flowrates are adjusted to keep the plant at maximum production capacity. New wells can be added to the drilling schedule as the flowing temperature declines and the associated power production also decreases. As individual wells continue to cool or reach an assumed lifetime, they are taken offline. This dynamic control methodology draws inspiration from shale gas development practices, particularly the "fill-to-spill" strategy, where staggered well activation maximizes long-term recovery. Similarly, the proposed EGS framework allows phased well activation and proactive flowrate adjustments, linking reservoir depletion assumptions with economic outcomes.

3 RESULTS

Production optimization through flowrate adjustments is demonstrated for a test development case using a constant flowrate of 94 L/s versus adjusting the flowrates in order to mitigate rapid temperature decline. The minimum flowrate used was 15 L/s and the well life was assumed to be 10-12 years. Figure 4 demonstrates how adjusting the flowrates on a well-by-well basis over the production life of the well stabilizes the total flowrates and blended temperature.

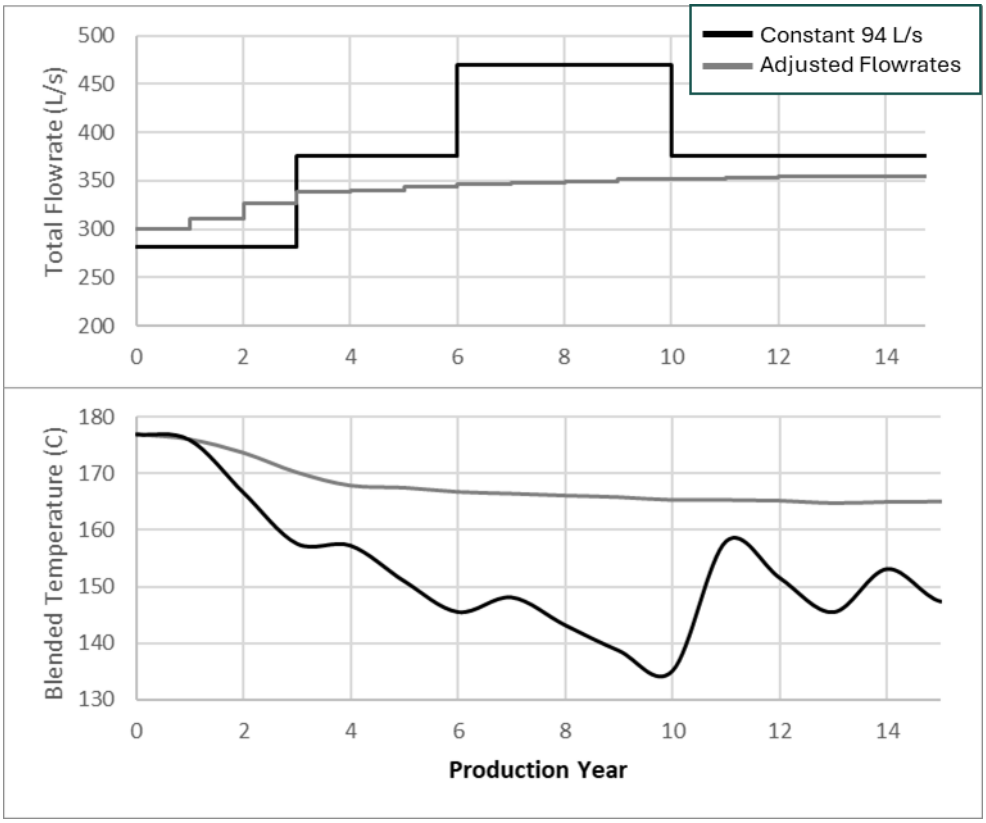


Figure 4. A comparison of the total flowrate (top) and blended temperature (bottom) for a constant flowrate of 94 L/s versus adjusted flowrates.

The thermal power generation potential depends jointly on the produced temperature and flowrate. Assuming a pentane working fluid in the binary ORC system, the gross power generation can be estimated. For this test case, the plant capacity is set at 25 MWe for gross generation. The parasitic load for pumping can be calculated by multiplying the total flowrate by an assumed constant pumping head pressure divided by pump power efficiency. For this case, a constant 125 Bar of pumping head pressure and a 67% pump power efficiency are assumed. The resulting gross electrical power generated and net power available for the market after subtracting pumping parasitic losses can be compared for the production strategies described above. Figure 5 highlights how dynamic flowrate reduction mitigates parasitic pumping losses, preserve thermal output, and improve overall net power available for revenue generation.

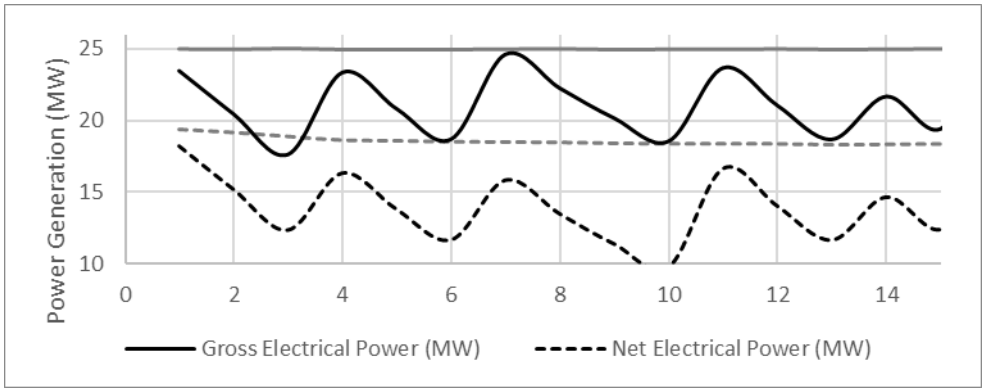


Figure 5. A comparison of the total gross power generation and net power available for market for the constant flowrate case (black) and the flowrate adjusted case (grey).

Optimizing the net power generation is achieved not only by flowrate and temperature optimization, but also by the well schedule. New wells need to be brought online to boost the blended fluid temperature. A surprising effect of reducing the well flowrates to optimize net power production is that more wells will need to be drilled. Figure shows the total number of production wells that are brought online and the number of active production wells. The scenario for flowrate adjustment results in a steady increase in the number of wells and requires over 2 times as many wells as the constant flowrate scenario. The implication of more wells is more capital cost which needs to be evaluated versus the increased revenue of the optimized generation.

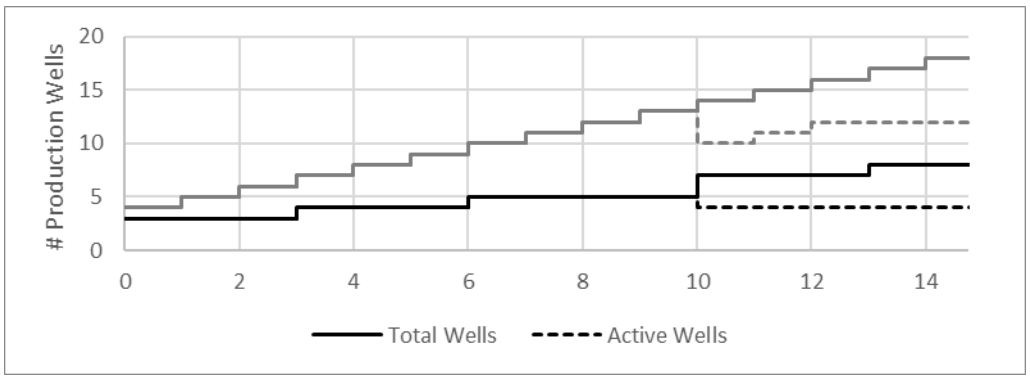


Figure 6. A comparison of the drilling schedules for the two scenarios demonstrates how optimizing the power production can impact the drilling requirements. The flowrate adjusted scenario (grey) requires over twice as many total wells after 7 years of production.

4 IMPLICATIONS AND CONCLUSIONS

The presented workflow provides a practical and adaptable framework for optimizing EGS development strategies during early-stage feasibility and long-term planning. By explicitly coupling reservoir temperature decline with flow-rate control and drilling schedule optimization, the approach captures the thermodynamic and economic trade-offs inherent in managing an evolving geothermal reservoir.

Results from the test scenario demonstrate that dynamic flow-rate reduction can meaningfully improve the net power output of an ORC facility by limiting parasitic pumping losses and preserving higher produced temperatures. However, this benefit is offset by the requirement for increased well count to sustain overall plant capacity. The resulting balance between reduced operating costs and higher capital expenditures underscores the importance of integrated techno-economic analysis early in project design.

Beyond individual case studies, the methodology supports scenario-based decision-making by allowing rapid testing of multiple thermal decline profiles and operational constraints. This enables project developers to evaluate the sensitivity of financial outcomes to reservoir performance assumptions and to design adaptive drilling and flow-control strategies that respond to observed temperature trends during operation.

In practice, this approach can be extended to incorporate real-time production monitoring and predictive control, providing a pathway toward closed-loop optimization of geothermal field performance. By linking

subsurface thermodynamics, surface plant efficiency, and economic planning, the workflow contributes to de-risking EGS developments and advancing them toward reliable commercial baseload deployment.

Acknowledgements

The author would like to thank valuable input from George Brindle on the methodology and flowrate optimization.

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Janiga, D., Kwaśnik, J., and Wojnarowski, P.: Utilization of discrete fracture network (DFN) in modelling and simulation of a horizontal well-doublet enhanced geothermal system (EGS) with sensitivity analysis of key production parameters, *Energies,* **15**(23), (2022), 9020.

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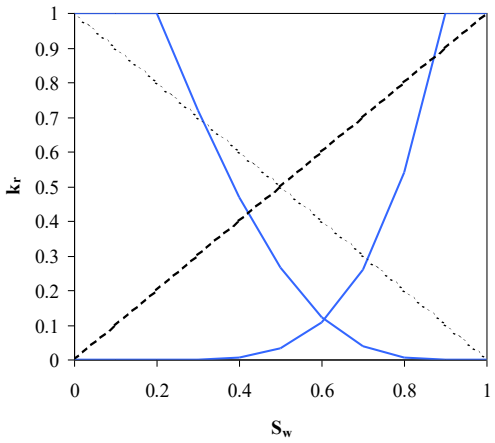


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