The Role of Flexible Geothermal Power in Decarbonized Electricity Systems[*]

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Abstract

Enhanced geothermal systems (EGS) are an emerging energy technology with the potential to significantly expand the viable resource base for geothermal power generation. Although EGS has traditionally been envisioned as a 'baseload' resource, flexible operation of EGS wellfields could allow these plants to provide load-following generation and long-duration energy storage. In this work we evaluate the impact of operational flexibility on the long-run system value and deployment potential of EGS power in the western United States. We find that load-following generation and in-reservoir energy storage enhance the role of EGS power in least-cost decarbonized electricity systems, increasing optimal geothermal penetration and significantly reducing bulk electricity supply costs compared to systems with inflexible EGS or no EGS. Flexible geothermal plants displace the most expensive competing resources by shifting their generation on diurnal and seasonal timescales, with round-trip energy storage efficiencies of 81-98%. Benefits of EGS flexibility are robust across a range of electricity market and geothermal technology development scenarios.

Keywords: geothermal energy, macro-energy systems, electricity decarbonization, clean firm energy resources, energy storage, capacity expansion modeling,

1 Main

Clean firm energy resources are critical for cost-effective decarbonization of electricity systems, and total system costs are minimized when multiple clean firm technologies are available [1–3]. Geothermal power is one of the few existing energy technologies in this category, and could thus play an important role in future zero-carbon electricity systems. Unfortunately, conventional geothermal's reliance on rare, naturally-occurring hydrothermal reservoirs severely limits its future deployment potential. In the United States, where a significant portion of the high-quality hydrothermal resource has already been tapped, geothermal power makes up only 0.4% of annual electricity generation [4, 5].

Enhanced geothermal systems (EGS), which employ hydraulic stimulation to create artificial geothermal reservoirs in subsurface formations with low innate hydraulic permeability, have long been seen as a path to much larger-scale deployment of geothermal power [6, 7]. By eliminating the reliance on pre-existing hydrothermal reservoirs, EGS could unlock more than 5 TW of electric generating potential in the United States alone [4], nearly five times the total US generating capacity today. While it is likely that only a fraction of this total is economically viable, the massive resource potential offered by EGS could allow geothermal to play a meaningful role in electricity decarbonization.

Past studies of the potential role of geothermal power in future electricity systems have assumed that geothermal plants would operate as 'baseload' resources, generating at their maximum rated output at all times [2, 4, 7, 8]. This is the favored operating mode for most geothermal power plants today because these plants tend to have high fixed costs and near-zero variable costs, and derive few if any benefits from curtailing output [9]. However, as electricity systems continue to decarbonize through large-scale deployment of variable renewable energy resources (VREs), such as wind and solar power, the needs of these systems will shift away from traditional baseload resources toward more flexible alternatives [10–13]. In systems where demand in many hours of the year can be met cost-effectively with zero-marginal

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cost VREs, there is little economic incentive to pay high fixed costs for baseload generators that will only be needed when VRE supply is insufficient to meet demand.

In previous work, Ricks et al. [14] evaluated the potential for EGS power plants to adapt to this new market paradigm by adopting a flexible operating strategy. It was shown that a hydraulically-confined EGS reservoir can provide high-capacity energy storage by alternately accumulating and discharging pressurized geofluid within its engineered fracture network. This geomechanical in-reservoir energy storage (IRES) allows an EGS plant to time-shift its generation, producing less geofluid during times when there is a surplus of electricity in the grid and producing more when there is a shortfall. Flexible operation via IRES was shown to significantly improve the average value of a geothermal plant's energy in electricity systems with high VRE penetration. However, while this research demonstrated the value of flexibility for first-of-a-kind EGS power plants operating as price-takers, it did not capture the impact of this operating mode on operational dynamics or long-run technology deployment outcomes in the broader electricity system.

In the present work we expand on these previous modeling efforts by quantifying the impact of load-following generation and IRES on the value and deployment potential of geothermal power in future electricity systems under deep decarbonization. We use the GenX electricity system capacity expansion model [15, 16] to optimize investment and hourly operational decisions for electricity generation, storage, and transmission technologies at high temporal resolution (8760h) within an 11-zone representation of the US portion of the Western Interconnection, the synchronized grid serving all or part of 13 western US states (Supplementary Fig. 13). This methodology captures the declining marginal value of energy resources with increasing penetration and identifies least-cost equilibrium system configurations and operational profiles. It is therefore suitable for analyzing the long-run system impacts of EGS deployment and the relative benefits of operational flexibility.

We develop novel supply curves to represent the quality and availability of EGS resources across the western United States under multiple technology development scenarios (Table 1a and Extended Data Figure 1) using performance results from numerical reservoir simulations and existing temperature-at-depth and system component cost data from the literature [17–20]. We account for the substantial effect of local ambient temperature variability on air-cooled geothermal power plant conversion efficiency via a set of hourly capacity factor time series derived from historical weather data [21, 22], making this paper the first macro-energy systems study to model geothermal weather dependence. Finally, we model IRES at EGS power plants under multiple reservoir performance scenarios (Table 1b) using a novel set of linear constraints derived from numerical simulations of flexible reservoir operations. This model representation of IRES, first developed in previous work [14], has been adapted and expanded for inclusion in the GenX electricity system planning framework. It captures the complex relationship between EGS reservoir pressure and well flow rates, including the effects of wellbore friction, geomechanical fracture deformation, and variations in reservoir temperature, depth, and fracture network properties, and enables optimization of geothermal power plant operations at hourly intervals. Investments in individual plant components including the wellfield, power block, injection pumps, grid interconnection, and surface storage for excess geofluid are also independently co-optimized. Figure 1 illustrates the basic model structure. Costing and modeling methodologies are described further in the Methods section and the SI.

We assess the benefits of flexible operation across a set of EGS market opportunity cases representing a range of development scenarios for competing energy technologies (Table 1c) [23]. All modeled scenarios represent fully decarbonized electricity systems in the year 2045. We assess the impact of including EGS in the available resource mix, both as a traditional baseload generator and with flexible operations enabled. We analyze combinations of electricity market opportunity and EGS performance scenarios to quantify and bound the impact of load-following generation and IRES on major outcomes, including technology deployment levels, operational profiles, and total system costs. We futher explore the role and performance of both flexible and inflexible EGS in decarbonized electricity systems and identify primary value drivers for each.

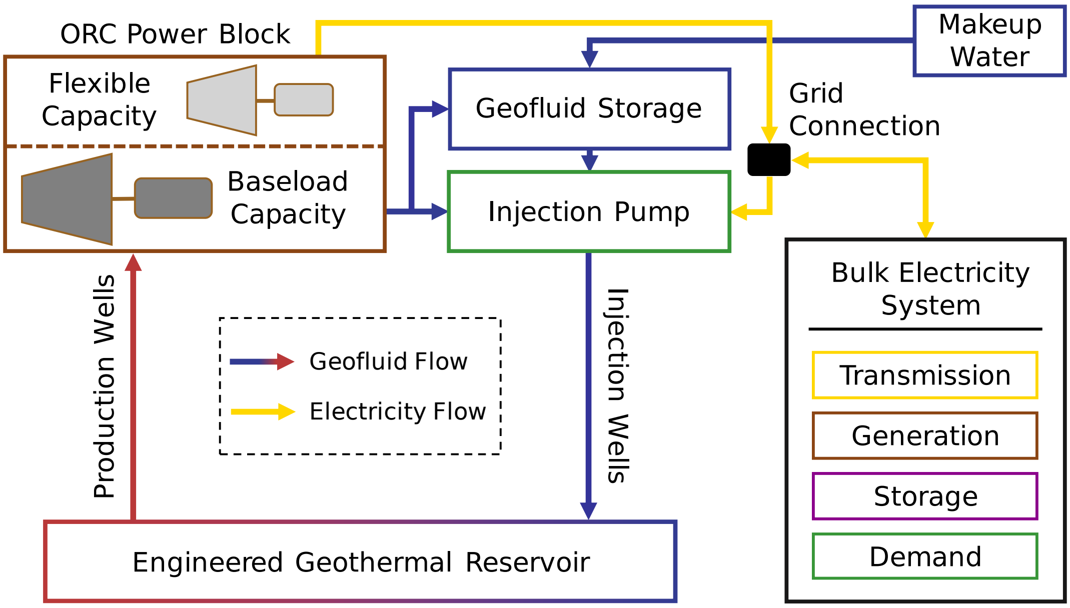

Figure 1: Schematic diagram of the flexible EGS optimization model. EGS power plant investments and operations are optimized in tandem with other bulk electricity system components in GenX.

a. Geothermal Drilling

Case	Rate of Penetration (m/hr)	Well Casing Program	Maximum Reservoir Temperature (°C)
Baseline	15.24	Conventional	250
Advanced	22.86	Mono-bore	325

b. Reservoir Performance

Case	Horizontal Matrix Permeability (m^2)	Vertical Matrix Permeability (m^2)	Fracture Conductivity (m^3)
Low	1.0×10^{-19}	2.0×10^{-20}	2.3×10^{-13}
Mid	1.0×10^{-17}	2.0×10^{-18}	4.5×10^{-13}
High	1.0×10^{-15}	2.0×10^{-16}	9.0×10^{-13}

c. Geothermal Market Opportunity

Case	Solar CAPEX (\$/kW)	Onshore Wind CAPEX (\$/kW)	Offshore Wind CAPEX (\$/kW)	LI Battery CAPEX (\$/kW)/(\$/kWh)	Metal-Air Battery CAPEX (\$/kW)/(\$/kWh)	Nuclear CAPEX (\$/kW)	Natural Gas Fuel Cost (\$/GJ)	Zero-Carbon Fuel Cost (\$/GJ)	Flexible Demand (% of EV Charging)/ (% of Residential Heating)
Low	575	630	4378	91/97	800/8	4311	3.52	10.14	90/20
Mid	721	874	4476	191/129	1200/12	6468	4.45	15.20	75/10
High	721	874	4476	191/129	2000/20	9702	7.51	22.81	60/0

Table 1: Major parametric variations across modeled geothermal drilling (top), reservoir performance (middle), and geothermal market opportunity (bottom) cases. Note: CAPEX refers to total capital expenditures per unit of installed ac electric generating capacity.

1.1 EGS Deployment Potential

We find that the ability to operate flexibly has a significant impact on geothermal deployment potential in the Western Interconnection. Figure 2 shows optimal installed capacities for flexible and inflexible EGS power in fully decarbonized electricity systems under a range of market opportunity, reservoir performance, and geothermal drilling scenarios. In cases with flexibility enabled we distinguish between 'baseload' EGS capacity, the capacity of a plant's power block when sized to match its wellfield's steady-state flow rate, and 'flexible capacity,' any additional power block capacity deployed to exploit temporarily elevated production flow rates. Baseload capacity effectively represents the total subsurface resource developed in a given scenario, and its modeled cost is inclusive of wellfield and reservoir development. Flexible capacity can be added at a significantly lower cost, and its relative sizing varies across scenarios. Supplementary Figs. 1 and 2 illustrate trends in optimal sizing of flexible capacity and other plant components.

Total installed EGS capacity ranges from 0-115 GW (0-36% of peak system load) across the scenarios shown in Figure 2 and is always greater with flexibility enabled (23-115 GW with flexible operation vs 0-96 GW without). In scenarios where geothermal drilling does not advance from the current state-of-the-art (e.g., 'Baseline Drilling'), we find that market entry for inflexible EGS is contingent on the failure of competing energy technologies to achieve advanced development targets (i.e., 'Mid' and 'High' geothermal market opportunity cases). In contrast, flexible operation enables deployment of EGS with baseline drilling even in 'Low' market opportunity scenarios and more than doubles optimal EGS capacity in other Baseline Drilling scenarios. Development of advanced drilling technologies enables both inflexible and flexible EGS to achieve significant deployment, meeting up to 45% of total annual electricity demand (Supplementary Fig. 3), and flexible operation further increases EGS capacity in all such cases. In some Advanced Drilling scenarios, flexibility leads to greater total EGS capacity but reduced baseload capacity and generation. This phenomenon is discussed further in Section 1.3.

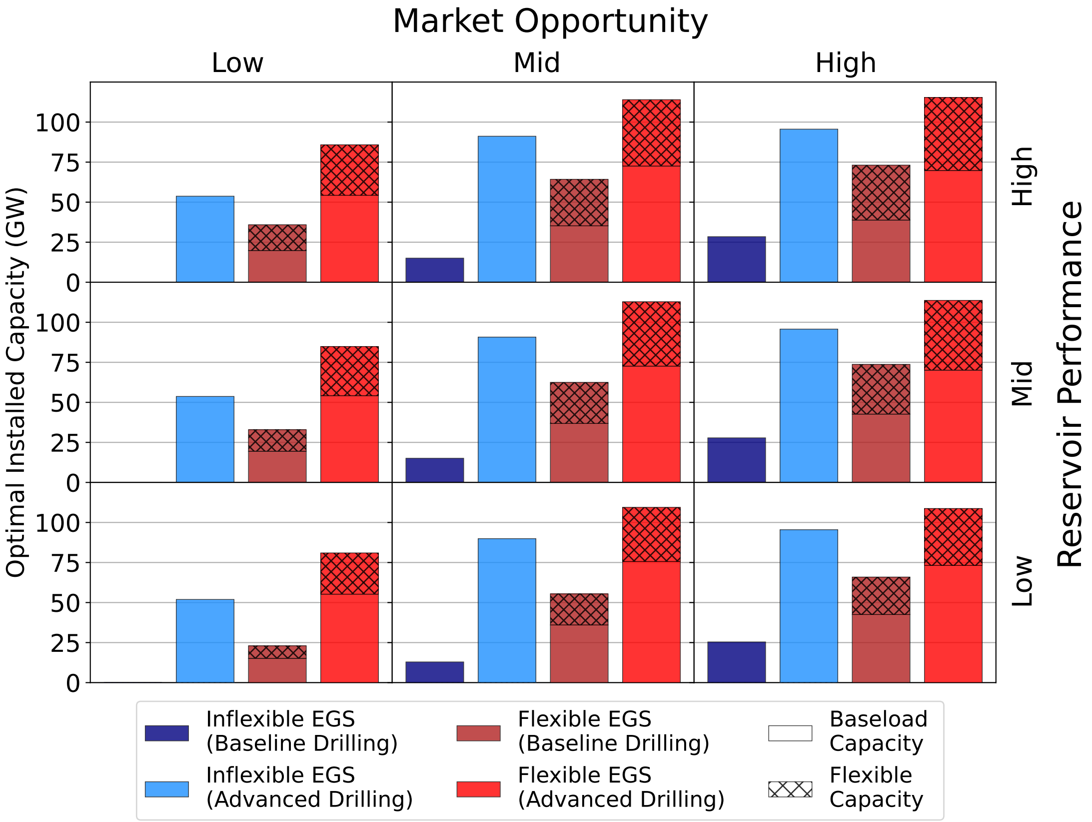

Figure 2: Optimal installed capacities for EGS power in the Western Interconnection under a range of scenarios combining EGS market opportunity, reservoir performance, drilling, and flexibility cases. Nameplate EGS capacity is equivalent to surface plant net generating capacity at the local average ambient temperature. Peak system load is 316 GW.

Comparison of optimal capacities for both flexible and inflexible EGS across modeled scenarios suggests that geothermal deployment is much more sensitive to economic conditions than to variations in reservoir performance. Optimal EGS deployment for otherwise identical cases varies by more than 25 GW between the low and high market opportunity scenarios, and to an even greater degree between baseline and advanced drilling scenarios. Uncertainties in the future cost of EGS and competing technologies thus lead to a wide range of possible outcomes. By contrast, changes in reservoir performance have minimal effect on optimal capacities for inflexible EGS. Optimal capacity for flexible plants increases only marginally with increasing reservoir performance. This is despite a difference of four orders of magnitude in matrix permeability, which was found in Ricks et al. [14] to be the strongest site-specific determinant of IRES performance, between the low and high reservoir performance cases. Although matrix permeability at depth can be highly variable and is not well characterized in most potential EGS target formations in the United States [24], this result suggests that such variability is unlikely to have a large effect on EGS deployments regardless of flexible status.

1.2 Electricity System Costs

Figure 3 shows the difference in total electricity system costs between optimized electricity systems with and without EGS available for the same scenarios illustrated in Figure 2. Modeled costs reflect total annualized generation and storage costs and costs for new transmission, but exclude recovery of currently existing transmission costs as well as distribution network and retailing costs, which are all unaffected by the deployment of EGS. The measured cost reduction can thus be interpreted as the net system value delivered by EGS at its optimal deployment level. We find that system cost reductions from EGS deployment are much greater when flexibility is enabled, and that this advantage is persistent across the range of modeled scenarios. In scenarios where some amount of inflexible EGS is deployed, enabling flexibility reduces total system costs by a further 5-10 percentage points. System value benefits from enabling flexible operations are comparable to those unlocked by achieving advanced geothermal drilling.

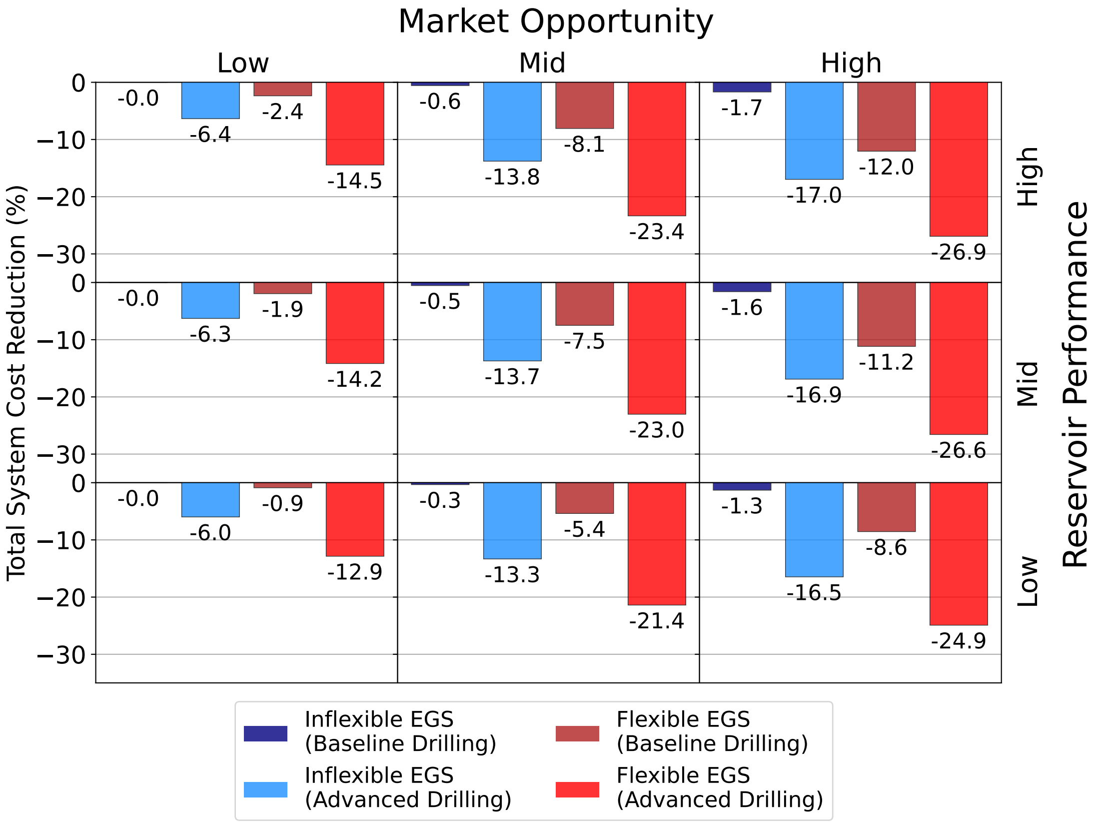

Figure 3: System cost reductions due to EGS deployment for the same set of scenarios shown in Figure 2. Reductions are given with respect to systems without EGS available.

As with EGS capacities, we find that the system cost reductions shown in Figure 3 depend more strongly on economic factors than on EGS reservoir performance. We do however observe that the relative impact of flexibility is moderately greater in scenarios with higher reservoir performance. Although changes in fracture conductivity affect both inflexible and flexible EGS by reducing or increasing parasitic injection pumping load, flexible plants are much more strongly affected by changes in reservoir matrix permeability. In cases with higher reservoir performance, greater matrix permeability enables more fluid to be held in the reservoir at a given time and increases the effective IRES duration. Better reservoir performance thereby increases the value of flexible EGS despite having little impact on optimal capacity.

1.3 System Configurations and Sources of Value

We find that the ability to operate flexibly enables EGS power to play a much more dynamic role in system operations and leads to notable changes in the optimal electricity resource portfolio. Figure 4 shows optimal capacity mixes, annual energy supply mixes, and system costs for fixed EGS baseload capacities between 0 and 160 GW. Scenarios assume mid-case market opportunity and reservoir performance, and advanced geothermal drilling. Supplementary Fig. 4 shows similar results for systems with baseline geothermal drilling and fixed EGS baseload capacities between 0 and 80 GW. Figure 5 and Supplementary Fig. 6 show the spatial distribution of EGS deployments and displacements of competing technologies.

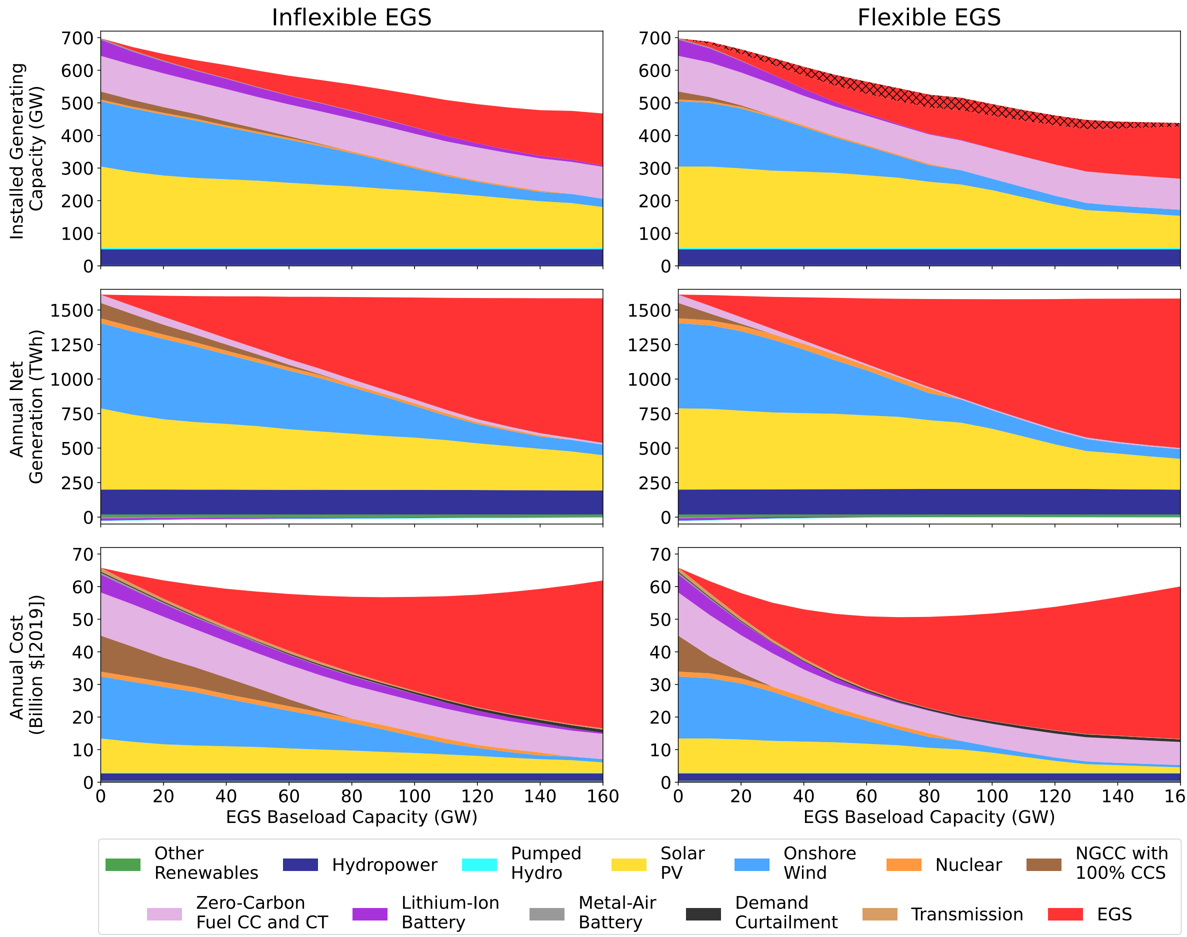

Figure 4: Optimal system configuration as a function of EGS baseload capacity, for EGS with advanced drilling. Charts show installed capacity (top), net generation (middle), and annual cost contribution (bottom) by technology for systems with inflexible (left) and flexible (right) EGS. Scenarios assume mid-case reservoir performance and market opportunity. Crosshatches indicate flexible EGS capacity.

Results in both cases suggest that inflexible EGS primarily displaces wind power in the capacity and energy mixes as its deployment increases. Solar power is also displaced, though at a slower rate. Wind and solar make up the bulk of energy supply and installed capacity in the baseline system, as well as the bulk of energy and capacity displaced by inflexible EGS, but account for a smaller relative share of total system costs due to their relatively low capital costs. Much of the system value of inflexible EGS instead comes from displacement of competing clean firm resources, primarily load-following natural gas plants with carbon capture and storage (CCS), which account for a smaller portion of total energy and capacity but have significantly higher costs than VREs. For this reason EGS is first deployed near coastal load zones with lower VRE potential and greater need for clean firm resources, despite the existence of lower-cost EGS resources in other regions (Figure 5). Although no new nuclear power is deployed in the systems shown here, alternate scenarios shown in Supplementary Fig. 5 indicate that inflexible EGS competes most strongly with baseload nuclear when the latter is cost competitive. Inflexible EGS does not rapidly displace battery energy storage or zero-carbon fuel (ZCF) peaker plants. Battery energy storage helps balance diurnal variability in wind and solar production and demand, while ZCF peakers have high variable costs and low capital costs, making them well suited to infrequent operation and complementary to the high capital cost and near-zero operating costs of inflexible EGS [2].

Enabling flexibility with IRES allows EGS plants to more rapidly displace competing clean firm generators, wind power, and energy storage. Accelerated displacement of ZCF generation and lithium-ion battery capacity suggests that flexible EGS, unlike its inflexible counterpart, can also fill the niche of a peaker plant and provide diurnal energy balancing. Despite displacing generation from ZCF peakers, installed ZCF capacity remains relatively constant in all cases even with EGS flexibility enabled, as these low capital cost plants are the cheapest means of meeting system capacity reserve margin requirements (i.e. functioning as 'standby' generators in case of forced generation or transmission outages or and uncharacteristically high demand). Notably, deployment of flexible EGS at baseload capacities up to 80 GW displaces very little solar power in the system. Flexible EGS can even increase the optimal solar penetration when it displaces nuclear power (Supplementary Fig. 5). This complementary relationship is discussed further in Section 1.4.

In general, flexibility adds system value by enabling EGS to efficiently replace the most expensive competing resources first. Whereas roughly 80 GW of inflexible EGS is required to fully displace natural gas plants with carbon capture in the system, this same displacement can be accomplished by only 30 GW of flexible EGS. In cases with baseline drilling where EGS has high costs, the added value from flexibility leads to a larger optimal EGS capacity (Supplementary Fig. 4). The extra cost from additional baseload EGS capacity and flexible plant components is more than offset by reductions in non-EGS system costs. In cases with advanced drilling where EGS is less expensive, the optimal baseload EGS capacity is *lower* when flexibility is enabled. Here flexibility adds value by reducing the installed baseload EGS capacity and associated cost needed to displace competing firm generation and storage resources.

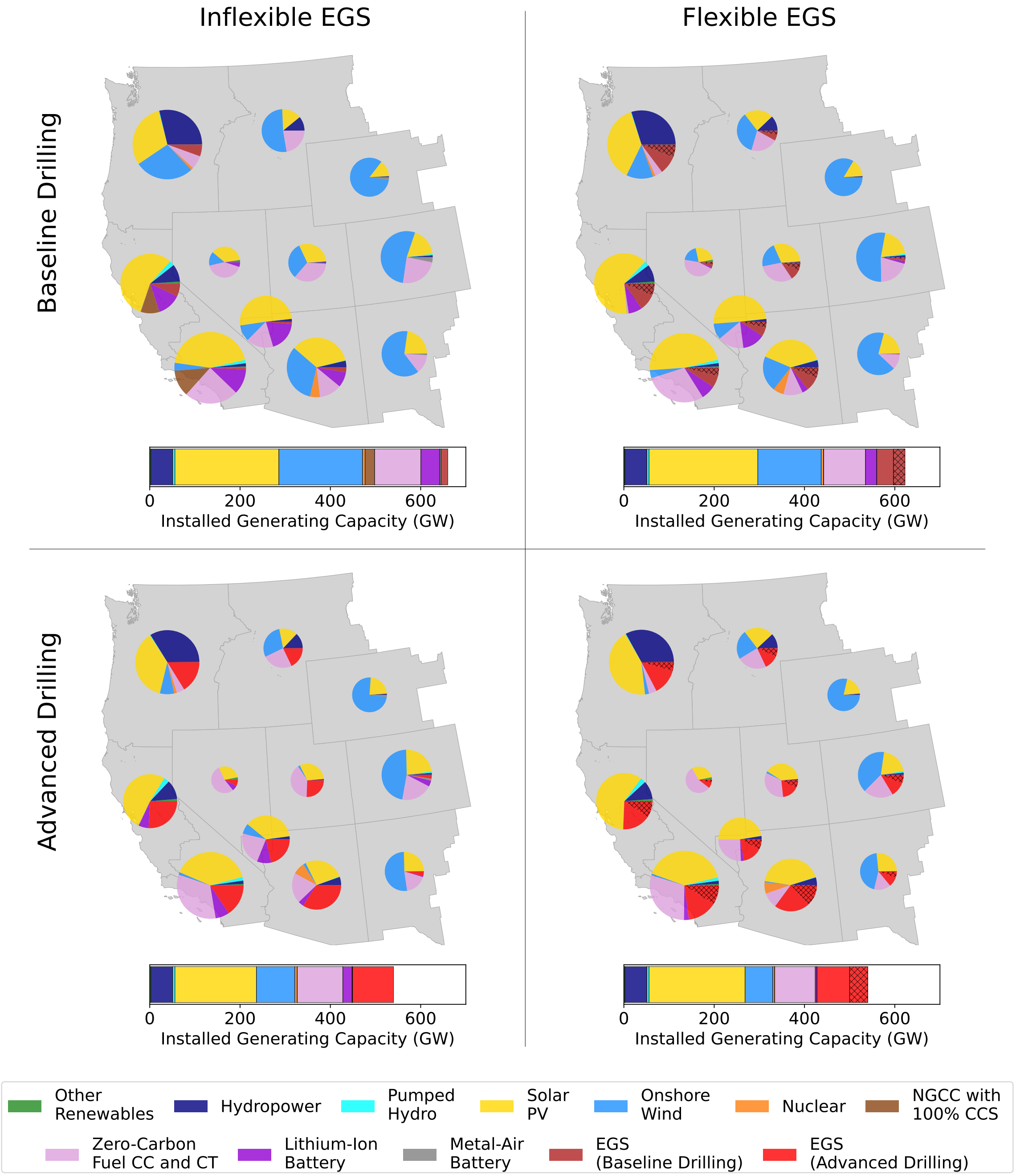

Figure 5: Cost-optimal installed capacities by technology and model zone for scenarios with mid-case market opportunity and reservoir performance. Scenarios assuming inflexible (left) and flexible (right) EGS with baseline (top) and advanced (bottom) drilling are shown. Zonal capacities scale with pie chart area, and crosshatches indicate flexible EGS capacity.

1.4 Optimized Operations and System Dynamics

The operational dynamics that enable flexible EGS to efficiently replace expensive competing resources are illustrated in Figure 6, which shows operational snapshots of optimized systems with and without flexibility enabled. EGS baseload capacity is fixed at 35 GW in both cases. Supplementary Fig. 7 shows similar dynamics for systems with baseload EGS capacity fixed at 70 GW. In both cases inflexible EGS fills a traditional baseload power role, generating at or near its maximum available capacity at all times. Fluctuations in inflexible EGS output are due primarily to changes in surface plant thermal efficiency driven by ambient temperature variability, although small amounts of forced curtailment occur occasionally. While the consistent baseload power supplied by inflexible EGS is valuable during times of low VRE output, it is also somewhat redundant during times of VRE abundance. Even with baseload EGS in the mix, the system remains dependent on storage and alternative clean firm resources (ZCF plants and gas plants w/CCS) to fill capacity needs during high-stress periods.

By contrast, enabling flexibility for EGS greatly reduces the need for alternative firm generation and energy storage while enabling new synergies with solar power. Flexible EGS generally shifts its generation to nighttime periods when the lack of solar generation creates the greatest need for firm capacity. It does so by reducing or completely curtailing output during midday hours when solar power is abundant. Geofluid accumulated in reservoir fracture networks during these periods is produced at higher rates during the night, making use of the additional flexible EGS capacity shown in Figure 4. While complete curtailment of EGS production flow occurs frequently under an optimal operational strategy, this action may also cause thermal stresses that negatively impact well integrity over time [25, 26]. Thermal stresses can be minimized through implementation of minimum production flow rates, which prevent wellhead temperature from dropping too low. We find that doing so reduces the benefits of flexibility only marginally (Supplementary Fig. 8), suggesting that production rates can still be maximized in most high-value hours of the year even when minimum flows are imposed during low-value periods.

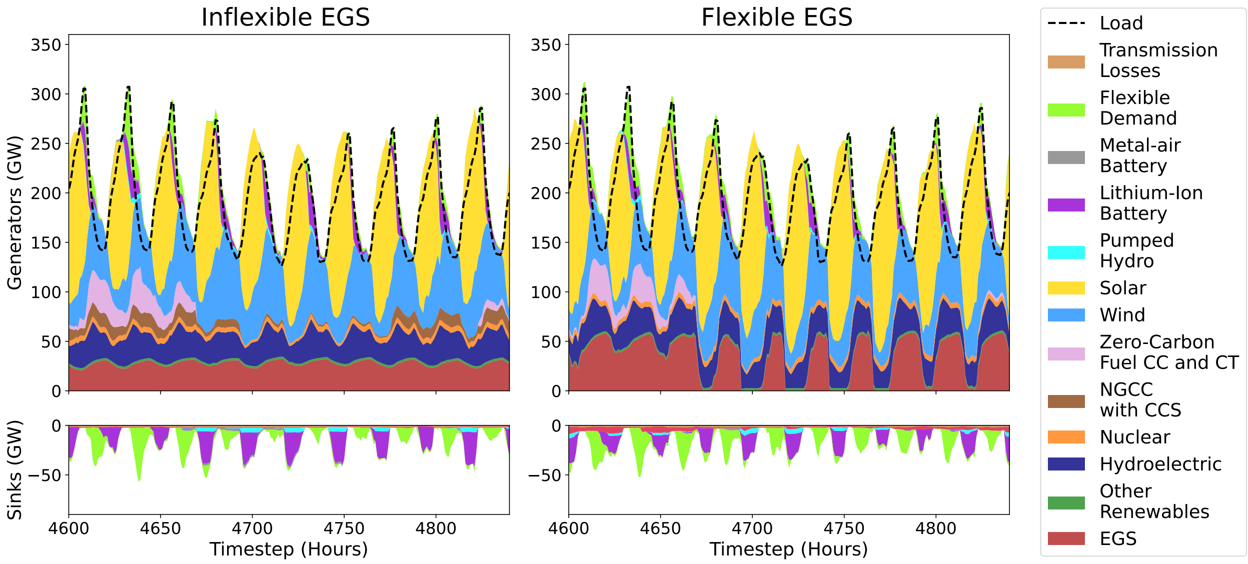

Figure 6: Hourly system-wide generation (top) and consumption (bottom) from generators, storage and flexible demand over a 240-hour period in the scenario with mid-case market opportunity and reservoir performance and baseline drilling, without (left) and with (right) flexibility enabled. EGS baseload capacity is fixed at 35 GW in both systems.

A diurnal IRES strategy optimizes utilization of both solar and geothermal power. In the system shown in Figure 6, combined annual solar and EGS curtailment falls by 40% (26 TWh) when EGS flexibility is enabled despite a 12% increase in installed solar capacity. As illustrated in Supplementary Fig. 9, EGS production flow rate is strongly anticorrelated with solar generation.

Diurnal energy shifting also takes advantage of air-cooled geothermal plants' increased thermal efficiency during cooler nighttime hours. By curtailing geofluid production during the day and increasing production at night, a flexible geothermal plant can effectively generate more electricity per unit of geofluid produced. As illustrated in Supplementary Fig. 10, flexible plants tend to prioritize production during hours when their thermal efficiency is maximized. This strategy results in an average round-trip energy storage efficiency from flexible geothermal plants of 91% in the scenario shown in Figure 6. Across the 18 flexible scenarios shown in Figures 2 and 3, round-trip storage efficiency ranges from 81% to 98% (Supplementary Fig. 11). Efficiencies are generally greater in scenarios with higher EGS reservoir performance. Observed efficiencies are comparable to Lithium ion battery performance and surpass those of all competing long-duration energy storage technologies [27]. Effective efficiencies modeled herein also represent a significant improvement over the average 81% IRES round-trip efficiency observed in Ricks et al. [14], which did not consider ambient temperature effects on thermodynamic efficiency of geothermal generators. Losses are primarily the result of maintaining elevated reservoir pressure and temporarily increasing injection flow rates during flexible operation, both of which increase the required injection pumping load.

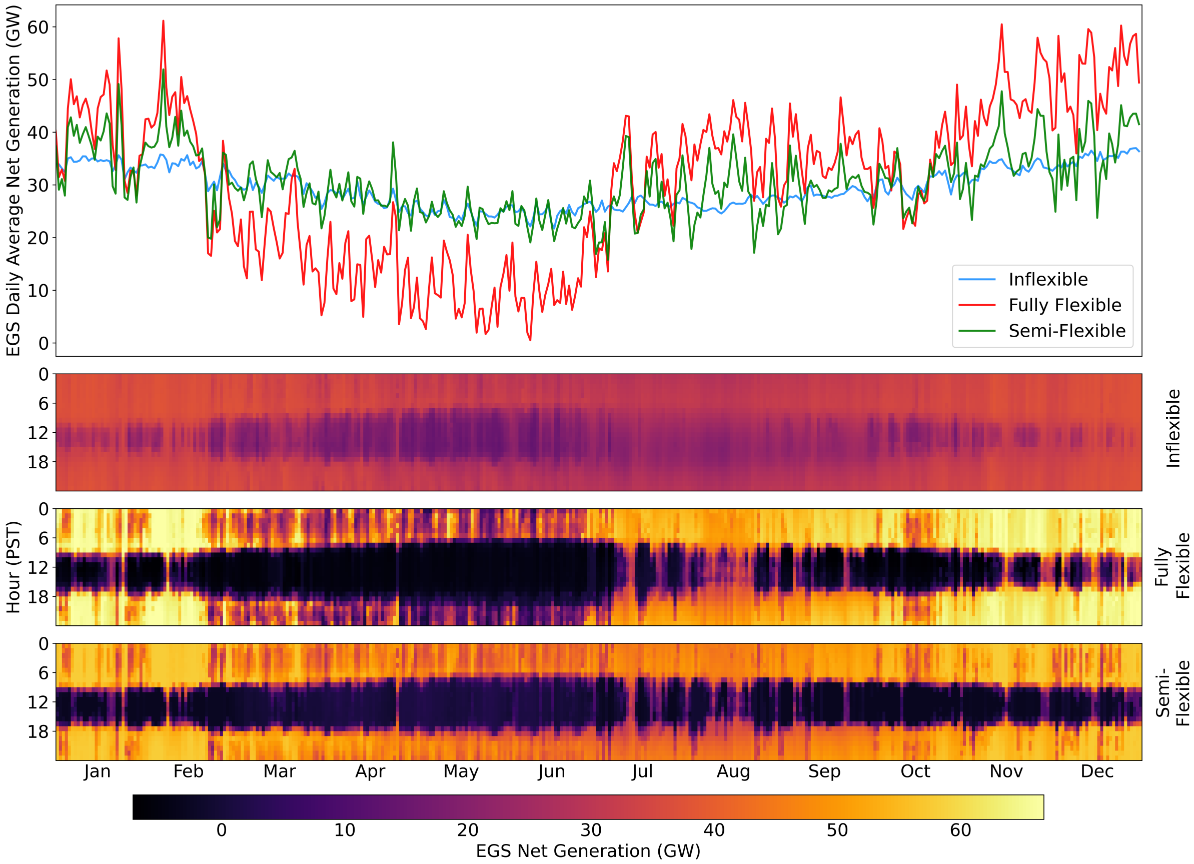

Figure 7: Daily average (top) and hourly (bottom) system-wide net generation from inflexible, fully flexible, and semi-flexible EGS with 35 GW of baseload capacity over a single weather year. Scenarios assume mid-case market opportunity and reservoir performance, and baseline drilling.

In addition to a consistent diurnal cycle, we find that flexible EGS also operates on seasonal cycles. Figure 7 shows hourly generation profiles, as well as average daily generation, for inflexible and flexible EGS with fixed baseload capacities over an entire weather year. All EGS plants have limits on total annual geofluid production driven by the need to manage long-term reservoir temperature decline, but flexible plants are able to concentrate this output in specific parts of the year rather than producing at a constant rate year-round. This is accomplished not only via IRES, which has been shown to enable multi-week energy shifting [14], but also by modulating average geofluid injection and production rates over much longer periods. In the 'fully flexible' case shown in Figure 7, generation is significantly reduced from March through June compared to the inflexible case. By reducing output during these months when hydropower is plentiful, flexible geothermal plants can produce at higher average rates in other periods without accelerating long-term thermal drawdown.

We find that this seasonal shifting accounts for a large part of the total added value of EGS flexibility, with daily or weekly energy shifting from IRES playing an equal or even secondary role. We isolate the effect of seasonal shifting by adding a model constraint that forces the average injection flow rate for each generator in each month to be less than or equal to the annual average. Operational profiles for this 'semi-flexible' case are shown in Figure 7 alongside the fully flexible and inflexible cases. Comparing total system cost reductions from fully flexible, semi-flexible, and inflexible EGS deployment across 18 geothermal drilling, reservoir performance and market opportunity cases (Supplementary Fig. 12), we find that seasonal shifting typically accounts for 40-50% of the total added value from flexibility. Thus, any factors that prevent EGS reservoirs from operating in a seasonally-variable manner could significantly reduce the overall value of geothermal flexibility. While the present work assumes that seasonal changes in average flow rates produce no deleterious effects as long as the annual average flow remains constant, this assumption must be validated by further simulation and field testing.

2 Discussion

Our results indicate that successfully-developed EGS can contribute to a least-cost decarbonized electricity system in the United States even without major advances in geothermal drilling, and can provide nearly half of the total electricity supply in the US Western Interconnection under more optimistic technology development scenarios. Although cost uncertainties lead to a wide range of possible outcomes, we find that flexible operation of EGS reservoirs and optimization of power plant configurations significantly enhance the role of geothermal power in all cases. By taking advantage of the natural properties of confined geothermal reservoirs to provide load-following generation and in-reservoir energy storage, next-generation geothermal power can achieve significantly greater deployment while reducing the overall cost of the electricity system. Flexible geothermal plants are able to shift energy at high efficiency on hourly to seasonal timescales, prioritizing generation during periods when the system value of firm power is greatest. By doing so, these plants can effectively reduce or even eliminate the need for alternative firm generation and storage technologies.

The large observed impact of operational flexibility on the role and deployment potential of geothermal power emphasizes the degree to which an energy technology's economic success depends on both its cost *and* its value. Although load-following generation and IRES do nothing to reduce the levelized cost of geothermal energy, they improve the average value of this energy enormously. For this reason, R&D efforts that aim to improve the economics of geothermal energy by enabling flexible operations can be considered of equal importance to those that seek to directly reduce geothermal capital costs. An extended discussion of our findings, including implications for EGS technology development and policy in the United States and beyond, is presented in the Supplementary Discussion.

3 Methods

3.1 Electricity System Capacity Expansion

We focus in this work on the impact of geothermal flexibility on decarbonized electricity systems in the western United States, which hosts the vast majority of the country's geothermal resource potential [17]. We choose 2045 as the model planning year, as this is the established target year for complete decarbonization of electricity supply in several western states. As this study focuses primarily on the role and impact of EGS power, we consider three primary electricity system cases (detailed in Table 1) reflecting differing levels of advancement for non-EGS technologies. All cases assume availability of multiple competing clean firm technologies, including nuclear power, natural gas with carbon capture, and zero-carbon fuel combustion. These three technologies span the range of high fixed/low variable costs to low fixed/high variable costs. We also assume availability of cost-competitive long-duration energy storage in the form of metal-air batteries, as well as varying levels of flexibility in residential heating and electric vehicle charging demand. The 'Low' and 'High' market opportunity cases bound the space of potential market niches for geothermal power, with the former case representing a plausible very poor long-run economic environment for EGS and latter representing a very favorable environment. The 'Mid' market opportunity case assumes mid-line cost and performance for competing technologies based on projections from NREL and the EIA [5, 23, 28]. All scenarios use load profiles that assume significant electrification of transportation and heating in line with results from Larson et al. [11] for the year 2045 and consistent with decarbonization goals in most western states. An aggregate load profile for the entire western interconnection is shown in Supplementary Figure 14. Model input data, including technology costs and performance parameters, load profiles, and transmission topologies, were compiled using PowerGenome, an open-source tool designed to create power system model inputs [29] from a range of publicly available data sources.

For this research we use the GenX electricity system capacity expansion model (CEM), an open-source model that has been described in detail elsewhere [15, 16]. The model determines an optimal set of investment and operational decisions that minimize the cost of meeting electricity demand over the course of one or multiple planning years, subject to policy and operational constraints. GenX is configurable to allow for varying levels of model complexity. In this research, GenX is configured to consider detailed planning and operating constraints including ramp rates, thermal power plant cycling costs and constraints ('unit commitment'), intertemporal constraints on energy storage, a detailed consideration of reservoir hydropower, demand-side flexibility, and a dynamic capacity reserve margin. GenX is a zonal CEM that captures major transmission pathways between regions, and in this study we use an 11-zone model to represent the transmission topology of the US western interconnection. Each zone is assumed to have well-developed, unconstrained transmission networks between demand centers within the zone and hosts multiple clusters of candidate sites for renewable energy deployment with varying transmission interconnection costs and generation profiles. System operations are modeled at 8760-hour temporal resolution over a single weather year, thereby capturing the hourly variability and covariance of regional load and renewable generation profiles. We run the model in two stages to simulate the expansion of the electricity system between the present and 2045. The model is first run with a planning year of 2030, constrained by existing state policies, and the results of this run are taken as initial conditions for subsequent runs with a planning year of 2045 and a target of zero-carbon electricity. This reflects a two-stage 'myopic' expansion path, as expansion in the first phase does not look ahead to consider needs in the second stage. EGS deployment is assumed to occur only in the 2031-2045 planning period. A detailed description of the capacity expansion modeling methodologies and assumptions used in this research is provided in Supplementary Note 1.

3.2 Modeling Flexible Geothermal Power

This work makes use of a novel linear model formulation originally developed in Ricks et al. [14] to optimize the investment and hourly operational decisions of flexible geothermal power plants within the GenX model framework. This formulation, described in detail in Supplementary Note 2, accurately reproduces the pressure and flow behaviors observed in numerical simulations of flexible EGS reservoir operations while maintaining computational tractability and suitability for inclusion in a linear programming optimization model. It optimizes EGS injection and production flow rates and well bottomhole pressures at hourly intervals while ensuring that these operations remain physically feasible. Investments in plant components including the wellfield, surface generator, injection pumps, grid interconnection, and surface geofluid storage are also optimized. Each of these components is assigned a fixed annual capacity cost based on techno-economic analysis, and their respective installed capacities constrain the plant's operational capabilities.

To calibrate the flexible geothermal model, numerical reservoir simulations are used to measure the transient responses of the injection and production well bottomhole pressures to step-wise changes in both injection and production rates. We linearize the four resulting nonlinear pressure response functions by taking their slopes at hourly intervals. The change in bottomhole pressure at a given model timestep is then calculated as the linear superposition of the linearized pressure response functions corresponding to changes in injection and production rates at the current and previous 50 timesteps. This formulation captures the dependence of the subsurface pressure response on the entire recent history of injection and production flow rates, not just the current rates. The model formulation also captures the relationship between production well bottomhole pressure and maximum achievable production flow rate, as well as the relationship between injection pressure, flow rate and required injection pumping power, as derived via reservoir simulations.

3.3 Reservoir Simulation and Design

We use a commercial reservoir simulation software package called ResFrac to simulate the operation of EGS reservoirs under variable injection and production flow rates over periods of up to 30 years [30]. These numerical simulations capture all of the coupled physical properties relevant to the present work, including fluid flow in fractured and porous media, wellbore interactions, heat transfer, and mechanical deformation of fractures in response to changes in fluid pressure. Relevant simulation outputs include:

1) the transient injection and production well bottomhole pressure responses to step-wise changes in injection and production flow rates, 2) the relationship between production well bottomhole pressure and maximum achievable production flow rate, 3) the relationship between injection flow rate and injection wellhead pressure, and 4) the long-term thermal drawdown over the lifetime of the system. We run a suite of simulations, varying reservoir depth, temperature, and performance conditions to cover the entire range of EGS operational conditions explored in this study. Low, mid, and high reservoir performance cases vary the permeability of the reservoir rock matrix and conductivity of engineered fractures as detailed in Table 1b. Further details on simulation methodology are provided in Supplementary Note 3.

We assume a standard at-scale EGS reservoir design featuring wells drilled vertically to the target reservoir depth and then deviated 90 degrees to terminate in 2286 m lateral sections. Laterals are run parallel to one another, alternating between injection and production wells. Wells are spaced 305 m horizontally from one another, and injection well laterals sit 152 m deeper than production well laterals. Injection and production wells are connected by an engineered fracture network consisting of 150 evenly spaced vertical fractures emanating from each injection well. This "wine rack" reservoir design, illustrated in Extended Data Figure 2, could theoretically be of indefinite length. For the purpose of the present work, which requires a fixed ratio of injection wells to production wells for plant costing, we assume that a standard reservoir consists of four injection wells and five production wells. Each injection well maintains a fixed injection flow rate of 159 l/s under steady-state operation. We performed production forecast simulations using this well pattern and reservoir engineering design to evaluate the long-term thermal performance of the system. We found that for all scenarios modeled in this study, this well pattern resulted in levels of thermal decline that are within the operational window of a given ORC power plant design. In addition, we found that cycling the wells on a daily basis caused no significant negative impacts on the long-term thermal decline rate.

3.4 EGS Costing

EGS power is an emerging technology, and as such its costs are not currently well-characterized. Depending on the well flow rates achieved and the cost of deep geothermal drilling, the capital cost of an EGS power plant could range from less than \$3000/kW to more than \$30000/kW [4, 23]. We do not attempt to predict future EGS costs in this work, but rather to accurately represent the economics of EGS deployment across a range of depths, temperatures, and locations under multiple distinct technology development scenarios.

We assume as a baseline condition in this analysis that the standard reservoir design described above can be deployed at scale. If reservoir fracture networks that deliver high hydraulic conductivity and avoid thermal short-circuiting cannot be successfully engineered, EGS will likely fail to achieve commercial viability and the distinction between flexible and inflexible operations will be of little consequence. Given the assumption of physical feasibility, we focus on two primary cases for the future development of EGS power. The 'Baseline Drilling' case assumes that geothermal drilling technology does not advance significantly beyond the current state of the art and that EGS drilling and reservoir engineering can only be successfully performed in subsurface formations with temperatures less than 250 C. Assumptions for this case are based on capabilities demonstrated in recent drilling and stimulation activities at the Utah FORGE EGS test site [31, 32]. The 'Advanced Drilling' case assumes major breakthroughs in deep drilling leading to drastically reduced costs, as well as the ability to deploy EGS in formations up to 325 C, and represents a best-case technology development scenario for EGS. Neither EGS cost case assumes major advances in surface plant design, as geothermal power plants are a relatively well-established technology by comparison to deep drilling and EGS reservoir stimulation [4].

We calculate EGS wellfield cost as a function of reservoir depth using cost curves developed by Lowry et al. [19], which we modify to reflect recent drilling cost and performance trends and differences in well design. For surface power plant costing we use NREL's Geothermal Electricity Technology Evaluation Model (GETEM) [20], which optimizes geothermal surface plant capital cost and efficiency to minimize the delivered cost of electricity. Using wellfield costs and flow rates as inputs, we run GETEM at a range of geofluid inlet temperatures to derive relationships for surface plant specific cost and brine effectiveness (the electrical energy extracted per unit mass of geofluid) as functions of inlet temperature. Following assumptions made in the US Department of Energy's *Geovision* report [4], we assume that all EGS surface plants are air-cooled organic Rankine cycle (ORC, also called binary-cycle) units. These zero-emissions plants are well suited for deployment in the arid western United States due to their minimal water use. They are also capable of very fast ramp rates, making them ideal for flexible geothermal applications [9]. A more detailed description of EGS wellfield and surface plant costing methodology is provided in Supplementary Note 4.

3.5 EGS Resource Potential

Representation of the significant variability in geothermal resource quality and availability across the western United States is necessary in order to accurately assess the impact of EGS flexibility on electricity systems in this region. For this work we develop full supply curves that characterize the developable EGS resource potential across a range of temperatures and depths in all modeled zones. We rely on temperature-at-depth datasets from Blackwell et al. [17], which covers depths from 3.5 to 10 km, and Mullane et al. [33], which covers depths from 1 km to 3 km. We derive our deep resource potential estimates (3.5-6.5 km) from those developed in Augustine [18], which are in turn based on temperature-at-depth data from Blackwell et al. [17]. We update these potential estimates to reflect the volumetric power density of our standard reservoir design, as calculated in numerical reservoir simulations. We also consider depths shallower than 3.5 km, as these host significant low-temperature geothermal resource potential. The Utah FORGE EGS test site, which features temperatures in excess of 220 C at less than 2.5 km, is a prime example of the importance of considering shallower resources [31]. We calculate regional potential at depths of 1.5 km and 2.5 km directly using datasets provided in Mullane et al. [33], using the same temperature bins, resource zones, and exclusion layers as were used by Augustine [18] in developing the deeper potential estimates. We calculate transmission interconnection costs for all EGS resources and assign them to GenX model zones using a least-cost transmission routing algorithm developed in Jenkins et al. [34]. Supplementary Note 5 provides a more detailed description of the process used to develop resource potential estimates. Extended Data Figure 1 shows full EGS supply curves for the western US, which incorporate the resource potential estimates and costing methodologies described above.

3.6 Geothermal Capacity Factors

Previous electricity system capacity expansion studies, including those that have assumed newly-built geothermal plants to be air-cooled ORC units, have modeled geothermal power as a traditional 'baseload' resource with constant power output [2, 4, 8]. However, the instantaneous brine effectiveness of a geothermal power plant exploiting a low-temperature thermal resource is in fact highly dependent on local atmospheric conditions [21, 35]. This is especially true for air-cooled plants, for which the ambient air serves as the cold sink for the plant's thermal power cycle. Due to the relatively low temperature of potential EGS resources (primarily in the 150-300 C range), the effects of changes in cold sink temperature on plant thermal efficiency and generation are much more significant than in other thermal generators. For this work, we use historical performance data from the Dora I air-cooled ORC geothermal plant in Turkey to calculate the change in plant power output as a function of the deviation in local ambient air temperature from the plant's design point [21]. We apply this relationship to all modeled EGS power plants in this study, deriving capacity factor time series composed of hourly multipliers that scale the instantaneous brine effectiveness of EGS plants to reflect local atmospheric conditions. We use NOAA ambient temperature data from the 2012 weather year to create average geothermal capacity factor time series for each geothermal weather region [22]. Capacity factor time series also account for thermal drawdown over the system's lifetime as measured in numerical reservoir simulations. One example time series, for the southern California weather region, is shown in Supplementary Figure 22. Plant generation at a constant geofluid production rate fluctuates between 56% and 116% of nameplate capacity, with higher capacity factors occurring during nighttime and winter hours. Further details on the derivation of EGS capacity factor time series are provided in Supplementary Note 6.

3.7 Flexible Geothermal Impact Measurement

Given deep uncertainty in the long-run evolution of electricity markets and EGS as a technology, we rely on scenario analysis in this work to assess the impact of EGS flexibility on major modeled outcomes under a range of possible conditions. Although individual modeled scenarios cannot be taken as predictive, assessing the relative impact of EGS flexibility across a wide range of scenarios provides insight into the benefits of this operating mode under specified conditions and the sensitivity of these benefits to parametric variations. We design our scenario space with the intention of bounding the range of plausible outcomes along the dimensions of EGS drilling cost, reservoir performance, and market opportunity. We focus on optimal EGS deployment and total system cost as primary outcomes of interest, as these emphasize the benefits of flexibility for EGS developers and system planners, respectively. System cost reductions are calculated with respect to ‘base case’ counterfactual scenarios in which EGS is not available as an electricity resource. We further explore sources of value for EGS, both flexible and inflexible, by comparing investment and operational decisions in systems with and without EGS available.

3.8 Limitations and Opportunities

Finally, we note several limitations of the present work. First, although we do consider the breakdown of EGS resource potential by temperature, depth, and region in an effort to better model deployment patterns in the Western Interconnection, our modeling assumes a universal plant size, reservoir design, and drilling cost for a given depth. In reality these metrics and others may vary significantly from project to project depending on financing, year of construction, land availability, and local subsurface conditions. Flexible plant configurations and system benefits will therefore be less uniform in reality than in our modeled scenarios. Second, this work relies on numerical reservoir simulations to assess EGS reservoir performance, including flow rates, thermal drawdown, and flexible capabilities. Even simulations of low-performance reservoirs assume uniform fracture networks and rock matrix properties, conditions that are unlikely to be replicated in real EGS reservoirs. Nonuniformities in reservoir characteristics could have unforeseen impacts on reservoir performance under both flexible and inflexible operations. The variable flow rates required for flexible operations could also have negative impacts on well and reservoir integrity that are not captured here. Future field experiments must therefore be designed to test the limits of the assumptions made in this analysis. Third, while we evaluate only electricity market economics in our optimization framework, considerations along other dimensions may significantly impact EGS development. The risk of induced seismicity, which was not considered in the EGS exclusion zones used in this work, may present a significant barrier to social acceptance of EGS deployment. It is possible that flexible operations could accentuate this risk or the perception of it, although implementing conservative bounds on bottomhole pressure can mitigate such risks. We also do not consider non-electricity and non-cost value streams that could impact EGS deployment. For example, low land and materials requirements could enable geothermal to be deployed more rapidly than other resources facing land acquisition or supply chain bottlenecks. The economic value of heat provided by geothermal resources, which could see use in industrial, district heating, direct air carbon capture, or hydrogen electrolysis applications, could enable greater EGS deployment in some areas than is observed in our electricity-focused study. The risks and co-benefits of EGS, both flexible and inflexible, should therefore be further evaluated across these non-modeled dimensions.

Data Availability

Primary input and results datasets relevant to this study are available at `https://zenodo.org/record/7072447`. Additional data are available from the corresponding author on reasonable request.

Code Availability

The ResFrac reservoir simulation code is a commercial software developed by the ResFrac Corporation. The GenX electricity system capacity expansion model is availabile open-source at `https://github.com/GenXProject/GenX`. The code for the flexible EGS optimization module developed in this work is available from the corresponding author on reasonable request, and will be included in an upcoming release of GenX.

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Contributions

W.R., J.D.J. and J.H.N. conceptualized the study. W.R. and J.D.J. developed the experimental design. K.V. designed and performed geothermal reservoir simulations. W.R. developed the optimization model, geothermal supply curves, and other input datasets. W.R. performed the formal analysis, visualization and investigation, and produced the figures. W.R. drafted and finalized the manuscript. J.D.J. and J.H.N. advised on the analysis and reviewed and revised the manuscript.

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Ethics Declarations

K.V. and J.H.N. are employees of Fervo Energy, a geothermal energy development company. J.D.J. is part owner of DeSolve, LLC, which provides techno-economic analysis and decision support for clean energy technology ventures and investors. He serves on the advisory board of Eavor Technologies Inc., a closed-loop geothermal technology company, and has an equity interest in the company. He also provides policy advisory services to Clean Air Task Force, a non-profit environmental advocacy group, and serves as a technical advisor to MUUS Climate Partners and Energy Impact Partners, both investors in early stage climate technology companies.

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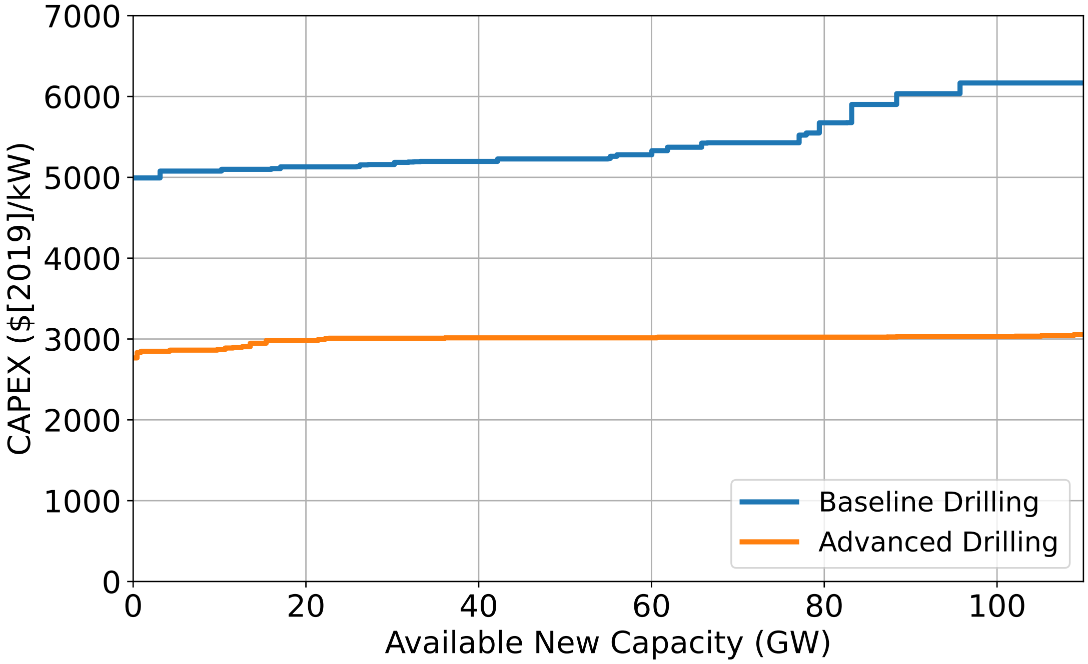
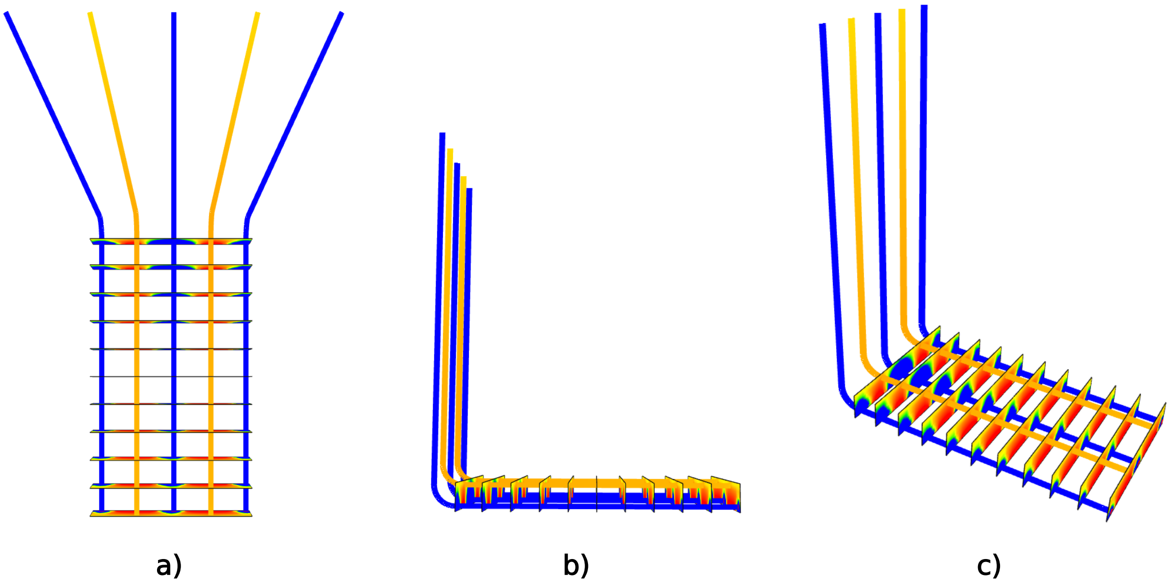
Extended Data



Extended Data Figure 1: Supply curves for EGS power in the United States Western Interconnection under Baseline and Advanced drilling scenarios. CAPEX is given with respect to plant net generating capacity (including steady-state injection load) at the local average ambient temperature, and does not include grid interconnection costs.



Extended Data Figure 2: Vertical (a), horizontal (b), and diagonal (c) views of the at-scale EGS reservoir design simulated in this work. Production and injection wells are shown in orange and blue, respectively, and well laterals are connected by an engineered fracture network. For visual clarity, only every 15th fracture is shown.