The Role of Flexible Geothermal Power in Decarbonized Electricity Systems

Wilson Ricks[1*] Katharine Voller[2] Gerame Galban[2] Jack H. Norbeck[2]
Jesse D. Jenkins[1]

[1]Princeton University
[2]Fervo Energy

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, significantly increasing optimal geothermal penetration and reducing bulk electricity supply costs compared to systems with inflexible EGS or no EGS. Flexible geothermal plants preferentially displace the most expensive competing resources by shifting their generation on diurnal and seasonal timescales, with round-trip energy storage efficiencies of 59-93%. Benefits of EGS flexibility are robust across a range of electricity market and geothermal technology development scenarios.

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 [6–8]. By eliminating the reliance on pre-existing hydrothermal reservoirs, successfully-developed 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 EGS plants would operate as 'baseload' resources, generating at their maximum rated output at all times [2, 4, 7–10]. 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 [11]. 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 [12–15]. In systems where demand in many hours of the year can be met cost-effectively with zero-marginal 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. Due in part to this unfavorable economic environment, past energy systems studies have concluded that the cost of geothermal drilling would need

*Corresponding author

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

to come down significantly for baseload EGS to play a major role in future electricity grids, even if basic technology development goals (e.g. successful engineering of artificial reservoirs) can be met [4, 8, 10].

In previous work, Ricks et al. [16] evaluated the potential for EGS power plants to adapt to a high-VRE electricity 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 study we expand on previous efforts by quantifying the impact of load-following generation and IRES (jointly referred to hereafter as 'flexible operation') on the value and deployment potential of geothermal power in future electricity systems under deep decarbonization. More broadly, we aim to better characterize the role that EGS could be expected to play in decarbonized electricity systems if it can be successfully developed and commercialized. We employ an updated version of the GenX electricity system capacity expansion model [17, 18] to co-optimize the deployment and operation of flexible and inflexible EGS power plants alongside a suite of other electricity generation and storage technologies (Figure 1) in a model of the US Western Interconnection subject to deep decarbonization policies circa 2045. The primary conclusion of this work is that flexible operation represents a viable pathway to significant deployment of EGS in future electricity systems, independent of basic cost reductions. This result suggests that EGS technology development efforts, which currently focus almost exclusively on reducing costs [8], should place a similar level of emphasis on the development and demonstration of flexible capabilities. We also find that flexible operation would allow successfully-developed EGS power plants to deliver significantly greater system-level benefits than had been previously assumed, a finding which may hold relevance for policymakers and analysts focused on identifying suites of technologies to address the broader challenge of energy systems decarbonization.

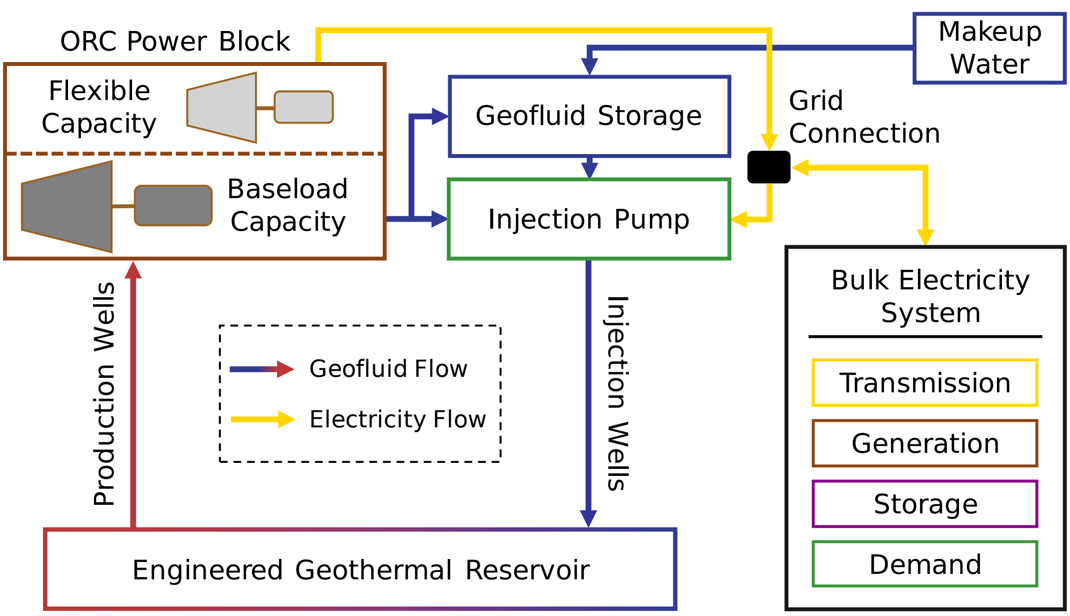

Figure 1: Schematic diagram of the flexible EGS optimization model. EGS power plant investments and operations are optimized in tandem with other bulk electricity system components in GenX.

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

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

Subsurface Favorability			
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}

Geothermal Market Opportunity									
Case	Solar PV CAPEX ($/kW)	Onshore Wind CAPEX ($/kW)	LI Battery CAPEX ($/kW)/($/kWh)	Metal-Air Battery CAPEX ($/kW)/($/kWh)	H_2 Storage CAPEX ($/$kW_{In}$)/($/kW_{Out}) /($/kWh)	Nuclear CAPEX ($/kW)	Natural Gas Fuel Cost ($/GJ)	Zero-Carbon Fuel Cost ($/GJ)	Flexible Demand (% of EV Charging) /(% of Res. Heating)
Low	575	630	91/97	800/8	300/810/2	4311	3.52	10.14	90/20
Mid	721	874	191/129	1200/12	450/810/5	6468	4.45	15.20	75/10
High	721	874	191/129	2000/20	675/810/10	9702	7.51	22.81	60/0

Table 1: Outline of model cases. Key parametric variations across modeled geothermal drilling, subsurface favorability, and geothermal market opportunity cases. CAPEX refers to total capital expenditures per unit of installed AC electric generating capacity, or per unit of energy storage capacity, in 2019 USD. Additional energy technology cost and performance assumptions are provided in Supplementary Tables 2 and 3.

1.1 EGS Deployment Potential

Given deep uncertainty in the long-run cost and performance of both EGS and key competing clean energy technologies, we employ scenario analysis in this work to explore outcomes of interest across a range of possible futures with differing assumptions for key uncertain parameters. We develop supply curves representing the quality and availability of EGS resources across the western United States (Supplementary Figs. 37 and 38) using performance results from numerical simulations of EGS reservoirs and existing temperature-at-depth, weather, and system component cost data from the literature [19–23]. We create curves for two geothermal drilling technology bounding cases (Table 1): one where drilling technology does not advance from the current state-of-the-art ('Baseline Drilling'), and one where new technologies and techniques lead to significantly lower well costs and allow reservoir engineering in higher-temperature environments ('Advanced Drilling'). We also assess multiple 'subsurface favorability' cases, where parameters in geothermal reservoir simulations are adjusted to reflect uncertainties in subsurface conditions that might positively or negatively impact EGS operations. These EGS cost and performance cases assume as a baseline that fundamental EGS technology development goals have been met, i.e. that artificial geothermal reservoirs delivering high flow rates and acceptable thermal performance can be successfully and consistently engineered. This degree of repeatable high-performance reservoir engineering has not been demonstrated in EGS field tests to date [21], and instead represents the goal of active RD&D efforts being undertaken by private and public institutions [8]. Finally, we include multiple 'market opportunity' cases that vary the costs of competing energy technologies between upper and lower bounds to create market conditions that are more or less favorable for EGS deployment [24]. Modeling combinations of geothermal drilling, subsurface favorability, and market opportunity cases allows us to assess the sensitivity of major electricity system outcomes to variations along these dimensions.

Model results indicate that the ability of EGS plants to operate flexibly has a significant and consistent impact on geothermal deployment potential. Figure 2 shows optimal installed capacities for flexible and inflexible EGS power in a fully decarbonized US Western Interconnection under various combinations of market opportunity, subsurface favorability, 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

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

of flexible capacity and other plant components.

Total installed EGS capacity ranges from 0-117 GW (0-37% of peak system load) across the scenarios shown in Figure 2 and is always greater with flexibility enabled (15-117 GW with flexible operation vs 0-96 GW without). Comparison of Figures 2 and 3 with Supplementary Figs. 5 and 8 shows that while EGS makes up a relatively small portion of the system's total installed capacity in these scenarios, it accounts for a larger share of total generation. In scenarios with 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. Notably, EGS flexibility is still selected for in these cases even when assuming extremely low costs for competing metal-air and hydrogen long-duration storage technologies. Flexible EGS is likely prioritized over these technologies due to its near-zero incremental energy capacity cost and relatively high round-trip storage efficiency (see below, and Ricks et al. [16]). Development of advanced drilling technologies enables EGS to achieve significant deployment in all cases, meeting up to 44% of total annual electricity demand in the western US (Supplementary Fig. 5).

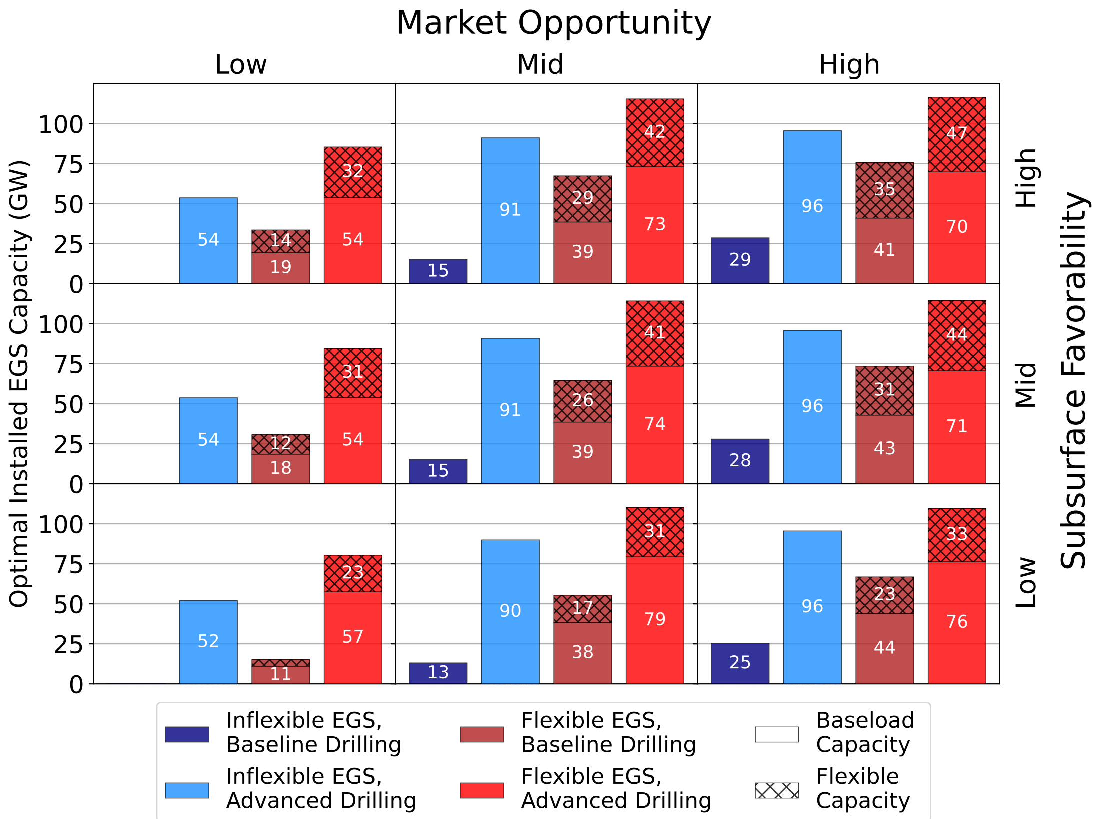

Figure 2: EGS deployment potential in fully-decarbonized electricity systems. Optimal installed capacities for EGS power in the Western Interconnection under a range of fully-decarbonized scenarios combining EGS market opportunity, subsurface favorability, drilling, and flexibility cases. Nameplate EGS capacity is equivalent to surface plant net generating capacity at the local average ambient temperature. Peak system load is 316 GW. Data labels are provided for capacities greater than 10 GW.

Results shown in Figure 2 suggest that geothermal deployment is much more sensitive to the economic environment than to variations in subsurface conditions. 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 simulated reservoir fracture conductivity and rock matrix permeability (i.e., 'subsurface favorability') have a much smaller effect on modeled optimal capacities. For inflexible EGS, although reductions

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

in fracture conductivity increase the parasitic pumping power required to maintain a given steady-state geofluid production rate, we find that the 4x variation in conductivity between the low and high subsurface favorability cases produces only marginal changes in outcomes. This result is tied to the long (2.3 km) lateral well sections in our simulated reservoir design, which reduce the relevance of fracture conductivity in comparison to wellbore friction as a source of hydraulic resistance in the system. For flexible plants, we find that optimal capacity has a somewhat greater dependence on subsurface favorability, though the effect is still much smaller than for market opportunity or drilling cost. This is despite a difference of four orders of magnitude in rock matrix permeability, which was found in Ricks et al. [16] to be the strongest site-specific determinant of IRES performance, between the low and high subsurface favorability 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 [25], this result suggests that such variability is unlikely to have a large effect on EGS deployments regardless of flexible status.

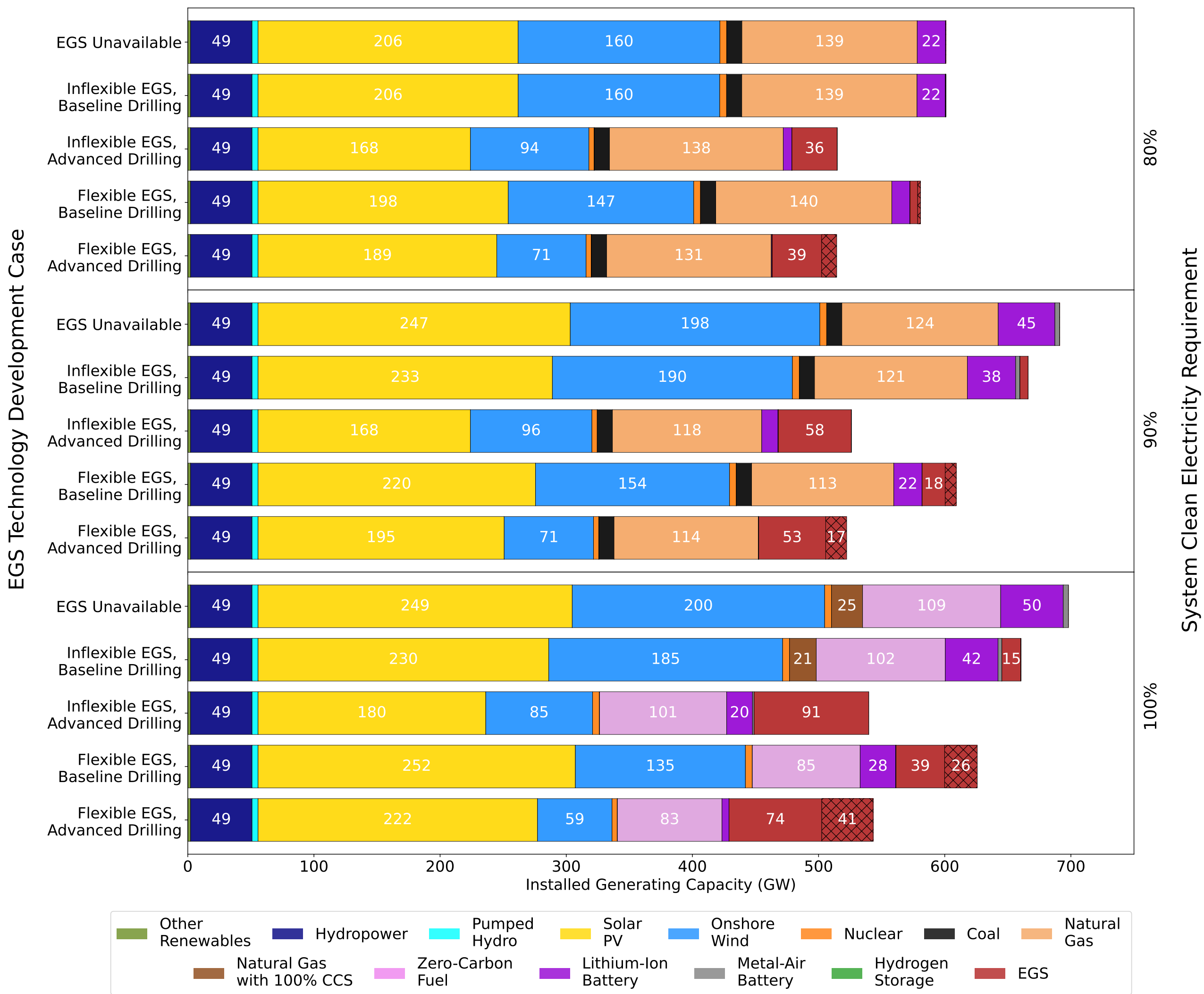

Figure 3: Optimal system-level capacity mixes. Cost-optimal installed capacities by technology and scenario for scenarios with mid-case EGS market opportunity subsurface favorability. The right y-axis indicates the system-wide clean electricity requirement, represented as a percentage of total generation. Data labels are provided for capacities greater than 15 GW.

EGS deployment is also highly sensitive to the overall decarbonization goal set for the system. As shown in Figure 3, cost-optimal EGS deployment decreases significantly in all technology development cases when the system-wide clean electricity requirement is reduced from 100% of total generation (as in Figure 2) to 90% or 80%, though the relative impacts of variations in drilling cost, subsurface favorability, and market opportunity are consistent with the fully decarbonized cases (Supplementary Figs. 3-4 and 6-7). The impact of these clean energy policy relaxations on total deployment is much greater for EGS

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

and other clean, firm resources than for wind or solar, as the former are forced to compete for the niche of firm, VRE-balancing resources with existing unabated gas and coal power. This outcome suggests that, absent specific policy support for early market deployment, EGS could be expected to achieve cost-effective wide-scale deployment only at the latest stages of decarbonization. Still, we do observe that operational flexibility can enable initial EGS deployments in earlier stages of decarbonization than would otherwise be possible. Such early deployments could drive learning curve effects that reduce costs and unlock greater deployment potential at later times [26–28], a dynamic which is not explored in this work.

1.2 Electricity System Costs

Figure 4 shows the difference in total annual electricity system costs between optimized electricity systems with and without EGS available for the same scenarios illustrated in Figure 2. Total system costs include real-dollar operational costs and annuities to recoup capital investments in generation, storage, and new transmission capacity, 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 4-10 percentage points. System value benefits from enabling flexible operations are often comparable to those unlocked by achieving advanced geothermal drilling.

Figure 4: System cost reductions due to EGS deployment. Percentage difference in total annual cost between fully-decarbonized systems with and without EGS available, for the same set of scenarios shown in Figure 2.

As with EGS capacities, we find that the system cost reductions shown in Figure 4 depend more strongly on economic factors than on subsurface conditions. We do however observe that the cost impact of flexibility is moderately greater in scenarios with increased subsurface favorability. As shown in Supplementary Figs. 9 and 10, system cost reductions from EGS deployment are relatively muted in

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

scenarios without requirements for complete decarbonization.

1.3 System Configurations and Sources of Value

We find that the ability to operate flexibly enables EGS power to play a more dynamic role in system operations and leads to notable changes in the optimal electricity resource portfolio. Figure 5 shows optimal capacity mixes, annual energy supply mixes, and system costs for fixed EGS baseload capacities between 0 and 160 GW. Scenarios assume full decarbonization with mid-case market opportunity and subsurface favorability, and advanced geothermal drilling, and all remaining operational and investment decisions are optimized to minimize cost with respect to the prescribed level of baseload EGS capacity. Supplementary Fig. 11 shows similar results for systems with baseline geothermal drilling and fixed EGS baseload capacities between 0 and 80 GW. Supplementary Figs. 13 and 14 illustrate the *change* in the absolute quantities shown in Figure 5 and Supplementary Fig. 11.

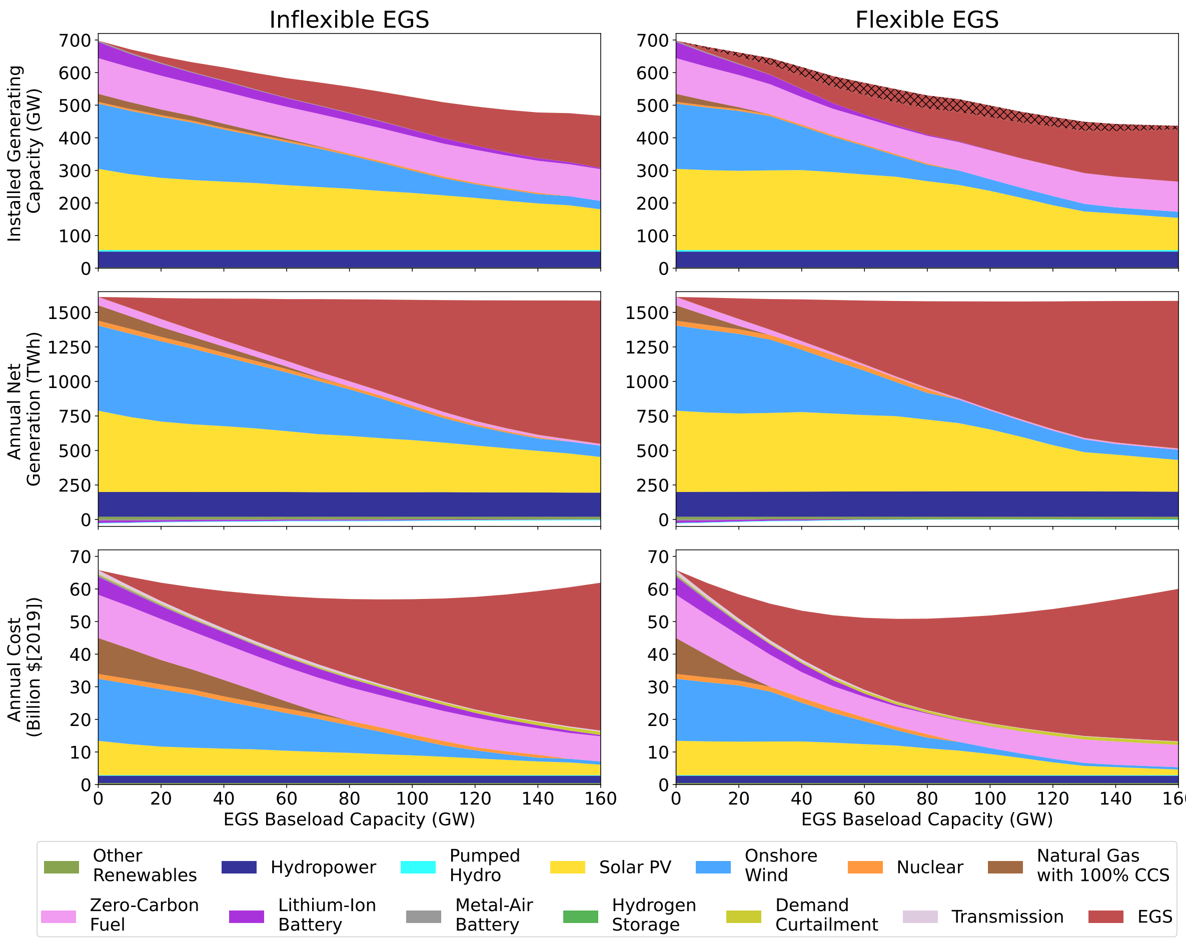

Figure 5: Optimal system configurations for different levels of EGS penetration. Changes in optimal installed capacity, net generation, and annual cost contribution by technology for systems with inflexible and flexible EGS, as a function of the installed EGS baseload capacity. Scenarios assume mid-case market opportunity and subsurface favorability, and advanced drilling. Crosshatches indicate flexible EGS capacity.

The results illustrated in these figures 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. Much of the system value of inflexible EGS 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

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

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 (Supplementary Figs. 16 and 17). Although no new nuclear power is deployed in the systems shown here, alternate scenarios shown in Supplementary Figs. 12 and 15 indicate that inflexible EGS competes most directly with baseload nuclear when the latter is cost competitive. In contrast, 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 flexible operations allows EGS plants to more rapidly displace competing clean firm generators, wind power, and energy storage. A significant amount of additional flexible surface power plant capacity is deployed when this option is available, despite relatively high capital costs in the $1400-2000/kW range. This added flexible capacity enables EGS plants to shift their energy output over long periods (see Section below) and provide greater instantaneous power output in hours when system capacity needs are greatest. Flexible EGS displaces ZCF generation and lithium-ion battery capacity more rapidly than its inflexible counterpart (Supplementary Figs. 13-15), suggesting that it is able to cost-effectively provide the same peaking capacity services. Despite displacing generation from ZCF peakers, a minimum amount of ZCF capacity always remains in the system even with EGS flexibility enabled, as these low capital cost plants are still the cheapest means of meeting system capacity reserve margin requirements (i.e., functioning as 'standby' generators in case of generation or transmission outages or uncharacteristically high demand). This same reserve role is filled by legacy gas and coal generators in cases without a requirement for complete decarbonization (Figure 3). Notably, we also observe that deployment of flexible EGS at baseload capacities up to 80 GW displaces very little solar power in the system. Deployment of flexible EGS can even significantly increase the optimal solar penetration when it displaces nuclear power (Supplementary Fig. 15).

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 (Supplementary Fig. 14). In cases with baseline drilling where EGS has high costs, the added value from flexibility leads to a larger optimal EGS capacity (Supplementary Fig. 11). 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 total baseload EGS capacity and associated cost needed to displace competing firm generation and storage resources.

The incremental system value added by flexibility at a given level of EGS deployment can also be interpreted as the cost threshold that EGS would need to achieve in order to reach that level of deployment. Supplementary Fig. 18 illustrates this interpretation, showing how the incremental system value of EGS (subtracting costs associated with the baseload EGS system) changes as a function of deployment from 0 to 80 GW. Whereas inflexible EGS would need to achieve a marginal CAPEX of roughly $5600/kW to reach 5 GW of total deployment, flexible EGS could do so at $7700/kW. This 37% increase in effective value due to flexibility could potentially play an important role in enabling early EGS deployments, where realized costs may be higher than those modeled here due to the emerging nature of the technology.

1.4 Optimized Operations and System Dynamics

The operational dynamics that allow 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, though other plant components are able to be optimized in the flexible case. Supplementary Fig. 19 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 conversion 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,

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

the system remains dependent on short-duration storage, large amounts of flexible demand (primarily in the form of delayed electric vehicle charging, and playing a similar role in the system to short-duration storage), and alternative clean firm resources (ZCF plants and gas plants with 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 creating 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 (Supplementary Fig. 20). Geofluid accumulated in reservoir fracture networks during these periods is produced at higher rates during the night, making use of any additional flexible surface plant capacity constructed. Complete curtailment of EGS production flow occurs frequently under a simulated optimal operational strategy, an action which may cause thermal stresses that negatively impact well integrity over time. These stresses can be minimized through implementation of minimum production flow rates, which prevent wellhead temperature from dropping too low [29, 30]. We find that doing so reduces the benefits of flexibility only marginally (Supplementary Fig. 21), likely because production rates can still be maximized in the highest-value hours of the year even when minimum flows are imposed during low-value periods. A second possible constraint on practical implementation of the optimized operational profiles shown here is the need to maintain elevated reservoir pressures during 'charging' periods, which could increase geofluid losses if subsurface permeability is highly pressure-dependent [31]. This phenomenon is unlikely to be of major consequence for the systems modeled here, as we enforce a maximum reservoir pressure of only 2 MPa above the baseline. However, sensitivity cases shown in Supplementary Fig. 22 illustrate that even if pressurization to this level were to drive temporary excess fluid loss rates of up to 20% of total injection, the impact on the value of flexibility would not be very large.

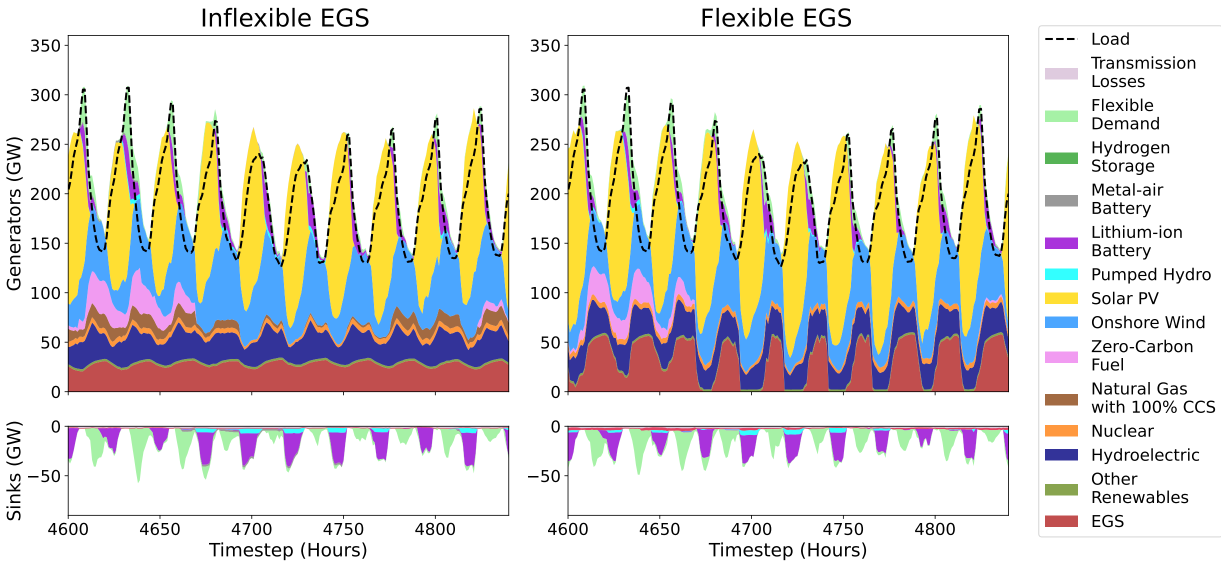

Figure 6: Operational profiles for systems with EGS. Hourly system-wide generation and consumption from generators, storage and flexible demand over a 240-hour period in the scenario with mid-case market opportunity and subsurface favorability and baseline drilling, with and without flexibility enabled. EGS baseload capacity is fixed at 35 GW in both systems.

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. Two flexible cases are shown: one 'fully flexible' case where both fluid injection and production rates can be modulated (as is assumed by default in this paper), and one 'semi-flexible' case where only production rates can be modulated. In the semi-flexible case, the model can take advantage of IRES to store fluid in the reservoir and shift output over multi-week periods [16], but must maintain a consistent average flow rate over the year. In the fully-flexible case we enforce a fixed annual cap on the square of injection flow rate, which ensures that long-term temperature decline in the reservoir does not proceed more rapidly than in the inflexible case [32]. Due to this constraint, any increases in injection rate beyond the baseline in certain periods must by offset by greater reductions during other periods. Although injection flexibility therefore comes at

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

the cost of aggregate annual power production, the model still opts to reduce average flow significantly during the period from March through June when hydropower is plentiful, and uses the resulting thermal 'budget' to enable increased flow rates during other parts of the year when power is more valuable. The total energy shifted from the March-June period to other parts of the year in the case shown in Figure 7 (calculated by comparing the baseload and flexible operating profiles) is equivalent to roughly 1100 hours of the baseload plant's average power output. Comparing total system cost reductions from fully flexible, semi-flexible, and inflexible EGS deployment across 18 geothermal drilling, subsurface favorability and market opportunity cases (Supplementary Fig. 23), we find that seasonal shifting typically accounts for 40-60% of the total added value from flexibility.

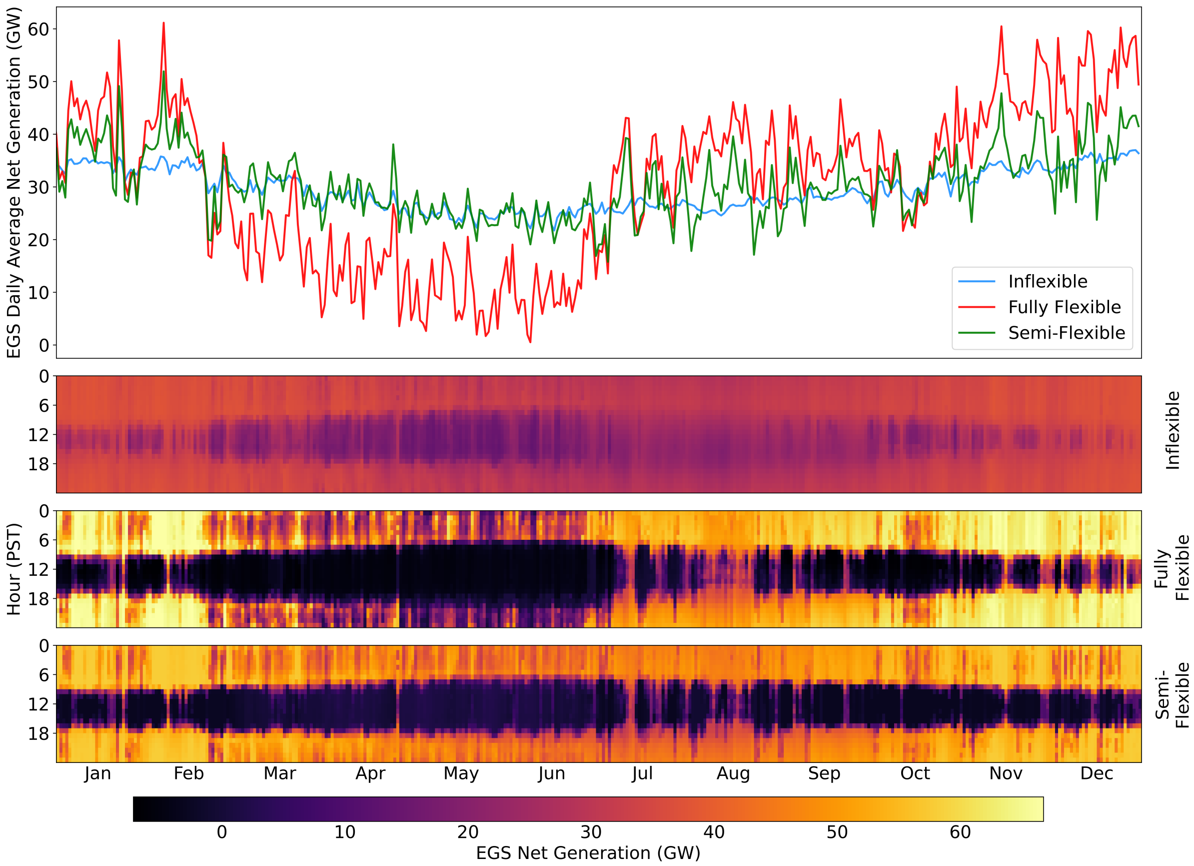

Figure 7: Annual operational profiles for EGS plants. Daily average and hourly system-wide net generation from inflexible, fully flexible, and semi-flexible EGS with 35 GW of baseload capacity over a single weather year. Scenarios assume mid-case market opportunity and subsurface favorability, and baseline drilling.

Both diurnal and seasonal EGS energy shifting come at the cost of reductions in total annual generation, which can be considered analogous to losses in conventional energy storage systems. Maintaining elevated reservoir pressure and increasing injection flow rates during flexible operation both increase pumping power requirements. The need to mitigate thermal decline also forces reductions in aggregate annual power output to compensate for any periods when injection flow rate is elevated above the baseline. On the other hand, flexible EGS plants can take advantage of the fact that air-cooled geothermal power conversion systems have increased thermal efficiency at lower ambient air temperatures (Supplementary Fig. 33) by shifting geofluid production to cooler hours, thereby generating more electricity per unit of geofluid produced. In combination, these factors lead to observed round-trip storage efficiencies across the 18 flexible scenarios shown in Figures 2 and 4 that range from from 59% to 93% (Supplementary Fig. 24). At the high end, observed efficiencies are comparable to Lithium ion battery performance and surpass those of alternative long-duration energy storage technologies [33].

Both the high round-trip efficiencies and diurnal-to-seasonal storage durations offered by flexible EGS distinguish it from potential alternative energy storage technologies. While relatively expensive surface generators must be oversized to enable greater peak power output from EGS plants, the extremely long

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

energy storage durations enabled by the flexible operation of EGS reservoirs come at effectively zero additional cost. Although certain competing long-duration storage technologies, particularly geologic hydrogen storage, could achieve very low (but nonzero) energy capacity costs, these technologies tend to have much lower round-trip storage efficiencies [34]. In isolation, EGS flexibility is therefore a uniquely competitive long-duration energy storage solution, with its primary limitation being the need to develop a full-sized EGS power plant in order to utilize it.

2 Discussion

EGS has the potential to unlock enormous clean energy resources in the United States and elsewhere, delivering firm zero-carbon power with minimal environmental impacts [35]. Still, it remains an early-stage technology, and successful commercialization will hinge on both minimizing its costs *and* maximizing its value in future energy ecosystems. Understanding the impacts of plant design, operational decisions, and systems-level interactions between energy technologies on this latter value term is therefore of great importance to ongoing EGS RD&D efforts.

In the present work we have sought to inform EGS development by comprehensively characterizing the role of this technology in decarbonized electricity systems. We use an electricity system capacity expansion model to determine the cost-optimal deployment and hourly operation of EGS power plants alongside a range of competing technologies in future low- and zero-carbon electricity grids in the western US. Our representation of EGS power plants takes into account regional variability in geothermal resource quality and ambient weather conditions, and utilizes numerical reservoir simulations to accurately characterize the short- and long-term behavior of EGS reservoirs under both flexible and inflexible operating modes. We explore a range of scenarios varying the cost, performance, and operational capabilities of EGS power plants, as well as the costs of competing technologies, and assess the impact of developments in each these areas on the long-run value and deployment potential of geothermal power in the Western Interconnection.

We find that with well-designed and successfully engineered reservoirs, EGS power plants could achieve capital costs on the order of \$5000-6000/kW utilizing current state-of-the-art drilling and power plant technology. If EGS plants in this cost range are operated as baseload generators, we find that realistic deployment targets in a fully decarbonized US Western Interconnection are 30 GW ($\sim$10% of peak system load) or less, and that EGS deployment is unlikely to have a major effect on total electricity system cost. Major advances in deep drilling and high-temperature reservoir engineering could enable EGS costs as low as \$3000/kW by unlocking deep high-temperature resources, and in this case nearly 100 GW of EGS deployment is possible in cost-optimized systems. Deployment of this low-cost EGS reduces electricity system cost by 6-17% depending on the costs of competing technologies. Baseload EGS could thus play a significant role in enabling cost-effective electricity decarbonization if drilling and stimulation technologies continue to advance.

Critically, this work demonstrates that cost reductions are not the only pathway to commercial viability for EGS. By increasing the average value of their energy through flexible operation, EGS plants can achieve significant deployment even at relatively high costs. Due to the need to oversize multiple components (Supplementary Figs. 1 and 2), a flexible EGS plant will actually have a higher levelized cost of electricity (LCOE) than an inflexible one. However, this increased cost is more than made up for by an increase in value to the system, and by extension revenue. This finding suggests that R&D efforts aiming to improve the value of EGS by enabling flexible operations can be considered of similar importance to those that seek to directly reduce geothermal capital costs.

The added value from flexibility can enable EGS deployment in scenarios where it would otherwise fail to find a market, including in partially-decarbonized electricity systems where round-the-clock clean power is not yet fully valued. The ability to gain an early commercial foothold will be critical for an emerging technology like EGS, which could see significant cost reductions through learning-by-doing as adoption increases [26–28]. If successfully-developed EGS cannot find an initial market until the very latest stages of decarbonization, it may fail to unlock significant learning benefits and become locked out of greater market share by competing technologies that do manage to benefit from early scale-up [36]. On the other hand, even limited early deployments could drive learning-based cost reductions that in turn enable further incremental deployment, creating a virtuous cycle that allows EGS to unlock its full potential. This potential is illustrated in our advanced drilling cases, which demonstrate that optimal deployment of flexible, low-cost EGS could reduce bulk electricity system costs in the western US by up to a quarter. By providing both firm, load-following generation and high-efficiency, long-duration energy

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

storage, successfully-scaled flexible EGS could fill a wide range of niches in the electricity system and serve as an ideal complement to cheap, variable wind and solar energy.

Although this study is focused on the geothermal-rich US Western Interconnection, EGS at advanced drilling costs would likely be deployable even in other regions of the country with lower-quality geothermal resources [19], as well as many other areas of the world [37–39]. For example, while far less common than in the more geologically active west, temperatures up to and exceeding 225 °C can be found at depths of 6.5 km or less in certain areas of the eastern US [19], suggesting that economically-competitive EGS with capital costs less than \$3500/kW could be developed there with advanced drilling (see Methods and Supplementary Note 5 for costing methodologies). Developing EGS into a globally-relevant resource will still require initial deployments and learning in regions like the western US, where high-quality geothermal resources are accessible at lower depths and costs. Initiatives that facilitate early EGS development in regions with high resource potential could thus have wide-ranging impacts in the long term, even if the initial projects are only regionally relevant.

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 [19]. 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 and low variable costs to low fixed and 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, 24, 40]. Although we focus primarily on fully-decarbonized systems in this work, we also include cases where zero-carbon resources make up only 80% or 90% of total electricity generation. All scenarios use final load profiles that assume significant electrification of transportation and heating in line with results from Larson et al. [13] 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 Fig. 26. 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 [41] 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 [17, 18], 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. 25). 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. 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. GenX is configurable to allow for varying levels of model complexity, and for this study 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 80%, 90%, or 100% 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 2.

3.2 Modeling Flexible Geothermal Power

This work makes use of a linear model formulation originally developed in Ricks et al. [16] 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 3, 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.

Due to the linear nature of the optimization model, we cannot endogenously represent the impact of changing production flow rates on the temperature of the produced fluid, which affects the amount of electricity generated per unit of geofluid produced. We make a simplifying assumption that the fluid production temperature is constant, which leads to the model slightly underestimating power production during periods of high flow and overestimating it during periods of low flow. Given that the former periods occur when electricity value is highest, this assumption likely underestimates the added value from flexibility. We also assume based on results from reservoir simulations that short-term changes in production flow rate due to IRES do not have a significant impact on long-run reservoir thermal decline rates (see Supplementary Fig. 35). However, given that analytical models of EGS represent non-dimensional time as a function of flow rate squared [32], we do place a constraint on the annual sum of (linearized) fluid injection rate squared, reflecting the need to maintain the reservoir's thermal decline rate under flexible operations.

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 [42]. 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. Initial field tests of flexible EGS operations have confirmed the accuracy of the reservoir simulation methodology used here and the basic technical feasibility of the reservoir design [43]. Reservoir simulation outputs relevant to the electricity

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

systems modeling 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 subsurface favorability cases vary the permeability of the reservoir rock matrix and conductivity of engineered fractures as detailed in Table 1. Further details on simulation methodology are provided in Supplementary Note 4.

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 Supplementary Fig. 27, could theoretically be of indefinite width. 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. This flow rate, which is generally achieved at injection wellhead pressures below 3 MPa, is higher than what has been demonstrated in EGS field tests to date [21]. In the present work the high simulated per-well flow rate is a product of the very long lateral sections in our standard reservoir design, which enable a much larger stimulated reservoir volume and increased connectivity between wells compared to past real-world projects. The flow rate per unit of well lateral length assumed in this work is consistent with what has been demonstrated at the most recent EGS field tests [43], where steady-state flow rates of ∼40 l/s were maintained in a doublet well system with 1067 m laterals. We also performed production forecast simulations using this well pattern and reservoir engineering design to evaluate the long-term thermal performance of the system, and 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 an ORC power plant design. In addition, we found that frequent changes in production flow 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 two greatest sources of uncertainty), the capital cost of an EGS power plant could range from less than \$3000/kW to more than \$30000/kW [4, 24]. We do not attempt to predict a single trajectory for future EGS costs in this work, but rather to calculate expected costs under two distinct technology development scenarios on opposite ends of the range of plausible commercially viable outcomes.

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 and consistently 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 basic 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 [44, 45]. 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. [21], which we modify to reflect recent drilling cost and performance trends and differences in well design. Supplementary Fig. 29 shows calculated drilling cost as a function of depth (not inclusive of stimulation costs) for both baseline and advanced cases. For surface power plant costing we use NREL's

Geothermal Electricity Technology Evaluation Model (GETEM) [22], 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 [11]. A more detailed description of EGS wellfield and surface plant costing methodology is provided in Supplementary Note 5.

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. [19], which covers depths from 3.5 to 10 km, and Mullane et al. [46], 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 [20], which are in turn based on temperature-at-depth data from Blackwell et al. [19]. 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. We calculate regional potential at depths of 1.5 km and 2.5 km directly using datasets provided in Mullane et al. [46], using the same temperature bins, resource zones, and exclusion layers as were used by Augustine [20] 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. [47]. Supplementary Note 7 provides a more detailed description of the process used to develop resource potential estimates. Supplementary Fig. 37 shows full EGS supply curves for the western US, which incorporate the resource potential estimates and costing methodologies described above. Supplementary Fig. 38 shows local supply curves for each model zone.

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, 9]. 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 [23, 48]. 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 [48]. 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 [49]. 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 Fig. 36. 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

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

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, subsurface favorability, 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 geologic 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 for low subsurface favorability scenarios assume uniform rock matrix properties, as well as robust connections between injection and production wells enabled via large numbers of discrete, uniform flow pathways. If fractures providing strong connections between wells cannot be reliably and consistently propagated, real EGS reservoirs could see performance that is significantly reduced even relative to our low favorability scenarios, increasing the number and length of wells that need to be drilled and reducing the economic competitiveness of the technology. Nonuniformities in reservoir characteristics could have unforeseen impacts on reservoir performance under both flexible and inflexible operations, and could lead to accelerated thermal drawdown [50]. 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. Finally, 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 limits on bottomhole pressures 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 processes, 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

All GenX input and results datasets relevant to this study are available at `https://doi.org/10.5281/zenodo.7023225` [51]. 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`. Source code for the modified version of GenX used in this work is available in the same repository as the results dataset.

Acknowledgements

This work was supported by the US Department of Energy Office of Science SBIR program under Award No. DE-SC0020823 (W.R., J.D.J., J.H.N., K.V., G.G.), and by Princeton University's Zero-Carbon Technology Consortium, which is funded by gifts from Breakthrough Energy, ClearPath, GE, and Google (W.R., J.D.J.). The authors thank all referees for their constructive engagement throughout the review process.

Author information

Authors and Affiliations

Andlinger Center for Energy and the Environment and Department of Mechanical and Aerospace Engineering, Princeton University, Princeton, NJ, USA
Wilson Ricks
Jesse D. Jenkins
Fervo Energy, Houston, TX, USA
Katharine Voller
Gerame Galban
Jack H. Norbeck

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. and G.G. 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, revised, and finalized the manuscript. J.D.J. and J.H.N. advised on the analysis and reviewed and revised the manuscript.

Corresponding Author

Correspondence to Wilson Ricks, wricks@princeton.edu.

Ethics Declarations

K.V., G.G., 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. Clients within the last 12 months include Radia Inc. and Rice Acquisition Corp II (now dba NET Power Inc.). He serves on the advisory boards of Eavor Technologies Inc., a closed-loop geothermal technology company, and Rondo Energy, a provider of high-temperature thermal energy storage and industrial decarbonization solutions, and has an equity interest in both companies. 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. W.R. has performed consulting work for Isometric, a carbon removal standard and registry.

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

References

[1] N. Sepulveda, J. Jenkins, F. de Sisternes, and R. Lester, "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation," *Joule*, vol. 2, no. 11, pp. 2403–2420, 2018.

[2] E. Baik, K. P. Chawla, J. D. Jenkins, C. Kolster, N. S. Patankar, A. Olson, S. M. Benson, and J. C. Long, "What is different about different net-zero carbon electricity systems?" *Energy and Climate Change*, vol. 2, p. 100046, 2021.

[3] W. J. Cole, D. Greer, P. Denholm, A. W. Frazier, S. Machen, T. Mai, N. Vincent, and S. F. Baldwin, "Quantifying the challenge of reaching a 100% renewable energy power system for the United States," *Joule*, vol. 5, no. 7, pp. 1732–1748, 2021. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S2542435121002464

[4] "GeoVision," U.S. Department of Energy (DOE), Tech. Rep., 2019.

[5] "Annual Energy Outlook 2021," U. S. Energy Information Administration (EIA), Washington, D.C., Tech. Rep., 2021.

[6] C. Williams, M. Reed, R. Mariner, J. DeAngelo, and S. Galanis, "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States," U.S. Geological Survey (USGS), Menlo Park, CA, Tech. Rep. 2008-3082, 2008.

[7] "The Future of Geothermal Energy," Idaho National Laboratory, Idaho Falls, ID, Tech. Rep. INL/EXT-06-11746, 2006.

[8] C. Augustine, S. Fisher, J. Ho, I. Warren, and E. Witter, "Enhanced Geothermal Shot Analysis for the Geothermal Technologies Office," National Renewable Energy Laboratory, Golden, CO, Tech. Rep. NREL/TP-5700-84822, 2023.

[9] J. Cochran and P. Denholm, "The Los Angeles 100% Renewable Energy Study," National Renewable Energy Laboratory, Golden, CO, Tech. Rep. NREL/TP-6A20-79444, 2021.

[10] P. Denholm, P. Brown, W. Cole, T. Mai, B. Sergi, M. Brown, P. Jadun, J. Ho, J. Mayernik, C. McMillan, and R. Sreenath, "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," National Renewable Energy Laboratory, Golden, CO, Tech. Rep. NREL/TP6A40-81644, 2022.

[11] B. Matek, "Flexible opportunities with geothermal technology: Barriers and opportunities," *The Electricity Journal*, vol. 28, pp. 45–51, 2015.

[12] Jenkins, Jesse D., Luke, Max, and Thernstrom, Samuel, "Getting to Zero Carbon Emissions in the Electric Power Sector," *Joule*, vol. 2, no. 12, pp. 2498–2510, 2018. [Online]. Available: https://doi.org/10.1016/j.joule.2018.11.013

[13] E. Larson, C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, E. Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, "Net-Zero America: Potential Pathways, Infrastructure, and Impacts," Princeton, NJ, 2020.

[14] C. Clack, A. Choukulkar, B. Coté, and S. McKee, "A Plan for Economy-Wide Decarbonization of the United States," Vibrant Clean Energy, LLC, Boulder, CO, Tech. Rep., 2021.

[15] J. H. Williams, R. A. Jones, B. Haley, G. Kwok, J. Hargreaves, J. Farbes, and M. S. Torn, "Carbon-Neutral Pathways for the United States," *AGU Advances*, vol. 2, no. 1, p. e2020AV000284, 2021.

[16] W. Ricks, J. Norbeck, and J. Jenkins, "The value of in-reservoir energy storage for flexible dispatch of geothermal power," *Applied Energy*, vol. 313, p. 118807, 2022.

[17] J. Jenkins and N. Sepulveda, "Enhanced Decision Support for a Changing Electricity Landscape: The GenX Configurable Electricity Resource Capacity Expansion Model," MIT Energy Initiative, Cambridge, MA, Working Paper, 2017.

[18] "GenX: a configurable power system capacity expansion model for studying low-carbon energy futures," 2022. [Online]. Available: https://github.com/GenXProject/GenX

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

[19] D. Blackwell, M. Richards, Z. Frone, J. Batir, A. Ruzo, R. Dingwall, and M. Williams, "Temperature-At-Depth Maps for the Conterminous U. S. and Geothermal Resource Estimates," *GRC Transactions*, vol. 31, pp. 1545–1550, 2011.

[20] C. Augustine, "Update to Enhanced Geothermal System Resource Potential Estimate," 2016, National Renewable Energy Laboratory. Presented at the 40th GRC Annual Meeting, Sacramento, CA, 2016.

[21] T. S. Lowry, J. T. Finger, A. Foris, M. B. Kennedy, T. F. Corbet, C. A. Doughty, S. Pye, and E. L. Sonnenthal, "GeoVision Analysis Supporting Task Force Report: Reservoir Maintenance and Development," Sandia National Laboratories, Albuquerque, NW, Tech. Rep. SAND2017-9977, 2017.

[22] G. Mines, "GETEM User Manual," Idaho National Laboratories, Idaho Falls, ID, Tech. Rep. INL/EXT-16-38751, 2016.

[23] E. Michaelides and D. Michaelides, "The effect of ambient temperature fluctuation on the performance of geothermal power plants," *Int. J. of Exergy*, vol. 8, pp. 86 – 98, 2011.

[24] "2021 Annual Technology Baseline," National Renewable Energy Laboratory, Golden, CO, Tech. Rep., 2021.

[25] C. E. Manning and S. Ingebritsen, "Permeability of the Continental Crust: Implications of Geothermal Data and Metamorphic Systems," *Reviews of Geophysics*, vol. 37, 1, pp. 127–150, 1999.

[26] R. Way, M. Ives, P. Mealy, and J. Farmer, "Empirically grounded technology forecasts and the energy transition," *Joule*, vol. 6, no. 9, pp. 2057–2082, 2022.

[27] A. Malhotra and T. S. Schmidt, "Accelerating low-carbon innovation," *Joule*, vol. 4, no. 11, pp. 2259–2267, 2020. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S2542435120304402

[28] T. Latimer and P. Meier, "Use of the experience curve to understand economics for at-scale egs projects," in *Proceedings of the 42nd Workshop on Geothermal Reservoir Engineering*, Stanford, CA, February 2017.

[29] J. Rutqvist, L. Pan, N. Spycher, P. Dobson, Q. Zhou, and M. Hu, "Coupled Process Analysis of Flexible Geothermal Production from Steam- and Liquid-Dominated Systems: Impact on Wells," in *Proceedings of the 45th Workshop on Geothermal Reservoir Engineering*, Stanford, CA, 2020.

[30] J. Rutqvist, L. Pan, P. Dobson, Q. Zhou, and M. Hu, "Coupled Process Analysis of Flexible Geothermal Production from a Liquid-Dominated System: Impact on Wells," in *Proceedings of the World Geothermal Congress 2020+1*, Reykjavik, Iceland, 2021.

[31] A. Pollack, R. Horne, and T. Mukerji, "What Are the Challenges in Developing Enhanced Geothermal Systems (EGS)? Observations from 64 EGS Sites," in *Proceedings of the World Geothermal Congress 2020+1*, Reykjavik, Iceland, 2021.

[32] C. Augustine, "A Methodology for Calculating EGS Electricity Generation Potential Based on the Gringarten Model for Heat Extraction From Fractured Rock," *GRC Transactions*, vol. 40, 2016.

[33] N. Sepulveda, J. Jenkins, A. Edington, D. S. Mallapragada, and R. Lester, "The design space for long-duration energy storage in decarbonized power systems," *Nature Energy*, 2021.

[34] V. Viswanathan, K. Mongird, R. Franks, X. Li, V. Sprenkle, and R. Baxter, "2022 Grid Energy Storage Technology Cost and Performance Assessment," Pacific Northwest National Lab, Richland, WA, Tech. Rep. PNNL-33283, 2022.

[35] J. Lovering, M. Swain, L. Blomqvist, and R. R. Hernandez, "Land-use intensity of electricity production and tomorrow's energy landscape," *PLOS ONE*, vol. 17, no. 7, pp. 1–17, 07 2022. [Online]. Available: https://doi.org/10.1371/journal.pone.0270155

[36] L. Haelg, M. Waelchli, and T. S. Schmidt, "Supporting energy technology deployment while avoiding unintended technological lock-in: a policy design perspective," *Environmental Research Letters*, vol. 13, no. 10, p. 104011, oct 2018. [Online]. Available: https://dx.doi.org/10.1088/1748-9326/aae161

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.

[37] Baillieux, Paul, "Multidisciplinary Approach to Understand the Localization of Geothermal Anomalies in the Upper Rhine Grabel From Regional to Local Scale," Ph.D. dissertation, University of Neuchatel, 2013.

[38] S. Huang, "Geothermal energy in China," *Nature Climate Change*, vol. 2, pp. 557–560, 2012.

[39] S. Grasby, D. Allen, S. Bell, Z. Chen, G. Ferguson, A. Jessop, M. Kelman, M. Ko, J. Majorowicz, M. Moore, J. Raymond, and R. Therrien, "Geothermal Energy Resource Potential of Canada," Geological Survey of Canada, Tech. Rep., 2012.

[40] T. Mai, P. Jadun, J. Logan, C. McMillan, M. Muratori, D. Steinberg, L. Vimmerstedt, R. Jones, B. Haley, and B. Nelson, "Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption in the United States," National Renewable Energy Laboratory, Golden, CO, Tech. Rep. NREL/TP-6A20-71500, 2018.

[41] G. Schivley, E. Welty, N. Patankar, A. Jacobson, Q. Xu, A. Manocha, and J. D. Jenkins, "PowerGenome/PowerGenome: v0.5.4," 2022. [Online]. Available: https://doi.org/10.5281/zenodo.6092712

[42] M. McClure, C. Kang, C. Hewson, and S. Medam, "ResFrac Technical Writeup," ResFrac Corporation, Palo Alto, CA, Tech. Rep., 2021, https://www.resfrac.com/wp-content/uploads/2021/06/ResFrac-Technical-Writeup-February-13-2021.pdf.

[43] J. Norbeck and T. Latimer, "Commercial-Scale Demonstration of a First-of-a-Kind Enhanced Geothermal System," 2023, Working paper. Available: https://doi.org/10.31223/X52X0B.

[44] F. Dupriest and S. Noynaert, "Drilling Practices and Workflows for Geothermal Operations," in *SPE/IADC Drilling Conference and Exhibition*, 2022.

[45] "Utah FORGE Wraps Up A 3-Stage Hydraulic Stimulation OF Well 16A(78)-32," 2022, U.S. Department of Energy, Utah FORGE. [Online]. Available: https://utahforge.com/2022/04/27/utah-forge-wraps-up-a-3-stage-hydraulic-stimulation-of-well-16a78-32/

[46] M. Mullane, M. Gleason, K. McCabe, M. Mooney, T. Reber, and K. Young, "An Estimate of Shallow, Low-Temperature Geothermal Resources of the United States," 2016, national Renewable Energy Laboratory. Presented at the 40th GRC Annual Meeting, Sacramento, CA, 2016.

[47] J. D. Jenkins, E. N. Mayfield, J. Farbes, R. Jones, N. Patankar, Q. Xu, and G. Schivley, "Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022," REPEAT Project, Tech. Rep., 2022.

[48] M. Karadas, H. M. Celik, U. Serpen, and M. Toksoy, "Multiple regression analysis of performance parameters of a binary cycle geothermal power plant," *Geothermics*, vol. 54, pp. 68–75, 2015. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0375650514001333

[49] "Hourly/Sub-Hourly Observational Data Version 3.0.0," 2021, National Oceanic and Atmospheric Administration, National Centers for Environmental Information. https://www.ncei.noaa.gov/maps/hourly/.

[50] M. L. McLean and D. N. Espinoza, "Thermal destressing: Implications for short-circuiting in enhanced geothermal systems," *Renewable Energy*, vol. 202, pp. 736–755, 2023. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0960148122017426

[51] W. Ricks, K. Voller, G. Galban, J. Norbeck, and J. Jenkins, "The Role of Flexible Geothermal Power in Decarbonized Electricity Systems: Supplementary Data," 2022.

This is a working paper. The published version is available at https://doi.org/10.1038/s41560-023-01437-y.