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U.S. DEPARTMENT OF ENERGY

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Executive Summary

Geothermal energy presents a significant opportunity for the United States (US). The US has the largest known geothermal resource in the world, with over 31 GW of conventional geothermal (i.e., hydrothermal) potential and another 5,158 GW of enhanced geothermal potential (DOE-GTO 2019). Despite this, the development of geothermal power plants has lagged other renewable resources. Though some of this gap stems from technical barriers and costs, several non-technical barriers are also preventing geothermal energy from reaching its potential. These gaps include a need to reduce the cost impacts of seismic risk, environmental risk, resource exploration, resource drilling, permitting, and variability in plant output by season (e.g., reductions in summer capacity). Ultimately, these barriers manifest in the difficulty of geothermal project developers to compete with wind and solar resources, and successfully contract the output of potential projects with off takers. This report identifies pathways to overcome this contracting challenge. We find that geothermal energy could increase its market presence by acting as a complement to lower cost renewables, providing firm baseload power in low carbon future scenarios as well as a delivering system flexibility. We also outline several contractual and operational strategies that resource developers and government regulators and policymakers can pursue to improve the value of geothermal resources, including pushing for multi-part remuneration mechanisms that guarantee revenue (e.g., availability payments or a contract for differences[1] approach) or resource risk hedging approaches (e.g., shaped market products and portfolio resource approaches).

Starting with an overview of the resource's properties, we conduct four separate analyses which speak to geothermal energy's development environment. This report is focused on hydrothermal resources (although we do address the potential for enhanced geothermal systems). Accordingly, the analysis effort is largely restricted to those regions with strong hydrothermal resources – the Western U.S., and in particular, the states of California, Oregon, Idaho, Utah, Nevada, New Mexico and Hawaii. See Figure ES-1 for the locations of existing geothermal power plants.

First, we provide a qualitative review of known risks within the geothermal energy development process, focusing on risk mitigation and remediation strategies. Next, we conduct a quantitative examination of historical generation contract prices, or power purchase agreements (PPAs), to help identify electric market trends and opportunities for geothermal power. After that, we evaluate a variety of PPA contracts (for both fossil and renewable resources) to identify mechanisms and strategies that could help to address some of the risks faced by geothermal developers or enhance system revenues. Finally, we conduct a techno-economic optimization and *pro forma* evaluation of some of the contract mechanisms and strategies using data from existing geothermal power plants.

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[1] Here, contract for differences refers to a government financial support mechanism used in the United Kingdom for power production, not the illegal securities contract in the United States.

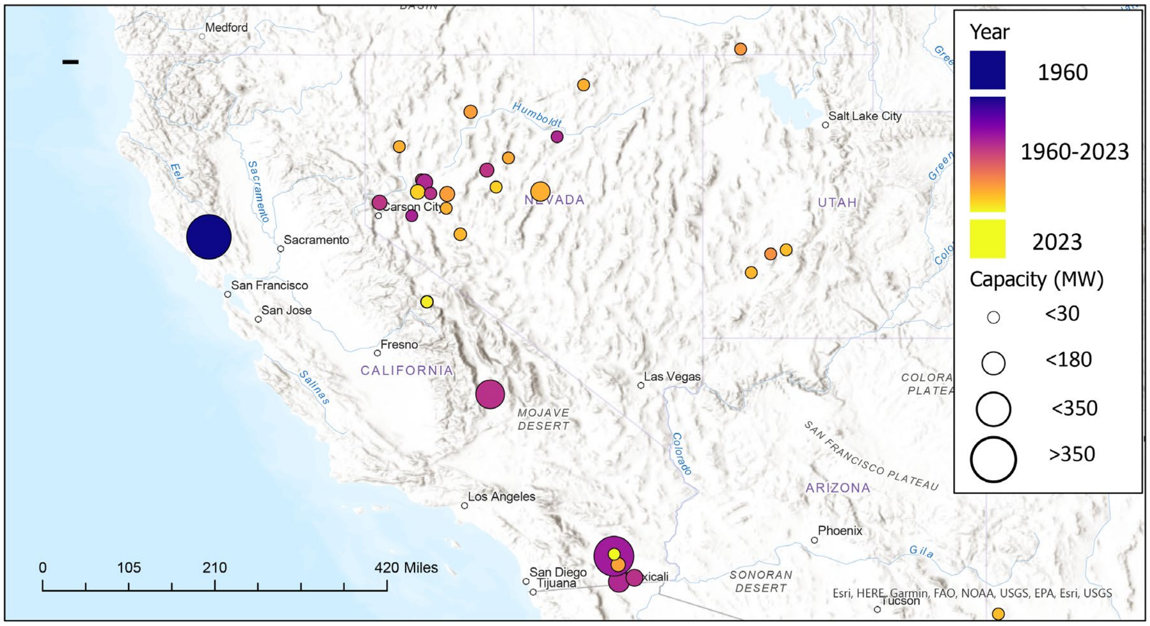

Figure ES-1. Location of active and planned power plants in the US western states (ARCGIS database created for the project). There is an additional project on the island of Hawai'i in Hawaii. Color scale corresponds to the year of creation of the power plant and the size of the symbol corresponds to its capacity in MW.

Key Findings

For the development risk analysis, we focus on pain points within the exploration, drilling, and construction process. While most of a project's risk and uncertainty stems from the resource identification and verification stage of development, other factors like environmental risks, and capacity risk (stemming from some geothermal power plants being unable to generate at their full capacity potential in the summer heat) can also threaten geothermal power profitability. We find that policy changes (such as loan guarantees and tax credits), as well as operational improvements (e.g., improving climate forecasts, power plant hybridization) could help mitigate these risks.

- Geothermal energy production could benefit from additional government support, such as the underwriting of loans or provision of grants. Federal and state incentives may further improve the upfront financial situation for project development by reducing project costs through the following mechanisms:
  - feed-in tariffs, accelerated depreciation and investment tax credits[2]; some states exempt projects from property and sales taxes;
  - mandates to ease the contract approval process which can create markets for environmental value; and
  - indirect mechanisms, such as increasing renewable portfolio standards across the US to create financial incentives like renewable energy credits (RECs), or the need for additional firm capacity.

[2] *See* the DSIRE database for a list of current federal and state incentives for geothermal projects.

In the historical PPA analysis, we examine and compare price and market trends for geothermal, wind, solar and hydroelectric power. We find few statistically and economically significant relationships between geothermal PPA prices and electricity market conditions (see Figure ES-2) but use our findings from the wind, solar, and hydroelectricity sections to identify potential market niches for geothermal energy. We find that geothermal electricity could be competitive in areas with high renewable penetration, due to its high-capacity factors and ability to provide flexible power. However, it will need to compete with offshore wind, onshore wind, and solar all coupled with energy storage, that have seen declining technology costs.

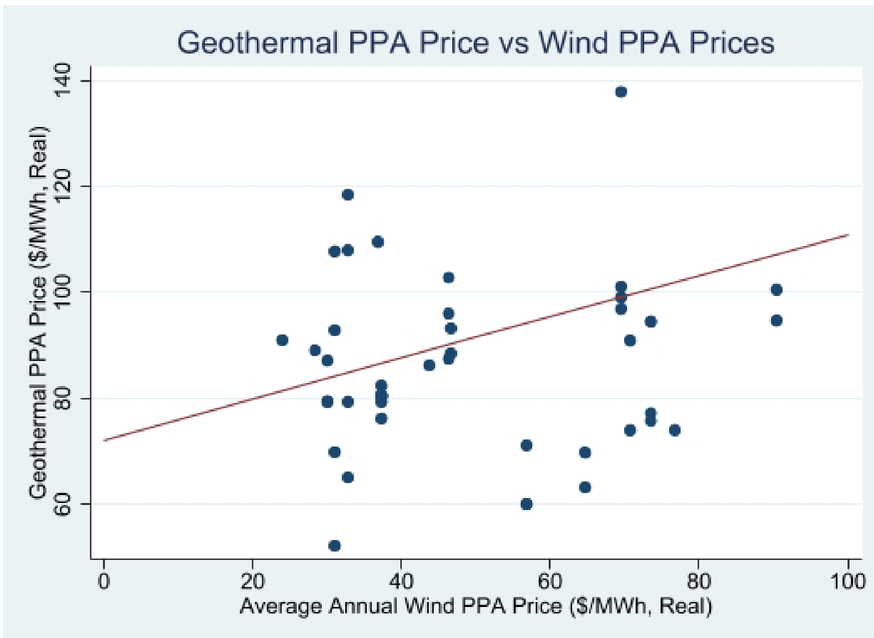

Figure ES-2. Geothermal and wind power contract price relationship.

- Though we find significant relationships between wind, solar, and hydroelectric prices, and market conditions, we have difficulty making similar claims for geothermal prices.
- Purchasers may be treating wind as a marginal renewable, with geothermal being forced to compete with declining wind prices, a significant barrier to entry for new geothermal plants.
- The analysis indicates that new sources of generation are in fierce competition with each other, and solar and wind prices (as well as wind and natural gas prices) are tightly correlated. This poses a challenge for geothermal energy, which historically has seen much higher costs than wind or solar power.
- As an example, California is seeking to manage issues related to the duck curve, through improved flexibility and complementary resources to solar (Lazard 2016). Geothermal energy could play a significant role in complementing low-cost PV (Section 5.2), but other technologies may compete for some share of capacity.

We also conduct a qualitative analysis of electricity contracts, reviewing 30 contracts for both fossil and renewable power plants, including geothermal resources, as identified in Figure ES-3.

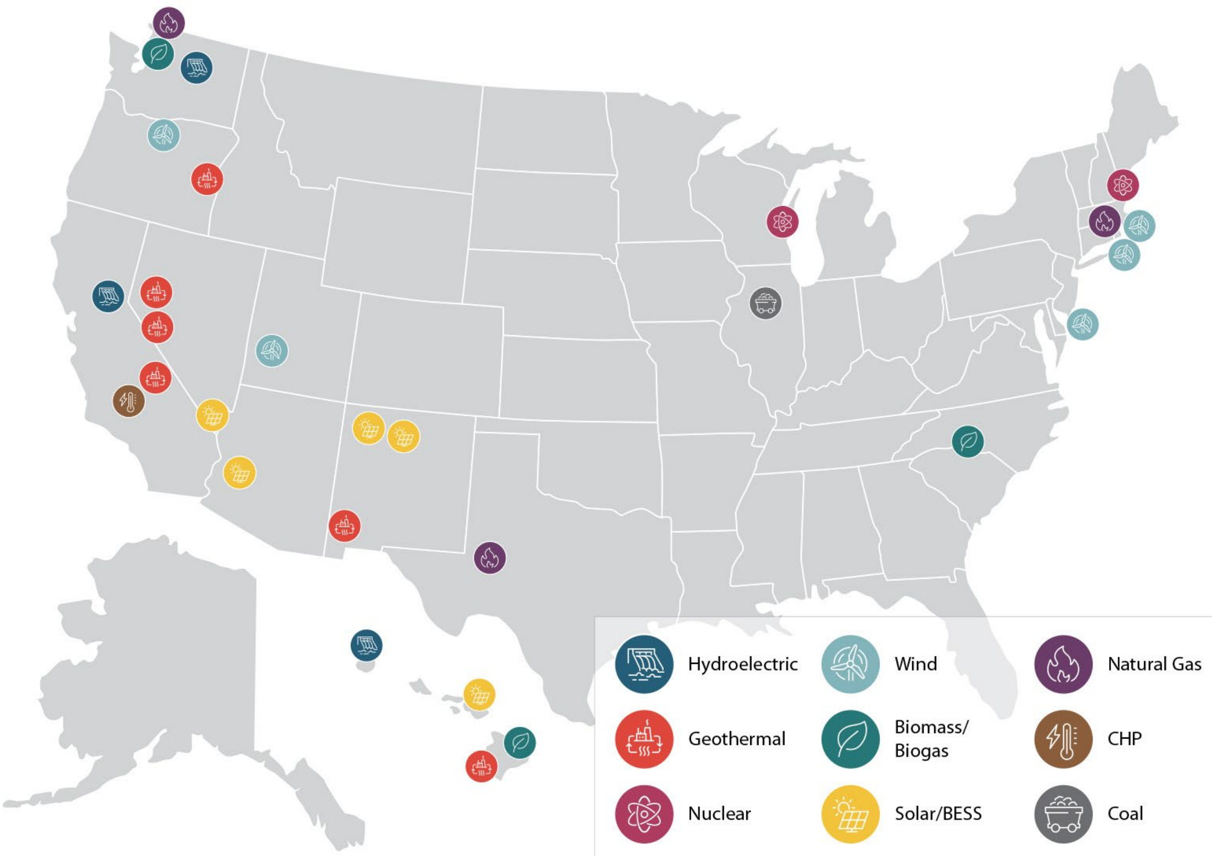

Figure ES-3. Map of the United States showing locations of energy projects whose PPAs were analyzed for this report. The symbols represent energy resource.

We find several novel payment and structuring options that could be beneficial for geothermal energy projects. First, contracts that include payments for factors beyond energy delivery (e.g., capacity, availability, or ancillary services) could provide additional value streams for geothermal developers while providing explicitly defined services for off takers and a firm, dispatchable and potentially flexible resource. Next, contracts that specifically address the risk associated with the geothermal resource could provide greater generation and operation output certainty for geothermal developers and operators and financiers. Finally, emerging market phenomena like plant hybridization, and new customer opportunities such as data centers and community choice aggregators (CCAs) deserve greater attention from geothermal developers.

- Because geothermal resources have the potential to provide both baseload capacity and flexible generation, this is an area where developers may be able to leverage resource value in the form of multi part contract remuneration structures to consider energy, capacity, availability, and grid services.
- The Ormat Northern Nevada Geothermal Portfolio contract provides an innovative approach. It features a large-capacity contract, which minimizes the risk of resource inadequacy by building a contract around a portfolio of geothermal plants, including backup plants in case one of the initially proposed plants proves insufficient to meet the capacity requirements.
- Given the fact that geothermal production can sometimes face seasonal variation, the potential to include seasonally variable output requirements (e.g., lower output

requirements in the summer when air temperatures are high) could be beneficial for future geothermal contracts.

- Flexibility through curtailment: In the Puna Geothermal Venture contract, during a curtailment event, the buyer continues to pay the capacity charge set in the contract but does not pay an energy price for deemed energy. This approach allows flexibility for the buyer while still providing guaranteed income for the seller. By structuring the curtailment process this way, PGV can make good on the potential for geothermal energy to act, not only as a firm baseload power supply, but also in a flexible capacity, providing the grid with a dispatchable energy supply that is available to make up shortfalls from variable energy sources.
- Two underperformance terms may be of particular interest for geothermal contracts. First is the ability for the net capacity stipulated in the contract to be derated because of underperformance rather than terminating the contract. This approach allows for adjustment to the capacity of the plant throughout the duration of the contract if the geothermal resource behaves differently than anticipated (e.g., the resource is depleted more quickly than anticipated). Second is the ability to make up energy shortfalls from one year in the following year. This would allow a geothermal plant to avoid damages from underperformance due to an anomalous year (e.g., significant summer underperformance resulting from high summer temperatures).

Our final analysis is the techno-economic optimization and *pro forma*[3] modelling of several hypothetical geothermal power plants as identified in Table ES-1. We identify potential revenue streams and investment returns that plant operators could receive if they were to explore different contract mechanisms and market opportunities. We find that though some geothermal plants are unprofitable in traditional market arrangements, developers that seek out new revenue streams like ancillary services, hybridize their geothermal resources with energy storage, or aim to sell their power under stable contracts to corporate off takers could improve their profitability and offer a more attractive rate of return to investors. Of course, decreasing technology costs also improve plant profitability.

Table ES-1 Case study projects: configuration and details

	Location	Type of plant	Configuration	Services	Grid Service Prices
1	Geysers (CAISO)	standard hydrothermal	Standalone; hybrid with battery	CAISO market services; corporate contract	CAISO market
2	Eastern Oregon	standard hydrothermal	Hybrid with battery/PV	Energy and ancillary services in a vertically integrated environment	WECC PCM Model HydroWires
3	East Coast (NYISO)	enhanced geothermal (EGS)	Standalone	NYISO services; corporate contract	NYISO Market

CAISO = California Independent System Operator; EGS = enhanced geothermal system; NYISO = New York Independent System Operator; WECC = Western Electricity Coordinating Council.

[3] A pro forma is a statement of cash flows including tax credits, accelerated depreciation, and other incentives that allows developers/investors to understand whether the project will provide adequate profits to meet investment requirements.

- The baseline California case almost meets the IRR hurdle rate threshold of 8%. Neither the Eastern Oregon nor the New York EGS baseline projects get near the hurdle rate. Adding the resource adequacy (capacity) payment increases the IRR above the hurdle rate, from 7.5% to 13%. The debt coverage ratio appears more than adequate to reduce the risk of default and allow a 70/30 debt equity ratio for the developer.

- Leveraging additional revenue streams, beyond energy, presents a significant improvement in project revenue across all projects relative to just energy delivery. In California (see Figure ES-4) and New York in particular, the delivery of ancillary services, specifically frequency regulation, represents significant value with a limited impact on energy generation.

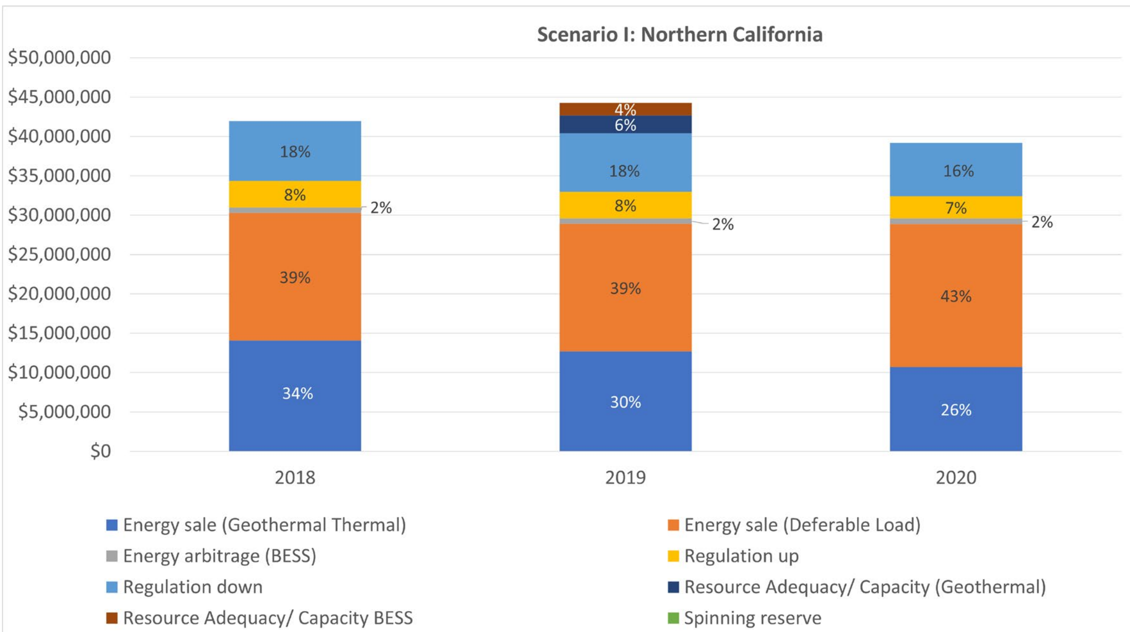

Figure ES-4. Annual benefits by year for the California case study (discussed in Section 6.0).

- Unfortunately, market prices or other estimates for other services such as inertia and primary frequency response are not readily available or easily calculated given the lack of market products.[4] However, these additional revenue streams would improve the viability of geothermal projects. It is important to note that geothermal plants by virtue of being spinning machinery automatically deliver physical inertia, but inverter-based (i.e., power electronics) resources like wind and solar, do not, yet both sets of resources receive the same compensation.

[4] Power system operators place an increased value on physical inertia delivered by spinning machinery. Synthetic inertia from power electronics associated with battery or other variable renewable systems has not been used in any significant quantity to prove itself for grid reliability in the absence of physical inertia. Further, using a battery system or variable renewables to deliver synthetic inertia requires holding back capacity from other services or operations. That is not the case with physical inertia and spinning machinery.

- As expected, as development costs decrease, IRR improves. Meeting the GTO's GeoVision report targets would present an improved base case for the California case study and a reasonable contract price for the New York case study. With the reduced costs, price levels identified are far below recent contracts for offshore wind.

- A steady revenue stream, such as the simulated corporate revenue in the California and New York examples, may be critical to maintaining IRR with uncertain future project revenues.

- Coupling geothermal resources with battery storage or PV systems may provide new revenue streams to a particular developer, but these added elements are largely additive. That is, revenue from a standalone geothermal system, a standalone battery system, and a standalone PV system will roughly sum to the revenue of the combined systems. That said, in the right market conditions and as the electric industry evolves, such hybridization may present additional value. For example, one could foresee a situation in which specific plant performance requirements necessitate the addition of a battery, or the addition of solar PV leverages land acquired, and electric infrastructure built for a geothermal development and compensates for any uncertainty in geothermal output.

We finish with a discussion of local economic impacts of geothermal development and pathways to a just transition away from fossil fuel use. We also consider next steps for research based on our work.

Overall, we conclude that though geothermal development has been limited to date, significant potential exists for new development, particularly as the nation moves towards an increasingly clean energy system with a heavy reliance on variable renewable technologies, while also electrifying transportation, industry and the economy at large, further increasing demand on the electric system. In the future grid environment where dispatchable fossil resources are not available, and hydroelectric and nuclear resources are likely to see limited buildout, geothermal technologies can play a crucial role in western states of providing a firm and predictable clean energy source that can also deliver grid services and flexibility.

However, as we find, and is evidenced by the lack of much recent development as well as some of the reasons behind development in the past, new geothermal development will require a concerted effort between the geothermal industry, system operators, and government entities, to enable geothermal resources to compete fairly in the energy system and appropriately compensate its characteristics, while also supporting the industry in reaching a point of competitiveness in costs and performance. This effort will require programs designed to lower exploration and capital costs, improving development and operational risk assessments, market mechanisms that compensate for capacity and grid services, and funds for further research and development. All of these will ultimately have to be incorporated into contracting mechanisms between geothermal developers and off takers.

Fortunately, there has been recent recognition in the electric industry that firm and reliable system capacity will be a critical component of future grids, and renewable resources that can deliver this capacity are limited. Geothermal resources can meet this need. They just need to be enabled to do so.

Acknowledgments

The authors wish to express their gratitude for the sponsorship and guidance of Sean Porse, Jeff Winick, and Jennifer Livermore (Boston Government Services, LLC) with the Geothermal Technologies Office Data, Modeling, and Analysis Program at the U.S. Department of Energy and to Susan Hamm, Director of the Geothermal Technologies Office, for her review. The authors also wish to express their thanks to the other Geothermal Technologies Office staff and several geothermal and electric industry stakeholders who contributed their time for interviews to discuss geothermal development and for providing feedback on early versions of this report. These include Susan Petty (Cyrq Energy), Aaron Mandell (GPV Fund), Adam Lewis, Garrison Marr (Snohomish County PUD), Jason Czapla (Commonwealth Scientific and Industrial Research Organisation), and Rose Anderson (Oregon Public Utilities Commission). Finally, the authors thank Dave Goodman, Patrick Mirick, Kyle Wilson, Dave Anderson, Hunter Knox, Casie Davidson, and TJ Heibel (Pacific Northwest National Laboratory) for their thoughtful insight and reviews.

Acronyms and Abbreviations

AGC	automated generation control
BESS	battery energy storage system
C	Centigrade or Celsius
CAISO	California Independent System Operator
CEC	California Energy Commission
CFE	carbon pollution-free electricity
CO_2	carbon dioxide
COD	Commercial Operation Date
ComEd	Commonwealth Edison Company
CHP	combined heat and power
CSP	concentrated solar power
CX	categorical exclusion
CREZ	Competitive Renewable Energy Zone
DCR	debt coverage ratio
DOE	Department of Energy
EA	Environmental Assessment
EAF	equivalent availability factor
EFOR	equivalent forced outage rate
EGS	enhanced geothermal systems
EIS	Environmental Impact Statement
EO	Executive Order
EPCA	Energy Policy and Conservation Act
ESET	Energy Storage Evaluation Tool
EU	European Union
FERC	Federal Energy Regulatory Commission
FORGE	Frontier Observatory for Research in Geothermal Energy
GEA	Geothermal Energy Association
GETEM	Geothermal Electricity Technology Evaluation Model
GLGP	Geothermal Loan Guarantee Program
GTO	Department of Energy Geothermal Technologies Office
GW	gigawatt
HDR	hot dry rock
HELCO	Hawai'i Electric Light Company
IRR	internal rate of return
IRS	Internal Revenue Service
JEDI	Jobs and Economic Development Impact

k	permeability
kWh	kilowatt hour
LCOE	Levelized cost of electricity
LCOS	Levelized cost of storage
MCE	Marin Clean Energy
MW	megawatt
MWh	megawatt hour
N_2	nitrogen
NEPA	National Environmental Policy Act of 1969
NPV	net present value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	operations and maintenance
ONGP	Ormat Northern Nevada Geothermal Portfolio
ORC	Organic Rankine Cycle
PCM	production cost model
PG&E	Pacific Gas & Electric Company
PGV	Puna Geothermal Venture
PNM	Public Service Company of New Mexico
PNNL	Pacific Northwest National Laboratory
PPA	power purchase agreement
PSH	pumped storage hydropower
PUCT	Public Utilities Commission of Texas
PV	photovoltaic
RA	resource adequacy
RCP	representative concentration pathway
REC	renewable energy credit
RPS	Renewable Portfolio Standard
RTO	regional transmission organization
SHR	super-hot rock
SCPPA	Southern California Public Power Authority
TI	technology improvement
US	United States
VRE	variable renewable energy
WECC	Western Electricity Coordinating Council

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1.0 Introduction

With the United States and the world transitioning to cleaner energy systems, there is a need for significant new clean energy generation resources. Not only are existing carbon emitting generation technologies being retired and replaced by renewables, but other sectors of the economy are also being electrified. They are being displaced primarily by wind and solar, and with continued widespread deployment, these two renewable energy sources will likely comprise a majority of the generation portfolio of the future electricity system. Their widespread deployment is a function of their low cost, enabled by strong governmental support in the form of mandates and incentives. However, with their inherent intermittency and variability, these resources require the support of other technologies, such as energy storage, to ensure reliability can be met. Indeed, the recent Executive Order (EO) 14057 requires federal agencies to achieve 100% carbon pollution-free electricity (CFE) on a net annual basis and 50% CFE 24/7 by 2030 (Biden 2021a). At present, there are few renewable energy generation technologies that that can, on their own, provide this 24/7 output. Geothermal energy, specifically electricity generation from hydrothermal resource utilization, is one of them. Not only has it been deployed for decades, but the untapped potential remains significant. Importantly, the characteristics of the resource—geothermal generation plants can provide a largely constant source of energy that can be dispatched and has the potential to operate flexibly—can complement and support the integration of variable solar and wind resources.

The geothermal power potential in the United States (US) is immense and widespread when including the potential for enhanced geothermal systems (EGS).[5] The U.S. Department of Energy's (DOE's) GeoVision report estimates that there is more than 31 GW of hydrothermal resource (identified and undiscovered) and over 5,158 GW of EGS potential across the country (DOE-GTO 2019). For context, the U.S. average power demand in 2020 was 424 GW and the total average energy demand 2,392 GWh.[6] Although not all 31 GW of the hydrothermal geothermal resource is easily recoverable, given their scale, clearly geothermal resources have a role to play.

Despite the potential for geothermal to provide value, its development has been limited due to issues like high and uncertain development costs, siting and permitting challenges, and competition from low-cost natural gas and variable renewable energy technologies (i.e. wind and solar).[7] These issues manifest as hurdles to the contracting and financing of new development, as well as the renewal of existing projects. Despite clear indications that geothermal power production can help decarbonize and stabilize reliable power supply, current market and contracting conditions limit the capture of this potential value. For example, the carbon costs of natural gas generation are currently not captured in its price in most jurisdictions, nor are the costs of balancing and integrating wind and solar captured in their costs (Hirth, Ueckerdt, and Edenhofer 2016). Meanwhile, geothermal resources, which are more expensive on a per capacity basis, generally do not see their baseload and non-variable nature valued.

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[5] EGS are man-made reservoirs and is discussed further in Section 2.5. For even further detail, please see EERE's "How an Enhanced Geothermal System Works." https://www.energy.gov/eere/geothermal/how-enhanced-geothermal-system-works

[6] Retail sales of electricity. 2021. U.S. Energy Information Administration. Retrieved September 29, 2011, from https://www.eia.gov/electricity/data.php.

[7] Variable means that the resource is intermittent and not dispatchable (or controllable).

To address challenges to geothermal deployment, electric system stakeholders need to understand the technology's ability to contribute to grid reliability, resilience, and wind and solar integration. The geothermal industry needs to demonstrate this value and state and federal regulators and policymakers need to ensure this value can be monetized.

The goal of this effort is to help industry, government, and other stakeholders understand the potential for geothermal development and charting pathways to capitalize on this potential. We do this by assessing historical geothermal and other resource financing and development trends and evaluating the evolving energy project development landscape.

1.1 Report Scope and Organization

This report starts with an overview of electric markets and geothermal resources, then describes historical and recent geothermal project development. We then get into the analysis, which is divided into four components. First, we provide a qualitative review of known risks within the geothermal energy development process, focusing on risk mitigation and remediation strategies. Next, we evaluate historical price trends for geothermal and compare them with trends seen in other renewable energy resources. Third, we evaluate energy contracts, that is, power purchase agreements (PPA) developed for a range of energy resources to identify contract mechanisms that could help to address some of the risks faced by geothermal ventures. Finally, we conduct a *pro forma*[8] evaluation of some of the proposed policy and contract approaches using data from existing geothermal power plants along with optimized potential revenue streams. The first three analyses inform the final analysis, and taken together, provide insights and strategies that are intended to help industry consider avenues for future geothermal deployment and for the Geothermal Technologies Office to direct research funding. We also discuss the potential for socio-economic value associated with geothermal development and how it could present opportunities for a Just Transition as the country moves away from fossil fuel use. Finally, we share some next steps that may be helpful to spur development.

It is important to note we are largely focused on near-term investment, and accordingly much of the work and discussion is targeted on hydrothermal resources, even when we broadly refer to geothermal energy. When discussing EGS in this report, it is explicitly identified. Longer-term, as the technology matures and costs decline, many of the insights and findings for hydrothermal resources are likely to apply to EGS development.

1.2 Key Findings

Based on our analysis, we identify several key focus areas that could benefit efforts to expand the development of geothermal power generation in the United States:

- Sources for renewable generation are in fierce competition with each other, with wind and solar prices being tightly correlated. Purchasers appear to be treating wind as a marginal renewable resource, with geothermal energy being forced to compete with declining wind and solar prices.

- However, unlike these variable renewable energy sources (VREs), geothermal energy resources provide more constant and available output and have the potential to provide

[8] A pro forma is a statement of cash flows including tax credits, accelerated depreciation, and other incentives that allows developers/investors to understand whether the project will provide adequate profits to meet investment requirements.

dispatchable and flexible generation. If the value of these services (e.g., capacity, availability, and grid services) can be captured by developers, geothermal energy may be enabled to play a role in complementing lower cost VRE. Contracts evaluated in this study show that this is not a novel concept, and such services are sometimes remunerated separately. For example, some contracts included capacity payments during curtailment events, allowing for guaranteed income for the energy producer. However, this is not pervasive in industry.

- Other observed strategies to incorporate flexibility into contracts include developing seasonally variable output requirements (e.g., in cases where geothermal production may decline in the summer).

- A significant barrier to geothermal financing and development results from exploration risk. One approach to addressing concerns around resource exploration and confirmation can be seen in the Ormat Northern Nevada Geothermal Portfolio contract, which is built around a portfolio of geothermal plants, including backup plants in case one of the initially identified locations is not sufficient to meet the PPA capacity requirements.

- Another approach that may prove valuable for geothermal development is for developers to enter contracts directly with corporate or federal customers.

- Geothermal energy production could benefit from government support through a range of strategies, including the underwriting loans or grants to geothermal developers. Other federal or state incentives that could improve the economics for geothermal development include feed-in tariffs, mandates to ease the contract approval process, and indirect mechanisms such as financial incentives for additional firm capacity.

1.3 Electricity Markets

In the electric system as it exists today, large scale electric generators convert a fuel source to electricity by either the burning of natural gas or coal, capturing the energy from nuclear reactions, or the harvesting of wind, the sun, water, or heat from the earth. This electricity is then transmitted over high voltage transmission lines to load centers through the transmission system. Once the electricity reaches load centers, it is distributed to end use customers at lower voltages through the transmission system. More recently, the development of distributed photovoltaic (PV) solar resources has meant more generation at the customer site, reducing the demand on large-scale generation and transmission, but this distributed resource development remains, relatively, low. There are different stakeholders from private entities to customer owned cooperatives, to government organizations involved in each of these steps, and there are different regulatory and market environments in which they operate that varies widely by state.

Across the states, there are two major electric regulatory environments: regulated states and deregulated states in a roughly equal proportion. Further, there are two types of electric market environments: formal organized markets and unorganized markets.

- Regulated states and unorganized markets: This is the traditional US electric market paradigm in which private, investor owned vertically integrated utilities (IOU) own and operate a single generation, transmission, and distribution system. As this is a monopolistic enterprise, a state economic regulator, the public utility commission (PUC), approves electricity rates and sets appropriate rates of return for these private utilities. The PUC is also often responsible for approving electric system investments, maintaining reliability and approving power plant and transmission siting. In addition to IOUs, there can be cooperative utilities as well as municipal or county-level utilities run by government entities. These are subject to regulation by utility boards and their customers in the case of cooperative utilities, and jurisdiction entities in the case of government utilities. In this environment, generation has traditionally been owned by the utility to serve all its demand. More recently, with the emergence of renewable resources, more and more generation is contracted with private independent power producers (IPP) under bilateral PPAs.

- Regulated states with organized markets: Like the prior construct, these states may have utilities participating in formal regional markets (i.e. independent system operator, ISO, or regional transmission operator, RTO, markets). The generation assets of participating utilities participate in the different markets of these ISOs/RTOs and their transmission systems are subject to market planning and rules. The state PUC maintains oversight control for IOUs, while utility boards or jurisdictions maintain oversight of the non-IOUs participating in the formal markets.
- Deregulated states with organized markets: These are states that have undergone deregulation of their electric systems, with generation, transmission, and distribution functions of utilities separated into different entities, with the intent being to promote competition in a monopolistic environment. Distribution utilities directly serve customers and operate distribution systems. As they are monopolies (it is unreasonable to have multiple distribution systems serving customers), they are subject to PUC regulation. Although some (former) IOUs may maintain some generation depending on the state (specifically California), largely, electric generators are owned by IPPs that contract with offtakers to deliver electricity. In addition to bilateral agreements, IPPs also directly participate in the different ISO/RTO markets with their assets. Offtakers in these environments may be distribution utilities but are more often power marketers that sell energy to distribution utilities or directly to customers by purchasing electricity on the market or contracting a portfolio of generation. As with the other environments, cooperative and government utilities exist and operate, often buying or selling power within the market environments.

ISOs and RTOs use competitive market processes to procure new generation resources, which are then compensated through market-based rates. ISOs/RTOs are federally licensed and regulated nonprofit organized electric market operators. Subject to Federal Energy Regulatory Commission (FERC) oversight and regulation, ISOs/RTOs set rules for the operation of different types of markets to effectively and reliability generate and deliver electricity. These markets can include energy markets, ancillary service markets, and capacity markets. Generation operating in these markets generally does not receive the same revenue guarantees as those operating in vertically integrated areas, where all its costs are underwritten by ratepayers and there is guaranteed recovery established by the PUC. Depending on the ISO/RTO in which it operates, an IPP generator may receive compensation for selling wholesale generation, capacity, and ancillary services into the market.

- Energy markets: There are different types of energy markets (i.e., day ahead and real time) that ensure generation supply meets demand at all hours of the day. Participants submit price bids into the market, and depending on expected demand, the market operator determines which bids will be successful. The operator aims to minimize cost, selecting the lowest cost bids until demand is met. The marginal bid, that is the last and most expensive bid selected, sets the market price for all participants in that period.

- Ancillary service markets: These markets procure different ancillary services, also known as grid services, to ensure continued reliable operations. Ancillary services can include frequency regulation, contingency reserves (including spinning and non-spin or supplemental reserve), and ramping reserve. These are often called operating reserves (which also includes frequency response) and are a part of the broader category of grid services.

Grid services include all those services necessary to maintain reliable operations of the electric system and include ancillary services and capacity which are market products. There are, however, additional grid services which do not have market products and generators may be not explicitly compensated for their delivery (though they may still be required to deliver them). These include inertia and primary frequency response, voltage and reactive power support, and black start (although some markets have specific non-market compensation).

- Capacity markets: These markets are intended to incentivize the development of new capacity a few years before it is needed in the electric system. Capacity markets were established following a concern that electric markets on their own were insufficient incentive to support the financing and development of new generation projects. The capacity payment provides for an additional, guaranteed, revenue stream in addition to energy and ancillary services. Market operators conduct auctions a few years before the commitment period, that is when that capacity must be made available to the system. The resources selected in the auction receive the clearing price on a per capacity basis, for example, $/kW-year or $/kW capacity per year of delivery.

For additional information about U.S. Electricity Markets, the FERC Energy Primer is an excellent reference.[9]

1.3.1 Geothermal Resources and the Electricity Market

Existing geothermal resources are almost entirely operated by IPPs and sell their power to offtakers, usually utilities of different types, but also some Customer Choice Aggregators (basically power marketers) through bilateral contracts (i.e. PPAs). Except for those in California, all geothermal resources operate in unorganized market environments where no market products exist and therefore compensation is entirely dependent on the negotiated contracting process with offtakers (subject to incentives and other requirements). For the most part, except for Hawaii, geothermal contracts are energy only contracts with agreed upon prices for the sale of electricity. In Hawaii, because of the nature of the small electric system on the island of Hawai'i where the states only geothermal plant operates, the contract includes explicit provisions for capacity. In both cases, however, the geothermal resources must directly compete with natural gas, wind and solar resources. In California where there is a formal organized market, geothermal resources also contract under PPAs with utilities and other

[9] *See* "Energy Primer: A Handbook for Energy Market Basics." Federal Energy Regulatory Commission. Staff Report. April 2020. Available at: https://www.ferc.gov/media/2020-energy-primer-handbook-energy-market-basics.

offtakers (i.e. community choice aggregators), but because there are explicit market constructs, they can participate in markets and monetize additional elements beyond just energy.

2.0 Geothermal Background

This section provides background into the development history of geothermal energy as an electric resource, as well as some high-level insight into the science and technology behind geothermal energy, to provide context for later sections focused on development and risk. DOE and other research institutions have spent decades understanding and improving the ability to harness the geothermal resource, and there is a wealth of information available on the topic. A good source for further information is GTO's 2019 GeoVision report (DOE-GTO 2019).

2.1 Geothermal Energy History

Today, more than 50 countries, including the US, Iceland, Mexico, Turkey, and New Zealand, use geothermal energy in the form of steam or superheated water to generate electricity, with the US being the leading producer of geothermal energy. Historically, the development of geothermal energy in the US was marked by steep barriers to entry leading to brief peaks of deployment followed by long stretches of low deployment. The first wave of deployment occurred in the late 1970s and early 1980s, following high federal funding levels in the 1970s, including support for the DOE Geothermal Technologies Office. This increased funding was a reaction to the 1970s oil crisis (EIA 2017). This wave included major increases in capacity at established geothermal plants such as The Geysers in northern California as well as significant new additions in Utah, California, and Nevada (DOE-GTO 2021; Calpine 2021). This period of development was accelerated in 1974 by the deployment of the decade-long DOE Geothermal Loan Guaranty Program, which provided federal guaranties up to $100M per project. This program was especially beneficial to smaller firms that would have difficulty raising capital (Nasr 1978).

Support for geothermal development was outstripped by DOE budgets for solar and coal starting in the mid-1980s, leading to a subsequent decrease in deployment of geothermal energy in the 1990s (EIA 2017). Increases in the availability of natural gas during this time hurt the deployment of all renewable energy resources, including geothermal energy (Kutscher 2000). In all cases, deployment lags significantly behind funding: the lag between the change in budgets and deployments is due to the large amount of capital and time involved in establishing a geothermal plant. The relatively high barriers, especially related to time and capital, have contributed to low deployment levels for geothermal plants. In the decades since the turn of the century geothermal capacity has not seen significant growth, with no additions of more than 250 MW occurring in this time (Young et al. 2017).

2.1.1 Policies to Support Geothermal Development

The first wave of geothermal deployment, which began in the late 1970s, was spurred by federal programs such as the Geothermal Loan Guarantee Program (GLGP). Established in 1975 by the DOE Geothermal Technologies Program, this program aimed to offset some of the barriers to entry for geothermal programs by encouraging private lending to geothermal projects. It initially guaranteed backing up to 75% of project costs (later increased to 90%) with a loan limit of $100 million per project (Lund and Bloomquist 2012). While this program did begin to address the barriers to entry for geothermal projects, by the end of the program 10 years later, only eight guarantees had been issued. The main shortcomings of the GLGP were the strict loan eligibility requirements leading to loans awarded to projects which likely would have gotten them without the program, and the lack of utility participation in the program (Speer et al. 2014). The program ended in the 1984 after not receiving congressional funding (Bloomquist 2003; Speer et al. 2014).

Another loan program passed as part of the Energy Security Act of 1980 was the Loans for Geothermal Reservoir Confirmation Program. This program was meant to aid with surface exploration and drilling. Projects would be able to borrow up to 50% of project costs up to $3 million. However, this program was never funded by the U.S. Congress (Speer et al. 2014).

In the Recovery Act of 2009, the Section 1703 Loan Program was extended as the Section 1705 Loan Program to support commercialized clean energy projects (Speer et al. 2014). This loan guarantee program required DOE to receive a Credit Subsidy Cost (CSC), estimated to be between 6–10%, either as an appropriation or as a payment from the borrower. The program also allowed applicants to participate in the DOE Financial Institution Partnership Program (FIPP). Applications using this pathway had to be submitted by a private lender who would be responsible for 20% of the loan (i.e., DOE guaranteed only 80%). Additionally, such projects could only receive a loan for 80% of their costs, ultimately resulting in DOE covering up to 64% of costs if the project was unsuccessful (Speer et al. 2014). Under the Section 1705 Loan Program, which ended in 2011, three successful geothermal energy plants were developed (DOE-LPO 2017).

Other examples of policies to support geothermal development include drilling failure insurance, lending support mechanisms, grants & cooperative agreements, and government led exploration. Drilling failure insurance protects the developer if the exploration drilling proves to be unsuccessful and can be used instead of loan guarantee programs. Drilling failure insurance has been implemented in France. Another option for U.S. geothermal project development during the exploration phase is lending support mechanisms, which provide government supported loans with a lower interest rate through interest rate subsidies to private lenders. This policy is in place in Germany. Government-led exploration has been effective in countries with minimal exploration. This type of policy may be unfit for the United States because it is not a market-based approach, and the U.S. geothermal market is already mature. Government led exploration has spurred growth in such as Iceland, Japan, New Zealand, and Indonesia (Speer et al. 2014).

Such examples of government intervention in exploration activities may mirror historical efforts in the oil and gas industry in the US. Play fairway analyses in the oil and gas industry provide basin-scale analysis that helps to focus further exploration in the most promising parts of a basin. Additionally, by aggregating such analyses between basins, these larger-scale geologic formations can be ranked in terms of relative exploration risk to further focus exploration efforts. The US government has supported such efforts in the oil and gas industry, including requirements to provide estimates of oil and gas resources on federal lands established under a 2005 amendment to the Energy Policy and Conservation Act (EPCA; BLM n.d.). This assessment provides estimates of undiscovered but technically recoverable resources, ultimate recovery appreciation, and proved reserves, though it does not consider whether the resources are economically recoverable (Eppink and Johnson 2005). GTO has used this concept to support play fairway analysis projects aimed at identifying geothermal resources with no obvious surface expression (DOE-GTO n.d.). These analyses use measurements of heat, permeability, and fluid to investigate unexplored or underexplored basins or regions and are aimed at reducing exploration risk for the geothermal industry.

2.1.2 Challenges to Development

The main developmental barriers to geothermal energy production have been high exploration costs and renewable energy policies and tax incentives that have focused on nameplate generation capacity (i.e., wind and solar capacity) (Young et al. 2017; Young, Levine, et al. 2019). The higher costs associated with geothermal resource survey and demonstration make the process of securing an offtake agreement, that is a PPA with a buyer, particularly challenging. To secure a PPA, a project developer must demonstrate the resource's viability and complete an interconnection study to connect the proposed development to the electric grid. Although interconnection studies are roughly equivalent in cost across power generation sources, demonstrating the resource for geothermal projects can cost a developer $5–10 million without the certainty that they will obtain a PPA. This demonstration cost can include geophysical surveys, thermal gradient holes, and a full-size diameter drilling well, for which there are no parallels in solar or wind project development (Young, Levine, et al. 2019). These demonstration steps remain both costly and time intensive even after decades of advancement in geothermal technology.

Geothermal deployment has also been affected by renewable energy policies, such as Renewable Portfolio Standards (RPSs) which have been more favorable to solar and wind development. Statewide RPS programs, most of which were adopted in the 2000s, establish dates by which electricity suppliers must generate a designated portion of their power through renewable energy sources (NCSL 2021). The metrics for measuring a power provider's renewable portfolio can be categorized as either capacity-driven or generation-driven. Capacity-driven RPSs favor higher capacity developments because they can provide a larger increase to clean energy capacity, allowing suppliers to more easily reach the requirements set forth. However, until technologies such as super-hot rock (SHR) EGS are more widely available, geothermal projects will have smaller nameplate capacity (up to 138 MW despite more consistent generation) making them less attractive for capacity driven RPSs than wind and solar which have nameplate capacities ranging up to 600 MW. Generation-driven RPSs generally benefit geothermal developments, although the conditions of the RPSs vary from state-to-state and may include incentives towards a specific type of renewable energy which could make them more or less favorable for geothermal (Young et al. 2017). For example, New Mexico's RPS requires electricity sales to comprise 20% solar, 30% wind, and 5% other renewables (including biomass and geothermal) by 2020 (NCSL 2021), a factor that has motivated some, albeit limited, geothermal uptake in the state. The long development time required to identify and construct geothermal energy sources also makes geothermal projects unfavorable for RPSs, because the timeline for geothermal development may not align with the deadline in the RPS. Because of these mitigating factors, the effect of RPSs on geothermal is subdued even though geothermal energy is a qualifying clean energy resource.

Geothermal projects in the US are also largely unable to take advantage of federal energy tax credits. This is due to the long early development timeframes of geothermal projects conflicting with the shorter tax credit windows (Young, Levine, et al. 2019). For example, the Energy Policy Act of 2005, which included tax deductions for various energy types including renewable energy only had a window of two years. Because the development of a geothermal resource would exceed this window, geothermal developments could, in general, not reap the incentives offered (Eppink and Johnson 2005). For some tax credits, such as the Investment Tax Credit, the credit is not equitable between different types of renewable energy production (30% credit for solar as opposed to 10% credit for geothermal; Sherlock 2018). Other non-technical barriers to geothermal energy include land access conflicts, delays in permitting, challenging access to transmission, low social acceptance, and resource conflicts (e.g., species impacts, cultural resources, water availability and environmental equity and justice); these barriers are not unique to geothermal, however, and must be overcome by developers of other energy resources as well (Young, Wall, et al. 2019).

2.2 US Geothermal Resource

Energy is produced from a geothermal resource using three main types of geothermal capture mechanisms: 1) geothermal heat pump, 2) hydrothermal, and 3) EGS, with the type of mechanism used depending largely on the temperature of the geothermal fluids in the resource (Figure 2). The resource can either be captured for a thermal use, that is direct use, or converted to electricity, the focus of this work. In 2020, the global installed capacity of geothermal power plants was 15.95 GW, forecasted to increase to 19.36 GW by 2025 (Huttrer 2021). The US leads geothermal electricity production with 3.7 GW, and the annual energy production was 18.4 TWh in 2020. By 2025, the US's installed capacity is projected to rise to 4.3 GW (Huttrer 2021). Most of this production is localized in the western continental US, mainly in California and Nevada.

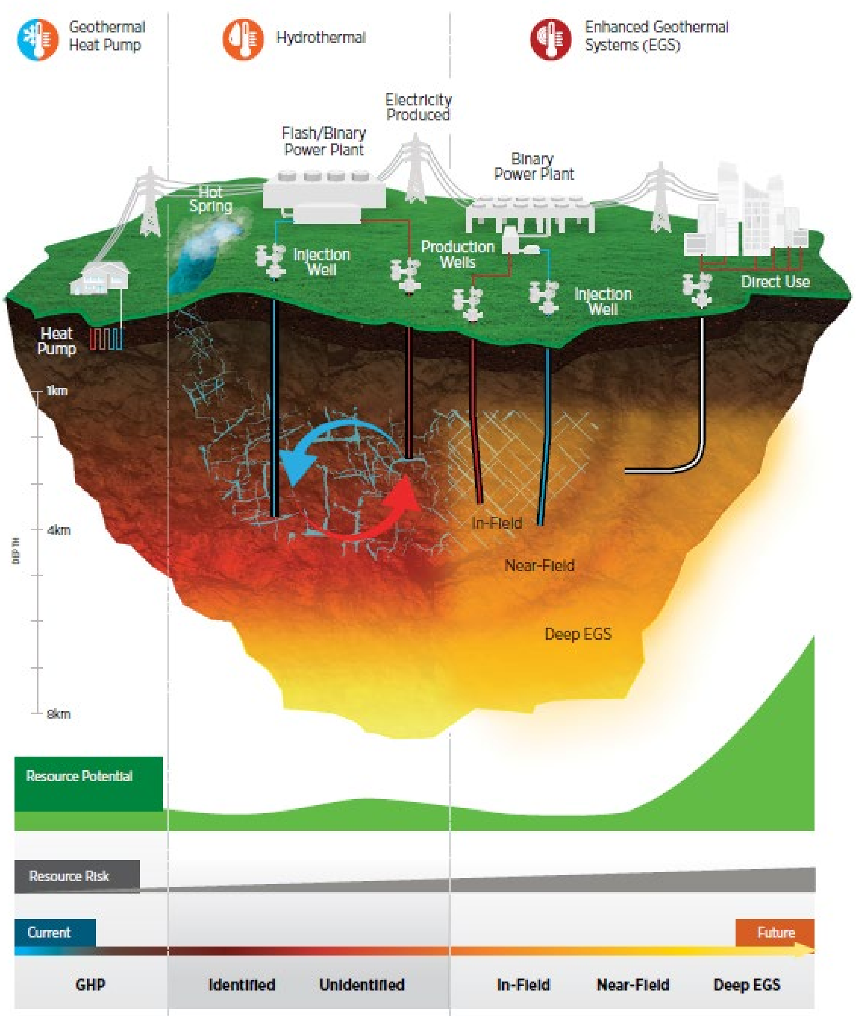


Figure 1. Geothermal resources and applications fall into three resource categories: geothermal heat pump, hydrothermal, and enhanced geothermal systems (Figure from GeoVision, DOE-GTO 2019).

Geothermal resources for power generation exist mainly in two categories:

- **Natural hydrothermal systems** where a sufficient rock permeability (connected pores and fractures) exists to allow the circulation of fluids underground and their production at the surface. Most hydrothermal resources contain liquid water, but higher temperatures or lower pressures can create conditions where steam and water or steam alone are the continuous phases (White, Muffler, and Truesdell 1971).
- **Hot dry rock (HDR)** with temperatures between 200 and 350°C and where there is not enough permeability to allow the natural circulation of fluids. In these cases, the permeability must be created by stimulating existing fractures. Cold water is then injected into an injection well and hot water is produced at production well(s) after circulation in the created artificial heat reservoir. The whole process is called an enhanced geothermal system (EGS).

All current US commercial geothermal power plants use hydrothermal resources. Geothermal energy's cost-effectiveness is oftentimes hampered by limited technological capabilities. For example, the typical energy conversion efficiency of a geothermal system is about 10 to 15% depending on the geothermal fluid temperature and the heat conversion to electricity (power cycle) employed (DiPippo 2015). However, by using new types of working fluids and more efficient power cycles, the energy conversion efficiency may reach and even exceed 25%.

EGS technology is still in the research stage (e.g., Frontier Observatory for Research in Geothermal Energy [FORGE] in Utah; Moore et al. 2020). However, installation of EGS geothermal power plants is theoretically possible anywhere, provided wells are drilled deep enough to reach the desired temperatures.

Additional information about technical and geologic considerations for the geothermal project development process can be found in Appendix A or in GTO's GeoVision report (DOE-GTO 2019).

2.3 Active and Planned US Power Plants in 2020

Figure 3 shows the locations of geothermal power plants in the US. Note that these geothermal power plants are located only in the western US and most of the plants are in California and Nevada. The corresponding Excel spreadsheet with further detail and links to each power plant can be found in 0.

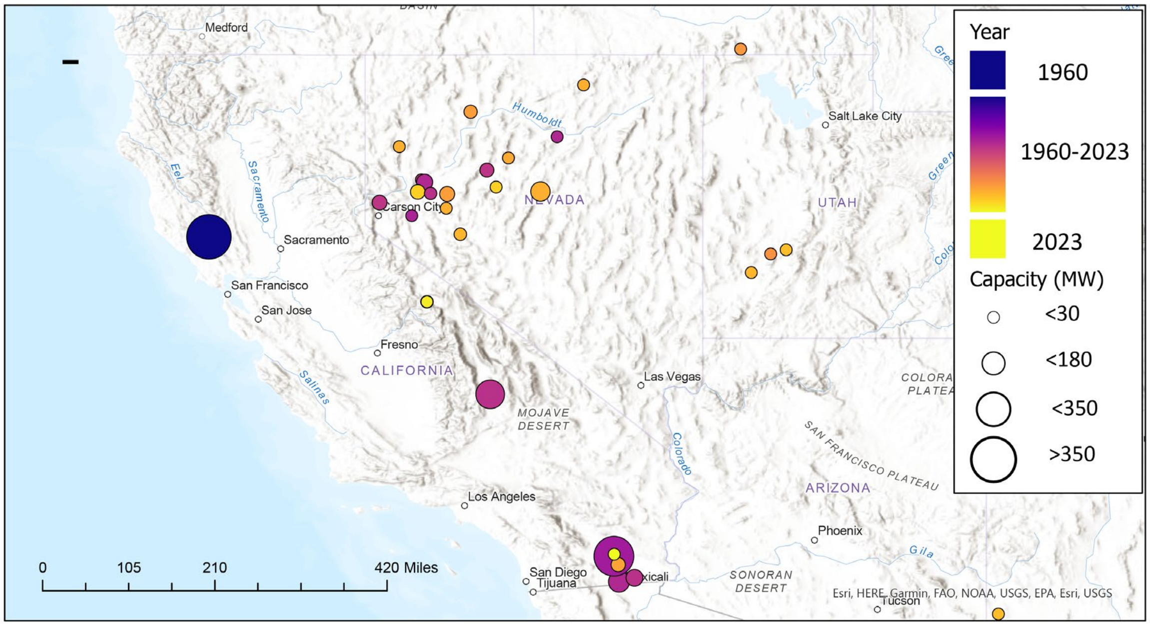


Figure 2. Location of active and planned power plants in the US western states (ARCGIS database created for the project). Color scale corresponds to the year of creation of the power plant and the size of the symbol corresponds to its capacity in MW.

2.4 Future of Geothermal Energy

As discussed above, all electric generation plants powered by geothermal energy resources are hydrothermal plants. In the US, there is a strong hydrothermal resource in the west that can play a major role in the future electric system, but as a proportion of overall energy needs, whether just in the west or in the US overall, the US hydrothermal resource can only meet 2.5% of current energy demand. However, recovering just 2% of the thermal energy stored in hot rock 3 to 10 km below the continental US would be sufficient to meet US energy consumption for more than 2000 years (Tester et al. 2006). This would require the development of commercial EGS. Theoretically, EGS power plants could be developed anywhere and would represent a renewable and clean energy resource in regions where other renewables are insufficient to meet energy needs.

2.4.1 Enhanced Geothermal Systems

Much of the thermal energy stored in hot rock is stored in rock at temperatures of 200°C and below; hence, in the last decade, most EGS research, development and deployment has focused on <200°C resources. Indeed, in the European Union (EU), EGSs and deep geothermal heat systems using resources below 200°C are enjoying economic success (Genter et al. 2016). However, this success required a combination of significant pre-engineered formation permeability, nearby thermal-heat users, and large feed-in tariffs for the electricity generated. Japan and South Korea have also explored the potential for EGS, but the lack of EGS development illustrates that the goal of economic EGS may not be achievable unless energy production per well can be significantly improved: costs are simply too high. In order to increase the energy production per well, producers must increase flow rate and/or increase flow temperature (Cladouhos et al. 2018).

2.4.2 Increasing flow rate in EGS and Development Risks

The DOE's FORGE project is focused on increasing flow rate by creating better permeability pathways in low permeability rocks (k<10–16 m^2) like crystalline basement and granites using an approach similar to the long horizontal reach wells and multi-stage stimulations that have been successful in the oil and gas industry (Moore et al. 2020). This approach might lead to technical success; however, large-scale global economic success will be far harder because of the sheer number of wells that would need to be drilled. The most optimistic estimates project that each EGS well producing 200°C water will generate 5 MW of electricity (e.g., Li, Shiozawa, and McClure 2016). To generate 100 MW of electricity delivered to the grid, at least 42 wells would need to be drilled, including production and injection wells (Figure 4, left).

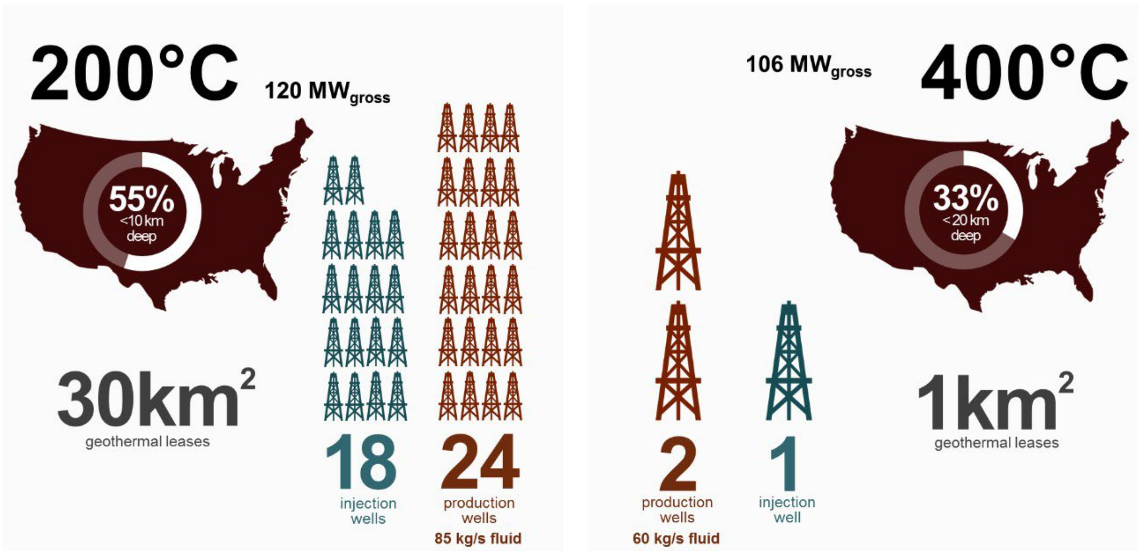


Figure 3 . Hypothetical 100 MW utility-scale power plant with 200°C and 400°C resources (Figure from Cladouhos et al. 2018).

Drilling to the depths required to meet these temperatures (3–10 km) is no easy feat, and although shale gas wells regularly reach these depths, as discussed above, there are significant differences that make geothermal drilling more expensive. Even if there is a breakthrough in drilling costs, the costs of materials needed to complete the drilled wells alone (250 miles of steel pipe and a half million cubic feet of concrete) would make the costs of electricity from a 200°C EGS uncompetitive in current and projected future electricity markets (Cladouhos et al. 2018).

There are several other factors beyond drilling that lead to challenges for EGS and would not be solved by better drilling technology. These include a poor understanding of subsurface permeability modification and evolution, the short circuiting of fractures created in the drilling process, and fluid injections that may lead to substantial earthquakes (>M5), amongst others.

2.4.3 Super-hot Rock EGS

Increasing the flow temperature of EGS wells has a greater potential payoff. Supercritical geothermal energy production represents the geothermal energy moonshot, a potential step-change in energy available per well using super-hot rock (SHR) EGS. A geothermal well that produces fluids at 400°C, above water's supercritical point of 375°C, would generate 10 times the amount of electricity of a 200°C well, because it has five times the energy content of the fluid and two times the conversion efficiency (Figure 4, right) (Cladouhos et al. 2018). Compared to a 200°C well in the same area, an SHR well would need to be drilled about twice as deep and creating or enhancing permeability in SHR (i.e., creating an EGS) will involve different geomechanics than creating an EGS in 175–225°C rock. However, creating the SHR EGS will not necessarily be more difficult. Iceland, Italy, Japan and New Zealand are all currently pursuing SHR projects (Dobson et al. 2017) and in the US, there was a proposal to develop an SHR EGS at the Newberry Volcano in Oregon (Bonneville et al. 2018) though this did not proceed due to technical challenges.

AltaRock Energy recently announced that Hughes Baker and the University of Oklahoma have completed and presented a study indicating that the electricity costs of an EGS at the Newberry Volcano are less than $0.05/kWh (Chast 2021). The study was presented at the World Geothermal Conference, the Geothermal Rising Conference and the Society of Petroleum Engineers Geothermal Workshop in the last quarter of 2021. The increased costs of the EGS system with super-hot rock ultimately leads to lower cost (compared to greater than $0.10/kWh) due to the five to ten times higher production at 400ºC versus 200ºC. The question will be whether the estimated costs and productivity match the actual costs and productivity.

3.0 Geothermal Project Development and Market Drivers

This section discusses how demand and market levers influence contracting and financing requirements, and the potential for geothermal resources to provide flexibility to meet grid needs. It also characterizes investment risk in geothermal development and discusses risk mitigation strategies.

3.1 Market Need

The economic and financial landscape for electric energy generation resources has been altered in recent years due to changing power system conditions on the supply side, like low natural gas prices and low wind and solar costs, and on the demand side, such as low load growth, and changing load shapes from new customer resources such as distributed solar or electric vehicles. Perhaps more significantly, a drive towards increasing levels of clean energy and state RPSs have led to VRE resources like wind and solar displacing traditional baseload energy generation in many areas. These changes have altered energy pricing trends and recently, have led to a need for resources that can provide ancillary services and resource adequacy to maintain frequency and reliability. Further changes are on the horizon as the country moves towards increasing levels of clean energy and economy electrification—technological, regulatory, and market dynamics and structures—that are likely to substantially alter the operational requirements of the power system and necessitate the buildout of new resources.

In these changing market conditions, geothermal resources are well placed to contribute in a significant manner to the nation’s electric system. Geothermal can provide a nonintermittent, largely non-variable renewable source of power that is available around the clock. It could be a valuable complement to VRE resources as fossil resources are retired and the need for system flexibility and resource adequacy are at a premium. From a benefit perspective, geothermal energy provides an opportunity to add baseload or dispatchable renewable energy production to the grid. This is essential for supporting grid reliability as the US moves towards a net-zero economy by mid-century (Biden 2021b, a).

3.1.1 Geothermal Resource Potential for Flexibility and Resource Adequacy

One of the attributes that makes geothermal energy an appealing renewable energy resource is its ability to provide consistent non-variable output, that is baseload power. Traditionally, geothermal energy has been operated in baseload configurations and considered a baseload resource that is limited in its ability to modulate its output in response to changing grid conditions or operator dispatch. This is great for system resource adequacy or capacity but leaves geothermal resources unable to deliver other grid services and system flexibility. As discussed above, the ability to provide flexibility is becoming increasingly important as more variable power generation is introduced onto the grid. Indeed, increased VRE generation has led to more frequent solar and wind curtailment events, including sometimes negative pricing when periods of high renewable generation overlap with low demand. Though geothermal plants are usually buffered from this price volatility by the fixed prices set in their long-term contracts, the observed price volatility is indicative of a market need for flexibility (Millstein, Dobson, and Jeong 2020). More importantly, beyond curtailment and negative pricing, the retirement of fossil generation and its replacement with VRE has resulted in resource adequacy constraints that manifest in challenges to maintaining system reliability. For example, in California in 2020, unexpectedly low solar output, coupled with limited available system generation and unavailable northwest hydroelectric imports, led the California Independent System Operator (CAISO) to institute rolling blackouts.[10]

Geothermal resources represent a clean capacity resource that could compensate for constraints to other resources in such situations, and if able to be developed and operated cost effectively in a flexible configuration, could be even more valuable. Further, the potential for enhancing flexibility by coupling a geothermal plant to deferrable load, such as hydrogen production, mineral extraction, cloud computing, or computational mining, could be significant.

Two examples offer insight into approaches that can allow a geothermal plant to operate more flexibly. First, in the Geysers geothermal field, Calpine has modified its existing operations, including building pipeline cross ties to allow transport of steam between power plants, and constructing turbine bypass systems for some of the units that allow steam to be diverted without producing power, to be able to meet current and expected future curtailment requirements from the ISO system operator (Dobson et al. 2020). These curtailments (i.e., need for flexibility) are expected to increase as California works to meet its renewable energy goals. Similarly, Puna Geothermal Ventures (PGV) signed an amended PPA with the Hawai'i Electric Light Company (HELCO) in 2011 that included enabling the plant to be fully dispatchable. This fully dispatchable system includes automated generation control (AGC), which allows grid operators to adjust PGV output within a contractually set range (22–38 MW) in response to grid demands. The PGV updates allow heat to bypass the turbine in its closed-loop organic Rankine cycle (ORC) system when output reduction is required (Nordquist, Buchanan, and Kaleikini 2013).

Unfortunately, the ability to operate a geothermal power plant flexibly comes with challenges, both contractual and technical. Many geothermal contracts are written with high energy prices on a per unit energy basis (i.e., price per MWh). This creates a financial disincentive for geothermal plants to reduce generation (Edmunds and Sotorrio 2015). Furthermore, repeatedly increasing and decreasing power output to enable flexible generation can lead to additional operations and maintenance (O&M) costs associated with equipment use, relative to constant production. Additionally, some methods for reducing power output, such as venting steam and bypassing the turbine can lead to an accelerated depletion of the geothermal resource in addition to the increased equipment O&M. The depletion can be diminished by throttling the wells, but this approach can damage wells, for example, decoupling the well casing and the cement lining the well due to thermal cycling. These problems are reduced for plants using ORC systems or by using battery storage (Matek 2015). Finally, there is potential for enhancing flexibility, and avoiding technical issues, by coupling a geothermal plant with another resource in a hybrid configuration (e.g., a battery) or with some type of deferrable load that could modulate its demand to effectively produce flexible geothermal output to the grid. Such deferable loads include hydrogen production with electrolysis, mineral extraction, cloud computing, or computational mining. Section 5.3 discusses these opportunities in more detail.

The ability to deliver system flexibility has been demonstrated by geothermal resources and the additional costs associated with providing ancillary services and flexibility could be incorporated and remunerated within contracts or through market participation in organized market environments. With the continued retirement of dispatchable resources, there is an opportunity

[10] Penn, Ivan. 2020. "Poor Planning Left California Short of Electricity in a Heat Wave." *The New York Times*, August 20, 2020, sec. Business. https://www.nytimes.com/2020/08/20/business/energy-environment/california-blackout-electric-grid.html.

to leverage geothermal's capabilities for flexibility to support the electric grid while increasing geothermal plant revenues.

3.2 Contracting and Financing for Development

Contracting and the corresponding financing of geothermal projects relies upon investors' belief they will get an adequate return on their investment. The PPA is a contractual mechanism between an electricity generator, the "seller," who typically develops and owns the project, and a dedicated purchaser of the power production, the "buyer." The PPA provides security to the seller by providing a pre-agreed price structure over a guaranteed time, usually several years.

Buyers may be one of three types: merchant/traders/marketers, utilities, or corporations. Merchant buyers are intermediaries who form other bilateral agreements with service providers, such as utilities, or they may sell to the market. Regardless of the type of buyer, their decision to sign a contract will be driven by market rates and considerations of what alternative energy resources are available for purchase.

Renewable resources in the US and in much of the world are built and operated by private developers. Building these power plants often requires buyers, also known as offtakers, to be established before a developer can obtain financing. Some countries have been known to use PPAs to finance construction (i.e., investment costs) and operations (i.e., operating costs) of renewable energy plants (Next Kraftwerke n.d.). Absent offtaker agreements (i.e., PPAs) of sufficient value, a developer is unlikely to receive private financing for development. A key to successful financing may be ensuring advantageous valuation through the development of appropriate markets. More recently the California Public Utilities Commission has seen this challenge and is reformulating its resource adequacy procurement mechanism to better incentivize firm resource development. Capacity or resource adequacy market value can be baked into PPAs, providing a developer a revenue stream, while not burdening an offtaker with the entire cost. However, outside California, amongst the western states where hydrothermal resources are best, there are no such mechanisms.

The project development and financing environment, specifically prices for energy and other services, as well as the costs associated with other technology types relative to geothermal projects, drives much of the investment climate for geothermal resources. It has been well established that the costs associated with geothermal development need to come down for more investment to take place. However, considering the low costs and advanced technology state of wind and solar technologies, it is unreasonable to think of geothermal resources directly competing with them. Instead, geothermal energy can leverage its strengths and value proposition, and despite higher costs (for now at least), pursue opportunities for deployment that leverage its value.

Geothermal energy production could also benefit from additional government support, such as the underwriting of loans or provision of grants. Federal and state incentives may further improve the upfront financial situation for project development by reducing project costs through the following mechanisms:

- feed-in tariffs, accelerated depreciation and investment tax credits[11]; some states exempt projects from property and sales taxes;

[11] *See* the DSIRE database for a list of current federal and state incentives for geothermal projects.

- mandates to ease the contract approval process which can create markets for environmental value; and
- indirect mechanisms, such as increasing renewable portfolio standards across the US to create financial incentives like renewable energy credits (RECs), or the need for additional firm capacity.

3.3 Risk Characterization and Mitigation

In finance, risk refers to the degree of uncertainty and/or potential financial loss inherent in an investment decision. Project investment requires weighing the economic benefits against this economic uncertainty. Despite its many potential benefits, geothermal project risks can be complex and hard to quantify given their dependence on early-stage exploration and resource confirmation. These risks span from the planning stage (e.g., siting, environmental assessment, and resource characterization) to ongoing costs after a plant has started operation (e.g., resource performance, increased operations and maintenance costs associated with flexible operations, and post-operational environmental risks). For geothermal energy to become more widely implemented, these risks must be better accounted for, either through government support (e.g., changes in tax incentives) or structuring of contracts, such as PPAs, to support the real development costs associated with the benefits that geothermal energy can provide.

3.3.1 Technical Development Risks

Development of a new geothermal resource for energy production can be considered in two general phases: 1) exploration and 2) exploitation (Aragón-Aguilar et al. 2019). During the first phase, a developer experiences significant risk due to uncertainties associated with the unexplored resource. In the second phase, risk is significantly reduced because the resource has already been characterized. However, at this point, the cost of development increases (Figure 5). Both phases can be broken into stages. During the exploration phase, developers must 1) conduct a regional exploration survey, 2) execute detailed exploration that will inform the selection of locations for drilling exploratory wells, and 3) drill exploratory wells for a prefeasibility study. During the exploitation phase, developers must 4) pursue field development, 5) begin field development, 6) construct the power plant, and finally, 7) distribute energy commercially (Aragón-Aguilar et al. 2019).

Figure 5 presents the evolution of a typical geothermal project risk profile with the different stages of development along with the percentage of relative cost. Most of the project budget is spent during field development and power plant construction (Stages 5 and 6), but it is interesting to observe that the exploration stages represent 50% of the risk. This risk dramatically decreases after the first exploratory well (Stage 3), which confirms the real potential of the resource identified by surface geochemical and geophysical methods during detailed exploration (Aragón-Aguilar et al. 2019; ESMAP 2012).

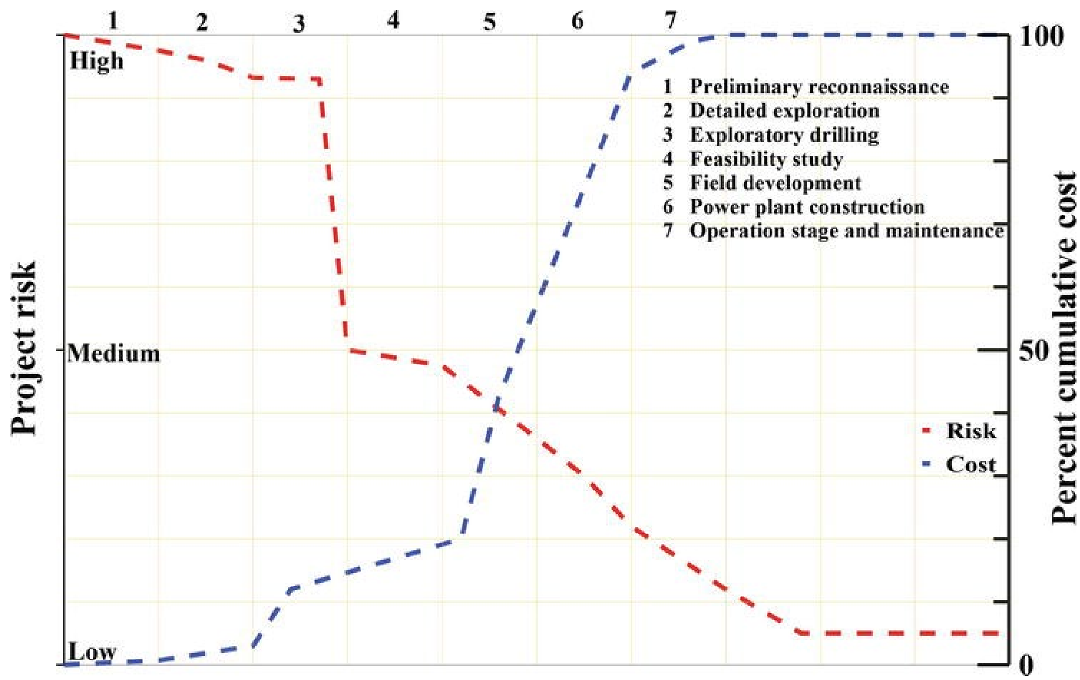


Figure 4. Typical profiles of risks and costs in a geothermal project, considering each stage of its development (Figure from Aragón-Aguilar et al. 2019)

The correct estimate of potential heat recovery from the geothermal reservoir is also of primary importance because it will determine the longevity of the reservoir and the number of wells that will need to be drilled during the life of the power plant to maintain the power production at its initial rate. Risk mitigation efforts should thus focus on these preliminary stages of exploration and characterization.

Once heat, and accordingly, power production has started, geothermal reservoirs are monitored by measuring well pressures, flow rates, and system enthalpies. Other valuable well health information can be observed by monitoring the chemistry of produced fluids and any microseismic activity associated with operations. All monitoring data can be incorporated into a geothermal reservoir management approach that continues to develop an understanding of the reservoir through all phases of development and operations. One important tool for gaining insight into reservoir management data is reservoir simulation using a three-dimensional model of geothermal reservoir systems. If production has occurred, the models can then be run in a "history matching" mode. In this process, model parameters are adjusted to achieve a match between the model outputs calculated by the simulation and the observed data (Archer 2020). In most cases the amount of energy taken out of a geothermal system by production is more than the natural recharge and these models can be used to predict the following (O'Sullivan 2014):

- How long a system can be economically exploited
- What schedule of new wells is required to maintain production
- How a system will respond to different rates of production
- How to best re-inject fluid into a system
- How the natural geothermal features will react to the system exploitation
- What other environmental effects may occur

Maintaining reservoir pressure and temperature is critical in sustainable production of geothermal energy systems, and the reinjection of produced fluid is an important reservoir management strategy to help sustain the pressure and to safely dispose of extracted fluid.

The long-term technical challenges are numerous: developing advanced and efficient prospecting methods; reducing the costs of drilling to great depths; controlling the creation and operation of deep geothermal reservoirs from the surface; improving the conversion of heat to electricity using new thermodynamic cycles and new heat transfer fluids (e.g., carbon dioxide [CO_2], nitrogen [N_2]). Progress in any of these domains will make the initial investment less risky and geothermal as an electric generation resource more attractive.

3.3.2 Nontechnical Development Risks

Apart from the technical challenges discussed above, major nontechnical barriers to geothermal development stem largely from the real and perceived high costs associated with the exploration and development process. Though predevelopment exploration costs at a specific site do not dominate the costs of developing a geothermal plant at that site (Figure 5), the low success rate of exploration activities can lead to accumulated costs prior to the ultimate identification and development of a successful geothermal resource. Indeed, only 16–21% of exploration leads to fully drilled and developed wells (Wall and Dobson 2016).

On top of resource uncertainty, perceived risk for geothermal projects is significantly increased by the long project development time frame. This process is often made even longer by the necessity of multiple (sometimes up to six) environmental reviews under the National Environmental Policy Act of 1969 (NEPA) and other federal environmental compliance requirements, such as the EPA Clean Water Act 404 certification, along with applicable state environmental requirements. Approvals for reviews can take months to years, with the completion and approval of Environmental Impact Statements (EIS) taking an average of about two years and up to four years (Young et al. 2014). This is a long process for a resource that is might not ultimately be found to be viable (Levine and Young 2014).

Maintaining EIS approvals can also be a barrier for already developed geothermal resources. The Hawai'i Public Utilities Commission suspended review of a 2019 PPA for the PGV project in 2021 pending the completion of an update to their 1987 environmental review (Big Island Video News, 2021). In this case, Hawai'i is potentially missing out on additional clean energy capacity, as the amended PPA would increase PGV capacity from 38 MW to 46 MW after equipment upgrades.

In addition to the length of time to get EIS approval, geothermal projects face significant risks associated with economic ramifications of the environmental risks themselves. These environmental risks include ground water contamination (Bonte 2014) and the possibility of geothermal steam or water containing non-condensable or liquifiable gases such as carbon dioxide and hydrogen sulfide and potentially carry trace amounts of mercury, arsenic, and radon (see TableA3.1)(Sharifi, Moore, and Keshavarzi 2016; Barbier 2002). Additionally, while geothermal projects generally do not generate large earthquakes, some EGS projects have generated damaging earthquakes, the largest of which was the M 5.5 earthquake induced by an EGS site in Pohang, South Korea (Lee et al. 2019). This possibility is likely to become more of a concern in the US with expansion of EGS plants.

Table 3.1. Comparison of subsurface environmental risks by geothermal energy (Bonte et al. 2011)

Environmental Risks	Conditions of Occurrence	Probability of Occurrence	Consequences	Risk Level
Hydrological Risks				
Changing water levels	Single-well geothermal system	High[(a)]	Water shortage for agriculture and production	Low
Cross-aquifer contaminant	Improperly plugged well or inadequate clay layer	Moderate	Increasing vulnerability, pollution	High
Changing groundwater chemistry	Temperature variation in shallow and deep geothermal systems	Moderate	Corrosion, nutrients	Moderate
Geological Risks				
Ground deformation and subsidence	Pressure drop in middle and deep geothermal systems	Moderate	Ground subsidence, earthquake, potential for structural damage to buildings[(b)]	High
Fault reactivation	High fluid pressure in middle and deep geothermal systems	Low		High
Induced micro-seismicity		Low		High
Microbiological Risks				
Changing the microbiological population and biodegradation rate	Temperature variation in shallow and deep geothermal systems	High	Nutrients and anaerobic corrosion	Low
Introduction or mobilization of pathogens		Low	Pathogens	Low

(a) Note that this probability is likely significantly lower for most geothermal plants which are generally multi-well systems that reinject fluid
(b) Giardini (2009)

Ongoing risks to geothermal energy production can continue throughout the duration of plant operation. For example, high summer air temperatures can lead to significant reduction in capacity due to decreased cooling efficiency (Ayling 2020). Furthermore, the capacity risk associated with high summer air temperatures may be exacerbated by climate change because peak summer temperatures and the number of heatwaves are expected to increase (USGCRP 2017).

3.3.3 Potential Remediation Methods for Nontechnical Development Risks

Although there are many risks associated with geothermal energy, there are also mitigation strategies that may better persuade investors to fund geothermal projects such as 1) reducing perceived development risk, 2) government-supported instruments, 3) technology hybridization, and 4) quantifying climate risk to geothermal power plant output. Note that both technical and non-technical risks can be characterized using approaches such as the GeoRePORT approach which allow a suite of relevant risks to be evaluated and summarized consistently (Young, Wall, et al. 2019).

As discussed above, some of the key risks related to geothermal projects center around perceived development risk. Indeed, a major barrier to geothermal development centers around social acceptance when stakeholders are not well-informed about geothermal energy development. This must be addressed through improved education and outreach (DOE-GTO 2019). Craig Dunn, a geologist with Borealis GeoPower, suggests that one of the problems with geothermal investment is the unknown risks and therefore, the geothermal industry needs to be more proactive and think like a potential investor (Richter 2010). Specifically, Dunn notes that developers must work to generate more concrete estimates for how likely an exploration process is to be successful, what the resource capacity is likely to be over time, and what the project's capital costs will be to allow investors to make informed decisions. Regarding excessive approval periods, federal agencies could expand access to Categorical Exclusions (CXs). Various CXs exist to streamline geophysical exploration but could potentially be expanded to encompass construction and production as well. These CXs allow projects to avoid conducting a lengthy Environmental Assessment (EA) or EIS in cases where there will not be a significant environmental impact. This could potentially allow for more rapid approvals early in the exploration process (Levine and Young 2014). Another option could be to "pre-clear" areas of high geothermal resource potential as was done with solar resources.[12]

Additional policy steps that could further mitigate nontechnical project risk include the development of a risk insurance product and government-supported instruments to mitigate financial risk (Antics and Ungemach 2010). Indeed, multiple national governments have worked toward such instruments by implementing loan guarantees and cost sharing for geothermal projects that are unsuccessful in moving beyond exploration. As discussed above, additional tools such as tax credits, feed-in tariffs and other incentives may help to encourage geothermal development by helping the developer cover upfront costs.

Plant capacity risk associated with seasonal temperature variation might be mitigated by counterbalancing production through pairing of geothermal and solar or other renewable resources. Some examples of geothermal power plants with installed solar capacity (either to provide parasitic load or to supplement the geothermal electricity generation) include Tungsten Mountain, Stillwater, and Patua geothermal plants (Ayling 2020). While solar can help balance reduced capacity from geothermal plants during summer months, geothermal plants can conversely balance reduced solar capacity during winter months. Indeed, a study of curtailment at the Geysers geothermal field found that the winter months have consistently shown significantly lower geothermal plant curtailment when solar power generation on the California grid is reduced (Dobson et al. 2020). However, this example also highlights that while pairing VRE with geothermal can be beneficial, it must be done carefully. Increased solar or hydro deployment on a grid can increase risks to a geothermal energy developer from an increased likelihood of curtailment.

Finally, to mitigate investor concerns about climate risk, financial analysts may use professionally recognized climate forecasts, such as those by the Intergovernmental Panel on Climate Change (IPCC 2014) or other professional forecasters, when weather-normalizing production results to estimate future geothermal output for project development financial

[12] *See* https://solareis.anl.gov/. Although the benefit this represented for solar is up for debate, discussions with geothermal industry representatives have indicated there may be merit to this approach.

analysis. For these assessments, analysts can try to capture the range of potential future temperatures described by both high and low representative concentration pathways (RCPs). It may be helpful for analysts to use recent and projected climate trends, as opposed to using only historical seasonal temperature averages to adequately capture climate-related risks as is often the standard approach in the electric industry.

4.0 Historical PPA Price Trends

This section provides a cross analysis of geothermal price trends, as well as trends for other renewables. Rather than a forward-looking analysis that uses exemplative projects as case studies, this work aims to understand existing markets for renewables. By focusing on existing PPAs and their associated prices, we examine how energy purchasers value a given resource and how that value changes in response to time, policies, and market conditions. By focusing on a group of resources, this analysis helps to illustrate how individual technologies compete with and complement each other and can potentially be used to identify market niches or comparative advantages. Additionally, because this work is backwards looking, it focuses on realized prices, rather than price projections. Each datapoint represents a signed contract, with purchasers agreeing to buy the power based on their own understanding of market conditions. By evaluating how prices change in response to these variables, we can tease out how these mechanisms influence value. We look for areas where geothermal energy resources can maintain a high price point, or competing resources are forced to offer lower prices.

4.1 Methods and Data Set

This research combines three datasets for analysis. The first is a database of wind, solar and geothermal PPAs maintained by Lawrence Berkeley National Laboratory (Bolinger 2020). This dataset contains information on about 80 GW of renewable energy projects, covering roughly 75% of operating geothermal capacity, and 50% of wind and solar capacity. This is paired with a database from Oak Ridge National Laboratory of hydroelectric PPAs that covers 52% of installed US capacity (Martinez and Johnson 2021). The relatively small share of hydropower featured in our analysis is largely due to the large number of regulated (i.e., non-contracted) assets in the US fleet (EIA 2017). These price data are paired with a novel internal PNNL database that illustrates the evolution of energy markets and policy over the analysis period. This dataset contains information on factors like RPS policies, natural gas prices, capacity retirements, and technology costs. These factors are included to control for the potential endogeneity in the analysis.

We use a standard ordinary least squares multi-regression model for the analysis, building in adequate controls for market conditions. Note that this analysis identifies correlations and does not aim to establish causal relationships within the data. To begin, we identified a list of 11 characteristics to investigate. These included electricity market conditions (retail prices, natural gas prices, thermal retirements, and renewable penetration), and policies (RPS, energy imbalance market participation, CO_2 prices, and mandates for energy storage). In each case, we attempt to control for nearly 20 factors (including location, hardware costs[13], and policy) to isolate the impact of the explanatory variable to the greatest extent possible. Standard robustness and significance tests are also conducted, including added variable tests, component-plus-residual tests, residual-vs-fitted tests, Cook-Weisberg's, and Cameron-Trivedi's tests for heteroskedasticity, Shapiro-Wilk tests for normality, variance inflation factor tests, and link tests for model specification. All models use robust standard errors to reduce the impact of heteroskedasticity.

[13] In the models, we control for wind turbine costs and solar hardware costs (we use a logarithmic transformation to control for the exponential decline in solar prices). Geothermal technology costs are assumed to be flat.

4.1.1 Strengths and Weakness

The strength of this approach lies in the richness of the data set, and the flexibility of the methodology. Because we have data for most utility-scale wind, solar, and geothermal PPAs (in capacity terms) in the US, and detailed information about numerous facets of the electricity system, we can investigate relationships across a broad variety of topics. Likewise, we can see how these relationships differ for four different renewable technologies. As electricity market and policy data can change over time, we incorporate these factors based on the year the PPA is set to begin. As an example, in 2011 California expanded their RPS from 20% to 33%. In our models a PPA signed in California with a start date of 2010 would see its RPS goal listed as 20%. A project with a start date in 2011 would be at 33%. This allows us to see how prices change based on an evolving market environment.

Despite this, the approach does come with a few weaknesses. First, the analysis only shows correlations between these factors, and should not be interpreted as causal. We are unable to say whether any of these market conditions caused a change in price, only that a change in price was observed at the same time as the market condition occurred. Further, though we perform standard tests and corrections for issues like outliers, multicollinearity, and heteroscedasticity, we are still unable to conclusively eliminate all sources of error from our models. In particular, many of the data are anormal, which could indicate that more efficient estimators may exist for some of these relationships.[14]

4.2 Geothermal Energy and Correlation to Grid Conditions

Though we find significant relationships between wind, solar, and hydroelectric prices, and market conditions, we have difficulty making similar claims for geothermal prices. Most of our models fail basic robustness tests and are sensitive to model definition. This is likely due to the small number of geothermal plants in the market and thus our database. While we have over 300 solar and hydroelectric projects in our sample, and nearly 500 wind projects, there are only 55 geothermal projects. The small sample size is likely preventing us from drawing more statistically significant conclusions, though even techniques like bootstrapping do not improve the model fit. It should be noted that absence of evidence should not be interpreted as evidence of absence, and we report possible relationships between geothermal prices and the market factors in Section 4.3.[15]

The one area where we are able to find a relationship that is both statistically and economically significant is between geothermal prices and wind prices, though even this is less robust than the correlations observed for wind and solar (Sections 4.3.1 and 4.3.2). We define a meaningful relationship as a model with statistically significant p-values (at the 5% level) and one that passes standard linearity tests. We observe that a $1 increase in wind prices is associated with a $0.57 increase in geothermal price, when controlling for factors like state, RPS policy, and thermal retirements (Figure 6). This indicates that purchasers may be treating wind as a marginal renewable, with geothermal being forced to compete with declining wind prices, a significant barrier to entry for new geothermal plants.

[14] Kim (2015) provides a good overview of this phenomenon.

[15] Detailed regression tables for geothermal projects along with wind and solar are found in Appendix D.

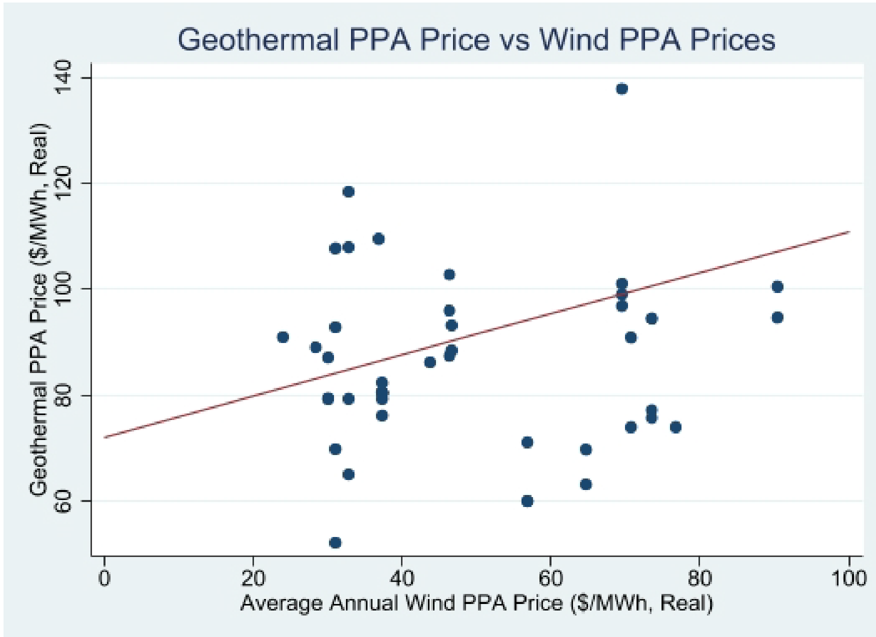


Figure 5. Geothermal and Wind Price Relationships

Table 4.1. Geothermal Regression Summary.

Explanatory Variable	Constant (Standard Error)	Coefficient (Standard Error)	Controlling variables
Average annual wind PPA price ($/MWh, real)[16]	4.098*** (0.146)	0.00681** (0.00218)	State Capacity retirements (5-year average)

4.3 Other Resources and Correlation to Grid Conditions

We also examine how other resource prices respond to market conditions. While this does not provide evidence of geothermal energy's value to the market, we use this analysis to examine whether market niches exist that could potentially be filled by geothermal energy. We consider areas where wind and solar energy have positive relationships with market conditions to be areas where geothermal energy may be less competitive. However, areas where the value of wind and solar power decline in relationship to these conditions may indicate areas where geothermal energy could be more valuable. Hydroelectricity, as a dispatchable renewable resource may act as a more direct competitor to geothermal and provide similar value streams, but its future development potential may be limited due to geographic limitations. Electricity markets are complex and multifaceted, and geothermal competes not only with renewable resources but also with fossil and nuclear plants, so these results show areas for further investigation by researchers and policymakers.

[16] Represents the average price paid in the United States for a wind PPA in the year the geothermal contract takes effect

4.3.1 Wind Power

4.3.1.1 Relationships Observed

As with geothermal, we examine wind's relationship between 11 market and policy factors. We find that five of these relationships—renewable penetration, RPS policies, retirements, solar and natural gas prices—are statistically and economically significant. These relationships are shown in Figure 7. Of these, the relationships between wind and solar prices and natural gas prices are strongest, based on the size of the leading beta coefficients, though substantial correlations exist between wind prices and RPS policies and capacity retirements as well. Of note, wind prices' response to renewable penetration is the most subtle. Though the observed negative relationship is significant, it is quite small, especially when compared to solar prices (Section 4.3.2).

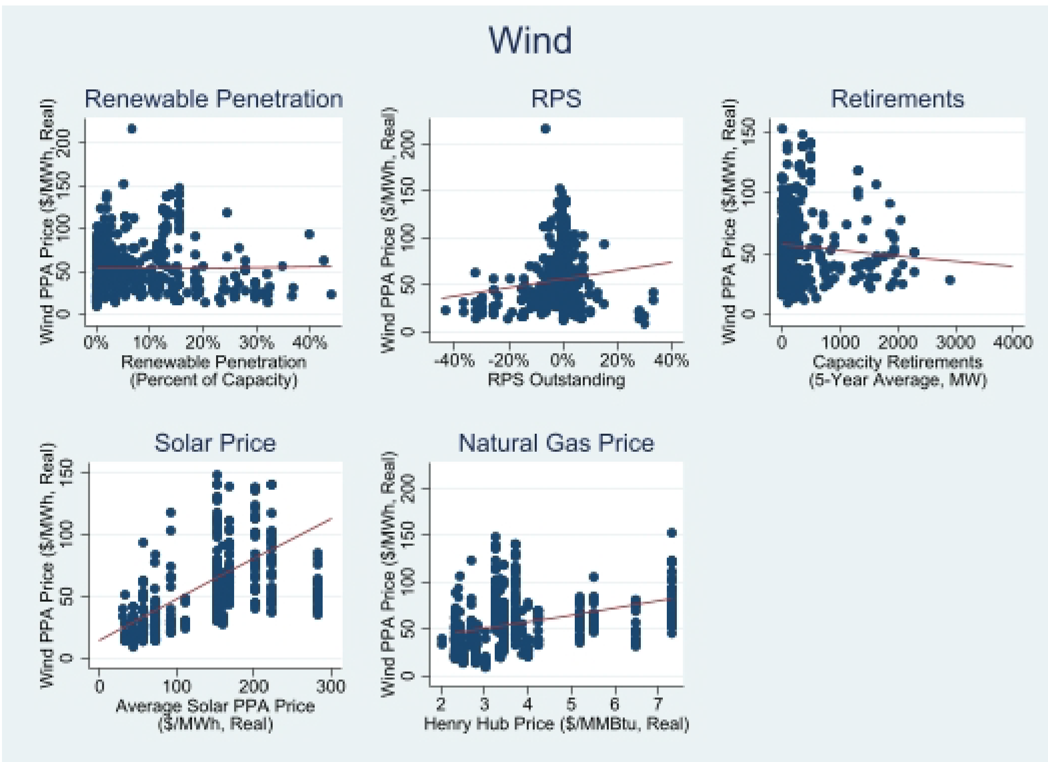


Figure 6. Wind price relationships

Table 4.2. Wind Regressions Summary.

Explanatory Variable	Constant (Standard Error)	Coefficient (Standard Error)	Controlling variables
Renewable penetration (percent of capacity)	-23.55*** (6.558)	50.65*** (13.39)	State RPS step Capacity retirements (5-year average) CO^2 price Hardware cost Annual average solar PPA price
RPS outstanding (percent of capacity)	-20.28** (6.425)	-45.18*** (12.65)	State Capacity retirements (5-year average) Hardware costs Annual average solar PPA price
Capacity retirements (5-year average)	-23.55* (10.38)	-0.00822** (0.00291)	State RPS step Renewable penetration CO^2 price Hardware costs Annual average solar PPA price
Annual average solar PPA price	-38.62*** (5.01)	-0.034* (0.01)	RPS RPS step Hardware costs
Henry Hub price	-13.59*** (6.69)	-1.870** (0.749)	State Capacity retirements (5-year average) Hardware costs

4.3.1.2 Implications in the Market

This analysis demonstrates the competitiveness of electricity markets. Resources are in steep rivalry with each other and are forced to respond to ever-decreasing prices. This relationship is most impactful for wind and solar costs, which are often competing for the same capacity in a state's renewable portfolio standards. Though wind prices historically have been lower than solar prices, wind has been forced to respond as solar costs decline. Likewise, wind prices are strongly correlated with natural gas prices, reducing costs in line with declines in the Henry Hub price. Though fossil fuel prices have broadly declined over the same period as solar and wind prices (2010-2020 for this period of analysis), renewables have made up an increasing share of new capacity (FERC 2021b). Wind and solar generation have also been more commonly procured outside of RPS policies—another sign of resource competitiveness (Barbose 2021). The relationship between wind prices and retirements also lends support to this idea. Because electricity demand growth has been below 1%/year, it appears that wind is replacing a large amount of retired capacity (EIA 2021a).

In terms of policies, there is no measurable relationship between wind prices and CO_2 pricing (in the states where it exists), energy storage mandates, participation in an energy imbalance market, or a state's top line RPS goal. However, wind prices are closely correlated with the subscription level of a state's RPS. Most states have interim RPS requirements and are required to make annual progress towards the topline RPS goal. When states are short on renewable capacity (i.e., they have not procured enough renewable energy to meet these targets), prices are higher, and prices are lower when capacity is long (i.e. states have procured more renewables than required by the RPS). Notably, more variation (and few overall prices) exists for states that are severely over or under scribed on RPS. This indicates that states are not deviating substantially from their RPS mandates, and such a response would largely be expected from a functional RPS policy.

4.3.2 Solar Power

4.3.2.1 Relationships Observed

The responses we observe for solar are quite like those we report for wind, though notably a statistically significant correlation is not observed for natural gas prices. By and large, the relationships between retirements and wind pricing are similar in shape and magnitude. Likewise, solar and wind power prices have similar correlations to RPS policies, when less than 10% of the state's RPS goal is outstanding. However, when RPS compliance is substantially short, there is a negative response for solar. This may be due to the relatively low number of systems procured under these conditions.

Perhaps the most notable difference between solar and wind power lies in the price response to renewable penetration. While wind power sees a more or less flat response to additional renewable deployment, solar power sees a roughly flat response while penetrations are below 20%, followed by a rather precipitous drop.[17] This nonlinear response has been observed elsewhere and is reflected in economic models of solar photovoltaics (PV) (e.g., Mills and Wiser 2015). We control for the linear reduction in wind costs from 2010–2020 in the analysis and the exponential decline in price for solar over the same period.

[17] Our analytic process results in a greater number of quadratic fits for solar prices due to the inclusion of the presence of a storage mandate as a control variable. In general storage mandates have a quadratic relationship with solar PPA prices. The inclusion of this variable results in a better model fit (in terms of a higher r^2 value, and less exogeneity).

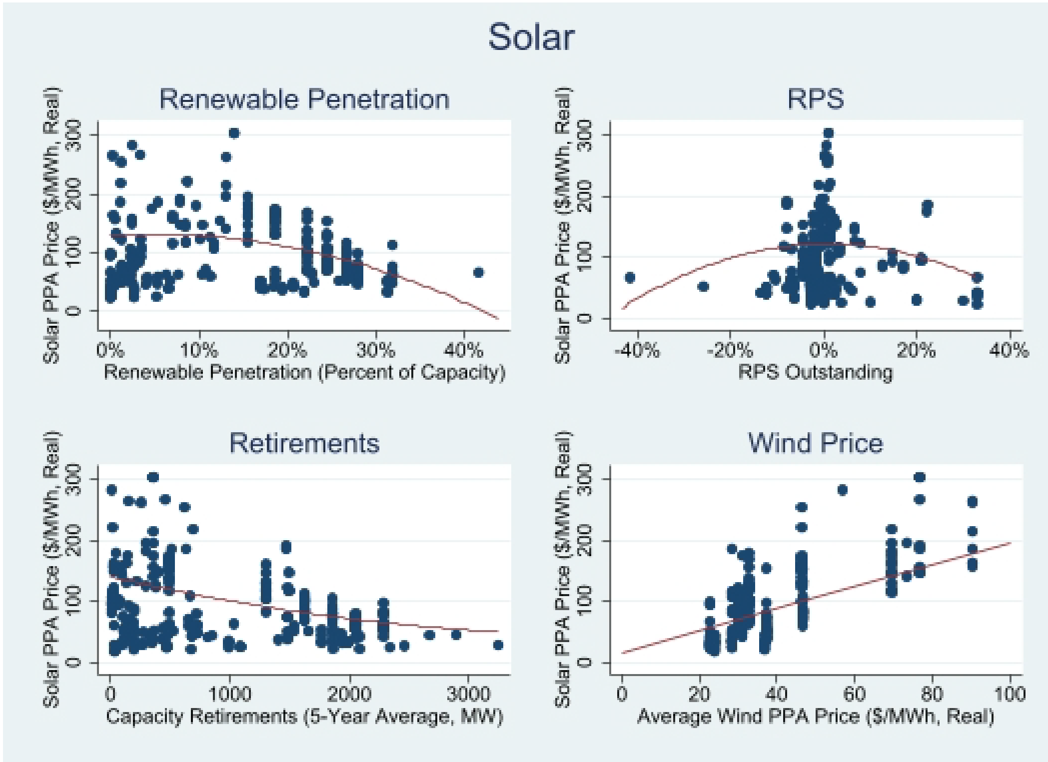


Figure 7. Solar price relationships

Table 4.3. Solar regressions summary.

Explanatory Variable	Constant (Standard Error)	Coefficient (Standard Error)	Controlling variables
Renewable penetration (percent of capacity)	-340.6*** (47.53)	-52.68* (26.12)	RPS step Capacity retirements (5-year average) Hardware costs (natural log transformation) Storage mandate Storage mandate^2 Annual average wind PPA price
RPS outstanding (percent of capacity)	-336.3*** (45.67)	59.63** (22.07)	Capacity retirements (5-year average) Hardware costs (natural log transformation) Storage mandate Storage mandate^2 Annual average wind PPA price
Capacity retirements (5-year average)	-340.6*** (47.53)	-0.0203*** (0.00294)	RPS step Renewable penetration Hardware costs (natural log transformation) Storage mandate Storage mandate^2

			Annual average wind PPA price
Annual average wind PPA price	-308.0*** (38.50)	0.700*** (0.174)	State Capacity retirements (annual) Capacity retirements (5-year average) RPS outstanding RPS goal CO^2 price Hardware costs (natural log transformation)

4.3.2.2 Implications in the Market

These results for solar energy broadly reinforce our findings for wind energy. Resources are in fierce competition with each other and must reduce costs to remain in the market. Solar prices are slightly less responsive to change in wind PPA prices than wind prices are to solar PPA prices, as one would expect based on their historical technology costs and generation profiles. Interestingly, unlike wind prices, solar prices do not see a statistically significant relationship with natural gas prices. This is likely because solar power has been priced higher than natural gas in most markets until relatively recently, though there may be some potential for a false result due to chance correlation between gas and wind prices. However, solar power does appear to be competing strongly to capture a share of retired capacity. Like wind energy's price response, solar energy's price response to RPS capacity demands is indicative of a functional market with prices declining when RPS programs are oversubscribed. However, it is relatively rare for these programs to be severely over or undersubscribed, which leads to higher standard error at extreme ends of the spectrum.

The most notable relationship is perhaps between prices and renewable penetration. Solar power sees rapidly declining prices (and thus value) when penetration exceeds 20%, even while controlling for technology cost declines. Notably, these PPAs are for generation only, so it appears that purchasers are attaching some implied capacity value to these procurements. Because solar power's load profile is more concentrated temporally than that of wind, it is reasonable to assume that its capacity value declines more quickly. Solar energy's value definition is well explored in the literature, and this model lends empirical support to these theories (e.g., Sivaram and Kann 2016; Breakthrough Institute 2021). Though prices decline overall, there are examples of solar power plants that are retaining their value despite high penetrations, perhaps due to mitigation strategies like those examined by Mills and Wiser (2015). This analysis does not include hybrid PV + battery systems, which could also help ameliorate these issues.

4.3.3 Hydropower

4.3.3.1 Relationships Observed

Only 78% of the hydroelectric projects from the original data set are included in the analysis. Projects were excluded based on sector and capacity: projects in the electric utility sector (i.e., owned by utilities) and those with a capacity less than or equal to 0.5 MW were removed. The capacity of the merchant hydroelectric plants included in this analysis are smaller than average hydroelectric plants by nature. Of the 11 market and policy factors, we find that 4 of these relationships—retirements, natural gas, wind, and solar prices—are statistically and economically significant (Figure 9). Of these, the relationships between hydroelectric prices and each of the wind prices and the solar prices are the most statistically significant. Though statistically significant, the relationship between hydroelectric prices and solar prices has less economic significance relative to wind. A weak negative slope could indicate that hydropower is acting as a flexible complement to PV, though other factors could be influencing the model. The relationship between hydroelectric prices and wind prices has a stronger positive slope, indicating greater competition between hydroelectric and wind than hydroelectric and solar. It should be noted that the magnitude of the hydroelectric prices' responses to retirements, wind prices and solar prices, while significant, are relatively small compared to the response to natural gas prices.

4.3.3.2 Implications in the Market

The implications of the relationships observed from the hydroelectric analysis are like those of the wind and solar analysis. Hydroelectric prices are positively correlated with wind and natural gas prices, indicating that hydropower is in competition with the other resources. The relationship between hydroelectric prices and solar prices is slightly negative, indicating hydroelectricity may be complementing solar and competing with wind. As with solar and wind power, hydroelectric power appears to be competing with other energy sources for retired capacity, as indicated by the negative correlation between retirements and hydroelectric prices. Unlike solar and wind prices; however, no relationship was found between hydroelectric prices and RPS capacity demands, likely due to the fact that many states to not allow conventional hydroelectric facilities, meaning facilities which produce their power purely from streamflow, to qualify in their RPS (NCSL 2021).[18]

[18] This definition of conventional hydroelectricity includes run of the river turbine systems, and dammed systems where water accumulates in a reservoir and is released through a turbine on an as needed basis (EIA 2021c).

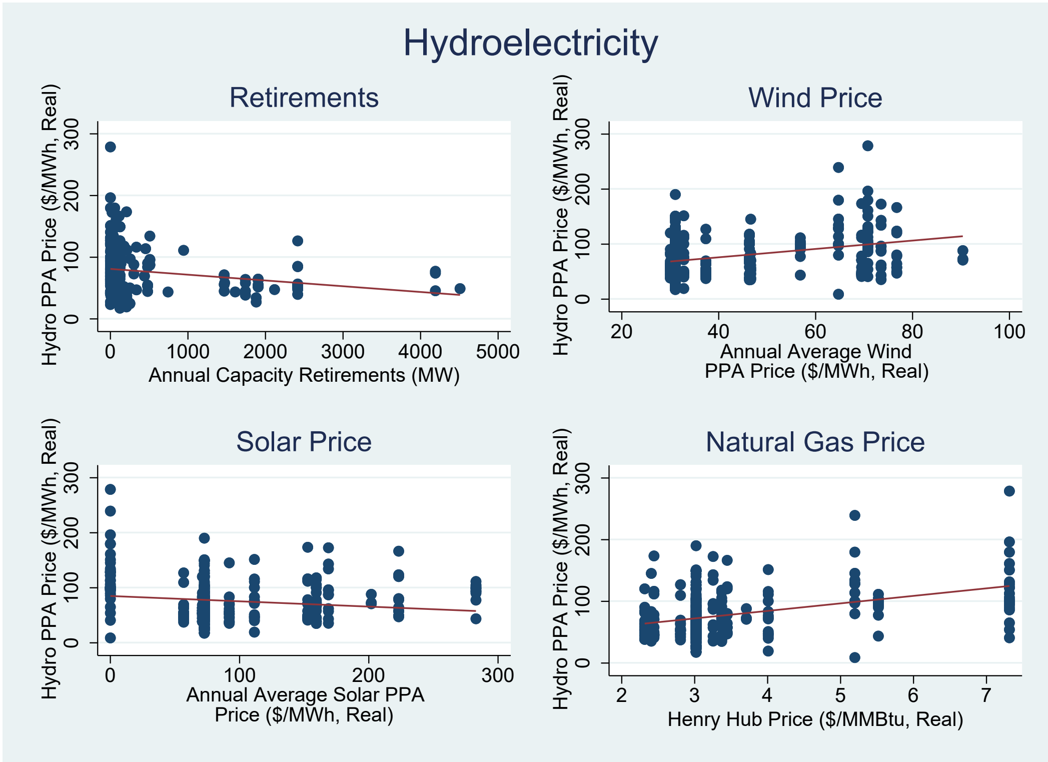


Figure 8. Hydropower price relationships

4.4 Price and Capacity Implications

Though the lack of available data prevents us from making definitive statements about high value applications for geothermal energy, the findings from our solar, wind, and hydroelectric analyses may provide some insights for future niches for geothermal development. The analysis indicates that new sources of generation are in fierce competition with each other, and solar and wind prices (as well as wind and natural gas prices) are tightly correlated. This poses a challenge for geothermal energy, which historically has seen much higher costs than wind or solar power. However, there are some areas where geothermal energy could begin to grow its market share, which we expand on in Section 4.4.1.

4.4.1 Future Niche for Geothermal and Policy Recommendations

As geothermal energy is more expensive than wind and solar on a per energy basis, developers will have to identify higher value applications, for example, by quantifying the unvalued energy system benefits geothermal could provide. If the prices analyzed in this section are indicative of how purchasers are valuing wind and solar resources, geothermal developers could potentially look to areas where PPA prices (and thus values) for wind and solar are low as opportunities for geothermal energy. Our analysis identifies several areas where wind and solar prices are lower, including when renewable penetration is high, competing resource costs are low, states are long on their RPS requirements, and retirements are high. However, not all these scenarios are likely to benefit geothermal. For example, the relationship between resource prices is likely a result of competition reducing margins, not an indicator of the value of solar and wind. As a result, policies like carbon pricing, which would drive up natural gas prices, and lessen price pressure on wind, would likely be advantageous for geothermal.

Similarly, while RPS expansions would create additional demand for renewables in general, it is unclear whether they would significantly affect geothermal deployment. In an expansion of the current framework, wind and solar could likely capture most of this new capacity as they do now. However, from the analysis of solar prices, we see that geothermal energy may be able to establish a competitive niche in areas with high levels of renewable penetration. Therefore, RPS policies that are greater than 40% could potentially help spur new demand for geothermal energy, in areas where the resource potential is good. RPS carve outs for resource diversity (like those seen in New Mexico) could also further support geothermal development, while policies that aim to concentrate renewable generation in certain time periods (e.g., clean peak standards) may also provide support depending on the coincidence with, or lack thereof, of those periods with other renewables.

4.4.1.1 Competition with Other High-capacity Value Renewables

In Section 4.3.2, the relationship between solar prices and renewable penetration seems to indicate that purchasers may be attaching some implied capacity value to solar generation. Geothermal energy, as a high-capacity value renewable resource, may be able to take advantage of this opportunity. But geothermal is not the only complementary resource. Wind energy (particularly offshore, but also some onshore depending on location) can have generation profiles temporally comparable to geothermal energy (NREL 2020a). As an example, California is seeking to manage issues related to the duck curve, through improved flexibility and complementary resources to solar (Lazar 2016).[19] Geothermal energy could play a significant role in complementing low-cost PV (Section 6.2), but other technologies may compete for some share of capacity. Figure 10 shows that California offshore wind, and New Mexico onshore wind can complement PV power, as can geothermal energy (NREL 2020b). However, the likelihood of adoption will depend on economic factors, in addition to the physical characteristics of the resources.

[19] The duck curve is a phenomenon cause by the large installed capacity of solar energy in California. Daytime net load (i.e., load minus renewable generation) is low, but as the sun sets and solar generation wanes, load ramps steeply. This must be met by generation resources or load flexibility to maintain reliability.

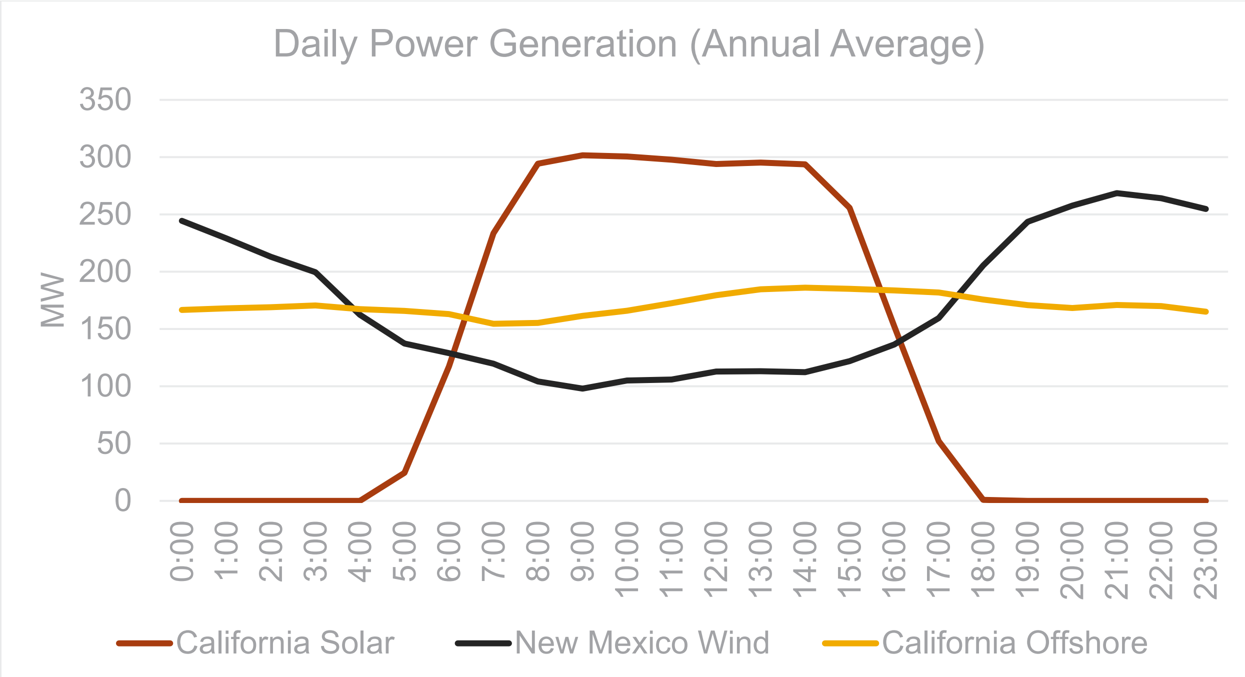


Figure 9. Comparison of renewable resource generation profiles. (Note: geothermal energy omitted as it is assumed to have a flat generation profile)

Figure 11 highlights the levelized capital costs of these resources. While geothermal energy is at the higher end of the cost spectrum, it is competitive with offshore wind power and New Mexico wind power when transmission costs are high. However, if offshore wind prices decline, as forecasted by Beiter et al. (2020), geothermal may find it more difficult to compete. Likewise, if retiring coal and gas capacity lead to less transmission congestion, as hypothesized by Lazar (2016), New Mexico wind power may become the low-cost option. Analysis of this competitive landscape may be useful for geothermal developers, researchers, and policymakers in setting technology cost targets.

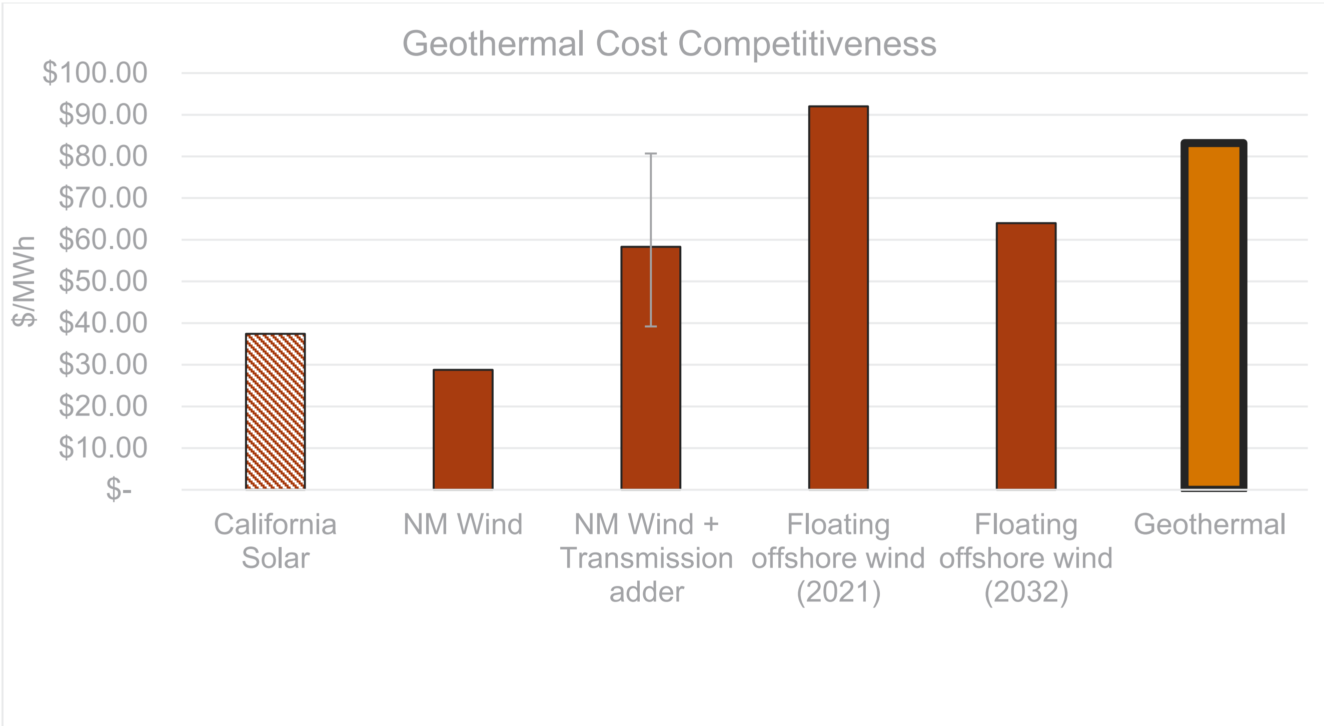


Figure 10. Levelized capital cost comparison of high-capacity factor renewables (Transmission Hub 2018; EIA 2018; WECC 2021)[20]

4.4.1.2 Competition with Other Balancing Resources

As mentioned previously, the increase in VRE creates additional need for balancing resources. In general, balancing resources can be thought of as serving a range of functions which promote grid security. These services are also called ancillary services and include black start capability (the ability to restart a grid following a blackout); frequency response (to maintain system frequency with automatic and very fast responses); and spinning reserve (which can provide additional energy when needed). The most prolific response to balancing with renewable resources has been the addition of battery energy storage systems (Rosewater et al. 2019; Choi et al. 2021). On the other hand, using geothermal for grid services is mostly theoretical at this point in time (Pili et al. 2020). Therefore, the remainder of this section compares costs of geothermal with battery storage.

The installed cost of geothermal is more expensive than solar (Table 4.4). In Table 4.4, we see that 'Base overnight cost' for geothermal is much higher than Solar PV alone, more than twice as high as standalone battery, and approximately 72% more expensive than solar/BESS hybrids.[21] Much reticence over geothermal investment is associated with the upfront capital costs. These upfront costs, and greater associated financial risks, make geothermal relatively less viable from an investor perspective. Also, according to a recent analysis by Lazard (2020), the unsubsidized LCOE of utility-scale solar falls between $.032/kWh and $.044/kWh which is less than half of geothermal energy's estimated LCOE (between $.069/kWh and $.112/kWh).

[20] Solar, onshore wind, and geothermal costs: LBNL/PNNL internal database; offshore wind: NREL, 2020; High Voltage Direct Current (HVDC) transmission costs derived from Northern Pass, WECC, and EIA, 2018
[21] 'Base overnight cost' is a simplified installation cost.

Investors are taking advantage of this cheaper renewable resource to meet their grid requirements, as seen in Figure 12 showing nearly 10,000 MW of planned solar capacity in 2021–2023 (EIA 2021b). Figure 12 shows planned capacity additions for stand-alone and co-located BESS. If geothermal energy is to provide an additional balancing role, it will have to compete with battery storage hybridization with renewable energy. According to a recent EIA release, large-scale battery energy storage systems (BESS) will contribute more than 6,000 MW between 2021–2023, which is 10 times the BESS capacity in 2019 (Figure 12).

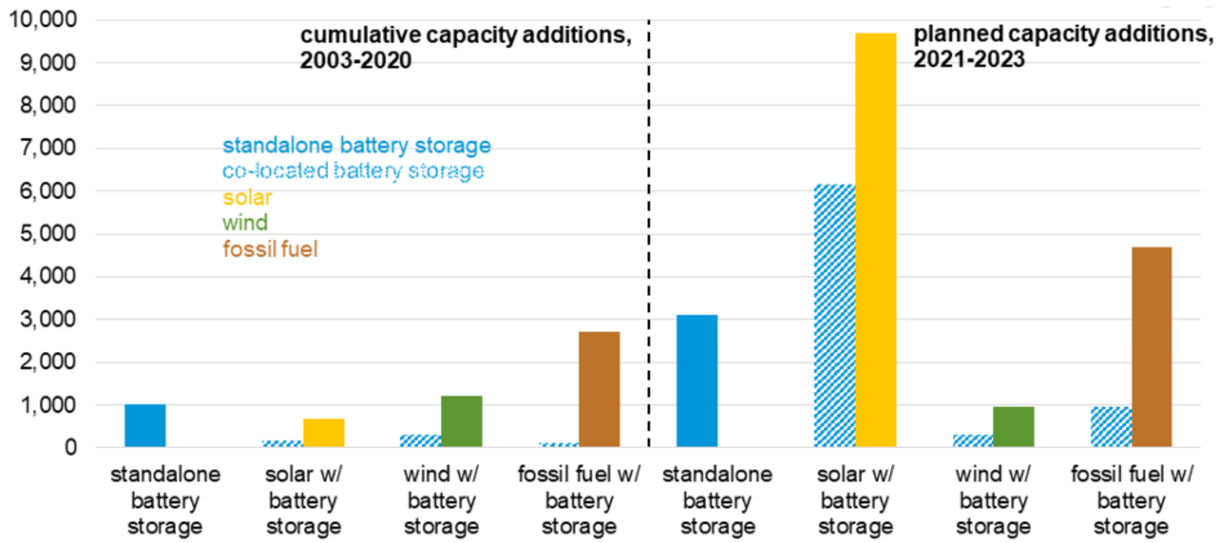
Table 4.4 Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021.

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost[2] (2020 $/kW)	Technological optimism factor[3]	Total overnight cost[4,5] (2020 $/kW)	Variable O&M[6] (2020 $/MWh)	Fixed O&M (2020$/kW-yr)	Heat rate[7] (Btu/kWh)
Fuel cells	2023	10	3	6,277	1.09	6,866	0.59	30.94	6,469
Nuclear—light water reactor	2026	2,156	6	6,034	1.05	6,336	2.38	122.26	10,455
Nuclear—small modular reactor	2028	600	6	6,183	1.10	6,802	3.02	95.48	10,455
Distributed generation base	2023	2	3	1,560	1.00	1,560	8.65	19.46	8,935
Distributed generation—peak	2022	1	2	1,874	1.00	1,874	8.65	19.46	9,921
Battery storage	2021	50	1	1,165	1.00	1,165	0.00	24.93	NA
Biomass	2024	50	4	4,077	1.00	4,078	4.85	126.36	13,500
Geothermal[9,10]	2024	50	4	2,772	1.00	2,772	1.17	137.50	8,946
Municipal solid waste, landfill gas	2023	36	3	1,566	1.00	1,566	6.23	20.20	8,513
Conventional hydropower[10]	2024	100	4	2,769	1.00	2,769	1.40	42.01	NA
Wind[5]	2023	200	3	1,846	1.00	1,846	0.00	26.47	NA
Wind offshore[9]	2024	400	4	4,362	1.25	5,453	0.00	110.56	NA
Solar thermal[9]	2023	115	3	7,116	1.00	7,116	0.00	85.82	NA
Solar PV with tracking[5,9,11]	2022	150	2	1,248	1.00	1,248	0.00	15.33	NA
Solar PV with storage[9,11]	2022	150	2	1,612	1.00	1,612	0.00	32.33	NA

[1] Represents the first year that a new unit could become operational.
[2] Base cost includes project contingency costs.
[3] The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first- of-a-kind unit.
[4] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2021.
[5] Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2019 in each region to account for the substantial regional variation in wind and solar costs (as shown in Table 4). The input value used for onshore wind in AEO2021 was $1,268 per kilowatt (kW), and for solar PV with tracking it was $1,232/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.
[6] O&M = Operations and maintenance.
[7] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to- storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion and no set British thermal unit conversion factors exist. The model calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.
[8] Combustion turbine aeroderivative units can be built by the model before 2022, if necessary, to meet a region's reserve margin.
[9] Capital costs are shown before investment tax credits are applied.
[10] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and Great Basin region for geothermal, where most of the proposed sites are located.

[11] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
Sources: Input costs are primarily based on a report provided by external consultants: Sargent & Lundy, December 2019. Hydropower site costs for non-powered dams were most recently updated for AEO2018 using data from Oak Ridge National Lab

One way to answer the question of whether geothermal can be cost competitive with co-located BESS is by comparing LCOE with levelized cost of storage (LCOS). LCOS is somewhat analogous to the levelized cost of electricity (LCOE). However, LCOS uses charging cost as fuel cost. Researchers point out the lack of consistency, as well as formulation challenges when estimating LCOS due to BESS dependence upon economic storage conditions and temporal characteristics of energy prices (Belderbos et al. 2017; Schmidt et al. 2019). For example, one LCOS using fixed tariffs rates for groups of hours, is not a direct comparison with a battery that is charged with electricity purchased on the open market with variable hourly rates. Or, a battery that is used specifically for ancillary services, may have a lower depth of discharge, but may use more cycles per year, impacting both the battery life, as well as the number of kWh discharged.



Source: U.S. Energy Information Administration, Dec 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

Note: Solid yellow, green, and brown bars indicate generating total capacity of solar, wind, and fossil fuels that have battery storage on-site.

Figure 11. US large-scale battery storage power capacity additions, standalone and co-located.

Table 4.5 shows a range of LCOS across a variety of applications. Mongird et al. (2020) provides LCOS for stand-alone BESS at $.38/kWh. Since we're considering balancing capabilities of renewable resources, it may be more appropriate to compare co-located BESS costs. Two examples of hybridized BESS and solar PV provides LCOS estimates ranging from $.08–$.14/kWh (EIA 2021a; Lazard 2020).

Table 4.5. A Range of LCOS and Applications.

Author	LCOS ($/MWh)	Notes – some factors that drive varying battery cost
EIA "Levelized Costs of New Generation Resources in the Annual Energy Outlook 2021", Feb 2021	$121.84	Average capacity-weighted LCOS for 4-hr systems across all regions for projected builds in 2026. Details on size were not provided. Batteries were stand-alone, as well as coupled with a single-axis PV.
Lazard, "Lazard's Levelized Cost of Storage Analysis – Version 6.0" 2020	$81–$140	Utility scale PV + storage projects for 50 MW – 4-hr BESS. Lithium-ion. Lazard assumes $0.03/kWh cost of fuel.
Mongird et al. "Energy Storage Grand Challenge Cost and Performance Assessment 2020" 12-11-20	$382.09	Lithium-ion LFP, 10 MW 4-hr battery with 6-year life, with a $0.0349/kWh cost of fuel. This is a stand-alone facility, hence the higher cost.

Table 4.6. Estimated capacity-weighted[1] LCOE and LCOS for new resources entering service in 2026 (2020 $/MWh)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[2]	Levelized variable cost	Levelized transmission cost	Total system COE or LCOS	Levelized tax credit[3]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Ultra-supercritical coal	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Combined cycle	87%	$7.00	$1.61	$24.97	$0.93	$34.51	*NA*	$34.51
Combustion turbine	10%	$45.65	$8.03	$45.59	$8.57	$107.83	*NA*	$107.83
Advanced nuclear	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Geothermal	90%	$18.60	$14.97	$1.17	$1.28	$36.02	-$1.86	$34.16
Biomass	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*
Battery storage	10%	$57.51	$28.48	$23.93	$11.92	$121.84	*NA*	$121.84
Non-dispatchable technologies								
Wind, onshore	41%	$21.42	$7.43	$0.00	$2.61	$31.45	$0.00	$31.45
Wind, offshore	45%	$84.00	$27.89	$0.00	$3.15	$115.04	*NA*	$115.04
Solar, standalone[4]	30%	$22.60	$5.92	$0.00	$2.78	$31.30	-$2.26	$29.04
Solar, hybrid[4, 5]	30%	$29.55	$12.35	$0.00	$3.23	$45.13	-$2.96	$42.18
Hydroelectric[5]	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*	*NB*

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2021*

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions from 2024 to 2026. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB*, or *not built*.

[2]O&M = operations and maintenance

[3]The tax credit component is based on targeted federal tax credits such as the production tax credit (PTC) or investment tax credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2026 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA,* or *not available*. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[4]Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[5]As modeled, EIA assumes that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availability by site and season for hydroelectric and by daytime for hybrid solar PV.

In addition to the LCOS, it may be important to consider the projected costs of resources. EIA, in the Annual Energy Outlook 2021, has estimated the 2026 geothermal LCOE at $.036/kWh (Table 4.6), based on the least expensive plant that could be built in the Great Basin region, where most of the proposed sites are located (see footnote 10 in Table 4.4). Also, EIA evaluated 'Solar, standalone', which is solar coupled with a four-hour battery, estimated at $.031/kWh, but categorized it with the 'non-dispatchable' group. When using this 2026 projection of 'dispatchable' battery storage, geothermal is at least three times cheaper.[22]

Another competitive geothermal price forecast comes from AltaRock Energy, who concluded that SuperHotRock resources (>400 °C) "could achieve a competitive LCOE of less than $0.05/kilowatt-hour", while the corresponding output of conventional EGS (200–230 °C) produces power at less than $0.10/kwh (Gottlieb and Hughes 2021).

There is increasing consideration and research for applying geothermal more flexibly (McTigue et al. 2018; Caldwell and Anthony 2016). The CEERT speaks to geothermal energy having broader implications in the California market, including grid services, such as ancillary services. CEERT's research found that a geothermal portfolio that replaces 3,800 MW of solar with 1,250 MW of new geothermal generation produces the same capacity due to geothermal have a capacity factor three times that of solar PV plants. This strategy saves $662 Million/yr. in energy and ancillary service costs, saves $44 M/yr. in system resource adequacy costs, and reduces overall utility revenue requirements by 2%. The CEERT research says that even with $4.5 billion in new transmission infrastructure needs, geothermal is over $20/MWh more valuable than new solar capacity. McTique et al. (2018) compared two hybrid systems: 1) geothermal with solar PV (geothermal + PV) and 2) battery with solar PV (PV + BESS). They found the geothermal + PV LCOE was comparable to PV when there was no storage. However, the geothermal + PV achieves lower LCOE's than PV + BESS "because thermal storage is relatively inexpensive compared to batteries" (McTique et al. 2018). Further, they found the longer the duration, the greater the price differential in favor of the geothermal + PV system due to the low replacement rate of heat transfer fluid compared to battery life and corresponding battery replacement costs.

Further, Millstein, Dobson, and Jeong (2020) find that that as solar capacity increases, pricing patterns change and the value of generation from all technologies is reduced while geothermal becomes relatively more valuable than solar. Similarly, Orenstein and Thomsen (2017) find that recent pricing trends have increased the value of geothermal generation relative to solar generation in Southern California.

4.4.1.3 Transmission

Other considerations when calculating geothermal viability are the regulatory and financial implications of transmission. Bringing geothermal energy to market is likely to require an expansion of transmission resources. Transmission and distribution costs are not part of the LCOE/LCOS values above. It is well known that transmission access is sometimes difficult to obtain and can be quite expensive to build, with one WECC report estimating transmission costs to roughly lie between $1M to $3M/mile (Dombek 2012). What complicates geothermal, relative to other renewable energy sources and battery resources is that its location is stationery and cost-dependent upon proximity to the load center. One of the benefits of energy storage is its placement accessibility, not just for distribution networks, but for transmission, as well (Motalleb, Reihani, and Ghorbani 2016). Motalleb, Reihani, and Ghorbani (2016) state that "optimal siting and sizing of BESS is important to have the minimum costs and losses". However, batteries

[22] It is important to note that this information doesn't necessarily match other cost estimates (e.g. Lazard) where geothermal is not three times cheaper.

must be placed near the renewable resource and the plant sites for renewable resources (land for utility-scale wind and solar farms) are starting to experience similar cost prohibitive constraints as land near load centers gets used up, i.e., the growing need for offshore wind (St. John 2020).

The recent LA100 study from NREL concludes that in order for Los Angeles to meet its 100% renewable energy targets by 2045 (and, if biofuels do not qualify as “renewable”), that new and substantial amounts of geothermal would be needed to meet the firm capacity void created by natural gas power plant retirements (Cochran and Denholm 2021). The study also has various transmission scenarios, which will be required to “provide further access to out-ot-basin geothermal, wind, and solar resources” (Cochran and Denholm 2021). Table 2 from Chapter 6 of the LA100 study, included transmission in their renewable energy technology costs assumptions and is reproduced below (Table 4.7). Installed geothermal costs of the least expensive plant in the most advantageous geothermal location (Table 4.4), are approximately half of the costs shown below. The difference is negligible, or the estimates from Table 4.4 are more expensive for wind and solar.[23] One may infer that a large part of the differential is due to varying transmission needs. Regardless, the LA100 study, along with McTigue et al. (2018) and Millstein, Dobson, and Jeong (2020) speak to the need and upcoming value of geothermal energy in regions trying to incorporate increased renewable energy. It may be prudent for planners to consider transmission and distribution infrastructure and timing to most cost-effectively meet RPS planning.

Additionally, governments (and in particular state governments) have a history of building transmission to support renewable energy development. One of the most notable projects, the Competitive Renewable Energy Zone (CREZ) initiative, was chartered in 2005 to unlock wind development in West Texas and the Texas Panhandle. Within 9 years, over 3,600 miles of transmission were installed within the CREZ zone, unlocking over 8 GW of wind generation (Cohn and Jankovska 2020).

The CREZ process began with a prolonged stakeholder engagement initiative. Over three years, the Public Utilities Commission of Texas (PUCT) worked with utility and industry groups to identify transmission planning pathways, and associated costs. The commission then worked with utilities and local governments to build and approve the lines. At the time, Texas had pre-existing processes for the reimbursement of transmission costs through the rate base, which reduced complexity, and limited developer liability. Costs averaged about $1.2 million per circuit mile and reached a total of $6 billion, an investment of $750,000 for each MW of capacity (Cohn and Jankovska 2020). For geothermal, CREZ could serve as a model for building other resource-focused transmission pathways.

[23] To make the comparison more equivalent, we only consider the least expensive geothermal technology available in Table 4.7.

Table 4.7. Modeling Assumptions for Renewable Energy Technologies (NREL, Table 2, Chapter 6, LA100 Study)

	Capital Cost in 2030 (2019 $/kW)	Capital Cost in 2045 (2019 $/kW)	Technology Subcategory
CSP (no thermal storage)	3,628	3,118	No thermal storage
Geothermal	4,208	3,904	Hydrothermal; flash cycle
	5,429	5,036	Hydrothermal; binary cycle
	14,442	13,396	Near-hydrothermal; flash cycle
	32,112	29,786	Near-hydrothermal; binary cycle
	14,442	13,396	Deep enhanced system; flash cycle
	32,112	29,786	Deep enhanced system; binary cycle
Utility PV	1,266	1,065	Out-of-basin single-axis tracking
	1,862	1,588	In-basin fixed-tilt
Wind	1,417	Resource-specific: 1,185–1,251	Onshore
	Resource-specific: 2,017–3,126	Resource-specific: 1,237–1,645	Offshore

CSP is concentrated solar power. Costs are taken from the 2019 Annual Technology Baseline, adjusted for inflation from 2017 to 2019 dollars, and scaled using regional multipliers from the U.S. Energy Information Administration's Capacity Cost Estimates for Utility Scale Electricity Generating Plants (see Table 4). Utility PV costs are reported in $/kW_{AC}$.

5.0 Energy Contracts and Contract Mechanisms

This section describes the contracts reviewed for a wide variety of resources and the contract structures that may present market opportunities for geothermal energy development.

5.1 Historical PPA Contracts identified for Analysis

We reviewed 30 PPAs for both renewable and nonrenewable resources (Table 5.1). Figure 13 identifies the number, technology type, and location of resources reviewed. In addition to technology types, the PPAs vary in their buyers and sellers (often electric utilities and project developers, respectively), payment constructs, and other contract terms. Despite the wide variety of PPAs, they nonetheless have many similarities as might be expected with energy project development in the US, particularly renewable resources. Several of the PPAs are of geothermal plants. Nearly 25% of the PPAs we evaluated are hybrid resources, containing some level of battery storage, including six of the seven solar PV PPAs (two sets of the solar projects were co-located, hence only five solar icons), which contained provisions or companion contracts for battery storage. Additionally, one of the hydroelectric contracts, the West Kauai Energy Project, includes battery storage, pumped storage, and solar PV, in addition to run of river hydropower. We also reviewed the Tungsten Mountain Geothermal Project, a similar multi-resource project where an 18 MW solar PV system was developed to serve the plant’s parasitic load.[24]

[24] The Tungsten Mountain Geothermal Project is part of the Ormat Northern Nevada Geothermal Portfolio and is classified as a geothermal project because the solar energy does not contribute to the resource provided to the grid. Rather it provides only load to serve internal operations (i.e., parasitic load).

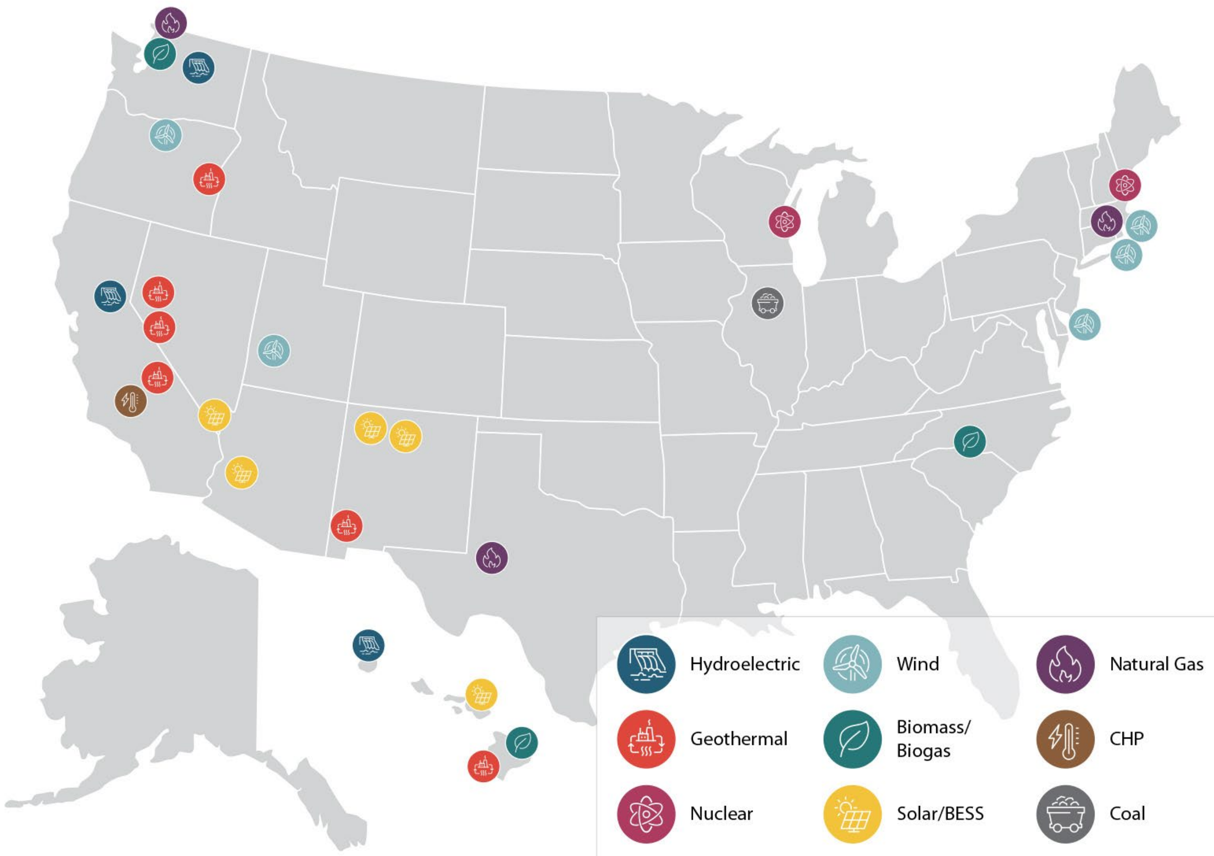


Figure 12. Map of the United States showing locations of energy projects whose PPAs were analyzed for this report. The symbols represent energy resource.

Table 5.1. Number of PPAs reviewed by resource type

Renewable		Nonrenewable	
Resource	**# PPAs reviewed**	**Resource**	**# PPAs reviewed**
Solar	7	Gas	2
Geothermal	6	Nuclear	2
Wind	5	Coal	1
Hydroelectric	3	CHP	1
Biomass	2		
Waste	1		
Total	**24**	**Total**	**6**

CHP = combined heat and power.

In reviewing the 30 PPAs, we evaluated terms and conditions to gain insight into mechanisms that might support geothermal project development, especially those terms related to addressing technology or development risk. The team compiled the 30 PPAs based on factors such as whether they had market environments similar to those of geothermal resources, whether they used technologies with significant risk profiles that may hold value for comparison to geothermal resources (e.g., hydroelectric output uncertainty due to climate change), and renewable market trends. In particular, as a comparison point we evaluated the following: price structures (e.g., energy or capacity prices and how they are defined); performance requirements and operational requirements; any special requirements associated with project development including environmental and siting risk control measures; contract default requirements, and renewable energy credit and attribute allocation (UCS 2013). Another key term we considered across all the projects is transmission interconnection and how interconnection costs and requirements factor into the PPAs (see Section 4.4.1.3). The contract structures are considered in the context of the regulatory and market environments in which these agreements are established.

The following subsections review contract structures (Section 5.2), discuss new market opportunities and corporate contracts (Section 5.3) and summarize findings from our contract review. We summarize the terms of interest and consider implications and value for future geothermal project development.

5.2 Review of PPA Contract Structures

Rather than detailing contract terms for each of the 30 PPAs, we introduce the types of terms and conditions that are common and highlight details that may be of interest for future geothermal project development (more details about each PPA can be found in Appendix B). Of course, not all 30 of the PPAs provide insights for each contract term type. The terms of interest we highlight below are based on conversations we undertook with developers and offtakers to discuss geothermal project development risk and contract mechanisms and strategies that may help address those risks.

5.2.1 Remuneration Structure

An obvious key component of a PPA is its remuneration structure and associated prices. Traditionally, in energy project contracting, and as is the case with several of the identified contracts here, the contract payment structure takes the form of a simple dollars per megawatt-hour ($/MWh) payment for the delivery of energy. This has been true for nonrenewable projects (here we analyzed contracts for several Commonwealth Edison Company (ComEd) coal plants and the Point Beach Nuclear plant) as well as renewable energy projects (e.g., solar, wind, and geothermal). Such straightforward payment structures were appropriate when dispatchable fossil resources, largely owned and operated by vertically integrated utilities, were the largest proportion of generation.[25] However, that has changed. With the emergence of formal organized markets for energy, capacity and ancillary services, contracts began to explicitly require and compensate some level payments for both energy and capacity.[26] More recently, as renewable

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[25] That's not to say there were not more complex remuneration structures in the past. For example, the PGV plant had a multi-part payment structure in the form of energy and capacity payments (Section 3.1.1).

[26] In the early 2000s, several states undertook the process of deregulation to increase competition in the electric system, separating existing vertically integrated utilities into separate entities for generation, transmission, and distribution. Several Independent System Operators of Regional Transmission Organizations were established to operate regional electric systems, creating markets for generation and rules for transmission. The FERC was assigned regulatory oversight for these markets. Since then, the FERC has promulgated several Orders specifying market products and compensation. Formal markets (ISO and RTOs) deliver about half of retail electric sales in the country, with the remainder being vertically integrated utilities in regulated states in non-market regions and municipal, cooperative and other public

resources have increased as a proportion of generation, more multi-part and otherwise complex payment structures are emerging to procure and compensate different components of a plant's output. In theory, these differentiated components could be sold to one offtaking entity or could be separated with different components sold to different entities. In practice though, it is likely one entity purchases all characteristics of the output. In this section we discuss several of these structures as identified among the evaluated PPAs.

Table 5.2 below identifies the variation in remuneration structures across the 30 reviewed PPAs. Just over half of analyzed contracts (16) have either multi-part payment structures or some accounting of capacity value, while another 14 PPAs remunerate on an energy-only payment. Of the multi-part contracts, four include ancillary service payments in addition to energy and capacity payments and two other contracts also consider energy availability. More broadly, across the energy industry, most contracts only include energy prices with those in organized market regions, often having provisions to monetize capacity in existing capacity markets. Few contracts include more novel elements, such as ancillary or grid services, or availability payments. Where these have been developed, however, both offtakers and developers have cited the need for increased dispatchability for the offtaker, particularly if the offtaker is a utility, and increased revenue certainty for the developer.

Table 5.2. Remuneration structures observed in the 30 PPAs analyzed in this study.[27]

Remuneration Structure	All (Total: 30)	Geothermal (Total: 6)
Energy only	14	5
Energy and capacity	10	1
Energy, capacity, and ancillary services	4	
Energy and availability	1	
Energy, availability, and capacity	1	

Amongst the reviewed geothermal contracts, five have an energy-only payment with one plant having a multi-part energy and capacity payment (PGV). Across the identified geothermal energy contract prices (see Section 4.0), they only report energy prices and not separate capacity prices. On the surface, it seems there may be a ripe opportunity for geothermal plants to capitalize on these different payment mechanisms.

utilities that operate as independent entities both inside and outside markets. For further background and detail see the FERC Energy Primer: https://www.ferc.gov/media/2020-energy-primer-handbook-energy-market-basics.

[27] *See* Energy Market Primer and Denholm, Paul, Yinong Sun, and Trieu Mai. 2019. An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72578. https://www.nrel.gov/docs/fy19osti/72578.pdf.

Energy Payments

As mentioned above, across contract structures in the US and worldwide, it appears that energy-only payments are the norm. They certainly pay for the energy attribute of the resource, but other attributes are left unremunerated, and in many situations, an energy-only payment can undercount benefits.[28] For example, the Lightning Dock Geothermal Project contracted by the Public Service Company of New Mexico (PNM) and the Neal Hot Springs Geothermal facility contracted by Idaho Power Company both have an energy-only payment. The payment may be modified by escalation rates (2.75% annual for Lightning Dock) and/or seasonality multipliers (a multiplier on the price of Neal Hot Springs to account for higher or lower priced energy in some months). However, neither of these contract structures remunerate for the spinning turbines associated with the power-generating cycle of the geothermal facility providing system inertia or AGC (to deliver primary frequency response). Further, the capacity contributions of both plants to the PNM system and the Idaho Power system remain unremunerated. Similarly, the Sierra Pacific Biomass Cogen Project PPA, signed by Puget Sound Energy in 2020, also includes a flat energy price without provisions to remunerate capacity, inertia, or frequency response. In contrast, when these utilities build out their own facilities, planned in integrated resource plans and submitted to their Public Utility Commissions for economic and “just and reasonable” review, they inherently capture capacity value, inertia, and frequency response to their systems.

The Increasing Value of Capacity and Resource Adequacy

As the deployment of renewable resources continues to increase and dispatchable resources are increasingly retired or otherwise limited, the value of capacity or resource adequacy to ensure reliability of supply will be critical. The electric industry, generally, seems to have coalesced around the idea that long duration energy storage resources will be the key to meeting capacity or resource adequacy needs, charged from intermittent renewables and available to fill gaps in renewable output. This may be true given the current uncertainty in non-carbon emitting resources that are otherwise available and the uncertainty of the emergence of large-scale carbon capture. However, there is also uncertainty in the emergence of long-duration energy storage technologies, whether hydrogen, longer-term pumped storage, or long-duration batteries. Accordingly, there is clearly a space for established and developing geothermal technologies to play a significant role. This can be as a standard hydrothermal resource delivering high-capacity energy, or it can be as a thermal storage resource, storing energy in the form of heat underground for use in future electricity generation or in reducing electricity needs.

Capacity Payments

Although only a single geothermal contract reviewed included a capacity remuneration element, several other resource contracts had such elements. Many, but not all, of these are in organized market environments where capacity markets exist; for example the Seabrook Nuclear facility in New Hampshire, the (currently under construction) Vineyard Wind facility off the coast of Martha’s Vineyard, and the Bellingham Cogeneration Natural Gas Facility

[28] See the discussion on the benefits beyond energy that can be provided by geothermal resources in Section 3.

in Massachusetts.[29] Examples of the non-organized market region resources with capacity remuneration elements include the Honua Ola Bioenergy facility and the Puna Geothermal Facility both in Hawai'i. These non-organized market facilities are more recent contracts in western states, highlighting that with increasing renewables deployment, there has been an increasing recognition of the capacity and resource adequacy needs of grids and explicit efforts to procure and remunerate those services. Unfortunately for hydrothermal resource developers, only California includes capacity payments in the form of its Resource Adequacy construct. Other states with significant hydrothermal resource do not have capacity renumeration. That said, the need for firm capacity is increasingly being recognized in these states, with the Oregon PUC currently (as of 2022) undertaking a resource adequacy proceeding to explicitly value resource capacity contributions, and the Nevada PUC recently approving solar and storage hybrid contracts explicitly paying for firm output.

The California Resource Adequacy program has been recognized by stakeholders in the state as inadequate to incent firm, clean generation capacity given the state's aggressive clean energy goals. The California PUC is currently undertaking a proceeding to reshape and strengthen the incentive. In its current form, load serving entities (e.g. utilities) subscribe resource adequacy resources, or RA resources conducting auctions to determine pricing. The construct pays RA resources based on $/MW-year of Resource Adequacy provided. The current framework explicitly includes a provision for geothermal resources. In procuring resource adequacy, a California load serving entity may specifically contract with a resource for the delivery of the resource adequacy. In PPAs, resource adequacy or capacity payments may be included within a bundled PPA rate (i.e. $/MWh), or as a separate element, being paid on a $/MW basis, with a provision that resource adequacy or capacity rights are transferred to the offtaker.

[29] California does not have a capacity market, but the California Public Utilities Commission has resource adequacy (RA) requirements and those are contracted and monetized with payments delivered to resources providing RA.

Availability Payments

Another payment element rarely found in PPAs is the availability payment. Here, because of the inclusion of more recent projects in Hawai'i, we included two contracts with availability payments. Availability payments, in effect, pay for potential energy to be delivered; that is, pay up-front for a resource to be available to deliver energy (or other services). Availability payments are different than capacity payments, which explicitly pay for available capacity in certain periods over short timeframes. Availability payments are often lump sum (usually monthly) payments over the duration of a contract term with the intention to ensure a resource is available to deliver services to the system. In the contracts reviewed here, the Chuckwalla Solar project with Nevada Power Company and Sierra Pacific Power and the (AES) Kuihelani Solar project with Maui Electric both include availability payments. The Kuihelani contract specifies its availability payment as "The Lump sum payment is made in exchange for the right to dispatch the facility's energy production." The Kuihelani contract is an example of Hawai'ian Electric's recent Renewable Dispatchable PPAs with solar, wind, and other renewable resources (often

Pumped Storage Hydro in Israel

Israel has developed a payment mechanism with a remuneration structure intended to ensure private financing and development as a part of the Israel Electric Corporation determination that the system required a significant deployment of long duration storage. Based on this structure, two major pumped storage projects have been evaluated for the Israeli market: the 344 MW Kokhav Hayarden project owned by Star Pumped Storage and under development, and the 300 MW Gilboa pumped storage project which is already operational.

The payment structure pays on plant availability over an 18 to 20-year timeframe, which, as discussed above, is traditionally not available to resources in liberalized electric markets. This approach mimics, in some form, an asset in a vertically integrated market with a guaranteed level of payment to ensure development, but at the same time includes delivery and performance requirements to promote efficiency and a high level of resource performance.

The three-part payment scheme consists of the following revenue streams:

1. Primary source of revenue: An availability payment that forms the bulk of revenue and requires the plant to be available for a minimum time during a year (90%). In addition, there is an availability requirement that has been passed on to the equipment manufacturer who is supplying plant availability guarantees through a long-term O&M contract. This payment also includes bonus payments for dynamic benefits including ramp rates, pumping to generation switching timeframes, startup and shutdown speeds, etc.
2. Payment for energy.
3. Start-up and shut down payments.

These plants are being provided a fixed revenue stream over a long time based on certain performance requirements, and additional incentives for flexibility and reactivity. A developer argues that this mitigates market and regulatory risk for the developer. The grid operator bears long-term development risk, while the developer bears the plant's performance risk, which is also being shared by equipment suppliers. This allows for risk allocation and sharing among all involved parties and has led to these two successful deployments.

battery-hybrid systems, but not required to be) that include multi-part lump sum availability payments and sometimes payments for delivered energy, enabling the utility to have full control of resource dispatchability. Availability payments potentially provide for a project de-risking element, allowing the developer to have a guaranteed revenue stream that is less subject to curtailment and provides the utility and its ratepayers a lower cost firm renewable energy resource. This can provide a project developer with a guaranteed long-term revenue stream, while enabling a dispatchable resource for the utility.

Ancillary Service or Grid Service Payments

We identified six contracts that include some form of ancillary service or grid service payments. These payments can provide additional revenue streams for services that either in the past were required as part of interconnection (and not compensated) or were not requested despite a facility being able to provide them. As with capacity or resource adequacy, ancillary and grid services are becoming more and more critical to ensuring system reliability with the continued retirement of dispatchable units and replacement by intermittent renewables. Often, resources providing grid services are dispatchable units (e.g., natural gas) and more recently, battery-hybrid systems. However, as the Golden Hills Wind Facility contract shows, other resources can deliver different types of grid services. In the case of Golden Hills, the plant is contracted to deliver a shaped winter product during winter super-peak hours and receives increased payments to do so. The seller is permitted to use a combination of its own resources and limited market purchases to fulfill its commitment to meeting the required winter capacity. These additional resources must not include coal fired electricity beginning in 2026 and must be carbon neutral after 2030. Several other contracts include ancillary services baked into energy prices, such as the Douglas County Wells Hydroelectric contract with Portland General Electric and the Arroyo Solar and Battery Project and the Jicarilla Solar 1 and Battery Project in New Mexico, contracted with PNM. There is likely additional value to be captured in splitting out payments for these services.

Clearly, current market trends are seeing broad deployment of storage hybrid systems, largely solar and battery, but in some instances with wind and with pumped storage (internationally). The rapidly declining costs of battery systems have played a major part in this. For short duration services (e.g., frequency or voltage regulation) such systems have an advantage – batteries are quite capable (modulation of output), and hybrid configurations can enable longer duration. However, battery systems are in most instances limited to 4 hours and even in hybrid configurations are limited in their capability to deliver longer duration grid services (they must be charged at some point). This may represent an opportunity for geothermal resources in delivering longer duration services or those requiring less higher frequency modulation (e.g., operating reserves, contingency reserves, or capacity, relative to frequency response). As with the higher frequency services, these services are likely to be in demand as renewable deployment increases and dispatchable fossil or nuclear generation is retired. Further, in the right circumstances, geothermal resources may also be able to leverage battery storage systems (like with solar) to increase their capability to deliver higher frequency services while having the advantage of firm and predictable capacity from the geothermal resource.

Performance Payments and Penalties

In the case of several, if not all, of the reviewed contracts, resource performance and minimum requirements are subject to penalties. For example, many of the Hawai'i contracts, across resource types, have large, liquidated damages associated with under-delivery of minimum requirements, such as damages on equivalent availability factor (EAF), equivalent forced outage rate (EFOR), and excessive unit trips, among others. Other contracts, such as the Bellingham Cogeneration Facility contract with Boston Edison (now Eversource) stipulate penalty payments equivalent to energy replacement costs. Finally, the Yuba Bear Hydroelectric contract with Pacific Gas and Electric Company (PG&E), a nontraditional contract as identified by the utility, allows for capacity and efficiency testing throughout the duration of the term and permits the seller, the Nevada Irrigation District, to correct for any capacity and efficiency shortfalls below 90%; if capacity cannot be corrected, the contract enables a negotiation to reduce contract pricing.

There are, of course, different motivations behind performance penalties. Hawai'ian Electric, for example, operates a small and inflexible grid that can be adversely affected by insufficient operations of single generation plants; meanwhile, both the Bellingham and Yuba Bear facilities are in large electrical interconnects and organized markets with significant capacity. We only analyzed one contract with a performance payment, or bonus: the Rio Bravo Poso Combined Heat and Power (CHP) facility in California contracted by PG&E (now retired). This facility had an energy payment and a capacity payment, which included a performance bonus based on facility output, while still having minimum performance requirements and the potential for reduced payments directly tied to shortfalls in performance. Finally, the contract included provisions for long-term shortfalls to trigger a reduction in contracted capacity. We discuss underperformance terms in more detail in Section 5.2.3.

Identified Useful Structures and Models

As a result of increasing adoption of variable renewable resources and retirement of fossil resources, grid operators have begun to recognize the higher value of ancillary services and guaranteed capacity, but as discussed previously, the recognition of higher value has not necessarily translated to increased compensation. While the Energy Imbalance Market has presented an opportunity for dispatchable resources on the west coast to increase revenue and California has implemented a ramping market construct, several other initiatives in California and other states are still in progress (e.g., the modification or development of new resource adequacy or capacity payment constructs).

Because geothermal resources have the potential to provide both baseload capacity and flexible generation, this is an area where developers may be able to leverage resource value in the form of multi-part contract remuneration structures to consider energy, capacity, availability, and grid services. While one geothermal contract analyzed here (PGV) has taken advantage of this opportunity to include a capacity payment in addition to the standard energy payment, and does have some provisions for flexible services, it does not pay for them. This indicates that the market is not fully recognizing the value of these flexible services, or at least did not recognize the value of these services when the PPA was signed. Further, most of the geothermal contracts analyzed include only an energy payment.

5.2.2 Output Terms

Output terms are used to describe the energy or capacity requirements associated with project contracts. These terms may include elements such as minimum values of energy or capacity or both, seasonal variations in both, and intraday output requirements. Output terms may also include annual capacity or energy degradation schedules.

Required Minimums and Ability to Meet Specifications

Most contracts include output specifications related to the quantity of energy expected to be produced throughout the year and/or at any given discrete period. This includes output minima (e.g., firm capacity levels) and output maxima. For example, the Neal Hot Springs Geothermal PPA specifies that there cannot be deliveries exceeding 36 MW at any given moment in time or exceeding the maximum capacity (revised as part of the development milestones, not to exceed 30 MW) for five consecutive minutes. Energy minima are generally specified as an annual guaranteed availability level. Additionally, some contracts include more specific requirements for output characteristics. For example, the Honua Ola Bioenergy PPA specifies the quick load pick-up rate and ramp rates associated with different levels of output if the system experiences a frequency drop.

One innovative approach to addressing risk in terms of output uncertainty can be seen in the 2016 Ormat Northern Nevada Geothermal Portfolio PPA between the SCPPA (buyer) and Ormat Northern Nevada Geothermal Portfolio (ONGP) LLC (seller)[30]. This contract was written with a minimum and maximum output requirement based on nine geothermal plants whose expected net capacity totals 150 MW (see Table 5.3). To address risk that one or more of the designated geothermal plants is unable to meet its required output, the contract includes a list of 16 predefined additional plants that can be substituted for one of the initial set.

Table 5.3. Geothermal plants included in the Ormat Northern Nevada Geothermal Portfolio PPA, with expected net capacity totaling 150 MW.

Geothermal Plant	**Expected Net Capacity** (Total = 150 MW)	**Existing or New**	**Expected Delivery Commencement Date**
Tungsten Mountain Geothermal Energy Facility	24 MW	New	12/31/2017
Steamboat Hills Geothermal Energy Facility	12 MW	Existing	3/31/2018
Dixie Meadows Geothermal Energy Facility	21 MW	New	12/31/2018
Tungsten Mountain 2 Geothermal Energy Facility	24 MW	New	12/31/2020
Baltazor Hot Springs Geothermal Energy Facility	20 MW	New	12/31/2020
Dixie Meadows 2 Geothermal Energy Facility	21 MW	New	12/31/2020
Brady Geothermal Energy Facility	12 MW	Existing	8/31/2022
Steamboat 2 Geothermal Energy Facility	8 MW	Existing	12/31/2022
Steamboat 3 Geothermal Energy Facility	8 MW	Existing	12/31/2022

Additionally, several contracts include seasonal output terms. The Golden Hills Wind PPA provides for a shaped product, where the seller is required to deliver a firm capacity of 150 MW/hr for 7 hr./day during winter super-peak hours (November–February, Monday–Saturday, specific hours are redacted). Based on the intermittency of the main wind product in this PPA, the developer can supplement energy deliveries using a mix of resources they own in addition to up to 12% market purchases per year. A slightly simpler version of this is seen in the Sierra Pacific Biomass Cogeneration PPA, which specifies a guaranteed winter period monthly output, separate from the guaranteed annual availability factor that applies to the year. The Rio Bravo Poso CHP PPA specifies a minimum firm capacity level (80%) specifically for the summer months (June–August).

Identified useful structures and models

While many geothermal projects struggle to meet the capacity levels that can be provided by other resource types, the ONGP PPA provides an innovative approach. It features a large-

[30] A similar portfolio approach is used in other resource types. In this analysis, a portfolio approach is also seen in the Crawford, Fisk, Waukegan, Will County, Joliet, and Powerton Coal PPA.

capacity contract, which also minimizes the risk of resource inadequacy by building a contract around a portfolio of geothermal plants, including backup plants in case one of the initial ones proves insufficient to meet the capacity requirements. Additionally, given the fact that geothermal production can sometimes face seasonal variation, the potential to include seasonally variable output requirements (e.g., lower output requirements in the summer when air temperatures are high) could be beneficial for future geothermal PPAs.

5.2.3 Performance and operational requirements

Curtailment

Most contracts we reviewed include a relatively standard treatment of curtailment events where the buyer is required to pay the seller for the energy that would have been delivered if not for the curtailment (i.e., deemed energy) at the energy price stipulated in the contract. There are four notable exceptions to this approach that provide more favorable curtailment conditions for the buyer.

- The PGV PPA requires only that the buyer continue to pay the capacity charge and pay for any energy that they can accept during the curtailment period.[31]
- The Rio Bravo Poso CHP PPA allows the buyer to pay a reduced price during a curtailment event based on what the electricity price would be with spillover from excess hydropower production, or the buyer can simply require the seller to interrupt or reduce deliveries without payment. Additionally, the seller cannot use excess energy to meet their parasitic load during a curtailment event but must continue to purchase energy from the buyer if that is their standard operating procedure. The buyer's main responsibility to the seller during a curtailment event is to provide the seller with reasonable notice and to attempt to make an economy sale of surplus energy.
- The Sierra Pacific Biomass Cogen PPA stipulates that the buyer is permitted to curtail energy without liability in the months of May and June. However, in this case, the buyer is not allowed to curtail energy from November through February.
- Finally, the Neal Hot Springs PPA permits the buyer to curtail energy by up to 1,620 MWh per contract year at no cost. However, any curtailment beyond that limit incurs a cost equivalent to the normal energy price for the energy that would have been delivered if not for curtailment. This contract also allows the seller to try to sell curtailed energy to a third party, with 75% of the net energy sales payments deducted from the amount the buyer is required to pay for curtailed energy.

A few contracts also stipulate the amount of notice required for a buyer-initiated curtailment, ranging from 2 to 48 hours. While some of these terms may yield additional risk for a geothermal plant in terms of not receiving expected energy payments, the structure used in the PGV PPA demonstrates one contractual approach for incorporating flexibility in a geothermal contract. By explicitly requiring capacity payments to continue during a curtailment event, this contract places a value on having the *option* to use the resource, even at times when it is not used.

[31] The PGV PPA has an interesting capacity construct, both addressing shorter-term capacity needs and longer-term system availability, but both included in a single capacity payment.

Force Majeure

Force majeure[32] was also considered an important part of this analysis, especially given the observed association between geothermal energy production and hazards such as earthquakes (Giardini 2009; Lee et al. 2019) and volcanic eruptions. One example of this hazard exposure is the 2018 Kilauea volcanic eruption, which shut down the PGV plant for about two years (The Guardian 2018; Big Island Video News 2020). In this particular contract, force majeure events are excluded from calculations of performance metrics such as the EAF, thereby protecting the seller from underperformance penalties when faced with such an event. As seen in other contracts, the PGV PPA includes terms allowing for the termination of the agreement if the party affected by the force majeure event is unable to resume their obligations within a given amount of time (in the PGV contract, 9 months for one event, 12 months for multiple events). In the case of the Kilauea eruption, however, the buyer elected not to terminate the agreement.

While the terms for force majeure events in other analyzed contracts are generally like those described above, one key difference observed across contracts is the maximum duration for which a force majeure event can be declared before the unaffected party is able to terminate the PPA. This duration varies from 90 days (e.g., Golden Hills Wind Shaped PPA, Rio Bravo Poso CHP PPA) to 365 days (e.g., Lightning Dock Geothermal Energy PPA, Arroyo Solar PPA). Some contracts also include terms specifying the allowable development delay if a force majeure event were to take place during the development phase of the project. For example, the Bluewater Offshore Wind PPA specifies that critical milestones can be delayed for up to 18 months due to a force majeure event.

Notably, the contracts analyzed here did not include terms for hazards that could be induced by the energy production, such as induced seismicity (relevant for geothermal energy and hydropower), groundwater contamination, and flooding.

Underperformance Terms

Like terms around curtailment, underperformance terms may hold value for geothermal project development. Most reviewed contracts included penalties for underperformance. For example, the Honua Ola Bioenergy PPA specifies liquidated damages on a progressive basis associated with performance metrics such as EAF, EFOR, and Excessive Unit Trips. In this case, charges increase with increasing deviation from performance targets. Several contracts, including the Lightning Dock Geothermal PPA and the Golden Hills Wind PPA include minimum performance thresholds. If the seller fails to meet that threshold for a given amount of time or is unable to remedy the underperformance, this could lead to them paying damages, constitute a cause for default, or lead to a renegotiation of prices. This is like a mechanism included in the Yuba Bear and Rio Bravo Poso CHP PPAs; however, these contracts allow for the capacity to be derated because of underperformance. In the case of the Yuba Bear PPA, the PPA permits a change in capacity during the term of the contract and a potential reset of contract capacity, maintaining the price. If equipment efficiency drops below 90%, the parties can renegotiate prices, after allowing the seller to address the efficiency drop. In the case of the Rio Bravo Poso CHP PPA, the seller receives reduced capacity payments if they do not meet performance requirements (e.g., minimum firm capacity of at least 80% during on-peak hours in June–August, at least 70% average annual firm capacity during first part of the fixed price period, etc.) for a maximum of 15

[32] Force majeure refers to unforeseeable circumstances outside of the affected party's control that prevent them from fulfilling the terms of the contract and are sometimes referred to as "Acts of God".

months. After that probationary period, the buyer can derate the firm capacity under the contract.

A more lenient approach to underperformance is found in both the Ormat Northern Nevada Geothermal Portfolio PPA and the Neal Hot Springs PPA. In both contracts, the seller can avoid paying damages for underperformance by producing excess energy in subsequent contract years. Additionally, in the case of the Neal Hot Springs PPA, energy shortfall is not measured for the first three years of the term. Net energy shortfall is only measured starting at the end of the fourth year of the term, meaning that the earliest the seller would have to pay shortfall damages would be at the end of the fifth year of the contract term.

One contract included a more unusual set of terms related to underperformance. In addition to standard force majeure terms (discussed above), the Sierra Pacific Biomass Cogeneration project included a clause related to “extraordinary excuse events.” This clause allows the seller to declare up to two such events throughout the entire duration of the contract term where they are excused for underperforming. Extraordinary excuse events cannot be declared for the same outage that has been declared a force majeure event. During an extraordinary excuse event (maximum duration 60 days), the seller can include the amount of energy that they would have produced if there had not been an outage (deemed energy) in any bills to the buyer for that time period.

Identified Useful Structures and Models

From the contracts reviewed in this study, a few key performance and operational requirement structures stood out as being potentially useful for geothermal PPAs going forward. A key example is the PGV PPA. PGV is one of the first geothermal plants to incorporate flexibility into its operating model, both technologically and contractually. One of the important ways in which this is achieved contractually is through terms related to curtailment. During a curtailment event, the buyer continues to pay the capacity charge set in the contract but does not pay an energy price for deemed energy. This approach allows flexibility for the buyer while still providing guaranteed income for the seller. By structuring the curtailment process this way, PGV can make good on the potential for geothermal energy to act, not only as a firm baseload power supply, but also in a flexible capacity, providing the grid with a dispatchable energy supply that is available to make up shortfalls from variable energy sources.

In terms of force majeure structures, the contracts had relatively consistent approaches, with the main variations being in the allowable duration of a force majeure event before it becomes a justification for terminating the contract. Decisions about this duration are likely to be based upon local hazard conditions and the risk tolerance of the parties involved. Another key factor to consider is the insurance carried by the resource developer. For example, the 1996 Deep Heat Mining project in Basel, Switzerland, generated a M 3.4 earthquake, larger than expected for the project, causing operations to be suspended and resulting in over $9 million in claims for minor structural damages in the area (Giardini 2009). This example highlights the importance of ensuring that insurance required in a geothermal contract is sufficient to cover any damage induced by the resource development or exploitation. Additionally, future geothermal contracts may benefit from including terms related to default or termination due to inducing environmental damage, though these terms may be most relevant in the case of induced seismicity for EGSs.

Two underperformance terms may be of particular interest for geothermal contracts. First is the ability for the net capacity stipulated in the contract to be derated because of underperformance rather than terminating the contract. This approach allows for adjustment to the capacity of the plant throughout the duration of the contract if the geothermal resource behaves differently than anticipated (e.g., the resource is depleted more quickly than anticipated). Second is the ability to make up energy shortfalls from one year in the following year. This would allow a geothermal plant to avoid damages from underperformance due to an anomalous year (e.g., significant summer underperformance resulting from high summer temperatures).

5.2.4 Project Development

Milestones

As discussed above, unlike other renewables, especially wind and solar energy, developing a geothermal project necessitates potentially expensive and unfruitful resource exploration. To see whether contract design may be a pathway to help mitigate some of these development challenges, we considered how the reviewed contracts deal with the issue of project development risk. For example, several contracts for new projects incorporate a capacity test in the development process. One example is the Honua Ola Bioenergy PPA, where the final firm capacity in effect for the performance period was set by a capacity test. However, to pass that capacity test, the project had to achieve at least 10 MW capacity.

The Ormat Northern Nevada Geothermal Portfolio PPA, which includes nine geothermal plants, five of which are new (Table 5.3), addresses uncertainty in the final output of the project through a phased approach. In this project, the geothermal plants are incorporated in three phases. Though the goal net capacity for the project is 150 MW, each phase has a minimum and maximum capacity, respectively: for the first development period – 60 MW and 85 MW; for the second development period – 90 MW and 130 MW; and for the third development period – 135 MW and 185 MW. If the seller strays outside of these ranges, they have the option to substitute or add in geothermal plants from a pre-approved list or designate a plant as a “former facility.”

The Neal Hot Springs PPA addresses development risk using an approach specifically targeted for geothermal energy development. In this PPA, the first three milestones focus on completing the resource characterization prior to commencing construction. This process ends with completing exploration and developing a resource feasibility report. The resource feasibility report details the capacity that the geothermal resource can support. If the capacity is less than 14 MW, the seller can propose to modify or terminate the existing agreement. If the capacity is less than 10 MW, the buyer can terminate the agreement. Both scenarios result in no damages associated with termination.

If a milestone is not met, the contracts include penalties that the seller must pay to the buyer to avoid default. There appear to be two extremes in the set of reviewed contacts: stringent penalties for not meeting intermediate milestones and commercial operation date (COD) or some flexibility in meeting these milestones.

Most reviewed contracts included penalties for missing milestones leading up to the project’s COD. These penalties generally involved a charge for damages for each day that a milestone was delayed. For example, the Coso Geothermal project PPA requires the seller to meet an October 1, 2021, deadline for California Energy Commission (CEC) compliance or pay $5,000/day for each additional day required. Some contracts specify certain penalties for missing intermediate milestones and include an increase in the penalty if the final milestone is missed. For example, the Honua Ola Bioenergy project PPA penalizes the seller with a $1,000/day charge for missing a milestone and a $3,500/day charge for missing the COD by more than a set grace period. The Arroyo Solar and Jicarilla Solar (1 & 2) contracts include a

$200/MW charge per day for missing the COD (capped at $36,000/MW) and a $500,000/MW (Arroyo Solar) or $600,000/MW (Jicarilla Solar) charge for missing the Guaranteed Start Date milestone. An alternative stepped penalty system is seen in the Arrow Canyon Solar PPA where delays of up to 60 days incur a $267.36/MW for each day delayed. Between 60 and 90 days, the penalty increases to $534.72/MW for each day delayed.

Some PPAs include milestone terms that allow for additional flexibility for the developer/seller. The Golden Hills Wind PPA includes damages for missing milestones. However, this PPA specifies that the penalties for missing intermediate milestones are to be refunded if the seller ultimately meets the COD milestone. Similarly, the Neal Hot Springs PPA requires the seller to post the damages in a security account and have that money refunded if they can cure all defaults and material breaches. The Vineyard Offshore Wind project PPA also requires a guaranteed COD with daily delay damages if the COD is not met. However, the seller may extend critical milestone dates six months if they provide additional security payments for each such extension (up to four extensions). Alternatively, the seller can modify the facility size subject to technical development constraints. Specifically, they can use a “Capacity Downsize Option” and pay any necessary capacity deficiency damages, which are limited relative to the daily delay damages, or increase the facility capacity size and increase payments subject to the “Contract Maximum Amount.”

Defaults

After commercial operation has begun, the PPAs analyzed here generally include terms allowing default if the contract is breached. Default terms around actual or delivered capacity generally allow for a margin of error in time and in an allowed difference between the nominal capacity and the actual capacity. For example, the Golden Hills Wind PPA allows default only if the seller fails to achieve a given availability factor for two years in a row. Similarly, the Arroyo Solar PPA allows for default if the seller is unable to maintain at least 75% availability over any consecutive 24-month period. The Jicarilla Solar 1 and 2 PPAs allow for default if the seller is unable to maintain at least 80% availability over any consecutive 24-month period or at least 65% availability over any consecutive 12-month period.

One notable contract in terms of default provisions is the Yuba-Bear Hydroelectric PPA. This contract does not include a guaranteed energy production requirement, but rather is based on a provision of local reliability. As a result, the PPA does not include default provisions related to delivery guarantees.

Some PPAs also include default terms related to emissions targets. In the Golden Hills Wind PPA, the seller is required to supplement the wind power produced by the contracted wind farm during the winter months using other energy resources in its portfolio plus a limited amount (up to 12% annually) of market purchases, which, as of 2026, may not include coal-fired resources. Additionally, the energy production is required to be carbon neutral by 2030. If the seller is found to have delivered energy from a coal-fired resource four times, the buyer is permitted to terminate the contract.

Identified Useful Structures and Models

Terms of interest for geothermal energy related to milestones and defaults focus on addressing project development risk because this has been indicated to be a key area of concern for the industry. One example of this is the Neal Hot Springs PPA. This contract explicitly incorporates development risk for geothermal energy into the pre-construction milestones, culminating in a resource feasibility report. By including this more detailed resource characterization as part of the PPA, the seller can reduce some of their development risk. Note that the buyer in this case, Idaho Power Company, was particularly motivated to acquire geothermal energy as part of its portfolio due to its potential to operate as a baseload renewable resource and the high geothermal potential in Idaho Power's service area. Another approach to reducing the financial risks associated with geothermal development is to refund damages paid for missed milestones if the ultimate COD milestone is met. This allows the buyer to maintain development milestones in the contract to encourage the project to remain on schedule. However, it also allows the seller flexibility to accommodate unexpected delays in development if they can make up the time at another point during the development process.

5.3 New Market Opportunities

The move to a clean energy system and the electrification of other sectors of the economy are likely to lead to more opportunities for geothermal resources. This move come with changes in electricity markets, the regulatory environment, and policies that impact the delivery of electricity and the use of energy more broadly. In the near term, the biggest growth in electricity consumption is anticipated to be derived from the electrification of transportation (Mai et al. 2018).

5.3.1 Public Power Authorities and Community Choice Aggregators

A relatively recent trend in the utility regulatory environment has been the emergence of community choice aggregators or other similar entities that procure power for a subset of a utility's customers. Although many of these entities procure energy (and the other services needed to deliver that energy to customers) through power suppliers who procure the energy in the market, more recently these entities have begun to directly contract for plant capacity. Two examples of this are in California. First, the SCPPA contracts power plants to deliver energy to its member municipal utilities and, as discussed above, has contracted with several geothermal power plants in Nevada and California for the delivery of energy and, in some cases, capacity (SCPPA 2020). Second, Marin Clean Energy (MCE), the first community choice aggregator in California, provides energy service to 86% of all customers in Marin, Napa, Solano, and Contra Costa counties in the Bay Area and is now the default electricity generation supplier for new or relocated customers in those counties, supplanting PG&E.[33] MCE contracts for a minimum of 60% of its energy from renewable resources and offers customers higher levels of renewable supply mixes, up to 100%, with a target of its entire supply mix to be 95% free of greenhouse gas emissions by 2022. MCE contracts directly with energy suppliers and renewable energy and hydroelectric projects, including a relatively small proportion of geothermal resources (MCE 2020).[34] Finally, Silicon Valley Clean Energy and Monterey Bay Community Power will each purchase 7 MW of geothermal energy from Ormat (Geothermal Rising 2020).

[33] Pacific Gas & Electric maintains delivery of the purchased energy through its transmission and distribution network.

[34] Many of the power authority contracts have provisions that electricity must come from the contracted resource, ensuring environmental attributes are maintained. They do, however, include provisions for the makeup of "shortfall energy" to address any output deficiencies. In the case of the Coso Geothermal SCPPA contract, for example, this provision requires the delivery of environmental attributes (e.g. RPS certificates) with any makeup energy delivery.

5.3.2 Corporate Contracts

Another growing trend is the direct procurement of renewable energy by corporations through corporate PPAs. The numerous examples of these include the procurement of large-scale wind and solar by Google, Walmart, and others. Although we could not find a complete PPA for the procurement of geothermal energy via a corporate contract, the University of Utah has signed a contract with Cyrq Energy for almost 50% of its energy demand from geothermal resources (Utendorfer 2022; Tanner 2020) and there may be other examples as well. This may be a ripe opportunity for further geothermal resource procurement as several corporations have announced aggressive sustainability and clean energy goals, and corporate renewables procurements are likely to continue. For the information technology industry, data server farms are significant large flat load demands, often located in relatively remote areas to minimize land and energy costs. Geothermal energy's natural advantages in delivering a steady baseload resource may serve it well in providing energy services to such demands, enabling an avoided reliance on large-scale battery storage development or market purchases to address the intermittency associated with wind and solar energy.

A key example of corporate implementation of PPAs to procure renewable energy, and an opportunity for geothermal resources to play a role (despite higher capital costs per unit capacity) can be seen in the case of Google. In 2019, the company used approximately 12.2 TWh of electricity, largely associated with data centers (Terrell 2021). This significant energy use presents challenges with respect to the company's goal to achieve carbon-free energy 24/7 by 2030. On the path to achieving this goal, Google entered into its first corporate PPA for renewable energy in 2010 through a 20-year contract for a 114 MW wind farm in Iowa and has subsequently entered into 20 PPAs, consisting of over 2.6 GW of renewable energy (Google 2019). Because the contracted energy is produced offsite due to space limitations, the electricity to Google's facilities is still obtained from the grid. Therefore, energy produced through Google's renewable PPAs is actually sold on the wholesale market, with Google receiving RECs associated with that produced energy to offset their actual usage of energy derived from the grid (Google 2013). Google identifies this disconnect between competitive purchased power and retail delivery as a challenge for itself because it would prefer to have a more direct connection between purchased and used power. But perhaps more importantly, it indicates this presents a challenge for smaller corporations that may not have the legal and financial services bandwidth to undertake resource contracting and market sales. Accordingly, smaller corporations and companies wishing to procure more renewable resources are left to competitive suppliers or their utilities for the delivery of renewable energy products, for which opportunities may be limited in many parts of the country (Google 2019).

That said, one of the main drivers for Google to use mechanisms such as PPAs to contract for energy is that they aim to achieve what they refer to as "additionality." In other words, Google's renewable energy projects must spur the development of new renewable energy that would otherwise not have been added to the grid (Google 2016). Further, the company has more recently indicated an intent to "broaden the scope of energy sources to include technologies or services that enable 24-7 clean energy," indicating a preference for resources that provide nonintermittent supply, whether battery-hybrid renewables or perhaps geothermal resources. Some of the contract structures outlined in Section 5.2 may be instructive or useful for such development, particularly multi-part payment structures that incorporate energy and other services required for continuous operations.

5.3.3 Hybrid Systems and Alternative Revenue Streams

> **Cryptocurrency Mining**
>
> Cryptocurrency generation (or mining as it is referred to colloquially) is an energy intensive process in which computers solve very complex mathematical problems. The process often uses a specific algorithm that develops a value iteratively. The mining is a competitive process and the moment a solution is reached all other competitors must start over again without earning a coin. As such a significant amount of electricity is consumed in the process of creating a coin which in certain cases could be as much as 90% of the cost of producing the coin. The degree of difficulty in solving the mathematical problem directly relates to the amount of coin produced. Currently, in the case of bitcoin, problems are solved by a network of computing resources working together.

A variant of a corporate contract is the use of a geothermal resource that might be directly tied to high energy demands. For example, we reviewed a contract between a natural gas facility and Cipher Mining to locate a cryptocurrency mining facility next to a natural gas generation facility in Texas. Cryptocurrency mining is an extremely energy-intensive process that has recently received criticism of its environmental footprint.[35] The evaluated contract provides the cryptocurrency mining facility direct resource access, rather than having to wheel the energy over the existing transmission system, thereby reducing the costs of energy. Similarly, a cryptocurrency mining facility could be located next to a geothermal facility, leveraging the baseload clean energy generation available. Additionally, server farms which are becoming more and more ubiquitous around the country as cloud computing needs increase, could also be located near existing geothermal resources, and there has been discussion and efforts to evaluate minerals mining leveraging geothermal resources located in mineral heavy areas.[36] Finally, the potential to leverage geothermal resources to generate hydrogen through electrolysis is another opportunity that may materialize as, or if, the value of hydrogen as a transportation or industrial fuel or as an energy storage medium increases. In all these cases, the reliable and relatively constant energy source from geothermal may be an advantage relative to using intermittent resources and building out large energy storage facilities.

In all these cases, the directly served load could operate as an energy buffer to modulate geothermal output and enable additional geothermal plant flexibility, addressing some of the technical challenges to flexibly operate geothermal resources, as we discussed above. Each of these loads, perhaps except server farms, are flexible and can theoretically be easily modulated. Such plants could leverage batteries, hydrogen, or geothermal thermal storage to provide additional operational flexibility, both for the grid and the co-located energy demand. The contracts review dives into some of these opportunities above, and the techno-economic evaluation in Section 6.0 below considers the opportunity to serve such loads.

5.3.4 Contracts for Differences

Another potential contract that could be used to support higher cost flexible resources like geothermal is the contract for differences. The contract for differences is a government support

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[35] For example, *see* Jon Huang, Claire O'Neill and Hiroko Tabuchi. "Bitcoin Uses More Electricity Than Many Countries. How Is That Possible?" New York Times. Sept 3, 2021. Available at: https://www.nytimes.com/interactive/2021/09/03/climate/bitcoin-carbon-footprint-electricity.html

[36] For example, Controlled Thermal Resources Limited is developing a project to extract lithium leveraging the geothermal resource at the Salton Sea in Imperial Valley, CA. *See* https://www.cthermal.com/projects

mechanism that provides a level of support at an agreed upon strike price (government support price). The project earns the market price for its transactions and the government (or project) pays the difference between the average market price and the strike price. Thus, if the average price earned in the market is below the strike price, the government pays the difference. However, if the strike price is below the average market price the project pays the government the difference. This contract type is prevalent in the United Kingdom and will potentially be introduced in Germany (Gödeke and Lambe 2021).

6.0 Techno-economic Evaluation of Future Geothermal Project Development

Building on the insights and opportunities identified from the contract and market analysis above, we conducted several quantitative case studies to showcase the potential impact these insights and opportunities might have on new geothermal development. Three case study projects were selected and run through PNNL's Energy Storage Evaluation Tool (ESET) for resource dispatch over several market frameworks. Using the revenue generated by the ESET tool, PNNL then ran its FATE-2P *pro forma* contract analysis tool to evaluate rates of return and average price requirements. Together, these analyses help illustrate the extent to which the insights and opportunities we identified can enhance geothermal system profitability.

6.1 Case Study Projects and Future Market Conditions

We identified the following potential deployments to use as case study projects.

1. Northern California near the existing Geysers power plants as representative of a hydrothermal development in a hybrid organized market environment,

2. Eastern Oregon near the Neal Hot Springs Geothermal plant to represent a hydrothermal development in an unorganized market environment, and

3. Central New York, near the Cornell University campus to represent an EGS power plant in an eastern organized electric market environment.

Rather than identifying new potential greenfield sites, we leveraged existing developments, and a potential development in the case of New York, to consider as representative case studies. This allowed us to use actual inputs to several modeling elements and reduce the number of assumptions needed to be made. Table 6.1 below details each of the identified case studies.

Table 6.1. Case study projects: configuration and details

	Location	Type of plant	Configuration	Services	Grid Service Prices
1	Geysers (CAISO)	standard hydrothermal	Standalone; hybrid with battery	CAISO market services; corporate contract	CAISO market
2	Eastern Oregon	standard hydrothermal	Hybrid with battery/PV	Energy and ancillary services in a vertically integrated environment	WECC PCM Model HydroWires
3	East Coast (NYISO)	enhanced geothermal (EGS)	Standalone	NYISO services; corporate contract	NYISO Market

CAISO = California Independent System Operator; EGS = enhanced geothermal system; NYISO = New York Independent System Operator; WECC = Western Electricity Coordinating Council.

The contribution a geothermal unit can provide to the power system is highly dependent on the characteristics of its design as well as its placement on the grid. Two geothermal projects with identical characteristics can have vastly different dispatch operations and portfolios of benefits. The availability of markets for grid services is also a factor that influences the total value that can be derived. These elements require geothermal units to have highly site-specific analysis and simulations to consider resource potential, derive total value, and estimate the viability of the project. To highlight the differences in potential value based on locational and jurisdictional differences, we defined a range of use cases that reflect a wide range of potential market products, and modeled prices, based upon the grid conditions considered:

- Different services/market environments: California Independent System Operator (CAISO), Oregon and New York Independent System Operator (NYISO)
- The flexibility potential of the resource: although traditionally used as a baseload resource, we consider the potential for geothermal to deliver flexibility services (i.e., ancillary services)
- Pairing with other resources: A benefit of using the ESET toolset is the ability to pair the geothermal asset with different types of storage and PV combinations as well as unique alternate loads that may provide additional value (e.g., corporate contracts, cryptocurrency mining, etc.)
- Hydrothermal and EGS project designs

6.1.1.1 Central California

For this case study we consider a hydrothermal system located near the Geysers,[37] participating in the CAISO energy and ancillary service markets. An additional revenue stream is a corporate load opportunity representing a corporate contract for a server farm or a cryptocurrency mining facility.[38] This system is evaluated in both standalone and battery-hybrid configurations and has an added element of quantifying resource adequacy value, that is capacity value, in the CAISO market.

6.1.1.2 Eastern Oregon

This project is another hydrothermal site located near the Neal Hot Springs Geothermal Plant in Eastern Oregon. Considering the strong solar potential in this location, it is co-located with a solar photovoltaic facility as an electrical hybrid. It is assumed to contract with a utility to deliver energy and ancillary services. This project does not include a battery system.

6.1.1.3 Central New York

Unlike the first two case studies, which consider hydrothermal project development near/on established geothermal fields, this case study plant is a hypothetical EGS plant. Cornell University is undertaking an effort to develop thermal EGS based on an identified deep EGS resource. Here we assume deeper drilling to find a hotter resource that would enable electricity generation. The intent of this case study is to evaluate a theoretical EGS located in an east coast market environment. This system includes a potential battery system hybrid as well as sale of energy under a corporate contract.

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[37] The Geysers, located approximately 70 miles north of the San Francisco Bay Area, is the world's largest geothermal field. It delivered approximately 20% of California's renewable energy in 2019. For more details see https://geysers.com/.

[38] We assume that the corporate contract is a deferrable load contract and that the resource can choose to deliver energy to the market or the corporate load depending on price.

6.2 Technical Characterization and Optimization of Geothermal Resources Using ESET

6.2.1 ESET Geothermal Module Development

ESET was developed at PNNL and is a multi-objective optimization formulation that co-optimizes energy asset dispatch across multiple grid and non-grid value streams. It was originally developed to evaluate energy storage systems, specifically battery storage, with the intent of identifying optimum storage dispatch across monetizable grid services (market or non-market) and local value streams over a year. As part of the formulation, it can run several iterations to identify optimum asset sizing relative to grid service values and ultimately presents an economic analysis over the lifespan of the asset (Wu et al. 2015). Distinct modules have been added to ESET for different technologies such as PV, wind, and hydrogen fuel cells. The ESET toolset is available publicly and is used by researchers, energy planners, and utilities.[39]

For this project, we developed a module within ESET to evaluate a geothermal resource. We use the module to evaluate the optimal dispatch of a theoretical geothermal power plant (i.e., selected case studies) subject to technology characteristics and monetizable grid services available across the jurisdictions of interest. The goal of the ESET modeling is to develop geothermal dispatch scenarios and associated revenue for further analysis via *pro forma* contract modeling to better understand the potential for and trade-offs associated with geothermal resources providing different services. For example, delivering frequency regulation, which is higher value than energy, but limited in market size.

6.2.2 Baseline Geothermal Resource

Because this effort is not intended to be included in in-depth technical resource analysis of a potential power plant, we leverage existing power plant operations to inform the potential resource availability to the ESET model. Unfortunately, unlike the case with wind and solar resources, there is no easily available repository of geothermal resource data on which to base output. This is a function of the differing nature of the resources themselves as well as the relatively lower interest in the deployment of geothermal resources relative to wind and solar resources.

As an aside, when geothermal resources are modeled in power system models of different types, such as production cost models, they are often considered constant output resources with minimal ability to modulate their output and generally relatively coarse modeling of their capabilities and operations; for example, the same long startup and shutdown timeframes applied across all geothermal plants within a model. Accordingly, geothermal plants are only considered to deliver baseload energy, and not able to provide other grid services.

Using Geysers data as a resource reference, we adapted the existing ESET formulation to consider geothermal plant output. Data from the FERC Energy Quarterly Reports (FERC 2021a) form the available resource base for the plant (see Figure 14 below), and from there, the tool is free to dispatch the plant subject to grid service values in different market environments of interest.

[39] *See* https://eset.pnnl.gov/overview.

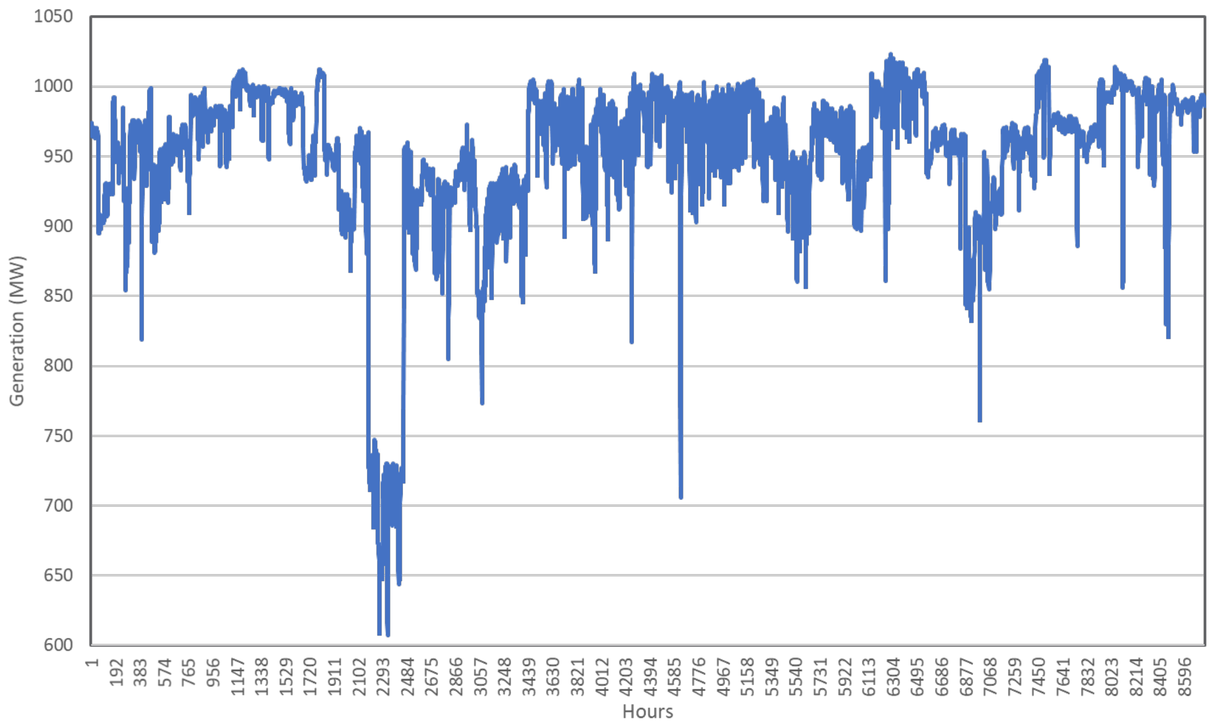

Figure 13. Geysers plant output for Geysers Unit 17, proportionally escalated to a maximum output of 1,050 MW for visualization. (FERC 2021a).

6.2.3 Modeling of System Prices

Energy and ancillary service prices are key inputs for both optimization in ESET and *pro forma* analysis. In CAISO and NYISO, historical prices for energy, capacity (resource adequacy in California) and ancillary services are readily available. In the non-market regions, energy pricing data are identified from market index data. Where prices cannot be identified (e.g., energy in a specific balancing area or ancillary services), we used modeling tools. As needed, future expected grid conditions are used as inputs to GRAF-Plan, an existing PNNL tool, to characterize and quantify the ancillary service requirements associated with a particular grid resource profile. We used these requirements as constraints in a production cost model (PCM) for the Western Interconnect to evaluate the resulting set of prices for energy and ancillary services for the states of interest (WECC 2021).[40]

Once system-level prices were determined, we used the prices as inputs to model resource-level operational parameters. The operations of the geothermal projects (i.e., case studies) in question were modeled for input into the *pro forma* analysis. These operations were optimized over the set of services and prices to identify optimal system output to maximize plant revenue over different use cases. The potential for providing multiple services over a set period is also considered. The modified ESET model was then used to run a multi-year simulation of geothermal operations to determine the optimized control strategy for hourly dispatch, using a

[40] We use industry vetted models of future grid conditions, specifically the WECC 2030 Anchor Data Set model to establish baseline pricing.

look-ahead optimization. The detailed modeling and formulation of this method is reported by Wu et al. (2015).

6.3 *Pro Forma* Analysis for Case Study Projects

Pro forma analysis allows decision-makers to evaluate whether projects can meet developer hurdle rates by evaluating the revenue streams available to potential or existing projects. This may include whether there is a reasonable set of use cases the project can meet through markets or other value streams that provide greater value than general energy prices. A mix of services such as energy, capacity, frequency regulation, and spinning/non-spinning reserve payments could provide a higher revenue stream than simply playing the baseload energy market. In addition, the analysis can undertake sensitivity analysis of interest rate parameters, revenue parameters, evaluate the impact of production tax credits or other incentives, and characterize debt service ratio at current rates.

The FATE-2P model we use allows for over 200 other financial parameters to be varied, provides sources and uses of funds, earnings statements, cash flow statements, and capital at risk requirements (Boyd et al. 2010). It is a financial tool that applies inputs like detailed capital cost summaries, capacity factors (variable or fixed), O&M costs, financial parameters such as debt/equity requirements, financial fees, and revenue streams to determine cash flows and the resulting internal rate of return. The tool provides *pro forma* balance sheets, sources, and uses of funds, earnings and cashflow statements. In addition, the tool provides debt coverage ratios and Internal Revenue Service (IRS) requirements evaluation for capital at risk. The tool includes items specific to geothermal modeling such as depletion allowances, the proportion of the cost that is intangible (expensed), and the proportion that is tangible (depreciated), and it is designed to reflect the IRS tax code. The model also evaluates impacts of production tax credits or investment tax credits. The tool calculates the rate of return after Federal, state, and local taxes, including sales tax, gross receipts taxes, and property taxes. In addition to the PPA pay price, the model calculates the levelized cost of electricity (LCOE) for the project. The model was designed to be modified easily so additional components that affect the LCOE can be explored along with sensitivity analysis. It has been formally reviewed by the Wharton Business School and SunPower and was used in evaluating reductions in cost from using renewables and batteries in Alaska villages and Department of Defense installations (Boyd et al. 2010).

Appendix C identifies the path inputs, assumptions, and variables of analysis used for the *pro forma* modeling of the three identified case studies. We evaluated the three case studies to consider risk allocation, rates of return, capital cost requirements, and debt/equity ratios. Even in the situations where a near-term clear market value proposition is not identified, we indicate the cost reductions or price targets that may need to be achieved, or incentives that may enable the project to be feasible.

6.4 *Pro Forma* Results

6.4.1 Northern California

The northern California case study consists of the following elements:

- a 45 MW hydrothermal power plant (evaluated with and without a battery system),
- a 45 MW battery system with 4 hours of storage,
- offtaker type: utility/corporate, and

- Services delivered: energy, ancillary services, resource adequacy (RA) and energy for a corporate customer.

Appendix C includes additional plant details and financial inputs.

6.4.1.1 Northern California ESET Results

The outputs of the ESET tool for this scenario are given in Table 6.2 and Figure 15.

Table 6.2. ESET results for Northern California[41]

	2018	2019	2020
Energy sale (Geothermal Thermal)	$14,076,937	$12,703,721	$10,707,272
Energy sale (Corporate Load)	$16,193,250	$16,187,320	$18,168,750
Energy arbitrage (BESS)	$705,189	$711,119	$715,794
Regulation up	$3,386,681	$3,386,681	$2,822,754
Regulation down	$7,590,642	$7,391,479	$6,789,630
Resource Adequacy/Capacity (Geothermal)	-	$2,200,770	-
Resource Adequacy/Capacity BESS	-	$1,467,180	-
Spinning Reserve	-	-	-
Total annual benefits	**$41,952,699**	**$40,380,320**	**$39,204,200**
Total annual benefit with RA		**$44,048,270**	

As expected, the delivery of energy forms the bulk of annual benefit for geothermal output with a significant proportion also coming from the delivery of regulation services. Coupling the resources to create a hybrid system within the CAISO jurisdiction does not initially present added hybrid value, rather the individual components are additive. But future work considering other jurisdictions and possible contract terms on delivery may identify added value to a hybrid approach. Spinning reserve service is not scheduled alone due to the lower price than the regulation service for the entire year. However, if we were to remove regulation as an option, we might see spinning reserve dispatch.

[41] Energy sales are the MWh sold both on the wholesale market and to the offtaker such as one the corporations devoted to green power like Google or Starbucks. Energy arbitrage occurs when the battery is charged at low prices and discharged back to the grid during high prices. Regulation up and regulation down are ancillary services that maintain frequency within specified limits. Regulation up refers to placing power into the system while regulation down means extracting power. Capacity payments pay power producers to have capacity online when required. ESET does not currently calculate resource adequacy payments and they were estimated separately to understand the impact on IRRs.

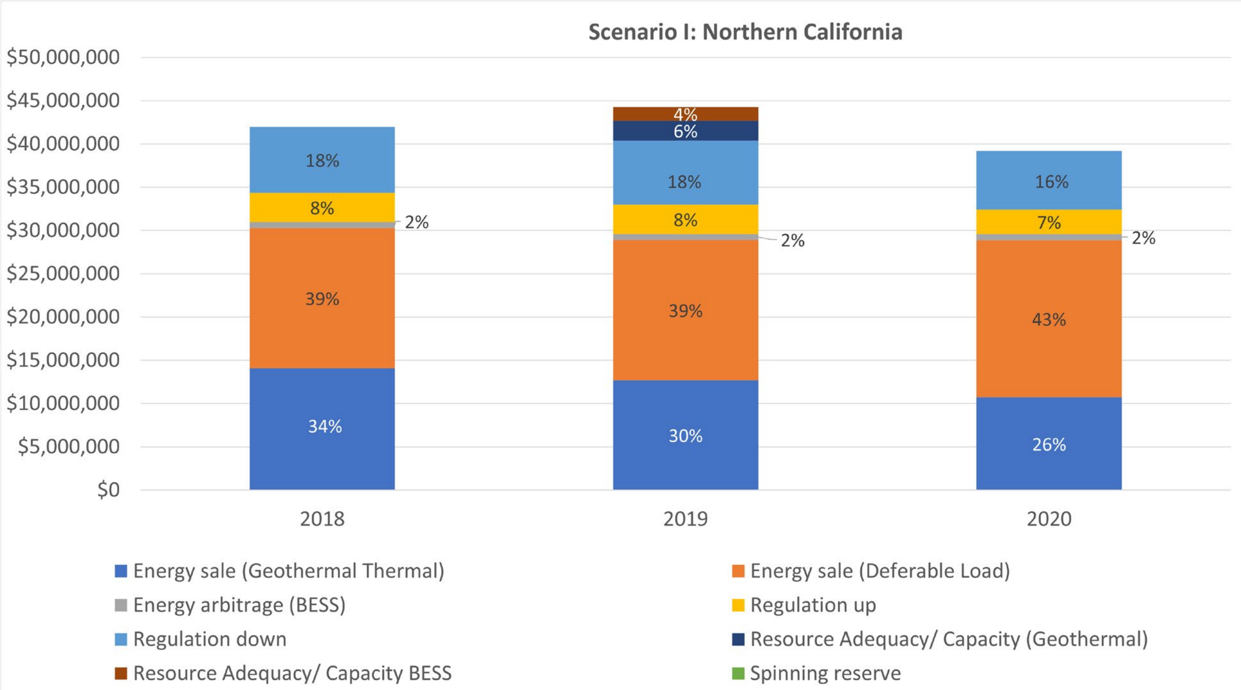

Figure 14. Annual benefits by year for the California case study.

6.4.1.2 Northern California *Pro Forma* Results

This case study was evaluated using the FATE-2P *pro forma* model based on average revenue over the period of 2018–2020 from the ESET solutions and on each of the annual revenue streams to determine whether adequate internal rates of return were provided for this project deployment. Further, the effects of price escalation were evaluated at the rate of inflation, half of inflation, and no inflation. The impact of financing elements on the bottom line was also evaluated.

Given that costs can rise during construction, we used a 10% increase in construction cost assumption.[42] In addition, because costs to develop geothermal are expected to decline by 22% as identified by the DOE GeoVision report (DOE-GTO 2019), the plant was evaluated at the reduced cost with all equity financing and without (i.e., debt), and with the average revenue increasing at the rate of inflation.

The results of the analysis (see Table 6.3) indicate that the baseline model (Case 1) at estimated costs and average revenue (from ESET), price escalation at inflation, and all equity financing, would provide a little more than a 7.5% internal rate of return (IRR), not quite at the 8% hurdle rate but very close.[43] The highest average revenue year returned an 8.5% return while the two lower priced years did not meet the 8% hurdle rate. Further, reducing the level of revenue escalation provided internal rates of return below the hurdle rate.

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[42] This escalation rate is informed by other *pro forma* evaluations using FATE-2P and actual project deployments.
[43] The internal rate of return is the rate of return of an investment where present value revenues are equal to present value costs, a metric that evaluates an investment's rate of return and signifies profitability. The hurdle rate is the level of the internal rate of return acceptable to a project developer, often 8% in the energy industry.

A 70/30 debt to equity financing ratio with revenue escalation at inflation, increased the IRR to almost 23% at the average revenue value. The debt coverage ratio (DCR) was adequate in this case at 1.35.[44] However, with decreasing annual revenue escalation (i.e., below inflation) the DCR dropped below 1.0 even when the IRR was sufficient. Increasing construction costs 10% led to insufficient IRRs. Adding an element of decreasing costs from technology improvements by (a 22% cost decrease as discussed above) increased the IRR to above 10% for all equity and above 34% for the 70/30 debt-equity financing alternative.

A separate analysis including an RA value[45] indicated that average revenue (15.82¢/kWh) earned including all the energy sales, arbitrage and frequency regulation would push the internal rate of return for an all-equity analysis to almost 13%. Such an IRR provides a return above the hurdle rate and indicates a high revenue potential in the CAISO market which could make high-potential geothermal resources profitable. This is true especially in proven geothermal fields.

Calculating RA or Capacity Value

$$yearly\ RA\ value\ \left[\frac{\$}{yr}\right] = P_{max} * WACC * (12\ months) * NQC$$

where,

- *P_{max} is maximum capacity of the resource*
- *WACC is the weighted average capacity price (per month)*
- *NQC is net qualifying capacity, defining the capacity value ascribed to a resource*

For the geothermal component of the plant capacity value in this case study:

$$\$2{,}200{,}770/year = (45\ MW) * (\$4.29/kW\text{-}month) * (12\ months) * (95\%)$$

where,

- *P_{max} is 45 MW, the output of the geothermal component of the case study plant*
- *WACC is \$4.29/kW-month for CAISO system resource adequacy north of Path 26 for 2019[46]*
- *NQC is estimated to be 95% for the geothermal resource[47]*

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[44] The debt coverage ratio or debt service coverage ratio is the ratio of operating income to debt obligations and is a metric used to evaluate the bankability of projects by financiers. A higher debt service cover ratio indicates more cash flow or revenue is available to repay debt and thus reduces the risk of default. A debt coverage ratio of 1 indicates there is enough cash to cover the payments. Typically, banks would like to have a DCR of more than 1 due potential shortfalls in revenue. Thus, DCRs of 1.25 or higher are generally desirable.

[45] California capacity value is derived from the California Resource Adequacy Program which is not a capacity market but a program where bi-lateral contracts are placed between load serving entities and generators. Formal capacity markets are available in the New York Independent System Operator (ISO), PJM Interconnection, New England ISO and the Midwest ISO.

[46] *See* Lakey, J. et al. "2019 Resource Adequacy Report." California Public Utilities Commission Energy Division. March 2021. https://www.cpuc.ca.gov/RA/.

[47] The California Qualifying Capacity Methodology Manual assigns qualifying capacity value to different resources. Geothermal resources receive monthly QC values based on a three-year rolling average of production during specified hours. *See* "2020 California Qualifying Capacity Methodology Manual." California Public Utilities Commission. November 2020. https://www.cpuc.ca.gov/RA/.

Table 6.3. Geysers project results indicating that if producers were willing to accept a lower hurdle rate than assumed, Geysers would be feasible.

Case	Revenue level	Revenue escalation	Equity	Cost	Price (¢/net kWh)	Electricity Price Escalation (%)	Minimum DCR (ratio)	Internal Rate of Return (%)	Net Present Value ($ Mil.)
1	Average	Inflation rate	All equity	-	11.19	2.3	-	7.65	-10.72
2	High	Inflation rate	All equity	-	11.91	2.3	-	8.5	15.6
3	Medium	Inflation rate	All equity	-	11.2	2.3	-	7.66	-10.35
4	Low	Inflation rate	All equity	-	10.47	2.3	-	6.74	-37.34
5	Average	Half inflation rate	All equity	-	11.19	1.15	-	4.95	-78.6
6	Average	None	All equity	-	11.19	-	-	1.64	-133.52
7	Average	Inflation rate	70/30 debt equity	-	11.19	2.3	1.35	22.96	77.28
8	Average	Half inflation rate	70/30 debt equity	-	11.19	1.15	0.81	13.01	9.41
9	Average	None	70/30 debt equity	-	11.19	-	0.29	-	-45.52
10	Average	Inflation rate	All equity	10% more cost	11.19	2.3	-	6.68	-43.25
11	Average	Half inflation rate	All equity	10% more cost	11.19	1.15	-	3.98	-111.12
12	Average	None	All equity	10% more cost	11.19	-	-	0.58	-166.05
13	Average	Half inflation rate	70/30 debt equity	10% more cost	11.19	1.15	0.71	-	-14.32
14	Average	None	70/30 debt equity	10% more cost	11.19	-	0.23	-	-69.24
15	Average	Inflation rate	All equity	22% less cost	11.19	2.3	-	10.41	60.84
16	Average	Inflation rate	70/30 debt equity	22% less cost	11.19	2.3	1.81	34.16	129.48
17	Average with RA payment	Inflation rate	All equity	-	15.83	2.3	-	12.71	159.7

Eastern Oregon

The Eastern Oregon case study consists of the following elements:

- a 22.5 MW hydrothermal power plant,
- a 22.5 MW photovoltaic system,
- offtaker type: municipal utility, and
- services delivered: energy, and ancillary services.

Appendix C includes additional plant details and financial inputs

6.4.1.3 Eastern Oregon ESET Results

The outputs of the ESET tool for this scenario are given in Table 6.4 and Figure 16.

Table 6.4. ESET results for Eastern Oregon

	2020	2030
Energy sale (Geothermal Thermal)	$3,159,631	$3,583,832
Energy sale (PV)	$577,513	$554,356
Regulation up	$40,516	$119,120
Regulation down	$69,806	$466,645
Spinning reserve		
Total annual benefits	**$3,847,466**	**$4,723,953**

Once again, the delivery of energy forms the bulk of annual benefit for geothermal output with a small and insignificant proportion coming from the delivery of regulation services. The PV facility is an added coupling that, like the battery in the other case study, does not initially present added hybrid value, rather the individual components are additive. But contract requirements and any variability in geothermal output for this specific site may present added value with the hybrid approach. Once again, spinning reserve service is not scheduled alone due to a very low price in this non-organized market environment.

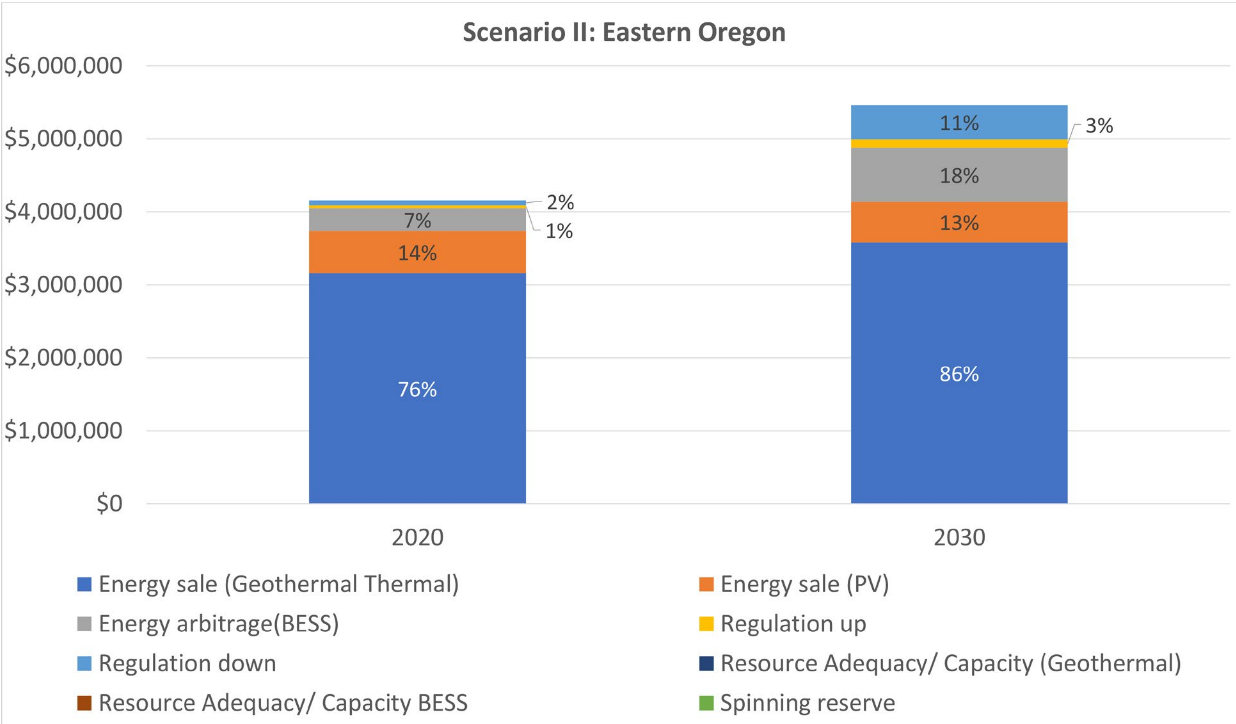

Figure 15. Annual benefits by year for the for the Eastern Oregon case study.

6.4.1.4 Eastern Oregon *Pro Forma* Results

The Eastern Oregon case study, as discussed above, is based on the existing Neal Hot Springs Geothermal plant. The Neal Hot Springs Plant, with its relatively low temperature resource 141°C (but high throughput), was developed with significant subsidies, low-cost government loans, and government guarantees (Weijermars, Zuo, and Warren 2017). We evaluated this case study with the FATE-2P *pro forma* model using average revenues from 2020 (based on simulated prices, as discussed above) from the ESET solution to determine whether adequate internal rates of return were provided for this project deployment.

In the base case analysis, the revenue generated provides an average price of only $0.022 per generated kilowatt-hour (see Table 6.5), clearly leads to an inadequate IRR, thus no financing scenarios were attempted. To meet the 8% IRR hurdle rate, we had to increase revenue to an average of $0.1221 per generated kWh. Reducing costs by 22% (the target from the technology improvement scenario indicated in the GeoVision report (DOE-GTO 2019)) did not increase the rate of return sufficiently enough to meet the hurdle rate. With this cost reduction, the required revenue per generated kilowatt-hour decreased to $0.1025 to reach the hurdle rate. Note in the analysis, net present value is negative at the average price and zero when the target IRR is met. No debt coverage ratio was calculated because there was no financing.

Unlike the other two case studies, we do not include a corporate contract option here, instead modeling revenue with respect to simulated system prices, and accordingly, the results will be subject to future system price changes and contract price elements. A successful project will require significant subsidies or escalated prices.

Table 6.5. Neal Hot Springs project results where base case internal rates of return are negative or undefined indicating the that the project can't be financed without incentives

Case	Revenue Level	Escalation Rate	Equity	Cost	Price (¢/net kWh)	Electricity Price Escalation (%)	Minimum DCR (ratio)	Internal Rate of Return (%)	Net Present Value ($)
1	Average	Inflation rate	All equity	-	2.24	2.3	-	-	-187.28
2	Average, Break-even price	Inflation rate	All equity	-	12.21	2.3	-	8	0
3	Average	Inflation rate	All equity	22% less cost	2.24	2.3	-	-	-150.46
4	Average, Break-even price	Inflation rate	All equity	22% less cost	10.25	2.3	-	8	0

6.4.2 New York

The New York case study consists of the following elements:

- a 45 MW hydrothermal power plant (evaluated with and without a battery system),
- a 45 MW battery system with 4 hours of storage,
- Offtaker type: utility and corporate, and
- Services delivered: energy, ancillary services, corporate energy.

Appendix C includes additional plant details and financial inputs.

6.4.2.1 New York ESET Results

The outputs of the ESET tool for this scenario are given in Table 6.6 and Figure 17.

Table 6.6. ESET results for New York

	2018	2019	2020
Energy sale (Geothermal Thermal)	$14,076,937	$12,703,721	$10,707,272
Energy sale (Corporate Load)	$16,193,250	$16,187,320	$18,168,750
Energy arbitrage (BESS)	$705,189	$711,119	$715,794
Regulation up	$3,386,681	$3,386,681	$2,822,754
Regulation down	$7,590,642	$7,391,479	$6,789,630
Spinning reserve	-	-	-
Total annual benefits	**$41,952,699**	**$40,380,320**	**$39,204,200**

In the New York analysis, the delivery of energy again forms the bulk of annual benefit for geothermal output with a significant proportion also coming from the delivery of regulation services, particularly regulation down, to which both the battery and the geothermal resource can contribute. Spinning reserve service is again not scheduled due to low pricing in the current market.[48] The variability across market years is similarly impactful to the bottom-line revenue, reflecting the impact market pricing can have on ongoing revenue.

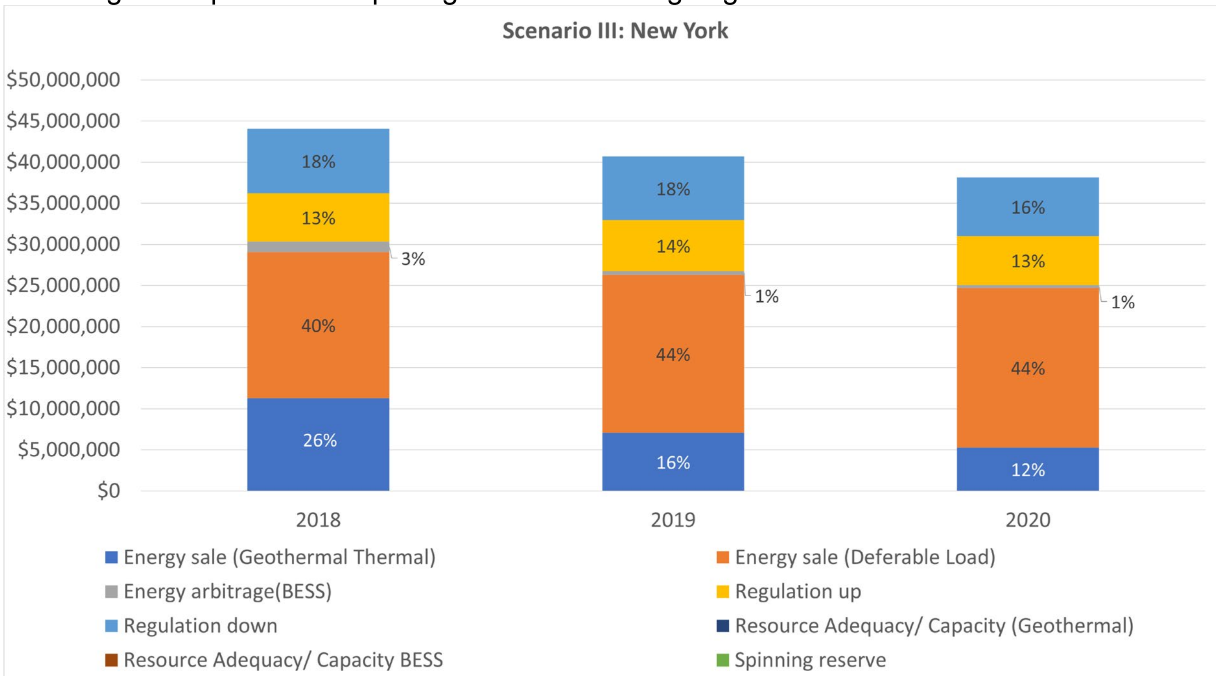

Figure 16. Annual benefits by year for the New York case study.

6.4.2.2 New York *Pro Forma* Results

Cornell University is developing a thermal EGS to provide district heating to the campus in an effort to move to zero emissions associated with its energy use.[49] The 4,100 m planned well depth provides for a 100°C resource, which is not an adequate temperature for electricity generation, but Cornell hopes it will be sufficient to provide a district heating system for the university. Hence, to reach a temperature sufficient for electric generation will require a deeper well. Based on resource analyses conducted by GTO, we identified a roughly 6,000 m depth needed to meet a 180°C heat target.

As discussed above to identify project pricing, we used the Geothermal Electricity Technology Evaluation Model (GETEM) to estimate the cost of a plant at the 6,000 m depth, estimating $54,000/kW. Unfortunately, as EGS is an emerging technology with no commercial deployment in the US, it is not possible to identify an example price point to use. The high cost along with the added battery system leads to a required average contract price point of nearly $1.09/kWh to meet the hurdle rate (see Table 6.7). This is despite the significant revenues that such a system might obtain in the NYISO market, delivering multiple services in addition to a flat

[48] In future markets with high levels of renewable development (beyond 80%), one might expect reserve needs and prices to rise due to increased volatility in generation of VRE. Indeed, this is the general expectation in the electricity industry given current technology trends (e.g. current batteries can only supply 4 hours of energy and are limited in total capacity relative to cost, which limits their value as spinning reserve resources). However, there are not many forecasts of these requirements for future systems and reserve requirements are likely to vary based on future system topology and technology. If the grid becomes more interconnected or there is significant technology and cost advancements in long duration storage technologies, you might see lower reserve prices as volatility may be mitigated.

[49] *See* "Earth Source Heat." Cornell University. https://earthsourceheat.cornell.edu/

revenue stream from a corporate contract. Adding the capacity payment did not improve the IRR for the New York project.[50]

Reducing the cost with technology development by 82% lowered the breakeven revenue level to a $0.22/kWh price point, which is quite a bit more reasonable, but still above market pricing in NYISO. That said, a future market might see elevated pricing at that level with increased decarbonization. Further, recent offshore wind contracts in New York have seen “all in development cost” levels at $0.8336/kWh, far above $0.22/kWh (NYSERDA 2020). The 82% cost reduction is identified as a long-term cost reduction target for EGSs in the GeoVision report (DOE-GTO 2019).

Table 6.7. Cornell EGS project results indicating that it isn’t currently feasible but could be marginally feasible with 82% cost reduction

Case	Revenue Level	Escalation Rate	Equity	Cost	Price (¢/net kWh)	Electricity Price Escalation (%)	Minimum DCR (ratio)	Internal Rate of Return (%)	Net Present Value ($)
1	Average	Inflation rate	All equity		14.52	2.3	-	-	-2,877.61
2	Average, Break-even price	Inflation rate	All equity		108.68	2.3	-	8	-0.01
3	Average	Inflation rate	All equity	18% of original cost	14.52	2.3	-	3.04	-228.31
4	Average, Break-even price	Inflation rate	All equity	18% of original cost	21.99	2.3	-	8	0.01

6.5 Summary of ESET and *Pro Forma* Results

From the ESET and *pro forma* results, we identify a few key takeaways:

- The baseline California case almost meets the IRR hurdle rate threshold. Neither the Eastern Oregon nor the New York EGS baseline projects get near the hurdle rate. Adding the resource adequacy (capacity) payment increases the IRR above the hurdle rate. The debt coverage ratio appears more than adequate to reduce the risk of default and allow a 70/30 debt equity ratio for the developer.

- Leveraging additional revenue streams, beyond energy, presents a significant improvement in project revenue across all projects relative to just energy delivery. In California and New York in particular, the delivery of ancillary services, specifically frequency regulation, represents significant value. Further, because of the characteristics of frequency regulation, a modulating requirement that can often be close

[50] The calculation for capacity value is similar to that for California Resource Adequacy as identified above. The weighted average capacity price per month of $2.71/kW-month for 2020 was used in this calculation. *See* https://www.nyiso.com/installed-capacity-market.

to energy neutral, requiring a relatively small amount of energy, the delivery of it has limited impact on energy revenues.

- Unfortunately, market prices or other estimates for other services such as inertia are not readily available or easily calculated given the lack of market products.[51] However, added revenue streams would improve the viability of the geothermal case study projects. Unlike geothermal resources, wind and solar resources do not automatically provide inertia to the system, yet both sets of resources are not compensated differently.

- As expected, as development costs decrease, IRR improves. Meeting the GTO's GeoVision report targets would present an improved base case for the California case study and a reasonable contract price for the New York case study. With the reduced costs, price levels identified are far below recent contracts for offshore wind. Despite the reduction in costs for Eastern Oregon, low market pricing associated with plentiful system hydroelectric power limits the benefit from reduced system costs.

- Annual revenue escalation plays a key role in IRR. The ESET model develops an annual revenue given input pricing but does not forecast revenue in future years during the project timeframe. Accordingly, revenue is based on the current market situation and does not account for the future. Increasing renewables deployments, fossil retirements, electrification and changing markets are likely to have an impact on future project revenues.

- A steady revenue stream, such as the simulated corporate revenue in the California and New York examples, may be critical to maintaining IRR with uncertain future project revenues.

- The addition of a battery or a PV system provides additional revenue, and in the case of ancillary services, batteries can provide significant value. However, based on this analysis, the additional elements are additive. That is, revenue from a standalone geothermal system, a standalone battery system, and a standalone PV system will roughly sum to the revenue of the combined systems. This would change, of course, if additional contract elements were required by the standalone or combined systems and/or there would be a direct advantage to hybridization (e.g., specific performance requirements like output ramp requirements or specific output timeframes in the case of bulk system projects, or demand charges in the case of a distributed project subject to a customer rate tariff). These instances are likely to be situationally dependent and required by offtakers of contracted resources. A geothermal developer could target such environments, which may be more likely with increasing variable renewable development and dispatchable fossil retirements.

[51] Power system operators place an increased value on physical inertia delivered by spinning machinery. Synthetic inertia from power electronics associated with battery or other variable renewable systems has not been used in any significant quantity to prove itself for grid reliability in the absence of physical inertia. Further, using a battery system or variable renewables to deliver synthetic inertia requires holding back capacity from other services or operations. That is not the case with physical inertia and spinning machinery.

7.0 Local Economic Impacts of Geothermal Development

In addition to providing value to the electricity grid, new geothermal development can add to local and regional economies via the development and operation of geothermal plants. Geothermal exploration, drilling, construction, and operations have the potential to transition fossil fuel workers from fossil fuel drilling operations to similar paying jobs in geothermal fields while also providing construction and power plant operator jobs. This is particularly relevant as the transition to a clean energy economy is likely to leave workers in fossil fuel industries out of work. Further, the potential for new jobs could support local economies in areas with geothermal potential, while providing geothermal development with seasoned workers.

7.1 Geothermal Jobs

As the US works towards transitioning energy systems away from fossil fuels and toward renewable energy, it is important to consider the potential economic impacts of this transition on fossil fuel workers. Fortunately, the growth of the renewables industries provides a significant opportunity to create new jobs. Geothermal energy may present an opportunity to rehire oil and gas workers into an industry that could specifically benefit from their skills. This effort to ensure that workers and communities that are economically dependent on the fossil fuel industry are not left behind is known as a just energy transition.

Though geothermal employment is relatively low compared with other renewables (in absolute numbers), with a 2019 U.S. Energy Employment Report estimating 8,526 directly employed in 2018, it is also one of the fastest growing renewable energy workforces (McGinn and Schneer 2019). The development, construction, and operation of a geothermal power plant can generate significant employment in a wide range of job types. For example, a typical 50 MW plant employs an estimated 697–862 people throughout the development cycle, with 10–25 of those jobs in O&M, a function that then continues throughout the lifetime of the plant (Jennejohn 2010). Indeed, the Geothermal Energy Association (GEA) estimated that in some circumstances, geothermal energy employs 19 times more people than solar PV or wind per MW and 5 times more people than a concentrating solar project (Matek 2015).

7.2 A Just Transition for the Oil and Gas Industry

Over the last few decades, employment in oil and gas has demonstrated significant volatility, largely due to the extreme sensitivity to oil prices, with the most recent round of layoffs tied to the ongoing COVID-19 pandemic (Dickson et al. 2020). These patterns foreshadow even more significant job loss in the oil and gas industry as the United States transitions its energy systems away from fossil fuels. A key step towards ensuring that this energy transition is equitable (i.e., a just energy transition) is to identify industries where transferrable skills from oil and gas workers could be directly (or with minimal additional training) applied to other industries. Areas where there is an overlap in skill sets between oil and gas workers and workers in industries expected to expand under an energy transition include geothermal energy, methane management and flaring elimination, decommissioning of orphan oil and gas wells, and carbon capture and storage (Prasad and Baxter 2021). The geothermal industry provides a broad spectrum of employment overlap, ranging from engineers, geologists, and hydrologists to operational jobs such as drillers and roustabouts (Table 7.1).

Table 7.1. Geothermal occupations highlighted by U.S. Bureau of Labor Statistics and corresponding employment opportunities and wages in the oil and gas industry.

	Occupation	Geothermal[a]	Oil and Gas[b]	Annual Mean Wage[b] (oil and gas, 2020 estimates)
Science	Environmental scientist	X	X[c]	$97,590
	Geologist	X	X[c]	$170,870
	Hydrologist	X	[c]	
	Wildlife biologist	X		
Engineering	Civil engineer	X	X	$124,670
	Electrical engineer	X	X	$131,710
	Electronics engineer	X	X	$107,320
	Mechanical engineer	X	X	$117,000
Drilling	Derrick operators	X	X	$57,480
	Rotary driller operators	X	X	$64,100
	Roustabouts	X	X	$48,770
Construction	Carpenters	X		
	Construction equipment operators	X	X	$58,130
	Construction laborers	X	X	$42,110
	Construction managers	X	X	$137,330
	Electricians	X	X	$77,000
	Plumbers, pipefitters, steamfitters	X	X	$58,490
Ongoing	Plant operators	X	X	$75,810

(a) Liming (2012)
(b) BLS (2020)
(c) Oil and gas job types include related “technician” job type (e.g., hydrologic technician)

Of course, the process of transitioning the oil and gas workforce to other industries that require their skills is likely to face obstacles. One of these is that the workforce will need to be able to shift focus from a business trading a commodity in a global market to one focused on providing energy at a more local scale (Brommer 2020). Additionally, the workforce for the oil and gas industry may not align geographically with the most favorable locations in the US for geothermal development (Figure 18). Indeed, while many of the major shale plays and gas fields in the contiguous US are found in the middle and eastern parts of the country, geothermal potential is concentrated west of the Rockies where more active tectonics lead to higher heat flows. However, there are some areas where high geothermal favorability overlaps with areas of oil and gas production (e.g., California and Texas), which could serve as potential focus points for transitioning the workforce to jobs in the geothermal industry.

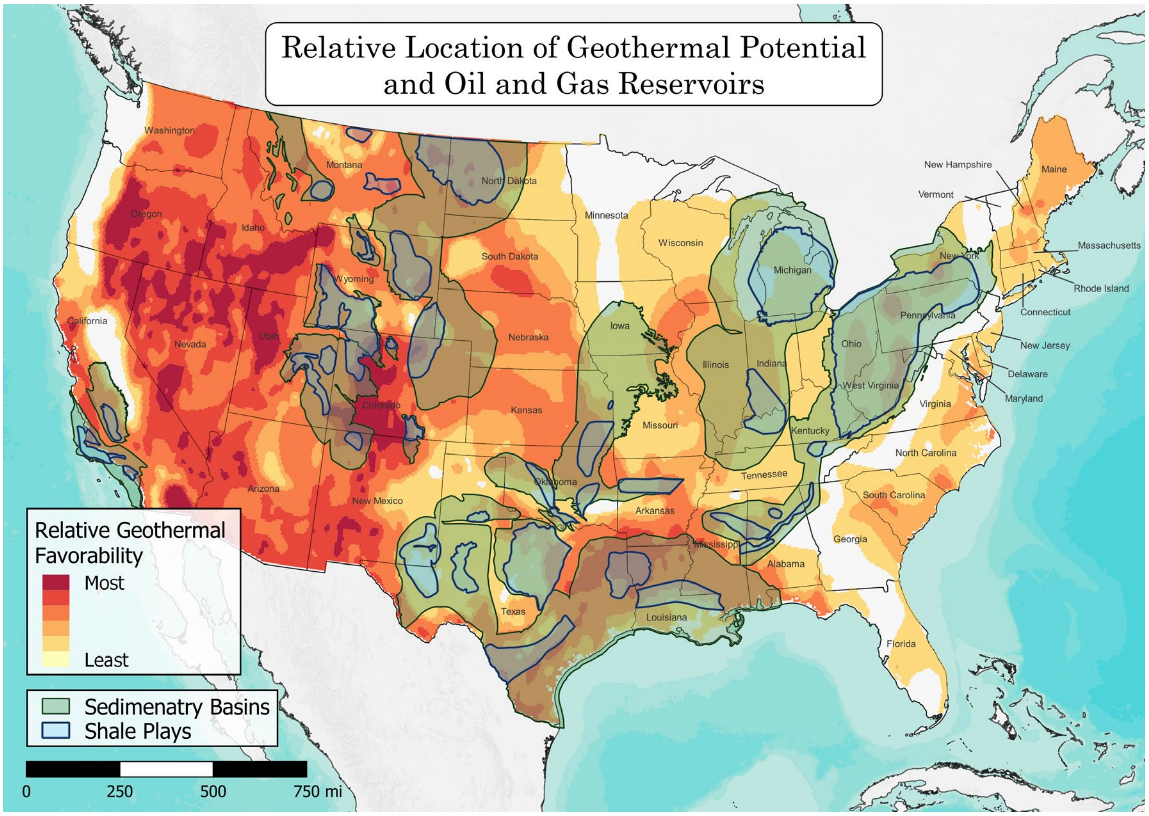

Figure 17. Map of the United States showing deep enhanced geothermal potential (NREL, n.d.), overlain with the locations of major sedimentary basins (green) and shale plays (blue) (EIA, n.d.).

Aside from those most favorable locations where geothermal favorability and the oil and gas workforce are collocated, there is potential for the geothermal industry to leverage the oil and gas workforce due to its high mobility. A 2021 global survey of oil and gas workers found that people working in the industry are quite willing to move locations for work—89% of respondents indicated they would be willing to relocate to another region for work (Donaldson 2021). The survey found that the main reason that respondents were willing to move was for career progression opportunities as well as the potential to find a permanent staff position, indicating an overarching concern about job security. These drivers are important to consider in future efforts to attract oil and gas workers into the geothermal industry. Indeed, such outreach is complementary to Key Action 4.3 from DOE-GTO's GeoVision report, which focuses on increasing awareness and availability of training opportunities to build a geothermal workforce to support potential resource expansion (DOE-GTO 2019).

7.3 Job and Economic Impact of the GeoVision Target

Though to date the geothermal industry has been significantly smaller than other energy industries, policymakers have outlined examples of how it could expand rapidly. The GeoVision study quantified these potential scenarios and showed that the US could be capable of adding nearly 60 GW of geothermal capacity by 2050, if technology improves (DOE-GTO 2019). The economic impact from such an expansion would be significant. Analysis from the National Renewable Energy Laboratory's Jobs and Economic Development Impact Model (JEDI), shows that the building the capacity associated with the GeoVision Technology Improvement scenario, could result in as many as 262,000 full time jobs created (Millstein et al. 2019). Though these figures are smaller than those of oil and gas industry, they are still a significant employment opportunity that would create tremendous economic growth, much of which would remain in local communities.

8.0 Conclusions

The potential for geothermal energy to provide value in a future clean energy system is significant: the strengths of the geothermal resource can complement a future grid that is likely to be heavily powered by intermittent renewable resources. Geothermal power plants deliver a clean and firm energy resource that is predictably available around the clock and is not subject to weather patterns. This can reduce the need for supportive resources, like energy storage, to address energy shortfalls and can further enable the integration of wind and solar resources. As discussed in this report, however, there are several challenges to new geothermal development, both technical and non-technical. This project develops a better understanding of these non-technical barriers, particularly as they relate to new project development and contracting.

Emerging electricity market trends and energy needs may provide opportunities for geothermal project development. In particular, the declining marginal value of renewable resources as they continue to be built out, like solar and wind, could present an opportunity for geothermal energy, as renewable deployment increases. Our analysis indicates that offtakers may already be attaching some implied capacity value (i.e., negative value) to solar PV in areas with significant levels of solar deployment. This is evidenced by lower levels of capacity attribution to solar resources and demands for solar storage hybrids. Geothermal, as a high-capacity value resource could capture additional value in such environments. However, geothermal will have to compete with other clean high-capacity value resources like hydroelectricity and energy storage. That said, geothermal technologies may have some advantages here. New hydroelectricity development is limited by siting challenges, and storage technologies beyond 4 hours are quite limited (pumped storage continues to have siting and development challenges). To capitalize on these advantages, however, will require electric markets and contract mechanisms that value the benefits of geothermal resources—the predictable and firm nature of its energy output.

Leveraging remuneration structures to capture the services geothermal resources can provide, including capacity, availability, and/or ancillary services, may allow for increased profitability in certain markets as indicated by our analysis. Although costs remain a challenge, adding ancillary service revenues shows increased profitability in our California (hydrothermal) and New York (EGS facility) case studies. Adding a capacity payment in the form of a resource adequacy payment, further improves the profitability of our California plant, increasing the internal rate of return from 7.5% to 13%. In both cases it is unfortunately difficult to predict future market conditions as there is so much uncertainty in market evolution. However, if capacity and ancillary service prices are maintained or increase (which seems likely given dispatchable generation being replaced by variable wind and solar) the business case for geothermal development should only improve. In California in particular, there is ongoing work to strengthen the Resource Adequacy incentive, and recent capacity market results from different markets show capacity shortfalls in the near future, which result in much higher capacity clearing prices.

We also explore the profitability of EGS, but the high costs of drilling to meet minimum heat needs does not currently justify development. Meeting the GTO's GeoVision targets for cost declines presents an improved business case across the evaluated case studies, both hydrothermal and EGS, presenting reasonable contract prices in line with or lower than prices for current renewable deployments for hydrothermal and lower than offshore wind for EGS.

Beyond the value that can be captured by projects, development risk remains a challenge. Based on our analysis of contracts of other resources, we identify that contracting mechanisms or strategies to address development risk could include the creation of portfolio PPAs that permit the seller to substitute geothermal energy from a predefined list of alternative geothermal resources if contracted capacity falls short. Seasonal capacity variations can also be addressed within PPAs by allowing developers to use other resources or market purchases to meet offtaker requirements. Seasonality risk can also be addressed by pairing geothermal with other renewable energy resources such as solar power or battery systems.

Geothermal developers could also leverage new market opportunities to support deployment, including corporate contracts to service large loads such as server farms, cryptocurrency mining, or hydrogen generation. Leveraging corporate revenues in our case studies not only increases revenues but also provides for more stable long-term revenues. Coupling geothermal resources with battery storage or PV systems may provide new revenue streams to a particular developer, but these added elements are largely additive. That is, revenue from a standalone geothermal system, a standalone battery system, and a standalone PV system will roughly sum to the revenue of the combined systems. That said, in the right market conditions and as the electric industry evolves, such hybridization may present additional value. For example, one could foresee a situation in which specific plant performance requirements necessitate the addition of a battery, or the addition of solar PV leverages land acquired and electric infrastructure built, for a geothermal development and compensates for any uncertainty in geothermal output.

Though challenges remain, the future for geothermal energy looks bright. But it will require a concerted effort by government and the geothermal industry to prove and capitalize on geothermal energy’s potential.

9.0 Recommendations and Next Steps

Based on the work performed here, we present several recommendations or next steps that can be taken by developers, researchers, offtakers, and government entities to improve the ability of geothermal resources to better represent its value and compete in the market. These next steps include new policy and market development and further study around a Just Transition and equity and would be in addition to the continued efforts across industry, academia, and by the Department of Energy to advance the technology's capabilities and reduce costs.

9.1 Policy and Market Development

If geothermal resources are to be key elements of the future electric system, governments may wish to examine the efficacy of using new, existing, or even former legislation to support geothermal development. One policy is the Investment Tax Credit. As discussed, geothermal has not received the same benefit as other renewable resources, this could be amended. Additionally, policymakers may wish to investigate the development of a government supported risk insurance product to address geothermal development and operational risks. Finally, governments may want to research the cost-effectiveness of other financial instruments, such as loan guarantees, cost sharing for geothermal projects, dedicated tax credits, feed-in-tariffs and other incentives that may help to support development. An analysis that evaluates the potential value that geothermal could provide in balancing a grid with 75–90 percent variable renewable energy might provide the basis for establishing the level of such a support mechanism required, considering no improvements in technology, and with the improvements envisioned in the GeoVision Report. This analysis could provide a curve by which an inventive could vary with deployment and costs to ensure cost-effectiveness. It could also be set to the characteristics of the development environment, e.g., EGS, super-hot rock, resource temperature, and depth.

Beyond financial support, support in securing rights to, or simply evaluating the land available for development could help address an initial obstacle to potential development. As in the western US, much of the land with geothermal resource is Federal, and obtaining lease agreements or use permits can take a significant amount of time. The Federal government could provide additional support to BLM and the Forest Service in the way of geothermal expertise and staffing to support more timely analysis of development inquiries and requests.

Another set of recommendations relate to the utility and regulatory arena. Regulators could require their utilities to consider the capacity value and potential to provide system flexibility of geothermal resources as their utilities develop resource plans and begin to solicit the development of new clean resources. Resource planners often use least cost as a primary means to evaluate future resources to meet goals, but this approach may leave out value represented by geothermal power. Regulators could push planners to also use 'least risk' methods to consider reliability, or a combination of costs, and reliability and risk tradeoffs, in addition to an analysis approach that considers value provided by a resource. Utilities and resource modelers could develop better and uniform protocols to incorporate price volatility stemming from increased VRE and their impacts to the system, to ensure that avoided costs are more accurately determined, and future geothermal value streams are correctly represented.

9.2 Just Transition

The potential to leverage the oil and gas workforce to build up the geothermal workforce provides an appealing avenue to support the geothermal industry, while also working toward the broader goal of achieving a just energy transition. However, to make this avenue a reality, further analytical work is necessary. Key next steps include the following:

- Conduct a more in-depth survey of job types involved throughout the geothermal development process and crosswalk the job types with Bureau of Labor Statistics data on oil and gas jobs.
- Distinguish areas where workers from the oil and gas industry can directly transfer their skills to geothermal from those where additional training is required and identify the additional training requirements.
- Characterize the geothermal workforce demand, and the number of jobs that could be filled from the oil and gas industry.
- Quantify the social and economic costs and benefits associated with oil and gas retirements and potential geothermal build out.
- Apply this framework to EGSs.
- Compare the wage and cost of living of geothermal and fossil fuel workers.

Beyond workforce effects, the development of geothermal resources may present other equity and environmental justice benefits. This can be a continuing area of research. Potential questions to be answered include the following:

- Can the geothermal resource enable a faster replacement of polluting fossil resources, particularly those sited in disadvantaged communities? Such a study would require data on available geothermal resources near disadvantaged communities served by polluting facilities as well as the location of disadvantaged communities and transmission lines near the resource. Disadvantaged communities would be as defined by the 42 U.S. Code § 300j–19a.
- What are the societal and social costs of using geothermal technologies relative to other renewable resources (e.g., wind, solar, hydro, pumped hydro, offshore wind, marine energy, etc.)? This includes water use, agricultural land use, other land use, wildlife, and environmental impacts.
- What are the tradeoffs between increased customer resource or distributed energy resource development and increased geothermal development, a pathway likely to require additional transmission buildout?
- What multiplier effects exist for geothermal capacity expansion and local economic development?

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Appendix A – Geothermal Energy Production

A.1 Active and Planned Geothermal Power Plants

Geothermal electricity production in the US is limited to a set of power plants located in the western part of the country. Below, find an embedded Excel file with information about the current and planned geothermal powerplants. This data was compiled by Wikipedia (Wikipedia n.d.).

US_Power_Plants.xlsx

A.2 Project Development: Characterization of the Geothermal Resource for Development

Geothermal resource characterization involves determining geothermal gradients, measuring rock permeability, conducting related site exploration and drilling. It is a necessary first step to developing a power plant.

A.2.1 Geothermal Gradient and Rock Permeability

The first factor controlling the location of a potential geothermal resource is the geothermal gradient which corresponds to the increase in temperature with depth due to the conductive cooling of the Earth. Mostly controlled by the regional geology and tectonic setting, the geothermal gradient can vary from 20°C/km (i.e., an increase in 20°C per km of depth below the surface) for stable continental cratons to more than 150°C/km for the most tectonically active regions in the world (e.g., an active volcanic range). Therefore, the first source to consult when identifying a new geothermal resource is a regional heat flow map, where heat flow is the geothermal gradient multiplied by the thermal conductivity. Except for EGS, the second major factor to consider is the natural presence of rock permeability and fluids. Sufficient permeability is required to allow for the flow water from injection wells to reach production wells. In the case of EGS, permeability can be enhanced through fluid injection.

Although direct use applications of geothermal energy (e.g., district heating, greenhouses, and industrial uses) can be implemented with temperatures as low as about 35°C, the minimum temperature suitable for electrical generation is about 75–80°C using a binary system with an organic working fluid, and about 135°C when directly using the geothermal fluid to generate electricity. Therefore, geothermal resources for electricity generation occur in areas of higher-than-average subsurface temperatures (Finger and Blankenship 2011) and their depth and temperature vary considerably. Several power plants, (e.g., Steamboat Hills, Nevada and Mammoth Lakes, California) operate on lower-temperature fluid (below 200°C) produced from depths of approximately 330 m, but wells in the Geysers Geothermal Field (hereafter called the Geysers) produce dry steam (above 240°C) and are typically 2,500 to 3,000 m deep. In extreme cases, exploratory wells with bottom hole temperatures of 500°C at depths greater than 3000 m have been completed in Iceland, Italy, and Japan, and experimental holes into molten rock (above 980°C) have been drilled both in Hawai’i and Iceland.

A.2.2 Exploration and Drilling

Exploration aims to locate geothermal reservoirs for possible exploitation and to select the best sites for drilling production wells with the greatest possible confidence. Geothermal exploration involves several methods and techniques from various fields of Earth Sciences (geology, geophysics, geochemistry, drilling technology, etc.) to locate reservoirs, characterize their conditions, and optimize the locations of wells.

Drilling exploratory wells, or confirmation wells, represents the final phase of any geothermal exploration program. It is a means of determining the real characteristics of the geothermal reservoir and thus of assessing its potential (Combs and Muffler 1973). Geothermal drilling relies on technology used in the oil and gas industry, modified for high-temperature applications and larger well diameters. The data provided by exploratory wells should be capable of verifying all the hypotheses and models elaborated from the results of surface exploration. Data from drilling should also confirm that the reservoir is productive and that it contains enough fluids of adequate characteristics for its intended utilization. Siting and drilling of exploratory or confirmation wells are therefore the most important and costly operations of any geothermal resource characterization. More recently, there has been a lot of work on “slim” holes for confirmation. These wells are significantly cheaper than the traditional exploratory well.[52]

As the transition to clean energy resources continues, there has been strong interest in leveraging the prior efforts, capabilities, equipment and personnel from the oil and gas industry to either utilize former oil and gas wells or to bring down the costs of future drilling. Although this may be a beneficial approach, unfortunately, geothermal drilling is more expensive and complicated than onshore oil and gas drilling for three principal reasons (Augustine et al. 2006):

1. **Technical challenge:** the conditions described above mean that special tools and techniques are required for the harsher down-hole conditions.

2. **Large diameters:** because the produced fluid (hot water or steam) is of intrinsically low value and exhibits large flow rates, geothermal drilling requires large holes and casing. In many cases, it will also require more casing strings to achieve a given depth in a geothermal well than in an oil well drilled to the same depth.

3. **Uniqueness:** geothermal wells, even in the same field, are more different from each other than oil and gas wells in the same field, so the learning curve from experience is less useful.

[52] *See* https://www.geoenergymarketing.com/energy-blog/slimhole-drilling-for-geothermal-exploration-and-reservoir-assessment/.

A.3 Geothermal Power Plants

Once a resource has been characterized, with exploratory wells drilled, the next step is to develop the resource into a power plant. There are three main types of geothermal power plants: dry steam, flash steam, and binary cycle power plants, as shown in Figure 19.

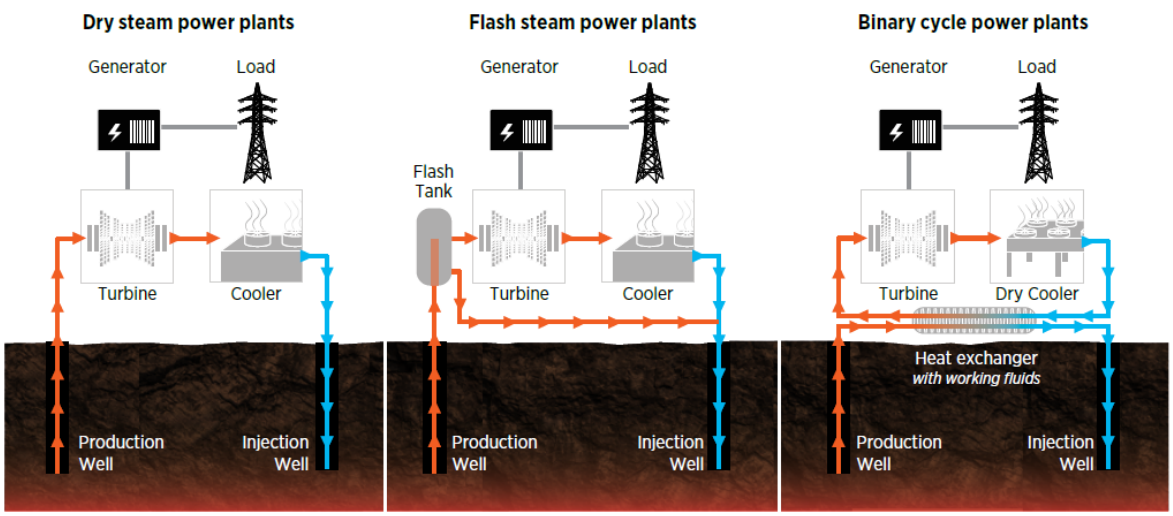

Figure 18. Geothermal powerplant configurations: dry steam, flash steam, and binary cycle (Figure from the GeoVision Report, DOE-GTO 2019)

A.3.1 Dry Steam Power Plant

In a dry steam power plant, the geothermal fluid is in the form of dry pressurized steam that is superheated at temperatures from 180°C to over 350°C. This dry steam is brought to the surface and directly turns the turbine of a power plant operating following the Rankine power cycle. The steam output is then condensed to water which is injected back into the geothermal reservoir. Dry steam power plants account for many of the early geothermal power plants, such as the first Geysers units in California.

A.3.2 Flash Steam Power Plant

Flash steam power plants use geothermal water resources with temperatures in the range of 177°C to 260°C. This water is brought to the surface and then converted to steam in a flash tank held at lower pressure than the reservoir pressure. The steam is then used to turn the turbine of the power plant. A single flash condensing cycle is the most common energy conversion system for using geothermal fluids (geofluids) because of its simple construction and the resultant low possibility of silica precipitation in plant equipment.

A double flash cycle can produce 15–25% more power output than a single flash condensing cycle for the same geothermal fluid conditions by flashing any fluid remaining in the first tank in a second flash tank. The resulting cooled water is injected into the geothermal reservoir.

A.3.3 Binary Cycle Power Plant

Binary cycle power plants operate utilizing lower-temperature geothermal water resources, ranging from 74°C to 177°C. These plants use the heat of the hot water to vaporize a “working fluid”, which is usually an organic compound with a low boiling point, in a heat exchanger at the surface. The vaporized working fluid then is used to turn a turbine to generate electricity while the cooled water is reinjected. After the turbine the working fluid is cooled and then re-used in a continuous closed loop. The geothermal water and the working fluid are confined to separate process loops, so there are no air emissions nor any mixing. Because lower-temperature water is much more plentiful than high-temperature water or steam, binary cycle systems make up the dominant type of geothermal power plant.

Appendix B – Summary of Power Purchase Agreements

Project Name	Resource Type	Location	Buyer	Year	Term (years)	Capacity	Offtaker has remote control	Remuneration Structure	Services provided
AES Kuihelani Solar	Solar/ BESS	Kuihelani Highway, HI	Maui Electric Company, Limited	2019	25	PV: 90 MWdc Storage: 60 MWac	Yes	Availability only	availability (of dispatchable energy)
AES West Kauai Energy Project	Hydropower/ PV/ Pumped and BESS	Kauai, HI	Kauai Island Utility Cooperative (KIUC)	2019	25	Maximum Output: 120 GWh Expected Output: 110 GWh	Yes	Energy and capacity	capacity
Arrow Canyon Solar	Solar/ BESS	Clark County, NV	Nevada Power Co D/B/A NV Energy	2019	25	PV: 200 MW Storage: 75 MW	Yes	Energy only	capacity, voltage support, reactive power, operating reserve, spinning reserve, frequency response; guaranteed storage availability
Arroyo Solar	Solar + Storage	Pueblo Pintado, McKinley County, NM	Public Service Company of New Mexico (PNM)	2019	20	PV: 300 MW Storage: 40 MW, 4 hr duration	Yes	Energy, capacity, and ancillary services	storage
AZ Solar Storage 2	Solar + Storage	Salome, AZ	Central AZ Water Conservation District (Central Arizona Project)	2019	20	20 MW	No	Energy only	capacity and ancillary services (unspecified)
Bellingham Cogeneration Facility	Natural Gas	Bellingham, MA	Boston Edison Company (Eversource)	2004	14	150 MW (varies by	No	Energy and capacity	capacity

Project Name	Resource Type	Location	Buyer	Year	Term (years)	Capacity	Offtaker has remote control	Remuneration Structure	Services provided
						month, 110-150 MW)			
Block Island Offshore Wind	Offshore Wind	Offshore Rhode Island	National Grid	2010	20	30 MW	No	Energy and capacity	capacity
Bluewater Offshore Wind*	Offshore Wind	Atlantic Ocean, 11.5 nautical miles east of Rehoboth Beach, DE	Delmarva Power & Light Company	2008	25	200-600 MW (final capacity determined 2 yrs after execution date)	No	Energy and capacity	capacity
Chuckwalla Solar	Solar/ BESS	Clark County, NV	Nevada Power Co, Sierra Pacific Power	2020	22	PV: 200 MWac Storage: 180 MW, 4 hr duration (nameplate: 185 MW)	No	Energy and availability	storage product associated with battery system; incl. in energy rate: voltage support
Cipher Mining Technologies Inc.	Natural Gas (corporate)	Texas	Cipher Mining Technologies Inc.	2021	5	1,054 MW	No	Energy only	
Coso Geothermal	Geothermal	Inyo County, CA	Southern California Public Power Authority (SCPPA)	2020	20	Nameplate: 266 MW Maximum Output: 150 MW Expected Output: 130 MW	No	Energy only	capacity rights

Project Name	Resource Type	Location	Buyer	Year	Term (years)	Capacity	Offtaker has remote control	Remuneration Structure	Services provided
Crawford, Fisk, Waukegan, Will County, Joliet and Powerton Coal* **	Coal	IL (multiple coal units)	Commonwealth Edison Company	1999	5	By year (1) 2,896 (2) 2,582 (3) 2,582 (4) 2,060 (5) 522	Yes	Energy and capacity	capacity, reactive supply and voltage control; regulation and frequency response; operating reserve - spinning; operating reserve - supplemental
Douglas County Wells Hydroelectric	Hydroelectric	Douglas County, WA	Portland General Electric	2020	5	840 MW (100-160 MW contracted for PG&E)	Yes	Energy, capacity, and ancillary services	flexible capacity, reserves, frequency response
Duke Waste to Energy	Anaerobic Digestion Biogas Plant	Charlotte, NC	Duke Energy	2016	14	5.2 MW	No	Energy only	
Golden Hills Wind Shaped	Wind	Sherman County, OR	Puget Sound Energy	2020	20	200 MW	No	Energy, capacity, and ancillary services	capacity, shaped winter product
Honua Ola Bioenergy	Biomass	Pepeekeo, HI	Hawaii Electric Light Company, Inc.	2017	30	21.5 MW	Yes	Energy and capacity	capacity
Jicarilla Solar 1	Solar + Storage	Jicarilla Apache Nation, Rio Arriba County, NM	Public Service Company of New Mexico (PNM)	2019	20	PV: 50 MW Storage: 20 MW, 4 hr duration	Yes	Energy, capacity, and ancillary services	storage
Jicarilla Solar 2	Solar	Jicarilla Apache Nation, Rio Arriba County, NM	Public Service Company of New Mexico (PNM)	2019	15	50 MW	Yes	Energy only	capacity, operating reserves, regulation, black-start capability, reactive supply, voltage control, frequency response *(ancillary services not remunerated separately)*

Project Name	Resource Type	Location	Buyer	Year	Term (years)	Capacity	Offtaker has remote control	Remuneration Structure	Services provided
Lightning Dock Geothermal	Geothermal	~20 miles SW of Lordsburg , NM	Public Service Company of New Mexico (PNM)	2012	20	10 MW	No	Energy only	
Milford Wind	Wind	Milford, UT	SCPPA	2010	20	102 MW	No	Energy only	
Neal Hot Springs Geothermal	Geothermal	Vale, OR	Idaho Power Company	2009	25	22 MW	No	Energy only	
Ormat Northern Nevada Geothermal Portfolio**	Geothermal	Churchill County, NV	Southern California Public Power Authority	2016	25	150 MW	No	Energy only	
Point Beach Nuclear	Nuclear	Two Rivers, WI	Wisconsin Electric Power Co.	2006	18	1,055 MW Avg. Winter capacity: 1,054MW Avg. Summer capacity: 1,041MW Avg. Shoulder: 1,052MW	No	Energy only	
Puna Geothermal	Geothermal	Pu'u Honuaula, HI	Hawaii Electric Light Company, Inc.	2011 (restated 2019*)	25	2011 PPA: 38 MW 2019 PPA: 46 MW	Yes	Energy and capacity	capacity
Rio Bravo Poso CHP	Combined Heat and Power (CHP)	Bakersfield, Kern County, CA	Pacific Gas and Electric Company	1985	30	37 MW, broken into 30 MW firm capacity, 7 MW as available capacity	No	Energy and capacity	

Project Name	Resource Type	Location	Buyer	Year	Term (years)	Capacity	Offtaker has remote control	Remuneration Structure	Services provided
Seabrook Nuclear	Nuclear	Seabrook, NH	Green Mountain Power	2011	22.83	Maximum Output: 1,246 MW Expected Output: 1,096.48 MW	No	Energy and capacity	capacity
Sierra Pacific Biomass Cogen	Biomass Cogeneration	Skagit County, WA	Puget Sound Energy, Inc.	2020	17	28 MW	No	Energy only	
Vineyard Wind*	Offshore Wind	Martha's Vineyard, MA	NSTAR (Eversource)	2018	20	400 MW	No	Energy and capacity	capacity
Wild Rose Geothermal	Geothermal	Mineral County, NV	SCPPA	2012	20	Nameplate: 25 MW Maximum Output: 16.2 MW	No	Energy only	
Yuba-Bear Hydroelectric	Hydroelectric	Nevada City and Grass Valley, CA	Pacific Gas and Electric Company	2012	20	76.6 MW	Yes	Energy only	capacity, spinning and nonspinning reserves

* Ultimately cancelled
** Includes Tungsten Mountain Geothermal
*** Includes performance payments for starts and stops (rates vary by type of start, i.e., cold vs. warm)

Appendix C – *Pro forma* Assumptions

The following tables provide the assumptions and any associated reference for developing the results of the *pro forma* analysis.

Table 10.1. Plant details used in *pro forma* modeling and analysis

	Geysers (CAISO)	Eastern Oregon	New York
Type of Plant	hydrothermal	hydrothermal	EGS
Configuration	Standalone; hybrid w/ battery; deferable load	Hybrid with PV	Standalone; deferable load for hydrogen
Location	Sonoma County, Federal Land	Vale Oregon (Malheur)	Cornell Land
Geothermal Plant Size (MW)	45	22.5	45
Depth of Wells	8500 ft	915 meters	4100 meters
Number of Wells	4 injection, 18 steam wells	5 injection, 4 steam well	
Temperature and Pressure of Wells	371.8°F, 189°C, 81.8 psi	286°F, 141°C	180°C at 6 km
Battery Size	45 MW/4 hr.	22.5 MW/4 hr.	45 MW/4 hr.
Energy Generated (kWh)	374,490,000	185,782,080	303,534,000
PV Size (MW)		22.5[53]	
PV Capital Cost		31,950,000[54]	
PV Fixed Cost ($/kW)		16[55]	
Load	Corporate load		Corporate load
Geothermal Plant Cost ($)	303,829,752[56]	139,300,000[57]	2,448,152,631[58]
Battery Cost 4 MW/4 MWh (LFP) [59]	6,872,000	35,820,000	71,640,000
Battery replacement cost at 10 years[60] ($)	1,297,000	6,760,556	13,521,112

53 (Bolinger et al. 2021)
54 Ibid.
55 Ibid.
56 Geothermal Electricity Technology Evaluation Model (GETEM).
57 (Weijermars, Zuo, and Warren 2017)
58 GETEM
59 (Mongird et al. 2020)
60 Email from Patrick Balducci, 10/19/2021 describing approach to calculate it based on component replacement.

	Geysers (CAISO)	Eastern Oregon	New York
Battery replacement cost at 20 years[61] ($)	4,844,000	25,249,139	50,498,277
Battery O&M per year[62] ($)	18,860	106,088	212,175

Table 10.2. Inputs from this project used in *pro forma* modeling and analysis based on contract best practices

Geysers (CAISO)	Eastern Oregon	New York	
Offtaker Type	utility/corporate	utility	Municipal/corporate
Interconnection Costs ($)	1,900,000.0[63]		
Level of Insurance[64]	0.001	0.001	0.001
Locational Value	CAISO market	PCM output	NYISO Market
Prices (2020 and 2030)	CAISO market	PCM output	NYSIO Market
Corporate Load Price	$50/MWh, flexible delivery relative to market price	-	$50/MWh, flexible deliver relative to market price

[61] Ibid.
[62] (Mongird et al. 2020)
[63] (Richter 2016)
[64] Assumption based on pumped storage hydropower developers

Table 10.3. Assumptions and input from outside of this project used in *pro forma* modeling and analysis

Geysers (CAISO)	Eastern Oregon	New York	
Price Escalation[65]	0.023	0.023	0.023
Technology Costs	published cost data/GETEM	published cost data/GETEM	GETEM
Variable and Fixed O&M	GETEM	GETEM	GETEM
ROR, Developers[66]	0.080	0.080	0.080
WACC[67]	0.08	0.08	0.08
Debt-Equity Ratios[68]	0.7	0.7	0.7
Cost of Debt Capital[69]	0.06	0.06	0.06
Site Basis: State Tax	0.0884[70]	0.076[71]	0.065[72]
Site Basis: Federal Tax[73]	0.21	0.21	0.21
State Incentives	Sales Tax Exemption[74]	Property Tax Exemption;[75] Business Energy Tax Credit of 33.33 NPV of eligible value. This program died in 2017.	No state incentives
Federal incentives: ITC[76]	0.1	0.1 and .26	0.1
Depreciation (MACRS)[77]	5-year schedule	5-year schedule	5-year schedule
Sales Taxes	0.0625[78]	0	0.08[79]
Property Tax	0.01234[80]	0.01101[81]	0.018065523[82]
Gross Receipts Tax		0.0057[83]	
Royalty Rate[84]	0.035	0.035	0.035
Depletion Allowances	Calculated	Calculated	Calculated
Insurance Rates[85]	0.002	0.002	0.002

[65] (DOE-FEMP 2021)
[66] Assumed
[67] Assumed
[68] Assumed
[69] Assumed
[70] (State of California n.d.)
[71] (Oregon Department of Revenue 2020a)
[72] (New York State 2020)
[73] (Department of the Treasury 2021)
[74] (NC Clean Energy Technology Center 2021d)
[75] (NC Clean Energy Technology Center 2021c); OR HB3680, BETC; Permanent Oregon Administrative Rules, OR 315.354 et seq, ORS 469 185 et seq; Kimmelfield, ND, L Powell. 2008. "The Oregon Business Energy Tax Credit." Oregon State Bar Taxation Section Vol 11(1).

[76] (NC Clean Energy Technology Center 2021a)
[77] (NC Clean Energy Technology Center 2021b)
[78] (Sales Tax Handbook 2021)
[79] (New York State 2019)
[80] (County of Sonoma 2021)
[81] (Oregon Department of Revenue 2020b)
[82] (Thompkins County 2020)
[83] (State of Oregon 2020)
[84] Based on GETEM
[85] Assumption based on pumped storage hydropower developer information

Appendix D – Regression Outputs for PPA Analysis

For our multi-regression analysis we utilize a backwards elimination process, whereby we begin with the full set of control variables and one by one eliminate those that are not statistically significant, based on the p-value of each control.[86] When all terms are statistically significant, we preform the significance tests described in section 4.1. Reasons to add or delete a variable in this stage include attempts to eliminate multicollinearity or the addition of an interaction or higher order term. As a result of this process, the best fitting model for each technology will not necessarily contain all our potential explanatory variables. A blank in the tables below indicates that, while tested, this term did not have a statistically significant effect on the model output. The primary explanatory variable is listed in bold. In all cases the dependent variable is PPA price.

Table 10.4. Wind price regressions

	(1) Solar	(2) Geothermal	(3) Hydro
Annual average wind PPA price	0.700*** (0.174)	0.00681** (0.00218)	0.671*** (0.140)
AR	0 (.)		
AZ	12.68 (13.78)	0 (.)	
CA	67.85*** (14.01)	-0.266* (0.126)	0 (.)
CO	-13.13 (14.16)		-28.37* (12.49)
CT	54.18*** (15.17)		12.26 (12.40)
FL	47.64** (14.82)		
GA	9.069 (13.54)		-21.25 (29.06)
HI	84.26*** (15.22)		184.3*** (29.34)
IA			-11.28 (28.85)
ID			16.01* (7.889)
IL			28.12 (15.04)
MA			35.21** (11.05)
MD	23.01 (17.80)		
ME			55.86*** (10.85)

[86] The sole exception to this rule is our dummy variable for states. We only remove the control for state effects if many states are statistically insignificant.

MI			-27.33 (17.10)
MN	10.91 (19.69)		-33.64* (14.93)
MO	5.891 (24.83)		
MS	0.360 (16.47)		
MT			13.56 (12.56)
NC			1.438 (11.07)
NE	15.53 (24.82)		
NH			21.16* (8.770)
NM	-7.730 (15.24)	0.178 (0.112)	
NV	8.423 (14.27)	-0.436** (0.122)	18.98 (15.00)
NY	134.6*** (17.85)		14.65* (6.010)
OH	130.3***		
OR			21.91* (8.601)
PA			-4.355 (14.91)
RI			13.92 (20.67)
SC	-1.739 (19.64)		-0.263 (10.61)
SD			-37.02 (28.85)
TX	28.18 (15.23)		-11.27 (20.89)
VA			37.49 (28.85)
VT			37.49 (28.85)
WA	-13.04 (17.56)		17.17 (10.03)
WI			-32.20 (17.10)
WV			-5.721 (20.64)
WY			-23.36 (20.65)
Retirements	0.0000628* (0.0000248)		

Retirements (5-year average)	-0.0253*** (0.00387)	-0.000105*** (0.0000222)	
CO^2 price	-1.412** (0.516)		
ln(hardware costs)	52.49*** (6.145)		
RPS goal	0.934** (0.319)		
RPS outstanding	1.159*** (0.247)		
Annual average solar PPA price			-0.106** (0.0407)
Constant	-308.0*** (38.50)	4.098*** (0.146)	47.02*** (7.731)
Observations	259	42	246
R-squared	0.858	0.575	0.474

Standard errors in parentheses
* p < 0.05, ** p < 0.01, *** p < 0.001

Table 10.5. Solar price regressions.

	(1) Wind	(2) Geothermal	(3) Hydroelectric
Annual average solar PPA price	.034 (0.0110)	0.0121 (0.0352)	-0.106** (0.0407)
AK			
AL			
AR			
AZ		0 (.)	
CA		-14.02 (16.49)	0 (.)
CO			-28.37* (12.49)
CT			12.26 (12.40)
DC			
DE			
GA			-21.25 (29.06)
HI		9.064 (16.50)	184.3*** (29.34)
IA			-11.28 (28.85)
ID		-26.00 (16.71)	16.01* (7.899)
IL			28.12 (15.04)

IN		
KS		
KY		
MA		35.21**
		(11.05)
MD		
ME		55.86***
		(10.85)
MI		-27.33
		(17.10)
MN		-33.64*
		(14.93)
MO		
MT		13.56
		(12.56)
NC		1.438
		(11.07)
ND		
NE		
NH		21.16*
		(8.770)
NM	4.504	
	(19.00)	
NV	-21.72	18.98
	(16.88)	(15.00)
NY		14.65*
		(6.010)
OH		
OK		
OR		21.91*
		(8.601)
PA		-4.355
		(14.91)
RI		13.92
		(20.67)
SC		-0.263
		(10.61)
SD		-37.02
		(28.85)
TN		
TX		-11.27
		(20.89)
UT	-48.75**	
	(16.32)	
VA		38.19*
		(14.97)
VT		37.49
		(28.85)

WA			17.17 (10.03)
WI			-32.20 (17.10)
WV			-5.721 (20.64)
WY			-23.36 (20.65)
RPS Goal	24.91* (0.01)		
RPS step	131.28*** (28.04)		
Hardware costs	0.059*** (0.003)		
Annual average wind PPA price			0.671*** (0.140)
Constant	-38.62*** ()	100.0*** (16.71)	47.02*** (7.731)
Observations	387	45	
R^2	0.421	0.330	

Standard errors in parentheses
* p < 0.05, ** p < 0.01, *** p < 0.001

Table 10.6. Henry Hub regressions.

	(1) Wind	(2) Solar	(3) Geothermal	(4) Hydroelectric
Henry Hub price	-1.870* (0.74)	-1.197 (2.138)	2.722 (1.452)	4.442* (2.157)
AL	0 (.)	0 (.)		
AR	7.50 (6.34)	-3.605 (24.84)		
AZ	43.95*** ()	-1.872 (22.88)	0 (0)	
CA	69.33*** (6.63)	34.54 (26.62)	-18.53 (15.84)	0 (.)
CO	4.97 (5.25)	-44.43 (26.13)		-26.29* (12.73)
CT	27.13*** (7.11)	26.54 (26.04)		12.74 (12.47)
DE	47.63*** (9.40)			
FL		42.55 (22.44)		
GA		5.346 (22.07)		-21.53 (29.26)
HI		61.38* (24.99)	11.35 (15.46)	183.1*** (29.86)

IA	4.2572.67 (5.1410.54)			-12.71 (29.02)
ID	19.49** (5.5610.60)		-13.47 (21.48)	14.97 (7.985)
IL	12.0714.28 (7.8711.82)			29.33 (15.11)
IN	17.6716.81* (5.78)	31.59 (30.59)		
KS	-0.75 (.92)	19.71 (30.35)		
MA	58.57*** (10.16)	-7.212 (31.23)		34.17** (11.26)
MD	38.42*** (8.29)	0.397 (26.68)		
ME	36.13*** (6.69)			54.66*** (11.19)
MI	36.14*** (7.43)	3.914 (30.94)		-28.76 (17.22)
MN	5.39 (5.21)	-24.66 (30.50)		-35.02* (15.13)
MO	4.00 (5.59)	-10.53 (30.89)		
MS		-4.070 (23.97)		
MT				12.14 (12.65)
NC				-0.218 (11.15)
NE	0.42 (5.17)	2.790 (26.39)		
NH	1.14** (18.06)			16.70 (8.855)
NJ				
NM	0.15 (5.25)	-34.38 (25.57)	7.210 (17.79)	
NV		-23.40 (26.19)	-23.07 (15.79)	17.55 (15.11)
NY		102.0*** (28.57)		13.42* (6.044)
OH	33.12*** (7.23)	115.8*** (27.01)		
OK	-0.617 (9.293)	-21.13 (30.47)		
OR				20.49* (8.695)
PA	33.80*** (6.90)			-4.435 (15.03)
RI				12.49 (20.81)

SD	10.91 (6.97)			-1.692 (10.70)
SC		-6.600 (26.31)		-38.45 (29.02)
TN	34.51*** (5.22)	-4.198 (30.23)		
TX	38.35*** (7.39)	16.34 (22.96)		-25.64 (20.82)
UT	37.89*** (4.86)		-47.35** (15.43)	
VA	37.52*** (8.12)			31.41* (15.03)
VT	69.90*** (4.98)			36.06 (29.02)
WA	24.37* (7.67)	-30.67 (25.57)		16.11 (10.07)
WI	15.07* (4.88)			-36.29* (17.25)
WV	24.33** (7.48)			-4.912 (20.76)
WY	11.47 (7.63)			-28.69 (21.22)
RPS step		136.0* (66.95)		
Retirements (5 year average)	-0.017*** (0.004)	-0.0255*** (0.00391)		
Hardware costs	0.044*** (0.003)			
Annual average wind PPA price		0.821*** (0.182)		
CO^2 price		-1.716** (0.535)		0.380* (0.159)
ln(hardware costs)		57.13*** (6.528)		
Constant	-13.59 (6.70)	-334.7*** (44.74)	91.30*** (16.09)	36.37*** (8.212)
Observations	387	267	53	246
R^2	0.766	0.862	0.316	0.468

Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 10.7. Renewable penetration regressions.

	(1) Wind	(2) Solar	(3) Geothermal
Renewable penetration	50.65*** (13.39)	-52.68* (26.12)	50.24 (45.07)

AL	0 (.)	
AR	6.289 (5.597)	
AZ	43.23*** (5.930)	0 (0)
CA	63.15*** (6.586)	-23.89 (16.21)
CO	2.123 (5.154)	
CT	31.35*** (7.086)	
DE	46.17*** (7.361)	
IA	-8.263 (5.844)	
ID	17.98** (5.858)	-25.41 (18.67)
IL	9.692 (7.666)	
IN	13.61** (5.032)	
KS	-8.497 (4.753)	
MA	65.70*** (10.56)	
MD	39.89*** (7.319)	
ME	27.52*** (7.449)	
MI	37.24*** (7.185)	
MN	-0.835 (4.937)	
MO	6.446 (4.706)	
ND	1.532 (4.172)	
NE	-2.769 (4.440)	
NH	47.55* (18.91)	
NM	-1.462 (5.084)	5.673 (18.72)
NV		-31.87* (14.45)
OH	30.26*** (7.116)	
OK	-8.831	

	(4.653)		
PA	31.58*** (4.994)		
SD	4.023 (6.173)		
TN	33.47*** (4.643)		
TX	12.43* (6.117)		
UT	38.80*** (3.947)		-44.01*** (12.75)
VA	33.72*** (7.442)		
VT	71.69*** (6.297)		
WA	24.48*** (6.710)		
WI	14.93*** (4.402)		
WV	23.58*** (7.097)		
WY	10.72 (6.257)		
RPS step	-33.22 (19.85)	70.67* (33.17)	
Capacity Retirements (5-year average)	-0.00822* (0.00370)	-0.0203*** (0.00294)	
CO^2 price	-1.226 (0.778)		
Hardware costs	0.0420*** (0.00366)		
Annual average solar PPA price	0.0355** (0.0108)		
Annual average wind PPA price		1.154*** (0.220)	0.492** (0.169)
ln(technology costs)		57.57*** (7.587)	
Storage mandate		-0.198*** (0.0349)	
Storage mandate^2		0.000162*** (0.0000276)	
Constant	-23.55*** (6.558)	-340.6*** (47.53)	76.32*** (14.29)
Observations	388	267	46
R^2	0.777	0.712	0.411

Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 10.8. Retirement regressions.

	(1) Wind	(2) Solar	(3) Geothermal	(4) Hydroelectric
Retirements (5 year average)	-0.00822** (0.00291)	-0.0203*** (0.00294)	-0.00369 (0.00190)	
Annual Retirements				-0.0069** (0.003)
AL	0 (.)			
AR	6.289 (11.52)			
AZ	43.23*** (10.53)		0 (.)	
CA	63.15*** (9.977)		-24.05* (10.15)	
CO	2.123 (9.862)			
CT	31.35* (12.60)			
DE	46.17*** (11.86)			
IA	-8.263 (11.38)			
ID	17.98 (10.55)		-40.67* (15.61)	
IL	9.692 (11.68)			
IN	13.61 (9.522)			
KS	-8.497 (9.908)			
MA	65.70*** (11.92)			
MD	39.89*** (11.28)			
ME	27.52 (15.36)			
MI	37.24*** (9.596)			
MN	-0.835 (9.927)			
MO	6.446 (9.543)			
ND	1.532 (9.465)			
NE	-2.769 (9.494)			

NH	47.55*** (12.13)			
NM	-1.462 (10.43)		14.29 (12.29)	
NV			-30.82** (8.821)	
OH	30.26** (10.29)			
OK	-8.831 (9.663)			
PA	31.58** (11.62)			
SD	4.023 (12.62)			
TN	33.47** (10.46)			
TX	12.43 (10.02)			
UT	38.80** (13.82)		-39.23* (15.41)	
VA	33.72** (11.15)			
VT	71.69*** (13.25)			
WA	24.48* (10.53)			
WI	14.93 (9.910)			
WV	23.58* (11.11)			
WY	10.72 (10.98)			
RPS step	-33.22 (21.94)	70.67* (33.17)		
Renewable penetration	50.65** (18.86)	-52.68* (26.12)		
CO^2 price	-1.226* (0.507)			
Hardware costs	0.0420*** (0.00422)			
Annual average solar PPA price	0.0355*** (0.0104)			-0.163*** (0.0437)
Annual average wind PPA price		1.154*** (0.220)	0.583** (0.185)	0.867*** (0.136)
ln(hardware costs)		57.57*** (7.587)		
Storage mandate		-0.198*** (0.0349)	0.0169* (0.00703)	
Storage mandate^2		0.000162***		

		(0.0000276)		
Constant	-23.55* (10.38)	-340.6*** (47.53)	73.49*** (11.73)	57.88*** (6.28)
Observations	388	267	45	246
R^2	0.777	0.712	0.505	0.194

Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Table 10.9. RPS regressions.

	(1) Wind	(2) Solar	(3) Geothermal
RPS outstanding	-45.18*** (12.65)	59.63** (22.07)	22.22 (54.39)
AL	0 (.)		
AR	6.419 (6.039)		
AZ	42.30*** (6.342)		
CA	64.93*** (6.133)		
CO	2.771 (5.114)		
CT	29.13*** (7.056)		
DE	43.22*** (7.028)		
IA	-8.111 (6.082)		
ID	16.77** (6.216)		
IL	10.20 (8.295)		
IN	13.89* (5.697)		
KS	-8.646 (5.214)		
MA	60.63*** (10.07)		
MD	36.99*** (7.275)		
ME	24.04*** (6.578)		
MI	37.63*** (7.184)		
MN	-0.281		

	(5.112)	
MO	5.827 (5.230)	
ND	0.450 (4.748)	
NE	-3.762 (5.003)	
NH	42.67* (18.23)	
NM	-0.758 (5.331)	
NV		
OH	30.93*** (7.090)	
OK	-8.975 (5.120)	
PA	32.23*** (5.939)	
SD	3.144 (6.550)	
TN	32.80*** (5.184)	
TX	18.27** (6.094)	
UT	37.22*** (4.560)	
VA	32.74*** (7.813)	
VT	70.45*** (7.073)	
WA	24.50*** (6.890)	
WI	14.92** (4.841)	
WV	22.96** (7.479)	
WY	9.975 (6.593)	
Retirements (5 year average)	-0.0128*** (0.00293)	-0.0204*** (0.00293)
Hardware costs	0.0407*** (0.00328)	
Annual average solar PPA price	0.0365*** (0.0107)	
Annual average wind PPA price		1.169*** (0.216)
ln(hardware costs)		57.05*** (7.365)
Storage mandate		-0.195***

		(0.0340)	
Storage mandate^2		0.000161*** (0.0000270)	
Constant	-20.28** (6.425)	-336.3*** (45.67)	85.48*** (2.521)
Observations	388	267	46
R^2	0.773	0.711	0.0041

Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

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