A Preliminary Techno-Economic Model of Superhot Rock Energy

Prepared for **Clean Air Task Force**
by **LucidCatalyst and Hotrock Research Organization**

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CLEAN AIR TASK FORCE

About

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LucidCatalyst is a highly specialized international consultancy offering thought leadership, strategy development, and techno-economic expertise. LucidCatalyst specializes in interventions that deliver the critical strategic changes necessary to bring about deep and rapid cuts to carbon emissions worldwide while expanding affordable energy access. As a mission-driven for-profit enterprise, LucidCatalyst prioritizes partnership with clients whose needs are aligned with our broader goals on climate and energy access.

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SECTION 1

Introduction

This revised technical report provides the analytical basis for the levelized cost of electricity (LCOE) estimates described in the November 2022, Clean Air Task Force (CATF) report entitled, *Superhot Rock Energy: A Vision for Firm, Global Zero-Carbon Energy*. This report illustrates that, with engineering innovations in deep drilling, reservoir creation, well construction and downhole tools, superhot rock energy could achieve competitive costs at scale – potentially as low as $20-35 per megawatt-hour (MWh). This would make superhot rock energy competitive in nearly every global electricity market. Combined with its zero emissions profile and ability to tap energy dense heat nearly everywhere means the superhot rock energy could be truly transformative.

The purpose of this technical whitepaper is to provide a detailed description of the superhot rock techno-economic cost model and present the underlying assumptions for estimating constructing and operating costs for a superhot rock project. This cost projection was calculated using a techno-economic cost model developed by the Hot Rock Energy Research Organization (HERO) and LucidCatalyst. It also includes the assumptions and methodology for calculating LCOE, the net present cost of electricity generation over the lifetime of the plant. This report presents the underlying model and provides an update to an earlier 2021 analysis and includes a sensitivity analysis that reflects the change in LCOE based on different input parameters.

Detail is provided such that the reader can easily follow the model structure and effectively recreate the calculations published in CATF's report. Assumptions are transparent so they can be used as reference or interrogated and substituted for others that readers may feel are more suitable.

It is important to note that although supercritical systems have been drilled, superhot rock heat reservoirs have yet to be developed nor have power plants been constructed. Plant costs therefore reflect the best available cost data on constituent systems, components, drilling, and well field development expected to be required. Also, as highlighted in CATF's report, new tools and technologies will be needed to commercialize and scale superhot rock technology. Currently, these advancements are at various stages of development and address critical elements to project development (e.g., geothermal reservoir creation, well metallurgy and cements, downhole power supply and monitoring, and surface power conversion). Even though these innovations are still in development, the model assumes that they are commercially available. Importantly, the cost model does not estimate costs for the First-of-a-kind (FOAK) superhot rock plant (or even the first few plants). Instead, it estimates costs for an "Nth-of-a-kind" (NOAK) plant. Consequently, by definition, these technologies in development are assumed to be available. Estimating costs for a NOAK plant was an intentional decision as such costs are more useful in determining the cost horizon for a particular technology class. It allows for a more meaningful comparison to other incumbent technologies that have known NOAK costs.

This white paper consists of two sections. The first section offers a structural overview of the superhot rock cost model and presents various material input assumptions. The second provides input the assumptions for calculating LCOE and a brief commentary on the value and limitations of LCOE analysis. The reader should note that a separate, companion white paper is forthcoming that estimates the cost of producing hydrogen and ammonia production, two critically important zero-carbon fuels/energy carriers, using the heat and electricity from a superhot rock plant.

What is a NOAK Superhot Rock Energy Plant?

An Nth-of-a-kind power plant reflects the lessons learned in construction and operations from the first commercial plant (as well as the second, third, fourth, etc.) to a point where all potential cost savings/efficiencies are integrated into the project delivery process. A first-of-a-kind plant includes the cost of the initial detailed plant engineering, regulatory interaction, and typically has higher equipment and materials costs and lower labor productivity. Eventually, when the same plant is built by the same vendors and contractors for the same price, that is reflective of a NOAK cost. There is no universally recognized number of plants that need to be built before achieving NOAK costs; however, some literature define NOAK cost as those "achieved for the next plant after 8 gigawatts (GWe) [of deployment]."[1] Others have defined it as "after the technology has been deployed 10 times."[2] For the purposes of the superhot rock model, defining the quantity or capacity to achieve a NOAK plant is less important as understanding that all model costs are derived from peer-reviewed studies that reference NOAK plants.

1 Boldon, Lauren M., & Sabharwall, Piyush. Small modular reactor: First-of-a-Kind (FOAK) and Nth-of-a-Kind (NOAK) Economic Analysis. United States. https://doi.org/10.2172/1167545

2 Idaho National Laboratory. Nuclear-Integrated Ammonia Production Analysis. Technical Evaluation Study. Project No. 23843. United States.

SECTION 2

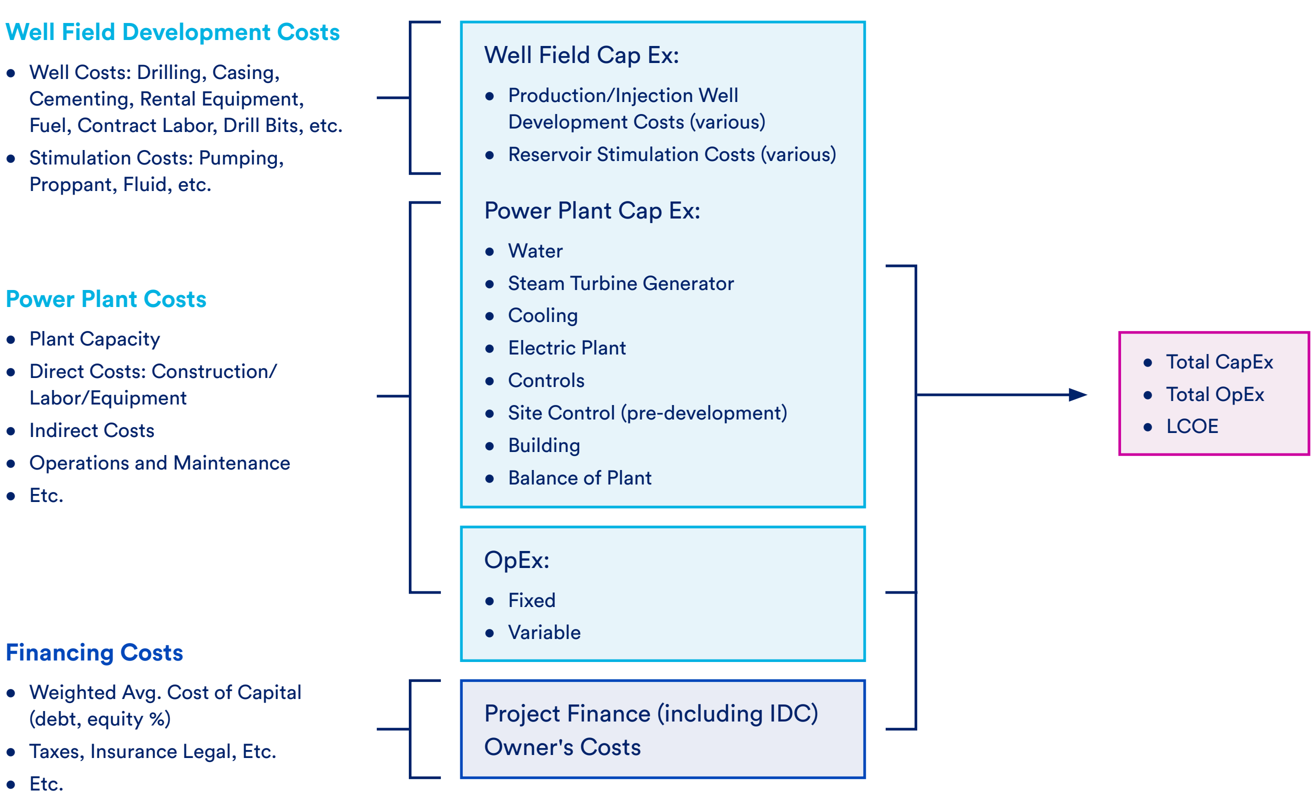
Overview of the Superhot Rock Cost Model

The superhot rock cost model organizes costs into three categories, as shown in Figure 1. These include:

1. **Geothermal Drilling & Reservoir Costs:** all costs related to drilling, casing, and reservoir stimulation.
2. **Power Plant Costs:** all costs for systems, components, and structures on the "power island" used to generate electricity. Specifically, this consists of all costs related to water, steam turbines, cooling infrastructure, power conversion equipment, controls, and the physical site (including all buildings).
3. **Project Financing Costs:** reflects the cost of capital (a mix of equity and debt) to finance the costs from the start of construction through plant commissioning.

Figure 1: Superhot Rock Model Architecture and Input Categories

There are three categories of input costs: 1) Well Field Development, 2) Power Plant, and 3) Weighted Average Cost of Capital (WACC). Each are described on the next page.



2.1 Input Assumptions

The quantity and scope of peer-reviewed, cost literature is relatively limited. Lowry et al. (2017)[3] provided the best available summary of geothermal well cost data and serves as the basis for all well field costs in the SHR technoeconomic model. Lukawski et al.[4,5] provides a superior cost breakdown and yields very similar well cost results, so it is used for reference purposes in this report to show well costs at a more granular level. Geothermal reservoir stimulation costs, which largely consists of pumping, proppant, and fluid ("mud") costs, are not sourced from the geothermal industry, but taken from the best practices in the oil and gas sector.[6] With these qualifications in mind, the geothermal drilling and reservoir development costs reflect the best available data. More data would provide more precision in the results. Fortunately, power plant costs are highly detailed and resolved. For these costs, the superhot rock model pulls from a blend of geothermal and natural gas plants from NTEL (2019). Natural gas plants were included as superhot rock plants are envisioned to be sized and operate more like natural gas plants than conventional geothermal plants.

1) Well Field Development Costs

Well field development costs, which includes activities like drilling, casing, and cementing, etc. are sourced from the 2017 Geothermal Vision Study (Lowry et al.) published by the Geothermal Technologies Office within the U.S. Department of Energy. Reservoir stimulation costs come from the EIA's 2016 Trends in U.S. Oil and Natural Gas Upstream Costs.[7] Several well field assumptions are held constant and listed in Appendices A and B. Table 1 presents the cost breakdown ($/kWe) the primary well field cost categories for a 250 MWe superhot rock plant. As shown a majority are related to drilling activities while almost 20% are slated for reservoir stimulation.

Lowry et al. (2017) publishes a well cost curve based on depth for small and large diameter bore holes, as well as vertical and directional drilling. The cost curves were developed in the proprietary Well Cost Simplified (WCS) model developed at Sandia National Laboratories. While WCS is not publicly available, the cost curve formulas can be found within the code of the GEOPHIRES model.[8,9] These curves estimate well development costs by depth and are employed in the SHR techno-economic model. As mentioned above, the costs in Lowry et al (2017) rely on costs published in Lukawski's 2014 and 2016 publications, which offer very similar cost results. Because Lukawski provides a more granular cost breakdown, for reference purposes, this breakdown is highlighted in Figure 2. As shown, completion costs for geothermal wells, cementing and casing, appear to be roughly equivalent to drilling costs. In the case of superhot rock, completion costs may be higher than drilling costs. This is because new types of cement and casing alloys may be needed to complete these wells at higher temperatures and pressures. However, is it not yet clear whether more advanced cements and steel alloys will be needed. Recent advancements demonstrated in FORGE demonstrate that these wells will be able to use polycrystalline diamond compact (PDC) bits for hard rock, significantly increasing drilling rates, yet further innovations are being tested and proven in the field such as hybrid particle drilling with PDC bits. Therefore, there are both upward and downward pressures on future costs, and this model has elected to not consider either of these factors – at least for the time being.

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3 Lowry, Thomas Stephen, Finger, John T., Carrigan, Charles R., Foris, Adam, Kennedy, Mack B., Corbet, Thomas F., Doughty, Christine A., Pye, Steven, & Sonnenthal, Eric L. GeoVision Analysis: Reservoir Maintenance and Development Task Force Report (GeoVision Analysis Supporting Task Force Report: Reservoir Maintenance and Development). United States. https://doi.org/10.2172/1394062

4 Lukawski, M. Z., Anderson, B. J., Augustine, C., Capuano Jr., L. E., Beckers, K. F., Livesay, B., & Tester, J. W. Cost Analysis of Oil, Gas, and Geothermal Well Drilling. United States. https://doi.org/10.1016/j.petrol.2014.03.012

5 Lukawski, Maciej Z., Silverman, Rachel L., & Tester, Jefferson W. Uncertainty analysis of geothermal well drilling and completion costs. United Kingdom. https://doi.org/10.1016/j.geothermics.2016.06.017

6 U.S. Energy Information Administration (2016). Trends in U.S. Oil and Natural Gas Upstream Costs. Independent Statistics & Analysis. https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

7 Beckers, K.F., McCabe, K. GEOPHIRES v2.0: updated geothermal techno-economic simulation tool. Geotherm Energy 7, 5 (2019). https://doi.org/10.1186/s40517-019-0119-6

8 The cost curves in Figure 6 of Lowry et al. (2017) are available in phyton code (lines 1981-1988) from the GEOPHIRES model, which is accessible at: https://github.com/NREL/GEOPHIRES-v2

9 U.S. Energy Information Administration (2016). Trends in U.S. Oil and Natural Gas Upstream Costs. Independent Statistics & Analysis. https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

The well cost of $22.8M in Table 1 reflects the cost of the first well. The model includes a logarithmic cost reduction curve such that the 10th well is 75% the cost of the first well. This cost reduction is applied to all wells beyond the 10th well; however, the incremental cost reduction between each subsequent well is minimal. This cost reduction curve assumption is consistent with the cost reductions found in the Lukawski (2016) dataset, and is spread out over more wells than the 5 wells needed to reach that same cost reduction in a 2006 Idaho National Laboratory report on Enhanced Geothermal Systems.[10] In the table, this learning curve is reflected as "learning curve elasticity." Drilling and reservoir development costs are determined by the depth required to reach the target temperature and the number of wells needed to reach the required plant capacity.

The model uses the drilling cost correlation from Lowry et al. for a vertical, open hole with a large diameter well bore.

The cost curve formula is the following:

$$y = 0.2818x^2 + 1275.5213x + 632{,}315$$

Equation 1. Cost curve for vertical geothermal well as a function of measured Depth. Y is cost of the well and X is measured depth. Equation was sourced from code in GEOPHIRES model, which reflects cost curves in Lowry et al. (2017).

As stated, this cost curve was originally derived from the Well Cost Simplified model developed by Sandia National Laboratories. The figures in Lowry et al. present costs to 7,000m. Using the equation above, the SHR techno-economic model goes to 10,000m.

For further background on determining the power production potential for individual wells, please see Appendix A.

Table 1: Breakdown of Well Field Costs

Wells	Estimated Cost	% Cost of Well	Source
Well Cost*	**$19,152,708**	**84%**	**Well costs estimates sourced from Lowry et al. (2017)**
Stimulation**	**$3,650,000**	**16%**	EIA 2016
Pumping	$1,650,000	7%	
Proppant	$1,000,000	4%	
Fluid	$1,000,000	4%	
Total Well Cost	**$22,802,708**	**100%**	
Cost for All Wells	$206,443,622		
Learning Curve Elasticity***	-0.124938737		
Piping + Valves	$57,504,807		

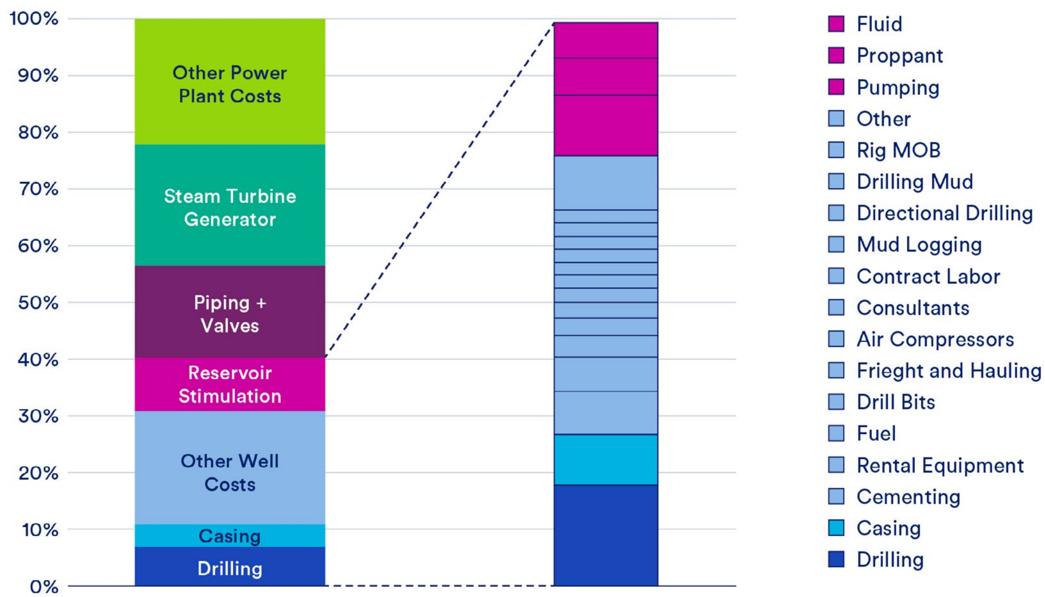
** Drilling costs are sourced from Lowry et al 2017 ("GeoVision Analysis: Reservoir Maintenance and Development Task Force Report"). Specifically, they are taken from the curve fit correlations for the well costs, which were obtained from the phyton code (lines 1981-1988) from the GEOPHIRES model, accessible at: https://github.com/NREL/GEOPHIRES-v2. Drilling costs are correlated to depth. This figure assumes a 6km well at 400°C.*

*** Stimulation costs are assigned by the user. $3.65M is the average cost for a stimulated oil and gas well in the Eagle Ford according to the EIA (EIA, 2016). It should be noted that because no superhot rock plant has been built, there is inherent uncertainty surrounding reservoir stimulation costs. Stimulation costs may be higher than anticipated given the use of FOAK tools in the first few wells. However, like, drilling, it is highly likely that these will come down over time (as the technology scales) and warrant their own cost reduction curve.*

**** Learning curve elasticity defines the logarithmic slope of the learning curve, which reduces well costs 25% from the 1st to the 10th well, and then continues to reduce costs for each subsequent well by a relatively de-minimis amount.*

10 MIT (2006). The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century. https://www1.eere.energy.gov/geothermal/pdfs/future_geo_energy.pdf (Figure 9.13)

Figure 2: Estimated Cost Breakdown of a Superhot Rock Plant (by percentage)



2) Power Plant

At the surface, superhot rock plants are largely made up of systems that are common to most thermal power plants. These include steam turbines to generate electricity, a system to cool steam, controls to adjust plant operations, power electronics to make the power useable and reliably dispatched onto the grid, transmission infrastructure, and buildings in which all of these systems are housed. For these reasons, superhot rock construction costs reference data from both geothermal *and* applicable costs from thermal plants.

Instead of averaging the costs for several thermal plants, a cost curve was built based on seven projects, shown in Table 2. These include three combined-cycle natural gas plants and two coal plants from NETL,[11] and two geothermal plants (Mannvitt and an undisclosed plant).

Typically, large plants enjoy economies of scale and can spread capital costs across more MWh over the plant's operating life (leading to lower costs per unit power). Correspondingly, plants with smaller power ratings have higher relative costs per unit power (typically expressed as dollars per kilowatt or "$/kW").

The superhot rock model references the best-fit cost curve highlighted in Figure 3 to estimate the cost for a superhot rock plant in terms of its power rating.

The corresponding regression equation (Equation 2) is below:

$$\text{Power Plant Cost} = \frac{1}{.000153 * MW^{.3334}}$$

Equation 2. Regression fit of power plant cost data provided by NETL, Mannvit and an undisclosed source. Equation used to estimate cost of a power plant as a function of Capacity. MW in Equation 2 means MW capacity.

[11] NETL (2019). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. https://www.netl.doe.gov/energy-analysis/details?id=3745

Table 2: Plants Informing Power Capacity Cost Curve

Plant	Steam Turbine Rating	$/kW	Source
NETL NGCC Plant 1	301	884	NETL (2019)
NETL NGCC Plant 2	213	1,105	NETL (2019)
NETL NGCC Plant 3	299	850	NETL (2019)
NETL Coal Plant 1	687	824	NETL (2019)
NETL Coal Plant 2	770	727	NETL (2019)
Geothermal Plant 1	90	1,578	Mannvitt
Geothermal Plant 2	25	2,200	Confidential (HERO)

Figure 3: Power Plant Cost Model

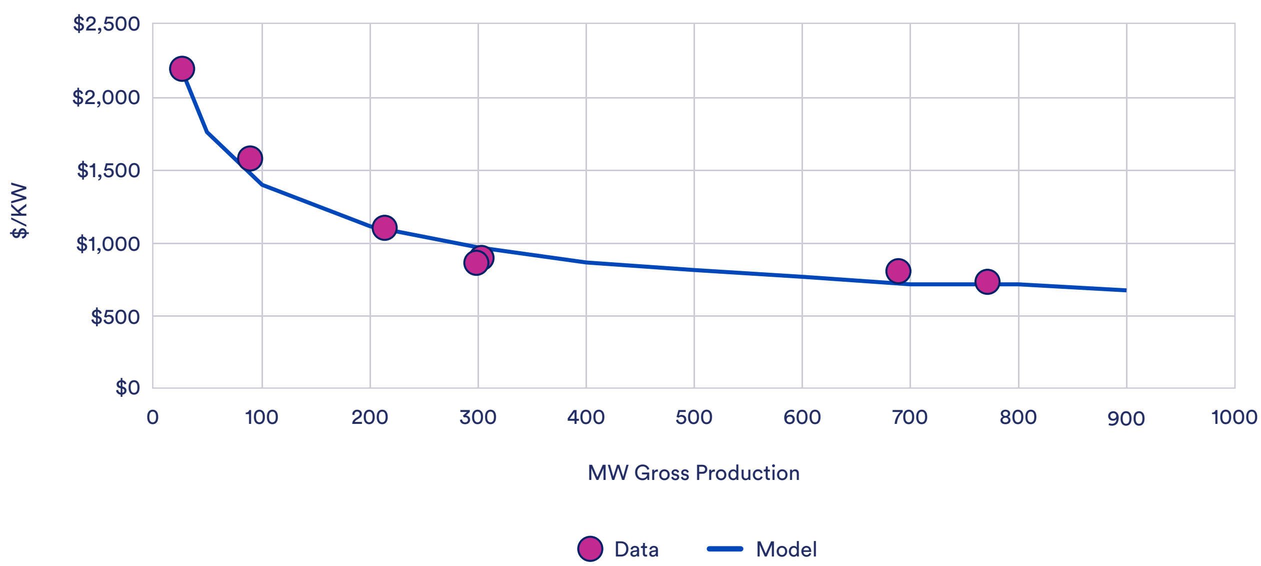


Figure 4 presents a cost breakdown of the major systems following the same best-fit curve methodology. As shown, the Steam Turbine Generator (STG) is the plant component most sensitive to the size of an individual plant, which ultimately translates to a reduction in $/kW. Most STGs are designed for thermal plants (coal and natural gas), which have generally higher capacities (i.e., between 200-600 MW). Smaller STGs can often require custom design and engineering and are consequently more expensive (on a per MW basis).

Superhot rock steam temperatures are assumed to be relatively constant at 400°C, and free of entrained gases.[12] Achieving these temperatures mean that well depths may vary depending on region. With consistent steam temperatures, superhot rock projects are anticipated to be built more like relatively standardized natural gas plants as opposed to bespoke conventional geothermal plants.

Figure 4: Power Plant Cost Model by System

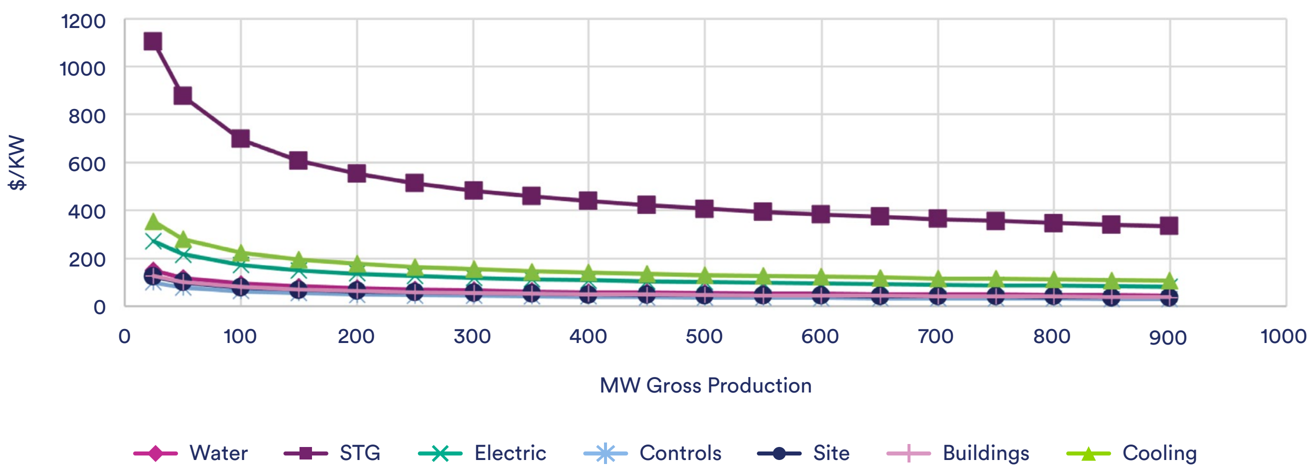
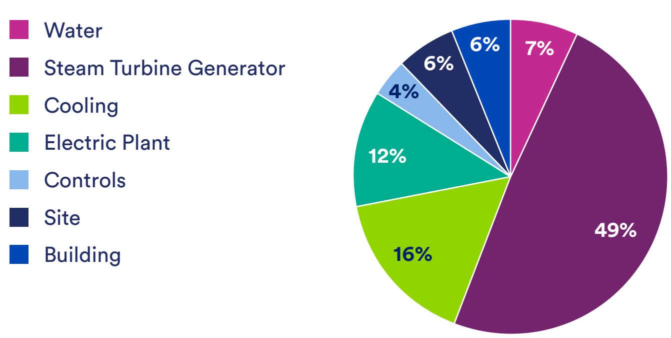


Figure 5: Relative Cost of Each Major Power Plant System (Est.)



[12] Acidic gases can become entrained in steam in hydrothermal/magmatic settings. For example, the Iceland Deep Drilling Project (IDDP) I well at Krafla experienced casing failure as a result of hydrochloric acid entrained in the production steam. When vapor condensed, extremely acidic water droplets corroded the steel casing. In contrast, with the exception of projects on the margins of existing hydrothermal fields, superhot rock will be drilled in dry, generally impermeable rock will not encounter acid gases, reducing risk of corrosion.

Currently, geothermal plants are designed specifically for a particular resource, which typically governs the power rating of a plant. Superhot rock wells produce high-pressure flow and higher-enthalpy (heat carrying) fluids, such as superheated steam and considering that a superhot rock reservoir can be engineered (which is the promise of engineered geothermal systems more broadly) this enables geothermal projects[13] with significantly larger power ratings. Further, it allows for a modular design and construction approach, which can enable significant cost savings in engineering and plant delivery.

Weighted Average Cost of Capital (WACC)

Plant owners will typically finance projects through a mix of higher-risk, higher return equity investment, and lower-risk, lower return bank loan(s) (often called "debt"). Each investor can demand different rates of return depending on their risk appetite. The collective cost of borrowing from all sources represents the weighted average cost of capital or "WACC."

Because the cost model assumes a NOAK plant, the ratio between equity and debt is 30% to 70%, which is relatively typical for investments perceived to be stable (a higher equity ratio would reflect higher perceived risk). Table 3 highlights the model's default WACC assumptions.

As shown in Table 3, the model assumes two tiers of equity – an initial, higher risk (higher reward) tranche with a 25% return, and second lower-risk (lower return) tranche of 14%. Collectively, the return on equity investment is 16%. The debt return is 6%. Assuming a corporate tax rate of 21%, the WACC is 8%, which is not uncommon for a power project that includes well-established technology.

Table 3: Weighted Average Cost of Capital Assumptions

WACC Calculation	
Capital Structure	
Debt to Total Capitalization	70%
Tier 1 Equity to Total Capitalization	5%
Tier 2 Equity to Total Capitalization	25%
Debt / Equity	233%
Cost of Equity	
Tier 1 Equity Risk Premium	25%
Tier 2 Equity Risk Premium	14%
Cost of Equity	16%
Cost of Debt	
Cost of Debt	6%
Tax Rate	21%
After Tax Cost of Debt	4.7%
WACC	**8%**

[13] Traditional geothermal power stations produce about 100 MW or less per turbine. This appears to be caused by limited power density seen in traditional geothermal resources, where the available energy per volume of rock/fluid will not allow for greater power plant sizes. The few geothermal power plants above 100 MW are found in either steam dominated reservoirs or high-pressure dual phase reservoirs. These larger resources can be found in places such as in Indonesia, Iceland, the Philippines and other magmatic provinces.

SECTION 3

Levelized Cost of Electricity

The superhot rock model is a basic input-output model where the primary output is levelized cost of electricity. LCOE is a metric used to compare different electricity generation technologies and ultimately inform investment and planning decisions. It reflects the average cost of building and operating the plant over its lifetime, divided by all the energy it generates (expressed in kWh). Put simply, it is the price at which electricity can be sold that enables an investor to break even over the course of its lifetime.

To calculate LCOE, the model calculates the net present value (NPV) of all fixed capital and variable costs and the MWhs produced across the lifetime of the plant. Dividing the total cost by total MWhs yields the LCOE.

The capital and variable costs vary based on the plant's operating capacity, however, for a hypothetical 250 MW superhot rock plant, the net present cost for the wellfield and power plant are approximately $536.4M and $5.4M for O&M, as highlighted in Table 4.

Additional assumptions to calculate LCOE include the following:

- Discount Rate is 8%.
- Plant capacity factor (i.e., ratio of power produced to the maximum possible power produced over the year) is assumed to be 95%.
- The plant lifetime is 30 years.
- All costs are reflected in 2021 dollars.
- Plant construction is assumed to be 2 years. This is akin to the construction schedule of a new combined cycle natural gas plant, which, again, is assumed to be a more appropriate proxy for a NOAK superhot rock plant (than existing geothermal plants). The allocation of capital expenditures are as follows:
    - Year 1 – 30% of power plant is constructed, 70% of well field is development
    - Year 2 – remaining 70% of power plant is constructed, remaining 30% of well field is developed

It is worth noting that while LCOE is a simple, easily understood, and widely used metric, it does have its shortcomings. It tends to oversimply cost, project risk, and other elements related to the cost of capital. There are also other, more practical critiques like how it ignores resource flexibility, resource reliance and resiliency, and negative externalities like carbon pollution. It is important to note that *the model does not incorporate any kind of beneficial tax treatment (e.g., investment or production tax credits) or the existence of a carbon tax or carbon credit market*.

3.1 LCOE for Different Depths and Superhot Rock Technology Regimes

Drilling depths where temperatures are high enough for superhot rock geothermal vary around the globe. In some regions, reaching >400°C will require drilling to a minimum of 3km in depth while and in later projects, it will require going beyond well 10 km in depth. Cost effectively reaching certain depths is dependent on technology availability. With that in mind, LCOE is presented as a function of both drilling depth and two different technology regimes – described below (and highlighted in Figure 6):

- **Accessible with Today's Drilling & Casing Technology:** This reflects temperatures up to 300°C, which is what that today's geothermal projects typically do not exceed. Most conventional drilling and widely available casing technologies are not designed to go much higher temperatures.
- **Advanced Drilling without Casing Needed:** This assumes that high energy drilling technology (e.g., millimeter wave, plasma drilling) shortens drilling times by reducing trips and the ability to 3-D print casing, or displace casing through vitrification or applying an impermeable coating such as Eavor's experimental Rock Pipe.

It is important to note that irrespective of whether energy drilling technology is commercially available, conventional drilling will always be used to get beyond where water is a factor. This will be site-specific, however, for this model assumes this is around 3 km.

Table 4: Superhot Rock Capital and O&M Expenditures (250 MWe plant)

Cost Assumptions			
Well Field	**Value**		**Unit**
Producer/Injector Ratio		2	
Number of Producers		7	wells
Number of Injectors		4	wells
MW/well*		38.63	MW
Learning Curve (% reduction after 10 wells)		25%	
Initial Well Cost Reduction (Technology)		0%	
Cost of First Well	$22,802,708		
Piping + Valves**	$57,504,807		
Total Cost $/kW	$976		$/kW
Total Well Field Cost $	**$263,948,430**		
Power Plant	**Value**		**Unit**
Capacity Input		250	MW
Capacity Actual***		270.4	MW
Service Water System (all the pumps to move water throughout the plant and back into the injection wells)		67.8	$/KW
Stream Turbine Generator		499.2	$/KW
Cooling System (circulating water pumps, foundations, and auxiliaries; make-up water, piping, etc.)		159.8	$/KW
Power Conversion (switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, all required foundations, and any standby equipment)		123.1	$/KW
Instrumentation and Controls (control equipment for steam turbine, other major components, and signal processing; wiring and tubing, panels and racks, etc.)		44.7	$/KW
Site Preparation, Improvements, and Facilities (offices, labs, roads, etc.)		56.0	$/KW
Building		57.1	$/KW
Total Cost $/kW		1007.7	$/KW
Total Power Plant Cost $	**$272,483,935**		
Total Installed Cost	**Value**		**Unit**
Total Cost $	**$536,432,364**		
Total Cost $/kW	$1,984		
Operations and Maintenance	**Value**		**Unit**
Percentage of Capital Costs****		1.00%	
Annual costs	**$5,364,324**		

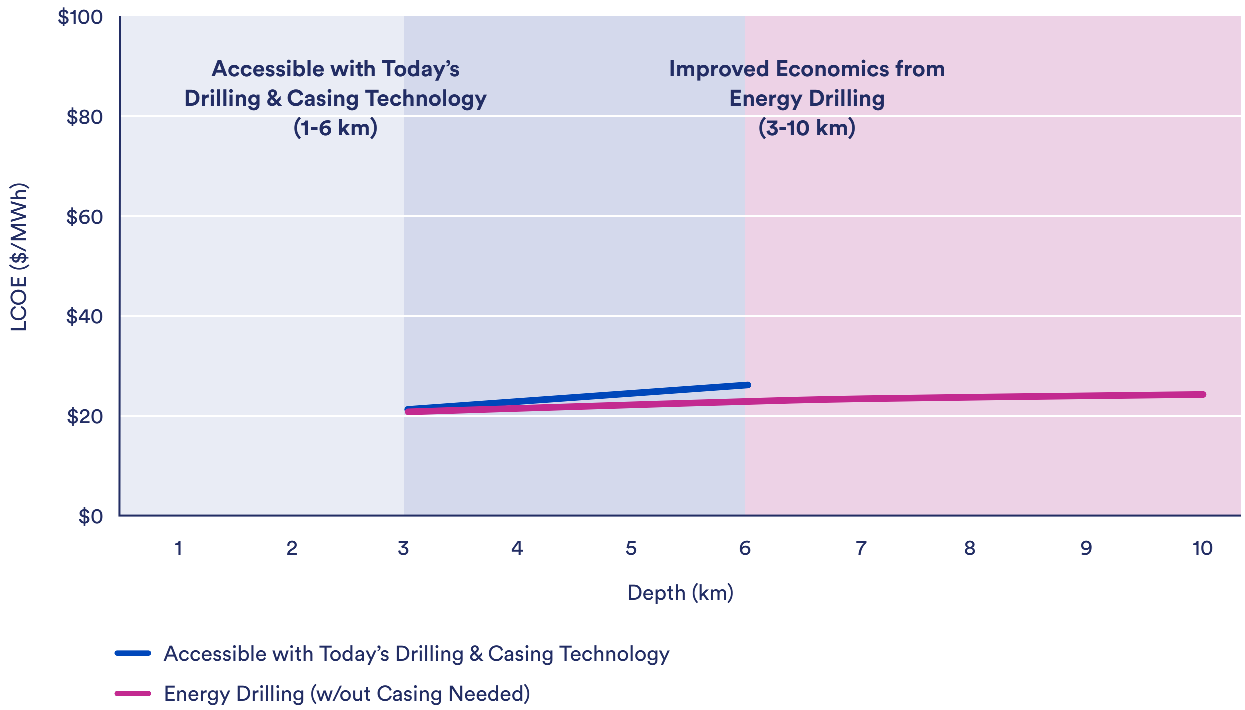
** See Appendix A for methodology on calculating well production.*

*** Piping + Valve costs are a rough approximation based off proprietary data. It scales based on the number of wells, and accounts the valves on the wellhead, the piping into the plant and the separator which knocks out the entrained water from the steam.*

**** The model identifies the minimum number of production wells that are needed to meet the user-defined plant capacity. Most often, the actual production capacity will slightly exceed the user-defined production capacity based on how many MWs are assumed to be produced by each well.*

***** This is a user-defined parameter. A generally accepted percentage is 2.5-3.5% (see: IEA (2010), Geothermal Heat and Power. IEA ESTAP – Technology Brief E07. May 2020), but this reflects significant staffing reductions per MW (due to remote operations reducing redundancies across plants).*

Figure 6: Superhot Rock LCOE by Depth and Technology Regime



Appendix B provides model assumptions for the two technology regimes shown above. This model indicates that a step down in cost will occur once improvements in technology are realized. Without further information, it is difficult to determine if energy drilling will drive the price down further. Also, as the prospective targets for superhot rock energy developments move into deeper and deeper lithologies, the cost is expected to increase linearly.

SECTION 4

Model Sensitivities

The superhot rock model tracks the influence of eight input variables on levelized cost of electricity (the eight variables are shown below). Specifically, the model presents the change in LCOE based on the percent change in one of the eight variables, listed below:

1. **Plant capacity (MW):** maximum rated power output of the plant expressed in MWs.
2. **Decline Rate (%):** rate at which the well productivity declines every year based on heat loss. This is based on the Gringarten analytical model.
3. **Inlet Pressure (MPa):** pressure of the inlet steam entering the steam turbine. This is partially a function of the thermal reservoir temperature.
4. **Depth (km):** depth to the bottom of the production well from the surface.
5. **Flow (kg/s):** describes the rate of heat extraction from the thermal reservoir, one of the most crucial factors in energy production.
6. **Parasitic Load (%):** describes electrical loads such as pumps, fans, controls, and other energy-consuming subsystems of a superhot rock plant that are necessary to operate the facility. Parasitic load losses can be expressed in terms of mass, energy, and exergy flows for various subsystems (e.g., downhole pump, evaporator, turbine, internal heat exchanger, condenser, reinjection pump, etc.).
7. **Learning Curve (%):** an assumption related to the reduction in capital costs after drilling 10 wells.
8. **Operations and Maintenance (O&M) Costs (%):** annual costs as a percentage of total installed capital cost.

Figure 7 highlights the change in LCOE based on the variables above, with several variables are held constant.[14] The most influential variable, by far, driving economics is flow rate, or how much mass flow can be cycled through the superhot rock reservoir (and doing it in such a way that the specific enthalpy is sustainable and decline is manageable). The default flow rate value 55 kg/s reflects a modeled distribution of 28 EGS projects throughout the worldand our belief that this value could be routinely achieved for NOAK projects. It is important to note that flow rate is the least constrained variable in the model and moreover, models to estimate flow have only been recently developed. Several different methods are currently being developed to extract heat from the reservoir, each having its own influence on flow rate. The second most important driver is plant capacity, followed by the learning curve that reduces drilling costs from one well to the next.

The decline rate of reservoir temperature over time was modeled using the Gringarten analytical model. This estimates decline rates assuming a flow of fluid through a homogeneous fractured space between an injection and production wells. Using this model, the average reservoir decline rate over 30 years was estimated at 0.02%. Assumptions for the Gringarten model are listed in Appendix C.

Three additional analyses were run to understand the influence of other variables on LCOE. These included reductions in drilling cost, the change in LCOE from different production well output assumptions (MW), and change in LCOE as OpEx (expressed as a percentage of CapEx) is increased. Each are presented in Figure 8. It should be noted that the reductions in drilling cost figure references drilling costs as a percentage of overall well costs from Lowry et al. (Table 3).[15]

Interestingly, despite the concentration of R&D resourced dedicated to high energy drilling and reducing drilling costs overall, because drilling costs are such a relatively small percentage of overall costs (as highlighted in Figure 2), dramatic reductions in drilling cost do not significantly reduce CapEx or LCOE. The affects that high energy drilling may have on the LCOE could increase beyond these predictions if they precipitate significant reductions in casing and completions.

14 This sensitivity analysis is based on the following, user-defined inputs: Plant capacity: 250 MW; Production well decline rate: 0.2%; Inlet pressure 8 Mpa; Depth to well bottom: 6km; Flow rate: 55 Kg/s; Parasitic load: 4%; WACC: 8%; Learning curve (cost reduction from 1st to 10th well and beyond): 25%; O&M costs (as a % of CapEx): 1%.

15 Table 3 from Lowry et al. (2017) references a 5km well and drilling costs are assumed to include drilling time (6.6%), bits (5.22%), and BHA (2.61%) for a total of 14.43%.

One of the biggest drivers of LCOE is how many MWs can be produced through each production well. MW output is a function of flow rate (flow of heat to the surface in the production well) and conversion efficiency of heat to electricity. Figure 9 highlights the reduction in LCOE as MWs per well increases (showing the default MW/well value in the model as well as the highest estimated/observed energy output – from the Iceland Deep Drilling Project's Krafla well).

Figure 7: Superhot Rock Sensitivity Analysis

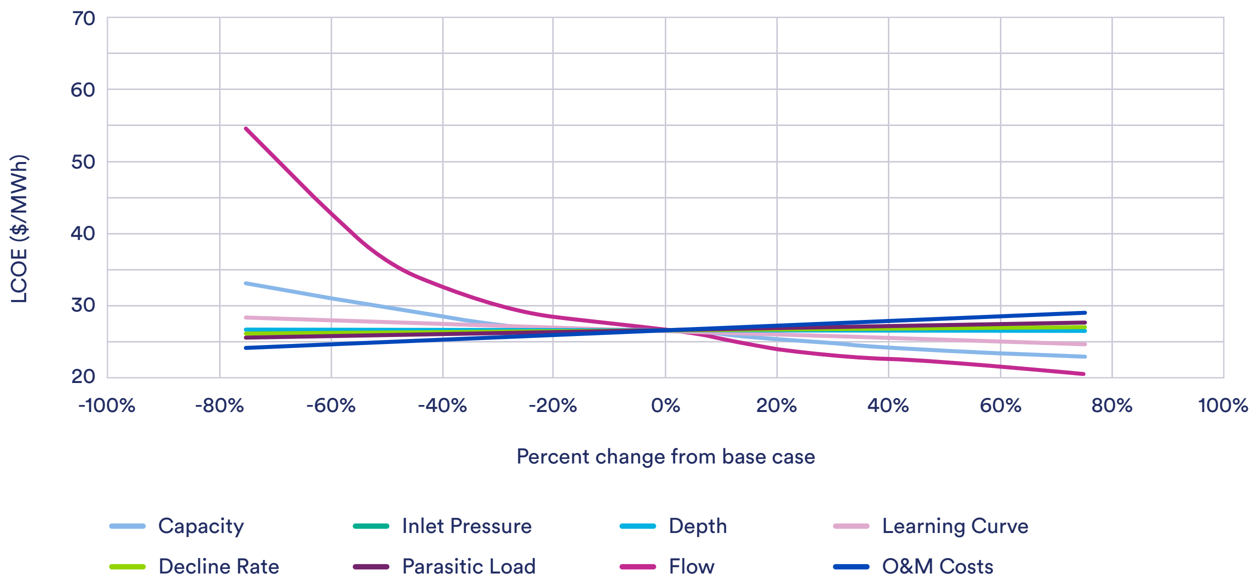


Figure 8: Changes to CapEx and LCOE by Reducing Drilling Costs

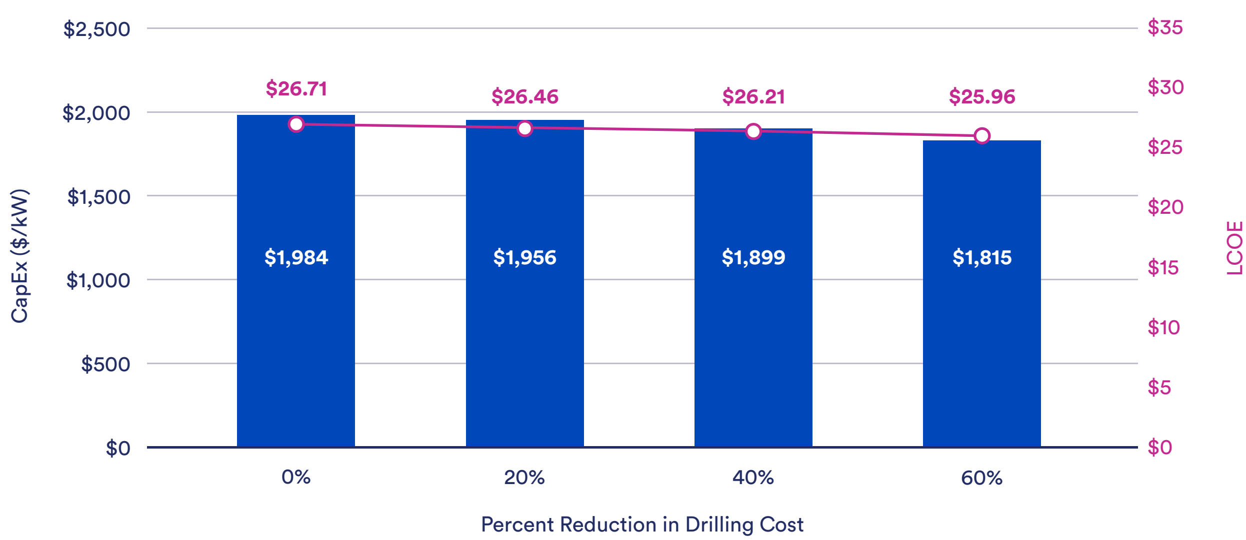
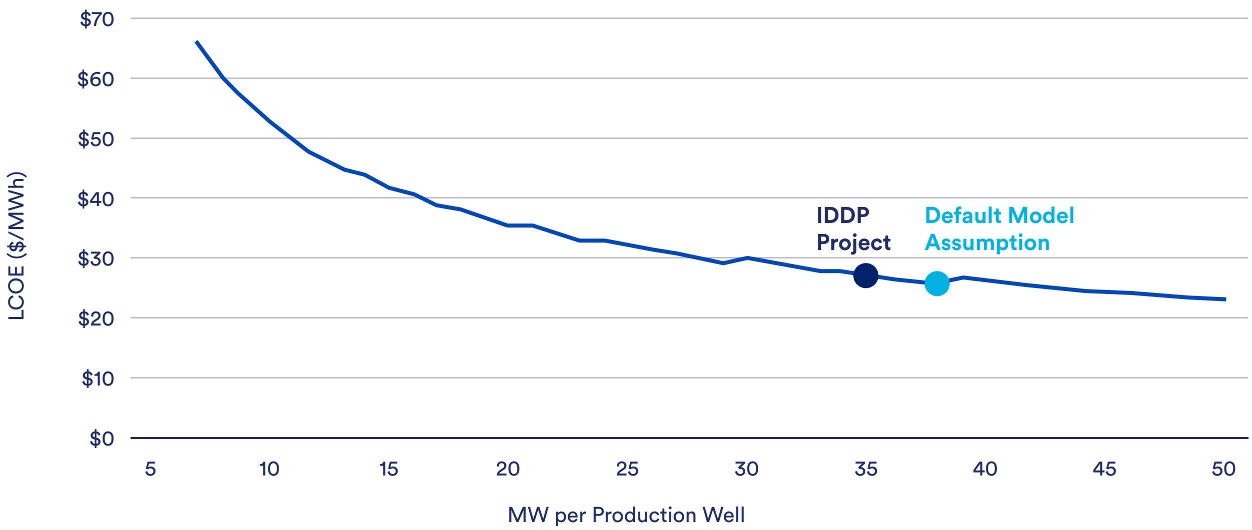
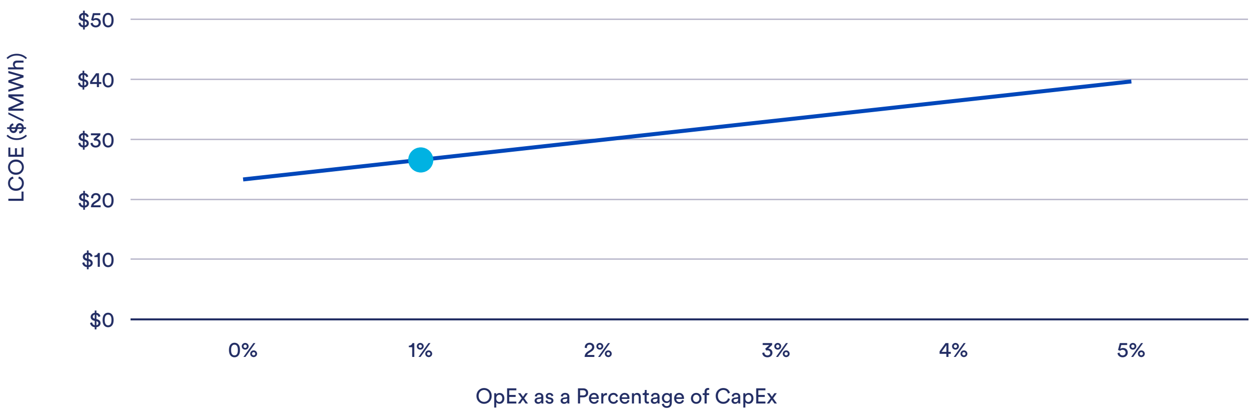


Figure 9: LCOE Sensitivity to MW/Production Well





Similar to the cost of drilling, another interesting finding is the relative lack of significance on LCOE from the displacing of casing with hypothetical borehole vitrification from high energy drilling. Using casing beyond certain depths may increase project risk (not captured in the model), which may translate to cost; however, because the relatively influence of casing cost on LCOE is minor, the cost reduction potential of high energy drilling – as it relates to eliminating the use of casing – is relatively limited.

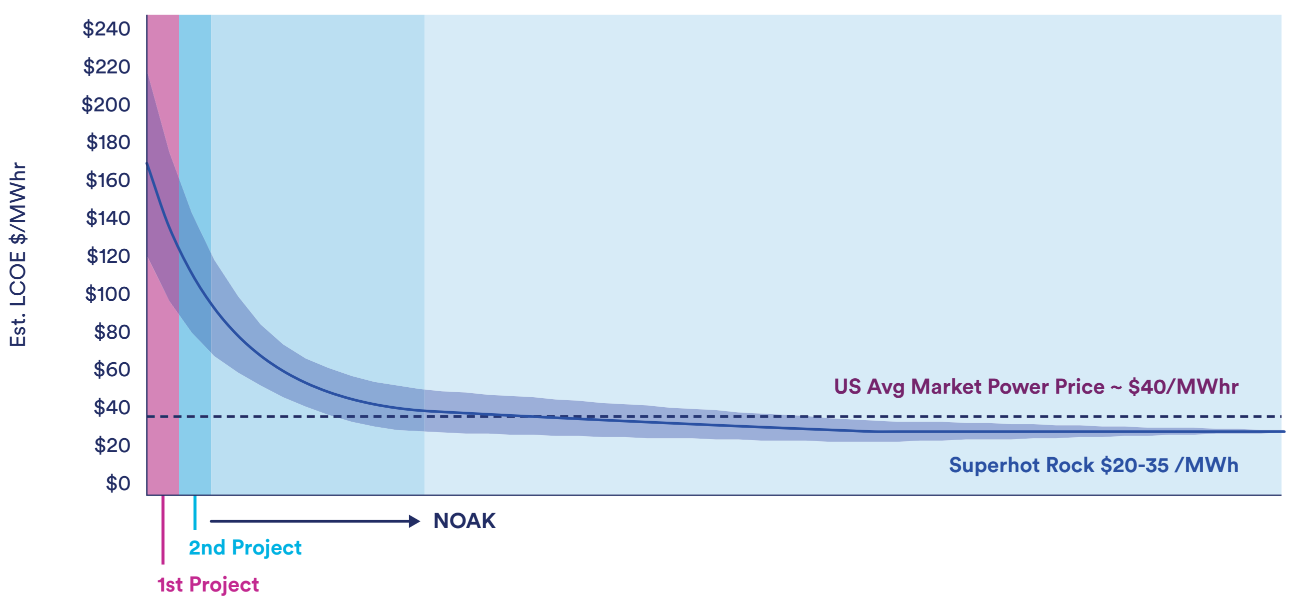
Also note that every energy technology (e.g., solar PV, battery storage, onshore wind, offshore wind, etc.) has its own cost curve. The first plant is nearly always the most expensive, followed by the 2nd and so on. A NOAK model is much more useful when it comes to identifying a technology's scaling potential and future value to the grid. It matters less what the first five plants cost than plants #20-100.

SECTION 5

Conclusions and Considerations

The superhot rock model represents a preliminary attempt to assess the possible competitiveness of superhot rock energy assuming the technical innovations currently in development will be commercially available. The model reveals that, for a NOAK plant, LCOE is predicted at $20-35 per megawatt-hour (as highlighted in an illustrative cost curve in Figure 10 below). This suggests that superhot rock plants could be globally cost competitive with other zero-carbon, dispatchable generation technologies. While we are optimistic about the pace of necessary innovation the timing of these is currently unpredictable, necessarily dependent on the investment in and ability to learn and innovate from drilling many wells.

Figure 10



The results of the analysis suggest successful superhot rock energy has the potential to play an important role in decarbonizing the electricity sector, with the energy density and other qualities needed to pivot from fossil fuels. It is important, however, to be clear about the model is limited by the assumptions and high degree of uncertainty given the low readiness levels (TRL) levels of the component technologies. The major innovations necessary for superhot rock plants to be successfully commercialized – implicit in this exercise – must function routinely in high temperature, high pressure conditions and include:

- Casing and cementing[16]
- Downhole power
- Well logging and coring tools
- Directional drilling tools
- Advanced ultra-deep drilling methods such as energy drilling that minimize drilling downtime
- Thermal reservoir creation
- Management of "felt" or damaging induced seismicity

Such breakthroughs are fundamental to the costs assumed in the model and implicit in a NOAK plant. Further, the assumptions of reservoir temperature, the chemical composition of fluids coming from production wells, or how the reservoir will perform (in terms of heat retention and flow rate, etc.) will require site-specific analysis. Default values for reservoir performance (reflected by variables like flow rate, temperature, and pressure of the production steam) are roughly based on the conditions seen at the Iceland Deep Drilling Project. Moreover, data taken in or near hydrothermal systems (e.g. IDDP) may represent a best case given typical natural permeabilities. Therefore, readers should be mindful that the defaults values represented in the model reflect one of many possible scenarios and that each individual site will be unique.

While the superhot rock model estimates costs based on a set of user-defined inputs, in reality, the marginal cost of a superhot rock plant will likely be driven by two additional factors not included in the model: 1) the number of superhot rock plants in a given region, where developers can leverage the plant design, construction experience of previous projects, and understanding of the subsurface geology and thermal reservoir; and 2) the transfer of learnings in project delivery between regions.

16 Conventional cement is problematic above 275°C (or thereabouts). Temperatures beyond 275°C require formulations other than Portland cement. Phosphate based cement is currently stable to 350°C and past 350°C, but would require modified well completion methods (e.g. packers and expandable couplings).

SECTION 6

Recommendations

To improve the superhot rock cost model going forward there are three variables not currently linked to the estimated LCOE: 1) heat extraction possible from the reservoir rock, 2) years of production, and 3) total available thermal power.[17] These are difficult to estimate without knowing what the reservoir is capable of producing (and consequently how to best orient the injection and production wells). These values should ultimately be tied to LCOE and will be predicated on well and stimulation design – as well as the numerous design decisions that affect how much energy can be pulled from the subsurface (e.g., how many fractures should be created within a given volume of rock, whether to tube insulation or not, whether wellhead pressure should be added, etc.). The model does tie subsurface temperatures, MW output per well, annual heat decline rate to LCOE; however, ultimately connecting the three variables above will allow for even greater precision.

It will also be important to continually integrate the latest published literature on superhot rock-related costs like drilling, reservoir stimulation, and the CapEx for various power plant systems and components. As more data is made available (either through published literature or obtained through private sector companies with intimate knowledge of certain costs), the model will produce estimates with a greater precision. However, it should be noted that more data will not obviate the need for the level of site-specific engineering and modeling work required for project financing. The superhot rock model is meant to highlight the "should cost" for the entire technology class within certainty bounds tight enough to provide meaningful results.

Ongoing EGS projects such as the U.S. Department of Energy, University of Utah FORGE project in Utah, Soultz-sous-Forêts and Rittershoffen plants in north-eastern France, the Newberry project in Oregon (targeting reservoir development and eventual commercial operations >400C), research and development at such universities as the Helmholz Center at the University of Potsdam, Germany, and venture capital funded projects and collaborations such as Quaise, GA Drilling (energy drilling), Eavor (e.g. drilling, completions in hot granite) will continues to provide helpful direction on potential FOAK engineering costs. By understanding the costs of these project in detail, it could help provide additional guidance on how much cost reduction will be necessary to achieve the NOAK costs reported in the model – but also where those reductions need to take place.

17 These variables are within the "Well Output" table in the "Well Field CapEx" worksheet.

APPENDIX A

Well Production Calculations

Estimating the power rating per production well requires understanding the flow rate of the heated steam moving through the production wells and the efficiency of converting that heat to power (MW), or conversion efficiency. The 41.48 MW per production well is calculated by multiplying the flow rate of 50 Kg/s by the Conversion Efficiency of 0.702345115 MW/(Kg/s) – see Table 5.

The flow rate assumption of 50 Kg/s per well is a user defined parameter. Flow rate is likely to be in the range of 30 kg/s - 100 kg/s. The maximum rate of extraction is a function of the density of the fluid being produced. The denser the fluid, the bigger the flow from the producer well. If producing dry steam, 30 kg/s is likely the max flow. However, two-phase and supercritical fluid will enable much higher flow rates-up-to 100 kg/s. These flow rates assume a 7" production string. However, if one telescopes the casing, it is possible to get around some of these flow restrictions but it more difficult to design such a well. To be clear, flow rate is a complex optimization function as it blends well design, reservoir, and power plant constraints. For the purposes of the superhot rock model, a range of 30-100 kg/s with an average expected value of ~50 kg/s (skewed distribution) is arguably the best way to approach this variable. Conversion efficiency is calculated by dividing the amount of energy to do work (309.51 KJ/kg – see Table 7) by 1,000, which is the conversion factor needed to calculate MW/(Kg/s), listed in Table 4.

Table 5: Energy Conversion Calculations

Energy Conversion	Value	Unit
Conversion Efficiency	0.702345115	MW/(Kg/s)
Flow Rate	55.00	Kg/s
MW Output	38.63	MW

Table 6: Enthalpy Calculation

Superheated Steam Enthalpy	Value	Unit
Pressure	**8000.00**	kPa
Temperature	**400.00**	°C
Enthalpy	3139.31	kJ/kg
Density	29.11	kg/m3
Entropy	6.37	kJ/kgK
Vapor Fraction	100	%
IF97 Region	0	
Isobaric Heat Capacity	2.803749556	kJ/kg
Speed of Sound	593.6498659	m/s

Table 7: Well Production Assumptions: Power Generation Efficiency

Power Generation Efficiency	Value	Unit
Calculated Enthalpy	3,139.31	kJ/kg
Reservoir Model Inlet Enthalpy	2,200	kJ/kg
Efficiency Calculation		
For <=2900 KJ/kg Fluid Use: Efficiency = 7.8795*Ln(Enthalpy) - 45.651 Hyungsul Moon and Sadiq J. Zarrouk 2012 For >=2900 KJ/kg Fluid Use: Efficiency = (Enthalpy-2400)/Enthalpy Assuming that Turbine exhaust is 0.15 bar and steam fraction is 91.6% and turbine efficiency is 80%		
Efficiency Calculation		
Input Enthalpy	3,139.31	KJ/kg
Efficiency	23.55	%
Generator Efficiency	0.95	
Work	702.345115	KJ/kg

APPENDIX B

Model inputs for the 2 Technology Regimes

Figure 6 highlights change in LCOE across two technology regimes. The input parameters were kept the same; however, there are basic differences between the two model parameters:

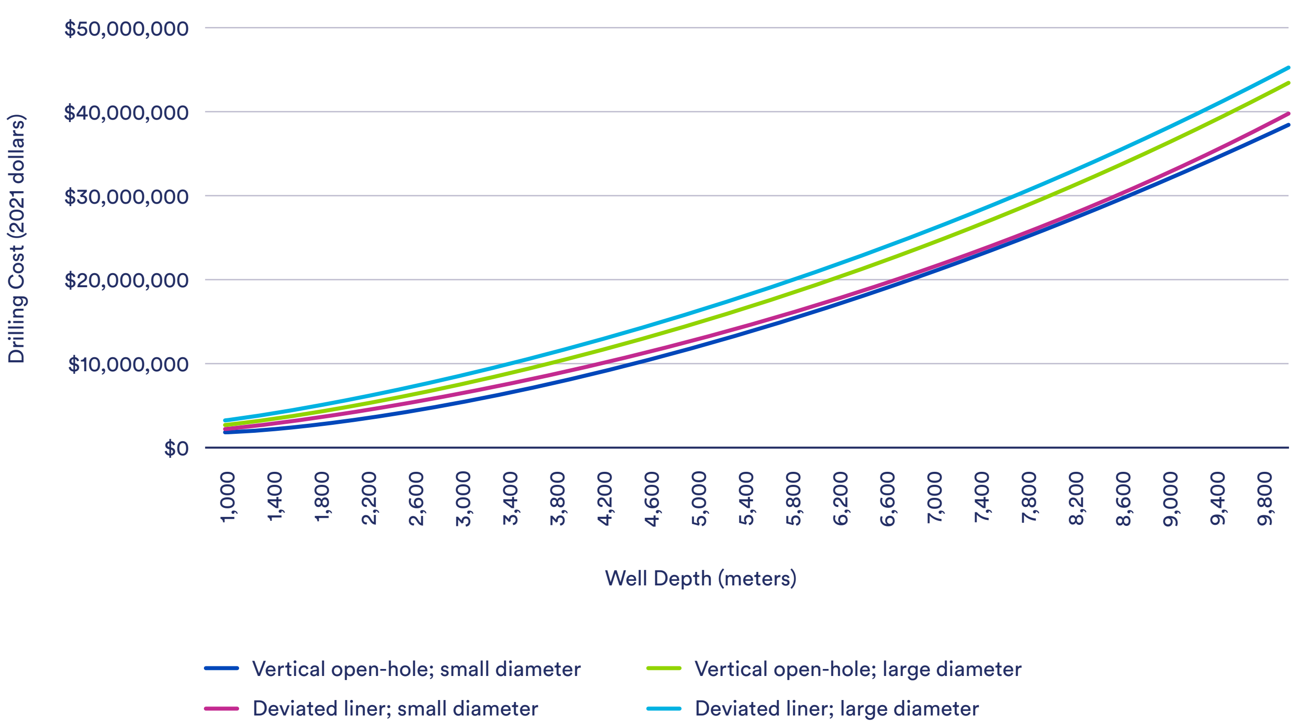
- **Accessible with Today's Drilling & Casing Technology:** assumes that energy drilling is not used at all. Therefore, the well cost estimates follow a formula from Lowry (2017):

  Well Cost = $0.2818\times2 + 1275.5213x + 632{,}315$

  - The default cost curve used in the techno-economic model is for a “Vertical open-hole, large diameter”
  - The inflation factor of 103.92% is used to bring 2019 dollars to 2021 dollars
- **Advanced Drilling without Casing Needed:** assumes that energy drilling is ~$1000/meter to drill and create an impermeable wellbore without use of casing and cements.

The model includes a toggle that can incorporate energy drilling, which is assumed to begin at 3km.

Figure 11: Drilling Cost Correlations from Lowry et al. (2017)



APPENDIX C

Additional Drilling and Reservoir Creation Assumptions

Several additional assumptions were made to estimate well field costs and to understand how much geothermal energy can be harvested through a given production well. Each superhot rock project is going to be unique. It will have its own location, a different depth by which to access the required temperatures, a different power rating (which is determined by the number of wells and temperature), etc. Below includes a list of well field assumptions that are held constant in the model (see Table 8), as well as calculations used to determine power plant efficiency (via the energy contained in the steam traveling from the reservoir to the power plant, or the heat content of the system known as enthalpy).

Table 8: Well Field Model Assumptions Held Constant

Reservoir Inputs	Value	Unit
Decline Rate	0.2%	
Temperature	400	°C
Pressure	8	Mpa
Depth	6	km
Distance Between Wells	0.5	km
Production Interval Length	1.5	km
Producer/Injector Ratio	2	
Number of Producers	7	wells
Number of Injectors	4	wells
Well Output	**Value**	**Unit**
Reservoir Rock	Granite	
Specific Heat	1.1	KJ/Kg*K
Density	2650	Kg/m^3
Production Temperature	400	C
Years of Production	30	years
Heat Extraction %	0.092906742	%
Heat Extracted/m^3	1166	MJ/m^3
Production Volume	337500000	m^3
Heat Generation	415.7823269	MW
Energy Conversion	**Value**	**Unit**
Conversion Efficiency	0.70	MW/(Kg/s)
Flow Rate	55	Kg/s
MW Output	38.63	MW

Once the cost of individual well has been made, the next step is to determine the number of wells needed to reach the intended power plant capacity set by the user. This is done by determining the power production for a single well. Equation 3 can be used to estimate the power plant efficiency given the enthalpy of the fluid in the well. The equation accounts for the use of binary, double flash, single flash, and dry steam turbines.[18] The equation does not account for the use of triple flash steam turbines, which are rare because they require high pressures. Also, it should be noted that the SHR model does not include any scrubbing of steam coming from the production well (to remove any corrosive elements before reaching the steam turbine). The model assumes that the steam from the production well is compatible with the steam turbine.

$$\mathrm{Eff} = 7.8795 * \ln(h) - 45.6$$

Equation 3. Describes the efficiency of a geothermal power plant as a function of enthalpy of produced fluid. Eff efficiency and h is enthalpy of the fluid. Equation is from (Moon et al., 2012). Equation generated using production data from 92 power plant from around the world. Equation is only used for enthalpies of <2900 KJ/kg.

One drawback of using Equation 3 is that it can only be used for power plants with fluid enthalpies of <2900 KJ/kg. This is because the dataset used to generate the equation did not incorporate any power plants with fluid enthalpies >2900 KJ/kg and because the relationship between enthalpy and efficiency for dry steam turbines is different than it is for flash turbines. Given limited data, a new method is required to calculate enthalpy for systems with fluid enthalpies >2900 KJ/kg. Equation 3 has been developed to solve this issue. Equation 3 assumes a standard outlet condition with a condenser pressure of 0.115 bar and steam quality of ~92%. These values were derived using data from (Moon, 2012).

$$\mathrm{Eff} = (h - 2400)/h$$

Equation 4. Describes the efficiency for power plants where fluid enthalpy is >2900 KJ/kg. Equation was formulated using a turbine exhaust pressure of 0.15 bar and a steam quality of ~92%. These values were derived using data from (Hyungsul Moon and Sadiq J. Zarrouk, 2012). This equation is predicated on the assumption that an operator can obtain a specific the inlet pressure into the power plant using one of many potential methods. This equation is necessary because Equation 2 did not use data from any plants with enthalpies above 2900 KJ/kg.

This outlet condition correlates to an outlet enthalpy of 2400 KJ/kg. This equation assumes that an operator will be able to reach the inlet conditions needed to produce these outlet conditions while considering the entropic losses of the turbine. Using the calculated efficiency, it is possible to determine the specific work provided by the produced fluid for a specific well. Multiplying the specific work of the fluid with the estimated flow rate provides the total power production on a per well basis.

With the power output of an individual well know, the number of wells needed to reach the intended power plant capacity can be ascertained. The user is responsible for determining the ratio of producers to injectors. The model starts with a ratio of 2 producers to 1 injector. This is because the permeability in many reservoirs is anisotropic. In reservoirs where permeability is more isotropic a user may want to use a different ratio.

In addition to the cost of wells, the model estimates the cost of the gathering system. Equation 5 was generated using confidential data as well as data from the literature, but available data was limited and the equation will be revised as more information is known (Ingason and Sæther, 2018).

[18] Moon, Hyungsul, and Zorrouk, Sadiq J. (2012). Efficiency of Geothermal Power Plants: A Worldwide Review. International Geothermal Association. https://www.geothermal-energy.org/pdf/IGAstandard/NZGW/2012/46654final00097.pdf

$$\text{Gathering System Cost} = \left(\frac{6.5}{1.02^{\text{wells}}}\right) * \text{wells}$$

Equation 5. Shows the cost for a gathering system based on the number of wells. In this equation wells is the number of wells in the field. Output is given in terms of $M of dollars.

Table 9: Inputs to the Gringarten Analytical Model to Estimate Reservoir Temperature Decline Over Time

Gringarten Model Input Variable	Value
Initial Rock Temperature [deg.C]	400
Re-injection Temperature [deg.C]	319
Total Mass Flow Rate [kg/s]	55
Fluid Density [kg/m3]	975
Specific Heat Capacity Water [J/kg/K]	4195
Thermal Conductivity of the Rock [W/m/K]	2.83
Density of the Rock [kg/m3]	2730
Specific Heat Capacity of the Rock [J/kg/K]	825
Fracture Separation [m]	50
Number of Fractures [-]	50
Fracture Width [m]	250
Fracture Height [m]	250
System Lifetime [years]	30
Time Steps	1