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A Simple Data-Centric Methodology for Producible Geothermal Well Determinations

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ABSTRACT

The Bureau of Land Management (BLM) contracted the National Renewable Energy Laboratory (NREL) to help develop a streamlined methodology for determining if a newly drilled geothermal well is "producible," which means a well is producing or capable of producing geothermal resources in commercial quantities. This designation is essential for the BLM to grant a production extension to the respective lease or unit. This is a straightforward problem to solve in oil and gas: Demonstrate that a well is economically viable, meaning it is capable of producing sufficient oil or gas to exceed direct operating costs and lease-related expenses, such as rentals or minimum royalties. In oil and gas, it is possible to produce from a single oil or gas well and these costs are known or possible to estimate. In geothermal, the problem is more complex: more than one successful well is necessary to define the potential output of a geothermal resource (in MWe) to design appropriate power plant(s). As such, power plant(s) are not designed until well after additional wells are drilled and tested. Therefore, in the case of geothermal, the operating costs are not known after drilling just the first successful well, as can be the case in oil and gas.

Although this designation is critical for advancing geothermal power plant development on BLM-managed lands, current geothermal well assessments often rely on ad hoc approaches that can be complex, operator-biased, and heavy in assumptions related to economic viability. To address this, we have developed two complementary methodologies: a minimum power requirement-based approach and a productivity index (PI)-based approach. These methods leverage key flow test data—pressure, temperature, flow rate, and specific enthalpy—to provide reliable and standardized producible well determinations. The minimum power requirement-based approach evaluates wells against specific power output thresholds informed by reservoir experts and the associated temperature requirements. The PI-based approach assesses well productivity using widely accepted reservoir engineering metrics, proposing a threshold of 2.5 kg/s/bar. Both methods are data-driven and grounded in empirical production data from operational geothermal wells, avoiding uncertain economic assumptions while maintaining decision-making accuracy. Wells falling below key performance thresholds (i.e., PI, specific power) are deemed non-producible.

These methodologies aim to streamline BLM's decision-making process, reduce nontechnical barriers to geothermal energy adoption, and enable regulatory expansion into states lacking geothermal expertise. Preliminary results indicate clear trends and thresholds in production data that provide actionable insights for evaluating well producibility. Validation using well completion report (WCR) data is ongoing, with promising results demonstrating the potential for these standardized methodologies to impact geothermal development significantly.

1. INTRODUCTION

The U.S. Bureau of Land Management (BLM) manages geothermal resources on approximately 245 million acres of surface estate and 700 million acres of subsurface public lands. Geothermal energy was the first renewable resource approved for production on public lands, with the first project authorized in 1978. As of September 2023, BLM lands host 51 operating geothermal power plants with a combined capacity of more than 2.6 gigawatts. The BLM oversees 344 competitive leases and 188 noncompetitive leases, totaling over 1 million acres across seven western states, ensuring the sustainable development of geothermal resources while meeting regulatory requirements (DOI, 2024; BLM, 2025a).

The BLM oversees geothermal resource development on public lands through a structured process comprising four stages: exploration, resource drilling, production, and reclamation. Each stage necessitates separate authorizations and adherence to the National Environmental Policy Act when ground-disturbing activities are proposed (BLM, 2025a).

During the resource-drilling stage, operators are required to submit a Geothermal Well Completion Report (Form 3260-4) within 30 days after completing permitted operations. This report provides detailed information about the well's mechanical and physical condition, geologic data, and, when applicable, production details (BLM, 2025a).

A critical aspect of this stage is the determination of a well's producibility. A "producible" well designation is essential for deciding whether a lease should be granted a production extension, allowing progression to the next step of developing a geothermal power plant on BLM-managed land. Currently, the BLM lacks a standardized methodology for making these determinations, leading to ad hoc approaches that can be complex, operator-biased, and inconsistent (BLM, 2025b).

To address this issue, we have developed a straightforward, data-centric methodology that leverages key flow test data—pressure, temperature, and flow rate—to support reliable producible well determinations. Our method relies on empirical production data from operational geothermal wells, representing the actual requirements for wells in production. By simplifying the process and focusing on well performance data, we avoid uncertain assumptions about economic projections or operator decisions, while maintaining a sufficient level of decision-making accuracy (BLM, 2025b).

Standardizing this methodology has the potential to significantly impact the geothermal industry by streamlining the BLM's decision-making process and enabling easier regulatory expansion into new geothermal states. This will help reduce nontechnical barriers to geothermal energy adoption in regions currently lacking regulatory expertise. Validation of the methodology is ongoing, using production and flow test data from operational and newly drilled wells.

2. APPROACH

Our approach included the following steps:

1. Literature review:
    a. Geothermal reservoir engineering, focused on well flow testing and measurement of well producibility
    b. A review of producible well determination approaches for oil and gas wells
    c. A review of historical geothermal producible well determinations.
2. Assembling a dataset to use in this investigation: Although flow test data in a well completion report (WCR) would eventually provide the inputs to this methodology to determine whether a well is producible or not, we were only able to obtain about six of these well flow tests. Geothermal production data was more readily accessible due to California's reporting requirements, as well as BLM's production data reporting requirements (proprietary dataset). Therefore, to avoid the bias that would be introduced by developing this methodology using only six flow tests, a geothermal production dataset was assembled in the hopes that actively producing geothermal wells would demonstrate similar behavior to wells during flow testing.
3. Analysis of the data: Data were analyzed for meaningful trends, particularly focused on the following parameters: temperature, pressure, mass flow rate, specific enthalpy, productivity index (PI), and specific power.
4. Industry outreach: To ensure that our approach was robust, realistic, and considerate of all geothermal resource regimes in the United States, we hosted a series of interviews with reservoir engineers working at operating geothermal power plants in the United States. These conversations were used to gather areas of agreement and disagreement, where areas of disagreement require additional follow-up to gather consensus (in progress).
5. Validation: Using real WCR flow test data to validate the methodology (in progress).

This ultimately resulted in two different proposed methodologies: One based on PI, and one based on minimum specific power requirement per well.

2.1 Background

A geothermal reservoir can be defined as the section of an area of geothermal activity that is hot and permeable so that it can be exploited economically to produce fluid and heat (Grant and Bixley, 2011). Geothermal reservoirs can be classified by the reservoir temperature, low-temperature (<150°C) and high-temperature (>200°C) reservoirs, and by the dominant fluid phase, liquid-dominated and vapor-dominated reservoirs.

Reservoir engineering teams assess the magnitude of the resource and the size of electric or thermal power plant that can be supported by a field over a designated project life of 20 to 30 years. This assessment is achieved by field tests and analyses, including subsurface temperature and pressure surveys, interpretation of well tests to evaluate the reservoir characteristics, evaluating flow rates and enthalpies of producing wells to determine the deliverability of the wells, and analyzing performance of injection tests (Grant and Bixley, 2011).

2.1.1 Relevant Reservoir and Well Properties

In this work, the following reservoir and well properties are discussed and utilized as well producibility indicators:

Specific power output: Specific power is the ratio of power output to the production mass flow rate at a given well. In one of the proposed methodologies in this paper, specific power is modeled using the methods described in Aljubran and Horne (2025) and used to correlate reported mass flow rates and temperatures to reasonable minimum power requirements.

PI: PI is the ratio of the production or flow rate to the pressure drawdown at the midpoint of the producing interval. It is a measure of the well potential, or the ability for a well to produce. Calculating an accurate PI requires flowing a well sufficiently long to reach pseudo-steady-state flow, when the pressure drawdown is relatively constant (Craft and Hawkins, 1959). In the second proposed methodology in this paper, PI is estimated for each data point, and a minimum PI requirement is imposed on the data.

Total and specific enthalpy: Specific enthalpy is the amount of thermal energy per unit mass of a substance. In geothermal systems, it is often expressed in kilojoules per kilogram (kJ/kg). For a fluid, specific enthalpy accounts for both the internal energy (due to temperature) and the work done against pressure. It is a critical property for evaluating the energy content of geothermal fluids and is used to distinguish between liquid, vapor, and two-phase states (Grant and Bixley, 2011). This concept is essential for geothermal reservoir engineering, as it enables the calculation of energy extraction rates and the characterization of fluid properties in geothermal wells. In the methodology presented in this paper, specific enthalpy is analyzed but not explicitly used in either of the proposed methodologies. It may, however, be used in combination with the PI to quantify flowing enthalpy in a future version of the proposed methodology.

2.1.2 Completion Testing

Completion tests are carried out immediately after the drilling and completion of a geothermal well or after a period of heat-up. These tests provide for the collection of data that characterizes the well, the formations surrounding the well, and the geothermal resource into which the well has been drilled. These tests allow for an early assessment of the likely production or injection capacity of the well, for the development of understanding of the characteristics of the geothermal resource, and benchmark information on the casing condition of the newly completed well (Hole, 2008).

During completion testing, pressure and temperature are monitored as key indicators of reservoir behavior. The process typically involves altering the well flow rate—either by fluid production or water injection—and observing the pressure and temperature responses over time. The resulting data help establish deliverability, completion efficiency, and potential production capacity (Grant and Bixley, 2011).

For production wells, these tests focus on determining the well production capacity, focused on the following local reservoir and fluid properties: fluid state (pressure/temperature/enthalpy), reservoir state (liquid- or vapor-dominated), reservoir permeability, reservoir chemistry (salinity, cation, and isotopic ratios), and noncondensable gas content. Completion tests are helpful for identifying potential feed zones, determining the overall permeability and thus an estimate of the well's likely production (or injection) capacity, and, in some cases, allocating permeability characteristics to individual feed zones (Grant and Bixley, 2011).

Completion tests usually involve pumping cold water into (injection test) or out of (flow test) the wellbore at different rates. Pressure is measured downhole near the feed zone when possible to avoid thermal effects. The choice of depth for pressure analysis is important for producing reliable results. If pressure is measured too shallow, the pressure change will be underestimated, leading to overestimation of reservoir performance. Because of the uncertainties around the correct depth to measure pressure, an initial PI is calculated as a first estimate, which can later be refined by additional testing and analysis. PI is generally assumed to be constant with varying flow rates. It has proven effective in liquid-dominated wells, but is less reliable in two-phase wells because flowing mobility varies with enthalpy in two-phase fluids (Grant and Bixley, 2011).

Ultimately, a completion flow test provides relevant characteristics about a well that must be reported on a WCR and submitted to BLM to be used in a producible well determination. Some of the relevant required fields on the WCR include total liquids produced during test (steam, water, total), surface and subsurface pressure, and surface and subsurface temperature (BLM 2025b).

2.1.3 Producible Well Determinations

Producible well determinations are sometimes referred to as “paying well” determinations. These determinations establish whether a newly drilled well is capable of sustained production that justifies retaining the lease under development, ultimately establishing that the well is economically viable.

In oil and gas, producible or paying well determinations are used to decide if a lease qualifies for a production extension. Such determinations confirm that a well is economically viable, meaning it produces sufficient oil or gas to exceed direct operating costs and lease-related expenses, such as rentals or minimum royalties (CFR 3160.0-5). Once a well is classified as a paying well, the lease can be extended beyond its primary term as long as the well continues to produce in paying quantities (CFR 3135.1-5).

The regulatory framework for oil and gas is well-defined. For instance, CFR 3162.3-4 mandates the plugging and abandonment of wells that are not producing in paying quantities unless approved for alternative uses, such as injection for enhanced recovery or disposal. Additionally, CFR 3135.1-5 outlines conditions under which leases may be extended, emphasizing the production of oil or gas in paying quantities or ongoing drilling or reworking operations.

Economic evaluations in oil and gas are relatively straightforward due to clear definitions of production thresholds and costs. These evaluations rely on well-established metrics and financial analyses to demonstrate a well's profitability. For example, guidance such as IM2020-006 Attachment 4[1] provides a template for determining economic viability.

In contrast to oil and gas, producible well determinations for geothermal wells are inherently more complex. Historically, these determinations have often attempted to mimic the economic evaluation framework used in oil and gas. However, this approach is problematic for geothermal resources due to the unique nature of geothermal energy production. Unlike oil and gas, where the economic viability of a well can often be assessed independently, geothermal wells are tightly coupled with the downstream infrastructure—specifically, the power plant.

When no preexisting power plant exists, it is challenging to estimate the economics of a geothermal well because the type and size of the plant, as well as the associated development costs, are unknown at the time of drilling. Developers may make assumptions to estimate economic viability, but these are often fraught with uncertainties. In cases where a power plant already exists, such as when developers

[1] IM2020-006 Attachment 4: https://www.blm.gov/sites/default/files/policies/IM2020-006_att4.pdf

seek to expand a participating area or develop brownfield sites, the determination process becomes somewhat clearer. However, it still requires careful consideration of the well's potential contribution to the plant's capacity.

Historically, geothermal producible well determinations have been conducted using ad hoc methodologies in an attempt to mimic the oil and gas producible well determination methodology. For example, one used data from a pumped well test to determine the productivity of the well, and then performed a discounted cash flow analysis to determine if a reasonable rate of return could be achieved after consideration of the costs of drilling and producing the well. Another used temperature, pressure, production and geophysical logging, fluid chemistry, and flow test history to analyze reservoir productivity before conducting a discounted cash flow analysis. A third used pressure transient test data to verify the permeability-thickness of the reservoir, and a fourth calculated PIs for each newly drilled well.

To address these challenges, a shift toward non-economic criteria has emerged. A more robust approach to geothermal producible well determinations focuses on thermodynamic properties obtained from well flow tests. These properties—such as pressure, temperature, and enthalpy—provide direct insight into well production capacity to support geothermal energy production, independent of economic assumptions. This method offers greater reliability and objectivity, ensuring that well determinations are based on the resource's physical properties rather than speculative economic projections.

The regulatory framework for geothermal well determinations is outlined in CFR Title 43, Parts 3260 and 3270. These sections address lease management, production requirements, and operational approvals for geothermal resources. While less prescriptive than their oil and gas counterparts, these regulations provide the basis for evaluating producible wells in the context of geothermal development.

2.2 Assembling the Production Dataset

The production dataset used in this study was compiled from multiple sources, integrating public and proprietary data to create a comprehensive view of geothermal production across several states. Data acquisition involved leveraging CALGEM Well STAR, a publicly accessible resource from the California Geologic Energy Management Division, using a custom data-scraping script. Proprietary monthly production reports from Nevada, Utah, and New Mexico were also incorporated into the dataset. To ensure confidentiality, all proprietary data was anonymized in this study. All of this was compiled into a production dataset containing monthly production parameters for each well, for a given month of operation.

Once collected, significant data cleaning was performed to address inconsistencies across sources. Erroneous string values in numerical fields were corrected, and the dataset was harmonized to account for variations in reporting requirements between states. Missing values presented additional challenges, necessitating careful review and supplementation where feasible. Records with mass flow values of less than 10 kg/s were filtered out, along with temperatures less than 50° C.

In addition, since production data is made public on CALGEM, the initial dataset was heavily biased towards California production wells, where we automatically obtained up to 40 years of data per well as opposed to manually obtaining up to five years of data per well for Nevada, Utah, and New Mexico. This is especially problematic because California has a large number of very high enthalpy wells (i.e., Geysers, Salton Sea) compared to other states. To mitigate this issue, we randomly sampled 10 records per well to be included in our dataset. While some wells have less than 10 records, this provided a good balance of reducing bias while maintaining a sufficient number of records to represent diverse operating conditions in our analysis.

Despite these efforts, several challenges persisted. The dataset contained imperfect data, requiring manual corrections for entry errors. In some cases, assumptions had to be made to resolve ambiguities, introducing potential uncertainty. Labeling the data presented further difficulties, particularly due to the absence of a status or condition explicitly indicating "producing, but not enough." Differentiating between production clusters was also challenging, as clear distinctions were not always apparent.

Depth data posed another significant obstacle. No consolidated source of well depth information was available, and an incomplete depth dataset had to be assembled from various disparate sources. This limitation underscores the need for more centralized and standardized reporting mechanisms for geothermal wells.

Enthalpy was calculated as follows:

$$\mathrm{H_{total}} = \mathrm{H_{liquid}} + \mathrm{H_{vapor}}$$

$$H_{liquid} = \dot{m}_{liquid} \cdot h_f, \qquad H_{vapor} = \dot{m}_{vapor} \cdot h_g$$

where, $\dot{m}_{liquid}$ and $\dot{m}_{vapor}$ are the mass flow rates of the liquid and vapor phases, and h_f and h_g are their specific enthalpies acquired through steam table lookups (Lemmon et al., 2018) based on measured wellhead pressure and temperature.

From here, a specific enthalpy was calculated as:

- If the well operates in the **saturated region** (pressure and temperature match saturation conditions):
$$h_f = h_{saturated,liquid}, h_g = h_{saturated,vapor}$$

- If the well operates in the **superheated region: ($T > T_{saturation}$):**
$$h_f = h_g = h_{superheated}$$

- If the well operates in the single-phase region ($T < T_{saturation}$ or $P > P_{saturation}$):

$$h_f = h_g = h_{single-phase}$$

where the values $h_{saturated,\, liquid}$, $h_{saturated,\, vapor}$, and $h_{superheated}$ are interpolated from thermodynamic steam tables based on the measured wellhead pressure and temperature (Moran and Shapiro, 2018).

Next, we evaluated the power generation potential across the well production parameters reported for each (well, month) pair, generally following the approach developed by Aljubran and Horne (2025). This method focused on analyzing specific power output across wells where the heat-to-power conversion is achieved using binary power plants. This is because, other than one triple-flash plant constructed in 2011, all geothermal capacity additions across the United States from 2000 through 2020 have been binary plants (Robins et al., 2022; EIA 2020). An organic Rankine cycle binary power plant can operate efficiently even with moderate-enthalpy geothermal resources; thus, it is suitable for a larger number of geothermal resources (Eberle et al., 2017). Binary plants are modular and scalable, allowing for incremental capacity additions and easier adaptation to varying resource conditions (DiPippo 1999). Additionally, binary power plants are closed systems, minimizing emissions and environmental impact, unlike flash plants, which could release toxic and greenhouse gases such as hydrogen sulphide and carbon dioxide (Bonalumi et al., 2017). This is critical for compliance with the increasing environmental sensitivity and demand for cleaner energy. Thus, we focused on the utilization of organic Rankine cycle binary power plants.

2.3 Analysis

2.3.1 Exploratory Data Analysis

We began the development of this methodology with an in-depth analysis of the trends in the data. This was done using the plots in Figure 1 and Figure 2, which include pair plots, distribution plots (i.e., based on kernel density estimation), and histograms of the main parameters of interest. These parameters included wellhead temperature, wellhead pressure, mass flow rate, specific enthalpy, year, actual power output, and theoretical specific power output.

In Figure 1, trends were further investigated through the use of color coding the data by the type of liquid mass flow (i.e., liquid- versus steam-dominated). From these plots, we can distill a few things, most of them expected and some surprising:

- Steam-dominated wells tend to operate at higher temperatures, pressures, and specific enthalpies.
- Pressure and temperature are mostly linearly related (Gay-Lussac's Law).
- Mass flow rate is significantly lower for steam-dominated wells.
- Pressure and mass flow have no obvious trend.
- Our data is somewhat dominated by steam-dominated wells, but more recently years are dominated by liquid-dominated wells.
- The most common value of actual power output is around 1 MWe per well.
- The most common specific power output is around 2E-5 MWhe/kg for steam-dominated wells, and around 1 MWhe/kg for liquid-dominated wells..
- Specific power output is logarithmically related to temperature (this is because of the model used to calculate specific power).

Figure 2 shows a three-dimensional plot of pressure versus mass flow rate versus temperature, colored by geothermal field. Because most of the production data we have compiled is proprietary, with the exception of California, a legend is not provided. This plot highlights that pumped wells behave unusually in terms of pressure. It also shows that the Geysers (darker yellow) and Salton Sea (red) have unique regimes that are different from the other power-producing fields. Lastly, it demonstrates a clear linear trend between pressure and temperature.

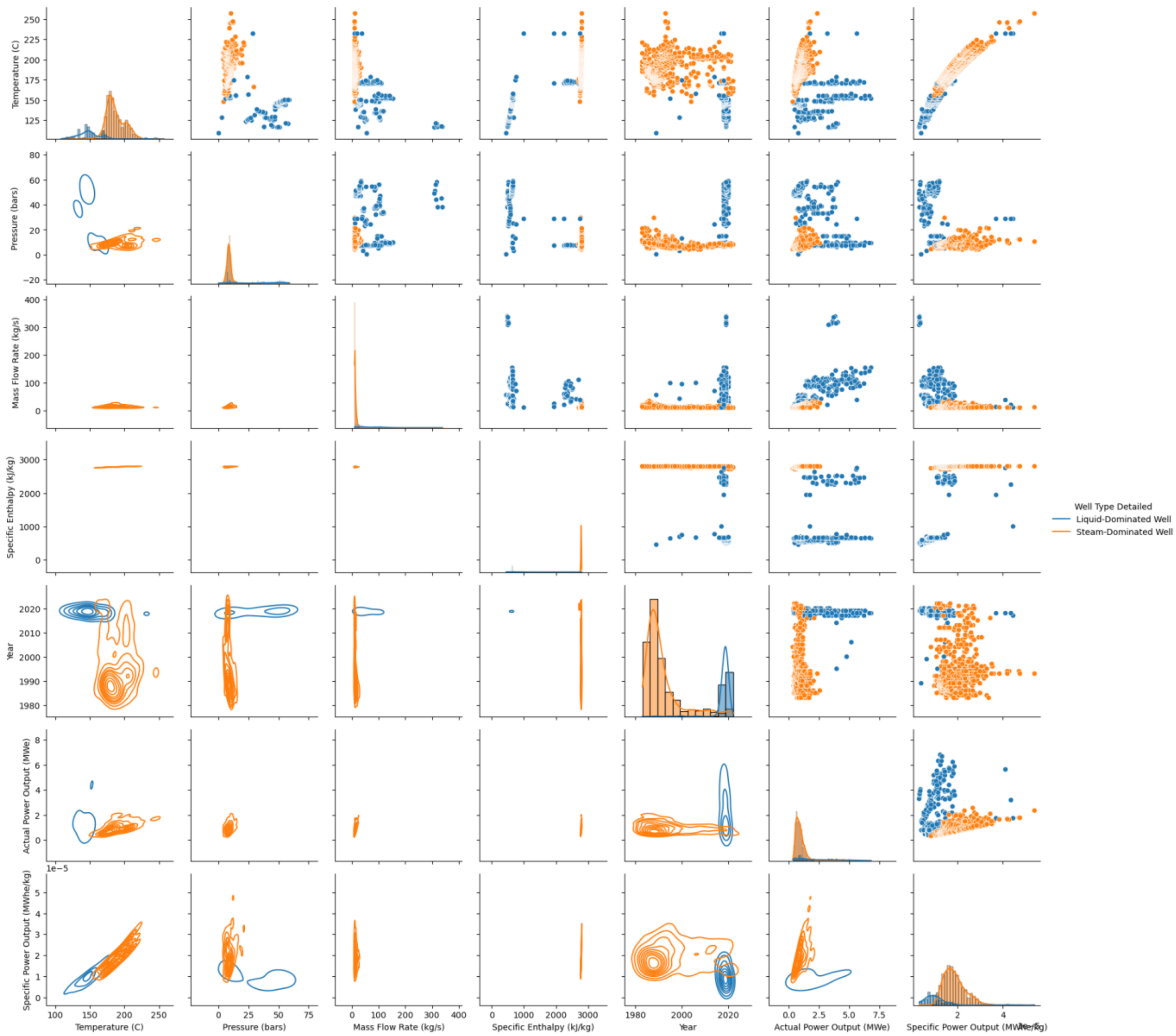

Figure 1: Pair plot and kernel density estimation plots showing relationships between each of the following parameters for all wells in the production dataset, colored by the type of liquid mass flow (i.e., liquid- versus steam-dominated): wellhead temperature, wellhead pressure, mass flow rate, specific enthalpy, and year associated with the production record.

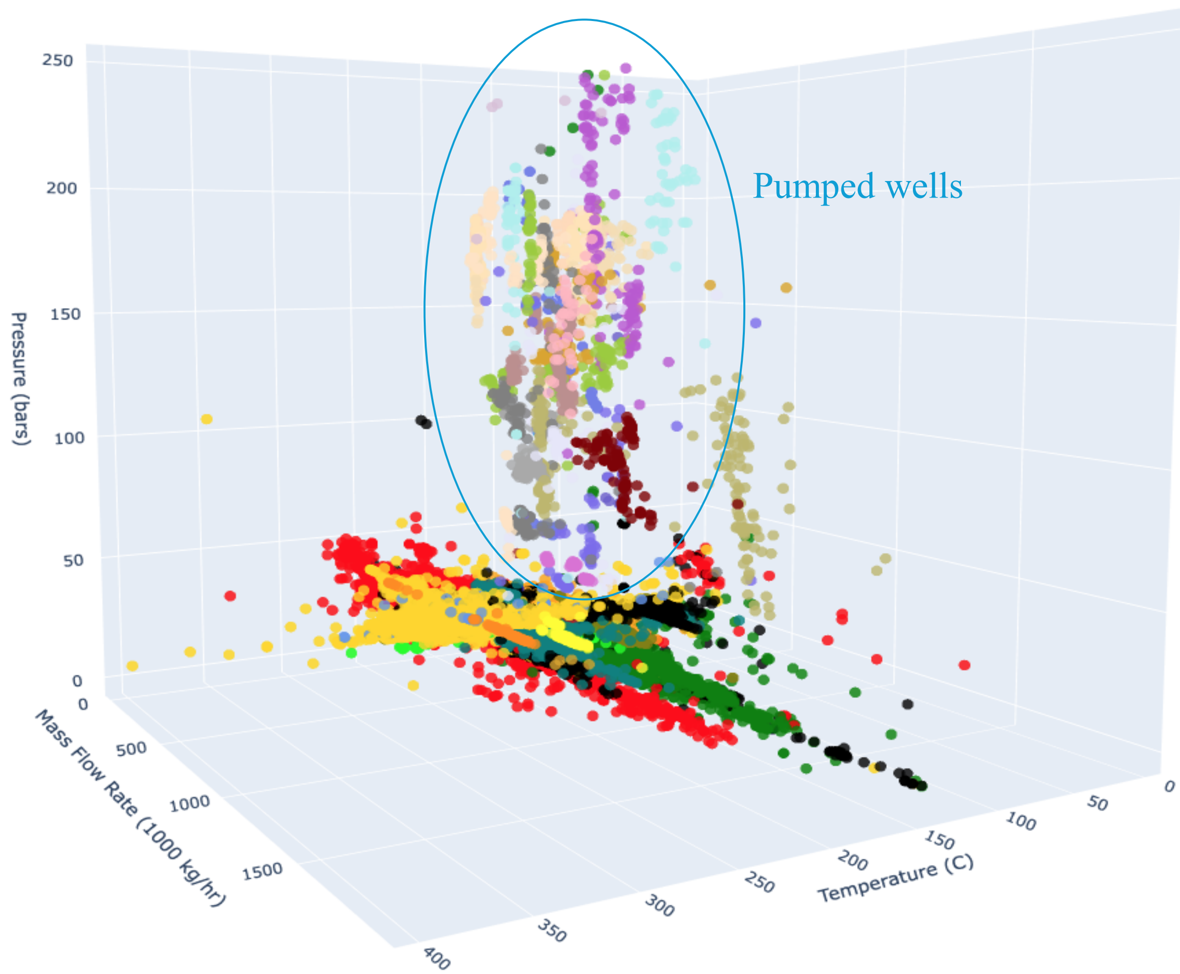

Figure 2: Three-dimensional plot of pressure versus mass flow rate versus temperature, highlighting that pumped wells behave unusually in terms of pressure. Colors of points represent individual power-generating fields, but a legend is not provided because this data is proprietary. We do, however, specify that the red points represent the Salton Sea, and the darker yellow points represent the Geysers.

2.3.2 Minimum Power Requirement-Based Approach

Next, we evaluated the power generation potential across the well production parameters reported for each (well, month) pair, with the goal of determining a minimum power output requirement based on realistic temperature and flow conditions. We limited this analysis to records with reasonable operating conditions by removing likely erroneous and outlier data points. Specifically, we only retained records with wellhead temperature of 50°C–375°C and wellhead mass flow rate of 10–-300 kg/s. Using historical ambient temperature records for 2023, each record was assigned an ambient temperature based on its geographical location and month.

As noted previously, this analysis modeled specific power output across all (well, month) pairs assuming that heat-to-power conversion is achieved using binary power plants. Specifically, we adopted an air-cooled organic Rankine cycle power plant model (Aljubran and Horne 2025), originally developed and integrated in a geothermal economics modeling frameworks (Aljubran and Horne 2024b).

Using the wellhead and ambient temperatures of each (well, month) pair and assuming butane as the binary working fluid, we modeled the theoretical specific power output in MWhe/kg using the Flexible Geothermal Economics Model (FGEM; Aljubran and Horne 2024b). Aljubran and Horne (2025) equipped FGEM with on-design and off-design, air-cooled ORC binary power plant models which we used to compute the heat-to-power conversion efficiency across records. As seen in Figure 3, the plotted points do not perfectly fall on a smooth curve because ambient temperature is different across sites, where thermal power output is inversely proportional to ambient temperature. Overall, the theoretical trend manifests in an increasingly nonlinear increase in power plant thermal efficiency and can be best described by a polynomial function.

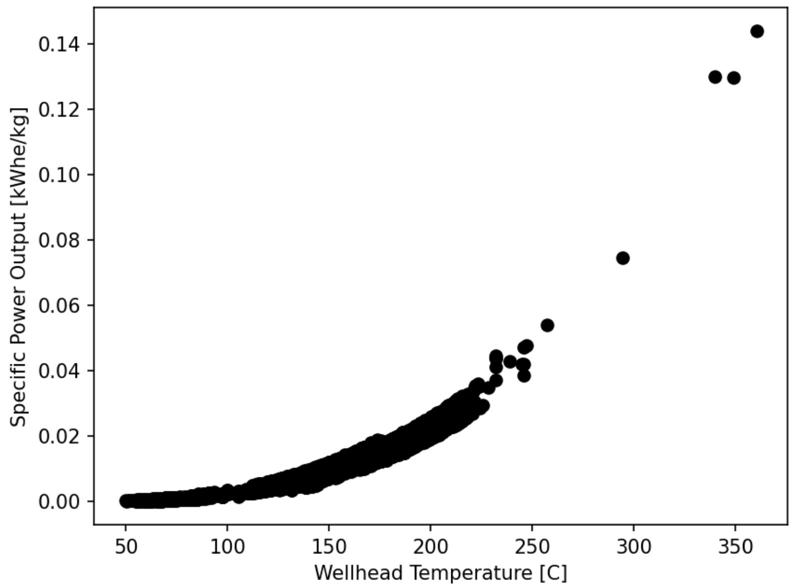

Figure 3: Plot of theoretical specific power output versus wellhead temperature for each (well, month) pair.

Using the reported wellhead mass flow rate alongside the computed specific power output, we computed the actual power output for each (well, month) pair (Figure 4). Compared to Figure 3, power output estimates are scattered because of the significant variation in measured well production mass flow rates. Nevertheless, power output estimates still retain the increasingly nonlinear and nearly polynomial behavior as a function of temperature.

One might rightfully argue that a well with wellhead temperature of >150° C and a reasonable mass flow rate is likely producible. So we created Figure 5, which limits wellhead temperature to <150° C and additionally shows characteristic power output at mass synthetic flow rate values of 50, 100, and 150 kg/s. We postulate reasonable values for the minimum power output requirement of somewhere between 1 and 5 MWe, shown in Figure 4 and Figure 5 as horizontal dashed lines to aid interpretation. These minimum power requirements can be used to derive minimum temperature requirements based on mass flow and ambient temperature.

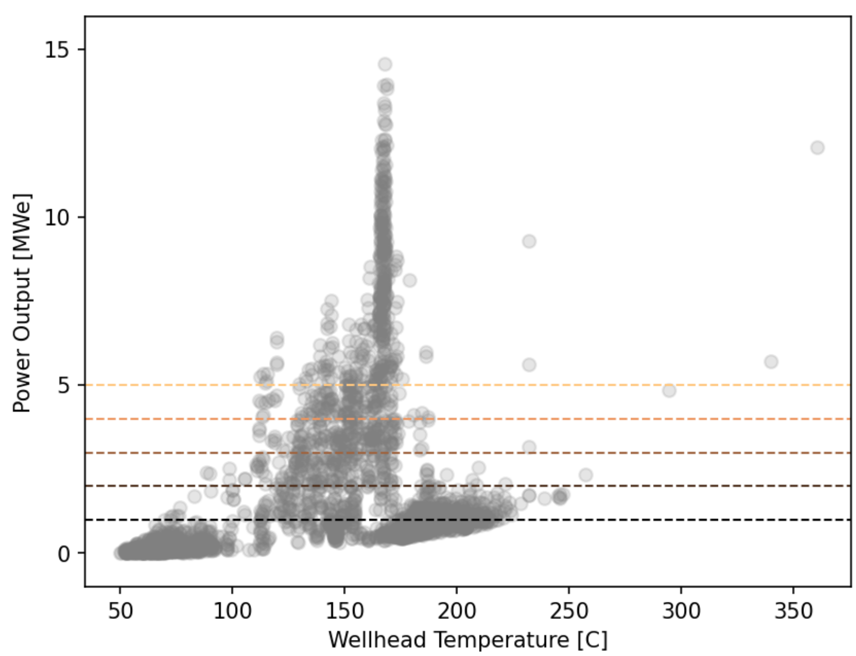

Figure 4: Plot of calculated power output versus wellhead temperature for each (well, month) pair. Potential minimum power requirements are represented as horizontal dashed lines to aid interpretation (1, 2, 3, 4, and 5 MWe). The y-axis is truncated at 15 MWe for visual convenience.

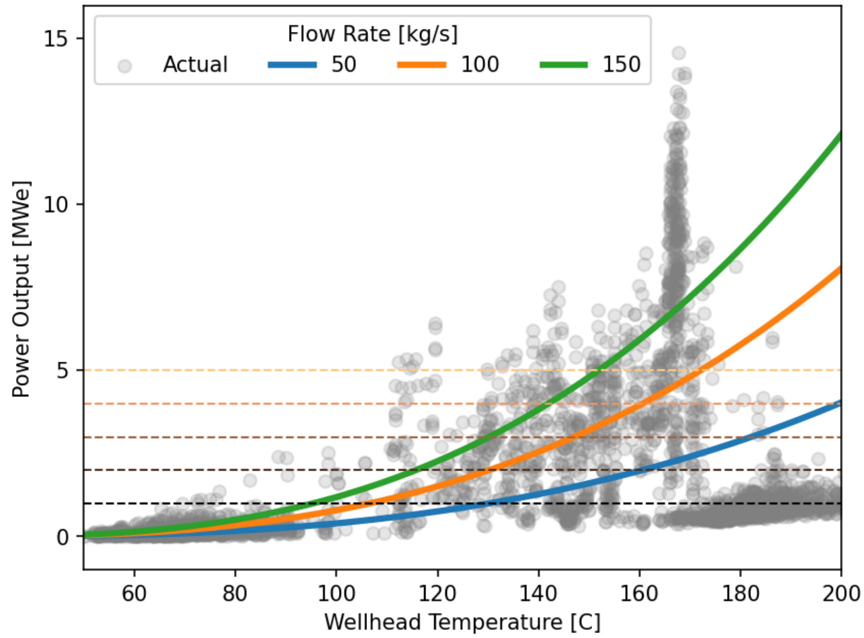

Figure 5: Plot of calculated power output versus wellhead temperature for each (well, month) pair (gray) for wellhead temperatures <150°C, with simulated mass flow rate power outputs for different ambient temperatures plotted on top for interpretability (blue, orange, green). Potential minimum power requirements are represented as horizontal dashed lines to aid interpretation (1, 2, 3, 4, and 5 MWe). The y-axis is truncated at 15 MWe for visual convenience.

Based on a this methodology, heat maps were produced for three different ambient temperatures (10, 20, and 30°C) to map mass flow rate and production temperatures to associated power outputs. These heat maps are shown in Figure 6. Based on this analysis combined with what is known about production temperature requirements for power production at different ambient temperatures, it appears that somewhere in the range of 3-5 MWe per well is the most reasonable.

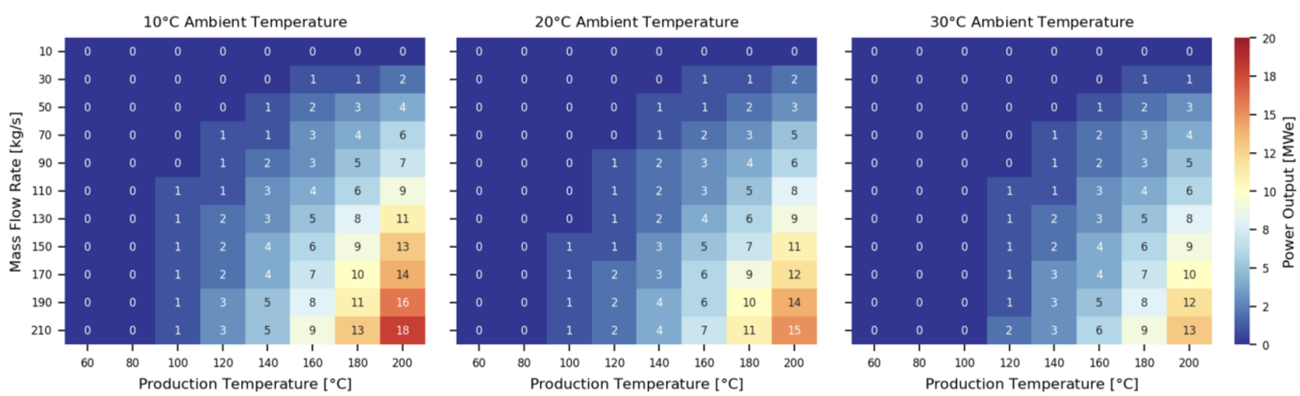

Figure 6: Plot of theoretical power output as a function of production temperature, ambient temperature, and mass flow rate. Power output values were rounded to the nearest integer and displayed for visual convenience.

This approach uses mass flow rate, wellhead temperature, and ambient temperature, but does not explicitly account for wellhead pressure. Pressure drives mass flow rate, so in some way it is implicitly incorporated. The FGEM model used for the ORC power plant can calculate the pumping requirement if well depth and production casing internal diameter are known, but since we do not have production casing diameter, the specific power output analysis in this study assumes zero wellbore fluid pumping requirements. Since pumping of liquid-dominated geothermal wells can consume a significant amount of the gross power output, this is an important aspect that we are currently excluding from our analysis. Note that we do, however, account for surface parasitic losses in the power plant (i.e., power needed for fan to blow air and condense butane and feed-in pump to push butane from the air condenser to the heat exchangers). It is however worth noting that incorporating wellhead pressure into this method would require special considerations for pumped wells (Figure 2).

2.3.3 PI-Based Approach

PI is typically calculated as:

$$PI = \frac{\dot{m}}{P_{reservoir} - P_{flowing}}$$

where $\dot{m}$ is the mass flow rate, $P_{reservoir}$ is the final hydrostatic buildup pressure in the reservoir, and $P_{flowing}$ is the flowing pressure prior to shut-in (Glapsey et al., 2008). Measuring $P_{flowing}$ directly at the depth of fluid entry is challenging, as it requires downhole pressure gauges and accurate depth-specific measurements. In many geothermal and production settings, wellhead pressure ($P_{wellhead}$) is easier to measure because it is available at the surface. $P_{wellhead}$ can approximate the flowing pressure at the production zone if wellbore pressure losses are negligible or accounted for separately (Grant and Bixley 2011). Therefore, we approximate that $P_{flowing} \approx P_{wellhead}$, acknowledging that this may be a source of error in certain data points (i.e., when wellbore friction is high, multiphase flow, etc.).

Because we only have well test data for a few wells, and most of the data used in this analysis is production data, we need to estimate $P_{reservoir}$. We can do this by first estimating the hydrostatic pressure loss using the well depth, and then estimating the frictional pressure loss based on averages.

The hydrostatic pressure loss accounts for the weight of the fluid column:

$$\Delta P_{hydro} = \rho_{avg} \cdot g \cdot \frac{depth_m}{10^5}$$

where ρ_{avg} = average density of the two-phase mixture (kg/m³), g = 9.81 m/s^2, $depth_m$ = depth in meters, and 10^5 converts pressure from Pa to bar (Grant and Bixley, 2011).

According to Grant and Bixley (2011), empirical estimates for frictional losses in geothermal production wells commonly range from 2 to 5 bar/km. Therefore, the frictional pressure loss is estimated empirically as:

$$\Delta \mathrm{P}_{\mathrm{friction}} = 3\left(\frac{\mathrm{depth}}{10000}\right)$$

where 3 bar/km[3] is an approximated frictional loss for geothermal wells.

The reservoir pressure is not measured in the majority of our data, so it is calculated as the sum of the wellhead pressure, hydrostatic pressure loss, and frictional pressure loss (Grant and Bixley, 2011):

$$\mathrm{P}_{\mathrm{reservoir}} = \mathrm{P}_{\mathrm{wellhead}} + \Delta \mathrm{P}_{\mathrm{hydro}} + \Delta \mathrm{P}_{\mathrm{friction}}$$

The pressure drawdown, representing the pressure difference driving flow, is calculated based on estimated properties above:

$$\Delta \mathrm{P} = \mathrm{P}_{\mathrm{reservoir}} - \mathrm{P}_{\mathrm{wellhead}}$$

The average density of the two-phase mixture is given by:

$$\rho_{avg} = x \cdot \rho g + (1 - x) \cdot \rho_f$$

where ρ_g = vapor density (kg/m³, taken from CoolProp database based on wellhead pressure, assuming pure water) and ρ_f = liquid density (kg/m³, taken from CoolProp database based on wellhead pressure, assuming pure water).

From here, we can calculate a mass-based PI:

$$\mathrm{PI}_{\mathrm{mass}} = \frac{\dot{m}}{\Delta \mathrm{P}} \text{ [kg/s/bar]}$$

where $\dot{m}_{kg/s} = \frac{\dot{m}_{kg/hr}}{3600}$ and ΔP = pressure drawdown (bar).

Depth could not be obtained for every well in the production dataset, and therefore the PI dataset is more limited. In particular, depths were not obtained for many California wells or New Mexico wells, meaning that this PI dataset is dominated by Nevada given that it has a significantly higher number of producing geothermal wells than Utah. In addition, this PI does not provide any information about the enthalpy of the well, which may leave part of the producible well definition unaccounted for. Figure 7 shows a plot of PI versus specific enthalpy, demonstrating that there is no clear relationship between the two parameters. It does, however, appear that most wells have a specific enthalpy > 500 kJ/kg, which is further supported by the exploratory data analysis. This could represent an additional qualifier in this approach to ensure that we quantify flowing enthalpy rather than just flowing fluid, given that enthalpy of the fluid is just as important as the ability to flow.

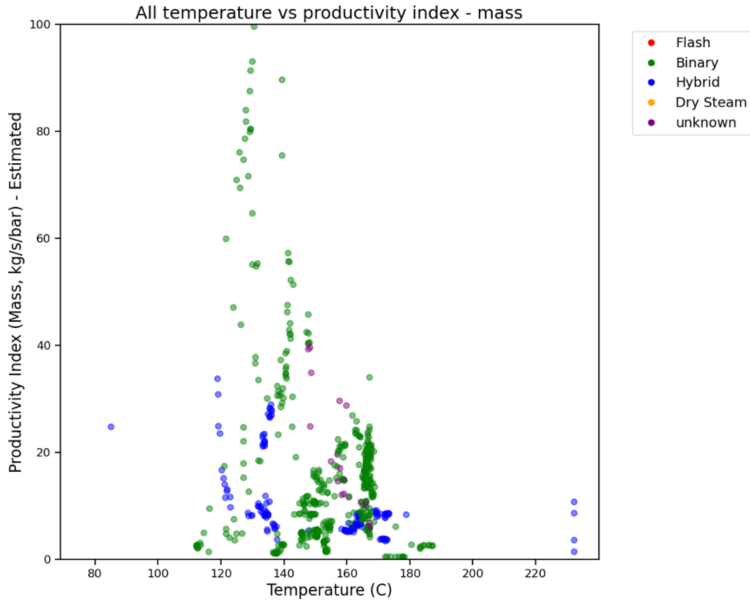

Figure 7: Plot showing calculated PI versus specific enthalpy

Figure 8 shows a histogram of the calculated PIs, along with a probability density function showing the distribution of the indices for use in determining a minimum requirement. A vertical line is drawn at 2.5 kg/s/bar, as this is often used as a minimum requirement for PI for a producible well (Glaspey et al., 2008). The mode of this dataset is between 5 and 7.5 kg/s/bar, and the mean is around 12.5, suggesting that 2.5 could be used as a cutoff for a minimum required PI for a producible well determination. This is further supported by input from some members of our group of reservoir experts (i.e., not much fluid is moved from the system below this value).

Some other members of our group of reservoir experts postulate that this value may be too high, given that many fields have been successful with for instance one producer at 3+ kg/s per bar and several others at around 1 kg/s per bar. This suggests that wells producing at 1 kg/s/bar should not be ruled out, but that an additional well with a higher PI would be needed before the lease is granted a production extension. Additional consideration for modern trends in development is needed before finalizing a minimum PI requirement.

Another consideration for this methodology is that PI changes over time as the pressure of the reservoir is disturbed. If other wells are drilled nearby or if there is some type of boundary in the reservoir, the change is bigger. This means that PIs calculated from production data are not necessarily reflective of PIs calculated from completion test data, and that additional considerations may be needed to account for wells drilled in close proximity to existing wells, or for reservoirs containing boundaries impacting the pressure distribution in the system.

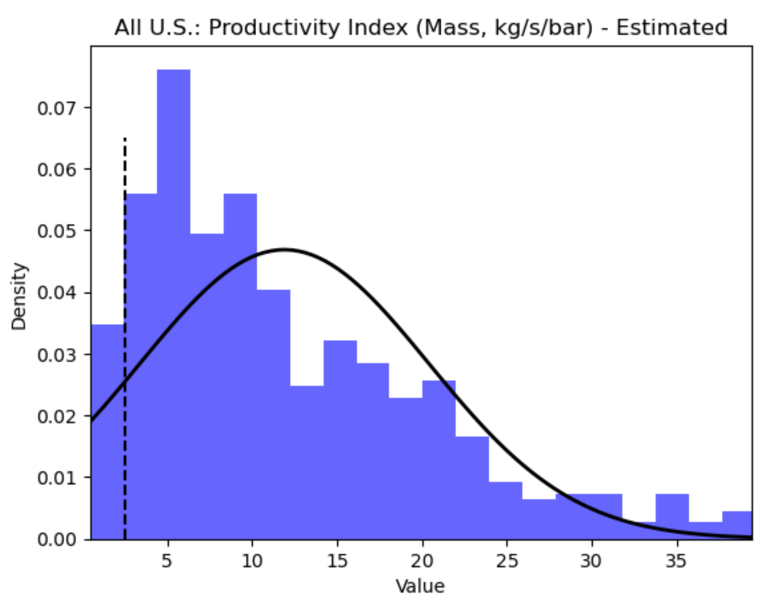

Figure 8: Histogram of calculated PIs, along with a probability density function showing the distribution of the indices for use in determining a minimum requirement. A vertical line is drawn at 2.5 kg/s/bar.

2.4 Input from Reservoir Experts

Six initial interviews were conducted with experienced reservoir engineers and researchers from various geothermal fields across the United States. The primary objective of these interviews was to gather insights on key parameters and their relationships, as derived from completion tests on geothermal wells, to assess their potential for producibility. The discussions also addressed play-specific requirements, including flow rate ranges and fluid chemical composition. The areas of agreement described in this section have been worked into the proposed methodologies to the extent possible, and the areas of disagreement provide areas for future consideration. After analyzing and comparing the interview responses, several points of consensus emerged:

- There is agreement that temperature is a significant factor in evaluating well productivity. However, several participants suggest that enthalpy is equally, if not more, important than temperature alone. <u>Specific power output (MWhr/kg) is viewed as a preferred metric</u>, especially if flow rate variability is conditioned by operator choices. This is particularly relevant for binary plants, where temperatures between 150°C–200°C are often used.
- There is broad agreement on assessing resource lifetime through metrics like pressure and heat depletion, enthalpy, and porous or reservoir volume. For conventional geothermal systems, pressure depletion is easier to monitor than heat depletion. Additionally, injectivity and PIs, along with production and injection tests, are suggested to evaluate the well's long-term viability
- Flowing enthalpy is a commonly accepted metric, with most participants agreeing it provides a more accurate representation of well productivity than mass flow alone. Steam quality, particularly distinguishing between saturated liquid and saturated steam, is also seen as relevant.
- Participants agreed that new plants require a higher minimum power threshold compared to existing plants, where lower-output wells may still be viable. For example, Operator 1 sets a 0.5-MW minimum power requirement for producible wells, while Operator 2 suggests that a wide range of temperatures and power outputs can still be economically viable under the right conditions.
- There is agreement on the importance of production data to better represent well producibility. Participants recognize traditional flow tests, such as the James Tube or lip pressure tests, as useful, although in the future adaptation of this methodology for enhanced geothermal systems (EGS), it should be taken into account that completion tests generally occur post-stimulation. Well tests should ideally provide both flow rate and enthalpy to fully characterize the well.

The disagreement is based mostly on differences of the plays and operations (e.g., the importance of fluid chemistry, or the need to account for the potential to pump wells). One of the most relevant discrepancies is over the inclusion of mass flow rate as a key metric. Some participants believe that mass flow rate is influenced too much by operator choice to be reliable, while others argue it provides useful information when combined with other metrics. Researcher 1 suggests charting enthalpy instead of mass flow to avoid this issue.

One other key area of disagreement was around reservoir working fluid, or testing fluid, and its impact on the methodology. As closed-loop and EGS systems grow closer to wide-scale deployment, this issue becomes more relevant. Different fluids have different specific heat capacities, critical points, and viscosities, meaning properties derived from mass flow, temperature, and pressure, such as enthalpy, power, and reservoir pressure may vary depending on the fluid in question. Despite this, some participants think that incorporating additional special considerations for different working fluids is incorporating unnecessary complexity. Lastly, some experts suggest 2.5 kg/s/bar as a minimum PI for a producible well, citing limited fluid movement below this value. Others argue this may be too high, noting successful fields often include wells producing as low as 1 kg/s/bar, provided higher-PI wells are also present.

3. MODIFIED METHODOLOGY PROPOSED

3.1 Minimum Power Requirement-Based Approach

Based on a visual inspection of the plot in Figure 6, rough minimum temperature and mass flow requirements are proposed here based on a potential minimum power requirement combined with ambient temperature. These estimates will be refined in the final producible well determination methodology. When a power plant already exists and a new well is drilled to be connected to the existing plant, a producible well determination is not needed.

If we are targeting 4 MWe as the minimum power requirement, assuming a binary plant, the following temperature and mass flow requirements exist:

- If the ambient temperature is around 10°C: A wellhead temperature of at least 130°C is required, and a mass flow rate of at least 40 kg/s is needed.
- If the ambient temperature is around 20°C: A wellhead temperature of at least 140°C is required, and a mass flow rate of at least 60 kg/s is needed.
- If the ambient temperature is around 30°C: A wellhead temperature of at least 150°C is required, and a mass flow rate of at least 60 kg/s is needed.

This approach only relies on mass flow, wellhead temperature, and ambient temperature as input parameters, which is beneficial, as it reduces the complexity of the calculation. It does, however, only currently apply to binary plants, which is a drawback in terms of extensibility. It also may have lower accuracy due to the fact that it does not account for pressure in any sense. It is, however, worth noting that incorporating wellhead pressure into this method would require special considerations for pumped wells (i.e., estimating pressure downhole). Lastly, it relies on a relatively complex FGEM model to produce the ranges, and is not necessarily ‘simple’ as the title of this paper implies.

3.2 PI-Based Approach

A proposed PI-based approach to producible well determinations offers a practical and measurable framework for evaluating geothermal wells. This approach leverages the PI, defined as the ratio of mass flow rate to pressure drop (kg/s/bar), to assess a well’s capacity to produce geothermal fluids. By establishing specific PI thresholds, this method provides clear criteria for determining whether a well can be classified as producible.

For new power plant developments, where higher production capacities are generally necessary to justify the investment, a threshold of 2.5 kg/s/bar is recommended. These thresholds provide a baseline for evaluating a well's potential contribution to geothermal energy production, making the process more transparent and consistent.

The proposed approach requires parameters such as mass flow rate, wellhead pressure, and well characteristics (including depth, diameter, and casing material roughness). These parameters ensure that all relevant physical and operational factors are accounted for in the assessment. The PI is already widely used in the geothermal industry for assessing well productivity, which supports the applicability of this method.

However, the PI-based approach has several limitations. The data analysis relies on assumptions to estimate reservoir properties from surface measurements and incorporates well characteristics that may not fully capture the complexity of subsurface conditions. The PI is also less accurate for two-phase wells, where varying viscosity and flow characteristics affect measurements. Additionally, while the PI provides valuable information about a well's ability to deliver fluids, it offers limited insight into the enthalpy of those fluids—a critical parameter for geothermal energy production.

To address these limitations, the PI-based approach could be augmented by incorporating a minimum requirement for specific enthalpy, which is a required metric on the geothermal WCR, or through incorporating the minimum power requirement approach described here. For example, wells might be required to meet both the PI threshold and a specific enthalpy or power value that reflects the energy content of the produced fluids. This combined metric would provide a more robust and comprehensive framework for evaluating geothermal wells, ensuring that both fluid productivity and energy quality are considered in producible well determinations.

By balancing simplicity with flexibility, this proposed method offers a practical path forward for improving geothermal producible well determinations, while also leaving room for refinement as more data and improved methodologies become available.

3.3 Future Considerations

Several key factors should be considered for refining producible well determination methodologies in the future. One area of focus is the role of pressure in power-based approaches. Pressure directly influences the minimum power that can be extracted from a geothermal system and governs production mass flow rates, yet its variability across different reservoirs and well designs requires further investigation to ensure accurate assessments.

Similarly, the impact of enthalpy within PI-based approaches deserves greater attention. While the PI is a widely used measure of a well’s productivity, it does not fully account for the energy content of the produced fluids, which is critical for determining the overall power generation potential. A more comprehensive method might integrate both pressure and enthalpy, offering a hybrid approach that balances fluid productivity with energy quality.

Next-generation technologies like closed-loop systems and EGS will still need to demonstrate the ability to produce sufficient flowing enthalpy for each well, but adjustment to the methodology will be required to account for differences in the reservoir working fluid of test fluid. Variations in fluid composition, such as the highly saline and mineral-rich fluids found in the Salton Sea geothermal field, also highlight the need for adaptable assessment methods that can account for complex chemistry.

Finally, the next step for each of these methodologies should include validation using WCR data. Leveraging detailed data from existing wells can help calibrate and validate new approaches, ensuring they are grounded in real-world performance. By addressing these considerations, producible well determinations can evolve to meet the demands of increasingly diverse geothermal technologies and resources.

4. CONCLUSIONS

This study explored methodologies for defining producible well determinations in geothermal systems, a critical step for resource development and lease management on public lands. By drawing from existing practices in the oil and gas industry and adapting them to the unique challenges of geothermal energy production, we proposed two distinct approaches: one based on a minimum power requirement and another leveraging the PI.

The minimum power requirement-based approach offers a straightforward framework, tying producibility to specific power outputs. This method aligns well with binary power plants, which dominate recent geothermal capacity additions, but its reliance on limited parameters, such as wellhead temperature and mass flow rate and its assumptions about non-reservoir factors like working fluid, ambient temp and other operational factors, underscores the need for further refinement to account for pressure and other variables.

The PI-based approach provides a more comprehensive evaluation, considering parameters like pressure, mass flow rate, and well characteristics. However, its application is limited by uncertainties in estimating subsurface conditions and its reduced accuracy in two-phase wells. To enhance its utility, we propose integrating a specific enthalpy or minimum power requirement to capture the energy quality of produced fluids, creating a more robust and balanced assessment.

Both approaches demonstrate potential for improving geothermal producible well determinations. However, each has limitations that highlight the complexity of assessing geothermal resources, particularly in fields with unique fluid chemistry and in unconventional systems such as EGS and closed-loop technologies. Addressing these challenges requires a deeper focus on factors like enthalpy, fluid composition, and reservoir pressure, alongside continued validation using WCR data.

Future refinements to these methodologies should aim to incorporate additional physical and thermodynamic parameters while ensuring adaptability to diverse geothermal resource conditions. By advancing producible well determination practices, the geothermal industry can better align resource development with environmental and economic goals, supporting the sustainable expansion of geothermal energy production on public lands.

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