Analysis of Heat Recovery Time Predictions for Multiple Periods of Temporary Reinjection in Geothermal Well Production at Lumut Balai Field

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Keywords: *Re-injection wells, Thermal recovery rate, Geothermal reservoir, Hot reinjection, Reservoir management strategies.*

ABSTRACT

In Lumut Balai geothermal projects, where suitable re-injection wells are lacking, the temporary reinjection of hot fluid into high-temperature wells has become necessary, albeit risky. Initially designated as production wells, three wells have been temporarily repurposed as reinjection wells due to the urgent requirements for the commissioning of the Power Plant Operation. Over a period of approximately four years, a focus of concern has arisen, especially as the current project is in the process of developing Power Plant Unit 2, in which these three wells will revert to being production wells. A significant concern in this scenario is the duration required for the wells to return to their natural state. Our research approach encompasses several key steps: developing a two-dimensional conceptual model of the geothermal reservoir, simulating the temperature distribution under natural operating conditions, assessing the effects of cold reinjection during three distinct periods (three months, six months, and one year), conducting a comprehensive evaluation of the results, with a specific focus on the evolution of the temperature profiles of the wells, the rate of thermal recovery, and associated risks. This research is aimed at deepening our understanding of the challenges posed by temporary hot reinjection in geothermal projects. Ultimately, it seeks to inform the development of best practices and effective reservoir and risk management strategies for addressing similar challenges in the future.

1. INTRODUCTION

1.1 Lumut Balai Field Overview

The Lumut Balai Geothermal Field is a geothermal field located in the Semendo highlands. The prospect area encompasses the Lumut Hill, Balai Hill, parts of Ringgit Hill, and parts of Pandan Hill. This complex of volcanic hills is a series of eruption centers situated within an old caldera with a diameter of approximately 9 km. Within this old caldera, north-south and northeast-southwest-trending tectonic structures have developed, intersecting each other. These tectonic structures have evolved into faults and fractures that have been proven to be sources of permeability in the Lumut Balai field.

The subsurface fluid conditions in Lumut Balai are estimated based on the Na-K-Mg and SO4-Cl-HCO3 analyses obtained from drilling fluids. The fluids in the Lumut Balai field are in a state of equilibrium, with geothermometer temperature ranges of 250-300°C. The chloride-rich water type characterizes the chemical composition of the well fluids in the Lumut Balai field.

The dimensions, size, and boundaries of the Lumut Balai reservoir zone were determined through MT-Resistivity measurements extended to the east and north of the existing prospect. The Lumut Balai reservoir is bounded by the Lumut Hill fault, which trends NNE-SSW in the west, and the caldera wall in the east. In the north, the reservoir zone is estimated to extend into the Bunbun Hill area, controlled by the Air Ringkih fault, which trends NE-SW. The reservoir zone is also expected to extend to the northwest, controlled by the Air Udangan fault, which trends NW-SE. The southern extent of the reservoir zone is supported by surface manifestations controlled by the Gemurah-Pamalebar fault, which trends NNW-SSW. Therefore, the Lumut Balai prospect is estimated to cover an area of 65 km², with a proven area of 25 km².

The temperature in the Lumut Balai Field varies between 230°C and 260°C, and the reservoir pressure ranges from 50 to 60 bar. It is a water-dominated system with a two-phase zone in its cap rock. The depth of the feed zone ranges from 500 to 1400 meters above sea level, and the permeability falls within the medium to high range.

Figure 1: Lumut Balai Geothermal Field with Distribution of Wells (Production, Reinjection and Monitoring Wells)

1.2 Power Generation

The Lumut Balai Field commenced production on September 1, 2019, with the operation of Unit-1 generating 55 MW. Unit-2, with a planned capacity of 55 MW, is scheduled for commissioning in 2024. The average gross generation in 2022 was 53.7 MW, which is below the Net Capacity Factor (NCF) due to the First Year Inspection carried out from February to March 2022. Steam utilization remained relatively stable, ranging from 360 to 365 t/hr between 2020 and 2022.

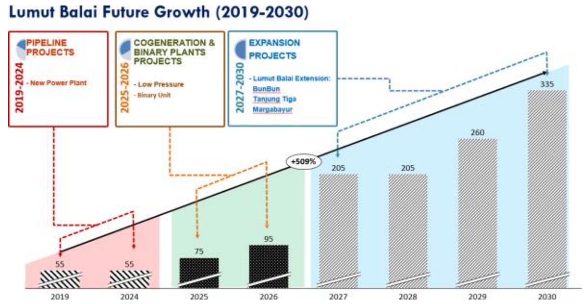

Figure 2: Lumut Balai Geothermal Future Growth of Power Generation Plan until 2030

PT. Pertamina Geothermal Energy is planning to boost its installed capacity by 600 MWe across all geothermal fields. Lumut Balai, due to its promising subsurface resources, stands out as a field with significant growth potential. The goal is to develop Lumut Balai to a capacity of 335 MWe, exceeding half of PGE's overall future capacity expansion plan as depicted in Figure 2.

1.2.1 Reservoir Characteristics

Reservoir monitoring in 2022 showed a very minor decline in the Lumut Balai Field, approximately 0.5% per year, and a reservoir pressure decline of approximately 0.25 to 0.38 bar per year in the western and eastern areas of the reservoir. Steam Supply projections, assuming a conservative 3% decline, indicate the need for makeup well drilling in 2027.

The current steam availability in Lumut Balai is 75.6 MW, with a total of 9 production wells for Unit-1 and 46.6 MW for Unit-2 from 5 production wells. The steam deficiency in Unit-2 will be supplemented from Unit-1 wells through an interconnected network, as outlined in the Unit-2 bidding contract. During Unit-1 operations, the reinjection strategy involves using wells in Cluster A as temporary reinjection wells, with a total reinjection fluid of approximately ~1890 t/hr. The transfer of reinjection from Cluster A to Cluster 18 is planned for late 2023. Monitoring heating-up will be a concern as an evaluation of Cluster A well performance when they are used as production wells.

The proven reservoir area is approximately 24 km^2, to the west bounded by a north-south trending fault and a northeast trending fault in the east. No clear structural boundaries can be proposed to the north and south of the system. The deep liquid upflow, with temperatures over 266ºC, is located in the SW (near LMB-5, LMB-6, LMB-1 and LMB-2), with outflow to the NE and N. Wells produce from a liquid dominated reservoir. There is good potential for high temperatures between clusters LMB-2, LMB-7, LMB-6, LMB-5. To the northeast of the reservoir area, according to geochemistry, there is potential for the reservoir to extend. If it is proven by drilling, then this would increase the reservoir volume and provide a potential upside to the reservoir capacity (Figure 3).

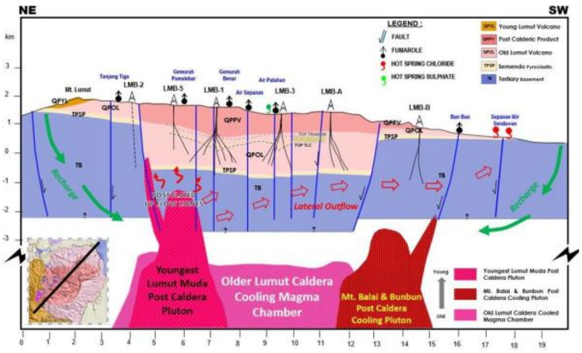

Figure 3: Static Conceptual Model of Lumut Balai Geothermal Field

1.2.2 Issues

The main issues in the Lumut Balai Field can be categorized into four aspects: steam availability, well and reservoir monitoring, reinjection strategy, and well integrity. The steam availability issue for Unit-2 and excess steam for Unit-1 necessitates the interconnection of steam lines from Unit-1 to Unit-2.

This results in excess brine production from Unit-1, requiring comprehensive engineering design to ensure that excess brine can be redirected from Unit-1 to Unit-2 reinjection wells. Steam availability for Unit-2 is also influenced by the performance of Cluster A (with a risk of losing 32 MW of steam potential) due to two years of reinjection. The transfer of reinjection to Cluster 18 needs to be expedited to reduce the negative impact of further temperature decline. Hole cleaning and accelerated makeup well strategies will be further evaluated as mitigation if Cluster A discharge is unsuccessful. The total brine reinjected to these three wells are about 27.000 kilo-liters during 2020-2023 (Table 1&2).

Another concern in steam availability is the low well and separator pressures. So far, production wells have been choked to openings of 40-50%. The low well pressure is due to the relatively deep Lumut Balai reservoir and low reservoir pressure. Therefore, routine weekly monitoring continues, and optimization of production facilities is required if the well pressure approaches the separator pressure.

Table 1. Total liquid injection during drilling operation

Wells	Spud In	Finish Drilled	Duration (Days)	Total liquid injected during drilling (bbls)
LMB-A1	20 Aug 2012	11 Oct 2012	52	253830
LMB-A2	21 Oct 2012	3 Dec 2012	43	123755
LMB-A3	9 Mar 2013	24 Apr 2013	46	287314

Table 2. Total cumulative liquid injection 2020-2023

Wells	Injection Cummulative (kilo liter)(1)
LMB-A1	-
LMB-A2	14,454.82
LMB-A3	12,617.52

(1)Injection Period from 2020 to 31 January 2023

ISSN2703-4275

2. METHODOLOGY

2.1 Reservoir Surveillance

In the management of the Lumut Balai reservoir and wells, monitoring well performance in 2022 included production tests on well LMB-19.2. However, Tracer Flow Tests were not conducted in 2022, resulting in a lack of enthalpy data for further evaluation. This limitation complicates the accurate determination of decline rates. In geochemical monitoring, the FPT results for well LMB-1.4 indicate that chloride values have not increased and tend to decrease, while well LMB-1.6 shows stable chloride values. NCG values in well LMB-1.6 tend to be consistent with the latest data, while well LMB-1.4 has seen a slight increase in NCG values.

Silica concentration in well LMB-1.4 has shown a decreasing trend, but in this data, it tends to slightly rise, whereas LMB-1.6 shows stability. Silica scaling in both wells is likely to occur below 150°C, and Calcite formation occurs above 200°C for LMB-1.4 and 150°C for LMB-1.6. Scaling simulations for LMB-1.6 are consistent with the scale catcher results at a depth of 1160 mMD, which contains Magnetite, Calcite, and Pyrite. Additionally, the consistently high TDS values in LMB wells, with an average of ~18,000 ppm, raise the potential for casing and production facility abrasion. Casing thickness monitoring conducted since 2020 with periodic measurements has not shown any casing or pipe thickness reduction. However, this program should continue to ensure that the effects of high TDS on LMB production and reinjection facilities are continuously monitored.

3. ANALYSIS

3.1 Thermal Recovery Analysis

The reinjection strategy in wells LMB-A1, LMB-A2, and LMB-A3 throughout 2022 did not negatively impact production wells. Static PT monitoring in well LMB-1.3, the closest well to the reinjection cluster, showed no change in temperature.

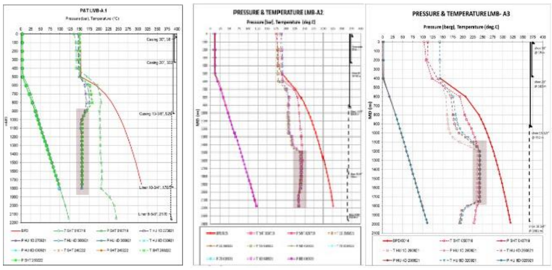

Figure 4: Multiple Heating Up Pressure & Temperature Monitoring of Cluster A (2021, 2022, 2023)

This will be evaluated through the implementation and analysis of an Inter-well Tracer Test in 2023. This study is expected to provide insights and comparisons when reinjection is shifted to Cluster 18.

Well integrity (Figure 5) is a primary concern in Cluster A. Caliper results indicate thinning and ovality in well LMB-A1, along with the presence of silica fragments. These findings raise the risk of casing collapse during well LMB-A1 discharge. Caliper surveys has been conducted in 2023 on wells LMB-A2 and LMB-A3. The results of these caliper surveys will be considered when Cluster A wells are discharged.

As part of the 600 MW development program, the Brine to Power and Low Pressure Lumut Balai development stages have undergone resource verification and simulation. Confirmed low-pressure well potential through production tests amounts to 20 MW from five monitoring wells: LMB-1.1, LMB-1.2, LMB-2.1, LMB-3.1, and LMB-3.2.

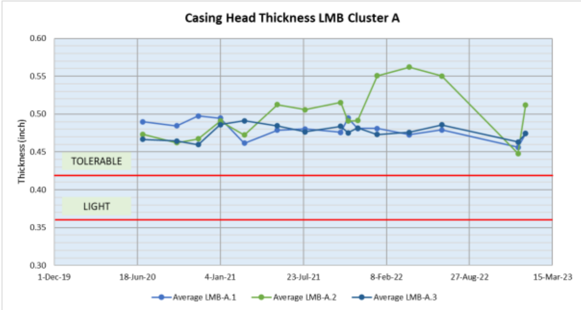

Figure 5: Casing head thickness monitoring of Cluster A

Meanwhile, the planned binary plant from the total produced brine, approximately 3780 t/hr, can generate about 20 MW, assuming an outlet binary temperature of 105°C. Based on this plan, the bottoming resource potential from the low-pressure and binary units is approximately 40 MW. To support reservoir sustainability, reservoir simulation studies indicate that Lumut Balai's bottoming resource development can last for the 25-year contract period. On the other hand, one emerging risk is silica scaling in Lumut Balai at 150°C.

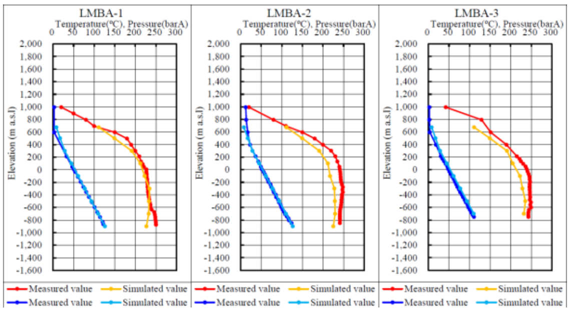

Figure 6: Natural State Pressure & Temperature Monitoring of Cluster A

Figure 4 and Figure 6 show that the hot brine reinjection is not significantly impactful on reservoir cooling since the pressure and temperature can revert back to their steady state values even though it requires a longer time because the brine volume is high and there is a long injection period.

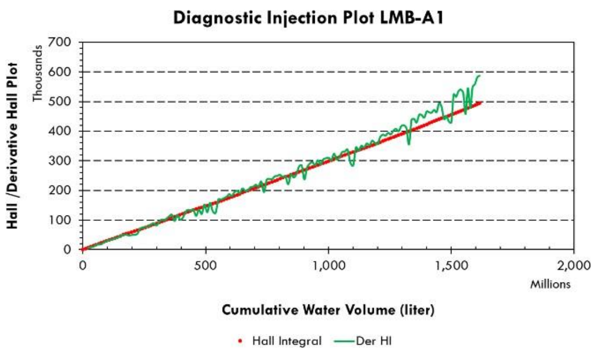

Figure 7: Diagnostic Injection of LMB A-1 using a Horner Plot

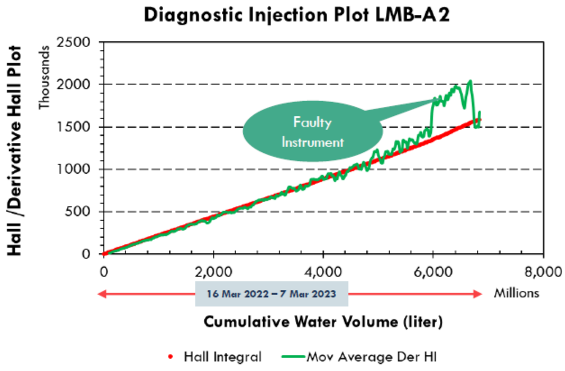

Figure 8: Diagnostic Injection of LMB A-2 using a Horner Plot

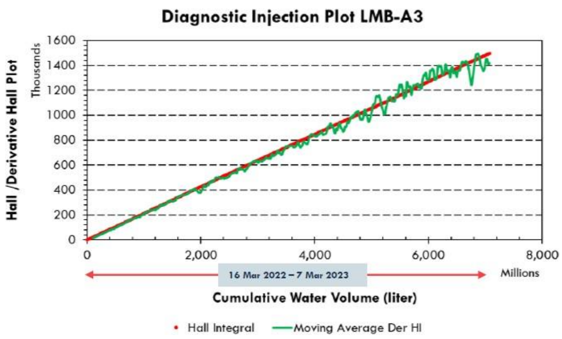

Figure 9: Diagnostic Injection of LMB A-3 using a Horner Plot

Figures 7, 8 and 9 show the diagnostic analysis of reinjection impact on the well performance. The curve of Hall Integral and moving average of Hall Integral derivative are overlapping each other which means that the hot brine reinjection is not significantly influencing the well performance for production in the future.

A kinetic study of silica will be conducted in 2024 after reinjection relocation. The kinetic study will provide optimal treatment options to prevent scaling at lower temperatures due to increased heat extraction. Another risk is thermal breakthrough, and so an inter-well tracer test will be conducted after reinjection is moved from Cluster A to Cluster 18. This evaluation is expected to provide recommendations for optimum development, enabling the COD of LP (Low Pressure) and BU (Binary Unit) Unit-1 in 2025, as per the 600 MW development plan.

4. RESULT

The rate of temperature recovery at production and injection wells upon cessation of injection after one, two, or five years exhibits variability. The injection well experiences notably swifter recovery due to the presence of larger temperature gradients near the injection point and the formation of a counterclockwise buoyancy-driven convection cell within the fracture, which displaces cold fluid away from the injection site. While this phenomenon does slow down the pace of temperature recovery at the production well, a substantial improvement is still noticeable within a few months. These findings are encouraging and suggest that halting injection in a well can effectively rectify undesirable temperature declines in a production well linked by a favored flow path experiencing thermal interference. Comparable instances of thermal recovery have been documented in diverse geothermal fields.

$$\zeta(x,t) = \frac{\sqrt{\lambda_2\rho_2c_2}\;x}{w\phi_f\rho_w c_w v_w\;\sqrt{t - t^*}}$$

$$= \frac{\sqrt{\lambda_2\rho_2c_2}\;x}{c_w(q/H)\;\sqrt{t - t^*}} \qquad (1)$$

where $q/H = w\phi_f\rho_w v_w$ njection rate per unit fracture height, and U is the Heaviside step function, Here, t* is the breakthrough time of the thermal front in the absence of lateral heat conduction, and is given by (Bodvarsson, 1982)

$$t^* = \frac{\rho_1 c_1 x}{\rho_w c_w \phi_f v_w} \qquad (2)$$

Thermal breakthrough :

$$t_f = t^* + \frac{\alpha}{\zeta_f^2}\,\frac{x_f^2}{(q/H)^2} \qquad (3)$$

$\alpha = \lambda_2\rho_2c_2/c_w^2$ is a group of thermal parameters which is not strongly dependent upon site specific conditions.

Using the formula above, then the thermal recovery for those 3 wells in cluster A need a maximum of ~3.5 months (Figure 10) to reach the static, initial condition. This is faster than cold reinjection since the hot brine maintains the heat and enthalpy in the wellbore and reservoir.

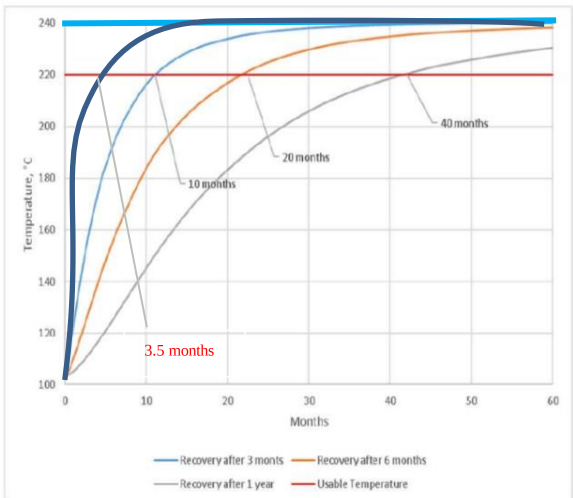

Figure 10: Temperature recovery for 4 scenarios which shows the time to reach 240 °C is about 3.5 months for all wells in Cluster A (Kaypakoglu and Barbon, 2018)

5. CONCLUSION

- Predictions regarding thermal interference can be derived solely from tracer data. However, this usually necessitates an ad-hoc model for assessing flow path geometry, and the reliability of thermal forecasts based on this approach remains uncertain.
- In cases where undesirable declines in production temperature are caused by thermal interference along a favored flow path, resolving the issue can often be achieved by temporarily shutting down the injection well involved. This action typically results in a substantial temperature recovery within a few months, offering an acceptable solution.
- The average thermal recovery time for all wells in cluster A where there has been multiple reinjection and shut-in conditions using hot brine will be approximately 3.5 months.

ACKNOWLEDGEMENTS

We would like to express our sincere gratitude to the Lumut Balai management team, reservoir and geoscience team at PT Pertamina Geothermal Energy, whose invaluable contributions were pivotal in the successful completion of this research paper. The insightful guidance of our mentors, the collaborative efforts of our colleagues, support from resource-providing institutions, and constructive feedback from reviewers all played vital roles in shaping the outcome of this study. Furthermore, the encouragement and support received from friends, family, and the broader academic community were instrumental in keeping us motivated throughout this research journey. We deeply appreciate the collective efforts that enriched this endeavor and made its successful culmination possible.

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