

Technical and Financial Feasibility of Green Hydrogen Production with Geothermal Energy Systems

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ABSTRACT: This study provides a thermo-economic assessment of geothermal-based hydrogen production systems over 30 years. A detailed 3D finite element model is developed to simulate underground system components, including impervious ground layers above the aquifer reservoir, integrated with a semi-analytical model for aboveground processes. The methodology combines thermodynamic and economic evaluations to compare advanced Organic Rankine Cycle (ORC) configurations against a baseline simple ORC system. The findings reveal significant thermal interactions between geothermal wells and the surrounding ground. Heat losses in the production well result in a temperature differential of up to 7°C between the bottom and top of the well, leading to a 19% reduction in hydrogen production rates and an increase in production costs during the first five years of operation. These effects diminish over time, with temperature differences reducing to 1.4°C by the final decade, resulting in lower variations in production rates and costs, respectively. Advanced ORC configurations incorporating Thermoelectric Generators (TEGs) demonstrate potential to mitigate these losses, optimise efficiency, and lower costs. The inclusion of geological storage would allow offsetting variability in hydrogen production and improving economic feasibility, and is subject of a follow on work. Long-term storage in aquifers can complement geothermal systems by balancing operational challenges and enhancing market flexibility. This study underscores the need for accurate modelling of heat loss in geothermal wells and costs when assessing the performance and viability of geothermal hydrogen systems. These insights provide a framework for optimising system design, supporting the development of sustainable hydrogen production technologies to meet future energy demands.

KEYWORDS: hydrogen, electrolysis, geothermal, h₂ storage, numerical modelling.

1 THE ROLE OF GEOTHERMAL ENERGY IN GREEN HYDROGEN PRODUCTION

Geothermal energy is increasingly recognised as a sustainable and reliable alternative to fossil fuels, offering a clean, constant, and weather-independent electricity supply. It holds strong potential for cost-effective hydrogen production via renewable electrolysis, with potentially lower production costs and higher energy conversion efficiency than solar and wind technologies. This study investigates the often-overlooked impact of heat losses within geothermal wells and their influence on hydrogen production rates and associated costs when hydrogen is produced through electrolysis powered by geothermal-generated electricity and heat.

Previous research into geothermal hydrogen systems has typically assessed performance over short timeframes, often limited to a single year, neglecting long-term geothermal reservoir cooling effects (Chang et al. 2025). In addition, existing geothermal models frequently oversimplify the subsurface by ignoring low-permeability caprock layers above the reservoir and the heat losses that occur along the wellbore (Shi et al. 2023). A common modelling assumption is that the bottomhole temperature is preserved all the way to the surface, neglecting conductive losses even in insulated wells (Hsieh et al. 2024). This simplification may result in overestimated surface temperatures and, consequently, hydrogen yields. In doublet geothermal systems, the thermal interactions between the reservoir, wells, and ground mass have shown a crucial role in the geothermal system's performance over its lifespan (Cai et al. 2024).

To address these limitations, this study presents a detailed subsurface model incorporating caprock and saturated aquifer layers, enabling accurate prediction of the production well's wellhead temperature—an often overlooked parameter (Hamlehdar et al. 2024). The objective is to deliver a more representative and accurate assessment of system performance and economics across the full operational lifespan of a geothermal reservoir.

2 MODELLING APPROACH: COUPLING SUBSURFACE AND SURFACE SYSTEMS

To enable a rigorous and comprehensive assessment of the hybrid geothermal–hydrogen production system, this study employs an integrated modelling framework that couples both underground and aboveground system components (Figure 1).

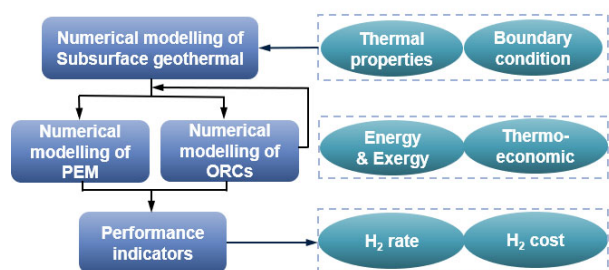


Figure 1. Integrated modelling framework

2.1 Subsurface (Geothermal) Model

For the geothermal system, a detailed three-dimensional finite element (FE) model is developed. This model captures the saturated aquifer reservoir, the overlying low-permeability strata (caprock), and the entire subsurface infrastructure, including the wellbores. The FE approach is particularly well-suited to investigate the sensitivity of geothermal doublet performance to key design and geological parameters.

The geothermal configuration modelled here involves a deep doublet system, comprising one production and one reinjection well, a typical arrangement in geothermal developments designed to ensure sustainable energy extraction and effective reservoir pressure management. Heat transfer is modelled through both conduction (within the geological formations and wellbore grout) and convection (within the aquifer fluid and circulating wellbore fluids), with transport processes simulated over a 30-year operational timeframe.

The geological setting is based on the Early Permian Sandstone formation in the northern Perth sedimentary basin, Western Australia, located at a depth of approximately 3,000 metres and confined by impermeable overburden. The aquifer and adjacent formations are represented in full 3D, while the wells are modelled using 1D elements to capture vertical heat

transfer efficiently. Unlike many existing models that assume no thermal losses along the well, this approach explicitly accounts for wellbore heat dissipation, enabling the estimation of the actual production temperature at the wellhead.

Figure 2 shows the two key numerical models of a doublet geothermal system and key boundary conditions. The injection temperature and flow rate are 62°C and 100 l/s, respectively. The pressures at the bottom of the production and injection wells are equal to the reservoir pressure. On the left, a typical aquifer-only (3D) model, which assume the wellhead production temperature is the same as the bottomhole temperature. On the right, a 3D view of the full geometry model. Details on the various governing equations for the aboveground components in the different configurations can be found elsewhere (Hamlehdar et al. 2024). This study extends that framework by incorporating a full 3D ground model and explicitly accounting for wellbore heat losses, elements not fully addressed in previous analyses. The computed wellhead temperatures are then used as the input for the surface system, improving realism and accuracy over models that simplistically apply the bottomhole temperature at surface level.

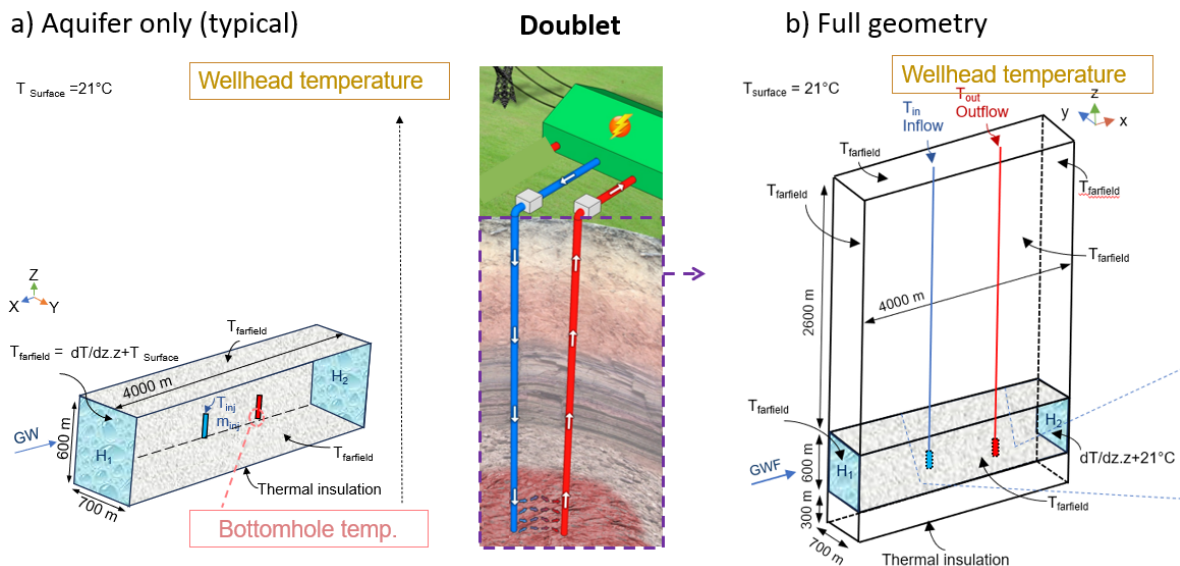


Figure 2. Numerical model of a doublet geothermal system and key boundary conditions (temperatures T , groundwater flow (GWF), heads H , and production and injection rates: (left) 3D view of a typical aquifer-only model, which assume the surface production temperature is the same as the bottomhole temperature, and (right) 3D view of the full geometry model. Both models are implemented and solved in the FE package Comsol Multiphysics (COMSOL, 2024).

2.2 Aboveground (Hydrogen Production) Model

The temperature output from the geothermal model is dynamically coupled with a semi-analytical model of the surface system, which includes geothermal heat extraction, power generation via Organic Rankine Cycle (ORC) systems, and hydrogen production through a proton exchange membrane (PEM) electrolyser.

Multiple ORC configurations are assessed:

- A baseline system employing a simple ORC;
- Three advanced configurations integrating waste heat recovery and ORC cycle enhancements:
 1. IHX-based system: featuring an Internal Heat Exchanger;
 2. ORG-based system: utilising an Open Regenerator;
 3. CRG-based system: using a Closed Regenerator.

In all advanced configurations, a thermoelectric generator (TEG) is incorporated to convert residual thermal energy into additional electrical power. This supplementary electricity helps power the PEM electrolyser, increasing overall system efficiency.

Details on the various governing equations for the aboveground components in the different configurations can be found elsewhere (Hamlehdar et al. 2024). In the present work, this framework is enhanced through the integration of updated performance models and long-term heat-loss representations, thereby improving the accuracy and realism of the overall system analysis. These are implemented and solved using the Engineering Equation Solver (EES) software (ESS, 2025).

2.3 Performance Evaluation

The aboveground modelling involves both thermodynamic and thermo-economic analyses. The thermodynamic assessment applies conservation laws of mass, energy, and exergy to each system component. The thermo-economic evaluation uses the Specific Exergy Costing (SPECOC) method to estimate cost contributions from exergy losses and calculate the cost of the hydrogen product.

Performance metrics include the hydrogen production rate and the specific cost of hydrogen over the system's operational life. This integrated approach provides a robust basis for comparing system configurations, identifying cost-performance trade-offs, and informing future design improvements for hybrid geothermal-hydrogen systems.

3 IMPACT OF GEOTHERMAL WELL HEAT LOSSES ON SYSTEM PERFORMANCE

This study quantifies the influence of thermal losses along the vertical length of geothermal wells, a factor frequently overlooked in conventional modelling approaches. As geothermal fluid ascends from the reservoir to the surface, a notable temperature drop is observed due to conductive heat loss through the surrounding geological strata and well materials.

The simulation results indicate a clear time-dependent reduction in the temperature differential between the geothermal reservoir and the surface facilities, reflecting the cumulative effects of long-term operation and progressive thermal depletion.

During the initial five years of operation, the system experiences the largest thermal gradient, with an average temperature drop of approximately 7.3 °C between the reservoir and the surface. As operation continues, this differential decreases noticeably, falling to 3.8 °C and 2.7 °C over the subsequent 15-year period. In the final decade of operation, the temperature difference further declines to approximately 1.4 °C, indicating a significant reduction in the effective geothermal gradient as heat is progressively extracted from the system.

These thermal losses have a direct and material impact on both hydrogen production and overall project economics. In the first five years, models that neglect wellbore heat losses, specifically aquifer-only models, substantially overestimate system performance. During this period, hydrogen production is over-predicted by 19.3%, while associated costs are underestimated by approximately 12%, leading to an overly optimistic assessment of project viability. Although the magnitude of this discrepancy decreases over time as the geothermal gradient diminishes, the effect remains non-negligible throughout the project life.

Specifically, hydrogen production is overestimated by 9.95% during years 6–10, 7.0% during years 11–20, and 4.0% in the final decade when wellbore heat losses are ignored. When considered across the full operational lifespan, the cumulative effect results in an average cost underestimation of 9.36%, highlighting the importance of explicitly accounting for wellbore thermal losses in system-level models. These findings demonstrate that simplified modelling approaches can lead to systematic bias in both performance and cost estimates, particularly during the early, most economically critical stages of operation.

In other words, these findings highlight the importance of incorporating the full vertical heat exchange pathway, including low-permeability overburden layers and wellbore conduction, into geothermal system models. Failing to do so risks unconservative system designs, leading to overestimated

performance and underestimated costs, particularly in the early operational years when investor and policy decisions are most sensitive to projected returns.

4 ABOVEGROUND SYSTEM CONFIGURATIONS AND PERFORMANCE OF GEOTHERMAL WELL HEAT LOSSES ON SYSTEM PERFORMANCE

Based on the wellhead temperatures predicted by the coupled three-dimensional geothermal reservoir model, a comprehensive performance assessment of multiple aboveground hydrogen production system configurations was undertaken.

This analysis aimed to quantify how different thermal cycle designs and waste heat recovery strategies influence overall system efficiency, electricity generation, and downstream hydrogen production via PEM electrolysis.

The configurations evaluated include a baseline simple Organic Rankine Cycle (ORC) as a reference case, alongside the three enhanced configurations: the Internal Heat Exchanger (IHX) system, the Open Regenerator (ORG) system, and the Closed Regenerator (CRG) system. These configurations were deliberately selected to explore progressively higher levels of thermal integration and to assess the effectiveness of regenerative heat recovery and cycle modification strategies under realistic geothermal operating conditions.

Among the systems examined, the simple ORC configuration consistently exhibited the lowest hydrogen production rates and overall efficiency, primarily due to its limited ability to recover and reutilise low-grade waste heat. The absence of regenerative components restricts the system's thermodynamic performance, resulting in lower net power output available for hydrogen generation. In contrast, the enhanced configurations, particularly the CRG system, demonstrated substantially improved performance. The CRG configuration consistently outperformed all other designs across the full range of operating scenarios, delivering superior thermodynamic efficiency, higher hydrogen output, and improved cost-effectiveness.

The strong performance of the CRG system can be attributed to its integrated regenerative heat exchange architecture, which significantly improves internal energy utilisation, coupled with supplementary power generation via a thermoelectric generator (TEG). The TEG enables recovery of residual thermal energy that would otherwise be rejected, converting it into additional electrical power. This additional power directly enhances the net electricity supplied to the PEM electrolyser, thereby increasing hydrogen production without requiring additional geothermal extraction or capital-intensive infrastructure (see Table 1).

To better understand system behaviour and robustness, comprehensive sensitivity analyses were undertaken to evaluate the influence of key design and operational parameters. These included turbine inlet and outlet pressures, working fluid mass flow rates, and temperature differentials across major cycle components such as heat exchangers and regenerators. The results of these analyses identified well-defined parameter ranges that maximise hydrogen output while simultaneously minimising system costs, highlighting the importance of careful design tuning and operational optimisation.

Building on these insights, a multi-objective optimisation framework was implemented to balance competing objectives of performance maximisation and cost minimisation. Over a 19-year simulation horizon, the optimisation process achieved a 15.5% increase in average hydrogen production, while inducing only a marginal change in the levelised cost of energy, limited to 0.24%. This outcome demonstrates that substantial

performance gains can be realised through system-level optimisation without compromising economic viability.

Overall, the CRG configuration delivered the most promising results, achieving daily hydrogen production rates ranging from 408.7 to 460.6 kg, with corresponding specific hydrogen costs between AUD 50.87 and AUD 51.21 per gigajoule. These findings clearly demonstrate the value of integrated thermal recovery, advanced cycle design, and optimisation-driven system analysis in enhancing the technical and economic performance of hybrid geothermal–hydrogen energy systems.

Table 1. Performance comparisons over the 1st year.

Parameter	Simple	CRG	Unit	Description
η_{ex}	11	12	%	Exergy efficiency
W_{net}	2028	2676	kW	Net output power
\dot{m}_{H_2}	390	408.7	kg/day	Hydrogen production rate
$c_{t,p}$	54.54	51.21	\$/GJ	Total product cost

5 INFLUENCE OF GROUND CONDITIONS: THERMAL CONDUCTIVITY AND GEOTHERMAL GRADIENT BODY

A significant advantage of employing a detailed three-dimensional (3D) finite element model is the ability to explore the effects of key subsurface parameters, particularly those associated with the low-permeability layers above the reservoir and the wells that traverse them. This section examines how ground thermal conductivity and the geothermal gradient influence system performance, using the optimised CRG-based surface configuration as a reference.

5.1 Ground Thermal Conductivity

Ground thermal conductivity plays a fundamental role in governing the heat transfer processes that occur around the wellbore, particularly in the near-surface sections of the system where geothermal fluids are most exposed to thermal losses. In these shallow regions, the temperature difference between the ascending geothermal fluid and the surrounding ground is the greatest, making conductive heat dissipation a dominant mechanism influencing overall system performance. When the surrounding ground exhibits lower thermal conductivity, the rate at which heat is conducted away from the wellbore into the formation is reduced. This effectively acts as a form of thermal insulation, limiting energy losses during fluid ascent.

As a consequence, geothermal fluids retain a larger proportion of their thermal energy as they travel toward the surface, resulting in higher wellhead temperatures. These elevated temperatures directly improve the efficiency of the aboveground energy conversion systems, increasing the amount of usable electricity generated and, in turn, enhancing hydrogen production rates. Conversely, higher ground thermal conductivities facilitate faster heat transfer to the surrounding formation, accelerating thermal losses and reducing the thermal potential available at the wellhead.

Simulation results clearly demonstrate the importance of this effect. Scenarios with relatively low ground thermal conductivities (below $\sim 3 \text{ W}/(\text{m}\cdot^\circ\text{C})$) exhibited an average 21.7% increase in hydrogen production over the initial 19-year operational period when compared with reference conditions. In contrast, cases with thermal conductivities equal to or greater than $3 \text{ W}/(\text{m}\cdot^\circ\text{C})$ showed a smaller, but still significant, average increase of 18.12% in hydrogen production. Although the absolute difference between these two cases may appear modest, it reflects a meaningful cumulative gain in long-term hydrogen output attributable to improved thermal retention.

These results highlight the thermal shielding effect provided by low-conductivity formations, particularly during the early and mid-life stages of operation when temperature gradients are highest. Notably, despite the clear influence of ground thermal conductivity on hydrogen production rates, the overall cost of hydrogen production remained relatively insensitive to variations in this parameter. This suggests that the gains in thermal efficiency and productivity achieved under low-conductivity conditions are not offset by increases in capital expenditure or operational costs.

Taken together, these findings indicate that geological site selection plays a critical role in the performance of geothermal-based hydrogen systems. Sites characterised by naturally lower ground thermal conductivities offer a strategic advantage, as they minimise wellbore heat losses, improve system efficiency, and enhance hydrogen productivity without adversely impacting economic viability. This underscores the importance of incorporating detailed thermal property characterisation into early-stage feasibility assessments and system design processes.

5.2 Geothermal Gradient

The geothermal gradient represents the rate at which subsurface temperature increases with depth and is a key parameter governing the thermal potential of geothermal systems. It is intrinsically linked to the thermal and geological characteristics of the subsurface, including heat flow, lithology, and regional tectonic setting. A steeper geothermal gradient results in higher temperatures being reached at shallower depths, which directly increases the temperature of the extracted geothermal fluid. This, in turn, enhances the performance of the aboveground energy conversion systems and improves overall hydrogen production efficiency.

In addition to improving thermal output, higher geothermal gradients can significantly reduce the required drilling depth to achieve target reservoir temperatures. This reduction has important economic implications, as drilling represents one of the largest components of capital expenditure in geothermal projects. Shallower wells reduce drilling time, material requirements, and construction risks, thereby offering potential cost savings and improving project feasibility (see Figure 3).

Figure 3 illustrates the direct relationship between geothermal gradient and geothermal wellhead temperature, clearly showing that steeper gradients yield higher surface temperatures for the same reservoir depth. This increase in wellhead temperature translates into improved thermodynamic efficiency of the power cycle and greater electrical output available for hydrogen production.

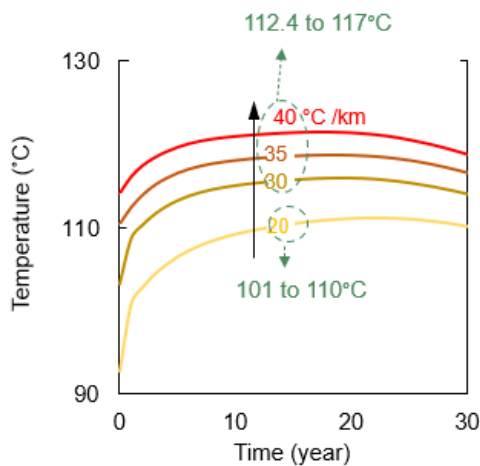


Figure 3. Geothermal gradient impact on) geothermal wellhead temperature.

The range of geothermal gradients assessed in this study reveals a strong and consistent correlation between gradient steepness and overall system efficiency. As shown in Figure 4, increasing the geothermal gradient leads to substantial reductions in the normalised cost of hydrogen production, alongside higher daily hydrogen yields over the 30-year operational period. For example, at a relatively low gradient of 20 °C/km, hydrogen production costs remain high, ranging between AUD 102.30 and AUD 82.00 per GJ, reflecting limited thermal potential and lower system efficiency.

When the gradient increases to 30 °C/km, costs decrease markedly to a range of AUD 56.41 to AUD 54.16 per GJ, indicating a significant improvement in both energy conversion efficiency and economic performance. At 35 °C/km, costs are further reduced to between AUD 51.21 and AUD 50.94 per GJ, demonstrating diminishing but still meaningful gains as thermal conditions improve. The most favourable results are observed at a gradient of 40 °C/km, where hydrogen production costs reach their lowest levels, ranging from AUD 44.47 to AUD 44.70 per GJ, supported by consistently higher hydrogen yields throughout the operational lifespan.

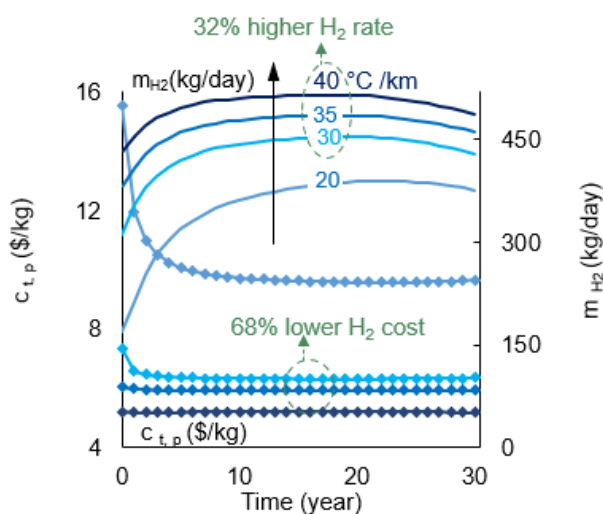


Figure 4. Geothermal gradient impact on normalized cost of hydrogen production and daily yield along 30 years of operation.

Figure 4 highlights not only the magnitude of these cost reductions but also their persistence over time, confirming that geothermal gradient exerts a long-term influence on system performance rather than a short-lived initial benefit. The results emphasise that sites with higher geothermal gradients provide sustained advantages in both productivity and cost efficiency.

In summary, the integrated modelling framework confirms that ground thermal properties, and in particular the geothermal gradient, have a measurable and enduring impact on the technical and economic performance of hybrid geothermal–hydrogen systems. Careful site selection, accounting for both geothermal gradient and ground thermal conductivity, is therefore critical for maximising system efficiency, reducing costs, and ensuring long-term project viability.

6 CONCLUSIONS

This study presents a comprehensive 30-year performance evaluation of a geothermal-based hydrogen production system, employing an integrated modelling framework that combines detailed subsurface and aboveground components. A full three-dimensional finite element model was used to simulate not only the geothermal aquifer but also the overlying low-permeability ground layers and wellbores—elements frequently neglected in prior studies. By capturing conductive heat losses from the production well as fluid ascends to the surface, the model provides a more accurate representation of the thermal energy available for hydrogen production.

The findings clearly demonstrate that heat losses in geothermal wells, particularly during the early years of operation, lead to significant reductions in wellhead temperature, which in turn diminish hydrogen output and increase production costs. In contrast, simplified aquifer-only models that omit these thermal losses consistently overestimate system performance and underestimate economic requirements, leading to potentially misleading design and investment decisions.

Among the surface system configurations assessed, the Closed Regenerator (CRG) system consistently outperformed the baseline simple ORC design in terms of both hydrogen production rate and cost-efficiency. The inclusion of thermal regeneration and waste heat recovery, particularly through the use of thermoelectric generators (TEGs), was shown to significantly enhance performance without substantially increasing capital or operating costs.

The study also investigated the influence of subsurface ground conditions, highlighting the importance of site-specific thermal properties. Lower ground thermal conductivity was found to reduce heat losses in the wellbore, resulting in higher surface temperatures and greater hydrogen yields. Similarly, higher geothermal gradients were associated with increased reservoir temperatures at shallower depths, enabling both improved efficiency and reduced drilling costs.

Taken together, the results emphasise the critical importance of adopting comprehensive, coupled modelling approaches that accurately represent subsurface thermal dynamics and integrate them with advanced surface system configurations. Such modelling is essential for realistic, long-term performance forecasting and cost assessment of hybrid geothermal–hydrogen systems. By accounting for thermal losses, geological variability, and system-level optimisation, this approach supports more robust techno-economic evaluations and informs better decision-making for future deployments.

7 ACKNOWLEDGEMENTS

The second author gratefully acknowledges the University of Melbourne for the support provided through the Melbourne Research Scholarship. Additionally, she extends her thanks for the travel fellowship that enabled her to visit Europe and engage with leading experts in hydrogen storage. This paper is a direct outcome of those valuable interactions.

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