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Reservoir Modeling for Geothermal Energy and Lithium Recovery

Elena Meyer, Baker Hughes; Amir Moradi, Bahrain Petroleum Company; Colleen Barton, Ehsaan Nasir, Tim Salter, Christopher Harper, and William Pettitt, Baker Hughes; Danny Sims and William L. Osborn, Controlled Thermal Resources

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Abstract

This paper presents the development and application of a natural state and dynamic numerical reservoir model for the Hell's Kitchen Geothermal LLC project located within the Salton Sea Geothermal Field. The work was performed to estimate the geothermal power potential and lithium production capacity of the resource to support a feasibility study. Using advanced simulation tools, coupled with geochemical and geomechanical inputs, the project assessed fluid dynamics across density gradients and forecasted production scenarios. Sensitivity analyses on permeability and well spacing provided insights into optimizing resource extraction. The findings emphasize the significance of a halocline barrier and fracture networks in controlling fluid behavior, demonstrating the potential for long-term sustainable production.

Introduction

The Hell's Kitchen Geothermal LLC (HKG) project is situated within the Salton Sea Geothermal Field (SSGF), one of the world's most active geothermal regions ([Figure 1](#)). Known for its high temperature mineralized brine and complex subsurface characteristics, the field is a critical resource for renewable energy and lithium production, a mineral essential for energy storage technologies.



Figure 1—HKG project location within the Salton Sea Geothermal Field.

The HKG project seeks to capitalize on the dual potential of geothermal energy and critical mineral production, specifically lithium, by employing innovative reservoir management strategies. The metasediment-hosted prograde magmatic hydrothermal system presents both opportunities and challenges for sustainable resource development. Effective modeling is essential for understanding subsurface dynamics and guiding operational decisions.

The primary objectives of this study were:

- To develop a robust natural state and dynamic reservoir model incorporating fracture networks and salinity gradients.
- To estimate geothermal power potential and lithium production capacity.
- To evaluate production and injection strategies for long-term sustainable development.

Past studies, such as [Araya & O'Sullivan \(2022\)](#), explored fluid pathways and fault dynamics within the SSGF. This work differs by integrating advanced methodologies, such as developing and incorporating a hydrostructural Discrete Fracture Network (DFN) ([Dershowitz, 2004](#)) and the integration of a halocline boundary ([Sims and Neuhoﬀ, 2018](#)) into the dynamic flow modelling, to provide more accurate forecasts and operational insights for development of SSGF.

Methodology

Overview of Approach

This study applied a comprehensive and integrated workflow to develop a natural state and dynamic numerical reservoir model for the HKG project. The approach focused on accurately simulating fluid flow, temperature gradients, and production performance, leveraging complex software and new data to optimize operational strategies.

The modeling process utilized several software platforms:

- A subsurface modeling platform: for geological modeling and constructing the 3D grid.
- A geomechanics package: for geomechanical modeling of 1D to 3D rock properties and stress field.
- A geomechanics-coupled DFN simulator: for discrete fracture network (DFN) modeling, enabling detailed analysis of fracture permeability.
- A reservoir simulation software: to perform reservoir simulations and predict production performance.

These tools were integrated to capture the complex interactions between geological features, fluid flow, and thermal behavior in the reservoir (Figure 2).

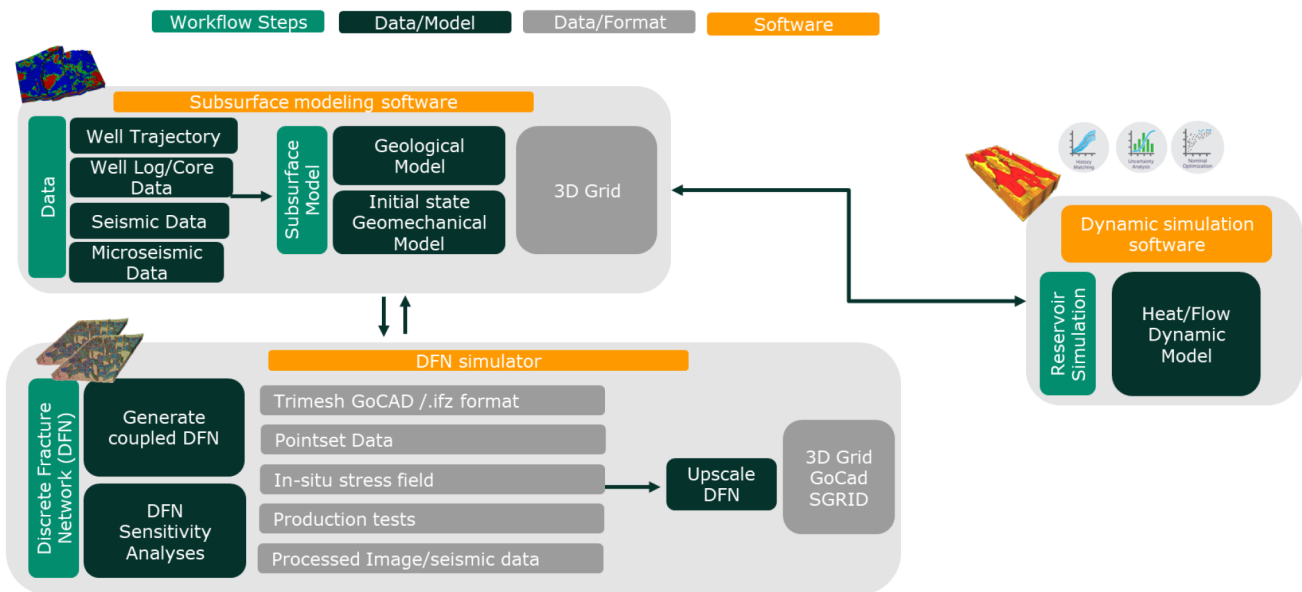


Figure 2—Integrated geothermal reservoir characterization workflow.

Data Sources and Preparation

The model development relied on the following data inputs:

- **Well Logs:** Detailed logs from Wells P1-1 and P1-2 provided subsurface property information.
- **Geochemical Analyses:** Laboratory results defined the reservoir fluid composition.
- **Geological Models:** Input from the HKG 3D model provided the basis for structural and stratigraphic frameworks.
- **Reservoir Fluid Properties:** Key parameters such as density, viscosity, and thermal conductivity were incorporated.
- **Temperature and Pressure Profiles:** Published SSGF data were used to validate model conditions.

Preparation involved refining data quality, upscaling well logs, calibrating fracture models, and reconciling temperature data with observed profiles.

Modeling Workflow

The modeling workflow includes the following key steps: geological modeling, geomechanical modeling, geochemistry, and dynamic simulation. Each step is described below with the focus on the dynamic simulation.

Geological Modeling

Building upon HKG's geology model, proprietary reports, presentations, and access to numerous published documents provided by HKG, Baker Hughes constructed a geological model over an area of 8×8.5 km that captures the eastern half of the SSGF. The grid is rotated 45° from north to align with regional-scale (NE-SW & NW-SE) intra-basin faults.

The SSGF reservoir includes a weakly altered cap underlain by a dual porosity reservoir that has brine within pore space intrinsic to the host sediments and porosity within faults and fractures (Helgeson, 1968). The model was constructed from ground level down to the base of the dual porosity reservoir, which coincides with the clinopyroxene isograd, the 5.6 km/s velocity surface, and the 370°C isotherm (Sims and Neuhoﬀ, 2018). The fractured reservoir below this surface was not included in the model volume.

Temperature Model

The 3D temperature model build followed previous such studies in combining different data sets. In order of importance these included individual well temperature vs. depth profiles (edited where considered necessary), previous isotherm maps for select depths/study areas, and inference from overall basin structure and faults controlling the SSGF.

An essential element of the temperature model (Figure 3) was to identify the halocline that separates Low Salinity Brine from High Salinity Brine in the reservoir (Williams and McKibben, 1989). The halocline correlates with a sharp transition from high geothermal gradient in the cap and Low Salinity Brine section down into a near isothermal geothermal gradient in the High Salinity Brine dual porosity reservoir section. This break from conductive heating to convective heating thermal profiles is clearly demonstrated in most wells. The base of the dual porosity reservoir, defined by the onset of clinopyroxene, is less clearly defined in temperature logs but is likely associated with an increase in the geothermal gradient owing to reduced inter-granular and possibly fracture permeability.

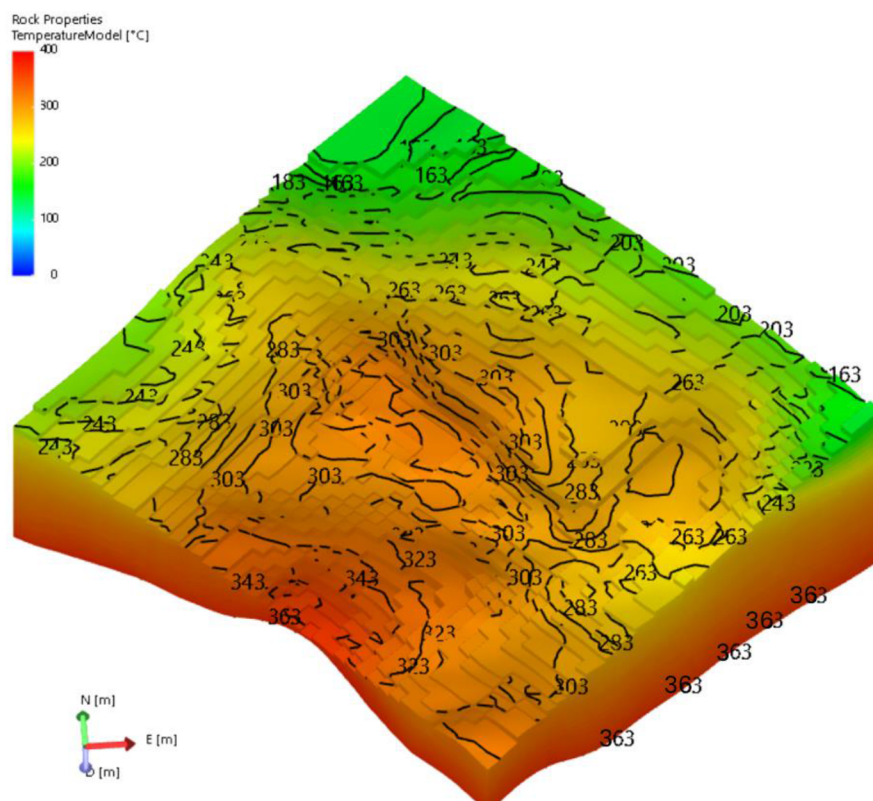


Figure 3—Temperature model.

Geomechanical Modeling

1D geomechanical models were derived through analysis of log data acquired in the HKG study wells to constrain the pore pressure, stress field, and rock strength properties as a function of depth. Bulk density logs were used to model the overburden stress. Measured pore pressure profiles indicate sub-hydrostatic absolute pressure consistent with regional water table data (Thompson et al., 2008).

A 3D geomechanical model was developed through the geomodel domain. Formation density from the HKG wells P1-1 and P1-2 and the State 2-14 well, which is drilled to 3050 m, was mapped to the 3D volume. Overburden stress was then calculated through vertical integration of density from the surface to the base of the model and benchmarked against the 1D geomechanical models. The reservoir volume pore pressure model was constructed based on pore pressure profiles provided from the study wells, drilling mud weights and drilling mud losses.

Geochemistry

The brine chemistry study was performed to define the lithium concentration distribution and brine densities, which are a function of temperature gradient and ionic composition variations. The presence of a halocline at a temperature of approximately 260°C greatly affects the density gradient of the fluids within the formations being investigated. Brines above the halocline are significantly less saline and less dense than the brines immediately below the halocline (Williams and McKibben, 1989). Immediately above the halocline the brine densities are calculated to be as low as 0.795 SG, while immediately below the halocline the brine densities are calculated to be as high as 1.01 SG (Figure 4). The change in density provides a significant barrier to upwards convective flow of sub-halocline brine.

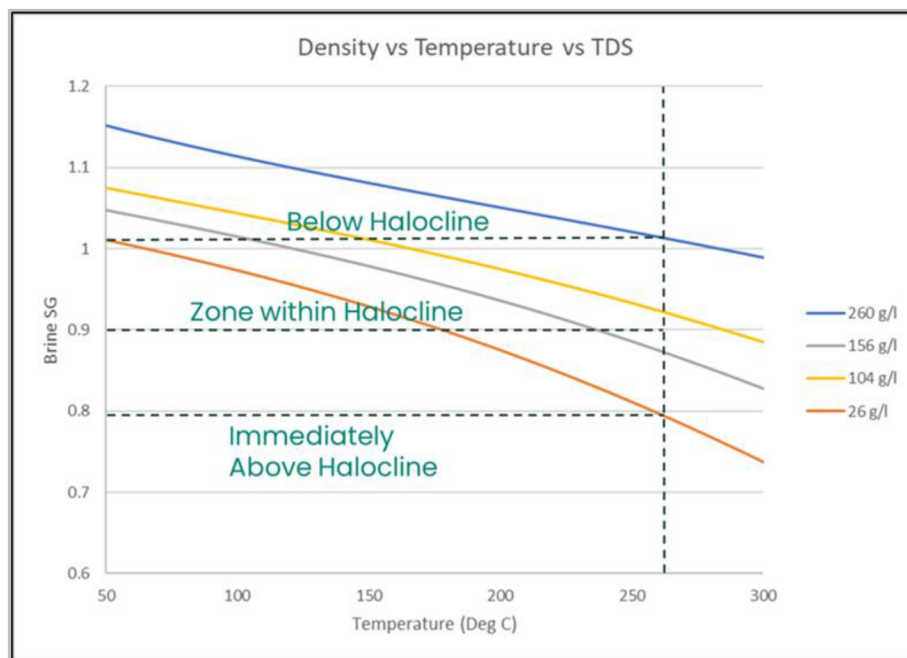


Figure 4—Density profiles for various salinity brines vs. temperature.

Fracture and Fault Model

A fracture network base model was developed to provide the fracture- and fault-derived permeability to the dynamic flow model. The DFN model is composed of large-scale hydro-structures (faults) that are described deterministically, and smaller structures that are described stochastically. The hydro-structural model is interpreted from the structural fault framework. The stochastic distributions of fracture geometries and intensities of the base DFN model were consistent with fracture analyses from wellbore image data acquired

from wells P1-1 and P1-2. The pervasive north striking sets observed in image log data are interpreted in this study to be associated with the current normal faulting extensional regime of the area and to be ubiquitous within the SSGF (Sims, 2023). A distance to faults fracture distribution was applied to the base fracture network model that assumes fault damage zones may develop a large number of fractures crosscutting the adjacent host rocks, where the length and density of fractures would decrease as a function of distance from the fault centerline (Ru Jia et al., 2019).

To test the sensitivity of the base DFN structural model, an alternative fracture network model was built from both the localized wellbore image data and regional structural data. Detailed field mapping of veins and breccias to the southeast of the SSGF provide significant data in support of a northwest trending fracture fabric in addition to the north striking fabric within the SSGF for all types of veins (Willis and Tosdal, 1992). Further, the James, et. al (1987) study of the nearby Heber geothermal reservoir defines northwest striking strike-slip faults and northeast trending normal faults with enhanced permeabilities over a broad area. The seismically well-defined Brawley shear zone within the SSGF is also interpreted to be along the same trend as the northwest strike slip fault zone found at Heber (Sims, 2023). A comprehensive refraction seismic survey across the Imperial Valley delineated these northwest trending structural features and revealed evident northeast trending features that cut the crystalline basement rocks within the Brawley seismic zone (Fuis et al., 1982). These features are interpreted as northeast striking active transfer faults (Fuis et al., 1982; Sims, 2023). The alternative fracture network model of this study combined these northwest and northeast oriented regional fracture sets with a Poisson distribution of the north striking fractures observed in wellbore image data that yields a significantly higher fracture surface area per unit volume than the base DFN model.

The transmissivities derived from the DFN models were upscaled to a hydraulic conductivity tensor for the reservoir volume (Figure 5). The resultant permeability was calibrated against measured production log data acquired in the two wells within the study area. Figure 5 compares the K_x , K_y , K_z permeabilities of the base DFN model (top row) with those of the revised DFN model (bottom row). The interconnected fractures of the revised DFN model have a more uniform and significantly higher permeability distribution than the more conservative base DFN model. This methodology is unique in that it can capture the underlying fracture dominated heterogeneity in the permeability field. The hydrostructural DFN modeling approach explicitly incorporates the geometry and properties of discrete features as a central component controlling flow and transport. The corresponding permeability tensor provides, in an average sense, the effective permeability tensor for each block composed of fractures in dynamic fluid modeling to explore well engineering scenarios for optimal production.

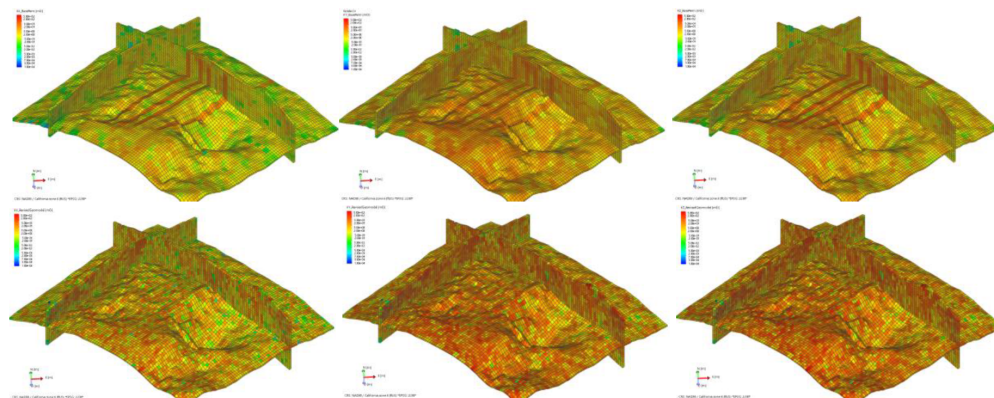


Figure 5—Upscaled base geomodel permeability distribution (top row) and revised geomodel permeability distribution (bottom row).

Dynamic Simulation

The 3D static base model was imported to the reservoir simulation software. The model consists of 57,000 grid blocks and covers an area of 8 km by 8.6 km with average block dimensions of 200 m by 200 m and an average grid thickness of 110 m (Figure 6). Porosity varies by depth. Permeability in three dimensions was developed based on DFN simulations, with maximum values of 58 mD in X direction, 100 mD in Y direction and 120 mD in Z direction.

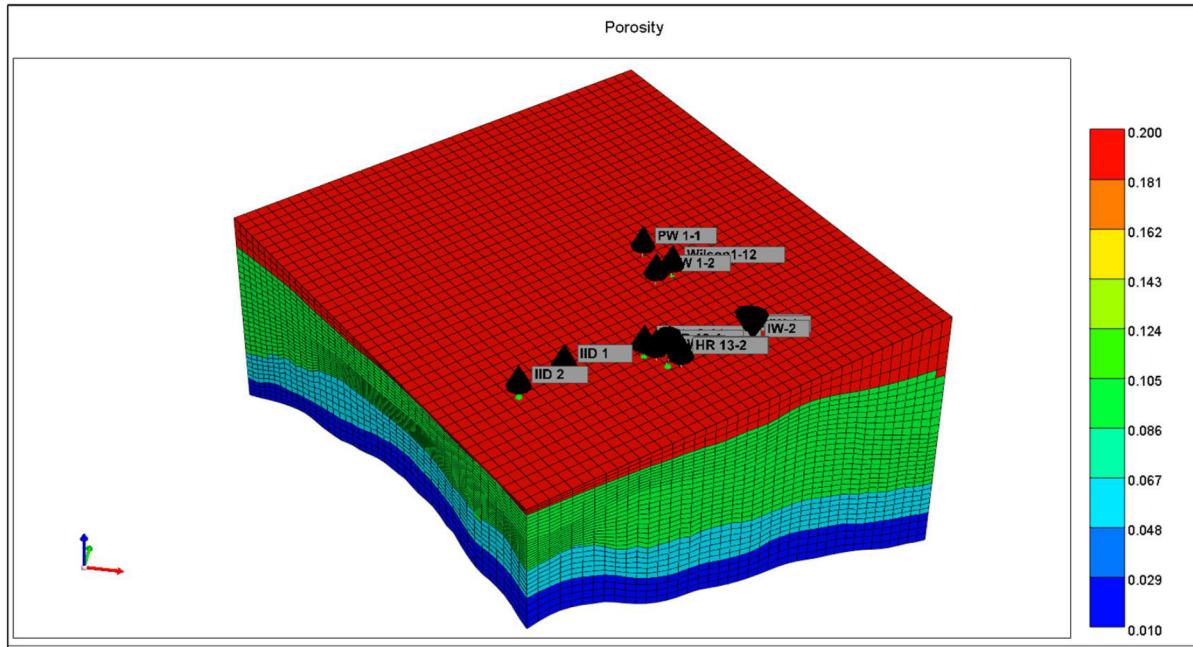


Figure 6—Model 3D view.

The thermal properties of the rock and the fluid used in the model are as follows:

- Volumetric heat capacity of the rock: $2.3 \times 10^6 \text{ J/(m}^3 \cdot ^\circ\text{C)}$
- Thermal heat conductivity of the rock: $1.728 \times 10^5 \text{ J/(m} \cdot \text{day} \cdot ^\circ\text{C)}$
- Thermal heat conductivity of the brine: $53,500 \text{ J/(m} \cdot \text{day} \cdot ^\circ\text{C)}$

The volumetric heat capacity and thermal conductivity of the overburden were tuned to maintain a constant temperature at the top of the reservoir. The final values are the following:

- Volumetric heat capacity: $2 \times 10^{20} \text{ J/(m}^3 \cdot ^\circ\text{C)}$
- Thermal heat conductivity: $21 \times 10^5 \text{ J/(m} \cdot \text{day} \cdot ^\circ\text{C)}$

Natural state matching is a critical step in developing a reliable reservoir model, as it ensures that the simulated reservoir conditions accurately represent observed field data under natural, undisturbed conditions. For the HKG project, the process involved iterative calibration of the model using data from wells P1-1 and P1-2 within the study area. The natural state matching process consisted of the following steps:

1. Initialization

The model was initialized with geological, geochemical, and geophysical parameters derived from field data. Key inputs included temperature profiles, pressure gradients, and fluid compositions

observed in the wells. Stratigraphic boundaries, including the halocline, were defined to reflect the distinct density and salinity contrasts observed in the reservoir.

2. Boundary Conditions

Lateral and vertical boundary conditions were set to replicate heat flux, fluid flow, and pressure behavior typical to the SSGF. The halocline was modelled as a low-permeability layer to limit vertical mixing of high- and low-salinity brines.

3. Simulation Runs

The natural state simulation involved running the model over geological time scales to achieve equilibrium. Initial runs often deviated from the observed conditions due to incomplete or uncalibrated input data, requiring iterative adjustments.

4. Calibration

Temperature and pressure outputs from the model were compared against available measured profiles from the wells, shown in [Figure 7](#). Key adjustments included fine-tuning permeability, inflow and outflow rates, location of the inflow and outflow wells and fracture density parameters. Iterative runs were performed until the model outputs aligned closely with the observed data. [Figure 8](#) shows the temperature comparison between the model, well logs, base case geomodel (blue curve) and sensitivity cases described in the following sections.

5. Validation

The final calibrated model was validated by ensuring consistent reproduction of key reservoir features, such as vertical and lateral temperature gradient across the field, pressure distribution throughout the reservoir, density stratification of high- and low-salinity brines.

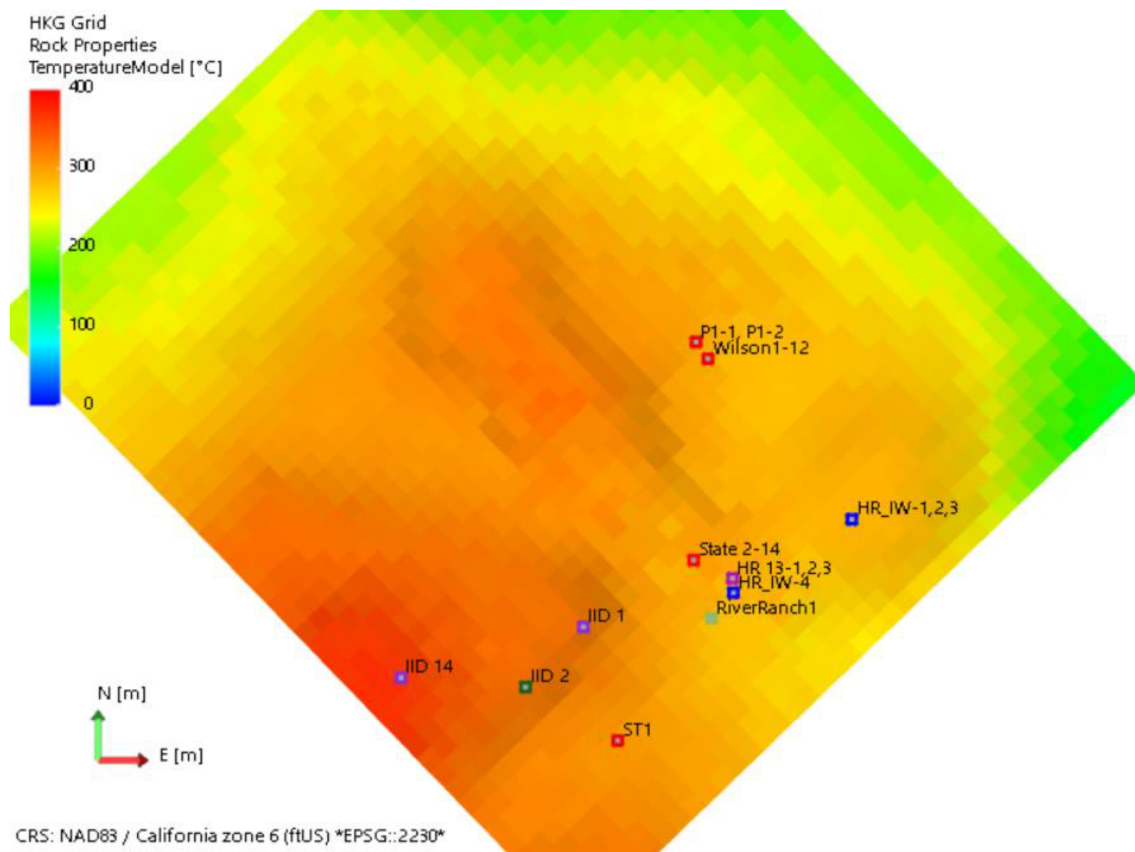


Figure 7—Natural state model wells.

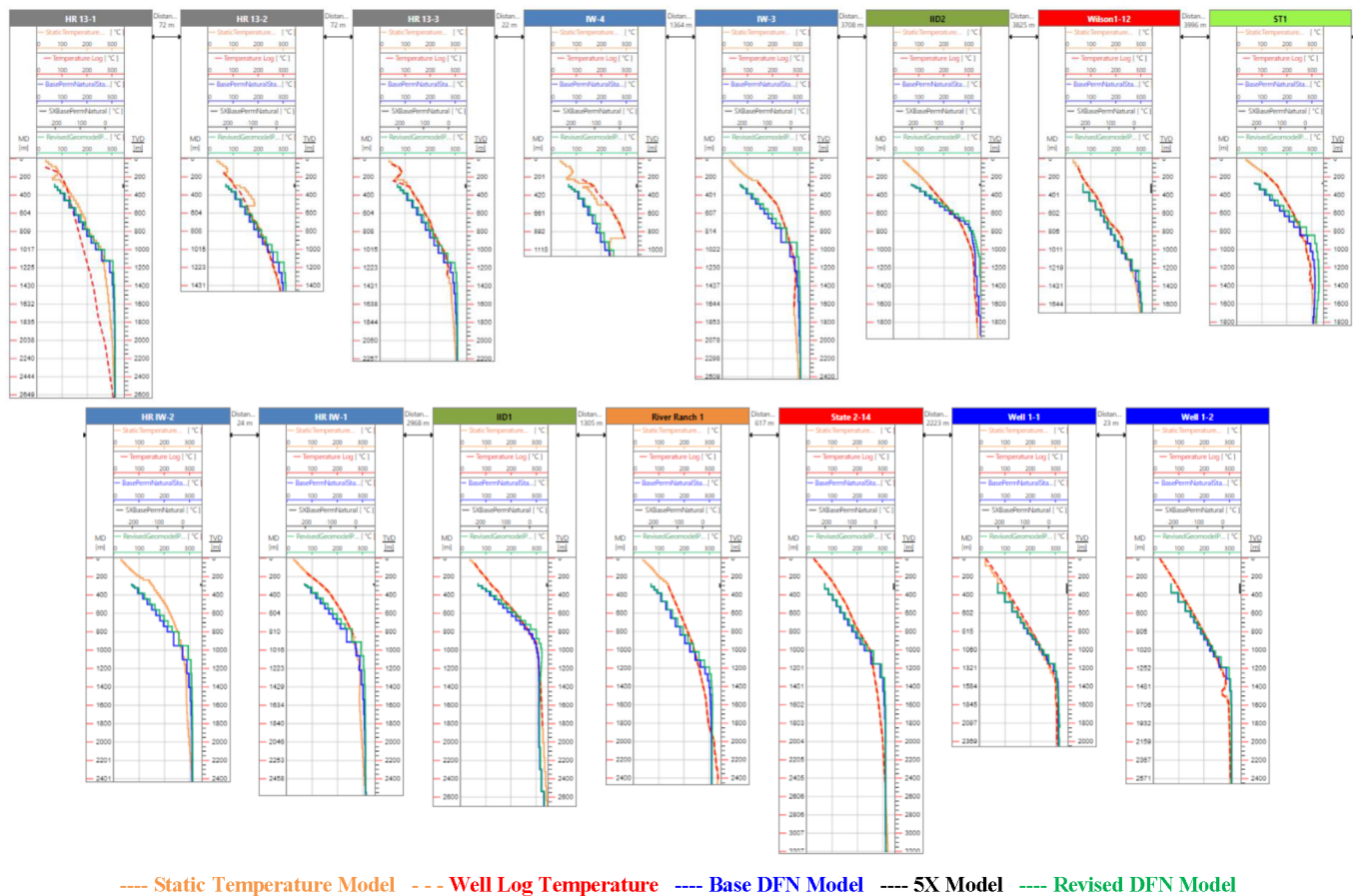


Figure 8—Temperature versus depth comparison for the natural state models.

Challenges addressed during the natural state matching include working with data gaps, halocline representation and fracture network dynamics. Limited direct measurements below 3000m required extrapolation and incorporation of pseudo-well data for deeper zones. Accurately modeling the halocline as a barrier to vertical fluid flow posed challenges due to its density stratified nature. Calibrating the fracture permeability to reflect realistic flow patterns involved detailed sensitivity analyses.

The successful natural state matching provided a robust baseline model that accurately represented the reservoir's undisturbed conditions. This ensured greater confidence in subsequent dynamic simulations of production and injection scenarios, enabling more reliable forecasts and optimization strategies.

Assumptions and Constraints

Key assumptions and constraints included establishing the halocline as a low-permeability barrier, restricting vertical fluid movement between high- and low-salinity brines (e.g., Williams, 1997); fracture networks play a dominant role in fluid flow within the high-salinity zones.

The described methodology provided a robust framework for assessing the geothermal and lithium production potential of the HKG project while identifying opportunities for optimization.

Results and Discussion

Overview

The results from the reservoir model provide critical insights into the geothermal and lithium production potential of the HKG project. Key findings include the role of the halocline in controlling fluid dynamics,

the role of the fracture network that creates the permeability heterogeneity throughout the reservoir, and the impact of operational parameters such as various production and injection scenarios, and well spacing.

Geological and Reservoir Characteristics

Brines above the halocline exhibit densities as low as 0.795 SG, while those below have densities as high as 1.01 SG. This density gradient acts as a barrier to upward convective flow of high-salinity brine, restricting fluid mixing and preserving thermal and chemical stratification and has a significant impact on fluid dynamics.

The Discrete Fracture Network (DFN) was found to dominate fluid flow in the high-salinity zones below the halocline. Fracture permeability significantly enhances fluid mobility and plays a critical role in maintaining production efficiency. However, localized variations in fracture density and orientation impact flow dynamics, requiring careful well placement to maximize recovery.

Initial Stage Production and Injection

The Initial Stage concept included 3 production wells and 4 injection wells that were open at the start of the forecast. Production wells were controlled by the maximum brine production rate of 246 kg/s and the minimum wellhead pressure of 1930 kPa. It was assumed that 95% of the produced brine was injected back into the reservoir.

Injection rates were assigned to the four injection wells on Pad A and their directionally drilled trajectories were optimized to reduce the risk of thermal and chemical breakthrough. The injection wells were controlled by a maximum wellhead pressure of 4137 kPa and maximum brine injection rate. The injection temperature was set to 60°C, and the lithium concentration was 7 ppm, consistent with the Initial Stage facility design.

Production wells maintained a constant brine production rate of 2662 tonne/hr during the forecast and no decline was observed (Figure 9).

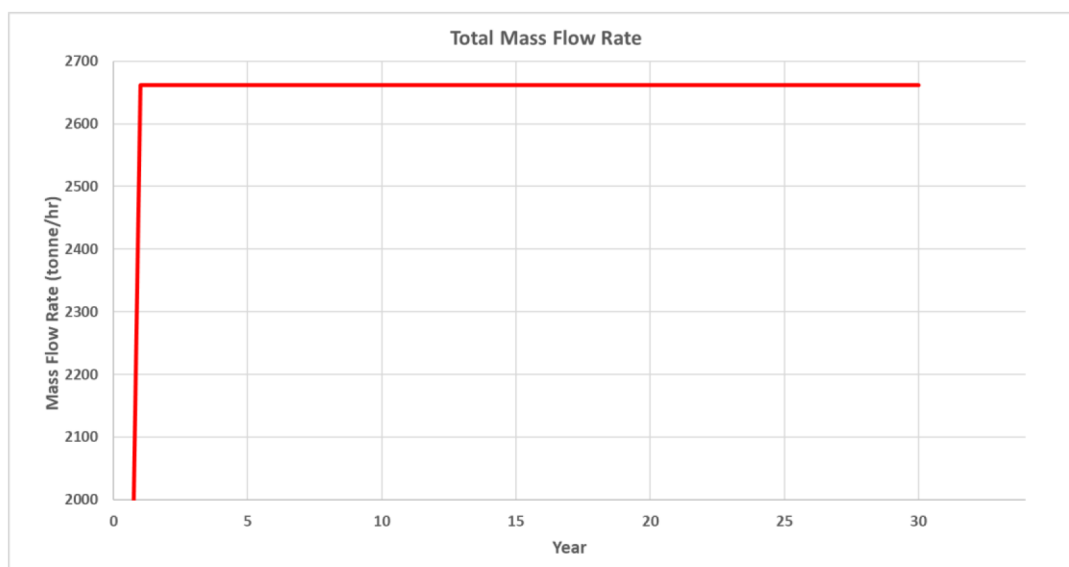


Figure 9—Total mass flow rate for the Initial Stage.

The reservoir single-phase enthalpy of production fluids in each well varied slightly due to the differences in the bottom-hole temperature but stayed relatively constant during the forecast for each well (Figure 10). The total energy rate reached 7.4×10^{13} J/day, equivalent to an enthalpy production rate of 463 BTU/lbm or 1076 kJ/kg.

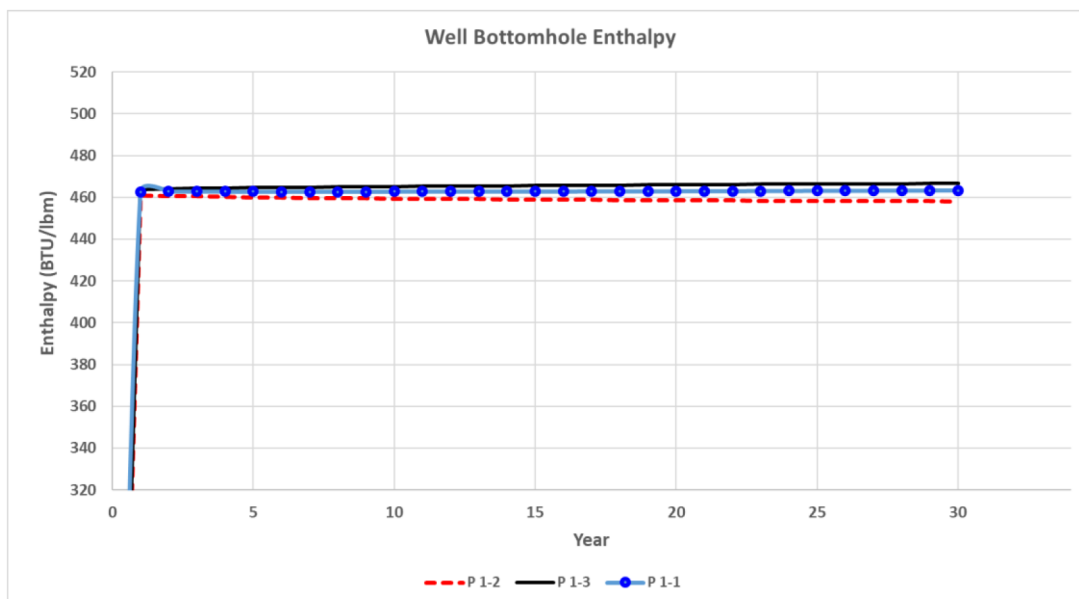


Figure 10—Production well single-phase reservoir enthalpies for the Initial Stage.

The modelled elemental lithium concentration showed a 4.6% decline in Well P1-1. It was constant in the production fluid of Well P1-2 and declined by 1% in Well P1-3 after 30 years. This decline in lithium concentration is attributed to chemical breakthrough (as opposed to thermal breakthrough) from the injection wells to production wells, a common occurrence in some reservoirs due to a pressure sink around the production wells and communication through connected fracture networks. Well P1-1 is extended in the direction of the injection well locations, and it showed the highest decline in lithium concentration. The total elemental lithium production rate (and concentration) for the Initial Stage declined by 1.9% over 30 years and dropped from 0.613 tonne/hr to 0.602 tonne/hr (Figure 11).

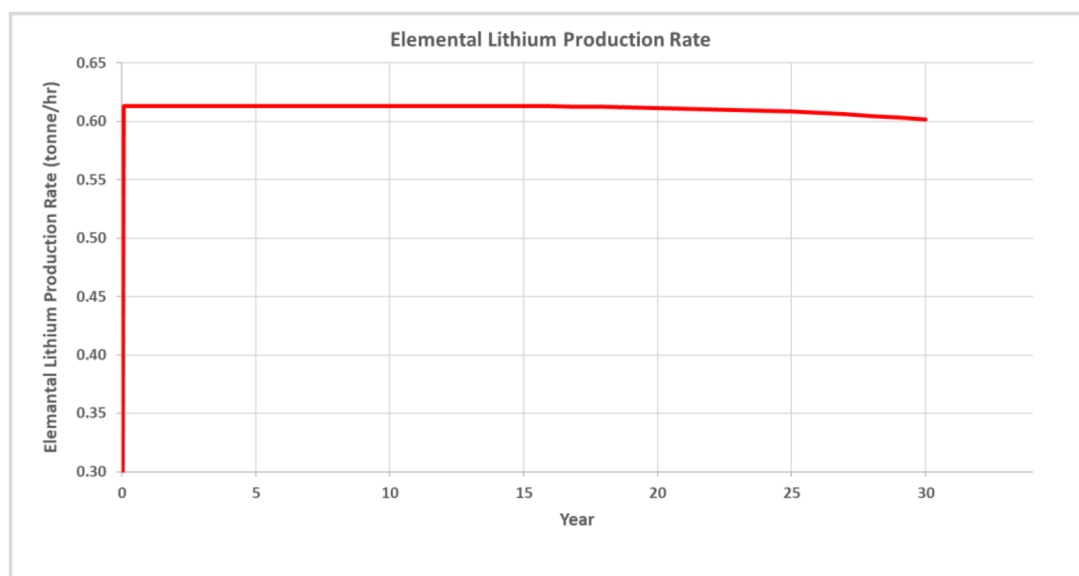


Figure 11—Elemental lithium production rate for the Initial Stage.

Cumulative elemental lithium production modelled from the three production wells in the Initial Stage increases linearly and reaches 160,000 tonnes over the 30 years (Figure 12).

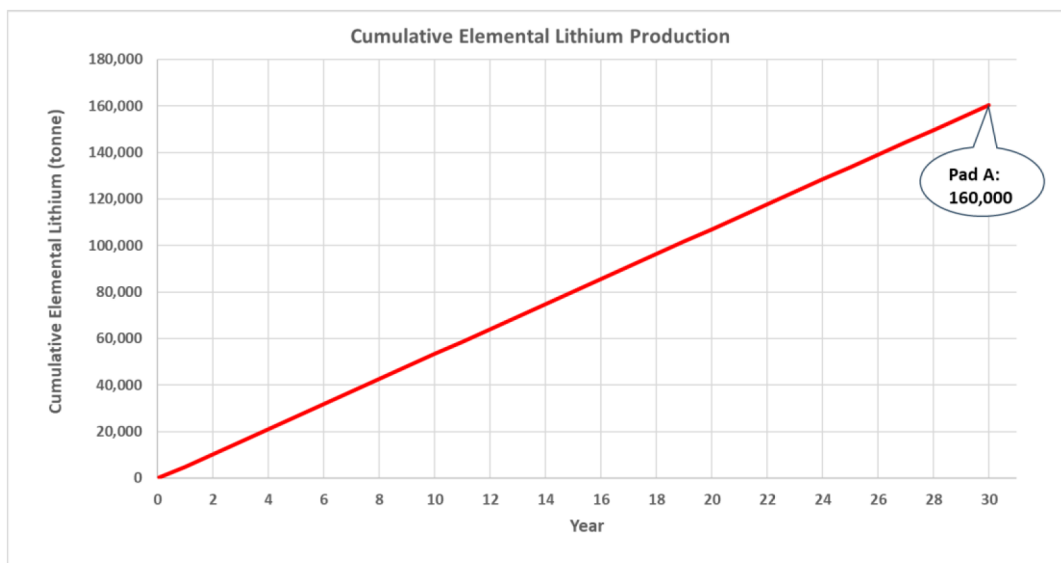


Figure 12—Cumulative elemental lithium production over 30 years for the Initial Stage.

Sensitivity Analyses

Sensitivity to Injection Well Location. Three injection pads (Pad A, Pad B, and Pad C) were tested for the Initial Stage. The same operating controls described above were applied to injection wells on Pads B and C. The injection pads are located approximately 2900 m (Pad A), 1300 m (Pad B), and 800 m (Pad C) from the producers. Figure presents the results of the three scenarios. Pad B forecasts 20% less, and Pad C forecasts 11% less lithium production than the Pad A scenario. The Pad A location is recommended for production in the Initial Stage.

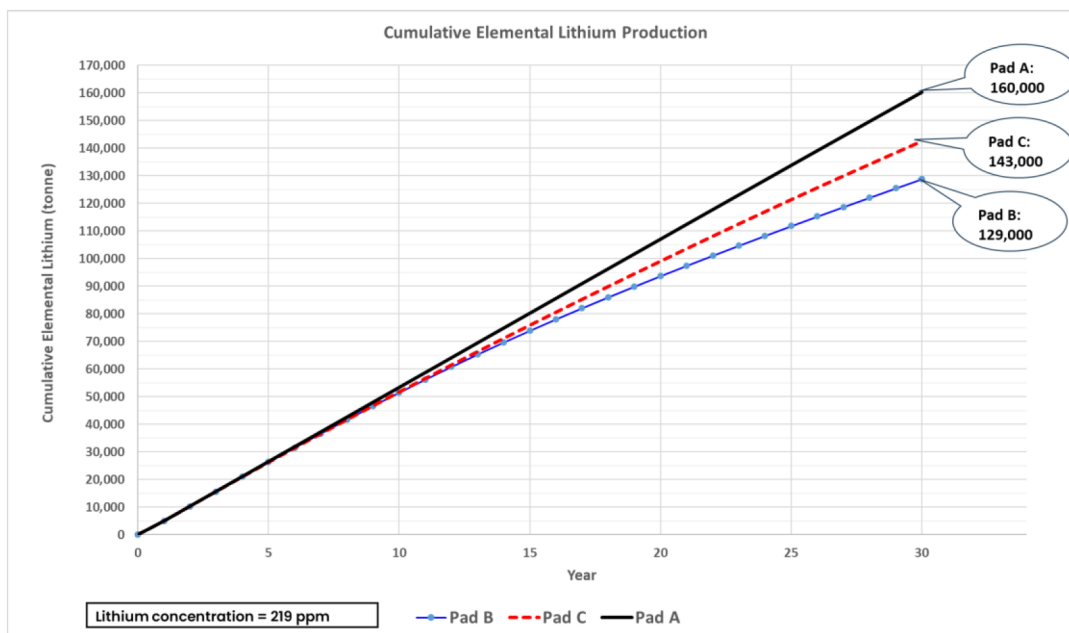


Figure 13—Cumulative elemental lithium production sensitivity to injection well location.

Sensitivity to Permeability Magnitude. An Enhanced Permeability case was evaluated to test the effect of increased permeability relative to the Base Case described above. For this analysis, a five-fold increase in fieldwide reservoir permeability was used to forecast production for Pad A in the Initial Stage concept. This

five-fold permeability factor was based on additional analysis of the Well P1-2 well test, which suggested the base permeability was conservative. The permeability increase was applied across the entire model volume. The natural state was again modeled using the same boundary conditions as the base model to evaluate the impact of an increase in permeability. The 5X permeability natural state model presented in Figure 8 (black curve) shows this global increase in permeability remains a very good match to field data of temperatures across the site. In many cases, the match is a better fit than was the base case permeability model (c.f., IW-1, IW-2, IW-3, HR-13-1, HR-13-2, HR-13-3).

As with the Base Case, single-phase reservoir enthalpy varied slightly due to the differences in the bottom-hole temperature but stayed constant at 463 BTU/lbm throughout the forecast, which shows that injected fluid is completely reheated along the flow path. The lithium production rate for the Enhanced Permeability case declined by 0.9% from 0.613 tonne/hr to 0.608 tonne/hr over 30 years. This decline is improved from the 1.9% decline modelled for the Base Case (Figure 14). The Enhanced Permeability cumulative elemental lithium production from the three production wells was about 1% higher than for the Base Case and reached 161,000 tonnes (Figure 15).

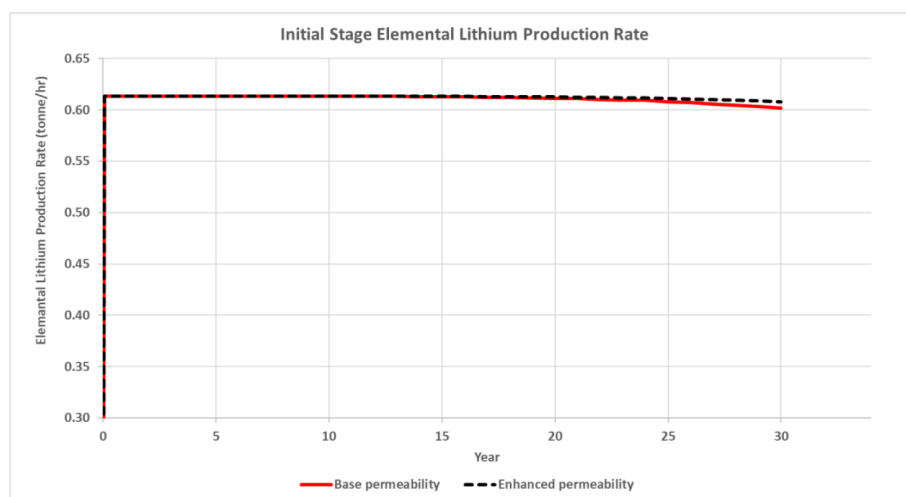


Figure 14—Elemental lithium production rate sensitivity to permeability variations.

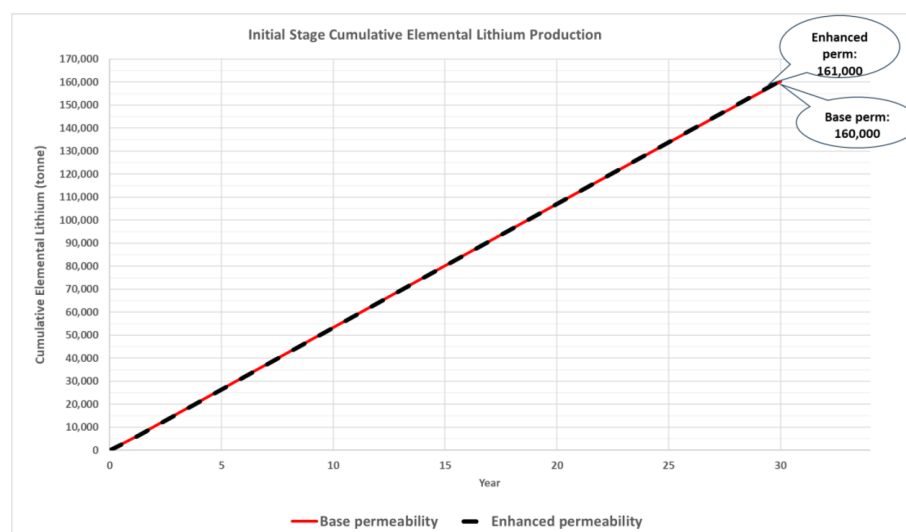


Figure 15—Cumulative elemental lithium production sensitivity to permeability variations.

Sensitivity to Permeability Distribution. A revised permeability distribution case was evaluated to test the impact of variability in natural fracture distribution relative to the Base Case described above. For this analysis, the revised DFN geomodel was used to define the permeability heterogeneity across the field. The natural state was again modeled using the same boundary conditions as the base model to evaluate the impact of variation in permeability distribution. This scenario was used to compare the cumulative elemental lithium production for Pads B and C relative to Pad A in the Initial Stage concept.

The cumulative lithium production for the Pad B case location remained relatively unchanged and shows the lowest results, however, the Pad C case is significantly improved compared to the base permeability distribution (Figure 16). The Pad C forecast is only 2% less cumulative lithium production than that of Pad A. Using the base permeability model, the Pad C forecast was 11% less than the Pad A case.

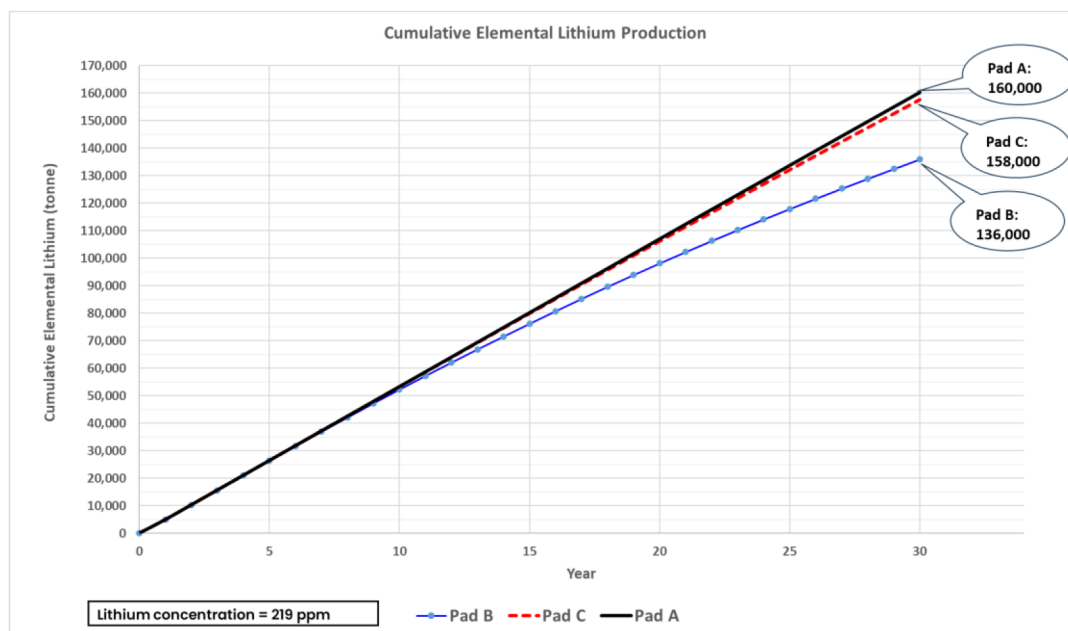


Figure 16—Cumulative elemental lithium production sensitivity to permeability distribution.

Key Observations

1. Thermal and Chemical Stratification: Accurate representation of the halocline density gradient is crucial for limiting vertical mixing.
2. Fracture-Driven Flow: Calibrated DFN modeling is essential for optimizing well placement and achieving sustainable production in the SSGF.
3. Injection Management: Proper injection strategies reduce the risk of thermal short-circuiting and chemical degradation of the reservoir.
4. Operational Trade-Offs: Sensitivity analysis underscores the need for a balanced approach to well spacing, permeability management, and production optimization.

Conclusions

The HKG project represents a significant opportunity for harnessing geothermal energy and extracting critical minerals such as lithium. This study developed and validated a comprehensive reservoir model that integrates geological, geomechanical, and geochemical data to provide actionable insights into resource development.

Key conclusions from this work are as follows:

1. **Fracture Network Influence:** Discrete fracture networks significantly influence fluid flow, particularly in high-salinity zones. Accurate DFN modeling is essential for optimizing well placement and maximizing resource recovery.
2. **Production and Injection Strategies:** Simulation scenarios demonstrate the importance of balanced well layouts for sustainable production.
3. **Dynamic Simulation Success:** The natural state matching process provides a robust baseline model that accurately reflects the reservoir's undisturbed conditions, enhancing confidence in production forecasts.
4. **Sensitivity Analysis Insights:** Variations in permeability magnitude, well spacing, and permeability distribution significantly affect production outcomes, highlighting the need for precise resource characterization and adaptive operational strategies.

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