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Assessment Of Formation Damage for CO_2 Injection Utilising a Deep Long Short-Term Memory Network Framework

K. Katterbauer, A. Al Shehri, A. Al Hashboul, Aramco

Abstract

CO_2 injection for CO_2 storage performance monitoring is an important consideration when evaluating the operational effectiveness of carbon sequestration. Since CO_2 may be permanently stored when it dissolves in brine, saline aquifers have garnered a lot of interest. In the CO_2 entrapment, both physical and geochemical mechanisms are at play. Physical trapping originates from CO_2's inability to flow through the cap layer, whereas geochemical trapping happens when CO_2 dissolves in salty water. The combination of CO_2 with rock formation and salinity may make determining the well's performance very difficult.

Pressure transient analysis, which enables the examination of reservoir characteristics based on pressure response data, is essential to the development of efficient CO_2 storage and CO_2 geothermal technologies. The injection-falloff cycle pressure and rate transient response in particular determines the permeability, distance to boundaries, and injection performance. This enables evaluation of the enhanced mobility of the supercritical CO_2 phase as well as any well damage. In order to assess the PTA response to temperature and rate dependent supercritical CO_2 injection, a physics-based deep learning model was developed to take temperature and rate influences into consideration. The deep learning model makes use of a time-series-based, modified Long Short-Term Memory Network to predict the pressure response.

Using the saline Ahuroa aquifer in New Zealand as a starting point, we investigated the pressure response brought on by temperature fluctuations. Natural gas has been kept in the Ahuroa gas reservoir, which is a part of the saline aquifer and is part of the Urenui formation. The saline aquifer is intersected by the CO_2 pumping well Ahuroa-3. A variety of injection-fall off studies were simulated using various CO_2 injection rates and temperature-dependent effects. According to the results, temperature variations may affect injection performance because they may alter the wellbore environment in the near-well phase. In particular, the explainable model demonstrates that although temperature effects do affect pressure, they have a negligible impact when compared to rates, porosity, and the viscosity of the CO_2 injection gas.

In order to determine the effects of temperature and pressure on injection falloff tests for CO_2 injection into saline aquifers, the performance of CO_2 storage injectivity and total CO_2 storability within the formation must be evaluated. The two-phase nature of saline aquifers requires a careful analysis of the multiple wellbores damaging effects due to CO_2 injection that the analytical deep learning model has outlined affecting the overall storage performance to ensure the aquifers' potential for storing CO_2.