Lessons learned from a geothermal well test with associated sour gas in the Vienna Basin

M. Maierhofer, N. Romich, T. Hollmann

OMV, Vienna, Austria

The city of Vienna intends to become carbon-neutral by 2040. To reach this ambitious goal, geothermal energy will play a crucial role and should become a dominating technology to produce the required energy for district heating. The geothermal gradient in the Vienna Basin is about 3°C per 100 meters. The Northern Calcareous Alps beneath the basin have the potential to deliver hot water between 90°C and 180°C to the district heating network. Besides high temperatures, a formation with sufficient permeabilities, to extract high flow rates, is crucial for a successful hydro-geothermal project.

In 2022 a geothermal well test was executed to acquire more information about the rock and fluid properties to better quantify the potential. A former gas production well, which has been drilled into the 2800m deep target formation, was selected to reduce expenditures. This well is located about 3km north-east of the Vienna city limits and therefore provides a possible close access point to the district heating network of the city.

A complex workover operation was necessary to access the fractured dolomite. The well was perforated from 2800 to 2873m in the aquifer below the initial gas-water contact and completed with a 4 ½” tubing.

After the acid stimulation, 2800m³ saline formation water was produced via coiled tubing lift at a rate of up to 40m³/h. The produced water was temporarily stored in 43 closed containers, as the associated gas contains H_2S. Finally, it was re-injected with up to 120m³/h into the same formation. The test objectives were amongst others determining key reservoir parameters and obtaining downhole fluid samples. Those were fully achieved.

The production and injection test delivered encouraging results. The inflow performance was excellent, low drawdowns below one bar were observed during the main flow period with 20m³/h. The calculated permeability is in the order of 500mD. Reservoir temperature is 102°C, the well head temperature increased up to 80°C during the test. The analyzed fluid samples of the formation fluid show an average gas-water ratio of 3,5Sm³/Sm³.The associated gas contains about 6mol% of H_2S and 15mol% of CO_2. A salinity of about 30.000ppm was measured in the formation water. Precipitations during the production test were mainly corrosion products, like iron sulfide (FeS). However, also some quartz and calcite materials were detected.

We recommend using high resolution gauges for geothermal well tests to avoid data smoothing. This might be required if high permeable formations with moderate rates are tested.