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Combined CO_2 Geological Storage and Geothermal Energy Utilization in Greece

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CO_2 injection and storage in deep geological formations can contribute to the exploitation of geothermal potential. CO_2 has significant advantages compared to water, due to certain favorable physical, chemical and thermophysical properties. Several proposals for the use of CO_2 in geothermal energy exploitation have been formulated but they still remain at an initial research stage (Arvanitis *et al.*, 2018):

- Supercritical CO_2 utilization as working fluid (heat transmission fluid) in Enhanced Geothermal Systems (EGS), where the natural permeability and/or fluid content is limited and insufficient. In EGS, fluid is injected from surface at high pressure into high-temperature deep rocks through wells under carefully controlled conditions to re-open the pre-existing natural fractures and flow through them into production wells extracting heat from the high-temperature rock formations. Supercritical CO_2 can be used as a working fluid instead of water or brine to recover the geothermal heat from the reservoir, due to specific thermodynamic advantages against water; e.g.: larger expansivity and compressibility, lower viscosity, higher mobility, larger flow velocity for a given pressure gradient, different enthalpy behavior in relation to pressure and temperature, higher heat extraction rates, less effective as a solvent for rock minerals (Brown, 2000; Pruess, 2006).
- Supercritical CO_2 injection into a deep saline aquifer and formation of “CO_2 Plume Geothermal" (CPG), which displaces native fluids and extracts heat from the geothermal reservoir. CPG involves pumping supercritical CO_2 into deep, naturally porous, permeable geologic reservoirs overlaid by low-permeability caprocks. The injected CO_2 absorbs heat from the reservoir, buoyantly rises to the surface, and drives a power generation system. The CO_2 is then cooled and re-injected into the reservoir. The produced CO_2 mass fraction depends on the stratigraphic positions of highly permeable layers which also affect the pore-fluid pressure drop across the reservoir. CPG systems provide viable geothermal energy resources for electricity production, even in regions with relatively low geothermal temperatures and heat flow rates, where suitable reservoirs exist (Randolph and Saar, 2011), leading to expansion of geothermal energy utilization. These systems are capable of achieving improvements in heat extraction efficiencies well above those accomplished by replacing water with CO_2 as the working fluid in EGS. Supercritical CO_2 has a large mobility (inverse kinematic viscosity) and thermal expansibility compared to water, resulting in the formation of a strong thermosiphon that typically eliminates parasitic pumping requirements (Garapati *et al.*, 2014). Traditional water-based geothermal development requires three geologic Conditions: (1) significant amounts of water, (2) a permeable formation to allow water extraction/reinjection, and (3) sufficient subsurface temperatures. EGS seeks to artificially generate Condition 2 and supply (water-based EGS) or avoid (CO_2-based EGS) Condition 1, thereby expanding geothermal heat mining prospects. On the other hand, CPG provides an alternative working fluid (avoiding Condition 1) with high mobility compared to water, thus expanding the range of usable natural-formation permeabilities (Condition 2). Similarly, CO_2 lowers minimum thresholds of economically and technologically viable subsurface temperatures (Condition 3), as its high mobility enhances heat extraction efficiency. Numerical simulations have indicated that CPG systems provide higher geothermal energy extraction rates significantly improving heat energy recovery over water-based systems (Randolph and Saar, 2011).
- A hybrid two-stage thermal energy recovery approach (initially brine and then brine and CO_2) from a deep saline aquifer. After the CO_2 injection, during the first stage, formation brine is pumped out to relieve the pressure. During the second stage and as CO_2 reaches the production wells, CO_2 and brine are produced together as working fluids. The produced brine can be used either for freshwater production by desalination (reverse osmosis), or as saline cooling water or even as injected water into adjacent EGS (Buscheck *et al.*, 2012).
- CO_2 utilization as a pressure-support fluid in order to create artesian pressures for CO_2 and brine production as working fluids. This can be achieved by developing a pattern of horizontal wells at reservoir bottom depths of 2.5-5 km and creating at least 4 concentric rings, consisting of inner ring brine/CO_2 producers, CO_2 injectors, brine reinjectors and outer-ring brine producers (Buscheck *et al.*, 2013).
- CO_2 dissolution in a saline aquifer and energy recovery of CO_2-rich hot brine through a geothermal doublet system (production and injection wells). This new approach involves (Kervévan *et al.*, 2017): (i) CO_2 capture with innovative technology based on the CO_2 dissolution in water (Pi-CO_2 technology), (ii) extraction of aquifer’s brine through a production well, (iii) heat recovery through a surface heat exchanger system, and (iv) re-injection of the cooled brine through the injection well, which will be linked to the new Pi-CO_2 technology.

Potential sites suitable for CO_2 geological storage in Greece have been studied (CERTH, IGME), with efforts was made to assess their storage capacity. The following sites and formations have been proposed:

- Miocene sandstone reservoirs, more than 1,600 m deep, in the hydrocarbon (oil and gas) fields of Prinos and South Kavala, with a total capacity of 35 Mt CO_2

- Oil reservoirs in Kallirachi (wider offshore Prinos basin), with a storage capacity of 30 Mt CO_2
- Upper Jurassic-Lower Cretaceous limestones in the Epanomi gas field (south of Thessaloniki), at a depth of 2,600m, with a capacity of 2 Mt CO_2
- Fractured Cretaceous-Eocene limestones in the hydrocarbon (oil and gas) fields of Katakolo (West Peloponnese), with a storage capacity of 3.2 Mt CO_2.
- Deep saline aquifers of Miocene age in the offshore Prinos basin, with an average depth of 2,400m, an area of 800km^2, an average thickness of 260m, an average porosity of 18% and estimated capacity of 1,350 Mt CO_2.
- Deep (900-2,400m) saline aquifers within the Eocene formations in the wider onshore basin of Thessaloniki (Central Macedonia), including the Loudias and Alexandria structural traps as well as the deeper clean sandstone bed, with an average porosity of 8-10% and a total storage capacity of 640 Mt CO_2.
- The sedimentary formations of the Mesohellenic Trough (NW Greece), with an average depth of 1,000m, average porosity of 10%, average thickness of 300m and a storage capacity of 216 Mt CO_2.

In the Thessaloniki onshore basin as well as in the Mesohellenic Trough, where a potential of CO_2 geological storage in saline aquifers has been assessed, temperature measurements in deep hydrocarbon exploration boreholes have given the following results:

- Thessaloniki Basin: The temperature of 65ºC (Horner Correction) was recorded in borehole ALEXANDRIA-1 at 1,705m depth, within the ophiolithic bedrock. In borehole LOUDIAS-1, the temperatures of 74ºC and 83ºC were measured at depths of 1,520m and 2,614m respectively, within Eocene-Oligocene sediments. Temperatures of 73ºC, 76ºC and 79.5°C have been recorded at depths of 3,130m, 3,629m and 2,745m, within Paleogene (Eocene-Oligocene) sediments, in boreholes KORYFI-1, KLEIDI-1 and AEGINIO-1 respectively (Karytsas, 1990).
- Mesohellenic Trough: In borehole NEAPOLIS-2, a temperature of 49°C (uncorrected value) has been measured at a depth of 1,126m in the Senonian formations. In borehole NEAPOLIS-1, the temperature of 50°C has been recorded at 600m depth, on the roof of the Senonian limestones (Karytsas, 1990). However, in 1998, the temperature of 23°C was recorded at 605m depth in an exploration borehole drilled by the Institute of Geology and Mineral Exploration.

The offshore Prinos basin is located in the Gulf of Kavala and the available thermometric data have no significance, since the geothermal potential cannot be exploited. To the Northeast, the Nestos River Delta basin can be considered as its onshore extension. Hydrocarbon exploration boreholes N-1, N-2 and N-3 were drilled in the Nestos River Delta basin and the temperatures of 115ºC, 127ºC and 138ºC have been recorded at depths of 2,970m, 3,104m and 3,601m respectively, within the Miocene sediments. Additionally, the temperature of 122°C has been measured at the bottom of the geothermal exploration borehole N-1G (NW of the village of Eratino), 1,377m deep, in the metamorphic basement.

Considering that to date there are no studies on the implementation of EGS in Greece, it is considered more feasible to combine CO_2 geological storage and geothermal energy utilization in deep saline aquifers by mainly applying CPG technology. Among the studied CO_2 geological storage sites in deep aquifers, the Thessaloniki basin has been recognized as having an extensive geothermal potential of moderate temperatures (up to 89ºC). Bearing in mind that a CPG system provides greater power and more extensive thermal extraction over water-based systems, it is obvious that the case of the Thessaloniki basin requires further study so that CPG technology can optimize its geothermal potential.

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