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Sedimentary Basin Geothermal Resource for Cost-Effective Generation of Renewable Electricity from Sequestered Carbon Dioxide

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ABSTRACT

We investigated the efficacy of generating electricity using renewable geothermal heat that is extracted by CO_2 that is sequestered in sedimentary basins, a process described as CO_2-Plume Geothermal (CPG) energy production. We developed an integrated systems model that combines power plant performance modeling, reservoir modeling, and the economic costs of a CPG power plant and a CO_2 storage operation in order to estimate the levelized cost of electricity (LCOE). The integrated systems model is based on inverted five-spot injection patterns that are common in CO_2-enhanced oil recovery operations. Our integrated systems model allows for these patterns to be coupled together, so that the CO_2 that is extracted by a production well can be composed of portions of the CO_2 that was injected in the four neighboring injection wells. We determined the diameter of the individual wells and the size coupled inverted five-spot well patterns that most effectively used the physical and economic economies of scale for the coupled reservoir and power plant. We found that substantial amounts of power, on the order of hundreds of megawatts, can be produced as the size of the injection pattern increases, and that the estimated LCOE decreases as these patterns expand. Given the appropriate combination of depth, geothermal gradient, and permeability, CPG power plants can have LCOEs that are competitive with other unsubsidized sources of electricity.

1. INTRODUCTION

Two of the most fundamental challenges facing modern electricity systems are to decrease the amount of carbon dioxide (CO_2) emitted to the atmosphere and to increase the amount of electricity that is generated by renewable energy technologies. Worldwide, progress on these two dimensions has been mixed; CO_2 emissions have been increasing, but so too has the deployment of renewable energy technologies. In 2013, 36.2 $GtCO_2$ were from combusting fossil fuels, primarily for energy and cement production—a 46% increase from the emissions in 2000—which is twice the amount emitted in 1976 (Boden et al., 2013). By 2013 deployment of wind energy technologies reached 318.1 GW worldwide—18.3x the capacity in 2000—and the deployment of solar energy photovoltaic technologies reached 138.8 GW—107.2x the capacity in 2000 (EPIA, 2014; GWEC, 2013), but only 12 GW were installed worldwide as of 2013 (Geothermal Energy Association, 2014).

Most present geothermal facilities are located in faulted and fractured systems that allow water to migrate between the deep subsurface and shallower depths that are economically accessible with present drilling technologies. Sedimentary basins are emerging options for geothermal development in due in part to the ubiquity of sedimentary basins throughout the world and their large heat resource (SedHeat, 2013). These sedimentary basins are also potential targets for CO_2 storage as an approach to mitigating climate change by capturing CO_2 from large point sources (e.g., coal-fired power plants) and transporting that captured CO_2, most likely by pipeline, to locations where it is injected into geologic storage reservoirs for long-term sequestration from the atmosphere (e.g., IPCC, 2005). This process is called CO_2 capture and storage (CCS), and saline aquifers in sedimentary basins have the largest estimated CO_2 storage capacities among the types of geologic reservoirs that could contain large amounts of CO_2 for hundreds to thousands of years (NETL, 2015).

Recent efforts have investigated how geothermal energy production can be combined with CCS, where the sequestered CO_2 could be used to extract heat from sedimentary basin geothermal resources. One proposed process for extracting usable heat from these geothermal resources uses the pressure drive from nearby CO_2 injection to displace hot native brine for use in a geothermal power plant (e.g., Buscheck et al., 2013). Another process, called CO_2-Plume Geothermal (CPG) energy, uses the CO_2 itself as the heat extraction fluid (Randolph and Saar, 2011). Thermophysically, CO_2 extracts heat more efficiently than the brine that naturally exists within the pores of the sedimentary rock (Adams et al., 2015; Randolph and Saar, 2011). Since CO_2 is buoyant at reservoir conditions, it will form a plume beneath an overlying impervious layer, and this buoyant plume can be produced to the surface where the heat in the CO_2 can be converted into electricity in a power plant. Previous analyses have investigated the amount of electrical power that can be generated from a CPG power plant (Adams et al., 2015), and here we investigate the cost-effectiveness of this process in terms of the levelized cost of electricity (LCOE) from a CPG power plant.

2. METHODOLOGY

We combined our coupled model of CPG reservoir and a direct CO_2 power plant with cost estimates that are derived from the Geothermal Energy Technology Evaluation Model (GETEM) and the U.S. EPA Carbon Sequestration Technology Cost Analysis in order to estimate the LCOE from a CPG power plant (Adams et al., 2015, 2014; U.S. DOE EERE, 2012; U.S. EPA, 2008). Our reservoir model assumes a fully developed CO_2 plume so that production wells contain only pure CO_2 in a 305 m thick reservoir with 10% porosity. We use an inverted 5-spot well pattern, where relatively cool CO_2 is injected through a single injection well located in the middle of a square. Each corner of the square has a production well to produce CO_2 from the reservoir. This produced CO_2 is routed through a direct CO_2 power plant, which extracts heat directly from the CO_2 and converts that CO_2 into electricity. The cooler CO_2 is then re-injected into the reservoir in a closed-loop cycle that circulates a portion of the sequestered CO_2 between surface facilities and the geothermal reservoir.

In practice, multiple inverted 5-spot injection patterns may be created by adding additional injection and production wells. Since the produced fluid can be the result of injection from multiple wells, economies of scale may be achieved by adding additional production and injection wells, each with diameters that are optimally sized to handle the expected amount of CO_2 that would be injected / produced with the well. We describe and model the expansion of the well patterns by assigning a "configuration number" (N), which is the number of inverted 5-spot patterns on each side of a larger square that is comprised of these inverted 5-spot injection patterns. The configuration number thus determines how many injection wells and production wells must be drilled to establish the overall well pattern.

The surface power plant is comprised of a turbine and generator, a condensing unit and cooling tower, as well as the requisite piping. Power is calculated for injection-production well pairs, including the pressure drop and the heat loss as CO_2 expands while flowing up the production well, both of which depend, in part, on the diameters of the injection and production wells (Adams et al., 2015). As in our previous work, we considered two system designs for circulating the CO_2 between the reservoir and the CPG power plant. One system relies on the self-convecting thermosiphon in the CO_2 and the other system augments this flow with mechanical pumps (Adams et al., 2015, 2014). We assumed that the surface temperature was 15°C. This surface temperature serves two purposes in our modeling: (1) the ambient temperature to which the CPG power plant rejects excess heat, and (2) the basis for calculating the initial temperature of the reservoir.

RESULTS

Figure 1 shows the estimated LCOE and net capacity (MW) for a CPG system in a 2.5 km deep reservoir with a 35°C/km geothermal gradient and permeability of 5×10^{-14} m^2 as the size of the well pattern increases from 1 km^2 (N = 1) to 100 km^2 (N = 10). The capacity of a CPG power plant increases substantially from N = 1 (a few MW) to N = 10 (almost 300 MW for a pumped system). The LCOE decreases as the well pattern expands, in part because more power can be produced when multiple CO_2 flows are combined into larger diameter wells and because these wells are cheaper per unit of cross-sectional area (m^2) as the diameter increases. This decrease in LCOE is most pronounced at small configuration numbers, and the decrease in LCOE becomes relatively negligible around N = 5. In fact, the LCOE starts to increase when N = 9 and N = 10. Figure 1 also shows that pumped systems tend to produce more power than systems that only rely on the thermosiphon to circulate CO_2. Even though these pumps are costly to purchase, install, and operate, the additional power that results from using them to circulate CO_2 between the geothermal reservoir and the CPG power plant results increases the power more than the costs increase. The difference in capacity between a pumped system and a thermosiphon system for a given configuration number increases as the well pattern expands from N = 1 to N = 10, whereas the difference in LCOE between a pumped system and a thermosiphon system decreases as the well pattern expands.

Figure 2 shows the estimated LCOE and net capacity for a reservoir with a higher permeability than in Figure 1: 1×10^{-12} m^2. Compared to the less permeable 5×10^{-14} m^2 reservoir, the LCOE for a thermosiphon-based system decreases from $415/MWh to $332/MWh and the capacity increases from 3.14 MW to 6.85 MW for a single inverted 5-spot in the more permeable 1×10^{-12} m^2 reservoir. These differences are more pronounced as the well pattern expands. For the N = 10 well pattern, pumped systems can provide a net capacity of 296 MW for $216/MWh in the 5×10^{-14} m^2 reservoir, whereas a similar system in the 1×10^{-12} m^2 reservoir can provide a net capacity of 450 MW for $162/MWh. In general, the LCOE is lower, and the net capacity is higher, for a CPG system in a more permeable reservoir, but the difference in LCOE and net capacity between pumped systems and thermosiphon systems decreases as the permeability increases; the difference in net capacity and LCOE is almost negligible for a highly permeable 1×10^{-12} m^2 reservoir.

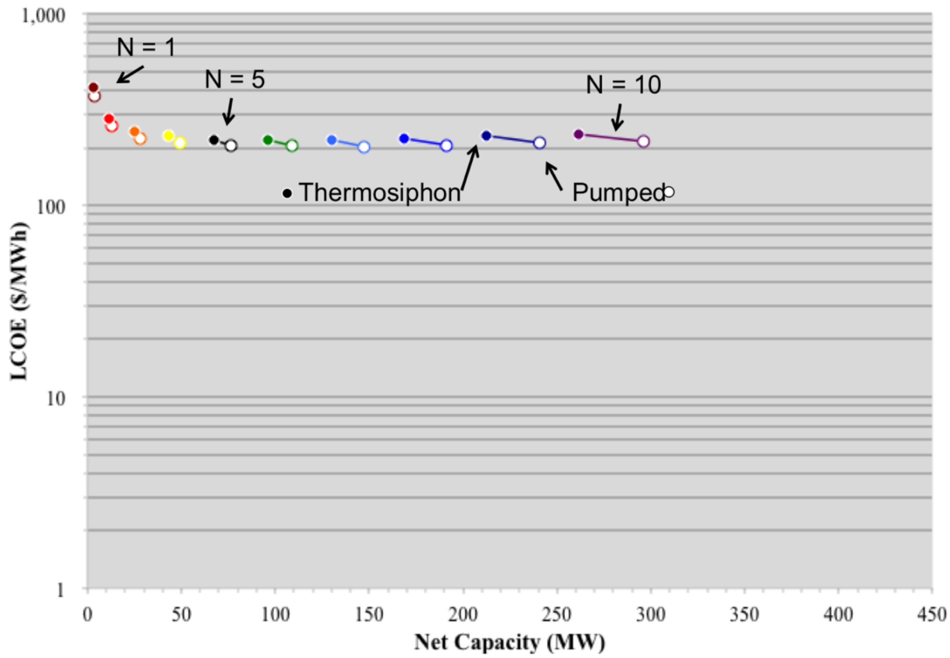

Figure 1: Levelized Cost of Electricity (LCOE) for a Carbon Dioxide Plume Geothermal System in a Reservoir with 5 x 10^{-14} m^2 permeability – Reservoir depth = 2.5 km; Geothermal gradient = 35 ^oC/km; Permeability = 5 x 10^{-14} m^2.

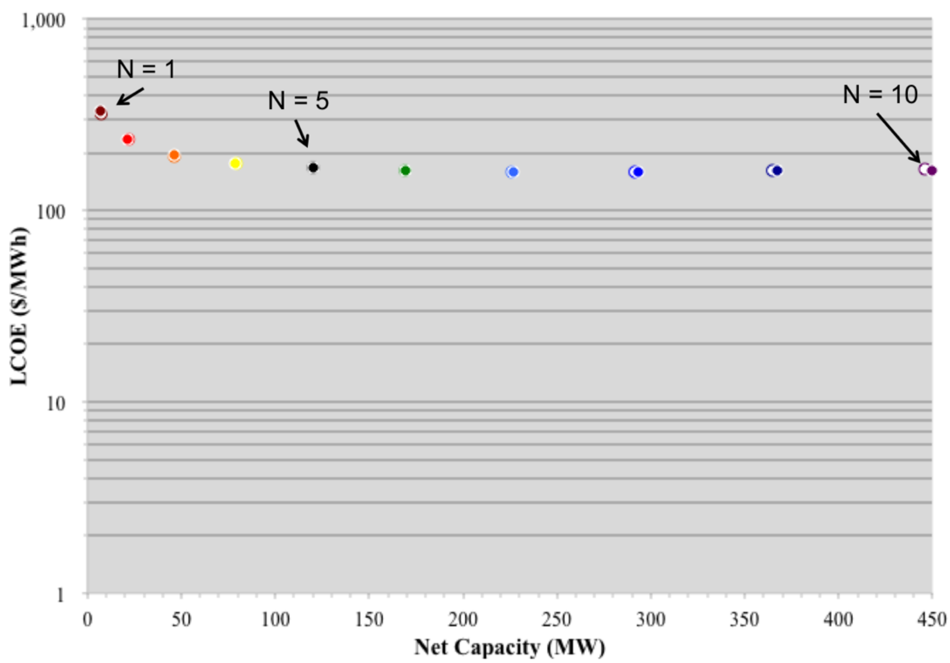

Figure 2: Levelized Cost of Electricity (LCOE) for a Carbon Dioxide Plume Geothermal System in a Reservoir with 1 x 10^{-12} m^2 Permeability – Reservoir depth = 2.5 km; Geothermal gradient = 35 ^oC/km

CONCLUSIONS

Sedimentary basin geothermal resources may be attractive candidates for geothermal energy development. In this study we investigated the cost-effectiveness of CPG systems, where sequestered CO_2 is used as the geothermal heat extraction fluid in inverted 5-spot injection patterns. As more of these patterns are coupled together to increase the size of the overall well pattern, the estimated net capacity increases and the LCOE decreases, with hundreds of megawatts of net electrical generating capacity that can be generated for just over $150-$200/MWh in 2.5 km deep reservoirs with a geothermal gradient of 35^{o}C/km. Given the appropriate combination of depth, geothermal gradient, and permeability, CPG power plants can have LCOEs that are competitive with other unsubsidized sources of electricity.

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