ASSESSMENT OF PERFORMANCE AND COSTS OF CO2 PLUME GEOTHERMAL (CPG) SYSTEMS

Jil Hansper[1)], Stefanie Grotkamp[1)], Stefan Glos [1)], Marcel Langer[1)], Michael Wechsung[1)],

Benjamin M. Adams [2) 3)], Martin O. Saar [2) 3)]

[1)]Siemens AG, Power and Gas Division, Germany

[2)] ETH Zurich, Geothermal Energy and Geofluids Group, Dept. of Earth Sciences, Switzerland

[3)] CO2 POWER, Zürich, Switzerland

stefan.glos@siemens.com

Keywords: Carbon dioxide, geothermal energy, power generation, LCOE

ABSTRACT

Geothermal power generation with supercritical carbon dioxide (sCO_2) has been the object of numerous research studies over the past years. In comparison to conventional hydrothermal power plants, both direct and indirect (e.g. ORC systems), such CO_2 Plume Geothermal (CPG) systems exhibit several thermophysical, subsurface and power plant equipment, advantages. Essentially, a more effective geothermal heat extraction and less need for auxiliary pumping power, due to a much stronger thermosiphon effect, compared to water-based geothermal energy extraction can be highlighted. In this paper a thermodynamic and energy conversion evaluation of CPG systems is provided. The results are compared to conventional hydrothermal power cycles. In particular, the impact of geologic conditions, such as reservoir permeability, depth and temperature gradient, on power plant layout to assess both performance and costs are assessed. Based on the thermodynamic and energy conversion simulation calculations, various component designs are considered. The results show that CPG systems can supply significantly more electricity, compared to hydrothermal systems, particularly at “shallow" depths of 2-3 km and at low reservoir permeabilities. Additionally, CPG systems can generate electricity at competitive levelized costs of electricity (LCOE) at much lower resource temperatures than hydrothermal systems, thereby considerably expanding the geothermal resource base worldwide.

1. INTRODUCTION

In contrast to other fluctuating renewable energies, such as wind and solar energy, geothermal energy is fully dispatchable, i.e the electricity feed-in is controllable and demand-oriented, which is a major advantage of geothermal power plants. However, due to the necessary geological boundary conditions, only a few regions on Earth are suitable locations for conventional geothermal power plants.

Against this background, the use of supercritical carbon dioxide (sCO_2) as an alternative energy-extraction medium from naturally permeable sedimentary-basin reservoirs and use in direct and indirect geothermal power plant applications has been discussed in several publications (Randolph and Saar, 2011; Adams et al., 2014; Adams et al., 2015; Garapati et al., 2015)

The principle idea of a CPG system may be summarized as follows: Waste CO_2 from one or several fossil fuel power plants, or other CO_2 emitters, is captured, employing Carbon-Capture (CC) technologies after which the CO_2 can be transported, for example through pipelines, to a CPG site, where the CO_2 is injected into a geologic CO_2 storage formation, resulting in Carbon Capture and Storage (CCS). For CPG, the CO_2 storage formation needs to exhibit a temperature that is sufficiently high to conduct CPG operations economically, i.e., at least about 100°C. These geologic formations or reservoirs also need to have sufficient permeability of >10 mD (1 mD = 10^{-15} m^2) and need to be overlain by a caprock of sufficiently low permeability of about <0.01 mD to enable efficient CO_2 injectivity into the reservoir through the injection well and to prevent CO_2 flow through the caprock, against which the CO_2 pools upwardly. In the reservoir, the CO_2 is geothermally heated and a portion is piped back to the surface power plant, where it is expanded in a turbine, driving a generator, and hence producing electricity.

The temperature-dependent density variation of sCO_2 is large compared to water. In addition, supercritical CO_2 has a kinematic viscosity that is, under base-case CPG conditions (Randolph and Saar, 2011; Adams et al., 2014, 2015) of a reservoir at a depth of 2.5 km under hydrostatic fluid pressure and a temperature of 100°C, about 25% the kinematic viscosity of water. In other words, the mobility of sCO_2 is four times that of water under these conditions. Furthermore, the thermal expansibility of sCO_2 is much larger than that of water. The low kinematic viscosity and high thermal expansion coefficient of sCO2 result in the formation of a strong thermosiphon, a physical effect which circulates a fluid without the necessity of a mechanical pump. Driven by this thermosiphon a Brayton cycle can be established, generating electricity, eliminating this particular parasitic power requirement of water-based geothermal systems.

The basic principle of the CPG system is shown in Figure 1. The related thermodynamic changes in the state of the CO_2 cycle are shown in the T-s diagram in Figure 2.

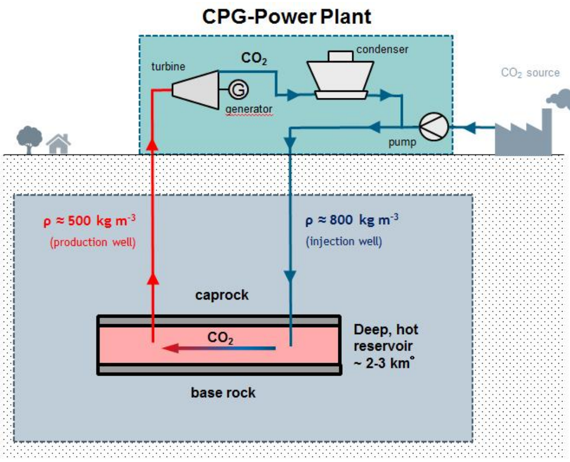

Figure 1: Exemplary illustration of a geothermal power cycle based on CO_2.

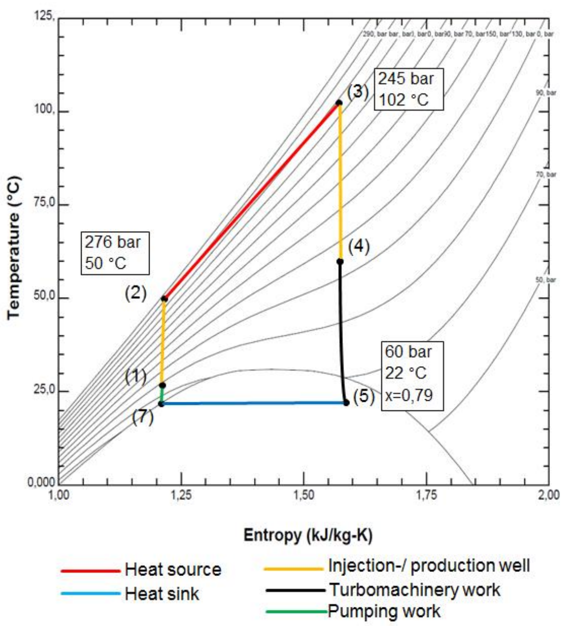

Figure 2: Exemplary illustration of an geothermal power cycle based on CO_2.

After the expansion in the turbine, the CO_2 is condensed/cooled and reinjected into the geologic reservoir. To increase the net power output slightly, a supplementary pump can be used optionally. (Adams et al. 2015).

In this paper, the thermodynamic evaluation of CPG systems is provided in a first step. Based on the work of Adams et al. (2015), thermodynamic simulations were carried out and compared with results for conventional hydrothermal power cycles. In particular, the impacts of the geologic conditions, such as reservoir permeability, and depth are assessed. In further sensitivity investigations, the influences of the heat sink of the power plant and impurities of the geothermal fluid on the power output are investigated.

In a second step, the costs of two scaled CPG system applications with 51 MW and 157 MW net power output were evaluated. The resulting levelized costs of electricity (LCOE) are derived and compared with other power generation technologies.

2. THERMODYNAMIC EVALUATION

The thermodynamic calculation is based on the substance data from the Microsoft Excel Add-In REFPROP (REFerence fluid PROPerties), developed by the National Institute of Standards and Technology Lemmen et al (2013). Cycle layout and reference conditions correspond to those of Adams et al. (2015). However, in Adams et al. (2015), R245fa was used as ORC-fluid medium. Here, Isobutane is used as the ORC-fluid medium, because of its lower environmental impact, lower costs, and as it is a common fluid in the considered temperature range. According to Adams et al. (2015) the evaluation was carried out for a single 5-spot well pattern (Coordination number N=1) consisting of one injection well and four production wells. The “base case” conditions, reflecting typical geologic reservoirs, are summarized in Table 1

Table 1: Summary of CPG base case conditions

	CPG Base Case
Coordination number N [-]	1(1km x1km)
Depth [m]	2500
Permeability [m^2]	50
Temperature gradient [°C/km]	35
Well diameter [m]	0.41
Cooling Type	Wet Cooling tower
Heat Sink Temperature [°C]	15
Approach Temperature [°C]	7

2.1 Results for CPG Base Case

In Figure 3, the results of the performed thermodynamic analysis are summarized. The cumulative column represents the turbine power output.

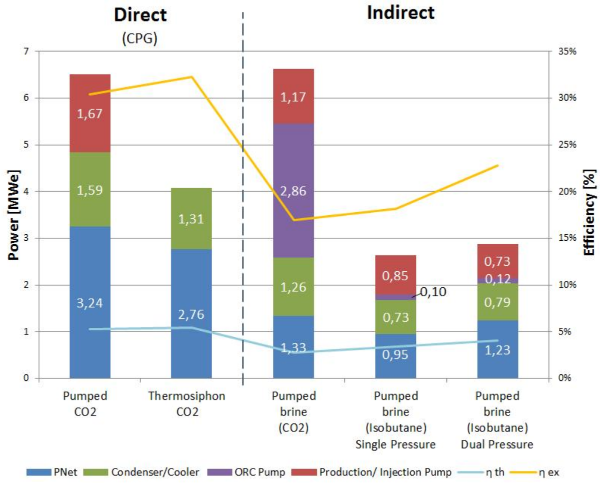

Figure 3: Comparison of the power output for different geothermal concepts (i.e. CPG and indirect brine) at base case conditions.

Under the above-stated reference conditions, direct CO_2-systems achieve a significant larger net power output compared to conventional, brine based (indirect) power plants (blue bars). The main driver of this is the strong thermosiphon effect and lower pressure losses of the reservoir flow as a result of a lower kinematic viscosity. The 4-times higher mobility of sCO_2, compared to water, results in an approximately quadrupling of the CO_2 mass flowrate through the turbine. On the other hand the specific heat capacity of sCO_2, is approximately half of that of water, so that the transferred heat, and thus the resulting net electric power output of the CPG power plant, is approximate 2-3 times larger compared to conventional water-based (indirect) geothermal power plants. In addition, the direct conversion of the thermal energy in the turbine eliminates the exergy losses in a heat exchanger, so that the exergetic efficiency is higher than that of the indirect systems. In indirect systems, the Isobutane-driven cycles achieve a higher net output. This can be explained by the high parasitic power losses in the secondary cycle when a gas, such as CO_2, is compressed.

The efficiency of the brine (Isobutane) case can be increased by installing a dual-pressure process, which is also shown in Figure 3. In this case, the heat is transferred to the working medium at two different pressure levels, which reduces the temperature differences between the fluids and thus the exergy losses in the heat exchanger. A larger amount of heat is thus extracted from the geothermal medium, which improves the thermal efficiency and decreases the reinjection temperature. The amount of heat absorbed in the reservoir is therefore correspondingly larger. However, overall both the efficiency and the net power output are below the values of the direct CO_2 cycle. Furthermore, it must be considered that the complexity of the system is increased by installing the two-pressure process. In summary, it can be stated that the results of Adams et al (2015) could be confirmed by the present thermodynamic analysis.

2.2 Impact of deviating site conditions

Geothermal power generation depends on the conditions of specific geological formations. The impact of varying reservoir conditions was investigated for four combinations of reservoir depth and permeability. The results are summarized in Figure 4.

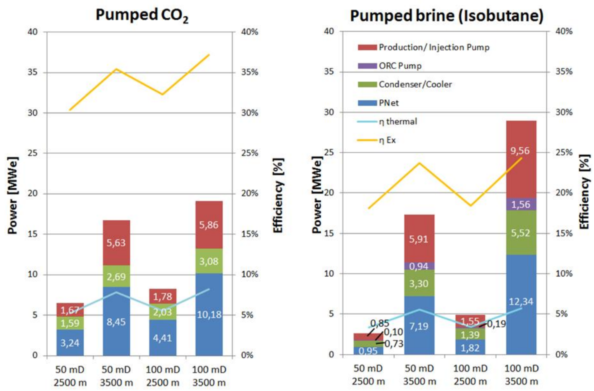

Figure 4: Illustration of the impact of different geologic conditions, (i.e. reservoir permeability and depth) on electric power output.

As the drilling depth increases the reservoir temperature due to the geothermal temperature gradient (geotherm), the temperature of the extracted geothermal fluid also increases. In both cycles the turbine inlet temperature and hence the turbine power increase. For the direct CO_2 system, the higher reservoir temperature results in a greater difference in the average density between the injection and the production wells, thereby intensifying the thermosiphon effect. Conversely, in the indirect cycle, the increased reservoir temperature has an influence on the flow behaviour of the brine and thus on the pressure losses in the reservoir flow. The lower the dynamic viscosity of the geothermal medium, the lower the pressure losses in the reservoir flow. In contrast to the dynamic viscosity of CO_2, that of brine is strongly dependent on the temperature. With increasing reservoir depth and temperature, the dynamic viscosity of the brine decreases significantly. As a result, the pressure losses in the reservoir and thus the required pumping capacity of the geothermal pump decrease, so that it is possible to extract a larger brine mass flow and achieve larger component outputs. The increase in performance due to an increased drilling depth is therefore essentially the result of the temperature increase in the reservoir and its influence on the flow behaviour of the brine.

At increased permeability (with the same drilling depth) the pressure losses in the reservoir, which need to be compensated, are lower. This results in a lower required pumping capacity and thus a higher net power output.

For greater drilling depths and simultaneously enhanced permeability, the increase in performance is correspondingly greater.

The top two plots in Figure 5 show the exergy transferred in the reservoir and the resulting net power as a function of the mass flow for the reference case and for changed reservoir conditions. The lower two plots in Figure 5 show, the corresponding exergy losses.

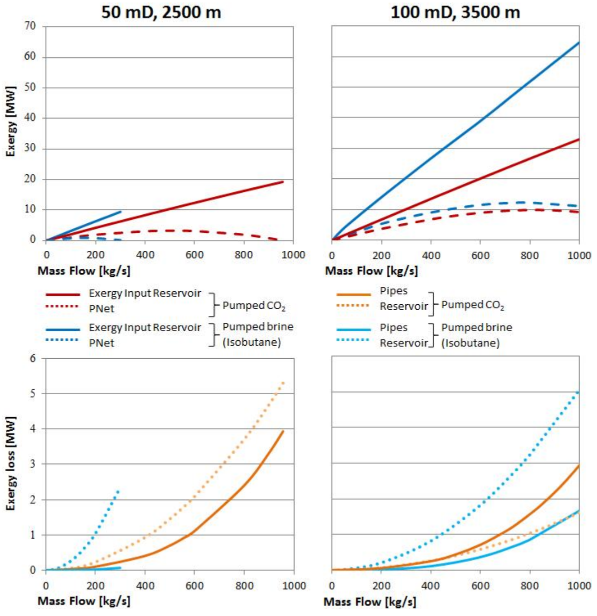

Figure 5: Comparison of exergy transfer and exergy losses for CPG and brine based systems.

The amount of absorbed heat increases linearly for both investigated reservoir cases. However, as the mass flow increases, the pressure losses in the pipes and in the reservoir also increase. The quadratic rise of the exergy losses deviates depending on the geothermal fluid.

In the reference case, the limiting factor for the brine (Isobutane) system is the pressure loss in the reservoir. For an increased permeability, i.e. 100 mD and drilling depth of 3500 m, the pressure loss is reduced so significantly that the net output is even greater than that of the direct CO_2 system. In this case the net output for both systems reaches a maximum at similar mass flow rates. Due to the higher isobaric heat capacity of brine, compared to CO_2, a larger amount of heat is transferred from the reservoir in the indirect, hydrothermal system. Although the reservoir conditions are also of energetic advantage for the CPG system, the high flow velocities of the CO_2 limit the net output. In contrast to the indirect system the pressure loss of the wells is the limiting factor for the CPG system.

The investigations show that the net output depends strongly on the reservoir conditions and furthermore confirm the results from Adams et al. 2015. CO_2-based systems are advantageous to (indirect) brine-based systems for shallower depths and low permeabilities. The higher the reservoir permeability, the more the viscosity advantages of CO_2 become less important and the greater heat absorption capacity of the brine leads to a higher net output of conventional plants.

Since a global application is conceivable for geothermal power generation, different ambient air temperatures must be additionally taken into account, which have a decisive influence on the cooling conditions of the systems. The direct CO_2 concept and the indirect plants with brine as geothermal fluid and Isobutane are investigated regarding their sensitivity to changed ambient temperatures, i.e. the heat sink temperature. Figure 6 shows the analysis results. The middle column for 15 °C corresponds to the reference case.

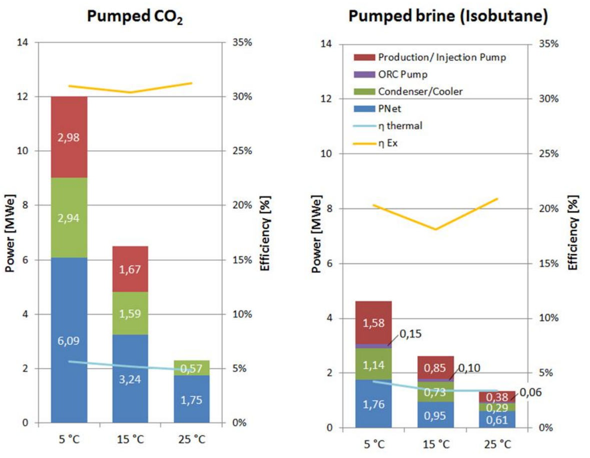

Figure 6: Impact of the ambient air (heat sink) temperature on the electric power output of CPG and brine-based systems.

With an ambient air temperature decrease from 25 to 5°C, the direct CO_2 plant turbine output is five times higher and the net output is three times higher. For lower ambient air temperatures, the lower the injection temperature of the CO_2 and the higher the averaged density of the fluid in the injection well. For constant reservoir conditions, this raises the difference in density between the injection and the production well, thus there is an intensified thermosiphon effect for lower ambient air temperatures. In addition, the amount of heat absorbed in the reservoir increases with decreased injection temperature, which can also be seen in the larger parasitic load of the cooling system. Furthermore, with lower ambient air temperature both the condensing temperature and the condensing pressure decrease. This results in a lower turbine back pressure. The enthalpy difference and thus the power output of the turbine are accordingly higher.

At an ambient air temperature of 25°C, the CO_2 is in a supercritical state during the entire process. Due to the energy-intensive compression of gases, the additional use of a compressor would only reduce the net output. Powered entirely by the thermosiphon, the system still achieves a higher net output, compared to the brine-based systems, even at ambient temperatures of 25°C, under the given reservoir conditions. In contrast to the brine (Isobutane) system, the dependence between density and fluid temperature of the CO_2 results in a higher sensitivity on ambient temperature changes of the CPG system, compared to the brine-based system. However, for low ambient temperatures, e.g. 5 °C, direct CO_2 systems can achieve an even greater net power output.

2.3 Initial design considerations

On the basis of the thermodynamic calculations, first the turbines are pre-dimensioned for different conditions. The pumped CPG system and the hydrothermal (Isobutane) system were investigated. Initial blade path designs of the turbines were carried out with Siemens in-house software tools. Figure 7 shows the comparison of the CO_2 turbine and Isobutane turbine for the base case.

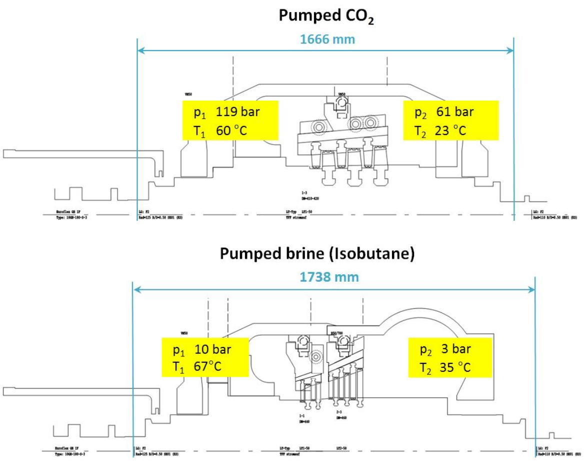

Figure 7: Scaled representation of the CO_2 turbine (top) and the Isobutane turbine (bottom) of the reference case.

Although the thermodynamic calculation for the direct CO_2 cycle provides almost a seven times larger mass flow, the volume flow in the turbine inlet is less than half compared to the Isobutane turbine. This is caused by the nearly sixteen times higher density of the CO_2 at the same state point. The near-critical expansion of CO_2 results in a small density difference compared to Isobutane, so that the increase in volume flow during the expansion is also low leading to a small widening of the flow path.

On the other hand the large pressure difference in the CO_2 turbine, with simultaneous small enthalpy drop, leads to comparable large bending forces in the airfoils. As a result, an enlargement of the blade roots and the hub diameter is necessary to avoid impermissible stresses in the blade roots and airfoils.

Further design optimization potentials, for example by reducing the turbine speed, need to be investigated. A low-speed operation mode could increase the number of stages and thus decrease the pressure drop across a single turbine stage.

The impact of varying reservoir conditions, for example an increased permeability of 100 mD and drilling depth of 3500 m, on the turbine design was also investigated. Due to the changed process parameters, the mass flow in both turbines increases. The thermodynamic analysis shows that the geothermal mass flow of the brine (Isobutane) system and thus the amount of heat absorbed in the reservoir is considerably larger under changed reservoir conditions. This results in a seven times larger secondary mass flow in order to absorb the whole amount of geothermal heat. So while the inlet volume flow of the Isobutane turbine increases almost by a factor of 4, it is not even doubled in the CO_2 turbine. The result is a significantly more compact turbine design of the CO_2 turbine for changed reservoir conditions due to the strong increase in volume flow in the Isobutane turbine.

Conventional geothermal power plants are characterized by a large amount of heat to be dissipated in the condenser and a low thermodynamic average temperature. Thus, the required heat exchanger surfaces are large and increase the costs of the cooling system significantly. Based on initial design considerations of a shell-and-tube heat exchanger, the required heat exchanger surfaces of the direct CPG- and the (indirect) brine-based (Isobutane in the secondary loop) system have been investigated. Figure 8 illustrates the ratio of the respective heat exchanger surfaces according to different reservoir conditions.

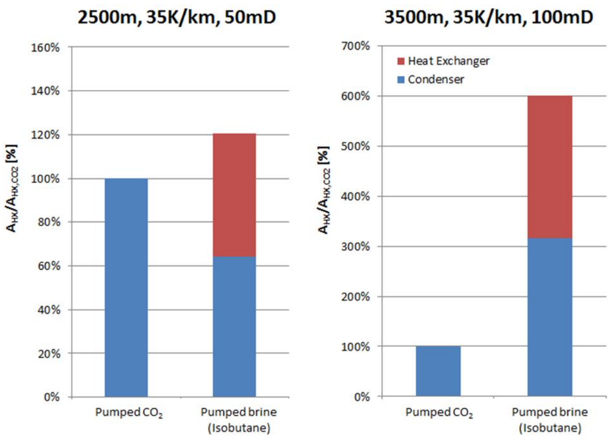

Figure 8:Comparison of heat exchanger surfaces for CPG and brine based systems for different reservoir conditions (depth, geothermal gradient, permeability).

Under base case conditions, the overall required heat exchanger surface of the Isobutane plant is about 20 % larger than that of the CO_2 plant. Although only half the amount of thermal energy is transferred in the Isobutane-condenser, it already represents more than 60% of the CO_2 condenser, which can be explained by the reduced heat transfer in the ORC condenser. In contrast to the CPG system, the Isobutane is superheated at the condenser inlet. In this gaseous state, the heat transfer is very low, leading to a large total heat exchange surface. Combined with the additional heat exchanger for the secondary cycle, the total required exchange surface of the brine (Isobutane) system is larger.

For the modified reservoir conditions, i.e. 3500 m and 100 mD, the transferred exergy in the reservoir is approximately doubled for the (indirect) brine (Isobutane) case, which can be seen in Figure 5. Thus, the emitted heat in the condenser is even greater than that of the CO_2 plant. As a result the overall required heat exchange surface is approximately six times larger.

From the above-stated initial design considerations, it can be concluded that the surface power plant of CPG systems is less complex, with less and smaller components, compared to the brine-based (indirect) ORC systems. This economic benefit will be partially compensated by the higher pressure level of the CO_2 cycle, leading to larger wall thicknesses of the components. To evaluate the different designs at the plant level, a detailed comparative design study would be the next step. However, as part of this work, a first generic economic assessment for CPG, based on LCOE calculations, was carried out, described next.

3. ECONOMIC EVALUATION

The thermodynamic benefits of a simple CO_2-Plume Geothermal (CPG) energy system, described in the previous section, were derived for a simple 5-spot well pattern (N=1). According to Bielicki et al. (2016) the levelized costs of electricity (LCOE) for CPG systems are decreasing when the power plant capacity is increasing from N=1 to higher coordination numbers until a minimum appears to be reached at N=5. Therefore, two N=5 cases were investigated for the economic evaluation.

Figure 8 illustrates the model of the considered multiple 5-spot injection patterns (N=5) which can be derived by adding additional injection and production wells with a central power station.

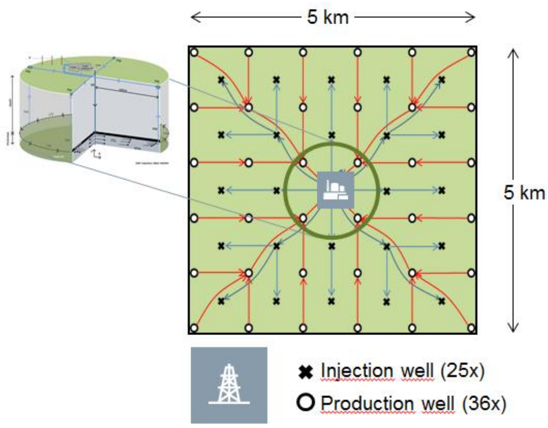

Figure 8: Exemplary illustration of a CPG system with a coordination number of N=5.

The geothermally heated CO_2 from the production wells is piped to the central power station (red lines). After the heat rejection in the cooling tower, the liquid CO_2 is fed to the injection wells (blue lines). In total 25 injection wells and 36 production wells are used for N=5. The pattern of the piping was chosen in order to achieve a minimum total pipe length (ca. 65 km). In order to minimize the pressure losses in the pipe line an average diameter of 1 m was defined.

For both cases we also considered supplemental pumping to increase the net power output. The heat sink was assumed to be a wet cooling tower, whereby heat is transferred with an intermediate water circuit. Table 2 summarizes the geologic properties of the reservoirs, the thermal boundary conditions of the power plants and the most relevant thermodynamic assumptions and characteristics for the two considered cases. During the assumed operation lifetime of 25 years, no thermal depletion of the reservoirs was assumed.

Table 2: Geologic boundary conditions of the two considered cases for the economic evaluation.

	Case 51 MW_e	Case 157 MW_e
Coordination number N [-]	5	5
Depth [m]	2500	3500
Permeability [m^2]	50	100
Temperature gradient [°C/km]	35	35
Well diameter [m]	0.41	0.41
Cooling Type	Wet Cooling tower	Wet Cooling tower
Ambient air heat sink Temperature [°C]	15	15
Approach temperature [°C]	15	15
P gross [MW_e]	79	255
P net [MW_e]	51	157

3.1 Capital cost modelling

For capital cost modelling purposes, the CPG energy system may be structured in two parts: the well field, and the surface power plant, the latter including surface piping, as shown in Figure 8.

The wellfield costs include all activities for wellfield completion such as well drilling or monitoring equipment. For cost assessment, CO_2 wellfield and well drilling cost estimates by Fleming et al. (in preparation) are used. This is based mainly on the detailed cost analysis for geologic CO_2 sequestration published by the United States Environmental Protection Agency, EPA (2008), and well drilling estimates from the Geothermal Electricity Technology Evaluation Model (GETEM).

In the brownfield approach, an already developed wellfield with existing wells, which can be re-used as CO_2-injection wells, is assumed. This may be the case, for example, for carbon capture and storage (CCS) systems and for depleted gas or oil fields especially when CO_2 is injected for enhanced oil recovery (EOR) or enhanced gas recovery (EGR).

Fleming et al. (in preparation) identify the production well cost as the main cost driver. The well costs for CO_2 corrosion resistant wells are estimated here to be 5 M$ for a 2.5 km deep reservoir and 10 M$ for a 3.5 km deep reservoir. Only small additional costs (lower than 10 M$) are identified for other wellfield-related efforts and equipment, such as for additional seismic exploration, monitoring, permits and engineering, assuming brownfield conditions.

The current estimates of brownfield wellfield costs in sum are ca. 225 M$ for the 51 MW case and 425 M$ for the 157 MW case using relations from Fleming et al. (in preparation).

The basic surface power plant concept is shown in Figure 1 and Figure 8. The estimated costs include the power island and all necessary systems, infrastructure, buildings, efforts for planning, engineering, commissioning etc. that are typically within the scope of a turnkey project. An addional 10% in costs is assumed for project development. The power plant can be realized by adjusting components which are currently used in gas combined cycle or steam power plants. Preliminary calculations, based on Siemens' product portfolio and in-house data show that the main cost drivers are related to the heat rejection, i.e. cooling tower, and gas cooler. Favourable cooling conditions, for example access to direct cooling at coastal or offshore locations, can therefore lead to significant cost reductions.

Cost estimates for the CO_2 pipelines are difficult, since the costs are subject to a certain dispersion reflecting variations caused by the impact of specific terrain, land use, and population density. Dubois et al. (2017) summarized different cost models which show large deviations. In the technical report EPA (2008) averaged specific pipeline costs of 1.5 $/(km m) are assumed, whereby the referenced data basis shows values up to 2.4 $/(km m). In the present investigation the costs for the 65 km surface piping are calculated on average with ca. 2.2 $/(km m), including all necessary equipment, corrosion protection cost as well as all activities e.g. for planning engineering and installation. Considering the published data mentioned above this approach is assumed to be conservative.

In sum, the current cost estimates for the surface plant, including piping, are 300 M$ (52 MW_e) and 480 M$ (157 MW_e). Further cost optimization potentials, e.g. by improving the heat rejection systems, seem likely and need to be investigated.

3.2 Levelized cost of electricity (LCOE)

To evaluate the economic competitiveness of a CPG power plant, the LCOE can be compared. The LCOE are calculated based on assumptions and boundary conditions following Lazard's latest comparative LCOE analysis (Lazard, 2018 - Table 3).

Table 3: Assumptions for LCOE calculation for the two example CPG systems.

Capacity factor	90%
Operation lifetime	25 years
Project development/ construction time	1 year
Annual O&M cost	360 – 630 $/kW
O&M cost escalation rate	2.25%
Equity rate	40%
Cost of equity	12%
Cost of debt before tax	8%
Debt payback period	Operation lifetime
Principal payment type	Levelized debt service
Combined tax rate	40%
Depreciation schedule	Modified accelerated cost recovery system (MACRS) 5-years

The capacity factor defines the assumed operational time of the power plant.

Operation and maintenance (O&M) cost for the wellfield and the surface power plant are for first calculations estimated in accordance with the assumptions used in GETEM (Mines, 2016) as a percentage of the capital costs. The resulting annual costs seem quite high, compared to experience with conventional power plants. Evaporated cooling water is considered with 1 $/m³.

In sum, the O&M costs contribute ca. 40% to the estimated LCOE. Therefore, more detailed cost investigations should be conducted in a next step to evaluate the differences between CPG systems and geothermal power plants regarding O&M efforts.

Table 4 shows the resulting LCOE compared to Lazard's results for some conventional and renewable technologies in 2018.

No revenues or costs of CO_2 storage are included in this comparison. These will have to be considered in addition.

Given the presented boundary conditions and assumptions, Table 4 shows that a 52 MW_e CPG power plant may be too small to reach competitiveness. In contrast, the calculated LCOE for the 157 MW_e example CPG power plant does appear to fall within the LCOE range that is typical for other baseload-capable power plants, such as coal, nuclear or solar-thermal towers, the latter with energy storage.

Table 4: LCOE Comparison for various baseload-capable power plants

	Technology	LCOE [$ ct/kWh]
Lazard (2018)	Solar Thermal Tower with Energy Storage (110 -135 MW)	9 – 18
	Geothermal (20 -50 MW)	7 – 11
	Nuclear (2200 MW)	11 – 19
	Gas Combined Cycle (550 MW)	4 – 7
	Coal (600 MW)	6 – 14
CPG (brownfield)	Case 52 MW	20
	Case 157 MW	12

3. CONCLUSIONS

The results of the technical evaluation show that the net power output of CO2-Plume Geothermal (CPG) systems is significantly larger than conventional (indirect) hydrothermal systems, particularly at “shallow" depths of 2-3 km and low reservoir permeabilities. Higher reservoir temperatures, e.g. due to greater drilling depth, reduce the kinematic viscosity of the brine and thus the pressure losses occurring in the reservoir. The greater the reservoir permeability and the higher the reservoir temperature, the greater the energetic advantage of indirect brine systems with a secondary Isobutane process.

While the variable density of the CO_2 leads to a higher performance for relatively shallowreservoir depths, due to the thermosiphon effect, this property also results in a greater sensitivity of CPG systems to cooling conditions, compared to brine-based geothermal systems, where low ambient air heat rejection temperatures are particularly advantageous for CPG systems.

Furthermore our initial design considerations showed that the surface power plant for a CPG system is less complex, with less and smaller components, compared to indirect hydrothermal systems.

The calculated LCOEs for the example cases show, that with suitable geologic properties, CPG systems can generate electricity at competitive costs, when brownfields are used. Including the costs of CO_2-emissions and the economic benefits of providing CO_2 storage in the cost comparison can lead to a further shift in favour of CPG systems.

Additional cost analyses should be carried out in future studies, for example, to determine the boundary conditions for competitive CPG systems when greenfields are used.

REFERENCES

Adams, B.M., Kuehn, T.H., Bielicki, J.M., Randolph, J.B., & Saar, M.O.: A comparison of electric power output of CO2 Plume Geothermal (CPG) and brine geothermal systems for varying reservoir conditions, *Applied Energy* 140, 265-377 (2015)

Adams, B.M., T.H. Kuehn, J.M. Bielicki, J.B. Randolph, and M.O. Saar, On the importance of the thermosiphon effect in CPG (CO2 Plume Geothermal) power systems, *Energy* (2014).

Bielicki, J.N., Adams, B.M, Choi, H., Jamiyansuren, B., Saar, M.O., Taff, S.J, Buscheck, T.A, Ogland-Hand, J.D.: Sedimentary Basin Geothermal Resource for Cost-Effective Generation of Renewable Electricity from Sequestered Carbon Dioxide, *Proceedings, 41st Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California* (2016)

Dubois, M.K., McFarland, D., Bidgoli, T.S.: CO2 Pipeline Cost Analysis Utilizing a Modified FE/NETL CO2 Transport Cost Model Tool. *2017 Mastering the Subsurface Through Technology Innovation, Partnerships and Collaboration: Carbon Storage and Oil and Natural Gas Technologies Review Meeting, Pittsburgh* (2017)

EPA (United States Environmental Protection Agency): Geologic CO2 Sequestration Technology and Cost Analysis, *Technical support document* (2008)

Fleming, M.R., Adams, B.M., Kuehn, T.H., Bielicki, J.M., and Saar, M.O. (in preparation). The Generation, Storage, and Operation of CO2-Plume Geothermal Energy Storage (CPGES) in a Low-Temperature Sedimentary Reservoir. *Applied Energy*.

Garapati, N., J.B. Randolph, and M.O. Saar, Brine displacement by CO_2, energy extraction rates, and lifespan of a CO_2-limited CO_2 Plume Geothermal (CPG) system with a horizontal production well, Geothermics, doi.org/10.1016/j.geothermics.2015.02.005, 55:182–194, 2015.

Lazard: Lazard's Levelized Cost of Energy Analysis – Version 12.0, retrieved from https://www.lazard.com (2018)

Lemmen, E.W., Huber, M.L., McLinden M.O.: NIST Reference Fluid Thermodynamic and Transport Properties—REFPROP Version 9.1 (2013)

Mines, G.: GETEM User Manual, retrieved from https://www.energy.gov (2016)

Randolph, J.B., and M.O. Saar: Combining geothermal energy capture with geologic carbon dioxide sequestration, *Geophysical Research Letters*, doi.org/10.1029/2011GL047265, 38, L10401, 2011.