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Feasibility Study of Carbon Dioxide Plume Geothermal Systems in Germany—Utilising Carbon Dioxide for Energy

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Abstract: To manage greenhouse gas emissions, directives on renewable energy usage have been developed by the European Commission with the objective to reduce overall emissions by 40% by 2030 which presents a significant potential for renewable energy sources. At the same time, it is a challenge for these energy technologies which can only be solved by integrated solutions. Carbon capture and storage combined with geothermal energy could serve as a novel approach to reduce CO₂ emissions and at the same time facilitate some of the negative impacts associated with fossil fuel-based power plants. This study focuses on the technical and economic feasibility of combining these technologies based on a published model, data and market research. In the European Union, Germany is the most energy intensive country, and it also has an untapped potential for geothermal energy in the northern as well as the western regions. The CO₂ plume geothermal system using supercritical carbon dioxide as the working fluid can be utilized in natural high porosity (10–20%) and permeability (2.5×10^{-14} – 8.4×10^{-16} m²) reservoirs with temperatures as low as 65.8 °C. The feasibility of the project was assessed based on market conditions and policy support in Germany as well as the geologic background of sandstone reservoirs near industrialized areas (Dortmund, Frankfurt) and the possibility of carbon capture integration and CO₂ injection. The levelized cost of electricity for a base case results in € 0.060/kWh. Optimal system type was assessed in a system optimization model. The project has a potential to supply 6600/12000 households with clean energy (electricity/heat) and sequester carbon dioxide at the same time. A trading scheme for carbon dioxide further expands potential opportunities.

Keywords: geothermal; carbon dioxide; sequestration; Germany; coal; carbon capture and utilization

1. Introduction

With an increasing concern about global warming, incentives [1,2] have been introduced to reduce greenhouse gas emissions. In the European Union, Directive 2012/27/EU [1] sets target goals by 2020 to increase the share of renewable energy systems by 20% and reduce greenhouse gas emissions by 20% compared to 1990 emission levels. However, continuing progress is needed as by 2030 emission levels should be reduced by 40% and the share of renewable energy in total energy consumption should reach at least 27% [2]. Member States adopt national plans to cope with the inevitable impacts of climate change [2,3]. Among them, Germany is the biggest energy consumer, while only producing half of its energy needs (Figure 1 [4]). The industry and the public sector are currently dependent on coal power plants, nuclear energy and various fossil fuel (including natural gas) resources. The discrepancy in

energy supply due to the phase out of nuclear power plants in Germany [5], results in an increase of energy generation from renewables and fossil fuels [6,7].

Figure 1. (a) Energy production and consumption in the EU and (b) final renewable energy consumption in Germany [4,8].

In the European Union biomass is the main source of renewable energy followed by wind and solar power. In Germany the main source of renewable energy is from the bio resources (biomass, biogas biodiesel) but wind and solar photovoltaics are representative with 18% and 9% respectively (Figure 1. [4]). As of 2016 gross final renewable energy consumption in Germany was below the 18% target at 14.8% [4]. While the share of geothermal energy generation is marginal both in the European Union (3.2%) and Germany (2.5%), unlike most renewable energy sources it is a viable option in terms of consistent, reliable electricity production without the need for energy storage [4,8]. Capacity factors of geothermal energy are the highest among energy systems above 80% and even 90% [9].

Current life cycle assessment and economic studies [10–14] have been carried out for geothermal energy and found to be competitive among renewable energy systems. New techniques have the potential to extract the geothermal heat and sequester carbon dioxide at the same time [15,16]. Furthermore, geologic carbon dioxide sequestration has been considered and promoted for reducing anthropogenic CO₂ emissions from fossil fuel-based power plants [2,17–19].

Randolph and Saar [20] have investigated and developed a technology to utilize geothermal energy in sedimentary basins where natural high porosity and high permeability reservoirs are present. Instead of water, they modelled the use of supercritical CO₂ as the geothermal heat extraction fluid [21]. Due to the better thermodynamic and fluid mechanical properties of CO₂ [22–25] it is possible to utilize geothermal energy in areas where temperature of prospective reservoirs are as low as 65.8 °C [16,26,27].

The Federal Government of Germany has created an opportunity for new projects offering a 20-year feed-in-tariff of 15.0 € cents per kWh for geothermal electricity [3] while promoting and supporting the installation of renewable heat for buildings. Favourable conditions opened up the development of binary cycle geothermal in North Germany, the Upper Rhine Graben from Frankfurt to Basel (Switzerland) and the South German Molasse Basin at the latitude of Munich. As, 55% of the final energy consumption in Germany is accounted for district heating, hot water and process heat [28,29], the direct use of geothermal energy would supplement the demand for heat especially in the commercial and residential sectors.

Further developments and working geothermal power plants exists in South Germany using heat from the upper Jurassic limestone reservoir [30,31]. In the Upper Rhine Graben favourable conditions are the increased heat flow and higher temperatures. Existing power plants are in Sauerlach,

Unterhaching, Dürnhaar, Kirchstockach (South Molasse Basin) Insheim, Landau, Bruchsal (Upper Rhine Graben) [32]. Geothermal energy is a mature technology, but carbon capture and storage [17,18] which has been used as an example project [33,34] is still not widely accepted. However, the hydrocarbon industry has long term experience with the transportation and injection of CO₂ for enhanced oil recovery (EOR) [35,36]. Also, example projects exist to produce coal-bed methane by CO₂ injection into coal seams [37].

Conventional CO₂ storage is in operation [34,38] at various sites throughout the world. Various research and development phase projects [39–41] are promising and future work could ensure their integration into energy systems. In the EU, large stationary sources (>10⁶ tons of CO₂/year) emitted 37% of European global CO₂ emissions which is accounted for 337 power plants generating electricity [42,43]. Grid emissions are calculated as 3722 × 10⁶ tons of CO₂/year while the average emissions for coal power plants are 1.04 g CO₂/kWh [44]. In case of Germany 81% of the electricity generated is based on coal [4]. New power plants need to qualify and limit emission levels [43] while older builds may also be suitable to retrofit facilities for CO₂ separation [45,46]. Power plants could avoid CO₂ penalties [47] and be within the emission limits of policies and regulations. Potential sites for the CO₂ plume geothermal (CPG) technology exists in the Northern part of Germany in the North East German Basin [28,48,49]. The Upper Rhine Graben has a significant potential with sandstone reservoirs and proven geothermal fields [32,50]. However, a number of concerns have to be investigated including seismicity [51,52], CO₂ hazards [19,53], Power Plant emissions, pollution levels and land use change [54,55]. Opposition to geothermal energy came from enhanced geothermal systems (EGS) induced seismic events [56]. In Northern Germany the first working EGS Power Plant was located in Landau. An intense monitoring of injection/production ratios and measured seismic events were assessed in the work of Vasterling et al. [56]. Significant seismic events in the area were recorded only historically in 1903 and 1880 [57], while only minor events were recorded during the monitoring ($M_L \leq 2$).

A detailed risk assessment is out of scope of this study, however possible options were investigated and proposed for thorough investigation and periodic inspections. Sites of interest include sandstones in the North East German Basin [49,58,59] and the Upper Rhine Graben [32,60]. The most prominent reservoir layer in the North Sea is extending to North Germany [61] where conventional and tight gas fields are indicators of prospective options and the possibility of technology integration for enhanced gas recovery [62,63]. Currently hard coal power plants supply energy along the Datteln-Hamm canal (North Rhine Westphalia, north of Dortmund, Figure 2), from Lünen through Bergkamen to Hamm [7,64,65]. The Hayden Power Station and the Mehrum Power Station (Lower Saxony) near Hanover are 920 and 620 MW, respectively, but fossil fuel power stations are located near Frankfurt and surrounding areas as well (Figure 2).

In this study the feasibility of geothermal energy was investigated with the possibility of carbon capture and storage, to serve not only as a renewable source, but to sequester CO₂ at the same time. The goal of this study is to investigate the possibility of using the CO₂ plume geothermal system in Germany, and to assess the economic feasibility of energy generation and the amount of carbon dioxide sequestration.

Figure 2. Power plants and transmission network in Germany with power plants over 100 MW. Compared to a previous 2008 version nuclear energy was substituted at various locations throughout the country by fossil fuel power plants. Reproduced from Federal environmental Agency of Germany 2020 [66].

2. Data Requirements and Calculation Methods

Various data requirements, calculation methods and stages of the project were investigated with varying level of interest and accuracy. The integration of the system, the efficiency and the possible energy generation potential is assessed based on researched data and works of Randolph and Saar [16,20]. The life cycle of the project is taken as 20 years as currently a feed in tariff for electricity exists in Germany for that time period. It is assumed that the drilling technology is not going to be a

limiting factor as well as the carbon capture and transportation from the coal power plant. The volume of reservoir is calculated, and the amount of sequestration is expressed as g/kWh. This makes it possible to compare and expand results with current LCA studies [12,13]. The combination of both technologies, the carbon capture from the flue gas at atmospheric pressures [45] and the geological storage in deep underground reservoirs [34] would join two value and product chains expanding business potential at the same time. Pilot projects are supported by grants, or governmental support. The levelized cost of electricity (LCOE) and return on investment (ROI) are calculated as well as the supply demand scenario e.g. how many households can be supplied by the electricity generated by the CPG system. In case of geothermal energy, the leading example states are Iceland, Italy, New Zealand [67]. Iceland uses its natural resources mainly for district heating saving almost 80% on other type of resources. Geothermal energy serves as a base load while hydro power takes up the variable load in Iceland's energy network [68]. Italy utilizes hot geothermal fluids to generate electricity [69]. The introduction of new technologies also facilitates the exploitation of deep underground heat for power generation on a wider area [15].

For this feasibility study the project starts with an exploration phase to delineate geological formations suitable for heat extraction and CO₂ injection. The CPG system and model is assessed according to Randolph and Saar [16,20]. Naturally high porosity and permeability reservoirs, without the need of well stimulation were researched in Germany and applied for this study. The technology for carbon dioxide capture is assessed based on possible power plant integration and available power plant production and consumption rates. Transportation and injection is based on production and transportation methods, fluid characteristics and safety standards. Economic calculation is based on a spreadsheet model for the specified location, local conditions and market characteristics. A short risk assessment with most probable drawbacks and difficulties are mentioned and treated as a required separate in depth study.

2.1. Geological Setting

Proposed sites for harnessing geothermal energy are located in NW Germany. The North East German Basin part of the South Permian Basin is located south of the Trans European Suture Zone [48]. The main targets are sandstone reservoirs like the Rotliegend sandstone extending in the North Sea where it is one of the main reservoirs for hydrocarbon exploration and production [61]. Oil and gas reservoirs hence layers of altered and diagenetically modified sandstones are also targets of interest as well as deep saline aquifers.

In the North German Basin, the movement of Zechstein salts (Late Permian evaporites) resulted in tectonic deformation of Mesozoic and Cenozoic layers. In the Lower Saxony basin at Woitzel quarry Upper Carboniferous outcrops were investigated [49] as analogues to gas and tight gas sandstone reservoirs [50]. Also, the area is well known of intense coal mining of coal seams interbedded with sandstone layers (Figure 3).

The aeolian and fluvial depositional system represents good reservoir characteristics in terms of porosity and permeability [49]. However, diagenetic processes may override initial conditions. Primary porosity in siliciclastic rocks is reduced by compaction of ductile quartz grains, crystal overgrowth formation of clay minerals thus intense illitization [53]. The Upper Carboniferous sandstones were deposited in the NW European Carboniferous Basin, a foredeep NW of the Variscan (Hercynian) orogenic belt [70]. This sub-basin was part of The Central European Basin System formed as a result of Early Mesozoic rifting and wrench tectonics [71–74]. Sub-basins including the Lower Saxony Basin underwent subsidence (sedimentation of sandstones and organic matter) until the Late Cretaceous followed by subsequent inversion [75,76]. The Upper Carboniferous (Westphalian) which are the fossil coal bearing sectors represent the main source rock of the natural gas-migrated and trapped-in the reservoirs of the Central European Basin System [77–79]. Production of tight gas deposits has a history of several decades, and the Upper Carboniferous sandstone reservoirs have shown to have continued exploration potential in NW Germany [80]. The Permian Rotliegend sandstone and

Zechstein carbonates are the main reservoir levels in the region, while Zechstein (Late Permian) evaporites continues to act as a provincial seal across the entire basin for both Carboniferous and Permian reservoirs [78,79]. Stratigraphic layers similar to the Upper Carboniferous Westphalian D section are considered among target locations for the present study.

Figure 3. Location map of fields producing from Upper Carboniferous reservoir rocks in NW Europe. (a) A: = onshore UK; B = North Sea, C = onshore Netherlands and Germany. (b) Outline map of the southern and central part of the Lower Saxony Basin showing the locations of Upper Carboniferous outcrops (grey), and of tight gas fields producing from Upper Carboniferous reservoir rocks (black). (c) The Upper Carboniferous to Permian coal bearing stratigraphy (black lines = mineable coal seams) and the stratigraphic positions of the study areas at the Hüggel (H) and Woitzel (W) quarries, together with the position of the reservoir interval at an actual tight gas field ("field X": location in b), are shown in the stratigraphic column.). Reproduced from the Journal of Petroleum Geology 2017 [49].

Similar objects are the oil and gas producing reservoirs in the vicinity of surrounding areas [50]. Research done by Müller et al. [60] concludes a good potential exists in the North Rhine Graben region. Near Frankfurt the reservoir temperatures of the Permocarboniferous sandstones modelled by Arndt et al. [81] and Agemar et al. [82,83] exceed 150 °C. Therefore the potential for electricity generation in association with binary geo-thermal plants is possible and additionally deep geothermal energy is currently utilised in similar settings (Figure 4) in the middle Upper Rhine Graben [32]. In the regions of Landau, Insheim and Bruchsal, the producing basins are cracked crystalline rocks, and fractured sandstones of the Triassic Buntsandstein and the Permocarboniferous. The initial geothermal power plant operating in the siliciclastic and volcanic succession of the Permocarboniferous in the northern Upper Rhine Graben is proposed for Groß-Gerau. The Aeolian sandstones [32] exhibit the highest porosities (16.4, 12.3%) and permeabilities (2.0×10^{-15} , 8.4×10^{-16} m²), with the average well depth for both regions is in the range of 3000–4000 m [28].

Figure 4. A geological overview map of the Upper Rhine Graben in SW Germany. Modeled reservoir temperatures reach 150 °C. The top of the permocarboniferous reservoir is at 600–2990 m. Reproduced from International Journal of Earth Science 2016 [32].

2.2. CO₂ Plume Geothermal System (CPG)

The CPG system described here [20] involves the pumping of supercritical CO₂ into natural high porosity and permeability reservoirs described in the previous chapter. The patent which the concept is based on includes the technology and the use of supercritical CO₂ for energy generation purposes in the form of electricity or exchanged heat [84,85]. The injected CO₂ is heated by the geothermal heat flux from Earth's interior. At the production side of the system the CO₂ is utilized either for electricity production through a turbine connected to a generator, or in a binary cycle through a heat exchanger to provide energy for electricity generation (binary system), and/or direct use of the thermal energy in district heating systems (Figure 5). In either case the heated carbon dioxide will increase its enthalpy which can be converted through a mechanical system into power or energy. In return carbon dioxide is stored and sequestered for long term in the reservoir. The possibility of a geothermal system coupled with CO₂ sequestration has been investigated previously [16,21]. The authors have determined that such a system can provide three times greater heat extraction rates compared to conventional water-based systems [20]. In a steam turbine high pressure high temperature steam is used to power the system. The higher the pressure and temperature the more energy is stored in the steam. At a supercritical state the fluid has both gaseous and liquid like characteristics. In case of water the triggering pressure and temperature are 22.06 MPa and 373.95 °C [24]. However, CO₂ ($P_{cr} = 7.37$ MPa, $T_{cr} = 30.97$ °C) has a much lower pressure/temperature ratio, thus limited usage in low temperature systems. A supercritical CO₂ power cycle is used to extract energy from a high-pressure low enthalpy reservoir [86]. A numerical simulation is used to assess the available thermal energy. For each case parameters shown in Table 1. (Reservoir parameters based on geological formation; injection/production conditions; initial and boundary condition [20,32,49] are set in a reservoir simulator TOUGH2 (Version 2.0, Lawrence Berkeley National Laboratory, Berkeley, CA, USA) [22] with a supplementary fluid property (CO₂, water, NaCl) module ECO2N. The model [20] was constructed as a reference for a five-spot well configuration with 1 km² map view area and 707 m between the injection and the production wells. For the model the reservoir thickness was set for 305 m. For the modelled scenario the heat extraction rate was calculated as 47.0 MW, averaged over a

25-year period. The amount of sequestered CO₂ is calculated according to the occupiable space in the reservoir. Secondly a natural 5% fluid loss is expected using CO₂ as the working fluid in tight reservoirs. Randolph and Saar [20] are calculating this with a 7% loss based on the assumption that fluid loss is higher in naturally permeable formations [23]. This means a permanent e.g. non-recoverable CO₂ fraction during the operation period of the power plant:

$$\text{CO}_2 \text{ loss} = V * 0.05 * 25 \quad (1)$$

$$V = \text{Area} * \text{thickness} * \phi \quad (2)$$

where V is reservoir volume and ϕ is the porosity. The total amount of possible sequestration for the whole 20-year lifetime of the project is calculated by the maximum possible occupiable space in the reservoir, the reservoir volume multiplied by the fluid loss over the 20 years. This is then added to the overall CO₂ amount in the reservoir.

Figure 5. Schematic representation of the CO₂ plume geothermal (CPG) system showing the possibility of CO₂ sequestration and scenarios with optional elements for electricity production, or district heating systems. The electricity generator is driven by a turbine maintained by the flow of high pressure vaporized CO₂ gas. The waste heat can be further utilized through a heat exchanger for district heating or cooling purposes [20].

Table 1. Base case reservoir parameters of the studied geothermal system. Reproduced from Energy Procedia 2011 with data from Artz et al. 2016 and Becker et al. 2017 [20].

Base Case Parameters			
Geological formation		Injection/production conditions	
Reservoir area	3 km ²	Temperature of injected fluid	15 °C
Thickness	100 m	Injection/production rate	max. 300 kg/s (variable)
Well separation	707 m	Injection rate	126 kg/s
Permeability	1.4×10^{-15} m ²	Downhole injection pressure	31 MPa
Porosity	15% (0.15)	Downhole production pressure	30 MPa
Rock grain density	2650 kg/m ³	Injection duration	8 years
Rock specific heat	1000 J/kg/°C	Production duration	20–25 years
Thermal conductivity	2.6 W/m/K		
Formation initial conditions		Formation boundary conditions	
Fluid in pore spaces	CO ₂ /H ₂ O	Top and sides	No fluid or heat flow
Temperature	130 °C	Bottom	Heat conduction, no fluid flow
Pressure	30 MPa		

2.3. Carbon Dioxide Capture

The difference between CPG and a conventional H₂O-based geothermal system is the requirement for the supply of carbon dioxide. Sources of carbon dioxide can be categorized as aerial and stationary, the latter including industrial processes (cement production), fuel combustion (power plants) and natural gas processing. The purpose of the separation process in a power plant is to enable the production of a concentrated stream of CO₂ at high pressure, ready for further usage and for transportation and injection into the reservoir [17]. There are two main approaches to capturing the CO₂ generated from a fossil fuel power plant and the choice is determined by the technology or plant configuration. In the post-combustion process system, the separation of CO₂ from the flue gas produced by the combustion of the primary fuel in air [45], usually use a form of liquid solvents to absorb the low amount of CO₂ (typically 3–15% by volume) contained in the flue gas stream with nitrogen as the main component from air (Figure 6). For current pulverized coal (PC) power plant technologies or for a natural gas combined cycle (NGCC) power plant, the common post-combustion capture systems tend to utilise an organic solvent such as (MEA) monoethanolamine [34,45].

Figure 6. Post combustion capture process for a pulverized coal power plant. The CO₂ separation unit using the monoethanolamine absorption process is located before the stack. The amount of captured CO₂ is dependent on efficiency factors or desired amounts of CO₂. The excess CO₂ is then released with the flue gas. Reproduced from NREL 2007 [45].

The exhaust gases from the turbine and the boiler are captured, collected and sent to the separator unit based on MEA absorption. After separation, the CO₂ is compressed and liquified, becoming a cool (5 °C) fluid [17]. Pre-combustion is divided into two methods which can be utilised at a system that uses an integrated gasification combined cycle (IGCC) technology. The fossil fuel is used to produce syngas (H₂) and separates CO₂ before combustion. Among them an oxyfuel combustion approach uses oxygen instead of air for ignition of the principal fuel to generate a flue gas that consists primarily of water vapour and CO₂. As an approach for CO₂ capture in boilers, the oxyfuel technologies are in the validation and demonstration phase [87]. Currently the post-combustion as well as the pre-combustion technologies that are being deployed on generation plants could capture 85–95% of the CO₂ that is generated. While a potentially greater capture efficiencies may be achievable, the required separation equipment is significantly larger, required a higher energy input and is more capital intensive. Further treatment of the flue gas may also be needed to remove air pollutants and non-condensed gases (such as nitrogen) from the flue gas before the CO₂ is sent to storage site. Capture and compression roughly need 10–40% more energy (depending on the type of the system) than the equivalent plant without

capture technology. The pulverized coal power plant at Lünen operated by Trianel is a modern state of the art power plant with space for carbon capture technology integration [7]. The post combustion capture system based on MEA absorption is capable for a variable CO₂ capture ratio based on reservoir size [45]. The capture process includes the compression and liquefaction of the CO₂ into 10 MPa which is the standard preparation pressure for transportation [88]. The Lünen power station with 750 MW, 86% capacity factor and almost 1.5×10^6 t coal consumption per year produces 4.5×10^6 t CO₂ annually [89].

2.4. Transportation and Injection

Different transportation methods are optional including truck, rail, ship and pipeline. In this study pipeline transportation is assessed as the most suitable method based on safety concerns. The previously discussed capture method [45] and the distance of the reservoir would involve a pipeline transportation at 0–250 km [44,90,91]. The majority of the worldwide (6500 km) CO₂ pipelines are linked to EOR, especially in the US [92]. In case of EOR the revenue is made by the increased rate of oil production, which offsets the cost of pipelines. With changing market conditions a project may temporarily shut down while in case of Europe, CO₂ storage is viewed as a mitigation option (Table 2). Additionally, pipeline technology used for hydrocarbon transportation could be modified and utilized and where possible underground burying should be assessed regarding safety and alternative options with associated natural landscape interference [17]. The European dedicated standard for CO₂ pipeline is: DNV-RP-J202 while an international standard also exists: ISO/TC 265. This study calculates with 400 mm diameter pipes and investigates different pipeline length to a maximum of 250 km onshore from source to site. Pressure stations, safety valves and safety signals and signs are planned according to standards and directives of the European Parliament. The method, mode and technology of CO₂ injection has been used for decades in the hydrocarbon industry [36]. It is a well-established technology that is used for enhanced oil or gas recovery in mature hydrocarbon fields (Table 3.). Similarly, for the CPG system CO₂ is pumped to the reservoir. Based on Soultz Enhanced Geothermal Power Plant the downhole electrical pumping requirement is approximately 100 kW_e [52]. In case of CO₂ instead of water, the larger expansion coefficient generates larger buoyancy forces which results in the net pressure increase between production and injection wells, thus a thermosyphon effect applies which would decrease pumping requirements or can operate without one [86,93]. Carbon dioxide in the form of a dense and cool liquid ($\rho = 950 \text{ kg/m}^3$, $T = 5 \text{ }^\circ\text{C}$) would sink into the reservoir [94] where conditions of high pressure and temperature ($p = 30 \text{ MPa}$; $T = 130 \text{ }^\circ\text{C}$) would transform the CO₂ into its supercritical form ($p > 7.37 \text{ MPa}$; $T > 30.97 \text{ }^\circ\text{C}$; $\rho = 560 \text{ kg/m}^3$). For the above-mentioned reasons, the parasitic load of the injection is assumed to be negligible, thus not influencing the net power output of the geothermal power plant.

Table 2. Drivers of CO₂ pipeline projects. Reproduced from IEAGHG 2013 [92]).

Motivator	Comments	Example Project
Enhanced Oil Recovery (EOR)	CO ₂ is used as a tertiary recovery agent to increase oil production in depleting or mature oil fields	see Table 3.
CO ₂ reduction targets	CO ₂ is stored in deep saline formations or depleted oil or gas fields	see Table 3.
Enhanced Coal Bed Methane Recovery (CO ₂ -ECBMR) and Enhanced Gas Recovery (EGR)	CO ₂ is used to enhance coal bed methane production from coal-beds or coal bearing formations or re-injected in suitable gas formations (depleted or for EGR)	see Table 3.
Use of CO ₂ for industrial purposes	CO ₂ is transported to greenhouses and used to stimulate growth of plants and crops	OCAP, Netherlands

Table 3. Worldwide CO₂ utilization sites for enhanced oil recovery (EOR), CO₂-enhanced coalbed methane (CO₂-ECBM) and CO₂ storage. Reproduced from Renewable & Sustainable Energy Reviews 2014 [34].

Project Name	Type	Location	Start Year	Max. CO ₂ Injection Rate (t/Year)
Jilin oil filed	EOR	Jilin, China		100,000
Weyburn-Midale	EOR	Saskatchewan, Canada	2000	2,200,000
Paradox Basin	EOR	Utah, USA	2005	140,000
Salt Creek	EOR	Wyoming, USA	2006	2,200,000
Williston Basin	EOR	North Dakota, USA	2011	1,000,000
South Heart	EOR	North Dakota, USA	2012	600,000
Oologah	EOR	Oklahoma, USA	2012	1,500,000
Masdar	EOR	Abu Dhabi, United Arab Emirates	2012	1,700,000
Hatfield	EOR	Hatfield, UK.	2013	6,500,000
California (DF2)	EOR	California, USA	2014	5,000,000
Mongstad	EOR	Mongstad, Norway	2014	1,500,000
Trailblazer	EOR	Texas, USA	2014	4,300,000
Greengem	EOR	China	2015	700,000
Genesee (EPCOR)	EOR	Alberta, Canada	2015	3,600,000
San Juan Basin	CO ₂ -ECBM	New Mexico, USA	1996	100,000
Permian Basin	CO ₂ -ECBM	Texas, USA	2005	300,000
Farnham	CO ₂ -ECBM	Utah, USA	2005	900,000
Dome/Uinta Basin	CO ₂ storage	Alberta & B.C., Canada	1990	100,000
Mountaineer	CO ₂ storage	West Virginia, USA	2009	100,000
Brindisi	CO ₂ storage	Italy	2012	1,200,000
Sleipner	CO ₂ storage	North sea, Norway	1996	1,000,000
Snøhvit	CO ₂ storage	Barents sea, Norway	2008	700,000
Latrobe Valley	CO ₂ storage	Victoria, Australia	2015	13,000,000

2.5. Economic Calculation

For the economic model the carbon capture technology with the compression and liquefaction stage together with the transportation through pipelines were assessed. An average 32 €/t CO₂ capture price was accepted based on Ramezan et al. [45] and an IPCC report [17]. The cost of transportation based on Morbee et al. [91] for a reference case is between 1.7–3.5 €/t. Haumann et al. [88] have investigated a pipeline route from Germany to Algeria through Sardinia (Italy). The cost of pipeline transport for their model was normalized as 11.3–13.7 €/t. Their calculation included a section across the Mediterranean Sea, which translates to increased overall costs. A recent study by d'Amore and Bezzo [44] indicates a unitary pipeline transportation cost of 0.04009 €/t CO₂/km under 1 million tonnes of CO₂ transported per year. In case of 5 million tonnes of CO₂ annually, the pipeline transportation cost decreases to 0.01476 €/t CO₂/km. As a rule, the cost of CO₂ transported through the pipeline decreases with increasing amount of CO₂. A different study by Heddle et al. [90] calculates with 1.5–2 \$/ton of CO₂/100 km. The initial phase of the project the exploration phase is planned for four years for the exploration drilling and testing period (including licensing and permission). After an initial investigation a 3D seismic survey have to be measured for further exploration and delineation of possible prospects [30]. The measurement and the processing periods are taken to be 6 months. The seismic interpretation and the mapping of the reservoirs is considered feasible within an 18-month period. The planned steps are a small 3D seismic reflection survey to explore facies and geological structures, regional geological 3D modelling of structures aided by additional existing 2D seismic profiles, hydrogeological modelling, and numerical simulation of fluid flow, heat transfer and corresponding forecasting [30]. Another 6 months is considered for reservoir simulation before the drilling period. The cost of drilling of a geothermal well is based on hydrocarbon and hydrogeological well costs. Based on Kipsang [95] the drilling of a 3000 m geothermal well costs 5.8 million \$. A different

study from Lukawski et al. [96] is calculating the cost (million US dollars) of a geothermal well based on statistical analysis of hydrocarbon and geothermal well cost trends.

$$\text{Geothermal well cost} = 1.72 \cdot 10^{-7} \cdot \text{MD}^2 + 2.3 \cdot 10^{-3} \cdot \text{MD} - 0.62 \quad (3)$$

where MD is the measured depth of the geothermal well. In case of this study two 3000 m wells were calculated with one for injection and one for production. A possibility of a reuse and modification of a hydrocarbon well would significantly decrease capital cost requirement but would not necessarily mean less construction time. North Germany hosts hydrocarbon fields including natural gas reservoirs. If carbon dioxide is used for enhanced hydrocarbon recovery, the revenue price of the net produced oil, natural gas or methane could be accounted as an additional product. The cost of the power plant including a high-pressure turbine, heat exchanger reinjection unit with a control station and safety measures is taken from Stefansson [68]. The study calculates with 977 \$/kW for the surface equipment costs for power plants in the range of 20–60 MW. To mitigate investment costs and efficiency loss a study by Wang et al. [97] investigates geothermal energy integration with a post-combustion 300 MW_e coal fired power plant. The renewable heat fraction is used for the sorbent regeneration in the capture process. In case of a CPG system this means that part of the heat could be utilized regardless of consumer demand thus decreasing the energy used for the capture process. The capacity factor in case of a geothermal power station is actually an operator choice. After the initial reservoir fill up of circa 10% according to Randolph and Saar [20], the reservoir can produce work continuously if desired. With proper planning, only minimal maintenance is required, which is calculated as Operation and Maintenance, $3 \times 7 \times 24$ h/year. Stefansson [68] indicates an 8000 h/year operation for average geothermal power plants in Iceland. The possibility for governmental support in form of grants and funds are calculated in the present study. The amount is assumed to cover exploration costs. Exploration costs includes data room, data acquisition, data processing, 3D survey measurement and processing as well as interpretation. Data is based on Clauser and Ewert [98] and includes software and labour for the exploration and drilling cost of one well. Several organisations offer favourable conditions for investments and pilot/demonstration projects. A study by Weber et al. [28] indicates an overall sum of € 20.6 million in awarded grants for 20 geothermal projects. Averaged over projects it translates to € 1 million per project. The government of Germany [3], offered a 15 cent/kWh feed in tariff for 20 years. This means the selling price of the generated electricity is granted and the profit/investment ratio will determine the ROI and the break-even point expressed as % and years. The LCOE is based on the electricity generation potential/total life cycle cost. It is assumed that all the electricity generated is sold back or is required hence the demand for electricity is not a limiting factor. In case of the utilization of geothermal heat, the supply is calculated based on the heat recovery ratio of the heat exchanger. A continuous supply is possible, but the actual demand (district heating, greenhouses) sets a limit to the useful heat energy. In this study the district heating system is outside of the system boundary, while the geothermal heat is calculated based on average heating days multiplied by the average heat usage of a household in Germany [4]. To summarize, the available supply of households is calculated. The price of thermal energy was based on a study by Routledge and Williams [29]. They estimated an average 4 € cent/kWh consumer price for the supplied equivalent thermal energy. In contrast, the price estimate of gas burned in boilers to produce hot water was 5 € cent/kWh. Prices reflect UK market (prices converted to Euro on Q2 2018 £–€ conversion rates) and it is assumed that the scenario will effectively describe the German household heat market as well. The system is assessed and fine-tuned in an optimization model by HOMER Energy (Homer Pro 2018). The optimal system is graphed based on sensitivity analysis of parameters (cost of electricity, sellback rate, CO₂ price). The model is used to assess renewable energy systems and while geothermal energy is a special case it is simulated as a generator with CO₂ as the fuel. Parameters of the CO₂ like the heating value and density at reservoir conditions are given based on Pioro and Mokry [24] as well as Randolph and Saar [16] and Saar et al. [84,85].

3. Risk Assessment

Every project is presented with a specific amount of risk. In case of geothermal energy, and CPG system in general the associated risks are the success of the exploration and drilling of the production and injection wells. To mitigate risk and increase success rate a geological risk analysis is conducted. Other risks include environmental CO₂ hazards due to leakage from transportation, leakage of the CO₂ from the well and the reservoir through various routes [17,53]. In case of EGS in Germany, the first power plant in Landau [56] and a second one at Soultz EGS reservoir [52] was extensively monitored for induced seismicity. Injection rates were determined safe from 20 to 80 kg/s (L/s). According to Directive 2011/92/EU of the European Parliament [99], an environmental impact assessment (EIA) is required for projects with increased potential of landscape change. In case of this report the buried depth, the accessibility, installation of safety valves to isolate faulty sections, failure and corrosion prevention both in and outside of pipe wall are the required cases that have to be assessed. Apart from risks concerning the environment risk involving economic uncertainties also exists. These including electricity prices, change in feed-in-tariffs, change in policy and legislations. Public perception on various projects is not negligible and often moving forward into implementation phase fails because of inadequate information and involvement of public and the society.

4. Results and Discussion

The objective of this paper was to locate a potential site for the installation of the CO₂ plume geothermal system. Parameters for the reservoir simulation have to be further researched but based on Randolph and Saar [2] as well as Weber et al. [28] calculations were performed for natural high porosity and permeability formations existing in northern and western Germany. The support of geothermal energy is favourable in Germany as a feed-in tariff exists for a 20-year period. Additionally, the cost of drilling and construction of the power plant will be offset by the CO₂ sequestration as an additional layer to the renewable energy generation facilitating an existing fossil fuel-based power plant as the source of CO₂ as well. In case of this study the source of CO₂ was chosen to be from the Lünen Pulverized coal power plant operated by the company Trianel. Currently regulations calculate with €40/t carbon dioxide emission penalty [47]. If that was to apply for the emitted CO₂ by the coal power plant, the cost would be in the range of €180 × 10⁶. However, a €100 penalty (€450 × 10⁶) is proposed to be applied in the future therefore, the power plant was constructed with possible carbon capture and storage integration. For this reason and considering the carbon penalty, the capital investments associated with the separation and capture technology is accounted for the coal power plant. In the case of a post combustion process the technology includes the absorption unit, the regenerator unit, compressor and possible storage tanks. The total capture cost per tonne of CO₂ was based on Ramezan et al. [45], using costs of €32/t CO₂ price. The cost of capture is €116 × 10⁶ with pipeline transportation as the safest solution to transport large amounts of liquid CO₂. In case of the Lünen power plant the possible amount of CO₂ after capture and compression is 3.9 × 10⁶ tons of CO₂/year. This value falls within a range of current injection rates to enhanced oil recovery, coalbed methane and CO₂ storage sites. A 100 km radius delineating a pipeline transportation area is illustrated on Figure 7. The calculated price of the transportation of the amount of CO₂ from the coal power plant at a distance to 100 km is €7.3 × 10⁶. If possible a shorter distance route of 0–50 km is preferred for lower costs and less permitting issues. A range of 20 km would cover the populated area around power plants. This case also represents power stations closer to CO₂ utilization sites. The possibility of long term usage of the pipelines requires an extensive CO₂ pipeline network from and around major fossil fuel power plants. A pipeline network from source to 250 km with Lünen power station as the source (Figure 7) correlates well with the location of major power stations and possible reservoir sites. The geothermal well cost was based on statistical well cost analysis. For a 3000 m geothermal well the current study calculates a cost of €6.6 × 10⁶. Exploration costs are based on Clauser and Ewert [98] as €1.3 × 10⁶. The cost of constructing a 50 MW geothermal power plant with the machinery is predicted as €42 × 10⁶. The total project cost with power plant machinery and construction excluding the pipelines was calculated as

€54.1 × 10⁶. This project has calculated the reservoir potential based on previous studies and reservoir characteristics of sandstones in the North German Basin as well as the North Upper Rhine Graben. Based on simulations in works of Randolph and Saar [16], Garapati et al. [21] an analogy was drawn to the present study which calculates with the power generation potential of 50 MW. The electricity generation potential is calculated by multiplying the gross thermal output with the Carnot efficiency and the turbine mechanical efficiency. In case of the studied sites the reservoir temperature is set as 130 °C (403 K) while the average ambient outside temperature is taken as 15 °C (288 K). This gives a Carnot efficiency of 0.29. The system utilization efficiency of the turbine was set to 0.45, while the heat recovery ratio is calculated as 55%. The calculated electricity generation potential is 6.5 MW_e, while the thermal output potential is 24 MW_{th}. The annual electricity generation potential with a 94% capacity factor is 52,850 MWh (Table 4). Calculating with a fixed € 0.15/kWh feed-in-tariff for geothermal electricity the LCOE for a base case is €0.059/kWh which includes the exploration, drilling, power plant construction and operation costs (case 1). The pipeline transportation cost to a distance of 100 km if accounted in the geothermal power plant (case 2) increases the levelized cost of electricity to €0.107/kWh. Based on gathered and calculated data the model was expanded into the HOMER Pro optimization model (Version 3.13, Homer Energy LLC, Bolder, CO, USA) to test sensitivities and determine optimal system type. Values for electricity prices were tested in the range of €0.0–0.3/kWh while a lower feed-in-tariff and zero value was also investigated. Carbon dioxide as a fuel was added to the model and the price (€/kg) was converted as pipeline costs. The primary electrical and thermal load was added based on the previous calculations; hence a system was built where the supply demand scenario is more or less the same. Furthermore, the real and nominal interest rates for Germany in 2018 were incorporated to the model as −1.91% and 0.0%. Results of the sensitivity analysis and optimal system are shown on Figure 8. For case 1 the HOMER model resulted in €0.060/kWh while case 2 with a 100 km pipeline cost would give € 0.093/kWh. Both cases represent a 94% geothermal capacity factor serving as base load. The return on investment is 21.5% for case 1 and 18% for case 2 while the simple payback time was calculated as 3.8 and 4.3 years, respectively. In Figure 9, subfigures (c) and (d) represent an incorporated pipeline cost to 250 km and 400 km as still being feasible under certain conditions like electricity price and sellback rate. In case of utilising the carbon capture technology the LCOE of the coal power plant increases by 36%. Data and calculated values correlate well with recent studies [98,100]. Figure 9 compares the levelized cost of electricity from various renewable energy sources. Compared to geothermal energy solar PV is the most variable in terms of price/kWh but wind energy is considerably more capital intensive as well. While biomass derived, energy is comparable with geothermal energy it has significantly higher impact in terms of land use change, GHG emissions (Figure 10) and possible air pollution (PM_{2.5}). The high variability between energy sources in energy price/kWh could be interpreted as lack of legislative support or funds for the installation of the power plants as well as local conditions. Geothermal energy is still among the cheapest and most reliable sources of energy, competitive with fossil fuel power plants.

Table 4. Parameters of the components and capital cost requirements of deploying the system.

Parameters	Value	Unit	Reference
Lifetime	20	years	
Germany electricity price	30	€/MWh	
Sellback rate	20	€/MWh	[3]
Pulverized Coal Power Plant			
PP size	750	MW	[89]
Operation	7800	h/year	
Production	5,850,000,000	kWh/year	
Coal consumption	1,500,000	t/year	
Coal price	93.5	€/t	
CO ₂ amount	4,500,000	t/year	
Capture Ratio	90	%	[45]
CO ₂ to Capture	4,050,000	t/year	

Table 4. Cont.

Parameters	Value	Unit	Reference
CO ₂ emitted (calculated)	0.769230769	kg CO ₂ /kWh	
CO ₂ emitted (reference)	0.75	kg CO ₂ /kWh	[43,89]
Power Plant cost	1,400,000,000	€	[89]
Operation and Maintenance	140,250,000	€/year	
CO ₂ penalty	100	€/t CO ₂	[47]
CO ₂ penalty	450,000,000	€/year	
Capture cost	32	€/t CO ₂	[45]
Total Capture cost	116,640,000	€/year	
Pipeline			
Length	100	km	
Transportation capacity	50	106 t/year	[88]
Transportation cost	0.02	€/t CO ₂ /km	[44]
Transportation cost	7,290,000	€/year	[44]
Exploration and drilling			
Drilling cost	6,653,800	€	[96]
Exploration cost	1,330,760	€	[98]
Number of wells	2		
Exploration and drilling cost	14,638,360	€	[96]
Reservoir			
Depth	3000	m	[32,49]
Temperature	130	°C	[32,49]
Area	3	km ²	[32,49]
Thickness	100	m	[32,49]
Volume	0.3	km ³	
CO ₂ density	560	kg/m ³	[24]
Fluid loss	5	%	[22]
Geothermal Power Plant			
Size	50	MW	[16,20]
Electricity output	6.5	MW	[16,20]
Thermal output	28	MW	[16,20]
Electricity Generation (potential)	56,200	MWh/year	
Thermal energy generation (potential)	248,000	MWh/year	
Construction and machinery	41,522,500	€	[68]
Operation and Maintenance	504	h	[68]
O&M	800	€/h	
	403,200	€/year	[68]
Grants	2,000,000	€	[3,28]
TOTAL PROJECT COST	54,160,860	€

Figure 7. Illustration of pipeline length and reachable distance up to 400 km.

Figure 8. Sensitivity analysis and optimal system based on HOMER Pro. Pipeline costs were calculated for case 1 (a) and case 2 (b) while a third case (c) represents the optimal system type with 250 km pipelines. Case 4 (d) was calculated as the highest distance of pipelines (400 km) where the project is still feasible with €0.3/kWh electricity prices and €0.0/kWh REFIT. Project life was set for 20 years as a REFIT scheme is offered for that time period.

Global levelised cost of electricity from utility-scale renewable power generation technologies 2010 - 2017

Figure 9. Levelized cost of electricity change from 2010 to 2017 for biomass, geothermal, hydropower, solar PV, concentrating solar power, offshore and onshore wind energy. Case 1 and case 2 is in the range of the assessed levels of LCOE for geothermal energy. Reproduced from IRENA 2018. [100].

While other renewable energy systems are comparable in GHG emissions (Figure 10), geothermal energy offers an obvious and readily available integration into carbon capture and storage that other systems lack. The LCOE of the studied CPG system in Germany falls within the range shown on Figure 9. The increase in LCOE in case of the coal power plant correlates well with data from Ramezan et al. [45].

The amount of sequestered CO₂ is calculated based on the reservoir area, thickness, porosity and CO₂ characteristics at reservoir pressure and temperature (30 MPa, 130 °C). The result gives a 29×10^6 tonnes CO₂ sequestration potential over 20 years including the 5% natural non-recoverable fluid loss [22]. This value is converted to g/kWh to compare the sequestration potential and global warming potential from LCA studies expressed in CO₂ equivalents as g/kWh. Data and results from LCA studies are representative for current EGS power plants in Germany producing electricity [12,13]. Results and data for comparison are summarized on Figure 10. Additionally, the project has a potential to reduce the emission levels of the coal power plant from 750 g/kWh ([43] reference value) to 585 g/kWh. Moreover, thermal energy is often viewed as a less valuable product but has interesting potentials considering advancing technologies. The amount of potential thermal energy in the geothermal power plant is 209,977 MWh/year. This thermal energy is present in the system regardless of the electricity generation. In Germany the average household consumption of thermal energy (heating and hot water) with a range of 6218–14,306 kWh/year (depending on the type of dwelling) was based on Routledge and Williams [29] for dwellings build after the year 2000. The cost of thermal energy was determined as € 0.04/kWh. Compared to the present study the CPG system utilising a heat recovery efficiency of 55% could distribute energy at a price of € 0.028/kWh. Based on the average electricity (7900 kWh) and thermal energy consumptions (10,000 kWh)/household the CPG system could provide clean electricity and thermal energy for 6600 and 12,000 households, respectively. Considering land use change the average measured area required for binary cycle geothermal power plants in Germany is 4 acres (16,000 m²). The sequestration potential of this land area is 29×10^6 tons of CO₂ over 20 years of project lifetime which translates as 988 t carbon/m². This value was compared to results in Karjalainen [101] as well as Stinson and Freedman [102] where the authors have determined a maximum sequestration potential of 473 t carbon/ha or 47.3 kg carbon/m² for Acadian mixed tolerant hardwood forests in Canada over a 200-year period. It is visible that the CPG system has order of magnitudes higher sequestration potential compared to a conventional forest land.

Figure 10. Global warming potential from LCA studies compared to emission levels and sequestration potential of the current project. Reference power plants are located in Germany in the Upper Rhine Graben working on Enhanced Geothermal Systems producing Combined Heat and Power. (a) The height of the bars and the numbers above them represents the arithmetic mean value of emissions. Numbers below each bar represents the number of estimates made during assessing the emission levels. Minimum and maximum values are visualised by the whiskers. (in [12]) A horizontal red line represents the average emissions from a coal power plant [43] while a green line is the value of the emission levels after CO₂ sequestration. (b) global warming potential of selected EGS power plants producing electricity (in [13]) Values are expressed as CO₂g/kWh.

5. Future Work and Considerations

A deployment of any energy system depends on many factors, but reliability, efficiency and of course low carbon impact are among the critical requirements. For this reason, the research

and development of novel technologies as well as supporting prototype projects is considered as an investment. The bladeless turbine was invented by Tesla as an alternative to conventional turbines [103]. Recent research also studied the operation of the turbine with a one-dimensional model analysis [40] and lab scale demonstration [41]. Data indicates elevated attributes to efficiency and capacity. A further research and a possible grant for the development and prototype production would be an added layer of interest for higher efficiency and productivity factors. The planning, engineering, prototype production is assumed as € 1.5×10^6 for a test phase device (equivalent to ca. 2.3% of total capital, or for an optimal system ca. 1.5% of net present costs). A loop from the main CO₂ stream could be used to test the device under safe and controlled conditions. The excess thermal energy, or the energy that is not required for district heating could be utilized for agricultural purposes. Greenhouses are used widely in Netherlands, Spain, but in Eastern Europe as well [104,105]. Greenhouses are used as efficient facilities in agricultural production to decrease fresh water consumption and input requirements under controlled environment. Even research phase projects could be demonstrated. Algal photobioreactors are another possible candidate for such a project [106,107]. Base parameters are controlled, CO₂ availability from power plants is adequate for algal growth and the bioproducts are environmentally friendly and compostable.

6. Conclusions

The objective of this paper was to investigate the feasibility of deploying the CPG technology in Germany. Renewable energy systems are currently being favoured and supported by the EU. Although, Geothermal energy is a mature technology it is represented with the least ratio among renewable sources. To promote geothermal energy a new approach was recommended where emerging and novel technologies facilitate the use of geothermal energy across a broader aerial scale. By utilising carbon dioxide and sequestering it from the environment the increasing rate of global warming can be mitigated. The pulverized coal power plant at Lünen (North Rhine Westphalia, Germany) was taken as a reference for a modern state of the art coal power plant with possible integration of a post combustion capture technology. Pipeline transportation was assessed as the safest and most economical option for long term and transportation of large amounts of liquid carbon dioxide. Sandstone reservoirs are proved to be present in Northern Germany and the North Rhine Graben where geothermal energy is exploited with binary cycle technology. The CPG technology widens the possibilities as no initial geothermal fluid is required in the system. Carbon dioxide is pumped to the reservoir and the heat and energy is extracted at the production end of the system. The hydrocarbon industry with its well-established exploration, production and development background already using the CO₂ injection technology for enhanced hydrocarbon recovery. Even with a relatively long pipeline distance reaching the North Sea and expanding the possibility of offshore CO₂ storage the project could still be feasible. Given the impact that a material like carbon dioxide is having on the global environment it is imperative that the rates and volumes entering and exiting the ecosystem are managed. For a comparison if the sequestration potential of the CPG system was compared with natural indices like forests it would require 334 km² land compared to the approximately 0.016 km² occupied by the CPG geothermal power plant. In addition, the overall emissions during the life cycle of the project were considered as well. Values were converted to g/kWh and compared with LCA studies of enhanced geothermal systems, fossil fuel and various renewable energy systems. Binary cycle geothermal energy or geothermal energy that is non-dependent on volcanic activity is among energy systems with the lowest overall life cycle impacts. Environmentally as well as economically the project was proved to be feasible. Legislations and incentives support the deployment of geothermal energy in Germany but at the same time projects have to be within limits of regulations. Geothermal energy is among the candidates of such a system where multiple localized geothermal power plants form a network either as localized centres or as a centralized system. In such a case the heat extraction rate could be controlled, and power plants could be temporarily shut down for a resting and recovery period [108]. In addition, the stored carbon dioxide can be viewed as a stock. Future developments of technologies

could further utilise carbon dioxide in which case it could be recovered from the reservoir and reused. A carbon trading scheme in the EU is already in place [109], which creates opportunity for companies to trade CO₂ emissions and hence indirectly decrease their greenhouse gas emissions.

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Nomenclature

EGS	Enhanced geothermal system
EOR	Enhanced oil recovery
g	Grams
IGCC	Integrated gasification combined cycle
CO ₂	Carbon dioxide
CO ₂ -ECBM	Carbon dioxide enhanced coalbed methane
CPG	Carbon dioxide plume geothermal
kg	Kilograms
km	Kilometre
kW	Kilowatt
kWh	Kilowatt hour
LCA	Life cycle assessment
LCOE	Levelized cost of electricity
m	Meter
MD	Measured depth
MEA	Monoethanolamine
MPa	Megapascal
MW	Megawatt
MW _e	Megawatt electricity
MWh	Megawatt hour
MW _{th}	Megawatt thermal
NGCC	Natural gas combined cycle
P _{cr}	Critical pressure
ROI	Return on investment
s	Second
t	Metric tonnes
T	Temperature
T _{cr}	Critical temperature
ρ	Density

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