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Costs of Co2-Mitigation by Deployment of Enhanced Geothermal Systems Plants

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ABSTRACT

The paper refers recent investigations on costs of EGS and the CO_2-emissions providing energy with EGS based on life cycle analyses. So, options for favorable CO_2-mitigation costs by deployment of EGS can be shown. In addition, a cost reduction potential exists in planning and designing such systems. For a worldwide deployment of EGS substituting mainly coal fired power plants, the CO_2-mitigation costs will be derived from estimating the specific energy production costs and the probable CO_2-emissions of EGS-plants using the results from life cycle assessment calculations. The conclusion is that significant CO_2-emissions in the order of gigatons in the year 2050 can be mitigated at costs competitive with other CO_2-mitigation strategies.

1. INTRODUCTION

Energy markets are not only driven by demand and supply. The provision of energy addresses also societal and political issues for the present and future generation. On one side, today's live is directly linked to the use of energy. The provision of energy must be secure and its utilization affordable. On the other side, today's energy provision depletes finite resources and emits substances, which are damaging the local environment and especially the global climate. A goal, which is defined in many energy-political frameworks, is to increase the share of renewable energies in the provision of energy, in order to mitigate green house gas emissions and reduce the consumption of finite energy resources. Since the costs of renewable energies are not yet competitive to the prices on the energy market (and these prices normally do not reflect the full lifecycle costs related to the use of energy resources) or their integration in the existing structures of energy provision is still an obstacle in many cases, promotion measures have been implemented in many countries over the last decade.

One future option, which has to be considered in this context, is the use of Enhanced Geothermal Systems (EGS). They are supposed to make a large contribution to a sustainable energy mix in the future. This means that, besides improving technical aspects, EGS must be realizable with a climate friendly life cycle and competitive energy production costs. Regarding the sustainability, competitiveness does not refer to break even with the energy costs from conventional energy carriers, because the prerequisite of the environmental compatibility is not included in this comparison. Integrating the environmental aspect in such a comparison, competitiveness must rather be referred to CO_2-mitigation costs.

2. COSTS ANALYSIS

The total costs of an EGS project are dominated by the investments at the beginning of the project. These investments mainly consist of costs for:

- reservoir exploration
- drilling and borehole completion,
- reservoir engineering measures,
- the installation of the geothermal fluid cycle, and
- the construction of the plant unit on the surface for power and/or heat provision.

Further investments can include exploration measures, project planning, risk insurances or replacement purchases during the operational phase. The variable costs during the operation phase are mainly caused by the salaries for personnel, and supplies to run and maintain the subsurface and surface installations. Additionally, payments for the consumption of auxiliary power need to be considered in case the needed power to produce the geothermal fluid from the reservoir is not provided by the plant itself (for example in case of EGS heat plants).

2.1 Costs of reservoir access and development

The costs for accessing and developing the reservoir represent the largest part of the investments in EGS projects. A general assessment of these costs is difficult due to the different geologic conditions at each site, which influence the drilling, completion and stimulation process. When estimating the cost previous to the operational activities, the geologic conditions are only roughly predictable, especially when a site is located in an unexploited geologic area. In case of the reservoir engineering measures, the so far little experience is a further factor which increases the uncertainties in cost estimation.

Borehole costs. The estimation of the borehole costs, including drilling and borehole completion, depends on the project stage and the geologic site information which are available at a specific project stage. Rough cost estimation, which is done at the beginning of a project, are usually based on existing cost data for already drilled and completed boreholes. However, getting access to such data is not always possible because the data are often confidential, not reported in a comparable way of documentation and/or not aggregated by a central authority.

Detailed cost calculations, which are carried out by drilling engineers, use geographical and geological site information. Such calculations usually consider also a supplemental charge for unforeseen troubles, such as stuck pipes or hole-stability problems. This charge typically lies between 10 and 20 %, but can also be higher in unknown geologic areas.

The drilling and completion costs can be split into following cost items:

- rig rent,
- material cost,
- energy cost, and
- costs for services.

The rig rent is usually paid in an hourly or daily rate for the time, the drilling rig is needed. The rate for a particular drilling rig thereby depends on its specifications such as hook load and depth capacity. A drilling rig with larger hook load results in a higher rate but, on the other side, can realize a faster drilling progress and a decrease of the term of lease. From an economic viewpoint, the choice of the drill rig is therefore a compromise between rig capacity and drilling progress. The material cost basically includes the expenditures for casings, drilling mud and drilling bits. These costs depend on the borehole design, such as diameter, depth and well course, as well as on the site-specific stratigraphy, which is for example determining the casing material and its insulation thickness. The energy costs refer to the power to drive the drilling rig and the drilling mud pumps and also depend on the means of energy provision, such as energy provision from electricity grid or diesel-electric rig drive.

The service costs include quantity-dependent service costs, which are borehole related services such as installation of the casings, cementation and logging, and drilling site related activities such as installation and dismantling of the drilling rig and drilling site preparation. Time-dependent service costs contain costs for core barrels, jars, stabilizers, surveys and drilling mud treatment.

Depending on the site and borehole design, the composition and the total amount of the borehole costs can significantly vary such as shown in Figure 1. The borehole costs thereby increase over-proportionally with the depth. This is mainly related to the decreasing drilling progress with larger depth. Whereas the costs increase nearly linearly with increasing time, the drilling progress decreases larger depths because especially the round trip times increase.

Besides geological and technical influences, also the situation on the drilling rig and the commodity markets has a decisive impact on the borehole costs. The price development on the steel markets, for example, and the increased demand on drilling rigs from the oil and gas industry (which usually can offer the drilling rig operator a better capacity utilization) have resulted in significantly increasing borehole costs. Figure 2 shows the results of a study done by Tester et al. 2008, which represent the development of the borehole costs compared to the year 1977 based on a drilling cost index.

Stimulation costs. The estimation of the cost for reservoir engineering measures cannot be based on existing cost data since they are scarcely existent. Existing data is furthermore only valid for particular sites with comparable characteristics referring to petrophysical and rock mechanical properties of the reservoir and therefore a comparable technical effort for the stimulation measures. Further factors which influence the technical effort are skin damage caused by drilling and the targeted increase of transmissibility.

Based on existing experiences and publications it can however be derived, that the stimulation costs can also be split into equipment rent, material cost, energy cost and service cost. The equipment rent includes the cost for fluid pumps, blenders for mixing the frac-fluid and miscellaneous peripheral equipment. The material costs depend on the used fluid and additives and the respective amounts, which are injected into the reservoir. The energy cost refers to the power which is consumed by the injection pumps for example. The needed power is determined by the injection pressure, the flow rate and the duration of the stimulation measures.

There is no common approach to estimate the stimulation costs. In Tester and Herzog 1990 the estimation of the cost for basement rock stimulation is based on a defined reservoir area, which needs to be stimulated to obtain 1 kW electric power output. The declared stimulation cost thereby varies between 360 and 1,200 €/kWel depending on the size of the reservoir. Legarth (2003), in contrast, estimates the stimulation costs per well at a specific site based on the frac-fluid volume and amount of proppants which are needed for a specific reservoir and comes to total costs between 0.32 and 0.64 Million € (excluding permanent or temporary installations such as injection tubes and packer). More recent publications such as Heidinger et al. 2006 and Sanyal et al. 2007 assume fixed costs of 0.36 to 0.71 Million € per well or 0.58 Million € per reservoir respectively.

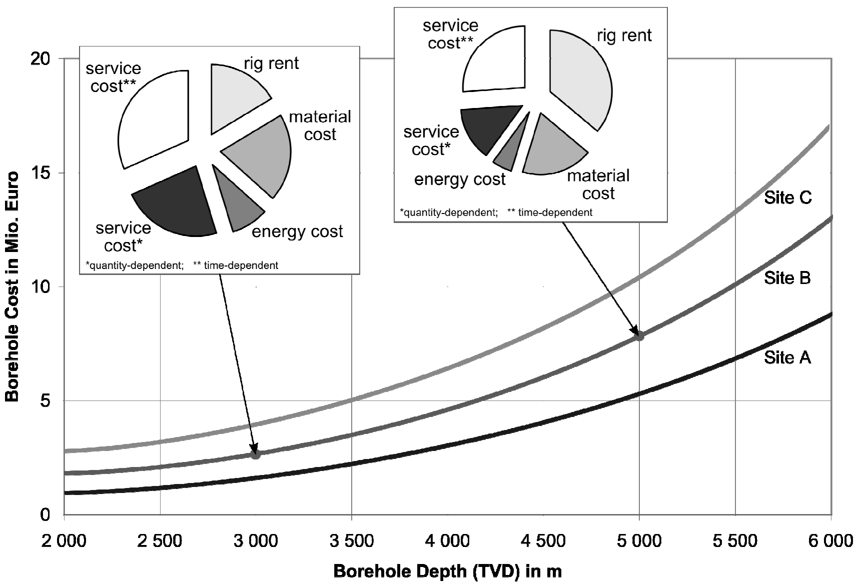

Fig.1: Development of borehole costs versus depth for the example of different sites (=different geologic conditions and borehole design) and typical compositions of borehole costs at a depth of 3,000 and 5,000 m (based on Legarth 2003).

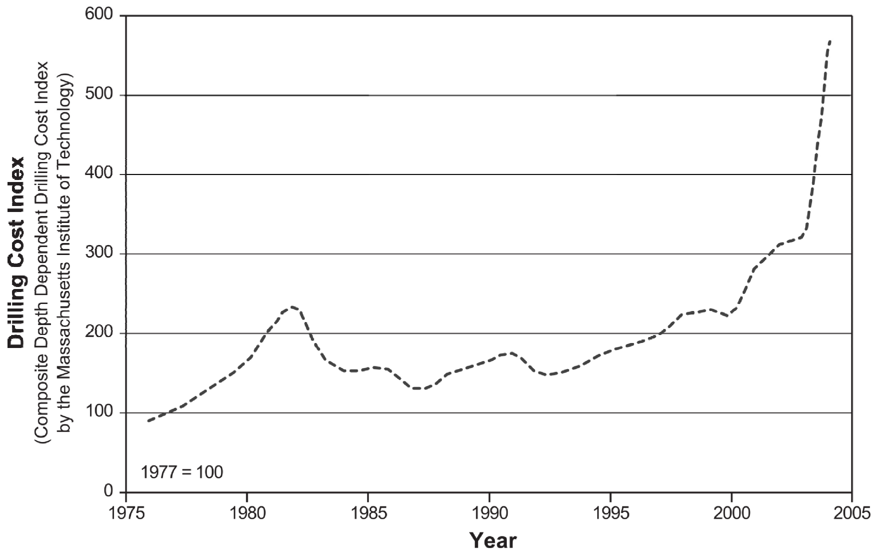

Fig.2: MIT Depth Dependent drilling cost index made by Tester et al. 2008 using average cost per well from Joint Association Survey on Drilling Costs (1976-2004, well depths 400 to 6,000 m), with data smoothed using a three-year moving average (1977 = 100).

2.2. Cost of surface installations

The investment costs for the surface part of an EGS plant include the cost for the geothermal fluid cycle and cost for the plant unit. The estimation of these costs can be based on cost estimations for the single components and peripheral equipment and for their installation at the plant site.

Geothermal fluid cycle cost. The investments for the geothermal fluid cycle contain the cost for the equipment to produce and circulate the geothermal fluid, such as pumps, pipes, filter and slop systems. At some sites also injection equipment is needed. In most EGS projects, the production pump will represent the main cost factor because of the technical requirements, which this component has to meet. The pump must be capable to supply the necessary pressure increase to produce the geothermal fluid from the reservoir and to handle temperature, chemistry and gas content of the geothermal fluid for a possibly long period of application. Furthermore, the production is based on the use of submersible pumps at many EGS sites. Since these pumps are installed in the production well, also design constraints such as installation depth and diameter, mechanical drive and energy provision are further technical restrictions. Depending on the site- and plant-specific conditions, the cost for a production pump are in the order of magnitude between 2,000 €/(m^3/h) (e.g. Legarth 2005, Rogge 2004) and 5,000 €/(m^3/h) (Saadat pers. comm. 2009).

The costs for other components such as pipes and filter and slop systems mainly depend on the flow rate of the geothermal fluid and the necessary over-pressure in the fluid cycle. Further influencing parameters are chemistry, gas content and temperature of the geothermal fluid, which determine the material choice. The cost for the pipelines also depends on their length and, in case of long-distance pipelines, on the laying (i.e. surface or subsurface). The cost for the geothermal fluid cycle, excluding the production pump, can vary between 75 and 600 €/m (e.g. Kaltschmitt 2007, Rogge 2004).

Cost for power plant unit. The costs for a binary power unit are generally related to the installed capacity, whereby the specific investments decrease with larger capacity due to economy of scale. The main cost factors of a binary plant are the turbine and generator unit, the heat exchangers and the cooling unit. Referring to EGS projects, the influence of the geothermal fluid temperature and site-specific conditions, which determine the mode of the installed cooling system (water- or air-cooling), are further important factors. For installing the same capacity at a site with a low geothermal fluid temperature, for example, will be more expensive due to the necessarily larger heat exchange area compared to a site with higher geothermal fluid temperature. Referring to the installation of the cooling system at a specific site, the realisation of air cooling is in many cases more expensive than using wet-cooling towers. Furthermore, the complexity of the power conversion cycle (e.g. basic Rankine cycle, Rankine cycle with two pressure levels or Rankine cycle with working fluid mixture) are influencing the cost. The characteristics of the geothermal fluid need to be considered for determining the material and layout of the respective heat exchangers. According to Köhler 2005, the specific binary plant investment is approximately between 1,400 and 2,300 €/kW for an installed capacity in the range from 500 to 2,000 kW (Figure 3).

Cost heat plant unit. When referring to a geothermally based heat supply without additional heat generators as back-up or peak-load units, the investments for the heat plant unit mainly include the cost for heat exchanging equipment. Depending on the layout and design of the heat exchangers, the specific cost can range approximately between 10 and 100 € per kW thermal capacity. Investments for the construction of a heating grid are not considered in this section.

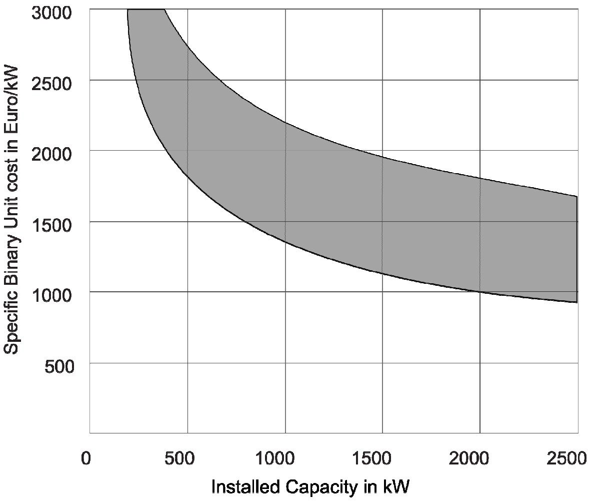

Fig.3: Range of specific binary plant unit cost according to (Köhler 2005).

2.3 Operation and other costs

The annual operating cost of EGS plants mainly include the cost for personnel and overhaul and maintenance. In many cases, EGS plants can operate without continuous supervision so that the annual personnel cost is low. The cost for overhaul and maintenance is usually estimated with a small percentage of the investments for the subsurface and the surface part. If the auxiliary power demand cannot or is not provided by the EGS plant itself, the cost for auxiliary power consumption also needs to be considered.

Depending on the project, potentially additional investments need to be considered. Project planning, for example, can be a complex and time-intensive part of realizing successful EGS projects including feasibility studies, site preparation, permitting and coordinating the engineering design of the boreholes and the surface installations. Project planning can take up to 10 % of the overall investments. Depending on the available geologic information for a site, further information on the subsurface is needed. Subject to the planned programme, exploration can take up to one Million € (Heidinger et al. 2006). Further investment costs can also accrue if a project is carried out close to housing areas, where noise protection, such as the erection of sound insulating walls, needs to be foreseen. Insurances, such as for covering the geologic risk, are further cost factors which might need to be considered when estimating the costs for EGS projects.

2.4 Representative case studies

Frick et al. (2010) analyzed the specific costs for different representative EGS plants, from which power and/or heat is provided. By means of case studies general correlations plant data and the specific costs referring to electricity or heat were derived in this study as follows:

Specific costs for electricity provision: Both reservoirs are assessed with two deep wells in a depth of 4,000 m. Due to different underlying temperature gradients, the reservoirs differ in temperature. The reservoirs are engineered with the same technical effort but reach a different transmissibility because of differences in the natural reservoir conditions. The geothermal fluids are produced from the reservoirs using submersible pumps in the production wells. On the surface, the geothermal energy is converted to power within binary power plant units.

Power plant 1 produces the geothermal fluid with a temperature of 125 °C and a flow rate of 250 m3/h. For power plant 2, the temperature is 165 °C and the flow rate 120 m3/h. On the surface, the fluid is on each site transported in a closed fluid cycle. The geothermal heat is transferred to the binary plants which contain a low-boiling working medium and the turbine-generator unit. After the heat transfer, the cooled geothermal fluid is transferred to the respective injection well, which is located 500 m away from the production well, and returned into the reservoir with an assumed temperature of 70 °C.

The installed capacity of both power plants is 1.6 MW. The auxiliary power needed for circulating the geothermal fluid is assumed with 1.3 kW/(m^3/h) for both sites. The auxiliary power need in the binary cycle (e.g. for the feed-pump and cooling) is defined with 10 % of the installed capacity. Both power plants are operating 7,500 full load hours per year which corresponds to an availability of 86 %. The total technical operating time is 20 years. As a result for both plants, the investment costs sum up to 23 Million € or a specific investment of about 15,000 €/kW. The borehole costs represent with 69 % the largest cost factor of the overall investments. The next largest investment, with a share of 12 %, is the binary plant unit.

Within the miscellaneous costs, additional costs such as for exploration activities or project planning and management are considered with a flat-rate of 10 % in the total investments. The costs for the reservoir engineering measures are assumed with 0.75 Million € per well, which corresponds to a share of 6 % in the investments. The cost share for installation of the geothermal fluid cycle is about 3 %. Based on an imputed interest rate of 6 %, and a technical lifetime of 20 a, the overall investments result in an annuity of about 2 Million €/a, which represents 80 % of the annual payments. The remaining 20 % are the annual operating costs, which include the cost for personnel and overhaul and maintenance, which also contain the replacement costs for components with a shorter physical life than the operating period. Overhaul and maintenance costs of the subsurface and surface installations are estimated with 1.5 % of the corresponding investments and 6 % respectively.

With these data, Frick et al. (2010) calculated specific costs of **0.32 €/kWh** for Power plant 1 and **0.26 €/kWh** for Power plant 2. The difference of 19 % in the specific costs indicates that they do not only depend on the investments for a specific installed capacity since these costs only differ by 2 % comparing power plant 1 and 2. Therefore, the plant-specific net-power output is the decisive factor, because power plant 2 has a lower auxiliary power consumption due to the lower flow rate in the geothermal fluid cycle and the lower demand for cooling based on the higher conversion efficiency in the binary unit.

The result reflects the order of magnitude of expectations of recently private financed geothermal power plant projects in Germany under the conditions of the feed in law before 2009 with guarantied prices of **0.15 €/kWh** leading to the Landau geothermal power plant, which started operation 2007 (Menzel, 2008) respectively a number of other projects after lifting the tariffs EEG (2009) to **0.16 €/kWh** + 0.04 € for so called petrothermal use (i.e. EGS**).**

Specific costs for heat provision: Using a similar methodology, Frick et al. (2010) compared the specific costs for two EGS heat plants at different representative sites. Analogue to the analysis of the power provision, at both sites a borehole doublet taps the reservoirs, which are located in the same depth but differ regarding temperature and natural conditions.

Heat plant 1 is characterized with a geothermal fluid temperature of 100 °C and a flow rate of 210 m^3/h. In Heat plant 2, a geothermal fluid with 130 °C and a flow rate of 120 m^3/h is produced. On the surface, the geothermal heat is transferred to a low temperature district heating grid with a feed temperature of 70 °C and a return temperature of 50 °C. The cooled geothermal fluid is reinjected with a temperature of 60 °C. It is assumed that the heat plants are only driven by geothermal energy so that no additional equipment, such as back-up or peak-load systems, is considered.

Based on these data, a thermal capacity of 9.8 MW is installed at both sites. The auxiliary power, which is needed for circulating the geothermal fluids, is assumed with 1.3 kW/(m^3/h). Based on a typical seasonal demand for district heat, the heat plants are operating 3,100 full load hours per year. The total operating time is 20 years.

The total investments are about 16 Million € or 1,600 € per installed thermal kW. The borehole costs cause 74 % of the overall investments and are the predominant cost factor. Reservoir engineering is declared with 0.5 Million € per well and represents 6 % of the investments. The influence of the heat plant unit on the total capital investment is in the same order. The investments for the geothermal fluid cycle sum up to 4 % of the total budgets. The miscellaneous costs include exploration activities, project planning and management and are assumed with a flat rate of 10 % of the total investments. With an imputed interest rate of 6 %, and a technical lifetime of 20 a, the annuity of the capital investments sums up to 1.4 Million €/a. The overall annual payments therefore consist to approximately 78 % of the investment annuity and to 22 % of the operating costs. The annual operating costs contain the cost for personnel, overhaul and maintenance and the annual consumption of auxiliary power. According to these assumptions, the specific costss are calculated with **0.061 €/kWh** for Heat plant 1 and **0.059 €/kWh** for Heat plant 2, which results in a difference of 4 % between the compared heat plants. Since the provided amount of district heat is the same for both plants and overall investments only differ by 2 %, this difference mainly reflects the different operating costs, which are larger for Heat plant 1, due to the larger geothermal fluid flow.

2.5 Cost reduction potentials for geothermal energy provision

Improved project design: Due to learning curve effects, further technical developments and the deployment of EGS will lead to a reduction of the investment costs. According to Entingh and McVeigh (2003), a cost reduction of 50 % is considered for each stimulation measures, binary units and overhaul and maintenance. In case of Power plant 1, such improvements lead each to a reduction of the specific costs of 3 to 9 %. Regarding the borehole costs, in contrast, the same cost reduction could lead to a decrease of the specific costs by more than 30 %. However, the existing cost saving potential for drilling and borehole completion is limited. Even if technical improvements or a better knowledge of specific geologic areas result in a more efficient drilling and completion process, the price increases on the drill rig and steel market can compensate these improvements. Considering a 25 % decrease of the borehole costs as realistic value, the specific costs of Power plant 1 are reduced by 17 %.

Besides the reduction of investment and overhaul and maintenance costs, the specific costs from EGS plants can also be improved by increasing the net-power output at a specific site. In this context, Figure 8 shows the influence of an increased flow rate on the specific costs based on an enhancement of the reservoir productivity in Power plant 1. With an improvement of the existing reservoir engineering measures in the future, the same technical effort (and therefore the same cost for stimulation) can lead to a higher reservoir productivity or transmissibility so that significantly higher flow rates can be produced with the same specific effort for pumping. An increase of the flow rate by 50 % reduces the specific costs by 27 %. If the flow rate can be doubled, a cost improvement of 39 % is achieved. Apart from the improvement of reservoir engineering in the future, also the enhancement of the reservoir productivity with a larger technical and therefore monetary effort can reduce the electricity production costs since higher cost of stimulation has a comparatively small impact (cf. Figure 7). Even if the increase of the cost for reservoir engineering is five times higher than the realized increase of the flow rate, the specific costs are still reduced. For Power plant 1, a doubling of the flow rate will in this case result in 25 % lower production costs.

The representative site studies conclude with in today specific costs at about **0.27 €/kWh** for EGS power and **0.060 €/kWh** for EGS heat. Regarding these studies it can be summarized that the learning curve to an economic use of EGS is still at the beginning. Specific costs for geothermal energy provision can be reduced in different independent system elements from today up to several tenth of percentage each by improving the related technology. In this context e reduction to 33% of today costs is thinkable (with technology development an assumption can be **0.09 €/kWh** for EGS power and **0.02 €/kWh** for EGS heat). However, the cost reduction effect depends on the type of site. Further monitoring of geothermal technology development is required to quantify the learning curve better.

3. GREENHOUSE-GAS-EMISSIONS OF EGS GEOTHERMAL POWER PLANTS

Even if geothermal binary power plants are not related to (continuous) gaseous emissions during operation due to the transport of the geothermal fluid in a closed pipeline-system on the surface, airborne emissions related to the overall life cycle must be considered. Therefore, different publications have made Life Cycle Assessments (LCA). Kaltschmitt et al. (2006) calculated CO_2-equivalent emissions between 59 and 79 g/kWh. Nill (2004) analysed the learning curve effects on the life cycle and indicates CO_2-equvilant emissions of 80 g/kWh for a binary plant in the year 2000 and 47 g/kWh in 2020. Pehnt (2006) presents a CO_2-equivalent of 41 g/kWh.

3.1 Geothermal Life Cycle Assessments

The geothermal life cycle is characterized by large material and energy inputs especially due to the construction of the part of the power plant located below the surface. For the life cycle analyses the access to a highly productive reservoir with a minimum of drilling and completion efforts has to be taken into the considerations.

The geothermal fluid must be extracted from the underground in a sufficient amount. Due to the high influence of the energy needed to produce the geothermal fluid from the reservoir, the reservoir productivity or injectivity are important parameters of such an environmental study. Therefore, the development of new and the improvement of existing stimulation measures for a successful enhancement of the reservoir characteristics is a key aspect for the improvement of the environmental performance of such power plants.

When operating a geothermal power plant using low enthalpy geothermal resources, all parts including the reservoir management, the geothermal fluid cycle, the binary power unit, and the cooling of the binary cycle need to be seen as an overall system. This power plant system needs to be optimized according to the net-energy output. For the surface equipment this means for example that not only the improvement of the conversion efficiency of the binary power unit but also the reduction of the power needed for cooling needs to be considered. The development of an improved power plant operation and the design of innovative overall concepts maximizing the net-energy output – allowing for a reliable operation free of unplanned shutdowns throughout the year – are thus needed to characterize the overall environmental performance.

3.2 Case studies

Frick et al. (2009) compare two binary plants at different sites and have calculated a CO_2-equivalent between **55** and **58 g/kWh** electrical power. Fig. 4 shows these data together with the other emission data of the representative sites. They come to the conclusion that these figures show that the use of geothermal energy for the provision of electricity (and heat) using low enthalpy geothermal resources is environmentally promising compared to the current electricity generation mix in Europe. However, geothermal binary power plants must be located at appropriate sites, where the energy and material input to lock up the geothermal reservoir can be compensated by the provided energy.

The supply of EGS power is a low CO2-emission technology. Most of the emissions are due to accessing and operating the subsurface system. Therefore a co-generation of power and heat from the same source with heat supply into a district heating system strongly influences further positively the environmental impact of geothermal binary power generation; the more heat can be used the better the environmental key factors are. The possibility to supply heat is however based on adequate heat sinks, which need to be developed already at the beginning of a geothermal power plant project.

If these aspects are taken into consideration, geothermal heat and power generation from low enthalpy resources can make an even larger contribution to a more sustainable energy system today and in the future.

4. CO2-EMISSION BY ELECTRICITY GENERATION FROM DIFFERENT ENERGY SOURCES

EGS plants usually require deeper boreholes than conventional geothermal plants and significant more effort to engineer the reservoir. However, EGS plants are operated in closed systems at the surface. The thermal water is reinjected after utilization its heat at the heat exchanger. There exists no gaz release during the operation. The comparison of the result of emission studies on conventional systems in USA (see Bloomfield et al. 2003) and life cycle analyses of EGS with as given in Figure 5 show that still lower CO2-emissions are referred to EGS.

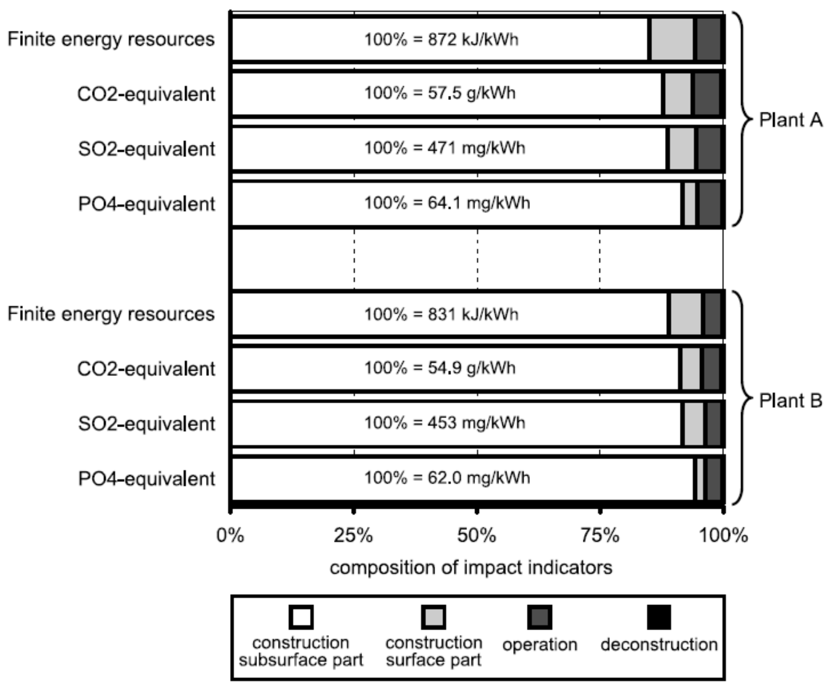

Fig.4: Composition of Life Cycle impact indicators for two representative geothermal binary power plants (Frick et al.). Most of these emissions are referred to access and operate the underground system (Not shown here but given in the Frick-paper).

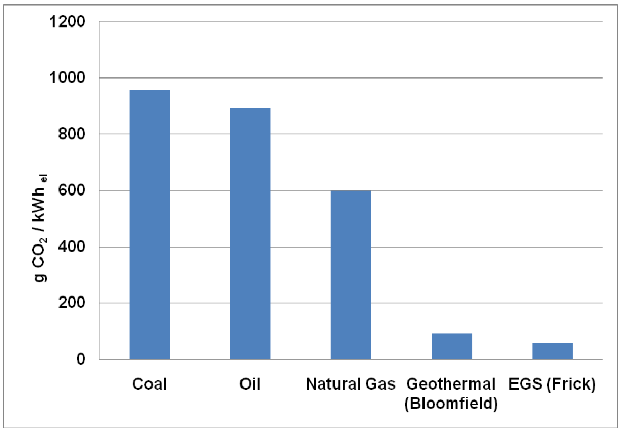

Fig.5: Comparison of CO2 emission from electricity generation from different energy sources. Data from Bloomfield et al. (2003) in the USA and from Frick et al. (2009).

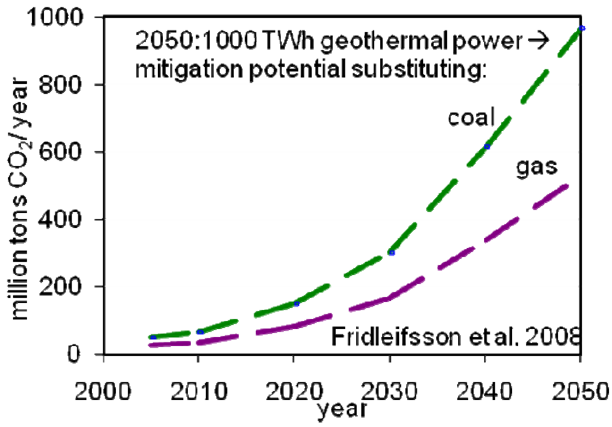

Fig. 6: CO2-mitigation calculation based on a forecast of the development of installed capacity of geothermal electricity up to about 140 GW providing about 1000 TWh from about 10 GW providing about 70 TWh in the year 2010.

Coal fired power plants are widely spread all over the world and responsible for several gigatons of CO_2-emissions every year. In addition, there are huge programmes all over the world now to build up new coal fired power plants every year with the result of further impact on the climate change due to there operation. An emission of 960 g/kWh for operation of coal fired power plants (as given in fig. 5) was reported by Bloomfield, other studies give numbers somewhat above 1000. Thus, substituting coal fired power plants by EGS plants to fulfill a given task of energy supply lead to a CO_2-mitigation of about 800 g/kWh.

During the discussion providing a report on renewable energy in the framework of the IPCC process, scenarios were made for a reasonable development of the capacity of geothermal plants worldwide. Fig. 6 is based on such a scenario from a 2010 capacity of 10 GW to an extension of the capacity of 140 GW 2050 with a yearly contribution of about 1000 TWh. Half of the future capacity is expected to be contributed by EGS plants. The substitution of coal fired power plants by extended geothermal energy provision, which can be reached in the year 2050, mitigates every year more than 1 gigatons CO_2-emissions worldwide.

Fridleifsson et al (2008) calculated about 80 Million tons CO_2-mitigation per year by deployment in the year 2050 of about 280 TWh geothermal heat from direct use of deep resources, i.e. other than Geothermal Heat Pump systems.

5. COSTS OF MITIGATION OF CO_2-EMISSIONS

Society is highly engaged at the moment to develop strategies for mitigation of CO_2-emissions. A pronounced role plays nowadays the development of technologies of capture CO_2-emissions mainly from coal fired power plants, transport them, and store the CO_2 in the underground (i.e. CCS). The IPCC report from 2005 presented costs between 25 and 55 €/ton CO_2 for CCS inclusive the sequestration in deep reservoirs. It is important to note that other authors assume higher costs, because costs for storage and monitoring are poorly presented in the report due to the lack of experiences from given field experiments. Given these cost estimates, which would increase costs for the generation of electricity from coal-fired power plants, the question is, if the EGS concept is cost-competitive under these circumstances.

Numbers from studies at representative sites lead to the following conclusion, which is represented here for clarification with rounded figures: The costs for power supply from EGS today allow provision of 200 kWh for the 50 € that are estimated for the mitigation of 1 ton CO_2 by CCS. Taking into account the estimated effect of geothermal technology development even about 600 kWh could be delivered in the future. As mentioned above, substituting coal fired power plants by EGS plants would lead to a CO_2-mitigation of about 800 g/kWh Therefore, for 50 € about 600 kWh electrical power can be supplied and a mitigation of 600 times 800 g CO_2 that result in about 500 kg CO_2 by substituting coal fired power plants is possible. In summary, double of the currently assumed costs for CCS, which may have also some cost reduction following a learning curve, deliver the same CO_2-mitigation and additional power supply from EGS. The interaction of CO_2-sequestration with other utilization of underground reservoirs and the probable prevention of these is not yet transferred to costs. Fischedick and Esken (2007) calculated that the costs of low carbon emission coal fired power plants (i.e. conventional power plant + efficiency loss due to carbon capture + transport and storage of CO_2) are comparable to the costs of renewables.

For 1 kWh geothermal heat provision, which was calculated to cost 0,06 € a mitigation of several 100 g CO_2 (depending on the substituted fuel) can be expected. Therefore, also geothermal heat provision contributes significantly to CO_2-mitigation.

All these approaches in this paper are related to sites with normal geothermal gradients and can become much more favorable for EGS in in preferred geothermal environments. Therefore, it can be concluded that the deployment of geothermal energy is the way for provision of base load energy as part of future renewable energy supply and part of the CO_2-mitigation strategy by substituting fossil fuels and the costs of an extended installation of EGS power plants is highly competitive with other CO_2-mitigation strategies.

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