Helmholtz-Zentrum Potsdam
Deutsches
GeoForschungsZentrum

Ben Norden (ed.)

Geothermal Energy Utilization in Low-Enthalpy Sedimentary Environments

Scientific Technical Report STR11/06

www.gfz-potsdam.de

Helmholtz Gemeinschaft

Impressum

HELMHOLTZ-ZENTRUM POTSDAM
DEUTSCHES GEOFORSCHUNGSZENTRUM

D-14473 Potsdam

Gedruckt in Potsdam
März 2011

ISSN 1610-0956

Die vorliegende Arbeit
in der Schriftenreihe
Scientific Technical Report (STR) des GFZ
ist in elektronischer Form erhältlich unter
www.gfz-potsdam.de - Neuestes - Neue
Publikationen des GFZ

Ben Norden (ed.)

Geothermal Energy Utilization in Low-Enthalpy Sedimentary Environments

Scientific Technical Report STR11/06

Geothermal Energy Utilization in Low-Enthalpy Sedimentary Environments

Edited by B. Norden

The authors are thankful for fruitful discussions and valuable remarks of the co-workers within the research project "The geothermal energy potential in Denmark", especially for comments given by Anders Mathiesen (GEUS), Lars Henrik (GEUS), Troels Laier (GEUS), Niels Balling (AU), and Jesper Magentgaard (DONG). The Danish Council for Strategic Research is thanked for financing this project.

Scientific Technical Report STR 11/06
DOI: 10.2312/GFZ.b103-11066

Deutsches GeoForschungsZentrum GFZ

Content

DOI: 10.2312/GFZ.b103-11066

Ben Norden and Andrea Förster

Ben Norden and Inga Moeck

Ben Norden, Inga Moeck, M. Guido Blöcher, and Günter Zimmermann

List of Figures

DOI: 10.2312/GFZ.b103-11066

List of Tables

DOI: 10.2312/GFZ.b103-11066

Ben Norden

Introduction

The geothermal energy market is a strongly growing sector worldwide. As stated in a review on the direct geothermal energy use (Lund & Freeston, 2010), the installed thermal power for direct utilization of geothermal energy is estimated at the end of 2009 to amount 50,583 MW, almost a 79 % increased over data of 2005, growing with a compound rate of 12.3% annually. This growth is strongly linked to the growing awareness and popularity of geothermal (ground-source) heat pumps, which could utilize groundwater or ground-coupled temperatures anywhere in the world. The increase in the field of geothermal electricity generation from 2005 to 2010 is in the range of 20 %, showing an installed capacity of 10,715 MW in 2010 worldwide (Bertani, 2010).

What is geothermal energy and what is the geothermal potential?

Geothermal energy becomes obvious when volcanoes are active or hot springs and other thermal phenomena are present at the surface. These phenomena are normally related to geologically active parts of the Earth, like continental (plate) margins. They are like a window towards deeper parts of the earth, showing us that the interior of the Earth is partly hot. In sedimentary basins, the temperature is more or less constant near the surface reflecting more or less the annual mean near-surface temperatures. Below that zone, the temperature may be variable because of geological structure and different thermal conductivity of geological formations or because of groundwater circulation masking the temperature distribution caused by heat diffusion from the Earth interior. In general, the temperature in the Earth's crust increases with depth. Down to depths of about 10,000 m, the average geothermal gradient is about 2-3 °C/100 m (Press & Siever, 1984); resulting in temperatures around 100 °C at 3 km depth.

How are geothermal resources classified?

Geothermal resources are classified based on their reservoir temperatures alone (e.g. Muffler & Cataldi, 1978; Hochstein, 1990; Benderitter & Cormy, 1990; Haenel et al., 1988) or with reference to their specific exergy index to reflect their ability to do thermodynamic work (Lee, 2001). In this report, the classic approach related to the reservoir temperature is considered. According to Haenel et al. (1988), a low-enthalpy resource corresponds to reservoir temperature of less than 150 °C. High-enthalpy resources are present if the temperature exceeds 150 °C (see also Chandrasekharam & Bundschuh, 2008).

How can this energy reserve be assessed?

The term "geothermal energy" is understood not only as the heat contained within the Earth. Geothermal energy is more often used to "indicate that part of the Earth's heat that can, or could, be recovered and exploited by man" (Dickson & Fanelli, 2004). In general, geothermal energy is extracted from geothermal reservoirs. According to the Encyclopedia of Physical Science and Technology (Meyers, 1992), geothermal reservoirs are defined as a "geometrically definable volume of permeable rock which contains a proven reserve of thermal energy, such as water or steam that can be extracted in a practical, economic way". In other words, a geothermal reservoir could be considered a geothermal system consisting of three main elements: a heat source, a reservoir, and a fluid. The fluid is the carrier that transfers the heat (Dickson & Fanelli, 2004). Geothermal energy, made assessable by man, can be used for different purposes like district or local heating, chill provision, or power generation (section *A. Geothermal Applications and Plant Technologies*, p. 5). The main advantage of using geothermal energy for direct use in the low- to intermediate-temperature range is that these resources are more widespread and exist at economic drilling depths (Lund, 2007). In addition, parts of a geothermal system could be used for example as an underground thermal energy storage system (Andersson, 2007).

The general strategy of geothermal resource development (section *B. Exploration of Geothermal Reservoirs*, p. 31) starts with the development of a conceptual model of the potential geothermal resource. At this early stage, also secure leases and permits play a role. The review of existing data, especially on geology (structural geology, stress field, hydraulic transport properties, (thermal) rock properties, petrography and mineralogy), temperature, heat flow, and geochemistry form the base to identify the potential geothermal reservoir and to estimate the size and the heat content of it. These steps are part of the geothermal exploration (section *B.1 The Exploration Concept*, p. 31) resulting in mapping and integrated modelling based on the available data. Depending on the exploration targets, different geophysical or geochemical exploration surveys may become relevant. Those new exploration data should be integrated in geological site models, on which the well positioning and the well path planning for geothermal wells, the risk assessment concerning the borehole stability, and the simulation of the reservoir behaviour (during production) is based. The drilling of new wells, providing further information to the local conditions and thus to the models, should be performed according to the requirements of geothermal wells and the site-specific conditions (section *C. Drilling*, p. 38). The last steps in the assessment and development of a geothermal resource require the installation and management of the whole geothermal system including the geothermal plant technology (section *D. Management of Geothermal Systems*, p. 47). Models and computer simulations to predict the reservoir behaviour are important tools for these objectives and may be used for a sustainable, reliable, and efficient energy provision, for the planning of further reservoir treatments, and for the consideration of environmental aspects.

The evaluation of the financial aspects for the development of a geothermal system depends strongly on a proper site characterization, which in turn forms the basis for the overall site development. If the intended extraction of the thermal energy of the reservoir could be utilized economically depends not only on the properties of the reservoir; other important factors are the legal and political framework (the 'outer conditions'), the drilling and exploitation technique of the reservoir, the reservoir management, a smart combination of available (surface) technologies and the life-time of the installations. In this report, we focus on the technological aspects of geothermal energy utilization. Nevertheless, we cannot omit the 'outer conditions' as they play an important role in the decision process of the planning and erection of geothermal facilities. These topics are addressed in section *D.3 Regulations, economics, risk assessment, and insurances of geothermal projects*, p. 66.

Finally, several tasks related to the utilization of geothermal energy in low-enthalpy sedimentary settings can be identified (section *D. Outlook*, p. 71). For example, the exploration techniques of the oil and gas industry are less effective in geo- (hydro-)thermal environments. In contrast to the hydrocarbon industry, one successful geothermal well is often not enough to ensure economic provision of geothermal energy. Therefore, the costs of the reservoir exploitation (especially when deeper wells have to be drilled) needs to be reduced. In addition, several (economical) uncertainties do influence the geothermal project decisions very individually: the price of energy (electricity or heat) that can be sold may vary during the time of project; the available transmission for the energy produced may be unanswered; and the years to bring the resource into production even in the best of circumstances may be hardly addressed (Taylor, 2007). The plant technologies may further develop and thus may give power generation under low-enthalpy conditions more relevance. Some examples of different geothermal applications in low-enthalpy sedimentary environments and their historical development are given in the section *F. Geothermal Sites and Applications* (p. 72).

The present work tries to condense the state-of-the-art for the exploration and exploitation of geothermal energy. Although a lot of experiences from different sites worldwide are integrated in this study, some sections do reflect the German experience. For example, the German Renewable Energy Sources Act (EEG, see page 78) enables also a specific promotion and growth of the geothermal sector in Germany by guaranteeing special feed-in tariffs for a 20-years period. During the last years, several countries worldwide have introduced similar renewable energy promotion policies (some of them restricted to certain energy sources only or requiring a certain renewable energy quote), supporting investigations also in geothermal applications. Thus, the experiences in Germany may be of some value. Dependent on the political-economical framework, the geothermal exploration and exploitation of deeper reservoirs represents an excellent option to extend geothermal applications also in areas where shallow geothermal reservoirs may not be able to match the local energy demand. Therefore, also challenges related to the exploration and exploitation of deep low-permeability reservoirs are included in this study.

4

A. Geothermal Applications and Plant Technologies

In this study, geothermal applications refer to plants in which a heat carrier is pumped from the geothermal reservoir to the surface. Plant set-ups, in which the heat carrier has only indirect contact to the reservoir, such as borehole heat exchangers, will not be addressed in detail.

Heat that is extracted from geothermal reservoirs can be used to supply:

- heat and/or
- chill and/or
- power

depending on the temperature of the heat carrier and the implemented plant technology (Figure 1). For the non-electrical use of geothermal energy, the main applications are in the field of geothermal heat pumps, balneology, space heating, greenhouse heating, industrial process heating, and aquaculture (Lund & Freeston, 2010).

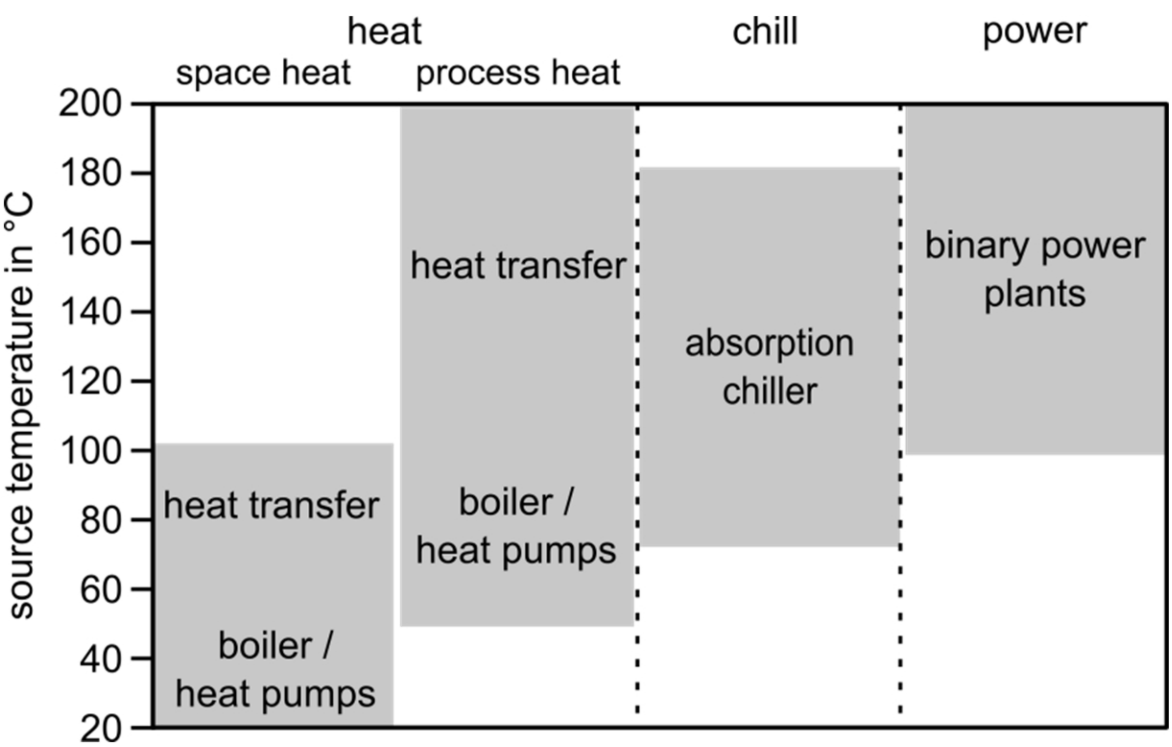


Figure 1: Energy supply options with different plant technologies from heat sources with temperatures between 20 and 200 °C derived from Lindal (1973)

DOI: 10.2312/GFZ.b103-11066

Geothermal reservoirs can be used as

- heat source or
- thermal energy storage.

If the extracted heat is geothermal heat that is naturally available in the reservoir, then, the geothermal reservoir is used as heat source. The extracted heat, however, can also be surplus heat that can be stored in the underground. In this case, the geothermal reservoir is used as thermal energy storage.

Geothermal reservoirs can be utilized by:

- a single plant on the surface (e.g. geothermal binary power plants),
- a plant in a compound of different energy suppliers (e.g. geothermal heat plants supplying heating systems together with solar and fossil supply technologies), or
- a hybrid plant that integrates other energy sources in the plant concept (e.g. binary power plants that are fed with geothermal heat and heat from a biomass combustion).

These different utilization and supply options result in a variety of different potential geothermal plant concepts. For the development of geothermal projects, the characteristics of both, the reservoir as well as the particular supply options, must be known. The necessary plant technology for geothermal applications is generally available on the market. Since many components are predominantly used in other fields of application, their adaptation and thorough selection according to the specific preconditions of a project site are very important. Cascading and combined uses do enhance the feasibility of a geothermal project (Gudmundsson, 1988; Lund et al., 2005). For example, low-to-moderate temperature geothermal resources can be used in combined heat and power plants (CHP), where hot waters with temperatures as low as 100°C are first run through a binary (Organic Rankin Cycle) power plant and then cascaded for space, swimming pool, greenhouse and aquaculture pond heating, before being injected back into the aquifer (Lund et al., 2005).

The following sections will give a general overview on these different utilization and supply options of geothermal reservoirs and the most important aspects of geothermal plant design.

A.1 Utilization of geothermal reservoirs

A.1.1 Heat source

When using geothermal reservoirs as heat source, the heat carrier is pumped from the reservoir through the production well to the surface. The heat is extracted from the fluid with a heat exchanger and the cooled fluid is re-injected into the reservoir in the injection well (Figure 2). The focus of this study is on typical geothermal applications that use formation water as heat carrier. In research, however, also other plant concepts are discussed and might be realised at a few sites in the future. Such future possible concepts refer to geothermal plants using other heat carriers than formation water such as CO_2 (c.f. Pruess & Spycher, 2007). Kolditz et al. (2010) calculated the relative efficiency of heat extraction (CO_2 vs. H_2O) depending on fluid pressure and temperature. For reservoir conditions found under a typical geothermal gradient of 30 °C km^{-1} the results show that at a depth of 800 m to approximately 4 km, CO_2 will be more efficient than H_2O. These calculations do, however, not consider the efficiency of the whole geothermal process chain.

The extracted heat can be used to supply heat and/or chill and/or power. Different examples for plants using the reservoir as heat source are given in section *A.2 Energy supply options*, p. 9.

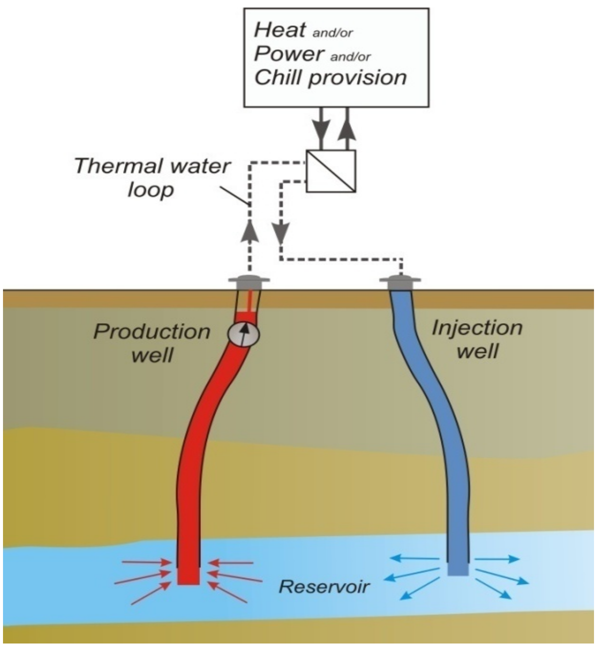


Figure 2: Principle for using a geothermal reservoir as heat source showing a well doublet, the geothermal fluid loop and a heat exchanger on the surface

A.1.2 Thermal energy storage

In Aquifer Thermal Energy Storage (ATES) systems, water bearing sandstones are used as storage medium for thermal energy resulting from combined heat and power plants (CHP),

DOI: 10.2312/GFZ.b103-11066

solar energy or industrial waste heat. The groundwater serves likewise as heat transfer medium and storage medium. Common ATES systems consist of two well groups or at least two wells (well doublet), “cold” wells and “warm” wells (Figure 3). This indication refers to the temperature level in the aquifer used. Due to the large storage capacity of water bearing sandstones, ATES systems are used to store thermal energy seasonally, mainly for the provision of room heat and cold in buildings. When charging the ATES system with heat, the groundwater is produced from the cold well, heated at the surface by means of heat exchangers and injected into the aquifer via the warm well. During discharging the operation is reversed and the still heated groundwater is produced from the warm well, cooled off while passing through heat exchangers and injected again into the aquifer via the cold well.

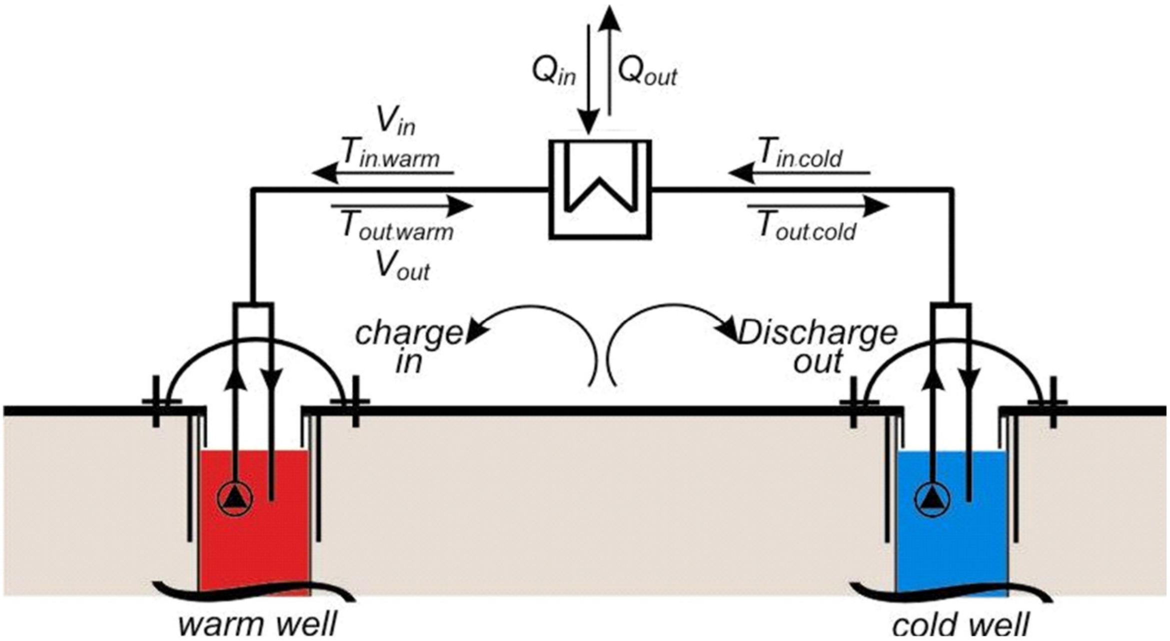


Figure 3: Scheme of an ATES doublet and notation

Many of the ATES systems that are designed for heating purposes are linked to heat pumps. But also direct use of the stored thermal energy is possible if the extracted ground water provides sufficiently high temperatures.

The storage through borehole heat exchangers (BTES, Borehole Thermal Energy Storage) system consists of a number of closely spaced boreholes, 50-200 m deep. These are serving as heat exchangers to the underground. The storing process is mainly conductive.

Underground Thermal Energy Storage (UTES) systems are typically applied for combined heating and cooling, normally supported with heat pumps for a better usage of the low temperature heat from the storage (Andersson, 2007). In general, UTES systems offer a large primary energy saving potential for providing heat and cold. In order to tap their full energy saving potential, an efficient integration of UTES in energy provision systems is essential. More information on ATES is provided by Paksoy (2008), Dincer & Rosen (2002) and Schaetzle et al. (1980).

A.2 Energy supply options

Geothermal energy can be used to supply different forms of energy. In order to compare different supply options for one site, it needs to be considered that not only the conversion efficiency of a particular supply option is important, but also the amount of geothermal energy that is actually being used and the auxiliary power demand. Comparing different geothermal sites, it must be considered that quality of the heat source varies. The quality thereby decreases with decreasing heat source temperature. Since power for example has a higher quality than heat, it can only be generated (considering the ambient conditions) from heat sources with high enough temperatures. Other issues refer to geochemical aspects and the hydraulic productivity of a geothermal reservoir. In Frick et al. (2010) a more detailed discussion on the evaluation and comparison of geothermal plants is presented.

A.2.1 Heat supply

Geothermal reservoirs can be exploited in order to directly supply heat, such as for district heating grids or process heat applications. If the temperature of the fluid from the reservoir is not sufficient to meet the required supply temperatures, the temperature can be increased by heat pumps or conventional boilers, which however, need extra energy.

The (direct) supply of heat from a geothermal reservoir is for example realised by transferring the geothermal heat to a water-operated heating network or a heat carrier used in process heat applications. In contrast to electrical power grids, which are widely-developed networks in many countries due to the good physical transport properties of electricity, heating networks refer to local supply structures. Typical district heating networks are fed by a small number of heating stations, which are located preferably close to the heat customers in order to avoid large energy losses when transporting the heat. The design of geothermal plants for direct heat use does therefore in most cases not only depend on the site-specific reservoir conditions but also on the structure of the heat customers within a heating network. The characteristics of heat consumption and their influence on plant design are outlined in the following.

A schematic set-up of a geothermal heat plant feeding a district heating system is shown in Figure 4. At some sites heat plants must also foresee a back-up system (for example in case the geothermal plant is the only heat provider of the district heating system) or a peak-load system (in case the geothermal heat plant is designed to cover the base load demand). The heat demand of a heating network is defined by its supply and return temperature and the demanded heat capacity which is the sum of the simultaneous demands of the connected heat customers. The temperature level of a single heat customer depends on the use of the heat, such as for space heating, warm water production or also industrial, e.g. Lindal (1973).

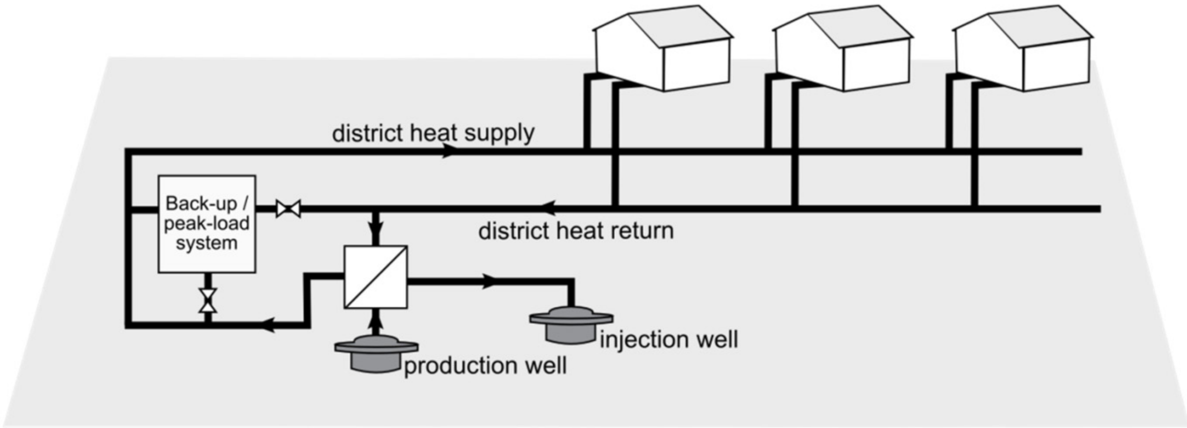


Figure 4: Scheme of a well doublet with back-up/peak-load system feeding a district heating grid

Existing geothermal heat plants typically feed district heating networks which are mainly used for space heating. Space heating represents about 40 % of the world wide heat demand (OECD/IEA, 2008). The supply of district heat is characterised by supply temperatures between 50 and 90 °C and return temperatures between 30 and 70 °C, sometimes even lower. In contrast to an annually constant heat demand for many industrial processes, the demand for space heating is characterised by a variable heat demand during the year. Regarding the heat demand characteristics, it must be considered that a geothermal heat source is not optimally utilized because with a variable heat demand the continuously available heat source can only partly be used over the year. If the return temperature of a district heating system is above the temperature, down to which the geothermal heat can be used, the heat source is also not utilized to its full extent. Based on these considerations, different design aspects of geothermal plants are discussed in the following.

Referring to a given heat demand, geothermal plant design, including borehole and reservoir stimulation concept and dimensioning of the heat exchanger and other surface installations, aims to fully cover this heat demand by geothermal energy. In the case that the given heat demand varies during the year, the energetic potential of the geothermal reservoir is only used to a small part. As shown in Figure 5 (left), the geothermal full load hours of such a plant are low. Another possibility is to design the geothermal driven part of the heat plant for a part of the heat supply which can, for example, be the base load heat demand (Figure 5, right). For the hours of the year, where this base load demand is exceeded, a peak-load system such as another renewable heat technology or a conventional boiler is installed. This way, the geothermal full load hours can be increased and the use of the geothermal resource can significantly be improved.

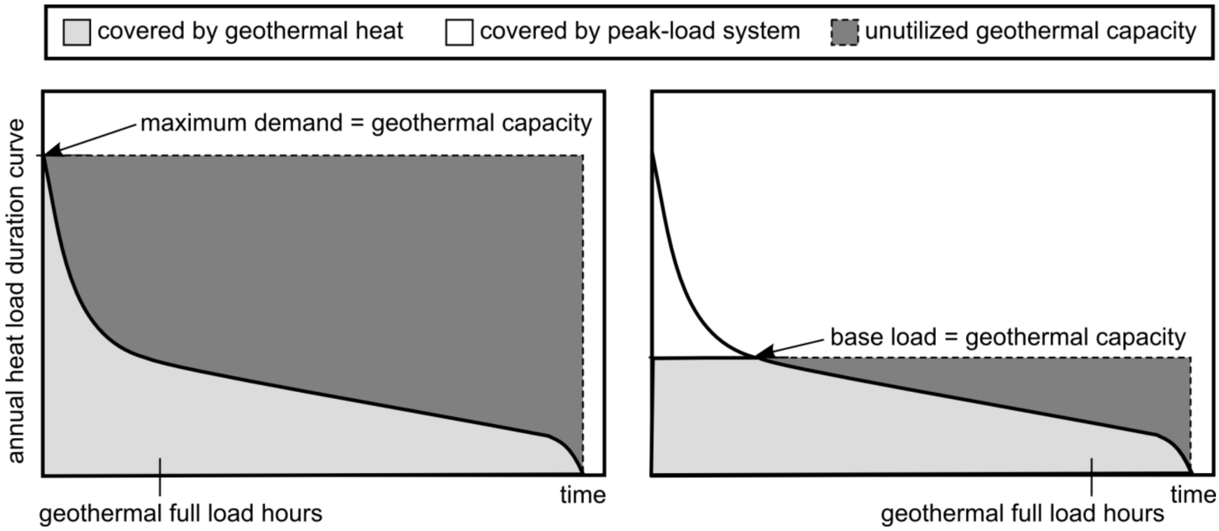


Figure 5: Annual heat load duration curves and corresponding geothermal plant design

Another approach to geothermal plant design is to adapt the heat demand side to the continuous characteristics of the geothermal resource. In the summer months, where the demand for space heat is lower, the geothermal heat can, for example, be used for the supply of chill. This can be done by directly supplying chill (which requires a cooling grid) or connecting consumers which use the heat for decentralised chill provision. Presently, a more common way is to use the geothermal heat, available off the heating period, to produce power.

Besides the "design" of the heat consumer structure in terms of a more continuous heat demand throughout the year, also the cooling of the geothermal fluid is an important aspect. By cascading heat consumers with different temperature levels, the utilization of the geothermal resource can be optimized.

More examples for the heat supply from geothermal reservoirs are given e.g. in Geo-Heat Center Oregon (2005)[1] or can be found on the Geothermal Conference Papers Database from the International Geothermal Association (IGA)[2].

A.2.2 Chill supply

Besides the provision of heat for space heating or industrial processes, geothermal energy can also be used for the provision of low temperature heat needed for refrigeration. The heat driven absorption refrigeration cycle applied in ARSs (absorption refrigeration systems) is the most applicable for this purpose. In general, also vapour-compression-refrigeration, which is the most commonly used refrigeration principle, or adsorption refrigeration exist. The principle scheme of an ARS is shown in Figure 6. A typical ARS uses a mixture consisting of a refrigerant and an absorbent as working fluid and consists of an evaporator, a

[1] http://geoheat.oit.edu/pdf/tp115.pdf
[2] http://geothermal.stanford.edu/standard/

condenser, a generator, an absorber, a solution heat exchanger, a solution pump and throttling valves.

As most refrigeration cycles, absorption refrigeration is based on evaporating the refrigerant at low temperature and pressure, compressing the vapour, and condensing it at a higher temperature and pressure level. During evaporation, the refrigerant absorbs the heat from the heat source that has to be chilled. During condensation this heat is transferred to a heat sink at a higher temperature level, such as a water or air driven re-cooling system.

Evaporator, condenser and throttling valve are similar to the ones used in vapour-compression-refrigeration systems. Due to the use of a mixture instead of a pure fluid as working fluid, ARSs contain a thermal instead of mechanical compressor. Such a thermal compressor is comprised of three main elements: absorber, solution pump and generator (Figure 6). In order to obtain a higher efficiency a solution heat exchanger is used for energy recuperation.

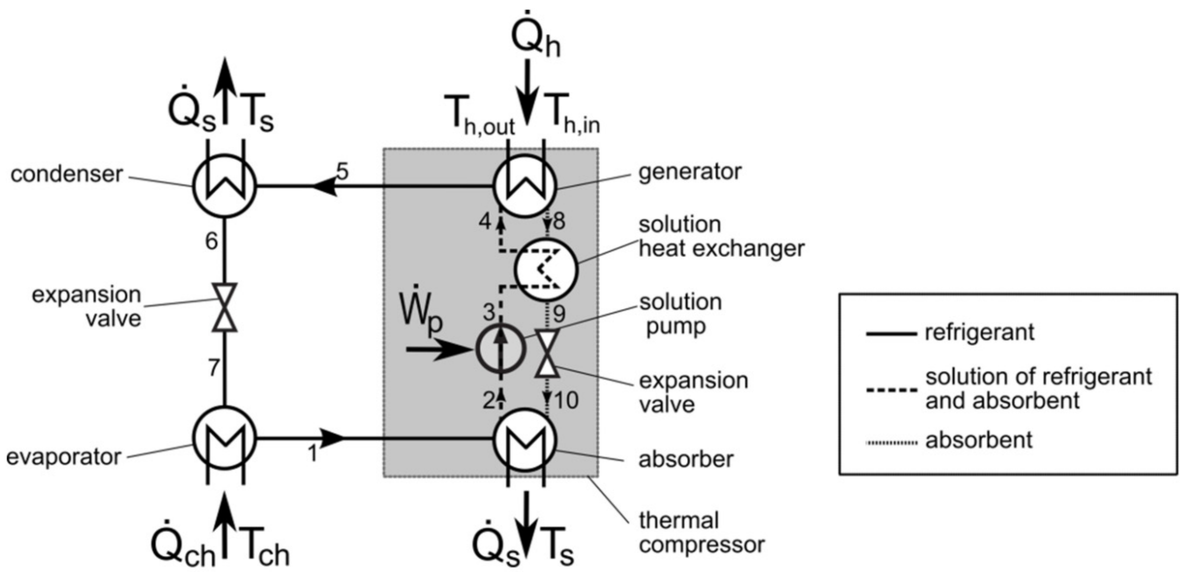


Figure 6: Principle of an absorption refrigeration cycle

In the following paragraph the principle of cycle operation is explained using the example of an ammonia water ASR. The ammonia (refrigerant) vapour exits the evaporator (Figure 6, step 1) and is absorbed by the water (absorbent) inside the absorber at low pressure (approx. 2.5 bar) and relatively low temperature. The resulting heat of absorption $\dot{Q}_s$ has to be removed from the cycle. The liquid solution (2) contains a relatively high concentration of water. The solution passes the solution pump (2→3) which raises the pressure up to the pressure level (approx. 10 bars) of the generator and the condenser. Inside the generator (3→4) the ammonia is driven off the water by means of heat input $\dot{Q}_h$, such as from a geothermal fluid. Afterwards the ammonia vapour (5) enters the condenser and the water (8), which contains a low concentration of ammonia, passes the solution heat exchanger (8→9), expands to the low pressure level inside the throttling valve (9→10) and enters the absorber. The solution heat exchanger reduces both the heat, needed in the generator and the one that has to be removed from the cycle. Inside the condenser the ammonia is cooled until it condenses. The heat of condensation $\dot{Q}_S$ has to be removed as well. After leaving the condenser (6) the liquid ammonia is expanded by the throttle to the lower pressure level (6→7) of the evaporation. In the evaporator the ammonia evaporates completely at a low temperature and pressure level. The heat needed for evaporation corresponds to the refrigeration capacity of the ARS. After evaporation the ammonia vapour (1) is redirected to the absorber.

More information on geothermal driven ARSs can be found in Lund (1998). Since networks supplying chill only scarcely exist at the moment, geothermal driven ARSs have only been installed in small scale applications.

A.2.3 Power supply

The principle of converting heat into power by means of an evaporable working fluid is referred to as Rankine cycles. The most common working fluid is water, but also other working fluids exist. Due to the variety of evaporable fluids, Rankine cycles are versatile applicable, also for low temperature heat sources. Most other types of thermodynamic cycles used for low temperature heat are essentially modifications of it (e.g. Organic Rankine Cycle or Kalina; Kalina, 1983). The basic form of the Rankine cycle is shown in Figure 7. It consists of the following changes of state:

- pressure increase of the liquid working fluid with a feed-pump (1→2),
- heating of the pressurized liquid up to the evaporation temperature (2→3),
- evaporation of the liquid at constant temperature and pressure (3→4),
- expansion of the vapor in an expansion machine (4→5) which produces mechanical work, and
- condensing the expanded vapor at constant pressure and temperature (5→1).
-

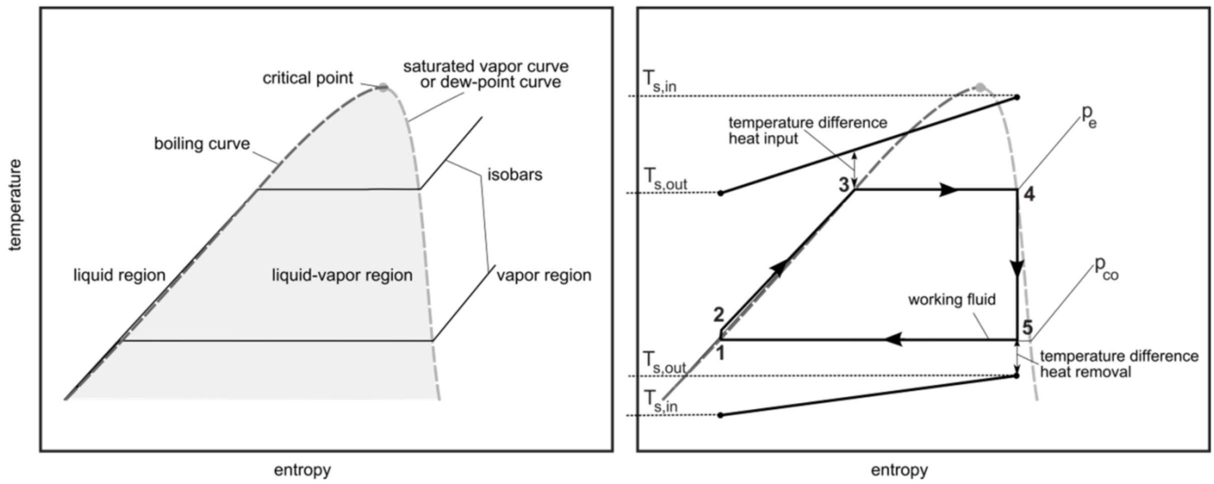


Figure 7: Temperature-entropy-diagram (T-s diagram) of an example working fluid showing general notations (left) and a corresponding Rankine cycle with saturated vapor (right)

For the conversion of heat from geothermal reservoirs into power, the heat is transferred to the working fluid contained in a so called binary power unit. As shown in the schematic set-up of a geothermal driven binary cycle in Figure 8, this working fluid is preheated and evaporated. The generated vapour is expanded and the released enthalpy is used by an expansion machine. In most applications turbines are used as expansion machines due to their wide application range and widespread availability. For small power rating also screw or piston expanders are available. The expansion machine is connected to a generator in order to convert the mechanical work into electricity. The exhaust vapour from the turbine is condensed. The cooled working fluid is pressurised in the feed pump and recycled to the preheater. The power that is produced in a binary conversion cycle depends on the heat source and, on the binary side, on component-specific parameters (such as efficiency of the turbine, generator and feed-pump, temperature differences in heat exchangers) and binary cycle design.

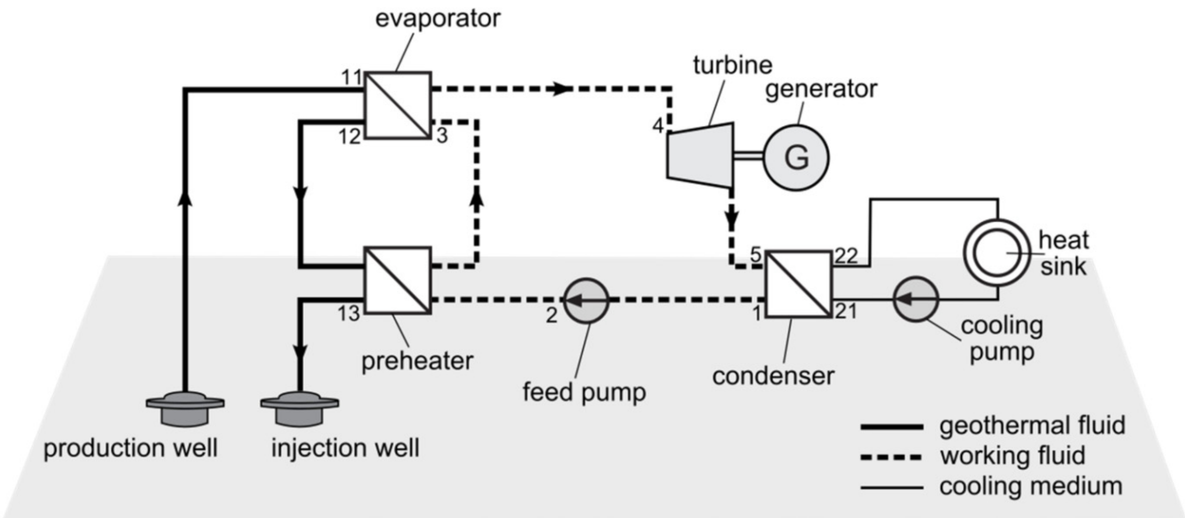


Figure 8: Schematic set-up of Rankine cycle using geothermal heat as heat source

Existing binary conversion cycles generally use different working fluids and cycle layouts (such as cycles with superheating, super-critical cycles, cycles with internal heat recuperation, cycles with different evaporation stages and working fluid mixtures).

A general characterisation of different working fluids can be expressed according to the saturation vapour curve in the temperature-entropy diagram (Figure 9). A “wet” fluid shows a negative slope of the saturation vapour curve. When expanding saturated vapour in an expansion machine the state obtained is always located in the two phase region. Water and ammonia, for example, are typical “wet” fluids. A “dry” fluid, such as isobutane, shows a positive slope of the saturated vapour curve. After expanding saturated vapour from a dry fluid, its state is always located in the superheated region. If the saturated vapour curve does not show any slope, the fluid is called “isentropic”. A wide range of possible working fluids are investigated in Saleh et al. (2007) with regard to the achievable cycle efficiency and considering a minimum and maximum cycle temperature of 100°C and 300°C, respectively. Saleh et al. thereby consider subcritical as well as supercritical cycle designs.

Referring to geothermal resources, the Organic Rankine Cycle (ORC), which uses an organic working fluid, is the most common type. At the moment more than 150 binary units with an average capacity between 1 and 3 MW are installed worldwide (DiPippo, 2008). Another often discussed but so far rarely installed type is the Kalina cycle. One Kalina plant has been installed in Húsavik, Iceland (Maack and Valdimarsson, 2002). A second plant is operated in Unterhaching, Germany (Knapek and Kittl, 2007). The Kalina cycle is characterised by an ammonia-water-mixture and an absorption- and desorption-process within the cycle. However, also Rankine Cycles with inorganic working fluids, such as pure ammonia, or other mixtures are possible. A detailed overview of existing geothermal binary power plants is given in DiPippo (2008).

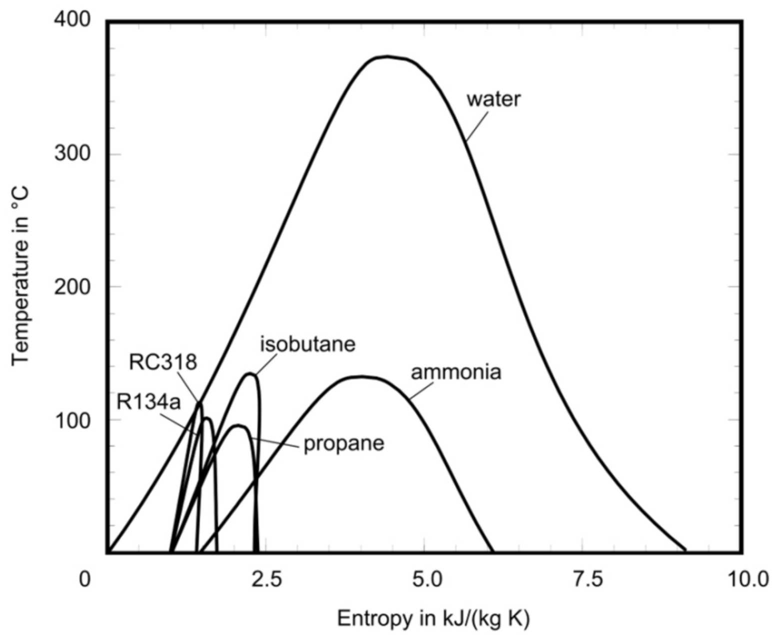


Figure 9: Temperature-entropy diagram showing the saturation vapour curves of different working fluids

Geothermal driven binary cycles are designed according to the temperature level and the characteristics that are encountered at a specific site. Site-specific cycle design has to aim at a high utilization of the geothermal heat with an efficient and reliable power conversion technology. Compared to conventional power plants, some geothermal particularities have to be considered.

The highest efficiency, for example, does not result in the highest power output, such as shown in Figure 10. The cycle efficiency increases with higher evaporation temperatures. The evaporation temperature, however, also influences the cooling of the geothermal fluid.

The utilization of the geothermal fluid thereby decreases with higher evaporation temperatures. For the maximum power output, the optimum evaporation temperature has to be found.

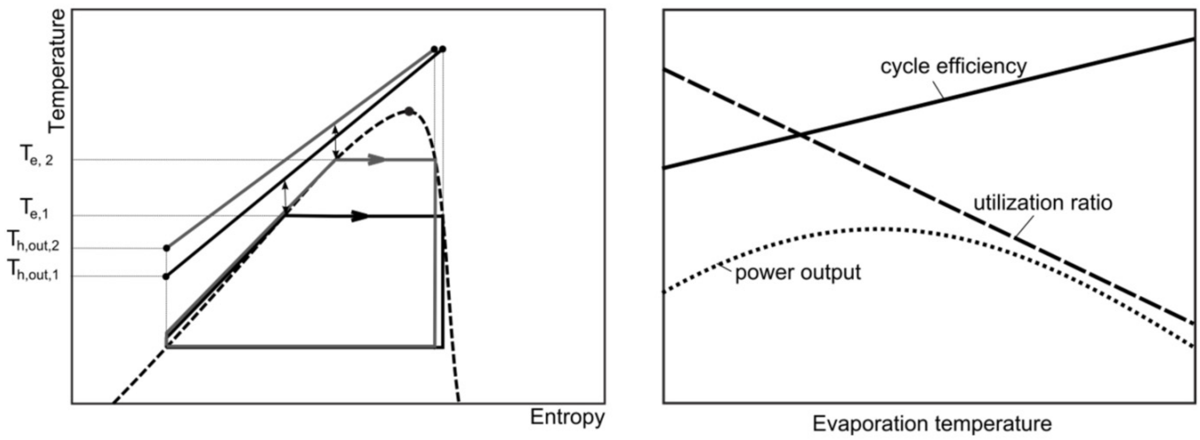


Figure 10: T-s diagram showing the correlation of evaporation temperature and geothermal outlet temperature (left) and development of power output as a function of the evaporation temperature (right)

Attention must also be given to the design of the re-cooling system of a binary cycle because power conversion from geothermal reservoirs has to deal with large amounts of waste heat and engineering of such cooling systems must consider site-specific preconditions.

Binary power units using heat sources with temperatures up to approximately 200 °C are discussed in more detail, e.g. in Saadat et al. (2010), Frick et al. (2010), Köhler (2005), Saleh et al. (2007) and DiPippo (2008).

A.2.4 Combined energy supply

Besides the provision of heat, chill and power from separate plants, geothermal reservoirs also offer the possibility for a combined energy supply. This is possible, for example, with cogeneration or combined heat and power supply (CHP) which is known from conventional power plant design. In this set-up the waste heat from the conversion process, which otherwise would be discharged to the environment, is used for heat supply (Figure 11). Cogeneration is therefore characterised by a simultaneous supply of power and heat from the same unit and leads to a significantly higher utilization of the heat source driving the conversion process.

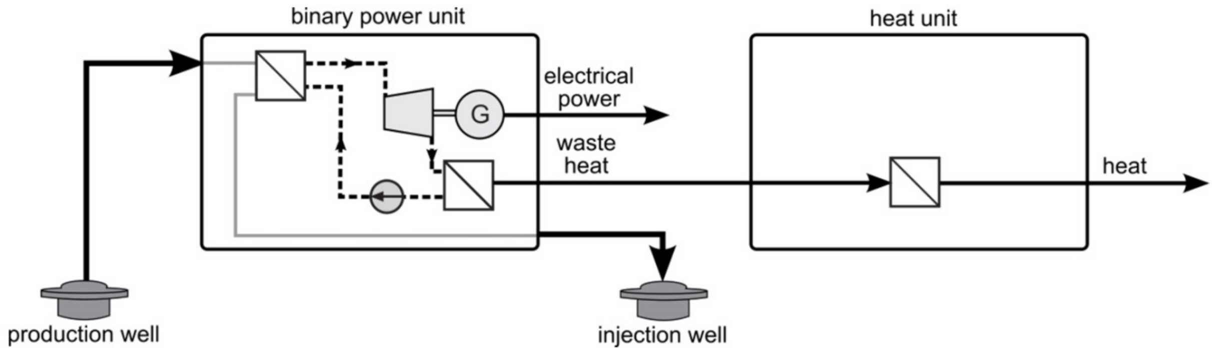


Figure 11: Schematic set-up of a plant with conventional cogeneration of power and heat

The heat contained in the exhaust vapour at the outlet of the turbine from conventional power plants can for example be used to supply district or process heat with supply temperatures above 100 °C or to convert this heat and provide chill. In geothermal power plants, in contrast, the temperature of the exhaust vapour is normally lower than in conventional power plants. The temperature correlates with the geothermal fluid temperatures. For geothermal fluid temperatures of up to 170 °C, the exhaust vapour temperature typically lies below 60 °C; for higher fluid temperatures of up to 200 °C, an exhaust vapour temperature of about 80 °C can be expected (Köhler, 2005). It is generally possible to raise the exhaust vapour temperature though this measure has limited influence and leads to a considerable efficiency decrease in the conversion process.

Cogeneration in geothermal plants is therefore dependent on a suitable heat consumer structure characterised by low supply temperatures. Regarding the relatively large waste heat amounts of geothermal power plants, cogeneration is, however, also interesting because the technical use of the waste heat can reduce the demand for re-cooling.

Following the combined energy supply approach for geothermal applications, more or less independent plant parts are often installed, which are connected in parallel or serial.

A typical geothermal serial connection is represented by a unit providing power and a downstream unit providing heat (Figure 12). If a binary unit optimised for power output has a geothermal outlet temperature of 70 °C, the heat unit can, for example, feed a low temperature heating grid with a supply temperature of 60 °C and a return temperature of 40 °C. If the heat unit has to provide 70 °C instead, the power conversion cycle needs to be adapted in order to cool the geothermal fluid only to about 75 or 80 °C, which leads to a lower power output. Assuming a typical heat demand which varies throughout the year, this reduction in the power output is only relevant for times of heat demand.

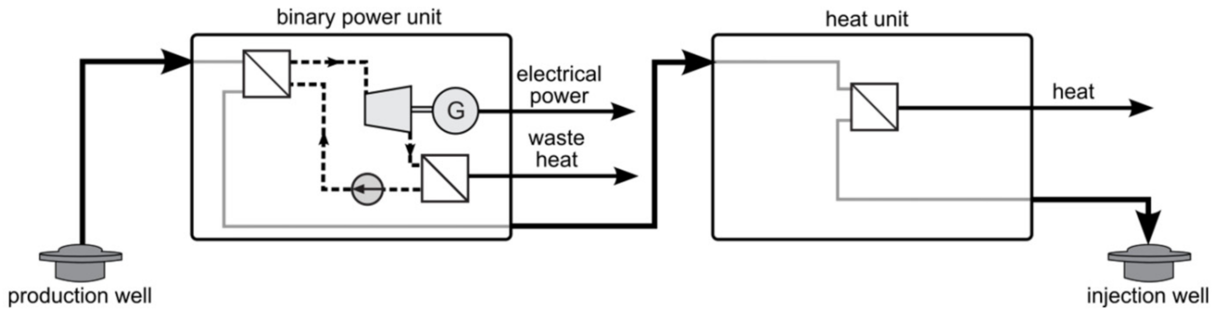


Figure 12: Schematic set-up of a geothermal plant with power and heat supply in serial connection

Based on these considerations, a serial connection is especially advantageous when the in- and outlet temperatures of the connected units closely match the optimum temperatures of their single application.

In a parallel connection of different energy supply units the geothermal mass flow is split between these units so that the inlet temperatures of all units are the same. The main design criterion is the split-up of the geothermal mass flow. Each energy supply unit is optimised for the geothermal fluid temperature and a certain mass flow. In comparison to units connected in series, units connected in parallel can be designed more independently. Parallel connections can also be designed easily for a varying energy provision mix. In case of a variable mass flow, the part load behaviour of a unit needs to be considered.

Parallel connections are advantageous when the necessary inlet temperatures of different energy supply units are at the same temperature level and especially when these temperatures are close to the geothermal fluid temperature. A geothermal plant with parallel supply of power and heat, for example, uses all of the geothermal mass flow for heat provision in times of large heat demand. In times of lower heat demand (but still with a supply temperature close to the geothermal fluid temperature), only a part of the geothermal mass flow is used for heat supply so that the remaining mass flow can be used in a binary power unit.

Geothermal plants can also combine cogeneration, serial and parallel connection in one plant concept, so that a variety of plant set-ups are possible depending on the demand characteristics at a specific site. An overview of existing geothermal plants providing power and heat is given by Lund & Chiasson (2007).

A.2.5 Energy networks

Energy networks are a compound of different, separately running energy suppliers. The network is designed and operated according to the energy demand but also according to the characteristics of each energy supplier and existing synergies. Energy networks offer the possibility to combine base load and peak load systems, to integrate components in order to uncouple energy demand and supply, such as storage systems, and to make use of waste energy streams.

Due to the variety of set-ups of geothermal plants, they also offer a variety of ways to be integrated in energy networks. Geothermal plants can especially serve as base load capacities for heat, chill or power supply. ATES can especially serve to decouple heat demand and supply in a network.

The energy supply system of the German Parliament Buildings in Berlin, Germany, for example, comprises several components that allow an energy efficient and environment-friendly energy supply. Apart from energy conversion components (such as combined heat and power units, refrigeration machines), there are two seasonal ATES systems involved. One ATES system is used as heat storage and is located at a depth of app. 300m. The second ATES serves as cold storage and uses an aquifer at a depth of 40 to 70m. The heat storage is charged with surplus heat from a biofuel driven cogeneration plant (CHP) in summertime. In wintertime, the ATES is discharged to supply the buildings with low temperature heat. The temperatures are 45°C and 30°C for flow and return respectively. The cold storage is cooled down by means of dry cooling in case of the ambient temperatures being low. In summertime, the cold groundwater is used to cool the buildings (Kabus & Seibt, 2000; see also p. 74).

A.2.6 Hybrid systems

Hybrid systems refer to technologies that use different energy carriers within the same plant. In such plants, the internal processes need to be optimized in order to get a higher energy output compared to the separate use of the energy carriers.

Regarding geothermal energy, hybrid power plants are mostly discussed at the moment in which the geothermal heat is combined with a heat stream of higher temperature (Figure 13). In this case, the process temperatures of the conversion process and therefore the conversion efficiency can be increased compared to power plant only fed by geothermal energy. The higher temperature heat can be any heat such as waste heat from other processes (e.g. biogas motors) or the combustion of biomass or biogas. Depending on the site and the available energy carriers, geothermal energy can be used to come up for partial or total preheating of the working fluid or also full evaporation (Figure 13).

One hybrid power plant is presently under construction in Neuried, Germany (Kreuter & Schrage, 2010). Astolfi et al. (2010) have recently discussed a solar-geothermal hybrid power plant.

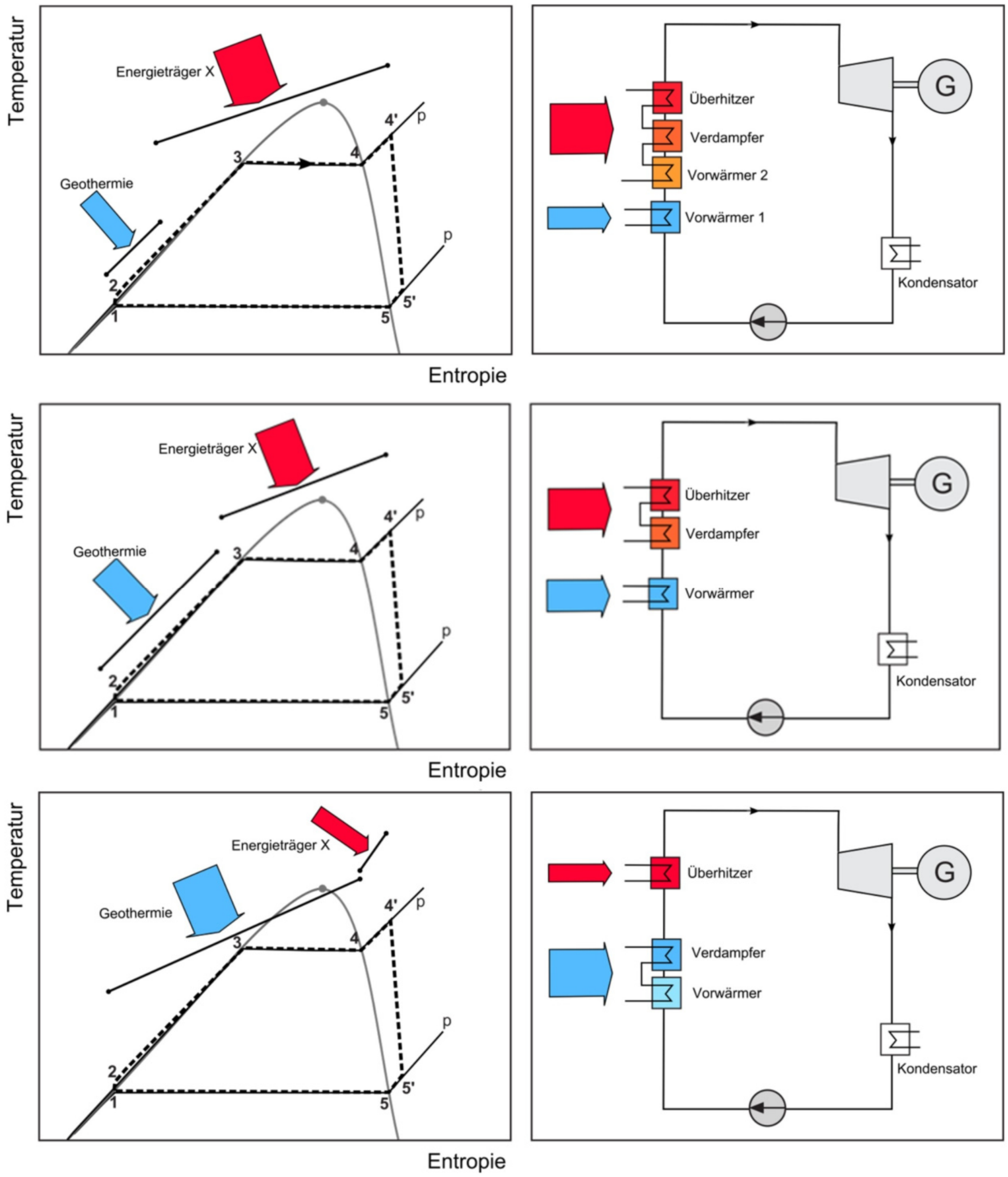


Figure 13: Temperature-Entropy Diagrams of a potential hybrid power plant. The relative input of geothermal energy increases from the concept at the top to the concept at the bottom.

A.3 Plant design

A.3.1 General Aspects

Geothermal plants can basically be divided into different technical subsystems such as the geothermal reservoir, the fluid loop connecting the underground with the surface, and the energy supply unit. The challenge in designing geothermal plants is to meet the different design characteristics of these subsystems and manage their efficient and reliable interaction. Boundary conditions and design criteria of geothermal and their subsystems thereby vary from site to site. Based on this variety in plant design, the design optimization of a geothermal plant at a specific site requires the comparison of different technical solutions. In this context simulation tools are an important instrument.

For planning a geothermal plant, the characteristics of the reservoir must be known or evaluated. Besides the reservoir temperature, the temperature of the heat carriers on the surface, and the volume flow rate that can be pumped to the surface, also the auxiliary power demand for operating the geothermal reservoir and technical restrictions are important. Technical restrictions may need to be considered such as allowable operation temperatures and pressures based on geochemical considerations or the design of deep wells (diameters, inclination, etc.), causing also constraints for the installation and configuration of downhole pumps.

The geothermal fluid loop carries the geothermal energy and is therefore a very decisive part of geothermal plants. It needs to integrate different functions such as the production of geothermal fluid from the reservoir, its transport onto the surface, the processing, and finally its reinjection into the reservoir. Regarding the design of the geothermal fluid loop and the components contained, such as production pump, pipelines, heat exchangers, filters and injection pump, the following aspects need to be considered.

Properties of geothermal fluids differ depending on the site-specific reservoir characteristics and the change of temperature and pressure during energetic utilization. Knowing the geochemical composition of the fluid and assessing its alteration in the geothermal fluid loop or in the reservoir during reinjection must be an integral part of geothermal plant design.

The operational reliability is strongly affected by interaction of the geothermal fluid with the plant materials. Especially corrosion and scaling are technical risks which need to be considered for optimizing design and successful operation of the geothermal fluid loop. Adequate measures include selection of durable materials and monitoring of physico-chemical conditions of the fluid.

The reliability of the geothermal fluid loop is based on the choice of suitable materials and component layouts according to the characteristics of the geothermal fluid and local fluid properties which are expected during operation. Improper design can lead to deterioration of geothermal plant performance or even plant failure if components of the geothermal fluid loop have to be replaced. For the operation of a geothermal plant, corrosion of plant materials and clogging of the pipes (scaling) are the two risks which affect strongly plant reliability.

Aspects of overall plant design for geothermal reservoirs are discussed in more detail in e.g. Kranz & Bartels (2010); Frick, Kaltschmitt, & Schröder (2010); Frick, Kranz, & Saadat (2010); Saadat et al. (2010) and Huenges (2010).

A.3.2 Geothermal plant efficiency

The efficiency of a process is defined as the ratio of the effective or useful output to the total input in a system and is typically used to evaluate the performance of a system. For energy supplying plants efficiency refers to the ratio of total energy input to useful energy output. The calculation of the energetic efficiency for evaluation and comparison purposes, however, must be based on a reasonable definition of the system boundaries for energy input and output in order to consider the (different) particularities of the compared and evaluated systems.

In many plants the energy input is related to a defined input of fuel (e.g. fossil fired power plants, gas fired boilers) which has to be delivered to the plant site. Geothermal plants, in contrast, use an energy source that is directly available at the site so that the efficiency of geothermal plants should also consider the ratio of used energy to available energy. Furthermore, the quality of the geothermal energy input varies from site to site depending on the reservoir temperature and geochemical composition. This needs to be taken into account, for example, when comparing the efficiencies of geothermal plants at different sites.

According to Kagel (2008) and Saadat et al. (2010), the efficiency of a geothermal plant could be calculated using different approaches depending on the evaluation purpose:

1.) First law efficiency (η): ratio of useful energy (e.g. heat or net power) to the energy input (First Law of Thermodynamics, Law of Conservation of Energy). In case of refrigeration cycles and heat pumps, this efficiency is also referred as coefficient of performance (COP). The first law efficiency is the most common way to evaluate the performance of a plant but does not distinguish between the quality of energy that is received or delivered by a plant. Comparing the performance of two power plants with different heat source temperatures, for example, based on the first law efficiency is not sufficient. The plants might have identical first law efficiency. But the power plant using the heat source with the lower temperature uses the available exergy more efficiently. The first law efficiency is, however, very useful for comparing different plant concepts or analyzing the overall plant performance at a specific site.

2.) Second law efficiency: ratio of first law efficiency of the real plant to the first law efficiency of a thermodynamically ideal cycle operating under the same thermodynamic conditions. This measure is based on the Second Law of Thermodynamics, which does not only consider the conservation of energy in a system but also the irreversibilities of thermodynamic processes due to the production of entropy and the destruction of exergy related therewith. Using this efficiency for evaluation purposes, the work output is compared to the potential of the input to do work. Regarding power plants, the second law efficiency hence compares the first law efficiency of the real plants with the Carnot efficiency for the same upper and lower process temperatures.

3.) Resource utilization: ratio of the geothermal heat used by a plant to the maximum usable heat available from the geothermal source. The maximum usable geothermal heat can be determined by the ambient temperature as lower temperature limit or a minimum allowable temperature. Comparing two geothermal plants, the plant with the higher utilization ratio is using the geothermal resource to a larger extent and re-injects less heat unused into the reservoir.

4.) Efficiency based on Power and Fluid measurements: here, the amount of net power produced per unit flow of geothermal fluid is considered. For given resource conditions, the higher this value the more efficient a plant is. Such measurements are classified as Specific Power Output (SPO), measured in watt hours per pound or kilogram of geothermal fluid, or Specific Geofluid Consumption (SGC), which is the inverse of the SPO. Dividing the SPO by the available energy is one way to measure second law efficiency.

While efficiency is important, it is only one characteristic among many that must be considered when choosing the most appropriate energy option for a particular location (Kagel, 2008).

A.3.3 Geochemical aspects

The geothermal fluid is defined as a heated multiphase substance consisting of mainly gas and liquid, which flows within pores of a geological formation (= bedrock) of the deep geothermal reservoir. As a consequence of temperature and pressure change during uplift and processing, as well as by re-injection of the chilled fluid into the reservoir, various chemical and physical processes (e.g. degassing, mineral solution and precipitation) can be expected to occur within the fluid and by interaction with the surrounding materials (rock, tubing, casing). These reactions can damage the plant due to corrosion and fouling of tubes or clogging of the reservoir pores during re-injection. Thus, for proper design of the geothermal fluid loop, the fluid needs to be characterized in terms of its composition and its effects to alter both, the used materials and the reservoir.

An introduction to fluid types and compositions as well as the main compounds of the fluids and potential interactions with the plant materials will be given in the following.

Fluid composition and classification

The geological source of the fluid bedrock as well as interactions of the fluid with the surrounding rocks during migration determines the chemical composition of geothermal fluids. Roughly, fluids can be divided according to their geological source: sedimentary basin fluids and crystalline rock fluids (Drever et al., 2004). The fluids are usually classified according to their major chemical compounds (i) or according to their salinity (ii).

(i) Depending on their dominant ions, fluids are grouped in different types representing the major components of the system. In sedimentary basin fluids, the most frequently occurring compounds are sodium (Na^+), calcium (Ca^{2+}) and chloride (Cl^-) (Figure 14, left) as well as occasionally the organic anion acetate (CH_3COO^-).

(ii) Due to the strong variation in salinity from few milligrams to several hundred g/l total dissolved solids (TDS), fluids are classified in freshwater (< 1 g/l TDS), brackish water (1-10 g/l), saline water (10-100 g/l), and brine (> 100 g/l; Davis, 1964). In general, salinity increases with increasing depth (Figure 14). Most geothermal fluids are brines although less salty waters are less corrosive and thus easier to handle and would consequently be more favorable in geothermal systems. In low-enthalpy geothermal systems, lower salinities have only been reported from few, evaporate-free regions.

Extensive overviews about fluid formation and composition considering a large number of samples from all over the world are given by Hanor (1994) and Kharaka and Hanor (2004) for sedimentary basin fluids and by Frape et al. (2004) for deep fluids from crystalline rocks.

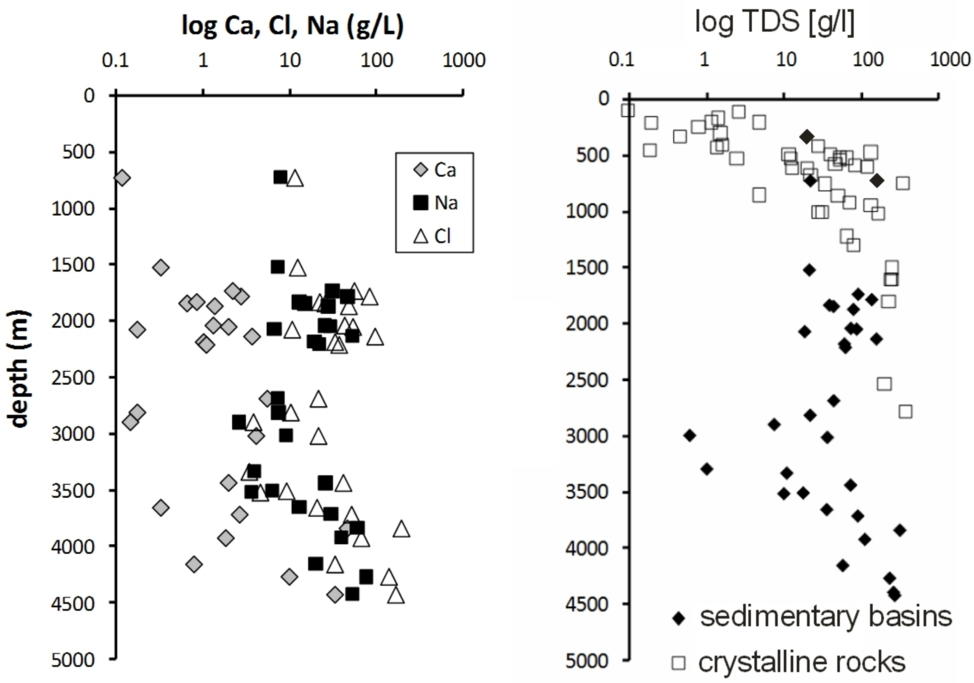


Figure 14: Depth distribution of main elements of sedimentary basin fluids plotted versus depth. They represent 78 to 98 wt.-% of total fluid salt content (Kharaka and Hanor, 2004) (left). Modified figure after Regenspurg et al., 2009. Depth distribution of dissolved solids (log TDS); data from sedimentary basins (black diamonds; Förster et al., 2006; Hanor et al., 2004; Giese et al., 2002; Wolfgramm et al.; 2007) and crystalline rock formations (white squares; Frape et al., 2004) (right)

Effect of the fluid properties on plant operation

Geothermal fluids represent a mixture of many inorganic ions, dissolved silica, organic materials and dissolved gases. Some of these compounds are highly dominant in the solution, but of less importance for operating the geothermal plant. Other are highly reactive and even trace amounts can have effects on the production process.

Variation of fluid conditions, e.g. induced by pressure (p) and temperature (T) change can provoke a change in fluid composition due to degassing or precipitation of minerals because mineral solubility and formation depends strongly on pT-conditions. These processes would further affect the pH-value or induce interaction of the fluid with the plant materials. Thus knowledge of the fluid composition and properties can indicate not only the reservoir type and the origin of the water but also the potential risk for plant corrosion and formation of scaling (=mineral precipitation).

An overview of the most relevant properties of a geothermal fluid is given in Saadat et al. (2010). The most relevant properties are:

Temperature, pressure: Both, pressure- and in particular temperature changes affect strongly the solubility of minerals and thus need to be considered in order to assess scaling of minerals and fouling of casing.

Physicochemical conditions (pH- and redox value): At given pT-conditions of a solution, the parameters pH-value and redox potential determine the dominant species in which a compound (e.g. a metal) occurs in solution. This knowledge is important to estimate if this compound of certain concentration would remain in solution or precipitate. Silica precipitation is especially undesired in plants, because it can hardly be removed and solely the addition of HF, which is of high handling risk, can dissolve these precipitates.

Cations and anions of importance: Na^+ and Ca^{2+} are the highest concentrated cations in geothermal fluids which are mainly enriched due to halite (NaCl) and calcite ($CaCO_3$) dissolution or mineral transformation. Other metals, such as iron (Fe), lead (Pb), manganese (Mn), magnesium (Mg), barium (Ba), are often oversaturated and thus play also an important role in terms of mineral precipitation (scaling). The anion showing by far the highest concentration in geothermal fluids is Cl^-. Its enrichment is a consequence of its frequency in salts and minerals as well as of its relatively low solubility. Since it is known for its corrosive properties if oxygen is available in the system, it needs special attention in geothermal plants.

Dissolved gasses: Fluids contain various amounts of dissolved gasses (0.05-1 liter gas per liter fluid) consisting mainly of a mixture of nitrogen (N_2) and carbon dioxide (CO_2) as well as occasionally hydrogen sulphide (H_2S), methane (CH_4) and traces of helium (He). The solubility of both N_2 and CO_2 increase upon cooling of the water. A gas phase may form if pressure drops below bubble point. Of special interest for plant design is the content of non-condensable gases (NCG) such as CO_2 and N_2, which are not easily condensed by fluid cooling and thus may not be simply injected back into the reservoir. Moreover, NCGs also vary over time at a given field, which can cause problems with the fluid production equipment. Depending on the local flow conditions, the NCG would then accumulate in the installations of the geothermal fluid loop (such as heat exchangers, injection well). To avoid scaling and corrosion induced by reaction of gas with plant material, a removal system (vacuum equipment) would be necessary. Of special concern is the gas hydrogen sulphide (H_2S), because sulphide can react with metals such as Pb, Cu or Fe to form various sulphide minerals which would clog the pipes, whereas the free protons (H^+) induce their corrosion. Carbon dioxide and methane are greenhouse gases and measures have to be taken to avoid their escape into the atmosphere if they are present in the geothermal system at all.

The amount and composition of gasses can vary dramatically from reservoir to reservoir and from well to well within the same reservoir. Consequently, it is very difficult to establish accurate design bases for the gas fraction in geothermal plants.

A.3.4 Thermal water pumps

Pumping and injecting the geothermal fluid is often to a considerable amount related to auxiliary power. The power needed depends mainly on the reservoir characteristics and the design of the thermal water loop. To energetically optimize the plant operation, the auxiliary power input must be ameliorated / minimized.

Under typical geological conditions, the pressure in geothermal reservoirs will not overcome the hydrostatic pressure of the water head which builds up in the well. In this case, fluid production technology to lift the geothermal fluid from the reservoir is needed. Designing geothermal plants, the reliability of the fluid production technology and the auxiliary power to run the equipment is a crucial aspect. More information on downhole pumps are given e.g. in Economides and Ungemach (1987), Culver and Rafferty (1998), Aksoy (2007), and Legarth (2003). Flashman and Lekic (1999) give a brief overview of other technical fluid production options.

The use of downhole pumps installed below the fluid level in the production well is most common for geothermal plants. Downhole pumps are distinguished depending on their mode of operation in a) line-shaft pumps or b) electrical-submersible pumps. Line-shaft pumps are driven by a shaft and an electrical motor located above ground. This limits their application to vertical wells and installation depths of up to 600 m (Aksoy, 2007). In contrast, electrical submersible pumps are driven by an electrical motor located in the production well and have a wider range of application.

Although the physical life of geothermal downhole pumps is typically limited to several years, its lifetime could be affected depending on the site and the operating conditions in the production well. It has to be considered that the replacement of a downhole pump can take up a significant amount of time. Such as for the design of other components in the geothermal fluid loop, aspects of corrosion, scaling, and thermal expansion must be considered for design and operation of downhole pumps. A further limiting condition for the physical life of downhole pumps are high temperatures of the geothermal fluid. This is especially a problem for electrical submersible pumps. Since the cooling of the motor must be realised by the streaming hot geothermal fluid, overheating of the motor is an issue. Other aspects, which can limit the physical life of downhole and especially electrical submersible pumps, is the aggressiveness of the produced fluid, which can be a problem, e.g. for seals. Unintentional degassing of the geothermal fluid in the pump due to potential local pressure drops results in material stresses and may lead to material failure. Other production technologies do exist but presently have less relevance for geothermal systems. Gas lift based on inert gases, for example, is not considered a solution for continuous fluid production due to high costs. The turbo-pump-technology, which consists of a turbine driven submersible pump supplied by high-pressured water from the surface, has only been installed at one site so far due to its low efficiency (Boissavy and Dubief, 1995).

Depending on the reservoir pressure, the production well is filled with geothermal fluid up to a certain level, which is called the static fluid level and is usually measured in distance from the surface. If geothermal fluid is produced from the reservoir, the fluid level in the production well lowers. The fluid level during production mainly depends on the produced flow rate and the reservoir characteristics and is called dynamic fluid level. Compared to the static fluid level, the dynamic fluid level is therefore lower and decreases with increasing flow rate. Accordingly, the installation depth of the downhole pump must be adapted to the design flow rate and the fluid level drawdown related therewith. Furthermore, it has to be considered that downhole pumps need a minimum intake pressure (approx. 10 to 20 bar) so that the pump must be installed at a sufficient depth referring to the lowest dynamic fluid level which occurs during operation in order to ensure this intake pressure with the overlying water head (Figure 15). According to the state-of-the art, with electric submersible pumps installation depths of up to 3,000 m can be realised (Legarth, 2003).

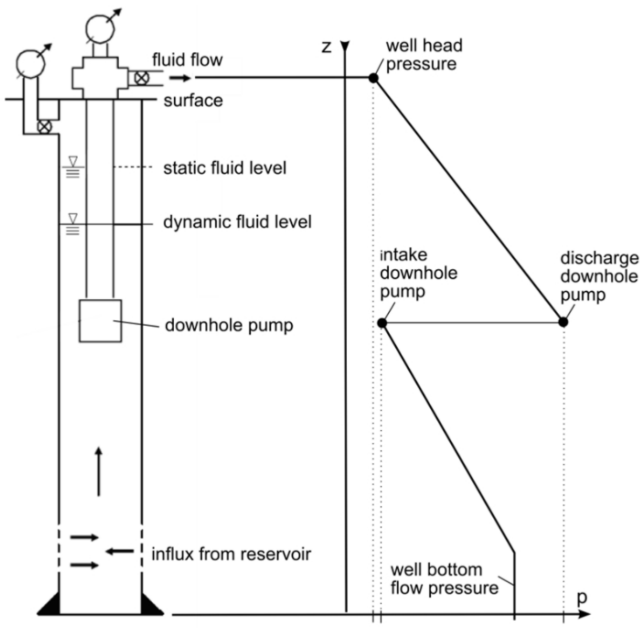


Figure 15: Scheme of a production well showing downhole pump, static fluid level and dynamic fluid level (left) and the pressure curve during fluid production (right)

The effort to produce the geothermal fluid from the reservoir is derived from the flow rate, the pressure increase applied by the downhole pump, and the efficiency of the pump. Downhole pumps typically have an efficiency of approximately 50 to 75 % depending on the temperature conditions and the contents of dissolved gases in the produced fluid. The pressure increase of the downhole pump must be regulated according to the pressure to overcome the difference in height between the dynamic fluid level in the production well and the surface and the necessary well head pressure. The latter is set in order to avoid degassing and to ensure the needed injection wellhead pressure (in cases where there is no injection pump). The hydraulic conditions in the production well and the pipes of the geothermal fluid loop and therefore pressure losses due to friction must also be considered.

Designing the fluid production also needs to take technical restrictions into account, such as a maximum installation depth. For downhole pumps, the maximum producible fluid flow is approx. 600 m^3/h and the maximum motor capacity is about 1,200 kW (Legarth, 2003).

From an energetic viewpoint, another very important aspect for the design of fluid production is the increase of the production effort with increasing flow rate. The pumping of a higher flow rate results in a larger draw down of the fluid level and a larger difference in height which the downhole pump has to compensate. The production effort therefore shows a quadratic dependence on the flow rate (Figure 16). The influence of an increasing flow rate on the fluid production effort is thereby larger for lower reservoir productivities.

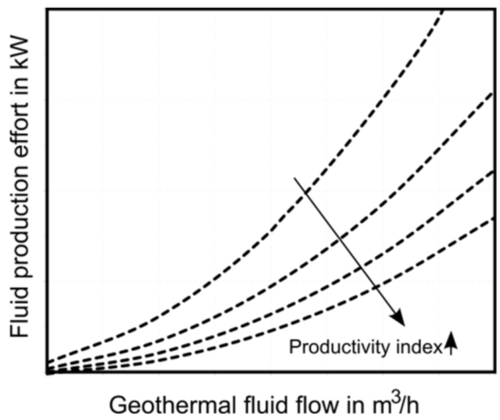


Figure 16: Qualitative development of fluid production effort as a function of geothermal fluid flow for different reservoir productivities

At geothermal sites, where the pressure at the bottom of the injection well resulting from the water head in the injection well and the wellhead pressure, is not sufficient to overcome the reservoir pressure, an injection pump must be installed on the surface. This is the case when the injectivity of a reservoir is lower than its productivity.

A.3.5 Heat exchangers supplied with thermal water

Heat exchangers used in geothermal plants are essential components for producing power as well as providing heat and/or chill. Heat exchangers should enable the optimum heat transfer from one fluid to another fluid for any given application. Depending on the geothermal application, various types of heat exchangers are required. Because of the different boundary conditions in geothermal applications no off-the-shelf heat exchanger will meet all requirements and almost every heat exchanger has to be designed separately.

The needed heat transfer rate of a heat exchanger, which is the heat transferred per unit time, has to be considered in the preliminary planning of the geothermal plant. Concerning a binary power plant, the necessary heat transfer rate of a specific heat exchanger is defined by the binary cycle design calculation. The heat transfer rate is determined by the overall heat transfer coefficient and the driving temperature difference between the fluid streams, allowing also to calculate the needed heat transfer surface area.

The materials used in the construction of a heat exchanger can be an important issue. The chemical properties of the geothermal fluid as well as the fluid on the secondary side of the heat exchanger (such as the working fluid in a binary cycle) require corrosion resistant materials such as stainless steel and titanium, or coatings.

Due to the different requirements of heat transfer applications many types of heat exchangers are available and therefore a wide range of design approaches have been developed. A general distinction is made between the flow arrangements of the fluids within the heat exchanger. In parallel flow, both fluids enter the heat exchanger at the same end and flow in the same direction. In counter flow, both fluids enter the heat exchanger at opposite ends and flow in opposite directions. The third flow arrangement is called cross-flow. Here, the fluids move perpendicular to each other through the heat exchanger. The different flow arrangements of the heat exchanger result in different temperature profiles, which need to be considered. In most cases, a combination of the mentioned arrangements is used.

Focusing on construction-related classifications, shell-and-tube heat exchangers and plate heat exchangers are commonly used in geothermal applications (Figure 17). Plate heat exchangers are characterized by a high surface-to-volume ratio which leads to a compact construction form. Once installed, they can easily be expanded when more heat capacity or heat exchange surface is needed. Plate heat exchangers are commonly used as preheaters (e.g. Rafferty and Culver, 1998). Their use as evaporators is also possible as it is the case in chilling technologies. However, the design of plate heat exchangers is based on more detailed calculations compared to the design of shell-and-tube heat exchangers (e.g. Zhu and Zhang, 2004). In comparison, shell-and-tube heat exchangers have a larger surface-to-volume ratio and larger realizable temperature gradients. Furthermore, fouling can be a larger issue than for plate type heat exchangers (e.g. Chandrasekharam and Bundschuh, 2002).

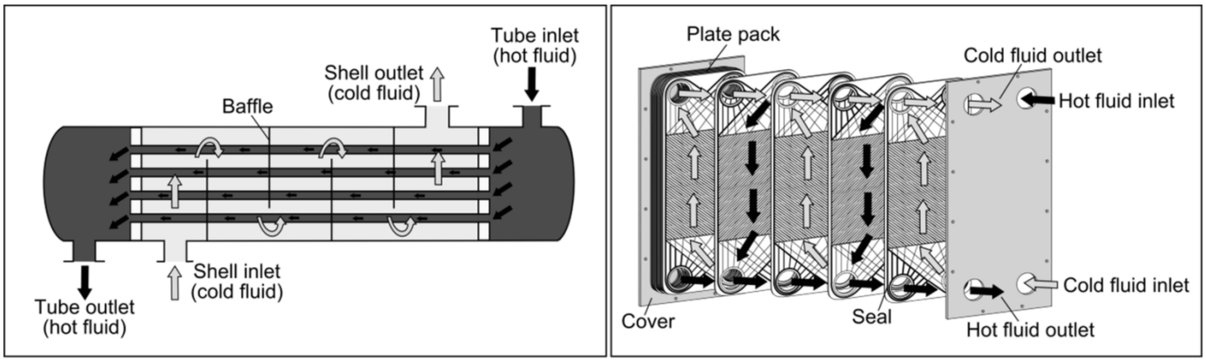


Figure 17: Illustration of a shell-and-tube heat exchanger (left) and a plate heat exchanger (right)

Heat exchangers are designed for special applications and specific operational modes depending on inlet and outlet temperatures and mass flow rates. When operating a geothermal plant, particularly a binary power plant, different operational modes occur due to changing parameters and boundary conditions. Considering a combined heat and power provision, the temperatures and the heat capacity of the district heating system will affect the operating conditions. For that reason, the heat exchanger design has to be focused on full load as well as part load conditions. The part load behaviour becomes a crucial factor when operation off the design point is predominant.

Heat exchanger design must consider fouling, i.e. precipitation of minerals such as silica and deposits which accumulate on the heat transfer surface. This is a very important issue due to the changes of the chemical equilibrium of geothermal fluids which results from the transport and cooling of the fluid and the pressure and temperature changes related therewith. The layer of deposits represents an additional heat transfer resistance between the hot and the cold fluid. Therefore, the knowledge of thermo-physical fluid properties such as specific heat capacity, viscosity and density is important. With regard to geothermal fluids the manifold chemistry may hinder the calculation of properties with the required accuracy. Methods for calculating density, heat conductivity and viscosity depending on temperature, pressure and salinity are given e.g. in McDermott et al. (2006). Methods for calculating the specific heat capacity are given e.g. in Thomsen (2005) and Millero (2009). In case sufficient methods for calculating these properties are not available, the data need to be measured.

An additional issue is the need for low temperature differences between the geothermal fluid and the fluid on the secondary side, particularly the working fluid in binary cycles. The small temperature difference is important for decreasing the exergy destruction during heat transfer. It must be considered, however, that low temperature differences lead to an increasing heat transfer surface.

B. Exploration of Geothermal Reservoirs

B.1 The Exploration Concept

In contrast to classical geothermal exploration, where the existence of geothermal reservoirs at depth often is indicated by surface manifestations (e.g. hot springs), the respective reservoirs in sedimentary basins are "hidden". However, a basic comprehension of the geological and geothermal conditions of a sedimentary basin is the basis in the application for licences of target areas to be further explored and finally used to mine geothermal energy.

To delineate geological formations presumably hosting geothermal reservoirs an exploration concept needs to be developed. This concept is heavily dependent on the state of exploration that the basin has undergone prior to geothermal exploration. Many basins are explored for hydrocarbons so that a comprehension of the major features of the basin is already available. If those legacy data are for a geothermal assessment, they should be screened for quality. However, the hydrocarbon industry often holds subsurface (analogue or digital) data and reports (with or without raw data) that are often not accessible to geothermal projects or only at an oil-based price. If those data sources would be made available for the geothermal community (as it is the case for example in the Netherlands and in the USA), faster and better quantifications of geothermal resources and reservoirs could be made. Unfortunately, case studies on the success or failure of geothermal exploration using legacy data are not published making it impossible to evaluate in detail the usefulness of their implementation into targeted geothermal exploration.

The exploration concept to be developed will slightly differ according to the two types of geothermal resources: (1) hydrothermal resources/reservoirs and (2) petrothermal resources, which both may occur in sedimentary basins, but for which slightly different approaches apply. While the fluids of the type-(1) reservoirs often can be pumped to the surface without stimulating the reservoir, the type-(2) reservoirs show low porosity/permeability and low or no natural fluid flow so that they need to be artificially stimulated by frac operations, requiring also the use of an additional artificial heat transfer medium to produce the heat from the reservoir (Hot-Dry-Rock system).

B.1.1 Borehole Data

In general, if no background geological data of a sedimentary basin are available, exploration starts as a green field approach. Drilling of some exploration wells in conjunction with geophysical surveys conducted at the surface (see *B 1.2 Surface Geophysical Surveys*) provide the first basic insight, preferentially on the structure and lithology of the basin. Although the drilling of several km-deep exploration wells is expensive, they provide the only sources on which the reservoir lithology and related reservoir performance can be sufficiently investigated.

First attention in geothermal exploration needs to be drawn to the temperature at depth as this parameter decides the type of geothermal use and the cost of drilling. If borehole temperature data (logs and/or BHTs, e.g. Förster, 1999) are available only from shallow depth (where temperatures of hydrothermal fluids are too low for a geothermal use) or are from locations outside the target area, temperature profiles need to be extrapolated from one area to another or calculated for greater depth using data on surface heat flow (e.g. Norden et al., 2008, Blackwell et al., 2006). The surface heat flow therefore is an important parameter on which the geothermal potential of an area can be quantified. To determine a reliable heat flow value in a heat conduction/diffusion domain a high-resolution temperature log as well as values of thermal conductivity of the logged section are necessary (e.g. Fuchs and Förster, 2010).

Boreholes also provide the first information on the structuring of the sedimentary sequence and, if abundant, also on the areal extent of geological formations being perspective as geothermal reservoirs (e.g. Feldrappe et al., 2008). This information, usually integrated with seismic data, can be shown by maps, cross sections or 3D models. Examples on how this information is provided are given in Hurter and Haenel (2002) in the Atlas of Geothermal Resources in Europe.

Borehole analyses (cores, logs, tests) add important information on the hydraulic parameters of perspective reservoirs, which are the effective porosity and permeability (e.g. Wolfgramm et al., 2008). Again, this information is responsible in decision making with regard to the type of the geothermal use (e.g. hydrothermal versus EGS). In sedimentary basins of high porosity/permeability, the general hydrogeology should be investigated and the major fluid flow directions and velocities delineated. High fluid velocities can essentially overprint the conductive temperature field resulting in temperature anomalies other than those caused by the geological structure and different thermal conductivities of the geological formations.

Mineralogical and geochemical analyses of the reservoir rock as well as an analysis of the chemistry of reservoir fluids should be available (e.g. Wolfgramm et al., 2008) in order to assess the fluid-rock interactions that may occur if the physico-chemical conditions of the reservoir will change over time.

Data on the regional and local stress/strain field are necessary if the reservoir/formation needs to be artificially stimulated by the generation of fractures (e.g. Moeck et al., 2009). The same applies to the mechanical properties, on which the design of frac operations is based (e.g. Zimmermann et al., 2010).

Thermal conductivity and thermal resistivity (e.g. Norden and Förster, 2006; Fuchs and Förster, 2010; Hartmann et al., 2007) as well as hydraulic rock properties from laboratory measurements of cores and from the analysis of well logs play an important role in models that address the life-time assessment of a reservoir during operation (e.g. Blöcher et al., 2010).

Based on the available data and the gained geological understanding of the site, the set-up of an integrated geological model (*D.1.1 Geological Models (static modelling)*, p. 48) is recommended.

B 1.2 Surface Geophysical Surveys

Geophysical methods can provide important data in the exploration of sedimentary geothermal reservoirs (Table 1, p. 37). The methods aiming at imaging the underground provide different information at different resolution and scale. The methods comprise conventional geophysical surveys (e.g. 3D seismic imaging developed in the hydrocarbon industry) as well as unconventional exploration methods.

Electrical methods

Geothermal reservoirs representing volumes of rock filled with fluids may be identified by the electrical resistivity measured the surface (Bruhn et al., 2010). The electrical resistivitiy of a rock volume is strongly temperature dependent, increasing by more than one order of magnitude when temperatures are raised from room temperature to 200 ◦C (Yokoyama et al., 1983). One approach to be applied in the exploration of hydrothermal systems is the measurement of electrical resistivity in the subsurface by applying an electric potential to two electrodes driven into the ground separated some distance from each other (*direct current* [DC] method). The effective probing depth is related not only to the spacing between the current electrodes but also to the distribution of different resistivities in the ground. Different electrode configuration settings (Wenner or Schlumberger electrode configuration) and the usage of dipole sources (dipole-dipole or bipole-dipole arrangements) enables reasonable resolution down to depths of 1000 to 2000 m (Lumb, 1981). Today, DC tomography techniques are more commonly applied in geological settings where the geothermal reservoir is not capped by evaporitic successions (Bruhn et al., 2010).

Elelectromagnetic (EM) soundings have been used in several fields and settings. In contrast to the DC methods, the depth of penetration could be varied by altering the signal frequency and without changing the geometry of the instrumental set-up. Most EM techniques use a controlled artificial electromagnetic source as a primary field that induces a secondary magnetic field. EM methods can be used in the exploration and monitoring of circulating fluids within the reservoir or along faults and thus provide important information about geothermal activity and fluid migration (Bruhn et al., 2010). In practice, the maximum depth of application is usually between 2 and 3 km. The EM methods are often combined with magnetotelluric surveys to enhance resolution and help to determine the resistivity pattern of the uppermost kilometer, defining constraints for the interpretation of the magnetotelluric data for deeper formations (Bruhn et al., 2010).

Magnetotelluric (MT) methods, in contrast to EM methods, use the earth's natural electromagnetic field as source signal to measure the natural EM wave field to extract information on the resistivity variation in the subsurface. MT methods are able to probe depths of several tens of kilometers to investigate the deeper geological setting (running in a low frequency method). The goal of any MT interpretation is a representation of true resistivity with depth, either by forward or inverse modeling. Forward modeling codes can resolve 1D, 2D, and 3D structures by creating a synthetic cross section of the subsurface, computing its MT response, and then comparing it with the actual MT data, using the time-consuming trial-and-error approach (Bruhn et al., 2010). Inversion codes also exist and have been used routinely for computing 1D and 2D responses. 3D inverse codes, even though they have been available for some time, are mostly still in the development stage. Main problems of the MT method exist with noise in the measurements and the lack of an adequate interpretation. These problems are tried to overcome with improvements in data collection, data processing, and three-dimensional numerical modeling. Although inverse modeling results in a good data fit, the results are ambiguous. Thus, the MT data can just give an estimate of resistivity variations with depth, but will not have the resolution of seismic sections (Bruhn et al., 2010). An example of joint interpretation of magnetotelluric and seismic tomography models is provided by Munoz et al. (2010).

Another disadvantage of the MT methods is that they cannot distinguish between mobile fluids and immobile fluids, as they occur in claystones. Below evaporates (e.g. salt), it is almost impossible to detect a geothermal reservoir. On the other hand, MT methods could help in the detection of connected of reservoirs and in the detection of the fluid content if the fluid id of high salinity (=low resistivity). In general, MT methods are widely used in geothermal exploration but must be analyzed together with a well constraint geological model of the site (Bruhn et al., 2010).

The biggest problem in the applicability of any EM method are the noise sources as power lines, pipelines, and DC trains among others that disturb the geophysical signal.

Seismic methods

Seismic methods are well developed as a standard exploration method for hydrocarbon exploration. They can provide the most detailed structural information at depth. Seismic methods can be divided in active seismic methods (using body waves created by artificial sources) and passive seismic methods (using natural sources or induced rupture processes like hydraulic fracturing). Both methods determine subsurface elastic properties influencing the propagation velocity of elastic waves: as the waves travel through the subsurface, wave velocities change depending on the density of the rock, and wave paths are reflected and refracted by elastic discontinuities such as sedimentary layering, boundaries between different rock units, and fractures. Two basic types of seismic waves are of interest in exploration of subsurface resources: P-waves and S-waves. In *active seismic* surveys, the elastic waves are generated by explosions or weight drops. Seismic resolution decreases with depth as the velocities normally increase and high frequencies are lost due to absorption. So, the smallest features to be seen on a seismic diagram are still large at the surface outcrop scale. A subsurface structure of interest can be imaged with the transformation of the acquired data from the timescale, to the depth scale. Depth conversion is ideally an iterative process. Good seismic processing, seismic velocity analysis, and, if available, information from wells in the area are required to refine a conversion. Fractures, higher temperatures, and the presence of fluids cause a decrease in *v*p and the ratio *v*p/*v*s (Bauer et al., 2010).

The interpretation of seismic data set can shed light into the local fracture trends and may even locate the fracture zones. 3-D seismic imaging is a powerful tool to resolve complex geological structures, to identify faults and fractures with adequate precision, and to obtain 3-D structural models of use in the identification and assessment of geothermal resources (e.g. Lüschen et al., 2011). The main problem is that seismic data is sensitive to acoustic impedance contrasts; different types of fluids and/or variations of temperature may have little effect on those. A joint seismic and EM imaging and inversion approach could circumnavigate this problem.

The *passive seismic* method uses naturally (or induced) seismicity. In tectonic not active sedimentary basins, sources for the passive seismic monitoring may be related to the collapse of caverns, or to microseismicity related to fluid injection. Passive seismic experiments need a long recording time and a dense network. Therefore, passive seismic are not an often exploration method in low-enthalpy sedimentary basins.

Summary

The diversity of geological settings that host geothermal resources requires a variety of exploration methods. There is no uniform geothermal exploration method. The applied exploration strategies are rather site specific and best performed using a combination of methods (Taylor, 2007). Often, a fair amount of existing hydrocarbon exploration data may be available and could be revisited and re-used for geothermal assessment. Borehole data can provide direct access to the underground and may together with geophysical surveys already allow for drawing a clear picture of potential geothermal reservoirs. Technical drilling reports may give special clues for water-bearing or permeable horizons (water in-flow or drill mud losses), and borehole measures of lithology, porosity, and temperature reading logs may also allow to estimate thermal and petrophysical properties of the rocks. Based on temperature measurements and core-measured thermal conductivity, heat flow could be calculated at a specific site. The heat flow and the temperature log information could be used (if the temperature profile is undisturbed) to calculate formation thermal conductivity indirectly for the reminder of the section, devoid of laboratory values. In low-enthalpy sedimentary settings, a proper characterization of the reservoirs and the intermediate layers are of most relevance. Beside the spatial characterization/exploration (e.g., 3D seismic, magnetotellurics; Table 1), the representative parameterization of geothermal reservoir properties may often be most important to enhance planning reliability. A proper characterization is performed on the required scale of investigation and should use all available data, combined in integrated geophysical and geological models. Joint interpretations of geophysical data sets and/or geophysical-hydrothermal data sets do help to produce more realistic estimates of the rock and hydrothermal properties (e.g. Muñoz et al., 2010). Joint inversion methods are configured either as a coupled inversion of geophysical and hydrological data or as a coupled inversion of multiple geophysical data.

For the successful assessment of geothermal reservoirs, a precise knowledge of the subsurface conditions is necessary. In order to address different tasks related to different scale levels in the assessment procedure, different subsurface model scales should be developed. Models on the basin, reservoir, borehole, and micro-scale are required to estimate geothermal potentials, environmental and (life-time) reservoir behaviour, and well path planning (see *D.1.1 Geological Models (static modelling)*, p. 48). The initial models are subsequently updated as new data becomes available. The geological models should be cross-checked with all available (jointly interpreted) geophysical exploration data and provide an integrated picture of the subsurface. Depending on the geothermal application aimed for, the geological model is the basis for optimized well path planning including risk assessment for borehole stability, for reservoir simulations and risk assessment for induced seismic activities.

Method	Characteristics
Self-Potential (SP)	Electrodes placed in contact with surface at a number of survey stations—from these stations measurements of natural subsurface electrical potentials are taken. Most useful when shallowest groundwater flow is of interest Relatively inexpensive
DC Resistivity, Electrical Resistivity, Vertical Sounding	Electrical currents are sent into the subsurface creating voltages by which resistivity and its inverse, conductivity, can be measured Resistivity depth is directly proportional to distance between surface electrodes Resistivity methods very widely used; much data from previous studies already available
E-Scan	E-Scan is somewhat commonly used and relatively new proprietary method of DC resistivity Not always cost-effective, especially for large prospect areas
Time Domain Electromagnetics (TDEM)	Electrical signal from artificial circuit placed on surface creates magnetic field—over time, field transmits deeper and deeper and dies-out depending on conductivity of subsurface geology TDEM has no static distortion
Magnetotellurics (MT)	Measure subsurface electricity created by naturally occurring magnetic fields (magnetic fields caused by lightning, solar winds, and ionosphere Indirectly detects temperature and permeability patterns by imaging the resistivity pattern associated with temperature-sensitive clay alteration Can measure tens of kilometers deep Can be used to develop 3D images of subsurface (reliability and resolution are matters of some concern) Very commonly used Said to be cost-effective
Controlled Source Audio-Frequency Magnetotellurics (CSAMT)	Similar to MT, but uses a man-made signal source Lower cost than MT and works near power lines Used for measurements of relatively shallow depths: 20-2000m
3D Seismic Tomography	Seismic waves are directed into the subsurface using sources such as explosives or vibrators. Waves that are reflected off of subsurface structural features are recorded, rendering a 3D image of the subsurface. Used very commonly in geothermal, as well as oil and gas exploration Few well targeting success case histories are published Among the more costly geophysical surveys
Passive Seismics	Long recording period Only useful if seismicity could be expected (in low-enthalpy sedimentary basins: man-made events like hydraulic fracturing)

Table 1: Geophysical exploration techniques (modified after Taylor, 2007).

C. Drilling

The bivalent challenge of geothermal drillings is to access the reservoir with minimum drilling-induced formation damage (i.e. permeability impairment) at minimum costs. This generally requires excellent data of the reservoir which may be cost-intensive to derive from a short-time point of view, but be economically profitable from the long-term perspective as the data will reduce drilling and exploitation risks. Especially in the low-enthalpy geothermal setting, when deeper wells are necessary to achieve higher (moderate) temperatures, the drilling costs play an important economic factor for the site development. According to Sperber et al. (2010), geothermal drillings can be even more expensive (in cost/depth) than onshore oil and gas drilling for two principal reasons:

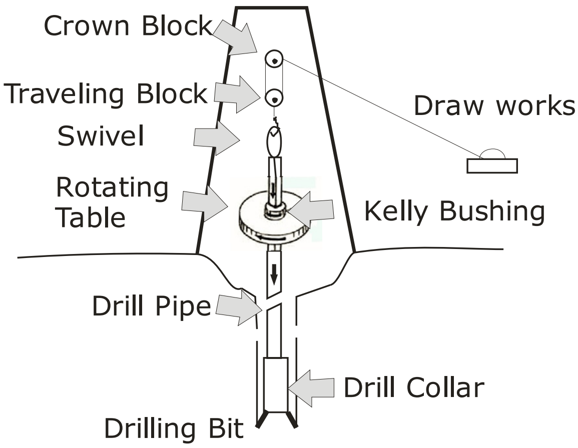
1) Technical challenge: Geothermal reservoirs may host highly corrosive fluids of higher temperature in great depth, which can require special tools and techniques suitable for the harsh downhole conditions.
2) Large diameters: Because the produced fluid (hot water) is of intrinsically low value, large flow rates and thus, large holes and casings, are often required.

Drilling means the interaction of geology and engineering, of rock material and techniques (Sperber et al., 2010). Cost reductions can be obtained by minimizing drilling failure risks due to a better understanding of the geological-technical risks related to the geological setting before drilling, by choosing optimized drilling techniques and tools, and by optimized planning of drilling operations.

C. 1.1 Drilling-related equipment and technologies

The following section summarizes the main equipment and techniques used in geothermal drilling as described by Culver (1989) and Sperber et al. (2010). The drilling techniques differ due to the variety of drill rigs as well as how the rock fragments (drill cuttings) are shifted from the bottom hole to the surface. For targets close to the surface, mobile drilling rigs, mounted on trucks or truck trailers, may be used up to depths of 100 to 1500 m. For deeper wells, bigger rigs are necessary. Drilling rigs are classified based on their attributes: e.g. drilling method or height of the rig. Cable-based drill rigs use a cable to lift and drop a heavy bit repeatedly to crush and break the formation. This type of drilling is very time consuming; depth and penetration rates are limited (Culver, 1989). The method can be used for drilling vertical holes only. Due to these disadvantages, the more common methods are rotary or top drive drilling (Sperber et al., 2010). In rotary drilling, the drill bit, usually a tricone roller, is rotated by the hollow drill collar and drill pipe. Torque is applied through the rotary table and the kelly (Figure 18a). Drilling fluid (mud) is circulated down the drill pipe and out openings in the bit where it cleans cuttings from beneath the bit, cools it, and carries rock cuttings to the surface. Rigs with top drive use a hydraulic or electric motor (Figure 18b) that travels up and down the mast, applying torque directly on the drill pipe. Often, a rotary table is installed as a backup for the top drive.

a)



b)

Figure 18: Rotary drilling. a) Rotary Table , b) Top Drive (Photo by B. Norden).

Drilling fluids can be water, mud (water with additives such as bentonite, polymer, KCl, $CaCO_3$, etc.), air and water (mists), air, or air and water and foaming agents (Culver, 1989). Oil-based mud is mainly used in extremely water-sensitive formations to ensure good borehole stability even under adverse situations (Sperber et al., 2010). The adequate mud composition and pressure plays an important role by drilling creeping formations like salt and clay formations. Using a very low mud pressure, these formations tend to decrease the calliper, whereas washouts could be produced by choosing a very high mud flow. All drilling fluids should meet the demands of cooling the bit and transport of the cuttings up the hole. In addition, the drilling fluid can also stabilize the hole, minimize the formation fluid invasion into the hole, and minimize the drilling fluid losses to the formations. The drilling fluids lubricate mud pump, bit, and the annulus between drill string and the hole, reduces drill string corrosion, and has to be considered for the conduction and interpretation of borehole logging. In *conventional circulation*, mud pumps are used to circulate the drill mud through the standpipe, drill string, and the bit down to the borehole and in the annulus between the drill string and the borehole wall back upward to the surface. The pumps equipped with strong engines are the main power consuming machines of a drill rig because they have to circulate the mud with high pump rates and high pressures. The drilling mud is re-conditioned at the surface before being circulated again. This is done by shale shakers with screens, hydro-cyclones (desander, desilter), and centrifuges to remove ultrafine solids. When drilling with mists or air, large compressors have to be used and the mud tank or pit, used in the water-based drilling, is replaced by a cyclone-type separator. In contrast to the conventional circulation, in the *reverse circulation*, drilling fluid flows down the annulus and up the drill pipe, lifting the cuttings inside the pipe that has a smaller cross section than the annulus. It has some severe disadvantages (see Culver, 1989: could require a large amount of water; annulus fluid must be under high pressure to create lifting capacity inside the drill string thus pushing under-pressured geothermal fluid into the formation; geochemistry of geothermal fluids can be changed), so this type of circulation is not recommended for geothermal drilling. The mayor handicap of this circulation method is that it is suitable for drilling at shallow depths only (to depths of up to 150 m).

Drilling in gas bearing formations, safety reasons require a *blowout preventer* (BOP, Figure 19). In case of a gas kick, the preventer can close the borehole completely, even if any pipe is in the hole. The BOP often consists of several sub units, which are built of ram or annular BOPs. A ram BOP used horizontally opposed hydraulic rams that can be fitted out to close around the drill string, to shear through the drill string and then seal, or to close off a wellbore when no drill pipe or tubing is in it. The annular BOP closes with hemispherical rubber elements around the drill string, allowing under some circumstances to move the drill string vertically while pressure is contained below. A special high pressure accumulator closing unit is needed for doing this.

Figure 19: Blowout preventer unit of a drill rig in Ketzin (Photo by B. Norden)

The *drill string* used for drilling consists of the *drill pipe* and the *bottom-hole assembly*. All elements are hollow to allow circulation of drill mud through them. The drill pipe is constructed to transmit rotation and torque from the surface to the bit and to pipe the drilling fluid. The drill pipe is thin-walled and has only low bending stiffness. The bottom-hole assembly consists of the drill bit, drill collars, stabilizer, a jar, a shock sub, and heavy wall drill pipes. *Drill bits* are available in very different designs (Figure 20). *Rollercone bits* are available for every rock type and have three conical shaped rollers, which are equipped with teeth of steel or tungsten carbide. The rotating bit crushes the rock when the rollers roll on the bottom of the hole. The teeth or insert size decreases for harder rock while the total number increases. *Polycrystalline diamond compacts* (PDC) bits have fixed cutters distributed to three and more blades. They are preferred in soft to medium rock formations. *Diamond bits* are used for very hard rocks. They are available in two different types: surface set (diamonds fixed in a matrix body) and impregnated (diamond particles are embedded into the matrix material). The second type gives a more constant “rate of penetration” (ROP), whereas the first one slows more down when the exposed diamonds are losing their sharpness. *Drill collars* are thick-walled pipes giving high “weight on the bit” (WOB) to assure penetration of the bit cutters into the rock. *Stabilizers* are used to centralize the drill collar in the open hole. A *jar* is a tool to deliver an impact load to another downhole component (e.g. drill string), especially when that component is stuck. By pulling the free part of the drill string into tension, energy is stored in the drill string and suddenly released by the jar when it fires. A *shock sub* damps axial vibrations from the drilling process by rubber elements or hydraulic fluid dampeners. Heavy wall drill pipes can withstand some axial load due to a thicker wall than the normal drill pipe and are used to keep a well vertical (Sperber et al., 2010).

Figure 20: Drill bits (PDC bit, roller bit, and different core bit units (Photos by B. Norden)

Directional Drilling

In general, drilling a well is kept as straight forward and simple as possible. For most of the direct-use geothermal application, a vertical drilled well is often preferred because well completion and installation of pumps are easier and more economical. However, especially in urban environments, several reasons may exist to plan a directional drilling. Reasons could be the necessity of drilling several wells from one drill site or the intention to drill in a direction which will enhance productivity (e.g. by connecting hydraulic active fault systems).

In addition to the drilling equipment listed above, devices are needed to direct the drilling in the planned direction. This can be performed by using a downhole motor (DHM) which consists of a rotor which is connected via a flexible joint to the drill bit and driven by the pumping drill mud, and a stator connected to the drill string. This stator allows defining the inclination of the drilling. It is constructed in a way that the DHM will deviate the borehole direction into the specified direction as long as the drill string is not rotated; if the drill pipe is rotated slowly no preferred direction is given anymore and the trajectory will be (more or less) straight. DHMs show a better rate of penetration (ROP), they are therefore sometimes used instead of a rotary/top drive system although they are available at higher daily costs. A cost-expensive alternative are the rotary steerable systems (RSS). Here, the whole drill string is rotated and the bit direction is controlled by stabilizers and a bent housing. A DHM is still part of this system.

To have control on the borehole trajectory, a downhole measuring system (measuring while drilling, MWD) with a signal transmission unit (pulser) is a fundamental part of a directional drilling system. Sensors for borehole inclination and borehole azimuth, but also geophysical logging parameters (like gamma-ray or resistivity) are sometimes included. Measurements occur when the drill string is not rotated and sent via a magnetic valve data pulser through the down-flowing drill mud inside the drill string to the surface. The pulse pattern is deciphered at the surface and the data evaluated in specialized software applications which allow the accurate planning of the well trajectory.

Coring

Core drilling (coring) is basically an exploration method enabling to study the subsurface directly. Coring is more expensive then drilling because of longer drilling times. Often coring and logging is often seen in direct rivalry. However, it should be clearly stated that all geophysical logging methods are indirect measures of rock/formation attributes, only the rock itself enables a direct investigation. Two different techniques are used for the drilling of core: the wireline coring method and the spot coring method. In *wireline coring* procedures, hollow drag-type bits (Figure 20) are rotated by the drill rod. A core barrel (a pipe with grips to hold the core) is lowered insight the rod by means of a cable, and over the core being drilled. When the barrel is full, it is pulled out and replaced with another, while the core is removed from the barrel. This method requires adequate drill pipes, enabling the core barrel to travel insight the pipes up and down. A benefit of this method is that it enables a relative fast coring for longer distances as there is no need to pull the whole drill string out of the hole. In conventional *spot coring*, the drilled core is housed in an inner barrel, which is in a drill pipe. Typically, cored sections are 9, 18, or 27 m long. To recover the core, the whole drill string must be dismounted.

Logging

A core-based log interpretation enables a proper site characterization. Items of interest are: stratigraphic correlation and lithology determination, correlation with cuttings and geophysical surveys, and formation evaluation (like determination of porosity, permeability, fault and fractures, and the fluid salinity). Technical borehole measurements necessary for checking borehole integrity or the calculation of cement volumes for the cementation of casings include the measurement of the borehole diameter (*caliper log*) and *mud parameters* (especially temperature and pressure). Geophysical logging performed in the open-hole section often include: (spectral) gamma ray, gamma density, deep and shallow reading resistivity, sonic velocity, and neutron porosity.

The *standard gamma ray* measures the total natural gamma activity of potassium (K), thorium (Th) and uranium (U), while the *spectrum gamma* measures the natural gamma activity in the three distinct energy windows for these elements. The spectrum gamma is more meaningful for the lithological interpretation because the three elements are related to different minerals or geological environments. For example, the amount of K-feldspars, sylvinite and a subset of clay minerals determines the K concentration. Th is frequently existing as adsorbed layer on the internal surface area or related to certain minerals, which often show also a high U content. U is most often related to organic components or to crystalline rocks.

DOI: 10.2312/GFZ.b103-11066

The *gamma density* is measured by the absorption of gamma rays which are actively sent into the formation. Both Compton effect and photo effect are influencing the response, and by discrimination of the prevailing energy windows the Compton effect is used for electron density measurements and the photo effect (PEF) for a rough estimation of the mean atomic number. Density is used for lithological analysis, porosity determination and seismic interpretation (acoustic impedances). Together with the spectral gamma ray the PEF and density logs are most significant parameters for the discrimination of different lithologies.

Resistivity of the rock is measured most often with different depths of penetration (shallow and deep resistivity), enabling filtration analysis and an estimation of permeability. Resistivity readings depend strongly on the porosity and water (brine) saturation of the rock as it is the case for acoustic readings.

The standard *sonic* tool measures the borehole-compensated P-wave velocity. P-wave velocity (and density logs) may be used for the correlation and interpretation of seismic field data and for porosity estimations.

Neutron porosity is determined by the absorption of neutrons caused by inelastic scattering at hydrogen nuclei. The reading measures the amount of hydrogen atoms and thus mainly the water content of the rock, although some interferences with some special minerals, chlorine and some other elements may occur. The main disadvantage is the need for a neutron source requiring safety precautions.

Further logs enable a more detailed characterization of the formation (at additional (higher) costs): *highly resolved resistivity measurements* or *borehole* acoustic *televiewer* (BHTV) measurements could produce high-resolution image logs for the detection of inhomogeneities, laminations, and fractures down to the mm scale. They can be used for sedimentological and tectonic analysis and thus for lateral prediction of geological structures. Whereas the electrical methods need a direct coupling to the formation, the BHTV does not need this requirement and can receive high resolution in large calipers. However, in weakly consolidated sediments, the acoustic contrast is often not sufficient and the electrical methods are often more significant. The *nuclear magnetic relaxation* of protons that are excited by a high-frequency pulse is measured by the NMR log. Depending on their bonding, water protons adsorbed on surfaces and in thin capillaries are relaxing much faster than protons in free water or in large pores. The integral signal is caused by the total amount of protons and thus yields the water content. The primary result of the NMR measurement is the water content and the radii distribution of sites containing water. By petrophysical modeling this radii distribution yields a rather significant estimate of permeability. Another quantity which can only derived with NMR-logging is the distinction of the amount of surface bound water, capillary bound water, and free pore water.

Well completion

Casing materials, thickness for various diameters, and other specifications must meet the demands of the site-specific geology (borehole stability) and the applicable local and state regulations. The *casing string design* is also related to the used casing material: thermoplastic, fiber glass, and steel are possible choices. Steel is most often used. By planning the casing and cementation of the well, the effect of thermal expansion or contraction of the steel should be considered (Sperber et al., 2010). In addition, collapse pressure must be regarded which may be highest during the cementing procedure (Culver, 1989). All steel casings are in danger to corrode, especially if air (oxygen) is allowed to get in contact with the formation water. Sealing the top of the casing and any openings as well as increasing the wall thickness will increase well life. Casing is normally run with centralizers or centering guides to assure that all voids are filled and channeling does not occur during cementing. For cementing, Portland cement is the most common grouting material. Depending on the borehole stability, the geothermal target (reservoir zone, "pay zone") is connected to the borehole with a slotted or predrilled *liner* or without a liner. The latter is called *barefoot completion*. This is the preferred option if there is no risk of borehole collapsing because it enables the lowest flow resistance. At the top of the casing, the *wellhead* is situated. The wellhead is screwed-on or welded to the anchor casing. Depending on the number of surface casing strings additional flanged parts may be added on top of the each other; also a hanger may be needed for the pump string or an injection string. Normally each annulus between the casing strings can be accessed through valves which are mounted onto the side outlets. A *Christmas tree* is part of the wellhead and comprises valves, a choke, and several connections. It is the key part for the controlled access to the fluids and ensures the safety of the facility. The well completion consists of the casing, an annular seal or production packer, which does isolate the casing from the pressure in the well and from fluid contact, the *tubing* (production tubing, injection string), and downhole valves and landing nipples within the tubing. In the case that the water has to be pumped to the surface, downhole pumps need to be installed, too.

C. 1.2 Geological-technical drilling risks

As stated by Sperber et al. (2010), drilling problems mostly arise from unexpected geomechanical behavior of known or unknown formations or if drilling technology is insufficiently matched to known geological conditions. For deeper wells, the rock mechanical understanding and geomechanical modeling will help to identify risk zones and to quantify rock failure under certain conditions. Stability problems may arise due to borehole break-outs, cavings, and washouts which may be induced by too low drill mud pressures. The squeezing and creeping of salt-bearing formations is increased at higher temperature conditions and a thick overburden (i.e. at deeper drilling depths, for rock salt in the Northeast German Basin below 2000 m; Sperber et al., 2010). Swelling formations (clayey formations) could also produce drilling or casing failure. To avoid this, the drill mud could be conditioned in a way that the clay minerals do not swell (e.g. potassium inhibitor). Massive to total *loss of circulation* (LOC) can occur in high porous rocks and highly fractured or karstic rocks. When circulation is lost, the drilling mud could no longer fulfill its function and cuttings are no longer transported to the surface. This may result in stuck pipe and possible lost of the bit, collars, part of the string and perhaps of the hole. To avoid this scenario, *lost circulation materials* (LCM) are added to the drilling mud. They should build a bridge across openings in the formation, enabling the development of a filter cake. Organic and inorganic materials are used as LCMs like sawdust, chicken feathers, walnut shells, hog hair, mica flakes, plastics, etc. Gas kicks can occur when gas-bearing high pressure zones were encountered during drilling. So called *keyseats* (smaller diameter along a short distance in the hole, e.g. in alternating sequences of harder and softer rock types) could cause getting the drillstring stuck by hindering the bottom hole assembly to went through this narrowing. Another way getting the drillstring stuck is by *differential pressure sticking*. This can occur by overbalanced drilling and when the drilling mud forms a thick filter cake at the borehole wall. The differential pressure presses the DCs into the filter cake, and if the contact area is large enough the string gets stuck due to the high-contact forces. The risk of getting stuck is higher when the drillstring is not moving. The respective general tendency of different lithologies to enable drilling problems is listed in Table 2.

C. 1.3 Well planning

The costs for the subsurface part of a deep geothermal project are often higher than the costs for the surface installations. Therefore, an integrated approach should be chosen, considering the geological situation and the engineering capabilities. The goal should be to develop a site-specific integrated concept (expected reservoir characteristics - geothermal water demand - plant engineering - costs) to increase the chance of an optimum total economic development of the geothermal site. In detail, the well orientation may become a very important factor for fluid flow if projects in low-permeability settings want to succeed. Here, it may be of utmost importance to orient the drilling path in a way that the well is connected to potentially open fracture or fault systems, thus enhancing the productivity of the well. The decision on the well completion should be done in a very early phase during the planning of the well. Borehole size does play an important role for the total drilling costs. Here, it should be deciphered to which depth which diameter is needed, e.g. for installing downhole pumps etc. A planning tool, used in industry, is the so called "*drilling well on paper*" (DWOP) workshop. Here, all details of the drilling and well completion procedure are discussed, together with representatives from all participating parties (reservoir engineers, drillers, cement crews, facility engineers, chemists, geologists, casing crew, etc.). Such a meeting requires a profound preparation and may be repeated on different detail levels. The dissemination of expertise knowledge, looking beyond one's own nose, is helping to avoid conceptual, technical, and logistical failures. During such a meeting, competences should be clarified and responsible persons authorized to assure fast decisions when drilling is performed in reality. During drilling, new and unexpected structural geologic/stratigraphic results may be achieved. Therefore, real-time correlation must be systematically planed in advance, key marker beds and decision points predefined.

DOI: 10.2312/GFZ.b103-11066

Lithology	Risk of Wash-outs	Sand production	Caving / breakouts	Collapse	Swelling	Creeping	Lost circulation	Gas kick
Sandstone		XX	XXX	X			XXX	
Siltstone		X	XX	XX			X	
Mudstone			XX	XXX				X
Claystone	X		XX		XX			
Unconsolid. Sand	XXX	XXX						
Clay / salt	XX				XXX	XXX		
Marl	XX		X					
Limestone			XXX	X			XXX	
Shale			XX	X	XX			XXX
Schist / phyllite			XX	X	X			
Gneiss			XX				X	
Granite			XXX				XX	
Basalt			XX				XX	

Table 2: Drilling risks related to geology (Sperber et al., 2010)

Horizontal Wells and Multi-well settings

The drilling of horizontal instead of vertical wells may be an option to increase water flow volumes in thin or only vertically fractured reservoirs. To ensure sustainability, it should be considered that the groundwater recharge rate compensates the production rate. Therefore, a well doublet installation of two horizontally drilled wells may become necessary, especially in low-enthalpy areas and where in addition no substantially topographically driven groundwater flow may be observed. They have to be located in an appropriate distance from each other, most likely requiring different drill sites and therefore causing higher costs. As horizontal drilling requires adequate techniques for the monitoring of the drilling progress and control of the well path, horizontal wells are in general more expensive than vertical wells. In addition, the completion of the well has to be chosen according to the geological setting. There are, however, situations where the investment into horizontal wells may be worth it. There is no general rule as every geothermal project is different. Decisions are triggered by the political and economical framework, the (geological) risks of the project, and possible investment alternatives that may compete.

In order to increase flow rates, multi-well designs, e.g. with hexagonal or five spots patterns of (vertical) wells, may be realized for heat-transfer maximization. The optimization of the number of wells includes several constraints which depend crucially on the target depth and hence the individual costs for drilling, the initial productivity of the reservoir rocks, and the required costs for stimulation treatments to enhance this productivity (Schulte et al., 2010). For the successful implementation of a multi-well design for geothermal applications, two (conflicting) goals need to be considered: a) the pressure in the reservoir should not drop significantly during production (i.e. the distance between injection well and production wells have to be related to each other) and b) a thermal short circuit between the injector well and the production well(s) is not wanted.

D. Management of Geothermal Systems

Every project management is unique and restricted to the individual project dealing with the efficient usage of the financial, personal, and physical resources to reach the project goal: the efficient supply of energy (heat or power). The targets of the owner, the site characteristics, and the planned energy usage differ from one geothermal project to another geothermal project. The main tasks of the project management are to provide a project workflow, to coordinate project partners (to clarify partnerships and responsibilities), to work in the field of public relations and approval procedures, to enable a smooth and proper information flow between the groups participating, to check the schedule, and to provide an actual financial overview (including controlling). Quality management and a proper risk assessment are also mandatory for geothermal projects.

The management of geothermal systems normally has to assure that the geothermal site could be utilized as sustainable and economical as possible. A fundamental part of the management is an adequate reservoir and site characterisation. Reservoir models were used to reproduce or predict reservoir behaviour and to help in decision-making for the operation of the geothermal site. Often the geothermal system is complex and reservoir models need to be adjusted according to unforeseen reservoir behaviour which gives the chance of a better geological knowledge and understanding of the site. In the phase of operation, a coherent history matching of real production (and/or injection) data and modelled values give confidence to the applied reservoir simulation. In combination to the reservoir model, numerical simulations of installed surface facilities enable a close monitoring of the development of the geothermal site and a good check on the efficiency of the system. Based on the integrated analysis, several actions may be performed to optimize the productivity and the economics of the geothermal site. Figure 21 (next page) shows a flowchart of a combined, integrated sustainable reservoir management strategy.

D.1 Reservoir analysis

Whereas a characterization based on borehole logging data and core experiments gave the possibility to investigate the reservoir by up-scaling from the micro-scale to the reservoir-scale along the borehole profile, well-test data can give additional information on the spatial behaviour of the reservoir and possible reservoir boundaries. A conceptual model of the reservoir is important at every stage of the geothermal exploration and site development. The geologic model and the well test data are used iterative to develop an integrated model from which the production of a geothermal reservoir is planned.

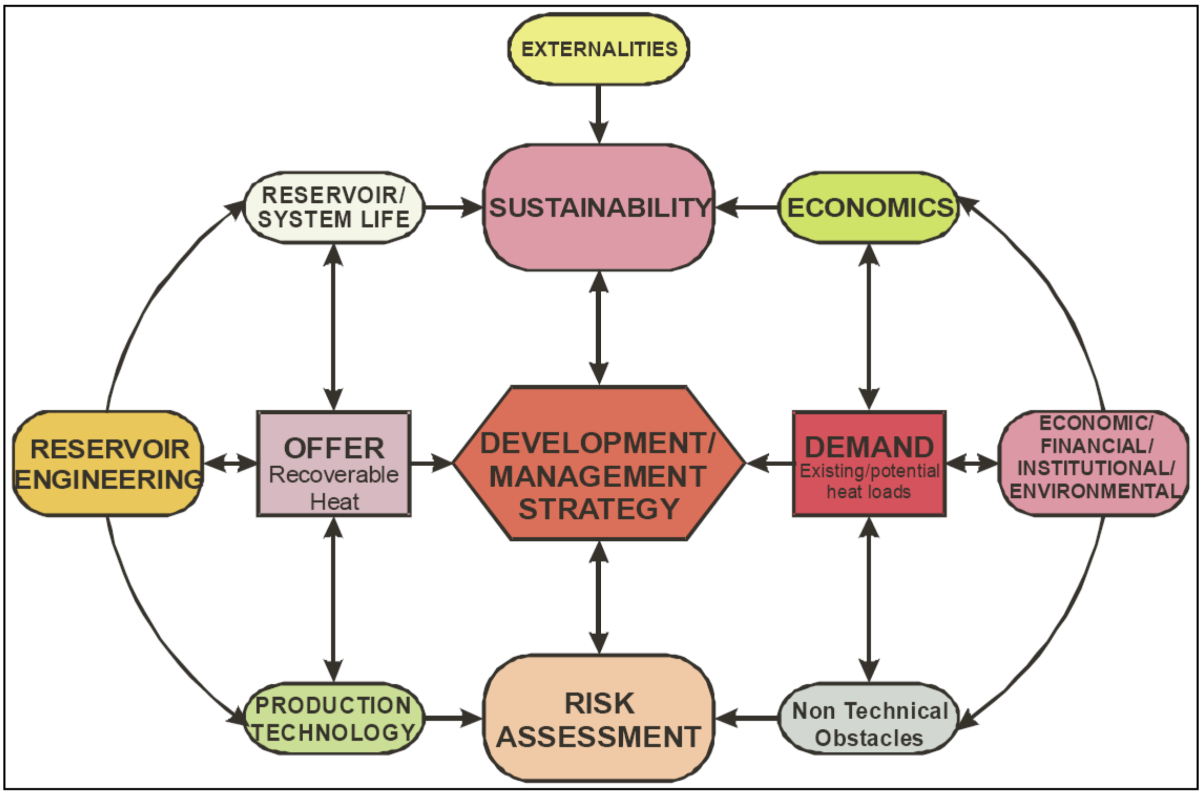


Figure 21: Reservoir management diagram (Ungemach et al., 2005)

D.1.1 Geological Models (static modelling)

Geological models hold a key-position for understanding the subsurface (Figure 22). 3-D models of the underground enable the consistent visualization of the mapped formations and reservoirs of a certain area corresponding to their (expected) depth position and their (expected) distribution. The conception and design of a geological model relies, on one hand, on the knowledge and data base available, and, on the other hand, also on the objectives of the modelling. In the beginning of the site development, the conceptual geological model will rely to a large extent on presumptions based on experiences from similar geological settings. Data collected before drilling is used to advise well location and drilling path(s). As the level of geological details increases, a refinement of the model will be performed according to the conditions of the respective, unique reservoir. In principle, the amount of geologic and well test data required to build a reliable geological model depends on the complexity of the system, the rapidity of change in (reservoir) properties in space, and the degree to which the reservoir will be produced relative to its maximum potential. The 3-D geological model represents also the basis for the simulation of dynamic processes which may interact with model conception if the simulation results give hints for further constraints of the geological model.

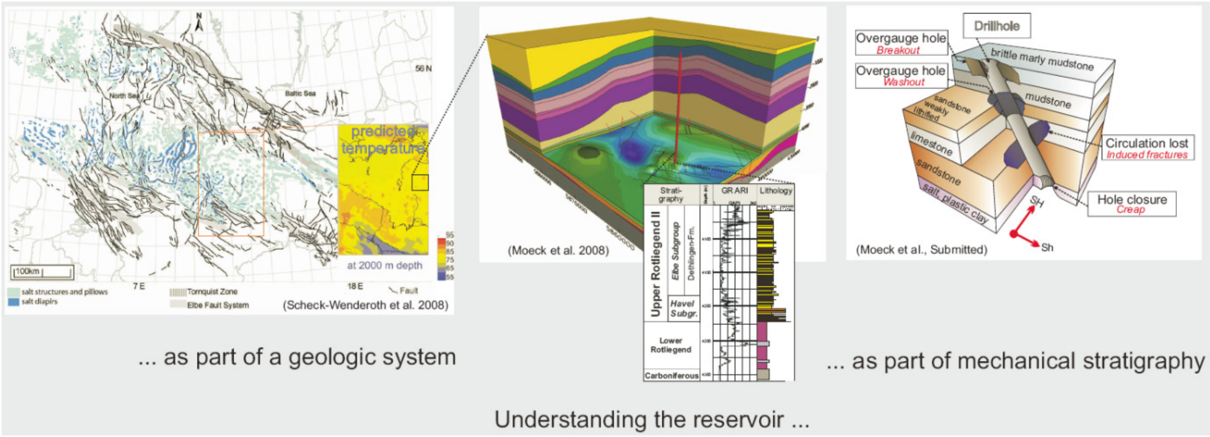


Figure 22: Geological models on basin, reservoir, and borehole scale (GFZ Potsdam)

A detailed mapping of formations and structures forms the basis of the 3-D model. It is based on well data, seismic data, and other data. Outcrop analysis studies can help to understand the general depositional system of a formation and to get a feeling for the possible spatial variation of (initial) petrophysical parameters (e.g. Pringle et al., 2006; Hornung & Aigner, 2002). If high resolution 3-D seismic data is available, it may be possible to deduce principal facies distribution patterns (e.g. flood plain – channel facies; see e.g. Carter, 2003). The indirect exploration methods require always a check up of their quality and informational value and their sensitivity (what has really been measured?). The consolidation of the available information (provided in different data formats) and the integrated interpretation resulting in one geological model is a challenging task. The generation of 3-D geological models is supported by special software packages, which do mainly originate from the oil and gas business. Software products are e.g. *Petrel* (Schlumberger) and the *Jewel Suite* (joa oil & gas B.V.), with special emphasis on seismic data processing but also containing geological modeling tools for the petrophysical-hydraulic parameterization of the model, *EarthVision* (Dynamic Graphics), *GoCAD* (Paradigm Geophysical), and *Surpac* (Gemcom). Like every reservoir represents a unique system, there is no software which is the best choice for all reservoirs. By means of these models, even the stress field can be determined, analyzed or characterized. The choice of the software depends among others on the data available, the expected complexity of the model, the purpose of the modeling, and how the interface to dynamic simulators is realized.

D.1.2 Well testing and reservoir evaluation

Well testing is a tool to provide the necessary data for the evaluation of the reservoir performance. First tests can be performed during drilling activities (normally short-time duration) to find the most productive horizon or to analyze the stress field (e.g. by extended leak-off tests for in-situ stress measurements, see e.g. Enever et al., 1996) of the site. For more reliable hydraulic testing results, the duration of the hydraulic test is normally much longer and can take months. Factors affecting the test duration include environmental constraints, fluid disposal considerations, equipment availability, money and pressure from investors (Stiger & Renner, 1989).

A common procedure in well testing is to vary the well flow rate (or establish a constant rate) which in turn disturbs the existing pressure in the reservoir. Measuring the pressure variation with time (in the well where the flow rate has been changed or in another well as it is the case in an *interference well test*) results in a data set which could be used in an appropriate mathematical solution to determine the hydraulic characteristics of the reservoir (transmissivity (and transmissivity-derived permeability), storativity, boundary conditions). The choice of the mathematical solutions needed depends upon the hydrogeology of the site (e.g. confined / unconfined aquifer, porous and/or natural fractured reservoir) and the completion of the well, i.e. the connection of the reservoir to the well. The design of the hydraulic test (and the test evaluation) will be specified according the purpose of the pumping test: for production or injection. The measured data should be cross-checked for consistency and necessary conversion factors applied. The data may also require corrections for the removal of external influences on the drawdown data like fluctuations due to barometric pressure, tidal fluctuation, and skin effects. Input data and graphs may use seconds or minutes for time, and the calculated *transmissivity* could be given in square meter per second (m^2/s) or in square meter per minute (m^2/min). A value for the *hydraulic conductivity* (κ) is obtained by dividing the transmissivity by the reservoir thickness (units: m/s or m/min). The *permeability* (k) as a property of the porous media could be calculated after $k = \kappa[(\rho g)/\mu]$ with ρ the density of the fluid ($kg\cdot m^{-3}$), μ the dynamic viscosity ($kg\cdot m^{-1}\cdot s^{-1}$), and g the acceleration due to gravity ($m\cdot s^{-2}$). The basic methods of well test analysis of confined aquifers are:

- Semi-log plots of distance vs. drawdown data after Thiem (1906) and Jacob (1946). The solution by Jacob and Thiem is valid for steady-state and transient conditions for homogeneous aquifers. However, it should be applied with care as the calculated transmissivity is strongly affected by heterogeneities.
- Type curve matching of distance vs. drawdown data and also time vs. drawdown data for observation wells after Theis (1935). The Theis solution is the most important analytical solution for well hydraulics because most other transient models tend towards it either for early or late times (Figure 23).
- Semi-log plots of time vs. drawdown data for observation wells after Cooper & Jacob (1946)

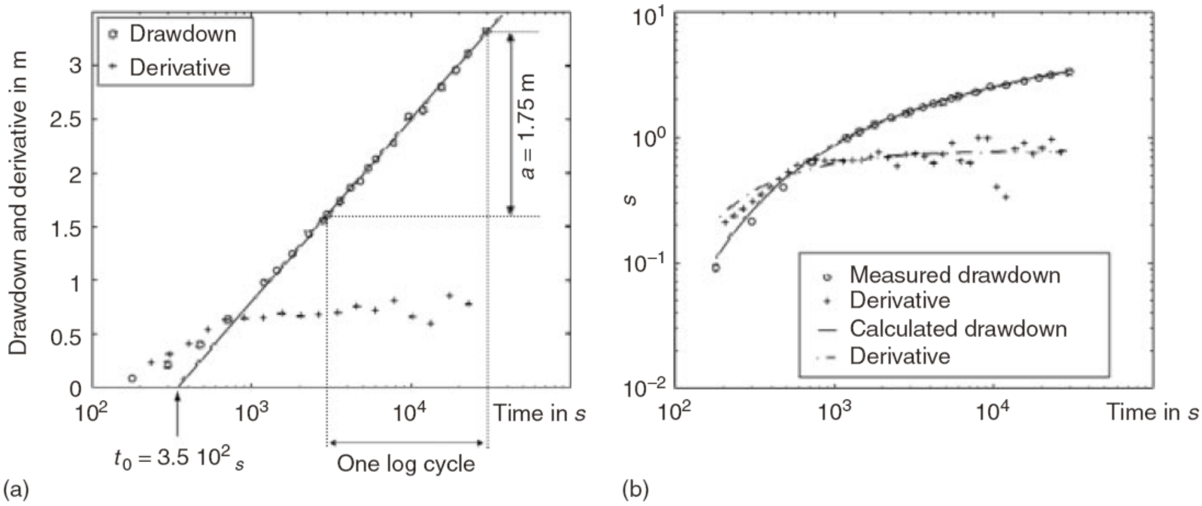


Figure 23: Interpretation of a well-test data set with the Theis method. (a) semilog plot of drawdown and derivative; (b) superposition of the data with the model after automatic fitting (Renard, 2005)

The mentioned methods are applicable for infinite aquifers (in aerial extent) which are homogeneous and isotropic and show a uniform thickness over the area influenced by the test. Other pre-conditions are horizontal groundwater flow (radial to the pumped well), the complete aquifer has been connected to the wells, the pumping rate is constant, water density and viscosity are constant. When some of the mentioned conditions are not met, it is possible to use other techniques to analyze the data. For heterogeneous aquifers, the study of Meier et al. (1998) shows that the apparent transmissivity of the transmissivity fields that they investigated is almost identical in all observation wells. However, the estimated storativities vary within several orders of magnitude as the apparent heterogeneity in storativity is a consequence of the heterogeneity in transmissivity. Therefore, such apparent heterogeneity in estimated storativity may be used as an indicator of the degree of heterogeneity of the transmissivity field (Renard, 2005).

According Renard (2005), testing procedures may be classified according to the type of perturbation and to the type and location of response monitoring as listed in Table 3.

The interpretation of hydraulic test data needs a proper understanding of the geological setting and should be performed in an integrated manner, as the test results are strongly related to the casing and well completion(s), the reservoir architecture, and the hydraulic test settings (e.g. Wiese et al., 2010).

Well test	Testing principle	Possible information
Single well test	The perturbation and the monitoring are conducted in the same borehole.	
Interference test	The perturbation and the monitoring are conducted in separate boreholes.	Communication between wells, reservoir-type behavior, porosity-compressibility-thickness product, interwell permeability, anisotropy of permeability
Pumping test	The aquifer is perturbed by pumping. It can either be a single well test or an interference test. Generally the pumping rate is constant, but variable pumping- rate tests can also be interpreted. An *injection test* is similar to a pumping test, but water is injected rather than being extracted.	
Step-drawdown test	A single well test with a series of successive constant pumping rates.	Pressure profile, reservoir behavior, permeability, skin, fracture length, reservoir limit and shape
Buildup or recovery test	It follows a pumping test. After the pump has been stopped, the recovery to the initial level is observed, either in the pumping well or in observation wells.	Reservoir behavior, permeability, fracture length, skin, reservoir pressure, boundaries
Constant head test	The head is maintained constant and the water discharge is recorded in the perturbation well. Head changes can be recorded in observation boreholes.	
Slug test	The perturbation is a sudden modification of the head in the well; the response is the head variation in the well itself or in observation boreholes.	
Packer test	It can be any of the above tests, but it is conducted in an interval of the well isolated with the help of packers. The packers are inflatable or mechanical and allow testing a distinct zone within a well.	Reservoir behavior, permeability Skin, fracture length, reservoir limit, boundaries

Table 3: Types of well tests and kind of information which could be obtained (Renard, 2005; Ahmed & McKinney, 2005)

Skin factor

The permeability around the wellbore could be damaged during any well operation, including drilling, cementing, perforating, production, workover, or stimulation. Materials such as mud filtrate, cement slurry, or clay particles may enter the formation and reduce the permeability. The region of the altered permeability is called the “skin zone” (Figure 24) and the effect is referred to as “wellbore damage”. The affected zone could reach a few inches to a few meters into the formation. In case of wellbore damage, the skin zone causes a higher pressure gradient around the wellbore. In contrast to wellbore damage, also wellbore improvement is possible in the near-wellbore region leading to reduction of the pressure gradient. Based on the assumption that the permeability in the skin zone, i.e., k_{skin}, is uniform and the pressure drop across the zone can be approximated by Darcy's equation, the effect of the skin zone could be related to

$$\Delta p_{\text{skin}} = [\Delta\text{p in skin zone due to } k_{\text{skin}}] - [\Delta\text{p in skin zone due to } k],$$

resulting in the formula given in Figure 25.

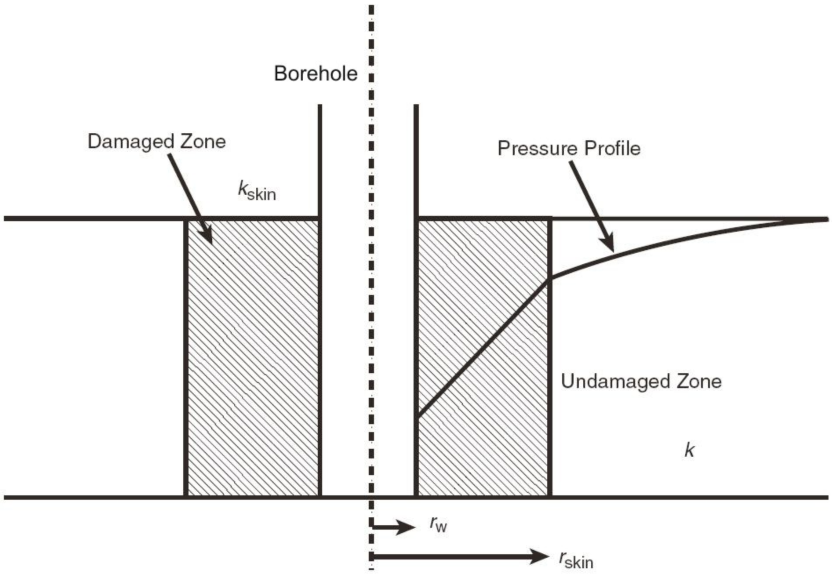


Figure 24: Sketch of the damaged zone and the pressure profile (near-wellbore skin effect), after Ahmed & McKinney (2005)

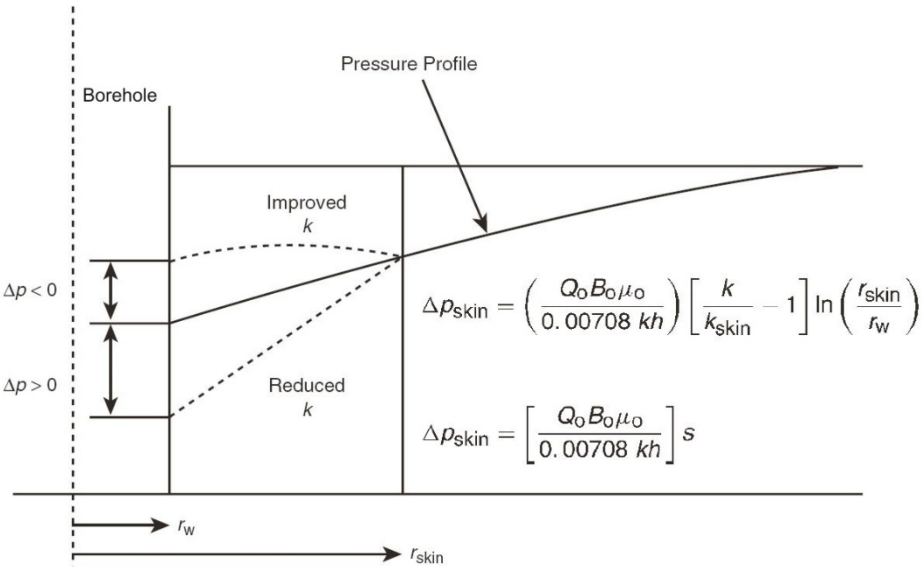


Figure 25: Improved and reduced near-wellbore permeability (positive and negative skin effects). Darcy's law equation with the skin term "s" (after Ahmed & McKinney, 2005)

DOI: 10.2312/GFZ.b103-11066

Depending on the permeability ratio (k/k_{skin}) and if $\ln(r_{skin}/rw)$ is always positive (Figure 25), there are only three possible results in evaluating the skin factor *s*:

(1) *Positive skin factor, s*>0: k_{skin} is less than *k* due to the near-wellbore damaged zone and hence *s* is a positive number. The magnitude of the skin factor increases as k_{skin} decreases and as the depth of the damage (r_{skin}) increases.
(2) *Negative skin factor, s*<0: k_{skin} is higher than that of the formation *k* due to an enhanced permeability in the near-wellbore zone.
(3) *Zero skin factor, s* = 0: Zero skin factor occurs when no alternation in the permeability around the wellbore is observed, i.e., $k_{skin} = k$.

Assuming that $(\Delta p)_{ideal}$ represents the pressure drawdown for a drainage area with a uniform permeability *k*, then: $(\Delta p)_{actual} = (\Delta p)_{ideal} + (\Delta p)_{skin}$. These concept could be applied to the steady-state flow, the unsteady-sate (transient) flow, and the pseudosteady (semisteady)-state flow regime. By analyzing transient well tests, the skin factor could be estimated (Table 3, p. 52). On a semilog plot of pressure drawdown data (pressure over time), the transient flow zone will appear as a straight line, whereas skin or wellbore storage effects would result in deviations from the straight line (Figure 26).

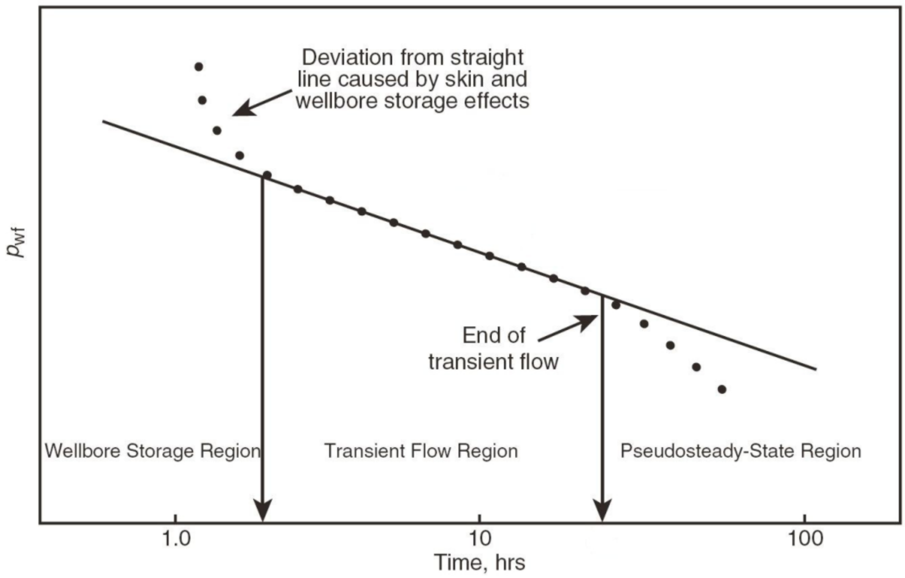


Figure 26: Semilog plot of drawdown data (after Ahmed & McKinney, 2005)

To proper assess the parameter of the near-wellbore area and of the reservoir is a prerequisite for further geothermal system management. In the case, that formation damage in the reservoir zone is present, adequate stimulation workovers may be performed (see Chapter *D.2.1 Enhance productivity*, p. 59).

D.1.3 Simulations (dynamic modelling)

The dynamic modelling of the geothermal reservoir behaviour is of importance for the site operation and the expected life-time of the geothermal facility. In the case of enhanced geothermal systems (EGS), dynamic modelling could also help in the prediction of the growth behaviour of hydraulically induced reservoirs. For every site-specific geothermal system, different reservoir simulations may be necessary, ranging from calculation of cooling-down and breakthrough scenarios up to modelling even more complex coupled thermo-hydro-mechanical (THM) processes, which are closely linked to the pore-space scale of the reservoir. Therefore, also different reservoir simulation model domains and modelling techniques may be required (Figure 27), which has to deal with the respective simulation goal. All models have also to take the uncertainty of the model parameterization into account, as most often detailed spatial knowledge of the geology related petrophysical properties are not available in high-resolution.

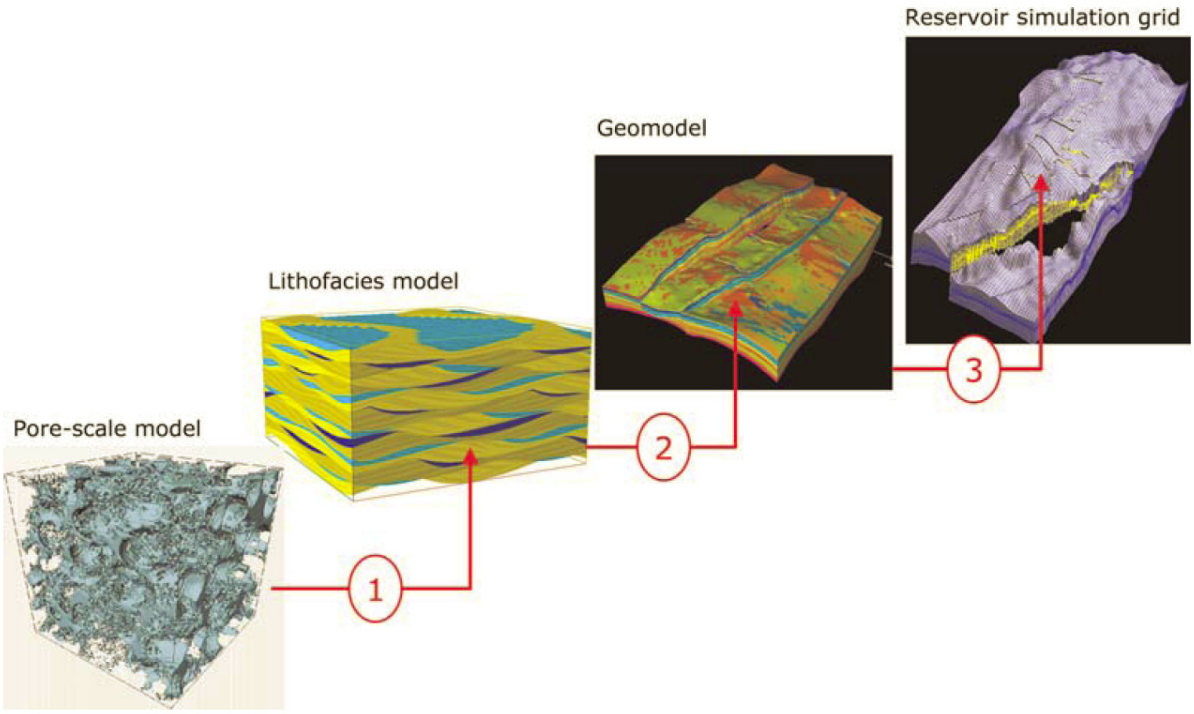


Figure 27: Example of reservoir simulation models at pore scale and at reservoir scale, linked by (static) litho-facies model and the geo-model (after Ringrose et al., 2008)

The use of computer modelling in the planning and management of the development of geothermal fields has become standard practice during the last 20 years (Kolditz et al., 2010). Numerical methods are widely used for the geothermal reservoir simulation to handle the complexity and the number of processes involved (e.g. geometry, hydraulics, thermal effects, geochemical reaction, and stress changes).

DOI: 10.2312/GFZ.b103-11066

The uncertainty of the input data is one of the major problems in subsurface reservoir analysis (Kolditz et al., 2010). Direct measurement of reservoir properties are rare and have to be assessed to the reservoir model dimensions, resulting in uncertainties of the model parameterization. In Addition, depending on the regarded reservoir scale and the processes to follow in the simulation, the input parameters itself will have different impacts for the simulation results. Monte Carlo simulation is one common method to quantify parameter uncertainty and the corresponding system evolution. Inversion methods have been used to identify physical rock parameters in order to reproduce the observed reservoir behavior (Finsterle & Pruess, 1997; Lehmann et al., 1998). As the parameters of interest are related to the structural reservoir geology, geostatistical approaches which take into account the status of the incomplete knowledge and enable the generation of multiple stochastically equivalent realizations of the reservoir may already be part of the geological modeling. Appropriate software solutions for this kind of analysis are available by commercial codes (Petrel, EarthVision, and others).

For geothermal reservoir simulations of fractured and porous media, several modeling concepts do exist (Table 4; for more details and the applied equations see Kolditz et al. (2010) and references therein). All concepts require an understanding of the complex three dimensional geometry of the reservoir. This geometry is difficult to assess, because the scale of numerical and experimental investigation alters the size of the measured parameters. Therefore, geometric modeling and mesh generation is an important object in performing reservoir simulations (Blöcher et al., 2010a).

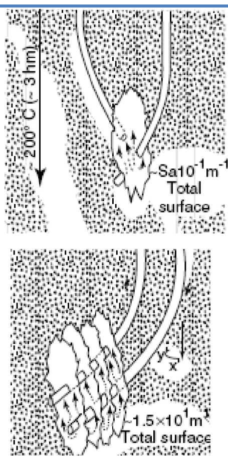
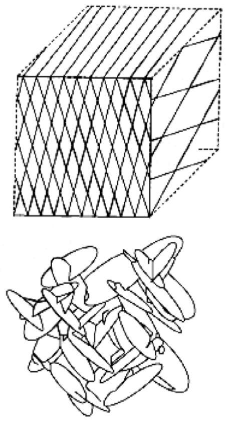
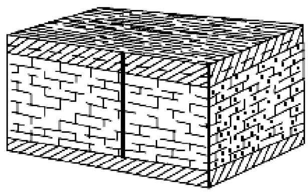
Hydro-geological system: porous and fractured reservoirs			
Concept	Fracture model		Continuum model
Geometry	Single fracture, parallel fractures	Fracture network (stochastic, deterministic)	Multiple porous media
Examples	 Cornet (1985)	 Kolditz (1995), Bruel & Cacas (1992)	 Stober (1986)

Table 4: Conceptual models for fractured rock after Kolditz (1997)

Scientific Technical Report STR 11/06
DOI: 10.2312/GFZ.b103-11066

Reservoir properties

The most important reservoir properties which are needed for running a dynamic simulation are (Table 5): reservoir permeability and the properties of the geothermal fluid (i.e. density and viscosity). Reservoir permeability is governing advective transport processes. In most cases, the reservoir permeability is difficult to assess, as often only limited spatial data is available (pumping tests give information only about the near-field area). Often used relationships between porosity and permeability may be inadequate for geothermal reservoir simulation, if larger temperature differences need to be considered because the reservoir conditions may change over time. A temperature decrease at the injection well results in a thermoelastic response and the pore pressure will also vary. This leads to a poroelastic response of the reservoir rocks depending on the effective stress (difference between confining stress and pore pressure), resulting in a change in permeability and porosity. Therefore, permeability can be expressed as a function of confining pressure and pore pressure (Al-Wardy & Zimmerman, 2003). Bear (1972) provides a general overview on the dependency of permeability on pore structure.

Thermophysical properties	Thermal conductivity Heat production Rock density Heat capacity Temperature Heat flow
Storage and flow properties	Permeability Transmissibility Porosity Storage coefficient Production index
Mechanical properties	Strain and stress conditions Geomechanical rock properties Pore pressure
Geological properties	Structural geology Petrography Facies and stratigraphy Pore / joint geometry
Fluid properties	Physical properties (density, viscosity) Chemical properties

Table 5: Reservoir parameters (after VBI, 2010)

The thermal conductivity of rocks is also temperature dependent. Somerton (1992) provides a relationship which is most suitable for sedimentary rocks and should be incorporated in the thermal modeling:

$$\lambda(T) = \lambda_{20} - 10^{-3}(T - 293)(\lambda_{20} - 1.38) \times (\lambda_{20}(1.8 \times 10^{-3}T)^{-0.25\lambda_{20}} + 1.28)\lambda_{20}{}^{-0.64}$$

with λ_{20}, the thermal conductivity of the rock measured at 20° Celsius.

The properties of the geothermal fluid depend mainly on temperature and salinity; the effects of changes in pressure are smaller (Kolditz et al., 2010). The dynamic viscosity of the fluid phase is typically regarded as a function of concentration and temperature (see Diersch, 2002). The equation of state for the fluid density (ρ^f) is related to reference temperature (T_0), reference pressure (p_0), and reference concentration (C_0) of the fluid (Kolditz et al., 2010; Diersch 2009):

$$\rho^f(p,T,C) = \rho_0^f\left(1 - \bar{\beta}(T - T_0) + \bar{\gamma}(p - p_0) + \frac{\bar{\alpha}}{C_S - C_0}(C - C_0)\right)$$

with $\bar{\beta}$, the coefficient of thermal expansion (K^{-1}); $\bar{\gamma}$, the coefficient of compressibility (Pa^{-1}); and $\bar{\alpha}$ considering the effect of density change due to the concentration of a dissolved component at constant pressure and temperature (see also Magri, 2010).

Other fluid properties also depend on temperature and salinity changes: the thermal conductivity of the fluid and its heat capacity. However, the expected influence of changes of these parameters for the simulation is most often negligible in low-enthalpy settings (at temperatures below 150 °C; see McDermott et al., 2006).

Simulation software

For running reservoir simulations, several software solutions are available accounting for the relevant equations which are derived from the conservation principles for linear momentum, mass, and energy. Based on the simulation goals, the appropriate software solution should be selected and adapted.

Commercial simulators used are e.g. FEFLOW, Eclipse, and for geomechanical simulations VISAGE (FEFLOW is trademark of DHI-WASY; ECLIPSE and VISAGE are trademarks of Schlumberger). FEFLOW is a finite element simulator allowing also incorporating fracture and borehole elements into the model more easily, but is also limited to vertical and/or horizontal structures. The software and modelling is described in more detail in Diersch (2002) and references therein. The FEFLOW software is not capable to integrate mechanical properties and chemical interactions, which will allow a better prediction of the long-term reservoir behaviour (Blöcher et al., 2010b). ECLIPSE is a standard simulator primary developed for the oil and gas industry also providing a thermal module. It allows analysis of gas, water, and solids (useful with chemical reactions) behaviors. It models the flow of steam and fluids. In conjunction with the ECLIPSE multi-segmented well model, complex well topology, including dual-tubing and horizontal wells and multiphase flow effects in the wellbore, could be simulated. Together with the VISAGE software, also the geomechanical behavior of the reservoir could be modeled. The software is, however, quite expensive.

Non-commercial software solutions are also used in geothermal simulations. OpenGeosys[3] is an open-source finite element simulator used for solving of thermal, hydraulic, mechanical and chemical (THMC) processes in fractured porous media and developed in cooperation between the Department of Environmental Informatics of the Helmholtz Centre for Environmental Research (UFZ, Leipzig), the TU Dresden, the Federal Institute for geosciences and natural Resources (BGR, Hannover), the Paul-Scherrer Institute (PSI, Villigen, Switzerland), the University of Kiel, and the University of Edinburgh (see: Wang et al., 2009).

[3] www.opengeosys.net

D.2 Operations to optimize the geothermal system

The overall productivity of a geothermal system could be optimized by optimizing the single components of the system – with respect to the overall goal of an efficient thermal recovery. The optimization may include the stimulation (e.g. chemical treatments and/or hydraulic fracturing) of geothermal wells that may become virulent if the well productivity is too low to assure an economical operation of the geothermal system. Another option to increase the productivity (mass flow) from the reservoir to the geothermal plant installations is to enhance the connectivity between well and reservoir by drilling multiple or horizontal wells (section *C. 1.3 Well planning*, p. 45) or a combination of well-planning and well-stimulation (section *D.2.1 Enhance productivity*). Optimization is also requested for running the surface installations of a geothermal plant. Therefore, another chapter (section *A.3.2 Geothermal plant efficiency*, p. 22) is discussing possible action points to consider. Obviously, there is no general solution for every geothermal application. The best concept for the optimal geothermal system performance will be different for every specific geothermal system – strongly dependent on the respective geological setting.

D.2.1 Enhance productivity

The productivity is measured by the productivity index (PI) defined as flow rate divided by pressure change. Stimulation techniques were developed by the hydrocarbon industry for improving the productivity of oil and gas wells. The techniques used in oil and gas industry were partially adapted to geothermal wells over the last two decades. They become necessary if reservoir formation damages affect the reservoir productivity or if – due to a low natural inflow – the primary productivity of the well needs to be increased. To be done properly, the well stimulation planning must be performed very carefully and requires a considerable knowledge of many diverse processes. The planning should result in an appropriate design of the selected specific treatment. This includes choosing among the various options for reservoir stimulations, of which one is to do nothing. Therefore, a means for an economic comparison of the incremental benefits weighted against the costs is necessary (Economides & Boney, 2000). Stimulation techniques can be subdivided with respect to their radius of influence (Schulte et al., 2010). In the near-wellbore area, chemical (acid) treatments or thermal fracturing can be performed at moderate prices (Economides & Boney, 2000). Reservoir stimulation of the far field (up to several hundred meters into the formation could be achieved by hydraulic fracturing.

Chemical treatments

Chemical treatments are most often used for an (initial) wellbore cleaning of geothermal wells, to remove the mineral scaling deposited in the wells after several years of exploitation and also to enhance fracture network in the reservoir. Acidizing is probably the most widely used work-over and stimulation practice in the oil industry. Whereas matrix acidizing is performed below fracturing rate and pressures to flow through the matrix and to allow reactions taking place in natural pores and present fractures, fracture acidizing is performed above fracturing rates (see hydraulic fracturing, p. 63). The idea of acid fracturing is not only to reduce formation damage but also to retain generated hydraulic connectivity for longer time.

For all subsurface activities to be performed in (deep) boreholes, it is mandatory to know as much as possible on the geology and the mineralogy as well as the fluid content, the wellbore, and the reservoir conditions.

Matrix acidizing

The main goal of matrix acidizing is to remove near-wellbore formation damage (Crowe et al., 1992). To assess formation damage, it is first necessary to know the skin term in the Darcy's law equation. Skin damage is a mathematical representation of the degree of damage present. Permeability and skin can be measured with a pressure transient well test (see section *D.1.2 Well testing and reservoir evaluation* - Skin factor, p. 52). To elaborate the appropriate well treatment, the well history needs to be studied carefully. Portier et al. (2007) recommend the following general workflow: first, select a stimulation candidate well; second, design an effective treatment; and third, monitor the treatment for subsequent improvement. In addition, any corrosion of the (well) installations should be avoided.

Based on the reservoir characteristics and the subsurface conditions, different acids are used for matrix acidizing such as hydrochloric acid (HCl), hydrofluoric acid (HF), acetic acid (CH_3COOH), formic acid (HCOOH), sulfamic acid (H_2NSO_3H), and chloroacetic acid ($ClCH_2COOH$). Factors controlling the reaction rate of acid are: area of contact per unit volume of acid; formation temperature; pressure; acid concentration; acid type; physical and chemical properties of formation rock and flow velocity of acid. These factors are strongly interrelated (Portier et al., 2007). The very fast reaction rate of hydrochloric acid, and other acids listed above, can limit their effectiveness in a number of applications, where deep acid penetration is needed. Therefore, retardants could be added to slow the reaction rate of acid with the minerals (see e.g. Crowe et al., 1992; Malate et al., 1998). Methods include emulsifying of the aqueous acid solution in oil to produce an emulsion which reacts slower or dissolving of the acids in non-aqueous solvents. Gelling agents used in the hydrocarbon industry to retard the acid reaction are restricted to lower formation temperatures because most gelling agents degrade rapidly in acid solution at temperatures above 55°C. According to Portier et al. (2007), chelatants (e.g. Ethylenediaminetetraacetic acids or Nitriloacetic acids) for dissolving some minerals containing Fe, Ca, Mg, and Al are rarely applied for formation clean-up in geothermal reservoir settings. Chelatants have two major disadvantages for a geothermal application: high costs compared to acids and, partly, a strong environmental impact.

Portier et al. (2007) stated that the only acid additives necessary in a geothermal acid job are a) corrosion inhibitor and inhibitor intensifier (often required) and b) high-temperature iron-control (reducing) agent. Water-wetting surfactants, necessary in oil well stimulation, are not needed in geothermal wells because of the absence of hydrocarbons. Suspending agents

DOI: 10.2312/GFZ.b103-11066

(nonemulsifier surfactants) are also not needed, although they seem to be included often in geothermal well stimulation job proposals. A clay stabilizer is often recommended to prevent migration and/or swelling of clays following an acid treatment but represents no fixed component of acid treatments. Clay stabilizer seems to be most effective when added to the overflush only (Portier et al., 2007).

The successful application of the acidizing approach on geothermal sandstone reservoirs requires the removal of the existing damage without creating additional damage due to rock-acid fluid interactions (Portier et al., 2007). The interactions depend on temperature, mineralogy (e.g. the spatial distribution of cement and minerals inside the porous network), and permeability of the formation. The specific composition of the acid should be chosen on a detailed formation evaluation. It has to be considered, that through the acid fluid cementing material is dissolved and may release clays and other fines from their setting. In addition, clay and fines will dissolve too and become gradually reduced in size. As a consequence, acid-released clays and fines can be dislodged and plug pore throats (Lievaart & Davies, 1987). In addition, clay swelling can be caused by ion exchange between acidizing fluids and formation minerals or changes in salinity, choking off production by obstructing pores and/or fractures. A general treatment design is given by Portier et al. (2007; see Table 6 and Table 7). In the case that the treated well should be used as an injection well it may be advisable to backflow the well after the stimulation job to avoid that an aggregation of fine particles form a permanent damage inside the reservoir. The produced fluids (containing the dissolved products of all chemical reactions triggered by the chemical treatment) could then be analyzed and used together with flow rates and produced volumes to calculate material balances. These balances are of help in interpreting the treatment success (Schulte et al., 2010).

Planning of the acidization	A typical acid treatment procedure
1. Determine the presence of acid-removal skin damage	1. Formation water displacement;
2. Determine appropriate fluids, acid types, concentrations, and treatment volumes;	2. Acetic acid stage;
3. Determine proper treatment additive program;	3. HCl preflush stage;
4. Determine treatment placement method;	4. Main acid (HF) stage;
5. Ensure proper treatment execution and quality control;	5. Overflush stage;
6. Evaluate the treatment.	6. Diverter stage;
	7. Repeat steps 2-7 (as necessary);
	8. Final displacement stage.

Table 6: Steps in sandstone acidizing (Portier et al., 2007)

DOI: 10.2312/GFZ.b103-11066

Temp. (°C)	Rock mineralogy (%)	Rock permeability (millidarcy [md]) > 100 md HCl (%)	HF (%)	20 to 100 md HCl (%)	HF (%)	< 20 md HCl (%)	HF (%)
< 100	High quartz (> 80), low clay (< 10)	12	3	10	2	6	1.5
	High clay (> 10), low silt (< 10)	7.5	3	6	1	4	0.5
	High clay (> 10), high silt (> 10)	10	1.5	8	1	6	0.5
	Low clay (< 10), high silt (> 10)	12	1.5	10	1	8	0.5
> 100	High quartz (> 80), low clay (< 10)	10	2	6	1.5	6	1
	High clay (> 10), low silt (< 10)	6	1	4	0.5	4	0.5
	High clay (> 10), high silt (> 10)	8	1	6	0.5	6	0.5
	Low clay (< 10), high silt (> 10)	10	1	8	0.5	8	0.5

Table 7: Acid guidelines for the chemical treatment of sandstones according to the composition of the formation (Crowe et al., 1992)

An overview of several acidizing procedures applied in the Soult-sous-Forts EGS system in France is given by Portier et al. (2009). At present, matrix acidizing treatments exhibit at least four serious limitations: inadequate radial penetration, incomplete axial distribution, corrosion of the pumping and wellbore tubing, and iron precipitation (Schulte et al., 2010).

Fracture acidizing

In fracture acidizing, an acid fluid is injected at pressures which lead to a failure of the rock, creating artificial fractures. In contrast to hydraulic fracturing (see section *Hydraulic fracturing*, p. 63), the reactive acid fluids should render the fracture surfaces in a non-uniform manner that the fracture conductivity stays on a similar level when the fracture is released to normal pressures (closure stress) again. In principle, the acid fluid penetration should be as deep into the formation as the fracture plane to enable maximum conductivity. The main challenge in performing an acid fracturing job is therefore, to estimate correctly a) the reactivity of the rock along the fracture surfaces and b) the volume of acid fluid needed to ensure that the fracture surfaces are modified all along up to the fracture surface tip. Portier et al. (2007) list values in the order of 12.000 – 25.000 liter per meter of open hole. Often a fluid mixture of 15% HCl and 10% acetic acid is used.

Acid fracture treatments are widely used for stimulating limestone, dolomite, or formations presenting above 85 % acid solubility. According to Portier et al. (2007) the major problem in fracture acidizing is the development of wormholes in the fracture face; these wormholes increase the reactive surface area and cause excessive leak-off and rapid spending of the acid fluids. Further on, Portier et al. (2007) stated that when the leak-off rate of the acid fluid exceeds the pump rate (due to wormholding and excessive leak-off), a positive net fracturing pressure cannot be maintained to keep the fracture open. This may happen as soon as 6 minutes after starting to pump the acid fluid. To ensure deeper penetration in fracture acidizing, the acid reaction rate is often retarded by gelling (polymers and surfactants), emulsifying, or chemically-retarding the acid. For example, HCl can be retarded by adding $CaCl_2$ or CO_2. Another approach is to use naturally retarded acetic or formic acid. Fracture acidizing is performed in several ways: with a viscous preflush, different additives for selective etching and a combination of density and viscosity controlled fracture acidizing.

Thermal treatments

Thermal treatments follow the same goals as chemical treatments: increase of productivity or injectivity of a well by enhancing near-well permeability or by opening of hydraulic connections to naturally permeable zones. The injection of cold water into a hot well leads to a cooling of the rock which contracts and induces a tensile component of stress near the injection area. The value of this thermally induced stress depends on the shape and volume of the cooled region, the thermal and elastic properties of the rock, the difference between the reservoir and injected fluid temperatures, and the injection rate (pressure). In case the water bottom-hole pressure exceeds the minimum horizontal stress including the thermo-elastic stress, a fracture can propagate from the wellbore. Although the processes involved in thermal treatments are not fully understood (Schulte et al., 2010), numerical models have been developed (Perkins & Gonzales, 1985; Gadde & Sharma, 2001) and tested for planning thermal treatments, e.g. for enhanced gas-oil recovery (Hartemink et al., 1997) or in high-temperature systems (Tester et al., 1989; Axelsson et al., 2006).

The thermal treatment starts after water circulation through the drillstring by pumping cold water into the formation. The treatment could be paused to allow the well to heat up again and to enable a combination of thermally induced cracking forces and pressure impulses which could increase fracture permeabilities. Stimulations in low-enthalpy settings (below 150 °C) primarily involve pressure changes induced either directly at wellhead or downhole, where inflatable packers (seals) are placed to more effectively address deeper well sections (Schulte et al., 2010). Air-lift pumping is commonly used in low-temperature stimulation operations. The operations generally are applied for a period of a few hours to a few days. They are normally performed immediately after drilling, when the drill rig and other equipment is still available. Testing may affect the down-hole installations. Injecting cold water can lead to a failure of the eventually present cemented casing, if the different materials show different expansion coefficients, too.

Hydraulic fracturing

For performing hydraulic fracturing, the knowledge of the local stress regime is of outstanding importance to understand or predict the fracturing process. Data on the stress regime could be derived from the interpretation of borehole breakouts, borehole fractures, and the analysis of microseismic events. This data should be evaluated to confine the orientation and the amplitude of the principal stress components (see e.g. Zoback et al., 2003). Minimum stress is perpendicular to the fracture plane orientation and equivalent to fracture opening pressure plus cohesion. The magnitude of vertical stress can be calculated by the density of the overburden. Maximum stress can be derived by stress ratio analysis (see e.g. Moeck et al., 2009a, b). Formations with high stress anisotropy and hence, a high shear stress, should be best candidates for hydraulic fracturing in low permeable rock (Schulte et al., 2010). Hydraulic fracturing treatments could be subdivided in waterfrac treatments, gel-proppant treatments, and hydbrid frac treatments.

Examples of (geothermal) waterfrac treatments are given in Legarth & Tischner (2003), Legarth et al. (2005), Zimmermann et al. (2010), and Zimmermann & Reinicke (2010).

Waterfrac treatments

Waterfrac treatments use high amounts of water in a low permeable or even impermeable rock to produce long fractures (a few 100 m) with low width (approx. 1 mm) compared to gel-proppant or hybrid frac treatments. Maximum fracture performance is achieved with high flow rates which alternate with lower flow rates. To enhance height and conductivity of the created (or re-opened) fractures, abrasive sand or proppants could be added. Compared to hydrocarbon reservoir stimulation, application to geothermal systems requires techniques that will radically increase fluid production to make a project economically feasible.

Gel-proppant treatments

These treatments could be applied in a wide range of formation with varying permeabilities (Schulte et al., 2010). The produced fractures have shorter length than obtained from waterfracs (50-100 m), but show higher width (of up to 10 mm). Due to the limited depth range of the method, it is often used to solve drilling or cementing induced formation damage problems in high permeable reservoirs. However, gel-proppant fracs are more expensive than water fracs.

Gel-proppant fracs are normally performed in two phases. In step one; a first frac will be carried out using an uncross-linked gel to evaluate the near wellbore conditions. After pumping a cross-linked fluid to predict the leak-off range, the closure pressure present, the frac geometry, and whether there is any indication of pressure dependent leak-off. A cross-linked fluid is a water-based system with a specially designed polymer loading composed of a refined guar gelling agent cross-linked by a borate solution. For geothermal purposes it should include a fluid's high-temperature stability and a time-delayed cross-linked reaction. In step two, the main frac procedure will be performed by injecting gel-proppants with a stepwise increase of proppant concentration with a high viscous cross-linked gel. Using a fluid with as low a polymer loading as possible is essential to ensure that both the effective fracture half-length and the polymer degradation are maximized (Schulte et al., 2010). An adjustment of step rates and proppant concentration during the treatment is possible and often necessary to avoid a screen-out of the well. One can adjust the treatment by varying the flow rate and the proppant concentration in case the pressure progression suspects a failure of the treatment (Schulte et al., 2010).

Hybrid frac treatments

In hybrid frac treatments, slickwater is pumped first to generate a fracture. Then, a gel-pad with cross-linked gel is injected, followed by proppants or sand of a certain mesh size with a cross-linked gel to fill the fracture. This method can be applied to low permeable reservoirs and provide sustainable production rates (Schulte et al., 2010).

Treatment monitoring and treatment evaluation

According to G. Paccaloni, cited in Crowe et al. (1992), only 27% of failed acidizing treatment jobs in the hydrocarbon industry are related to incorrect choice of fluids and additives. The main reasons for failed acidizing treatments were due to poor field practice. In fact, all treatment jobs altering the reservoir should be carefully supervised, monitored, and documented. Monitoring should include the injection flow rate, the wellhead pressure during stimulation and the temperature of the injected fluid temperature. Profiles of temperature and pressure along the borehole can help in addressing flow zones. The success of the treatment should be evaluated by measuring the (enhanced) productivity (e.g. by the productivity index after hydraulic fracturing treatments) or with the achievement of a specific skin improvement (e.g. after chemical treatments).

Dependent on the main purpose of the respective treatment, the monitoring will be performed in the *wellbore scale* or in the *reservoir scale*. In the well scale the success of the treatment could be measured by temperature logging (cool down of the formation), by spinner surveys for the quantitative assessment of the flow into the well, by gamma ray logging surveys if radioactive tracers were used in the stimulation fluid, and by using borehole imager logging tools for rock wall examination and fracture identification.

In the reservoir domain, *hydraulic well tests* may be performed for the assessment of fractures induced by the (hydraulic) treatment and to check for reservoir compartments. A pressure drawdown test for example, where the flowing bottom-hole pressure is measured while the well is flowing, allows giving a value of the productivity index (PI). After shut-in of the well, the evaluation of pressure build-up tests may allow determining reservoir properties and near-well effects (skin, see also section *D.1.2 Well testing and reservoir evaluation*, p. 49). Tracer tests are applied for detection and characterization of hydraulic connectivity between wells and/or aquifer units. Flow rates and velocities, residence times, and reservoir volumes and other characteristics of the reservoir may be obtained. As stated in Schulte et al. (2010) the physicochemical behavior of the tracers under given reservoir conditions (high-salinity fluid, very low redox potential, low pH, etc.) is not always well known. Therefore, the use of a minimum of two tracers (or comparison with a natural tracer

DOI: 10.2312/GFZ.b103-11066

or laboratory experiments) is recommended by the authors. Tracers should be inexpensive, environmental safe, non-adsorptive, detectable at low concentrations, and absent from natural geothermal fluids (Adams et al., 1992). Substances used as tracers are e.g. inorganic anions, radio-isotopes, activatable elements, organic dyes and aromatic acids. In addition, gas tracers or vapor or two-phase tracers (alcohols) are used (see Schulte et al., 2010, and references therein). The tracer could be injected continuously or by slug injection in one well with backflow of the fluid in the same well or by performing fluid flow between two or more wells (inter-well flow). By sampling and analyzing of the fluid in the respective well, the gathered data set enables the interpretation of the fluid flow conditions. Return-Curve data from a slug injection could be analyzed and modeled by signal processing codes such TEMPO (based on a model of dispersive transfer; Sanjuan et al., 2006) or using the moment analysis method, hydraulic or hydrodynamic codes such as SHEMAT (Clauser, 2003) or TOUGH2 (Pruess et al., 1999), and other.

The best evaluation of the treatment success is achieved by a combination of pressure, flow, and temperature monitoring at the wellhead with temperature, pressures, and wellbore imaging downhole (Schulte et al., 2010). In addition, the composition of the produced fluid (before and after stimulation) may be analyzed.

Ben Norden and Stephanie Frick

D.3 Regulations, economics, risk assessment, and insurances of geothermal projects

Energy markets are not driven by demand and supply only. In addition, also political and social issues do control the provision of energy for the present and the future. Sustainable energy markets need to manage three dimensions of energy provision: security of supply, economic affordability, and environmental compatibility (Frick et al., 2010). In many energy-political frameworks an increase of the share of renewable energies is claimed. Often, the costs of energy provision from renewable sources of energy are not fully competitive to the energy in the market (at prices which do not always reflect the full lifecycle costs). To support investments in renewable energy systems, promotion measures like feed-in tariffs, quota models, or fiscal instruments have been introduced in many countries[4]. The most important policy instruments for promoting geothermal energy (heat production) in the European Union according to Bürger et al. (2008) are investment incentives (in the order of

---

[4] Definitions as given in Bürger et al. (2008): *Feed-in scheme* describes a support mechanism for electricity from renewable sources, where a fixed amount of money is paid to the electricity producer per kilowatt hour ‘‘fed’’ into the grid. *Quota Models* set a share of renewable energy sources in the energy mix (heat and/or electricity) that has to be reached by producers. Some countries use a quota approach to fulfil the EC targets. Since a Quota Model needs to provide an option if the required shares are not reached, the success of the Quota Models crucially hinges on the opting-out possibilities (amount of penalty for not fulfilling the quota).

15-40%), tax break, and use obligation (e.g. Sweden requires heat pumps for new buildings). Another important aspect for heat provision by geothermal systems is that the establishment of local heat networks are necessary to make the extraction of geothermal heat from greater depths (more than 2.000 m) economically feasible. Bürger et al. (2008) recommend a so called *bonus model*. This model is characterized by a purchase / remuneration obligation with fixed reimbursement rates. The basic idea of the bonus model is that operators of renewable energy systems will receive a fixed price per kWh (bonus) corresponding to the amount of heat they produce. The respective bonus is set by the government and established by law. The bonus payments should depend on the type of technology used. The bonus is paid by the producers and importers of heating fuels following the "polluter-pays principle" to the operators of renewable installations (Bürger et al., 2008).

D.3.1 Economical aspects of geothermal projects

Like other commercial projects, the planning and the decision to realize a geothermal project is based on the estimation of the expected costs and revenues. In general, geothermal projects may have a longer planning phase and a longer technical lifetime than other investments. To estimate the costs and revenues reliably is therefore a challenge as risks and uncertainties increase with longer periods under consideration (see e.g. Frick et al. (2010) for more details). In addition, in geothermal development nothing is 100% certain about the resource until a well has been drilled and an "economical" flow of water has been proven (Thorsteinsson & Tester, 2010). To run geothermal projects economically successful, the average energy provision cost needs to be competitive to the price level in the energy market. This cost is often referred as the levelized cost of energy (LCOE) and is calculated based on the total costs throughout the overall economic lifetime of a plant related to the provided energy. Details on the methodology to calculate the LCOE are given in Ahmed (1994). All payments related to the project are related to the monetary value of a chosen reference year and include e.g. costs of capital related to investments, operation costs such as for service and personnel, costs for consumables and auxiliary power, costs for insurances and taxes, and possible revenues due to cascade use of the geothermal system (Frick et al., 2010).

The investments at the beginning of a project are in most cases dominating the total costs of a geothermal project. The investments necessary at the early phase of the geothermal project consist of costs for reservoir exploration, well drilling and completion, reservoir engineering measures, and other (Frick et al., 2010). Investments for the surface part of the geothermal application depend on the technological specifications and rely on the site-specific geological and technical parameters. The upfront capital costs are offset by lower operating costs as e.g. fuel does not need to be purchased (Thorsteinsson & Tester, 2010).

In general, costs for reservoir assessment and development rise with reservoir depth. This is mainly due to the well costs which increase disproportionately high with depth due to decrease in drilling progress. The drill costs should be estimated based on already drilled and completed wells of the area, if such information is available. Such calculation should also consider a supplemental charge for unforeseen troubles in the order of 10-20% of the well costs (Frick et al., 2010). Besides geological and technical influences, the situation on the drilling rig and the commodity markets does influence the well costs. The MIT drilling index (Augustine et al. (2006), in: Thorsteinsson & Tester, 2010) shows that drilling costs are closely linked with the oil price. From the year 2000 to 2005, the drilling costs have risen dramatically. This effect is most prominent for the shallowest wells (up to about 800 m) which are of special interest for geothermal heating applications (Thorsteinsson & Tester, 2010). In 2009, the oil price dropped from nearly 100 US-$/barrel to 62 $/barrel resulting in cheaper rig times. However, the average oil price reaches 80 $/barrel in 2010 again[5]. Beside rig and drilling costs, the installation of a downhole pump requiring special constraints for well completion may add further costs for deep geothermal projects. If stimulation of the well / reservoir becomes necessary, the evaluation of the relevant costs should be based on the costs for equipment rent, material, energy, and service.

Surface installations like pipes and filters for installing a geothermal loop may cost between 75 € and 600 € per meter (Frick et al., 2010). Investment costs for heating plants are given by the same authors with 10 -100 € per kW thermal capacity, excluding costs for the construction of heating grids.

D.3.2 Risk assessment, decision making, and insurances

Geothermal investment often requires a high dose of risk. What are the chances of the project failing? What is the potential reward of the investment? And the most important question for the investor is 'how high is the probability of a zero return'? The experience of the hydrocarbon industry shows that a lot of projects may fail to deliver the promised performance as a result of risk underestimation. Risks may be related to human controlled factors (mainly technically and engineering options) and to parameters which are uncertain and uncontrollable (like reservoir temperatures, productivity of the reservoir, or unforeseeable changes in energy prices). Quantitative risk and decision analysis techniques enable a better integration of risk mitigation actions into the project planning at the early project stage, where it is possible to consider different exploration strategies.

For decision making, the net present value (NPV) is used instead the LCOE which is – at the early stage of the project – an estimation based on a chosen scenario of the geothermal system. The NPV is defined as the total present value of a time series of outgoing and incoming cash flows related to a project. To calculate NPV, all cash flows are discounted back to its present value and are summed into the cumulative discounted cash flow (CDF, Figure 28). For a realized project, the NPV equals the CDF at the end of the project. If a project needs to be aborted before it reaches the production stage, the NPV value is negative. The financial risk therefore is defined by the so-called downside, which equals the average returns below the target of NPV ≥ 0 (see Frick et al. (2010), and references therein).

[5] WTI oil price as listed on http://www.worldoils.com/oilprice.php (18.01.2011).

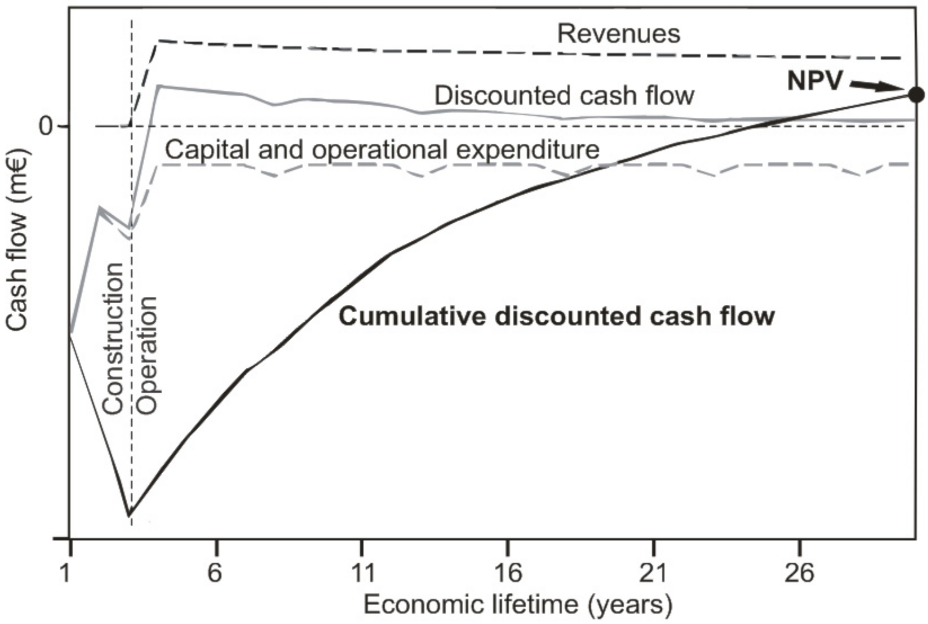


Figure 28: Cumulated discounted cash flow and net present value (after Frick et al., 2010)

The overall goal is to minimize financial risk and to increase the expected return. Several management instruments were successfully applied in geothermal projects and help to optimize the project execution plan: probabilistic models, sensitivity analysis, decision trees, portfolio analysis, and evaluation of risk mitigation options (For further details and case scenarios for EGS sites see ENGINE (2008) and Frick et al. (2010). The following section is mainly based on these references). *Probabilistic models* are used to assess the impacts of uncertainties in technical and economic parameters on the expected distribution of NPV, based on multiple runs and using Monte Carlo sampling. The average performance is considered as the expected NPV. In addition, based on the model runs, a probability could be given for the event that the NPV is less than zero. Probabilistic models for different geothermal projects could be compared and the financial risk of the project ranked. *Sensitivity analyses* study the impact of single or various selected uncertainties on the NPV. This enables the evaluation of the impact of single parameters on the NPV. Therefore, key parameters could be identified and risk mitigation options developed to reduce uncertainties and financial risks. Another tool for project execution is the establishment of a *comprehensible decision making* in regard to project continuation, modification, or even abortion. Therefore, project milestones need to be identified which act as major decision points. At each "decision gate" the criterion should be defined which has to be fulfilled for the respective continuation of the project. *Decision trees* can be used to present the possible workflows based on different scenarios depending on alternate decisions. An integrated technological-economical approach for optimized decision making which includes all decision options is the overall goal; a very detailed analysis of every single component is not helpful for the overall project management. In the *portfolio analysis approach*, possible project workflows are plotted in a portfolio plot with risk on the horizontal axis and the average NPV as expected return for the different possible project execution paths on the vertical axis. Economically promising project paths are thereby marked by a large expected return at low risk. The scatter in the portfolio plot allows also benchmarking the robustness of the overall project development strategy. The portfolio analysis approach could also be applied on different projects to rank the projects relative to each other.

Due to the diversity of different risks associated with large-scale (deep) geothermal projects, it may be desirable to find possibilities to contract *geothermal insurances*. As every geothermal project has its own characteristics, no general rule for insurances could be given. However, especially for deep geothermal projects, insurances will cover only single aspects of the project. For example, to full assure the financial risk of drilling “lost wells” will not make sense economically, whereas a gradational flow-rate insurance cover may help to ensure several options for the project to proceed. Events which are most often not included in insurances are loss of borehole, financial problems, and sabotage. For any insurance cover an individual risk assessment will be required comprising the business plan, feasibility studies, data pools of the region of interest, and further internal and external reports. The costs of the insurance will be related to structuring fees, expert fees, and insurance premium. Further insurances may cover parts of the surface installations (turbines, boilers, etc) and liability insurances (for bodily injury, property damage, etc.).

For small-sized (shallow) geothermal applications, like installed borehole heat exchangers, insurances are available in some countries. The contracts cover costs for the detailed investigation of the defect, the overhaul of the probe, and expenses for possible disposal. Often not included are damages which are related to foreseeable (natural) influences, damages of pumping units, damages related to research, and damages related to fluid losses.

E. Outlook

From the global view, only a marginal part of the underground heat reservoir potential is used until now. The main promising areas are seen in the construction of district heating (and cooling) networks as it is the most competitive geothermal energy technology, the optimization of existing networks, and the usage of geothermal energy in processes linked with transport (storage), industry, and agriculture. Direct heating technologies, district heating, and also methods to set-up enhanced geothermal systems (EGS) are available. The direct use of thermal fluids from deep aquifers, and heat (and/or power) extraction using EGS, have costs and risks, which can be reduced by further technical improvements associated with accessing and engineering fractures in the geothermal reservoirs. The latter requires a better knowledge and measurement of the subsurface stress fields. According to Huenges (2010), the remaining challenges are drilling, well completion, brine management, mitigation of induced seismicity, reliability of system components, and mitigation for corrosion and scaling. Knowledge acquired while developing geothermal reservoirs will lead to better practices and standards and increased deployment confidence.

F. Geothermal Sites and Applications

Numerous of different geothermal sites and settings are described in the literature. The examples listed in this section give insight into some aspects of geothermal applications. The field of geothermal use is wide and as it was discussed in the previous chapters, every site is different. Therefore, the examples do not cover the whole range of geothermal applications possible.

F.1 Heat Pumps

The installations of geothermal heat pumps have been strongly increased in the last decade. Their great advantage is that they enable the utilization of the ubiquitous shallow geothermal resources. Geothermal heat pump systems use the earth as a heat source (in winter) or a heat sink (in summer). They can reduce energy consumption—and corresponding emissions—from 45 to 70 percent when compared to traditional systems (Kagel, 2008). The system benefits from the moderate and constant temperatures of the subsurface to enhance the efficiency and to reduce the operational costs of heating and cooling systems. Even higher efficiency may be reached by combining the system with solar heating. Several versions of geothermal heat pump systems have evolved for both, residential and commercial applications (Figure 29; Rybach & Sanner, 2000; Sanner et al., 2003; Omer, 2008; Schellschmidt et al., 2010):

- Open and closed loop. Close loop systems keep the fluid used for heat transfer within the system. Open loop systems use fluid in a reservoir (pond, well, lake) as the heat transfer fluid.
- Vertical and horizontal systems. Vertical systems use two long pieces of pipe with a "U" at the bottom in a hole bored in the ground. Horizontal systems are installed in trenches. Sometimes, two or more pipes are spaced vertically in the same trench to increase heat transfer per foot of trench.
- “Geostructures” (foundation piles equipped with heat exchangers).

DOI: 10.2312/GFZ.b103-11066

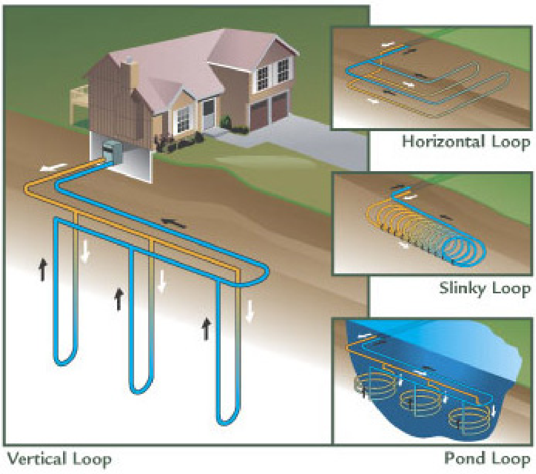


Figure 29: Geothermal heat pump installation systems (Reference: www.architecture2030.org, 19-05-2010)

Geothermal heat pumps are sometimes referred to as Ground Source Heat Pump (GSHP), Earth-Coupled Heat Pumps, Earth-Coupled Water Source Heat Pumps, Earth Exchange Systems (EES) or Geo-Exchange systems.

For the planning and installation of geothermal heat pumps, several objectives have to be considered:

- Planning phase
- Calculation of the (heating) loads and estimation of the hours of operation
- Estimation of the necessary heat-abstraction capacity
- Design of the geothermal heat pump system: number and depths of boreholes and tubes/pipes; calculation of the expected heat-abstraction capacity of the system
- Application phase
- Application for a permit
- Maps of the area, presentation of the individual geothermal heat pump concept and the technical details, expected geology
- Listing of the intended drilling method
- Consideration of environmental aspects during construction and operation of the facility, especially at higher salinities and temperatures (see e.g. Kristmannsdóttir & Àrmannsson, 2003)
- Construction phase
- Compilation of drilling reports, drilling samples, and site map
- Proof of tube quality and tube/pipe installation
- Confirmation on the composition of the used liquids
- Photo documentation

Larger geothermal heat pump plants for offices or commercial areas have been erected world-wide (Curtis et al., 2005). In Germany, borehole heat exchangers (BHE) were installed at the German Air Traffic Control (DFS) Headquarter in Langen based on-a BHE system with 154 BHE, each 70 m deep, integrated into the cooling and heating system of the office (Sanner et al., 2003). The system was designed to run with pure water only, without any antifreeze additives. In addition, a temperature monitoring programme was developed to have control on the induced temperature variations of the groundwater aquifer managed. The operating parameters were calculated using the computer program Earth Energy Designer (EED), developed by Universities of Sweden and Germany (Hellström & Sanner, 1994). According to Rybach (2001), the software EED has some limitations. Varying ground thermal properties cannot be considered, irregular BHE configurations which are often dictated by ground property boundaries cannot be handled. Also, the influence of moving groundwater cannot be taken into account. More flexible software like the package FRACTure (Kohl and Hopkirk 1995) has been used instead to eliminate these shortcomings. There are several other packages available like the Ground Heat Exchanger Design Program CLGS from the International Ground Source Heat Pump Association[6].

To minimize geological risks related to geothermal heat pumps, knowledge of the local geology is most important. In Staufen (Breisgau, Germany), drilling activities for heat pumps performed in September 2007 connected layers of anhydrite hydraulically to the present groundwater aquifer, resulting in a chemical reaction of the anhydrite with the water. This process includes a swelling of the anhydrite and a transformation of anhydrite to gypsum, resulting in an increase of the volume in the order of 67% (Schmid, 2009). As a consequence, the surface started uplifting up to 15 cm per month, damaging the buildings of the historic centre. Because if the process started, not much could be done to stop it, a careful planning is very important in areas with known anhydrite/gypsum deposits.

F.2 Aquifer Thermal Energy Storage: Reichstag (Berlin, Germany)

At the Spree peninsula in Berlin, representing the central governmental and parliamentary district of Germany, one example of a successful implementation of underground thermal energy storage in the energy concept of the new and refurbished buildings could be studied (Sanner et al., 2005). Two aquifers at different depth are used to store cold and heat. By using dry coolers and five 60-m deep wells for storing ambient cold in wintertime, the cold storage is used for cooling the building in summertime. The heat storage uses two 320-m deep boreholes and enables an enhancement of the effectiveness of the also installed CHP (Figure 30; Kranz et al., 2008; Kranz & Bartels, 2010).

In winter time (loading regime), water with a temperature of 5°C is injected into the cold ATES. From the deeper warm ATES system, temperatures of 65°-30°C could be retrieved for heating issues. In summer time, the warm ATES system is loading (injection temperature of 70°C) and the cold ATES system is producing cold water of 6-10°C for cooling issues. At the Reichstag, 60% of the required cooling need during summer time is performed by the cold

[6] http://www.igshpa.okstate.edu/publication/software.htm

storage. According to the information service BINE[7], the investment for aquifer storage amounts up to 25 € per cubic meter (at volumes of 100,000 m³) only.

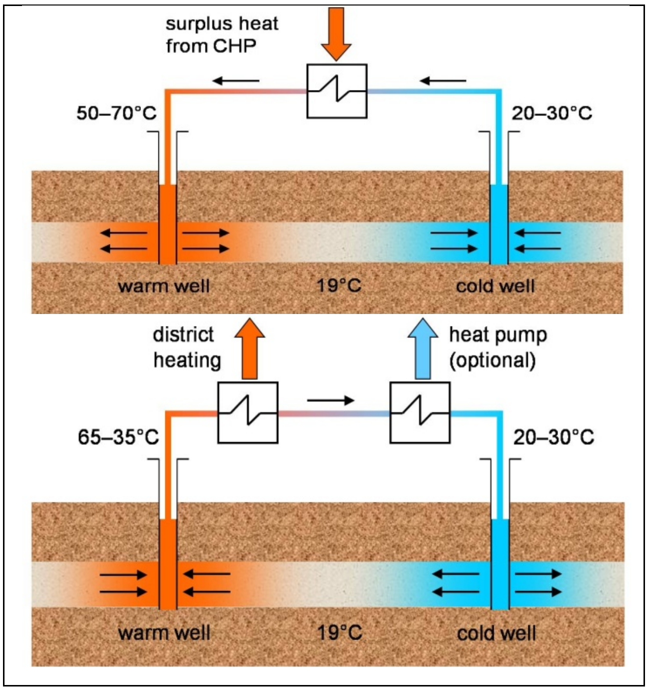


Figure 30: Schemes of summer (top) and winter operation (bottom) of the deep ATES system of the Reichstag, Berlin

F.3 Heat and Power Supply

Geothermal space heating is one of the oldest direct uses of geothermal energy. Space heating could be provided by means of pumped wells or through the use of subsurface heat exchangers (if high enough ground temperatures are present in the depth range of 20-200 m). Where temperatures do not meet the space heating requirements of residential or commercial buildings, heat pumps can be used to boost the temperature to the requested level. In addition, underground thermal storage may complete the installation.

District heating networks are designed to provide space heat to multiple consumers and are often using several geothermal wells. Because of the larger dimensions of a district heating system, wells are often drilled deeper and with larger diameter than would be cost-effective for an individual system (Bloomquist, 2003). In both applications (individual and district heating) it is often necessary to isolate the geothermal fluid from the use side to prevent corrosion and scaling. Generation of heat could be combined with power generation, even at low fluid temperatures as in Neustadt-Glewe (see p. 78).

---

7 http://www.bine.info/hauptnavigation/publikationen/projektinfos/publikation/aquiferspeicher-fuer-das-reichstagsgebaeude/fazit-und-ausblick/

F.3.1 Oregon Institute of Technology (USA)

Lund & Boyd (2009) published details on the geothermal heating facility of the Oregon Institute of Technology. Three wells between 365 and 550 m deep were drilled, producing 89°C water at a maximum flow of 38 l/s for the heating of 12 buildings covering approximately 70,900 m² of floor space, saving approximately $1,000,000 annually in heating costs (Lund & Boyd, 2009). The geothermal fluids are produced with line-shaft pumps, steered with variable frequency drives. The hot water is then fed to all buildings on campus by gravity. In each building, plate heat exchangers are located to separate the corrosive geothermal fluids from a secondary water loop for heating the rooms. The geothermal water is injected into two injection wells located approximately 625 m from the production wells. Lund & Boyd (2009) also report pipeline corrosion effects, which are not related to the geothermal fluid directly. The pipeline initially consisted of steel pipe covered by a rigid foam glass insulation buried directly in the ground between the buildings. Due to variable flow rate of the geothermal water and changed supply temperature of the geothermal water, the metal pipe did expand and contract whereas the insulation did not. Thus, ground water entered the cracks of the insulation and corroded the steel pipe. In addition, oxygen was introduced into the water from a vent in the storage tank causing internal corrosion of the pipes. Therefore, it was necessary to install a new utility system.

At the Oregon site, it is planned to install also a power-generating geothermal system with 150°C warm geothermal water from a depth of 1800 m. Already in operation is an absorption cycle chiller system, to provide cooling of the campus buildings.

F.3.2 Geothermal Plants in Denmark

In Denmark, one geothermal plant was commissioned in 1984 at Thisted and is in operation since then (Mahler & Magtengaard, 2010). The plant utilizes water at a temperature of 43°C and a salinity of 15w% from high permeable sandstone layers (the Gassum sandstone) at a depth of approximately 1,250 m. The water is cooled to 11°C through a heat exchanger before being returned to the subsurface (Figure 31). The production and the injection wells are situated 1.5 km apart from each other. The geothermal plant is connected to the town's waste-based CHP plant. The geothermal component of the plant can produce the equivalent of the annual heat consumption of approximately 2,000 households.

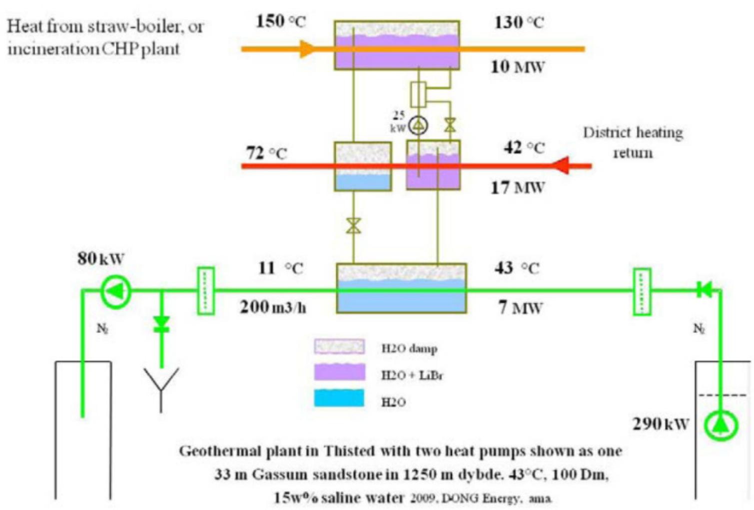


Figure 31: Geothermal plant in Thisted (Mahler & Magtengaard, 2010)

Another geothermal plant started operation in 2005 in Amager, Copenhagen. The geothermal plant is located adjacent to the Amager power station. This plant produces hot water at a temperature of around 73°C and a salinity of 19 w% from sandstone layers situated at a depth of 2.6 km from the Bunter Formation. The water is cooled in a heat exchanger (three absorption heat pumps in series) to approximately 17°C, before being returned to the subsurface (Mahler & Magtengaard, 2010). The district heating water from the heat exchanger is mixed with district heating water preheated to the same temperature in the absorbers; and the condenser supply the remaining heat to reach a supply temperature of up to 85°C (Figure 32). The annual heat production from the geothermal plant is equivalent to the consumption of around 4,600 households.

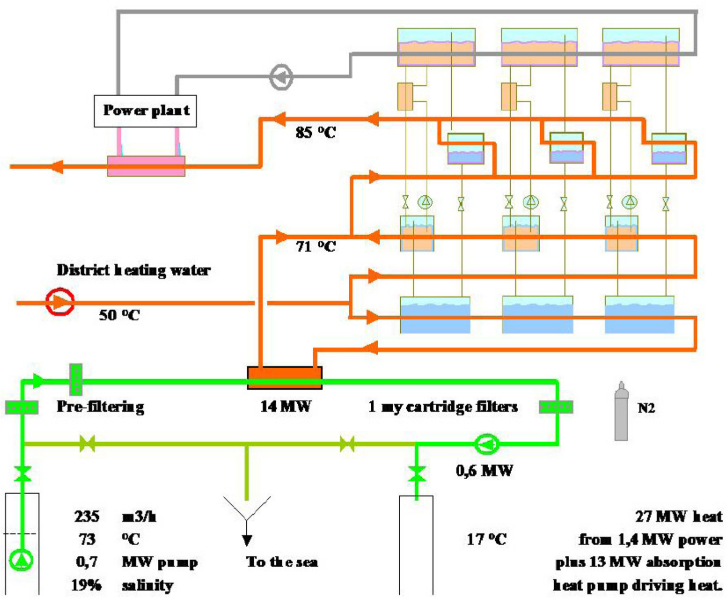


Figure 32: Amager geothermal plant, Copenhagen (Mahler & Magtengaard, 2010)

DOI: 10.2312/GFZ.b103-11066

Two wells have been drilled during summer 2010 in the Sønderborg area[8] to be used by a new geothermal plant. The original target reservoir in the Bunter Formation at a depth of 2.1 km was not found, but the sandstones of the Gassum Formation at a depth of about 1.2 km proved to be an acceptable alternative. The plant will be established using driving heat from a new biomass boiler plant. The geothermal heat production is scheduled to start up late 2012 (Magtengaard, pers. comm. 2010).

F.3.3 Heat and Power Generation: Geothermal Plant Neustadt-Glewe, Germany

The commercial Neustadt-Glewe geothermal heating plant was commissioned in January 1995 and planned for supplying the heat demand of the major part of the town Neustadt-Glewe. In 2003, the plant was extended by a power generation unit of 210 kWe gross. This is the first geothermal electric generation plant in Germany, and uses only 98°C (208°F) water, the lowest temperature used in the world, based on an organic rankine cycle using n-Perfluorpentane as working fluid. The power plant is running economically under the conditions of the German Renewable Energy Sources Act (EEG[9], Erneuerbare Energien Gesetz). The water is produced from a depth of 2.1 to 2.3 km with a flow rate of 40-110 m^3/h and a total dissolved solid content of 220 g/l. The Neustadt-Glewe plant supplies heat and power using a parallel-series connection of power plant and heating station (Figure 33). The heating station takes priority over the power plant. The incoming mass flow rate of the brine is split and a part is fed to the power plant (Lund, 2005). The brine leaves the power plant at constant outlet temperature. The two flows, one at initial brine inlet temperature, the other at outlet temperature of the power plant, are joined upstream from the heating station. The mixing temperature should be high enough to meet the heating demand. In summertime, a minimum temperature of 73°C is required. To meet the heating demand in wintertime, higher temperatures are necessary, amounting up to the initial brine temperature (98°C).

[8] http://www.dongenergy.com/geotermi/

[9] From Bürger et al. (2008): The EEG specifies that the producers of electricity from renewable energy sources can demand that the nearest power grid operator purchases the entire renewable electricity for a period of 20 years at a fixed rate (whereby the individual grid operators are obligated to equalize the burden amongst them and to distribute it in equal proportions to the final consumers). For more information about this feed-in tariff system and other instrumental approaches in the power sector, please see the communication from the EU commission from 7/12/2005 (KOM (2005) 627) on the promotion of electricity from renewable energy sources as well as the publication from the German Ministry of the Environment (2007): EEG—The Renewable Energy Sources Act.
(http://www.erneuerbare-energien.de/files/pdfs/allgemein/application/pdf/eeg_brochure_engl.pdf).

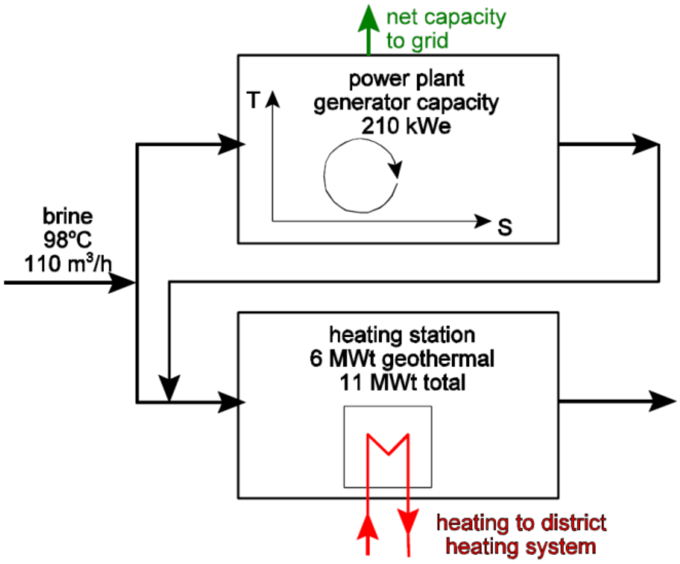


Figure 33: Combined heat and power supply in Neustadt Glewe (in: Lund, 2005)

F.3.4 Heat and Power Generation: Unterhaching, Bavaria, Germany

At Unterhaching, two wells were drilled and tested for the cogeneration of heat and electricity (Figure 34). Temperatures are about 123°C to 134°C. The plant supplies heat to a part of the local community. Surplus heat arising in the summer is used for electricity generation. The high temperatures obtained in the wells are related to waters circulating in a deep-reaching fault system, which was successfully drilled (Wolfgramm et al., 2007).

In Unterhaching, the first commercial geothermal Kalina plant in Germany was build. A flow rate of 150 l/s is used in the geothermal plant. 25 l/s of the thermal water that pass through the facility are extracted for the district heating system. The left water leads to the Kalina cycle that produces the electricity. The hot water heats a mixture of around 89 % ammonia and 11 % water that is already simmering at 50 °C. That's enough for the turbine—and to generate 3.4 MW of electricity in Unterhaching. The water, cooled to 60 °C, is pumped into an injection borehole three kilometers away in order to retain the underground water balance. The project starts in August 2002 and was fully constructed in April 2009. The total investment amounts to 80 million Euro (including 16 million for the Kalina facility). It benefitted from several subsidies (German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety; the Free State of Bavaria; and the KfW Entwicklungsbank: 25 million Euros, whereas 22.4 million Euros are related to special loan conditions. The amortization period of the investment is expected to amount to 15 years. The site is running economically under the conditions of the German Renewable Energy Sources Act (see EEG, p. 78). In 2009, 4,069,775 kWh of electricity and an equivalent of 51,934,000 kWh of heat were produced in Unterhaching. Further information is available at the "Geothermie Unterhaching" website[10].

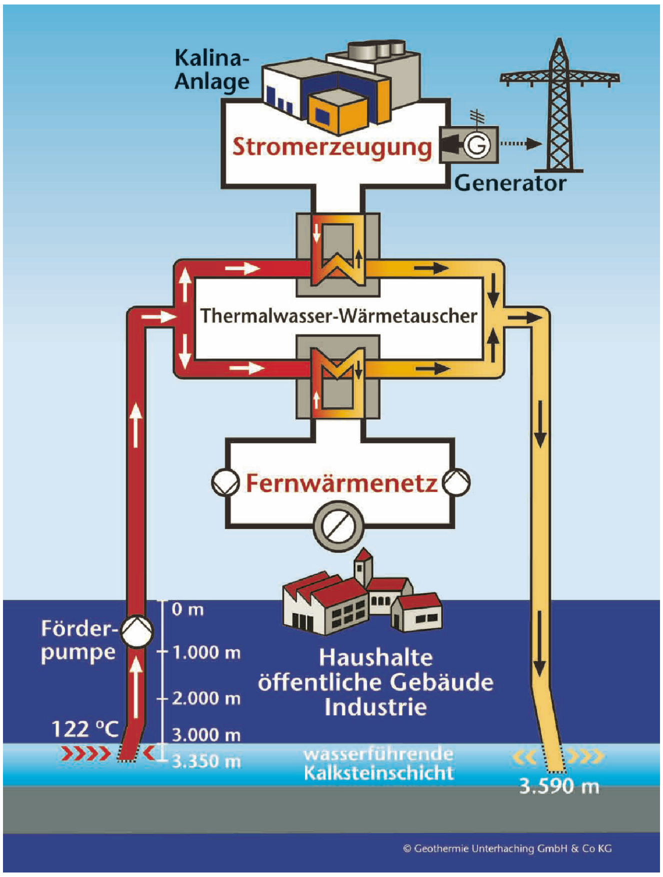


Figure 34: Scheme of the Unterhaching geothermal plant

F.3.5 Geothermal Laboratory Groß Schönebeck

Two research wells, a former gas exploration well E GrSk 3/90 and a new drilled well (Gt GrSk 4/05), give access to water-bearing horizons at depths between 3.9 and 4.4 km and temperatures of about 150 °C. The site is used as an in-situ downhole laboratory for investigating deep sedimentary structures and fluids under natural conditions. In-situ experiments and borehole measurement can be performed with the purpose of studying how to enhance the productivity of low-permeability geothermal reservoirs. In the research well at Groß Schönebeck, stimulation methods commonly used in the oil industry have been successfully adapted and tested for geothermal applications. After a series of stimulation experiments in 2003, reservoir productivity was enhanced to a level that is interesting for energy-efficient power generation at this site.

[10] http://www.geothermie-unterhaching.de

Presently, a long-term circulation test between the boreholes is being set up to demonstrate the sustainability of the reservoir, since the life cycle of a geothermal power plant requires a reliable thermal water production for 20-30 years. After the circulation test, a research power plant will be installed at the site until end of 2011. The plant will provide valuable operational data to assess plant performance and to identify optimization potential for making geothermal power generation cost-effective and energy-efficient.

Details on this research project can be found in Huenges & Moeck (2007), Zimmermann & Moeck (2008), Blöcher et al. (2010b), Frick, Kranz, & Saadat (2010), and on the gfz website[11].

F.4 Greenhouse heating

Low-temperature fluids are adequate for greenhouse heating. Therefore, greenhouse heating is in some regions one of the most common uses of geothermal resources. Due to the low temperatures needed for greenhouse heating, this application could be run as an add-on of geothermal cascade utilization (e.g. Lund & Boyd, 2009) or in conjunction with geothermal heat pumps (e.g. Chiasson, 2005). The heating requirements have to be evaluated first. They depend on the climate, on the desired greenhouse crops, and on the construction method of the greenhouse (affecting the heat loss based on transmission through the walls and the roof of the greenhouse and based on the heating of cold outside air). According to Rafferty (1998), six main geothermal heating systems for distributing the geothermal heat in the greenhouse are applied (finned pipe, standard unit heaters, low-temperatures unit heaters, fan coil units, soil heating, and bare tube). The choice of heating system type depends on the evaluation of the heating requirements. The actual heating equipment is normally separated from the geothermal fluid with a heat exchanger to avoid scaling and corrosion problems (Figure 35).

[11] http://www.gfz-potsdam.de/portal/gfz/Struktur/Departments/Department+4

DOI: 10.2312/GFZ.b103-11066

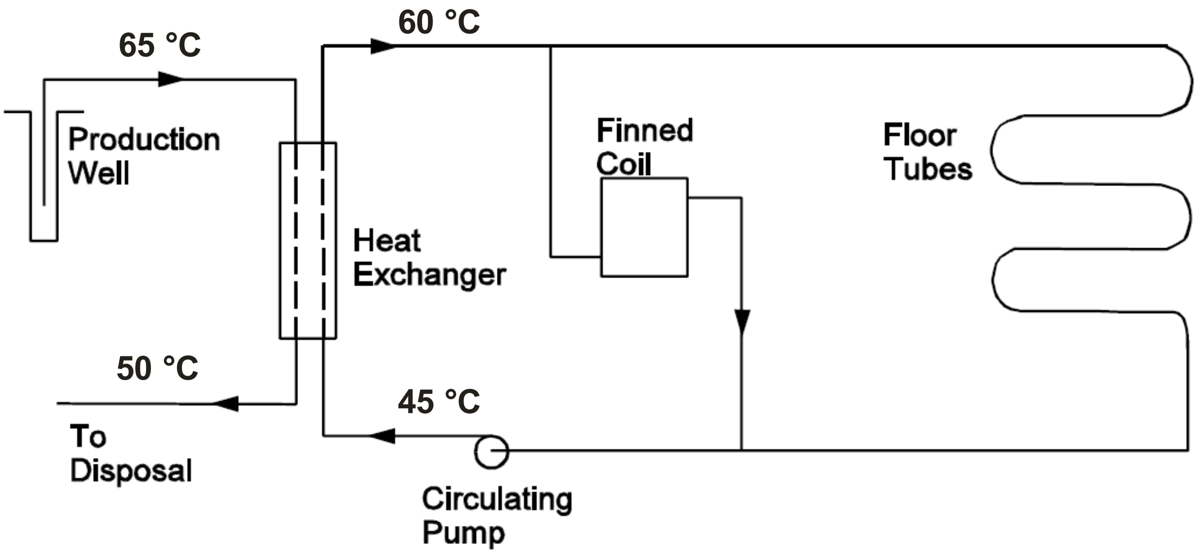


Figure 35: Example of a greenhouse heating system (modified from Rafferty, 1998)

If the geothermal system does not allow meeting 100% of the peak load, the remaining load could be met with a conventional (fossil-fuel) system.

Another application for greenhouse heating is the coupling with geothermal storage (Figure 36). For example, solar energy can used to generate electricity. The solar cells are cooled by water, which is then heating up a geothermal reservoir in the subsurface. This water could be used for floor heating purposes in the winter (Kleinwächter et al., 2006).

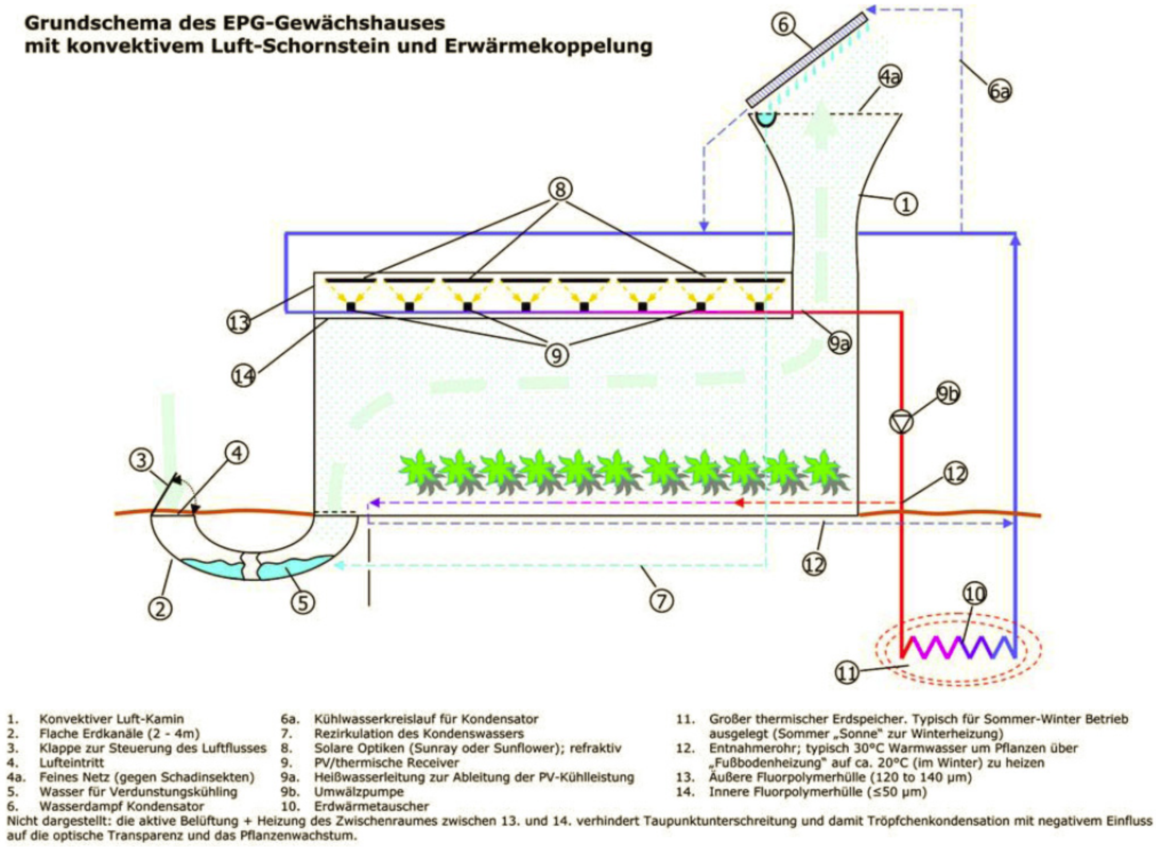


Figure 36: Sketch of a greenhouse using solar heat and underground thermal storage (Kleinwächter et al., 2006)

F.4.1 Drenthe Study, Netherlands

In the Netherlands, a comprehensive, multi-disciplinary feasibility study for the application of geothermal energy for Greenhouses has been published by Heijnen et al. (2010). The zone of interest comprises two designated areas of greenhouse development sized 100 and 180 ha respectively. 3D seismic data have been interpreted in conjunction with borehole data in order to obtain a detailed subsurface model and guide drill-site decisions based on acoustic impedance data. Target horizons are Triassic sandstones in 2–4 km depth. Temperatures are estimated to amount at least more than 100 °C. Petrophysical data was estimated based on core data and well-log data analysis. The petrophysical data was integrated in the site model of acoustic impedance and used to calculate a transmissivity map of the target formation. The results of the different disciplines were then analyzed in an uncertainty analysis showing that the estimated productivity of the site has a certainty of 90%.

F.5 Other Uses

Industrial processes. Although industrial processes consume substantial amounts of heat, the temperatures at which the heat is required are far above the typical range encountered in low-temperature geothermal resources. As a result, it is unlikely that industries will be able to take advantage of low-enthalpy geothermal resources. By carefully targeting those processes characterized by lower temperature heat input requirements, possibly taking advantage of power plant effluent and technologies such as vapor recompression, there may be niche applications which can yield attractive economic savings (Rafferty, 2003).

Drying. Dehydration (or drying) of foods is defined as the application of heat under controlled conditions aiming at removing the majority of the water normally present in a food by evaporation (Fellows, 2009). The drying process involves the slow removal of the largest part of water contained in the fruit, grain, vegetable, or fish so that the moisture contents of the dried product is below 20%. In general, the whole drying process can be divided in three stages: (1) pretreatment stage (selecting, sorting, washing of fresh produce, processing for color preservation etc.), (2) drying stage (mainly using a hot air environment) and (3) post-drying treatment stage (quality control of the product, storage, and packaging; see Mujumdar, 1987). Other products which could be dried by geothermal driven dryers are for example: wood chips, saw dust, yard waste, silage, and diatomaceous earth. Dehydration-drying of agricultural products comprises an interesting application of low and medium-enthalpy geothermal energy, especially when dealing with sensitive fruits and vegetables (Kostoglou et al., 2010). Fresh or recycled air is forced to pass through an air-water converter and to be heated to temperatures in the range 40-100°C. The hot air passes through or above trays or belts with the raw produce, resulting in the reduction on their moisture content. In geothermal drying, electric power is only used to drive fans and pumps. The geothermal drying could also be linked with an existing greenhouse heating system.

Aquaculture involves the raising of freshwater or marine organisms in a controlled environment to enhance production rates. The main species reared in this way are carp, catfish, bass, Tilapia, frogs, mullet, eels, salmon, sturgeon, shrimp, lobster, crayfish, crabs, oysters, clams, scallops, alligators, mussels and abalone (Boyd & Lund, 2003).In the design of geothermal heated ponds and raceways, in order to determine the heat loss, it is necessary to first select the temperature at which the water must be maintained. Then, for a non-covered body of water, exposed to the elements, it exchanges heat with the atmosphere by way of four mechanisms: (1) evaporation, (2) convection, (3) radiation, and (4) conduction. For a detailed planning, modeling and energy balances are required (e.g. Klemetson & Rogers, 1985; Boyd & Rafferty, 1998; Lamoureux et al., 2006). Temperatures required and growth periods for selected aquaculture species could be found in Boyd & Rafferty (1998).

Swimming and **balneological use.** Geothermal waters are extensively used for hot pools and baths. The desirable temperature for swimming pools is from about 27 °C to over 40 °C in spas. In the past, the geothermal water was seldom used for heating or cooling of the spa buildings. Today, indoor adventure pools are often designed instead of pure medical application spas or a combination of both. Especially in low-enthalpy environments, the balneological use often enhances the efficiency of a modern geothermal system as it could be used at the end of other geothermal applications (cascade use). Spas or natatoriums require year-round humidity levels between 40 and 60% for comfort, energy consumption, and building protection. For the design of a spa, the expected heat loads have to be addressed correctly. Heat loads include building heat gains and losses from outdoor air, lighting, walls, roof, and glass, with internal latent heat loads coming generally from people and evaporation (Lund, 2010). The evaporation loads are large compared to other factors and are dependent on the pool characteristics such as the surface area of the pool, wet decks, water temperature and the activity level in the pool (Lund, 2010).

G. References

Adams, M. C., Moore, J. N., Fabry, L. G., & Ahn, J.-H. (1992). Thermal stabilites of aromatic acids as geothermal tracers. *Geothermics , 21* (3), pp. 323-339.

Ahmed, K. (1994). *Renewable Energy Technologies - A Review of the Status and Costs of Selected Technologies, Technical Report No. 240.* Washington D.C.: The International Bank for Reconstruction and Development/THEWORLDBANK.

Ahmed, T., & McKinney, P. D. (2005). *Advanced Reservoir Engineering.* Elsevier.

Aksoy, N. (2007). Optimization of downhole pump setting depths in liquid-dominated geothermal systems: A case study on the Balcova-Narlidere field, Turkey. *Geothermics , 36*, pp. 436-458.

Al-Wardy, W., & Zimmerman, R. (2003). Effective Stress Law for the Permeability of Clay-rich Sandstones. *16th ASCE Engineering Mechanics Conference.* University of Washington, Seattle.

Andersson, O. (2007). Aquifer thermal energy storage (ATES). In H. Paksoy, *Thermal Energy Storage for Sustainable Consumption* (pp. 155-176). Berlin, Heidelberg: Springer.

Astolfi, M., Xodo, L., Romano, M., & Macchi, E. (2010). Technical and economical analysis of a solar–geothermal hybrid plant based on an Organic Rankine Cycle. *Geothermics* (http://dx.doi.org/10.1016/j.geothermics.2010.09.009).

Augustine, C. A., Tester, J. W., Anderson, B., Petty, S., & Livesay, B. J. (2006). A comparison of geothermal with oil and gas well drilling costs. *Geothermal Resources Council Annual Meeting.* San Diego, CA, September 10-13.

Axelsson, G., Thórhallson, S., & Bjönsson, G. (2006). Stimulation of geothermal wells in basaltic rock in Iceland. *ENGINE – Workshop 3.* June 29- July 1, Zürich.

Bauer, K., Moeck, I., Norden, B., Schulze, A., Weber, M., & Wirth, H. (2010). Tomographic P-wave velocity and vertical velocity gradient structure across the geothermal site Gross Schoenebeck (NE German Basin): Relationship to lithology, salt tectonics, and thermal structure. *Journal of Geophysical Research , 115*, p. B08312.

Bear, J. (1972). *Dynamics of Fluids in Porous Media.* Elsevier.

Benderitter, Y., & Cormy, G. (1990). Possible approach to geothermal research and relative cost estimante. In M. Dickson, & M. Fanelli, *Small geothermal resources* (pp. 61-71). Rome, Italy: UNITAR/UNDP Centre for Small Energy Resources.

Bertani, R. (2010). Geothermal Power Generation in the World 2005-2010 Update Report. *Proceedings World Geothermal Congress* (p. 41). Bali, Indonesia: Conference CD.

Blackwell, D., Negraru, P., & Richards, M. (2006). Assessment of the Enhanced Geothermal System Resource Base of the United States. *Natural Resources Research , 15* (4), pp. 283-308.

Blöcher, M. G., Cacace, M., Lewerenz, B., & Zimmermann, G. (2010). Three dimensional modelling of fractured and faulted reservoirs: Framework and implementation. *Chemie der Erde , 70* (S3), pp. 145-153.

Blöcher, M. G., Zimmermann, G., Moeck, I., Brandt, W., Hassanzadegan, A., & Magri, F. (2010). 3D numerical modeling of hydrothermal processes during the lifetime of a deep geothermal reservoir. *Geofluids , 10*, pp. 406-421.

Boissavy, M., & Dubief, R. (1995). New Technologies in the Geothermal Well. *Proceedings World Geothermal Congress 1995.*

Boyd, T. L., & Lund, J. W. (2003). Geothermal heating of greenhouses and aquaculture facilties. *International Geothermal Conference*, *S14 Paper029*, pp. 14-19. Reykjavík.

Boyd, T. L., & Rafferty, K. (1998). *Aquaculture Information Package.* Klamath Falls, OR: Geo-Heat Center.

Bruel, D., & Cacas, M. (1992). *Numerical Modeling Technique: Contribution to the Soultz Project.* Gordon and Breach Science Publisher.

Bruhn, D., Manzella, A., Vuataz, F., Faulds, J., Moeck, I., & Erbas, K. (2010). Exploration Methods. In E. Huenges (Ed.), *Geothermal Energy Systems* (p. 464). Berlin: Wiley-VCH.

Bürger, V., Klinski, S., Lehr, U., Leprich, U., Nast, M., & Ragwitz, M. (2008). Policies to support renewable energies in the heat market. *Energy Policy , 36*, pp. 3150-3159.

Carter, D. (2003). 3-D seismic geomorphology: Insights into fluvial reservoir deposition and performance, Widuri field, Java Sea. *AAPG Bulletin , 87* (6), pp. 909-934.

Chandrasekharam, D., & Bundschuh, J. (2002). *Geothermal Energy Resources for Developing Countries.* The Netherlands: AA Balkema Pub.

Chandrasekharam, D., & Bundschuh, J. (2008). *Low-Enthalpy Geothermal Resources for Power Generation.* Leiden, Netherlands: CRC Press/Balkema.

Chiasson, A. (2005). *Greenhouse heating with geothermal heat pump systems.* Oregon Institute of Technology. Klamath Falls, OR, US: Geo-Heat Center.

Clauser, C. (Ed.). (2003). *Numerical Simulation of Reactive Flow in Hot Aquifers.* Berlin: Springer.

Cooper, H., & Jacob, C. (1946). A generalized graphical method for evaluating formation constants and summarizing well field history. *Transactions of the American Geophysical Union , 27*, pp. 526-534.

Cornet, F. (1985). *An overview on research on energy production from hot-dry-rocks.* Jülich: Geotechnik und Lagerstätten.

Crowe, C., Masmonteil, J., & Thomas, R. (1992). Trends in Matrix Acidizing. *Oilfield Review* , pp. 24-40.

Culver, G. (1989). Drilling and Well Construction. In P. J. Lienau, & B. C. Lunis (Eds.), *Geothermal Direct Use - Engineering and Design Guidebook* (pp. 95-130). Klamath Falls, Oregon: Geo-Heat Center.

Culver, G., & Rafferty, D. (1998). Well pumps. In J. Lund, J. Lienau, & B. Lunis (Eds.), *Geothermal direct-use, Engineering and Design Guidebook* (pp. 211-239). Idaho: Geo-Heat Center, Oregon Institute of Technology.

Curtis, R., Lund, J., Sanner, B., Rybach, L., & Hellström, G. (2005). Ground Source Heat Pumps - Geothermal Energy for Anyone, Anywhere: Current Worldwide Activity. *Proceedings World Geothermal Congress 2005*, (pp. 1-9). Antalya, Turkey.

Dickson, M., & Fanelli, M. (2004). *What is geothermal energy.* Pisa, Italy: Instituo di Geoscienze e Georisorce.

Diersch, H. (2002). *FEFLOW Finite Element Subsurface Flow and Transport Simulation System - User's Manual.* Berlin: WASY Ltd.

Diersch, H.-J. (2009). *Interactive, graphics-based finite-element simulation system FEFLOW for modeling groundwater flow, contaminant mass and heat transport processes.* Berlin: DHI-WASY GmbH.

Dincer, I., & Rosen, M. A. (2002). *Thermal Energy Storage: Systems and Applications.* John Wiley & Sons.

DiPippo, R. (2008). *Geothermal Power Plants, Principles, Applications, Case Studies and Environmental Impact.* Oxford: Elsevier Ltd.

Drever, J., Holland, H., & Turekian, K. (Eds.). (2004). *Surface and Groundwater, Weathering, and soils* (Vol. Treatise on geochemistry). Oxford: Elsevier.

Economides, M., & Boney, C. (2000). Reservoir Stimulation in Petroleum Production. In M. Economides, & K. Nolte (Eds.), *Reservoir Stimulation* (3 ed., pp. 1.1-1.30). Wiley-VCH.

Economides, M., & Ungemach, P. (1987). *Applied Geothermics.* Wiley & Sons.

Enever, J. R., Yassir, N., Willoughby, D. R., & Addis, M. A. (1996). Recent experience with extended leak-off tests for in-situ stress measurements in Australia. *APPEA Journal , 36* (1), pp. 528-535.

ENGINE. (2008). Performance Assessment Tool ENGINEPA.XLS, ENGINE DSS. *Deliverable No~51 of the ENGINE Coordination (ENhanced Geothermal Innovative Network for Europe)* . Utrecht.

Feldrappe, H., & Obst, K. W. (2008). Mesozoic sandstone aquifers of the North German Basin and their potential for geothermal utilization. *Zeitschrift für geologische Wissenschaften , 36*, pp. 199-222.

Fellows, P. (2009). *Food Processing Technology: Principles and Practice.* New York: CRC.

Finsterle, S., & Pruess, K. (1997). Development of Inverse Modeling Techniques for Geothermal Applications. *Proceedings, Geothermal Program Review XV*, (pp. 2-47-2-54). San Francisco, CA.

Flashman, R., & Lekic, H. O. (1999). Artificial Lift for High-Volume Production. *Oilfield Review , 11* (1).

Förster, A., & Merriam, D. (1999). Problems and potential of industrial temperature data from a cratonic basin environment. In A. Förster, & D. Merriam (Eds.), *Geothermics in basin analysis* (pp. 35-59). New York: Kluwer Academic/Plenum Publisher.

Förster, A., Norden, B., Zinck-Jorgensen, K., Frykman, P., Kulenkampff, J., Spangenberg, E., et al. (2006). Baseline characterization of the COSINK geological storage site at Ketzin, Germany. *Environmental Geosciences , 13* (3), pp. 145-161.

Frape, S., Blyth, A., Blomkvist, R., McNutt, R., & Gascoyne, M. (2004). Deep Fluids in the Continents: II. Crystalline Rocks. In J. Drever, H. Holland, & K. Turekian (Eds.), *Surface and Groundwater, Weathering, and Soils* (Vol. Treatise on geochemistry, pp. 541-580).

Frick, S., Kaltschmitt, M., & Schröder, G. (2010). Life cycle assessment of geothermal binary power plants using enhanced low-temperature reservoirs. *Energy , 35*, pp. 2281-2294.

Frick, S., Kranz, S., & Saadat, A. (2010). Holistic Design Approach for Geothermal Binary Power Plants with Optimized Net Electricity Provision. *Proceedings World Geothermal Congress 2010.* Bali, Indonesia.

Frick, S., van Wees, J. D., Kaltschmitt, M., & Schröder, G. (2010). Economic Performance and Environmental Assessment. In E. Huenges (Ed.), *Geothermal Energy Systems: Exploration, Development and Utilization* (pp. 371-418). Weinheim: Wiley-VCH.

Fuchs, S., & Förster, A. (2010). Rock thermal conductivity of Mesozoic geothermal aquifers in the Northeast German Basin. *Chemie der Erde - Geochemistry , 70* (3), pp. 13-22.

Gadde, P., & Sharma, M. (2001). Growing Injection Well Fractures and their Impact on Waterflood Performance. *SPE Paper 71614* .

Geo-HeatCenterOregon. (2005). Geothermal direct-use case studies, prepared for the U.S. Department of Energy. (I. o. Geo-Heat Center Oregon, Ed.) Klamath Fallls. Retrieved from http://geoheat.oit.edu/pdf/tp115.pdf

Giese, L., Seibt, A., Wiersberg, T., & Pekdeger, A. (2002). Geochemistry of the Formation Fluid. *GFZ Scientific Technical Report , STR02/14*, pp. 145-169.

Gudmundsson, J.-S. (1988). The elements of direct uses. *Geothermics , 17* (1), pp. 119-136.

Haenel, R., Rybach, L., & Stegena, L. (1988). Fundamentals of geothermics. In R. Haenel, L. Rybach, & L. Stegena, *Handbook of Terrestrial Heat-Flow Determination* (pp. 9-57). Dordrecht, Netherlands: Kluwer Academic.

Hanor, J. (1994). Origin of saline fluids in sedimentary basins. In J. Parnell (Ed.), *Geofluids: Origin, Migration and evolution of Fluids in Sedimentary Basins* (Vol. 78, pp. 151-174). London: Geological Society Special Publication.

Hartemink, M., Escovedo, B., Hoppe, J., & Macaulay, R. (1997). Qarn Alam: the design of a steam-injection pilot project for a fractured reservoir. *Petroleum Geoscience , 3*, pp. 183-192.

Hartmann, A., Pechnig, R., & Clauser, C. (2007). Petrophysical analysis of regional-scale thermal properties for improved simulations of geothermal installations and basin-scale heat and fluid flow. *Int. J. Earth Sci. (Geol. Rundsch.) , 97*, pp. 421-433.

Heijnen, L. J., Diephuis, G., Betts, P., Huck, A., Willemsen, A., & Buik, N. A. (2010). Feasibility for the Application of Geothermal Energy for Greenhouses in South-East Drenthe, the Netherlands, Results of a Multi-Disciplinary Study. *Proceedings World Geothermal Congress 2010*, (pp. 1-6). Bali, Indonesia.

Hellström, G., & Sanner, B. (1994). Software for dimensioning of deep boreholes for heat extractrion. *Proceedings CALORSTROCK 94*, (pp. 195-202). Espoo/Helsinki.

Hochstein, M. P. (1990). Classification and assessment of geothermal resources. In M. Dickson, & M. Fanelli, *Small geothermal resources* (pp. 31-59). Rome, Italy: UNITAR/UNDP Centre for Small Energy Resources.

Hornung, J., & Aigner, T. (2002). Reservoir architecture in a termianl alluvial plain: An outcrop analogue study (Upper Triassic, southern Germany) Part II: cyclicity, controls, and models. *Journal of Petroleum Geology , 25* (2), pp. 151-178.

Huenges, E. (Ed.). (2010). *Geothermal Energy Systems: Exploration, Development and Utilization.* Wiley-VCH.

Huenges, E., & Moeck, I. (2007). Directional drilling and stimulation of a deep sedimentary geothermal reservoir. *Scientific Drilling , 5*, pp. 47-49.

Hurter, S., & Haenel, R. (2002). In S. Hurter, & R. Haenel (Eds.), *Atlas of geothermal resources in Europe.* Luxemburg : Office for Official Publications of the European Communities.

Jacob, C. E. (1946). Effective radius of drawdown test to determine artesian well. *Proceedings of the American Society of Civil Engineers , 72* (5), pp. 629-646.

Kabus, F., & Seibt, P. (2000). Aquifer Thermal Energy Storage for the Berlin Reichstag Building – New Seat of the German Parliament. *Proceedings Word Geothermal Congress*, (pp. 3611-3615). Kyushu - Tohoku, Japan.

Kagel, A. (2008). *The State of Geothermal Technology - Part II: Surface Technology.* Washington: Geothermal Energy Association.

Kalina, A. (1983). Combined cycle and waste heat recovery power systems based on a novel thermodydnamic energy cycle utilizing low-temperature heat for power generation. *Proceedings of the 1983 Joint Power Generation Conference* (pp. 1-5). Indianapolis: American Society of Mechanical Engineers.

Kharaka, Y., & Hanor, J. (2004). Deep Fluids in the Continents: I Sedimentary Basins. In J. Drever, H. Holland, & K. Turekian (Eds.), *Surface and Groundwater, Weathering, and Soils* (Vol. Treatise on geochemistry, pp. 499-540).

Kleinwächter, J., Schreier, F., Amandie, T., & Rueter, H. (2006). Autarkes – Erdwärmegekoppeltes – Stromerzeugendes Envelope Gewächshaus. (G. Vereinigung, Ed.) *Geothermische Energie , 4*, pp. 19-20.

Klemetson, S. L., & Rogers, G. L. (1985). Aquaculture pond temperature modeling. *Aquacultural Engineering , 4* (3), pp. 191-208.

Knapek, E., & Kittl, G. (2007). Unterhaching Power Plant and Overall System. *Proceedings European Geothermal Congress*, (pp. 1-6). Unterhaching.

Kohl, T., & Hopkirk, R. (1995). "FRACTure" – A simulation code for forced fluid transport in fractured, porous rock. *Geothermics , 24*, pp. 333-343.

Köhler, S. (2005). *Geothermisch angetriebene Dampfkraftprozesse – Analyse und Vergleich binärer Kraftwerke.* Technische Universität Berlin, Berlin.

Kolditz, O. (1995). Modelling of flow and heat transfer in fractured rock: conceptual model of a 3-D deterministic fracture network. *Geothermics , 24* (3), pp. 451-470.

Kolditz, O. (1997). *Strömung, Stoff- und Wärmetransport im Kluftgestein.* Borntraeger Publisher.

Kolditz, O., Blöcher, M., Clauser, C., Diersch, H.-J., Kohl, T., Kühn, M., et al. (2010). Geothermal Reservoir Simulation. In E. Huenges (Ed.), *Geothermal Energy Systems* (p. 464). Berlin: Wiley-VCH.

Kostoglou, M., Chrysafis, N., & Andritsos, N. (2010). Modeling a Tomato Dehydration Process Using Geothermal Energy. *World Geothermal Congress* (p. 7). Bali, Indonesia: Conference-CD.

Kranz, S., & Bartels, J. (2010). Simulation and Data Based Optimisation of an Operating Seasonal Aquifer Thermal Energy Storage. *Proceedings World Geothermal Congress 2010.* Bali, Indonesia.

Kranz, S., Bartels, J., Gehrke, D., Hoffmann, F., & Wolfgramm, M. (2008). Wärme- und Kältespeicherung in Aquiferen. *bbr Fachmagazin für Brunnen und Leitungsbau , 59* (7/8), pp. 34-43.

Kreuter, H., & Schrage, C. (2010). The Hybrid Power Plant Neuried, Germany. *Proceedings Word Geothermal Congress 2010.* Bali, Indonesia.

Kristmannsdóttir, H., & Àrmannsson, H. (2003). Environmental aspects of geothermal energy utilization. *Geothermics* , pp. 451-461.

Lamoureux, J., Tiersch, T., & Hall, S. G. (2006). Pond heat and temperature regulation (PHATR): Modeling temperature and energy balances in earthen outdoor aquaculture ponds. *Aquacultural Engineering , 34* (2), pp. 103-116.

Lee, K. (2001). Classification of geothermal resources by exergy. *Geothermics , 30*, 431-442.

Legart, B. (2003). *Erschließung sedimentärer Speichergesteine für eine geothermische Stromerzeugung.* Berlin: TU Berlin (diss.).

Legarth, B., & Tischner, T. H. (2003). Stimulation experiments in sedimentary, low-enthalpy reservoirs for geothermal power generation, Germany. *Geothermics , 32*, pp. 487-495.

Legarth, B., Huenges, E., & Zimmermann, G. (2005). Hydraulic fracturing in a sedimentary geothermal reservoir: results and implications. *International Journal of Rock Mechanics and Mining Sciences , 42*, pp. 1028-1041.

Lehmann, H., Wang, K., & Clauser, C. (1998). Parameter identification and uncertainty analysis for heat transfer at the KTB drill site using a 2-D inverse method. *Tectonophysics , 291* (1-4), pp. 179-194.

Lievaart, L., & Davies, D. (1987). The role of fines during acidizing treatments. *Marine and Petroleum Geology , 4*, pp. 127-131.

Lindal, B. (1973). Industrial and other applications of geothermal energy. In B. Lindal, *Industrial and other applications of geothermal energy* (pp. 135-148). Paris: UNESCO.

Lüschen, E., Dussel, M., Thomas, R., & Schulz, R. (2011, January). 3D seismic survey for geothermal exploration at Unterhaching, Munich, Germany. *First Break , 29*.

Lumb, J. (1981). Prospecting for geothermal resources. In L. Rybach, & L. Muffler, *Geothermal Systems: Principles and Case Studies* (pp. 77-108). New York: John Wiley & Sons, Ltd.

Lund, J. (2007, June). Characteristics, development, and utilization of geothermal resources. *Geo-Heat Center Quarterly Bulletin , 28* (2), pp. 1-9.

Lund, J. (2005). COMBINED HEAT AND POWER PLANT NEUSTADT-GLEWE, GERMANY. *GHC BULLETIN , 26* (2), pp. 31-34.

Lund, J. (Ed.). (1998). Geothermal direct-use equipment. *Geo-Heat Center Quarterly Bulletin , 19,1* . Klamath Falls.

Lund, J. W., & Boyd, T. (2009). Oregon Institute of Technology geothermal uses and projects past, present, and future. *Thirty-Fourth Workshop on Geothermal Reservoir Engineering. SGP-TR-187*, p. 7. Stanford University, Stanford, California: Proceedings.

Lund, J. W., & Freeston, D. H. (2010). Direct Utilization of Geothermal Energy 2010 Worldwide Review. *Proceedings World Geothermal Congress* (pp. 1-23). Bali, Indonesia: Conference CD.

Lund, J., & Chiasson, A. (2007). Examples Of Combined Heat And Power Plants Using Geothermal Energy. *Proceedings European Geothermal Congress.* Unterhaching.

Lund, J., Freeston, D., & Boyd, T. (2005). Direct application of geothermal energy: 2005 Worldwide review. *Geothermics , 34*, pp. 691-727.

Maack, R., & Valdimarsson, P. (2002). Operating experience with Kalina power plants. *Geothermische Stromerzeugung.* Potsdam: VDI Berichte 1703.

Magri, F. (2010). Derivation of the coefficients of compressiblity, thermal expansion and fluid density difference ratio for reproducing aqueous NaCl density. In D.-W. GmbH, *DHI-WASY Software FEFLOW - White Papers* (Vol. V, pp. 97-104). Berlin: DHI-WASY GmbH.

Mahler, A., & Magtengaard, J. (2010). Country Update Report for Denmark. *Proceedings World Geothermal Congress 2010*, (pp. 1-9). Bali, Indonesia.

Malate, R., Austria, J. S., DiLullo, G., Sookprasong, A., & Fancia, E. (1998). Matrix Stimulation Treatment of Geothermal Wells Using Sandstone Acid. *23rd Workshop on Geothermal Reservoir Engineering.* California, USA: Stanford.

McDermott, C., Randriamanjatosoa, A., Tenzer, H., & Kolditz, O. (2006). Simulation of heat extraction from crystalline rocks: the influence of coupled processes on differential reservoir cooling. *Geothermics , 35*, pp. 321-344.

Meier, P., Carrera, J., & Sánchez-Villa, X. (1998). An evaluation of Jacob's method for the interpretation of pumping tests in heterogeneous porous media. *Water Resources Research , 34*, pp. 1011-1025.

Meyers, R. A. (1992). *Encyclopedia of Physical Science and Technology.* San Diego: Academic Press.

Millero, F. (2009). Thermodynamic and Kinetic Properties of Natural Brines. *Aquatic Geochemistry , 15*, pp. 7-41.

Moeck, I., Kwiatek, G., & Zimmermann, G. (2009). Slip tendency analysis, fault reactivation potential and induced seismicity in a deep geothermal reservoir. *Journal of Structural Geology , 31* (10), pp. 1174-1182.

Moeck, I., Schandelmeier, H., & Holl, H.-G. (2009). The stress regime in a Rotliegend reservoir of the Northeast German Basin. *International Journal of Earth Sciences , 98* (7), pp. 1643-1657.

Muffler, P., & Cataldi, R. (1978). Methods for regional assessment of geothermal resources. *Geothermics , 7*, pp. 53-89.

Mujumdar, A. (Ed.). (1987). *Handbook of Industrial Drying.* New York: Marcel Dekker Inc.

Muñoz, G., Bauer, K., Moeck, I., Schulze, A., & Ritter, O. (2010). Exploring the Groß Schönebeck (Germany) geothermal site using a statistical joint interpretation of magnetotelluric and seismic tomography models. *Geothermics , 39* (1), pp. 35-45.

Norden, B., & Förster, A. (2006). Thermal conductivity and radiogenic heat production of sedimentary and magmatic rocks in the Northeast German Basin. *AAPG Bulletin , 90* (6), pp. 939-962.

Norden, B., Förster, A., & Balling, N. (2008). Heat Flow and lithospheric thermal regime in the Northeast German Basin. *Tectonophysics , 460* (1-4), pp. 215-229.

OECD/IEA. (2008). World Trends in Energy Use and Efficiency. *Technical Report* . Paris: International Energy Agency/Organisation for Economic Cooperation and Development/Nuclear Energy Agency.

Omer, A. M. (2008). Ground-source heat pumps systems and applications. *Renewable and Sustainable Energy Reviews , 12* (2), 344-371.

Paksoy (Ed.). (2008). *Thermal Energy Storage for Sustainable Energy Consumption: Fundamentals, Case Studies and Design* (Vols. NATO Science Series II: Mathematics, Physics, and Chemistry). Springer.

Perkins, T., & Gonzales, J. (1985). The effect of thermoelastic stresses on injection well fracturing. *SPE Journal , 25*, pp. 77-88.

Portier, S., André, L., & Vuataz, F. D. (2007). *Review on chemical stimulation techniques in oil industry and applications to geothermal systems.* Neuchâtel: CENTRE DE RECHERCHE EN GEOTHERMIE.

Portier, S., Vuataz, F.-D., Nami, P., Sanjuan, B., & Gérard, A. (2009). Chemical stimulation techniques for geothermal wells: experiments on the three-well EGS system at Soultz-sous-Forêts, France. *Geothermics , 38*, pp. 349-359.

Press, F., & Siever, R. (1984). *Earth.* New York: W.H. Freeman and Company.

Pringle, J., Howel, J., Hodgetts, D., Westerman, A., & Hodgson, D. (2006). Virtual outcop models of petroleum reservoir analogues: a review of the current state-of-the-art. *EAGE first break , 24*, 33-42.

Pruess, K., & Spycher, N. (2007). ECO2N - a fluid property module for the TOUGH2 code for studies of CO2 storage in saline aquifers. *Energy Conversion and Management , 48* (6), pp. 1761-1767.

Pruess, K., Oldenburg, C., & Moridis, G. (1999). *Numerical Simulation of Reactive Flow in Hot Aquifers.* Berkeley, California: Lawrence Berkeley National Laboratory.

Rafferty, K. D. (1998). Greenhouses. In P. Lienau, & B. Lunis, *Geothermal direct use engineering and design guidebook* (pp. 307-326). Klamath Falls, OR (US): Oregon Institute of Technology.

Rafferty, K. (2003). Industrial processes and the potential for geothermal applications. *Geo-Heat Center Bulletin , 24* (3), pp. 7-11.

Rafferty, K., & Culver, G. (1998). Heat Exchangers. In J. Lund, J. Lienau, & B. Lunis (Eds.), *Geothermal direct-use, Engineering and Design Guidebook* (pp. 261-277). Idaho: Geo-Heat Center Oregon Institute of Technology.

Regenspurg, S., Schmidt, K., & Saadat, A. (2009). Geochemische Aspekte zu Risiken in der Geothermie: Korrosion und Scaling. *Der Geothermiekongress 2009*, (p. 10). Bochum.

Renard, P. (2005). Hydraulics of Wells and Well Testing. In M. G. Anderson, *Encylopedia of Hydrological Sciences* (pp. 1-18). John Wiley & Sons, Ltd.

Ringrose, P., Martinius, A., & Alvestad, J. (2008). Multiscale geological reservoir modelling in practice. (A. Robinson, S. Price, J. Hegre, & A. Muggeridge, Eds.) *Geological Society Special Publications , 309*, pp. 123-134.

Rybach, L. (2001). DESIGN AND PERFORMANCE OF BOREHOLE HEAT EXCHANGER / HEAT PUMP SYSTEMS. *Proc. European Summer School of Geothermal Energy Applications*, (pp. 173-181). Oradea/Romania.

Rybach, L., & Sanner, B. (2000). Ground-source heat pump systems - the European experience. *GHC Bulletin* , 16-26.

Saadat, A., Frick, S., Kranz, S., & Regenspurg, S. (2010). Energetic Use of EGS Reservoirs. In E. Huenges (Ed.), *Geothermal Energy Systems* (p. 464). WILEY-VCH.

Saleh, B., Koglbauer, G., Wendland, M., & Fischer, J. (2007). Working fluids for low-temperature organic Rankine cycles. *Energy , 32*, pp. 1210-1221.

Sanjuan, B., Pinault, J.-L., Rose, P., Gérard, A., Brach, M., Braibant, G., et al. (2006). Tracer testing of the geothermal heat exchanger at Soultz-sous-Forêts (France) between 2000 and 2005. *Geothermics , 35* (5-6), pp. 622-653.

Sanner, B., Kabus, F., Seibt, P., & Bartels, J. (2005). Underground Thermal Energy Storage for the German Parliament in Berlin, System Concept and Operational Experiences. *Proceedings World Geothermal Congress 2005*, (pp. 1-8). Antalya, Turkey.

Sanner, B., Mands, E., & Sauer, M. K. (2003). Larger geothermal heat pump plants in the central region of Germany. *Geothermics , 32*, 589-602.

Schaetzle, W., Brett, C., Grubbs, D., & Seppanen, M. (1980). *Thermal Energy Storage in Aquifers: The Design and Applications.* Pergamon Press.

Schellschmidt, R., Sanner, B., Pester, S., & Schulz, R. (2010). Geothermal Energy Use in Germany. *Proceedings World Geothermal Congress 2010* (pp. 1-19). Bali, Indonesia: Conference-CD.

Schmid, W. (2009). Geologisches Landesamt empfiehlt: Bohrstopp bei Gips. *TGA Fachplaner , 6*, pp. 33-35.

Schulte, T., Zimmermann, G., Vuataz, F., Portier, S., Tischner, T., Junker, R., et al. (2010). Enhancing Geothermal Reservoirs. In E. Huenges (Ed.), *Geothermal Energy Systems.* Weinheim: Wiley-VCH.

Somerton, W. (1992). *Thermal Properties and Temperature-related Behavior of Rock/Fluid Systems.* Elsevier.

Sperber, A., Moeck, I., & Brandt, W. (2010). Drilling into Geothermal Reservoirs. In E. Huenges (Ed.), *Geothermal Energy Systems* (p. 464). WILEY-VCH.

Stiger, S. G., & Renner, J. (1989). Well testing and reservoir evaluation. In P. J. Lienau, & B. C. Lunis, *Geothermal Direct Use - Engineering and Design Guidebook* (pp. 131-148). Klamath Falls, Oregon, US: Geo-Heat Center.

Stober, I. (1986). Strömungsverhalten in Festgesteinsaquiferen mit Hilfe von Pump- und Injektionsversuchen. *Geologisches Jahrbuch , C 42*, p. 204.

Taylor, M. A. (2007). *The State of Geothermal Technology - Part I: Subsurface Technology.* Washington: Geothermal Energy Association.

Tester, J., Murphy, H., Grisgsby, C., Potter, R., & Robinson, B. (1989). Fractured Geothermal Reservoir Growth Induced by Heat Extraction. *SPE Reservoir Engineering , 4* (1), pp. 97-107.

Theis, C. (1935). The relation between the lowering of the piezometric surface and the rate and duration of discharge of a well using groundwater storage. *Transactions of the American Geophysical Union , 2*, pp. 519-524.

Thiem, G. (1906). *Hydrologische Methoden.* Leipzig: Gebhardt.

Thomsen, K. (2005). Modeling electrolyte solutions with the extended universal quasichemical (UNIQUAC) model. *Pure and Applied Chemistry , 77* (3), pp. 531-542.

Thorsteinsson, H. H., & Tester, J. W. (2010). Barriers and enablers to geothermal district heating system development in the United States. *Energy Policy , 38*, pp. 803-813.

Ungemach, P., Antics, M., & Papachristou, M. (2005). Sustainable Geothermal Reservoir Management. *Proceedings World Geothermal Congress.* Antalya, Turkey.

VBI (Ed.). (2010). *Tiefe Geothermie VBI-Leitfaden* (Vol. 21). Berlin: Verband Beratender Ingenieure VBI.

Wang, W., Kosakoswki, G., & Kolditz, O. (2009). A parallel finite element scheme for thermo-hydro-mechanical (THM) problems in porous media. *Computer and Geosciences , 35* (8), pp. 1631-1641.

Wiese, B., Böhner, J., Enachescu, C., Würdemann, H., & Zimmermann, G. (2010). Hydraulic characterisation of the Stuttgart formation at the pilot test site for CO2 storage, Ketzin, Germany. *International Journal of Greenhouse Gas Control , doi:10.1016/j.ijggc.2010.06.013*.

Wolfgramm, M., Bartels, J., Hoffmann, F., Kittl, G., Lenz, G., Seibt, P., et al. (2007). Unterhaching geothermal well doublet: structural and hydrodynamic reservoir characteristics, Bavaria (Germany). *Proceedings European Geotherma Congress 2007*, (pp. 1-6). Unterhaching, Germany.

Wolfgramm, M., Rauppach, K., & Seibt, P. (2008). Reservoirgeologische Charakterisierung mesozoischer Sandsteine im Norddeutschen Becken auf Basis petrophysikalischer und petrographischer Daten. *Z. geol. Wiss. , 4* (5), pp. 249-266.

Yokoyama, H., Nakatsuka, K., Abe, M., & Watanabe, K. (1983). Temperature dependency of electrical resistivity of water-saturated rocks and the possibility of underground temperature estimation. *Journal of Geothermal Research Society of Japan , 5* (2), pp. 103-120.

Zhu, J., & Zhang, W. (2004). Optimization design of plate heat exchangers (PHE) for geothermal district heating systems. *Geothermics , 33* (3), pp. 337-347.

Zimmermann, G., & Moeck, I. (2008). Geothermische Forschungsbohrung in Groß Schönebeck - von der Planung bis zur Stimulation. *Brandenburgische geowissenschaftliche Beiträge , 15* (1/2), pp. 155-164.

Zimmermann, G., & Reinicke, A. (2010). Hydraulic stimulation of a deep sandstone reservoir to develop an enhanced geothermal system; laboratory and field experiments. *Geothermics , 39* (1), pp. 70-77.

Zimmermann, G., Moeck, I., & Bloecher, G. (2010). Cyclic waterfrac stimulation to develop an enhanced geothermal system (EGS); conceptual design and experimental results. *Geothermics , 39* (1), pp. 59-69.

Zoback, M., Barton, C., Brudy, M., Castillo, D., Finkbeiner, T., Grollimund, et al. (2003). Determination of stress orientation and magnitude in deep wells. *International Journal of Rock Mechanics & Mining Sciences , 40*, pp. 1049-1076.

H. Index

H

I

J

K

L

M

N

O

P

Q

R

S

T

U

DOI: 10.2312/GFZ.b103-11066

W

ISSN 1610-0956