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2014 JRC Geothermal Energy Status Report

Technology, market and economic aspects of geothermal energy in Europe

Bergur Sigfússon
Andreas Uihlein

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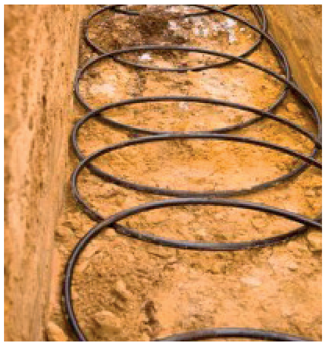


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Abstract

Geothermal energy resources have been used by mankind in some form for thousands of years. Depending on the temperature of the resource, it may be used for power production, supply of heat or a combination of both. This report presents the current status of the major technologies to utilize the full temperature range of geothermal resources ranging from shallow and borehole ground source heat pump systems, direct use facilities to power plants deriving their fluids from volcanic systems. Power production from hydrothermal resources where natural permeability coincides with hot bedrocks is a mature technology. Power and heat production from engineered geothermal systems where permeability has to be artificially created is less mature and needs further development and support for large scale implementation. Currently, geothermal provides 0.2 % of EU final electricity demand. Although the EU theoretical power production potential with the EGS technology is very high, public support for geothermal is limited compared to other renewable technologies. In order to expand the potential for geothermal power production, focus should be made on facilitating the deployment of the EGS technology. The understanding of successful long term EGS reservoir management has to be elevated and cheaper and more reliable drilling technologies should be developed.

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ACRONYMS AND ABBREVIATIONS

CAPEX	Capital expenditure or capital cost
CF	Capacity factor
CHP	Combined heat and power
COP	Coefficient of performance
EEPR	European Energy Programme for Recovery
EGEC	European Geothermal Energy Council
EGS	Engineered geothermal system
EU	European Union
FIT	Feed-in-tariff
FOM	Fixed operation & maintenance cost
FRP	Fibre-reinforced plastic
GSHP	Ground source heat pumps
GW	Gigawatt
HDR	Hot, dry rock
HVAC	Heating, ventilation, and air-conditioning
kW	Kilowatt
LCOE	Levelised cost of energy
LME	Large magnitude event
M_L	Local magnitude of an earthquake
MW	Megawatt
NCG	Non condensable gases
NER 300	New Entrants' Reserve 300
NREAP	National Renewable Energy Action Plan
η_u	Utilisation efficiency (or exergy efficiency) for a power plant or utilisation ratio for a heat exchanger
O&M	Operation & Maintenance
OEM	Original equipment manufacturer
OPEX	Operational expenditure
ORC	Organic rankine cycle
PDC	Polycrystalline diamond compact (bits)
ppm	Parts per million
PV	Photovoltaics
R&D	Research and development
RD&D	Research, development and demonstration
RES-E	Renewable electricity
ROI	Return on investment
ROP	Rate of penetration
TGC	Tradable Green Certificate
UTES	Underground thermal energy storage

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EXECUTIVE SUMMARY

Geothermal energy is derived from the thermal energy generated and stored in the interior of the earth. This energy is accessible since groundwater transfers the heat from rocks to the surface either through boreholes or natural cracks and faults. The geothermal resource is a renewable resource because there is a constant heat flow to the surface and atmosphere from the immense heat stored within the earth while the groundwater is replenished by rainfall and circulation within the crust.

A geothermal system is called hydrothermal when a natural aquifer usually with fracture permeability coincides with elevated temperatures in the crust. Hydrothermal resources have been subdivided based on the temperature of the crustal fluids. Low enthalpy resources are below 100 °C at 1 km depth, whereas medium enthalpy resources are between 100-180 °C and high enthalpy resources are above 180 °C at 1 km. Waters from low enthalpy resources are directly used for example for heating and sometimes heat is extracted with the aid of ground source heat pumps. Water from medium enthalpy resources may be directly used and used for power production with the aid of binary turbines. High enthalpy resources, which have the smallest geographical distribution, are suitable for power generation and often supply heat to combined heat and power plants.

Rocks without natural permeability but displaying high temperatures may also be stimulated by physical and chemical treatments. Once an adequate stimulation has been performed, the resource is called engineered geothermal system (EGS). Production wells in hydrothermal systems are most often stimulated during the drilling process. Further, the hydrothermal reservoirs may be stimulated or affected through re-injection wells by chemical additives and elevated pressures during operations. Geothermal power production from hydrothermal systems is a proven technology with a 100 year history. However, EGS are still in the development phase and have not been demonstrated under many different geological conditions. As hot dry rocks are much more widespread than hydrothermal resources, successful EGS have the potential to produce power and or heat on much larger scale than the hydrothermal resources.

The heat from geothermal fluids may be extracted through series of processes reaching from producing power, drying materials, district heating, fish farming and snow melting. Optimum heat extraction efficiency can be achieved and the usage can be tailor made for specific locations.

Since no fossil fuels are needed for their operation, emissions from geothermal power plants are much lower than those of coal or natural gas fired power plants. Geothermal plants emit approximately 5 % of carbon dioxide, 1 % of sulphur dioxide equivalents and less than 1 % of nitrous oxide emitted by a coal power plant of equal size. Hydrogen sulphide poses the largest localised environmental threat from high enthalpy power plants. Some plants like binary plants are nearly emission free during operation but emissions are associated with drilling operations. In areas with high power and heat demand, production of heat rather than electricity using geothermal resources may be more effective to reduce overall CO_2 emissions when replacing fossil fuels. The main environmental concern with EGS plants is induced seismicity during reservoir stimulation. Stimulation programs have to be well organised and properly presented to the public prior to any operations. Seismicity may also be associated with operations of hydrothermal power plants but is usually less intense.

Flash power plants associated with high enthalpy hydothermal resources are the cheapest power plants compared to binary plants from hydrothermal or binary plants associated with EGS. Drilling frequently constitutes more than 50 % of the capital expenditure (CAPEX) of geothermal power plants. Cost reductions in drilling technologies and effective reservoir management scenarios have the potential to lower these costs. Although the CAPEX of geothermal plants is high compared to other renewable technologies, geothermal plants have low levelised cost of electricity (LCOE) making them a worthwhile investment opportunity.

The total installed capacity of geothermal energy amounts to about 60 GW worldwide with shares of 18 %, 26 %, and 56 % for power generation, direct use, and ground source heat pumps (GSHP), respectively. Lead markets for geothermal energy are in America, Europe and Asia.

In the EU, the installed capacity of GSHP was about 16.5 GW_{th} while direct use capacity amounted to about 3.0 GW_{th}. The capacity of the 51 geothermal power plants in operation is about 0.95 GW_e. Sweden, Germany, and Italy are the countries with greatest installed capacity of geothermal energy in the European Union (EU). Geothermal energy provided about 0.2 % of the total EU final electricity demand and 0.9 % of the electricity generated by renewable sources (about 660 TWh) in 2012.

The annual production of geothermal energy in the EU could reach about 49 TWh of heat from GSHP and 30 TWh from direct use in 2020. Projections for power generation assume an installed capacity of 1.6 GW_e by 2020. Global hydrothermal power production capacity will increase by 0.6 GW_e to 1 GW_e per year in the mid-term (until 2030) and might reach 140 to 160 GW_e by 2050. In comparison, general estimates, provided technological challenges are overcome, suggest between 1200 GW_e to 12000 GW_e could be installed applying EGS technology worldwide.

National Renewable Energy Action Plans (NREAP) lay out how the EU member states will achieve their mandatory targets of 20 % share of energy from renewable sources in overall consumption by 2020. In 2012, shallow geothermal (mainly GSHP) heat production exceeded the NREAP target by 40 %, direct heat production was 90 % of the NREAP target and installed power capacity was 11 % above the NREAP target.

Geothermal projects receive a small share of public financial support from the EU and Member States compared to other renewable energies. Until 2012, geothermal projects had received EUR 29.4 million through FP6 and FP7 compared to EUR 1.7 billion spent to date by EU on renewables through FP6, FP7 and the European Energy Programme for Recovery (EEPR). No geothermal project has received funding from EEPR and three projects have been funded through the New Entrants' Reserve 300 (NER 300)

The geothermal industry is still relatively small with few companies active in the supply chain. The activities in the power and direct use sectors range from exploration, drilling, engineering, to construction and plant operation. Clearly, vertical integration is one of the strategies a number of companies pursue while others are offering highly specialised services (e.g. drilling). The geothermal power plant turbine market is dominated by large industrial corporations such as Mitsubishi, Ormat and Fuji. In Europe, Ansaldo-Tosi is the market leader with about 40 % of installed capacity. The European GSHP market has developed from a market with many small companies to a market dominated by major heating and air-conditioning manufacturers. The main European players are from Germany and Sweden but Asian producers from the heating, ventilation, and air-conditioning (HVAC) sector are starting to enter the market.

Due to the limited size of hydrothermal resources, the market share of geothermal power in Europe is small (0.2 %). Large scale deployment of geothermal power production requires the demonstration of successful EGS projects extracting heat from reservoirs constituting a variety of geological conditions. An adequate management of deep engineered reservoirs and highly efficient thermal transfer from the rocks has to be demonstrated. The drilling technology to reach these reservoirs has to become cheaper. Then, the geological risk associated with each project will minimize, the EGS capital and operation expenditure will decrease and possibilities to enter new areas expand.

1 INTRODUCTION

This is the first edition of an annual report with which the Institute for Energy and Transport wants to contribute to the general knowledge about the geothermal energy sector, its technology and economics with a focus on the European Union.

Geothermal energy is derived from the thermal energy generated and stored in the earth interior. The energy is accessible since groundwater transfers the heat from rocks to the surface either through bore holes or natural cracks and faults. The geothermal resource is a renewable resource because there is a constant heat flow to the surface and atmosphere from the immense heat stored within the earth while the groundwater transferring the heat is replenished by rainfall and circulation within the crust. Geothermal energy is a commercially proven renewable form of energy that can provide constant power and heat. A hot rock formation with natural fractures and or porous structure where water can move is termed hydrothermal reservoir. The technology associated with hydrothermal power and heat production may be considered as mature. Conversely hot rock formations may have insufficient or little natural permeability or fluid saturation and need to be stimulated to allow for movement of water. Fluid is injected into the subsurface under carefully controlled conditions, which cause pre-existing fractures to re-open, creating permeability. Increased permeability allows fluid to circulate throughout the now-fractured rock and to transport heat to the surface where electricity can be generated. Once stimulation has been carried out, these formations are termed EGS, a technology proven on small scale since 2007 but still in development process. To date, the large majority of geothermal energy extraction is done from hydrothermal resources and few small EGS in operation exist.

The geographical distribution of heat within the Earth's crust is highly variable. Highest heat gradients are observed in areas associated with active tectonic plate boundaries and volcanism (Figure 1).

The geologic potential (heat in place) for geothermal power in Europe and the World is very large and exceeds the current electricity demand in many countries. However only a small portion of the heat in place can be realistically extracted for power production and the heat in place is therefore often translated to economic potential using levelised cost of energy (LCOE). The geothermal energy potential using LCOE value less than 150 EUR/MWh in 2020 is 21.2 TWh which is considerably higher than the planned 11 TWh production in the EU member states according to their NREAP for

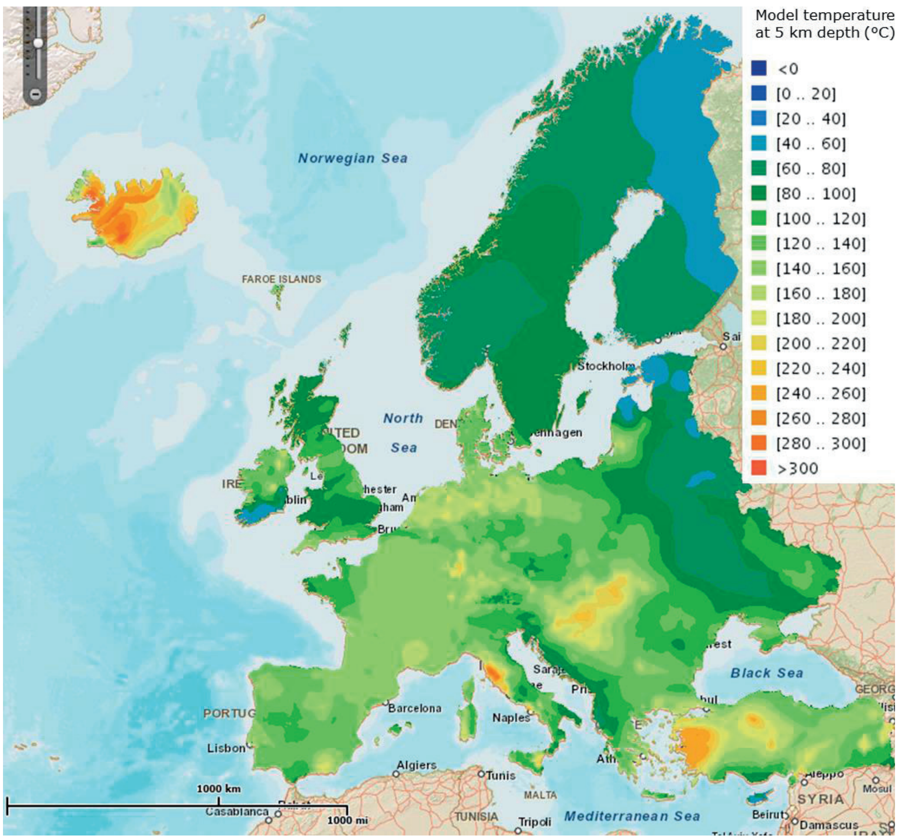


Fig. 1: Modelled temperature at 5 km depth in Europe (Source: Modified from GeoELEC Graphical Information System [ThermoGIS 2014])

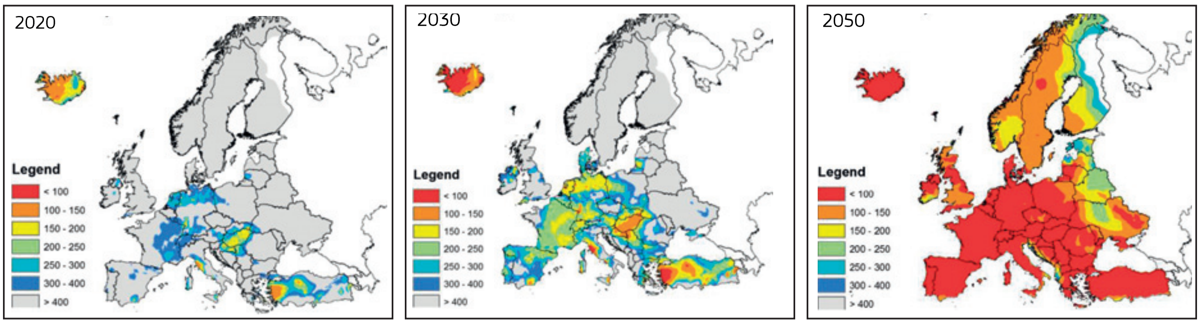


Fig. 2: Minimum levelised cost of electricity in 2020, 2030 and 2050. The economic potential for these scenarios translates to 21.2 TWh, 34 TWh and 2570 TWh within the EU. Source: [van Wees et al. 2013]

the same year. For 2030, using LCOE of 100 EUR/MWh, the economic potential amounts to 34 TWh or 1 % of the projected total electricity production in the EU [van Wees et al. 2013]. The same authors estimated the economic potential to grow to 2570 TWh in 2050 (as much as 50 % of the electricity produced in the EU) mainly due to economies of scale and innovative drilling concepts [van Wees et al. 2013]. However, innovative drilling concepts not relying on mechanical drilling have been in development for many years and to date, none has been demonstrated to reach the depth needed for high temperature geothermal applications and it is clear that EGS have to be demonstrated more fully before the 2030 and 2050 predictions are realised. Figure 2 displays the spatial distribution of the predicted minimum LCOE for geothermal energy in 2020, 2030 and 2050 [van Wees et al. 2013].

Due to their tectonics, hydrothermal reservoirs tend to be fractured, therefore facilitating movement of water that can be extracted through production wells to the surface either to turn turbines or for direct use for heating. In addition to electricity production, the thermal capacity of the ground can provide heating or cooling with the aid of ground source heat pumps either extracting heat from shallow soils or deeper boreholes. Geothermal energy provides an opportunity to be exploited by cascade utilisation (stepwise usage at progressively lower temperatures) and therefore increase the total efficiency and results in economic benefits. The most important cascade applications present in today's market are power generation, district heating and cooling, industrial processing, greenhouses, fisheries, de-icing, and spa bathes.

Geothermal power and heat installations draw their energy from resources of variable depths and temperatures. So far, no general consensus has been agreed on how to classify geothermal heat sources and production. In this report, when reporting on production values, the following classification according to [Antics et al. 2013] and Directive 2009/28/EC [EC 2009a] which has been adopted by Eurostat and national statistics offices, will be used:

- Power generation
- Direct use
- Ground source heat pumps

The report aims to present the overall state of the geothermal industry in Europe. Chapter 2 investigates the technological situation of geothermal technologies: state-of-the-art, research, innovations, current challenges and possible bottlenecks, and its possible future evolution. Chapter 3 investigates EU policies related to geothermal energy. Chapter 4 focuses on the geothermal market status, both globally, and in Europe; proposes some deployment scenarios and analyses industrial strategies as made public by manufacturers and developers. Chapter 5 analyses the economic aspects and implications: cost aspects focus on capital costs (CAPEX), the operational expenditure (OPEX), and the resulting cost of the energy produced. In Chapter 6, environmental impacts of geothermal energy will be discussed, with a focus on emissions and induced seismicity. Chapter 7 then provides a summary of findings.

2 TECHNOLOGY STATUS AND DEVELOPMENT

Geothermal energy is defined as heat from the earth. From a practical point of view, geothermal resources may be defined as thermal energy reservoirs that can be reasonably exploited at costs competitive with other forms of energy within some specified period of time. Geothermal resources have been classified according to their reservoir fluid temperatures into low-, medium- and high-enthalpy fields. Additionally, the temperatures found at very shallow depths may be used to extract and store heat for heating and cooling by means of ground-source heat pumps.

In 1973, Lindal indicated the temperature range of geothermal water and steam suitable for various applications [Gudmundsson et al. 1985] (Figure 3). Conventionally, geothermal resources are hydrothermal resources that include reservoirs of hot water and/or steam, and are categorised as vapour-dominated or liquid-dominated resources. The temperature for low-enthalpy resources is below 100 °C, while medium- and high-enthalpy resources imply the temperature range of 100-180 °C and above 180 °C, respectively. Low-enthalpy, hydrothermal resources are mainly used for direct heat use, whereas medium- and high-enthalpy resources are used to generate power and in some cases also heat in cogeneration plants.

Hydrothermal resources exist at shallow to moderate depths and are the least abundant source of geothermal resource. Other geothermal resources include geo-pressured, magma and the more widespread hot, dry rock (HDR). In addition, use of supercritical unconventional resources (temperature > 374 °C and pressure > 222 bar referring to pure water) is under investigation through the Icelandic Deep Drilling Project. The process involves transferring supercritical fluids to the surface and converting all the mass flow (compared to 20-30 % for flash power plants) into superheated steam thus increasing the overall efficiency of the process [Friðleifsson et al. 2014]. A detailed overview of historical developments in the geothermal industry in America between 1976 and 2006 was published in 2010 [U.S. DOE 2010a, U.S. DOE 2010b, U.S. DOE 2010c, U.S. DOE 2010d].

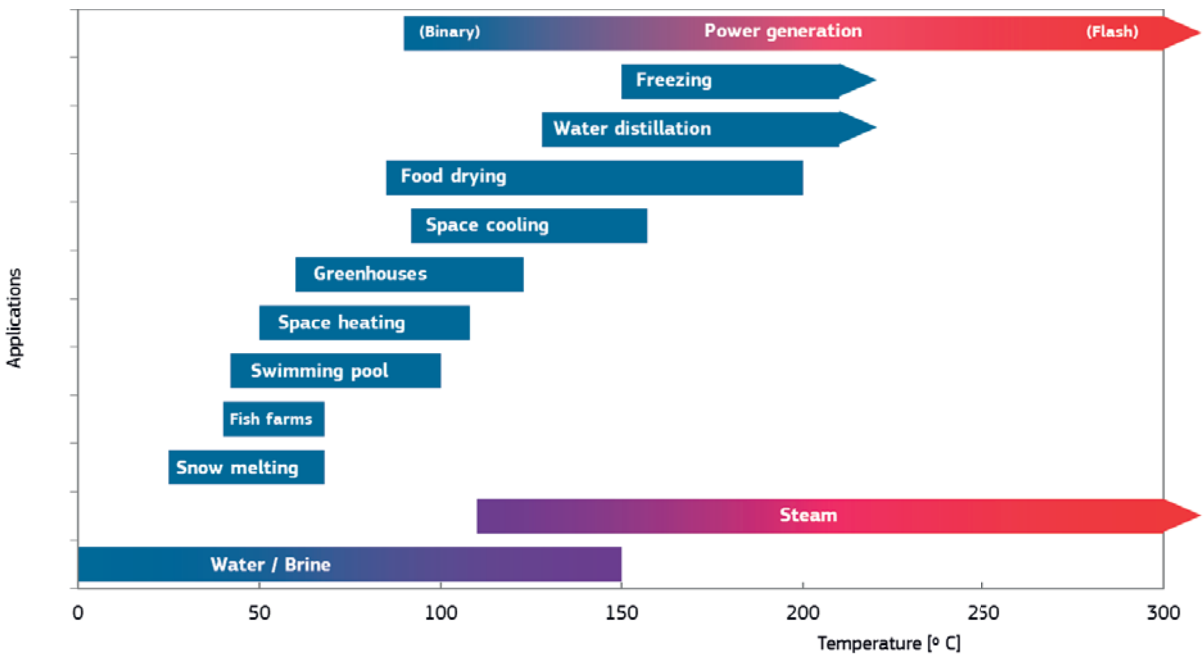


Fig. 3: A Lindal diagram of temperature of geothermal water and steam suitable for various applications

2.1 Current geothermal energy state-of-the-art

2.1.1 Power plant design

Geothermal power plants use steam from reservoirs of hot fluids found close to the Earth's surface or deeply buried into the crust to produce electricity. Generally, below-ground fluid production systems are derived from the oil and gas industry, and above-ground conversion systems are based on traditional steam-electric power generation technology. A geothermal power plant's annual capacity factor (CF) is generally above 90 %. Even higher values up to 97-98 % might be achieved, but with increased maintenance costs; which might be compensated by higher-priced electricity.

The efficiency of a geothermal power plant plays an important role when estimating the economic factors under different conditions and the terms of reference should be established when collecting and comparing data from different authors. The performance of a geothermal power plant can be measured using the second law of thermodynamics as the basis for the assessment of the utilisation efficiency (η_u). Since geothermal plants do not operate in a cycle but instead as a series of processes, the cycle thermal efficiency η_{th} for conventional plants does not apply (except for the closed cycle of the secondary working fluid in a binary plant). The utilisation efficiency, also called exergy efficiency, measures how well a plant converts the exergy (available work) of the resource into useful output. For a geothermal plant, it is found as follows [DiPippo 2012]:

$$\boldsymbol{\eta_u} = \frac{\dot{W}}{\dot{m}\, e}$$

Equation 1

Where $\dot{W}$ is the net electric power delivered to the grid, $\dot{m}$ is the required total geofluid mass flow rate and e is the specific energy of the geofluid which is given by:

$$\boldsymbol{e = [h(P_1, T_1) - h(P_0, T_0) - T_0[s(P_1, T_1) - s(P_0, T_0)]}$$

Equation 2

Where h is specific enthalpy and s is specific entropy at reservoir conditions (P_1,T_1) and at the so-called dead state (P_0,T_0). The efficiency η_u as described above is the efficiency used throughout this report.

The type and temperature of a geothermal resource determines the design of the power plant and the efficiency is highly dependent on the resource temperature.

The amount of non-condensable gases (NCG) generally correlates with reservoir temperatures. These gases (mainly CO_2 and H_2S) do not condense with the steam in condensers and have to be extracted by means of pumping). The existence of these gases may play an important role on the efficiency of the whole energy conversion process and corrosive resistant materials often have to be used, thus affecting the economics of the power plants.

2.1.1.1 Direct dry steam

Dry steam is the oldest type of geothermal power plant, first being used in 1904. Dry steam plants amount to almost a quarter of geothermal power capacity today. Dry steam technology is used in conjunction with vapour-dominated resources. An overview is provided in Figure 4. The steam from production wells (PW) with several wellhead valves (WV) is transferred through a particulate remover (PR) in steel piping (SP) towards moisture removers (MR) adjacent to the powerhouse. There, control and stop valves (CSV) adjust the flow of steam into the turbine attached to the generator (T/G). The steam condenses in a condenser (C) and is then pumped (CP) towards a cooling tower (CT). The cooling water is recirculated by cooling water pumps (CWP) towards the condenser again or re-injected to the reservoir through re-injection wells (IW). Make-up water (usually less than for fossil fuel plants since the condensate is used for cooling) is required and the quantity depends on the climate and configuration of the power plant. The amount of non-condensable gases (typically between 0.5 to 10 wt % of steam, sometimes higher) requires a gas extraction system to be installed. As NCG are ejected from the top of the cooling towers and gas extraction pumps work on different efficiency, the cooling water may become corrosive. The pH of cooling water is therefore monitored and can be adjusted with for example caustic soda. Control of steam flow at the wellheads to meet electricity demand fluctuations is easier than in flash steam plants.

Dry steam power plants have the highest efficiency among all geothermal power plants, reaching values of 50-70 % [DiPippo 2012]. They are commercially proven, simple to operate and require relatively low capital costs. However, they are only suitable for dry steam resources, of which there is little known untapped potential. Dry steam plants are not suitable for combined heat and power (CHP) applications.

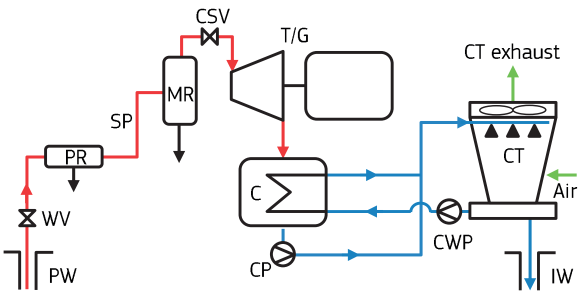


Fig. 4: Simplified flow diagram for direct steam geothermal power plant. See text for details. Source: [DiPippo 2012], adapted

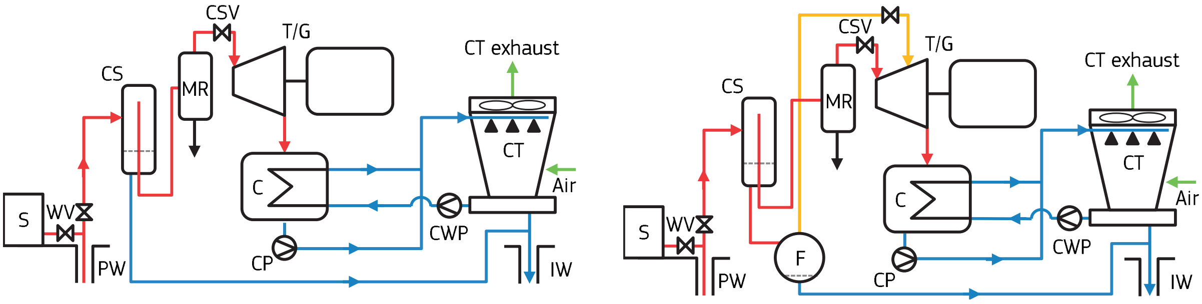


Fig. 5: Simplified flow diagram for a single flash (left) and a double flash (right) geothermal power plant. See text for details. Source: [DiPippo 2012], adapted

2.1.1.2 Flash cycle and dual flash

Flash steam power plants are the most common type of geothermal power plants, making up about two thirds of geothermal installed capacity. The flash steam technology makes use of liquid-dominated hydrothermal resources with a temperature above 180 °C. In the high-temperature reservoirs, the liquid water component boils, or 'flashes' as pressure drops (Figure 5). The fluid from production wells (PW) flows through cyclone separators (CS). The flow path for the steam after the cyclone separators is usually the same for flash plants as with dry steam power-plants after the particulate removers. The steam may be condensed in either direct contact condenser or indirect condenser. When direct contact condensers are used a higher fraction of non-condensable gases (mainly the water soluble gases CO_2 and H_2S) are partly captured into the condensate. The design of the condenser may have detrimental impact on treatment of the gases as will be discussed in Section 2.1.5. In a single flash plant the separated water from the cyclone separators is pumped towards injection wells. The separated water may also be flashed in a flasher (F) where additional steam is generated at lower pressure than the first flash. This steam is diverted into the turbine at a lower pressure stage. During the second and third stage flashing, the risk of scaling increases as the temperature of the fluid is reduced and the concentration of solutes increases. The scaling risk may be decreased by diluting the separated waters with condensates prior to re-injection.

Combined-cycle flash steam plants use the heat from the separated geothermal brine in binary plants (described in next section) to produce additional power before re-injection. The thermal energy of the brine may also be extracted via heat exchangers prior to re-injection. The single-flash and dual-flash power plants reach efficiencies between 30–35 % and 35–45 %, respectively when electricity is the sole product. The overall efficiency is greatly increased by adding heat exchangers and producing hot water since the conversion factor in a heat exchanger is far greater than converting heat to electricity. Flash power plants have a simple configuration and are already proven technologically; several commercially available system suppliers are present in the market already. Single-flash power plants require low capital but are typically economically competitive only when the harvested geothermal resources are at 200-240 °C or higher temperatures. Double-flash power plants have an increased power output and efficiency (by 5-10 %) in comparison with single-flash ones but require higher capital costs and higher resources temperature (> 240 °C) in order to be competitive. In both technologies, the operation and maintenance (O&M) costs increase significantly when dealing with high mineral content brine resources. Flash power plants come in different sizes with individual turbine units ranging from < 1 MW to > 100 MW and container modules are available on the market.

2.1.1.3 Binary

Electrical power generation units using binary cycles constitute the fastest-growing group of geothermal plants as they are able to use low- to medium-temperature resources, which are more prevalent. Today, binary plants have an 11 % share of the installed worldwide generating capacity and a 45 % share in terms of number of plants [Bertani 2012]. Binary cycle power plants, employing organic rankine cycle (ORC) or a kalina cycle, operate at lower water temperatures of about 74-180 °C using the heat from the hot water to boil a working fluid, usually an organic compound with a low boiling point (Figure 6).

In ORC plants, geothermal fluid is usually pumped (P) from production wells (PW). A sand remover (SR) removes debris before the fluid enters an evaporator (E), and passes a pre-heater (PH) before it is pumped back into injection wells (IW). In the evaporator a preheated working fluid from a pre-heater is boiled prior to entering a turbine unit (T/G). The working fluid is condensed in a condenser (C) and pumped back to the pre-heater in a closed loop. Cooling water is pumped from a cooling tower (CT) towards the condenser and make-up water (M) is pumped into the cooling tower to compensate for losses by evaporation.

Kalina plants operate with a mixture of ammonia and water and the chemical composition of the

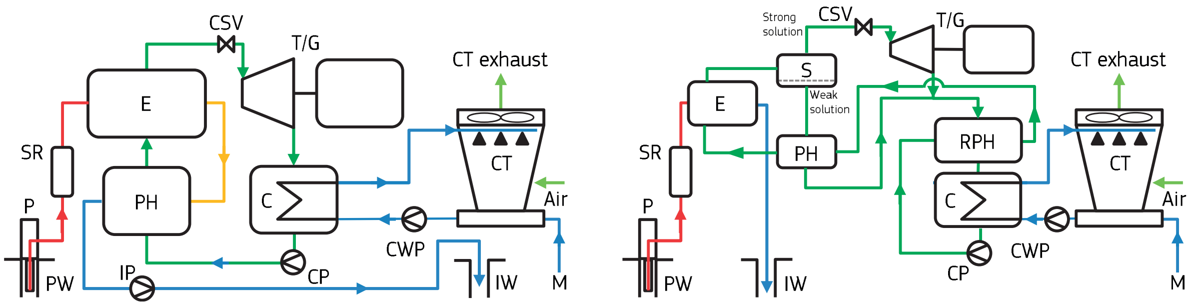


Fig. 6: Simplified flow diagram for an organic rankine cycle (left) and a kalina (right) binary geothermal power plant. See text for details. Source: [DiPippo 2012], adapted

working fluid is adjusted to the temperature of the geothermal fluid. The simplest form of a Kalina plant is displayed in Figure 6. The geothermal fluid is pumped (P) from production wells (PW) into an evaporator (E) prior to being diverted back to injection wells (IW) or it can be used for district heating. The working fluid is evaporated into a separator (S) from where saturated vapour rich in ammonia flows to the turbine (T), thus permitting a smaller less costly turbine to be installed. The remaining water rich solution flows through a preheater (PH) and is then throttled down (TV) and mixed with the ammonia rich solution. The mixture enters a recuperative preheater (RPH) prior to being fully condensed (C). Following condensation the working fluid is first heated in the recuperative preheater and then in the preheater prior to entering the evaporator. Cooling water is pumped from a cooling tower (CT) towards the condenser and make-up water (M) is pumped into the cooling tower to compensate for losses by evaporation. As with most geothermal power plant configurations, the cooling tower may be omitted by pumping cold water directly into the condenser and using the resulted heated water for district heating. This option requires more direct use of water but may be feasible option where water is not a limited resource.

In binary plants, the geothermal water and the working fluid are kept separated during the whole process, so there are little or no air emissions. The binary units can be produced in very small sizes (0.1-5 MW), even as container module units allowing for a modular design.

The ORC can reach efficiencies between 25 % and 45 % [Emerging Energy Research 2009]. High O&M costs are present when the resource has a high salinity, which comes in direct contact with the plant. The technology suppliers are scarce, with only a few being commercially available.

The kalina cycle can, under certain design conditions, operate at higher cycle efficiencies of between 30 % and 65 % [Emerging Energy Research 2009]. It has an abundant, more environmentally friendly heat-transfer fluid (ammonia/water). RD&D should focus on reducing the costs to make technology competitive with current ORC alternatives. Presently, kalina cycle plants are associated with high capital costs and technological complexity. The technology is not yet bankable and few plants are currently operating.

2.1.2 Drilling methods

Drilling represents 30 % to 50 % of the cost of a hydrothermal geothermal electricity project and more than half of the total cost of EGS. Lowering drilling costs is therefore a key issue for reducing the capital investment and operation costs of geothermal power plants. Geothermal drilling technology shares much of its state of the art with technology in the oil and gas industries, especially in low temperature reservoirs. Several distinctive attributes though exist such as massive losses of circulation fluids, high to very high temperatures with related string and casing expansion and the prerequisite of high, full bore, production rates [Dumas et al. 2013].

The established deep drilling technique is the rotary drilling. Tri-cone rotary bits were introduced in 1909 and supplemented in the 1970s by the polycrystalline diamond bit. These are applied by diesel-electric drilling rigs to create boreholes protected by steel casings. The casings are arranged one inside another until the final diameter is only a small fraction of the initial diameter on the surface. This arrangement is viewed by many as the biggest drawback of conventional hole-making technology [Dumas et al. 2013]. The highest CO_2 emissions from geothermal power plants are often indirect emissions resulting from drilling with diesel powered rigs. In multi-production well geothermal developments, CO_2 emissions associated with drilling might be reduced by using the power generated by modular small power plants run on steam from previous wells therefore reducing the total CO_2 emissions considerably. This setup however requires some adjustment to the existing drill rigs.

Geothermal drilling benefits from on-going industry improvements. Examples are the placement of casings while drilling in the 1950s; top drive power swivels, air/foam balanced drilling, and polycrystalline diamond compact (PDC) bits in the 1970s; microdrill and coiled tubing in the 1980s; and horizontal drilling, reverse circulation cementing, logging while drilling, and environmentally safe fluid formulations since the 1990s.

Despite these improvements, drilling costs continue to be high and therefore considerable emphasis has been placed on the development of new drilling technologies [Dumas et al. 2013]. A list of selected drilling technologies is provided in Table 1.

2.1.2.1 Conventional mechanical drilling methods

The classical drilling method used today with rotary drilling is crushing or scratching the rock by means of a rotating drilling bit. Two main designs exist: roller cone bits and drag bits. The roller cone bits are preferably used in hard rock formations. The roller cone bits crush the rocks while the drag bits scratch and shear the formation [Teodoriu & Cheuffa 2011]. These methods may be combined for example with PDC to shear the formation and rollers to crush it.

Hammer drilling is another mechanical rock drilling method. The method is not common for deep drilling activities. A combination of rotation and hammering can increase the rate of penetration (ROP) significantly through the increase in force between bit and formation. Hammer drilling works well in hard formations but has low or no efficiency in soft formations.

2.1.2.2 Experimental drilling methods

The mechanical methods described above are all proven technologies and are compatible with existing surface and down-hole hardware. However these methods provide lower ROP than many other drilling methods which include: jetting (high performance/mud jet bits), thermal drilling (spallation, molten ion penetration, plasma bit), direct stream, millimetre wave, high voltage electro impulses.

Jetting or jet drilling uses the drilling mud energy to destroy the rock. The ROP can be 100 times higher compared to mechanical drilling in shallow horizontal wells [Kolle 1999]. When deep drilling is required, the total pressure losses in the system may limit the applicability of the jet drilling systems. The jet drilling technologies require high pressure/high flow rate pumps, special drill string and down hole pressure enhancer. It might become an alternative when drilling surface casings in sedimentary rocks but not yet the adequate technology for deep geothermal drilling.

Thermal drilling uses heat to destroy or melt the rock. Laser drilling is based on three common energy transfer processes between the laser and the rock: reflection, scattering and absorption. Some rock properties help the laser drilling process: Low thermal conductivity keeps the heat around the hole, low reflectivity allows for good laser-to-rock energy transfer and deep penetration that allows

Table 1: Overview of selected drilling methods

Technology	Advantages	Disadvantages
Rotary drilling, roller cone bits	Compatible with existing hardware.	Low Rate of Penetration (ROP)
Rotary drilling, drag bits	Compatible with existing hardware.	Low ROP
Rotary drilling, hybrid (PDC/roller)	Compatible with existing hardware. Up to four times faster than roller cone bits	Low ROP but faster than above.
Hammer drilling	Compatible with existing hardware. Suitable for wide shallow conductor and surface casings	Uncommon in deep formations. No efficiency in soft formations.
Jetting	Up to 100 times higher than diamond bits in hard formations	Large pressure losses in deep wells. Special equipment. 10-15 times higher energy demand than rotary.
Laser, ablation		Immature technology. Complicated transport of beam into deep wells.
Laser, spallation	Less energy intensive than ablation	Immature technology. Complicated transport of beam into deep wells.
Spallation	Can work in deep hydrothermal environment.	Immature technology. 10-15 times higher energy demand than rotary.
Plasma bit	Potentially 4 times faster ROP than conventional drilling.	Immature technology, pilot system exists.
Millimetre wave	Rate of penetration should be 10- 15 m h^{-1} and should not lower with increased depth.	Has only been demonstrated in the laboratory, energy intensive.
High voltage electro impulses	Potentially 5-10 times faster ROP than conventional drilling	Immature technology. High current and power transmission from surface to the bottom. Special insulators needed. ROP may decrease with depth.

good volumetric absorption. Two main ways have been proposed for laser deep drilling: Rock weakening with further application of mechanical tools and direct rock destruction via ablation (ablation, fusing or vaporising). The spalling or spallation process will fragment the rock in smaller parts due to temperature gradients within the rock which can then be hydraulically moved to the surface. Spalling is less energy intensive than fusing or vaporising and is more likely to be used for deep drilling applications [Teodoriu & Cheuffa 2011].

The spallation drilling process may also be applied directly without laser melting. There, a confined volume of rock is heated rapidly and the rock fragments into disk like flakes. The method seems to work well in hard rocks. Fuel and oxidant are transported separately down hole where they ignite and the resulted flame is capable to burn under water. The process requires a certain minimum bottom hole pressure to be initiated and controlled.

The plasma bit drilling technology is a patented non-contact device with a plasma generator where water steam is heated inside an electrical arc above 5000 K [Kocis et al. 2013]. The heated rock fragments are rapidly cooled with water in a controlled way and diverted to a mud system. The technology should efficiently reach depths of 10 km with constant diameter and costs are predicted to be linear. Casing while drilling is achievable where casing is formed by the disintegrated rock fragments.

Millimetre wave drilling refers to drilling done with electromagnetic frequencies higher than microwaves but lower than infrared. The waves are insensitive to small particles and smoke but are short enough to be guided as an intensive beam within the cross sections of a typical borehole. Successful melting of hard rock has been achieved but high intensities are required (≥1 kW/cm²) [Woskov et al. 2014]. A gas stream purges vaporised particles upwards into the annular space where they form a glass wall upon cooling. The technology should efficiently reach a depth of 10 km but is currently in the development phase.

High voltage electro impulse drilling uses high voltage electric pulses to break the rock due to local pressure pulses induced at rock interface. The technology uses rotating electrode heads and can be used as an enhancement for conventional drilling by accommodating special electrodes to the drilling bit.

2.1.3 Drilling technologies (drilling and design)

Drilling technologies may be defined as the sum of all processes and equipment designed to support the drilling method [eg. Teodoriu & Cheuffa 2011]. A useful guide on geothermal drilling is provided by Dumas et al. [2013]. The enthalpy of geothermal fluids is not high (enthalpy of dry steam is 2750 kJ/kg at 300 °C while the energy value of one litre of crude oil is approximately 35 MJ). The exergy efficiency of flash and binary plants of converting geothermal steam/water to electricity is not high (25-50 %), therefore high mass flows and hence volume flow rates are required. These large flow rates necessitate large diameter production casings and liners [Dumas et al. 2013]. Typical standard diameter wells utilise a standard API 9 5/8" casing as production casing and either 7” or 7 5/8" diameter slotted liner in an 8 ½" diameter open hole. Typical large diameter wells utilise a standard API 13 3/8" casing as production casing and either 9 5/8” or 10 ¾"

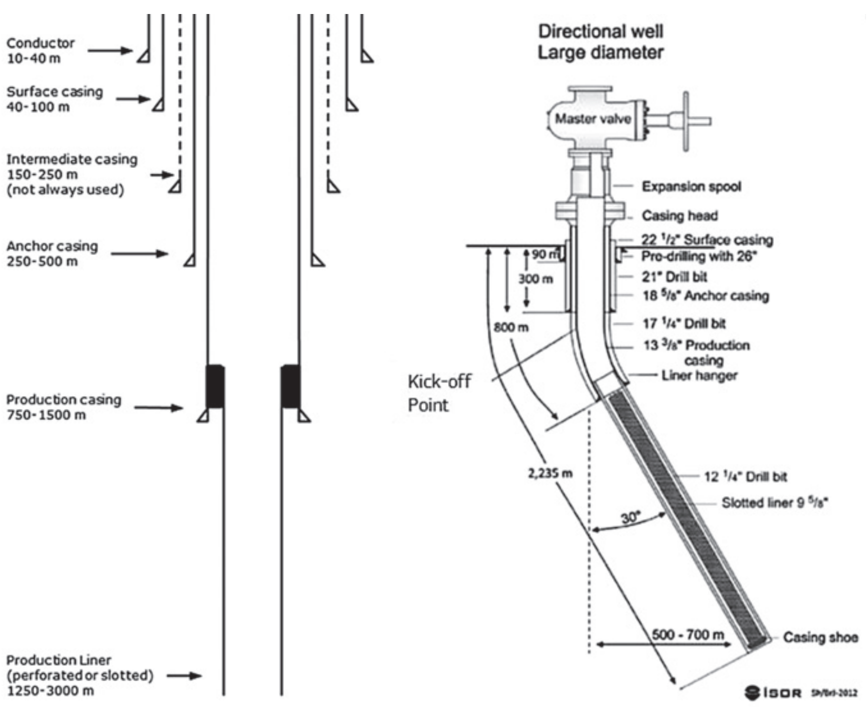


Fig. 7: Casing strings and liner in a typical geothermal well (left) modified from [Dumas et al. 2013]. The widths and depths are determined by geological and thermal conditions. A typical large diameter directional well from Hellisheiði, Iceland (right) [Sveinbjornsson & Thorhallsson 2014]

diameter slotted liner in a 12 ¼" diameter open hole. The diameters and depths for other casings depend on geological and thermal conditions. A typical well design is shown in Figure 7 and would include [Dumas et al. 2013]:

- Conductor: 30” set a at a depth of 24 metres, either driven or drilled and set with a piling augur;
- Surface casing: 20” casing set in 26” diameter hole drilled to 80 metres depth;
- Anchor casing: 13 3/8” casing set in a 17 ½” diameter hole drilled to 270 metres depth;
- Production casing: 9 5/8” casing set in 12 ¼” diameter hole drilled to 800 metres depth;
- Open hole: 7” perforated liner set in 8 ½” diameter hole drilled to 2400 metres.

The most commonly used drilling technologies will be described in the following sections.

2.1.3.1 Casing drilling

Standard oil field casing is used as the drill string and drilling and casing is done simultaneously. The casing is rotated from the surface with a top drive while drilling fluid is circulated down the casing and up the annulus towards the surface. For casing drilling, drill collars are not needed to provide weight-on-bit unlike for conventional drilling with drill pipes. The drilling rigs used for the casing drilling process can be either specially designed to apply this technology or modified from conventional rigs. Casing drilling does not have much better ROP than conventional drilling but may be useful when problems are expected. Casing drilling is not the first choice for deep hard rock formations and has been applied more in the oil and gas industry.

2.1.3.2 Coiled tubing drilling

The technology uses a conventional drilling assembly with a down-hole motor. Coiled tubing drilling uses higher bit speeds at lower weight-to-bit. With the technology, the coil tubing unit can either be stationary or it can revolve around the well centre [Reel 2014]. The advantages of coil tubing drilling are fast mobilisation and demobilisation, tripping times are faster than those of conventional drilling therefore lowering the overall operation duration of the drill rig. Coil tubing rigs require small footprint and enables underbalance conditions. The main disadvantages are depth limitation, the size restriction of the coil tubing and associated mechanical issues such as buckling and fatigue [Teodoriu & Cheuffa 2011]. Coil tubing drilling are therefore optimal for short small diameter wells as well as for re-entering or sidetracking wells. Coil tubing setup has proven effective when initiating discharge of production wells that do not produce automatically when the well is opened. There, air is pumped through the coil to lift the water column with air bubbles as opposed to push water column down. The coil tubing method decreases the strain on the casings as depressurisation rates are slower during transition from hydrostatic to flow conditions.

2.1.3.3 Underbalanced drilling

The drilling process intentionally keeps the wellbore fluid gradient less than the natural pore pressure gradient. This protects the reservoir as drilling mud is not lost in high quantities since the well starts flowing while drilling operation is still ongoing. Therefore dedicated wellhead and surface equipment is required. The ROP increases due to lower well pressure, this is especially important in hard rock formations.

2.1.3.4 Managed pressure drilling

Here the annular pressure profile in the well is controlled throughout the drilling operations. The technique may either be reactive or proactive. Reactive managed pressure drilling uses a rotating control device and a choke to deal with drilling problems. Proactive managed pressure drilling includes entire well design to manage the wellbore pressure profile throughout the drilling process.

2.1.3.5 Slim hole drilling

Slim hole drilling is not a special technology as such but due to its small diameter, the ROP and therefore overall costs can be reduced. The disadvantage is that production casing size is restricted and therefore slim holes may not be suitable as production wells. However, slim holes may be highly suitable for exploration and monitoring purposes.

2.1.4 Heat exchanger design

Heat exchangers play a central role in geothermal power plants but also for direct use and GSHP applications. Direct use and GSHP systems mainly deploy a liquid/liquid heat exchanger to transfer the heat from the geothermal fluid or the ground to a district heating or space heating system [Huenges 2011]. In geothermal power plants, a range of heat exchangers can be installed, fulfilling various tasks such as pre-heating, and superheating and serving as evaporator or condenser. In power plants, not only liquid/liquid but also liquids/liquids+gas and even liquids/liquids+solids heat exchangers can be found.

According to [Huenges 2011], the energy balance of an ideal heat exchanger without heat losses can be described by:

$$\dot{\boldsymbol{Q}} = \dot{\boldsymbol{m}}_c * (\boldsymbol{h}_{c,out} - \boldsymbol{h}_{c,in}) = \dot{\boldsymbol{m}}_h * (\boldsymbol{h}_{h,in} - \boldsymbol{h}_{h,out})$$

Equation 3

with $\dot{m}_c$ and $\dot{m}_h$ referring to mass flow rates, and h_c and h_h to the specific enthalpy. The rate of heat $\dot{Q}$ transferred from the hot to cold fluid (without nvolving a phase change) can then be expressed as:

$$\dot{Q} = \dot{m}_c * c_{p,c} * (T_{c,out} - T_{c,in}) = \dot{m}_h * c_{p,h} * (T_{h,in} - T_{h,out})$$

Equation 4

with T_c and T_h referring to the temperature of the hot and cold fluids and $c_{p,c}$ and $c_{p,h}$ being the constant-pressure specific heat capacities. Given a maximum usable heat of $\dot{Q}_{,0}$ at the ambient temperature T_0, the utilisation ratio η_U is:

$$\eta_U = \frac{\dot{Q}_h}{\dot{Q}_{h0}} = \frac{T_{h,in} - T_{h,out}}{T_{h,in} - T_0} \qquad \text{Equation 5}$$

For a plant using a geothermal resource at 150 °C down to 70 °C, the utilisation ratio at an ambient temperature of 20 °C is 62 % [Huenges 2011].

When designing a heat exchanger, the dimensioning of the heat transfer area *A* is key aspect and can be derived by:

$$\dot{Q} = U * A * \Delta T_m \qquad \text{Equation 6}$$

with ΔT_m being the mean temperature difference, and U being the overall heat transfer coefficient [DiPippo 2012, Huenges 2011]. Depending on the available knowledge on inlet and outlet temperatures, the mean temperature difference ΔT_m can be derived or calculated by different methods. The overall heat transfer coefficient U is influenced by fluid, flow conditions, shape of heat transfer area, and heat transfer regime (e.g. boiling, no phase change).

The design and layout of a heat exchanger has to take into account several parameters. As said before, the heat transfer rate is defined by the design of the geothermal energy plant and is used to calculate the required heat transfer surface area. Fluids can flow in parallel, in opposite (counter-flow), or in perpendicular (cross-flow) directions and the flow type influence temperature profiles and heat transfer characteristics [Huenges 2011]. Two basic types of heat exchangers are typically used in geothermal applications: shell-and-tube heat exchangers and plate heat exchangers. Plate heat exchangers show high surface-to-volume ratios and high heat transfer coefficients [Madhawa Hettiarachchi et al. 2007]. Thus, they are usually very compact and they can easily be expanded when the capacity needs to be increased [Zhu & Zhang 2004]. Shell-and-tube heat exchangers are very reliable and flexible and they can be used in almost all geothermal applications [Huenges 2011]. However, they are more susceptible to fouling and have lower surface-to-volume ratios compared to plate heat exchangers. They are usually used for evaporators and condensers.

2.1.5 Emission abatement systems

Gases that do not condense with the steam in the power plant's condensers are referred to as non-condensable gases (NCG). The main NCG species in geothermal steam are carbon dioxide (CO_2) and hydrogen sulphide (H_2S). Ammonia (NH_4) is often absent but may be up to 10 vol % in the steam. Smaller amounts of H_2, N_2, Ar, CH_4, CO and Hg may exist in the emitted gases.

Of these gases, H_2S is the gas of highest concern due to its toxic nature and therefore emphasis will be made on H_2S abatement systems. Depending on site specific factors, a specific process may have to be incorporated into the plant process to remove H_2S from the emissions stream. The location of the power plant has large impact on technology selected. Local emission regulations differ; the distance to resource materials (chemicals feeds and water) for the cleaning process as well as distance to markets for potential products may become detrimental. Finally, the design of the H_2S removal system has to take into account condenser type after the turbines. Therefore when choosing a H_2S removal technology, a combined technical, environmental and economic study needs to be carried out.

The geothermal gases have different solubility in water which will determine to some extent their behaviour in the condensers as well as in the gas removal process. Hydrogen gas may in extreme cases be up to 50-60 vol % of the emitted gas mixtures and as it is highly flammable may interfere with known H_2S removal technologies developed in the oil and gas industry. Ammonia may exist in smaller proportions and when NH_3 concentrations are high the choice of condensers design becomes important factor on the H_2S removal system design. Due to acid-base interactions between NH_3 and H_2S, partition of H_2S to the condensate in direct contact condensers may become significant and secondary treatment can be necessary [Mamrosh et al. 2012].

Many technologies exist for removing H_2S from gases and the selection of technology depends on gas amount and composition and the level of H_2S removal required. These include liquid redox sulphur recovery processes (e.g. Stretford, LO-CAT), the modified Claus process (gas phase oxidation), burn/scrub processes, burn/vent processes, amines and physical solvents, scrubbing H_2S with caustic soda, scrubbing with other alkaline earth minerals, wet sulphuric acid process (WSA), AMIS (Mercury and H_2S removal), direct acid gas injection, Paques/thiopac, ThioSolv, Biox and water adsorption and injection. These technologies are of different maturity, some have been developed for other industries and modified for the geothermal industry and others are developed within the geothermal industry. Below is a description of selected H_2S removal process.

2.1.5.1 Liquid redox sulphur recovery processes

The Stretford process is a vanadium based aqueous liquid redox process primarily used in older geothermal plants built before 1990 and is most suitable with indirect contact condensers. More recently the vanadium based technology has been replaced by iron based process due to concerns associated with V content in the waste sulphur and solutions. Briefly, H_2S is removed from NCG by contacting the NCG with the Stretford solution in a venturi scrubber and packed tower. In a reaction tank, alkali vanadates convert bisulphide (HS^-) to elemental sulphur and V^{+5} converts to V^{+4}. The V^{+4} is then regenerated to V^{+5} in oxidation tanks sparged with air using anthraquinone disulphonic acid (ADA) as an oxygen carrier. There, sulphur is also separated from the solution by flotation. The main chemicals used are vanadium, ADA and caustic soda. A newer version of the Stretford process (LO-CAT, SulFerox) uses chelated iron (Fe), thus allowing high concentrations of Fe in solution. Iron chelates react with H_2S in the gas contactor quickly forming solid elemental sulphur particles with high removal efficiency. Iron chelates are regenerated with oxygen from air and sulphur particles are removed by settling and filtration. When H_2 concentrations in the NCG are low enough, adsorption of H_2S, reduction and oxidation of Fe chelates can all occur in the same reaction vessel therefore significantly simplifying the process (less equipment and fewer side reactions) (LO-CAT Autocirc). The main chemicals used are Fe chelates, surfactants, caustic soda and sometimes chelant degradation inhibitors and biocides. Main problems associated with these processes are solution foaming, plugging of vessels and pipes by sulphur and high chemical make-up rates [Mamrosh et al. 2012].

2.1.5.2 Modified Claus process

The Claus process is the standard technology used for handling large amounts of H_2S at natural gas processing plants and oil refineries. There H_2S is converted to elemental sulphur. The NCG stream is burned where air is only enough to burn one third of the H_2S to SO_2 and to completely burn H_2 and CH_4. The SO_2 is then reacted with a solid catalyser at elevated temperatures with the remaining H_2S to form elemental sulphur. The elemental sulphur is condensed to molten sulphur. Hydrogen in the NCG may affect the H_2S conversion process in the Claus unit and an incinerator may be needed to remove additional H_2S from the tail gas [Mamrosh et al. 2012]. The Claus process is not common in the geothermal sector but a variety of the process, called Selectox where elemental sulphur production is carried out at lower temperature is operated in Japan

2.1.5.3 Burn scrub process

In a burn/scrub process the NCG stream is incinerated oxidizing H_2S to SO_2. The H_2 and CH_4 are also combusted. The incinerator may be equipped with a heat recovery system where water is converted to steam which is then diverted to the turbine generator. The incinerated NCG is then routed through a quench vessel to cool the gas and scrubbers to remove the SO_2 [Mamrosh et al. 2012]. The burn/scrub process is most often integrated into the cooling towers or is operated as a standalone system. When the process is integrated into the cooling towers, the SO_2 scrubbers are operated at pH 6-8 and require approximately two parts caustic soda per equivalent of SO_2 to form Na_2SO_3 and water. Standalone units may be operated at lower pH (as low as pH 4 for adequate adsorption efficiency) due to the relatively low dissociation constant (pK_{a1} = 1.9) of H_2SO_3. Therefore lower amounts of caustic soda may be required, however this is not normal mode of operation and is not widely applied [Mamrosh et al. 2012].

2.1.5.4 Amines and physical solvents

A process involving amines or physical solvents includes adsorption of a selected gas from the gas stream in a solvent and venting other gases (flue gases or natural gas) from the adsorption tower. This process is the most common CO_2 capture process in the carbon capture and storage/ utilisation industries. For geothermal applications, the H_2S is separated from the NCG in an adsorption tower containing solvent, the solvent is then diverted to a heater where H_2S is boiled from the solvent resulting in a more or less pure stream of H_2S that may be treated further, re-injected as a gas to the reservoir or dissolved in water prior to re-injection. A double system may be applied where H_2S from the NCG is dissolved in the first step. The resulting CO_2 rich gas may then be diverted to a second step where CO_2 is removed and the resulting gases, primarily H_2 may be incinerated or used further.

2.1.5.5 Water absorption and injection

Water is not typically used as H_2S absorbent as there are many sorbents that have much higher affinity to H_2S. The solubility of H_2S in water at high pressures can though be substantial. Briefly the technology includes compression of the NCG stream up to selected pressure. The gas enters an absorption column and water is pumped into the column from above. H_2S and CO_2 are dissolved in the water and other gases (H_2, CH_4 and others) are vented off. The H_2S loaded water is then pumped into the subsurface where pressure conditions are higher than the partial pressures of the dissolved gases to prevent degassing.

Where ample amount of water is available, water adsorption may be feasible to prevent release of chemical absorbents from the H_2S capture process. The water used to dissolve H_2S may be fresh ground waters, condensates or separated waters. Since the H_2S loaded fluid becomes acid (pH 3-5, depending on the partial pressure of H_2S and CO_2 in the water) corrosive resistant materials need to be used for all handling. Furthermore, prevention of air entering the condenser and therefore the NCG stream is critical to prevent oxidation of H_2S to sulphuric acid. An operation of this technology requires understanding of the reservoir conditions as well as the capture process itself. H_2S migration processes have to be understood. This technology is not widely adopted in the geothermal sector although it is known at some installations in the oil and gas industry [Mamrosh et al. 2012]. Currently, this type of system is operated as a demonstration plant attached to the Hellisheiði geothermal plant in Iceland [Aradottir et al. 2014]. There the NCG gas stream is compressed into an absorption tower where condensate waters dissolve the H_2S and CO_2. The mixture is then pumped to an re-injection well cased down to the high temperature reservoir [Aradottir et al. 2014]. In the reservoir the corrosive water is predicted to react with the host rocks and producing sulphides therefore minimizing the risk of the H_2S being transported to the surface again.

2.1.5.6 The AMIS system

Enel in Italy developed the AMIS system which is a technology for simultaneous removal of H_2S and mercury from the power plants emissions. The technology was developed as the NCG content is mainly CO_2 (< 95 % by weight) and therefore combustion would require additions of substantial amounts of fuel. The first commercial installation was started up in 2002 after developments since the early 1990s. Due to high NCG content all the condensers of Enel are direct contact condensers and NCG are extracted with centrifugal compressors. The process consists of three stages [Sabatelli et al. 2009]:

- Removal of mercury by chemical absorption;
- Selective catalytic oxidation of H_2S to SO_2;
- SO_2 scrubbing by a side stream of cooling water.

The technology has been proven to be successful and the majority of Enel power plants are equipped with it treating more than 80 % of the total H_2S emissions and they are available > 90 % of the time. Most problems rise from machinery problems. The rated values of efficiency for the technology are up to 90 % for H_2S and 95 % for Hg [Pertot et al. 2013]. The AMIS technology has also been simplified for H_2S treatment only in the Lardarello area [Sabatelli et al. 2009].

2.1.6 Engineered Geothermal Systems

Engineered geothermal systems (EGS) provide geothermal power by tapping into the Earth's deep geothermal resources that are otherwise not exploitable due to lack of water and fractures, location or rock type. EGS technologies have the potential to cost-effectively produce large amounts of electricity almost anywhere in the world. At the moment, several pilot projects are being conducted in Australia, Europe, Japan and the US. The basic concept is to drill two wells into a hot dry rock with limited permeability and fluid content at a depth of 5–10 km. High temperature reservoirs (200 °C) have though been found as shallow as 3 km, where the temperature gradient is high (60–65 °C/km).

The EGS technology creates permeability in the rock by hydro-fracturing the reservoir with cold water pumped into the first well (the injection well) at high pressure. The second well (the production well) intersects the stimulated fracture system and returns the hot water to the surface where electricity can be generated. Additional production wells may be drilled in order to meet power generation requirements.

Adoption of flash or binary technologies may be used with EGS depending on the temperature of geothermal fluid extracted from the artificial reservoir created by hydraulic stimulation.

Current practice for geothermal conversion systems shows that exergy efficiencies typically range from 25–50 %. Future engineering practice would like to increase these to 60 % or more, which requires further investments in research, development and demonstration (RD&D) to improve heat transfer, and improving mechanical efficiencies of converters such as turbines, turbo-expanders and pumps.

There is a strong need for EGS demonstrations to be scaled up. With wells extending up to 5 km in many cases, drilling poses a significant challenge for EGS developers. The cost reduction of injection and production wells is the next big technological issue facing the commercialisation of EGS technology. A significant technological hurdle is to control these deep-rooted fractures (exceeding 5 km) in order to create a large area for heat transfer and ensure sufficient mass flow between wells. Before reaching large-scale commercialisation, it still requires significant improvements to lower the costs.

2.1.7 Re-injection

Geothermal energy is regarded a renewable resource. However, the resource may be overexploited if there is no balance between production and inflow into the resource. The optimum level of long-term sustainable production depends on the resource characteristics. The production and re-injection may have to be amended during the production history and new wells (both production and re-injection wells) are often drilled in strategic locations as better understanding is gained on the geothermal resource behaviour. The production and re-injection rate is then controlled to prevent the adverse effects of premature pressure and temperature declines. The resource behaviour should therefore be monitored by the operators. The resource is frequently monitored by geochemical tracers, seismicity, reservoir pressure and temperature, micro-gravity. Results from these monitoring tools are then fed into reservoir simulation models which aid in planning the exploitation of the resource and predicting its behaviour in the future.

Re-injection wells may be as important as production wells for successful long-term production from a geothermal resource. The role and position of the re-injection wells is increasingly important as the reservoir permeability decreases. A hydrothermal resource with abundant fracture permeability may be operated without significant pressure drop for decades without any re-injection. An EGS however will not be operated without at least one re-injection well. Re-injection wells further serve the purpose of allowing for disposal spent geothermal fluids back into the ground, preventing the release of potential contaminants and heat into surface and shallow ground waters.

Successful re-injection of spent geothermal fluids relies heavily on maintaining the permeability of the feed zones intersected by the re-injection wells. Oversaturation of secondary minerals should therefore be prevented or their precipitation rates at least be slowed down if possible. In flash systems, this oversaturation may be decreased by dilution with condensate waters. Lowering scaling rates by various chemical methods such as pH adjustment, inhibitors have is a common practice to facilitate sufficient re-injection [Gallup 2011]. Re-injection of separated water into a fractured reservoir was greatly facilitated by mixing it with cooler condensate water prior to re-injection [Gunnarsson et al. 2015]. There the widening of fractures due to thermal contraction of the reservoir rocks were large enough to compensate for decreased viscosity of the fluid and the operation of the re-injection zones takes these effects into account. Prior to dilution of spent geothermal fluids during re-injection a thorough geochemical study should be carried out to predict if undesirable reactions may take place leading to scaling in re-injection wells or the feed zones. Furthermore dilution of spent fluids with cold water may not be desirable in a matrix dominated as the cooling front may reach the production wells faster than desired.

2.1.8 Direct use

Direct use is the oldest form of geothermal energy exploitation by mankind [Gudmundsson 1985]. Different categories of direct use exist, for example: space and district heating, greenhouse heating, aquaculture pond heating, agricultural drying, industrial uses, cooling, snow melting, bathing and swimming [Lund 2011]and updates the previous survey carried out in 2005. We also compare data from 1995 and 2000 presented at World Geothermal Congresses in Italy and Japan, respectively (WGC95 and WGC2000). The main applications worldwide are bathing & swimming and space/district heating (Section 4.1.2). Usually, direct use is working with temperatures below 150 °C [Blanco Ilzarbe et al. 2013]. Advantages of direct use are a widespread resource available at economic drilling depths and the use of conventional well drilling, heating and cooling equipment [Lund 2009]

A basic direct use system often applied in low permeability reservoirs is shown in Figure 8. Usually, heat exchangers are used in order to have a clean secondary fluid circulating through the user side of the system as the geothermal fluid usually is unsuitable for direct use due to fluid chemistry [Karlsson & Ragnarsson 1995]. The main components of a

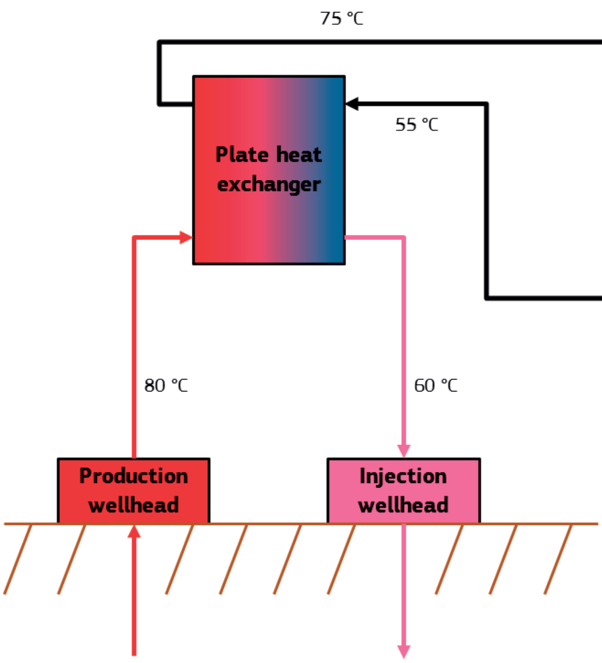


Fig. 8: Schematic process flow diagram for a direct use system with heat exchanger. Source: [Lund 1998], adapted

direct use system are the down hole and circulation pumps, pipelines, and the heat extraction and exchange parts [Lund 1998].

The downhole pumps used in direct use applications are lineshaft pumps or submersible pumps. Lineshaft pumps are less expensive and have successfully been used since long. However, for depths greater than about 250-350 m, submersible pumps are needed [Lund 1998].

Piping for transmission and distribution are usually made from carbon steel, especially when temperatures above 100 °C are involved. Also fibre-reinforced plastic (FRP) and polyvinyl chloride can be used. Pre-insulated pipelines are common nowadays [Yildirim et al. 2010]. Pipelines can be installed aboveground or underground. Aboveground installation allows for easy maintenance, however, damage from accidents or vandalism can be more probable. In addition, several issues might prevent aboveground pipelines, including difficulties with road crossings, expansion provisions, and insulation protection [Yildirim et al. 2010]. If pipelines are installed below ground, a protection by coatings or wrappings is needed. In some district heating systems, concrete tunnels have been used which is an expensive option but allows easier maintenance, future expansion, and also the possibility for co-utilisation with other users such as domestic water, electricity, telecommunication [Lund 1998, Yildirim et al. 2010]. A cheaper underground solution is to directly bury the pipelines.

Three different types of heat exchangers are suitable for direct use of geothermal energy: plate, shell-and-tube, and downhole heat exchangers [Lund 1998]. Plate heat exchangers are very common in geothermal applications due to small size, and fewer costs compared to other types of heat exchangers. In addition, plate heat exchangers can easily be increased or reduced in size if needed by adding or removing plates from the stack. In special applications, downhole heat exchangers are used.

Many geothermal direct use systems are equipped with a peaking system or a back-up plant for maximum load. Often, it is more economically to adapt the geothermal system to the base load and cover peak demand with a conventional boiler or other sources [Huenges 2011].

Concerning the development of the technology, already in 1984, Gudmundsson stated "the technology of direct applications is available and should not be a barrier to further developments" [Gudmundsson 1985]. Standard equipment is being used for direct use projects. Recently, [Blanco Ilzarbe et al. 2013] found that there are not many new patents in the area of direct use besides some developments in the area of integration of geothermal energy use in buildings. In the following sections we will focus on recent advances in the most important area of direct use, namely space and district heating.

The most common basic direct use systems, for example in Iceland, are composed of downhole and circulation pumps, transmission and distribution pipelines, peaking or back- up plants, and various forms of heat extraction equipment. Fluid is often disposed of at the surface [Lund 1998]. Doublet systems, with one production and one injection well were initially developed in the 1960s and became common in the 1980s [GEODH 2013]. Distance between wells is set in a way so that resource extraction for at least 20 years is guaranteed before the production wells start to cool down [EGEC 2007]. Wells can reach depths of about 2000 to 3500 m. To avoid corrosion of steel casings, fibreglass lined production wells, introduced in the 1990s are often used [EGEC 2007].

At the moment, district heating systems is the geothermal sector with the most dynamic development [EGEC 2013a]. Newer developments include concepts to extend lifetime of doublet design projects by drilling a third production well and converting the former two wells into injection wells (triplet system). This concept, mainly applied in France, can allow for 30 additional years of use of the geothermal resource [EGEC 2013a]. Concerning new space/district heating systems, more and more triplet systems are installed. Also smaller systems are becoming more common with shallower resources, sometimes used in combination with large heat pump systems [EGEC 2013a]. More recently, geothermal resources of low to medium temperature are now used for combined heat and power production with a binary cycle power plant first and subsequent direct use, which also improves the economics of geothermal projects [Lund 2011]and updates the previous survey carried out in 2005. We also compare data from 1995 and 2000 presented at World Geothermal Congresses in Italy and Japan, respectively (WGC95 and WGC2000).

2.1.9 Ground source heat pumps

Ground source heat pumps (GSHP) use shallow geothermal energy which is available almost everywhere. They convert the low temperature geothermal energy to thermal energy at a higher temperature which can be used for space or water heating [Ochsner 2008]. Usually, a refrigerant is used as the working fluid in a closed cycle [Self et al. 2013]. An antifreeze solution is circulated inside a closed coil and exchanges heat with the heat source/sink through the ground heat exchanger (Figure 9). While in Europe, water-to-water systems are common, mainly water-to-air systems are used in the US.

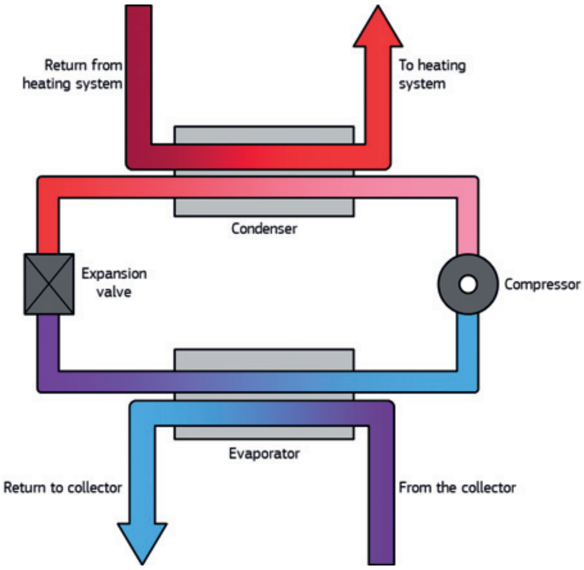


Fig. 9: Schematic process flow diagram for a ground source heat pump system

Electric energy is used to drive the compressor and the efficiency of the performance of a heat pump is measured by calculating the ratio of delivered to used energy which is the coefficient of performance (COP) [Ochsner 2008, Vellei 2014]:

$$\boldsymbol{\varepsilon = COP = \frac{Delivered\ heat\ energy\ [kW]}{Electrical\ input\ of\ compressor\ [kW]}}$$

Equation 7

The COP depends on the temperature difference between heat source and heat sink. The smaller the temperature difference, the more efficient the heat pump will be. GSHP usually have a COP in the range of 3-4 but can reach even up to 6 when well-designed [Carlsson et al. 2013, Goldstein et al. 2011, Puttagunta & Shapiro 2012].

The ground collector of a GSHP mainly takes the form of horizontal loops or vertical loops made of polyethylene or polypropylene tubes [Gazo & Lind 2010, Self et al. 2013]. Horizontal loops are the most common type of system since they offer the lowest costs. They offer a high flexibility with regards to installation options but need large areas. In contrast, vertical loop systems can be used when access to land is restricted. Due to higher drilling costs, vertical loop systems are more expensive than horizontal loops [Gazo & Lind 2010]. Another system uses direct exchange loops (often called single loops). These allow heat transfer between the ground and the refrigerant as closed (copper) loops are buried directly in the ground. Direct exchange systems have higher thermal efficiency and can be smaller. However, they are sensitive to damage on tubing and there is the risk of refrigerant leakage to the soil.

More recent innovations include the use of underground thermal energy storage (UTES). With UTES, heat is stored during the summer period and used in winter. Thermal energy can be stored in aquifers or in spaced boreholes. Also solar thermal collectors can be added to GSHP systems. They can be directly added to the GSHP's ground loop and to increase efficiency of the system while reducing the demand for land area.

The installed capacity of GSHP has seen a dramatic increase with annual growth rates of 10 % since 1994 with a main focus on Europe and the United States [Self et al. 2013]. Shallow geothermal energy use is much greater than geothermal energy direct use of electricity production both with respect to installed capacity, and energy production [EGEC 2013a]. Despite the successes in the past and continuous growth, RD&D in GSHP is focussing on further increasing the efficiency of GSHP systems and reducing costs [Angelone & Labini 2014a]. The main development areas include ease of maintenance and repair, improved control systems, more efficient working fluids, and increased efficiency of auxiliaries such as pumps and fans [Angelone & Labini 2014a]. Ground collectors should be improved by optimisation of design and grouting material [RHC 2014]. In the long term, the aim is to develop better materials for the ground collector. Currently mainly plastics tubes are used which offer low cost and corrosion resistance but show low thermal conductivity [Angelone & Labini 2014b]. The Geothermal Energy Roadmap of the European Technology Platform on Renewable Heating & Cooling recommends the development of new antifreeze fluids that are environmentally benign, and offer better thermal characteristics than current fluids [RHC 2014].

2.1.10 Materials in the geothermal sector

An important parameter in power plant design and operation is the selection of suitable materials during the construction process. Similarly strategic location of sampling points to collect steam, gases and fluids from the processes is important to allow for preventive measures to be taken prior to costly damage to equipment.

2.1.10.1 Corrosion

Geothermal fluids are often characterised by high salt concentrations, high temperature and pressure and the presence of dissolved gases such as H_2S. This may cause substantial corrosion to metal components of geothermal energy plants which leads to quicker wear of materials and eventually to higher maintenance and repair costs, and downtime [Milles 2012]. Corrosion is a great concern for geothermal power plant operators [Mundhenk et al. 2013]. It can occur at various components of geothermal power plants including liners and well casings, well heads, turbines, heat exchangers, and pipes. As condensers operate under vacuum conditions there is always a risk of leaking of atmosphere into the unit and resulting in both formation of elemental sulphur that can clog components and sulphuric acid. The atmosphere may also enter the condenser with gland steam if a turbine doesn't have specific extraction system to eject the gland steam. Liners and well casings are most affected when the deep fluid is acidic and/or saline while corrosion in heat exchangers is commonly due to stress corrosion cracking [Fridriksson & Thórhallsson 2006].

Material selection can prevent corrosion, however, may lead to increased costs [Fridriksson & Thórhallsson 2006, Gunnlaugsson et al. 2014, Mundhenk et al. 2013]. It is recommended not using high yield-strength steel for casing and liners, and to use chromium steel for the upper parts of casings. High-temperature cement should be used to fix casings [Fridriksson & Thórhallsson 2006]. Turbine components in geothermal power plants have to be made of materials that can resist corrosion which is mainly due to gases such as H_2S present in geothermal steam. In general, 12 % chromium steel has been successfully used [DiPippo 2012]. The selection of the most suitable alloy depends on the specific component and environment it will be used. Alloys that have been used include titanium, nickel, chromium, molybdenum, cobalt, zirconium, tantalum, and aluminium [Kaya & Hoshan 2005]. Under high H_2S concentrations indirect steam condensers are sometimes constructed with titanium pipes to prevent corrosion.

Besides careful material selection, research and development of new materials is proposed to mitigate the effects of corrosion on the economic performance of geothermal energy plants. [Angelone & Labini 2014a] mention new components from polymers or plastics, optimised coating, and the utilisation of aluminium. Fibre-reinforced plastics and concrete-polymer mixtures have seen increasing use in the past [Kaya & Hoshan 2005]. Another strategy proposed is to accept corrosion-related replacement of parts while using low-cost materials.

2.1.10.2 Scaling

Scaling is a phenomenon that can occur frequently in geothermal power plants. Solids are formed within a solution by chemical reactions or precipitation by oversaturation [Huenges 2011]. Often, scaling is due to pressure drops, temperature or pH changes, increased levels of oxygen and/or corrosion [Mundhenk et al. 2013]. In principle scaling can occur in production wells, the surface equipment, and reinjection wells [Fridriksson & Thórhallsson 2006]. The solids can form on the surfaces of e.g. heat exchanger, or pipes and can clog them. Once scaling has commenced on piping surfaces, the course surface promotes further crystal growth towards the water flow direction as turbulence is increased adjacent to the scale surface. The solid particles formed on pipe walls and heat exchangers can fall off the walls (for example during pipe expansion and shrinkage during heating and cooling) and ending up in pump heads causing mechanical erosion. A considerable scaling can occur during mixing of different water types, for example when cold oxygen rich water is drawn into a hotter oxygen poor reservoir.

Many ways to combat scaling exist, chiefly depending on the type of scaling (silica and sulphides in high temperature systems, carbonates in low and medium temperature systems and other types). They include preventing turbulent flow in pipes, reducing temperature changes and avoiding large pressure drops across valves. However, reduction of temperature decrease and pressure drop has to be studied in conjunction with the desired efficiency of the energy conversion process. Since the efficiency of the conversion process is directly related to the temperature difference through the process considerable effort has been placed into adjusting the pH of separated waters to prevent scaling [Gallup 2011, Sigfusson & Gunnarsson 2011]. Scaling inhibitors can also be applied and scale can also be removed mechanically or with acids [Huenges 2011]. Another approaches to prevent scaling is the application of coatings with anti-adhesive properties [Mundhenk et al. 2014]. Finally silica polymerisation has been proven to be successful to prevent silica scaling from separated waters prior to re-injection [Gunnarsson et al. 2010].

The knowledge of the chemical composition of the fluids and gases is important to understand potential scaling and corrosion problems during preparation, installation and operation of any geothermal installation. An effort should be made to sample and characterise fluids and gases likely to be involved in the processes. Based on these analyses, geochemical modelling may be carried out to predict scaling and corrosion problems. However, the thermodynamic and kinetic datasets used to predict mineral saturation state and rate of chemical reactions occurring in geothermal systems and power plants are not complete and the geochemical modelling therefore may have considerable margin of error. Therefore, laboratory experiments often need to be conducted to validate and compliment the modelled results. Although laboratory experiments take time and can bear some cost, the understanding gained on the process by accurately characterising each process can lead to significant cost savings during the design, construction and operation of the geothermal installations.

2.1.10.3 Saturated vapour in turbines

According to [DiPippo 2012], in liquid-dominated geothermal systems, steam is used as saturated vapour which leads to moisture being present in steam paths. As a consequence, droplets can form at the end of the lower pressure stages of turbines and strike the blade edges leading to erosion pits. To prevent this, turbine blades can be reinforced with appropriate alloys, for example, cobalt-rich alloys. Moisture separators are usually located directly in front of the turbine unit to remove moisture condensed in the pipelines leading from steam/ water separators to the turbines. Methods applied to monitor moisture entering the turbines include a regular monitoring of sodium in the steam. There, a small portion of the steam is condensed prior to being analysed either by a Na-selective electrode or with other analytical methods (atomic adsorption, ion chromatography). As Na only exists in the separated water, the measurement of Na in the steam gives a useful indication of the separated water portion in the steam and therefore the efficiency of steam / water separators. In vapour-dominated geothermal systems, the transition from superheated to saturated steam may lead to corrosion if hydrochloric acid is present in the superheated steam. Droplets in the steam may also be measured by laser absorption methods that are currently under development.

2.1.10.4 Shallow geothermal

In the shallow geothermal sector, research and development (R&D) has a key focus on improving materials used for borehole heat exchangers and ground loops. The main goal is to allow for a better energy transfer and to reduce costs by keeping lifespan similar to the materials currently used [RHC 2014].

2.2 Current challenges and possible bottlenecks

The key issue the geothermal power sector faces is the deployment of EGS technology. To date, the technology has been demonstrated on small scale in few locations. However, for an adequate proof of concept the technology needs to be demonstrated under different geological conditions where permeability can be produced and maintained without having to rely on pre-existing fractures in the reservoirs. Operators need to demonstrate the ability to adequately control reservoirs in different settings, both in terms of heat extraction and from chemical stimulants and seismic point of view. In the process of providing widely applicable proof of concept of EGS, drilling technologies as well as reservoir management and monitoring technologies should be developed extensively.

2.2.1 Estimate of resource potential

It is well known that the heat stored in the Earth's crust is very high. However, the estimation of heat in place would benefit from more direct measurements. An extensive drilling campaign has been proposed by the European Geothermal Energy Council (EGEC) and would bring benefits to the geothermal sector in two ways: first, it would facilitate a more accurate estimate of the resource potential in Europe by establishing temperature gradients and heat flows in the crust and provide a better picture of the geology in the area. Second, due to increased drilling activities in the sector, knowledge and experience would be accumulated quicker.

2.2.2 Drilling risks and costs

Today, drilling costs often constitute more than half of the cost associated with construction and commissioning of a geothermal power plant. Drilling into hydrothermal reservoirs includes drilling into highly heterogeneous materials where hard rocks may alternate with fractures where complete loss of circulation and collapsing geological formations may be experienced. Loss of circulation can lead to extensive losses of drill muds and cements. Collapsing formations may prevent movement of casings and in worst cases lead to the necessity of cutting the drill string causing the bottom hole assembly, collars and parts of the drill string to be left in the well [Sveinbjornsson & Thorhallsson 2014]. An intensive drilling campaign as mentioned in the chapter above provides the opportunity to develop and test novel drilling technologies in a reasonably short period of time and better direct resource potential and drilling development projects are therefore highly complementary.

2.2.3 Stimulation

Today, natural permeability of geothermal reservoirs determines the productivity of geothermal wells. Some effort has been put into geothermal reservoir stimulation but the knowledge gathered to date appears fragmented. Existing stimulation methods need to be refined to increase the rate of success, to improve predictability of results, to remove well and formation damage, to develop and prop fracture networks, and to reduce environmental hazard (pollution of aquifer, induced seismicity). Research should focus on understanding the underlying processes leading to improved permeability and develop concepts to minimise unwanted side effects. The reservoir stimulation research would complement the overall goal of proving the EGS concept under different geological conditions.

3 EU AND MEMBER STATE POLICIES RELATED TO GEOTHERMAL ENERGY

There are several EU directives affecting the geothermal sector the most important one being the Directive on the promotion of the use of energy from renewable sources adopted on 23 April 2009 [EC 2009a]. In the following sections, a summary of polices related to geothermal is given.

3.1 National Renewable Energy Action Plans (NREAP)

The Directive 2009/28/EC introduces National Renewable Energy Action Plans (NREAP) that each Member State must adopt [EC 2009a]. The NREAP lay out how the Member State will achieve the mandatory target of 20 % share of energy from renewable sources in total energy consumption by 2020. The NREAP include the use of geothermal for power production as well as heating and cooling. The Commission Decision 2009/548/EC establishes a template for the NREAP [Commission Decision 2009]. Nineteen of European countries have adopted one or more categories of geothermal into their NREAP. Table 3 provides a summary of the NREAP targets for geothermal energy in EU member states for the years 2012 and 2020 and reported values of geothermal energy use for the year 2012.

In 2012, the combined geothermal power capacity in EU-28 was 934 MW_e compared to NREAP 2020-targets of 1612 MW_e. Heat production from direct sources was 9400 GWh_{th} with NREAP 2020-target at 30589 GWh_{th}. Finally, shallow geothermal heat production was 27080 GWh_{th} in 2012 with NREAP 2020-target at 49340 GWh_{th}.

Table 2 displays that in 2012, the installation of geothermal power plants and the heat production from GSHP exceeded EU-28 NREAP targets of 2012. However the EU-28 2012 targets for direct heat production were slightly missed.

Table 2: Geothermal power capacity and heat production in the EU-28 in 2012 and NREAP targets in 2012 and 2020

Type		Reported values[1] 2012	NREAP target 2012	NREAP target 2020
Shallow geothermal (mainly GSHP)	GWh_{th}	27080	18946	49340
Deep geothermal resources (direct heat)	GWh_{th}	9404	10440	30589
Geothermal power capacity	MW_e	876	787	1612

1) Source: [Antics et al. 2013]

The NREAP predicted values for 2012 are compared to reported data from the Member States that have included the respective technologies into their plans in Table 3, Table 4 and Table 5 . Furthermore the 2020 target values are reported.

On the whole, the installation of GSHP has been faster than anticipated in Europe. Austria, Romania and Sweden have the highest proportional gain compared to their NREAP while Denmark, France, Italy, Netherlands, Slovenia and UK were furthest from reaching their 2012 NREAP targets.

For deep geothermal resources for direct use, the commissioning rate of new installations was low leading to heat production of 9404 GWh_{th} compared to the NREAP targets of 10440 GWh_{th} in 2012 (Table 4). Greece, Hungary and Lithuania have the highest proportional gain compared to their NREAP while Belgium and Netherlands are proportionally furthest from reaching their 2012 NREAP targets.

For geothermal power plants, the installed capacity in 2012 (876 GW) exceeded the NREAP targets of 787 GW (Table 5). The main reason is due to the commission of Italian power plants not anticipated in the NREAP. France and Germany are far from reaching their geothermal power targets. In France, no geothermal power development has occurred for the last 10 years except the EGS of Soultz-sous-Forets and targets will not be reached. In Germany, projects under construction promise 60 to 70 MW_e until the end of 2015.

Table 3: Geothermal heat production with ground source heat pumps in the EU-28 (GWhth) in 2012 and NREAP targets in 2012 and 2020

Country	2012				2020
	NREAP target	Reported values[1]	Difference	% difference	NREAP target
	GWh_{th}	GWh_{th}	GWh_{th}		GWh_{th}
AT	128	1440	1312	1026	302
BE	442	335	-107	-24	1710
DE	3710	4200	490	13	6059
DK	1570	695	-875	-56	2314
EL	105	135	30	29	582
ES	187	210	23	12	471
FR	3954	2775	-1179	-30	6629
HU	70	110	40	58	1244
IT	779	472	-307	-39	6071
NL	1372	880	-492	-36	2814
RO	12	32	20	175	93
SE	4431	15200	10769	243	9478
SI	151	96	-55	-37	442
SK	12		-12	-100	47
UK	2024	500	-1524	-75	11083
Total	**18947**	**27080**	**8133**		**49340**

1) Source: [Antics et al. 2013]

Table 4: Deep Geothermal heat production in the EU (GWhth) in 2012 and NREAP targets in 2012 and 2020. Includes district heating, industry and agriculture, balneology and other

Country	2012				2020
	NREAP target	Reported values[1]	Difference	% difference	NREAP target
	GWh_{th}	GWh_{th}	GWh_{th}		GWh_{th}
AT	256	184	-72	-28	465
BE	41	18	-23	-56	66
BG	28	16	-12	-44	105
CZ	0	25	25	0	174
DE	1326	729	-597	-45	7978
EL	244	504	260	106	593
ES	44			0	110
FR	2268	1316	-952	-42	5815
HU	1396	2849	1453	104	4152
IT	2780	2368	-412	-15	3489
LT	35	93	58	167	58
NL	872	202	-670	-77	3012
PL	337	187	-151	-45	2070
PT	163	96	-67	-41	291
RO	407	362	-45	-11	930
SE		270	270	0	
SI	209	164	-45	-22	233
SK	35			0	1047
UK		21	21	0	
Total	**10440**	**9404**	**-958**		**30589**

1) Source: [Antics et al. 2013]

Table 5: Installed geothermal power generation capacity in the EU-28 (MW) in 2012 and NREAP targets in 2012 and 2020

Country	2012				2020
	NREAP target	Reported values[1]	Difference	% difference	target
	MW	MW	MW		MW
AT	1	1.4	0.4	40	1
BE	0		0	0	3.5
CZ	0		0	0	4.4
DE	27	11.9	-15.1	-56	298
EL	0		0	0	120
ES	0		0	0	50
FR	37	17	-20	-54	80
HU	0		0	0	57
IT	787	875.5	88.5	11	920
PT	25	28.5	3.5	14	75
RO	0	0.05	0.05	0	0
SK	4		-4	-100	4
Total	**881**	**934**	**53**	**0**	**1613**

1) Source: [Antics et al. 2013]

3.2 EU and Member State policies and financing

Geothermal project development has high upfront cost and can take as little as 3 years but average development time is about five to seven years. Figure 10 shows the individual phases of a geothermal project and presents the financial instruments needed in each of these steps [EGEC 2013b]. EU legislation on renewable electricity requires that dispatch priority is given to renewable electricity insofar as the operation of the national electricity system permits [EC 2009a]. There exists a number of support schemes within the EU and they differ between the Member States. Below follows a short description of main mechanisms available for funding from the EU and Member states.

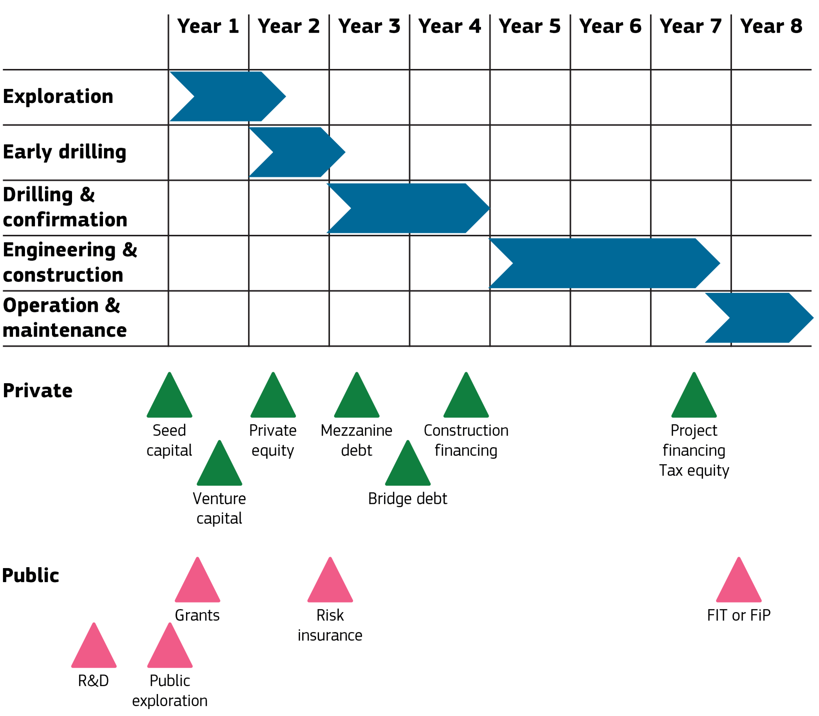


Fig. 10: The phases of geothermal projects and the mechanisms of funding throughout their duration. Reproduced from [EGEC 2013b]

3.2.1 Research, development and deployment

In the last 10 years, Member States have spent EUR 4.5 billion on renewable R&D. In the same period, the EU has spent EUR 1.7 billion from the Sixth (FP6) and Seventh Framework Programme (FP7), and the European Energy Programme for Recovery (EEPR). Until 2012, EUR 29.4 million were allocated from FP6 and FP7 to geothermal projects. Moreover, to date, the geothermal sector is the only one (with biomass) to have experienced a proportional reduction in FP7 funding (from EUR 17.3 million in FP6 to EUR 12.1 million). No geothermal project has been financed by the EUR 4.5 billion EEPR programme that commenced in 2009.

3.2.2 NER 300 programme

The New Entrants' Reserve 300 (NER 300) programme is another financing instrument at EU level used to subsidise installations of innovative renewable energy technology and CCS. In December 2012, the European Commission, in the first call for proposals, awarded about EUR 39 million to the Geothermal South Hungarian EGS Demonstration Project [Commission Decision 2012]. A second call was launched in 2013 and another 2 EGS projects have been awarded funding: the Croatian Geothermae project (about EUR 14.7 million) and the French Geostras project (about EUR 16.8 million) [Commission Decision 2014].

All the geothermal projects funded are EGS projects with a nominal capacity greater than 5 MW_e. The Hungarian EGS Demonstration project is a project falling under the subcategory "EGS in compressional stress fields" while the other two projects are of the subcategory "EGS in areas with deep compact sedimentary and granite rocks and other crystalline structures". Maximum funding rates for the projects are between about 21 EUR/MWh to 57 EUR/MWh.

3.2.3 Risk insurance funds

Risks associated with geothermal project development include short term risks such as the risk not finding an adequate resource and long term risks (e.g. decline of resource over time due to production). The resource is confirmed only after the exploration and drilling is finished; these two processes often represent most of the costs associated with the development of a geothermal project. The average period for developing geothermal power projects to commercial deployment is five to seven years. However, once the feasibility of a resource has been established, the probability of project success is higher than 80 %. Risk insurance funds for the geological risks associated with geothermal projects exist in three Member States as well as in Iceland and Switzerland [EGEC 2013b]. Geothermal developers struggle to find insurance (public or private) schemes with affordable terms and conditions for the resource risk. This is due to a relatively limited number of geothermal electricity operations in the EU and the difficulties met while assessing the probability of success. The European Geothermal Energy Council (EGEC) has proposed a European Geothermal Risk Insurance Fund (EGRIF) that aims at alleviating the shortage of insurance policies for the resource risk and easing investments in geothermal electricity projects.

3.2.4 Feed-in-tariffs

A feed-in-tariff (FIT) is a fixed and guaranteed price paid to the eligible producers of electricity from renewable energy sources. In 2014, this policy instrument was available in 23 EU Member States. Of these, Germany, France, Slovenia, Slovakia, Spain, Austria, Czech Republic, Greece, Portugal (Azores only) and Hungary have dedicated FIT for geothermal energy. The most attractive schemes are found in Germany (25 c EUR/kWh for all projects and additional 5 c EUR for EGS) and France (20 c EUR/kWh with an energy efficiency bonus of up to 8 c EUR/kWh) [Angelone & Labini 2014b]. In 2011, feed-in-tariff schemes were the most significant form of operating support for renewable energies [EC 2011]. Analyses on the effect of feed-in-tariffs in the geothermal sector remain few and more emphasis has been laid on their effect on for example photovoltaics (PV) and wind. For PV and onshore wind in Europe, [Jenner et al. 2013] concluded that feed-in-tariff policies had driven PV development in Europe since 1992 via their expected return on investment (ROI) faced by investors. They did not find clear evidence that feed-in-tariff policies had driven wind power development except when combined with tendering schemes. Similarly, [Jenner et al. 2013] showed that policy design, electricity price and electricity production cost were more important determinants of renewable electricity development than policy enactment alone.

A study on the combination of deployment instruments (feed-in-tariffs, investment subsidies and soft loans) did not result in lower policy costs [Mir-Atrigues and del Río 2014]. However, combinations of support schemes may lead to inter-temporal distributions of the same amount of policy costs. This redistribution of costs may affect social acceptability and political feasibility of renewable energy support [Mir-Atrigues and del Río 2014]. The timing of costs is of particular relevant for geothermal projects as the costs tend to occur over long times, for example, it typically takes seven to eight years from initiation of exploration until entry into operation for a geothermal power plant.

3.2.5 Feed-in-premiums

Feed-in-premiums grant a payment per kWh on top of the electricity wholesale-market price. Estonia, the Netherlands, Slovenia and Italy promote geothermal power generation by means of feed in premiums [Angelone & Labini 2014b].

3.2.6 Tradable Green Certificates

Tradable green certificate (TGC) programmes establish requirements to produce/deliver a certain percentage of electricity using renewable and other 'green' sources. Therefore technologies that qualify as green thus produce two distinct commodities, (1) electricity, which is sold in the normal electricity market and (2) green certificates, which are traded in a green certificate market. The income of selling the green certificates to producers or distributors of electricity from other sources covers the gap between the marginal cost of renewable electricity generation and the price of electricity. In 2014, six EU countries applied TGC schemes [Mir-Atrigues and del Río 2014] and Belgium (Flanders), Romania, and the UK apply the scheme for geothermal [Angelone & Labini 2014b].

3.2.7 Tendering

Tendering involves governments inviting renewable electricity (RES-E) generators to compete for either certain financial budget or a certain RES-E generation capacity. Cheapest bids per kWh are awarded contracts and receive the subsidy. In 2014, nine countries employ tendering schemes.

3.2.8 Soft loans

Soft loans are usually provided by governments with rates below market interest rates and can in some cases significantly lower capital costs. Furthermore, the repayment periods may be longer and interest holidays included.

4 GEOTHERMAL ENERGY MARKET STATUS

4.1 Global market status

As mentioned above, the following classification according to [Antics et al. 2013] and Directive 2009/28/EC [EC 2009a] is used to define the different markets within the geothermal industry:

- Power generation
- Direct use
- Ground source heat pumps

An overview over global installed capacity for power generation, direct use and GSHP in 2010 is shown in Figure 11. In general, lead markets for geothermal energy are in America, Europe and Asia. Installed capacity for GSHP is greatest, followed by direct use and power generation.

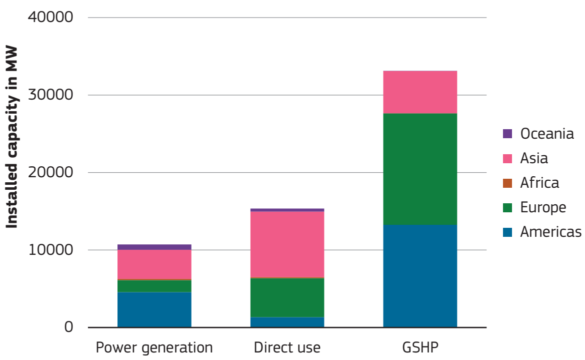


Fig. 11: Global installed capacity for power generation, direct use and GSHP in 2010 according to continent. Sources: [Boyd & Lund 2014, IGA 2014]

Some countries show significant shares for GSHP while others dominate power generation (Figure 12). Highest total installed capacity of geothermal energy is in the United States, followed by China, and Sweden. The top 10 countries have about 75 % and the top 15 countries about 84 % of total installed capacity worldwide.

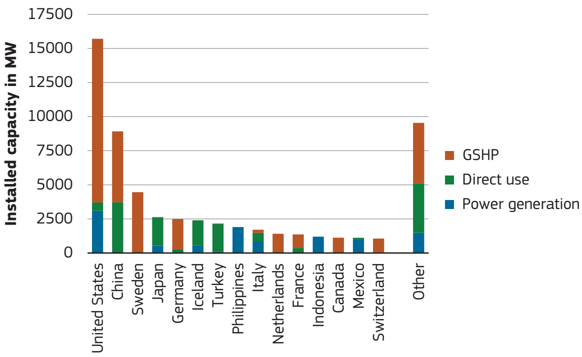


Fig. 12: Global installed capacity for power generation, direct use and GSHP in 2010 according to country Sources: [Boyd & Lund 2014, IGA 2014]

4.1.1 Power generation

In 2013, global installed capacity for geothermal power generation reached about 11.8 GW_e [GEA 2013, IGA 2014]. The new installed capacity in 2013 amounted to 530 MW_e [GEA 2014, REN21 2014], which is a new record in annual installations. Of this, 145 MW_e were installed in Europe, 107 MW_e in New Zealand, 85 MW_e in the US and 36 MW_e in Kenya [EGEC 2013a, GEA 2014, Mugo 2013, NZGA 2014]. The growth of global cumulative installed capacity was about 4 % in 2013 and higher than in the previous years when 3 % was reached for 2011 and 2012 [REN21 2014].

Asia is leading the cumulative installed capacity with 3.8 GW_e, dominated by the Philippines (1.8 GW_e) and Indonesia (1.3 GW_e), followed by the US with 3.4 GW_e (Figure 13). Total installed capacity in Europe amounts to about 1.7 GW_e. Concerning the rest of the world, Mexico deserves to be mentioned with an installed capacity of about 1 GW_e.

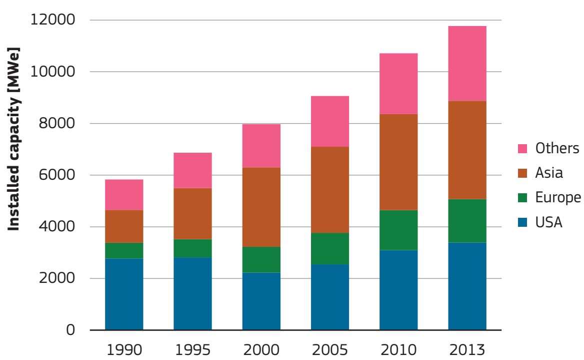


Fig. 13: Global installed capacity for power generation. Source: [IGA 2014]

Geothermal electricity generation has continuously increased and in 2012, more than 70 TWh have been produced (Figure 14). In 2012, geothermal electricity generation accounted for about 1.5 % of global renewable and 0.3 % of total global electricity production [Observ'ER 2013a].

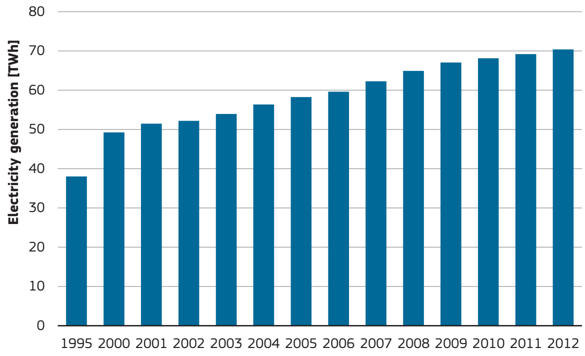


Fig. 14: Global electricity generation between 1995 and 2012
Sources: Own calculations, based on [IEA-GIA 2013, Observ'ER 2013a, OECD/IEA 2013]

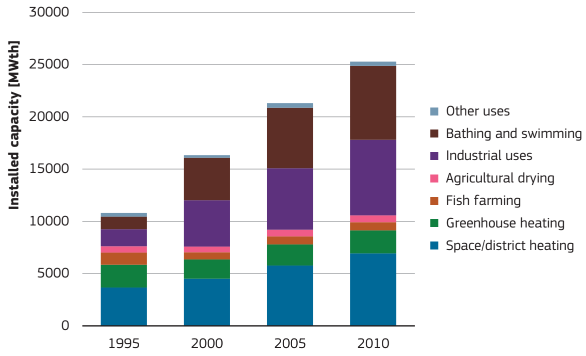


Fig. 15: Global installed capacity for direct use from 1995 to 2010
Sources: [IEA-GIA 2012, IEA-GIA 2013]

4.1.2 Direct use

The direct use of geothermal resources in this report means the direct thermal extraction for heating and cooling excluding heat pumps (for heat pumps, see Section 4.1.3). Possible direct uses are: space and district heating, heating of public baths and swimming pools, heating of greenhouses, industrial process heat, and agricultural drying.

Information on installed capacity for direct use is difficult to find and often, statistical data are missing [EGEC 2013a]. Global installed capacity of direct use (without heat pumps) is estimated between 19 GW_{th} and 26 GW_{th} [REN21 2014]. Countries with largest direct use (without heat pumps) include China (about 3.7 GW_{th}), Turkey (about 2.7 GW_{th}), Iceland (about 2.2 GW_{th}), and Japan with about 2.1 GW_{th} of installed capacity [REN21 2014].

In 2013, installed capacity for direct use of geothermal energy increased. However, it was difficult to find precise information on new installations. According to [REN21 2014], capacity grew in Europe (Hungary, Italy, Germany). Unfortunately, data on historical development of capacity for direct use (without heat pumps) according to country could not be found [Boyd & Lund 2014].

Data on the past development of installed capacity according to use shows a steady increase and capacity in 2010 was about 2.5 times the installed capacity in 1995 (Figure 15). The greatest increases in absolute terms have been achieved for bathing and swimming and industrial uses, followed by space/district heating. Direct utilisation of thermal resources in terms of heat followed a similar trend than installed capacity.

The share of the individual users differs considerably between countries, and regions. In Iceland, for example, space/district heating and snow melting dominates direct use while in Japan, bathing and swimming accounts for more than 80 % if direct use [Lund et al. 2010].

Production of geothermal heat by direct users amounted to about 225 PJ in 2010 (Figure 16). China shows highest use of geothermal heat, with estimated use of about 46 PJ in 2009 [Lund et al. 2010, OECD/IEA 2011]. In the past, total global growth followed to a great extent the trend of worldwide installed capacity.

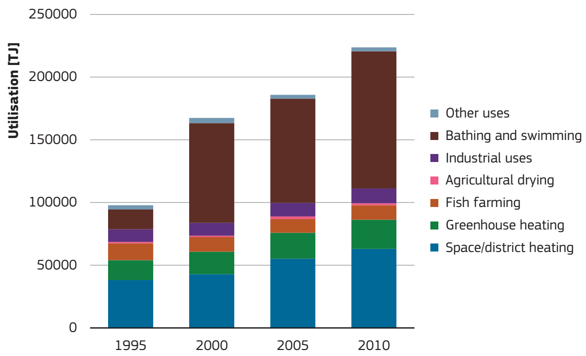


Fig. 16: Global direct use of geothermal energy
Sources: [IEA-GIA 2012, IEA-GIA 2013]

In 2010, the largest direct uses globally (excluding heat pumps) are bathing and swimming (44 %), space/district heating (35 %), and the heating of greenhouses (10 %). Other direct uses such as agricultural drying or pond heating are of minor importance, only.

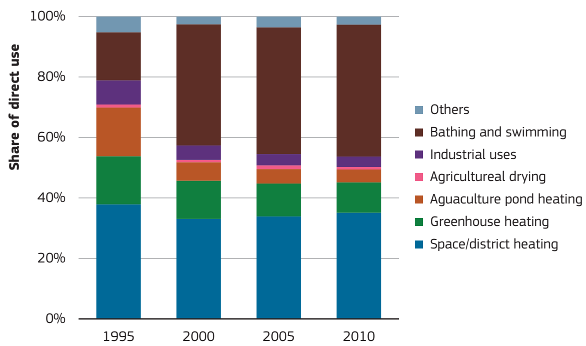


Fig. 17: Share of global installed capacity according to direct use
Sources: [IEA-GIA 2012, IEA-GIA 2013]

4.1.3 Ground source heat pumps

Installed capacity for ground source heat pumps by far exceeds installed capacity for power generation and direct use. However, statistical data often do not report the use of ground source heat pumps (shallow geothermal energy). Sometimes, they are subsumed under direct use. Data for global installed capacity and utilisation of heat pumps could be obtained from [IEA-GIA 2013] for 1995 to 2010. However, newer data was not available.

Both global installed capacity and use show a dramatic increase. In 2010, installed capacity was more than two times higher than 2005 about 18 times higher compared to 1995 and utilisation increased by 1200 % between 1995 and 2010.

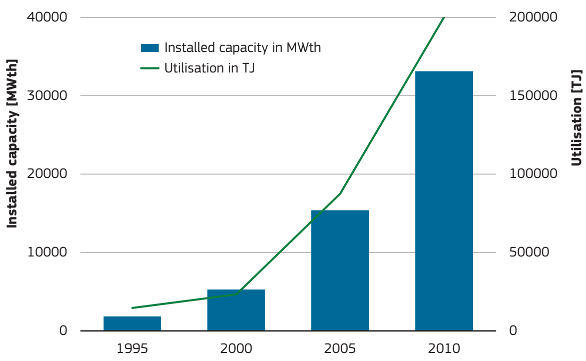


Fig. 18: Global installed capacity and utilisation of ground source heat pumps. Source: [IEA-GIA 2013]

4.2 Europe

4.2.1 Power generation

The installed capacity of the 68 power plants in operation in Europe was about 1850 MW_e at the end of 2013, producing about 11.7 TWh of electricity [EGEC 2013a]. The 51 geothermal power plants in the EU-28 account for about 946 MWe and 5.56 TWh of electricity produced (Figure 19).

In 2013, 8 power plants have entered into operation with a capacity of about 145 MW_e. In the EU-28, new plants have been added in Germany (16 MW_e), Romania (0.05 MW_e), and Italy (1 MW_e). Other new installations took place in Turkey (128 MW_e).

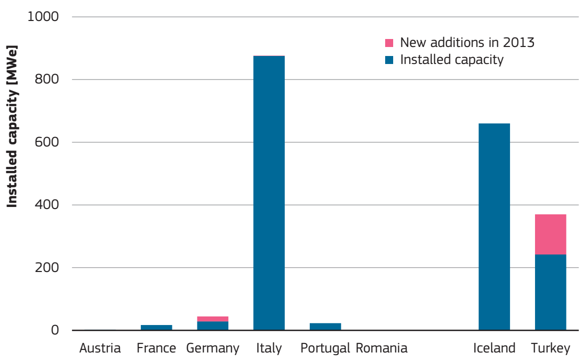


Fig. 19: Installed capacity for power generation in Europe and additions in 2013. Source: [EGEC 2013a]

In terms of power plant technology, dry steam and single flash technology dominate the European market, with shares of 48 % and 34 %, respectively [EGEC 2013a]. New installations in 2013 were mainly binary-ORC but one 80 MW_e project in the Turkey deployed triple flash (Figure 20).

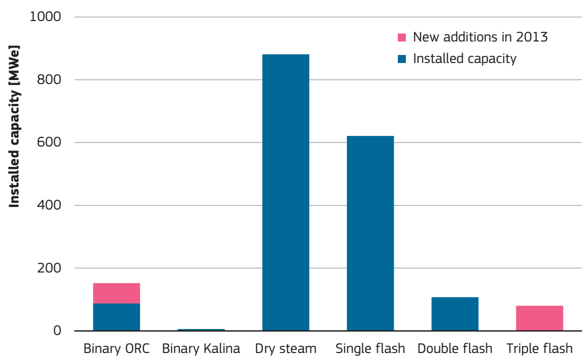


Fig. 20: Installed capacity for power generation in Europe according to technology. Source: [EGEC 2013a]

Production of electricity in Europe reached 11.7 TWh in 2012 and 5.6 TWh in the EU according to [EGEC 2013a]. Information from Eurostat gives slightly lower results with 5.4 TWh of generation in 2012 which is mainly due to the fact that the new plants in Germany have apparently not been accounted for by [Eurostat 2014]. Figure 21 shows that electricity production from geothermal energy in the EU-28 has been relatively stable during the past ten years.

In 2012, geothermal energy provided about 0.2 % of the total final electricity demand (about 2800 TWh) and 0.9 % of the electricity generated by renewable sources (about 660 TWh) in the EU-28. The capacity factor of the geothermal power plants in Europe was about 76 % in 2012, due to decommissioning and some plants had to be repaired and where only available from some days [EGEC 2013a].

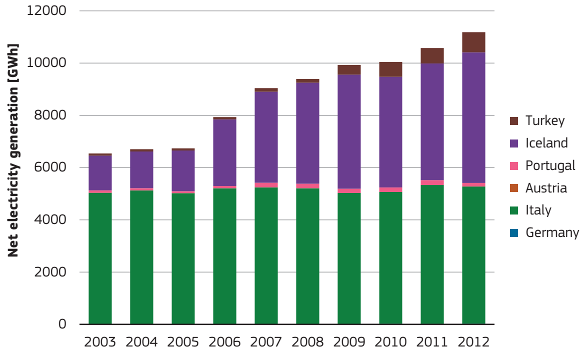


Fig. 21: Net electricity generation from geothermal in Europe from 2003 to 2012. Source: [Eurostat 2014]

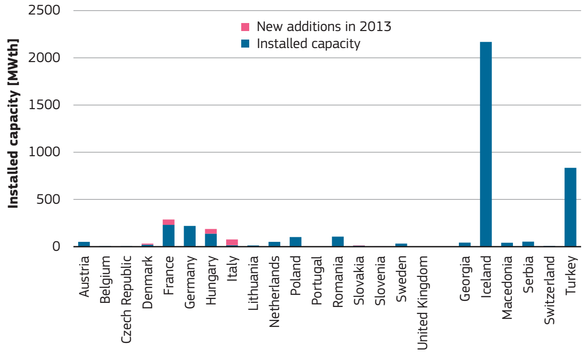


Fig. 23: Installed capacity and new additions in 2013 for district heating in Europe according to country. Source: [EGEC 2013a]

4.2.2 Direct use

The installed capacity for direct use of geothermal energy for heat in the European Union was about 3.0 GW_{th} in 2012 (Figure 22). The countries that show greatest direct use are Italy, Hungary, and France. Direct use increased by almost 25 % between 2011 and 2012. However, an improved methodology to calculate direct use was introduced between 2011 and 2012, which leads to higher capacity, especially for balneology in Italy [Observ'ER 2013b]. Main direct uses in the EU are heating networks (about 50 % of direct use) and balneology (about 20 % of direct use). Currently, geothermal district heating has a share of about 0.5 % of the total district heating market [Euroheat 2014].

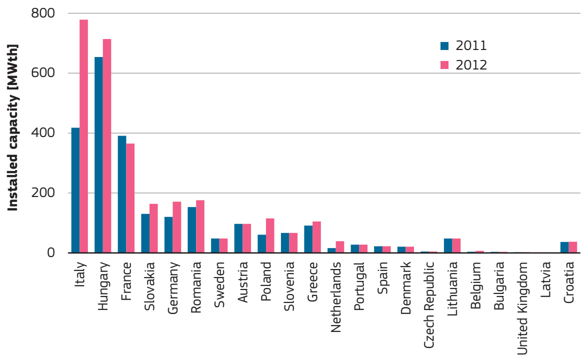


Fig. 22: Installed capacity for direct use in the European Union according to country. Source: [Observ'ER 2013b]

In total, about 27630 TJ of heat have been produced in 2012, which is an increase of 10 % compared to 2011 [Observ'ER 2013b].

Looking beyond the EU and considering Europe, only data for district heating could be found in [EGEC 2013a]. Total installed capacity in 2013 was estimated to be about 4.3 GW_{th} with a production of about 46 300 TJ (Figure 23). Main players are Iceland with about 50 % (2.2 GW_{th}) and Turkey with about 20 % (0.8 GW_{th}) of the installed capacity in Europe [EGEC 2013a].

New major additions of capacity occurred in France, Hungary and Italy. In Hungary, a district heating plant was opened in 2013 in Miskolc which might reach a capacity of 60 to 70 MW_{th} [PannErgy 2014, REN21 2014]. Another major inauguration took place in Italy where the Monteverdi Marittimo 6 MW_{th} district heating plant was opened [REN21 2014]. In future, the installed capacity will grow mainly in Germany, France, and Hungary [EGEC 2013a].

4.2.3 Ground source heat pumps

Installed GSHP capacity in Europe amounted to about 16.5 GW_{th} in Europe and 14.9 GW_{th} in the EU [EGEC 2013a]. Main markets for GSHP in the EU are Sweden, Germany, France, and Austria (Figure 24). The total number of units installed was estimated to be about 1.34 million units in Europe (1.21 million in the EU) in 2013.

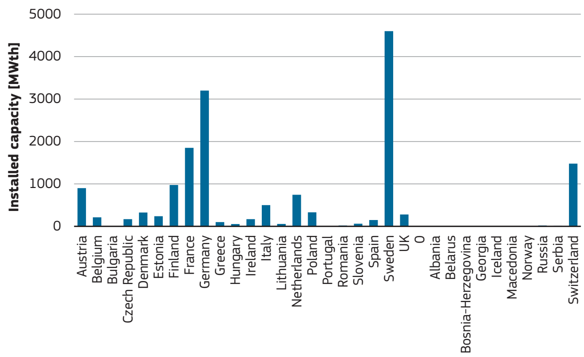


Fig. 24: Installed GSHP capacity in 2012 in Europe according to country. Source: [EGEC 2013a]

Major markets in the EU in 2012 were Sweden and Germany with 25 % and 21 % of market share, respectively (Figure 25). Total sales of geothermal heat pumps in 2012 were 6 % of installed units in 2011. European GSHP market has been shrinking in the recent years because the market is very much dependent on the new building market and since the construction sector still shrinks and fewer houses are built, also fewer GSHP units are sold [Observ'ER 2013b]. It is expected that the market will recover in the next coming years.

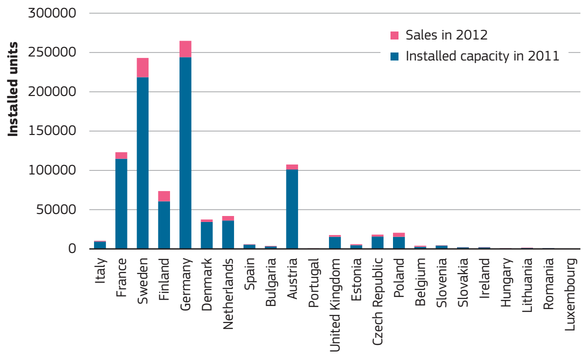


Fig. 25: Installed GSHP units in 2011 and sales in 2012 in Europe according to country. Source: [Observ'ER 2013b]

4.3 Asia

Figure 26 shows geothermal energy generation in Asia according to countries and use. In some countries, direct use & GSHP clearly dominates energy production, while in other countries, power generation (e.g. Indonesia, Philippines) has significantly greater shares. In Asia, China is the country leading in geothermal energy use. According to [REN21 2014], however, uncertainties for direct use are high and the estimates for China range between 13 to 45 TWh for direct use excluding GSHP. [Zhao & Wan 2014] have estimated total production at 12.8 TWh for direct use and about 8 TWh for GSHP.

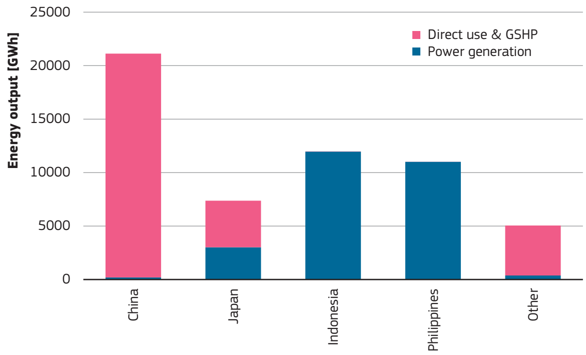


Fig. 26: Energy generation in Asia according to country. Source: [IGA 2014, OECD/IEA 2013], own calculations

The installed capacity for geothermal power generation increased significantly in Asia between 1990 and 2010. Since then, growth has been slower (Figure 27). In the Philippines, degradation of some geothermal fields occurred [Menzies 2013]. In contrast, electricity generation has not increased at the same rate (Figure 28).

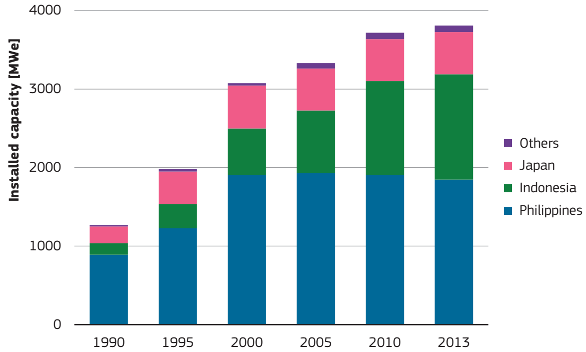


Fig. 27: Installed capacity for power generation in Asia according to country. Source: [IGA 2014]

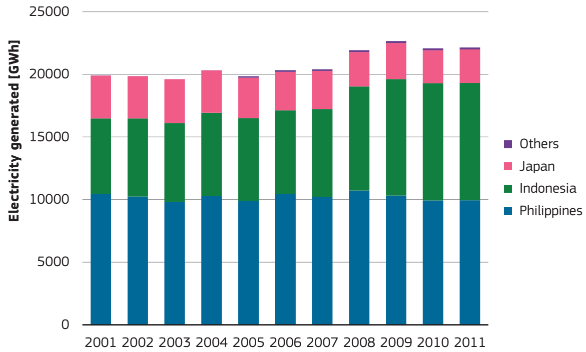


Fig. 28: Power generation in Asia according to country. Source: [OECD/IEA 2013]

Recent new installation of power generation capacity include the 20 MW Maibarara geothermal power plant in the Philippines that was opened in February 2014 [MGI 2014]. In addition, the Bacman plant resumed operations in 2014 for two units at 55 MW_e each [Business World 2014].

4.4 America

In America, only the United States, Canada and Mexico use geothermal energy to a greater extent (Figure 29). In the following, we will thus focus on those three countries only.

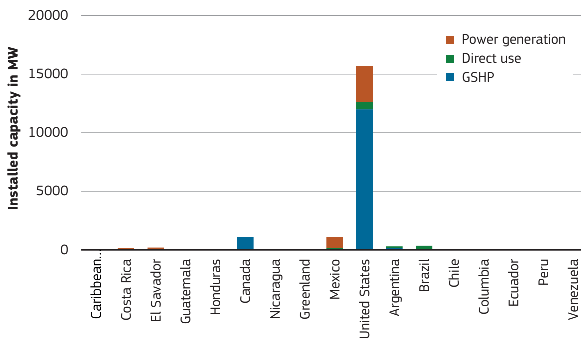


Fig. 29: Installed capacity for geothermal energy use in America. Source: [Boyd & Lund 2014]

4.4.1 United States

In the United States, about 3440 MW of power generation capacity were installed at the end of 2013 [GEA 2014]. In total, 85 MW have been installed during 2013 in Utah, California, Nevada and New Mexico (Figure 30). According to [GEA 2014], capacity additions have decreased by 40 % compared to 2012, mainly due to political barriers such as low prices for fossil fuels, and grid integration issues. In addition, it has to be noted that for many power plants, actual capacity is much lower than the initial capacity which is not reflected in statistics since often nameplate capacity is accounted for. The power plants at the Geysers geothermal field have now a capacity of about 950 MWe while the nameplate capacity or the initial capacity of these plants was about 1550 MW_e.

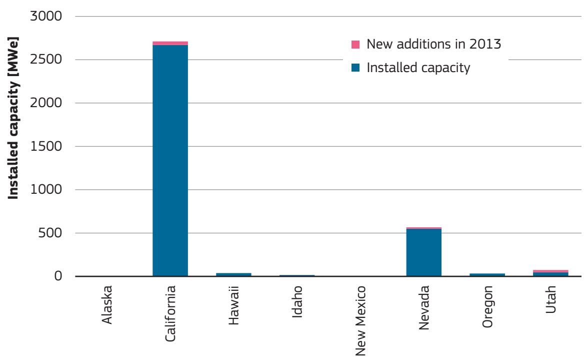


Fig. 30: Installed capacity for power generation in the United States and additions in 2013. Source: [GEA 2014]

GHSP account for about 12000 MW of installed capacity in the US and almost equals the installed capacity in Europe (Section 4.2.3). Market growth was about 10 % annually in the past [Trenchless 2010]. The largest manufacturers in the US are ClimateMaster and WaterFurnace [BNEF 2009].

Installed capacity for direct use in the United States is small compared to GSHP and electricity. Direct use in the United States takes many forms. It is dominated by space heating, aquaculture, bathing and swimming, and district heating (Figure 31).

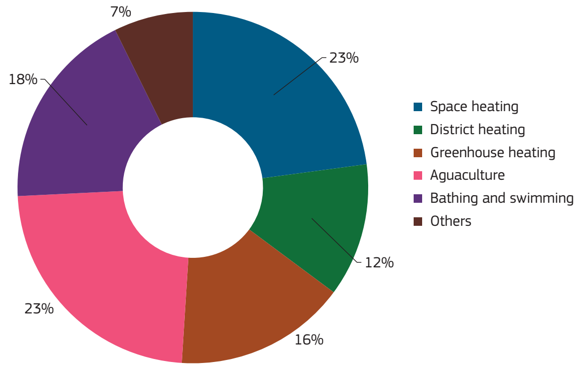


Fig. 31: Installed capacity for direct use in the United States in 2013. Source: [Boyd & Lund 2014]

4.4.2 Mexico

Mexico uses geothermal resources almost exclusively for power generation with about 1 GWe of installed capacity (Figure 32). Since 2012 no new capacity has been installed. Electricity production has grown from 193 GWh in 1973 to about 5400 GWh today [Quijano-León & Gutiérrez-Negrín 2003].

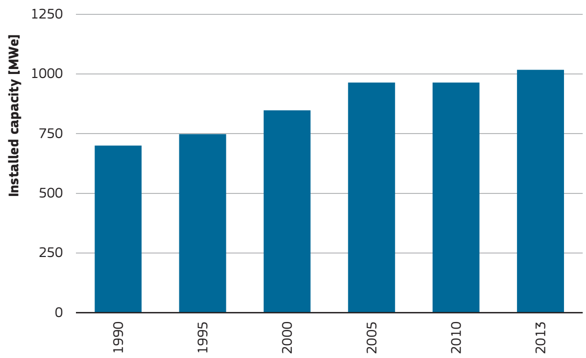


Fig. 32: Installed power generation capacity in Mexico from 1990 to 2013. Sources: [IGA 2014, Quijano-León & Gutiérrez-Negrín 2003], own calculations

4.4.3 Canada

In Canada, geothermal energy is used almost only for GSHP (about 1100 MW installed capacity in 2010). The GSHP market experiences considerable growth between 2003 and 2010 (e.g. more than 60 % annual growth in 2006, 2007, and 2008) but declined in 2010 and has stabilised since. In 2011, more than 12000 GSHP units have been installed [Canadian GeoExchange Coalition 2012].

Total installed capacity for direct use was 26 MW_{th} in 2013, with 15 MWth for bathing and swimming and [CanGEA 2013]. Geothermal energy is currently not being used for power production despite a potential of about 5000 MW_e [Thompson et al. 2013].

4.5 Rest of the world

4.5.1 Oceania

4.5.1.1 New Zealand

Currently, 13 geothermal power plants with an installed capacity of about 780 MW_e are in operation in New Zealand. In 2013, 107 MW were newly installed (25 MWe at TOPP1, Norkse Skog Tasman and 82 MWe at Ngatakariki, Mighty River Power). In 2014, the Te Mihi plant has been handed over from the construction contractor to the owner and operator and should reach full production (166 MW_e) at the end of the year. It is expected that the Wairakei plant will be phased out gradually from now on.

In New Zealand, geothermal power plants already provide 13 % of the country's electricity demand [NZGA 2014]. Direct use in 2010 amounted to about 10 PJ with 55 % of it being used in industrial applications such as timber drying and paper processing [Climo et al. 2014]. GSHP market is in its very early days in New Zealand, with only few installations so far.

4.5.1.2 Australia

In Australia, geothermal energy is mainly used directly. According to [Lund et al. 2010], total installed capacity is about 33 MW_{th}, mainly for bathing and swimming. Installed GSHP capacity amounts to about 24 MW_{th}. The only power generating plant is a small 80 kW unit in Birdsville [Ergon Energy 2013].

4.5.2 Africa

In Africa, geothermal energy for power generation is currently being used mainly in Kenya (about 270 MW_e installed capacity). In 2013, 36 MW_e have been added to the 2nd unit of the Olkaria III plant and in 2014, unit 3 of Olkaria III was opened, increasing total capacity of the project by 26 MW_e.

Geothermal energy is directly used in several countries, including Algeria, Tunisia, Kenya, South Africa, and Morocco [Lund et al. 2010]. The type of direct use differs between individual countries, however, in general, the heating of greenhouses and bathing and swimming are the two applications showing the highest shares of installed capacity (Figure 33).

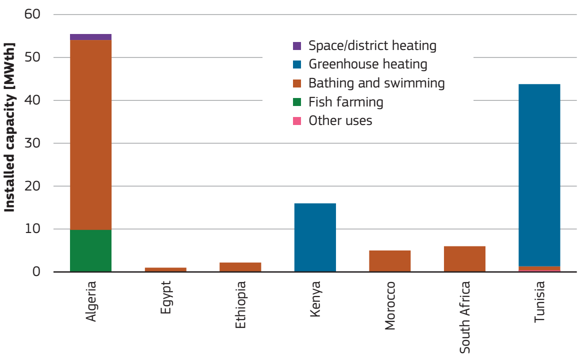


Fig. 33: Installed capacity for direct use in Africa in 2010. Source: [Lund et al. 2010]

4.6 Analysis and projections

Since only few sources were available concerning projections of direct use and GSHP, we will focus on power generation in this section. Current short-term projections for future growth in power generation capacity from [BNEF 2013] are shown in Figure 34. For the mid-term development, [BNEF 2013] estimates 10-16 GW_e net additions by 2030 and an average growth of about 600 to 950 MW_e per year. In the long term, the vision of [OECD/IEA 2011] is a worldwide installed capacity of 200 GW_e in 2050 while [Goldstein et al. 2011] expect a capacity of 140 to 160 GW_e by 2050.

According to [BNEF 2013], the total project pipeline encompasses 13.2 GW_e in about 30 projects, with Indonesia leading (about 3.2 GW). The top 10 countries account for 80 % of the projects in the pipeline. The most common project type is a flash cycle greenfield project and the top ranked developer is Ormat with about 1 GW in the pipeline [BNEF 2013]. Estimates from [GEA 2014] are slightly lower, stating a global project pipeline of about 12 GW_e with 1.9 GW_e already being under

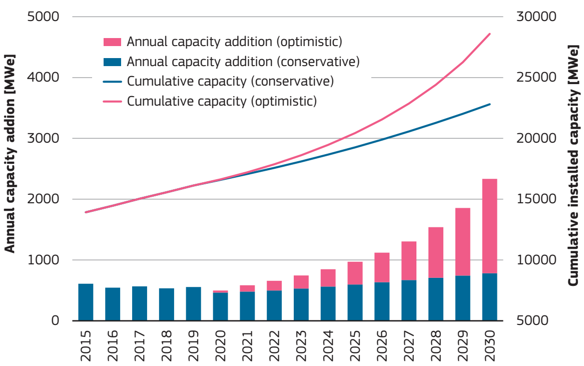


Fig. 34: Projections for global installed capacity and annual capacity additions 2015-2030. Source: [BNEF 2013]

construction. According to [GEA 2014], the cumulative installed capacity could reach 13.5 GW_e in 2017.

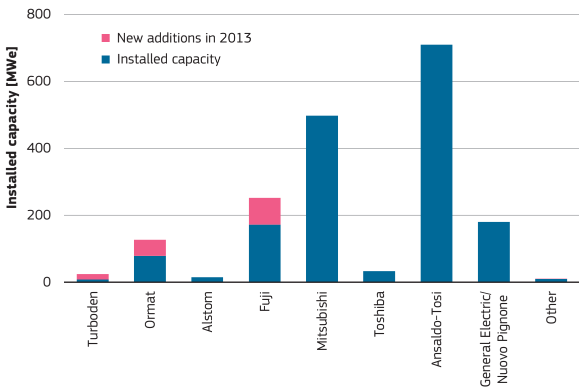
In Europe, currently 74 projects are under development and 144 are being explored [EGEC 2013a]. Capacity will grow to 2760 MW_e in 2017. A major increase of installed capacity is expected in Turkey. In the EU-28, expected capacity will be about 1.6 GW_e according to the National Renewable Energy Action Plans (NREAP) in 2020 [Observ'ER 2013b].

In Africa, Ethiopia deserves to be mentioned with 450-675 MW_e planned capacity by 2020 in six different projects [Kebede 2012]. Plans in Kenya include 790 MW_e of additional capacity by 2016 [Mugo 2013].

The current project pipeline in the Philippines includes additional capacity of about 1160 MW_e between 2016 and 2020 [Ogena & Fronda 2013]. In Indonesia, two fields of 275 MWe are currently under construction and project of about 2400 MW_e are in the pipeline [Samyanugraha & Lestari 2011].

Planned capacity additions in the United States amounted to 1000 MW_e in 2013 and 3100 MW_e of geothermal resources are under development [GEA 2014]. The geothermal project pipeline in the United States has decreased in 2013 compared to previous years, mainly due to lower demand in the U.S. for new geothermal power projects. It seems that major barriers are weak demand, inadequate transmission systems, permitting delays and a lack of coherent policy support. Thus, projects at an early stage of development are cancelled [GEA 2014]. Still, "the ratio of projects in later stages of development versus earlier stage projects has stayed roughly the same" [GEA 2014].

4.7 Power turbine manufacturer's market



Globally, three major manufacturers (Mitsubishi, Ormat, Fuji) dominate the market in geothermal power, accounting for about 75 % of the installed capacity [EGEC 2013a]. In Europe, Ansaldo-Tosi is the market leader with about 40 % of installed capacity. Other prominent players in Europe are Mitsubishi, Fuji, and General Electric/Nuovo Pignone (Figure 35). Industrial growth strategies and profiles of individual companies are discussed in Section 4.9.

Fig. 35: Installed capacity for power generation and new additions in Europe according to turbine manufacturer. Source: [EGEC 2013a]

4.8 Ground source heat pump market

Table 6: Overview of major European GSHP manufacturers and brands

Company	Brand(s)	Country	Capacity	Comments
BDR Thermea	De Dietrich	France	7-17kW	12 300 heat pumps sold in 2013
	Baxi	UK	4-20 kW	
	Brötje	Germany	6-21 kW	
	Sofath	France	6-32 kW	In total 50 000 heat pumps sold so far
Bosch Thermotechnik	Junkers	Germany	6-17 kW	
	Buderus	Germany	7-70 kW	
	IVT Industrier	Sweden	6-16 kW	Swan-labelled GSHP
Danfoss	Thermia Värme	Sweden	4-45 kW	
Nibe	Alpha-InnoTec	Germany	6-160 kW	Belongs to Schulthess (daughter company of Nibe)
	Nibe Energy Systems	Sweden	5-17 kW	Largest European manufacturer of domestic heating products
	KNV	Austria	4-78 kW	Acquired in 2008. 13 000 heat pumps sold so far
Vaillant	Vaillant	Germany	6-46 kW	Second largest HVAC manufacturer
Viessmann	Viessmann	Germany	2-117 kW	
	Satag Thermotechnik	Switzerland	3-19 kW	Acquired in 2004
	KWT	Switzerland	6-2000 kW	One of the pioneers in GSHP
Ochsner	Ochsner	Austria	5-61 kW	110 000 heat pumps installed so far
Stiebel Eltron	Stiebel Eltron	Germany	6-13 kW	Acquired 35 % of share capital of Ochsner

Sources: Own research, [EHPA 2013, Observ'ER 2013c]

The European heat pump and also the GSHP market has developed from a market with many small local companies to a market dominated by major heating and air-conditioning manufacturers [EHPA 2013]. For GSHP, the main European players are listed in Table 6. Countries of origin of manufacturers very much mirror the main markets for GSHP with many big producers being from Germany and Sweden.

Asian manufacturers which have been focussing on air/air heat pumps and air conditioning in the past are now more active on the European GSHP market. For example, Daikin recently launched a GSHP for residential usages while Mitsubishi's Ecodan GSHP systems target medium to large commercial installations [Daikin 2014, Mitsubishi 2014]. Other manufacturers such as Samsung, LG, Panasonic and Hitachi seem not to have GSHP in their portfolio yet.

4.9 Industrial strategies

The geothermal industry is small with few companies active in the supply chain. The activities in the power and direct use sectors range from exploration, drilling, engineering, to construction and plant operation. Clearly, vertical integration is one of the strategies a number of companies pursue, meaning that they are active in many or all stages of a geothermal project [REN21 2014]. Table 7 gives an overview over some of the major vertically integrated companies in the geothermal power sector. Most of the integrated companies play a strong role in the geothermal sector of a certain region or country and are now aiming at expand their footprint globally.

Other companies in the geothermal sector pursue a different approach by offering highly specialised services. Examples of drilling firms are Thermasource from the US or Iceland Drilling [Goldstein & Braccio 2014]. Examples for companies specialised in geothermal engineering are Mannvit and Verkis from Iceland and Power Engineers from the US [Goldstein & Braccio 2014, REN21 2014]. Only few companies are dealing with the cold end of large geothermal power plants with most turbine manufacturers being supplied by only one company, Balcke-Dürr [Gunnlaugsson 2014].

Table 7: Overview of major vertically integrated players in the geothermal industry

Company	Chevron	Enel Green Power	Ormat
Company profile	Multinational energy company. Active in oil, gas, and geothermal energy, including exploration, production, refining, chemicals manufacturing, power generation.	Active in all kinds of renewables (wind, solar, hydroelectric, geothermal and biomass). More than 750 plants in operation or under construction in 16 countries. Subsidiary of Enel, Italy's largest power company and Europe's second listed utility	World leader in geothermal and recovered energy generation. Develops, builds, owns and operates geothermal power plants but also manufactures and sells equipment Plants from 250 kW to 130 MW
Geothermal power plants in operation	647 MW in Indonesia (2 fields) 692 MW in Philippines[a)] (2 fields)	769 MW in Italy (34 plants) 194 MW in El Salvador[b)] (1 plant) 33 MW in the US (1 plant) Direct use in Italy: Provision of heat to 8 700 customers and 25 hectares of greenhouses	626 MW owned and operated worldwide 1750 MW supplied worldwide
Strategy	• Leverage worldwide technical and operational capabilities to enable investment in domestic, utility-scale geothermal projects • Assess further prospects in Indonesia and Philippines • Strategically grow Chevron's geothermal footprint (e.g. US, Hudson Ranch investment)	• Strengthen role in the global scenario, with new initiatives to be enacted abroad (focus on Central and South America and US) • Direct attention to markets with abundant renewable resources, stable regulatory frameworks and strong economic growth • Continue efforts to rationalize operating expenses by operating plants more directly and with greater efficiency • Continue to seek economies of scale, especially in procurement	• Use knowledge gained from own operations to increase competitiveness (efficient maintenance and response to operational issues) • Generate growth by securing leases, expanding exploration and developing high-performance projects • Current exploration in 39 sites (US, South America, Indonesia, New Zealand) • Established Geodrill, a drilling company executing exploration and drilling plans • Build a geographically balanced portfolio of geothermal and REG

[a)] through a 40 % interest in Philippines Geothermal Production Company; [b)] in partnership with national electric company
Sources: [Chevron 2014, Enel Green Power 2013, Enel Green Power 2014, Ormat 2012a, Ormat 2012b, Ormat 2014]

When it comes to turbine suppliers, some companies offer specific expertise and proprietary technology. Ormat, for example, is specialised in binary (ORC) power plants and their components [REN21 2014]. The Italian company Exergy produces highly efficient ORC plants using its newly developed radial outflow turbine concept [Exergy 2014]. Another example is Turboden, which is specialised in binary turbine-generators [Turboden 2014].

Despite the existence of highly specialised smaller companies, the geothermal power plant turbine market is dominated by big industrial corporations such as Mitsubishi Heavy Industries, Toshiba, Fuji Electric, Ansaldo, GE/Nuovo Pignone, and Alstom that are also active in other energy sectors (Table 8). Some of those companies such as Ansaldo or Alstom not only supply turbines but also offer additional services ranging from civil and mechanical design to installation and commissioning of whole plants.

So far, companies active in geothermal power generation or direct use are not active in the ground source heat pumps market (Section 4.8) or vice versa except for Mitsubishi that offers also a large GSHP system for commercial applications. Manufacturers of GSHP systems are mainly based in the HVAC sector or in consumer & household appliances.

Table 8: Overview of major turbine/power plant suppliers for geothermal power

Company	Company profile	MW supplied	Strategy
Alstom	Multinational company active in power generation, power transmission and rail infrastructure Geothermal power (50 years experience) is a key component of Alstom's clean power offering Product range covers medium size range (25-35 MW) and double-flow turbine (35-60+ MW) range Besides steam turbine and generators, Alstom offers condensers, hotwell pumps, instrumentation and control systems	350 MW_e	• Maximise benefits achieved through integration of Alstom produced components • Build on track record in project fields to further develop and adapt the offering to market requirements globally • Tailor-made packages to exactly suit customer's plant and business strategy • Other offers include parts, repairs, field service, technical expertise and operational support, service contracts and original equipment manufacturer (OEM) services
Ansaldo	Italy's largest supplier, installer and service provider for power generation plants and components. Experience with geothermal power plants since 1913 (first turbine-generator unit at Larderello)	2000 MW_e 130 units	• Provide optimized solutions for geothermal power plants (20 to 150 MW) • Provide not only steam turbine or generator sets, but also complete integrated package (including e.g. civil, electrical design, installation, commissioning) • Provide services for both OEM and non-OEM plants (turbines, generators, repairs, replacement parts, control systems
Fuji Electric	Manufacturer of thermal and electric energy technology Engaged in thermal power plant business since 1959 (planning, design, procurement, construction, commissioning and after sales service) Leading manufacturer of geothermal steam turbines and generators Delivered more than 34000 MW (545 units) of steam turbines and generators worldwide	2630 MW_e 67 units	• Japan: advance into the domestic geothermal market • Overseas: target increased orders from growing markets of Central and South America as well as Africa • US: expand operations
GE/Nuovo Pignone	Multinational company active in Energy, technology Infrastructure, consumer and industrial appliances GE Power & Water provides a broad array of power generation, energy delivery, and water process technologies Geothermal turbines offered from 5-100 MW_e	533 MW_e	• Highly reliable geothermal steam turbine generator sets allowing for long-term, reliable operation • Modular component structure to achieve the cost and reliability
Mitsubishi Heavy Industries	Multinational engineering, electrical equipment and electronics company Leading manufacturer of geothermal steam turbines and generators	3000 MW_e 100 units	• Pushes forward with continued growth and business expansion • Bought Pratt & Whitney Power Systems, including Turboden, creating a much stronger player
Toshiba	Toshiba Power Systems Company is a leading manufacturer of heavy electrical equipment. Delivered 1700 steam turbine units, 240 hydraulic turbine units, 300 hydraulic generator units and 32 nuclear reactor units so far Leading manufacturer of geothermal steam turbines and generators		• Still global leader in installed geothermal capacity • Focused on improvements and upgrades of existing plants in the past • Now again more active in supplying steam turbines for new projects

Sources: [Alstom 2013, Alstom 2014, Nuovo Pignone 2005, ThinkGeoEnergy 2011, Ansaldo 2011, Ansaldo 2014a, Ansaldo 2014b, Bertani 2012, Estabrook & Leger 2000, Fuji Electric 2013a, Fuji Electric 2013b, Fuji Electric 2014]

5 TECHNO-ECONOMIC ASSESSMENT OF GEOTHERMAL POWER PLANTS

The cost of building and operating a geothermal power plant varies widely and depends on such factors as [DiPippo 1999]:

- Resource type (steam or hot water) and depth;
- Resource temperature;
- Reservoir productivity;
- Power plant size;
- Power plant type;
- Environmental regulations;
- Cost of capital;
- Cost of labour

The first three factors influence the number of wells that must be drilled and are furthermore related to the size of the desired power plant. The resource type mainly influences the power plant type. Dry resources are suitable for dry steam plants that are the simplest type of geothermal power plants. Hot water resources may be suitable for either flash or binary power plants. Flash power plants typically extract from resource temperatures above 180 °C and as temperatures exceed 240 °C double (or even triple) stage flash power plants become economically feasible. ORC power plants are usually constructed when resource temperatures are below 180 °C. Combined heat and power plants are only constructed from hot water type resources. The depth of the resource directly influences the cost of drilling. The depth also influences the complexity of the reservoir management such as maintenance of permeability. Finally, the cost of monitoring activities in production and injection wells is dependent on the resource depth. Power plant size is entirely dependent on the size of the resource and can often not be decided on until some exploration and testing of the reservoir has been carried out. Environmental regulations vary between regions but often limit the emission allowances from power plants. For geothermal, the primary emissions of concern are H_2S and mercury. The chemical compositions of the geothermal fluids are highly variable and depend on the resource temperature and the supply of mobile components, primarily chloride, CO_2 and H_2S all of which tend to increase near active volcanism zones. Due to the corrosive nature of H_2S, its treatment may constitute high proportion of the construction costs where strict environmental regulations are in place. The high variability of these factors makes a cost estimation of geothermal power plant development and construction rather complex as site specific factors related to the resource may have detrimental effect on costs.

5.1 Cost and performance characteristics of geothermal installations

The performance characteristics of power plants for the time period 2010 to 2050 were evaluated based on the methodology of [EIA 2013] and is the same as applied in a JRC report that discusses the evaluation method in more detail [ETRI 2014]. A recently published software [Dauenhauer 2014] was used to calculate the CAPEX of a binary power plant with and without EGS for comparison to other literature. In geothermal power plants, drilling and reservoir engineering often constitutes more than 50 % of the CAPEX in conventional hydrothermal plants and even higher in EGS that rely on heat from even deeper sources than hydrothermal. This specific cost is highly dependent on the geology and depth of the reservoir. In conventional hydrothermal systems, fluids are frequently extracted from 2-2.5 km depths. Engineered Geothermal Systems may extract heat from as deep as 5.5 km and predictions assume 10 km wells in the future.

Historically, geothermal energy has mainly been harnessed where bedrock permeability and heat gradients are high. Recently, increased effort has been put into the concept of EGS where heat is extracted from deep reservoirs that may need stimulation due to low permeability. Therefore when addressing the CAPEX of geothermal power plant construction, it is logical to separate the cost of equipment on the surface on one hand and drilling and reservoir stimulation on the other.

The expenditure categories were classified according to Table 9. This report presents performance characteristics of selected geothermal power production technologies for the time period from 2010 to 2050. The data for each technology refer to sizes and configurations which are typical of average geographic locations within the European Union. The most relevant types of each technology were selected for presentation in this report. The CAPEX is reported as overnight capital expenditure which means the cost of delivery of a plant as if no interest was incurred during construction i.e. as if the project was completed and delivered “overnight”.

The CAPEX is given as a reference value with a lower and higher bound. All cost data were converted to EUR 2013 values. Neither taxes nor subsidies were incorporated in the economic estimations presented in this report.

Table 9: Division of CAPEX of geothermal power plants.

Item	Description	Remark
Civil and structural costs	allowance for site preparation (excluding the costs of infrastructure connections i.e. electricity, fuel and water connections): - clearing, drainage, etc. - installation of underground utilities - structural steel supply and installation - construction of buildings and roads on the site	
Mechanical Equipment |supply and Installation, Major Equipment, Surface	Power Plant buildings, Fluid delivery/re-injection system and surface pumps, heat exchangers turbine generators, condensers, cooling towers, desulfurization system, fresh water supply.	• Specific cost to ORC hydrothermal and EGS are heat exchangers to boil the working fluid. • EGS operate with higher pump capacity than hydrothermal system although re-injection pumps may be needed for hydrothermal systems • Specific cost to flash hydrothermal plants can be desulfurization system.
Mechanical Equipment supply and Installation costs, Subsurface -Surface	Production and re-injection wells, submersed pumps, reservoir stimulation	• A hydrothermal reservoir may be stimulated in conjunction with well drilling. • A EGS reservoir always needs to be stimulated to enhance permeability between production and re-injection well.
Electrical and I&C supply and installation	All electrics except generator inside the power plant.	
Project indirect costs	Planning, consulting, project management	
Owner costs, Development costs	Geological, geochemical and geophysical exploration of the reservoir is included here.	
Owner costs, Interconnection costs	Grid connection	
Owner costs, Insurance costs	Insurance costs.	

Three reference power plant types are provided in this report:

- A Flash power plant extracting fluid from a hydrothermal system at 2.5 km depth;
- An ORC power plant extracting fluid from a hydrothermal system at 2.5 km Depth;
- An ORC power plant extracting 165 °C fluid at 100 kg s^{-1} from EGS at 5.5 km depth. CAPEX values are also provided for 150 °C and 180 °C fluids at 50–150 kg s^{-1} and at 3 and 4 km depths.

The CAPEX of these plants may then be adjusted based on the depth of the main feed zones of the production and re-injection wells and in the case of EGS the pump rate of the circulation fluid. The low/high margins are dependent on cost with EGS stimulation (EUR 4-8 million for each system) and the drilling cost is assumed to fluctuate +/- 10 %. In Table 10, the cost components included in the CAPEX estimates are shown.

5.1.1 Flash power plants from a hydrothermal reservoir

The CAPEX breakdown for a flash power plant is given in Figure 36. Mechanical equipment costs represent more than 51 % of CAPEX, followed by owner's cost (mainly development costs) and project indirect costs.

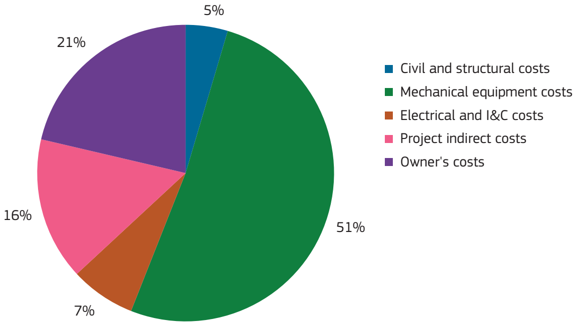


Fig. 36: CAPEX breakdown of a hydrothermal flash power plant

Table 10: Cost components included in the CAPEX estimates for geothermal power plants

Cost component	Flash power plants from a hydrothermal reservoir	Organic Rankine Cycle from a hydrothermal system	Organic Rankine Cycle from an Enhanced Geothermal System
Civil and structural costs			
Civil and structural costs	X	X	
Mechanical equipment costs			
Major equipment costs	X	X	X
Balance of plant costs	X	X	X
Electrical and I&C costs			
Electrical and I&C supply and installation	X	X	
Project indirect costs			
Project indirect costs	X	X	
Owner's costs			
Development costs	X	X	X
Interconnection costs	X	X	X
Insurance costs		X	X

Table 11 summarises the economic indicators for the flash power plant. The upper CAPEX range assumes that the production and injection wells are 3.5 km deep instead of 2.5 km.

Table 11: Indicators for a flash power plant extracting fluid from hydrothermal system at 2.5 km depth

Parameter	Unit	2010	2020	2030	2040	2050
Net electrical power	MW	45	45	45	45	47
Gross electrical power	MW	47	47	47	47	47
Thermal power	MW	196	191	188	184	189
Net efficiency	%	23	23.5	23.9	24.4	24.9
Max. capacity factor	%	95	95	95	95	95
Avg. capacity factor	%	95	95	95	95	95
Technical lifetime	years	30	30	30	30	30
CAPEX ref	$€_{2013}/kW_e$	5530	4970	4470	4020	3610
CAPEX low	$€_{2013}/kW_e$	2500	2500	2500	2500	2500
CAPEX high	$€_{2013}/kW_e$	5930	5370	4870	4420	4010
CAPEX floor	$€_{2013}/kW_e$	2000	2000	2000	2000	2000
Quality of CAPEX estimate				medium		
CAPEX learning rate	%	-	-	-	-	-
FOM	% of CAPEX ref.	1.4	1.6	1.8	2.0	2.2

5.1.2 Organic Rankine Cycle from a hydrothermal system

The CAPEX breakdown for an ORC plant is given in Figure 37. Similar to flash power plants, the mechanical equipment costs represent the greatest share of CAPEX (about 50 %), followed by project indirect costs and owner's cost (mainly development costs).

Table 12 summarises the economic indicators for the ORC power plant.

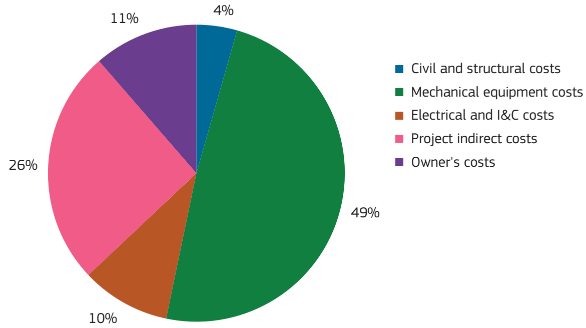


Fig. 37: CAPEX breakdown of an organic rankine cycle power plant

5.1.3 Organic Rankine Cycle from an Enhanced Geothermal System

A detailed CAPEX breakdown for an ORC-EGS plant could not be derived due to data limitations. Table 13 summarises the economic indicators for the ORC power plant.

Table 12: Indicators for a organic rankine cycle power plant from hydrothermal system

Parameter	Unit	2010	2020	2030	2040	2050
Net electrical power	MW	7.3	7.5	7.7	8.0	8.2
Gross electrical power	MW	9.0	-	-	-	-
Thermal power	MW	54	54	54	54	54
Net efficiency	%	13.3	13.8	14.2	14.7	15.1
Max. capacity factor	%	95	95	95	95	95
Avg. capacity factor	%	95	95	95	95	95
Technical lifetime	years	30	30	30	30	30
CAPEX ref	$€_{2013}/kW_e$	6970	6600	6240	5870	5510
CAPEX low	$€_{2013}/kW_e$	6470	6100	5740	5370	5010
CAPEX high	$€_{2013}/kW_e$	7470	7100	6740	6370	6010
CAPEX floor	$€_{2013}/kW_e$	-	-	-	-	-
Quality of CAPEX estimate				low		
CAPEX learning rate	%					
FOM	% of CAPEX ref.	2.1	2.2	2.3	2.5	2.7

Table 13: Indicators for a organic rankine cycle power plant from an Enhanced Geothermal System

Parameter	Unit	2010	2020	2030	2040	2050
Net electrical power	MW	4.4	4.6	4.8	5.1	5.3
Gross electrical power	MW	4.9	5.1	5.4	5.6	5.9
Thermal power	MW	41	41	41	41	41
Net efficiency	%	10.6	11.2	11.8	12.3	12.9
Max. capacity factor	%	95	95	95	95	95
Avg. capacity factor	%	95	95	95	95	95
Technical lifetime	years	30	30	30	30	30
CAPEX ref	$€_{2013}/kW_e$	12600	10300	9000	8600	8200
CAPEX low	$€_{2013}/kW_e$	11700	9600	8400	8000	7600
CAPEX high	$€_{2013}/kW_e$	13400	11000	9600	9100	8700
CAPEX floor	$€_{2013}/kW_e$	-	-	-	-	-
Quality of CAPEX estimate				medium		
CAPEX learning rate	%					
FOM	% of CAPEX ref.	1.8	1.8	1.9	1.9	1.9

5.2 Approaches to reducing the cost of energy

As mentioned above, the CAPEX of geothermal power plants is dependent on several factors and in particular the resource conditions at the power plant site. Cost analyses have been carried out by changing well depth, production fluid temperature and fluid flow rate from reservoir to power plant. The price of the turbine was kept constant at 4000 EUR/kWe. Figure 38 shows the effect of pump rate and well depth on CAPEX. The highest gain of increasing pump rate is observed between 50-75 kg s^{-1} but lowers as pump rate is increased towards 150 kg s^{-1}. Assuming the thermal transfer from reservoir rocks to the circulating geothermal fluid is sufficient; the figure also shows that for 4 km deep wells, slightly higher financial benefit may be expected by increasing pump rate from 75-100 kg s^{-1} than by extracting from 180 °C compared to 165 °C. Therefore, creation and maintenance of adequate fracture network in the reservoir is paramount. Similarly, Figure 39 highlights the importance of maintaining high flow through the reservoir. In all modelled scenarios, the CAPEX with 100 kg/s flow is lower than the CAPEX with 50 kg/s.

Further cost reducing factors include:

- Cheaper drilling technology through advances in the state of the art of drilling;
- Increased efficiency of the energy conversion process;
- Cheaper corrosion resistant materials;
- Cheaper scaling mitigation methods;
- More reliable resource potential prediction minimizing the number of abandoned projects;
- Improved exploration techniques minimizing the number of abandoned projects far into development.

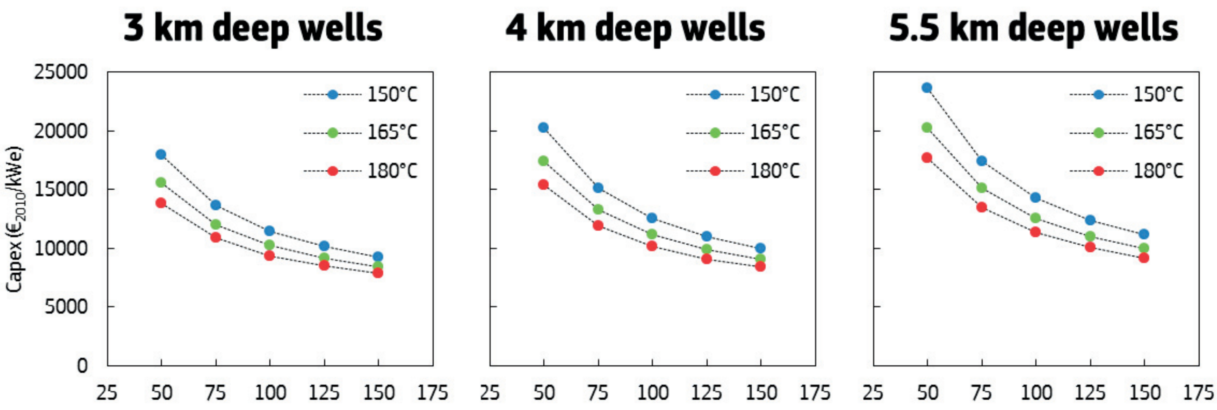


Fig. 38: Influence of pump rate (and therefore permeability) on the CAPEX of an EGS ORC power plant. The reference case provided is that of 5.5 km deep wells, 100 kg/s pump rate and 165°C inlet water. CAPEX numbers are those generated by the model and have not been corrected for the CAPEX brake down used. Source: JRC own analysis with GeoELEC software [Dauenhauer 2014].

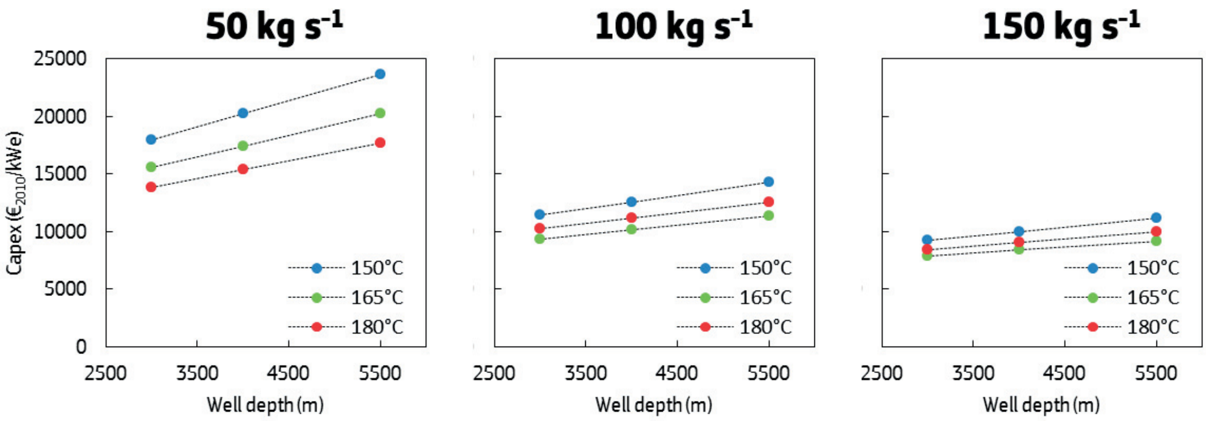


Fig. 39: Influence of well depth and pump rate on CAPEX of an ORC EGS power plant. It may be much more cost effective to increase the permeability of a reservoir between injection and production wells than to drill deeper for higher reservoir temperatures. Source: JRC own analysis with GeoELEC software [Dauenhauer 2014]

5.3 Integration in the electricity system

Geothermal power plants can produce base-load electricity with a high capacity factor (about 90-95 %). They can be very flexible since they can operate in partial load and allow for a fast ramp-up of 5-6 hours from cold to full output compared to 9 hours and 50 hours for lignite power and nuclear power plants, respectively [Eggeling et al. 2012]. Considering the flexible output of flash geothermal plants though, one needs to take into account the increased demand this kind of operation has on man power requirements (to oversee successful operation of the production wells and steam delivering system). Variable power output may lead to elevated wear and tear in equipment and one has to bear in mind that turbine units are not designed for highly variable operation.

No technical barriers prevent the integration of geothermal power to the European electricity grid. In general, small geothermal power plants will feed electricity into the middle-voltage system by the means of a transfer station which will lead to minor local effects only [Auer et al. 2004, Eggeling et al. 2012]. In the future, we will see a clear trend towards distributed generation in Europe with increasing shares of volatile producers (e.g. wind, PV) which will require adaptations of the current electricity network [Reitenbach 2014]. Base-load geothermal electricity could play an important role in stabilising the grid and reducing the needs for and costs of grid infrastructure changes [Eggeling et al. 2012].

The costs of the grid connection of a geothermal power plant differ according to local grid structure and site specific conditions. Usually, the grid connection includes fixed costs for a transfer station, estimated at about 80000-85000 EUR for a small 1 MW_e plant [Eggeling et al. 2012]. In addition, costs depending on the distance to the location of grid connection assigned by the grid operator occur. Grid connection costs have to be considered in the early planning phase of geothermal power plants since often a trade-off between the quality of a hydrothermal resource and the distance to the grid connection point exists; a fact that has to be taken into account from an economic point of view [Huenges 2011].

5.4 Cost of Energy

The levelised cost of energy (LCOE), a common indicator for assessing energy costs, has been calculated for different types of geothermal power plants based on the figures given in Section 5.1 for CAPEX and OPEX applying different discount rates and CAPEX assumptions. Figure 40 shows the results for varying discount rates with using the reference values for capital costs and Figure 41 shows the LCOE for varying CAPEX predictions at a discount rate of 7 %.

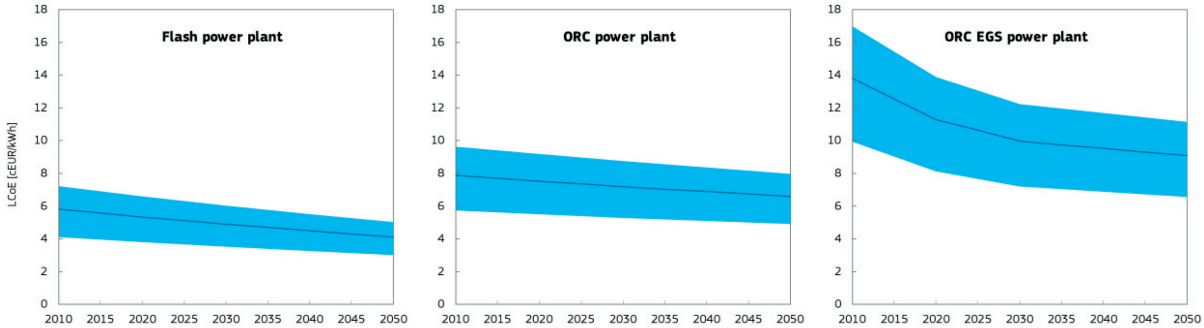


Fig. 40: LCOE of different geothermal power plants for discount rates between 3 % and 10 %. CAPEX: reference values from [ETRI 2014] (Line: 7 %)

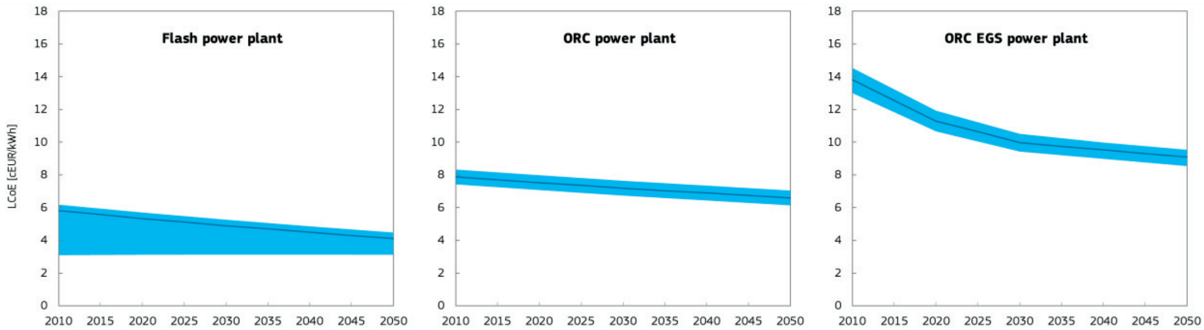


Fig. 41: LCOE of different geothermal power plants for different capital costs. CAPEX values from [ETRI 2014] , 7 % discount rate.

From the literature, current LCOE estimates could be retrieved (Table 14). These LCOE calculations are comparable with values from [Goldstein et al. 2011, OECD/IEA 2011].

Table 14: Current LCOE in $cEUR_{2013}$/kWh

Reference	Flash power plant	ORC power plant	ORC EGS power plant	Comment
This report, based on [ETRI 2014]	5.8 (4.1-7.2)	7.9 (5.7-9.6)	13.8 (9.9-17.0)	7 % discount rate 3 %-10 % discount rate
[Goldstein et al. 2011]*	4.5-6.6	4.9-8.5	n.a.	Current LCOE, CF 74 %, 7 % discount rate
[Goldstein et al. 2011]*	2.9-12.0	3.0-15.7	n.a.	Current LCOE, CF & discount rate ranges
[OECD/IEA 2011] **	4.0-6.3	4.7-8.7	7.9-15.0 (US) 19.8-23.7 (EU)	CF 85 %, 35 years

* Conversion from USD_{2005} to EUR_{2005} with 1 USD = 0.8453 EUR, from EUR_{2005} to EUR_{2013} by applying GDP deflator values from Eurostat
** Conversion from USD to EUR with 1 USD = 0.79 EUR

In addition, to the calculation of LCOE based on [ETRI 2014], we have also applied learning rates using the global capacity projections from [Goldstein et al. 2011]. According to [Jamasb & Köhler 2007], learning rates can range between 3 % to over 35 %. Often, a learning rate of 20 % has been applied for energy generation technologies in the past. For our calculations, learning rates of 10 % and 20 % have been assumed (Figure 42).

The LCOE for 2050 calculated according to the both methods can be compared to literature values (Table 15). Both methods show similar results and are comparable to [DLR 2010].

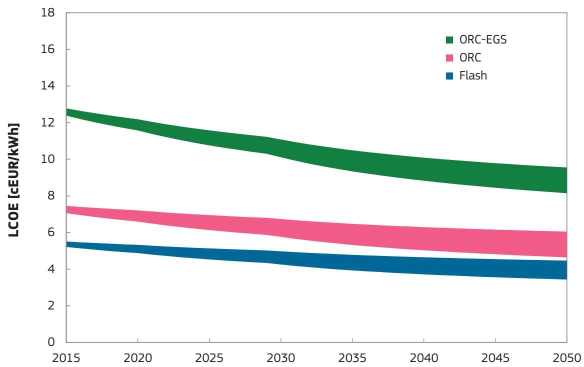


Fig. 42: LCOE predictions of different geothermal power plants based on learning curves between 10 % and 20 %

Table 15: LCOE estimates for 2050 in $cEUR_{2013}$/kWh

Reference	Flash power plant	ORC power plant	ORC EGS power plant	Comment
This report, based on [ETRI 2014]	4.1 (3.0-5.0)	6.6 (4.9-8.0)	9.1 (6.6-11.1)	7 % discount rate 3 %-10 % discount rate
This report, based on learning curves and capacity forecast from [Goldstein et al. 2011]	3.4-4.5	4.6-6.0	8.1-10.6	Learning rate between 10 % and 20 % assumed
[DLR 2010]	n.a.	n.a.	10.0 (7.1-20.0)	Depending on region and reservoir characteristics

* Conversion from USD_{2005} to EUR_{2005} with 1 USD = 0.8453 EUR, from EUR_{2005} to EUR_{2013} by applying GDP deflator values from Eurostat
** Conversion from USD to EUR with 1 USD = 0.79 EUR

A comparison of the LCOE of geothermal power plants with other energy technologies is shown in Figure 43. LCOE is in the range of other renewable energy technologies and higher compared to advanced fossil fuels and nuclear power. When comparing geothermal power plants with other renewables, it has to be kept in mind that geothermal power plants deliver base-load electricity, also reflected by a high capacity factor which many other renewables are not (e.g. wind, PV). The LCOE does not take into account the effects of fluctuating supply (and demand).

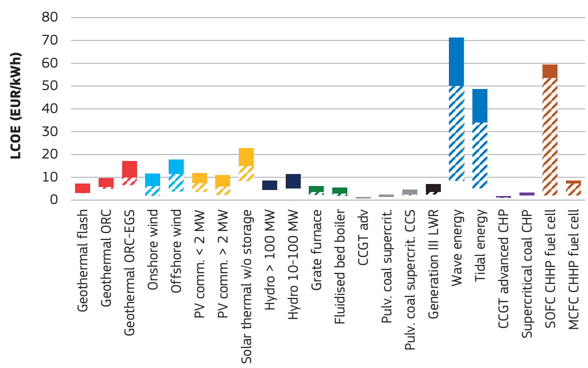


Fig. 43: Comparison of LCOE of different energy technologies. Calculations based on [ETRI 2014]. Solid bars: current LCOE (low-high CAPEX). Shaded: Possible LCOE reductions until 2050

6 ENVIRONMENTAL IMPACTS OF GEOTHERMAL ENERGY

Environmental impacts of geothermal activities may occur during construction of geothermal facilities or during the operation. The environmental impact of geothermal facilities has been classified as [Mannvit hf 2013]:

- Surface disturbances (access roads, pipe and power lines, plant associated land use);
- Physical effects (effect of fluid withdrawal on surface manifestations, land subsidence, induced seismicity, visual effects due to structures);
- Noise (during drilling, construction and operation);
- Thermal pollution (hot liquids and steam released from discharging boreholes and the power plant;
- Chemical pollution (disposal of liquids and solid waste, gaseous emissions, natural radioactivity);
- Impact on protected faunas and floras.

The location and type of facility determines the environmental impacts associated with daily operation.

- Flash and direct steam plants exploiting high enthalpy resources release steam and gases to the atmosphere and fluids either at the surface or into deeper reservoirs. Induced seismicity is primarily associated with re-injection of fluids and can vary from virtually non-existent to generation of > M3 earthquakes in extreme cases. However distinction between induced seismicity and natural seismicity is not easy in hydrothermal fields.
- Binary plants exploiting medium enthalpy resources with natural permeability can operate in closed systems without considerable release of steam or gases to the atmosphere. Induced seismicity may be associated with their operation.
- Enhanced geothermal systems rely on heat extraction from reservoirs that have been created or improved artificially. The power plant associated with the EGS will usually be binary so emissions are limited. The most significant environmental impact is induced seismicity associated with the fracturing of the reservoir and earthquakes up to M 3.4 were detected in Basel [Deichmann and Giardini 2009, Zang et al. 2014]
- Direct use facilities release heat to the environment after use but the effects are usually very local. The geofluids may contain elevated concentrations of toxic elements but direct CO_2 emissions are typically negligible
- The CO_2 emissions from GSHP systems depend on the energy source used to power the pumps. Otherwise the main environmental threat from closed loop GSHP systems is the accidental release of antifreeze into the environment.

The reader is referred to other comprehensive studies for further discussion on the environmental effects of geothermal utilisation [Clark et al. 2012, GEA 2012, Mannvit hf 2013].

6.1 Emissions to air and ground waters during power production

Carbon dioxide (CO_2) is the main gas species emitted by geothermal operations. Hydrogen sulphide (H_2S) is often the second most important species. Other gases include hydrogen (H_2), methane (CH_4), ammonia (NH_3) and nitrogen (N_2). All of these do not condense with the steam in the power plant's condensers and they are therefore termed as non-condensable gases (NCG) Generally the concentration of the gas species increases with increased resource temperature. Mercury, arsenic, radon and boron may also be present. The amount of these gas species released is highly site-specific and depends on the geological conditions such as resource rock type and temperature. In addition, the technology used for energy production influences atmospheric emissions. Flash and direct steam power plants direct the geothermal fluids through the turbines and gases are extracted from condensers. Conversely, binary power plants direct the geothermal fluids in a closed loop through heat exchangers prior to re-injection therefore facilitating nearly emission free operation.

6.1.1 CO_2 emissions

CO_2 is mainly emitted from power plants after being extracted from condensers but may also be released from two phase heat exchangers. On average, CO_2 constitutes 90 % of the NCG. CO_2 emission rates range between 4-740 kg CO_2/MWh from geothermal power plants with an average of 122 kg CO_2/MWh [Bertani and Thain 2002]. Direct use CO_2 emissions tend to be on the order of 0-1 kg CO_2/MWh [Fridleifsson et al. 2008]. CO_2 emissions from GSHP depend on the efficiency of the equipment used as well as the fuel mix and the efficiency of electricity generation needed to run the heat pumps. The average CO_2 emissions associated with generation of electricity in Europe has been estimated to be 550 kg CO_2/MWh. A GSHP run on electricity may emit 45 % less CO_2 than an oil boiler and 33 % less than a gas boiler. If the GSHP is run on renewable electricity, CO_2 savings can be higher [Fridleifsson et al. 2008]. The total CO_2 reduction potential of heat pumps has been estimated to be 1.2 billion tonnes per year or about 6 % of global emissions [ISEO 2014].

When estimating potential CO_2 emission savings by utilising geothermal energy the question on whether to produce electricity or heat is more effective arises. To compare potential CO_2 emission savings, a small geothermal plant was assumed that produces either only electricity or only heat. For simplicity, co-generation was not used. The plant is fed by a single production well with a pump delivering 50 kg/s of 150 °C water. For electricity production, an ORC plant is assumed returning 60 °C water. The net capacity is 1863 kW and the plant is able to produce 15.5 GWh_e assuming an capacity factor of 0.95. For heat only plant, the utilisation ratio of a heat exchanger may be estimated as shown in equation 5. Assuming the same geothermal fluid of 150 °C, return temperature of 60 °C and ambient temperature of 20 °C, the utilisation ratio is 0.69. The net capacity is therefore 2887 kW_{th} and the plant is able to produce 24 GWh_{th} using the same amount of fluid as the ORC plant.

The direct and indirect CO_2 emissions from an ORC power plant are 96 kg CO_2/MWh_e [ETRI 2014]. The same fluid is used for the heat plant. Therefore the direct and indirect CO_2 emissions for heat production are 62 kg CO_2/MWh_{th} since the heat plant capacity is higher than for the electricity plant. Direct and indirect emissions from steam turbine coal supercritical CHP are 456 kg CO_2/MWh_e and 323 kg CO_2/MWh_e from combined cycle gas turbine CHP [ETRI 2014]. Direct and indirect emissions producing heat with hard coal are 414 kg CO_2/MWh_{th} and 227 kg CO_2/MWh_{th} from natural gas [Biomass Energy Centre 2014].

Using the geothermal fluid, the production of 15.5 GWh_e of electricity emits 1488 tons CO_2 annually. Using the same geothermal fluid, the production of 24.0 GWh_{th} of heat emits 1488 tons CO_2 annually. Potential savings producing electricity or heat with geothermal as compared with either coal or natural gas may therefore be estimated (Table 16).

In all cases, high CO_2 savings can be achieved by producing electricity or heat by geothermal compared to coal and gas. Higher CO_2 savings may be expected by using low and medium temperature geothermal resources for heat production than for power production but this difference is only three percent when comparing geothermal to gas as an energy source. However, it must be stressed that frequently there is lack of infrastructure and potential buyers of this heat and from economical point of view for the developer, electricity production may be a better option.

6.1.2 H_2S emissions

Of the gases emitted from high temperature power plants, H_2S is of primary concern due to its toxicity and because it may constitute a large share of emission (up to 20-35 vol % of NCG). At low temperatures, H_2S concentrations usually do not exceed few tens parts per million (ppm). Power plants may emit between 0.05 g/kWh to 9800 g/kWh [Carlsson et al. 2013]. Low levels of H_2S may be tolerated as the human body has enzymes capable of detoxifying H_2S to sulphate but this capability is limited to low levels of H_2S. Short-term high level exposure may lead to loss of breathing and high probability of death. Table 17 shows the effects of different levels of H_2S exposure on the human body and various limits of exposure.

H_2S is soluble in water but it primarily partitions to the gas phase in the condensers. Therefore depending on the H_2S fraction in the geofluid and local regulations, the gas extracted from the condensers may have to be treated to prevent H_2S emissions to the atmosphere. H_2S treatment methods are described in chapter 2.1.5.

6.1.3 Mercury emissions

Mercury (Hg) is not present in every geothermal resource. However, if Hg is present, it may be emitted during power production from that resource. As with other gases, Hg is not emitted from closed binary plants as the geothermal fluid is simply passed through a heat exchanger prior to being re-injected. Mercury is emitted from geothermal power plants both in gaseous and in particulate form. Gaseous Hg is more reactive than particulate Hg and is more soluble in water. It remains in the atmosphere for 1-10 days and can be deposited locally and regionally. Particulate Hg binds to drift water droplets and is mainly deposited locally. The gaseous Hg

Table 16: Potential CO_2 emission savings by using geothermal resource compared to coal or natural gas as energy source. Values are in tonnes CO_2/year (% saving) and apply for 15.5 GWhe or 24 GWhth annual production supplied by a single geothermal well at 50 kg/s and 150 °C. Source: JRC analysis

	Heat production	Power generation
Steam turbine coal supercritical	8460 (85 %)	5581(79 %)
Combined cycle gas turbine	6274 (73 %)	3519 (70 %)

Table 17: Established dose-effect relationships of hydrogen sulphide [WHO 2000] and limits of exposure [EC 2009b]

Lower value	Limit value	Upper value	Effects, limits
	mg/m³ (ppm in brackets)		
0.001 (0.0007)		0.190 (0.13)	Human recognition threshold. Human sensitivity to the smell is variable
	0.150 (0.1)		Maximum time-weighted average (24 hours) according to WHO
	7 (5)		8 hour exposure limit
	14 (10)		Short-term exposure limit (STEL) where exposure should not exceed 15 minutes
15 (10)		30 (20)	Threshold for eye irritation
70 (50)		140 (100)	Serious eye damage
210 (150)		350 (250)	Loss of olfactory sense
450 (320)		750 (530)	Pulmonary oedema with risk of death
750 (530)		1400 (1000)	Strong stimulation of the central nervous system followed by respiratory arrest
1400 (1000)		2800 (2000)	Immediate collapse with paralysis of respiration

has higher bioavailability than the particulate form [Pertot et al. 2013]. The main identified Hg occurrence in geothermal resources in Europe is in the Lardarello-Travale-Radicondoli geothermal area in Tuscany, Italy. There, annual emissions decreased from 0.21 µg/kWh to 0.16 µg/kWh between 2003-2007 when the local operator installed dedicated H_2S and mercury removal systems, known as AMIS [Pertot et al. 2013]. The AMIS has a tested efficiency of 95 % Hg removal. The overall Hg emission reduction from the area was lower than 95 % as in 2007, 10 out of 27 power plants with combined capacity of 720 MW were equipped with the AMIS system. The AMIS system and those used in the Geysers area in USA utilize activated carbon to absorb mercury from the gas stream prior to converting sulphur from its gaseous form to solid form. Therefore the hazardous waste produced during power production is reduced by thousands of tons annually [GEA 2007].

6.2 Induced seismicity

Earthquakes are the primary process to release stress built up in the Earth's crust. Earthquakes occur when stresses on pre-existing planes of weakness exceed their stress. Although damages to buildings associated with shallow geothermal activities and GSHP are not common [Grimm et al. 2014], induced seismicity related to deep geothermal applications has been known for long time. Induced seismicity has received increased attention with the introduction of the EGS concept. Although the exact mechanisms triggering earthquakes during geothermal applications is not understood, earthquakes occur primarily during re-injection and maximum observed earthquakes in a given reservoir are dependent on the injected volume [Zang et al. 2014]. Rock properties, injection pressure, and temperature all influence the nature of the failure that occurs. For today's EGS developed between 2-5 km of depth, there is no relationship between the number of recorded events or the maximum magnitude and reservoir depth [Evans et al. 2012]. Induced seismicity is not as prevalent and often not recognised with the surface monitoring system in place when no re-injection is carried out. As EGS are often located near densely populated areas, borehole sensors may need to be installed to increase signal-to-noise ratios and therefore achieve a better picture of the reservoir response to production and re-injection. Installation of sensors at depth increases the sensitivity of the seismic monitoring network thereby increasing the resolution of the reservoir models.

The goal of an engineered or enhanced geothermal system operation is to locate or safely create permeability through fractures and voids in high temperature rock such that water and steam can circulate through these pathways and transfer heat to the surface. An engineered system is one where natural fractures do not occur and have to be created or existing ones need to be reactivated. An enhanced system, the natural rock permeability is increased by massive water injection (up to 100 kg s^{-1} in extended open hole sections. The fluids are pumped under high pressure to enhance permeability through hydraulic fracturing (mode I crack), hydro shearing (mode II crack), a combination of both or acidizing [Zang et al. 2014].

Most commonly, earthquakes occur during or slightly after stimulation of geothermal systems. These earthquakes are predominantly under a local magnitude (M_L) 2 and below the threshold to be felt [Evans et al. 2012]. The geothermal sites near Basel, Landau and Soultz-sous-Forêts in the upper Rhine valley have experienced up to M_L 3.4 event due to EGS activities causing public concern [Zang et al. 2014].

Prior to drilling, obtaining a P-wave and S-wave model of the reservoir is recommended as it is necessary to accurately pinpoint the origin of earthquakes during stimulation and operation [Zang et al. 2014]. The spatiotemporal distribution of seismicity is often a gradual migration from the vicinity of the borehole to distances farther from the borehole as fluid injection is progressing. The change in ratio of P-wave to S-wave velocities has further been observed to correlate with the progression of injected fluids. Hence the 3D model of the reservoir has to incorporate temporal aspects of P-wave and S-wave velocities. Pre-stimulation seismic monitoring might be useful to identify buried faults. The stimulation and operation of an EGS should be designed as to prevent large magnitude events (LME). These LME may not only cause damage on the surface but can also lower the efficiency of the geothermal system by creating high permeability pathways preventing sufficient heat exchange. LME have mainly been reported after long term fluid injections or as a result of reservoir impoundment both of which can bring pre-existing fractures in the shallow crust closer to failure. EGS stimulations generally show higher propensity to produce LME compared to hydraulic fracturing in the oil and gas industry and seismogenic indices were higher for stimulations in crystalline rocks than in sedimentary rocks. During the early stimulation phase, pore pressures are high in the vicinity of the injection well and many small events, often on faults with low applied shear stress are induced. As the injected water migrates away from the injection point and the pore pressure far from the injection well decreases, the shear stress necessary to trigger an event must increase. This increases the probability of the often observed larger magnitude events at the periphery of the stimulated volume and at the later stages of the stimulation [Zang et al. 2014].

7 KEY FINDINGS AND CONCLUSIONS

This report aims at presenting the overall state of play of geothermal energy in Europe in 2014. Geothermal energy is a renewable source of energy that can provide constant power and heat. The technologies to exploit its potential are commercially proven today apart from EGS. In Europe, the geologic or theoretical potential is very large and exceeds current electricity demand in some countries. However, distribution of geothermal heat is highly variable and only a small part of the theoretical potential can actually be exploited due to technical and economic barriers.

Three forms of geothermal energy use can be differentiated: power generation, direct use, and ground-source heat pumps. In Europe and worldwide, installed capacity for GSHP is greatest, followed by direct use and power generation.

Ground source heat pumps (GSHP)

GSHP use geothermal energy from shallow depths, which is available almost everywhere. They convert the low temperature geothermal energy to thermal energy at a higher temperature which can be used for space or water heating and cooling.

The installed capacity of GSHP has seen a dramatic increase with annual growth rates of 10 % since the mid-1990s with a main focus on Europe and the United States. The installed GSHP capacity in the EU reached to about 14900 MW_{th} (1.2 million units). The main markets for GSHP in the EU are Sweden, Germany, France, and Austria. The European GSHP market has been shrinking because of its dependence on the new building market which has decreased in the recent years. A market recovery is expected in the coming years.

- ***To increase overall system efficiency, efforts should be made to optimize all components of borehole heat exchangers with emphasis on pipe materials and better thermal transfer fluids.***

Direct use

Being the oldest form of geothermal energy exploitation, direct use works with higher resource temperatures than GSHP but still below 150 °C. Examples of direct use include space and district heating, heating of swimming pools, spas, and greenhouses, but also industrial uses and snow melting. Direct use benefits from a widespread resource available at economic drilling depths and the use of conventional equipment.

The installed capacity in the EU was about 3 GW_{th} and about 27600 TJ of heat are produced annually. The major markets for direct use are Italy, Hungary, and France. The main direct uses in the EU are district heating and bathing. District heating is currently the geothermal sector with the most dynamic development. Installed capacity is expected to grow mainly in Germany, France, and Hungary.

- ***Geothermal direct use and GSHP for heating and cooling is best integrated in a regional approach to reduce cost and increase security of supply. Solutions to integrate the refurbishment of old buildings to district heating networks are key to lower the overall energy consumption and CO_2 emissions for heating and cooling in the short term.***

Power generation

For power generation, the type and temperature of the geothermal resource determines power plant design and efficiency. Dry steam plants and flash plants use reservoirs with a temperature above 180 °C. They account for the majority of geothermal power generation capacity today and are commercially available. Binary plants derive their fluids from cooler resources (about 75-180 °C). They represent about 10 % of the installed global geothermal power generating capacity and 45 % in terms of number of plants but they are the fastest-growing group since they use more prevalent resources. However, only few technology suppliers are available for binary plants and only a limited number of - potentially highly efficient - kalina type binary plants exist.

The installed capacity of power generation in the EU was about 0.9 GW_e and 2013 electricity production was about 5.6 TWh. In 2013, the new installed capacity worldwide amounted to 0.5 GW_e, a new record in annual installations. Of these, 145 MW_e were installed in Europe (including Turkey and Iceland) and about 17 MW_e in the EU. A moderate growth is expected during the next years in the EU, with the installed capacity in 2020 to be about 1.6 GW_e.

- ***Lowering drilling costs is a key issue for lowering CAPEX and OPEX of power plants. Heat exchangers play a central role in geothermal binary power plants but also for direct use and GSHP applications.***

- ***Design and layout of heat exchanger heavily influence both CAPEX and OPEX and R&D efforts are focussing on reducing heat exchanger costs.***

A key issue to expand the resource potential of the geothermal power sector is the deployment of EGS technology. EGS has been demonstrated on small scale in few locations so far.

- ***For an adequate proof of concept, the EGS technology needs to be demonstrated under different geological conditions.***

Operators of EGS need to demonstrate the ability to adequately control reservoirs in different settings, both in terms of heat extraction and from chemical stimulants and seismic point of view.

EU targets and policies

Geothermal project development has high upfront cost and it might take 3-6 years to realise a project. EU legislation on renewable electricity requires that dispatch priority is given to renewable electricity insofar as the operation of the national electricity system permits. A number of support schemes for geothermal energy within the EU exist but they differ between Member States.

Risks of geothermal project development include the short term risk of not finding an adequate resource and the long term risk that the resource declines over time due to production. The resource is confirmed only after exploration and drilling, and these two processes often are responsible for the majority of the costs associated with the development of a geothermal project.

- ***The most important market push instrument is the implementation of a risk insurance fund which exists in 3 Member States.***

EGEC has proposed a European Geothermal Risk Insurance Fund aiming at alleviating the shortage of insurance policies for the resource risk and easing investments in geothermal electricity projects.

Today, geothermal energy is a proven technology with a long history. Due to the limited size of hydrothermal resources, the market share of geothermal energy in Europe is still small. Large scale deployment of geothermal power production requires the demonstration of successful EGS projects extracting heat from reservoirs constituting a variety of geological conditions and drilling technology has to become cheaper. Future deployment of GSHP and direct use resources for district heating is very much linked to the recovery of the building sector.

- ***During refurbishment, heating and cooling systems of existing buildings should be integrated to district heating and developers of new buildings and infrastructures should be made aware of the flexibility and benefits of geothermal resources.***

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