INTERGOVERNMENTAL PANEL ON climate change

Chapter 4

Geothermal Energy

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Author(s):	CLAs:	Barry A. Goldstein, Gerardo Hiriart			
	LAs:	Ruggero Bertani, Christopher J. Bromley, Luis C.A. Gutiérrez-Negrín, Ernst Huenges, Hirofumi H.M. Muraoka, Arni Ragnarsson, Jefferson W. Tester, Vladimir I. Zui			
	CAs:	David Blackwell, Trevor N. Demayo, John W. Lund, Mike Mongillo, David Newell, Ladislaus Rybach, Subir Sanyal, Kenneth H. Williamson, Doone Wyborne [AUTHORS: to be finally completed].			
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Chapter 4 has been allocated a total of 20 - 34 pages in the SRREN. The actual chapter length (excluding references & cover page) is 38 pages: a total of 4 pages over target. Government and expert reviewers are kindly asked to indicate where the chapter could be shortened in terms of text and/or figures and tables.

All monetary values are presented in 2005 US$.

Chapter 4: Geothermal Energy

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EXECUTIVE SUMMARY

Geothermal resources correspond to the accessible thermal energy stored in the Earth's interior, and are used to generate electric energy in a thermal power plant, or in other domestic and agro-industrial applications requiring heat. **Near-term (by 2015)** geothermal-electric **deployment** is estimated to be 121.6 TWh/y (0.44 EJ/y), and 250.4 TWh(thermal)/y (0.9 EJ/y) for heat applications. Forecast **long-term deployment (by 2050)** is 1266 TWh/y (4.56 EJ/y) for electricity and 2184 TWh(thermal)/y (7.86 EJ/y) for heat, representing 2.5%-4.1% of global electricity demand and 4.9% of global heat demand, with some countries obtaining most of their primary energy needs (heating, cooling and electricity) from geothermal energy. Global **technical potentials** are estimated to be between 91 EJ/y (to 3 km depth) and 1043 EJ/y (to 10 km depth) for electricity and between 10 EJ/y (minimum) and 322 EJ/y (maximum) for heat.

Geothermal heat is extracted using wells that produce hot fluids contained in hydrothermal reservoirs with naturally high permeability or by artificial fluids pathways in Enhanced (Engineered) Geothermal Systems (EGS). **Technology for electric generation from hydrothermal geothermal resources is mature, sustainable and reliable** since approximately 40% of the installed capacity has been operating for more than 25 years. Direct heating technologies using Geothermal Heat Pumps (GHP), district heating and EGS methods are available, with different degrees of maturity.

High availability is a comparative advantage of geothermal energy use. **Geothermal resources are currently used for base-load electric generation** in 24 countries with an installed capacity of 11 GW and a global average capacity factor of 71%, with newer installations above 90%, providing 10% to 30% of their electricity demand in six countries. Geothermal resources are also used directly for heating and cooling in 78 countries, accounting for 50 GW of thermal capacity with GHP applications having the widest market penetration.

Geothermal is a renewable resource as the extracted heat from an active reservoir is continuously restored by natural heat production, conduction and convection from surrounding hotter regions, and the extracted geothermal fluids are replenished by natural recharge and by injection of the depleted (cooled) fluids. **If managed properly, geothermal systems can be sustainable for the long term.** Direct CO_2 emissions average 120 g/kWh$_e$ for currently operating conventional flash and direct steam power plants and less than 1 g/kWh$_e$ for binary cycle plants with total injection. Corresponding figures for direct use applications are even lower. It should be emphasized that this emission is from natural CO_2 releases into the atmosphere, not created by any combustion process, since the exploitation of geothermal energy does not create any additional CO_2 production to the environment. Over its full life-cycle, the CO_2-equivalent emissions range from 23-80 g/kWh$_e$ for binary plants and 14-202 g/kWh$_t$ for district heating systems and GHP. **This means geothermal resources are environmentally advantageous and the net energy supplied more than offsets the environmental impacts of human, energy and material inputs.**

Like other RE, geothermal-electric projects have relatively high up-front capital costs, varying currently between 1800 and 5300 US$ (2005) per kilowatt, but with no recurring "fuel costs". **The levelised costs of electricity (LCOE) from conventional hydrothermal resources are competitive in today's electricity markets, ranging from 43 to 84 US$ (2005) per megawatt-hour (MWh).** LCOE projections for EGS electricity fall within a much wider range because of uncertainties regarding resource parameters (particularly sustainable flow-rate and heat recovery factor), and assumptions regarding future drilling costs. **Costs are expected to decrease – by about 15% for hydrothermal and by 50% for EGS by 2050**, assuming success in developing stimulation technology. Current costs of direct uses are generally competitive ranging from an average of <100 (pond heating) to 3900 (for building heating) US$ (2005) per installed thermal kilowatt and correspondingly low levelised costs for energy as they avoid inherent heat to power efficiency limitations.

Despite the present competitiveness of conventional geothermal energy for electric and non-electric applications, most operating systems today are utilizing the highest grade resources available. **Public and private support for research along with favourable deployment policies would assist the expanded utilisation of conventional geothermal resources and demonstration and commercialisation of EGS and other non-conventional geothermal resources.** This policy support could include subsidies, loan guarantees and tax write-offs to cover the risks of initial deep drilling and long term productivity. Feed-in tariffs with confirmed geothermal prices, and direct subsidies for district and building heating would also help to accelerate deployment.

Geothermal heat sources will not be impacted by climate change. Geothermal energy utilization is nearly climate neutral, and its many other positive environmental attributes enable it to operate in an environmentally sustainable manner. With its natural thermal storage capacity, geothermal is especially suitable for supplying dispatching base-load power. Thus **geothermal could function in a portfolio approach to increase the effectiveness of intermittent RE sources such as hydro, wind and solar, resulting in a much larger net impact for mitigating climate change.**

Although there are clear challenges to realizing the massive potential of geothermal energy, they are surmountable within 20 years with modest investments for research, development, and early deployment of advanced technologies. **Geothermal energy is uniquely positioned to play a key role in climate change mitigation strategies.**

4.1 Introduction

Geothermal resources consist of thermal energy stored at depth within the earth in both rock and trapped steam or liquid water. Geothermal systems occur in a number of geological environments where the temperatures and depths of the reservoirs vary accordingly. Many high-temperature (>180°C) hydrothermal systems are associated with recent volcanic activity and are found near plate tectonic boundaries (subduction, rifting, spreading or transform faulting), or at crustal and mantle hot spot anomalies. Intermediate (100-180°C) and low temperature (<100°C) systems are also found in continental settings, formed by above-normal heat production through radioactive isotope decay; they include aquifers charged by water heated through circulation along deeply penetrating fault zones. However, there are several notable exceptions, and under appropriate conditions, high, intermediate and low temperature geothermal fields can be utilised for both power generation and the direct use of heat.

Geothermal systems can be classified as convective, which includes liquid- and vapour-dominated hydrothermal as well as lower temperature aquifers, or conductive**,** which includes hot rock and magma over a wide range of temperatures. Lower temperature aquifers contain deeply circulating fluids in porous media or fracture zones, but lack a localized heat source. They are further sub-divided into systems at hydrostatic pressure and systems at pressure much higher than hydrostatic (geo-pressured). Resource utilisation technologies can be grouped under types for electrical power generation or for direct use of the heat. Geothermal Heat Pumps (GHP) are a subset of direct use, and Enhanced or Engineered Geothermal Systems (EGS), where fluid pathways are engineered by fracturing the rock, are a subset under both utilisation types. Currently, the most widely exploited geothermal systems for power generation are hydrothermal (of continental subtype). Table 4.1 summarizes all of these types.

Table 4.1 Type of geothermal resources, temperatures and uses.

Type	Natural fluids	Subtype	Temperature Range	Utilisation	
				Current	Potential
Convective (Hydrothermal)	Yes	Continental	H, I & L	Power, direct uses	
		Submarine	H	None	Power
Conductive	No	Shallow (<400 m)	L	Direct uses (GHP)	
		Hot rock (EGS)	H, I	Direct	Power, direct
		Magma bodies	H	None	Power, direct
Lower temperature Aquifers	Yes	Hydrostatic aquifers	I & L	Direct	Power, direct
		Geo-pressured		Direct	Power, direct

Temperature: H: High (>180°C), I: Intermediate (100-180°C), L: Low (ambient to 100°C). EGS: Enhanced (or Engineered) Geothermal Systems. Direct uses include GHP (Geothermal Heat Pumps).

In areas of magmatic intrusions, temperatures above 1000°C can occur at less than 10 km depth. Magma typically ex-solve mineralised fluids and gases, which then mix with deeply circulating groundwater. Heat energy is also transferred by conduction but in magmatic systems, convection is also important. Typically, a hydrothermal convective system is established whereby local surface heat-flow (through hot springs and steam vents) is significantly enhanced. Such shallow systems can last hundreds of thousands of years, and the gradually cooling magmatic heat sources can be replenished periodically with fresh intrusions from a deeper magma chamber. Finally, geothermal fields with temperatures as low as 5-10°C are also used for direct applications using heat pumps.

Subsurface temperatures increase with depth according to the local geothermal gradient, and if hot rocks within drillable depth can be stimulated to improve permeability, using hydraulic fracturing, chemical or thermal stimulation methods, they form a potential EGS resource that can be used for power generation and/or direct applications. EGS resources occur in all geothermal environments, but are likely to be economic in the medium term in geological settings where the heat flow is high enough to permit exploitation at depths of less than 5 km. Experiments have investigated the potential of such continental EGS settings in large areas of Europe, North America, Asia and Australia. In the longer term, and given the average geothermal gradients (25-30°C/km), EGS resources at relatively high temperature (≥180°C) may be exploitable in geological settings at depths up to 7 km, which is well within the range of existing drilling technology (~10 km depth). Geothermal resources of different types may occur at different depths. For example, fractured and water-saturated hot-rock EGS resources lie below hot sedimentary aquifer resources in the Australian Cooper Basin (Goldstein et al., 2009). These EGS resources include Hot Dry Rock (HDR), Hot Fractured Rock (HFR), Hot Wet Rock (HWR), among other terms.

Direct uses of geothermal energy have been practised at least since the Middle Palaeolithic when hot springs were used for ritual or routine bathing (Cataldi, 1999), and industrial utilisation began in Italy by exploiting boric acid from the geothermal zone of Larderello, where in 1904 the first kilowatts of electric energy were generated and in 1913 the first 250-kWe commercial geothermal power unit was installed (Burgassi, 1999).

For the last 100 years, geothermal energy has provided safe, reliable, environmentally benign energy used in a sustainable manner to generate electric power and provide direct heating services on both large and small scales. Approximately 40% of the present-day installed electricity capacity has been in operation for more than 25 years, demonstrating technical maturity and reliability. Geothermal typically provides base-load generation, but it can be dispatched and used for meeting peak demand. Today, geothermal represents a viable energy resource in many industrial and developing countries using a mature technology to access and extract naturally heated steam or hot water from natural hydrothermal reservoirs, and it has the potential to make a more significant contribution on a global scale through the development of advanced technology such as EGS that would enable energy recovery from a much larger fraction of the accessible stored thermal energy in the earth’s crust. In addition, GHP that can be utilized anywhere in the world for heating and cooling, have had significant growth in the past 10 years, and are expected to provide a significantly greater contribution to global energy savings in the future (Lund et al., 2003, 2010).

Today’s hydrothermal technologies have demonstrated very high average capacity factors (up to 90% in some plants) in electric generation with low carbon emissions. The capacity factor (CF) is the ratio of the actual generation of electricity (averaged across a year) to the installed electrical capacity, and is expressed as a percentage. Environmental and social impacts do exist with respect to land and water use and seismic risk, but these are site and technology specific and largely manageable. New opportunities exist to develop geothermal beyond power generation, particularly to use geothermal heat for district and process heating, along with GHP for space heating and cooling.

This chapter includes a brief description of the worldwide potential of geothermal resources (4.2), the current technology and applications (4.3) and the expected technological developments (4.6), the present market status (4.4) and its probable future evolution (4.8), the geothermal environmental and social impacts (4.5) and the cost trends (4.7) in using geothermal energy to contribute to reduce greenhouse gas (GHG) emissions and then mitigate climate change. As presented in this chapter, climate change has no major impacts on geothermal energy, but the widespread development of geothermal energy could considerably reduce the future emission of carbon dioxide into the atmosphere, and play a significant role in reducing anthropogenic effects on climate change by replacing fossil fuel burning plants.

4.2 Resource Potential

4.2.1 Global technical resource potential

The IPCC Fourth Assessment Report (AR4) estimated an available energy resource for geothermal (including potential reserves) of 5000 EJ/y (Sims et al., 2007; see Table 4.2).

The total thermal energy contained in the Earth is of the order of 12.6 x 10^{12} EJ and that of the crust the order of 5.4 x 10^9 EJ to depths of up to 50 km (Dickson and Fanelli, 2003). The main sources of this energy are due to the heat flow from the earth's core and mantle, and that generated by the continuous decay of radioactive isotopes in the crust itself. Heat is transferred from the interior towards the surface, mostly by conduction, at an average of 0.065 W/m^2 on continents and 0.101 W/m^2 through the ocean floor. The result is a global terrestrial heat flow rate of around 1400 EJ/y. Considering that continents cover ~30% of the earth's surface and their lower average heat flow, the terrestrial heat flow under continents can be estimated at 315 EJ/y (Stefansson, 2005).

Under continents, the stored thermal energy within 10 km depth (reachable with current drilling technology) has been estimated between 400 x 10^6 EJ (EPRI, 1978) and 105 x 10^6 EJ (Tester et al., 2005, see Table 11.1), within 5 km depth between 140 x 10^6 EJ (WEC, 1994) and 65 x 10^6 EJ and at 3 km depth between 43 x 10^6 EJ (EPRI, 1978) and 35 x 10^6 EJ (Table 4.2). For the Australian continent alone, Budd et al. (2008) estimated that recovery of just 1% of the stored geothermal energy above 150°C to 5 km in the Australian continental crust corresponds to 190,000 EJ. Based on these estimates, available resource is clearly not a limiting factor for geothermal deployment globally.

Estimates of stored geothermal energy can be regarded as theoretical geothermal potentials, e.g. the physical upper limit of the energy available from a certain source, in this case geothermal. Technical potential however, includes practical limits to development, and is defined as the amount of RE output obtainable by full implementation of demonstrated and likely to develop technologies or practices, with no explicit reference to costs, barriers or policies.

Table 4.2 Global theoretical and technical geothermal potential (for electricity).

Depth (km)	Theoretical Potential (thermal)		Technical Potential (electric) (EJ/y)			
	10^6 EJ	Reference	Identified resources	Reference	Hidden resources	Total
10	400	EPRI, 1978	5.7	Stefansson, 2005	1036.9	1042.6
10	105	Tester et al., 2005			267.8	273.5
5	140	WEC, 1994			359.2	364.9
5	65	--			163.6	169.3
3	43	EPRI, 1978			106.4	112.1
3	35	--			85.1	90.8

Recovery of geothermal energy utilises only a portion of the stored thermal energy due to limitations in rock permeability that permit heat extraction through fluid circulation, and to the minimum temperature limits for utilisation at a given site. To calculate an effective technical potential it is also necessary to exclude the heat which cannot be accessed at drillable depths or is insufficiently hot for practical use. Global utilisation has so far concentrated on areas in which geological conditions, such as natural fractures and porous formations, permit water or steam to transfer heat nearer to the surface, thus giving rise to convecting hydrothermal resources where drilling to depths up to 4 km can access fluids at temperatures of 180°C to more than 350°C.

For electric generation, Stefansson (2005) calculated the world geothermal potential for identified hydrothermal resources at 200 GWe (equivalent to 5.7 EJ/y with a capacity factor of 90%) with a lower limit of 50 GWe (1.4 EJ/y). Assuming the unidentified, hidden resources are 5-10 times higher than the identified ones, based on correlations in the US and other countries, he estimated the upper limit for the worldwide geothermal technical potential between 1000 and 2000 GWe (28.3 and 56.8 EJ/y with the same 90% capacity factor). Largely based on those estimations, Krewitt et al. (2009) made their estimations for geothermal technical potentials, particularly for 2050 at 45 EJ/y.

However, a more recent estimation for unidentified geothermal resources indicates that within the US alone the stored geothermal energy to 10 km depth is 13.6 x 10^6 EJ in conduction-dominated EGS of crystalline basement and sedimentary rock formations (Tester et al., 2006, see Table 1.1). Assuming that 2% of the heat is recoverable and taking into account all the aspects for conversion of the recoverable heat into electricity (thermal efficiencies, temperature drops, ambient temperatures, cooling cycles and others), and for conversion of the electric energy to electric power assuming a lifespan of 30 years, it is possible to obtain 1249 GWe (Tester et al., 2006, see Table 3.3). With this electric installed capacity, 35.4 EJ/y of electric energy can be produced with the same capacity factor of 90%, and for the US represents a geothermal technical potential additional to the identified hydrothermal resources in this country.

Making similar assumptions for the world and keeping the same relationship between theoretical (stored heat) and electric technical potentials (1 EJ theoretical ~ 2.61 x 10^6 EJ/y of technical potential at 90% capacity factor for 30 years), it is possible to obtain different worldwide technical potentials for hidden geothermal resources at different depths, as presented in Table 4.2. Based on this assessment, the total worldwide geothermal technical potential for electricity varies from a minimum of about 91 EJ/y (down to 3 km depth) to a maximum of 1043 EJ/y (down to 10 km depth) (Fig. 4.1). While these estimates are lower than the earlier projection of 5000 EJ/y in the AR4 (Sims et al., 2007) they still correspond to a large and well distributed global technical potential for geothermal. The minimum value down to 10 km depth (274 EJ/y) is less than the assessed continental heat-flow (315 EJ/y, Stefansson, 2005), implying that this global rate of extraction although calculated for a 30 year project lifespan, would actually be sustainable long term by natural heat recharge.

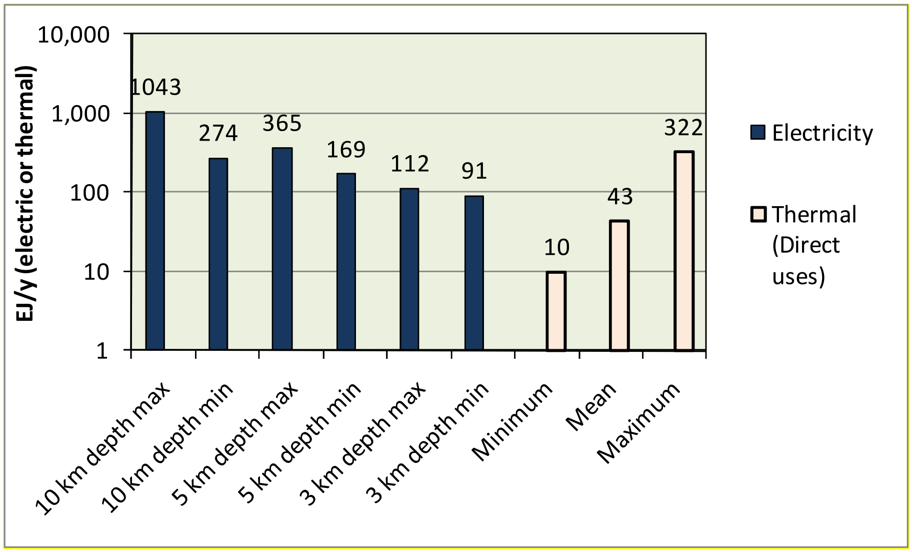

Figure 4.1 Geothermal technical potentials for electricity and direct uses (heat) (Prepared with data from Table 4.2 and 4.3)

Hidden or unidentified resources are mostly composed of low to mid grade conduction dominated environments. Estimating the technical potential of EGS recovery methods is uncertain because of the limited commercial experience to-date. Wide spread development is more likely to occur if commercial-scale demonstration plants successfully establish sustainable operation within the next decade. In particular, it is important to achieve sufficient reservoir heat exchange surface and volume, inter-well connectivity and production flow rates, with acceptable water consumption and pressure drops. Assuming successful resolution of these issues, EGS will become a leading technology for providing thermal energy and electricity globally because of its widespread accessibility.

For hydrothermal submarine vents, an estimation of >100 GWe (>2.8 EJ/y) offshore technical potential has been made (Hiriart et al., 2010). This is based on the 3900 km of ocean ridges confirmed as having hydrothermal vents, with the assumption that only 1% could be developed for electricity production using a recovery factor of 4%. This assumption is based on capturing part of the heat from the flowing submarine vent without any drilling. If offshore drilling becomes technically and economically feasible a technical potential of 1000 GWe (28 EJ/y) from hydrothermal vents may be possible.

For geothermal direct uses, Stefansson (2005) estimated 4400 GW_{th} for the world potential geothermal from resources <130°C, with a minimum of 1000 GW_{th} and a maximum, considering hidden resources, of 22,000-44,000 GW_{th}. Taking a worldwide average capacity factor for direct uses of 31%, the geothermal technical potential for heat can be estimated to be 43 EJ/y with a lower value of 9.8 EJ/y and an upper value of 322 EJ/y (equivalent to 33,000 GW_{th} of installed capacity) (Fig. 4.1). Krewitt et al. (2009) used the same values estimated by Stefansson (2005) in GW_{th}, but a capacity factor of 100% was assumed when converted into EJ/y, and then the average upper limit of 33,000 GW_{th} was converted into 1040 EJ/y.

4.2.2 Regional resource potential

The assessed geothermal technical potentials included in Table 4.2 and Fig. 4.1 are presented on a regional basis in Table 4.3.

Table 4.3 Geothermal technical potentials for the IEA regions (prepared with data from EPRI, 1978, and global technical potentials described in section 4.2.1).

IEA REGION	Technical potential in EJ/y (electric) at depths to:						Technical potential in EJ/y (heat for direct uses)		
	3 km		5 km		10 km				
	Min	Max	Min	Max	Min	Max	Min	Mean	Max
1. OECD North America	18.7	23.1	37.0	79.7	58.1	221.7	2.1	9.3	69.5
2. Latin America	10.4	12.8	21.3	45.9	32.9	125.5	1.2	5.5	40.9
3. OECD Europe	4.7	5.8	8.4	18.1	13.8	52.7	0.8	3.6	26.8
4. Africa	14.5	17.9	25.5	55.0	42.4	161.7	1.4	6.1	45.8
5. Transition Economies	17.2	21.2	29.5	63.6	49.6	189.1	1.5	6.8	51.1
6. Middle East	3.2	4.0	5.7	12.2	9.4	36.0	0.3	1.4	10.2
7. Developing Asia	7.3	9.1	14.6	31.5	22.9	87.2	0.8	3.7	27.6
8. India	2.4	3.0	4.0	8.7	6.9	26.1	0.2	1.0	7.2
9. China	6.4	7.9	12.9	27.7	20.1	76.6	0.7	3.3	24.5
10. OECD Pacific	5.9	7.3	10.4	22.4	17.3	65.9	0.6	2.5	19.0
Total	**90.8**	**112.1**	**169.3**	**364.9**	**273.5**	**1042.6**	**9.8**	**43.0**	**322.6**

The regional assessment of theoretical potential reported in Table 4.2 was conducted by the Electric Power Research Institute in 1978 (EPRI, 1978), based on a detailed estimation of the thermal energy stored inside the first 3 km under the continents accounting for regional variations in the average geothermal gradient and the presence of either a diffuse geothermal anomaly or a high enthalpy region, associated with volcanism or plate boundaries. The values in Table 4.3 followed the EPRI approach for each region and applied to the minimum and maximum technical potentials mentioned before at 3, 5 and 10 km depth. The separation into electric and thermal (direct uses) potentials is somewhat arbitrary in that most higher temperature resources could be used for either or both in combined heat and power applications depending on local market conditions.

4.2.3 Possible impact of climate change on resource potential

Geothermal energy is a renewable resource, but has unique sustainability characteristics. As thermal energy is extracted from the active reservoir, it creates locally cooler regions. Geothermal projects are typically operated at production rates that cause local declines in pressure and/or in temperature over the economic lifetime of the installed facilities. These cooler and lower pressure zones in the reservoir lead to gradients that result in continuous recharge by conduction from hotter rock, and convection and advection of fluid from surrounding regions. The time scales for thermal and pressure recovery are similar to those required for energy removal (Stefansson, 2000; Rybach and Mongillo, 2006). Detailed modelling studies (Pritchett, 1998; O'Sullivan and Mannington, 2005) have shown that this type of resource exploitation can be economically feasible, and still be renewable on a timescale useful to society, when non-productive recovery periods are considered.

Therefore, with proper well placement and reservoir management strategies, geothermal energy can be sustainably developed. In hydrothermal reservoirs sustainable production can be achieved by adjusting production rates and injection strategies, taking into account the local resource characteristics (field size, natural recharge rate, etc.).

Time scales for naturally recharging depleted geothermal reservoirs following the cessation of production have been determined using numerical model simulations for: 1) heat extraction by geothermal heat pumps, 2) the use of doublet (two wells) systems on a hydrothermal aquifer for space heating, 3) the generation of electricity from a high enthalpy hydrothermal or EGS reservoir (for details see Rybach and Mongillo, 2006; Axelsson et al., 2005; O'Sullivan and Mannington, 2005; Bromley et al., 2006). Models predict that replenishment will occur on time scales of the same order as the lifetime of the geothermal production cycle (Axelsson et al., 2005; Axelsson et al., 2010).

Geothermal resources are not dependent on climate conditions and climate change is not expected to have a significant impact on the geothermal resource potential. The operation of heat-pumps is not affected in any significant way by a gradual change in ambient temperature associated with climate change. On a local basis, the effect of climate-change on rainfall distribution may have a long-term effect on the recharge to specific groundwater aquifers, which in turn may affect discharges from some hot springs, and could have an effect on water levels in shallow geothermally-heated aquifers. Also a change in availability of cooling water from surface water supplies could be affected by changes in rainfall patterns, and this may affect the efficiency of cooling for power plant condensers. However, each of these effects, if they occur, can easily be remedied by simple adjustments to the technology.

4.3 Technology and applications (electricity, heating, cooling)

4.3.1 Geothermal energy utilisation

Geothermal energy is extracted from reservoir fluids by discharging various mixtures of hot water and steam through production wells. In high temperature reservoirs, as pressure drops, the water component boils or “flashes”. Separated steam is piped to a turbine to generate electricity and the remaining hot water may be flashed again two or three times at progressively lower pressures (and temperatures) to obtain more steam. The remaining brine is usually sent back to the reservoir through injection wells or first cascaded to a direct-use system before injecting. Few reservoirs produce “dry” steam, which can be sent directly to the turbine. In these cases, control of steam flow to meet power demand fluctuations is easier than in the case of two-phase production, where continuous upflow in the well-bore is required to avoid gravity collapse of the water phase. Intermediate temperature reservoirs are utilised by extracting heat from produced hot water through a heat exchanger generating power in a binary cycle or in heating and injecting the cooled water back into the reservoir.

Geothermal technologies belong to Category 1 (technologically mature with established markets in at least several countries). Key technologies for exploration and drilling, reservoir management and stimulation and energy recovery and conversion are described below.

4.3.2 Exploration and drilling

Since geothermal resources are underground, exploration methods (including geological, geochemical and geophysical surveys) have been developed to locate and assess them and these methods can be improved. The objectives of geothermal exploration are to identify and rank prospective geothermal reservoirs prior to drilling, and to provide methods of characterising reservoirs that enable estimations of geothermal reservoir performance and lifetime. Exploration of a prospective geothermal reservoir involves estimating its lateral extent and depth with geophysical methods and drilling exploration wells, minimising the risk.

Today, geothermal wells are drilled over a range of depths down to 5 km using conventional drilling methods similar to those used for oil and gas. Advances in drilling technology enable high temperature operation and provide directional capability. Typically, wells are deviated from vertical to about 30-50° inclination from a “kick off point” at depths between 200 m and 2000 m. Many wells can be drilled from the same pad, heading in different directions to access large resource volumes, target permeable structures and minimise the surface impact. Current geothermal drilling methods are presented in more detail in chapter 6 of Tester et al. (2006). In addition, for other geothermal applications such as GHP and direct uses, smaller and more flexible rigs have been developed to overcome accessibility limitations in built-up areas.

4.3.3 Reservoir engineering

The modern method of estimating reserves and sizing power plants is to apply reservoir simulation technology. Since it is not possible to gather all the data required to construct a comprehensive deterministic model, a conceptual model is built, using available data, then translated into a numerical representation, and calibrated to the unexploited, initial thermodynamic state of the reservoir. Future behaviour is forecast under selected load conditions using a heat and mass transfer algorithm (for example, Pruess, 2009), and optimum plant size selected.

Injection management is an important aspect of geothermal development. Cooling of production zones by injected water that has had insufficient contact with hot reservoir rock can result in severe production declines. Placement of wells should also aim to enhance deep hot recharge through production pressure drawdown, but suppress shallow inflows of peripheral cool water through injection pressure increase.

Given sufficient, accurate calibration with field measurements (surface and subsurface), geothermal reservoir evolution can be modelled and pro-actively managed. Hence, it is prudent to monitor and analyse the chemical and thermodynamic properties of geothermal fluids, along with mapping their flow and movement. This information combined with other geophysical data are fed back to re-calibrate models for better predictions (Grant et al., 1982).

4.3.4 Power plants

For electricity generation, dry steam, flash and binary plants are in use today. In all cases heat transfer and rejection are major considerations in the existing designs. Geothermal flash plants, the most common configuration, consist of pipelines, water-steam separators, vaporisers, de-misters, and different types of turbines. Steam turbines are driven by convective flow to a low pressure exhaust or a vacuum. In a condensing turbine (Figure 4.2, left), vacuum conditions are usually maintained by direct contact condenser.

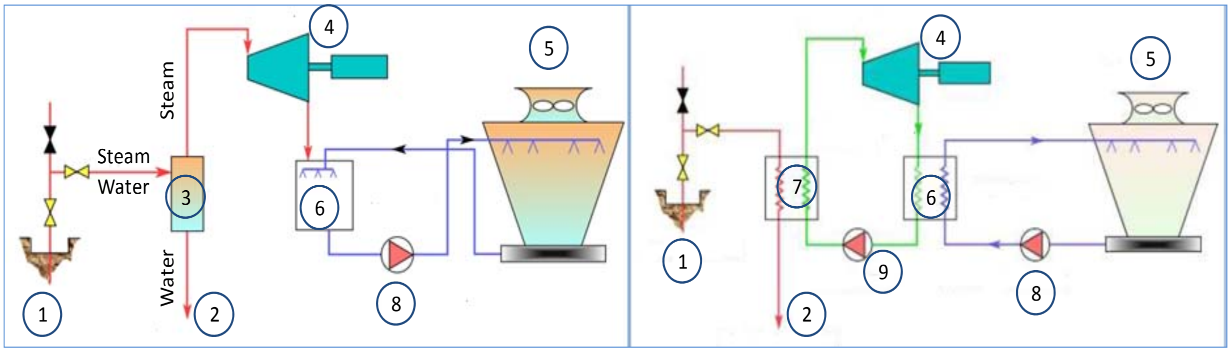

Figure numbers: 1: Production well, 2: Injection well, 3: Separator, 4: Turbo-generator, 5: Cooling tower, 6: Condenser, 7: Heat exchanger, 8: Water pump, 9: Feed pump.

Figure 4.2 Schematic diagram of a geothermal condensing steam power plant (left) and a binary-cycle power plant (right) (Adapted from Fridleifsson et al., 2008).

The unit sizes commonly range from 20-110 MWe (DiPippo, 2008). Design optimisation requires knowledge of reservoir behaviour. Double or triple flash cycles make use of excess brine separated at high pressure. A “triple flash” steam turbine can have three different inlets, operating at pressures and temperatures as low as 1.4 bar_a and 110°C. Dry steam plants do not need separators as geothermal fluids are steam (as in The Geysers, USA, Larderello, Italy, Matsukawa, Japan, and some Indonesian fields), and then their design is simpler. Back-pressure turbines are steam turbines that exhaust to the atmosphere, omitting the condenser and the cooling tower, and are frequently used as small plants to start the development of new fields. The efficiency is only about 50-60% of condensing turbines, but the cost is less. About 15 back-pressure units of 5 MWe have been successfully operating in Mexico since the 1980s (Hiriart and Gutiérrez-Negrín, 1994).

Binary cycle plants of Organic Rankine Cycle (ORC) type (Figure 4.2, right) utilise lower temperature geothermal fluids (ranging from about 70 to 170°C) than conventional flash and dry steam plants (from about 150°C to over 300°C). They are more complex since the geothermal fluid (water, steam or both) passes a heat exchanger heating another “working” fluid such as isopentane or isobutane with a low boiling point, which vaporizes and drives a turbine. The working fluid can then be air-cooled or condensed with water. Binary plants are often constructed as linked modular units of a few MWe in capacity or as bottoming cycle with flash steam plants.

Combined or hybrid plants comprise two or more of the above basic types to improve versatility, increase overall thermal efficiency, improve load-following capability, and efficiently would cover a wide (90-260°C) resource temperature range.

Cogeneration (Co-gen) plants, or Combined or Cascaded Heat and Power plants (CHP), produce both electricity and hot water for district heating or direct use at significantly higher utilisation efficiency than can be achieved for just generating electricity or supplying heat. Relatively small industries and communities of a few thousand people provide sufficient markets for combined heat and power applications. Iceland has two geothermal cogeneration plants with a combined capacity of 300 MWt in operation; the distance of the plants to the towns ranges from 12 to 25 km, over which cooling losses using large insulated pipes and high flow-rates, are negligible. At the Oregon Institute of Technology (OIT) with 3000 students, faculty and staff a CHP provides most of the electricity needs and all the heat demand (Lund and Boyd, 2009). Combined heat and power using low temperature geothermal resources have also been developed in Germany and Austria.

4.3.5 Technologies needed for EGS development

The principle of Enhanced Geothermal Systems (EGS) is as follows: in the subsurface where temperatures are high enough for effective utilisation, a fracture network is created or enlarged to act as fluid pathways. Water is passed through this deep reservoir using injection and production wells, and heat is extracted from the circulating water at the surface. The extracted heat can be used for power generation and for district heating.

EGS projects are currently at a demonstration and experimental stage. The key technical and economic challenges for EGS over the next two decades will be to achieve and maintain efficient and reliable stimulation of multiple reservoirs with sufficient volumes to sustain long term production at acceptable rates, with low flow impedance, limited short-circuiting fractures, and manageable water loss (Tester et al., 2006), and managing seismic risks.

Conforming research priorities for EGS and magmatic resources as determined in Australia (DRET, 2008), USA, the EU (ENGINE, 2008) and the International Partnership for Geothermal Technologies (IPGT, 2008) are summarised in Table 4.4. Successful deployment of the associated services and equipment is also relevant to many conventional geothermal projects.

Table 4.4 Priorities for advanced geothermal research (HTHF: high temperature & high flow-rate).

Complementary research & share knowledge	Education / training
Standard geothermal resource & reserve definitions	Improved HTHF hard rock drill equipment
Predictive reservoir performance modelling	Improved HTHF multiple zone isolation
Predictive stress field characterisation	Reliable HTHF slim-hole submersible pumps
Mitigate induced seismicity / subsidence	Improve resilience of casings to HTHF corrosion
Condensers for high ambient-surface temperatures	Optimum HTHF fracture stimulation methods
Use of CO_2 as a working fluid for heat exchangers	HTHF logging tools and monitoring sensors
Improve power plant design	HTHF flow survey tools
Technologies & methods to minimise water use	HTHF fluid flow tracers
Predict heat flow and reservoirs ahead of the bit	Mitigation of formation damage, scale and corrosion

4.3.6 Technology for submarine geothermal generation

Offshore, there are some 67,000 km of mid-ocean ridges, of which 13,000 km have been studied, and more than 280 sites with submarine geothermal vents have been discovered (Hiriart et al., 2010). Some discharge thermal energy of up to 60 MWt (Lupton, 1995) but there are others, such as ‘Rainbow’, with an estimated output of 1-5 GWt (German et al., 1996). The abundance of submarine hydrothermal systems indicates that technology for their future exploitation should be investigated further, providing such projects become economically feasible.

In theory, electric energy could be produced directly from a hydrothermal vent (without drilling) using an encapsulated plant, like a submarine, containing an ORC binary plant, as described by

Hiriart and Espíndola (2005). The operation would be similar to other binary cycle power plants using evaporator and condenser heat exchangers, with internal efficiency of the order of 80% (Hiriart et al., 2010). Overall efficiency for a submarine vent at 250°C of 4% (electrical power generated / thermal power) is a reasonable estimate for such an installation (Hernández, 2008). Other critical challenges for these resources include the distance from shore, water depth, grid-connection costs and the potential impact on unique marine life around hydrothermal vents.

Adaptation of off-shore drilling technology to tap into off-shore hydrothermal resources also has the potential of significantly increasing global technical geothermal resource potential. Integrated development, to share infrastructure with other renewable energy sources (such as offshore wind and wave power), may provide an economic platform for utilisation in the long term.

4.3.7 Direct use

Direct use provides heating and cooling for buildings including district heating, fish ponds, greenhouses and swimming pools, water purification/desalination and industrial and process heat for agricultural products and mineral extraction and drying.

For space heating, closed loop (double pipe) systems are commonly used. In this case, heat exchangers are utilised to transfer heat from the geothermal water to a closed loop that circulates heated freshwater through the radiators. This is often needed because of the chemical composition of the geothermal water. The spent water is disposed of into injection wells. Open loop systems do not inject produced geothermal fluids. However, in both cases a conventional backup boiler (as shown in Figure 4.3) may be provided to meet peak demand, to reduce the overall investment, and to conserve the geothermal resource.

In Iceland, the geothermal water is transported up to 63 km from the geothermal fields to towns. Transmission pipelines are mostly of steel insulated by rock wool (surface pipes) or polyurethane (subsurface). However, several small villages and farming communities have successfully used plastic pipes (polybutylene), with polyurethane insulation, as transmission pipes. The temperature drop is insignificant in large diameter pipes with a high flow rate.

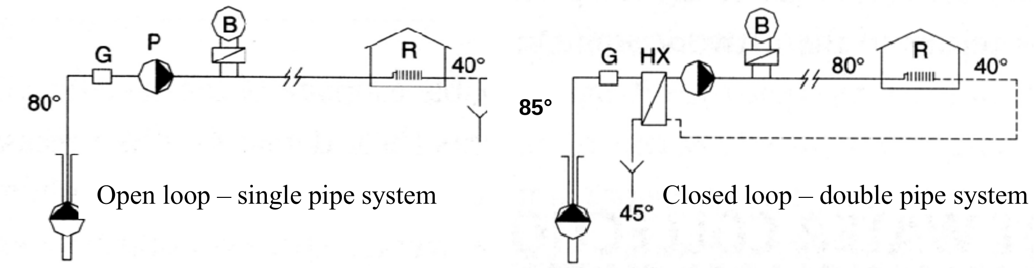

Figure 4.3 Two main types of district heating systems (Dickson and Fanelli, 2003). G=gas separator, P=pump, B=backup boiler, R=radiation heating, HX=heat exchanger.

4.3.8 Geothermal heat pumps

Geothermal Heat Pumps (GHP) have experienced one of the fastest growing applications of renewable energy in the world (Rybach, 2005; Lund et al., 2010). This form of direct use of geothermal energy is based on the relatively constant ground or groundwater temperature in the range of 4°C to 30°C readily available almost anywhere, to provide space heating, cooling and domestic hot water for all types of buildings. Extracting energy cools the ground, which creates temperature gradients, enhancing recharge thus, heating and cooling loads need to be balanced or mitigated.

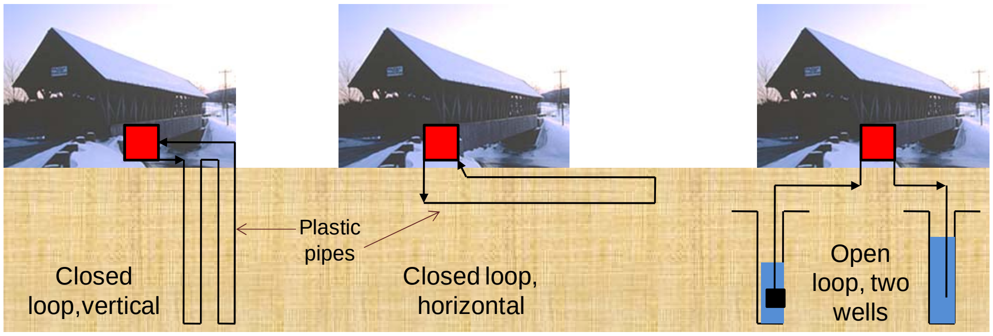

Figure 4.4 Closed loop and open loop heat pump systems. The heat pump that includes a compressor and heat exchangers is shown in red (Adapted from Lund et al., 2003).

There are two main types of geothermal heat pumps (Figure 4.4). In ground-coupled systems a closed loop of plastic pipe is placed in the ground, either horizontally at 1-2 m depth or vertically in a borehole down to 50-250 m depth. A water-antifreeze solution is circulated through the pipe. Thus heat is collected from the ground in the winter and optionally heat is rejected to the ground in the summer. An open loop system uses groundwater or lake water directly as a heat source in a heat exchanger and then discharges it into another well or into the same water-reservoir.

In essence heat pumps are nothing more than refrigeration units with the heat rejected in the condenser used for heating or heat extracted in the evaporator used for cooling. Their efficiency is described by a coefficient of performance (COP) which is the heating or cooling output divided by the electrical energy input. Typically this value lies between 3 and 4 (Lund et al., 2003; Rybach, 2005).

4.4 Global and regional status of market and industry development

Electricity has been generated commercially by geothermal steam since 1904. Presently the geothermal industry has a wide range of participants, including major energy companies, private and public utilities, equipment manufacturers and suppliers, field developers and drilling companies. Current industrial participants can be found by searching the IGA, IEA-GIA, GEA, GRC, and other national websites featuring energy attributes. [TSU: Full names missing.]

4.4.1 Status of geothermal electricity from conventional geothermal resources

In 2009, electricity was being produced from conventional geothermal resources in 24 countries with an installed capacity of 10.7 GWe (Fig. 4.5). The worldwide use of geothermal energy for power generation (predominantly from conventional hydrothermal resources) was 67.2 TWh/y in 2008 with a worldwide CF of 71% (Bertani, 2010). Many developing countries are amongst the top 15 in geothermal electricity production.

Conventional geothermal resources currently used to produce electricity are of high-temperature (>180°C), typically utilised through steam turbines (condensing or back-pressure, flash or dry-steam), and of low-intermediate temperature (<180°C) commonly utilised using binary-cycle power plants.

Currently the world's top geothermal producer is the US with almost 29% of the global installed capacity (3094 MWe, Fig. 4.5). The US geothermal resurgence is due to increased RE penetration in the US power generation market. State Renewable Portfolio Standards (RPS) demand and the Federal Production Tax Credit (PTC), increased natural gas price fluctuation, and a rapid acceleration of pushback against the permitting of new coal-fired power plants have all opened a clear market opportunity for geothermal growth. US geothermal activity is concentrated in a few western states, but only a fraction of the geothermal potential has been developed so far.

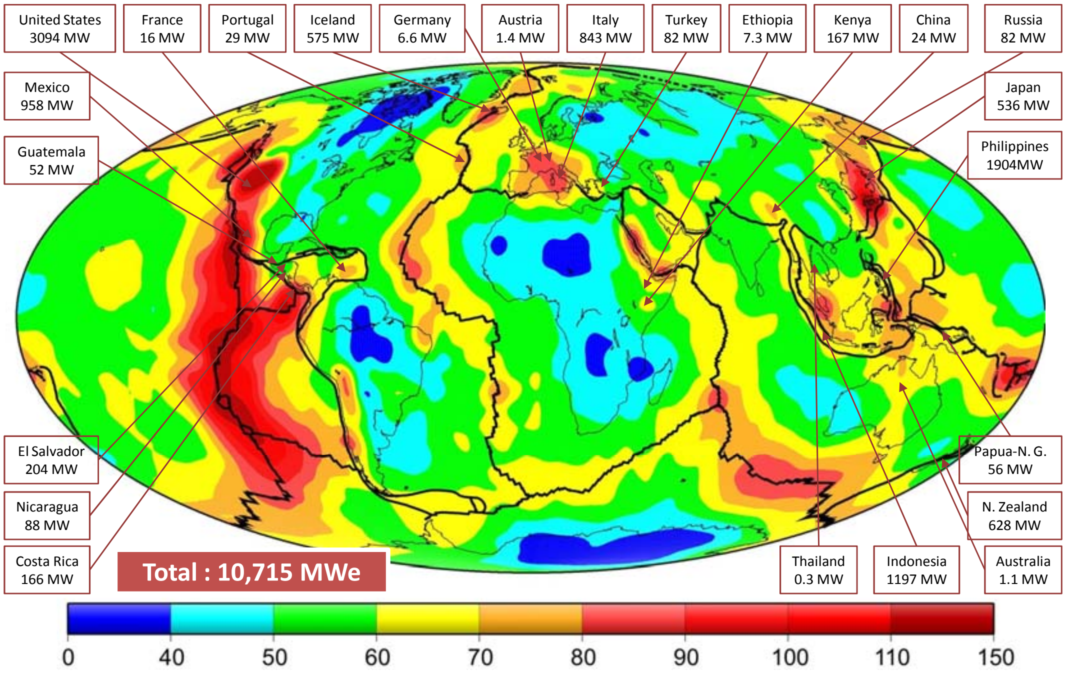

Figure 4.5 Geothermal-electric installed capacity by country in 2009. Figure shows worldwide average heat flow in mW/m2 and tectonic plates boundaries (Figure from Hamza et al., 2008; data from Bertani, 2010).

Outside of the US, about 29% of the global installed geothermal capacity resides in the Philippines and Indonesia, and then the markets of Mexico, Italy, Japan, Iceland, and New Zealand account for one third of the global installed geothermal capacity (Fig. 4.5). Although some of these markets have seen relatively limited growth over the past few years, in others, greater urgency to advance low-carbon base-load power generation is helping re-start new capacity growth (for example, installed capacity in New Zealand and Iceland has doubled in the past five years, IEA-GIA, 2009). Moreover, attention is turning to new markets like Chile, Germany, and Australia, and other more established markets as in East Africa, Turkey, Nicaragua and Russia.

The majority of existing geothermal assets are operated by state-owned utilities and Independent Power Producers (IPP). Currently, more than 30 companies globally have an ownership stake in at least one geothermal deployed project. Altogether the top 20 owners of geothermal capacity control approximately 90% of the entire installed global market.

At the end of 2009, the geothermal-electric capacity (10.7 GWe) represented only 0.21% of the total worldwide electric capacity, which was about 5,000 GWe. However, taken separately, six of those 24 countries shown in Figure 4.6 (El Salvador, Kenya, Philippines, Iceland, Costa Rica and New Zealand) obtain more than 10% of their national electricity production from high temperature, conventional geothermal resources (Bromley et al., 2010).

Worldwide evolution of geothermal power and geothermal direct uses during the last 40 years are presented in Table 4.5, including the annual average rate of growth over each period. The average annual growth of geothermal-electric installed capacity over the last 40 years is 7.2% [TSU to authors: Value inconsistent with value in table 4.5. Please clarify.], and for geothermal direct uses (heat applications) is 11% in the last 35 years.

Table 4.5 Average annual growth rate in geothermal power capacity and direct uses in the last 40 years. (Prepared with data from Bertani, 2010; Lund et al., 2005, 2010; Gawell and Greenberg, 2007; Fridleifsson and Ragnarsson, 2007.)

Year	Electric capacity		Direct uses capacity	
	MWe	%	MWt	%
1970	720	—	N.A.	—
1975	1,180	13.1	1,300	—
1980	2,110	15.6	1,950	10.7
1985	4,764	22.6	7,072	38.0
1990	5,834	5.2	8,064	3.3
1995	6,833	4.0	8,664	1.8
2000	7,972	3.9	15,200	14.4
2005	8,933	2.9	27,825	16.3
2010	10,715	4.7	50,583	16.1
Total annual average:		7.0		11.0

%: Average annual growth in percent over the period.

N.A.: Reliable data not available.

4.4.2 Status of Enhanced Geothermal Systems

EGS demonstration is active in Europe, the US and Australia. Since 2005 Australia has seen rapid acceleration in activity. By 2010, 18 stock market-registered enterprises held Australian geothermal licences. Cumulative investment amounted to US$ 248 M (to end of 2008) and was underpinned by government grants of US$ 267 M (to end of 2009) (Goldstein et al., 2010). In France the EU project “EGS Pilot Plant” at Soultz-sous-Forêts, started in 1987 and has recently commissioned the first power plant (1.5 MWe) to utilise the enhanced fracture permeability at 200°C. In Landau, Germany, the first EGS-plant, with 2.5 to 2.9 MWe, went into operation in late 2007 (Baumgärtner *et al.*, 2007). Deep sedimentary aquifers are tapped at the geothermal test site in Groß Schönebeck using two research wells (Huenges *et al.*, 2009).

The US in its recent clean energy initiatives has included large EGS research, development, and demonstration components as part of a revived national geothermal program. One of the main goals for EGS in the short term is to upscale to several tens of MWe.

The availability of financing, water, transmission and distribution infrastructure and other factors will play major roles in regional growth trends of EGS projects. In the US, Australia, and Europe, EGS concepts are being field tested and deployed, providing advantages for accelerated deployment in those regions as risks and uncertainties are reduced. In other rapidly developing regions in Asia, Africa, and South America, factors that would affect deployment are population density, distance to market, electricity and heating and cooling demand.

4.4.3 Status of direct uses of geothermal resources

Direct heat supply temperatures are typically close to actual process temperatures in district heating systems which range from approximately 60 to 120°C. As a result, only a small degradation of the thermodynamic quality of the geothermal heat occurs. The main types (and relative percentages) of direct applications in annual energy use are: space heating of buildings (63%, of which three quarters are from heat pumps), bathing and balneology (25%), horticulture (greenhouses and soil heating) (5%), industrial process heat and agricultural drying (3%), aquaculture (fish farming) (3%) and snow melting (1%) (Lund et al., 2010).

Heating of building spaces, including district heating schemes, is among the most important direct applications. When the resource temperature is too low for direct use, it is possible to use a geothermal heat pump (GHP). Also space cooling can be provided by geothermal resources, and GHP devices can heat and cool with the same equipment.

Bathing, swimming and balneology utilizing geothermal water have a long history and are globally wide-spread. In addition to the thermal energy the chemicals dissolved in the geothermal fluid are also important for treating various skin and health diseases.

Geothermally heated greenhouses allow cultivation of flowers and vegetables in colder climates where commercial greenhouses would not normally be economical. Heating soil in outdoor agricultural fields has also been applied at several places such as Iceland and Greece.

A variety of industrial processes utilise heat applications, including drying of forest products, food, and minerals industries as in the United States, Iceland and New Zealand. Other applications are process heating, evaporation, distillation, sterilisation, washing, CO_2 and salt extraction.

Aquaculture using geothermal heat allows better control of pond temperatures, which is of great importance for optimal growth. Tilapia, salmon and trout are the most common fish raised, but unusual species such a tropical fish, lobsters, shrimp or prawns, and alligators are also reported.

Snow melting or de-icing by using low temperature geothermal water is applied in some colder climate countries. City streets, sidewalks, and parking lots are equipped with buried piping systems carrying hot geothermal water. In some cases, this is return water from geothermal district heating systems as in Iceland, Japan and the United States.

The world installed capacity of geothermal direct use is currently estimated to be 50.6 GWt (Table 4.5), with a total thermal energy usage of about 121.7 TWh_t/y (0.438 EJ/y), distributed in 78 countries, with an annual average capacity factor of 27.8%. Geothermal heat pumps (GHP) contributed with 70% (35.2 GWt) of the worldwide installed capacity (Lund et al., 2010).

4.4.4 Impact of policies

To bring geothermal to its full capacity in climate change mitigation it is necessary to address the following main barriers, described according to the taxonomy of barriers used in this report.

I1 (Clarity in concepts [knowledge, understanding]). Lack of clarity in understanding geothermal is often a barrier. Improvements could include programmes to standardise on reliable and efficient geothermal technologies, to enhance public knowledge, to encourage more informed acceptance of geothermal energy use, and to conduct further research towards the avoidance or mitigation of induced hazards and adverse effects.

I2 (RE know-how systems). Efficient deployment of geothermal technologies relies on the availability of skilled installation and service companies with well-trained personnel. For deep geothermal drilling and reservoir management, such services are currently concentrated in a few countries. For GHP installation and district heating, there is also a correlation between local availability and awareness of service companies, and technology uptake. To increase development rates, this constraint could be overcome by improved global infrastructure of services.

T3 (Transport and accessibility). Distributions of potential geothermal resources vary from being almost site-independent (for GHP technologies and EGS) to being much more site-specific (for hydrothermal sources). The distance between electricity markets or centres of heat demand and geothermal resources, as well as the availability of transmission capacity, can be a significant factor in the economics of power generation and direct use.

E2 (Cost structure and accounting) & E3 (Project appraisal and financing). Reducing costs and increasing the efficiency of supplying geothermal energy will enhance its market competitiveness. Policies set to drive uptake of geothermal energy work better if local demand and risk factors are taken into account. For example, large numbers of small domestic heat customers can be satisfied using GHP technologies, requiring relatively small budgets. For other countries, district heating systems and industrial heat applications are more efficient and provide greater mitigation of CO_2 emissions, but these markets typically require larger scale investments and a different policy framework.

P3 (Energy subsidy, taxing, other support policies). Policies that support improved applied research and development would benefit all geothermal technologies, but especially emerging technologies such as EGS. Public investment in higher-risk geothermal research and exploration drilling is likely to lead to a significant acceleration in follow-up commercial deployment. Specific incentives for geothermal development can include subsidies, guarantees, and tax write-offs to cover the risks of initial deep drilling. Policies to attract energy-intensive industries to known geothermal resource areas can also be useful. Feed-in tariffs with confirmed geothermal prices have been very successful in attracting commercial investment in some countries (e.g. Germany). Direct subsidies for new building heating, refurbishment of existing buildings with GHP, and for district heating systems, may be more applicable in other settings.

P4 (Regulations and rules impeding RE). Experience has shown that the relative success of geothermal development in particular countries is closely linked to their government's policies, regulations, incentives and initiatives. Successful policies have taken into account the benefits of geothermal energy, such as its independence from weather conditions and its suitability for base-load power. Another important policy consideration is the opportunity to subsidize the price of geothermal kWh (both power and direct heating and cooling) through the mechanism of direct or indirect CO_2 emission taxes. A funding mechanism that subsidizes the commercial upfront exploration costs, including the higher-risk initial drilling costs, would also be useful. In this regard, a tax write-off provision for unsuccessful exploration drilling costs can, and has been, a useful incentive. Government legislation, regulations, policies and programs that target increased use of RE and lower greenhouse gas emissions will generally provide support to the increased use of geothermal resources.

4.5 Environmental and social impacts

One of the strongest arguments for using geothermal energy is its limited environmental impact. Sound practices protect natural thermal features that are valued by the community, and minimise any adverse effects from disposal of geothermal fluids and gases, induced seismicity and ground subsidence. Good practice can also optimize water and land use, while improving long-term sustainability of production. The following sub-sections address these issues in more detail.

4.5.1 CO_2 and other gas and liquid emissions while operating geothermal plants

Geothermal systems involve natural phenomena, and typically discharge gases mixed with steam from surface features, and minerals dissolved in water from hot springs. Apart from CO_2, geothermal fluids can, depending on the site, contain a variety of other gases, such as H_2S, H_2, CH_4,

NH_3 and N_2. Mercury, arsenic, radon and boron may be present. The amounts depend on the geological, hydrological and thermodynamic conditions of the geothermal field[1].

In high temperature hydrothermal fields, measured direct CO_2 emission from the operation of conventional power or heating plants is widely variable, from 0 to 740 g/kWh$_e$, but averages about 120 g/kWh$_e$ (weighted average of 85% of the world power plant capacity, according to Bertani and Thain, 2002, and Bloomfield et al., 2003). The gases are often extracted from a steam turbine condenser or two-phase heat exchanger and released through a cooling tower. CO_2, on average, constitutes 90% of these non-condensable gases (Bertani and Thain, 2002).

Of the remaining gases, H_2S is toxic, but is rarely sufficiently concentrated to be harmful after venting to the atmosphere and dispersal. Removal of H_2S released from geothermal power plants is practiced in parts of the US and Italy. Elsewhere, H_2S monitoring is a standard practice to provide assurance that concentrations after venting and atmospheric dispersal are not harmful. CH_4 is also present in relatively small concentrations (typically a few percent of the CO_2 concentration).

In low-temperature applications (<100°C), direct CO_2 emission from geothermal fluid is about 0-1 g/kWh (electric) depending on the carbonate content of the water. If the extracted geothermal fluid is passed through a heat exchanger and then completely injected (such as in a closed-loop pumped system), then CO_2 emission is nil. Other gas emissions from low-temperature geothermal resources are normally much less than the emissions from the high-temperature fields.

In Enhanced Geothermal Systems power plants are likely to be designed as closed-loop circulation systems, with zero direct emissions. (If boiling occurs within the circulation loop, then some non-condensable gas extraction and emission is likely.)

The possibility of using CO_2 as a working fluid in geothermal reservoirs is also under investigation. The fact that the rock volume of active commercial sized geothermal reservoirs is of the order of a cubic kilometre per well would enable storage of a large volume of supercritical CO_2 underground. If this method is successfully developed, it could provide a means for enhancing the effect of geothermal energy deployment for lowering CO_2 emissions beyond just generating electricity with a carbon-free renewable resource.

In direct uses (heating) emissions of CO_2 from low-temperature geothermal fluids are usually negligible (Fridleifsson et al., 2008). In Reykjavik (Iceland), the CO_2 content of thermal groundwater used for district heating (0.05 mg/kWh$_t$) is lower than that of the cold groundwater. In China (Beijing, Tianjin and Xianyang) it is less than 1 g CO_2/kWh. In the Paris Basin (a sedimentary basin), the geothermal fluid is kept under pressure within a closed circuit (the geothermal ‘doublet’) and injected into the reservoir without any degassing taking place. Conventional geothermal district heating schemes (such as Klamath Falls, Oregon, US) commonly produce brines which are also injected into the reservoir and thus never release CO_2 into the environment. CO_2 is also used in greenhouses to improve plant growth and extracted for use in carbonated beverages –such in Iceland.

Most hazardous chemicals in geothermal fluids are concentrated in the water phase. If present, boron and arsenic are likely to be harmful to ecosystems if released at the surface, so geothermal brine is usually injected into the reservoir. This avoids contamination of surface waterways. In the past, surface disposal of separated water has occurred at a few fields, but today it happens only in exceptional circumstances such as equipment failure. If the discharge is significantly in excess of

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[1] Note that SO_2, unlike H_2S, is a common source of acid rain, but is not usually present in geothermal emissions.

natural hot spring discharges, and is not strongly diluted, then the net effects on ecology of rivers, lakes or marine environments can be adverse. Shallow groundwater aquifers of potable quality may also need to be protected from contamination by injected fluids or from soakage ponds by using cemented casings or impermeable liners. Monitoring is undertaken to investigate, and if necessary mitigate, such adverse effects (Bromley et al., 2006).

After separation and condensation, surplus steam condensate may be suitable for stock drinking water or irrigation purposes instead of injection. At Wairakei, New Zealand, the steam condensate has been approved by environmental regulating agencies for irrigation purposes, but each case will be chemically different and must be judged on its own merits.

4.5.2 Life-cycle assessment

Life-cycle assessment (LCA) analyses the whole life cycle of a product “from cradle to grave”. For geothermal power plants all gas emission impacts directly and indirectly related to the construction, operation and deconstruction of the plant are considered in LCA.

Kaltschmitt et al. (2006) calculated CO_2-equivalent emissions of between 59 and 79 g/kWh for closed loop binary power plants. Pehnt (2006) calculated a LCA CO_2-equivalent of 41 g/kWh. Nill (2004) analysed the learning curve effects on the life cycle and predicts a reduction in CO_2-equivalent from binary plants from 80 g/kWh to 47 g/kWh between 2002 and 2020. Frick et al. (2010) compare two binary plants of the same capacity (1.75 MWe) with resources at different depths and temperatures, and calculated a CO_2-equivalent between 23 and 66 g/kWh. Binary closed loop systems are expected to have a greater use in future. They also presented other LCA environmental indicators, which are compared to those of a central European reference mix in Table 4.6, where it is observed that the geothermal CO_2-equivalent is between 4 and 12% of this reference mix. At sites with above-average geological conditions, CO_2-equivalent emissions can be less than 1%. The breakdown of the reference mix is: 26% lignite coal, 26% nuclear power, 24% hard coal, 12% natural gas, 4% hydropower, 4% wind power, 1% crude oil, 3% other fuels (Frick et al., 2010).

Table 4.6 Environmental impact indicators for a reference electricity mix and for typical geothermal binary power plants (Prepared with data from Frick et al., 2010).

LCA indicator	Reference electricity mix	Binary geothermal plants (1.75 MWe)
Finite energy resources	8.9 MJ/kWh	0.4-1.0 MJ/kWh
CO_2-equivalent	566 g/kWh	23-66 g/kWh

Using life cycle assessments for geothermal direct uses, Kaltschmitt (2000) published figures of 4-16 tonnes CO_2-equivalent /TJ (14.3-57.6 g/kWh$_t$) for low-temperature district heating systems, and 50-56 tonnes CO_2-equivalent/TJ (180-202 g/kWh$_t$) for heat pumps.

The life cycle of intermediate- to low-temperature geothermal developments is dominated by large initial material and energy inputs during the construction of the wells, power plant and pipelines. To maximize net-energy output and minimize emissions these can be optimised during the construction period. For hybrid electricity/district heating applications, more direct use of the heat optimizes the environmental benefits.

In conclusion, the LCA assessments show that geothermal is similar to other RE (hydro and wind) in total life-cycle emissions, and it has significant environmental advantages relative to a reference electricity mix dominated by fossil fuel sources.

4.5.3 Potential hazards of induced seismicity and others

Local hazards arising from natural phenomena, such as micro-earthquakes, hydrothermal steam eruptions and ground subsidence may be influenced by the operation of a geothermal field. Pressure or temperature changes induced by stimulation, production or injection of fluids can lead to geo-mechanical stress changes and these can then affect the subsequent rate of occurrence of these natural phenomena. A geological risk assessment can help avoid or mitigate these hazards.

With respect to induced seismicity, felt ground vibrations or noise have been an environmental and social issue associated with some EGS demonstration projects, particularly in populated areas (e.g. Soultz in France, Basel in Switzerland [subsequently suspended] and Landau in Germany). Such events have not lead to human injury or major property damage, but routine seismic monitoring is used as a diagnostic tool and management and protocols have been prepared to measure, monitor, and manage systems pro-actively as well as to inform the public of any hazards (Majer et al., 2008). Collaborative research initiated by the IEA-GIA (Bromley and Mongillo, 2008), and in Europe (GEISER, 2010), the US and Australia, is aimed at better understanding and mitigating induced seismicity hazards, and providing risk-management protocols.

During 100 years of development, although turbines have been tripped off-line, no buildings or structures within a geothermal operation or local community have been significantly damaged (more than superficial cracks) by shallow earthquakes originating from either geothermal production or injection activities. The process of high pressure injection of cold water into hot rock, which is the preferred EGS method of stimulating fractures to enhance fluid circulation, generates local stress changes which usually trigger small seismic events through hydro-fracturing or thermal stress redistribution. Proper management of this issue will be an important step to facilitating significant expansion of future EGS projects.

Hydrothermal steam eruptions have, in the past, been triggered at a few locations by shallow geothermal pressure changes (both increases and decreases). Such eruptions are generally caused by rapid boiling in a near-surface water body generating expansion forces that lift rock out of an expanding crater. These risks can be mitigated by prudent field design and operation.

Land subsidence has been an issue at a few high temperature geothermal fields, particularly in New Zealand. Pressure decline can affect some poorly consolidated formations (e.g. high porosity mudstones or clay deposits) causing them to compact anomalously and form local subsidence ‘bowls’. Management by targeted injection to maintain pressures at crucial depths and locations has succeeded in minimizing subsidence effects in the Imperial Valley (US) where maintaining levels to allow for irrigation drainage is important.

4.5.4 Benefits and impacts – economic, environmental, social

A potential economic benefit for geothermal power projects is the possibility to access the United Nations’ Clean Development Mechanism (CDM). The CDM provides a clear, market-driven valuation for the very low GHG emissions of geothermal power plants, and the revenue from certified emission reductions (CER) –carbon credits generated by CDM projects– can be used to reduce the price that would otherwise be charged to consumers of the electricity. The CERs, where each credit represents a reduction of one tonne of CO_2 or equivalent, are calculated by comparing the CO_2 emissions factor for the electricity generator, in tonnes per MWh, with that of the grid to which the electricity will be supplied. A recent, actual example of that is the Darajat III geothermal project, which was developed by a private company in Indonesia under prevailing international market conditions. This project started to operate in 2007 with 110 MWe and was registered by the CDM. The Darajat III plant is currently producing about 650,000 CERs per year. After factoring in the uncertainties of the CER market and the risks of continued CER revenue in the post-Kyoto (post-2012) period, the CDM reduces the life-cycle cost of geothermal energy by about 2 to 4% (Newell and Mingst, 2009).

A good example of the environmental benefits of geothermal direct use is the city of Reykjavik, Iceland, which has eliminated heating with fossil fuels, significantly reducing air pollution, and avoided about 100 Mt of cumulative CO_2 emissions (i.e., around 2 Mt annually) (Fridleifsson et al., 2008). Other examples are at Galanta in Slovakia (Fridleifsson et al., 2008), Pannonian Basin in Hungary (Arpasi, 2005), and Paris Basin in France (Laplaige et al., 2005).

The successful realization of geothermal development projects often depends on the level of acceptance by the local people. Prevention or minimization of detrimental impacts on the environment, and on land occupiers, as well as the creation of benefits for local communities, is indispensable to obtain social acceptance. Local people are often aware of the risks and benefits of geothermal projects and of their rights to protect their environment by participating in the management of resources in their territory. The necessary prerequisites to secure agreement of local people are: i) Prevention of adverse effects on people's health, ii) Minimization of environmental impacts, iii) Creation of direct and ongoing benefits for the resident communities.

Geothermal development often creates job opportunities for locals. This can be helpful for poverty alleviation in developing countries. Geothermal developments, particularly in Asian, Central and South American, and African developing nations, are often located in remote mountainous areas. Because drilling and plant construction must be done at the site of a geothermal resource, use of a local workforce can lead to better employment opportunities. Some geothermal companies and government agencies have approached social issues by improving local security, building roads, schools, medical facilities and other community assets, which may be funded by contributions from profits obtained from operating the power plant.

Multiple land-use arrangements that promote employment by integrating subsurface geothermal energy extraction with labour-intensive agricultural activities are also useful. In many developing countries, geothermal is also an appropriate energy source for small-scale distributed generation, helping accelerate development through access to energy in remote areas.

4.5.5 Land use

Environmental impact assessments for geothermal developments consider a range of land and water use impacts during both construction and operation phases that are common to most energy projects (e.g. noise, vibration, dust, visual impacts, surface and ground water impacts, ecosystems, biodiversity) as well as specific geothermal impacts (e.g. effects on outstanding natural features such as springs, geysers and fumaroles).

Land use issues in many settings (e.g. Japan, the US and New Zealand) can be a serious impediment to further expansion of geothermal development. National Parks, for example, have often been established in remote volcanic tourist areas where new geothermal prospects also exist. Despite good examples of unobtrusive, scenically-landscaped developments (e.g. Matsukawa, Japan), and integrated tourism/energy developments (e.g. Wairakei, New Zealand and Blue Lagoon, Iceland), land use issues still seriously constrain new development options in some countries. Potential pressure and temperature interference between adjacent geothermal developers or users can be another issue that affects all types of heat and fluid extraction, including heat pumps and EGS power projects. Regional planning takes this into account, through appropriate simulation models, when allocating permits for energy extraction.

Another measure of optimum land use that is relevant in some settings is the 'footprint' occupied by geothermal installations. Table 4.7 presents the typical footprint for common conventional geothermal power plants, taking into account surface installations (drilling pads, roads, pipelines, fluid separators and power-stations). The subsurface resource that is accessed by directional or vertical geothermal boreholes typically occupies an area equivalent to about 10 MWe/km^2.

Therefore, about 95% of the land above a typical geothermal resource is not needed for surface installations, and can be used for other purposes (e.g., farming, horticulture and forestry at Mokai and Rotokawa in New Zealand, and a game reserve at Olkaria, Kenya).

Table 4.7 Land requirements for typical geothermal power generation options.

Type of power plant	Land Use	
	m^2/MWe	m^2/GWh/year
110-MWe geothermal flash plants (excluding wells)	1260	160
56-MWe geothermal flash plant (including wells, pipes, etc.)	7460	900
49-MWe geothermal FC-RC plant (excluding wells)	2290	290
20-MWe geothermal binary plant (excluding wells)	1415	170

FC: Flash cycle, RC: Rankine cycle (Data from Tester et al., 2006).

4.6 Prospects for technology improvement, innovation, and integration

4.6.1 Technological and process challenges

Successful development and deployment of improved geothermal technologies will mean significantly higher energy recovery, longer field lifetimes and much more widespread availability of geothermal energy. Achieving that success will require sustained support and investment into technology development from governments and the private sector for the next 10 to 20 years.

With time, better technical solutions are expected to improve power plant performance and reduce maintenance down-time. More advanced approaches for resource development, including advanced geophysical surveys, reinjection optimization, scaling/corrosion inhibition, and better reservoir simulation modelling, will help reduce the resource risks by better matching installed capacity to sustainable generation capacity.

While conventional, high-temperature, naturally-permeable geothermal reservoirs are profitably deployed today for power production and direct uses, the success of the EGS-concept would lead to widespread utilization of lower grade resources. EGS requires innovative methods for exploring, stimulating and exploiting geothermal resources at any commercially viable site. Development of these methods will likely improve conventional geothermal technologies. The challenges facing EGS developers encompass several tracks (Tester et al., 2006):

1. Development of exploration technologies and strategies to reliably locate prospective EGS.
2. Improvement and innovation in well drilling, casing, completion and production technologies for the exploration, appraisal and development of deep geothermal reservoirs (as generalised in Table 4.4).
3. Improvement of methods to hydraulically stimulate reservoir connectivity between injection and production wells to attain sustained, commercial production rates.
4. Development/adaptation of data management systems for interdisciplinary exploration, development and production of geothermal reservoirs, and associated teaching tools to foster competence and capacity amongst the people who will work in the geothermal sector.
5. Improvement of numerical simulators for production history matching and predicting coupled thermal-hydraulic-mechanical-chemical processes during developing and exploitation of reservoirs.
6. Improvement in assessment methods to enable reliable predictions of chemical interaction between geo-fluids and geothermal reservoirs rocks, geothermal plant and geothermal equipment, enabling optimised, well-, plant- and field-lifetimes.

7. Performance improvement of thermodynamic conversion cycles for a more efficient utilisation of the thermal heat sources in district heating and power generation applications.

The required technology development would clearly reflect assessment of environmental impacts including land use and induced micro-seismicity hazards or subsidence risks (see section 4.5).

4.6.2 Improvements in exploration technologies

In exploration, R&D is required for hidden geothermal systems and EGS prospects. Rapid reconnaissance geothermal tools will be essential to identify new prospects, especially those with no surface manifestations such as hot springs and fumaroles. Satellite-based hyper-spectral, thermal infra-red, high-resolution panchromatic and radar sensors are most valuable at this stage, since they can provide data inexpensively over large areas.

Once a regional focus area has been selected, success will depend upon the availability of cost-effective reconnaissance survey tools to detect as many geothermal indicators as possible. Airborne-based hyper-spectral, thermal infra-red, magnetic and electromagnetic sensors are valuable at this stage, providing rapid coverage of the geological environment being explored, at an appropriate resolution. Ground-based verification, soil sampling and geophysical surveys (magneto-telluric, resistivity, gravity, seismic and/or heat flow measurements) should follow.

4.6.3 Accessing and engineering the reservoirs

Special research is needed in large diameter drilling through plastic, creeping or swelling formations such as salt or shale. Abnormally high fluid pressure in such formations causes abnormal stresses that differ considerably from those found in hydrostatic pressure gradients. To provide long-life completion systems in ductile formations, new cementing technologies regarding the geo-mechanical behaviour of plastic rock need to be defined, especially for deviated wells.

Drilling must minimise formation damage that occurs as a result of a complex interaction of the drilling fluid (chemical, filtrate and particulate) with the reservoir fluid and formation. The objectives of new-generation geothermal drilling and well construction technologies are to reduce the cost and increase the useful life of geothermal production facilities through an integrated effort (see Table 4.4).

The international Iceland Deep Drilling Project (IDDP) is a long-term program to improve the efficiency and economics of geothermal energy by harnessing deep unconventional geothermal resources (Fridleifsson *et al.*, 2010). Its aim is to produce electricity from natural supercritical hydrous fluids from drillable depths. Producing supercritical fluids will require drilling wells and sampling fluids and rocks to depths of 3.5 to 5 km, and at temperatures of 450-600°C.

All tasks related to the engineering of the reservoir require sophisticated modelling of the reservoir processes and interactions to be able to predict reservoir behaviour with time, to recommend management strategies for prolonged field operation, and to minimize potential environmental impacts.

In the case of EGS, reservoir stimulation procedures need to be refined to significantly enhance the hydraulic productivity, while reducing the risk of seismic hazard. Imaging fluid pathways induced by hydraulic stimulation treatments through innovative technology would facilitate this. New visualisation and measurement methodologies (imaging of borehole, permeability tomography, tracer technology, coiled tubing technology) should become available for the characterisation of the reservoir.

4.6.4 Efficient production of geothermal power, heat and/or cooling

Technical equipment needed to provide heating/cooling and/or electricity from geothermal wells is already available on the market. However, the efficiency of the different system components can still be improved, especially for low-enthalpy power plant cycles, cooling systems, heat exchangers and production pumps for the brine.

Thermodynamic cycles can be improved, and thermal heat sources utilised more efficiently, both in district heating and in conversion to electrical power. For power generation, a modular low-temperature cycle could be set up allowing for conventional and new working fluids to be examined.

New and cost-efficient materials are required for pipes, casing liners, pumps, heat exchangers and for other components to be used in geothermal cycles to reach higher efficiencies and develop cascade uses.

The potential development of valuable by-products may improve the economics of geothermal development, such as recovery of the condensate for industrial applications after an appropriate treatment, and in some cases recovery of valuable minerals from geothermal brines (such as lithium, zinc, high grade silica, and in some cases gold).

4.7 Cost trends

Geothermal projects have typically high up-front capital costs (mainly due to the cost of drilling wells and constructing surface power plants) and low operational costs. These operational costs vary from one project to another due to size and quality of the geothermal fluids, but are relatively predictable in comparison with power plants of traditional energy sources which are usually subject to market fluctuations in fuel price. This section describes the capital costs of geothermal-electric projects, the levelised cost of geothermal electricity and the historic and probable future trends, and also presents costs for direct uses of geothermal energy. It should be noted that that the following costs may have wide variations (up to 20-25%) between countries (e.g. between Indonesia, US and Japan).

4.7.1 Costs of geothermal-electric projects and factors that affect it

One of the main factors affecting the cost of a geothermal-electric project is the type of project: field expansion projects may cost 10-15% less than a new (greenfield) project, since investments have already been made in infrastructure and exploration and valuable resource information is available (learning effect) (Stefansson, 2002; Hance, 2005).

The cost structure of a geothermal-electric project is composed of the following components: a) exploration and resource confirmation, b) drilling of production and injection wells, c) surface facilities and infrastructure, and d) power plant.

The first component (a) includes lease acquisition, permitting, prospecting (geology and geophysics) and drilling of exploration and test wells. Drilling of this type of wells has a success rate typically about 50-60% (Hance, 2005), even though some sources reduce the percentage success to 20-25% (GTP, 2008). Confirmation costs are affected by: well parameters (depth and diameter), rock properties, well productivity, rig availability, time delays in permitting or leasing land, and interest rates. This first component represents between 10 and 15% of the total capital cost (capex) (Bromley et al., 2010) but for expansion projects may be as low as 1-3%.

Drilling of production and injection wells (component b) has a success rate of 60 to 90% (Hance, 2005; GTP, 2008). Factors influencing the cost include: well productivity (permeability and temperature), well depths, rig availability, vertical or directional design, the use of air or special circulation fluids, the use of special drilling bits, number of wells and financial conditions in a drilling contract (Hance, 2005; Tester et al., 2006). This component (b) represents 20-35% of the total capex (Bromley et al., 2010).

Surface facilities and infrastructure (component c) includes gathering steam and process brine, separators, pumps, pipelines and roads. Vapour-dominated fields have lower facilities costs since brine handling is not required. Factors affecting this component are: reservoir fluid chemistry, commodity prices (steel, cement), topography, accessibility, slope stability, average well productivity and distribution (pipeline diameter and length), and fluid parameters (pressure, temperature, chemistry) (Hance, 2005). Surface facilities and infrastructure represent 10-20% of the capex (Bromley et al., 2010).

The power plant (component d) includes turbines, generator, condenser, electric substation, grid hook-up, steam scrubbers, and pollution abatement systems. Power plant design and construction costs depend upon type (flash, back-pressure, binary, dry steam, or hybrid), as well as the type of cooling cycle used (water or air cooling). Other factors affecting power plant costs are: fluid enthalpy (resource temperature) and chemistry, location, cooling water availability, and the economies of scale (larger size is cheaper). This component varies between 40 and 81% of the capex (Hance, 2005; Bromley et al., 2010).

In the Table 4.8 are referred capital costs for typical geothermal-electric projects.

Table 4.8 Historic and current capital costs for typical turnkey (installed) geothermal-electric projects (2005 US$).

Type of project and plant	Capacity (MWe)	Year	Total Capex (2005 US$/kW)	References
Condensing flash plants:				
1. Greenfield (New)	n.s.	1997	1743	EPRI, 1997 (a)
2. Greenfield (New)	n.s.	2000	1631	Kutscher, 2000 (a)
3. Greenfield (New)	n.s.	2002	1143-2114	Stefansson, 2002 (a)
4. Greenfield (New)	n.s.	2003	1579-2053	Several included in (a)
5. Greenfield (New)	25-50	2004	2315-2666	California Energy Commission, 2004 (a)
6. Greenfield (New)	100	2006	~2200	Hjartarson & Einarsson, 2010
7. Greenfield (New)	50	2008	3244	Taylor, 2009 (b)
8. Greenfield (New) (worldwide average)	n.s.	2008	1778-3556	Bromley et al., 2010.
9. Expansion project	25	2009	2486	CFE internal data.
Binary cycle plants:				
10. Greenfield (New)	n.s.	1997	2548	EPRI, 1997 (a)
11. Greenfield (New)	n.s.	2000	2362	Kutscher, 2000 (a)
12. Greenfield (New)	n.s.	2002	2274	Owens, 2002 (a)
13. Greenfield (New)	n.s.	2003	1829-2906	Several included in (a)
14. Greenfield (New)	10-30	2004	3076-3383	California Energy Commission, 2004 (a)
15. Greenfield (New)	20	2008	3556	GTP, 2008
16. Greenfield (New) (worldwide average)	n.s.	2008	2133-5244	Bromley et al., 2010.

n.s.: Not specified. (a) References cited in: Hance, 2005. (b) Reference cited in: Cross and Freeman, 2009.

Labour and material costs are estimated to account for 40% each of total project construction costs. Labour costs can increase by 10% when a resource is remotely located. In addition to raw materials and labour, choice of power plant size is a key factor in determining the ultimate cost of a plant, but the optimum size of single units on a per-MW basis varies (Dickson and Fanelli, 2003; Entingh and Mines, 2006).

4.7.2 Levelised cost of geothermal electricity

The levelised cost of geothermal power corresponds to the sum of two major components: levelised cost of capital investment (LCCI) and operation and maintenance costs (O&M). The LCCI corresponds to the cost of the initial capital investment (i.e. site exploration and development & power plant construction) and its related financial costs, divided by the total output of the facility throughout the entire payback period (typically 25-30 years). Note, however, that payback period allows for refurbishment or replacement of aging surface plant, but is not equivalent to economic resource lifetime, which is typically more than 50 years, e.g. Larderello, Wairakei, The Geysers. In most cases, the LCCI represents a major part (about 65-80%) of the levelised cost of energy (LCOE) of geothermal projects.

Operating and maintenance (O&M) costs consist of fixed and variable costs directly related to the electricity production phase. O&M per annum costs include field operation (labour and equipment), well operation and work-over and facility maintenance. For geothermal plants, an additional factor is the cost of make-up wells, i.e. new wells to replace failed wells and restore lost production or injection capacity. Make-up wells can be considered equivalent to O&M costs since the purpose of make-up drilling is to maintain the full production capacity of the power plants (Hance, 2005). Costs of these wells are typically lower than those for the original wells, and their success rate is higher. Make-up drilling typically increases with time, but if distributed across the economic lifetime of a development, its cost, on average, amounts to an increase of about 30% in O&M costs per MWh.

Geothermal-electric O&M costs, including make-up wells, have been calculated for the US to be between 18.5 and 22.6 US$/MWh (Lovekin, 2000; Owen, 2002), and Hance (2005) proposed an average cost of 24.6 US$/MWh. Current O&M costs are ranged between 152 and 187 US$/kW per year, and then with an annual capacity factor of 71% (current worldwide average) those costs vary between 24.4 and 30.0 US$/MWh, but with an annual capacity factor of 90% can be as low as 19.3 and 23.7 US$/MWh. In other countries, O&M costs can be significantly lower than these figures. For example, in New Zealand operating experience shows that total costs are 10-14 US$/MWh for 20-50 MWe plant capacity (Barnett and Quinlivan, 2009).

Current LCOE (i.e., including LCCI and O&M costs) in 2005 US$/MWh for some of the typical geothermal-electric plants listed in Table 4.8 were calculated according to the methodology described in Chapter 1 [TSU: Annex II], using version 6 of the calculator developed by Verbruggen and Nyboer (2009), and are presented in Figure 4.6. In all cases the project lifetime was calculated to be 25 years and the capacity factor (plant performance) was 80%, which is the expected for new projects. For greenfield projects it was estimated that the plant starts to operate at the beginning of the fifth year after exploration starts, and for expansion projects the plant is commissioned by the third year. “Average flash” is the current worldwide average for greenfield projects and flash plants, and correspond to the middle value of the Case 8 rank in Table 4.8 (2667 US$/kWe); it was considered a plant of 100 MWe. “Average binary” is the correspondent middle value for binary plants in Case 16 in Table 4.7 (capex 3689 US$/kWe), considering a plant of 10 MWe.

There are significant variations in LCOE depending on the discount rate used, yet in general terms the LCOE for flash plants in high temperature fields is lower than for binary cycle plants in low to intermediate temperature fields. LCOE for expansion projects is also lower than for new projects and the larger the project (in MWe) the lower LCOE.

There are no actual LCOE data for EGS, but some projections have been made using two different models for several cases with diverse temperatures and depths (Table 9.5 in Tester et al., 2006). The obtained LCOE values for the MIT EGS model range from 100-175 US$/MWh for relatively high-grade EGS resources (250-330°C, 5 km depth wells) assuming a base-case present-day productivity of 20 kg/s per well. Assuming, however, that 20 years of technology development results in a 4-fold improvement in productivity by 2030 to 80 kg/s per well, then LCOE values for the same geological settings decrease by 65% to a range of 36-52 US$/MWh, and some less attractive geological settings (180-220°C, 5-7 km depth wells) become more economically viable at about 59-92 US$/MWh. Another model for a hypothetical EGS project in Europe considers two wells at 4 km depth, 165°C reservoir temperature, 33 kg/s flow-rate and a binary power unit of 1.6 MWe running with an annual capacity factor of 85.6% (data taken from Huenges, 2010). By applying the calculator (Verbruggen and Nyboer, 2009) the LCOE values are 139, 181 and 217 US$/MWh for discount rates of 3%, 7% and 10%, respectively.

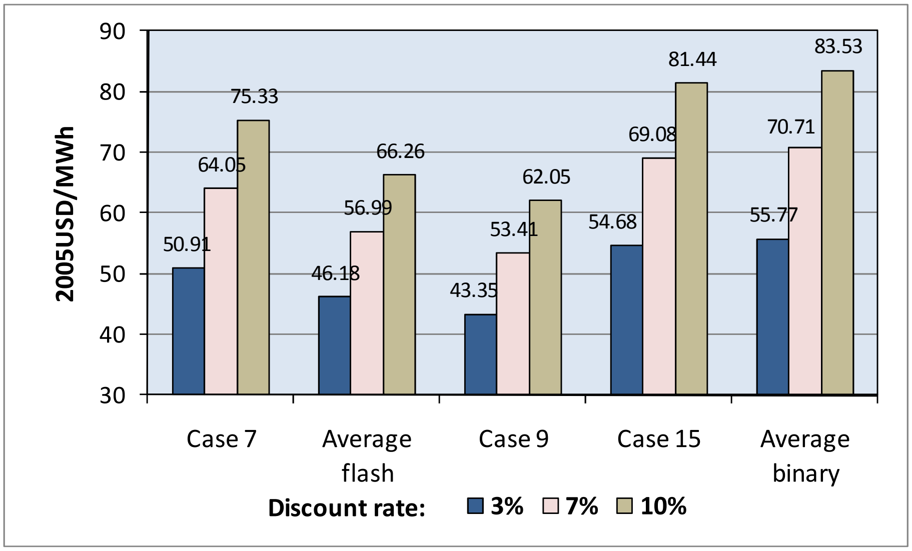

Figure 4.6. Current LCOE (LCCI plus O&M costs) in 2005 US$ per MWh for typical geothermal-electric plants using three different discount rates (3%, 7% and 10%). Cases 7, 9 & 15 are the same as in Table 4.8. “Average flash” is the Case 8 and “Average binary” the Case 16 in the Table 4.8.

4.7.3 Historical trends of geothermal electricity

From the 1980’s until about 2004, project development costs remained flat or even decreased (Kagel, 2006; Mansure and Blankenship, 2008). However, in 2006-2008 project costs sharply increased due to increases in the cost of commodities such as steel and cement, and drilling rig rates and engineering. This cost trend was not unique to geothermal and was mirrored across most other power sectors. Capex costs have since started to decrease due to the current economic downturn and reduced demand (Table 4.8).

On the other hand, the evolution of the worldwide average performance of geothermal-electric power plants is provided in Table 4.9 in the form of average capacity factor (CF) since 1995 and the projections to year 2100, calculated from installed capacity and average annual generation. The average capacity factor (CF) increased significantly between 1995 and 2000, and has since remained above 70%. The CF value incorporates a wide range of generation issues (unrelated to resource availability), including: grid connection failures (e.g. from storm damage), load following on smaller grids, and turbine failures. (Some operating geothermal turbines have exceeded their economic lifetime, so require longer periods of shut-down for maintenance or replacement.) Furthermore, a lack of make-up drilling to sustain long-term steam supply is sometimes due to financial constraints. Also, a substantial number of new power plants started during 2009, but their generation contributed for only part of the year.

Table 4.9 World installed capacity, electricity production and capacity factor of geothermal power plants 1995-2010 and forecasts for 2015-2050 (adapted from data from Bertani, 2010).

Year	Installed Capacity (GWe) actual or mean forecast	Electricity Production (GWh/y) Actual or mean forecast	Capacity Factor (%)
1995	6.8	38,035	64
2000	8.0	49,261	71
2005	8.9	56,786	73
2010	10.7	67,246	71
2015	18.5	121,600	75
2020	25.9	181,800	80
2030	51.0	380,000	85
2040	90.5	698,000	88
2050	160.6	1,266,400	90

Therefore, by projecting a further increase in CF, and assuming no such grid or load constraints for new developments, long-term CF of 80% to 95% can be expected (Fridleifsson et al., 2008). Several geothermal power plants are currently operating at CF of 90% and more.

4.7.4 Future costs trends

The future costs for geothermal electricity are likely to encompass a wide range because future deployment will probably include an increasing percentage of unconventional development types (such as EGS), which are currently in commercial demonstration mode and only limited cost data are presently available. However, considering the projected average capacity factor shown in Table 4.9 by 2020, 2030 and 2050, future LCOE for the cases before mentioned were calculated using the same calculator developed by Verbruggen and Nyboer (2009). The results are shown in Figure 4.7 using a discount rate of 7%, as used for all RE future cost trends in this report.

Some assumptions remained the same: the commissioning year for greenfield projects is the fifth year after exploration starts, while for expansion projects it is in the third year. However, the project lifetime was considered 27 years, considering improvements in materials, operation and maintenance and the fact that some actual plants currently in operation have achieved that lifetime. Figures for 2009 are those already presented in Figure 4.6. For 2020 it was assumed that the drilling cost (which represents between 20 and 45% of total capital costs) does not change but by 2030 this cost was estimated to be 7% lower and by 2050 15% lower than present costs, in all cases at 2005 US$. These decreasing costs are expected to occur due to better technologic practices in the drilling industry and to competition resulting from a greater availability of drilling rigs. Worldwide average capacity factor for 2020, 2030 and 2050 was assumed to be 80%, 85% and 90%, respectively, according to Table 4.9. All the remaining aspects and costs were considered, on balance, to be unchanging. Improvements in exploration, surface installations, materials and power plants are likely, and should lead to reduced costs, but these are expected to balance against increased commodity costs (especially steel and cement).

LCOE costs are therefore expected to decrease in an average of 1.7% by 2020, 8.5% by 2030 and 14.7% by 2050 (Fig. 4.7).

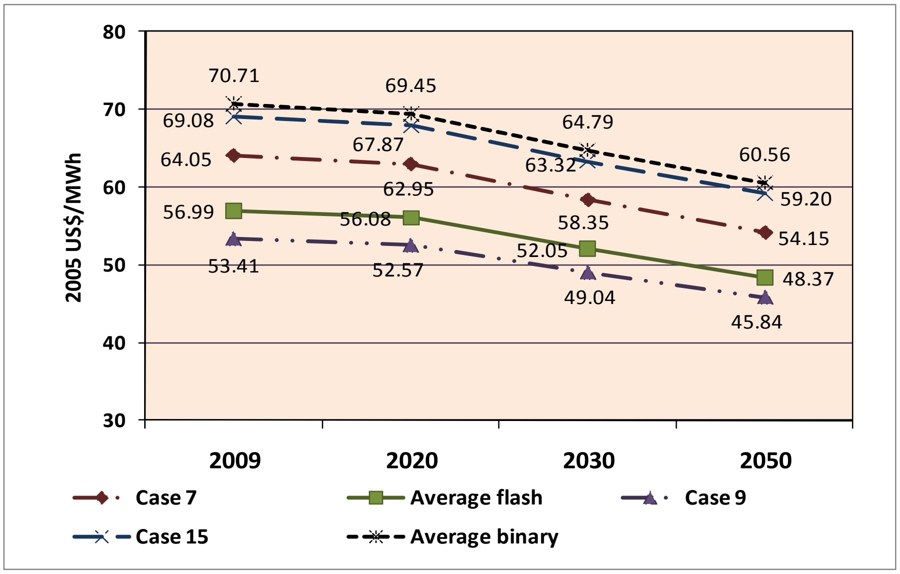

Figure 4.7 Present and projected LCOE in 2005 US$ for typical geothermal-electric plants at discount rate of 7%. Cases 7, 9 & 15 are the same as in Table 4.8. “Average flash” is the Case 8 and “Average binary” the Case 16 in the Table 4.8.

4.7.5. Economics of direct uses and geothermal heat pumps

Direct-use project costs have a wide range, depending upon the specific use, the temperature and flow rate required, the associate O&M and labor costs, and the income from the product produced. In addition, costs for new construction are usually less than cost for retrofitting older structures. The cost figures given in Table 4.10 are based on a temperature climate typical of the northern half of the United States or Europe, and obviously the heating loads would be higher for more northern climates such as Iceland, Scandinavia and Russia. Most figures are based on cost in the United States (expressed in 2005 US$), but would be similar in developed countries and lower in developing countries (Lund and Boyd, 2009).

Table 4.10 Capex and calculated LCOE for several geothermal direct applications (capex data taken from Lund, 1995; Balcer, 2000; Radeckas and Lukosevicius, 2000; Reif, 2008; Lund and Boyd, 2009).

Heat application	Capex (2005) US$/kW$_{th}$	LCOE in (2005) US$/kWh$_{th}$ at discount rate of		
		3%	7%	10%
Space heating (buildings)	1595-3940	0.115	0.144	0.168
Space heating (districts)	571-1566	0.063	0.079	0.093
Greenhouses	500-1000	0.033	0.043	0.050
Uncovered aquaculture ponds	50-100	0.036	0.037	0.038
GHP (residential)	938-1400	0.072	0.088	0.101
GHP (commercial)	938-3751	0.088	0.114	0.135

LCOE of the several direct uses included in Table 4.10 were calculated with the calculator by Verbruggen and Nyboer (2009). For building heating it was assumed a load factor of 0.30 and 20 years as the lifetime. For district heating was used the same load factor but 25 years of lifetime. District heating may be provided in the form of either steam or hot water and may be utilised to meet process, space or domestic hot water requirements. Often fossil fuel peaking is used to meet the coldest period, rather than drilling additional wells or pumping more fluids, as geothermal can usually meet all the load most of the time, thus improving the efficiency and economics of the system (Bloomquist et al., 1987). Thermal load density (heating load per unit of land areas) is critical to the feasibility of district heating because it is one of the major determinants of the distribution network capital and operating costs. Thus, downtown, high rise buildings are better candidates than single family residential area. Generally a thermal load density about 1.2 x 10^9 J/hr/ha is recommended.

For LCOE calculation of greenhouses it was assumed a load factor of 0.50 and for aquaculture ponds and tanks of 0.60, with the same lifespan of 20 years. Covered ponds and tanks would have higher capital cost than uncovered, but lower heating requirements.

Geothermal (ground-source) heat pump projects costs vary between residential installation and commercial/institutional installations, as the larger the building to be heated and/or cooled, the lower the unit (US$/kWt) investment and operating costs. In addition, the type of installation, closed loop (horizontal or vertical) or open loop using ground water, has a large influence on the installed cost (Lund and Boyd, 2009). The LCOE reported in Table 4.10 assumed 0.30 as load factor and 20 years as operational lifetime.

Industrial applications are more difficult to quantify, as they vary widely depending upon the energy requirements and the product to be produced. These plants normally require higher temperatures and often compete with power plant use; however, they do have a high load factor of 0.40 to 0.70, which improves the economics. Industrial applications vary from large food, timber and mineral drying plants (US and New Zealand) to pulp and paper plant (New Zealand). As an example, a large onion dehydration plant in the US (Nevada) uses 210 x 10^{12} J/year for drying 4500 kg/hour of wet onions over a 250 day period. This plant cost MUS$ 12.5 with the geothermal system, including wells adding MUS$ 3.37. The annual operation cost is MUS$ 5.63 and annual energy savings of MUS$ 1.5. With annual sales of MUS$ 5.63, a positive cash flow is realised in about two years (Lund, 1995).

4.8 Potential Deployment

Geothermal energy can contribute to near- and long-term carbon emissions reduction. In 2008 the worldwide geothermal-electric generation was 67.2 TWh_e (Sections 4.4.1 and 4.7.3) and the heat generation from geothermal direct-uses was 121.7 TWh_t (Section 4.4.3). These amounts of energy are equivalent to 0.24 and 0.44 EJ/y, respectively, for a total of 0.68 EJ/y (direct equivalent method). This represents only ~0.13% of the global primary energy demand in 2007. However, on a global basis, by 2050 geothermal could supply 2.5-4.1% of the global electricity demand and almost 5% of the global demand of heat-cooling, as it is shown in section 4.8.2.

This section starts by presenting the near-term (2015) global and regional deployments expected for geothermal energy (electricity and heat) based on current geothermal-electric projects under construction or planned, observed historic growth rates, as well as the forecast generation of electricity and heat. Subsequently, this section presents the long-term (2020, 2030, 2050) global and regional deployments comparing it to the IPCC AR4 estimate, includes results from scenarios provided by Chapter 10 of this report, and discusses their feasibility in terms of technical potential, regional conditions, supply chain aspects, technological-economic conditions, integration-transmission issues and environmental and social concerns. Finally, the section presents a short conclusion regarding the potential deployment.

4.8.1 Near-term forecasts

Historic growth rates of geothermal-electric capacity in the world over the past 40 years were presented in Table 4.5, as well as the growth rates of geothermal direct uses (heat) in the last 35 years. For power, the historic average annual rate is 7.0% and for direct uses 11%.

On the other hand, according to the latest country-update reports, the capacity of geothermal-electric projects stated as under construction or planned is expected to reach 18,500 MWe by 2015 (Bertani, 2010). This represents an annual average growth of 11.5%, higher than the historic rate, but is based on the present (BAU) conditions and expectations of geothermal markets.

For geothermal direct uses (heat applications) it is expected that the annual growth rate will be between the historic average rate (11%) and the rate over the last 5 years (2005-2010: 16.1%, Table 4.5). The average is 13.5% resulting in 95,300 MW_t by 2015. The expected deployments and generation by 2015 and by regions are presented in Table 4.11.

Table 4.11 Regional current and forecast installed capacity for geothermal power and direct uses (heat) and forecast generation of electricity and heat in the near-term.

REGION	Current capacity (2010)		Forecast capacity (2015)		Forecast generation (2015)	
	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)	Direct (TWh_t)	Electric (TWh_e)
1. OECD North America	13.893	4.052	30.7	6.5	80.8	43.1
2. Latin America	0.808	0.509	1.2	1.1	3.2	7.2
3. OECD Europe	20.357	1.551	36.6	2.1	96.2	13.9
4. Africa	0.13	0.174	2.5	0.6	6.5	3.8
5. Transition Economies	1.063	0.082	1.8	0.2	4.8	1.3
6. Middle East	2.362	0	3.1	0.0	8.2	0.0
7. Developing Asia	0.052	3.158	2.1	6.1	5.4	39.9
8. India	0.265	0	1.2	0.0	3.2	0.0
9. China	8.898	0.024	12.3	0.1	32.3	0.4
10. OECD Pacific	2.755	1.165	3.7	1.8	9.7	11.9
TOTAL	**50.583**	**10.715**	**95.3**	**18.5**	**250.4**	**121.6**

Notes: Current and forecast data for electricity taken from Bertani, 2010, and for direct uses from Lund et al., 2010. Average annual growth rate in 2010-2015 is 11.5% for power and 13.5% for direct uses.

For power, practically all the new power plants expected by 2015 will be conventional (flash and binary) in hydrothermal resources, with only a marginal contribution of EGS projects. In general terms, the worldwide trends in development of EGS are estimated to be slow in the next 5-10 years, and then present an accelerated growth.

On a regional basis, the deployment potential for harnessing identified and prospective conventional hydrothermal resources varies significantly. In Europe and Central Asia, there are a few countries that have well-developed high temperature resources (e.g. Italy and Turkey, see Figure 4.2). Many other European and Asian countries have huge under-developed hot water resources, of lower temperature, located within sedimentary basins at various depths (e.g. Paris, Pannonian, and Beijing basins). In the African continent, Kenya was the first country to utilise its rich hydrothermal resources for both electricity generation and direct use, and several other countries along the East African Rift Valley may follow suit.

The existing installed capacity in North America (US and Mexico) of 4 GWe, mostly from mature developments, is expected to increase by almost 60% in the short term, mainly in the US (from 3094 to 5400 MWe, according to Bertani, 2010). In the Central American countries the geothermal potential for electricity generation has been estimated to be 4 GWe (Lippmann, 2002) of which 12% has been harnessed so far (~0.5 GWe). South American countries, particularly along the Andes mountain chain, also have significant untapped --and under-explored-- hydrothermal resource potentials (at least 2 GWe).

For island nations with mature histories of geothermal development, such as New Zealand, Iceland, Philippines, and Japan, identified geothermal resources imply a future expansion potential of 2 to 5 times existing installed capacity, although constraints such as limited grid capacity, existing or planned generation (from other renewable energy sources) and environmental factors (such as National Park status of some resource areas), may limit the conventional geothermal deployment. Indonesia is one of the world's richest countries in geothermal resources, and other volcanic islands in the Pacific Ocean (Papua-New Guinea, Solomon, Fiji, etc.) and the Atlantic Ocean (Azores, Caribbean, etc.), have significant potential for growth from known hydrothermal resources, but are also grid constrained in growth potential.

Remote parts of Russia (Kamchatka) and China (Tibet) contain identified high temperature hydrothermal resources, the use of which could be significantly expanded given the right incentives and access to load. Parts of other South-East Asian nations (including India) contain numerous hot springs, inferring the possibility of potential, as yet unexplored, hydrothermal resources.

Taking the projected capacity factor (CF) for electric generation by 2015 (75% in Table 4.9), the expected generation of electricity for every region is also shown in Table 4.11. Of course, there will be variations in the CF for each region, but with the projected worldwide average it is expected that total electric generation will reach 121,590 GWh/y (Table 4.9) or 121.6 TWh/y (Table 4.11), equivalent to 0.44 EJ/y.

For geothermal direct uses projection on an annual growth rate of 13.5% results in 95,280 MWt (95.3 GWt) by 2015 with the regional contribution presented in Table 4.11. Using an average worldwide CF of 30% the expected generation of heat by 2015 will be 250,385 GWh_t/y or 250.4 TWh_t/y, equivalent to 0.9 EJ/y.

Expected high average annual growth of 13.5% in the geothermal direct use market is closely linked to the fact that space and water heating are significant parts of the energy budget in large parts of the world. In industrialised countries, 35 to 40% of the total primary energy consumption is used in buildings. In Europe, 30% of energy use is for space and water heating alone, representing 75% of total building energy use (Lund et al., 2010). The high potential deployment is due in large part to the ability of GHP to utilise groundwater or ground-coupled heat exchangers anywhere in the world. This use has large potential for replacing current energy-use in buildings.

4.8.2 Long-term deployment in the context of carbon mitigation

The IPCC Fourth Assessment Report (AR4) estimated a potential contribution of geothermal to the world electricity supply by 2030 of 633 TWh/y (2.28 EJ/y), equivalent to ~2% of the total (Sims et al., 2007; see Chapter 4.4.3). Other forecasts for 2020, 2030 and 2050 are presented in Table 4.12. As shown in this table, the IPCC AR4 estimate is a little higher than the maximum scenario of electric generation by 2030 (ETP 2008, Blue map scenario).

Table 4.12 Available scenarios of geothermal-electric installed capacity and generation of electricity in the long-term.

Year	Forecast installed capacity (GWe)			Forecast electric generation (TWh/y)		
	Min	Mid	Max	Min	Mid	Max
2020 (Reference)	19 (a)	33 (b)	57 (c)	128 (a)	231 (b)	392 (c)
2030 (Reference)	28 (a)	71 (b)	87 (c)	199 (a)	488 (b)	611 (c)
2050 (Reference)	38 (d)	134 (e)	152 (c)	264 (d)	934 (e)	1059 (c)

References: (a): IEA-WEO 08 (550 ppm policy scenario), (b): EREC-GPI 08, (c): ETP 2008 (Blue map scenario); (d): ETP 2008 (Base scenario); (e): ETP 2008 (ACT scenario).

A number of different scenarios with the contribution of geothermal resources have been modelled from the integrated assessment models presented in Chapter 10 of this report, taking into account the stabilization categories of CO_2 emissions regarded by the IPCC AR4 and grouping them into three: categories I+II (300-440 ppm), III+IV (440-600 ppm) and V+VI (600-1000 ppm). Results are presented in Figure 4.8; Primary Energy is provided as direct-equivalent, i.e. each unit of heat or electricity from RE (except from biomass) is accounted for as one unit at the primary energy level.

Projections of geothermal energy contribution to the global primary energy supply span a very broad range: up to 11.9 EJ/y in 2020, 21.3 EJ/y in 2030 and 50.1 EJ/y in 2050, taking the more stringent carbon mitigation policies (300-440 ppm in all years), and are sensitive to the carbon policy assumed by each projected year. Medians of all those scenarios are also sensitive to the carbon policy, ranging 0.39-0.68 EJ/y by 2020, 0.22-1.2 EJ/y by 2030 and 1.09-3.85 EJ/y by 2050, in all cases considering the baseline (600-1000 ppm) and the 300-440 ppm scenarios (Fig. 4.8).

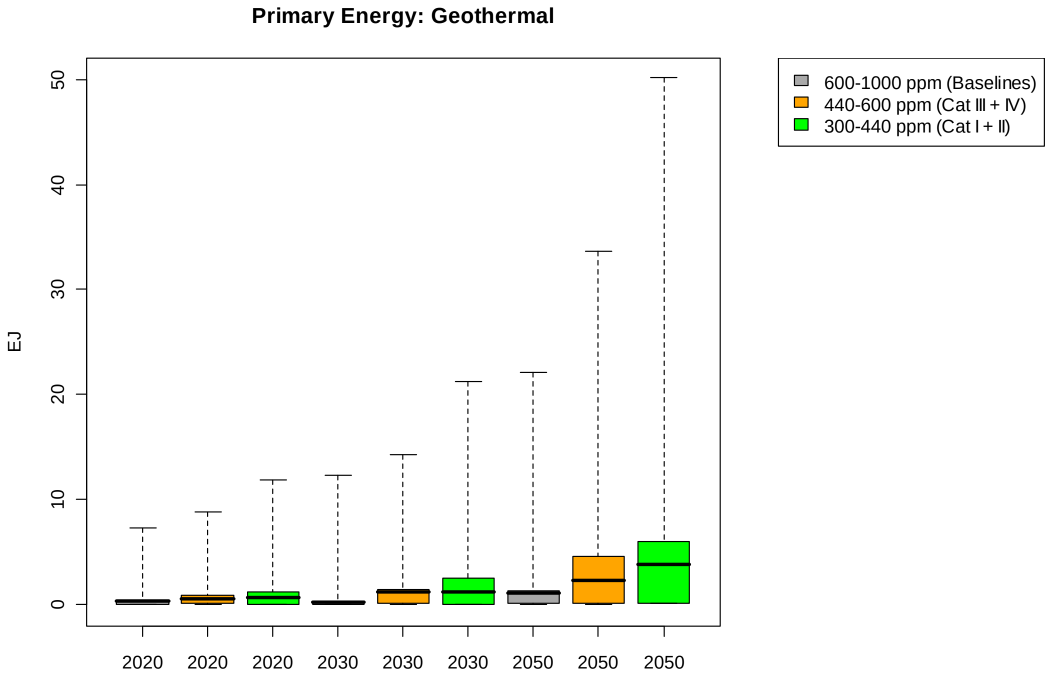

Figure 4.8 Primary energy from geothermal resources in the context of carbon mitigation for 2020, 2030 and 2050. Thick black line is the median, the coloured box corresponds to interquantile range 25th-75th percentile, and whiskers correspond to the total range across all scenarios. [TSU: adapted from Krey and Clarke, 2010 (source will have to be included in reference list); see also Chapter 10.2]

These amounts are not completely comparable with the IPCC AR4 estimate by 2030, since this included only geothermal-electric generation without reference to the geothermal contribution for heat supply. But even so, it is clear that the 2.28 EJ/y of electric generation estimated by the IPCC AR4 by 2030 results well above the medians considered by 2030, but lies in the 25-75% percentile for the more restricted scenario (Fig. 4.8).

Based on the current geothermal-electric and direct uses installed capacity and the near-term projections presented in Table 4.11, the long-term regional deployments presented in Table 4.13 were obtained. For electric power deployment, it was assumed that the average annual rate growth for 2015-2030 will be the historic rate (7%), and for 2030-2050 an annual rate growth of 5.9% is expected. Both rates are lower than the near-term rate (2010-2015) of 11.5%. All of these forecasts include EGS projects deployment.

For direct uses deployment, the assumed average annual rate growths were: 11% for 2015-2020 (historic rate, see Table 4.5), 9% for 2020-2030, 5.5% for 2030-2040 and 2.5% for 2040-2050, reflecting an expected decrease in the average annual rate of growth.

Table 4.13 Regional long term forecasts of installed capacity for geothermal power and direct uses (heat) and global forecast of electric and direct uses (heat) generation.

REGION	**2020**		**2030**		**2050**	
	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)
1. OECD North America	51.8	9.2	121.6	16.7	234.5	45.4
2. Latin America	2.1	1.5	5.1	3.0	10.2	8.5
3. OECD Europe	62.2	3.0	151.0	5.8	305.9	25.3
4. Africa	4.1	0.8	11.1	1.6	18.4	7.0
5. Transition Economies	3.1	0.3	5.1	0.6	10.2	4.8
6. Middle East	4.1	0.0	5.2	0.1	7.1	2.2
7. Developing Asia	4.2	8.5	10.0	15.3	20.4	35.2
8. India	2.1	0.0	5.1	0.2	10.2	2.8
9. China	20.7	0.1	50.7	2.8	127.5	13.7
10. OECD Pacific	6.2	2.5	15.2	5.0	86.7	15.7
TOTAL	**160.5**	**25.9**	**380.1**	**51.0**	**831.1**	**160.6**
Expected global generation (thermal and electric) in:	TWh$_t$/y	TWh$_e$/y	TWh$_t$/y	TWh$_e$/y	TWh$_t$/y	TWh$_e$/y
	421.9	181.8	998.8	380.0	2184.0	1266.4
	EJ/y	EJ/y	EJ/y	EJ/y	EJ/y	EJ/y
	1.52	0.65	3.60	1.37	7.86	4.56

Comparing the global forecasts for electric power with those presented in Table 4.12, one can see they are located between the minimum and medium estimates for 2020 and 2030, but are higher than the maximum estimates for 2050. For 2030, the projected electric generation (380 TWh/y or 1.37 EJ/y) is lower than the IPCC AR4 estimate of 633 TWh/y or 2.28 EJ/y.

Considering that the world electricity demand is projected to be between 25,743 (IEA-WEO 08) and 27,708 TWh/y (EREC-GPI 08) by 2020, geothermal would share around 0.7%of the total. For 2030 projections go from 28,997 to 33,265 TWh/y (IEA-WEO 08), and thus geothermal would share between 1.1% and 1.3% of the total electric demand. For 2050 estimates are between 30,814

(EREC-GPI 08) and 50,606 TWh/y (IEA-WEO 08), and then geothermal electricity would contribute with 2.5%-4.1% of the global electricity demand.

On the other hand, ERC-GPI 08 projects the global demand of heating-cooling by 2020 to be 156.8 EJ/y, by 2030 to be 162.4 EJ/y and by 2050 to be 161.7 EJ/y. Then, geothermal generation of heat by direct applications would supply about 1% of the total demand by 2020, 2.2% by 2030, and 4.9% by 2050.

According to the estimates in Table 4.13, total contribution (thermal and electric) of geothermal energy would be 2.17 EJ/y by 2020, 4.97 EJ/y by 2030, and 12.42 EJ/y by 2050. Considering each unit of heat or electricity accounted for as one unit at the primary energy level, these estimates are placed in the 75th-100th percentile of the Figure 4.8. Therefore, the estimates included in that figure in the 25th-75th percentile, including the mean, are feasible for 2020, 2030 and 2050.

To achieve the potential deployments presented in Table 4.13 and even the more conservative deployments shown by Fig. 4.8, economic incentive policies to reduce GHG emissions and increase RE will probably be necessary. Policy support for research and development would assist some geothermal technologies to demonstrate and commercialise EGS and other non-conventional geothermal resource development. This policy support could include subsidies, guarantees and tax write-offs to cover the risks of initial deep drilling and long term productivity. Feed-in tariffs with confirmed geothermal prices, and direct subsidies for district and building heating would also help to accelerate deployment. In addition, the following issues are worth to be highlighted.

Resource potential: Even the highest estimates for long-term contribution of geothermal energy to the global primary energy supply (50.1 EJ/y by 2050, Fig. 4.8), are well within the technical potentials described in section 4.2 (91 up to 1043 EJ/y for electricity and 10 up to 322 EJ/y for heat, Fig. 4.1). Thus, technical resource potential is not likely to be a barrier to reach the most aggressive levels of geothermal deployment (electricity and direct uses) in a global or regional basis.

Regional deployment: Forecast long-term (2020, 2030 and 2050) deployments for the IEA regions are presented in Table 4.13. The worldwide average annual rates of growth estimated for electricity deployment and for direct uses deployments are not the same for every region. Availability of financing, water, transmission and distribution infrastructure and other factors will play major roles in regional deployment rates. For instance, in the US, Australia, and Europe, EGS concepts are already being field tested and deployed, providing advantages for accelerated deployment in those regions as risks and uncertainties are reduced. In other rapidly developing regions in Asia, Africa, and South America, factors that would affect deployment are population density, market distance, electricity and heating and cooling demand.

Supply chain issues: Regional differences in technology development (for instance, deep drilling and reservoir management) may affect the adequate supply of labour and materials for geothermal deployment, but no relevant middle- or long-term constraints to materials supply, labour availability or manufacturing capacity are foreseen from a global perspective.

Technology and economics: Direct heating technologies using GHP, district heating and EGS methods are available, with different degrees of maturity. GHP systems have the widest market penetration, and an increased deployment will be supported by improving the coefficient of performance and installation efficiency. The direct use of thermal fluids from deep aquifers, and heat extraction using EGS, can be increased by further technical advances associated with accessing and engineering fractures in the geothermal reservoirs. Reducing sub-surface exploration risks will contribute to more efficient and sustainable development. Better reservoir management will optimize reinjection strategy, avoid excessive depletion, and plan future make-up well requirements, to achieve sustainable production. Improvement in energy utilisation efficiency from cascaded use of geothermal heat is an important deployment strategy. Evaluating the performance of geothermal plants, including heat and power EGS installations, will consider heat quality of the fluid by differentiating between the energy and the exergy or availability content (that part of the energy that can be converted to electric power). All of these technological improvements will lead to significantly reduce the capital costs and the LCOE of geothermal energy.

Integration and transmission: Due to the site-specific geographic location of conventional hydrothermal resources, there are some current transmission constraints for further deployments. However, no integration problems have been observed once transmission issues are solved, due to the base-load characteristic of geothermal electricity. In a long-term perspective, no transmission constraints are foreseen since EGS developments are less geography-dependant, even though the EGS's resource grades can vary substantially on a regional basis.

Social and environmental concerns: Concerns expressed about geothermal energy development include the possibility of induced local seismicity associated with hydro-fracturing in EGS, water usage by geothermal power plants in arid regions, land subsidence in some circumstances, fear of water and soil contamination, and potential impacts of facilities on scenic quality and use of natural areas and features (as geysers) that might otherwise be used for tourism. However, sound practices protect natural thermal features valued by the community, minimise any adverse effects from disposal of geothermal fluids and gases, induced seismicity and ground subsidence, and can optimize water and land use.

4.8.3 Conclusions regarding deployment

Overall, the geothermal-electric market appears to be accelerating compared to previous years, as indicated by the trends in both the number of new megawatts of power capacity installed and under development (Bertani, 2010). The gradual introduction of new technology improvements including EGS is expected to boost the growth rate exponentially after 10-20 years, reaching an expected global target of ~160 GWe by 2050 (Table 4.13). Some of the new technologies are entering the field demonstration phases to prove commercial viability (EGS), or early investigation stages to test practicality (utilization of supercritical temperature and submarine hydrothermal vents or off-shore resources). Power generation with binary plants opens up the possibility of producing electricity in countries which do not have high-temperature resources or may have requirements for total injection.

Direct use of geothermal energy for heating and cooling is currently commercially competitive, using accessible, hydrothermal resources. A moderate increase is expected in the future development of such hydrothermal resources for direct use, but a sustained compound annual growth is expected with the deployment of GHP and direct use in lower grade regions, which can be used for heating and/or cooling in most parts of the world, reaching up to 815 GWt by 2050 (Table 4.13). Marketing the cost/benefit advantages of direct use, including the inclusion of GHPs in programs, will support the uptake of RE and increase efficiencies of using existing electricity supplies by creating necessary infrastructure for widespread deployment.

Projections suggest that geothermal energy can provide 1.2% of the total electric demand by 2030 and between 2.5% and 4.1% by 2050. It also can provide 2.2% of the global demand for heat-cooling in 2030 and 4.9% by 2050.

Evidence suggests that the global and regional availability of geothermal resources is enough to meet the results of the modelled scenarios, and also that projected market penetration seems to be reasonable. With its natural thermal storage capacity, geothermal is especially suitable for supplying base-load power, and thus is uniquely positioned to play a key role in climate change mitigation strategies.

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