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Potentials, costs and environmental assessment of electricity generation technologies

Potenziale, Kosten und Umweltauswirkungen von Stromproduktionsanlagen

Final report in English with summaries in German and French

Hauptbericht auf Englisch, mit Zusammenfassung auf Deutsch und Französisch

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Contents

1 Executive summary

This report provides a comprehensive evaluation of technology-specific potentials and costs of electricity generation in Switzerland (and electricity imports from the neighborhood from selected technologies). In addition, the environmental performance of these power generation technologies is quantified and discussed. Potentials, costs and environmental performance indicators are provided for today, 2020, 2035 and 2050. The evaluation includes the following technologies:

- Large hydropower (LHP)
- Small hydropower (SHP)
- Wind power (onshore and offshore)
- Solar photovoltaics (PV)
- Electricity from biomass
- Deep geothermal power
- Wave and tidal power
- Solar thermal power (concentrated solar power, CSP)
- Nuclear power
- Natural gas and coal power
- Fuel cells
- Novel technologies

System aspects, i.e. the interaction of different power generation technologies as part of the overall electricity supply system, have not not been addressed. Out of scope of this analysis are also external costs[1].

The analysis was carried out by researchers at PSI[2] with support from WSL, EPFL and ETHZ on behalf of the Swiss Federal Office of Energy. The work is part of the activities of the two Swiss Competence Centers for Energy Research (SCCER) “Supply of Energy (SoE)”[3] and “Bioenergy (BIOSWEET)”[4]. The analysis represents a contribution to the ongoing technology monitoring program of the SFOE and the results will be used within the upcoming Swiss energy perspectives.

This summary is structured in the following way:

First, it provides a brief overview of generation technologies and their expected future development. Next, electricity generation and supply potentials are discussed, followed by comparative overviews of electricity generation costs and associated environmental life cycle burdens and potential impacts. All key information and most important performance data are summarized in technology-specific “fact sheets”. Finally, results are compared to

[1] External costs are costs that affects a party who did not choose to incur that cost (Buchanan and Craig 1962); i.e., often society has to bear these costs. External costs in the context of electricity generation can e.g. be due to health impacts as a consequence of combustion-related air pollution or due to potential costs as consequences of potential accidents not covered by insurances.

[2] Laboratory for Energy Systems Analysis (https://www.psi.ch/lea/); Laboratory for Thermal Processes and Combustion (http://crl.web.psi.ch/); Solar Technology Laboratory (https://www.psi.ch/lst/).

[3] http://www.sccer-soe.ch/

[4] http://www.sccer-biosweet.ch/

previous studies, current research gaps are summarized and recommendations for further work are provided.

1.1 Electricity generation technologies

1.1.1 Large hydropower (LHP)

Hydropower plants with capacities above 10 MW are categorized as “large” in Switzerland. Two types can be distinguished: reservoir/storage (damming the water and creating a reservoir lake) and run-of-river (only the water in the rivers coming from upstream is available for generation) power plants. In addition, there are pumped storage power plants, which produce electricity to supply high peak demands by moving water between reservoirs at different elevations using pumps. Often, pumped storage and reservoirs are combined using pumped water plus natural inflows to reservoirs for electricity generation. Hydropower plants use water turbines for electricity generation. The application of different turbine technologies mainly depends on useable water head and flow rate; main turbine types, reaching efficiencies of more than 90% today, are Francis, Kaplan and Pelton turbines (Figure 6.7). Hydropower plants are a mature technology and no major technology development can be expected in the future.

1.1.2 Small hydropower (SHP)

In Switzerland, hydropower plants are categorized as „small“, if the installed capacity is below 10 MW. SHP plants can be categorized according to construction type (run-of-river, “Ausleitkraftwerk”/diversion, storage, “Umwälzwerke”/circulation power plants) or according to runoff medium (river-fed, wastewater, drinking water, “Dotierkraftwerk”/discharge power plant). SHP technologies as such are similar to LHP technologies. However, technical limitations for small plants for certain applications and circumstances exist, and current research aims at providing alternative solutions for medium head and low-head, respectively, low-runoff applications (see sections 7.2.2 and 7.2.3).

1.1.3 Wind power

Horizontal axis wind turbines with three rotor blades represent the dominant wind power technology today and are installed onshore and offshore. Vertical axis wind turbines don’t play a role on the wind power market today due to economic and technical reasons, which is not expected to change until 2050. Modern wind turbines reach capacities of up to 8 MW with rotor diameters as large as 164 m and hub heights of up to 220 m. However, around 72% of the worldwide installed turbines are in the range of 1-3 MW, which is also the common size in Switzerland (Table 8.10). Small wind turbines with capacities below 100 kW are and will be a niche market. Current wind turbines are a relatively mature technology (especially onshore installations); future technology development aims at further increasing turbine capacities and improving reliability of offshore installations. Turbine capacities of 20 MW seem to be feasible. Increasing hub heights will allow for better exploitation of wind resources, since wind speeds increase with height above ground.

1.1.4 Photovoltaics (PV)

Photovoltaic cells directly convert solar irradiance into direct-current (DC) electricity. A converter is used to convert DC into alternate current (AC) before grid feed-in. In Switzerland, small-scale, roof-top PV installations are most common. About half of the installed capacity is in units below 100 kW, about half in units above 100 kW. In terms of numbers of installations, more than half of the units are installed on single-family houses. However, in terms of installed capacity, PV units on industrial and agricultural buildings are more important.

The most common way of PV technology categorization is based on the basic material used for the PV cells. The PV market today is dominated by crystalline silicon (c-Si) cells (first PV generation), mainly multi-c Si (Figure 9.10); single-c Si cells have continuously lost market share in recent years. So-called thin-film technologies (second PV generation) are alternatives to crystalline silicon; thin-film technologies that have been commercially developed use amorphous/microcrystalline silicon (a-Si), cadmium telluride (CdTe), or Copper Indium Gallium (di)Selenide (CIGS or CIS). Other advanced thin-film PV technologies, concentrating PV, dye-sensitized PV and organic PV (third PV generation) are in research and development and might be options in the future. Best commercial PV module efficiencies are 17% and 21.5% for multi-c Si and single-c Si, respectively, and 17% for CdTe thin-film modules (Table 9.2 and Figure 9.19). Future developments of PV technologies mainly focus on two aspects: reduction of manufacturing costs and efficiency improvement. However, there is a theoretical maximum efficiency of single-junction crystalline silicon PV cells of about 30%. Since due to system losses (inverter, transformer, etc.) the module efficiency is a few percentage points below the cell efficiency, a module efficiency of 27% is used as maximum in 2050 in this analysis. Lifetime of current modules is in the order of 30 years and is assumed to increase to 35 years from 2035 on.

1.1.5 Electricity from biomass

Biomass resources are a heterogeneous group, comprising feedstocks ranging from wastewater and manure, to municipal and industrial waste products, to forest wood (Figure 10.16 and Figure 10.18).

For the purposes of reporting costs and potentials for biomass-based electricity generation systems, the following three broad categories are used:

a) Waste management sector: Installations which receive gate fees or other income for providing a waste processing service. This category includes waste incineration systems (*Kehrichtverbrennungsanlage*, KVA), municipal and industrial wastewater treatment plants, and industrial biogas plants.

b) Wood sector: Installations which use woody biomass as a feedstock, but which are not paid as a waste processor. These installations typically depend heavily on heat sales for income. This category includes wood-based CHP[5] units, including combustion and gasification based systems.

c) Agricultural sector: Installations which mainly use agricultural substrates as a feedstock. For this feedstock, the installations do not receive gate fees and they are only waste processors to a minor extent. They also typically do not have very significant income from heat sales.

[5] CHP: Combined Heat and Power generation.

Non-woody biomass feedstocks with a high liquid content, such as wastewater or manure, are first processed through an anaerobic digestion step in which biogas is produced. Then, the biogas can be used in a combined heat and power (CHP) unit, such as an engine, a gas turbine or a fuel cell. Woody biomass feedstocks and non-woody biomass feedstocks with a low water content (such as municipal waste) can be combusted directly to drive steam cycles at large scales or organic Rankine cycle (ORC) at medium scales. At small scales, externally-fired gas turbines (EFGT) are also considered. Finally, the woody and dry non-woody feedstocks can be gasified, creating a syngas that can be burned in an engine or other CHP unit to produce electricity. An alternative pathway for all feedstocks is the creation of biomethane for injection into the natural gas grid and subsequent flexible use as energy carrier for electricity generation, but also heating or mobility. Therefore, biomass represents to some extent a "special case" in this analysis, since among all technologies and fuels addressed, "competition" for resources from different end-use sectors is only an issue in case of biomass.[6]

Ongoing research and technology development focus on the potential to maximize the electricity that can be produced from the same amount of feedstock, either by improving efficiencies of existing technologies (see specific numbers in Table 10.3), or by developing new ones such as hydrothermal gasification or manure digestion with phase separation of the feedstock into a solid and liquid fraction.

1.1.6 Deep geothermal power - EGS

Energy from deep geothermal installations (>400 m depth, >120°C) can be harvested in two ways: From hydrothermal systems and from so-called Enhanced Geothermal Systems (EGS) or petrothermal systems. Hydrothermal systems require high underground temperatures (>100°C), water-bearing geological formations and adequate generation of hot water in these formations. These pre-conditions seem to be present only at few places in Switzerland. Since EGS are not dependent on hot water in the underground, but simply make use of the natural temperature gradient towards the Earth's interior and the resulting hot rock in the underground, only such EGS could substantially contribute to electricity supply in Switzerland and are therefore evaluated in this analysis.

By drilling two or more wells and connecting them, cold water can be injected to these high-temperature formations, warm up there and then be pumped up through one or two other well(s). The resulting hot water drives a generator in a binary cycle. EGS only need a high temperature gradient from a geological point of view, but are more dependent on technical issues such as the drilling and the stimulation phase, or adequate treatment of mineral scaling during operation.

Typical well depths in Switzerland would be around 5 km. Geothermal gradients need to be above 30°C/km for power generation in order to reach reservoir temperatures above 160°C. Depending on geological conditions, net power plant capacities would be in the order of 1-5 MW_{el} (Table 11.1). Electric efficiencies are comparatively low due to low working fluid temperatures and large amounts of (waste) heat are available at such EGS plants, which should be used as far as possible in order to improve the economic viability of EGS.

[6] Other potentially competing interests such as the use of roof-top area for solarthermal heat generation and conversion of electricity into synthetic fuels via "power-to-gas" technologies are mostly out of scope of this analysis.

1.1.7 Wave and tidal power

Technologies to collect the wave power can be onshore or offshore. Energy from offshore installations is usually delivered as electricity by submarine cables. Wave power is generally less limited by site than current or tidal power. Several different wave power generator design options exist, most important onshore types are Oscillating Water Column (OWC), Pendulum and Tapered Channel designs. Hinged Float designs, Float Pump devices, Floating OWC and Floating Tapered Channel designs are the most important offshore technologies.

Compared to the other generation technologies evaluated in this report, wave and tidal power technologies are at a relatively early stage of development. Currently, there is no clearly dominant design (or design family) that will benefit by the industry concentrating on it and driving it down the learning curve over other designs. There does seem to be some dominance for electrical versus hydraulic power takeoff schemes, which seems likely to continue.

1.1.8 Concentrated solar power (CSP)

Concentrating solar power plants use mirrors to concentrate sunlight onto a receiver, which collects and transfers the solar energy to a heat transfer fluid that can be used to generate electricity through conventional steam turbines. Due to lack of sufficient direct normal solar irradiance, CSP cannot be considered as option for power generation in Switzerland, but electricity from such plants located in Southern Europe, Northern Africa or the Middle East can be imported to Switzerland through high voltage direct current (HVDC) lines. Modern CSP plants are equipped with a heat storage system to generate electricity also with cloudy skies or after sunset. To some extent CSP can therefore be considered as dispatchable generation.

There are four main CSP technologies, namely Parabolic Trough Concentrator (PTC), Linear Fresnel Reflector (LFR), Central Receiver System (CRS) and Parabolic Dish Concentrator (PDC) (Figure 13.2). The first three types are used mostly for power plants in centralized electricity generation, with the parabolic trough system being the most mature commercial technology. Solar dishes are more suitable for distributed generation. PTC plants are now designed for 6-7.5 hours of thermal energy storage (TES) and an annual capacity factor of 36-41%. Tower plants (CRS), with their higher temperatures, can charge and store molten salt used as thermal storage medium more efficiently, and projects have been designed and constructed for up to 15 hours of storage, resulting in an annual capacity factor of 75%. Annual solar-to-electricity efficiencies of current CSP plants are – depending on the technology – in the order of 10-25%. Future technology development primarily aims at cost reduction and focuses on power generation units and thermal storage systems in order to improve solar-to-electricity efficiencies, annual capacity factors and plant reliability.

1.1.9 Nuclear power

The Swiss nuclear power plants all belong to the second generation of nuclear reactors (GEN II), with extensive retro-fitting of the oldest plants in Beznau (KKB) und Mühleberg (KKM) („NANO“ bzw. „SUSAN“). Beznau I has not been operating for about two years now due to technical issues. KKM and the plant in Leibstadt (KKL) are boiling water reactors (BWR), the other ones (KKB and KKG in Gösgen) are pressurized water reactors (PWR).

The present day, dominant LWR technology can be considered relatively mature (at least marginal improvements are incremental), but the pressure to increase safety and remain cost-competitive is driving evolutionary designs (Generation 3+). This includes a recent trend to smaller, modular reactors with a wider design range that hopes to trade the benefits of standardized, factory construction for economies of scale. Beyond this, a broader spectrum of Generation 4 designs hopes to achieve more inherent safety and higher temperatures to increase efficiency and thermal applications.

A broad range of current and future reactor designs can also be fueled with thorium. Unlike U235, thorium is not fissile, but rather fertile (like U238), so the thorium is converted (or bred) to U233 inside the reactor, and the fuel cycle must be initially driven by another fissile fuel or a neutron accelerator. Thorium is more abundant, produces less waste with less transuranic elements, and is more proliferation resistant than present nuclear fuels. However, the breeding ratio limits the rate of fleet expansion, and there are still technical and economic uncertainties.

1.1.10 Natural gas and coal power

Both large, centralized combined cycle (CC) power plants and relatively small, decentralized combined heat and power (CHP) units in various sizes, operated in Switzerland, are considered for electricity generation with natural gas (NG). Electricity from hard coal and lignite power plants is taken into account as option for electricity imports. Both carbon capture and storage (CCS) as well as carbon capture and utilization (CCU) can be considered as future options and therefore, natural gas and coal power plants with CO_2 capture are included in the evaluation. However, due to many potential technology options for CCU[7] and the large uncertainties associated with costs of future CCS and CCU in Switzerland, geological storage and utilization of CO_2 are out of scope of a detailed quantitative analysis.

Net electric capacities of current and future NGCC power plants are typically in the order of 400-500 MW although there exist NGCC power plants with capacities up to the order of GW (1000 MW); coal power plant capacities are usually in the order of 500-1000 MW. Natural gas CHP units have electric capacities in the range of a kW to a few MW; CHP units of 1-1000 kW_{el} are evaluated within this analysis. Average electricity generation efficiencies of current NGCC power plants are 57-59%, those of coal power plants 44-46% (hard coal) and 39-44% (lignite), respectively. Current electric efficiencies of NG CHP units are – depending on the unit size – 25-42%, overall CHP efficiencies around 80-90%. Future technology development will allow for higher combustion temperatures and therefore increase these efficiencies to max. 65% for NGCC and around 50% for coal power plants in 2050. Electric efficiencies of CHP units are supposed to reach max. 30-47%, overall efficiencies values above 100% (based on low heating value of fuel). Implementation of CO_2 capture reduces power plant net efficiencies due to energy demand for CO_2 capture: in 2050, NGCC power plants with CO_2 capture are supposed to have efficiencies in the range of 54-56%, coal power plants with CO_2 capture in the order of 33-45%. Detailed figures are provided in Table 15.9. Besides efficiency improvements, technology development also aims at further reduction of combustion-related emissions of air pollutants.

[7] Captured CO_2 can be used for many purposes, e.g. as a carbon source in “power-to-gas” technologies, which can convert electricity via water electrolysis and methanation processes into synthetic fuels or chemicals for industrial purposes.

1.1.11 Fuel Cells

Within this report, fuel cells operating with natural gas and biomethane as fuels and acting as combined heat and power (CHP) generation units are addressed.[8] The types of fuel cells analyzed and their current key characteristics are listed in Table 1.1.

Table 1.1: Types of fuel cells included in this analysis and their characteristics. PEFC: Polymer Electrolyte Fuel Cells; PAFC: Phosphoric Acid Fuel Cells; MCFC: Molten Carbonate Fuel Cells; SOFC: Solid Oxide Fuel Cells.

Fuel Cell Type	Temperature	Operating Flexibility	Fuel Reformer	Technology Maturity
PEFC	<100 °C	Excellent	External	Maturing
PAFC	150-220 °C	Poor	External	Mature
MCFC	600-700 °C	Poor	Internal	Mature
SOFC	600-1000 °C	Poor	Internal	Maturing

Fuel cells, due to their high electrical efficiency and operational flexibility are well suited to household applications as well as commercial installations in larger buildings. These systems are typically heat-led so that the heating and hot water demands of the house are always met, while the balance of electricity demand is met by the grid. Fuel cell CHP systems are scalable and can be built small enough to meet the heating needs of a single family home, which is a market that other CHP systems, such as gas engines, cannot fill.

Electric efficiencies of current CHP-type fuel cells depend on technology and on size and vary over a large range of 32-54%. Overall CHP efficiencies are in the order of 70-90%. These efficiencies are estimated to increase to 42-68% and 80-95%, respectively, until 2050. Besides increasing efficiencies, ongoing technology development mainly aims at improving stack and system reliability and lifetime as well as reduction of manufacturing costs by e.g. reducing platinum catalyst loads. Further details concerning technology specification are provided in Table 16.3.

1.1.12 Novel technologies

The following power generation technologies are categorized as "novel": Hydrothermal methanation of wet biomass (PSI's catalytic supercritical water process), novel geothermal technologies, nuclear fusion, and thermoelectrics for stationary waste heat recovery.

In the context of this analysis, the term "novel technologies" refers to the fact that these technologies are still at an early stage of development and it can – as of today – not be judged whether further development will be sufficient in order to contribute to Swiss electricity supply in a meaningful way in the future. In addition, quantification of electricity generation costs, potentials and environmental burdens is hardly possible or speculative and associated with large uncertainties based on the currently available information.

Hydrothermal methanation of wet biomass is a technology actively developed in Switzerland and has been demonstrated at the laboratory scale. It is supposed to allow for a (more) efficient utilization of biomass with high water content (sludges) and can be used to convert biomass resources such as algae, coffee grounds and sewage sludge into electricity.

[8] Fuel cells that operate on hydrogen are assumed to be equipped with a fuel reformer to generate hydrogen on site as opposed to hydrogen being delivered from an external source. Fuel cells for backup and off-grid power are considered to be a niche market and are unlikely to contribute substantially to the Swiss electricity supply in the future.

Based on the available, appropriate biomass resources in Switzerland, the estimate for additional electricity generation is in the range of about 2-5 TWh/a.

Novel geothermal technologies cover deep geothermal energy extraction and conversion technologies beyond so-called Enhanced (or Engineered) Geothermal Systems (EGS) (those are covered in chapter 11). Two approaches are discussed: 1) Using a subsurface working fluid other than water/brine to extract geothermal energy for power production; 2) Auxiliary heating of geothermally preheated fluids. The first one is based on exchanging water or brine with a different subsurface working fluid (CO_2, and/or nitrogen) which enables using lower geothermal resource temperatures and lower permeabilities compared to water-based heat extraction. The second approach employs auxiliary heating (with some secondary energy source) of geothermally preheated fluids (water/brine, CO_2, N_2, etc.) produced from the subsurface which makes use of very low-temperature geothermal resources for electricity production that would otherwise be uneconomical.

Research in nuclear fusion is ongoing with ITER as most prominent infrastructure project. ITER is a collaborative project of 35 nations to build the world's largest tokamak, a magnetic fusion device that has been designed to prove the feasibility of fusion as a large-scale and carbon-free source of energy. ITER will be the first fusion device where the fusion power substantially exceeds (by a factor of 10) the necessary heating power. With the construction of ITER and the design study of the step which will follow ITER, namely DEMO, nuclear fusion is moving from only a science based field of study to a project oriented approach where technological constraints linked to industrial operation and grid connection will dominate. The deployment of fusion is expected for the second half of this century.

Thermoelectrics enables the direct conversion of heat flux into electrical energy. It can be regarded as alternative to conventional conversion of heat into electricity via water steam or organic rankine cycles and as additional process in order to use waste heat for additional electricity generation. Thermoelectric energy conversion suffers from comparatively low efficiencies and therefore, under many circumstances, thermoelectrics is not competitive with water steam and organic rankine cycles. From the current point of view, it will remain a niche product.

1.2 Electricity generation and supply potentials

Figure 1.1 shows current[9] electricity generation in Switzerland by technology, i.e. the “status quo” (BFE/SFOE 2016e, BFE/SFOE 2016g). Natural gas[10] is currently only used in CHP units, not in large combined cycle power plants. Today, generation of deep geothermal power and from fuel cells is zero and negligible, respectively.

[9] Year 2015, latest year with consistent statistics available, when this report was compiled.

[10] The category “fossil fuels” in the statistics is completely allocated to “natural gas” here. In reality, minor amounts of electricity from diesel-fuelled CHP units are included.

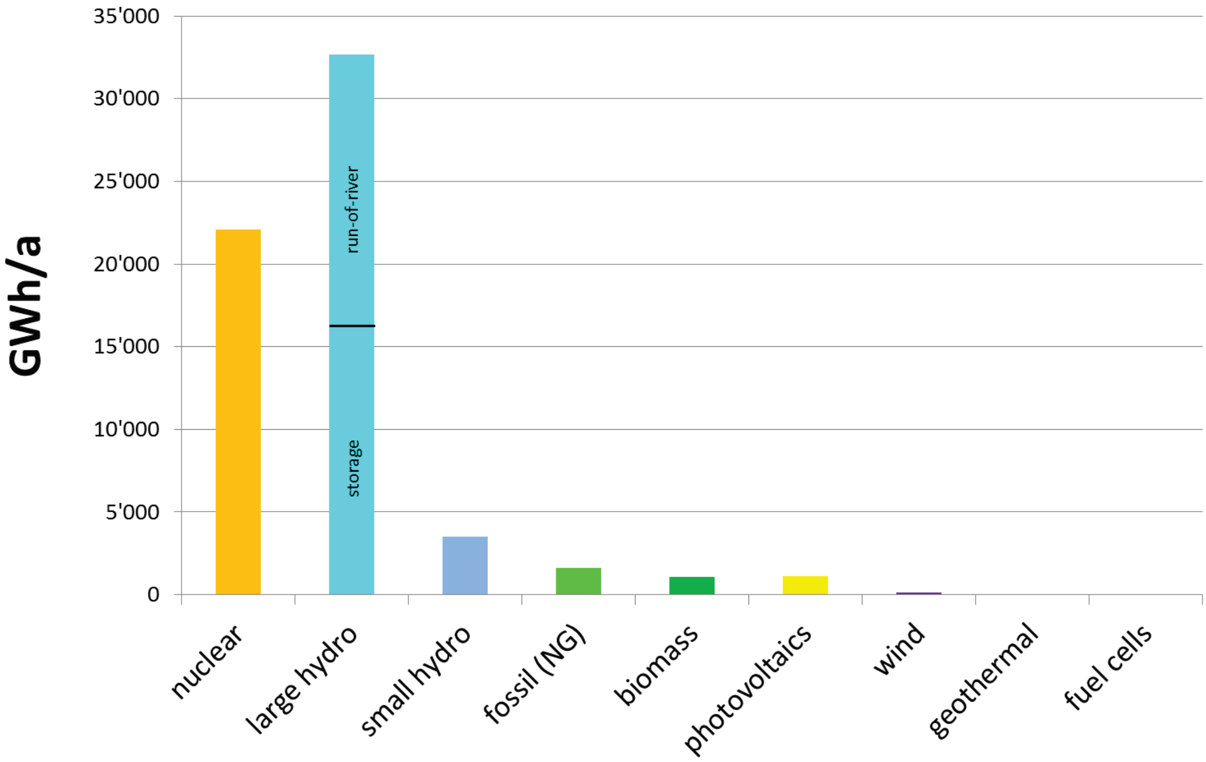

Figure 1.1: Electricity generation in Switzerland in year 2015 (BFE/SFOE 2016e, BFE/SFOE 2016g).

Figure 1.2 shows the estimated "exploitable potentials"[11] for electricity generation and supply with different fuels and technologies in Switzerland and for electricity imports from generation abroad in year 2050. Technical generation potentials are in case of renewable options subject to economic, environmental, social and political constraints resulting in reductions of the purely technical potentials. In case of fossil fuels, electricity generation is technically only constrained by import capacities for natural gas; economic and social/political constraints are decisive in reality. Electricity imports will most likely be constrained by the capacities of transmission lines and the ranges shown for wave and tidal power as well as concentrating solar power represent only rough, first estimates. Figures for the expected temporal development until 2050 (i.e. for 2020, 2035 and 2050) are provided in the technology fact sheets in chapter 1.5.

Among renewables within Switzerland, PV exhibits the largest potential; the range reflecting the associated uncertainties is broad. Uncertainties are even higher for deep geothermal power generation, since power generation with EGS still needs to be demonstrated. Potential generation using natural gas in NGCC and CHP plants or fuel cells is not quantified, since it depends on economic and political boundary conditions as indicated in Figure 1.2. Electricity imports from CSP, wave and tidal, and coal power plants are going to be limited by the availability of transmission lines as well as economic and political boundary conditions and are therefore also associated with large uncertainties.

[11] Terminology regarding electricity generation potentials is discussed in chapter 5.1, based on (BFE/SFOE 2007a). Exploitable potentials basically correspond to technical potentials reduced by environmental and economic constraints. The equivalent German term is "ausschöpfbare Potenziale". To some extent, also social aspects are taken into account as limiting factors.

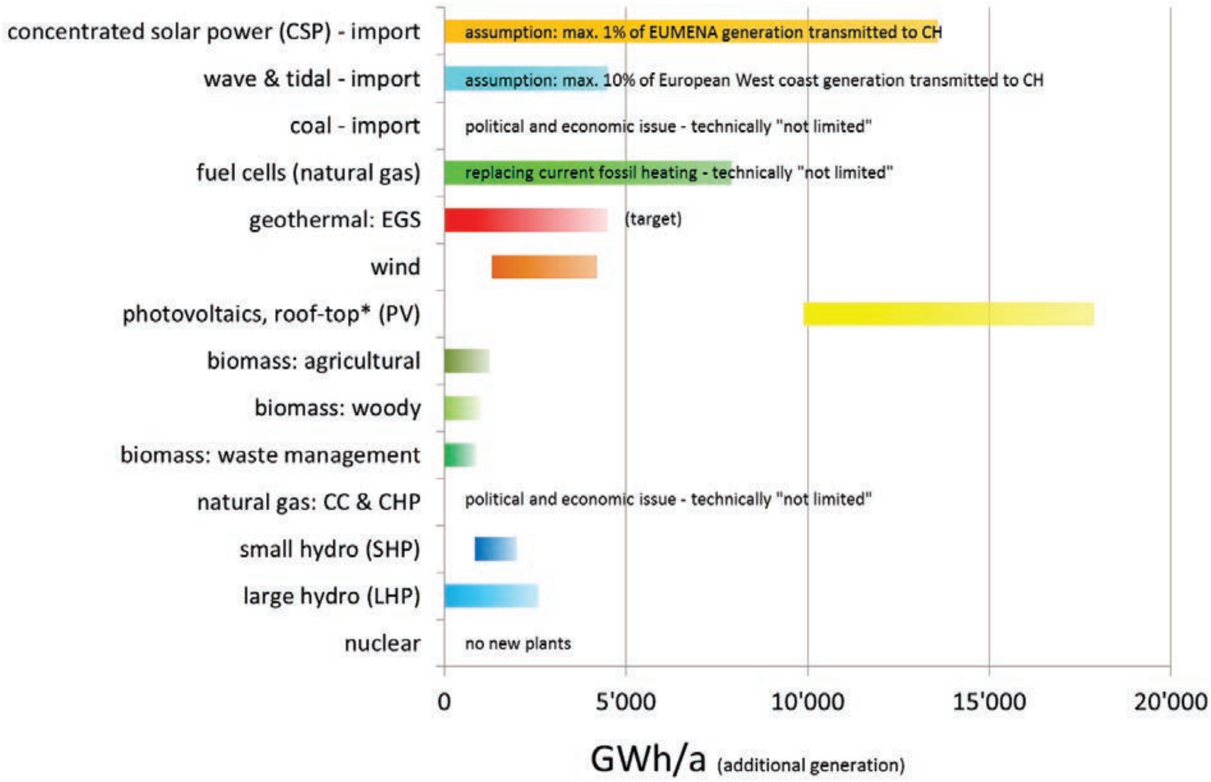

Figure 1.2: Estimated "exploitable potentials"[12] for additional electricity generation (compared to 2015) with different fuels and technologies in Switzerland and for electricity imports from generation abroad, respectively, in 2050. NG: natural gas; CC: combined cycle; CHP: combined heat and power; LHP: large hydropower; SHP: small hydropower; CSP: concentrated solar power; PV: photovoltaics; EGS: enhanced geothermal systems; EUMENA: Europe, Middle East, North Africa; "coal" includes hard coal and lignite. * PV potential does not include generation by modules installed on building facades – the sustainable potential of such facade PV installations is in the range of 3-5.6 TWh/a.

These technology-specific potentials are further discussed in the following sections 1.2.1 to 1.2.11.

1.2.1 Large hydropower (LHP)

The range for additional electricity generation provided in Figure 1.2 is based on a few recent estimates, which all roughly agree in their assessments (BFE/SFOE 2012b, BFE/SFOE 2013c, Filippini and Geissmann 2014). A number of potential sites for new LHP plants is identified; however, building these (or increasing the generation of existing plants by e.g. increasing heights of reservoir dams) is often impeded by social concerns. In addition the current situation on the electricity market reduces profitability of LHP. Future development of LHP will mainly depend on the economic (and political) boundary conditions. New legislation, considerably reducing the expected generation of existing and new hydropower plants, needs to be taken into account.

1.2.2 Small hydropower (SHP)

The potential for new SHP plants is relatively small, but non-negligible (BFE/SFOE 2012b). However, similar to LHP, new projects are often impeded by social (and environmental) opposition. In addition, electricity from SHP plants is usually expensive and cannot compete

[12] See chapter 5.1 for a discussion of terminology.

without governmental economic incentives. Thus, potential expansion of SHP mainly depends on future design of feed-in tariffs, subsidies and similar measures as well as acceptance.

1.2.3 Wind power (onshore and offshore)

Wind conditions in Switzerland are less beneficial for wind power than in other countries. Nevertheless, the potential for additional generation from wind turbines in Switzerland is substantial (BFE, BAFU et al. 2004a, BFE, BAFU et al. 2004b, BFE, BAFU et al. 2004c, Cattin, Schaffner et al. 2012, ARE 2015b, ARE 2015a, BFE/SFOE 2017, Kruyt, Lehning et al. 2017). However, similar to hydropower, expansion of wind power is frequently hampered by social opposition, since wind turbines are often considered as visual disturbance and implementation of wind power projects seems to be a challenge in Switzerland. Due to less favorable wind conditions, also economic constraints need to be taken into account. Overall, realizing the existing wind power potential will depend on legislative boundary conditions as well as governmental incentives.

1.2.4 Photovoltaics (PV)

The potential for additional electricity generation from PV in Switzerland is the largest among all renewables, even if only roof-top PV modules are considered. The range shown in Figure 1.2 corresponds to a technical potential for additional electricity generation based on well-suited roof area (Cattin, Schaffner et al. 2012, swisstopo 2012) reduced by technical, social and economic factors, considering expected future development of PV technology. Since PV faces much less opposition than other renewables in Switzerland, realizing this potential seems to be more realistic. However, since electricity from PV in Switzerland is still comparatively expensive, implementation within the next years will depend on governmental incentives and appropriate regulation. In addition, substantial amounts of decentralized, small-scale intermittent PV generation might be a challenge for the electricity grid from a system perspective, if large additional capacities are installed within a short period and without adequate grid reinforcement/expansion, or electricity storage. Optimal ways of integration considering the option of storage need to be investigated.

1.2.5 Electricity from biomass

The largest potential for future additional biomass-based electricity generation is from the mobilization of manure and woody biomass resources. The potential from manure comes from mobilizing the large resource that is currently not utilized energetically. Meanwhile, the potential from woody biomass comes from a combination of utilizing unused resources and redirecting wood from heat-only systems to CHP systems.

Realization of biomass potentials faces challenges in terms of logistics and, more important, costs. As opposed to renewables like wind and PV power, generation costs for biomass technologies are not expected to drop substantially, which is partially due to the relatively high biomass feedstock costs (Figure 10.21 and Figure 10.22). In addition, competition for biomass resources needs to be considered, since these can not only be used for electricity generation, but also for heating and as transport fuels.

Potential imports of biomass or energy carriers made from biomass are not addressed in this analysis.

1.2.6 Deep geothermal power

The potential provided for deep geothermal power generation in Figure 1.2 is the most uncertain among domestic generation options: EGS still needs to demonstrate its technical, economic and social viability. The potential shown corresponds to the political long-term EGS goal, which can only be realized, if currently prevailing geological, technical, legal, social and economic barriers can be overcome (Hirschberg, Wiemer et al. 2015). One central economic challenge is the use of heat, which is generated in large amounts as a by-product. Sites, which allow for utilization of this heat, need to be identified.

1.2.7 Wave and tidal power

Electricity from potential wave and tidal power plants could be imported from the coast of the Atlantic Ocean in France, Spain and Portugal. However, technology is still in research and development and not (yet) commercially available. Therefore, the potential is quite uncertain. In addition, it is comparatively small: the upper range in Figure 1.2 represents 10% of overall potential wave and tidal power generation at the European west coast (onshore and offshore), which could be – as first guess – be available for transmission to Switzerland.

1.2.8 Concentrated solar power

In comparison to wave and tidal power, the overall generation potential from CSP within a useful distance to Switzerland (i.e. the EUMENA[13] region) seems to be much larger. Also technology is further developed and has gained market share already in certain countries, e.g. Spain. However, large-scale employment especially in non-European countries seems to be challenging and the availability of electricity generated in North Africa and the Middle East for Switzerland is questionable. Therefore, the potential shown in Figure 1.2 only represents 1% of the technical generation potential in the EUMENA region.

1.2.9 Nuclear power

The zero potential shown in Figure 1.2 reflects the current Swiss policy, i.e. it is assumed that no new nuclear power plants will be built in Switzerland.

1.2.10 Natural gas and coal power

Power generation from fossil fuels – both natural gas combined cycle power plants and smaller CHP units in Switzerland as well as coal power plants abroad – is technically hardly limited, but depends on economic and political boundary conditions, such as price of CO_2 emissions, legislation concerning their compensation and the national and international climate policy. These factors are out of scope of this technology evaluation and therefore, specific numbers for generation potentials from natural gas and coal power are not provided. Limiting factors related to environmental concerns and climate policy could be mitigated with carbon capture and subsequent geological storage or utilization of CO_2. However, whether and at which point in time CCS and CCU could be an option for Switzerland and other European countries, is highly uncertain.

[13] EUMENA: Europe, Middle East and North Africa.

1.2.11 Fuel Cells

Similar to natural gas power plants and CHP units, electricity generation from natural gas fueled fuel cells is technically mostly limited by natural gas import capacities. The upper limit in Figure 1.2 represents the potential electricity production from grid-connected fuel cells, if these were replacing all current fossil heating systems in Switzerland. In reality, economic constraints need to be considered.

1.3 Costs of electricity generation

Figure 1.3 shows current electricity generation costs (levelised costs of electricity, LCOE) for all technologies considered in this evaluation (for potential new plants to be built today[14]), except of novel technologies. Electricity import costs for ocean power, offshore wind power and CSP with dedicated HVDC lines are in the order of 0.5-2 Rp./kWh and would have to be accounted for in addition. Ranges reflect variability in terms of site-conditions (e.g., annual PV and wind power yields), technology characterization (e.g., power plant capacities and efficiencies) and biomass feedstock costs. Costs of CO_2 emissions are not included.[15] Heat credits for natural gas and biomass CHP generation as well as fuel cells are taken into account; these technologies are usually operated for heat supply with electricity as co-product.

Overall, coal power, existing LHP and nuclear power as well as biomass technologies profiting from gate-fees[16] show the lowest LCOE. Small-scale natural gas CHP units and fuel cells generate electricity at highest costs. The large range for ocean power indicates immature technology and associated high uncertainties. The ranges for PV, fuel cells and NG CHP units basically indicate economy of scale (larger units being cheaper than small ones); the range of system capacities included in the analysis is indicated in the figure and results for specific unit capacities are provided in the technology fact sheets (chapter 1.5) as well as in the individual technology chapters. In case of PV, the ranges also include variation of annual yield in Switzerland, which depends on the location.[17] The large ranges for electricity from biomass reflect large variations in both technology as well as feedstock costs: electricity from municipal waste incineration and wastewater treatment plants is much cheaper than electricity from small-scale, agricultural biogas CHP units (manure digestion) and wood gasification/combustion; details are provided in the technology fact sheets (chapter 1.5) as well as in the biomass technology chapter.

[14] For large hydropower and nuclear power, current costs of operating power plants, which include partially amortized capital costs, are also shown for comparison, since these power plants will be part of the Swiss generation mix for many more years. More details are provided in chapters 6.5 and 14.6, respectively. In case of nuclear power, "hypothetical new plants" correspond to hypothetical reactors of latest technology (Gen III), for which the planning process would start today.

[15] Costs of CO_2 certificates for power generation at current price levels below 10 €/t of CO_2 are negligible. Estimating potential future costs of CO_2 certificates is out of scope of this analysis – these will primarily depend on international and European climate policy.

[16] Municipal waste incineration and wastewater treatment plants get paid for waste treatment, i.e. profit from negative fuel costs.

[17] Annual roof-top PV yields in Switzerland are in the range of 850-1500 kWh/kW_p. In this analysis, a reference yield of 970 $kWh/kW_p/a$ is used. Most buildings in Switzerland are in the densely populated area of the midland north of the Alps with relatively low yields.

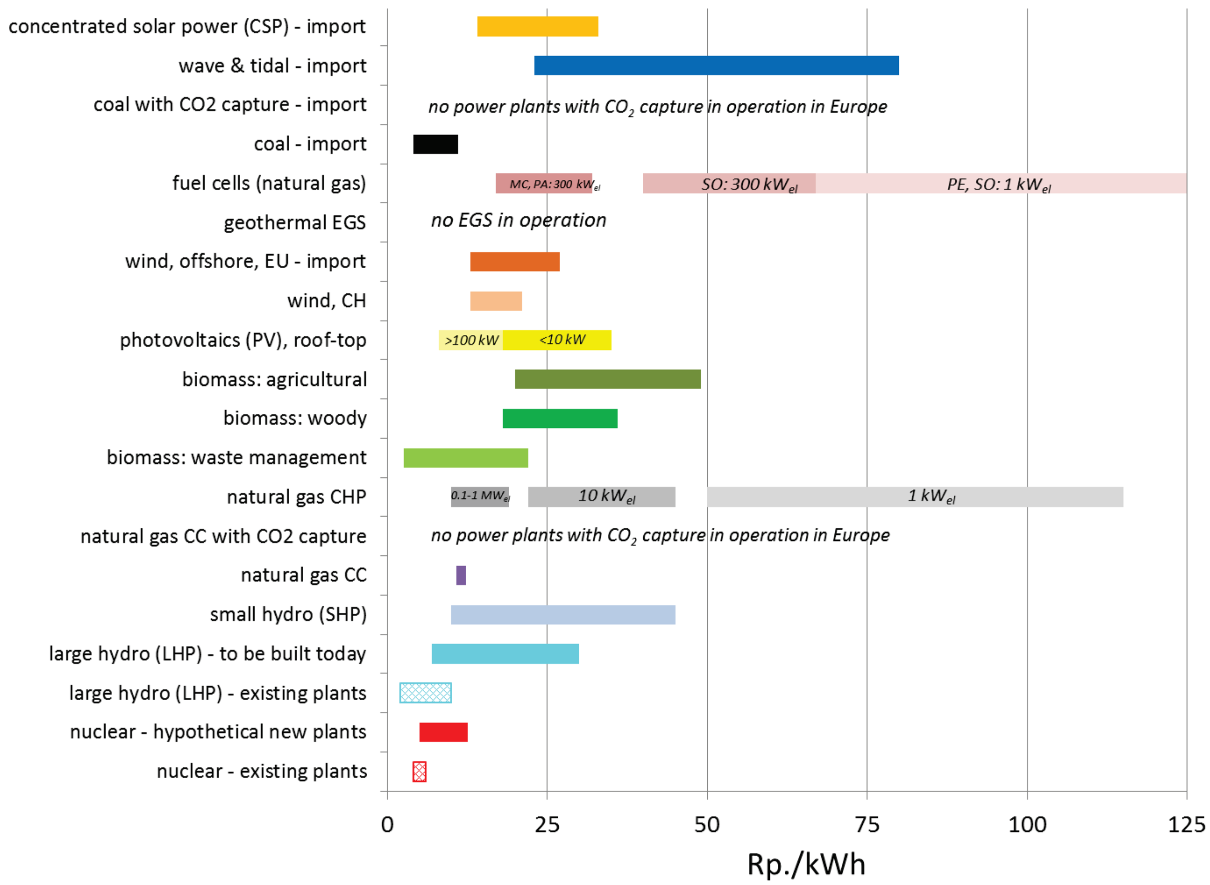

Figure 1.3: Costs of current (year 2015/2016) electricity generation (LCOE) with different technologies.[14] Ranges reflect variability in terms of site-conditions, technology characterization and biomass feedstock costs. Ranges for fuel cells, PV and NG CHP are mainly due to system capacities; LCOE for specific capacities are provided in the technology fact sheets (chapter 1.5) and the individual technology chapters. Electricity import costs with dedicated HVDC lines are in the order of 0.5-2 Rp./kWh and would have to be accounted for in addition. Costs of CO_2 emissions[15] are not included. Heat credits for natural gas and biomass CHP as well as fuel cells are considered. LCOE: Levelised costs of electricity; NG: natural gas; CC: combined cycle; CHP: combined heat and power; LHP: large hydropower; SHP: small hydropower; CSP: concentrated solar power; PV: photovoltaics; EGS: enhanced geothermal systems; MC: molten carbonate; SO: solid oxide; PE: polymer electrolyte; PA: phosphoric acid; "coal" includes hard coal and lignite.

Figure 1.4 shows LCOE estimates for year 2050. Ranges reflect variability in terms of site-conditions, technology characterization, biomass feedstock costs and due to uncertainties concerning the expected future technology cost developments. Potential variations (i.e. ranges) of fossil fuel costs have not been considered in this graph.[18] Electricity import costs with dedicated HVDC lines are in the order of 0.5-2 Rp./kWh and would have to be accounted for in addition. Neither potential heat credits for EGS[19], nor costs of CO_2 emissions are included. However, heat credits for natural gas and biomass CHP generation as well as fuel cells are taken into account; these technologies do not generate as large amounts of heat as EGS and are usually operated for heat supply with electricity as co-

[18] Costs of fuels and their estimated future development are provided in Table 5.3.

[19] The impact of heat credits on the economic viability of EGS wil be substantial, since the electric efficiencies of EGS are comparatively low and large amounts of heat are generated. However, from the current perspective and due to risk-related social issues, it seems to be difficult to implement EGS at sites with large heat demand, i.e. in areas with large residential heat demand and district heat networks.

product. Both technology fact sheets (chapter 1.5) as well as individual technology chapters provide LCOE with and without heat credits.

Compared to today, most substantial LCOE reductions can be expected for electricity from fuel cells as well as wave and tidal power generation followed by PV and CSP. Hydropower costs are likely to increase due to limited availability of remaining beneficial sites. Electricity from biomass as well as large NGCC and coal power plants tends to get slightly more expensive than today, since the reduction of technology costs does not compensate for the expected increase in fuel costs (Table 5.3). The same can be observed for large CHP units, while technology cost reductions for small CHP units more than compensate increasing natural gas prices. Electricity from EGS will be comparatively expensive, if heat credits cannot be credited.

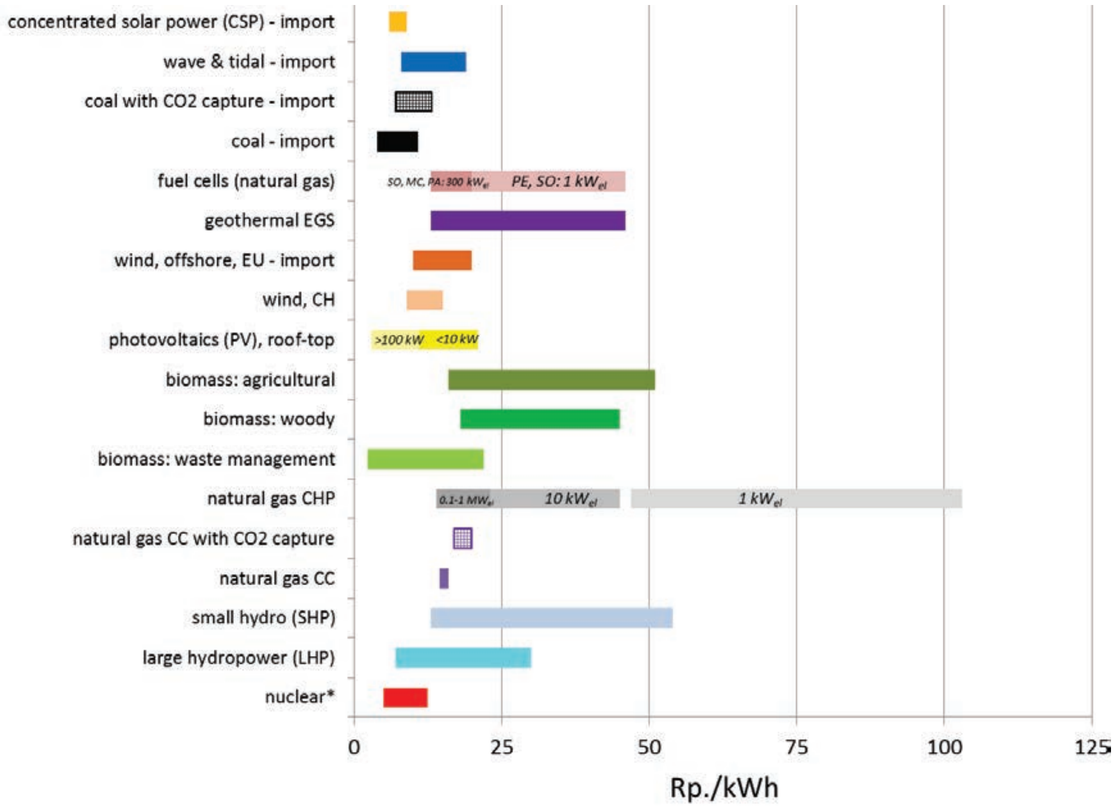

Figure 1.4: Costs of electricity generation (LCOE) with different technologies and fuels in year 2050.[20] Ranges reflect variability in terms of site-conditions, technology characterization, biomass feedstock costs and future technology cost developments. Ranges for fuel cells, PV and NG CHP are mainly due to system capacities; LCOE for specific capacities are provided in the technology fact sheets (chapter 1.5) and the individual technology chapters. Electricity import costs with dedicated HVDC lines are in the order of 0.5-2 Rp./kWh and would have to be accounted for in addition. Neither potential heat credits for EGS[19], nor costs of CO_2 emissions[15] are included. Heat credits for natural gas and biomass CHP as well as fuel cells are considered. LCOE: Levelised costs of electricity; NG: natural gas; CC: combined cycle; CHP: combined heat and power; LHP: large hydropower; SHP: small hydropower; CSP: concentrated solar power; PV: photovoltaics; EGS: enhanced geothermal systems; MC: molten carbonate; SO: solid oxide; PE: polymer electrolyte; PA: phosphoric acid; "coal" includes hard coal and lignite. *The LCOE range for nuclear represent Generation 3+ and small modular reactor (SMR) designs, since reliable cost estimates for Generation 4 designs, which might be an option in 2050, are not available.

[20] Based on the available information, technology-specific curves for generation potentials vs. generation costs cannot be generated for all renewables. It is unclear which fractions of the potentials can be realized at which levels of generation costs.

Technology-specific cost aspects and their sensitivities are further discussed in the following sections 1.3.1 through 1.3.11.

1.3.1 Large hydropower (LHP)

Capital costs and amortization represent the largest contributors to LCEO in case of currently operating LHP; therefore these LCOE are sensitive to interest rates (Figure 6.17). However, also O&M costs as well as water rates[21] are important cost factors. Electricity generation costs of potential new-built LHP plants today and in the future tend to be higher than those of existing LHP plants and very much depend on site-specific factors. According to (BFE/SFOE 2013c), additional LHP generation of 2 TWh/year with costs below 15 Rp./kWh is possible.

1.3.2 Small hydropower (SHP)

Investment costs are the most important cost factor for SHP as well; these vary over wide ranges, depending on site-specific conditions. Small SHP plants with capacities below 1 MW show much higher costs than SHP plants with capacities of 1-10 MW. From the economic point of view, integration into existing infrastructure provides substantial benefits. In general, drinking water and run-of-river/diversion SHP plants are the cheapest SHP options. Substantial cost reductions in the future are unlikely. Contrary, since well-suited locations tend to be exploited first, SHP costs are expected to increase slightly (Figure 7.12).

1.3.3 Wind power (onshore and offshore)

Calculation of LCOE for wind power in Switzerland shows that the generation costs are dominated by capital costs. Therefore, LCOE are quite sensitive to technology costs and interest rates. Also important is the site-specific annual yield (Figure 8.24). Compared to less mature renewable technologies, wind power will only profit from comparatively minor reduction of technology costs in the future; in addition project development costs are supposed to drop due to more straightforward implementation and less ambiguous environmental regulations. Increasing hub heights will increase annual generation and therefore reduce LCOE. Offshore wind power in general tends to be more expensive than onshore wind power, also in the future.

1.3.4 Photovoltaics (PV)

Capital costs are the most important cost factor for LCOE of PV; within those PV module costs exhibit the highest share (however, slightly below 50% on average). The other important capital cost factor is labor (installation costs). O&M costs contribute with about a third to LCOE. PV installations show a clear economy of scale, i.e. small units are substantially more expensive than larger units. In addition to capital costs, LCEO are most sensitive to annual yields (Figure 9.33). LCOE of future PV are expected to drop substantially; mainly due to reduction of module costs, which follow – compared to other renewable technologies – a steep learning curve.

[21] In German: “Wasserzinsen”.

1.3.5 Electricity from biomass

Biomass feedstock costs are the most important factor for LCOE of biomass conversion technologies and these feedstock costs show substantial variation depending on the type of feedstock (Figure 10.21 and Figure 10.22). Least expensive is electricity generation from waste biomass, i.e. municipal solid waste incineration and wastewater treatment plants. These plants profit from gate-fees, i.e. negative fuel costs. LCOE of wood combustion/gasification systems as well as manure digestion systems are much higher. An important factor for the economic operation of biomass based CHP units (e.g., wood combustion/gasification, biogas engines) is crediting for potential heat sales. Without an economically attractive way of using heat from such units, they are unlikely to be installed. Future costs of electricity from biomass are not expected to drop, they seem to be rather stable and will mainly depend on future biomass feedstock costs.

1.3.6 Deep geothermal power

LCOE of deep geothermal EGS crucially depend on geology and potential heat sales – potential ranges and associated uncertainties are high. The analysis shows that drilling the geothermal wells is by far the most important cost factor (Figure 11.7). It seems to be unlikely that EGS could be economically operated without being able to sell the large amounts of heat in a profitable way. Thus, sites with appropriate geologic conditions as well as heat demand in the proximity of the generation plants and risk-related social acceptance need to be identified. Most sensitive cost factors are well depth (since costs increase exponentially with depth) and sub-surface temperature gradient. Compared to other technologies, LCOE are much less sensitive to technology costs (Figure 11.10).

1.3.7 Wave and tidal power

Depending on the design of wave power plants, LCOE show a wide variation; capital costs are by far the most important cost factor. Investment costs show a clear dependence on plant size with substantial economy of scale. In the future, substantial cost reductions are expected (Figure 12.18); however, these depend on technology learning which can only be realized if substantial amounts of wave and tidal power generators will be installed worldwide.

1.3.8 Concentrated solar power

Cost estimates for CSP plants suffer from limited availability of data from most recent projects, which are often not in the public domain or based on inconsistent assumptions, which makes their use impractical. Cost estimates in this evaluation can only be based on a few recent publications from international organizations and are associated with comparatively high uncertainties. Nevertheless, it can be stated that key elements for the LCOE of CSP plants are investment and financing costs, capacity factors, lifetimes, local solar irradiation, discount rates and O&M costs. Future LCOE of CSP are expected to drop substantially, mainly due to three factors: reduction of technology costs, efficiency increases and economy of scale (installation of more and larger plants) (Figure 13.15).

1.3.9 Nuclear power

Nuclear power plants are capital intensive generation technologies. Therefore, LCOE are most sensitive concerning capital costs and interest rates (Figure 14.16). Also major delays in construction projects can lead to substantially higher generation costs as initially aimed for. Fuel costs are – compared to other thermal power plants such as natural gas and coal power – not a decisive factor for LCOE. While Generation 4 reactor designs might be an option in year 2050, LCOE for these plant types have not been quantified due to lack of reliable cost estimates (see nuclear fact sheet, chapter 1.5).

1.3.10 Natural gas and coal power

LCOE of large NGCC power plants are dominated by fuel costs, i.e. the natural gas price. The same pattern can be observed for CHP units with capacities in the order of 100-1000 kW_{el}. The smaller the CHP unit, the higher the share of capital costs in total LCOE (which become the most important contribution for the 1 kW_{el} CHP unit). Due to comparatively lower electric efficiencies, LCOE of small CHP units are more sensitive to heat credits than those of larger CHP plants. In case of electricity from coal power plants, all three factors capital, O&M, and fuel costs are about equally important. Fuel costs are contributing less in case of lignite compared to hard coal. Implementation of CO_2 capture increases LCOE of NGCC and coal power plants by roughly 25-60%, depending on technology, CO_2 capture rate, and fuel costs. Sensitivity analysis shows that besides capital costs (mainly for NGCC), load factors of coal power plants are important: the lower the load factor, the higher LCOE (chapter 15.5.4.3). Potential implementation of geological CO_2 storage, i.e. a full CCS chain, would further increase the LCOE of coal and natural gas power plants; however, compared to CO_2 capture, transport and geological storage of CO_2 are minor additional cost components and would increase LCOE of coal and natural gas power plants with CCS by further 5-10%[22] (ZEP 2011).

1.3.11 Fuel Cells

Electricity generation costs for current fuel cells are – especially for small-scale units – dominated by capital costs. These are expected to drop substantially in the future. Sensitivity analysis shows that the two main influential factors for LCOE are capital costs and system lifetime (Figure 16.6). Cost results are relatively insensitive to system efficiency and fuel price within the reasonable range of input parameters.

1.4 Environmental aspects

The comparative evaluation of environmental burdens and potential impacts of electricity generation is based on Life Cycle Assessment (LCA) covering entire electricity generation chains including supply of energy carriers, manufacturing of infrastructure, etc. (ISO 2006a, ISO 2006b, EC 2010, Hellweg and Milà i Canals 2014, Astudillo, Treyer et al. 2015, Astudillo, Treyer et al. 2016). Life-cycle Greenhouse Gas (GHG) emissions with the associated impact on climate change are used as main indicator for the environmental performance of current and future generation technologies. Further environmental burdens and potential impacts

[22] This range represents a rough estimate based on non-Swiss-specific references; Swiss specific numbers are not available, but are not supposed to be much different. While costs of CO_2 transport are rather well known, estimates for geological CO_2 storage are associated with large uncertainties and further research is required for a more solid quantification taking into account Swiss-specific boundary conditions. If captured CO_2 could be sold and utilized, e.g. for production of synthetic fuels, “CO_2 credits” could be accounted for. However, such an extended analysis is out of scope of this analysis.

are provided and discussed in a less detailed way and only for current technologies. A consistent set of inventory data for future technologies allowing for the evaluation of electricity generation up to 2050 in the same way as performed for current technologies is not available and generating such inventory data is out of scope of this analysis.

LCA methodology does not include impacts of potential accidents, but only takes into account "normal operation" of power plants and associated fuel chains. Further, the methodology does not allow for evaluation and quantification of local, mostly site-specific issues, e.g. visual impacts, noise, and effects on local ecosystems. These are – in addition to GHG emissions and other environmental burdens – qualitatively discussed in the technology-specific chapters of this report.

1.4.1 Life-cycle Greenhouse Gas (GHG) emissions

Figure 1.5 shows life cycle greenhouse gas (GHG) emissions of current, representative electricity generation technologies in Switzerland (and abroad for potential electricity imports); GHG emissions are used as key indicator for their environmental performance.[23]

Ranges are supposed to reflect variability in terms of site-conditions (e.g., annual yields of PV and wind power plants in Switzerland), technology specification (e.g., efficiencies, plant technologies and capacities) and fuel characteristics. Combined heat and power generation in CHP units and fuel cells is allocated according to exergy content of heat and electricity. Data availability for biomass is limited.[24] The results are provided for "electricity generation at the power plant", i.e. transmission and distribution is not taken into account. System aspects such as potentially required back-up technologies are also not considered, since these depend on the actual layout and composition of the electricity supply system.

Overall, hydropower, nuclear and wind power exhibit the lowest GHG emissions. Coal power generates the highest GHG emissions. The large ranges for coal power, natural gas fueled CHP units and fuel cells are due to different technologies and power plant capacities. The ranges for biomass reflect variability in feedstock and conversion technology. It is assumed that woody biomass is harvested at a sustainable rate, meaning that biogenic CO_2 emissions are not accounted for as part of the natural carbon cycle. The relatively large range for ocean power reflects the variety in terms of available design concepts and the comparatively immature technology status.

[23] In the context of environmental burdens, "current" refers to modern technology on the market today. Differentiation between currently operating power plants and plants "to be built today" in case of nuclear and large hydropower – as performed for quantification of LCOE – is not meaningful and thus not carried out.

[24] „biomass: agricultural" is represented by Swiss small-scale manure-to-electricity systems; GHG emissions are mainly due to methane emissions (leakage) during anaerobic digestion of manure – the associated uncertainties and hence the provided range are large. Systems with reduced leakage might exhibit substantially lower GHG emissions.

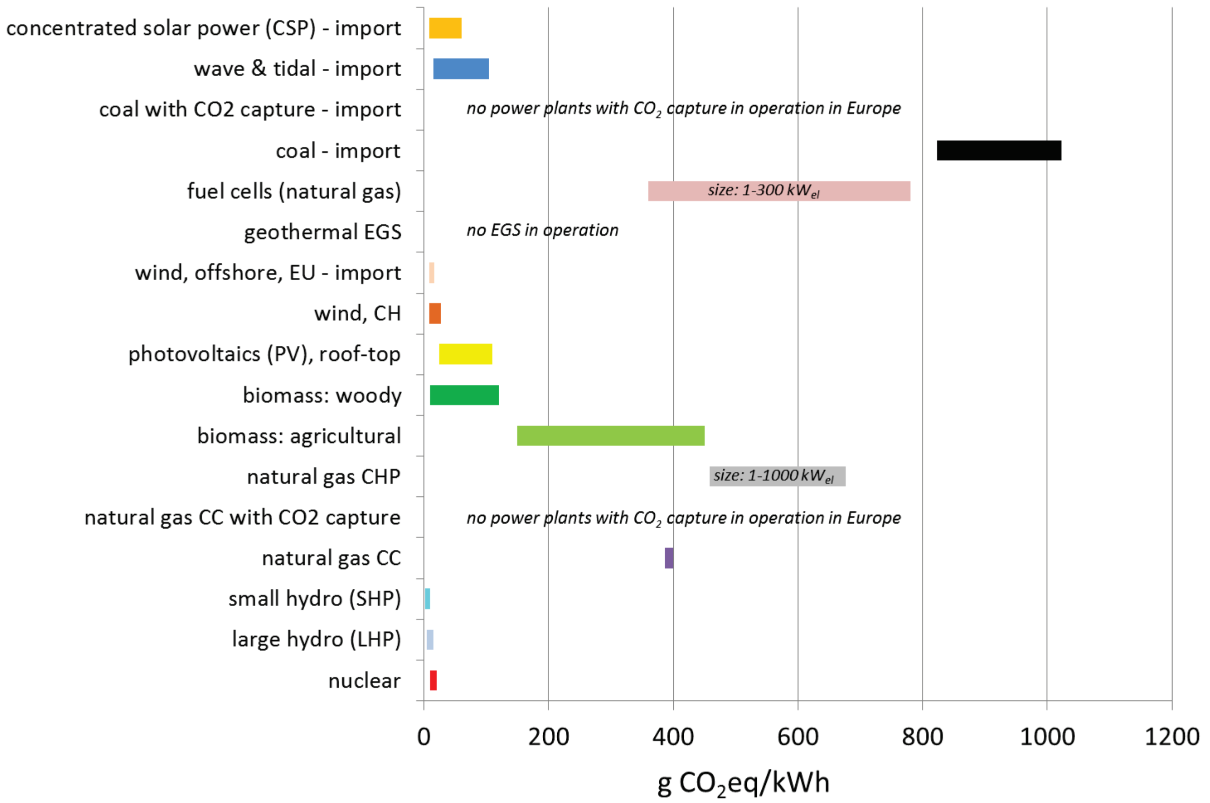

Figure 1.5: Life cycle GHG emissions of current electricity generation technologies (at the power plant[25]) for Swiss electricity supply. Ranges reflect variability in terms of site-conditions, technology specification and fuel characteristics. Combined heat and power generation in CHP units and fuel cells is allocated according to exergy content of heat and electricity. Data availability for biomass is limited. NG: natural gas; CC: combined cycle; CHP: combined heat and power; LHP: large hydropower; SHP: small hydropower; CSP: concentrated solar power; PV: photovoltaics; EGS: enhanced geothermal systems; "coal" includes hard coal and lignite.

Life cycle GHG emissions of electricity generation technologies for Swiss supply in year 2050 are shown in Figure 1.6. Ranges are supposed to reflect variability in terms of site-conditions, technology specification, fuel characteristics and expected technology development. Combined heat and power generation in CHP units and fuel cells is allocated according to exergy content of heat and electricity. Data availability for biomass is limited.

Life cycle GHG emissions are expected to be lower in 2050 than today for most of the technologies. Exceptions are hydro and nuclear power with hardly any improvement potential. Contrary, reduced uranium grades could result in higher emissions associated with the nuclear fuel supply, partially compensated by reduced emissions due to improvements of e.g. enrichment processes and reactor technologies. Even if the factor of decreasing availability of easily accessible resources could also play a role for fossil fuels, it could not be addressed in a systematic way due to limited data within the scope of this analysis. Fossil fueled technologies basically show a reduction of GHG emissions corresponding to their expected increases in efficiency. Implementation of carbon capture would substantially reduce CO_2 emissions of NGCC and coal power plants – depending on

[25] Electricity transmission and distribution is not accounted for.

the CO_2 capture rate to levels almost as low as the majority of renewables.[26,27,28] Among renewables, most substantial reduction of GHG emissions can be expected for PV due to expected efficiency increases both in manufacturing processes as well as conversion of sunlight into electricity.

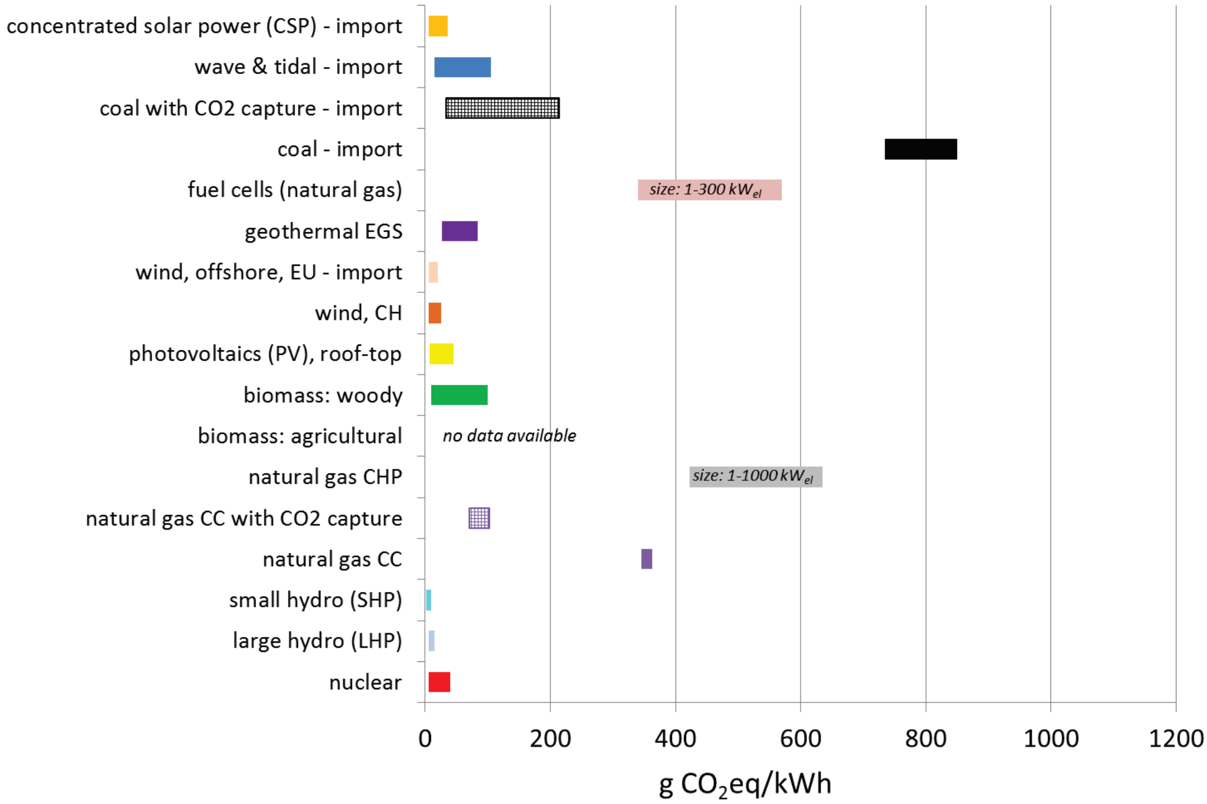

Figure 1.6: Life cycle GHG emissions of electricity generation technologies in year 2050 (at the power plant[29]). Ranges reflect variability in terms of site-conditions, technology specification, fuel characteristics and expected technology development. Combined heat and power generation in CHP units and fuel cells is allocated according to exergy content of heat and electricity. Data availability for biomass is limited. NG: natural gas; CC: combined cycle; CHP: combined heat and power; LHP: large hydropower; SHP: small hydropower; CSP: concentrated solar power; PV: photovoltaics; EGS: enhanced geothermal systems; "coal" includes hard coal and lignite.

1.4.2 Other life-cycle burdens and impacts

Figure 1.7 shows relative[30] Life Cycle Impact Assessment (LCIA) indicator scores for current electricity generation technologies[31] and – for comparison – for the current Swiss electricity

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[26] Potential implementation of the full CCS chain, i.e. permanently storing the captured CO_2 in geological formations, would increase life cycle GHG emissions of the electricity from coal and natural gas power plants with CCS only marginally, i.e. in the order of a few percent (Volkart, Bauer et al. 2013).

[27] Biomass technologies with CCS, which could exhibit negative GHG emissions, are not included in this graph, since CCS requires large, centralized power plants and those are not the most likely options for biomass utilization in Switzerland (See Figure 10.45 for further results).

[28] If captured CO_2 could be further used, substitution effects had to be taken into account (Zhang, Bauer et al. 2017); discussion of such aspects is out of scope of this analysis.

[29] Electricity transmission and distribution is not accounted for.

[30] In this context, „relative" means that the LCIA results are scaled relative to the technology with the highest (=worst, equal to one) score in each impact category.

[31] Consistent inventory data for concentrated solar power, small hydropower, fuel cells and novel technologies are not available. However, the technology-specific chapters for small hydropower and fuel cells contain a

consumption mix (including imports)[32]. The indicators and underlying assessment methods are selected based on the recommendations from Hauschild, Goedkoop et al. (2013). This comparison is based on Swiss-specific inventory data from the latest version of the ecoinvent LCA database (ecoinvent 2016)[33]. Most of the technology-specific chapters provide similar graphs with more extensive discussion of results and often a more comprehensive set of generation technologies.[34]

The results show the comparatively worst overall environmental performance (with equal weighting of single indicators) of lignite power plants and wood CHP units, mainly due to emissions from fuel combustion and also the fuel supply chains. The best overall performance show Swiss hydropower plants as a result of almost zero operational emissions and a low material intensity per kWh electricity generated; also wind power plants and geothermal power generation have comparatively very low impact scores. Natural gas CC plants, nuclear, PV and wave power show slightly higher potential impacts, each of them with peaks for one or few indicators. Biogas and natural gas CHP as well as hard coal power plants show relatively high potential impacts, similar to lignite power and wood CHP plants, but less pronounced.

quantification of selected LCA results in addition to GHG emissions. Results for small hydropower are supposed to be similar to those of large hydropower.

[32] LCIA scores for the Swiss consumtion mix correspond to the LCIA results of the high voltage electricity market in Switzerland according to (ecoinvent 2016).

[33] For electricity from biogas, the dataset "Electricity, at cogen, biogas agricultural mix, allocation exergy" from version v2.2 of the ecoinvent database (ecoinvent 2013) was used as data source due to a potential data quality issue with electricity from biogas in (ecoinvent 2016).

[34] The purpose of Figure 1.7 as part of this summary is a broader, but (compared to the technology-specific chapters) less detailed comparative overview of the environmental performance of power generation technologies. The results for some technologies might not exactly match those shown in the technology-specific chapters, since Figure 1.7 is supposed to represent average technologies, while the results in the technology-specific chapters provide more detailed technology insights (e.g., in terms of plant capacities, technology specification, etc.). Furthermore, the analysis in some technology-specific chapters refers to more recent data sources, for which the comprehensive and consistent set of LCIA indicators shown in Figure 1.7 is not available. Nevertheless, deviations between the results in this graph and those in the technology-specific chapters are minor and do not alter the technology ranking and conclusions concerning the environmental performance of generation technologies in general.

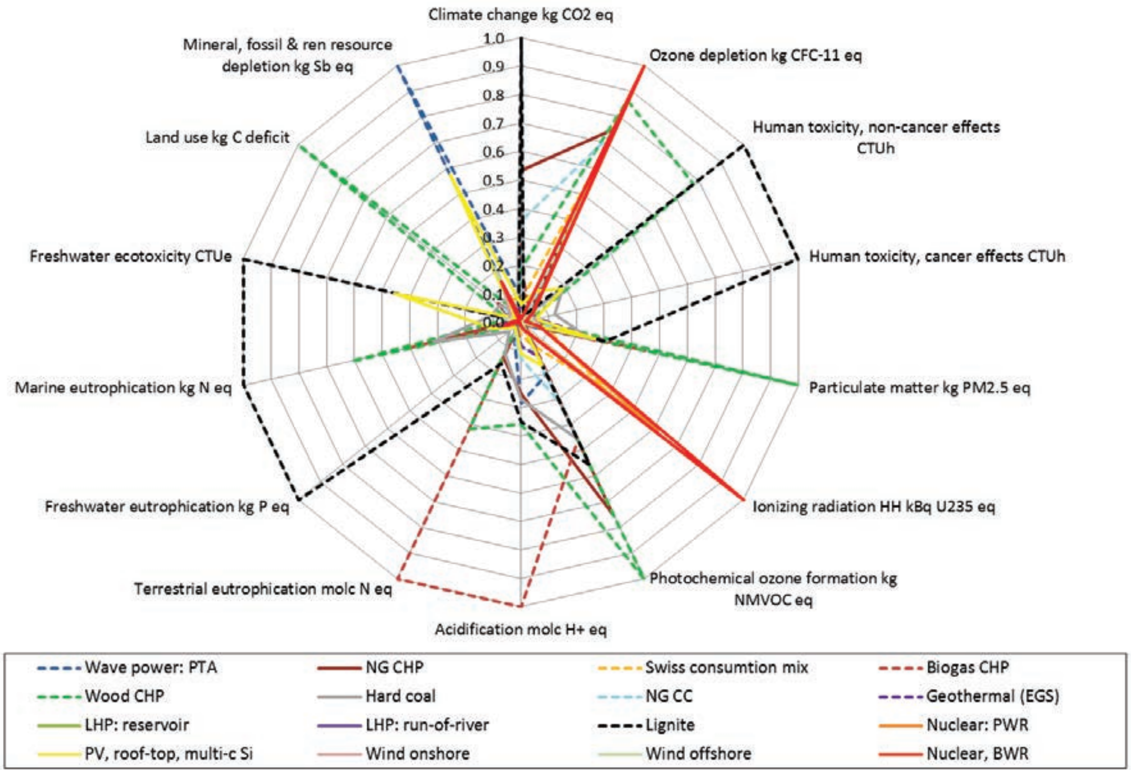


Figure 1.7: LCIA indicator results for different current power generation technologies for Swiss power supply, relative to the highest (=worst) result for each indicator (=1). All results for power plants operating in Switzerland except of offshore wind power, natural gas, hard coal, lignite (all Germany) and wave power (Atlantic ocean). Allocation according to exergy content of heat and electricity in case of natural gas, biogas and wood CHP. CHP: combined heat and power; NG: natural gas; CC: combined cycle; PTA: point absorber; BWR: boiling water reactor; PWR: pressurized water reactor; LHP: large hydropower; EGS: enhanced geothermal system.[35,36] No consistent results for fuel cells, concentrated solar power and small hydro power available. Data source: (ecoinvent 2016)[37].

1.5 Facts sheets

Fact sheets provide at a glance the most important results of the present technology evaluation on one or two pages per technology. These include exploitable potentials[11] for electricity generation, electricity generation costs (LCOE), and life cycle greenhouse gas (GHG) emissions as indicator for the environmental performance, each quantified for “today” (i.e. 2015/2016), 2020, 2035 and 2050. In addition, selected technology parameters and key data are provided.

Numbers are mostly provided as ranges reflecting on a case-by-case basis potential variations in terms of technology performance and expected future developments, annual yields (e.g., for PV and wind power), feedstock and fuel properties, and technology specification. For each technology the most driving factors are considered when generating the ranges. Comments with further explanations are given in footnotes for each technology table. The technology-specific chapters provide the complete background information.

[35] Result for land use not available for wave power.

[36] Results represent electricity at the busbars of the individual power plants without transmission and distribution.

[37] For electricity from biogas, the dataset “Electricity, at cogen, biogas agricultural mix, allocation exergy” from version v2.2 of the ecoinvent database (ecoinvent 2013) was used as data source due to a potential data quality issue with electricity from biogas in (ecoinvent 2016).

Fact sheet – Large hydropower (LHP)

Technology: Hydropower plants generate power by converting kinetic or potential energy of water into electricity. Power plants with capacities above 10 MW are categorized as “large” in Switzerland. Depending on the way the water is used, hydropower plants can be categorized as:

- Storage power plants: including a dam and a storage reservoir lake
- Run-of-river power plants: without a dam; the hydrological regime remains unchanged
- Pumped storage power plants: supplying peak power by moving water between reservoirs at different elevations using pumps.

LHP plants represent mature technology. Turbine efficiencies are not expected to increase substantially in the future.

LHP			New power plants: current[1]	2020	2035	2050
Potential[2] (expected production)	TWh/a		32.7	~32.7	33.9-35.3	33.9-35.3
					32.7-34.0	32.7-34.0
Investment costs[3]	CHF/kW		3’500 (2’000-10’000)	2’000-10’000	2’000-10’000	2’000-10’000
Electricity generation costs[4,5]	Rp./kWh	Run-of-river[8]	7-30	7-30	7-30	7-30
		Storage[9]				
GHG emissions[6,7]	g CO_2eq./kWh	Run-of-river	5-10	~5-10	~5-10	~5-10
		Storage	5-15	~5-15	~5-15	~5-15

[1] “current” refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today; current potential refers to current annual expected electricity production (actual production varies from year to year depending on rainfall, climate, etc.).

[2] Given the current lack of profitability of hydropower in Switzerland, substantial expansion of the current generation cannot be expected until 2020. Expansion and its speed beyond 2020 will predominantly depend on the economic boundary condition and social acceptance of new LHP. New constructions and renovations/extensions of existing power plants are supposed to contribute about equally to increasing generation. For 2035 and 2050, the upper row represents the technical potential without considering new legislation (“Gewässerschutzgesetz”); the lower row takes into account reduction of LHP generation of 1’260 GWh/a (overall reduction: 1’400 GWh/a; 90% assigned to LHP, 10% to small hydropower in proportion to current generation) due to effects of new legislation.

[3] Available data do not allow for differentiation between storage and run-of-river power plants. 3’500 CHF/kW represents a generation weighted average of potential additional LHP generation (new constructions and extensions of existing plants) excluding projects focusing on modification of hydropeaking.

[4] Generation costs include investment, operation & maintenance and other costs. Ranges provided represent variability due to site-specific aspects. Details concerning data used and sensitivities can be found in the report.

[5] Assuming that the economically more attractive power plant sites would be exploited first, electricity generation costs from new plants would increase from the lower range of the interval provided for today to the higher range in 2050. In total, additional 1.6 TWh/a (not considering the effect of new legislation (“Gewässerschutzgesetz”)) can be generated with production costs below 15 Rp./kWh.

[6] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided are supposed to reflect potential variability of performance due to site-specific conditions. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 g CO_2-eq./kWh (high voltage).

[7] Environmental burdens are assumed to stay constant in the future, since LCA-burdens of LHP are comparatively minor and technology development with substantial impact on LCA results of LHP is unlikely.

[8] LCOE of currently operating plants with partially amortized investments: 5-6 (2-10) Rp./kWh.

[9] LCOE of currently operating plants with partially amortized investments: 6 (3-9) Rp./kWh.

Fact sheet – Small hydropower (SHP)

Technology: Hydropower plants generate power by converting kinetic or potential energy of water into electricity. Power plants with capacities below 10 MW are categorized as "small" in Switzerland. Power plants with capacities below 300 kW are often referred to as "mini hydropower" plants. SHP plants can also be integrated in existing infrastructure, such as drinking water pipes. Depending on the way the water is used, SHP plants can be categorized as:

- Storage power plants: including a dam and a storage reservoir lake
- Run-of-river power plants: without a dam; the hydrological regime remains unchanged

Small hydropower plants represent mature technology. Current turbine efficiencies are not expected to increase substantially in the future. However, current research aims at providing new and more efficient solutions for medium head and low-head respectively low-runoff applications in order to make more sites exploitable.

SHP		**New power plants: current**[1]		**2020**	**2035**	**2050**
Potential[2]	TWh/a		3.5	~3.5	~4.3-5.5	~4.3-5.5
Investment costs[3]	CHF/kW	Diversion/ Run-of-river	6'160 (5'200-13'700)	~6'160	~7'150	~7'400
		Drinking water	11'150 (9'600-25'100)	~11'150	~13'000	~13'400
Electricity generation costs[4,5]	Rp./kWh	Diversion/ Run-of-river	12-28	~12-28	~14-33	~14-34
		Drinking water	17-42	~17-42	~20-49	~20-50
GHG emissions[6,7]	g CO_2eq./kWh	Diversion/ Run-of-river	~5-10	~5-10	~5-10	~5-10
		Drinking water	~2-5	~2-5	~2-5	~2-5

[1] "current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today; current potential refers to current annual expected electricity production (actual production varies from year to year depending on rainfall, climate, etc.).

[2] The range for future potentials reflects the variety of estimates in literature. The SFOE estimates additional potential of 1.3-1.6 TWh/a (other sources slightly more or less). These numbers are supposed to be reduced by ~140 GWh/a as an effect of new legislation ("Gewässerschutzgesetz"). Actual implementation of new SHP plants will depend on funding schemes.

[3] Estimates for current investment costs are based on SHP data in the "KEV-list" (cost-covering feed-in remuneration). The analyzed sample of new SHP constructions covers 1049 SHP projects. Future investment costs are supposed to increase due to exhaustion of favorable SHP sites and tightening of environmental regulations.

[4] Generation costs include investment, operation & maintenance and other costs. Electricity generation costs of SHP strongly depend on site-specific boundary conditions and have to be evaluated on a case-by-case basis.

[5] Assuming that the economically more attractive sites would be exploited first, future electricity generation costs would increase from the lower range of the interval provided in 2020 to the higher range in 2050.

[6] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided reflect potential variability of performance due to site-specific conditions and variations in power plant lifetime. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100 g CO_2eq./kWh (low voltage).

[7] Environmental burdens are assumed to stay about constant in the future, since burdens of SHP are minor and major technology development with substantial impact on the environmental performance of SHP is unlikely.

Fact sheet – Wind power

Technology: Horizontal axis wind turbines (HAWT) are dominating the world market. Kinetic energy from moving air is harvested and turned into electrical due to rotation of blades. Today's wind turbines can exploit wind speeds of 3-34 m/s.

Wind power			New power plants: Current[9]	2020	2035	2050
Capacity		Onshore	1-3 MW (70% of installed capacity) New turbines: 2-4 MW	Largest wind turbines today: 8 MW (on-/offshore), 164 m rotor diameter, 220 m hub height. Feasibility of 20 MW turbines was demonstrated.		
		Offshore	>3 MW (2/3 of installed capacity)			
Capacity factor (cf)[1]		General	0.1-0.55 World average ~0.23 (2013)	Capacity factors are expected to increase slightly due to technological improvements at the level of the wind turbine as well as wind speed forecasting and improved placement of wind turbines.		
		Onshore	CH: 20.8 (2015) Germany: 22.3 (2015)			
		Offshore	Up to 0.55 DK: 0.426 (2012)			
Potential	TWh/a	Switzerland	0.1	0.1-0.6	0.7-1.7	1.4-4.3
	TWh/a	Europe[6]	~260	580-630	2030: 604-988	No data available
Electricity generation costs[2,3]	Rp./kWh	Switzerland	13-21	11-19	10-17	9-15
		Europe, onshore	4-18	4-16	3-13	3-10
		Europe, offshore	13-27	13-25	12-23	10-20
GHG emissions[4,5,2]	g CO_2-eq./kWh	Switzerland	~15 (8-27)	5-30	5-30	5-30
		Europe, onshore[7]	8-21	5-25	5-25	5-25
		Europe, offshore[8]	8-16	5-20	5-20	5-20

[1] Annual "full load hours" divided by 8760 h/a. Annual full load hours are calculated as the time of the year, which a turbine would operate at its rated capacity in order to generate the annual electricity output.

[2] Generation costs include investment, operation & maintenance and other costs. Annual yield is the most important factor for both electricity generation costs and LCA results. Therefore, at sites with very favorable/unfavorable wind conditions, figures can be outside of the ranges provided here.

[3] Future cost estimates represent rough estimates based on scarce literature and recent trends in cost development, not taking into account potential substantial changes in commodity prices.

[4] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided reflect potential variability of performance due to site-specific conditions and turbine technology. For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 90 g CO_2eq./kWh (high voltage).

[5] Environmental impacts are not expected to change substantially. A decrease would mainly be due to better exploitation of the wind resource. An increase would mainly be due to reduced availability of good sites.

[6] Based on the available data, differentiation between future onshore and offshore generation is not possible.

[7] Estimated using capacity factors of 0.15-0.35.

[8] Based on the ecoinvent database, v3.3, "allocation – cut-off by classification". Estimated with cf of 0.30-0.55.

[9] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today.

Fact sheet – Photovoltaics (PV)

Technology: Photovoltaic modules directly convert solar irradiance into electricity. Roof-top PV installations are most common in Switzerland. PV technology can be categorized as follows:

- 1st generation: crystalline Silicon cells (single-c Si and multi-c Si); on the market today
- 2nd generation: thin-film technologies – CdTe, amorphous Si, CIGS; on the market today
- 3rd generation: concentrating PV, dye-sensitized PV and organic PV; in research and development

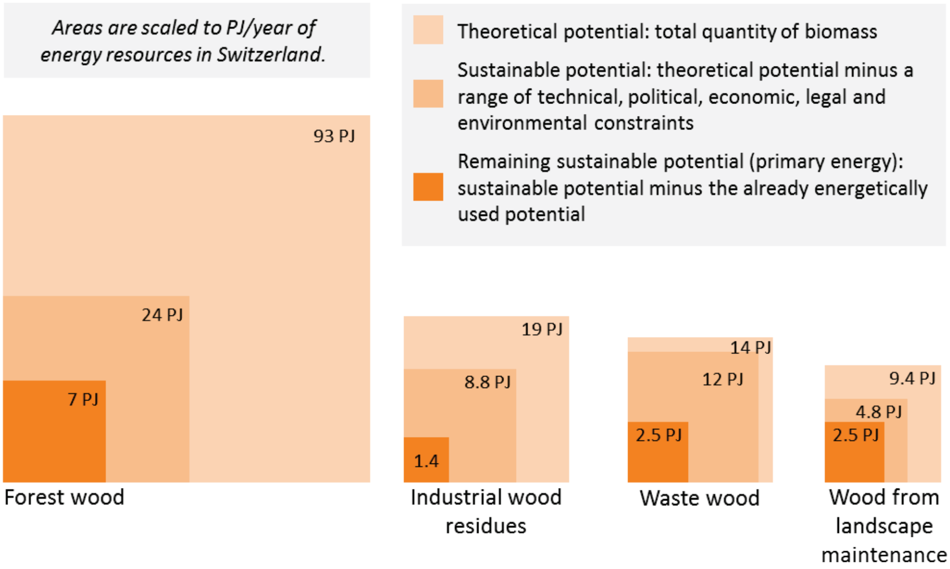
Technology development focuses on increase of efficiencies and reduction of manufacturing costs.

Photovoltaics				New power plants			
				Current[8]	2020	2035	2050
Potential[1]	Potential on roofs and facades	Area available (km^2)	fully built-out Switzerland	Facade[9]: 52			
				roof-top[10]: 79			
		Installed capacity (GW_p)	fully built-out Switzerland	Facades[9]: 7-13			
				roof-top[10]: 11-20			
			by year, PSI estimates[7]	1.4	~2.9-3.4	~5.7-16	~7.1-20
		Electricity generation (TWh/a)	fully built-out Switzerland	Facade[11]: 3-5.6			
				roof-top[10]: 11-19			
			by year, PSI estimates[7]	1.1	~2.8-3.3	~5.5-16	~6.9-19
Key technical parameters[1]	Solar irradiance ($kWh/m^2/a$)			Switzerland: 1100 (Mittelland)			
	Efficiency		Module (%)	14-16	15-18	20-26	23-27
			Inverter (%)	98			
	Area per kW installed PV module capacity (m^2/kW)			7.0-8.0	6.3-7.5	4.3-5.6	4.2-4.9
	Performance ratio (%)			80			
	Swiss average annual yield[2] ($kWh/kW_p/a$)			970			
	Lifetime of modules (a)			30	30	35	35
Costs[1]	System capital costs[3] (CHF/kW)		6 kW	2583	1791-2194	1052-1746	908-1545
			10 kW	2092	1543-1874	917-1488	771-1294
			30 kW	1815	1339-1626	796-1291	665-1118
			100 kW	1410	1040-1263	618-1003	538-886
			1000 kW	1350	996-1209	592-960	515-849
	Electricity generation costs[4] (Rp./kWh)		6 kW	31 (20-35)	24-27 (15-31)	15-21 (10-24)	14-19 (9-21)
			10 kW	27 (18-31)	22-25 (14-28)	14-19 (9-22)	13-17 (8-19)
			30 kW	22 (14-26)	18-20 (12-23)	11-16 (7-18)	10-14 (7-16)
			100 kW	15 (10-18)	12-14 (8-16)	8-11 (5-12)	7-10 (4-11)
			1000 kW	12 (8-13)	9-11 (6-14)	6-8 (4-10)	5-7 (3-9)
Life-cycle GHG emissions[1,5,6]	(g CO_2eq/ kWh)		multi-c Si	60 (39-69)	35-66	21-55	7-45
			single-c Si	95 (62-109)	56-104	33-88	11-71
			thin-film CdTe	38 (25-43)	23-42	15-36	8-30
			ribbon-Si	67 (43-76)	n.a.	n.a.	n.a.
			a-Si	63 (41-72)	n.a.	n.a.	n.a.
			thin-film CIS	53 (34-61)	n.a.	n.a.	n.a.

[1] All data provided here refer to building-attached or -integrated PV. Large open-ground PV installations have not been addressed due to likely social and political constraints in Switzerland.

[2] Assumed in this study in line with (Nowak and Biel 2012) and (Frischknecht, Itten et al. 2015) and used as reference value for cost & LCA calculations.
[3] Including PV module, balance of system, inverter, labor and other costs. Ranges provided for future costs reflect optimistic and pessimistic cost reduction rates.
[4] Calculation includes system capital costs as well as costs for decommissioning, operation and maintenance, and replacement of inverter and balance of system. Ranges provided for current costs reflect potential variation in annual yield (850-1500 kWh/kW/a). Future costs reflect optimistic and pessimistic cost reduction rates and efficiency increases; in brackets, variation in annual yield (850-1500 kWh/kW/a) is considered in addition.
[5] Greenhouse gas emissions are used as key indicator for the environmental performance; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of annual yields in Switzerland (850-1500 kWh/kW/a). For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 100 g CO_2eq./kWh (low voltage).
[6] Current reference values are calculated with a yield of 970 kWh/kW/a. No estimates for future ribbon-Si, a-Si and thin-film CIS modules available. Ranges for emissions of future technologies reflect both variability of assumptions concerning future technology development and variability of site-dependent annual PV yields in Switzerland (850-1500 kWh/kW/a).
[7] PSI estimates only consider well suited roof-top areas, as provided by (Cattin, Schaffner et al. 2012), corresponding to the “constrained potential” (or “exploitable potential”). Future temporal development of PV in Switzerland is difficult to estimate; thus, large ranges are provided. The development will depend on boundary conditions such as feed-in tariffs and other economic incentives, development of PV module, battery and electricity prices, political support, design of the Swiss electricity supply system, regulation concerning self-consumption for decentralized generators and integration of the European supply system. Most of these factors are beyond the scope of this analysis.
[8] “Current” refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today with generation and cost data from 2015/2016.
[9] Represents unconstrained potential of facade modules; estimates considering economic and social limitations are not available and thus, this potential cannot be added to the constrained roof-top potential in a consistent way.
[10] Corresponding to the available roof-top area considering technical, economic and social constraints (Cattin, Schaffner et al. 2012), i.e. this is the constrained (or exploitable) potential.
[11] Sustainable potential according to (Remund 2017).

Fact sheet – Woody biomass



Potentials of domestic Swiss woody biomass resources (Erni, Thees et al. in preparation, status: 16.11.2016).[38]

Technology: Woody biomass consists of forest wood, industrial wood residues, waste wood, and wood from landscape maintenance. Only a certain portion of these resources are currently recoverable – legally and economically – for energetic use in Switzerland. These resources can be converted to electricity either by combustion or gasification pathways. Combustion is followed by a combined heat and power system (CHP) to produce electricity and heat. Gasification is followed by any technology that can take gaseous fuel as an input (internal combustion engine, turbine or fuel cells). The following conversion technology types can be distinguished based on the classification used by BFE in the Swiss Renewable Energy Statistics:

- **Automatic wood combustion CHP:** Combustion of clean wood chips and logs for CHP use starting at 50 kW_{fuel}.
- **Combustion of wood and organic wastes:** Industrial-scale combustion of waste woods and organic wastes, which can be used for energetic uses.
- **KVA – waste incineration**: Large installations with the primary purpose of incinerating wastes.
- **Wood gasification CHP**: CHP unit based on the gasification of wood, instead of its combustion.


Autom. wood combustion CHP in Felben-Wellhausen (TG) © Schmid


Combustion of wood & organic wastes, Spiez (BE) © Eicher + Pauli


KVA, Basel (BS) © IWB


Wood gasifier, Stans (NW) © Korporation Stans

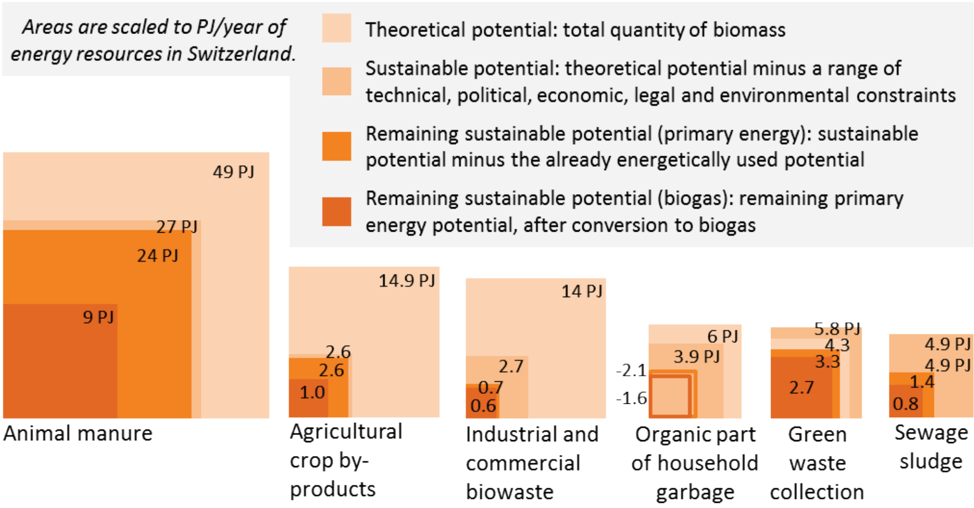
[38] The sustainable potential of forest wood shown here is the quantity using a price threshold without subsidies of 5.9 Rp./kWh. If considering subsidies to the feedstock costs, a larger potential would result.

Gasification technologies are not yet as widely used as combustion technologies. Combustion approaches have higher technological maturity, but most biomass combustion systems in Switzerland still produce heat only. Upgrading these installations to CHP units and utilizing currently unused feedstock represent the two largest potentials for added electricity generation from woody biomass.

Woody biomass		**New power plants**			
		Current	**2020**	**2035**	**2050**
Electricity generation potential[1] [GWh/a]	Autom. wood CHP[2]	126	126-225	126-614	126-1142
	Combustion of wood & organic wastes[3]	70	70	70	70
	KVA[4] – waste incineration[5]	1065	1065-1072	1065-1105	1065-1262
Electricity generation costs[6] [Rp./kWh$_{el}$] *(in italics without heat credits)*[7]	Autom. wood combustion	18-36 *(35-71)*	18-37 *(35-73)*	18-41 *(35-80)*	18-45 *(35-87)*
	Combustion of wood & organic wastes		18-36 *(35-71)*	18-36 *(35-71)*	18-36 *(35-71)*
	Wood gasification[8] CHP[2]	18-31 *(25-44)*	18-32 *(25-44)*	17-33 *(24-47)*	16-35 *(23-49)*
	KVA[4] – waste incineration	2.5-16[9] *(2.6-17)*	2.5-16 *(2.5-16)*	2.4-15 *(2.5-16)*	2.3-15 *(2.5-16)*
GHG emissions[10,11] [g CO_2eq/kWh]	Combustion and gasification	~10-120	~10-120	~10-100	~10-100 (minus ~1300)[12]

[1] The possible range of future potential is large, because these are still relatively new technologies. The lower end of the future potential range refers to today's electricity production. The upper end of the future potential range assumes a gradual increase in the use of technically and economically recoverable biomass resources, until 100% of this feedstock is utilized in 2050. It also assumes an increase in the efficiency of technologies by greater use of gasification for the use of the additional feedstock. A more conservative scenario is also considered in the report.
[2] CHP: Combined heat and power (Wärme-Kraft-Kopplung, WKK).
[3] This category does not increase in the future, because it is assumed that feedstock should be directed to the "Autom. wood CHP" category instead, as it has a significantly higher electrical efficiency.
[4] KVA: Kehrichtverbrennungsanlage (waste incineration plant).
[5] This category is also listed in the non-woody biomass factsheet. It should only be counted once making a total.
[6] Predictions in costs of electricity production are done by starting from today's costs. The cost structure of each technology (contribution from capital costs, fuel, O&M, etc.) is analyzed based on selected case studies, and assumptions are made about the outlook for each of these categories. Increases in these costs are due to predicted increases in the price of wood as a feedstock as more wood becomes utilized for energy uses.
[7] Costs are also estimated without heat credits using cost structures in Table 10.4. Capital costs, O&M costs are not otherwise changed; heat credits are only removed. However, in reality wood-based electricity systems depend heavily on heat sales, so it is strongly recommended to use the costs *with* heat credits.
[8] Gasification & combustion are combined in the "Autom. wood CHP" category for potentials but not for costs.
[9] The low end of the KVA cost range refers to "standard" KVA incinerating municipal waste. The high end refers to specialized units which burn more wood than waste, for example the KVA/Holzkraftwerk in Basel.
[10] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies and are quantified using LCA and thus represent the complete fuel cycle/energy chain. Further environmental indicators are discussed in the report. The ranges provided are based on literature and are supposed to reflect variability in terms of technology, fuel supply, etc. Due to lack of data, these ranges are not Swiss-specific and can only be provided on an aggregated level. Swiss-specific results for some selected technologies are provided in the report. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 $_g$ CO_2eq./kWh (high voltage).
[11] Decreasing emissions for 2035 and 2050 reflect expected increase in efficiency of electricity generation.
[12] Negative GHG emissions are possible with Carbon Capture and Storage (CCS).

Fact sheet – Non-woody biomass



Potentials[39] of domestic Swiss non-woody biomass resources (Burg, Bowman et al. in preparation, status: 2.2.2017).

Technology: Non-woody biomass consists of several feedstocks of varying liquid content, including organic parts of household waste, industrial and commercial bio-waste, agricultural crop by-products, green waste, animal manure, and sewage sludge. Feedstocks with high liquid content (sewage sludge, manure, etc.) are first processed through an anaerobic digester. The resulting biogas can be used to generate electricity and heat in an engine, turbine, or fuel cell. Feedstocks with lower liquid content can be combusted to drive a steam or organic Rankine (ORC) cycle. Gasification of waste feedstocks is also technically feasible. One commercial waste gasifier exists today in Lahti, Finland. The following conversion technology types can be distinguished based on the classification used by SFOE in the Swiss Renewable Energy Statistics:

- **KVA – waste incineration:** Large installations with the primary purpose of incinerating wastes.
- **Municipal WWTP:** Biogas produced by anaerobic digestion of municipal sewage sludge.
- **Industrial WWTP:** Biogas produced as a result of required pre-purification of effluents in some industries, especially in the processing of fruits and vegetables.
- **Industrial biogas:** Production of biogas from green waste, food waste, slaughter waste, etc. from municipal, commercial and industrial sources.
- **Agricultural biogas**: Production of biogas on farms from manure and co-substrates.

KVA, Basel (BS) © IWB

Municipal WWTP Morgental (SG) © morgenthal.ch

Industrial WWTP Rickenbach (LU) © Gefu Produktions

Industrial biogas KBA Hard, Beringen (SH) © abfall-sh.ch

Agricultural biogas Düdingen (FR) © ZHAW

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[39] The organic part of the household garbage is expected to decrease in future, as more green waste is separated at source. This is the reason for the negative value of the remaining potential for organic part of household garbage.

Anaerobic digestion is a relatively mature technology at large scales (e.g., wastewater treatment plants) but not yet at smaller scales. Manure represents the largest currently unused biomass potential in Switzerland, but it is distributed at many small farms. Small scale systems are still heavily supported by feed-in tariffs (KEV) and will need to reduce capital costs to become economical. Electrical efficiency for waste incineration is expected to improve as steam parameters become optimized (previously, the focus was only on waste destruction, not electricity).

Non-woody biomass		**New power plants**			
		Current	**2020**	**2035**	**2050**
Potential[1] [GWh/a]	KVA[2] – waste incineration[3]	1065	1065 – 1072	1065 – 1105	1065 – 1262
	Municipal WWTP[4]	119	119 – 129	119 – 170	119 – 225
	Industrial WWTP[4,5] Industrial biogas[5]	84	84 – 149	84 – 381	84 – 668
	Agricultural biogas	100	100 – 232	100 – 718	100 – 1342
Electricity generation costs[6] [Rp./kWh_{el}] *(in italics without heat credits)*[7]	KVA[2] – waste incineration	2.5 – 16[9] *(2.6-17)*	2.5 – 16 *(2.5-16)*	2.4 – 15 *(2.5-16)*	2.3 – 15 *(2.4-16)*
	Municipal WWTP[4] Industrial WWTP[4]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]
	Industrial biogas Agricultural biogas	20 – 49 *(23-55)*	20 – 49 *(22-55)*	18 – 50 *(20-56)*	16 – 51 *(18-57)*
GHG emissions[10,11] [g CO_2eq/kWh]	Agricultural biogas	150-450	150-450	no data	no data

[1] The lower end of the future potential range refers to today's electricity production. The upper end of the future potential range assumes a gradual increase in the use of technically and economically recoverable biomass resources, until 100% of this feedstock is utilized in 2050. It also assumes a gradual increase in the efficiency of technologies by greater use of fuel cells as biogas-to-electricity converters. A more conservative scenario, which assumes that technology does not improve even though more feedstock is used, is also considered in the report.

[2] KVA: Kehrichtverbrennungsanlage (waste incineration plant).

[3] This category is also listed in the woody biomass factsheet. It should only be counted once if making a total.

[4] WWTP: Wastewater treatment plant (Abwasserreinigungsanlage, ARA).

[5] These categories are combined in the future generation prediction because they utilize similar feedstocks.

[6] Predictions in costs of electricity production are done by starting from today's costs. The cost structure of each technology (contribution from capital costs, fuel, O&M, etc.) is analyzed based on selected case studies, and assumptions are made about the outlook for each of these categories. WWTP costs are not expected to change because the technology is assumed to be mature.

[7] Costs are also estimated without heat credits using cost structures in Table 10.4. Capital costs, O&M costs are not otherwise changed; heat credits are only removed. However, in reality some systems rely heavily on heat sales, so it is strongly recommended to use the costs *with* heat credits.

[8] It is assumed that the majority of heat produced at WWTPs is used on site and therefore no significant income results from heat sales.

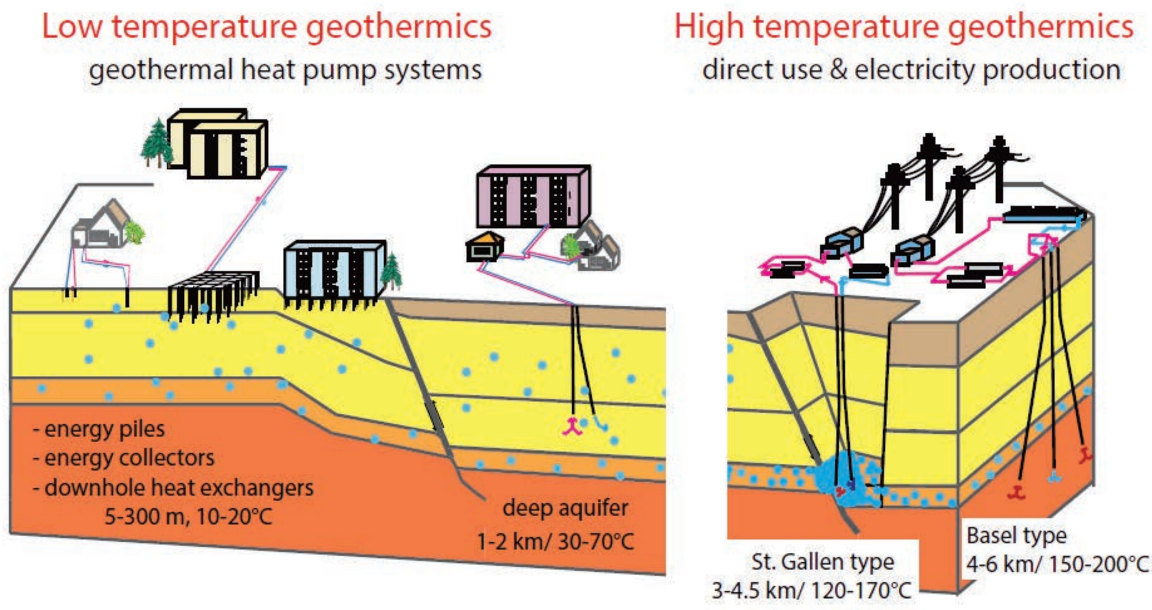
[9] The low end of the KVA cost range refers to "standard" KVA incinerating municipal waste. The high end refers to specialized units which burn more wood than waste, for example the KVA/Holzkraftwerk in Basel.

[10] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies and are quantified using LCA and thus represent the complete fuel cycle/energy chain. Further environmental indicators are discussed in the report. Consistent and recent LCA results for non-woody biomass conversion are scarce – uncertainties and ranges are large. The ranges provided are rough estimates for agricultural, small-scale manure gasification and CHP generation. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 g CO_2eq./kWh (high voltage).

[11] Life cycle GHG emissions are dominated by potential "leakage" of methane during anaerobic digestion of feedstock. No substantial changes can be expected until 2020. High-quality estimates for 2035 and 2050 are not available.

Fact sheet – Deep geothermal power

Technology: Deep geothermal electricity generation. In general, depths of wells are larger than 400m and underground temperatures are above 120°C. In Switzerland, due to lack of shallow geothermal resources, well depths will be most likely around 4-6 km.



Technologies can be categorized based on the way thermal energy resources are used:

- Flash steam, dry steam, back pressure plants: Such plants globally exist and are feasible at suited locations with hot water or steam reservoirs (not in Switzerland).
- Hydrothermal (HT) plants: HT plants are globally operated. The potential of these plants is limited as they require high underground temperatures (>100°C), water-bearing geological formations and structures, and adequate generation of hot water in these formations.
- Enhanced Geothermal Systems (EGS): EGS plants are envisioned to generate electricity in Switzerland in the future. Currently, EGS plants are not operated at commercial scale. The potential of EGS plants is high, as they do not depend on local conditions as much as the other deep geothermal plant types. EGS plants are more dependent on technical issues such as the drilling and a successful stimulation phase. By drilling two or more deep wells and connecting them, cold water can be injected to high-temperature rock formations, warm up there and then be pumped up through one or two other well(s) back to the surface. The hot water will drive a generator with or without an organic working fluid in a binary cycle.

Power plant (net) capacities are mainly determined by the temperature gradient, well depth, and reservoir impedance, i.e. are mostly site- and less time-dependent. Model reference cases for Switzerland result in capacities of ca. 1.5-3 MW_{el}, good cases (conditions are average or above expectations) reach 3-5.5 MW_{el}, and very beneficial conditions result in plants with up to 10 MW_{el} per well triplet. Well fields with several triplets may be built at such optimal locations.

Deep geothermal power - EGS		**New power plants**			
		Current	**2020**	**2035**	**2050**
Potential[1]	TWh/a	No deep geothermal power generation in Switzerland	n.a.	n.a.[9]	~4.5
GHG emissions[2,3,4,5]	g CO_2-eq./kWh		27 - 84		
Investment costs					
Well	Million CHF/well			18 - 30	15
Fracturing	Million CHF/well			3.3	3.3
Power generation plant	CHF/kW_{el}			4000	3500
Electricity generation costs[3,4,6,7] (without heat credits)	Rp./kWh			16 - 58	13 - 47 (~10)
Electricity generation costs[3,4,8] (with heat credits)	Rp./kWh			-3 - 33	-4 - 27

1 The Swiss energy strategy aims at 4-5 TWh/a in 2050. The number provided here for 2050 represents a long-term potential in line with this target, which can only be realized, if current geological, technical, legal, social and economic barriers can be overcome.

2 Greenhouse gas emissions are used as key indicator for the environmental performance; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability due to site-specific conditions. For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 90 g CO_2-eq./kWh (high voltage).

3 Figures provided here are results of a Swiss-specific coupled economic/environmental EGS model considering variability of geothermal conditions (temperature gradient, flow rates, etc.). The ranges in GHG emissions and LCOE provided here are supposed to reflect this variability.

4 Both the LCOE and the environmental impacts are very location-specific, mainly depending on geological conditions. Therefore, only a rough estimate for the potential development over time can be provided.

5 Emissions are completely allocated to electricity, since it's uncertain whether the by-product heat can be used.

6 LCOE are provided first without heat credits, since EGS plants are likely to be located in relatively remote areas without large heat consumers. More details are provided in chapter 9.4.

7 Very favorable geological conditions could result in LCOE of about 10 Rp./kWh.

8 Revenues from heat sales can substantially improve the economic performance of EGS (even lead to negative LCOE). More details are provided in chapter 9.4.

9 Still not seen as available on a large scale.

Fact sheet – Wave (and tidal) power

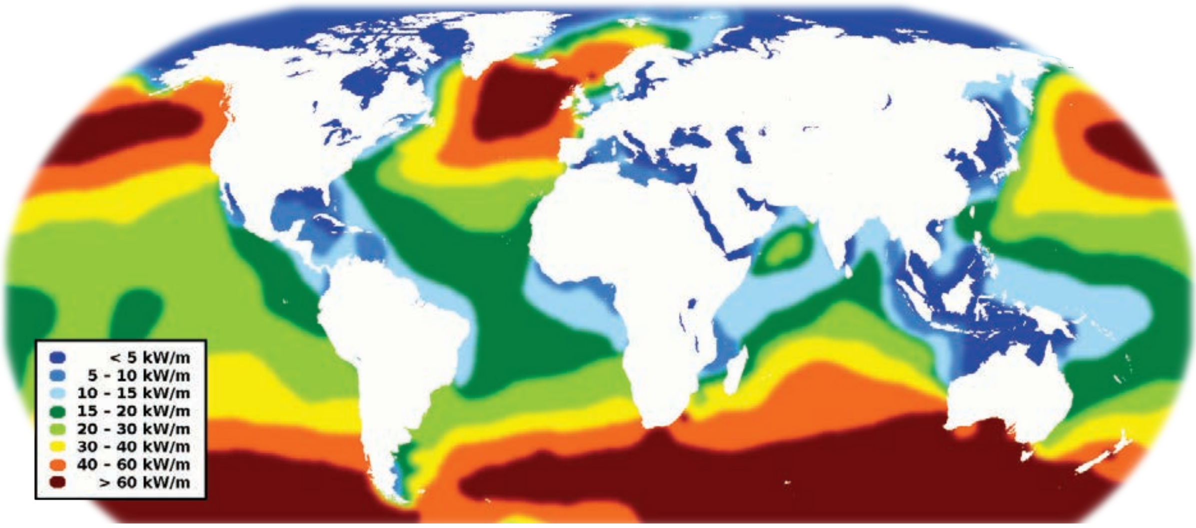
Technology: Wave power is the transport of energy by ocean waves driven by the wind, and the capture of that energy to do useful work, for example, electricity generation. Machines able to exploit wave power are known as wave energy converters (WEC). Tidal power converts the energy obtained from tides into electricity. Wave power technologies can be divided into two broad categories, **onshore** and **offshore**.

Wave power technologies. From the left to the right: Pelamis; SINN; Wave roller; Atlantis turbine; Wave dragon.

Wave and tidal power generation are still in their adolescence, with a relatively small number of demonstration scale installations scattered around the globe. Future developments are likely to focus on offshore designs due to larger energy density, less restricted siting and no visual disturbance.

Resource: Locations with the most potential for wave power include the western seaboard of Europe, the northern coast of the UK, and the Pacific coastlines of North and South America, Southern Africa, Australia, and New Zealand. The north and south temperate zones have the best sites for capturing wave power. The prevailing westerlies in these zones blow strongest in winter.

Wave energy for Switzerland would have to be imported, most likely from the Atlantic coast of Spain, Portugal or France.



World wave energy resource map; wave energy density in kW/m around the globe.

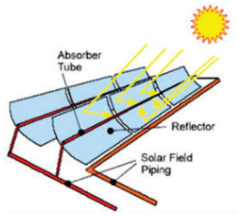
Wave and tidal power			New power plants			
			Current[1]	2020	2035	2050
Potential[2]	TWh/a	offshore	n.a.	30	30	30
		onshore	n.a.	10-15	10-15	10-15
Investment costs[3]	CHF/kW	offshore & onshore	4000-9500	3000-7000	2100-5000	1900-3500
Electricity generation costs[3,4,5]	Rp./kWh	offshore & onshore	~38 (23-80)	~30 (14-42)	~17 (9-24)	~11 (8-19)
Import costs[6]	Rp./kWh	~1000 km	n.a.	~0.5	~0.5	~0.5
GHG emissions[7,8]	g CO_2-eq./kWh	wave power	15-105			
		tidal power	15-70			

[1] “Current” refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today.
[2] Generation at the Southern European and French Atlantic coast with subsequent transmission to Switzerland.
[3] Available data do not allow for differentiation between onshore and offshore technologies.
[4] Generation costs include investment, operation and maintenance costs. Details concerning data used can be found in the report.
[5] Ranges provided are based on literature and reflect variations in site characteristics, technology and uncertainties in future developments.
[6] Costs for long-distance electricity transmission from the Atlantic coast to Switzerland.
[7] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect different technologies. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 $_{g}$CO2eq./kWh (high voltage).
[8] The ranges provided reflect a range of different current wave and tidal power concepts; more differentiated estimates concerning future development of LCA results are not possible given the technological maturity and due to limitations of available literature.

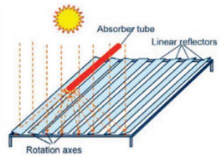
Fact sheet – Solar Thermal Electricity generation (Concentrated Solar Power, CSP)

Technology: CSP technologies produce electricity by concentrating direct solar irradiance to heat a liquid, solid or gas that is then used in a downstream process for electricity generation. Linear focusing systems with heat transfer fluid temperatures of up to about 550°C and point focusing systems allowing for higher temperatures and efficiencies are available. CSP plants are usually installed at locations with direct normal irradiation DNI >2000 kWh/m^2/a (i.e. not in Switzerland) at latitudes of <35-40° and can integrate thermal storage for peaking, intermediate and base load generation (less than one hour up to 15 hours of generation from stored energy). Electricity from CSP plants in the Mediterranean area could be imported to Switzerland. This can be accomplished with minor losses (3%/1000 km) via High Voltage DC (HVDC) power lines.

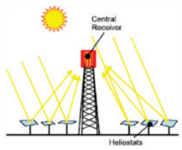
The following four CSP technologies can be distinguished:



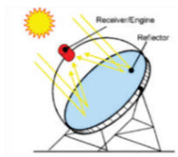
- Parabolic trough (PTC): Long parabolic troughs track the sun on one axis, concentrate the solar rays on linear receiver tubes isolated in an evacuated glass envelope, heat a transfer fluid, and then transfer this heat to a conventional steam cycle.



- Linear Fresnel reflector (LFR): Work similar to PTC and approximate the parabolic shape of trough systems, but use long rows of flat or slightly curved mirrors to reflect the sun's rays onto a downward-facing linear, fixed receiver.



- Central receiver or "Power tower" (CRS): A large number of mirrors ("solar field") is used to concentrate solar rays in a central receiver. Heat generated there is used to operate a conventional steam cycle.



- Parabolic dish (PDC): The concentrated sunlight is used to operate single heat-to-electricity engines (Stirling motors or micro-turbines) at the focal points of curved reflectors. Limited possibilities for integration of heat storage.

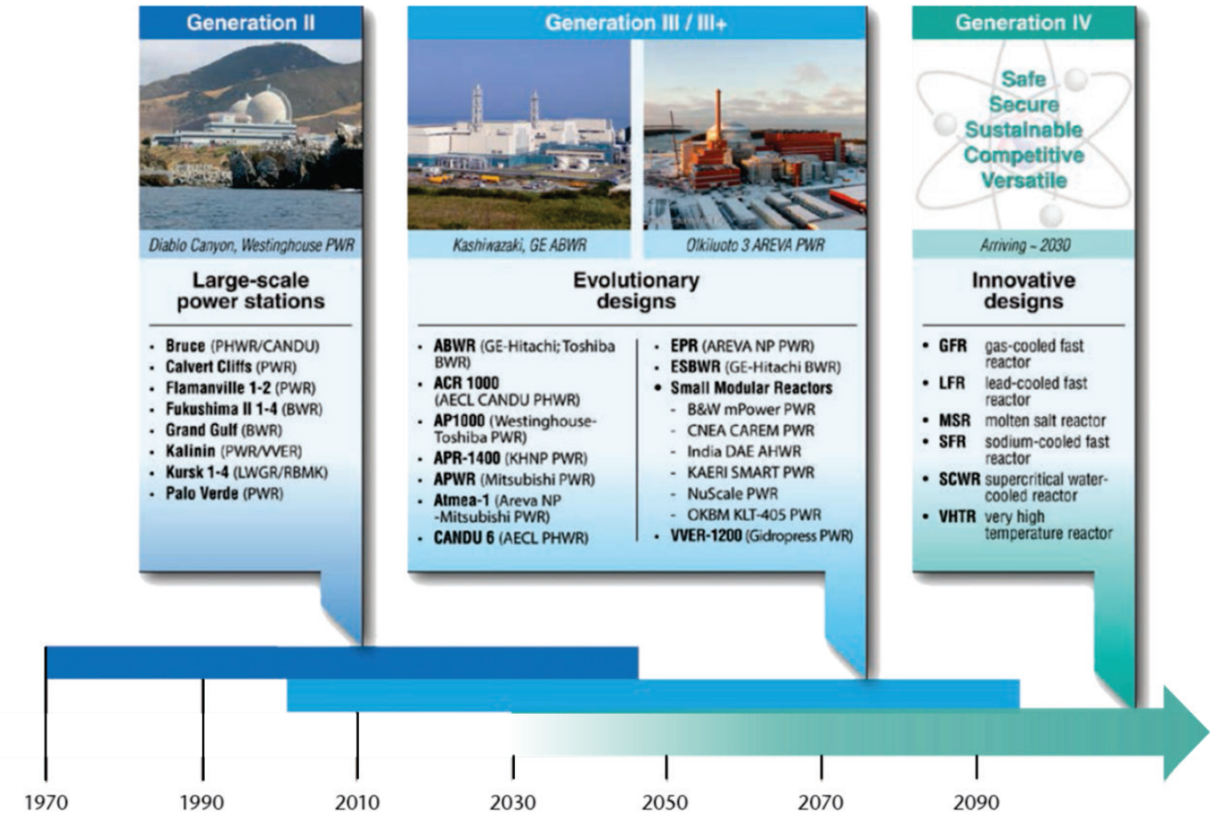
Few commercial CSP plants operate today, mainly in Spain and the USA. Largest plants today with capacities of up to 750 MW are installed in the USA. PTC and CRS, the two CSP technologies predominantly installed in recent years, can be considered as most mature and reliable in operation. PDC have almost disappeared from the commercial energy landscape, due to comparatively high costs and more difficult integration of heat storage. There is still a significant potential for technological improvement as well as for cost reduction due to mass production and larger scales. Further CSP development mainly aiming at cost reductions will still require substantial private and governmental R&D and market incentives. Learning rates are estimated as approximately 10%. Electricity imports from the Mediterranean area require the construction of additional transmission lines, either point-to-point HVDC transmission or connection to an extended future European grid.

Concentrated Solar Power, CSP			**New power plants**			
			Current[1]	**2020**	**2035**	**2050**
Potential	TWh/a	Worldwide	~25[2]	31-466	n.a.	222-9'348
		EUMENA[3]	n.a.	<99	<660	<1358
		MENA[4]	n.a.	<69	<490	<1150
Performance	Full load hours per year	(Switzerland)	n.a.	(1250)	(1375)	n.a.
		Spain[5] (incl. TES; max. 6400)	~5000	~5500	~5500	~5500
		Algeria[6] (incl. TES; max. 8000)	~5500	~6000	~6000	~6000
Annual solar-to-electricity efficiency	%	PTC (including storage)	13-15	n.a.	~19	~19
		LFR (<10min storage)	9-13	n.a.	~12	~12
		CRS (including storage)	14-18	n.a.	~18	~18
		PDC (no storage)	22-24	n.a.	n.a.	n.a.
Investment costs[7]	CHF/kW	PTC (without storage)	3'100-8'000	3'100-8'000	3'000-5'900	2'000-5'900
		PTC (0.5-8h storage)	3'400-12'800			
		CRS (0.5->8h storage)	3'400-12'800			
		LFR (0.5-4h storage)	3'400-6'700			
Electricity generation costs[8,9]	Rp./kWh	Without storage	16-33	n.a.	n.a.	n.a.
		With storage (4-15h)	14-28	6-23	7-11	6-9
Import costs[10]	Rp./kWh		n.a.	n.a.	~2	~2
GHG emissions[11]	g CO_2-eq./ kWh	Parabolic trough	13-55	13-55	5-44	5-36
		Central receiver system	9-42	9-42	5-25	5-21
		Parabolic dish	5-60	5-60	3-36	3-30

[1] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today.
[2] Rough estimate based on installed capacities.
[3] Europe, Middle East and North Africa. Only small fractions would probably be available for Swiss supply.
[4] Middle East and North Africa. Only small fractions would probably be available for Swiss supply.
[5] DNI 2000 kWh/m2/a; TES=Thermal Energy Storage. Rough estimate; actual performance in practice depends on dimensioning of solar field and TES (and other factors, see report).
[6] DNI 2500 kWh/m2/a; TES=Thermal Energy Storage. Rough estimate; actual performance in practice depends on the layout of the solar field and TES (and other factors, see report).
[7] Available data do not allow for differentiation between specific CSP technologies in the future.
[8] Generation costs include investment, operation and maintenance and fossil natural gas as fuel. Ranges provided here represent variability in literature. Details concerning data used can be found in the report.
[9] Literature data do not allow for estimation of CSP technology specific LCOE.
[10] Costs for long-distance electricity transmission from MENA countries to Switzerland.
[11] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of performance parameters. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 g CO_2-eq./kWh (high voltage).

Fact sheet – Nuclear power

Technology: Nuclear power is based on the fission of U-235 atoms in fuel that has generally been enriched from the natural level of 0.7%, producing fission fragments and enough neutrons to sustain a chain reaction. Beyond these fundamentals, there is a very broad range of possible choices: different fuel cycles (feedstock, enrichment, oxide vs. metal), whether the neutrons should be moderated (slowed down) from fast to thermal spectra, the material used as a moderator (light or heavy water, graphite, etc.), the coolant used to generate steam (water, molten metal or gas), and the overall reactor configuration. The dominant reactor designs have been based on uranium oxide enriched to 3-5%, using light water as a moderator for thermal neutrons (Light Water Reactors; LWR), and generating steam by either direct boiling (Boiling Water Reactors; BWR) or using pressurized steam generators (Pressurized Water Reactors; PWR). The figure below shows the successive generations of reactor designs and the many variations, driven by the goals of economic generation and increased safety.



Successive generations of nuclear power technologies (adapted from (OECD/NEA/IEA 2015)).

The presently dominant LWR technology can be considered relatively mature, but the pressure to increase safety and remain cost-competitive is driving evolutionary designs (Generation 3+). This includes a recent trend to small modular reactors (SMR) with a wider design range that it is hoped can trade the benefits of standardized, factory construction for economies of scale. Actual cost estimates are few and uncertain. Although some designs are potentially low in cost, most estimates of overnight costs (capital costs without interest) are not far from current designs, and the barriers of factory investment and first unit costs and orders are significant. Beyond this, a broader spectrum of Generation 4 designs are intended on a case-by-case basis to achieve more inherent safety, improved proliferation resistance, reduced volumes of long-lived radioactive wastes, and better resource sustainability (higher temperatures to increase efficiency and thermal applications).

A broad range of current and future reactor designs can also be fuelled with thorium. Unlike U-235, thorium is not fissile, but rather fertile (like U-238), so the thorium is converted (or bred) to U-233 inside the reactor, and the fuel cycle must be initially driven by another fissile fuel or a neutron accelerator. Thorium is more abundant, can produce less high level waste, and is somewhat more proliferation resistant than present nuclear fuels. However, the breeding ratio limits the rate of fleet expansion, and there are still technical and economic uncertainties.

Resource: The availability of uranium is not the dominant limiting factor in future nuclear generation. The use of present reasonably assured reserves in current reactor designs could conceivably limit a growing reactor fleet in the next century, but alternate fuel cycles, reactor designs, enrichment methods, and backstop fuel resources (e.g., uranium from seawater) all mean that the limits on reactor construction are more likely to be determined by cost competitiveness, and societal choices balancing the environment (climate change), safety and proliferation.

Nuclear power		**Currently operating plants in CH**	**“New plants”**[1] (hypothetical new, Gen III/III+)	**2035** (SMR[6])	**2050** (Gen IV)
Electricity generation potential[2]	TWh/a	not applicable			
Investment costs[3]	CHF/kW	1’300-6’000	4’000-7’000	3’000-9’000	not analyzed
Electricity generation costs[4]	Rp./kWh	4-6 [7]	7.5 (5.1 - 12.5)	7.4 (5.1 - 12.2)	not analyzed
GHG emissions[5]	g CO_2-eq./kWh	10-20	10-20	5-40	

[1] “Current” refers to power plants decided to be built today. Construction of new nuclear power plants in Switzerland is no longer allowed, since the Swiss population agreed to the energy strategy 2050 on May 25, 2017.

[2] As explained above, the energy resource (uranium or thorium) is not the limiting factor, but rather economic constraints and the societal choice to implement this technology.

[3] Overnight Capital Costs. The cost range for the presently operating Swiss plants includes the costs of major upgrades since start of operation (KKL and KKG). The capital cost provided for “current” represents the cost of present designs (Gen III/III+, e.g. the EPR) to be built in Switzerland. The capital cost given for the 2035 time period represents the possible range of capital costs for small modular reactors (SMR), but the Gen III/III+ price in the previous column would also be valid for 2035. Although the midrange cost value for the small modular reactor is only slightly higher than for the Gen III/III+, the considerably broader price range reflects a broader range of designs, potential savings and technical uncertainty. Based on the available information, Gen IV costs for 2050 are still too uncertain to indicate a cost range.

[4] Generation costs include investment, operation, maintenance as well as dismantling and waste disposal costs. For “current” and 2035 the cost range is based on sensitivity analysis varying single cost factors individually from 50% to 200%. Details concerning the data used can be found in the nuclear technology chapter. Gen III/III+ and SMR cost ranges reflect the base value, lower bound and upper bound of the single variable sensitivity analysis. Although the base SMR investment cost is higher, it is assumed to be built in only two years, and the lower interest cost means that the average cost is slightly lower.

[5] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the nuclear technology chapter. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect the variability concerning a range of assumptions in inventory data. Due to limited data availability, values for 2035 and 2050 represent only rough estimates and Gen IV reactors have not been analyzed due to lack of data. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 g CO_2-eq./kWh (high voltage).

[6] Small modular reactors.

[7] For average generation costs of the current Swiss nuclear power plants, capital costs are largely amortized, and the generation cost is taken from annual reports of KKL and KKG.

Fact sheet – Natural gas and coal power

Technology: Natural gas can be used in large Combined Cycle (NGCC) power plants as well as smaller, decentralized combined heat and power (CHP) generation units. Plant sizes range from 1 kW_{el} to the order of GW_{el}. Electricity from hard coal and lignite is generated in large power plants. "Carbon Capture, Utilization and Storage" (CCUS) for large natural gas and coal power plants is currently a field of research and development. Technologies (except of CCUS) are mature; future development aims at increasing generation efficiencies and further reduction of combustion-related emissions of air pollutants.

Abbreviations

NGCC	Natural gas combined cycle
NGCC post	Natural gas combined cycle, CO_2 capture post-combustion
NGCC pre	Natural gas combined cycle, CO_2 capture pre-combustion
NG turbine	Natural gas turbine
CHP 1kW_{el}	Natural gas piston engine combined heat and power plant 1 kW_{el}
CHP 10kW_{el}	Natural gas piston engine combined heat and power plant 10 kW_{el}
CHP 100kW_{el}	Natural gas piston engine combined heat and power plant 100 kW_{el}
CHP 1000kW_{el}	Natural gas piston engine combined heat and power plant 1000 kW_{el}
IGCC hard coal	Integrated Gasification Combined Cycle, hard coal
IGCC hard coal pre	IGCC, CO_2 capture pre-combustion, hard coal
SCPC hard coal	Supercritical pulverized coal, hard coal
SCPC hard coal post	Supercritical pulverized coal, CO_2 capture post-combustion, hard coal
SCPC hard coal oxy	Supercritical pulverized coal, CO_2 capture oxyfuel, hard coal
IGCC lignite	Integrated Gasification Combined Cycle, lignite
IGCC lignite pre	Integrated Gasification Combined Cycle, lignite, CO_2 capture pre-combustion
SCPC lignite	Supercritical pulverized lignite
SCPC lignite oxy	Supercritical pulverized lignite, CO_2 capture oxyfuel
SCFBC lignite	Supercritical fluidized bed combustion, lignite
FBC lignite post	Fluidized bed combustion, lignite, CO_2 capture post-combustion

Notes concerning the following table

[1] Calculations include capital, decommissioning, operation & maintenance costs. Ranges reflect optimistic and pessimistic technology specification and development, respectively, as well as future cost reduction rates.
[2] According to Table 4.3: natural gas prices for Swiss residential and industry; coal price (hard coal) for industry.
[3] GHG emissions are used as key indicator for environmental performance; further indicators can be found in the report. Indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. Ranges reflect optimistic and pessimistic technology specification and development. For comparison: the current Swiss electricity consumption mix (HV) has a GHG intensity of about 90 g CO2eq./kWh.
[4] GHG emissions of CHP units are calculated applying exergy allocation for combined heat and power generation.
[5] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today.
[6] Electricity generation (and import) is technically only limited by fuel/electricity import capacities; however, limited by economic, environmental and social constraints in reality. A thorough analysis of CHP potentials has not been performed, since such units are currently not economically viable options and space heating demand will considerably change in the coming years.

Electricity from natural gas and coal		**New power plants**			
		Current[5]	**2020**	**2035**	**2050**
Potential	TWh/a	1.6	n.a.[6]		
Electricity generation costs[1] (with heat credits for CHP) (Rp./kWh_{el})	NGCC	11.3 (10.8 - 12.3)	11.7 (11.1 - 12.6)	13.4 (12.9 - 14.2)	15.2 (14.5 - 16.0)
	NGCC post	14.1 (13.0 - 15.8)	14.4 (13.4 - 16.1)	16.3 (15.3 - 17.7)	18.4 (17.3 - 19.8)
	NGCC pre	14.2 (13.3 - 16.0)	14.3 (13.4 - 16.0)	16.1 (15.3 - 17.6)	18.1 (17.3 - 19.6)
	NG turbine	18.5 (16.8 - 20.9)	19.6 (17.9 - 22.0)	21.3 (19.6 - 23.8)	23.6 (21.8 - 26.1)
	CHP $1kW_{el}$	71.8 (50.2 - 114.6)	70.6 (49.5 - 112.5)	67.0 (47.4 - 106.0)	65.6 (46.9 - 103.1)
	CHP $10kW_{el}$	29.6 (22.2 - 45.3)	29.5 (22.2 - 45.6)	29.5 (22.5 - 44.8)	30.2 (23.4 - 45.3)
	CHP $100kW_{el}$	14.2 (9.6 - 19.2)	14.9 (9.6 - 20.4)	16.5 (11.1 - 21.9)	18.3 (12.7 - 23.9)
	CHP $1000kW_{el}$	12.0 (9.9 - 14.6)	12.7 (10.4 - 15.7)	14.5 (12.1 - 17.4)	16.6 (14.0 - 19.6)
	IGCC hard coal	7.1 (6.5 - 8.3)	7.2 (6.6 - 8.4)	7.5 (6.9 - 8.7)	7.7 (7.3 - 8.9)
	IGCC hard coal pre	9.5 (8.3 - 11.2)	9.3 (8.2 - 10.9)	9.0 (8.2 - 10.3)	9.4 (8.5 - 10.6)
	SCPC hard coal	5.5 (5.2 - 5.9)	5.7 (5.4 - 6.1)	6.3 (5.9 - 6.7)	6.8 (6.5 - 7.3)
	SCPC hard coal post	8.5 (7.6 - 9.6)	8.3 (7.5 - 9.3)	8.8 (8.0 - 9.7)	9.4 (8.6 - 10.3)
	SCPC hard coal oxy	8.5 (7.1 - 10.2)	8.5 (7.2 - 10.1)	8.6 (7.5 - 10.0)	8.9 (8.0 - 10.1)
	IGCC lignite	6.6 (5.6 - 7.6)	6.5 (5.6 - 7.5)	6.8 (5.8 - 7.7)	7.1 (6.1 - 8.0)
	IGCC lignite pre	8.6 (7.3 - 10.1)	8.4 (7.2 - 9.9)	8.6 (7.4 - 10.1)	9.0 (7.7 - 10.4)
	SCPC lignite	4.6 (4.0 - 5.6)	4.7 (4.1 - 5.6)	4.8 (4.2 - 5.8)	5.1 (4.4 - 6.0)
	SCPC lignite oxy	8.9 (7.4 - 10.6)	8.6 (7.1 - 10.5)	7.4 (6.3 - 10.4)	6.6 (5.5 - 10.4)
	SCFBC lignite	4.5 (3.9 - 5.3)	4.6 (4.0 - 5.4)	4.8 (4.3 - 5.6)	5.1 (4.6 - 5.9)
	FBC lignite post	7.7 (6.6 - 9.2)	7.8 (6.7 - 9.3)	8.0 (6.8 - 9.6)	8.3 (7.0 - 10.0)
Electricity generation costs[1] (without heat credits) (Rp./kWh_{el})	CHP $1kW_{el}$	93.2 (72.7 - 131.5)	92.4 (72.4 - 129.6)	91.6 (73-1 - 125.8)	89.3 (71.9 - 121.6)
	CHP $10kW_{el}$	48.8 (40.3 - 63.3)	49.1 (40.7 - 63.3)	51.5 (43.5 - 65.0)	51.3 (43.5 - 64.3)
	CHP $100kW_{el}$	22.3 (19.2 - 26.2)	22.2 (19.2 - 26.5)	25.4 (22.3 - 29.6)	26.2 (23.2 - 30.3)
	CHP $1000kW_{el}$	17.1 (15.5 - 19.3)	17.1 (15.5 - 19.2)	20.1 (18.4 - 22.2)	21.0 (19.3 - 23.1)
Fuel costs: natural gas[2] (CHF/MWh)	CHP 1 kW_{el}, 10 kW_{el}	84	87	103	110
	All other technologies	56	58	75	82
Fuel costs: hard coal/lignite[2] (CHF/MWh)	All technologies	13/6	18/8	20/9	22/10
Life cycle GHG emissions[3,4] (gCO_2-eq/kWh_{el})	NGCC	393 (387 - 400)	380 (374 - 386)	365 (359 - 371)	357 (346 - 363)
	NGCC post	104 (94 - 114)	99 (90 - 109)	90 (81 - 103)	83 (75 - 100)
	NGCC pre	97 (81 - 120)	91 (76 - 112)	86 (72 - 107)	83 (70 - 103)
	NG turbine	570 (556 - 585)	570 (556 - 584)	520 (509 - 533)	500 (489 - 511)
	CHP $1kW_{el}$	643 (611 - 677)	636 (605 - 670)	618 (589 - 648)	606 (578 - 635)
	CHP $10kW_{el}$	611 (583 - 633)	605 (575 - 632)	586 (558 - 613)	575 (546 - 601)
	CHP $100kW_{el}$	506 (476 - 529)	500 (464 - 530)	482 (448 - 511)	474 (441 - 503)
	CHP $1000kW_{el}$	481 (459 - 500)	473 (450 - 498)	452 (429 - 476)	445 (423 - 468)
	IGCC hard coal	841 (823 - 860)	820 (803 - 838)	807 (790 - 824)	748 (734 - 764)
	IGCC hard coal pre	205 (177 - 255)	190 (164 - 237)	172 (148 - 213)	156 (135 - 194)
	SCPC hard coal	845 (827 - 864)	825 (807 - 843)	803 (786 - 820)	785 (768 - 801)
	SCPC hard coal post	240 (223 - 268)	229 (214 - 256)	204 (181 - 234)	181 (159 - 214)
	SCPC hard coal oxy	158 (123 - 215)	153 (119 - 208)	145 (113 - 197)	137 (106 - 187)
	IGCC lignite	912 (892 - 934)	871 (852 - 891)	842 (824 - 861)	832 (815 - 850)
	IGCC lignite pre	128 (103 - 178)	121 (94 - 170)	109 (85 - 154)	107 (83 - 151)
	SCPC lignite	965 (942 - 1022)	929 (902 - 980)	837 (803 - 874)	801 (785 - 835)
	SCPC lignite oxy	83 (43 - 152)	79 (38 - 149)	71 (33 - 133)	67 (34 - 122)

Fact sheet – Fuel cells

Technology: Fuel cells electrochemically convert natural gas into heat and electricity. Systems operating on hydrogen are assumed to be equipped with a fuel reformer to generate hydrogen on site. Installations are extremely scalable from <1 kW to hundreds of kilowatts. Operation is very flexible, with high part load efficiency; start up times range from minutes to hours, depending on fuel cell type.

Some fuel cell types have been made commercially available, though most projects are still dependent on funding support for demonstration projects. Significant improvements to capital costs, system lifetimes and efficiencies are expected for the future.

Fuel cells		**New power plants: Current[1]**		**2020**	**2035**	**2050**
Potential[2]	TWh/a		<0.01	~1.2	~6.1	~7.9
Electricity generation costs[3,4] (with heat credits)	Rp./kWh	PEFC 1 kW_{el}	96 (65 - 125)	37 - 95	24 - 64	20 - 46
		SOFC 1 kW_{el}	96 (65 - 124)	35 - 98	23 - 60	19 - 44
		SOFC 300 kW_{el}	54 (40 - 70)	24 - 57	15 - 37	14 - 23
		MCFC 300 kW_{el}	23 (17 - 32)	15 - 30	16 - 31	14 - 24
		PAFC 300 kW_{el}	22 (17 - 32)	14 - 29	14 - 22	13 - 20
Electricity generation costs[3,4] (without heat credits)	Rp./kWh	PEFC 1 kW_{el}	108 (77 - 136)	49 - 106	36 - 75	30 - 57
		SOFC 1 kW_{el}	107 (76 - 134)	46 - 108	33 - 70	29 - 53
		SOFC 300 kW_{el}	58 (44 - 73)	27 - 60	18 - 39	17 - 25
		MCFC 300 kW_{el}	29 (23 - 37)	20 - 35	21 - 35	18 - 27
		PAFC 300 kW_{el}	29 (24 - 38)	21 - 35	22 - 30	21 - 28
Fuel costs: natural gas	CHF/MWh	1 kW_{el} / 300 kW_{el}[9]	84/56	87/58	103/75	110/82
Fuel costs: biomethane	CHF/MWh	1 kW_{el} / 300 kW_{el}[9]	159/131	162/133	178/150	185/157
GHG emissions[5,6,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	690 (590 - 780)	540 - 700	490 - 620	450 - 570
		SOFC 1 kW_{el}	610 (560 - 670)	520 - 630	480 - 560	440 - 520
		SOFC 300 kW_{el}	490 (360 - 540)	340 - 500	350 - 440	340 - 420
		MCFC 300 kW_{el}	560 (370 - 610)	360 - 580	380 - 490	360 - 450
		PAFC 300 kW_{el}	590 (500 - 650)	480 - 620	460 - 580	440 - 550
GHG emissions[5,7,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	440 (350 - 530)	330 - 470	320 - 430	300 - 410
		SOFC 1 kW_{el}	430 (350 - 520)	330 - 470	310 - 420	300 - 390
		SOFC 300 kW_{el}	390 (330 - 460)	310 - 420	300 - 380	290 - 370
		MCFC 300 kW_{el}	410 (340 - 490)	320 - 450	310 - 400	290 - 370
		PAFC 300 kW_{el}	410 (340 - 500)	320 - 460	310 - 420	300 - 400

[1] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new fuel cells to be built today.

[2] Potential is technically unlimited; this estimation is based on replacement of fossil fueled domestic heating.

[3] Generation costs include investment, operation and maintenance and fossil natural gas as fuel. Ranges provided here represent variability in assumptions concerning e.g. efficiency, investment cost, lifetime, etc. Details concerning data used and sensitivities can be found in the report.

[4] Results are shown for fossil natural gas as a fuel source. If biomethane is used, costs increase by 8-14 Rp./kWh.

[5] GHG emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in chapter 16.5. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of performance parameters such as efficiency and lifetime. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100 g CO_2-eq./kWh (low voltage).

[6] GHG emissions allocated between heat and electricity based on exergy. Results shown for electricity production.

[7] GHG emissions based on system expansion, which means that the GHG emissions associated with the equivalent heat produced by a modern condensing natural gas boiler have been subtracted from the total.

[8] GHG emissions for biomethane as fuel are not available.

[9] According to Table 5.3: natural gas prices for Swiss residential and industry, respectively, and a premium of 75 CHF/MWh for biomethane.

1.6 Comparison with previous studies

1.6.1 Scope and approach

In comparison to the previous analysis of potentials and costs of domestic electricity production and electricity imports (Hirschberg, Bauer et al. 2005), the scope of the present analysis is substantially more comprehensive:

- Several additional technologies are considered: large hydropower, natural gas combined cycle plants, CHP units and fuel cells, coal power, fossil power plants with CO_2 capture and novel technologies (Hydrothermal methanation of wet biomass, novel geothermal technologies, nuclear fusion, thermoelectrics).
- The analysis includes an evaluation of environmental burdens based on life-cycle assessment.
- Swiss-specific ranges for both electricity generation costs and environmental impacts are – as far as possible – provided in a consistent way for all technologies.
- Sensitivity of electricity generation costs is analyzed in a consistent way for most of the technologies.
- The whole analysis has been carried out in a more systematic, transparent and comprehensive way concerning differentiation according to technology specification, used references and input data as well as underlying assumptions.
- This analysis was extensively reviewed by experts from the federal offices, industry and academic institutions.
- The results of the analysis of electricity generation potentials and costs as well as environmental impacts are provided in the context of other national and international studies.

1.6.2 Estimates for electricity generation costs and potentials

Electricity generation potentials and generation costs from this analysis are compared to previous estimates according to (Hirschberg, Bauer et al. 2005, Hirschberg, Bauer et al. 2010, Densing, Hirschberg et al. 2014, Densing, Panos et al. 2016)[40]: maximum renewable generation potentials[41] (Figure 1.8) and LCOE in 2050 (Figure 1.9) are used for this purpose. Reference technologies and their applications are not always specified in detail in the various references, which might distort the comparison. Concerning generation potentials, only hydropower, electricity from biomass, deep geothermal, wind power and photovoltaics can be compared; the recent studies do not provide consistent data for other energy carriers and technologies. Concerning electricity generation costs in 2050, only LCOE from PV, wind power, natural gas CC plants and nuclear power can be compared. The evaluated studies do not provide data for other technologies and energy carriers.

The estimate for additional hydropower generation in the present analysis ("PSI 2017") includes both small and large hydropower; it's not clear whether this is also the case for the other studies, or whether only large hydropower is addressed. The comparatively low

[40] Densing, Hirschberg et al. (2014) compiled an extensive comparison of recent Swiss energy scenarios according to major studies, with explicit comparison of renewable generation potentials and generation costs.
[41] Consistent numbers from other studies are only available for hydropower, electricity from biomass, photovoltaics, wind power and deep geothermal power and refer to the "the economic and socially acceptable potential", which is here assumed to correspond roughly to "constrained technical potentials" or "exploitable potentials", as specified in this analysis.

numbers from (Barmettler, Beglinger et al. 2013, Teske and Heiligtag 2013) are due to environmental issues disfavoring a further expansion of hydropower. Variations of biomass-to-electricity potentials are due to different primary data sources and different assumptions concerning conversion technologies as well as competing biomass utilization (for heating and transportation purposes). The previous analysis of PSI (Hirschberg, Bauer et al. 2005) did not include large hydropower and biomass-to-electricity potentials. Wind power potentials are relatively uniform across the studies, most of them being based on the same primary source. In case of deep geothermal power, most of the studies (including this one) refer to the federal long-term target; this can only be realized, if current geological, technical, legal, social and economic barriers can be overcome (Hirschberg, Wiemer et al. 2015). PV potentials show the highest variations; however, it's unclear, whether all studies refer to roof-top PV installations only[42], or also include facade and open-ground installations.

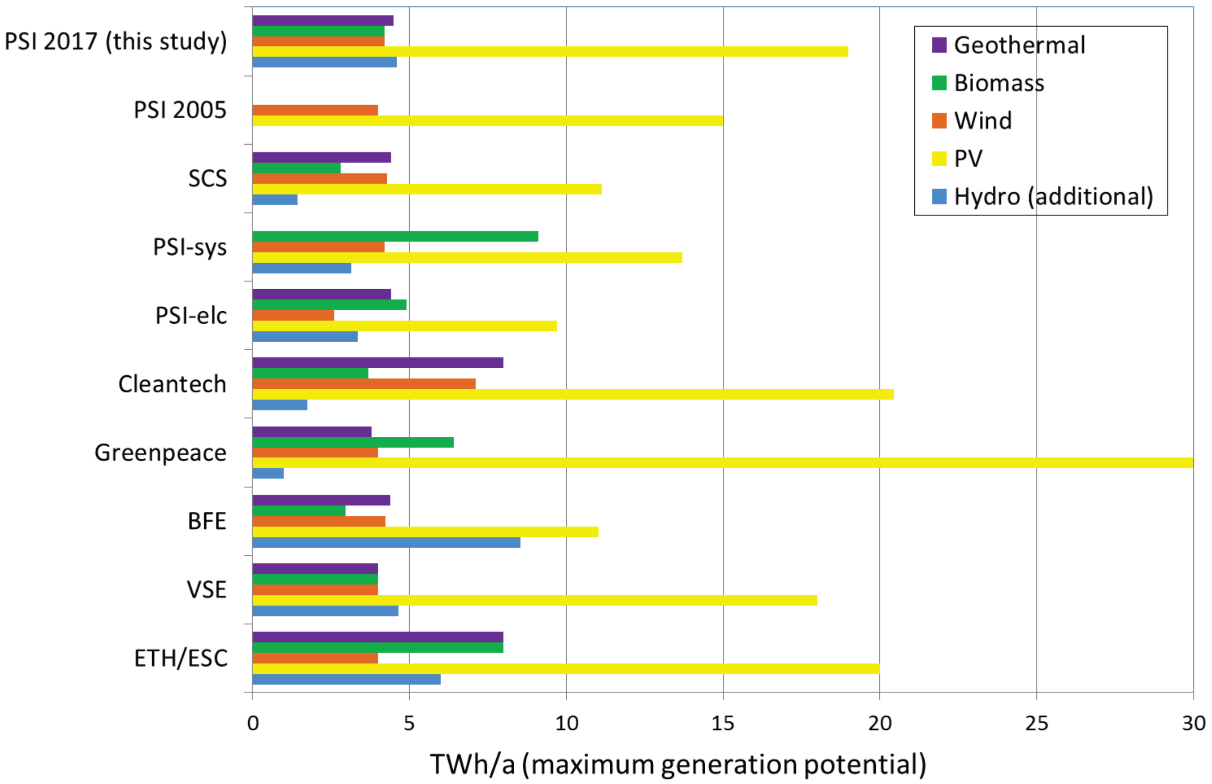


Figure 1.8: Maximum renewable generation potentials in Switzerland according to various recent evaluations. Consistent data for other technologies and energy carriers are not available. "Hydro" includes only additional generation from new and refurbished hydropower plants; for all other technologies, current generation is included[43]. PV: photovoltaics; ETH/ESC: (Andersson, Boulouchos et al. 2011); VSE: (VSE 2012); BFE: (Prognos 2012a); Greenpeace: (Teske and Heiligtag 2013); Cleantech: (Barmettler, Beglinger et al. 2013); PSI-elc: (Kannan and Turton 2012b, Kannan and Turton 2012a); PSI-sys: (Weidmann 2013); SCS: (SCS 2013); PSI 2005: only potentials for wind power and photovoltaics were quantified for 2050 (Hirschberg, Bauer et al. 2005); PSI 2010: (Hirschberg, Bauer et al. 2010); "PSI 2017" includes roof-top PV potentials only in this graph.

A more detailed comparison with (Hirschberg, Bauer et al. 2005) shows that the potential of small hydropower estimated in the present analysis is slightly lower. Wind power potentials remain basically equal, since major new estimates are not yet available. PV potentials of this analysis are higher than they have been before, due to new primary data sources and a

[42] For the present analysis ("PSI 2017"), this graph only includes generation potential from roof-top PV installations; available numbers for additional potential for facade PV installations are provided in chapter 9.3.
[43] Included due to limited data availability in original references.

more detailed analysis of future technology development. The new estimates for import of concentrated solarthermal power and power from the ocean are slightly higher, but of the same order of magnitude.

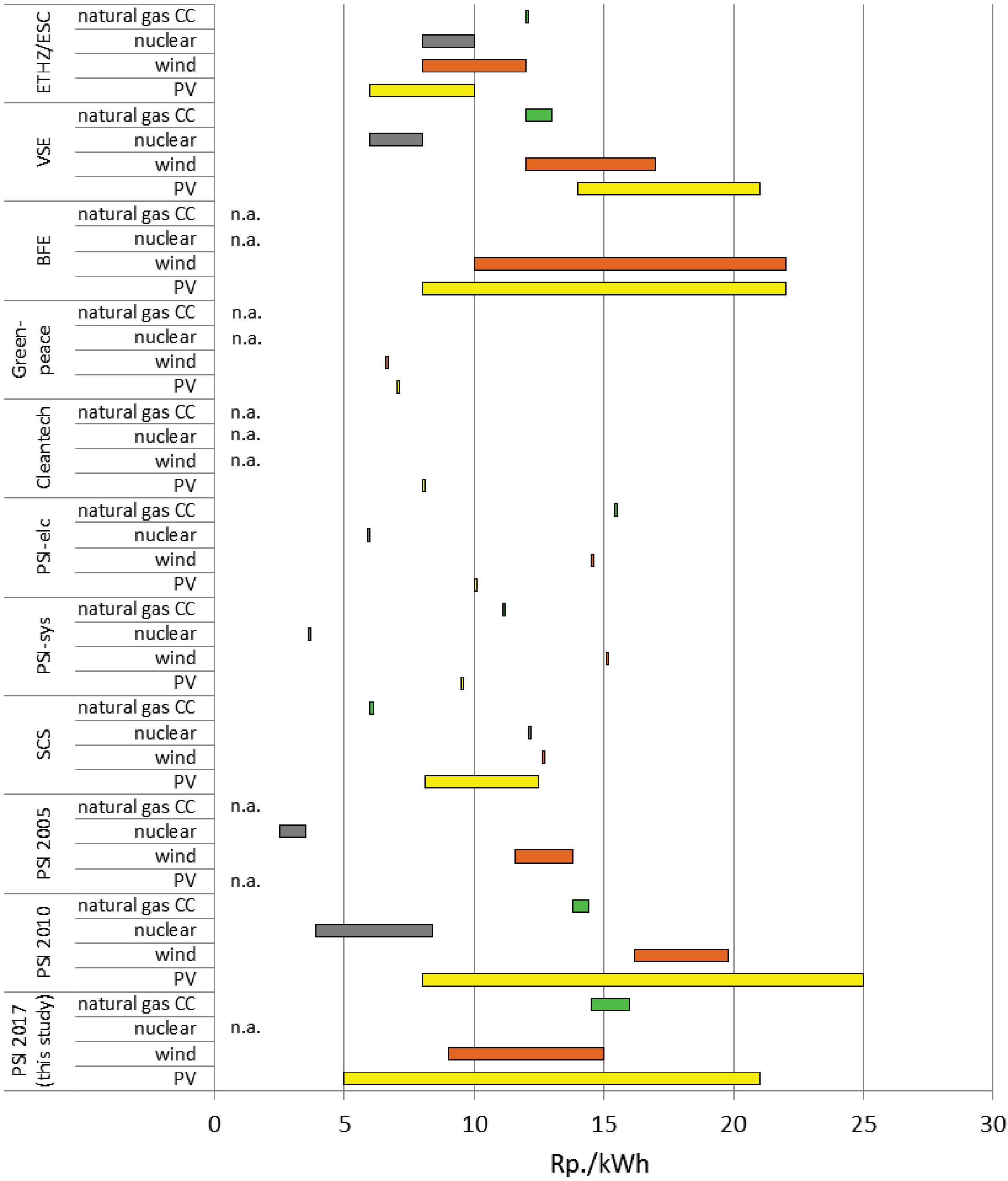


Figure 1.9: Electricity generation costs (LCOE) of different technologies in Switzerland in 2050 according to various sources. Consistent data for other technologies and energy carriers are not available. PV: photovoltaics; ETH/ESC: (Andersson, Boulouchos et al. 2011); VSE: (VSE 2012); BFE: (Prognos 2012a); Greenpeace: (Teske and Heiligtag 2013); Cleantech: (Barmettler, Beglinger et al. 2013); PSI-elc: (Kannan and Turton 2012b, Kannan and Turton 2012a); PSI-sys: (Weidmann 2013); SCS: (SCS 2013); PSI 2005: (Hirschberg, Bauer et al. 2005). n.a.: not analyzed. Cost ranges can indicate variation in technology specification, expected technology development, site-specific aspects or interest rates and are not always further specified in the references used. Not all references provide ranges.

Comparing estimated LCOE in 2050 from the present analysis with figures from the other recent studies shows that the range of generation costs from PV is broadest in the present analysis, since a wide range of unit capacities has been considered and large plants are substantially cheaper than small plants; in addition, this analysis takes into account variation due to the range of possible yields in Switzerland. Almost all LCOE from PV from other studies are within the range provided by this analysis. LCOE of wind power of this analysis are within the range of all other studies. LCOE of natural gas CC plants are relatively high compared to the other studies, which mainly seems to be due to the comparatively strong increase in gas prices assumed in this analysis based on authoritative sources.

A more detailed comparison with (Hirschberg, Bauer et al. 2005) shows that LCOE estimates for 2050 for small hydropower have slightly increased; new estimates for generation costs from PV are substantially lower, reflecting the strong decrease in module costs in recent years. Previous estimates for LCOE of wind power are within the range provided by this analysis. LCOE estimates for future nuclear power have increased compared to previous results. New estimates for CSP are lower than previous ones, while estimates for LCOE of deep geothermal power have increased. LCOE of electricity-to-biomass, large hydropower, wave and tidal power, electricity from natural gas CHP and fuel cells as well as coal power and natural gas and coal power plants with CO_2 capture have not been quantified in (Hirschberg, Bauer et al. 2005). In general, the comparison of LCOE shows the importance of a transparent procedure in quantification of LCOE with explicit specification of technology characteristics and input data.

1.7 Research gaps, outlook and recommendations

Despite of the extensive amount of literature reviewed and used for the present technology evaluation, and despite of the comprehensive and broad range of expertise of the researchers contributing to this analysis, some research gaps and open issues potentially important in the context of the future Swiss energy policy can be asserted:

- **Cost-potential curves**: Based on the available literature and current state of knowledge, it is not feasible to provide a detailed quantification of electricity generation potentials vs. generation costs for technologies for which such a dependence is likely. Thus, in a number of cases the detailed specification of which fractions of the overall technology potentials could be realized at which generation costs, is not provided in the present work.[44] This is potentially important for solar photovoltaics, hydropower, wind and geothermal power, electricity from biomass as well as building integrated combined heat and power generation with natural gas CHP units and fuel cells. Generation costs for these technologies are sensitive to site selection and local boundary conditions and these show large variations within the generation potentials provided. Based on the ongoing activities the corresponding differentiation should be relatively soon feasible for wind power plants while it won't be achievable for a long time in the case of deep geothermal plants.
- **Swiss specific cost data**: It is well known that prices in Switzerland are higher than on the European/international market. This also concerns the quantification of electricity generation costs (LCOE), since the infrastructure purchase costs (e.g., for generation

[44] However, such an explicit cost/potential curve is available for large hydropower, see Figure 6.19.

units) as well as project implementation and maintenance in Switzerland are more expensive, which can have a substantial impact on LCOE. However, available data sources mostly provide prices/costs for non-Swiss markets and reliable Swiss-specific figures are not always available (e.g., the price of a natural gas Combined Cycle power plant, to be constructed in Switzerland, will most likely be higher than available data indicate). Within this analysis, these effects could only be considered to a limited extent and not in a completely consistent way for the different technologies. The issue is implicitly addressed by sensitivity analysis for LCOE showing the impact of different cost factors on LCOE.

- **System aspects/electricity storage**: The present analysis addresses only single electricity generation technologies. However, in the context of both economic and environmental evaluation, issues concerning the whole electricity supply system such as seasonal and daily generation patterns of specific technologies, potentially required extension of the transmissions and distribution grid, back-up generation or electricity storage need to be evaluated in detail by modeling the whole supply system.
- **Environmental aspects**: The evaluation of life cycle environmental burdens and potential impacts of electricity generation technologies was supposed to be based on existing inventory data; only limited additional analysis was performed. Therefore, some of the results for current technologies are slightly outdated and some incompleteness and some inconsistencies could not be avoided. Partial incompleteness and inconsistencies in available inventory data concerning future technologies prevent a detailed analysis of the future environmental performance of Swiss electricity supply.
- **External costs**: State-of-the-art quantification of external costs of Swiss electricity supply are not available and calculating these was out of scope of this analysis. Therefore, this issue could not be addressed.

The scope of this analysis, specified by the Swiss Federal Office of Energy, did not allow for addressing these open issues. Further research is recommended to close these gaps.

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2 Zusammenfassung

Dieser Bericht enthält eine umfassende Evaluation der technologiespezifischen Potenziale und Kosten der Stromproduktion in der Schweiz sowie von Stromimporten bis ins Jahr 2050. Zusätzlich werden die Umweltauswirkungen dieser Stromproduktion quantifiziert. Potenziale, Kosten und Umweltauswirkungen sind jeweils für heute und die Jahre 2020, 2035 und 2050 angegeben. Die Evaluation beinhaltet folgende Technologien zur Stromproduktion:

- Grosswasserkraftwerke (GWK)
- Kleinwasserkraftwerke (KWK)
- Windturbinen
- Fotovoltaik-Anlagen (PV)
- Technologien zur Verstromung von Biomasse
- Geothermie-Kraftwerke
- Wellen- & Gezeitenkraftwerke
- Anlagen zur solarthermischen Stromerzeugung
- Kernkraftwerke
- Erdgas- & Kohlekraftwerke, Erdgas-BHKW
- Brennstoffzellen
- Neuartige Technologien

Systemaspekte, d.h. das Zusammenspiel der einzelnen Technologien innerhalb des gesamten Stromversorgungssystems, sind nicht Gegenstand dieser Analyse. Ausserhalb des Rahmens dieser Arbeit sind auch externe Kosten[45].

Diese Arbeit wurde federführend von Wissenschaftlern am PSI[46] durchgeführt; unterstützt durch Experten des WSL, der EPFL und der ETHZ. Auftraggeber war das Bundesamt für Energie (BFE). Die Analyse wurde im Rahmen der beiden „Swiss Competence Centers for Energy Research (SCCER)“ “Supply of Energy (SoE)”[47] und “Bioenergy (BIOSWEET)”[48] durchgeführt. Diese Arbeit stellt einen Beitrag zum „Technologiemonitoring“ des BFE innerhalb des Monitorings der Energiestrategie 2050 dar und die Ergebnisse der Analyse sollen in den kommenden Energieperspektiven genutzt werden.

Diese Zusammenfassung ist folgendermassen gegliedert:

Erst wird ein kurzer Überblick über die Stromproduktionstechnologien und die erwartete zukünftige Entwicklung gegeben. Danach sind die Potenziale zur Stromproduktion bzw. zur Stromversorgung dargestellt, gefolgt von den Kosten und Umweltauswirkungen der Stromproduktion. Die wichtigsten Informationen und Daten zu den verschiedenen Technologien

[45] Externe Kosten sind Kosten, die nicht vom Verursacher getragen werden müssen (Buchanan and Craig 1962). Meist werden externe Kosten von der Gesellschaft getragen. Externe Kosten im Zusammenhang mit der Stromproduktion entstehen z.B. durch Gesundheitsschäden als Folge von Luftverschmutzung durch die Verbrennung von Kohle, Holz, oder Erdgas. Nicht versicherte Kosten, die aufgrund von potenziellen Unfällen anfallen könnten, können auch als externe Kosten bezeichnet werden.

[46] Laboratory for Energy Systems Analysis (https://www.psi.ch/lea/); Laboratory for Thermal Processes and Combustion (http://crl.web.psi.ch/); Solar Technology Laboratory (https://www.psi.ch/lst/).

[47] http://www.sccer-soe.ch/

[48] http://www.sccer-biosweet.ch/

sind in so genannten „fact sheets" („Datenblättern", Kapitel 1.5) zusammengefasst. Abschliessend werden die Ergebnisse dieser Arbeit mit jenen aus früheren Studien verglichen sowie aktueller Forschungsbedarf aufgezeigt und Empfehlungen für weitere Arbeiten in diesem Zusammenhang gegeben.

2.1 Technologien zur Stromproduktion

2.1.1 Grosswasserkraft (GWK)

Wasserkraftwerke mit installierten Leistungen >10 MW fallen in der Schweiz in die Kategorie „Grosswasserkraft". Zwei Arten von Anlagen können unterschieden werden: Speicher- und Laufkraftwerke. Speicherkraftwerke besitzen eine Staumauer und einen zugehörigen Stausee, während Laufkraftwerke das direkt verfügbare Wasser in Flüssen nutzen. Ausserdem gibt es Pumpspeicherkraftwerke, die Strom zu Zeiten hohen Bedarfs produzieren und dazu Wasser zwischen Stauseen auf verschiedenen Höhen mittels Pumpen nutzen. Pumpspeicher- und Speicherkraftwerke werden of kombiniert, indem auch natürliche Wasserzuflüsse in die Stauseen genutzt werden. Der Strom in Wasserkraftwerken wird mit Turbinen erzeugt. Welche Turbinentechnologie verwendet wird, hängt vor allem von Durchflussraten und Fallhöhen ab; die wichtigsten Turbinenarten, die alle Wirkungsgrade von mehr als 90% erreichen, sind Francis-, Kaplan- und Peltonturbinen. Wasserkraftwerke sind eine Technologie, bei der keine substanziellen Fortschritte mehr erwartet werden können.

2.1.2 Kleinwasserkraft (KWK)

Wasserkraftwerke fallen in der Schweiz in die Kategorie „Kleinwasserkraft", wenn die installierte Leistung weniger als 10 MW beträgt. Kleinwasserkraftwerke können nach Typ kategorisiert werden (Laufwasser-, Ausleitungs-, Speicher oder Umwälzwerke) oder nach genutztem Abflussmedium (Fluss-, Abwasser-, Trinkwasser-, Dotierkraftwerke). Die Technologien an sich sind Grosswasserkraftwerken ähnlich. Es existieren jedoch unter Umständen technische Einschränkungen für KWK für bestimmte Anwendungen und die aktuelle Forschung zielt darauf ab, neue Technologien zur besseren Nutzung von kleinen Fallhöhen und geringen Abflussmengen zu entwickeln.

2.1.3 Windturbinen

Heute übliche Windturbinen haben drei Rotorblätter und eine horizontale Achse; sie werden zu Land (onshore) und zu Wasser (offshore) installiert. Turbinen mit vertikaler Achse spielen aus technischen und wirtschaftlichen Gründen heute keine Rolle und es wird nicht erwartet, dass sich dies bis 2050 ändert. Moderne Turbinen weisen Leistungen von bis zu 8 MW auf; Rotordurchmesser liegen bei bis zu 164 m, Nabenhöhen bei bis zu 220 m. 72% der heute installierten Anlagen haben Leistungen von 1-3 MW; dies stellt auch die heute übliche Grösse moderner Turbinen in der Schweiz dar. Kleinwindanlagen mit Leistungen von weniger als 100 kW sind und werden Nischenprodukte bleiben. Heutige Windturbinen sind eine weit entwickelte Technologie (besonders onshore-Anlagen). Die Technologieentwicklung geht in Richtung erhöhter Anlagenleistung und Steigerung der Verlässlichkeit. Leistungen von bis zu 20 MW einzelner Turbinen scheinen machbar. Grössere Nabenhöhen werden in Zukunft zu einer besseren Nutzung der Windenergie führen, da Windgeschwindigkeiten mit der Höhe über dem Boden zunehmen.

2.1.4 Fotovoltaik (PV)

Fotovoltaikzellen wandeln Sonnenstrahlung direkt in Strom um, und zwar in Gleichspannung. Mittels Wechselrichter muss diese Gleichspannung vor der Einspeisung ins Stromnetz in Wechselspannung umgewandelt werden. In der Schweiz werden Fotovoltaikanlagen üblicherweise auf Hausdächern installiert. Etwa die Hälfte der Anlagen in der Schweiz weist heute Leistungen unter 100 kW auf, etwa die Hälfte Leistungen über 100 kW. Mehr als die Hälfte der Anlagen sind auf Einfamilienhäusern installiert. Bezüglich insgesamt installierter Leistung sind jedoch (im Vergleich grössere) Anlagen auf Industrie- und Landwirtschaftsgebäuden bedeutender.

Üblicherweise werden PV-Zellen anhand der Basismaterialien kategorisiert. Der heutige Markt für PV-Zellen wird von kristallinen Siliziumzellen (c-Si) dominiert. Polykristalline (mc-Si) Zellen stellen die wichtigste Technologie dar, monokristalline (sc-Si) Zellen haben während der letzten Jahre kontinuierlich Marktanteile verloren. So genannte „Dünnschichtzellen“ sind eine Alternative zu kristallinem Silizium. Kommerzielle Dünnschichtzellen bestehen aus amorphem Silizium (a-Si), Cadmium-Tellurid (CdTe), oder Kupfer-Indium-Gallium (di) Selenid (CIGS oder CIS). Weitere fortschrittliche Dünnschichtzellen, organische Zellen und Konzentratortechnologien befinden sich im Forschungs- und Entwicklungsstadium. Die heute besten Zellen auf dem Markt erreichen Wirkungsgrade von 17% (polykristallin und CdTe) bzw. 21.5% (monokristallin). Die Technologieentwicklung im Bereich Fotovoltaik zielt hauptsächlich auf eine Reduktion der Herstellungskosten und auf eine Steigerung der Wirkungsgrade ab. Das theoretische Maximum für „single-junction“ kristalline Siliziumzellen liegt bei rund 30%. Da zwischen PV-Zellen und PV-Modulen stets Verluste auftreten (Wechselrichter, etc.) wird angenommen, dass bis ins Jahr 2050 das Maximum des Wirkungsgrades auf Modulebene bei 27% liegt. Die Lebensdauer heutiger PV-Module liegt bei etwa 30 Jahren und es wird angenommen, dass diese bis 2035 auf 35 Jahre steigen wird.

2.1.5 Strom aus Biomasse

„Biomasse als Ressource“ beinhaltet eine Reihe von verschiedenen Ausgangsstoffen zur Stromproduktion – vom Abwasser über Gülle, industrielle und kommunale Abfälle, bis zum Waldholz.

Um Potenziale zur Stromproduktion und die zugehörigen Kosten quantifizieren zu können, wird in dieser Analyse zwischen drei Kategorien von Anlagen zur Biomasseverstromung unterschieden:

a) Abfallsektor: Anlagen zur Verstromung von Biomasse, die Einkommen aus der Abfallbehandlung generieren, fallen in diese Kategorie; d.h., für diese Anlagen kann mit negativen Brennstoffkosten gerechnet werden. In diese Kategorie fallen Kehrichtverbrennungsanlagen (KVA), kommunale und industrielle Abwasserreinigungsanlagen sowie industrielle Biogasanlagen.

b) Holzsektor: Diese Kategorie beinhaltet Anlagen, die Holz als Brennstoff nutzen, bei denen aber im Gegensatz zu Anlagen im Abfallsektor Kosten für den Brennstoff anfallen. Strom wird meist gleichzeitig mit Nutzwärme in WKK-Anlagen[49] erzeugt, entweder durch Verbrennung oder Vergasung von Holz. Diese Anlagen weisen üblicherweise eine hohe wirtschaftliche Abhängigkeit vom Wärmeabsatz auf.

[49] WKK: Wärme-Kraft-Kopplung.

c) Landwirtschaftlicher Sektor: In diese Kategorie fallen Anlagen, die landwirtschaftliche Substrate als Biomasseressource nutzen. Üblicherweise ist das Einkommen durch Wärmeabsatz gering.

Nicht holzartige Biomasse mit hohem Wassergehalt, wie z.B. Abwasser und Gülle, wird in einem ersten Schritt über einen anaeroben Vergärungsprozess zu Biogas verarbeitet. Das Biogas kann anschliessend in einer WKK-Anlage genutzt werden, z.B. in einem Gasmotor, einer Gasturbine oder einer Brennstoffzelle. Holz- und nicht holzartige Biomasse mit einem geringeren Wassergehalt, etwa Siedlungsabfälle, können direkt verbrannt werden, um Dampf- oder ORC-Kreisläufe anzutreiben. Auch extern befeuerte Gasturbinen stellen eine Option dar. Holz- und nicht holzartige Biomasse können auch vergast werden zu einem so genannten „Syngas", das zur Stromproduktion in einem Motor oder anderen WKK-Anlagen verbrannt werden kann. Einen alternativen Nutzungspfad für alle Biomasserohstoffe stellt die Erzeugung von Biomethan dar. Dieses kann ins Erdgasnetz eingespeist und anschliessend flexibel als Energieträger genutzt werden – zur Stromproduktion, aber auch zum Heizen und als Treibstoff im Verkehr. Biomasse stellt also im Rahmen dieser Analyse einen Spezialfall dar, da es lediglich bei Biomasse zu einem „Wettbewerb" verschiedener Wirtschafts-/Energiesektoren um eine begrenzte Menge an Ressourcen kommt.[50]

Aktuelle Forschung und Entwicklung zielt darauf ab, die Stromproduktion aus einem beschränkten Biomasseangebot zu maximieren. Entweder durch eine Erhöhung der Umwandlungswirkungsgrade heutiger Technologien, oder durch die Entwicklung neuer Technologien, wie z.B. der hydrothermalen Gasifizierung oder der Güllevergärung mit Trennung der Biomasse in eine feste und eine flüssige Fraktion.

2.1.6 Geothermie

Energie zur Stromproduktion kann aus zwei verschiedenen Arten tiefer geothermischer Ressourcen (>400 m Tiefe, >120°C) gewonnen werden: entweder aus hydrothermalen, oder aus petrothermalen Systemen, so genannten "Enhanced Geothermal Systems (EGS)". Hydrothermale Systeme benötigen relative hohe Temperaturen im Untergrund (>100°C), wasserführende geologische Schichten und geeignete Erzeugung von heissem Wasser in diesen geologischen Formationen. Diese Voraussetzungen scheinen in der Schweiz nur an wenigen Orten gegeben zu sein. Da EGS nicht auf heisses Wasser im Untergrund angewiesen sind, sondern lediglich die natürlichen Temperaturdifferenzen zwischen Erdoberfläche und tiefem Untergrund nutzen, könnten nur diese EGS in Zukunft nennenswert zur Stromproduktion in der Schweiz beitragen. Folglich werden in dieser Arbeit nur solche Systeme analysiert.

Zur geothermischen Stromgewinnung werden zwei oder mehr Löcher in den tiefen Untergrund gebohrt und diese in der Tiefe miteinander verbunden. Kaltes Wasser wird von der Oberfläche in die Tiefe geleitet, wo es von der Erdwärme erwärmt und anschliessend wieder an die Oberfläche gepumpt wird. An der Oberfläche treibt das heisse Wasser über einen Organic Rankine Cycle (ORC) einen Generator an. EGS brauchen aus geologischer Sicht lediglich einen hohen Temperaturgradienten; entscheidend für eine erfolgreiche Umsetzung sind jedoch auch technische Aspekte wie eine erfolgreiche Stimulierung des Untergrundes

[50] Andere mögliche Interessenskonflikte wie z.B. um die Nutzung von Dachflächen für PV-Anlagen bzw. für solarthermische Warmwassererzeugung werden hier nicht untersucht.

und ein angemessener Umgang mit mineralischen Ablagerungen während des Anlagenbetriebs.

Typische Bohrtiefen für EGS lägen in der Schweiz bei etwa 5 Kilometern. Geothermische Temperaturgradienten müssen bei mehr als 30°C/km liegen, um Reservoirtemperaturen von >160°C zu erreichen. Abhängig von den geologischen Rahmenbedingungen wären für solche Geothermiekraftwerke (Netto-)Anlagenleistungen von 1-5 MW_{el} zu erwarten. Elektrische Wirkungsgrade wären wegen der geringen Temperaturen des Arbeitsmediums im Wärmetauscher vergleichsweise gering und deswegen würden grosse Mengen an Abwärme zur Verfügung stehen, die für einen wirtschaftlichen Betrieb so weit wie möglich genutzt werden müssten.

2.1.7 Wellen- und Gezeitenkraftwerke

Wellenkraftwerke können an der Küste (onshore) oder auf dem offenen Meer (offshore) errichtet und betrieben werden. Der Strom aus offshore Anlagen wird üblicherweise mit Kabeln am Meeresgrund an Land übertragen. Wellenkraftwerke sind weniger limitiert bzgl. Standortwahl als Gezeiten- oder Strömungskraftwerke. Zur Nutzung der Wellenenergie gibt es verschiedene Optionen, d.h. unterschiedliche Kraftwerkstypen; die wichtigsten onshore-Typen werden mit „Oscillating Water Column (OWC)“, „Pendulum“ und „Tapered Channel“ Design bezeichnet. „Hinged Float”, “Float Pump”, “Floating OWC” und “Floating Tapered Channel” Designs sind die wichtigsten offshore Technologien.

Im Vergleich zu den meisten anderen Technologien, die im Rahmen dieser Arbeit untersucht werden, befinden sich Wellen- und Gezeitenkraftwerke in einem frühen Entwicklungsstadium. Momentan kann keiner der erwähnten Kraftwerkstypen als am aussichtsreichsten bezeichnet werden und es ist nicht abzusehen, dass sich die Entwicklung der Industrie auf einen bestimmten Typ konzentrieren wird.

2.1.8 Solarthermische Stromerzeugung (concentrated solar power, CSP)

Solarthermische Kraftwerke nutzen Spiegel, um die Sonnenstrahlen zu konzentrieren und in einem „Empfänger“ zu sammeln. Die dort entstehende Wärme wird auf ein Fluid zur Wärmeleitung übertragen, mit dem ein konventioneller Dampfkreislauf zur Stromproduktion angetrieben wird. Da in der Schweiz die notwendige Sonnenintensität fehlt, können solarthermische Kraftwerke nicht als Option zur inländischen Stromproduktion betrachtet werden. Es kann jedoch Strom aus solarthermischen Kraftwerken in Südeuropa, Nordafrika oder dem Nahen und Mittleren Osten mittels Gleichstromübertragung importiert werden. Moderne CSP-Kraftwerke sind mit einem Wärmespeicher ausgestattet, um auch bei bedecktem Himmel oder in der Nacht Strom zu erzeugen. Dadurch können CSP-Kraftwerke bis zu einem gewissen Grad als regelbar angesehen werden.

Es existieren vier CSP-Kraftwerkstypen: “Parabolic Trough Concentrator (PTC)”, “Linear Fresnel Reflector (LFR)”, “Central Receiver System (CRS)” und “Parabolic Dish Concentrator (PDC)”. Die ersten drei werden hauptsächlich für relativ grosse Anlagen zur zentralen Stromproduktion verwendet, wobei der erste Typ mit Parabolspiegeln am weitesten entwickelt und verbreitet ist. PDC-Anlagen werden hingegen vor allem dezentral eingesetzt. PTC-Kraftwerke werden heute mit Speichern für 6-7.5 Stunden gebaut und erreichen damit jährliche Kapazitätsfaktoren von 36-41%. CRS-Anlagen mit einem Empfänger auf einem zentralen Turm erreichen höhere Temperaturen und können damit Flüssigsalzspeicher effizienter nutzen, womit sich Speicherdauern von 15h realisieren und jährliche Kapazitätsfaktoren von 75% erreichen lassen. Die jährlichen, durchschnittlichen Wirkungsgrade (Solarstrahlung-zu-Strom) heutiger CSP-Anlagen sind im Bereich von 10-25%. Technologieentwicklung zielt heute vor allem darauf ab, die Kosten der Anlagen zu senken sowie Stromerzeugungseinheiten und thermische Speicher zu optimieren, um Kapazitätsfaktoren und die Verlässlichkeit der Anlagen zu steigern.

2.1.9 Kernenergie

Die Kernkraftwerke in der Schweiz gehören alle zur zweiten Generation von Kernreaktoren (GEN II). Die älteren Kraftwerke in Beznau (KKB) und Mühleberg (KKM) wurden in den Jahren 1992/93 und 1990 umfassenden Nachrüstungen („NANO“ bzw. „SUSAN“) unterzogen. Beznau I ist aufgrund von zu beseitigenden technischen Problemen seit zwei Jahren vom Netz. Das KKM und das Kraftwerk in Leibstadt (KKL) sind Siedewasserreaktoren, das KKB und die Anlage in Gösgen (KKG) Druckwasserreaktoren.

Die heute dominierenden Leichtwasserreaktoren können als technisch ausgereift angesehen werden; allerdings besteht kontinuierlicher Druck zur Weiterentwicklung, vor allem um die Sicherheit zu erhöhen und gleichzeitig wettbewerbsfähig zu bleiben. Dies führt zu Weiterentwicklungen und neuen Designs (GEN III/III+). Teil der Entwicklung ist auch der Trend zu kleineren, modularen Reaktoren, deren Vorteil in einer standardisierten Produktion liegt. Darüber hinaus wird an der vierten Reaktorgeneration geforscht (GEN IV) – mit dem Ziel einer inhärenten Sicherheit, höherer Wirkungsgrade und einer besseren Nutzung der Ressourcen. Manche heutige und zukünftige Reaktoren können auch mit Thorium als Brennstoff betrieben werden. Im Gegensatz zu U235 ist Thorium kein spaltbares Nuklid, sondern ein brütbares (wie U238). Das heisst, dass Thorium im Reaktor zu U233 umgewandelt („gebrütet“) wird und dass der nukleare Kreislauf durch ein anderes spaltbares Element oder beschleunigte Neutronen angetrieben werden muss. Thorium ist im Vergleich zu den heutigen Kernbrennstoffen in grösseren Mengen vorhanden, verursacht weniger radioaktive Abfälle und ist vorteilhaft bzgl. Proliferation, da in diesem Kreislauf kein waffenfähiges Plutonium entsteht. Allerdings schränkt die Umwandlungsrate die Ausweitung von Thorium-Reaktoren ein; es existieren auch noch technische und wirtschaftliche Unsicherheiten.

2.1.10 Strom aus Erdgas und Kohle

Stromproduktion mit Erdgas kann in der Schweiz mit grossen, zentralen Kraftwerken (Gas- und Dampfkraftwerke, GuD) sowie kleineren, dezentralen Blockheizkraftwerken (BHKW), die gleichzeitig Strom und Nutzwärme erzeugen, erfolgen. Strom aus Braun- und Steinkohlekraftwerken ist eine Option für den Import. In Zukunft könnten Gas- und Kohlekraftwerke mit CO_2-Abscheidung ausgestattet werden; das abgeschiedene CO_2 kann geologisch gespeichert oder für andere Anwendungen genutzt werden. In diesem Zusammenhang wird in der vorliegenden Arbeit aufgrund der relativ grossen Unsicherheiten bei der CO_2-Speicherung und CO_2-Nutzung[51] lediglich der Schritt der CO_2-Abscheidung näher betrachtet.

[51] Abgeschiedenes CO_2 kann für verschiedene Zwecke genutzt werden, z.B. als Kohlenstoffquelle in so genannten „power-to-gas“ Prozessen, bei denen Strom via Elektrolyse von Wasser und einer darauf folgenden Methanisierung in synthetische Treibstoffe oder Chemikalien umgewandelt wird.

Erdgas-GuD-Kraftwerke weisen heute üblicherweise elektrische Leistungen von 400-500 MW auf; die Leistungen von Kohlekraftwerken sind im Bereich von 500-1000 MW. Erdgas-BHKW weisen elektrische Leistungen von 1 kW bis mehreren MW auf, wobei hier der Leistungsbereich von 1-1000 kW_{el} analysiert wird. Durchschnittliche Wirkungsgrade bei der Stromproduktion liegen heute bei Erdgas-GuD-Kraftwerken im Bereich von 57-59%, bei Steinkohlekraftwerken bei 44-46% und bei Braunkohlekraftwerken bei 39-44%. Elektrische Wirkungsgrade von BHKW hängen stark von der Anlagengrösse ab und liegen bei 25-42%; BHKW-Wirkungsgrade insgesamt liegen im Bereich von 80-90%.

Zukünftige Technologieentwicklung wird höhere Verbrennungstemperaturen ermöglichen und damit höhere Wirkungsgrade: 65% bei Erdgas-GuD-Kraftwerken und 50% bei Kohlke-kraftwerken im Jahr 2050 sind zu erwarten. Für BHKW werden elektrische Wirkungsgrade von 30-47% erwartet und Gesamtwirkungsgrade von über 100% (gemessen am unteren Heizwert des Brennstoffs). Prozesse zur CO_2-Abscheidung verringern wegen ihres relativ hohen Energiebedarfs den Wirkungsgrad von Kraftwerken. Für Erdgas-GuD-Kraftwerke mit CO_2-Abscheidung werden im Jahr 2050 Wirkungsgrade von 54-56% erwartet, für Kohlekraftwerke 33-45%. Neben der Steigerung von Wirkungsgraden zielt die Technologie-entwicklung auch auf eine weitere Reduktion des Schadstoffaustosses der Kraftwerke ab.

2.1.11 Brennstoffzellen

Die vorliegende Analyse beinhaltet Brennstoffzellen, die mit Erdgas oder Biomethan als WKK-Anlagen betrieben werden, also gleichzeitig Strom und Nutzwärme erzeugen. Folgende Technologien werden beurteilt: Polymer Electrolyte (PE), Phosphoric Acid (PA), Molten Carbonate (MC) und Solid Oxide (SO) Brennstoffzellen.

Brennstoffzellen können in Einzelhaushalten, grossen Gebäuden und auch in der Industrie eingesetzt werden. Solche Anlagen werden primär zur Wärmebereitstellung für Raumwärme und Warmwasser betrieben, sind also „wärmegeführt“. Strom kann für Eigenverbrauch genutzt und ins Netz gespeist werden. Reststrombedarf wird vom Netz bezogen.

Elektrische Wirkungsgrade solcher Brennstoffzellen hängen vom Brennstoffzellentyp und der Anlagengrösse ab und liegen heute bei 32-54%, bei Gesamtwirkungsgraden von 70-90%. Bis 2050 wird erwartet, dass diese Wirkungsgrade auf 42-68% bzw. 80-95% steigen werden. Neben der Steigerung der Wirkungsgrade zielt die Technologieentwicklung darauf ab, die Verlässlichkeit und Lebensdauer der Brennstoffzellen zu erhöhen sowie die Herstellungs-kosten zu senken.

2.1.12 Neuartige Technologien

Als „neuartig“ sind die folgenden Technologien zur Stromerzeugung kategorisiert: Hydro-thermale Methanisierung von wässriger Biomasse, neue geothermale Technologien, Kernfusion und thermoelektrische Stromerzeugung zur stationären Abwärmenutzung.

Im Rahmen dieser Technologiebewertung bezieht sich der Asudruck „neuartig“ auf die Tatsache, dass diese Technologien noch vergleichsweise weit weg von einer Marktanwendung sind und sich in einem frühen Entwicklungsstadium befinden; momentan kann nicht zuverlässig beurteilt werden, ob diese Technologien jemals den Durchbruch schaffen werden und in grösserem Massstab zur Stromversorgung der Schweiz zum Einsatz kommen können. Ausserdem ist beim heutigen Wissensstand eine Quanifizierung von

Kosten, Potenzialen und Umweltaspekten kaum möglich bzw. hoch spekulativ und mit hohen Unsicherheiten verbunden.

Die hydrothermale Methanisierung von wässriger Biomasse wird aktiv in der Schweiz entwickelt und wurde im Labormassstab bereits demonstriert. Diese Technologie erlaubt eine effizientere Nutzung von Biomasse mit hohem Wassergehalt und kann z.B. zur Verstromung von Algen, Kaffeesatz und Klärschlamm eingesetzt werden. Basierend auf der verfügbaren und geeigneten Biomasse in der Schweiz könnten damit 2-5 TWh Strom pro Jahr erzeugt werden.

Neuartige Geothermie-Technologien beinhalten Konzepte, die über EGS-Systeme hinausgehen (welche in Kapitel 11 behandelt werden). Hier werden zwei Ansätze diskutiert: 1) Die Nutzung eines anderen Wärmetauscherfluids als Wasser/Salzlösungen; 2) Eine zusätzliche Erwärmung von geothermisch vorgeheizten Wärmeträgern. Der erste Ansatz basiert auf der Verwendung von CO_2 und/oder N_2 als Wärmetauscherfluid, wodurch geothermische Ressourcen mit niedrigeren Temperaturen genutzt werden könnten. Der zweite Ansatz basiert auf der Nutzung von geothermisch vorerwärmten Fluiden, die mit Hilfe einer sekundären Wärmequelle (bzw. eines zusätzlichen Brennstoffs) wirtschaftlich zur Stromerzeugung genutzt werden könnten.

Die Kernfusion befindet sich weiterhin im Forschungsstadium, mit ITER als prominentestem Infrastrukturprojekt. ITER ist ein multinationales Forschungsprojekt, das zum Ziel hat, den weltweit ersten Kernfusionsreaktor zu bauen. ITER soll der erste Kernfusionsreaktor sein, bei dem der Stromoutput den Wärmebedarf deutlich überschreitet (Faktor 10). Mit dem Bau von ITER und der darauf folgenden Designstudie DEMO bewegt sich die Fusionsforschung weg von der reinen Forschung hin zu einem projektorientierten Vorhaben, in dem technische Hürden im Praxisbetrieb gelöst werden sollen. Es wird erwartet, dass die Kernfusion in der zweiten Hälfte dieses Jahrhunderts einsatzbereit sein wird.

Die Thermoelektrik ermöglicht eine direkte Umwandlung von (Ab-)wärme in Strom und kann als Alternative zu herkömmlichen Dampfkreisläufen oder ORC-Prozessen angesehen werden. Es kann auch zusätzlicher Strom über die Nutzung von Abwärme erzeugt werden. Die Thermoelektrik weist heute sehr geringe elektrische Wirkungsgrade auf und ist deswegen nicht konkurrenzfähig mit Dampfkreisläufen und ORC-Prozessen. Aus heutiger sicht wird thermoelektrische Stromproduktion eine Nischenanwendung bleiben.

2.2 Potenziale zur Stromproduktion und -versorgung

Abbildung 2.1 zeigt die aktuelle[52] Stromproduktion in der Schweiz. Erdgas[53] wird momentan nur in BHKW zur Stromproduktion genutzt, nicht in grossen GuD-Kraftwerken. Die Stromproduktion mit Geothermiekraftwerken und Brennstoffzellen ist heute noch inexistent bzw. vernachlässigbar.

[52] Jahr 2015; neuere konsistente Statistiken waren bei der Erstellung dieses Berichts nicht verfügbar.

[53] Die Kategorie "fossile Brennstoffe" wird hier komplett den Erdgas-BHKW zugerechnet. Dies ist nicht ganz korrekt, es wird auch eine geringe Menge an Strom von Diesel-BHKW produziert. Genaue Zahlen sind jedoch nicht verfügbar.

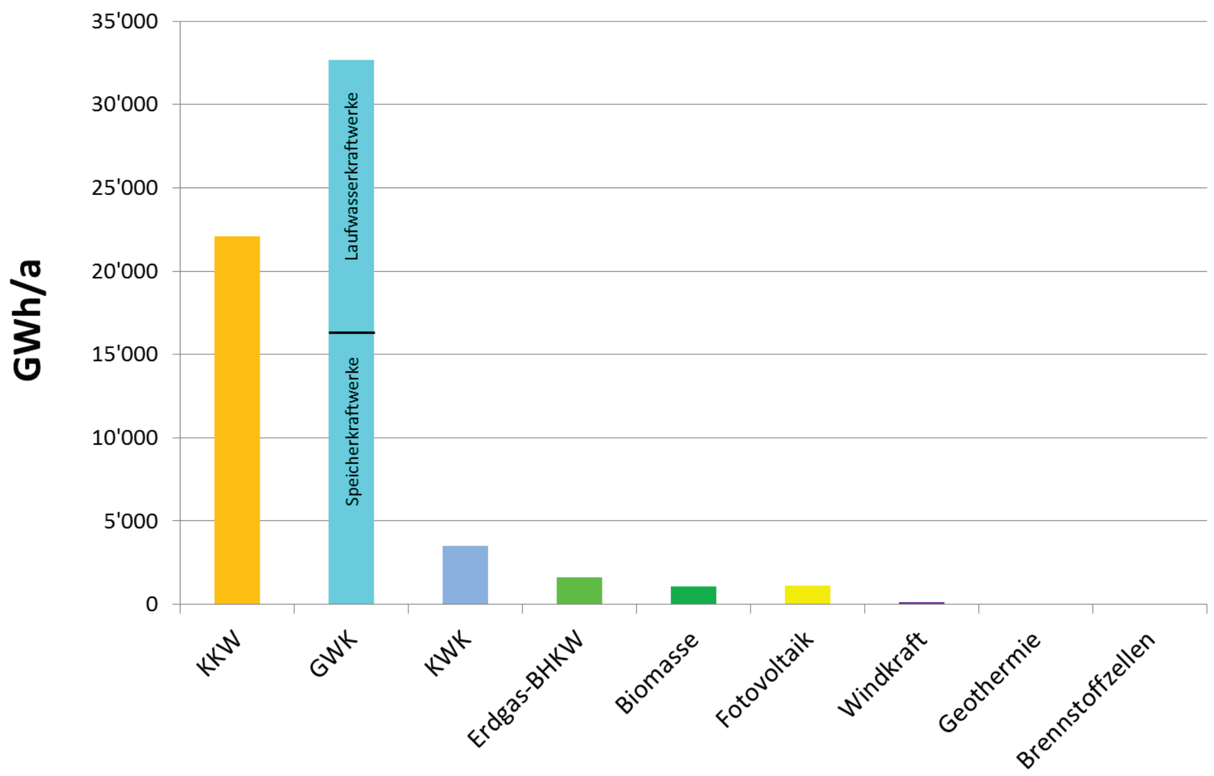


Abbildung 2.1: Stromproduktion in der Schweiz im Jahr 2015 (BFE/SFOE 2016e, BFE/SFOE 2016g).

Abbildung 2.2 zeigt die ermittelten „ausschöpfbaren Potenziale“[54] zur Stromproduktion und Stromversorgung mit verschiedenen Brennstoffen und Technologien in der Schweiz und für Stromimporte im Jahr 2050. Technische Potenziale sind bestimmten Einschränkungen ausgesetzt, sei es aus wirtschaftlichen, ökologischen, politischen oder gesellschaftlichen Gründen. Diese Einschränkungen reduzieren die technischen Potenziale. Als ausschöpfbares Potenzial wird hier in Übereinstimmung mit der Terminologie des BFE die Schnittmenge des ökologischen und erweiterten wirtschaftlichen Potenzials definiert. Bei Technologien, die fossile Brennstoffe nutzen, ist die Stromproduktion technisch lediglich durch die Importkapazitäten für Erdgas limitiert; in der Praxis sind jedoch auch politische und wirtschaftliche Faktoren limitierend. Stromimporte sind durch die Stromübertragungsinfrastruktur eingeschränkt; die dargestellten Mengen an Strom aus Wellen- und Gezeitenkraftwerken bzw. solarthermischen Kraftwerken sind lediglich als erste, rudimentäre Schätzungen zu verstehen. Zahlen für die geschätzten Potenziale in den Jahren 2020 und 2035 sind in den Datenblättern zu den einzelnen Technologien angegeben.

Unter den Erneuerbaren in der Schweiz weisen PV-Anlagen das grösste Potenzial auf; die Unsicherheiten sind jedoch relativ gross und spiegeln sich in der angegebenen Bandbreite wider. Die Unsicherheiten sind noch um einiges höher für die Geothermie, da eine Stromproduktion mit EGS in der Schweiz erst noch erfolgreich demonstriert und umgesetzt werden muss. Die Potenziale für Strom aus Erdgas-GuD-Kraftwerken und BHKW sowie Brennstoffzellen sind nicht quantifiziert, da der Einsatz dieser Technologien vor allem von politschen und wirtschaftlichen Rahmenbedingungen abhängt. Stromimporte aus CSP-,

[54] Terminologie bzgl. Potenzialen: Kapitel 5.1, basierend auf (BFE/SFOE 2007a). Der hier verwendete Begriff „ausschöpfbares Potenzial“ entspricht dem technischen Potenzial unter Berücksichtigung wirtschaftlicher und ökologischer Einschränkungen. Gesellschaftliche Faktoren sind zum Teil berücksichtigt. The corresponding term in english is „exploitable potential“.

Wellen- und Gezeiten-, sowie Kohlekraftwerken werden von der vorhandenen Stromübertragungsinfrastruktur sowie politischen Rahmenbedingungen limitiert sein und sind dementsprechend ebenfalls mit grossen Unsicherheiten verbunden.

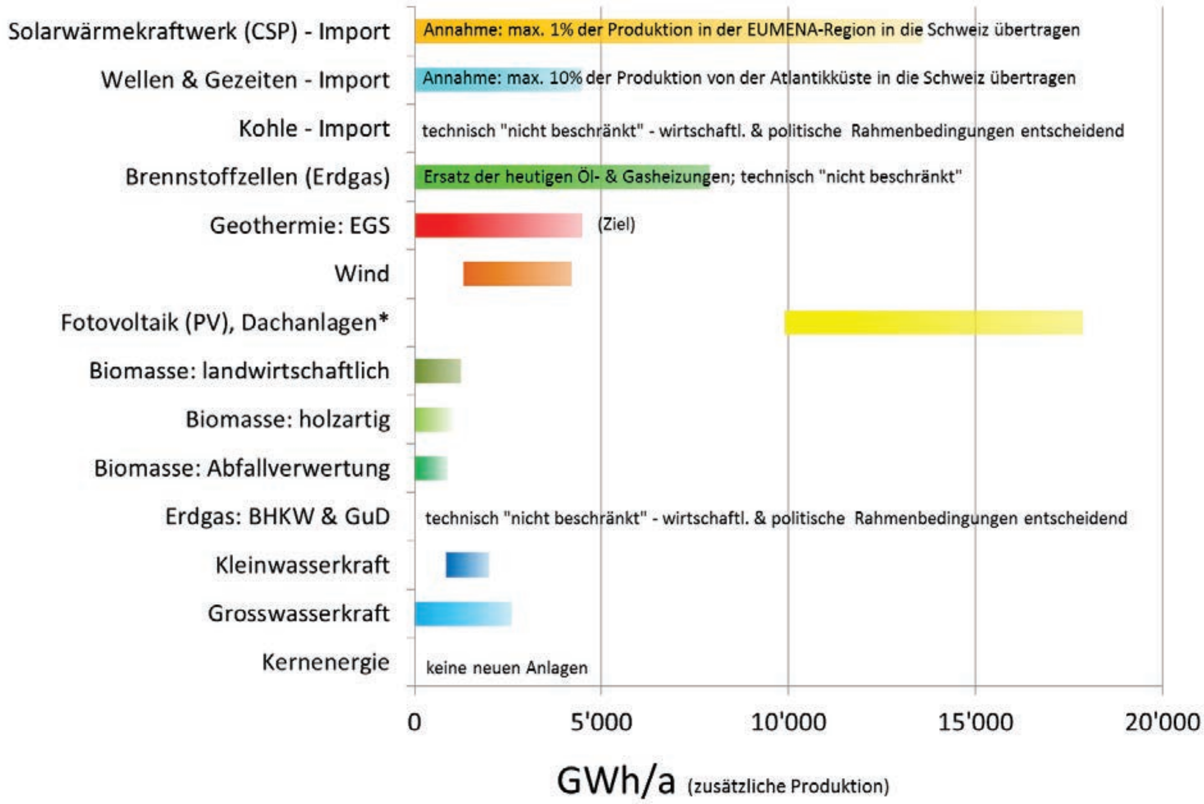


Abbildung 2.2: „Ausschöpfbare Potenziale“[55] zur zusätzlichen Stromproduktion und -versorgung im Jahr 2050 (im Vergleich zu 2015). GuD: Gas- und Dampfkraftwerk; BHKW: Blockheizkraftwerk; EGS: „enhanced geothermal systems“; CSP: „concentrated solar power“; EUMENA: Europa, Mittlerer Osten, Nordafrika; “Kohle” umfasst Stein- und Braunkohle. *Das PV-Potenzial beinhaltet hier nur Dachanlagen, keine Anlagen auf Fassaden – das nachhaltige Potenzial von Fassaden-Anlagen in der Schweiz wird auf 3-5.6 TWh/a geschätzt.

Diese technologiespezifischen Potenziale werden im Folgenden erläutert.

2.2.1 Grosswasserkraft

Die angegebene Bandbreite für Grosswasserkraft basiert auf einigen Abschätzungen der letzen Jahre, die recht gut übereinstimmen (BFE/SFOE 2012b, BFE/SFOE 2013c, Filippini and Geissmann 2014). Darin wird eine Reihe von möglichen Standorten für neue Grosswasserkraftwerke identifiziert. Die Realisierung dieser Projekte bzw. auch der Ausbau von vorhandenen Anlagen wird oft von fehlender Akzeptanz verhindert. Zusätzlich verringert die aktuelle Lage am Strommarkt die Wirtschaftlichkeit von Wasserkraftwerken. Die zukünftige Entwicklung der Wasserkraft wird hauptsächlich von den wirtschaftlichen und politischen Rahmenbedingungen abhängen. Neue Gesetzgebung bzgl. Restwassermengen, die die Stromproduktion vorhandener und neuer Kraftwerke reduziert, muss in den Potenzialabschätzungen berücksichtigt werden.

[55] Siehe Kapitel 5.1 bzgl. Definition der Potenzialbegriffe.

2.2.2 Kleinwasserkraft

Das Potenzial für Strom aus Kleinwasserkraftwerken ist relativ gering, aber nicht vernachlässigbar (BFE/SFOE 2012b). Neue Kraftwerke werden jedoch oft von nicht gegebener Akzeptanz verhindert. Dazu kommt, dass Strom aus Kleinwasserkraftwerken üblicherweise teuer und ohne Subventionen kaum konkurrenzfähig ist. Der Ausbau der Kleinwasserkraft wird in Zukunft daher hauptsächlich von der Gestaltung der Einspeisevergütung und der gesellschaftlichen Akzeptanz abhängen.

2.2.3 Strom aus Windturbinen

Die Windbedingungen in der Schweiz sind für die Stromerzeugung weniger vorteilhaft als in anderen Ländern. Dennoch ist ein substanzielles Potenzial für den Ausbau der Windenergie vorhanden (BFE, BAFU et al. 2004a, BFE, BAFU et al. 2004b, BFE, BAFU et al. 2004c, ARE 2015b, ARE 2015a). Ähnlich wie bei der Wasserkraft scheitern neue Windkraftwerke oft an lokalem Widerstand. Auch wirtschafliche Einschränkungen müssen berücksichtigt werden. Insgesamt wird der Ausbau der Windenergie vor allem von legislativen Rahmenbedingungen sowie von finanziellen Anreizmassnahmen abhängen.

2.2.4 Fotovoltaik

Das Potenzial für Strom aus PV-Anlagen ist in der Schweiz unter allen erneuerbaren Technologien am höchsten, auch wenn nur Dachanlagen berücksichtigt werden. Die dargestellte Bandbreite entspricht der zusätzlichen Stromproduktion aus neuen Anlagen auf Hausdächern, die sich für PV-Anlagen gut eignen (Cattin, Schaffner et al. 2012, swisstopo 2012); technische, gesellschaftliche und wirtschaftliche Einschränkungen sind hier berücksichtigt, ebenso die zu erwartende technische Entwicklung. Im Gegensatz zu anderen Erneuerbaren gibt es bei Fotovoltaik wenig Akzeptanzprobleme und eine weitgehende Realisierung des Potenzials erscheint realistischer. Da Strom aus PV-Anlagen noch vergleichsweise teuer ist, wird der weitere Ausbau in den nächsten Jahren noch von staatlichen Unterstützungsmassnahmen und einer geeigneten Regulierung abhängen. Es muss auch berücksichtigt werden, dass eine erfolgreiche Integration von grossen Mengen an PV-Strom aus dezentralen Anlagen, die unregelmässig erzeugt werden, geeigneter Massnahmen aus Systemperspektive bedürfen; dies betrifft etwa den Ausbau des Stromnetzes oder den Einsatz von Stromspeichern.

2.2.5 Strom aus Biomasse

Das höchste Potenzial für Strom aus Biomasse ergibt sich aus einer besseren Nutzung von Gülle und holzartiger Biomasse. Momentan wird nur ein kleiner Teil der in der Landwirtschaft anfallenden Gülle energetisch genutzt. Auch bei holzartiger Biomasse kann einerseits noch eine Menge Biomasse zusätzlich genutzt werden, andererseits kann mit einem Teil des heute nur für Wärme genutzen Holzes in BHKW zusätzlich Strom erzeugt werden.

Die Realisierung des Biomassepotenzials stösst auf einige Hindernisse, vor allem logistischer und wirtschaftlicher Art. Im Gegensatz zu anderen Erneuerbaren wie PV und Windkraft wird nicht erwartet, dass die Stromproduktionskosten bei Biomassetechnologien in Zukunft nennenswert sinken werden, was auch an den relativ hohen Biomassepreisen liegt. Weiter muss berücksichtigt werden, dass Biomasse nicht nur zur Stromproduktion genutzt werden kann, sondern auch als Treibstoff und Wärmequelle. Mögliche Importe von Biomasse werden in der vorliegenden Arbeit nicht untersucht.

2.2.6 Geothermie

Das hier angegebene Potenzial für Strom aus Geothermie weist unter allen Optionen zur Stromproduktion in der Schweiz die höchste Unsicherheit auf. Die Funktionalität von EGS-Anlagen in der Schweiz muss erst demonstriert werden, aus technischer, wirtschaftlicher und gesellschaftlicher Sicht. Das dargestellte Potenzial entspricht dem politischen Langzeitziel, welches nur dann erreicht werden kann, wenn die heute bestehenden geologischen, gesetzlichen, technischen, wirtschaftlichen und gesellschaftlichen Hürden überwunden werden können (Hirschberg, Wiemer et al. 2015). Der zentrale wirtschaftliche Aspekt ist die Nutzung der grossen Abwärmemengen. Passende Standorte, an denen dies sinnvoll möglich ist, müssen identifiziert werden.

2.2.7 Wellen- und Gezeitenkraftwerke

Strom aus Wellen- und Gezeitenkraftwerken im Atlantik an den Küsten vor bzw. an den Küsten von Portugal, Spanien und Frankreich könnte in die Schweiz importiert werden. Die Technologie ist jedoch noch nicht kommerziell einsatzfähig und das Potenzial dementsprechend unsicher. Es ist auch vergleichsweise gering: Das hier geschätzte maximale Potenzial entspricht bereits 10% der möglichen Stromproduktion aus Wellen- und Gezeitenkraftwerken an Europas Westküste.

2.2.8 Solarthermische Stromproduktion

Im Vergleich zu Strom aus Wellen- und Gezeitenkraftwerken scheint das Potenzial für Strom aus solarthermischen Kraftwerken in für die Schweiz interessanter Distanz (d.h. Südeuropa, Nordafrika und Mittlerer Osten) bedeutend höher zu sein. Auch die Technologie ist weiter entwickelt und hat in einigen Ländern wie z.B. Spanien schon Marktanteile erlangt. Eine Anwendung in grossem Massstab scheint jedoch speziell in nicht-europäischen Ländern schwierig zu sein und die Verfügbarkeit von Strom aus Kraftwerken in Nordafrika und dem Nahen/Mittleren Osten für die Schweiz ist aus heutiger Sicht fragwürdig. Folglich wird hier nur mit der Verfügbarkeit von höchstens 1% des technischen Potenzials solarthermischer Kraftwerke in der EUMENA-Region[56] für die Schweiz gerechnet.

2.2.9 Kernenergie

Das ausgewiesene Potenzial von Null spiegelt die aktuelle Haltung der Schweizer Politik wider, da angenommen wird, dass keine neuen Kernkraftwerke in der Schweiz errichtet werden.

2.2.10 Strom aus Erdgas und Kohle

Die Stromerzeugung mit Erdgas in der Schweiz – in zentralen GuD-Kraftwerken oder dezentralen BHKW – sowie der Import von Strom aus Kohlekraftwerken ist technisch kaum limitiert, sondern hängt von wirtschaftlichen, politischen, regulatorischen, gesellschaflichen und ökologischen Rahmenbedingungen ab; z.B. von der Preisgestaltung für CO_2-Emissionen und der nationalen und internationalen Klimapolitik. Solche Faktoren liegen ausserhalb des Rahmens dieser Analyse und daher sind hier für Strom aus Erdgas und Kohle keine Potenziale angegeben. Einschränkende Faktoren bzgl. Klimaschutz könnten mit einer Abscheidung von CO_2 aus den Kraftwerksemissionen und anschliessender geologischer

[56] EUMENA: Europa, Mittlerer Osten und Nordafrika.

Speicherung zum Teil eliminiert werden. Ob und wann CCS in der Schweiz und in Europa erfolgreich umgesetzt werden kann, ist jedoch höchst unsicher.

2.2.11 Brennstoffzellen

Ähnlich wie bei Erdgas GuD-Kraftwerken und BHKW ist die Stromproduktion mit Brennstoffzellen in der Schweiz technisch hauptsächlich durch die Erdgasimportkapazitäten eingeschränkt. Das hier als Maximum angegebene Potenzial entsprich der Stromproduktion aus Brennstoffzellen, die alle heutigen Öl- und Gasheizungen in der Schweiz ersetzen würden. In der Praxis werden vor allem wirtschaftliche Einschränkungen ausschlaggebend für den Einsatz von Brennstoffzellen sein.

2.3 Kosten der Stromproduktion

Abbildung 2.3 zeigt die Stromproduktionskosten (levelised costs of electricity, LCOE) für Neuanlagen, die heute gebaut würden[57]), mit Ausnahme der neuartigen Technologien. Kosten für Stromimporte aus Wellen- und solarthermischen Kraftwerken per Gleichstromübertragung, die sich im Bereich von 0.5-2 Rp./kWh bewegen, müssen zu den dargestellten Kosten addiert werden. Die dargestellten Bandbreiten spiegeln die Variabilität der Produktionskosten aufgrund von standortspezifischen Bedingungen (z.B. Jahreserträge von PV-Anlagen und Windturbinen), Charakteristika der Technologien (z.B. Kraftwerkswirkungsgrade und -leistungen) sowie Biomassekosten wider. Kosten von CO_2-Emissionen sind nicht berücksichtigt.[58] Die angegebenen Produktionskosten beinhalten Wärmegutschriften für Erdgas-BHKW, Brennstoffzellen und Biomasse-BHKW; diese Technologien werden üblicherweise so betrieben, dass ein Teil der Abwärme verkauft werden kann oder extern bezogene Wärme ersetzt.

Insgesamt weisen Kohlekraftwerke, existierende Grosswasserkraftwerke und Kernkraftwerke sowie Biomasseanlagen, die primär der Abfallbehandlung dienen und für die Abnahme von Abfallstoffen bezahlt werden[59], die geringsten Produktionskosten auf. Erdgas-BHKW mit kleiner Leistung sowie Brennstoffzellen weisen heute die höchsten Stromproduktionskosten auf. Die grosse Bandbreite bei Wellen- und Gezeitenkraftwerken resultiert aus der breiten Palette von Technologien und den mit der noch nicht gegebenen Marktreife verbundenen Unsicherheiten. Die Bandbreiten für Strom aus PV-Anlagen, Brennstoffzellen und Erdgas-BHKW spiegeln die so genannte „economy of scale“ wider, d.h. stark sinkende Anlagenkosten bei zunehmender Anlagenleistung; die Kosten für bestimmte Anlagenleistungen sind in der Grafik grob dargestellt – die genauen Zahlen sind in den jeweiligen Technologiedatenblättern und -kapiteln zu finden. Bei PV-Anlagen beinhaltet die Bandbreite der Kosten auch die möglichen standortabhängigen Schwankungen im

[57] Für Grosswasserkraftwerke und Kernkraftwerke werden auch die heutigen Stromproduktionskosten der aktuell in Betrieb stehenden Anlagen dargestellt (Kernkraft: KKW Gösgen und Leibstadt). Im Fall der Kernenergie beziehen sich die Kosten für „hypotetische Neuanlagen“ auf Reaktoren der dritten Generation, deren Planung heute gestartet würde.

[58] Die Kosten der CO_2-Zertifikate sind beim aktuellen Preis von rund 10 €/tCO_2 für die Stromproduktionskosten vernachlässigbar gering. Eine Abschätzung der zukünftigen CO_2-Preise ist ausserhalb des Rahmens dieser Analyse; CO_2-Preise werden primär von der nationalen und internationalen Klimapolitik bestimmt werden.

[59] KVA und Abwasserreinigungsanlagen werden für das Abfallbehandlungsservice bezahlt.

Jahresertrag in der Schweiz.[60] Die grossen Bandbreiten für Strom aus Biomasse ergeben sich aus der Kombination von unterschiedlichen Brennstoffkosten und Technologiekosten, die je nach Ressource und Umwandlungstechnologie sehr verschieden sein können: Strom aus KVA und Abwasserreinigungsanlagen ist z.B. bei weitem günstiger zu produzieren als Strom aus kleinen landwirtschaftlichen Biogasanlagen und Strom aus holzgefeuerten BHKW. Details zu diesen Kosten sind in den Technologiedatenblättern und im Kapitel Biomasse angegeben.

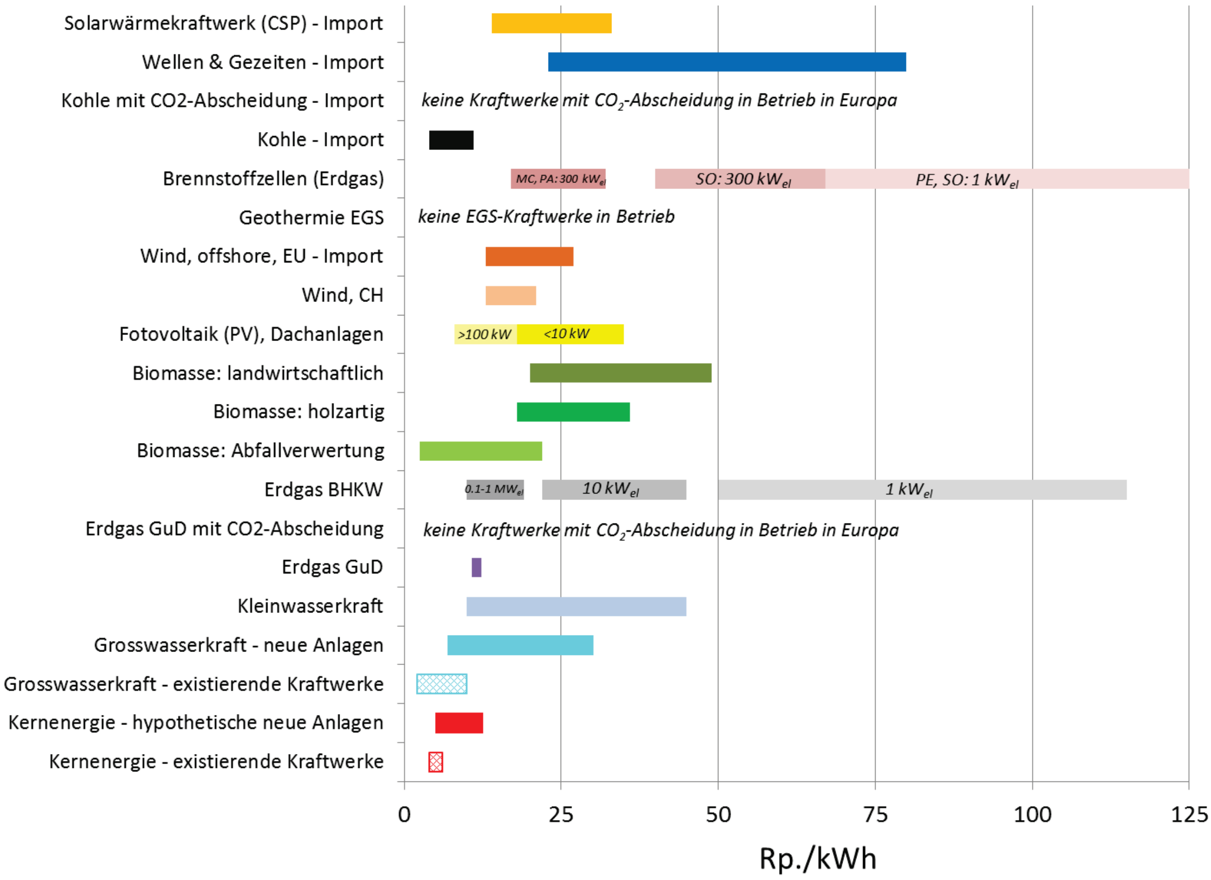


Abbildung 2.3: Kosten der heutigen (Jahr 2015/2016) Stromproduktion (LCOE) mit verschiedenen Technologien. Die dargestellten Bandbreiten spiegeln Variabilität aufgrund standortspezifischer Faktoren, Technologiecharakteristika und Biomassekosten wider. Die Bandbreiten für Brennstoffzellen, PV-Anlagen und Erdgas-BHWK resultieren hauptsächlich aus den Anlagenleistungen; Werte für bestimmte Anlagenleistungen sind in den Technologiedatenblättern und den einzelnen Kapiteln angegeben. Kosten für Stromimporte mittels Gleichspannungsübertragung im Bereich von 0.5-2 Rp./kWh müssen addiert werden. Kosten für CO_2-Emissionen sind nicht berücksichtigt.[58] Für Brennstoffzellen, Biomasse und Erdgas-BHKW sind Wärmegutschriften berücksichtigt. LCOE: "Levelised costs of electricity"; GuD: Gas- und Dampfkraftwerk; BHKW: Blockheizkraftwerk; CSP: "concentrated solar power"; EGS: "enhanced geothermal systems"; MC: "molten carbonate"; SO: "solid oxide"; PE: "polymer electrolyte"; PA: "phosphoric acid"; "Kohle" beinhaltet Stein- und Braunkohle.

Abbildung 2.4 zeigt die Stromproduktionskosten für das Jahr 2050. Die dargestellten Bandbreiten spiegeln die Variabilität der Produktionskosten aufgrund von standort-spezifischen Bedingungen (z.B. Jahreserträge von PV-Anlagen und Windturbinen), Charakteristika der Technologien (z.B. Kraftwerkswirkungsgrade und -leistungen) sowie

[60] Die jährlichen Erträge von PV-Anlagen auf Dächern in der Schweiz liegen im Bereich von 850-1500 kWh/kW_p. In der vorliegenden Studie wird mit einem Referenzertrag von 970 kWh/kW_p gerechnet. Die meisten Gebäude befinden sich im Mittelland, wo vergleichsweise geringe Jahreserträge gegeben sind.

Biomassekosten und der Unsicherheiten in den zu erwartenden Technologiekosten wider. Für fossile Brennstoffkosten wurden hier keine möglichen Bandbreiten bei den zukünftigen Kosten berücksichtigt.[61] Kosten für Stromimporte aus Wellen- und solarthermischen Kraftwerken per Gleichstromübertragung, die sich im Bereich von 0.5-2 Rp./kWh bewegen, müssen zu den dargestellten Kosten addiert werden. Kosten von CO_2-Emissionen sind nicht berücksichtigt. Für Geothermie wird keine Wärmegutschrift angerechnet.[62] Die angegebenen Produktionskosten beinhalten jedoch Wärmegutschriften für Erdgas-BHKW, Brennstoffzellen und Biomasse-BHKW; diese Technologien werden üblicherweise so betrieben, dass ein Teil der Abwärme verkauft werden kann oder extern bezogene Wärme ersetzt. Für alle Technologien sind Stromproduktionskosten mit und ohne Wärmegutschriften in den jeweiligen Datenblättern und Technologiekapiteln angegeben.

Im Vergleich zu den heutigen Stromproduktionskosten kann die grösste Reduktion für Strom aus Brennstoffzellen, Wellen- und Gezeitenkraftwerken erwartet werden, gefolgt von Fotovoltaik und solarthermischer Stromproduktion. Strom aus Wasserkraftwerken wird tendenziell teurer werden, da nur eine begrenzte Menge an vorteilhaften Standorten vorhanden ist. Strom aus Biomasseanlagen, Erdgas- und Kohlekraftwerken wird ebenfalls in Zukunft eher mehr kosten als heute, da von steigenden Brennstoffkosten auszugehen ist, welche nicht durch sinkende Technologiekosten kompensiert werden können. Das gleiche Muster ist für grosse Erdgas-BHKW zu erkennen, während die Stromkosten bei BHKW kleiner Leistung bis 2050 abnehmen; hier werden die steigenden Brennstoffkosten durch abnehmende Technologiekosten mehr als wettgemacht. Strom aus Geothermiekraftwerken wird vergleichsweise teuer bleiben, falls nicht mit Wärmegutschriften gerechnet werden kann.

[61] Siehe Table 5.3 für die angenommene zukünftige Entwicklung der fossilen Brennstoffkosten.

[62] Der Einfluss von Profit aus dem Wärmeabsatz auf die wirtschaftliche Machbarkeit von EGS-Anlagen ist bedeutend, da wegen relativ kleiner elektrischer Wirkungsgrade grosse Mengen an (Ab-)Wärme produziert werden. Aus heutiger Sicht erscheint es vor allem aus Perspektive der Risikowahrnehmung unwahrscheinlich, dass Geothermie-Kraftwerke meist in der Nähe von grossen Wärmeabnehmern errichtet werden können.

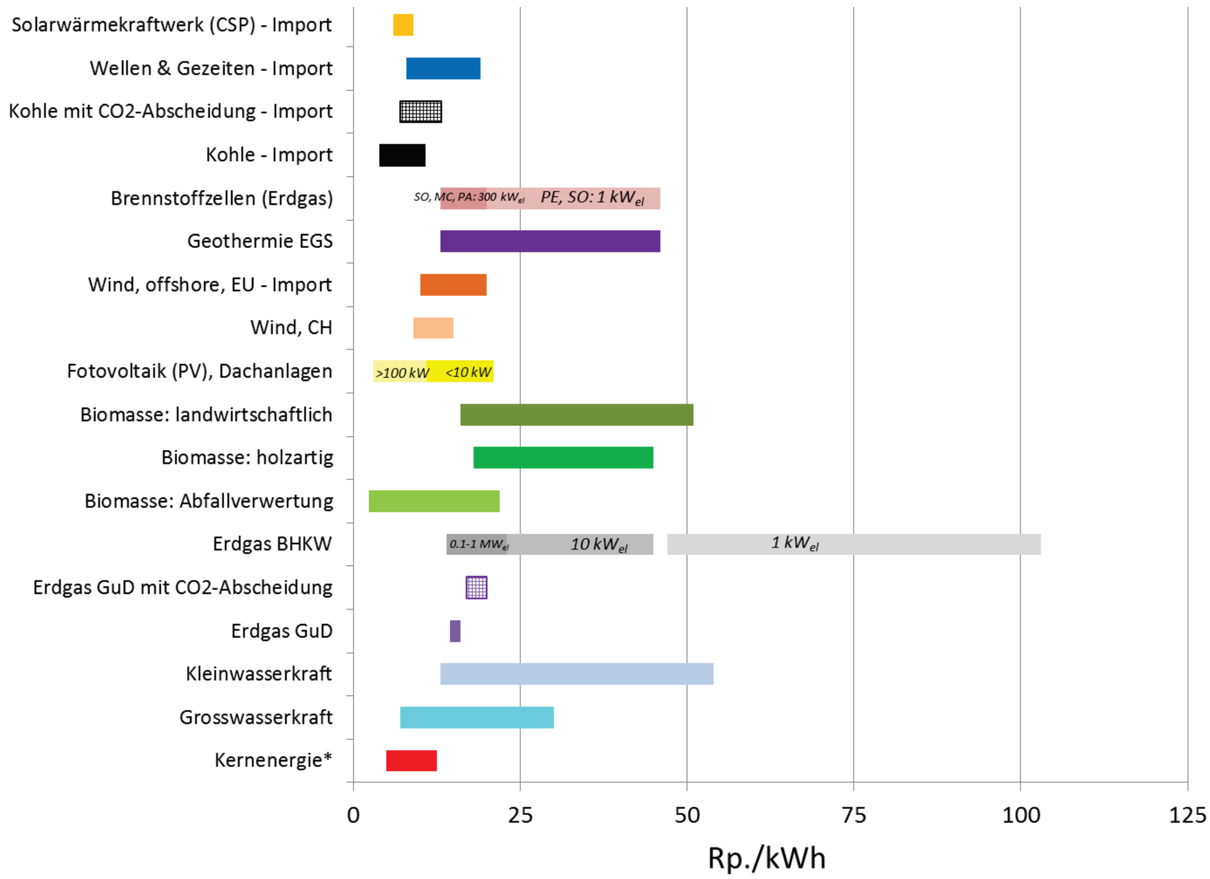


Abbildung 2.4: Kosten der Stromproduktion (LCOE) mit verschiedenen Technologien im Jahr 2050.[63] Die dargestellten Bandbreiten spiegeln Variabilität aufgrund standortspezifischer Faktoren, Technologie-charakteristika, Biomassekosten und der erwarteten zukünftigen Technologiekosten wider. Die Bandbreiten für Brennstoffzellen, PV-Anlagen und Erdgas-BHWK resultieren hauptsächlich aus unterschiedlichen Anlagenleistungen; Werte für bestimmte Anlagenleistungen sind in den Technologiedatenblättern und den einzelnen Kapiteln angegeben. Kosten für Stromimporte mittels Gleichspannungsübertragung im Bereich von 0.5-2 Rp./kWh müssen addiert werden. Kosten für CO_2-Emissionen sind nicht berücksichtigt.[58] Für Brennstoffzellen, Biomasse und Erdgas-BHKW sind Wärmegutschriften berücksichtigt, nicht aber für Geothermie.[62] LCOE: "Levelised costs of electricity"; GuD: Gas- und Dampfkraftwerk; BHKW: Blockheizkraftwerk; CSP: "concentrated solar power"; EGS: "enhanced geothermal systems"; MC: "molten carbonate"; SO: "solid oxide"; PE: "polymer electrolyte"; PA: "phosphoric acid"; "Kohle" beinhaltet Stein- und Braunkohle. *Die Kosten für Kernenergie gelten für Generation 3+ Reaktoren und so genannte „small modular reactors", da für Generation 4 Reaktoren, die 2050 eine Option sein könnten, keine belastbaren Zahlen vorliegen.

Technologiespezifische Kostenaspekte werden im Folgenden diskutiert.

2.3.1 Grosswasserkraft

Kapitalkosten und Amortisierung stellen bei den heute betriebenen, grossen Wasserkraftwerken die wichtigsten Beiträge zu den Stromproduktionskosten dar; die Stromkosten sind folglich relativ stark von den Zinsen abhängig. Zusätzliche ins Gewicht fallende Kostenfaktoren sind Betrieb und Wartung sowie die Wasserzinsen. Die Stromgestehungskosten von heute und in Zukunft neu gebauten Kraftwerken werden höher sein als jene der bereits existierenden Anlagen und stark vom jeweiligen Standort abhängen. Es

[63] Mangels geeigneter Daten können nicht für alle Erneuerbaren technologiespezifische Abhängigkeiten von Stromproduktionskosten und Potenzialen ermittelt werden. Es ist daher unklar, welche Teile der Potenziale zu welchen Kosten realisiert werden können.

besteht die Möglichkeit, mit neuen Kraftwerken und einem Ausbau von bestehenden Anlagen Strom im Umfang von 2 TWh/a mit Kosten von weniger als 15 Rp./kWh zu erzeugen (BFE/SFOE 2013c).

2.3.2 Kleinwasserkraft

Investitionskosten sind auch bei Kleinwasserkraftwerken der wichtigste Faktor bei den Stromgestehungskosten. Diese weisen je nach Anlage starke Schwankungen auf, je nach Standort und Grösse. Kleine Anlagen mit Leistungen von weniger als 1 MW weisen deutlich höhere Kosten auf als Anlagen mit Leistungen von 1-10 MW. Aus wirtschaftlicher Sicht haben Anlagen, die in vorhandene Infrastruktur integriert werden können, deutliche Vorteile. Im Allgemeinen sind Trink- und Lauf- bzw. Ausleitungswasserkraftwerke am günstigsten. Deutliche Kostenreduktionen sind in Zukunft unwahrscheinlich. Im Gegenteil, da vorteilhafte Standorte wahrscheinlich zuerst genutzt werden, wird Kleinwasserkraft einen steigenden Kostentrend aufweisen.

2.3.3 Strom aus Windturbinen

Der wichtigste Faktor bei den Stromproduktionskosten von Windturbinen sind die Kapitalkosten; deswegen sind Zinsen und Technologiekosten ausschlaggebend für die Stromproduktionskosten. Ebenfalls ein wichtiger Einflussfaktor ist der standortabhängige Ertrag der Turbinen. Im Vergleich zu weniger weit entwickelten Technologien sind bei Windturbinen (zumindest bei onshore-Anlagen) relativ geringe Kostensenkungen zu erwarten. Eine Steigerung der Nabenhöhe wird zu einem höheren Ertrag der Turbinen und damit zu reduzierten Produktionskosten führen. Die Produktionskosten von offshore-Anlagen sind tendenziell höher als jene von onshore-Anlagen und es ist anzunehmen, dass dies auch in Zukunft so bleiben wird.

2.3.4 Fotovoltaik

Investitionskosten sind der wichtigste Faktor bei den Stromgestehungskosten von PV-Anlagen. Innerhalb der Investitionskosten spielen die PV-Modulkosten die grösste Rolle mit einem Anteil von im Durchschnitt knapp 50%. Auch die Arbeitskosten zur Planung und Installation der Anlagen sind ein nicht zu vernachlässigender Faktor. Betrieb und Wartung tragen rund ein Drittel zu den Stromgestehungskosten bei. Strom aus PV-Anlagen wird mit zunehmender Anlagengrösse deutlich günstiger in der Produktion. Wie bei Windturbinen hat auch bei PV-Anlagen der standortspezifische Ertrag einen hohen Einfluss auf die Stromproduktionskosten (Figure 9.33). Es ist davon auszugehen, dass die Kosten von PV-Anlagen in Zukunft noch markant sinken werden, hauptsächlich wegen einer Reduktion der Zell- und Modulkosten, die im Vergleich zu anderen Technologien einer steilen Lernkurve folgen.

2.3.5 Strom aus Biomasse

Bei der Umwandlung von Biomasse zu Strom sind meist die Kosten für die Biomasse der wichtigste Faktor bzgl. Stromgestehungskosten und die Kosten der verschiedenen Biomasse-Rohstoffe schwanken stark, je nach Art der Biomasse (Figure 10.21, Figure 10.22). Am günstigsten kann der Strom mit Abfallbehandlungsanlagen erzeugt werden, die durch die Verwertung der Biomasseabfälle Einnahmen generieren können (also von negativen „Brennstoff"-Kosten profitieren); in diese Kategorie fallen KVA und Abwasserreinigungsanlagen. Für Anlagen, die gleichzeitig Strom und nutzbare Abwärme produzieren (z.B. holzgefeuerte und Biogas-BHKW), sind die Erlöse aus dem Verkauf der Wärme (bzw. die Einsparungen durch vermiedene Brennstoffkosten) entscheidend für die wirtschaftliche Machbarkeit. Ohne wirtschaftlich attraktive Nutzung der Wärme ist es unwahrscheinlich, dass solche Anlagen in Betrieb gehen. Zukünftige Kosten von Strom aus Biomasseanlagen werden voraussichtlich in etwa auf heutigem Niveau bleiben und hauptsächlich von den Brennstoffkosten abhängen.

2.3.6 Geothermie

Die Stromproduktionskosten von EGS-Geothermiekraftwerken hängen vor allem von der gegebenen Geologie und vom potenziellen Erlös aus dem Verkauf von Abwärme ab – die Unsicherheiten und möglichen Schwankungsbereiche sind bei beiden Faktoren hoch. Es zeigt sich, dass die Kosten für die Tiefenbohrungen bei weitem den höchsten Anteil an den gesamten Anlagenkosten haben. Im Allgemeinen scheint es unwahrscheinlich zu sein, dass EGS-Kraftwerke ohne eine ökonomisch attraktive Art der Abwärmenutzung wirtschaftlich betrieben werden können. Es gilt daher, mögliche Standorte für Geothermie-Kraftwerke zu identifizieren, an denen die Geologie und die Nähe zu Wärmeverbrauchern einen wirtschaftlichen Betrieb zulassen und an denen die gesellschaftliche Akzeptanz vorhanden ist. Die wichtigsten Einzelfaktoren bzgl. Stromgestehungskosten sind die Tiefe der Bohrungen (da die Bohrkosten exponentiell mit der Tiefe zunehmen) und der Gradient der Temperaturzunahme unterhalb der Erdoberfläche. Im Vergleich zu anderen Technologien sind die Technologiekosten an sich weit weniger ausschlaggebend für die Stromproduktionskosten (Figure 11.10).

2.3.7 Wellen- und Gezeitenkraftwerke

Je nach Typ von Wellen- & Gezeitenkraftwerken unterscheiden sich die Stromproduktionskosten stark. Die Investitionskosten sind der bei weitem wichtigste Faktor bzgl. Stromgestehungskosten. Je grösser die Anlagenleistungen, desto günstiger sind die spezifischen Kosten. Es wird mit in Zukunft stark abnehmenden Investitionskosten gerechnet. Diese erhofften Lerneffekte können jedoch nur bei stark ausgeweiteter Massenproduktion realisiert werden.

2.3.8 Solarthermische Stromerzeugung

Die Abschätzung der Stromgestehungskosten heutiger solarthermischer Kraftwerke leidet unter mangelnder Verfügbarkeit von belastbaren Daten aus der Praxis; Kosten heutiger Kraftwerke sind kaum verfügbar. Die Stromproduktionskosten in der vorliegenden Arbeit basieren auf wenigen kürzlich erschienenen Berichten internationaler Organisationen und weisen dementsprechende Unsicherheiten auf. Sicher ist jedoch, dass die treibenden Kostenfaktoren die Investitionskosten, die Sonneneinstrahlung, die Lebensdauern der Anlagen, Zinssätze sowie Betriebs- und Wartungskosten sind. Es wird erwartet, dass zukünftige Kosten deutlich tiefer sind als die heutigen, und zwar dank dreier Faktoren: Verringerte Technologiekosten, gesteigerte Wirkungsgrade mit höherer Verfügbarkeit der Anlagen und grössere Anlagen.

2.3.9 Kernenergie

Kernkraftwerke sind eine kapitalintensive Technologie; dementsprechend grossen Einfluss haben Zinssätze und Investitionskosten auf die Stromgestehungskosten (Figure 14.16). Auch substanzielle Verzögerungen während der Planungs-, Lizensierungs- und Bauphase können zu deutlich höheren Stromproduktionskosten als ursprünglich geplant führen. Brennstoffkosten sind – im Gegensatz zu Kohle- und Gaskraftwerken – ein Faktor von untergeordneter Bedeutung bzgl. Stromgestehungskosten. Mangels belastbarer Daten wurde davon abgesehen, die Stromproduktionskosten von Reaktoren der vierten Generation zu quantifizieren, auch wenn diese als neue Technologie im Jahr 2050 zur Verfügung stehen könnten (siehe Datenblatt Kernenergie, Abschnitt 2.5).

2.3.10 Strom aus Erdgas und Kohle

Die Stromgestehungskosten von Erdgas-GuD-Kraftwerken werden von den Brennstoffkosten dominiert, d.h. vom Erdgaspreis. Dies gilt auch für grosse Erdgas-BHKW mit Leistungen von mehr als 100 kW_{el}. Je kleiner die BHKW, desto höher wird der Anteil der Investitionskosten an den Stromgestehungskosten. Aufgrund der vergleichsweise geringeren elektrischen Wirkungsgrade von kleinen BHKW sind diese stärker auf eine ökonomisch attraktive Nutzung der Abwärme angewiesen. Bei Kohlekraftwerken tragen Investitionskosten, Betrieb und Wartung und Brennstoffkosten etwa gleich viel zu den Stromproduktionskosten bei. Brennstoffkosten sind bei Braunkohlekraftwerken weniger entscheidend als bei Steinkohlekraftwerken. Kraftwerke mit CO_2-Abscheidung auszurüsten erhöht die Stromproduktionskosten von Erdgas- und Kohlekraftwerken um 25-60%, je nach Technologie, Abscheiderate und Brennstoffkosten. Eine permanente, geologische Speicherung des abgeschiedenen CO_2 würde die Stromproduktionskosten weiter erhöhen; im Vergleich zur CO_2-Abscheidung sind die Kosten, die mit CO_2-Transport und -Speicherung verbunden sind, jedoch gering. Stromproduktionskosten von Erdgas- und Kohlekraftwerken würden um weitere 5-10% steigen.[64]

2.3.11 Brennstoffzellen

Die Stromproduktionskosten von Brennstoffzellen werden heute weitgehend von den Investitionskosten bestimmt, insbesondere für Anlagen mit kleiner Leistung. Es wird erwartet, dass diese Kosten in Zukunft stark sinken werden. Neben den Investitionskosten ist auch die Lebensdauer der Brennstoffzellen ein wichtiger Faktor für die Stromproduktionskosten. Vergleichsweise wenig Einfluss haben Wirkungsgrade und Brennstoffkosten.

2.4 Umweltaspekte

Die Quantifizierung und Bewertung der mit der Stromproduktion verbundenen Umweltauswirkungen basiert auf der Methode der Ökobilanzierung („Life Cycle Assessment“, LCA) und beinhaltet daher die vollständigen Energieketten inkl. Förderung und Bereitstellung der Energieträger, der Infrastruktur, etc. (ISO 2006a, ISO 2006b, EC 2010, Hellweg and Milà i Canals 2014, Astudillo, Treyer et al. 2015, Astudillo, Treyer et al. 2016).

[64] Diese Steigerung entspricht einer groben Abschätzung, die auf nicht Schweiz-spezifischen Daten basiert; Angaben für die Schweiz sind nicht verfügbar, die Kosten sollten aber ähnlich hoch sein. Während die Kosten für den Transport von CO_2 recht gut bekannt sind, sind jene für die geologische Speicherung von CO_2 sehr unsicher, da noch keine Erfahrungswerte vorhanden sind. Falls abgeschiedenes CO_2 verkauft und genutzt werden kann, z.B. zur Produktion von synthetischen Treibstoffen, wären „CO_2-Gutschriften“ anzurechnen. Eine solche Analyse ist jedoch ausserhalb des Rahmens der vorliegenden Arbeit.

Treibhausgasemissionen (THG) und die damit verbundene Wirkung auf den Klimawandel werden in der vorliegenden Arbeit als primärer Umweltindikator für heutige und zukünftige Stromproduktionstechnologien verwendet. Weitere Umweltauswirkungen heutiger Technologien werden auf weniger detaillierte Weise dargestellt und diskutiert; ein konsistentes Set an Inventardaten für zukünftige Technologien, welches eine Analyse auf gleichem Niveau wie für Treibhausgasemissionen erlauben würde, ist nicht verfügbar und die Erstellung neuer Inventardaten für zukünftige Technologien war ausserhalb des Rahmens der vorliegenden Arbeit.

Mit der Methode der Ökobilanz werden die Umweltauswirkungen des „Normalbetriebs" von Kraftwerken und Brennstoffversorgungsketten quantifiziert. Mögliche Folgen von schweren Unfällen sind nicht berücksichtigt. Die Methode erlaubt es nicht, lokale und standortspezifische Umweltauswirkungen zu messen, wie sie z.B. bei Kleinwasserkraftwerken in Bezug auf lokale Ökosysteme auftreten. Auch Lärm und visuelle Auswirkungen sind nicht Teil von Ökobilanzen. Solche Aspekte werden in Ergänzung zu den Ökobilanzergebnissen in den einzelnen Technologiekapiteln diskutiert.

2.4.1 Treibhausgasemissionen

Abbildung 2.5 zeigt die Treibhausgas (THG)-Emissionen der Stromerzeugung mit heutigen, repräsentativen Technologien in der Schweiz (und im Ausland für potenzielle Stromimporte).[65]

Die dargestellten Bandbreiten spiegeln Variabilität bzgl. Standortfaktoren (z.B. Jahresertrag von PV- und Windkraftanlagen in der Schweiz), Technologiecharakteristika (z.B. Wirkungsgrade, Anlagenleistungen) und Brennstoffeigenschaften wider. Bei gleichzeitiger Produktion von Strom und Nutzwärme in BHKW und Brennstoffzellen werden die Umweltauswirkungen anhand des Exergiegehalts von Strom und Wärme aufgeteilt (alloziert). Die Verfügbarkeit von Ökobilanzergebnissen für Biomassetechnologien ist eingeschränkt.[66] Die Ergebnisse beziehen sich auf die Stromproduktion „ab Kraftwerk", d.h. Stromübertragung und -verteilung ist nicht berücksichtigt. Systemaspekte, wie z.B. der mögliche Bedarf an „back-up" Technologien zum Ausgleich von schwankender Produktion, sind nicht berücksichtigt, da solch ein Bedarf von der Zusammensetzung des gesamten Stromversorgungssystems abhängt.

Im Technologievergleich verursacht die Stromproduktion mit Wasserkraft- und Kernkraftwerken sowie Windturbinen die geringsten Treibhausgasemissionen. Strom aus Kohlekraftwerken ist mit den höchsten Emissionen verbunden. Die grossen Bandbreiten für Kohlekraftwerke, Erdgas-BHKW und Brennstoffzellen ergeben sich aus unterschiedlichen Technologien und Anlagenleistungen. Die Bandbreiten für Biomasse spiegeln die Variabilität der Umwandlungstechnologien und Kategorien der Biomasse-Ausgangsstoffe wider. Es wird

[65] Im Zusammenhang mit Umweltaspekten bezieht sich der Ausdruck „heutige Technologien" auf moderne Kraftwerke, die heute am Markt sind. Eine Differenzierung zwischen heute betriebenen Anlagen und neu zu bauenden Anlagen für Grosswasserkraft und Kernenergie – wie bei den Stromgestehungskosten – ist hier weniger sinnvoll und wird folglich nicht durchgeführt.

[66] „Landwirtschaftliche Biomasse" wird von der Ökobilanz von kleinen landwirtschaftlichen, mit Gülle versorgten Biogasanlagen repräsentiert; die Treibhausgasemissionen werden hauptsächlich von Methanemissionen („Methanschlupf") aus der Güllevergärung verursacht – hier sind die Unsicherheiten und dementsprechend die angegebene Bandbreite hoch. Moderne Anlagen mit weniger Methanschlupf könnten deutlich geringere THG-Emissionen verursachen.

angenommen, dass Holz auf nachhaltige Weise geerntet wird; d.h., dass der Kohlenstoffkreislauf geschlossen ist und biogene CO_2-Emissionen in der Bilanz nicht berücksichtigt werden. Die Bandbreite für Wellen- und Gezeitenkraftwerke ergibt sich aus der grossen Zahl an möglichen Kraftwerksdesigns.

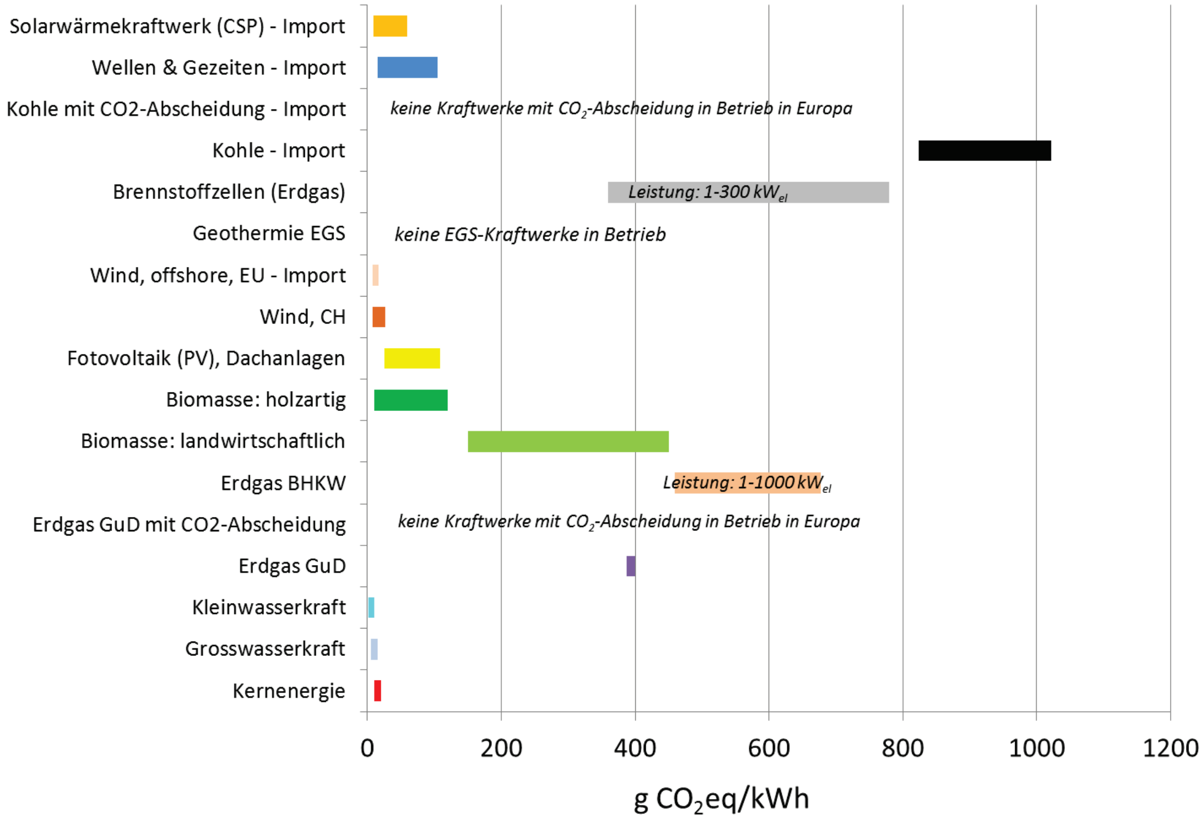


Abbildung 2.5: Treibhausgasemissionen (ganzer Lebenszyklus; Strom ab Kraftwerk[67]) von heutigen Stromproduktionstechnologien zur Schweizer Stromversorgung. Bandbreiten spiegeln Variabilität bzgl. Standortfaktoren, Technologiecharakteristika und Brennstoffeigenschaften wider. Emissionen von kombinierter Produktion von Strom und Nutzwärme werden anhand deren Exergiegehalts alloziert. Datenverfügbarkeit zu Biomassetechnologien ist beschränkt. GuD: Gas- und Dampfkraftwerk; BHKW: Blockheizkraftwerk; CSP: „concentrated solar power“; EGS: „enhanced geothermal system“; Kohle beinhaltet Braun- und Steinkohle.

Abbildung 2.6 zeigt die Treibhausgasemissionen der Stromproduktionstechnologien für die Stromversorgung der Schweiz im Jahr 2050. Bandbreiten spiegeln Variabilität bzgl. Standortfaktoren, Technologiecharakteristika und Brennstoffeigenschaften wider. Emissionen von kombinierter Produktion von Strom und Nutzwärme werden anhand des Exergiegehalts alloziert. Datenverfügbarkeit zu Biomassetechnologien ist beschränkt.

Für die meisten Technologien kann davon ausgegangen werden, dass die Treibhausgasemissionen bis ins Jahr 2050 abnehmen werden. Ausnahmen sind Wasserkraft und Kernenergie – hier besteht kaum ein Reduktionspotenzial. Im Gegenteil, abnehmende Urankonzentrationen könnten die Uranförderung aufwändiger machen und zu höheren Emissionen führen; dem gegenüber steht der zu erwartende technologische Fortschritt in der ganzen Prozesskette, z.B. bei der Urananreicherung. Der Faktor der in Zukunft schlechter verfügbaren Ressourcen könnte auch bei Erdgas- und Kohlekraftwerken zu

[67] Stromübertragung und -verteilung werden hier nicht berücksichtigt.

höheren Emissionen führen; dies konnte im Rahmen der vorliegenden Arbeit jedoch nicht quantifiziert werden. Erdgas- und Kohletechnologien zeigen eine Abnahme der Emissionen proportional zu den steigenden Wirkungsgraden der Kraftwerke und BHKW. Die Abscheidung von CO_2 in den Kraftwerken würde die Emissionen substanziell senken – abhängig von der Abscheidungsrate und vom Brennstoff fast bis auf das Niveau einiger Erneuerbarer.[68,69,70] Unter den Erneuerbaren sinken die Emissionen für Strom aus PV-Anlagen dank der zu erwartenden Fortschritte in Herstellungsprozessen der PV-Zellen und -Module sowie gesteigerter Wirkungsgrade am stärksten.

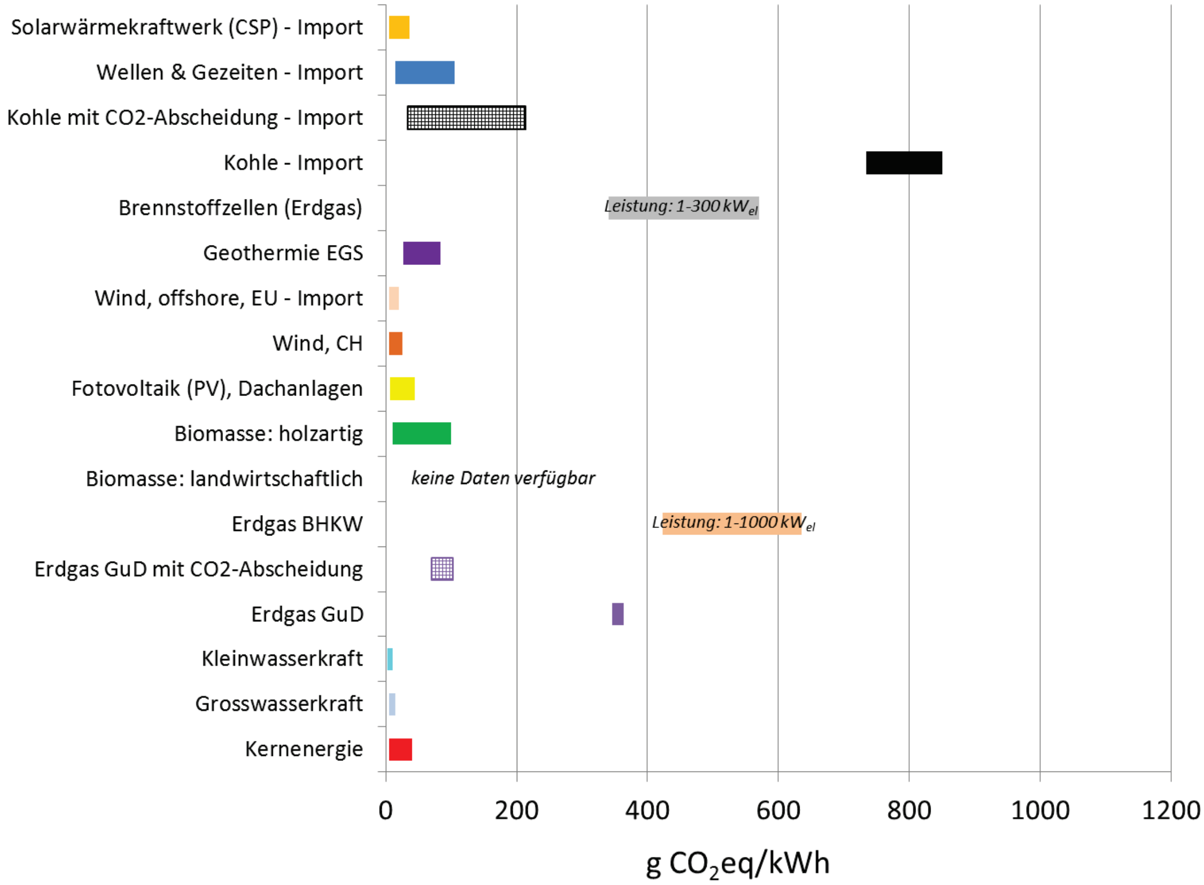


Abbildung 2.6: Treibhausgasemissionen (ganzer Lebenszyklus; Strom ab Kraftwerk[71]) von Stromproduktionstechnologien zur Schweizer Stromversorgung im Jahr 2050. Bandbreiten spiegeln Variabilität bzgl. Standortfaktoren, Technologiecharakteristika und Brennstoffeigenschaften wider. Emissionen von kombinierter Produktion von Strom und Nutzwärme werden anhand des Exergiegehalts alloziert. Datenverfügbarkeit zu Biomassetechnologien ist beschränkt. GuD: Gas- und Dampfkraftwerk; BHKW: Blockheizkraftwerk; CSP: „concentrated solar power“; EGS: „enhanced geothermal system“; Kohle beinhaltet Braun- und Steinkohle.

[68] Die Umsetzung der gesamten CCS-Kette, also CO_2-Abscheidung, -Transport und geologische -Speicherung würde die Treibhausgasemissionen von Strom aus Kohle- und Erdgaskraftwerken mit CCS nur sehr geringfügig erhöhen (Volkart, Bauer et al. 2013).
[69] Biomasseverstromung mit CCS wäre mit negativen Treibhausgasemissionen verbunden. Dies ist jedoch nicht Teil dieser Übersichtsgrafik, da eine Implementierung grosser Biomassekraftwerke mit CCS in der Schweiz aus heutiger Sicht eher unwahrscheinlich erscheint.
[70] Falls abgeschiedenes CO_2 in anderen Prozessen genutzt würde, müssten Substitutionseffekte in der Ökobilanz berücksichtigt werden (Zhang, Bauer et al. 2017); dies ist jedoch ausserhalb des Rahmens der vorliegenden Arbeit.
[71] Stromübertragung und -verteilung werden hier nicht berücksichtigt.

2.4.2 Weitere Ökobilanzergebnisse

Abbildung 2.7 zeigt die Ökobilanzergebnisse für weitere Umweltindikatoren für heutige Stromproduktionstechnologien[72]. Die Ergebnisse sind auf einen Wert von Eins skaliert für das höchste Ergebnis einer Technologie (entspricht den höchsten Umweltauswirkungen) bei jedem Indikator; zum Vergleich werden jeweils auch die Umweltauswirkungen des heutigen Schweizer Strommix (inkl. Importen)[73] dargestellt. Die Auswahl der Umweltindikatoren und der Methoden zur Bewertung basieren auf den Empfehlungen von Hauschild, Goedkoop et al. (2013). Für diesen Vergleich werden die Inventardaten der LCA Datenbank ecoinvent (ecoinvent 2016) verwendet.[74] Der Grossteil der technologiespezifischen Kapitel enthält ähnliche Grafiken mit einer breiteren Auswahl an Technologien.[75]

Die Ergebnisse zeigen, dass insgesamt die grössten Umweltauswirkungen (bei gleicher Gewichtung einzelner Indikatoren) von Strom aus Braunkohlekraftwerken und Holzverbrennungsanlagen verursacht werden; hauptsächlich wegen direkter Emissionen aus der Verbrennung von Kohle und Holz und teilweise auch der Brennstoffversorgung. Die geringsten Umweltauswirkungen werden von Strom aus Wasserkraftwerken verursacht, da beim Betrieb der Kraftwerke kaum Emissionen entstehen und die Materialintensität der Infrastruktur pro Kilowattstunde Strom gering ist. Auch Strom aus Wind und Geothermiekraftwerken weist eine geringe Umweltbelastung auf. Strom aus Erdgas-GuD Kraftwerken, Kernkraftwerken, PV-Anlagen, Wellen- und Gezeitenkraftwerken verursacht etwas höhere Umweltauswirkungen, mit jeweils schlechten Ergebnissen bei einem oder wenigen Indikatoren. Strom aus Biogas- und Erdgas-BHKW sowie Steinkohlekraftwerken verursacht vergleichsweise hohe Umweltbelastungen, ähnlich jenen von Braunkohlekraftwerken und Holz-BHKW, aber weniger stark ausgeprägt.

[72] Für solarthermische Stromproduktion, Kleinwasserkraft, Brennstoffzellen und neuartige Technologien sind keine konsistenten Inventardaten vorhanden. Die Kapitel zu Kleinwasserkraft udn Brennstoffzellen beinhalten jedoch verschiedene Ökobilanzindikatoren.

[73] Die Ökobilanzergebnisse für den Schweizer Stromversorgungsmix entsprechen dem Hochspannungsmix („market for electricity, high voltage") (ecoinvent 2016).

[74] Strom aus Biogas stellt eine Ausnahme dar; hier wurden die LCA-Ergebnisse des Datensatzes „Electricity, at cogen, biogas agricultural mix, allocation exergy" aus Version v2.2 der ecoinvent Datenbank (ecoinvent 2013) verwendet, da für Biogas evtl. qualitative Mängel in (ecoinvent 2016) bestehen.

[75] **Fehler! Verweisquelle konnte nicht gefunden werden.** dient in dieser Zusammenfassung dazu, einen Überblick über die Umweltauswirkungen der verschiedenen Technologien im Gesamtvergleich zu geben. D.h., dass hier auf einige Details, die in den technologiespezifischen Kapiteln enthalten sind, verzichtet werden muss. Manche der hier dargestellten Ergebnisse stimmen nicht vollständig mit den Ergebnissen in den verschiedenen Technologiekapiteln überein, da in **Fehler! Verweisquelle konnte nicht gefunden werden.** Inventardaten durchschnittlicher, repräsentativer Technologien verwendet werden, in den verschiedenen Technologiekapiteln hingegen oft Ökobilanzergebnisse spezifischer Technologien enthalten sind, um einen genaueren Einblick in technologische Aspekte und deren Auswirkungen auf die Ökobilanz zu geben. Teilweise werden in den Technologiekapiteln auch neuere Inventardaten genutzt, für die aber das in **Fehler! Verweisquelle konnte nicht gefunden werden.** dargestellte Set an Umweltindikatoren nicht verfügbar ist. Die Unterschiede zwischen den hier dargestellten Ökobilanzergebnissen und den Technologiekapiteln sind jedoch klein und haben bloss vernachlässigbaren Einfluss auf den Vergleich der Technologien bzgl. Umweltauswirkungen.

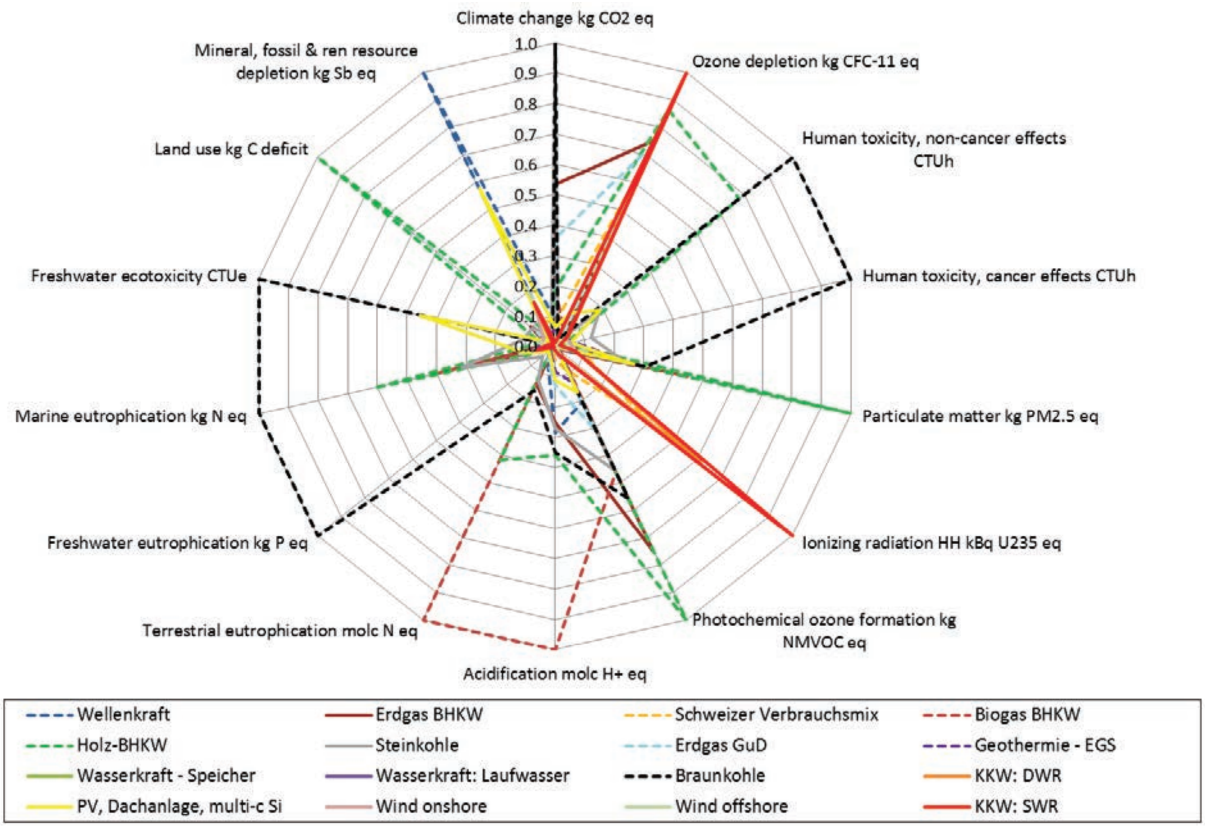


Abbildung 2.7: Ökobilanzergebnisse für heutige Stromproduktionstechnologien, jeweils skaliert relativ zum höchsten (=schlechtesten) Ergebnis (=1) einer Technologie pro Indikator (ab Kraftwerk[76]). Wahl der Indikatoren basierend auf (Hauschild, Goedkoop et al. 2013); Ökobilanz-Inventardaten aus (ecoinvent 2016)[77].[78] Sämtliche Technologien repräsentativ für heutige Anlagen in der Schweiz, mit Ausnahme von Wellenkraft, Steinkohle, Wind offshore, und Braunkohle (Strom jeweils importiert). Inventardaten für solarthermische Stromerzeugung, Brennstoffzellen und Kleinwasserkraft stehen nicht in konsistenter Form zur Verfügung. BHKW: Blockheizkraftwerk; PV: Fotovoltaik: multi-c Si: multikristalline Silizium PV-Zellen; GuD: Gas- & Dampfkraftwerk; EGS: Enhanced Geothermal System; DWR: Druckwasserreaktor; SWR: Siedewasserreaktor.

2.5 Datenblätter zu den verschiedenen Technologien

Die Datenblätter geben auf einer oder zwei Seiten pro Technologie einen Überblick über die wichtigsten Ergebnisse der Technologiebewertung. Sie beinhalten die Abschätzung der ausschöpfbaren Potenziale zur Stromproduktion, Stromproduktionskosten und Ökobilanzergebnisse für Treibhausgasemissionen als Indikator für die Umweltauswirkungen der Stromproduktion. Es sind jeweils die Zahlen für „heute“ (2015/16), 2020, 2035 und 2050 angegeben. Ergänzend sind einige Technologieparameter und Erläuterungen zu den Ergebnissen vorhanden.

Die Ergebnisse werden auch in Form von Bandbreiten dargestellt. Diese reflektieren Unsicherheiten und die möglichen Schwankungsbreiten aufgrund von Technologieeigen-

[76] Stromübertragung und -verteilung sind in diesen Ergebnissen nicht berücksichtigt.
[77] Strom aus Biogas stellt eine Ausnahme dar; hier wurden die LCA-Ergebnisse des Datensatzes „Electricity, at cogen, biogas agricultural mix, allocation exergy“ aus Version v2.2 der ecoinvent Datenbank (ecoinvent 2013) verwendet, da für Biogas evtl. qualitative Mängel in (ecoinvent 2016) bestehen.
[78] Für Strom aus Wellen- und Gezeitenkraftwerken ist kein Resultat für Landnutzung verfügbar.

schaften und der erwarteten Technologieentwicklung, standortabhängigen Jahreserträgen (z.B. für Fotovoltaik und Windturbinen) sowie Eigenschaften der Brennstoffe (nicht jedoch Brennstoffpreise). Für jede Technologie sind in den Bandbreiten die jeweils wichtigsten Einflussfaktoren berücksichtigt. Kommentare zu den Zahlen sind in Form von Fussnoten zu den einzelnen Tabellen angegeben. Die kompletten, weiterführende Informationen zur Herleitung der in den Datenblättern enthaltenen Zahlen sind in den Technologiekapiteln im Anschluss zu finden.

Datenblatt – Grosse Wasserkraftwerke

Technologie: Wasserkraftwerke erzeugen Strom durch die Umwandlung der im Wasser enthaltenen potenziellen oder kinetischen Energie in Elektrizität. Kraftwerke mit Leistungen von mehr als 10 MW gelten in der Schweiz als „gross“ und werden in folgende Kategorien eingeteilt:

- Speicherkraftwerke: Wasser wird mit einem Damm in einem Speichersee aufgestaut
- Laufkraftwerke: besitzen keinen Damm; das hydrologische Regime wird nicht oder kaum verändert
- Pumpspeicherkraftwerke: erzeugen Strom zu Spitzenlastzeiten, indem Wasser zwischen Speicherseen auf verschiedenen Höhen gepumpt und turbiniert wird

Grosse Wasserkraftwerke sind eine “fertig entwickelte” Technologie. Wirkungsgrade von Turbinen werden sich in Zukunft nur geringfügig steigern lassen.

Grosse Wasserkraftwerke		Neuanlagen: heute[1]		2020	2035	2050
Potenzial[2] (Produktionserwartung)	TWh/a		32.7	~32.7	33.9-35.3	33.9-35.3
					32.7-34.0	32.7-34.0
Investitionskosten[3]	CHF/kW		3’500 (2’000-10’000)	2’000-10’000	2’000-10’000	2’000-10’000
Stromproduktions-kosten[4,5]	Rp./kWh	Laufkraftwerk[8]	7-30	7-30	7-30	7-30
		Speicherkraftwerk[9]				
Treibhausgas-emissionen[6,7]	g CO_2eq./kWh	Laufkraftwerk	5-10	~5-10	~5-10	~5-10
		Speicherkraftwerk	5-15	~5-15	~5-15	~5-15

[1] “Heute” bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke; das heutige Potenzial entspricht der Produktionserwartung im Jahr 2016 (die tatsächliche Produktion hängt ab vom Niederschlag, vom Klima, etc.).

[2] Angesichts der tlws. heute nicht gegebenen Profitabilität der Wasserkraft kann bis 2020 nicht von einem substanziellen Ausbau ausgegangen werden. Dies trotz Investitionsbeiträgen aus dem Netzzuschlagsfonds für erhebliche Erweiterungen und Erneuerungen von GWK ab 1.1.2018. Der zukünftige Ausbau der Wasserkraft wird hauptsächlich von den wirtschaftlichen Rahmenbedingungen abhängen sowie von der Akzeptanz neuer Kraftwerke. Neubauten bzw. die Erweiterung bestehender Kraftwerke können etwa gleich viel zu einer gesteigerten Produktion beitragen. Die obere Zeile für 2035 und 2050 enthält die mögliche Produktion ohne Berücksichtigung neuer gesetzlicher Vorgaben (“Gewässerschutzgesetz”); in der unteren Zeile wird eine Reduktion der Produktion durch das Gewässerschutzgesetz von 1’260 GWh/a berücksichtigt (Reduktion insgesamt: 1’400 GWh/a; 90% werden der Grosswasserkraft angerechnet, 10% der Kleinwasserkraft – proportional zur heutigen Produktion).

[3] Die verfügbaren Daten erlauben keine Unterscheidung zwischen Lauf- und Speicherkraftwerken. 3’500 CHF/kW repräsentiert einen gewichteten Durchschnitt für Investitionen zur zusätzlichen Stromproduktion (in neue Anlagen und in die Erweiterung bestehender Anlagen) ohne Berücksichtigung von Bauten zur hauptsächlichen Regulierung der Schwall- und Sunkproblematik.

[4] Stromproduktionskosten beinhalten Investitionskosten, Betriebs- und Wartungs- sowie andere Kosten. Die Bandbreiten reflektieren standortspezifische Faktoren.

[5] Unter der Annahme, dass wirtschaftlich attraktive Standorte zuerst genutzt werden, tendieren die Stromproduktionskosten neuer Anlagen in Zukunft vom unteren Ende des Bereichs ans obere Ende zu steigen. Insgesamt können zusätzlich rund 1.6 TWh/a zu Produktionskosten von weniger als 15 Rp./kWh erzeugt werden (ohne Berücksichtigung des Gewässerschutzgesetzes).

[6] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf (Hochspannung).

[7] Es wird angenommen, dass die Umweltauswirkungen neuer Kraftwerke in etwa jenen der heutigen entsprechen.

[8] LCOE der heute bestehenden Kraftwerke mit tlws. amortisiertem Kapital: 5-6 (2-10) Rp./kWh.

[9] LCOE der heute bestehenden Kraftwerke mit tlws. amortisiertem Kapital: 6 (3-9) Rp./kWh.

Datenblatt – Kleinwasserkraft

Technologie: Wasserkraftwerke erzeugen Strom durch die Umwandlung der im Wasser enthaltenen potenziellen oder kinetischen Energie in Elektrizität. Kraftwerke mit Leistungen von weniger als 10 MW fallen in der Schweiz in die Kategorie „Kleinwasserkraft“. Kleinwasserkraftwerke können auch in bestehende Infrastruktur, etwa Trinkwasserleitungen, integriert werden. Unterschieden werden je nach Art der Nutzung des Wassers:

- Speicherkraftwerke: Wasser wird mit einem Damm in einem Speichersee aufgestaut
- Laufkraftwerke: besitzen keinen Damm; das hydrologische Regime wird nicht oder kaum verändert

Konventionelle Kleinwasserkraftwerke sind im allgemeinen eine “fertig entwickelte” Technologie. Wirkungsgrade von Turbinen werden in Zukunft nur geringfügig steigen. Aktuelle Forschung zielt jedoch darauf ab, Kleinwasserkraftwerke mit geringen Abflüssen und geringen nutzbaren Höhendifferenzen effizienter zu machen, um zusätzliche Standorte nutzen zu können.

Kleinwasserkraftwerke		**Neuanlagen: heute[1]**		**2020**	**2035**	**2050**
Potenzial[2]	TWh/a		3.5	~3.5	~4.3-5.5	~4.3-5.5
Investitions-kosten[3]	CHF/kW	Ausleitungs-/ Laufwasserkraftwerke	6’160 (5’200-13’700)	~6’160	~7’150	~7’400
		Trinkwasser-kraftwerke	11’150 (9’600-25’100)	~11’150	~13’000	~13’400
Stromproduktions-kosten[4,5]	Rp./kWh	Ausleitungs-/ Laufwasserkraftwerke	12-28	~12-28	~14-33	~14-34
		Trinkwasserkraftwerke	17-42	~17-42	~20-49	~20-50
Treibhausgas-emissionen[6,7]	g CO_2eq./kWh	Ausleitungs-/ Laufwasserkraftwerke	~5-10	~5-10	~5-10	~5-10
		Trinkwasserkraftwerke	~2-5	~2-5	~2-5	~2-5

[1] “Heute” bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke; das heutige Potenzial entspricht der Produktionserwartung im Jahr 2016 (die tatsächliche Produktion hängt ab vom Niederschlag, vom Klima, etc.).

[2] Die Bandbreiten der zukünftigen Potenziale reflektieren die Schätzungen einiger aktueller Studien. Das BFE geht von einem zusätzlichen Potenzial von 1.3-1.6 TWh/a aus. Es wird davon ausgegangen, dass diese Zahlen um rund ~140 GWh/a reduziert werden müssen, als Resultat des Gewässerschutzgesetzes. Die tatsächliche Ausweitung der Produktion mit Kleinwasserkraftwerken wird von finanziellen Unterstützungsmassnahmen abhängen.

[3] Heutige Investitionskosten wurden anhand der “KEV-Liste” (kostendeckende Einspeisevergütung) abgeschätzt. Das ausgewertete Sample umfasst Projekte für 1049 neue Kleinwasserkraftwerke. Zukünftige Investitionskosten werden tendeziell zunehmen, da zuerst an vorteilhaften Standorten gebaut wird und Regulierungen im Umweltbereich eher zunehmen werden.

[4] Stromproduktionskosten beinhalten Investitionskosten, Betriebs- und Wartungs- sowie andere Kosten. Die Bandbreiten reflektieren standortspezifische Faktoren.

[5] Unter der Annahme, dass günstige Standorte zuerst genutzt werden, werden die Kosten von 2020 bis 2050 vom unteren Ende der angegebenen Bandbreite bis zum oberen Ende zunehmen.

[6] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 100 g CO_2-eq./kWh auf (Niederspannung).

[7] Es wird angenommen, dass die Umweltauswirkungen neuer Kraftwerke in etwa jenen der heutigen entsprechen, da sie vergleichsweise gering sind und sich die Technologie nicht substanziell entwickeln wird.

Datenblatt – Windkraftwerke

Technologie: Windturbinen mit horizontalen Achsen dominieren den heutigen Markt. Strom wird mittels Rotorblättern durch die Umwandlung der kinetischen Energie des Luftstroms in Elektrizität erzeugt. Heutige Turbinen können bei Windgeschwindigkeiten von 3-34 m/s Strom erzeugen.

Windkraftwerke			**Neuanlagen: heute**[9]	**2020**	**2035**	**2050**
Leistung		Onshore	1-3 MW (70% der installierten Leistung) Neue Turbinen: 2-4 MW	Grösste Turbine heute: 8 MW (on-/offshore), 164 m Rotordurchmesser, 220 m Nabenhöhe		
		Offshore	>3 MW (2/3 der installierten Leistung)	Machbarkeit von 20 MW Turbinen wurde demonstriert.		
Kapazitäts-faktor (cf)[1]		Allgemein	0.1-0.55 Weltdurchschnitt ~0.23 (2013)	Kapazitätsfaktoren werden etwas zunehmen durch Verbesserungen der Turbinen und durch genauere Vorhersagen der Windgeschwindigkeiten zur optimalen Standortwahl.		
		Onshore	CH: 20.8 (2015) Deutschland: 22.3 (2015)			
		Offshore	Bis zu 0.55 DK: 0.43 (2012)			
Potenzial	TWh/a	Schweiz	0.1	0.1-0.6	0.7-1.7	1.4-4.3
	TWh/a	Europa[6]	~260	580-630	2030: 604-988	Keine Daten
Strom-produktions-kosten[2,3]	Rp./kWh	Schweiz	13-21	11-19	10-17	9-15
		Europa, onshore	4-18	4-16	3-13	3-10
		Europa, offshore	13-27	13-25	12-23	10-20
Treibhausgas-emissionen[2,4,5]	g CO_2-eq./kWh	Schweiz	~15 (8-27)	5-30	5-30	5-30
		Europa, onshore[7]	8-21	5-25	5-25	5-25
		Europa, offshore[8]	8-16	5-20	5-20	5-20

[1] Jährliche "Volllaststunden" dividiert durch 8760 h/a. Jährliche Volllaststunden entsprechen der Zeit, die sich aus der Jahresproduktion bei Nennleistung ergibt.
[2] Stromproduktionskosten beinhalten Investitionskosten, Betriebs- und Wartungs- sowie andere Kosten. Der Jahresertrag ist der wichtigste Einflussfaktor auf Stromproduktionskosten und Ökobilanzergebnisse. An Standorten mit sehr guten oder sehr schlechten Windbedingungen können Kosten und THG-Emissionen ausserhalb der angegebenen Bandbreiten liegen.
[3] Zukünftige Kosten sind grobe Schätzungen basierend auf Literatur und den aktuellen Trends.
[4] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren und Leistungsklassen der Turbinen. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf (Hochspannung).
[5] Es wird nicht erwartet, dass sich die Umweltauswirkungen in Zukunft stark verändern. Eine Abnahme würde aus der besseren Nutzung des Windes resultieren; eine Zunahme aus der Verschlechterung der verfügbaren Standorte.
[6] Keine Unterscheidung zwischen onshore- und offshore-Turbinen möglich.
[7] Bei Kapazitätsfaktoren von 0.15-0.35.
[8] Basierend auf der ecoinvent Datenbank, v3.3, "allocation – cut-off by classification" bei cf von 0.30-0.55.
[9] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke.

Datenblatt – Fotovoltaik (PV)

Technologie: Fotovoltaikzellen wandeln Sonnenstrahlung direkt in Strom um. In der Schweiz sind auf Dächern installierte Anlagen üblich. PV-Anlagen können folgendermassen kategorisiert werden:

- 1. Generation: kristalline Siliziumzellen (monokristallines Si und polykristallines Si); heute dominierend
- 2. Generation: Dünnschichtzellen – CdTe, amorphes Si, CIGS; heute bereits am Markt
- 3. Generation: konzentrierende Zellen, organische Zellen; in Entwicklung

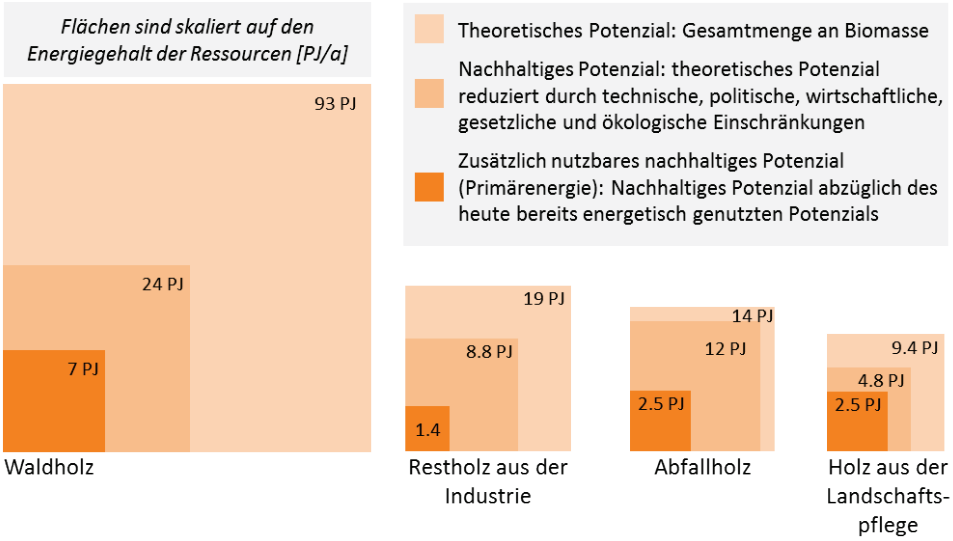
Die aktuelle Technologieentwicklung zielt vor allem auf erhöhte Wirkungsgrade und sinkende Produktionskosten ab.

Fotovoltaik				**Neuanlagen** heute[8]	**2020**	**2035**	**2050**
Potenzial[1]	Potenzial auf Dächern und Fassaden	Fläche (km²)	maximal	Fassaden[9]: 52			
				Dächer[10]: 79			
		Installierte Leistung (GW_p)	maximal	Fassaden[9]: 7-13			
				Dächer[10]: 11-20			
			PSI Schätzung[7]	1.4	~2.9-3.4	~5.7-16	~7.1-20
		Strom-produktion (TWh/a)	maximal	Fassaden[11]: 3-5.6			
				Dächer[10]: 11-19			
			PSI Schätzung[7]	1.1	~2.8-3.3	~5.5-16	~6.9-19
Technische Parameter[1]	Sonneneinstrahlung (kWh/m²/a)			Schweiz: 1100 (Mittelland)			
	Wirkungsgrad		Modul (%)	14-16	15-18	20-26	23-27
			Inverter (%)	98			
	Fläche pro kW installierter Leistung (m²/kW)			7.0-8.0	6.3-7.5	4.3-5.6	4.2-4.9
	Nutzungsgrad (%)			80			
	Durchschnittlicher Jahresertrag[2] ($kWh/kW_p/a$)			970			
	Lebensdauer der Module (a)			30	30	35	35
Kosten[1]	System Investitions-kosten[3] (CHF/kW)	6 kW		2583	1791-2194	1052-1746	908-1545
		10 kW		2092	1543-1874	917-1488	771-1294
		30 kW		1815	1339-1626	796-1291	665-1118
		100 kW		1410	1040-1263	618-1003	538-886
		1000 kW		1350	996-1209	592-960	515-849
	Stromproduktions-kosten[4] (Rp./kWh)	6 kW		31 (20-35)	24-27 (15-31)	15-21 (10-24)	14-19 (9-21)
		10 kW		27 (18-31)	22-25 (14-28)	14-19 (9-22)	13-17 (8-19)
		30 kW		22 (14-26)	18-20 (12-23)	11-16 (7-18)	10-14 (7-16)
		100 kW		15 (10-18)	12-14 (8-16)	8-11 (5-12)	7-10 (4-11)
		1000 kW		12 (8-13)	9-11 (6-14)	6-8 (4-10)	5-7 (3-9)
Treibhausgas-emissionen[1,5,6]	(g CO_2eq/ kWh)	multikristallines Si		60 (39-69)	35-66	21-55	7-45
		monokristallines Si		95 (62-109)	56-104	33-88	11-71
		Dünnschicht CdTe		38 (25-43)	23-42	15-36	8-30
		amorphes & ribbon-Si		65 (41-76)	k.a.	k.a.	k.a.
		Dünnschicht CIS		53 (34-61)	k.a.	k.a.	k.a.

[1] Alle Angaben hier beziehen sich auf PV-Anlagen auf bestehenden Gebäuden. Freiflächenanlagen werden nicht untersucht, da deren Akzeptanz in der Schweiz als nicht gegeben angesehen wird.

[2] Hier angenommen in Übereinstimmung mit (Nowak and Biel 2012) und (Frischknecht, Itten et al. 2015); wird als Referenzwert für Kostenrechnungen und Ökobilanzen verwendet.
[3] Inkl. PV-Modul, Inverter, weiteren Bauteilen, Arbeits- und anderen Kosten. Bandbreiten für zukünftige Kosten reflektieren optimistische und pessimistische Einschätzung der Entwicklung.
[4] Beinhaltet Kosten für Investitionen und Entsorgung, Betrieb und Wartung sowie Ersatz von Invertern und weiteren Bauteilen. Die Bandbreiten ergeben sich aus der Variation der Jahreserträge (850-1500 kWh/kW/a). Zukünftige Kosten beinhalten je ein Szenario mit optimistischer und pessimistischer Einschätzung der Entwicklung; in Klammer sind zusätzlich die Variationen der Jahreserträge (850-1500 kWh/kW/a) berücksichtigt.
[5] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren. Die angegebenen Bandbreiten ergeben sich aus der Variation der Jahreserträge (850-1500 kWh/kW/a). Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 100 g CO_2-eq./kWh auf (Niederspannung).
[6] Heutige Referenzwerte werden mit einem Ertrag von 970 kWh/kW/a berechnet. Zahlen für zukünftige ribbon-Si, a-Si und CIS Zellen sind nicht verfügbar. Die Bandbreiten für zukünftige Technologien reflektieren Unsicherheiten in der zukünftigen Technologieentwicklung und Variabilität der Jahreserträge (850-1500 kWh/kW/a).
[7] PSI-Schätzungen berücksichtigen nur gut geeignete Dachflächen nach (Cattin, Schaffner et al. 2012), entsprechend dem "eingeschränkten technischen Potenzial". Die zukünftige Entwicklung der PV-Stromerzeugung in der Schweiz ist schwierig abzuschätzen; deswegen werden grosse Bandbreiten angegeben. Die Entwicklung wird von den Rahmenbedingungen abhängen, wie z.B. Einspeisevergütungen und anderen Anreizen, der Entwicklung der PV-Technologie und der Strompreise, politischer Unterstützung, Regelungen bzgl. Eigenverbrauch, etc. Der Grossteil dieser Faktoren ist ausserhalb des Rahmens dieser Analyse.
[8] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke mit Kostendaten von 2015/2016.
[9] Uneingeschränkte Potenziale von Fassadenanlagen – nicht direkt vergleichbar mit den Zahlen zu Dachanlagen; Schätzungen unter Berücksichtigung von wirtschaftlichen und gesellschaftlichen Einschränkungsfaktoren sind nicht verfügbar. Potenziale von Dach- und Fassadenanlagen dürfen daher nicht einfach addiert werden.
[10] Entspricht den vorhandenen Dachflächen unter Berücksichtigung von technischen, wirtschaftlichen und gesellschaftlichen Einschränkungen nach (Cattin, Schaffner et al. 2012); d.h., dies ist das „eingeschränkte technische Potenzial“ (oder das „ausschöpfbare Potenzial“).
[11] Nachhaltiges Potenzial (Remund 2017).

Datenblatt – Holzartige Biomasse



Potenzial holzartiger Biomasse in der Schweiz (Erni, Thees et al. in preparation, status: 16.11.2016).[79]

Technologie: In die Kategorie “Holzartige Biomasse” fallen Waldholz, Restholz aus der Industrie, Abfallholz und Holz aus der Landschaftspflege. Nur ein Teil dieser Ressourcen ist momentan aus rechtlichen und wirtschaftlichen Gründen energetisch nutzbar. Diese Biomasse kann entweder durch Verbrennungs- oder Vergasungstechnologien in Strom umgewandelt werden. Mit Biomassefeuerungen werden meist gleichzeitig Strom und Wärme erzeugt, mittels Blockheizkraftwerken (BHKW) bzw. Wärme-Kraft-Kopplungsanlagen (WKK). Mit dem Gas aus der Holzvergasung kann z.B. mit Motoren, Turbinen oder Brennstoffzellen Strom produziert werden. Basierend auf der Schweizerischen Statistik der erneuerbaren Energien des BFE können die Umwandlungstechnologien wie folgt kategorisiert werden:

- **Automatische Holzfeuerungen mit BHKW:** Verbrennung von naturbelassenem Holz mit BHKW mit Leistungen ab 50 $kW_{Brennstoff}$.
- **Verbrennung von Abfallholz und biogenen Abfällen:** Industrielle Verbrennung von Abfallholz und biogenen Abfällen, die für energetische Zwecke genutzt werden können.
- **Kehrichtverbrennungsanlagen – KVA**: Grosse Anlagen mit dem Hauptzweck der Abfallentsorgung.
- **Holzvergasung mit BHKW**: WKK-Anlagen, die mit Gas aus der Holzvergasung betrieben werden.

BHKW mit autom. Holzfeuerung in Felben-Wellhausen (TG) © Schmid

Verbrennung von Abfallholz und biogenen Abfällen, Spiez (BE) © Eicher + Pauli

KVA, Basel (BS) © IWB

Holzvergaser, Stans (NW) © Korporation Stans

[79] Das nachhaltige Potenzial für Waldholz gilt für eine Preisschwelle (ohne Subventionen) von 5.9 Rp./kWh. Mit Subventionen würde sich ein grössers Potenzial ergeben.

Technologien zur Holzvergasung sind heute nicht so häufig im Einsatz wie jene zur Holzverbrennung. Die meisten Systeme zur Holzverbrennung erzeugen momentan nur Wärme. Eine Umrüstung dieser Anlagen auf kombinierte Strom- und Wärmeproduktion sowie die Nutzung heute ungenutzter Biomasseressourcen stellen die grössten Beiträge zur Erhöhung der Stromproduktion aus holzartiger Biomasse dar.

Holzartige Biomasse		**Neuanlagen**			
		heute	**2020**	**2035**	**2050**
Potenzial, Stromproduktion[1] [GWh/a]	Autom. Holz-BHKW[2]	126	126-225	126-614	126-1142
	Verbrennung v. Abfallholz und biogenen Abfällen[3]	70	70	70	70
	KVA[4,5]	1065	1065-1072	1065-1105	1065-1262
Stromproduktions-kosten[6] [Rp./kWh_{el}] *(kursiv ohne Wärmegutschriften)*[7]	Autom. Holz-BHKW[2]	18-36 *(35-71)*	18-37 *(35-73)*	18-41 *(35-80)*	18-45 *(35-87)*
	Verbrennung v. Abfallholz und biogenen Abfällen		18-36 *(35-71)*	18-36 *(35-71)*	18-36 *(35-71)*
	Holzvergasung[8] BHKW[2]	18-31 *(25-44)*	18-32 *(25-44)*	17-33 *(24-47)*	16-35 *(23-49)*
	KVA[4]	2.5-16[9] *(2.6-17)*	2.5-16 *(2.5-16)*	2.4-15 *(2.5-16)*	2.3-15 *(2.5-16)*
THG-Emissionen[10,11] [g CO_2eq/kWh]	Verbrennung und Vergasung	˜10-120	˜10-120	˜10-100	˜10-100 (minus ˜1300)[12]

[1] Die Bandbreiten für zukünftige Potenziale sind gross, da es sich zum Teil um relative neue Technologien handelt. Das untere Ende der Intervalle entspricht der heutigen Stromproduktion. Das obere Ende entspricht jeweils einem linearen Anstieg der Nutzung der Biomasseressourcen, mit 100% Nutzung im Jahr 2050. Auch eine Steigerung der Effizienz der Biomasseumwandlung in Strom wird angenommen, indem zusätzliche Ressourcen mittels Vergasung genutzt werden. Ein im Vergleich konservativeres Szenario ist im Technologiekapitel enthalten.

[2] BHKW: Blockheizkraftwerk mit Wärme-Kraft-Kopplung (WKK).

[3] Diese Kategorie nimmt in Zukunft nicht zu, da angenommen wird, dass Ressourcen stattdessen in der Kategorie “Autom. Holz-BHKW” genutzt werden, wo die Wirkungsgrade deutlich höher sind.

[4] KVA: Kehrichtverbrennungsanlage.

[5] Diese Kategorie wird auch im Datenblatt zu “nicht holzartiger” Biomasse angeführt. Für ein Gesamtpotenzial darf keine Doppeltzählung erfolgen.

[6] Für die Berechnung der zukünftigen Kosten wird als Basis von den heutigen Werten ausgegangen. Die Kostenstruktur aller Technologien (Investitionen, Brennstoff, Betrieb & Wartung, etc.) wird anhand von Fallstudien bestimmt; für alle diese Komponenten werden Annahmen bzgl. zukünftiger Entwicklung getroffen. Zunehmende Produktionskosten ergeben sich aus steigenden Holzkosten, da mehr Holz energetisch genutzt wird.

[7] Basierend auf der Kostenstruktur im Biomassekapitel werden die Stromproduktionskosten auch ohne Wärmegutschriften angegeben (andere Kostenkomponenten bleiben unverändert). In der Praxis werden solche Anlagen aber nur betrieben, falls die Wärme wirtschaftlich genutzt werden kann.

[8] Vergasungs- und Verbrennungstechnologien sind für Potenziale in der Kategorie “Autom. Holz-BHKW” zusammengefasst; Kosten sind separat angegeben.

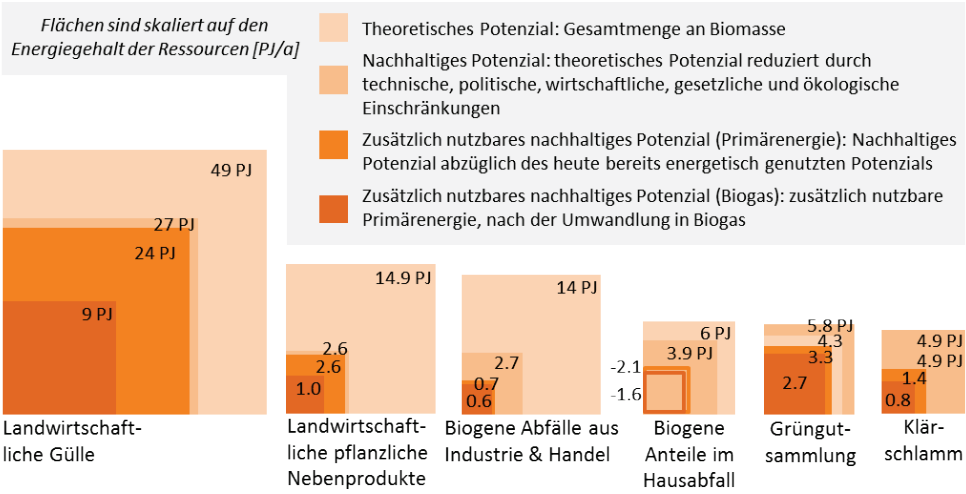
[9] Das untere Ende des Intervalls enspricht “Standard-KVA” zur Abfallentsorgung. Das obere Ende entspricht speziellen Anlagen, die mehr Holz als Abfall verbrennen, z.B. die Anlage (KVA/Holzkraftwerk) in Basel.

[10] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die Bandbreiten reflektieren unterschiedliche Technologien und Brennstoffe. Mangels Daten sind die Werte nicht schweiz-spezifisch und können nicht einzeln für alle Technologien angegeben werden.

[11] Die angenommene Abnahme der Emissionen ist auf gesteigerte Wirkungsgrade zurückzuführen.

[12] Negative THG-Emissionen sind bei einer nachhaltigen Nutzung von Holz in Verbindung mit CCS möglich.

Datenblatt – Nicht holzartige Biomasse



Potenziale[80] nicht holzartiger Biomasse in der Schweiz (Burg, Bowman et al. in preparation, status: 2.2.2017).

Technologie: In die Kategorie "nicht holzartige Biomasse" fallen verschiedene Stoffe mit recht unterschiedlichen Wasseranteilen, etwa die biogenen Anteile der Haushaltsabfälle, biogene Abfälle aus Industrie und Handel, Nebenprodukte aus der Landwirtschaft, Grüngutabfälle, Gülle und Klärschlamm. Stoffe mit hohem Wassergehalt (Klärschlamm, Gülle, etc.) werden zunächst anaerob vergärt. Das entstehende Biogas kann in Motoren, Turbinen oder Brennstoffzellen zur Stromproduktion genutzt werden. Stoffe mit geringem Wassergehalt können verbrannt werden und Dampfkreisläufe oder „organic rankine cycles (ORC)" antreiben. Vergasung von Abfallstoffen ist technisch auch möglich. Eine kommerzielle Vergasungsanlage existiert heute in Lahti, Finnland. Basierend auf der Schweizerischen Statistik der erneuerbaren Energien des BFE können die Umwandlungstechnologien wie folgt kategorisiert werden:

- **Kehrichtverbrennungsanlagen – KVA**: Grosse Anlagen mit dem Hauptzweck der Abfallentsorgung.
- **Kommunale ARA:** Biogas aus anaerober Vergärung von Klärschlamm in Abwasserreinigungsanlagen.
- **Industrielle ARA:** Biogas als Resultat der notwendigen Reinigung von Abwässern einiger Industrien, z.B. der Verarbeitung von Gemüse und Früchten.
- **Industrielles Biogas:** Produktion von Biogas aus Grüngutabfällen, Nahrungsmittel- und Schlachtabfällen, etc. aus kommunalen und industriellen Quellen.
- **Landwirtschaftliches Biogas**: Produktion von Biogas auf Bauernhöfen aus Gülle und Co-Substraten.

KVA, Basel (BS) © IWB

Kommunale ARA Morgental (SG) © morgenthal.ch

Industrielle ARA Rickenbach (LU) © Gefu Produktion

Industrielles Biogas KBA Hard, Beringen (SH) © abfall-sh.ch

Landwirtschaftliches Biogas Düdingen (FR)

[80] Der biogene Teil der Haushaltsabfälle wird in Zukunft voraussichtlich abnehmen, da mehr Grünabfälle an der Quelle gesammelt werden. Daraus ergeben sich negative Werte für das verbleibende Potenzial der biogenen Teile im Hausabfall.

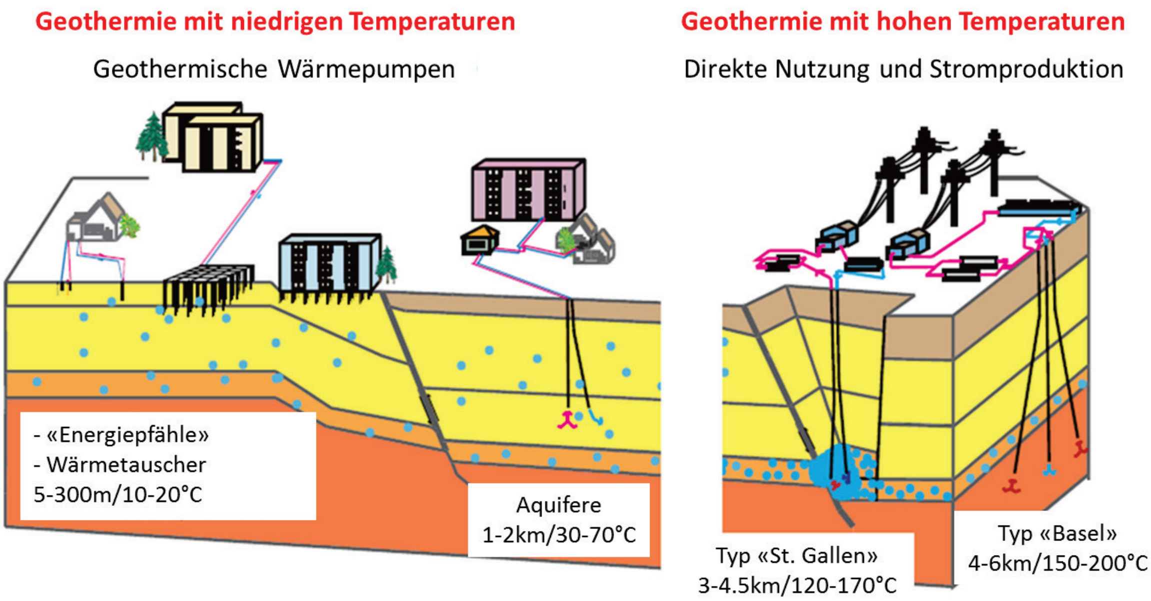
Die anaerobe Vergärung ist eine relativ ausgereifte Technologie in grossem Massstab (z.B. bei Abwasserreinigungsanlagen, ARA), nicht jedoch in kleinem Massstab in der Landwirtschaft. Gülle repräsentiert das heute grösste ungenützte nicht holzartige Biomassepotenzial, ist aber nur dezentral auf Bauernhöfen verfügbar. Kleine Anlagen sind stark auf wirtschaftliche Unterstützung angewiesen (kostendeckende Einspeisevergütung, KEV); um konkurrenzfähig zu werden, müssten die Investitionskosten deutlich sinken. Elektrische Wirkungsgrade bei der Abfallverbrennung werden in Zukunft zunehmen, da die Anlagen optimiert werden hinsichtlich Stromproduktion.

Nicht holzartige Biomasse		**Neuanlagen**			
		heute	**2020**	**2035**	**2050**
Potenzial Stromproduktion[1] [GWh/a]	KVA[2,3]	1065	1065 – 1072	1065 – 1105	1065 – 1262
	Kommunale ARA[4]	119	119 – 129	119 – 170	119 – 225
	Industrielle ARA[4,5] Industrielles Biogas[5]	84	84 – 149	84 – 381	84 – 668
	Landwirtschaftliches Biogas	100	100 – 232	100 – 718	100 – 1342
Stromproduktions-kosten[6] [Rp./kWh_{el}] *(kursiv ohne Wärmegutschriften)*[7]	KVA[2]	2.5 – 16[9] *(2.6-17)*	2.5 – 16 *(2.5-16)*	2.4 – 15 *(2.5-16)*	2.3 – 15 *(2.4-16)*
	Kommunale ARA[4] Industrielle ARA[4]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]
	Industrielles Biogas Landwirtschaftliches Biogas	20 – 49 *(23-55)*	20 – 49 *(22-55)*	18 – 50 *(20-56)*	16 – 51 *(18-57)*
THG-Emissionen[10,11] [g CO_2eq/kWh]	Landwirtschaftliches Biogas	150-450	150-450	k.A.	k.A.

[1] Das untere Ende der Intervalle entspricht der heutigen Produktion. Das obere Ende entspricht jeweils einem linearen Anstieg der Nutzung der Biomasseressourcen, mit 100% Nutzung im Jahr 2050. Auch eine Steigerung der Effizienz der Biomasseumwandlung in Strom wird angenommen, indem vermehrt Brennstoffzellen eingesetzt werden. Ein im Vergleich konservativeres Szenario ist im Technologiekapitel enthalten.
[2] KVA: Kehrichtverbrennungsanlage.
[3] Diese Kategorie wird auch im Datenblatt zu holzartiger Biomasse angeführt. Für ein Gesamtpotenzial darf keine Doppeltzählung erfolgen.
[4] ARA: Abwasserreinigungsanlage.
[5] Diese Kategorien werden bzgl. zukünftigen Potenzials zusammengefasst (ähnliche Ausgangsstoffe).
[6] Für die Berechnung der zukünftigen Kosten wird als Basis von heutigen Werten ausgegangen. Die Kosten-struktur aller Technologien (Investitionen, Brennstoff, Betrieb & Wartung, etc.) wird anhand von Fallstudien bestimmt; für alle diese Komponenten werden Annahmen bzgl. zukünftiger Entwicklung getroffen. Kosten der ARA werden als konstant angenommen, da kaum technische Entwicklung mit Wirkung auf Produktionskosten zu erwarten ist.
[7] Basierend auf der Kostenstruktur im Biomassekapitel werden die Stromproduktionskosten auch ohne Wärmegutschriften angegeben (andere Kostenkomponenten bleiben unverändert). Einige Systeme sind in der Praxis stark auf Erlöse aus dem Wärmeabsatz angewiesen.
[8] Es wird angenommen, das sein Grossteil der Wärme aus ARA direkt vor Ort verbraucht wird und daher kein substanzieller Erlös aus dem Wärmeabsatz generiert wird.
[9] Das untere Ende des Intervalls enspricht “Standard-KVA” zur Abfallentsorgung. Das obere Ende entspricht speziellen Anlagen, die mehr Holz als Abfall verbrennen, z.B. die Anlage (KVA/Holzkraftwerk) in Basel.
[10] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Konsistente und aktuelle Ökobilanzdaten für nicht holzartige Biomasse sind rar. Die Bandbreiten hier sind grobe Schätzungen für kleine landwirtschaftliche Biogas-BHKW. Zum Vergleich: Der Schweizer Stromversorgungsmix (Hochspannung, inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf.
[11] Die Emissionen sind stark abhängig vom „Methanschlupf“ bei der Biomassevergärung, dementsprechend hoch sind die Bandbreiten und Unsicherheiten. Für 2020 wird davon ausgegangen, dass sich die Emissionen höchstens geringfügig ändern. Für die fernere Zukunft sind keine belastbaren Schätzungen vorhanden.

Datenblatt – Geothermische Stromproduktion

Technologie: Strom aus Tiefengeothermie. Im Allgemeinen sind Bohrungen mehr als 400m tief und die Temperaturen im Untergrund müssen bei mehr als 120°C liegen. Da in der Schweiz in geringer Tiefe keine geothermischen Ressourcen vorhanden sind, werden Bohrungen Tiefen von 4-6 km erreichen.



Technologien werden anhand der Art die geothermischen Ressourcen zu nutzen kategorisiert:

- "Flash steam", "dry steam", "back pressure"-Anlagen: Solche Anlagen existieren weltweit und sind dort machbar, wo heisse Wasser- oder Dampfvorkommen zu finden sind (nicht in der Schweiz).
- Hydrothermale (HT) Anlagen: HT-Anlagen sind weltweit in Betrieb. Das Potenzial solcher Anlagen ist begrenzt, da im Untergrund hohe Temperaturen (>100°C), wasserführende geologische Schichten und eine ausreichende Menge and heissem Wasser vorhanden sein müssen.
- "Enhanced Geothermal Systems" (EGS): EGS-Anlagen wären die Technologie der Wahl für die Schweiz. Momentan werden weltweit noch keine EGS-Anlagen kommerziell betrieben. Das Potenzial solcher Anlagen ist gross, da sie nicht so stark auf passende, spezielle natürliche Gegebenheiten angewiesen sind wie die anderen Typen. EGS-Anlagen hängen mehr von technischen Aspekten ab wie erfolgreichen Bohrungen und wirkungsvoller Stimulation des Untergrundes. EGS-Anlagen funktionieren, indem zwei oder mehr Bohrungen vorgenommen werden, wovon eine dazu dient, kaltes Wasser in den Untergrund zu pressen. Dieses erwärmt sich im heissen Untergrund und wird über eine oder mehrere weitere Bohrungen zurück an die Oberfläche gepumpt. Das heisse Wasser wird mit einem Generator zur Stromproduktion genutzt.

Die (Netto-)Leistung eines EGS-Kraftwerks wird bestimmt vom unterirdischen Temperaturgradienten, der Tiefe der Bohrungen und der Impedanz des Reservoirs, ist also abhängig vom Standort. Die Modellierung solcher Anlagen für die Schweiz ergibt im Schnitt Leistungen im Bereich von 1.5-3 MW_{el}, bei aussergewöhnlich guten Bedingungen kann die Leistung pro Bohr-Triplett bei bis zu 10 MW_{el} liegen. An solchen Standorten könnten Anlagen mit mehr als einem Triplett realisiert werden.

Tiefengeothermie – EGS		**Neuanlagen**			
		heute	**2020**	**2035**	**2050**
Potenzial[1]	TWh/a	Keine geothermischen Stromproduktion in der Schweiz	n.a.	n.a.[9]	~4.5
Treibhausgasemissionen[2,3,4,5]	g CO_2-eq./kWh		27 - 84		
Investitionskosten					
Bohrung	Mio. CHF/Bohrung			18 - 30	15
Stimulierung	Mio. CHF/Bohrung			3.3	3.3
Kraftwerk	CHF/kW_{el}			4000	3500
Stromproduktionskosten[3,4,6,7] (ohne Wärmegutschrift)	Rp./kWh			16 - 58	13 - 47 (~10)
Stromproduktionskosten[3,4,8] (mit Wärmegutschrift)	Rp./kWh			-3 - 33	-4 - 27

[1] In der Schweizer Energiestrategie wird von einem Ziel von 4-5 TWh/a bis 2050 ausgegangen. Die Angabe hier für 2050 entspricht diesem Ziel und einem realistischen Langzeitpotenzial, das nur realisiert werden kann, falls die aktuellen wirtschaftlichen, technischen, geologischen, gesetzlichen und gesellschaftlichen Hürden überwunden werden können.
[2] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf (Hochspannung).
[3] Die Angaben hier sind die Ergebnisse eines schweiz-spezifischen, gekoppelten Modells zur wirtschaftlichen und ökologischen Bewertung von EGS-Anlagen; dabei wird die Variation von standortspezifischen Parametern (Temperaturgradient, Permeabilität, etc.) berücksichtigt. Die angegebenen Bandbreiten der Stromproduktionskosten und THG-Emissionen geben diese Variabilität wieder.
[4] Stromproduktionskosten und Ökobilanzergebnisse sind stark vom Standort abhängig. Da noch keine Erfahrungswerte vorliegen, kann die zukünftige Entwicklung nur grob abgeschätzt werden.
[5] Emissionen werden zu 100% dem Strom zugerechnet, da unsicher ist, ob die Abwärme in grossem Massstab genutzt werden kann.
[6] Stromproduktionskosten werden hier zuerst ohne Wärmegutschrift angegeben, da der Grossteil von EGS-Anlagen wahrscheinlich nicht in der Nähe von grossen Wärmeabnehmern betrieben wird. Details dazu im Geothermiekapitel.
[7] Bei äusserst vorteilhaften geologischen Bedingungen könnten die Stromproduktionskosten bei rund 10 Rp./kWh liegen.
[8] Erträge durch den Absatz von Wärme können die Wirtschaftlichkeit von EGS-Anlagen deutlich verbessern (im besten Fall zu negativen Stromproduktionskosten führen). Details dazu im Geothermiekapitel.
[9] Es wird nicht davon ausgegangen, dass Strom aus Geothermie schon in grossem Massstab erzeugt wird.

Datenblatt – Strom aus Wellen- (und Gezeiten-)Kraftwerken

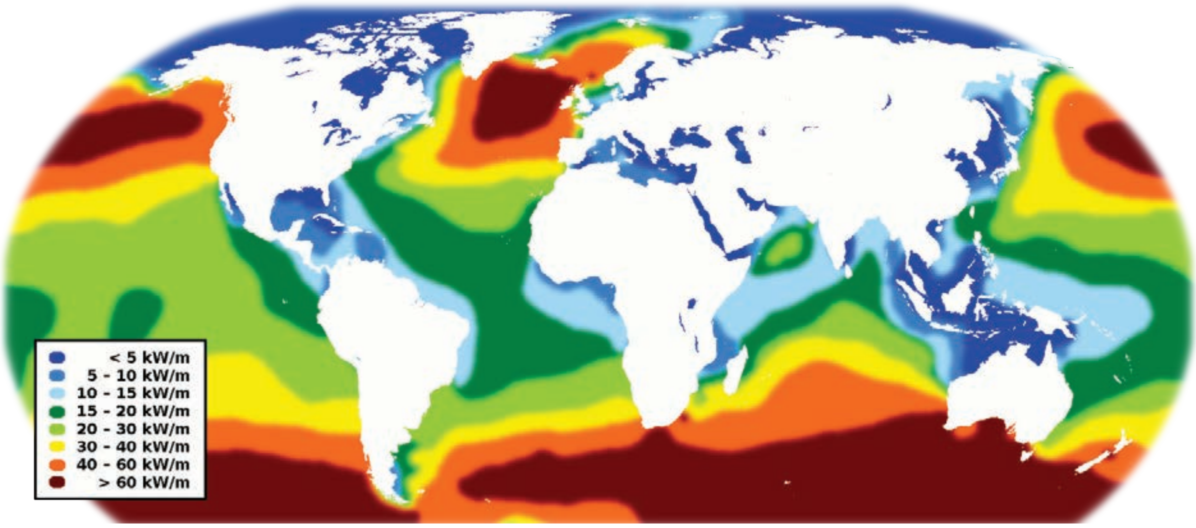
Technologie: Wind über den Meeren überträgt einen Teil seiner Energie auf Wellen und diese Energie kann zur Stromproduktion genutzt werden. Dies geschieht mit Wellenkraftwerken. Gezeitenkraftwerke können die Energie, die in den Gezeiten steckt, in Strom umwandeln. Wellenkraftwerke können in **onshore-** und **offshore-**Anlagen kategorisiert werden.

Wellenkraftwerke. Von links nach rechts: „Pelamis“; „SINN“; „Wave roller“; „Atlantis turbine“; „Wave dragon“.

Wellen- und Gezeitenkraftwerke stecken noch in einer relativ frühen Entwicklungsphase; weltweit gibt es erst wenige Demonstrations- und Versuchsanlagen. Die zukünftige Entwicklung wird sich wahrscheinlich auf offshore-Designs konzentrieren, da auf dem Meer die Energiedichte höher ist und weniger Einschränkungen, z.B. aus visuellen Gründen, vorhanden sind.

Ressourcen: Orte mit dem höchsten Potenzial für Wellenenergie beinhalten die Westküsten von Europa, die nördlichen Küsten von Grossbritannien, und die Pazifikküsten von Nord- und Südamerika, sowie das südliche Afrika, Australien und Neuseeland. Nördliche und südliche mittlere Breiten eignen sich am besten für Wellenkraftwerke. danke der stärkeren Winde kann im Winter mehr Strom produziert werden als im Sommer.

Strom aus Wellenkraftwerken müsste in die Schweiz importiert werden, höchstwahrscheinlich von der Atlantikküste Frankreichs, Spaniens und Portugals.



Karte zur Verteilung der Wellenenergie weltweit.

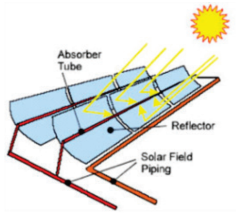
Strom aus Wellen- und Gezeitenkraftwerken			**Neuanlagen**			
			heute[1]	**2020**	**2035**	**2050**
Potenzial[2]	TWh/a	offshore	k.a.	30	30	30
		onshore	k.a.	10-15	10-15	10-15
Investitions-kosten[3]	CHF/kW	offshore & onshore	4000-9500	3000-7000	2100-5000	1900-3500
Stromproduktions-kosten[3,4,5]	Rp./kWh	offshore & onshore	˜38 (23-80)	˜30 (14-42)	˜17 (9-24)	˜11 (8-19)
Importkosten[6]	Rp./kWh	˜1000 km	n.a.	˜0.5	˜0.5	˜0.5
Treibhausgas-emissionen[7,8]	g CO_2-eq./kWh	Wellenenergie	15-105			
		Gezeitenenergie	15-70			

[1] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie (im Demonstrationsstadium); Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke.
[2] Stromproduktion an der Atlantikküste mit anschliessender Übertragung in die Schweiz.
[3] Verfügbare Daten erlauben keine Unterscheidung zwischen onshore- und offshore-Anlagen.
[4] Stromproduktionskosten beinhalten Investitionen, Betrieb und Wartung; Details zu den Kosten sind im entsprechenden Technologiekapitel zu finden.
[5] Die hier angegebenen Bandbreiten basieren auf Literaturangaben und reflektieren Unsicherheiten bzgl. zukünftiger Entwicklung und die Variationen möglicher Kraftwerksdesigns.
[6] Kosten für die Stromübertragung vom Atlantik in die Schweiz.
[7] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren Unterschiede möglicher Kraftwerksdesigns. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf (Hochspannung).
[8] Die angegebenen Bandbreiten gelten für eine Reihe möglicher Kraftwerksdesigns; detailliertere Schätzungen zur zukünftigen Technologienentwicklung und der damit verbundenen Auswirkung auf die Ökobilanzergebnisse sind derzeit nicht möglich.

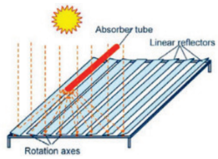
Datenblatt – Solarthermische Stromproduktion
(“Concentrated Solar Power“ – CSP)

Technologie: Die solarthermische Stromproduktion funktioniert mittels Konzentration direkter Sonnenstrahlung zum Aufheizen eines flüssigen, gasförmigen oder festen Wärmetauschermediums; mit diesem wird anschliessend ein (Dampf-)Kreislauf zur Stromproduktion angetrieben. Es gibt Systeme, welche die Sonnstrahlung linear kokussieren und Temperaturen bis 550°C erreichen und solche, die die Sonnenstrahlung punktförmig fokussieren und somit höhere Temperaturen und Wirkungsgrade erreichen. Solarthermische Kraftwerke werden an Orten betrieben, an denen die direkte Normalstrahlung bei DNI >2000 kWh/m^2/a liegt, was geografischen Breiten von <35-40° entspricht (d.h. nicht in der Schweiz). Teil der Anlagen ist meist ein thermischer Energiespeicher, der auch Grundlast-Stromproduktion ermöglicht. Diese Speicher werden so dimensioniert, dass mit der Wärme aus dem Speicher zwischen einer und 15 Stunden Strom produziert werden kann. Strom aus dem Mittelmeerraum könnte mit relativ geringen Verlusten (3%/1000 km) mittels Gleichspannungs-Hochspannungsübertragung in die Schweiz importiert werden.

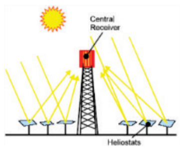
Die folgenden CSP-Technologien können unterschieden werden:



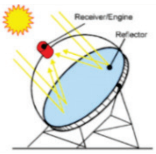
- Parabolrinnenkonzentrator („Parabolic trough”, PTC): Mit Parabolrinnen, die der Sonne folgen, werden die Sonnenstrahlen auf Röhren konzentriert. Diese Röhren enthalten eine Wärmetauscherflüssigkeit, die aufgeheizt wird und in einem Dampfkreislauf die Wärme zur Stromproduktion abgibt.



- Fresnel-Konzentrator (“Linear Fresnel reflector”, LFR): Das Konzept ist ähnlich wie bei Parabolrinnenkonzentratoren; die Parabolform von deren Spiegeln wird allerdings nur imitiert, indem eine grosse Zahl an flachen oder leicht gekrümmten Spiegeln so angeordnet wird, dass sie die Sonne auf einem nach unten gerichteten Empfänger konzentrieren.



- Zentraler Empfänger (“Power tower”, CRS): Eine grosse Zahl von Spiegeln (“solar field”) konzentriert die Sonnenstrahlung an einem zentralen Empfänger, der auf einem Turm montiert ist. Die erzeugte Wärme treibt wiederum einen Dampfkreislauf zur Stromproduktion an.



- Parabolschüssel (“Parabolic dish”, PDC): Mit der Wärme der konzentrierten Sonnenstrahlung wird bei jedem einzelnen Empfänger ein Motor zur Stromproduktion angetrieben (Stirling-Motor oder Mikroturbine). Diese Motoren befinden sich am Fokuspunkt der Parabolspiegel. Nachteil ist, dass die Wärme nur begrenzt gespeichert werden kann.

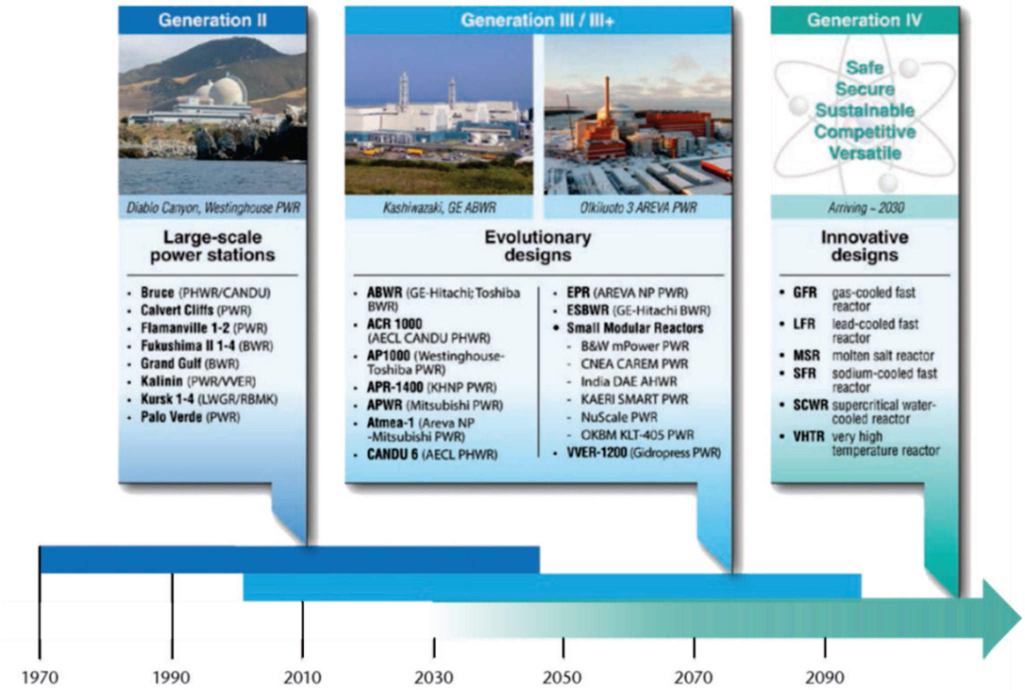
Heute sind erst wenige kommerzielle solarthermische Kraftwerke in Betrieb, vor allem in Spanien und den USA. Die grössten Anlagen mit Leistungen von bis zu 750 MW befinden sich in den USA. Parabolrinnenkraftwerke und Anlagen mit zentralem Empfänger sind die heute vorherrschenden und am weitesten entwickelten Technologien. Anlagen mit einzelnen Parabolschüsseln sind fast vom Markt verschwunden, da sie vergleichsweise teuer sind und Wärmespeicher schlecht integriert werden können. Das noch vorhandene Verbesserungspotenzial bei solarthermischen Kraftwerken ist gross. Stromproduktionskosten können durch Massenproduktion der Anlagen und Kraftwerke mit grösseren Leistungen gesenkt werden. Die Entwicklung der Technologie wird substanzielle Unterstützungs- und Anreizmassnahmen erfordern. Für mögliche Stromimporte in die Schweiz aus dem Mittelmeerraum muss eine geeignete Stromübertragungsinfrastruktur errichtet werden, entweder in Form von Hochspannungs-Gleichstromkabeln oder die Anbindung an ein zukünftiges, ausgeweitetes europäisches Stromnetz.

Solarthermische Stromproduktion			**Neuanlagen**			
			heute[1]	**2020**	**2035**	**2050**
Potenzial	TWh/a	Weltweit	~25[2]	31-466	n.a.	222-9’348
		EUMENA[3]	n.a.	<99	<660	<1358
		MENA[4]	n.a.	<69	<490	<1150
Betriebsdaten	Volllast-stunden pro Jahr	(Schweiz)	n.a.	(1250)	(1375)	n.a.
		Spanien[5] (incl. TES; max. 6400h)	~5000	~5500	~5500	~5500
		Algerien[6] (incl. TES; max. 8000h)	~5500	~6000	~6000	~6000
Jährlicher Wirkungsgrad (“solar-to-electricity”)	%	PTC (inkl. Speicher)	13-15	n.a.	~19	~19
		LFR (<10min Speicher)	9-13	n.a.	~12	~12
		CRS (inkl. Speicher)	14-18	n.a.	~18	~18
		PDC (ohne Speicher)	22-24	n.a.	n.a.	n.a.
Investitionskosten[7]	CHF/kW	PTC (ohne Speicher)	3’100-8’000	3’100-8’000	3’000-5’900	2’000-5’900
		PTC (0.5-8h Speicher)	3’400-12’800			
		CRS (0.5->8h Speicher)	3’400-12’800			
		LFR (0.5-4h Speicher)	3’400-6’700			
Stromproduktions-kosten[8,9]	Rp./kWh	Ohne Speicher	16-33	n.a.	n.a.	n.a.
		Mit Speicher (4-15h)	14-28	6-23	7-11	6-9
Import-Kosten[10]	Rp./kWh		n.a.	n.a.	~2	~2
Treibhausgas-emissionen[11]	g CO_2-eq./ kWh	PTC	13-55	13-55	5-44	5-36
		CRS	9-42	9-42	5-25	5-21
		PDC	5-60	5-60	3-36	3-30

[1] “Heute” bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke.
[2] Grobe Schätzung basierend auf der installierten Leistung.
[3] Europa, Mittlerer Osten und Nordafrika. Nur ein kleiner Teil davor würde für die Schweiz zur Verfügung stehen.
[4] Mittlerer Osten und Nordafrika. Nur ein kleiner Teil davor würde für die Schweiz zur Verfügung stehen.
[5] DNI 2000 $kWh/m^2/a$; TES=Thermischer Energiespeicher. Grobe Schätzung; in der Praxis hängen die Betriebsdaten von der konkreten Dimensionierung der Anlagen ab.
[6] DNI 2500 $kWh/m^2/a$; TES=Thermischer Energiespeicher. Grobe Schätzung; in der Praxis hängen die Betriebsdaten von der konkreten Dimensionierung der Anlagen ab.
[7] Die verfügbaren Daten erlauben keine Differenzierung zwischen verschiedenen CSP-Technologien.
[8] Stromproduktionskosten beinhalten Investitionen, Wartung und Betrieb sowie Erdgaskosten für Zufeuerung. Die Bandbreiten geben Literaturangaben wieder – Details dazu sind im Technologiekapitel vorhanden.
[9] Die verfügbaren Daten erlauen keine Unterscheidung zwischen einzelnen CSP-Technologien.
[10] Kosten für die Stromübertragung aus MENA-Ländern in die Schweiz.
[11] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren Unterschiede möglicher Kraftwerksdesigns und Unsicherheiten bzgl. zukünftiger Enrtwicklung. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf (Hochspannung).

Datenblatt – Kernenergie

Technologie: In heutigen Kernkraftwerken wird Strom durch die Spaltung von U-235 Atomen erzeugt; im Uranbrennstoff ist U-235 angereichert, d.h. zu einem grösseren Anteil als den natürlichen 0.7% vorhanden. Mit Hilfe der Zerfallsprodukte und genug Neutronen wird eine Kettenreaktion erzeugt. Es existiert eine Vielzahl von Technologievariationen: verschiedene Brennstoffzyklen (bzgl. Ausgangsstoff, Grad der Anreicherung, etc.), unterschiedliche Ansätze zur Steuerung der Neutronen, verschiedene Materialien als Moderator (Leicht- oder Schwerwasser, Grafit, etc.), unterschiedliche Kühlmittel zur Dampferzeugung (Wasser, Gas oder Flüssigsalze), und verschiedene Reaktor-konfigurationen stehen zur Auswahl. Die dominierenden Reaktordesigns basieren auf Uranoxid als Brennstoff, das angereichert ist auf 3-5%, Leichtwasser als Moderator für thermische Neutronen („Light Water Reactors"; LWR), und der Erzeugung von Dampf durch direktes Verdampfen des Wassers (Siedewasserreaktoren) oder unter hohem Druck (Druckwasserreaktoren). Die folgende Abbildung zeigt die zeitliche Folge der Reaktorgenerationen, die sich im Design und der verwendeten Technologie unterscheiden. Ziele der Entwicklung waren und sind die Verbesserung der Wirtschaftlichkeit und eine erhöhte Sicherheit.



Generationen von Reaktordesigns im Zeitverlauf (nach (OECD/NEA/IEA 2015)).

Die heute dominierenden Leichtwasserreaktoren können als relativ fortgeschrittene Technologie angesehen werden. Evolutionäre Designs (Generation 3+) werden mit dem Ziel einer erhöhten Sicherheit entwickelt, wobei die Wettbewerbsfähigkeit erhalten bleiben muss. Diese Entwicklung beinhaltet auch einen Trend hin zu kleinen, modularen Reaktoren ("small modular reactors", SMR), welche in standardisierten Verfahren in grösseren Stückzahlen zu geringeren Kosten hergestellt werden sollen. Aktuelle und verlässliche Kostenschätzungen sind jedoch rar und mit grossen Unsicherheiten behaftet. Die spezifischen Investitionskosten für solche SMR scheinen ähnlich hoch zu sein wie jene für aktuelle Reaktoren und die Hürden für den Aufbau einer Produktionslinie in Form von höheren Kosten für erste Anlagen bei unsicherer Auftragslage sind hoch. In weiterer Zukunft könnten Reaktoren der 4. Generation auf den Markt kommen. Verschiedene Designs versprechen je nach Reaktortyp inhärente Sicherheit, Verbesserungen bzgl. Proliferation, weniger radioaktive Abfälle, oder eine bessere Nutzung der Ressource Uran.

Eine Reihe von heutigen und zukünftigen Reaktordesigns kann auch mit Thorium betrieben werden. Im Gegensatz zu U-235 ist Thorium nicht spaltfähig, sondern ein sogenannter "Brutstoff" (wie U-

238), sodass das Thorium im Reaktor in U-233 umgewandelt („gebrütet“) wird, und der Brennstoffzyklus ursprünglich durch ein anderes spaltbares Material oder einen Neutronen-beschleuniger angetrieben werden muss. Im Vergleich zu den heutigen Kernbrennstoffen ist Thorium in grösseren Mengen vorhanden, kann weniger radioaktive Abfälle verursachen und ist weniger anfällig bzgl. Proliferation. Allerdings ist die Ausweitung der Nutzung von Thorium durch dessen Brutverhältnis limitiert und es sind noch technische und wirtschaftliche Unsicherheiten vorhanden.

Ressourcen: Die Verfügbarkeit von Uran wird in Zukunft nicht der hauptsächlich limitierende Faktor für die Kernenergie sein. Die Nutzung der heute nachgewiesenen Uranreserven mit heutigen Reaktoren könnte ein potenzielles Wachstum der Kernenergie weltweit im nächsten Jahrhundert einschränken; allerdings stehen alternative Brennstoffzyklen, Reaktordesigns, Anreicherungsmethoden, und Brennstoffquellen (z.B. Uran aus Meerwasser) zur Verfügung, was bedeutet, dass limitierende Faktoren eher in den Bereichen Wettbewerbsfähigkeit, Akzeptanz, Proliferation und Sicherheit liegen werden.

Kernenergie		**Heute** Existierende KKW in der Schweiz	**“Neuanlagen”**[1] (hypothetische neue Gen III/III+ Reaktoren)	**2035** (SMR[6])	**2050** (Gen IV)
Potenzial[2]	TWh/a	Nicht anwendbar			
Investitionskosten[3]	CHF/kW	1’300-6’000	4’000-7’000	3’000-9’000	keine Daten
Stromproduktions-kosten[4]	Rp./kWh	4-6 [7]	7.5 (5.1 - 12.5)	7.4 (5.1 - 12.2)	keine Daten
Treibhausgas-emissionen[5]	g CO_2-eq./kWh	10-20	10-20	5-40	

[1] “Neuanlagen” bezieht sich hier auf Kraftwerke, mit deren Planung heute begonnen würde. Nachdem das Schweizer Volk am 25. Mai 2017 der Energiestrategie 2050 zugestimmt hat, ist der Bau neuer Kernkraftwerke gemäss revidiertem Kernenergiegesetz verboten.
[2] Technisch kaum limitert; wird bestimmt von wirtschaftlichen Überlegungen und Akzeptanzfragen.
[3] Sogenannte “Overnight Capital Costs”. Die Bandbreite für die heute betriebenen KKW beinhaltet bisherige upgrades (KKW Leibstadt und KKW Gösgen). Die Investitionskosten für hypothetische, neue Anlagen gelten für aktuelle Designs (Gen III/III+, z.B. EPR), errichtet in der Schweiz. Die Investitionskosten für 2035 gelten für SMR; die Kosten für Gen III/III+ wäre allerdings auch für 2035 anwendbar. Die grössere Bandbreite für SMR ergibt sich aus höheren Unsicherheiten. Kosten für Gen IV Designs im Jahr 2050 können mangels belastbarer Daten und aufgrund hoher Unsicherheiten heute nicht sinnvoll abgeschätzt werden.
[4] Beinhalten Kosten für Investitionen und Betrieb, Wartung und Rückbau sowie Abfallentsorgung. Die Bandbreiten für “Neuanlagen” und 2035 basieren auf Sensitivitätsanalysen, bei denen die wichtigsten Kostenfaktoren von 50% bis 200% der Ausgangswerte variiert werden. Details sind im Kernenergie-Kapitel zu finden. Für Gen III/III+ und SMR sind jeweils die zentralen Werte (“Basisfall”) und die unteren und oberen Grenzen der ermittelten Kostenbereiche angegeben.
[5] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren mögliche Variabilität in den Inventardaten der Schweizer Kernenergiekette. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf (Hochspannung). Die Zahlen für 2035 und 2050 sind lediglich grobe Schätzungen, da Ökobilanzergebnisse beschränkt vorhanden sind; für Gen IV-Designs liegen keine belastbaren Ergebnisse vor.
[6] „Small Modular Reactors“.
[7] Bei den Stromproduktionskosten der heute betriebenen KKW sind die Kapitalkosten grossteils amortisiert, die Stromkosten sind den Jahresberichten von KKG und KKL entnommen.

Datenblatt – Strom aus Erdgas- und Kohlekraftwerken

Technologie: Erdgas kann in grossen Gas- und Dampfkraftwerken (GuD) und kleinen, dezentralen Blockheizkraftwerken (BHKW) zur Stromproduktion genutzt werden. Die Leistungen der Anlagen liegen in einem breiten Bereich von 1 kWel bis zu einigen hundert MWel. Mit Stein- und Braunkohle wird Strom in grossen Kraftwerken mit Leistungen von bis zu GWel erzeugt. Die Abscheidung, Nutzung und/oder geologische Speicherung von CO2 ("Carbon Capture, (Utilization) and Storage" (CCUS)) bei grossen Kohle- und Gaskraftwerken befindet sich heute im Versuchs- und Forschungsstadium. Die Kraftwerkstechnologien sind in einem fortgeschrittenen Entwicklungsstadium; zukünftige Verbesserungen zielen darauf ab, Wirkungsgrade zu erhöhen und Schadstoffemissionen zu senken.

Abkürzungen

NGCC – GuD	Natural gas combined cycle – Gas- & Dampfkraftwerk
NGCC post	GuD-Kraftwerk mit CO_2-Abscheidung "post-combustion"
NGCC pre	GuD-Kraftwerk mit CO_2-Abscheidung „pre-combustion"
NG-Turbine	Erdgasturbine
BHKW 1kW_{el}	Erdgas-Blockheizkraftwerk mit Kolbenmotor 1 kW_{el}
BHKW 10kW_{el}	Erdgas-Blockheizkraftwerk mit Kolbenmotor 10 kW_{el}
BHKW 100kW_{el}	Erdgas-Blockheizkraftwerk mit Kolbenmotor 100 kW_{el}
BHKW 1000kW_{el}	Erdgas-Blockheizkraftwerk mit Kolbenmotor 1000 kW_{el}
IGCC hard coal	Steinkohle-GuD-Kraftwerk mit integrierter Kohlevergasung
IGCC hard coal pre	Steink.-GuD-Kraftw. mit integr. Kohlevergasung, CO_2-Abscheidung „pre-combustion"
SCPC hard coal	Superkritisches Steinkohlekraftwerk
SCPC hard coal post	Superkritisches Steinkohlekraftwerk mit CO_2-Abscheidung "post-combustion"
SCPC hard coal oxy	Superkritisches Steinkohlekraftwerk mit CO_2-Abscheidung „oxyfuel combustion"
IGCC lignite	Braunkohle-GuD-Kraftwerk mit integrierter Kohlevergasung
IGCC lignite pre	Braunk.-GuD-Kraftwerk mit integr. Kohlevergasung und CO_2-Absch. „pre-combustion"
SCPC lignite	Superkritisches Braunkohlekraftwerk
SCPC lignite oxy	Superkritisches Braunkohlekraftwerk mit CO_2-Abscheidung „oxyfuel combustion"
SCFBC lignite	Braunkohlekraftwerk mit superkritischer Wirbelschichtverbrennung (WSVB)
FBC lignite post	Braunk.-kraftw. mit superkr. (WSVB), CO_2-Abscheidung "post-combustion"

Fussnoten zur folgenden Tabelle

[1] Berücksichtigt werden Kosten für Investitionen, Brennstoff, Entsorgung, Wartung und Betrieb. Die Bandbreiten reflektieren optimistische bzw. pessimistische Technologiespezifizierung und -entwicklung sowie die angenommenen Veränderungen der Kosten gegenüber heute.

[2] Nach Tab. 4.3: Erdgaspreise für Schweizer Haushalte und Industrie; Kohlepreise für die Industrie.

[3] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die Bandbreiten reflektieren Unterschiede in Kraftwerksparametern und der zukünftigen Entwicklung. Zum Vergleich: Der heutige CH-Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf.

[4] Bei BHKW werden Emissionen anhand des Exergiegehalts von Strom und Wärme aufgeteilt.

[5] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie; Stromproduktionskosten beziehen sich auf heute neu gebaute Anlagen.

[6] Stromproduktion bzw. Importe sind technisch vor allem von Erdgas- bzw. Stromimportkapazitäten limitiert; in der Praxis spielen vor allem wirtschaftliche, ökologische und gesellschaftliche Faktoren eine Rolle. Eine vertiefte Analyse zu BHKW-Potenzialen wurde nicht vorgenommen, da die Wirtschaftlichkeit derzeit nicht gegeben ist und sich der Bedarf an Raumwärme in den nächsten Jahrzehnten stark verändern wird.

Strom aus Erdgas- & Kohlekraftwerken		**Neuanlagen**			
		heute[5]	**2020**	**2035**	**2050**
Potenzial	TWh/a	1.6	n.a.[6]		
Stromproduktionskosten[1] (mit Wärmegutschrift für BHKW) ($Rp./kWh_{el}$)	GuD	11.3 (10.8 - 12.3)	11.7 (11.1 - 12.6)	13.4 (12.9 - 14.2)	15.2 (14.5 - 16.0)
	GuD post	14.1 (13.0 - 15.8)	14.4 (13.4 - 16.1)	16.3 (15.3 - 17.7)	18.4 (17.3 - 19.8)
	GuD pre	14.2 (13.3 - 16.0)	14.3 (13.4 - 16.0)	16.1 (15.3 - 17.6)	18.1 (17.3 - 19.6)
	NG-Turbine	18.5 (16.8 - 20.9)	19.6 (17.9 - 22.0)	21.3 (19.6 - 23.8)	23.6 (21.8 - 26.1)
	BHKW $1kW_{el}$	71.8 (50.2 - 114.6)	70.6 (49.5 - 112.5)	67.0 (47.4 - 106.0)	65.6 (46.9 - 103.1)
	BHKW $10kW_{el}$	29.6 (22.2 - 45.3)	29.5 (22.2 - 45.6)	29.5 (22.5 - 44.8)	30.2 (23.4 - 45.3)
	BHKW $100kW_{el}$	14.2 (9.6 - 19.2)	14.9 (9.6 - 20.4)	16.5 (11.1 - 21.9)	18.3 (12.7 - 23.9)
	BHKW $1000kW_{el}$	12.0 (9.9 - 14.6)	12.7 (10.4 - 15.7)	14.5 (12.1 - 17.4)	16.6 (14.0 - 19.6)
	IGCC hard coal	7.1 (6.5 - 8.3)	7.2 (6.6 - 8.4)	7.5 (6.9 - 8.7)	7.7 (7.3 - 8.9)
	IGCC hard coal pre	9.5 (8.3 - 11.2)	9.3 (8.2 - 10.9)	9.0 (8.2 - 10.3)	9.4 (8.5 - 10.6)
	SCPC hard coal	5.5 (5.2 - 5.9)	5.7 (5.4 - 6.1)	6.3 (5.9 - 6.7)	6.8 (6.5 - 7.3)
	SCPC hard coal post	8.5 (7.6 - 9.6)	8.3 (7.5 - 9.3)	8.8 (8.0 - 9.7)	9.4 (8.6 - 10.3)
	SCPC hard coal oxy	8.5 (7.1 - 10.2)	8.5 (7.2 - 10.1)	8.6 (7.5 - 10.0)	8.9 (8.0 - 10.1)
	IGCC lignite	6.6 (5.6 - 7.6)	6.5 (5.6 - 7.5)	6.8 (5.8 - 7.7)	7.1 (6.1 - 8.0)
	IGCC lignite pre	8.6 (7.3 - 10.1)	8.4 (7.2 - 9.9)	8.6 (7.4 - 10.1)	9.0 (7.7 - 10.4)
	SCPC lignite	4.6 (4.0 - 5.6)	4.7 (4.1 - 5.6)	4.8 (4.2 - 5.8)	5.1 (4.4 - 6.0)
	SCPC lignite oxy	8.9 (7.4 - 10.6)	8.6 (7.1 - 10.5)	7.4 (6.3 - 10.4)	6.6 (5.5 - 10.4)
	SCFBC lignite	4.5 (3.9 - 5.3)	4.6 (4.0 - 5.4)	4.8 (4.3 - 5.6)	5.1 (4.6 - 5.9)
	FBC lignite post	7.7 (6.6 - 9.2)	7.8 (6.7 - 9.3)	8.0 (6.8 - 9.6)	8.3 (7.0 - 10.0)
Stromproduktionskosten[1] (ohne Wärmegutschriften) ($Rp./kWh_{el}$)	BHKW $1kW_{el}$	93.2 (72.7 - 131.5)	92.4 (72.4 - 129.6)	91.6 (73-1 - 125.8)	89.3 (71.9 - 121.6)
	BHKW $10kW_{el}$	48.8 (40.3 - 63.3)	49.1 (40.7 - 63.3)	51.5 (43.5 - 65.0)	51.3 (43.5 - 64.3)
	BHKW $100kW_{el}$	22.3 (19.2 - 26.2)	22.2 (19.2 - 26.5)	25.4 (22.3 - 29.6)	26.2 (23.2 - 30.3)
	BHKW $1000kW_{el}$	17.1 (15.5 - 19.3)	17.1 (15.5 - 19.2)	20.1 (18.4 - 22.2)	21.0 (19.3 - 23.1)
Brennstoffkosten: Erdgas[2] (CHF/MWh)	BHKW 1 kW_{el}, 10 kW_{el}	84	87	103	110
	Alle anderen Technologien	56	58	75	82
Brennstoffkosten: Stein-/ Braunkohle[2] (CHF/MWh)	Alle Technologien	13/6	18/8	20/9	22/10
Treibhausgasemissionen[3,4] (g CO_2-eq/kWh_{el})	GuD	393 (387 - 400)	380 (374 - 386)	365 (359 - 371)	357 (346 - 363)
	GuD post	104 (94 - 114)	99 (90 - 109)	90 (81 - 103)	83 (75 - 100)
	GuD pre	97 (81 - 120)	91 (76 - 112)	86 (72 - 107)	83 (70 - 103)
	NG-Turbine	570 (556 - 585)	570 (556 - 584)	520 (509 - 533)	500 (489 - 511)
	BHKW $1kW_{el}$	643 (611 - 677)	636 (605 - 670)	618 (589 - 648)	606 (578 - 635)
	BHKW $10kW_{el}$	611 (583 - 633)	605 (575 - 632)	586 (558 - 613)	575 (546 - 601)
	BHKW $100kW_{el}$	506 (476 - 529)	500 (464 - 530)	482 (448 - 511)	474 (441 - 503)
	BHKW $1000kW_{el}$	481 (459 - 500)	473 (450 - 498)	452 (429 - 476)	445 (423 - 468)
	IGCC hard coal	841 (823 - 860)	820 (803 - 838)	807 (790 - 824)	748 (734 - 764)
	IGCC hard coal pre	205 (177 - 255)	190 (164 - 237)	172 (148 - 213)	156 (135 - 194)
	SCPC hard coal	845 (827 - 864)	825 (807 - 843)	803 (786 - 820)	785 (768 - 801)
	SCPC hard coal post	240 (223 - 268)	229 (214 - 256)	204 (181 - 234)	181 (159 - 214)
	SCPC hard coal oxy	158 (123 - 215)	153 (119 - 208)	145 (113 - 197)	137 (106 - 187)
	IGCC lignite	912 (892 - 934)	871 (852 - 891)	842 (824 - 861)	832 (815 - 850)
	IGCC lignite pre	128 (103 - 178)	121 (94 - 170)	109 (85 - 154)	107 (83 - 151)
	SCPC lignite	965 (942 - 1022)	929 (902 - 980)	837 (803 - 874)	801 (785 - 835)
	SCPC lignite oxy	83 (43 - 152)	79 (38 - 149)	71 (33 - 133)	67 (34 - 122)

Datenblatt – Strom aus Brennstoffzellen

Technologie: Die hier untersuchten Brennstoffzellen erzeugen elektrochemisch aus Methan (Erdgas oder Biogas) Strom und Wärme. Systeme, die mit Wasserstoff als Brennstoff funktionieren, sind mit einem Reformer ausgestattet, um vor Ort aus Erdgas Wasserstoff zu erzeugen. Die Leistungen von Brennstoffzellensysteme können stark variieren, von weniger als 1 kW_{el} bis zu Hunderten von kW_{el}. Im Betrieb sind Brennstoffzellen sehr flexibel und weisen hohe Wirkungsgrade unter Teillast auf; je nach Brennstoffzellentyp liegen die Anfahrzeiten im Bereich von Minuten bis Stunden.

Brennstoffzellen sind am Markt erhältlich. Die meisten Anlagen sind aber auf Unterstützungsmassnahmen im Rahmen von Demonstrationsprojekten angewiesen. Es wird davon ausgegangen, dass zukünftig Investitionskosten sinken, Lebensdauern und Wirkungsgrade substanziell zunehmen werden.

Strom aus Brennstoffzellen			**Neuanlagen: heute**[1]	**2020**	**2035**	**2050**
Potenzial[2]	TWh/a		<0.01	~1.2	~6.1	~7.9
Stromproduktions-kosten[3,4] (mit Wärmegutschrift)	Rp./kWh	PEFC 1 kW_{el}	96 (65 - 125)	37 - 95	24 - 64	20 - 46
		SOFC 1 kW_{el}	96 (65 - 124)	35 - 98	23 - 60	19 - 44
		SOFC 300 kW_{el}	54 (40 - 70)	24 - 57	15 - 37	14 - 23
		MCFC 300 kW_{el}	23 (17 - 32)	15 - 30	16 - 31	14 - 24
		PAFC 300 kW_{el}	22 (17 - 32)	14 - 29	14 - 22	13 - 20
Stromproduktions-kosten[3,4] (ohne Wärmegutschrift)	Rp./kWh	PEFC 1 kW_{el}	108 (77 - 136)	49 - 106	36 - 75	30 - 57
		SOFC 1 kW_{el}	107 (76 - 134)	46 - 108	33 - 70	29 - 53
		SOFC 300 kW_{el}	58 (44 - 73)	27 - 60	18 - 39	17 - 25
		MCFC 300 kW_{el}	29 (23 - 37)	20 - 35	21 - 35	18 - 27
		PAFC 300 kW_{el}	29 (24 - 38)	21 - 35	22 - 30	21 - 28
Brennstoffkosten: Erdgas	CHF/MWh	1 kW_{el} / 300 kW_{el}[9]	84/56	87/58	103/75	110/82
Brennstoffkosten: Biogas	CHF/MWh	1 kW_{el} / 300 kW_{el}[9]	159/131	162/133	178/150	185/157
Treibhausgas-emissionen[5,6,8]	g CO_2-eq./kWh	PEFC 1 kW_{el}	690 (590 - 780)	540 - 700	490 - 620	450 - 570
		SOFC 1 kW_{el}	610 (560 - 670)	520 - 630	480 - 560	440 - 520
		SOFC 300 kW_{el}	490 (360 - 540)	340 - 500	350 - 440	340 - 420
		MCFC 300 kW_{el}	560 (370 - 610)	360 - 580	380 - 490	360 - 450
		PAFC 300 kW_{el}	590 (500 - 650)	480 - 620	460 - 580	440 - 550
Treibhausgas-emissionen[5,7,8]	g CO_2-eq./kWh	PEFC 1 kW_{el}	440 (350 - 530)	330 - 470	320 - 430	300 - 410
		SOFC 1 kW_{el}	430 (350 - 520)	330 - 470	310 - 420	300 - 390
		SOFC 300 kW_{el}	390 (330 - 460)	310 - 420	300 - 380	290 - 370
		MCFC 300 kW_{el}	410 (340 - 490)	320 - 450	310 - 400	290 - 370
		PAFC 300 kW_{el}	410 (340 - 500)	320 - 460	310 - 420	300 - 400

[1] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie; Stromproduktionskosten beziehen sich auf heute neu gebaute Anlagen.
[2] Technisch kaum beschränkt; Schätzung gültig für den Ersatz heutiger Öl- und Gasheizungen in Haushalten.
[3] Berücksichtigt werden Kosten für Investitionen, Brennstoff, Entsorgung, Wartung und Betrieb. Die Bandbreiten reflektieren optimistische bzw. pessimistische Technologiespezifizierung und -entwicklung sowie die angenommenen Veränderungen der Kosten gegenüber heute.
[4] Ergebnisse gelten für Erdgas als Brennstoff. Mit Biogas erhöhen sich die Kosten um 8-14 Rp./kWh.
[5] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren Unterschiede in den Spezifikationen verschiedener Brennstoffzellentypen und mögliche zukünftige Entwicklung. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 100 g CO_2-eq./kWh auf (Niederspannung).
[6] Emissionen werden auf Strom und Wärme anhand des Exergiegehalts aufgeteilt.
[7] Treibhausgasemissionen berechnet mit Systemerweiterung: Die Emissionen der entsprechenden Wärmemenge einer Gasheizung werden von den Gesamtemissionen der Brennstoffzellen abgezogen.
[8] Treibhausgasemissionen für den Betrieb mit Biogas sind nicht verfügbar.
[9] Nach Table 5.3: Erdgaspreise für Haushalte/Industrie in der Schweiz; Aufschlag von 75 CHF/MWh für Biomethan.

2.6 Vergleich mit früheren Studien

2.6.1 Rahmen der Arbeit und Vorgehensweise

Im Vergleich zur „Vorgängerstudie" (Hirschberg, Bauer et al. 2005) ist der Rahmen der vorliegenden Arbeit deutlich umfangreicher:

- Mehrere zusätzliche Technologien werden berücksichtigt: Grosswasserkraft, Erdgas-GuD-Kraftwerke, -BHKW und Brennstoffzellen, Erdgas- und Kohlekraftwerke mit CO_2-Abscheidung sowie neuartige Technologien.
- Die vorliegende Arbeit beinhaltet eine Bewertung der Umweltauswirkungen der Stromerzeugung, d.h. Ökobilanzergebnisse.
- Es werden so weit wie möglich Schweiz-spezifische Bandbreiten für Stromproduktionskosten und Umweltauswirkungen in konsistenter Weise für alle Technologien angegeben.
- Die Sensitivität der Stromproduktionskosten ist weitgehend konsistent für alle Technologien analysiert.
- Die Technologiebewertung wird auf eine systematischere, umfassendere und transparentere Weise durchgeführt; dies betrifft die Differenzierung von einzelnen Technologien, die verwendeten Literaturquellen, Inputdaten und Annahmen.
- Die Arbeit wurde einem umfassenden Review unterzogen von Experten der Bundesämter, der Industrie und akademischer Institutionen.
- Die Ergebnisse der Arbeit – Potenziale, Stromproduktionskosten und Umweltauswirkungen – werden in den Kontext anderer nationaler und internationaler Studien gestellt.

2.6.2 Potenziale und Stromproduktionskosten

Die Stromproduktionskosten und Potenziale, die in der vorliegenden Arbeit ermittelt wurden, können mit den Ergebnissen früherer Studien verglichen werden (Abbildung 2.8 und Abbildung 2.9). Basis dafür sind (Hirschberg, Bauer et al. 2005, Hirschberg, Bauer et al. 2010, Densing, Hirschberg et al. 2014, Densing, Panos et al. 2016)[81]: Die maximalen Potenziale zur Stromproduktion[82] und die Stromproduktionskosten im Jahr 2050 werden dafür verwendet. Die Technologien und deren Anwendungen sind in den verschiedenen Studien nicht immer konkret spezifiziert. Bzgl. der Potenziale können nur Wasserkraft, Strom aus Biomasse, Geothermie sowie Strom aus Windturbinen und PV-Anlagen verglichen werden, da die Vergleichsstudien sonst keine konsistenten Zahlen enthalten. Bzgl. der Stromproduktionskosten im Jahr 2050 können lediglich PV-Anlagen, Windkraftwerke, Erdgas-GuD-Kraftwerke und Kernkraftwerke verglichen werden – Produktionskosten für andere Technologien und Brennstoffe fehlen in den Vergleichsstudien.

[81] Densing, Hirschberg et al. (2014) erstellten einen umfassenden Vergleich von aktuellen Energieszenarien für die Schweiz aufgrund der verfügbaren Literatur (explizit für Potenziale und Kosten der Stromproduktion).

[82] Konsistente Werte aus Vergleichsstudien sind nur für Wasserkraft, Strom aus Biomasse, Fotovoltaik, Windkraft und Geothermiekraftwerken verfügbar. Diese gelten für das „ökonomisch und gesellschaftlich akzeptierte Potenzial" der einzelnen Technologien, entsprechend den „ausschöpfbaren Potenzialen" in dieser Studie.

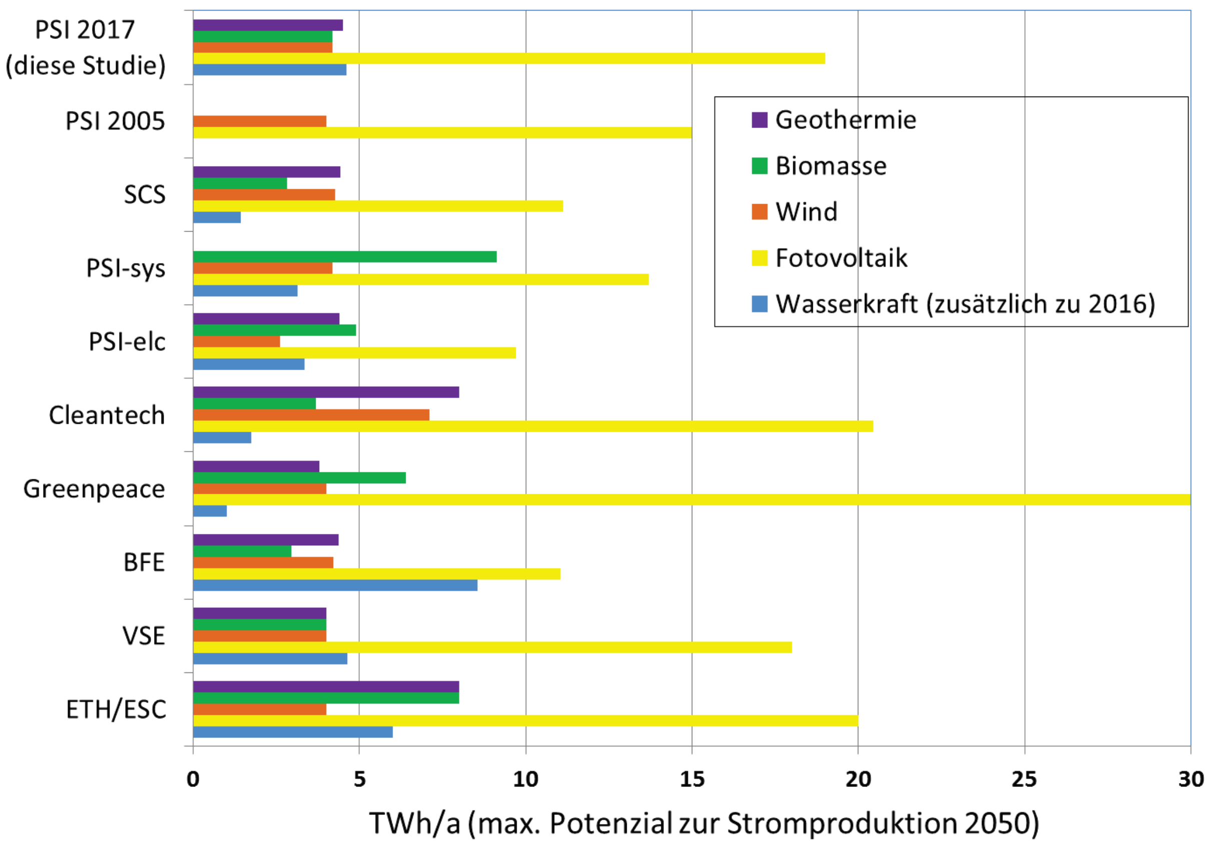


Abbildung 2.8: Maximale Potenziale zur Stromproduktion mit verschiedenen Technologien in der Schweiz im Jahr 2050 nach verschiedenen Studien. Konsistente Daten für andere Technologien sind nicht verfügbar. Bei Wasserkraft ist nur die zusätzlich zur heutigen mögliche Produktion dargestellt; die Balken für alle anderen Technologien beinhalten die heutige Produktion.[83] ETH/ESC: (Andersson, Boulouchos et al. 2011); VSE: (VSE 2012); BFE: (Prognos 2012a); Greenpeace: (Teske and Heiligtag 2013); Cleantech: (Barmettler, Beglinger et al. 2013); PSI-elc: (Kannan and Turton 2012b, Kannan and Turton 2012a); PSI-sys: (Weidmann 2013); SCS: (SCS 2013); PSI 2005: nur Potenziale fürWind und PV wurden für 2050 abgeschätzt (Hirschberg, Bauer et al. 2005); PSI 2010: (Hirschberg, Bauer et al. 2010); „PSI 2017" beinhaltet für Fotovoltaik nur Dachanlagen.

Die Potenzialabschätzung für Wasserkraft in der vorliegenden Studie beinhaltet Gross- und Kleinwasserkraft; es ist nicht klar, ob dies auch in den Vergleichsstudien der Fall ist, oder ob sich diese nur auf Grosswasserkraft beziehen. Die vergleichsweise tiefen Werte von (Barmettler, Beglinger et al. 2013, Teske and Heiligtag 2013) sind mit ökologischen Einschränkungen begründet. Die unterschiedlichen Potenziale für Strom aus Biomasse sind eine Folge von unterschiedlichen Primärdatenquellen, unterschiedlichen Annahmen bzgl. Umwandlungstechnologien sowie alternative Nutzung von Biomasse (für Nutzwärme und den Verkehr). (Hirschberg, Bauer et al. 2005) enthält keine Potenziale für Grosswasserkraft und Strom aus Biomasse. Die Potenziale für Strom aus Windturbinen sind in allen Studien recht ähnlich, da die meisten Abschätzungen auf der gleichen Quelle beruhen. Bei Strom aus Geothermiekraftwerken beziehen sich die meisten Studien (inkl. dieser) auf das vom Bund ausgegebene Langzeitziel; diese Menge an Strom aus Geothermiekraftwerken kann jedoch nur realisiert werden, falls die momentan vorhandenen Hindernisse und Unsicherheiten betreffend geologischer, gesellschaftlicher, legislativer und wirtschaftlicher Aspekte ausgeräumt werden können. Die grössten Unterschiede zwischen den verschiedenen Studien sind bei den Fotovoltaik-Potenzialen festzustellen; es ist allerdings nicht klar, welche

[83] Aufgrund beschränkter Verfügbarkeit der Daten in den Originalstudien.

Studien nur PV-Anlagen auf Dächern berücksichtigen und welche auch PV-Anlagen auf Fassaden.[84]

Ein genauerer Vergleich mit (Hirschberg, Bauer et al. 2005) zeigt, dass das Potenzial für Kleinwasserkraft in der vorliegenden Studie etwas geringer ausfällt. Das Potenzial für Strom aus Windturbinen ist so gut wie unverändert, da keine neuen Abschätzungen vorliegen. Das Potenzial für Strom aus PV-Anlagen wird in der vorliegenden Studie höher eingeschätzt als früher, da eine neue Schätzung bzgl. nachhaltig verfügbarer Dachfläche vorliegt und die zukünftige Technologieentwicklung berücksichtigt wird. Die neuen Schätzungen für den Stromimport aus solarthermischen und Wellenkraftwerken sind neu etwas höher, liegen aber in der gleichen Grössenordnung.

Der Vergleich der in der vorliegenden Studie ermittelten Stromproduktionskosten für das Jahr 2050 mit jenen aus Vergleichsstudien zeigt, dass in der vorliegenden Studie die Bandbreite für die Kosten von Strom aus PV-Anlagen am grössten ist; dies vor allem, weil in der vorliegenden Studie ein sehr breiter Bereich von Anlagenleistungen berücksichtigt wurde und der Strom aus kleinen Anlagen deutlich teurer ist, als jener aus grossen Anlagen; zusätzlich berücksichtigt die vorliegende Studie die in der Schweiz mögliche Variabilität im Jahresertrag. Die in den meisten Vergleichsstudien ausgewiesenen Stromkosten für PV-Anlagen liegen innerhalb des neu ermittelten Bereichs. Die Stromproduktionskosten für Windkraftanlagen, die in der vorliegenden Studie neu ermittelt wurden, liegen im Bereich der in den Vergleichsstudien ausgewiesenen Kosten. Im Vergleich zu den Vergleichsstudien sind die neu ermittelten Stromkosten für Erdgas-GuD-Kraftwerke relativ hoch, was hauptsächlich an den angenommenen Gaspreisen zu liegen scheint.

[84] In diesem Vergleich wird das in der vorliegenden Studie ermittelte Potenzial von Dachanlagen dargestellt („PSI 2017“); in Kaptiel 9.3 sind Abschätzungen für Fassadenanlagen enthalten.

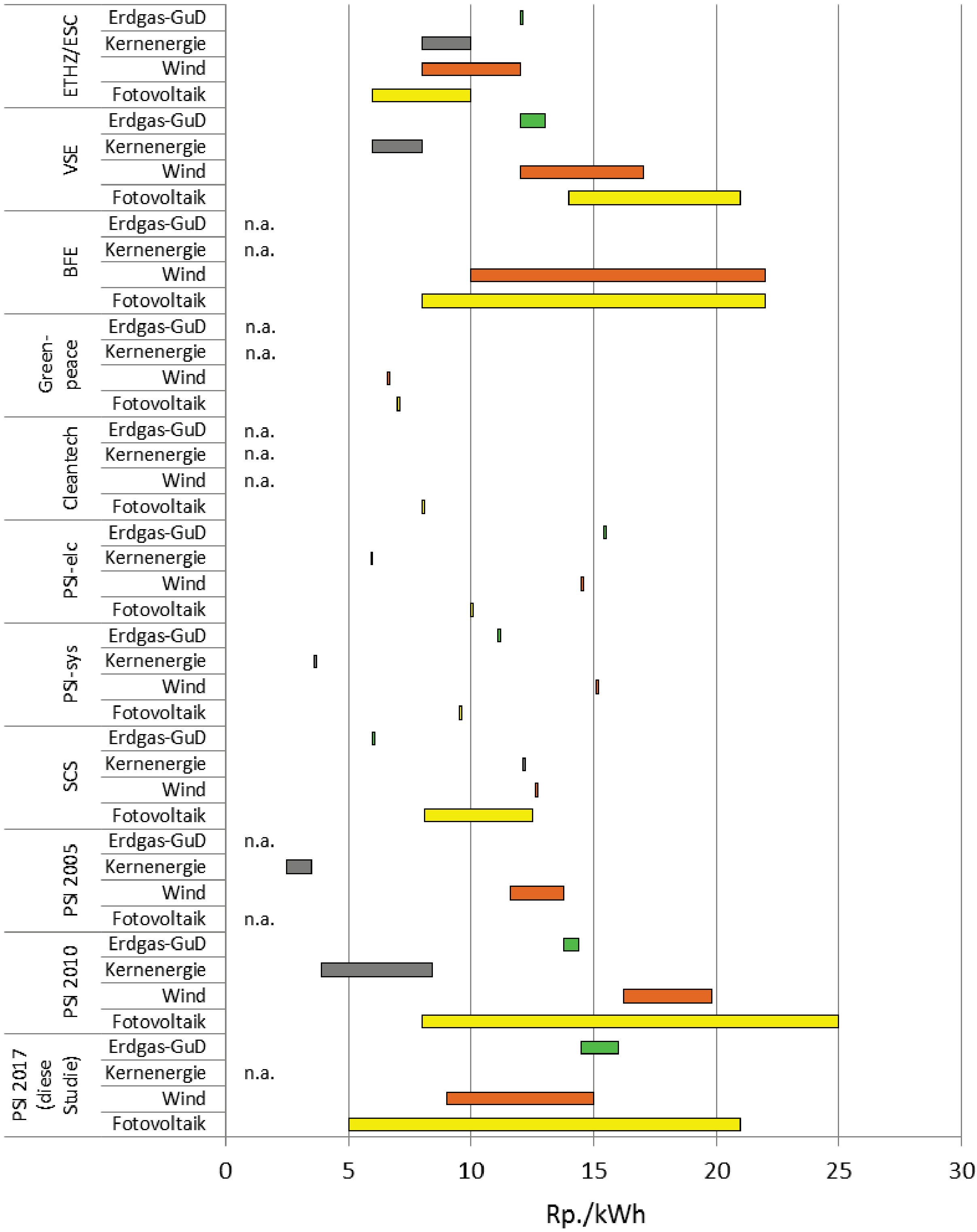


Abbildung 2.9: Stromproduktionskosten im Jahr 2050 nach verschiedenen Studien. ETH/ESC: (Andersson, Boulouchos et al. 2011); VSE: (VSE 2012); BFE: (Prognos 2012a); Greenpeace: (Teske and Heiligtag 2013); Cleantech: (Barmettler, Beglinger et al. 2013); PSI-elc: (Kannan and Turton 2012b, Kannan and Turton 2012a); PSI-sys: (Weidmann 2013); SCS: (SCS 2013); PSI 2005: (Hirschberg, Bauer et al. 2005); PSI 2010: (Hirschberg, Bauer et al. 2010); n.a.: keine Daten vorhanden.

Ein genauerer Vergleich mit (Hirschberg, Bauer et al. 2005) zeigt auch, dass die für das Jahr 2050 geschätzten Stromproduktionskosten für Kleinwasserkraftwerke etwas gestiegen sind. Die neuen Stromproduktionskosten für PV-Anlagen sind deutlich tiefer, was die in den letzten Jahren drastisch gesunkenen Preise von PV-Anlagen widerspiegelt. Die neuen Stromproduktionskosten für Windturbinen sind ähnlich wie jene in (Hirschberg, Bauer et al. 2005), während die geschätzten Kosten für Kernenergie gestiegen sind, ebenso jene für Strom aus Geothermiekraftwerken. Die neuen Kostenschätzungen für Strom aus solarthermischen Kraftwerken sind geringer. Alle anderen Technologien, die in der vorliegenden Studie bewertet werden, sind in (Hirschberg, Bauer et al. 2005) nicht enthalten. Generell zeigt der Vergleich der Stromproduktionskosten anhand der verschiedenen Studien sehr deutlich die elementare Bedeutung einer transparenten und nachvollziehbaren Darstellung der Inputdaten und Berechnungen.

2.7 Forschungsbedarf, Ausblick und Empfehlungen

Trotz der umfangreichen Literatur, die als Basis für die vorliegende Studie dient und obwohl ein grosses Team von Forschern mit breitem Hintergrund und Expertise zu dieser Arbeit beigetragen hat, bleiben einige Fragen offen, die im Zusammenhang mit der Schweizer Energieversorgung und Energiepolitik relevant sind:

- **Kosten-Potenzial-Kurven:** Die verfügbaren Informationen und Daten zu den Kosten und Potenzialen der Stromerzeugung in der Schweiz erlauben es nicht, Stromproduktionskosten vs. möglicher zusätzlicher Jahresproduktion zu quantifizieren. Dies wäre für Technologien, bei denen der Standort der Kraftwerke, die Rahmenbedingungen und die Art der Energieträger eine grosse Rolle für die Stromproduktionskosten spielen, anzustreben; unter diese Technologien fallen Wasserkraft[85], gebäudeintegrierte Erdgas-BHKW und Brennstoffzellen, Windturbinen, PV-Anlagen und Geothermiekraftwerke sowie Anlagen zur Biomasseverstromung. Innerhalb der ermittelten Potenziale zur Stromerzeugung können die Stromproduktionskosten all dieser Technologien (stark) schwanken und die in der vorliegenden Studie angegebenen Mittelwerte und Bandbreiten für die Stromgestehungskosten sind nicht immer aussagekräftig.
- **Kostendaten spezifisch für die Schweiz**: Preise in der Schweiz sind üblicherweise höher als jene in den Nachbarländern bzw. in Europa generell und auf dem internationelen Markt. Dies hat auch Einfluss auf die Stromgestehungskosten, da die Preise für die Infrastruktur der Kraftwerke in der Schweiz höher sind. Oft beziehen sich die verfügbaren Kosten- und Preisdaten jedoch nicht auf die Schweiz, müssen mangels Alternativen aber dennoch verwendet werden. Innerhalb dieser Studie konnte dieser Faktor nur bis zu einem gewissen Grad berücksichtigt werden – hauptsächlich in Form von Sensitivitätsanalysen zu den Stromgestehungskosten.
- **Systemaspekte und Stromspeicherung**: Diese Technologiebewertung bezieht sich ausschliesslich auf einzelne Technologien. Im Zusammenhang mit Kosten und Umweltaspekten der Strom- und Energieversorgung sollte für aussagekräftige Schlussfolgerungen das ganze Stromversorgungs- bzw. Energieversorgungssystem untersucht und beurteilt werden. Dies betrifft z.B. Faktoren wie den Tages- und Jahresgang der Stromproduktion einzelner Technologien im Vergleich zum Verbrauch oder auch die geografische Verteilung von Stromproduktion und -verbrauch in der Schweiz, und die damit evtl. nötigen Erweiterungen im Stromnetz oder potenzielle

[85] Für Grosswasserkraftwerke ist eine solche Kurve vorhanden, siehe Figure 6.19.

Stromspeicherung. Solche Aspekte müssen mit Modellen analysiert werden, welche das ganze Strom- oder Energiesystem beinhalten.

- **Umweltaspekte**: Dem Auftrag des BFE entsprechend wurden die Umweltbelastungen der Stromproduktion grossteils anhand von vorhandenen Ökobilanz-Inventardaten bestimmt. Einige der Ergebnisse sind folglich nicht mehr ganz aktuell; einige Lücken in den Inventardaten und Inkonsistenzen waren nicht zu vermeiden. Dies betrifft vor allem zukünftige Technologien, die mangels konsistenter Inventardaten derzeit nicht umfassend bewertet werden können.
- **Externe Kosten**: Es sind keine belastbaren und aktuellen Ergebnisse für die externen Kosten einzelner Stromversorgungstechnologien für die Schweizer Stromversorgung vorhanden. Deswegen konnte dieser Aspekt nicht behandelt werden.

Der Rahmen dieser Studie, festgelegt durch das Schweizer Bundesamt für Energie, liess es nicht zu, diese offenen Punkte zu behandeln. Um die Lücken zu schliessen, werden spezifische Forschungsaktivitäten empfohlen.

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3 Résumé

Le présent rapport évalue en détail les potentiels technologiques et les coûts de production de l'électricité en Suisse de même que les importations d'électricité jusqu'en 2050. Il chiffre par ailleurs l'impact environnemental de cette production. Les potentiels, les coûts et l'impact environnemental sont indiqués à chaque fois pour aujourd'hui et pour 2020, 2035 et 2050. L'évaluation porte sur les technologies de production suivantes:

- grandes centrales hydrauliques
- petites centrales hydrauliques
- éoliennes
- installations photovoltaïques
- technologies de transformation de la biomasse en électricité
- centrales géothermiques
- centrales houlomotrices et marémotrices
- centrales solaires thermiques
- centrales nucléaires
- centrales au gaz naturel et à charbon, CCF au gaz naturel
- piles à combustible
- nouvelles technologies

Les aspects systémiques, c.-à-d. l'interaction des différentes technologies au sein du système d'approvisionnement en électricité, ne sont pas l'objet de la présente analyse, qui ne tient pas non plus compte des coûts externes[86].

Cette étude a été réalisée sous la houlette de scientifiques du PSI[87], avec le soutien d'experts du WSL, de l'EPFL et de l'EPFZ. Commandée par l'Office fédéral de l'énergie (OFEN), elle a été menée par les deux «Swiss Competence Centers for Energy Research (SCCER)» «Supply of Energy (SoE)»[88] et «Bioenergy (BIOSWEET)»[89]. C'est une contribution au programme de «veille technologique» de l'OFEN, dont les résultats peuvent servir pour les prochaines perspectives énergétiques.

Le résumé s'articule comme suit:

Pour commencer, il donne un bref aperçu des technologies de production d'électricité et de leur évolution attendue, avant de présenter les potentiels de la production et de l'approvisionnement électriques, suivis des coûts et de l'impact environnemental de cette production. Les principales informations et données sur les différentes technologies sont résumées dans des *fact sheets* («Fiches de données», section 3.5). Enfin, le résumé compare

[86] Les coûts externes sont des coûts qui ne doivent pas être supportés par le responsable (Buchanan and Craig 1962). Le plus souvent, ils sont pris en charge par la société. Dans le cadre de la production d'électricité, les coûts externes résultent p. ex. des dommages causés à la santé par la pollution de l'air due à la combustion de charbon, de bois ou de gaz naturel. Les coûts non assurés qui pourraient découler d'accidents potentiels peuvent aussi être qualifiés de coûts externes.

[87] Laboratory for Energy Systems Analysis (https://www.psi.ch/lea/); Laboratory for Thermal Processes and Combustion (http://crl.web.psi.ch/); Solar Technology Laboratory (https://www.psi.ch/lst/).

[88] http://www.sccer-soe.ch/

[89] http://www.sccer-biosweet.ch/

ces résultats avec des études antérieures, montre les besoins actuels de la recherche et formule des recommandations pour de futurs travaux en la matière.

3.1 Technologies de production d'électricité

3.1.1 Grande hydraulique

Les centrales hydrauliques avec des puissances installées >10 MW entrent dans la catégorie de la grande hydraulique en Suisse. On peut distinguer deux types d'installations: les centrales à accumulation et les centrales au fil de l'eau. Les centrales à accumulation possèdent un barrage et un lac de retenue, tandis que les centrales au fil de l'eau utilisent l'eau directement disponible des rivières. Il existe par ailleurs les centrales à pompage-turbinage, qui produisent l'électricité à des heures de forte demande et exploitent pour ce faire l'eau entre les lacs de retenue à différentes altitudes au moyen de pompes. Les centrales à pompage-turbinage et les centrales à accumulation sont souvent combinées en ce qu'elles utilisent aussi les apports naturels des lacs de retenue. Dans les centrales hydrauliques, l'électricité est produite par des turbines. La technologie utilisée dépend surtout des débits et des hauteurs de chute; les principaux types de turbines, avec un rendement supérieur à 90%, sont les turbines Francis, Kaplan et Pelton. Les centrales hydrauliques sont une technologie pour laquelle aucun progrès substantiel ne peut plus être escompté.

3.1.2 Petite hydraulique

En Suisse, les centrales relèvent de la petite hydraulique quand la puissance installée est inférieure à 10 MW. Les petites centrales hydrauliques peuvent être classées par type (centrales au fil de l'eau, de dérivation, à accumulation ou de pompage-turbinage) ou par moyen d'écoulement (centrales au fil de l'eau, sur eaux usées, sur eau potable, de dotation). Les technologies sont similaires à la grande hydraulique. Le cas échéant, il existe des restrictions techniques pour certaines applications et la recherche s'attache actuellement à développer de nouvelles technologies pour mieux exploiter les petites hauteurs de chute et les faibles débits.

3.1.3 Eoliennes

Les éoliennes actuelles ont trois pales et un axe horizontal; elles sont installées sur terre (*onshore*) ou en mer (*offshore*). Les turbines à axe vertical ne jouent aucun rôle aujourd'hui pour des raisons techniques et économiques, et on ne s'attend pas à ce que cela change d'ici 2050. Les turbines modernes ont une puissance jusqu'à 8 MW; les diamètres de rotor vont jusqu'à 164 m, les hauteurs de moyeu jusqu'à 220 m. 72% des installations ont une puissance entre 1 et 3 MW; c'est la taille usuelle des turbines actuelles en Suisse. Les petites éoliennes d'une puissance inférieure à 100 kW sont et resteront des produits de niche. Les éoliennes sont une technologie avancée (en particulier *onshore*). Le développement technologique tend vers une augmentation de la puissance des installations et de leur fiabilité. Des puissances jusqu'à 20 MW semblent possibles pour certaines turbines. De plus grandes hauteurs de moyeu permettront une meilleure utilisation de l'éolien, car les vitesses du vent augmentent avec la hauteur au-dessus du sol.

3.1.4 Photovoltaïque

Les cellules photovoltaïques transforment directement le rayonnement solaire en électricité, et ce en tension continue. Un onduleur convertit cette tension continue en tension alternative avant l'injection dans le réseau électrique. En Suisse, les panneaux photovoltaïques sont généralement installés en toiture. Près de la moitié des installations photovoltaïques ont aujourd'hui une puissance inférieure à 100 kW dans notre pays, l'autre une puissance supérieure à 100 kW. Plus de la moitié des panneaux se trouvent sur des maisons individuelles. Mais s'agissant de la puissance installée, les installations (comparativement plus grandes) sur les bâtiments industriels et agricoles sont plus importantes.

D'ordinaire, les cellules photovoltaïques sont classées en fonction des matériaux de base. Le marché actuel est dominé par les cellules en silicium cristallin (c-Si). Les cellules polycristallines (mc-Si) représentent la technologie principale, tandis que les cellules monocristallines (sc-Si) n'ont cessé de perdre des parts de marché ces dernières années. Les cellules à couche mince sont une alternative au silicium cristallin. Les cellules commercialisées se composent de silicium amorphe (a-Si), de tellurure de cadmium (CdTe) ou de cuivre indium gallium (di-)sélénium (CIGS ou CIS). D'autres cellules avancées à couche mince, cellules organiques et technologies à concentrateur en sont au stade de la recherche et du développement. Les meilleures cellules disponibles sur le marché ont des rendements de 17% (polycristallines et CdTe) et 21,5% (monocristallines). Le développement technologique dans le domaine photovoltaïque vise principalement à réduire les coûts de production et à augmenter le rendement. Le maximum théorique des cellules en silicium cristallin à simple jonction est d'environ 30%. Comme il y a toujours des pertes entre les cellules et les modules photovoltaïques (onduleurs, etc.), on table sur un rendement maximal de 27% au niveau des modules d'ici 2050. La durée de vie des modules actuels est d'environ 30 ans, on s'attend à ce qu'elle passe à 35 ans d'ici 2035.

3.1.5 Electricité issue de la biomasse

En tant que ressource, la biomasse comprend une série de substances de départ pour la production d'électricité – des eaux usées au bois de forêt, en passant par le lisier, les déchets industriels et communaux.

Pour pouvoir chiffrer les potentiels de production et les coûts correspondants, la présente analyse distingue trois catégories d'installations de transformation de la biomasse en électricité:

a) Secteur des déchets: les installations de transformation de la biomasse en électricité dont le traitement des déchets génère des revenus entrent dans cette catégorie; on peut donc s'attendre à des coûts de combustible négatifs. Les usines d'incinération des ordures ménagères (UIOM), les stations d'épuration communales et industrielles ainsi que les installations industrielles au biogaz relèvent de cette catégorie.

b) Secteur du bois: cette catégorie comprend les installations qui utilisent le bois comme combustible mais pour lesquelles, contrairement au secteur des déchets, il y a des coûts de combustible. Le plus souvent, l'électricité est produite en même temps que la chaleur utile dans les installations de CCF[90], par combustion ou gazéification du bois. Ces

[90] CCF: couplage chaleur-force.

installations présentent en général une forte dépendance économique aux ventes de chaleur.

c) Secteur agricole: cette catégorie comprend les installations qui utilisent les substrats agricoles comme ressource de biomasse. D'ordinaire, le revenu découlant des ventes de chaleur est minime.

La biomasse non ligneuse qui présente une forte teneur en eau, à l'instar des eaux usées et du lisier, est transformée dans un premier temps en biogaz par un processus de fermentation anaérobie. Le biogaz peut être utilisé par la suite dans une installation de CCF, notamment dans un moteur à gaz, une turbine à gaz ou une pile à combustible. La biomasse ligneuse ou non ligneuse qui présente une plus faible teneur en eau, comme les déchets urbains, peut être directement incinérée pour faire marcher les circuits de vapeur ou ORC. Les turbines à gaz à combustion externe représentent une possibilité. La biomasse ligneuse ou non ligneuse peut aussi être gazéifiée en un gaz de synthèse qui peut être brûlé pour produire de l'électricité dans un moteur ou d'autres installations de CCF. La production de biométhane constitue une trajectoire d'utilisation alternative pour toutes les sources de biomasse. Celui-ci peut être injecté dans le réseau de gaz naturel et servir ensuite d'agent énergétique de manière flexible – pour la production d'électricité, pour le chauffage ou comme carburant dans la circulation routière. Dans le cadre de la présente analyse, la biomasse constitue donc un cas particulier, car c'est la seule source d'énergie où il existe une «concurrence» entre plusieurs secteurs économiques / énergétiques pour une quantité limitée de ressources.[91]

La recherche et le développement visent actuellement à maximiser la production d'électricité à partir d'une offre de biomasse limitée. Soit en augmentant les rendements de conversion des technologies actuelles, soit en développant de nouvelles technologies, comme par exemple la gazéification hydrothermale ou la fermentation du lisier en séparant la biomasse en une fraction solide et une fraction liquide.

3.1.6 Géothermie

L'énergie servant à la production d'électricité peut être obtenue à partir de deux types de ressources géothermiques profondes (>400 m, >120°C): les systèmes hydrothermaux ou les systèmes petrothermaux, appelés *enhanced geothermal systems* (EGS). Les systèmes hydrothermaux requièrent des températures relativement élevées dans le sous-sol (>100°C), des couches aquifères et une bonne production d'eau chaude dans ces formations géologiques. Ces conditions ne semblent réunies qu'à certains endroits en Suisse. Comme ils ne dépendent pas de la présence d'eau chaude dans le sous-sol et utilisent uniquement les différences de température naturelles entre la surface de la terre et le sous-sol profond, les EGS pourraient être les seuls procédés à contribuer notablement à la production d'électricité en Suisse. La présente étude se concentre ci-après sur ces systèmes-là.

Pour produire de l'électricité géothermique, il est nécessaire de percer deux trous ou plus dans le sous-sol profond et de les y relier entre eux. Depuis la surface, l'eau froide est transportée en profondeur, où elle est réchauffée par la chaleur de la terre avant d'être pompée à la surface. Là, l'eau chaude fait tourner un générateur au moyen d'un *organic*

[91] D'autres conflits d'intérêts potentiels, tels que l'utilisation de toits plats pour les installations photovoltaïques ou la production d'eau chaude par le biais de systèmes solaires thermiques, ne sont pas examinés dans ce cadre.

rankine cycle (ORC). D'un point de vue géologique, les EGS n'ont besoin que d'un gradient de température élevé; mais des aspects techniques sont aussi décisifs pour la réussite de la mise en œuvre, à l'instar d'une bonne stimulation du sous-sol et d'une utilisation appropriée des dépôts minéraux pendant l'exploitation de l'installation.

En Suisse, la profondeur de forage type pour les EGS est d'environ 5 km. Les gradients géothermiques doivent être supérieurs à 30°C/km pour que les températures des réservoirs atteignent >160°C. En fonction des conditions géologiques, on peut s'attendre à des puissances (nettes) entre 1 et 5 MW_{el} pour de telles centrales géothermiques. Les rendements électriques seraient comparativement peu élevés en raison des faibles températures du fluide de travail dans l'échangeur de chaleur. Il y aurait donc de grandes quantités de rejets de chaleur disponibles qu'il faudrait utiliser dans toute la mesure du possible pour que l'exploitation soit rentable.

3.1.7 Centrales houlomotrices et marémotrices

Les centrales houlomotrices peuvent être construites et exploitées sur le rivage (*onshore*) ou en haute mer (*offshore*). L'électricité produite par les installations *offshore* est généralement conduite vers la terre ferme par des câbles posés sur le fond marin. Les centrales houlomotrices sont moins limitées en termes d'implantation que les centrales marémotrices ou les centrales de courant marin. Il existe plusieurs moyens pour exploiter l'énergie des vagues, c.-à-d. plusieurs types de centrales; parmi les principaux types *onshore*, il y a les technologies *oscillating water column* (OWC), *pendulum* et *tapered channel*. Les systèmes *hinged float*, *float pump*, *floating OWC* et *floating tapered channel* comptent parmi les principales technologies *offshore*.

Par rapport à la plupart des autres technologies analysées dans la présente étude, les centrales houlomotrices et marémotrices en sont à un stade de développement précoce. Pour l'heure, aucun des types précités n'est plus prometteur qu'un autre et il n'est pas improbable que le développement de l'industrie se concentre sur un type en particulier.

3.1.8 Centrales solaires thermiques (*concentrated solar power*, CSP)

Les centrales solaires thermiques utilisent des miroirs pour concentrer les rayons du soleil et les recueillir dans un «récepteur». La chaleur accumulée est conduite par un fluide caloporteur qui fait marcher un circuit de vapeur traditionnel pour produire de l'électricité. Comme la Suisse ne dispose pas de l'intensité solaire nécessaire, ces centrales ne sont pas une option envisageable pour la production intérieure. Mais il est possible d'importer l'électricité issue de telles centrales dans le sud de l'Europe, l'Afrique du Nord, le Proche-Orient et le Moyen-Orient par courant continu. Les centrales CSP modernes sont équipées d'un accumulateur de chaleur afin de produire aussi du courant par ciel couvert ou la nuit. Elles sont donc réglables jusqu'à un certain point.

Il existe quatre types de CSP: *parabolic trough concentrator* (PTC), *linear Fresnel reflector* (LFR), *central receiver system* (CRS) et *parabolic dish concentrator* (PDC). Les trois premiers sont principalement utilisés dans d'assez grandes installations de production d'électricité centralisée, le premier, avec ses miroirs paraboliques, étant le plus développé et répandu. Les installations PDC ont surtout un usage décentralisé. Les centrales PTC sont construites à l'heure actuelle avec des cuves prévues pour un stockage de 6 à 7 heures et demie et ont ainsi des facteurs de capacité annuels de 36 à 41%. Les installations CRS, avec un récepteur sur une tour centrale, atteignent des températures plus élevées et utilisent plus efficacement les cuves de sel fondu, ce qui permet d'obtenir des durées de stockage de 15 heures et des facteurs de capacité annuels de 75%. Les rendements annuels moyens (rayonnement solaire en électricité) des installations CSP varient actuellement entre 10 et 25%. Le développement technologique vise aujourd'hui à baisser les coûts des installations et à optimiser aussi bien les unités de production d'électricité que les réservoirs thermiques afin d'augmenter les facteurs de capacité et la fiabilité des installations.

3.1.9 Energie nucléaire

Les centrales nucléaires suisses font toutes partie de la deuxième génération de réacteurs (GEN II). Les plus anciennes centrales de Beznau (KKB) et de Mühleberg (KKM) ont fait l'objet d'améliorations (« NANO » resp. « SUSAN ») importantes dans les années 1992/1993 et 1990. La centrale de Bezau I est à l'arrêt depuis 2 ans en raison de problèmes techniques à corriger. Les centrales de Mühleberg et de Leibstadt (KKL) sont dotées de réacteurs à eau bouillante, Beznau et Gösgen (KKG) de réacteurs à eau pressurisée.

Les réacteurs à eau légère, dominants aujourd'hui, sont considérés comme aboutis sur le plan technique, mais la pression au développement est constante, en particulier pour renforcer la sécurité tout en gardant la compétitivité. Cela conduit à des développements et à de nouvelles conceptions (GEN III/III+). Une partie du développement tend aussi à des réacteurs plus compacts et modulaires, dont l'avantage réside dans une production standardisée. La recherche porte par ailleurs sur la quatrième génération de réacteurs (GEN IV) – avec pour objectif une sécurité inhérente, des rendements plus élevés et une meilleure utilisation des ressources.

Certains réacteurs actuels et futurs peuvent aussi être exploités avec du thorium comme combustible. Contrairement à l'U235, celui-ci n'est pas un nucléide fissible mais fertile (comme l'U238). En d'autres termes, le thorium est transformé en U233 dans le réacteur (surgénérateur) et la réaction nucléaire doit être activée par un autre élément fissible ou des neutrons accélérés. Par rapport aux combustibles nucléaires actuels, le thorium est disponible en plus grandes quantités, occasionne moins de déchets radioactifs et présente des avantages en termes de prolifération car, dans ce cycle du combustible, aucun plutonium permettant la réalisation d'armes nucléaires n'est produit. Le taux de conversion limite toutefois l'extension des réacteurs au thorium; il reste aussi des incertitudes techniques et économiques.

3.1.10 Centrales au gaz naturel et à charbon

En Suisse, l'électricité à partir de gaz naturel peut être produite par de grandes centrales centralisées (centrales à gaz à cycle combiné) et de plus petites centrales décentralisées à couplage chaleur-force (CCF), qui produisent à la fois de l'électricité et de la chaleur utile. L'électricité issue des centrales au lignite et à la houille est une option pour l'importation. A l'avenir, les centrales à gaz et à charbon pourraient être dotées d'un système de capture du CO_2; celui-ci peut être stocké dans des formations géologiques ou utilisé pour d'autres applications. La présente étude n'examine que l'étape de capture du CO_2 en raison des incertitudes relativement importantes liées au stockage et à l'utilisation du CO_2.

Les centrales à cycle combiné au gaz naturel ont en général une puissance électrique de 400 à 500 MW, tandis que la puissance des centrales à charbon oscille entre 500 et 1000 MW.

Les CCF au gaz naturel présentent une puissance électrique de 1 kW à plusieurs MW, mais la présente analyse se limite à la gamme de puissance entre 1 et 1000 kW_{el}. Les rendements moyens de la production d'électricité sont aujourd'hui de 57 à 59% pour les centrales à cycle combiné au gaz naturel, de 44 à 46% pour les centrales à la houille et de 39 à 44% pour les centrales au lignite. Les rendements électriques des CCF dépendent fortement de la taille de l'installation et varient entre 25 et 42%; globalement, leur rendement total est de 80 à 90%.

Le développement technologique permettra des températures de combustion plus élevées et donc de meilleurs rendements: 65% pour les centrales à cycle combiné au gaz naturel et 50% pour les centrales à charbon en 2050. Pour les CCF, on s'attend à des rendements électriques de 30 à 47% et à un rendement global de plus de 100% (mesuré au pouvoir calorifique inférieur du combustible). Les procédés de capture du CO_2 réduisent le rendement des centrales en raison de leurs besoins énergétiques relativement importants. Pour les centrales à cycle combiné au gaz naturel avec capture du CO_2, des rendements de 54 à 56% sont escomptés en 2050, de 33 à 45% pour les centrales à charbon. En sus de l'amélioration des rendements, le développement technologique vise à réduire encore les émissions nocives des centrales.

3.1.11 Piles à combustible

La présente analyse porte sur les piles à combustible qui fonctionnent au gaz naturel ou au biométhane comme installations de CCF, c'est-à-dire qui produisent en même temps de l'électricité et de la chaleur utile. Les technologies suivantes sont évaluées: les piles de type *polymer electrolyte* (PE), *phosphoric acid* (PA), *molten carbonate* (MC) et *solid oxide* (SO).

Les piles à combustible peuvent être utilisées dans les ménages individuels, les grands bâtiments et même l'industrie. De telles installations sont exploitées en premier lieu pour le chauffage et l'eau chaude (primauté de la chaleur). L'électricité peut servir à la consommation propre et être injectée dans le réseau. Les besoins résiduels en électricité sont soutirés du réseau.

Les rendements électriques de telles piles à combustible dépendent du type de pile et de la taille de l'installation et atteignent aujourd'hui 32 à 54%, les rendements globaux 70 à 90%. D'ici 2050, on s'attend à ce qu'ils passent respectivement à 42-68% et 80-95%. En sus de l'amélioration des rendements, le développement technologique vise à augmenter la fiabilité et la durée de vie des piles à combustible et à diminuer les coûts de production.

3.1.12 Nouvelles technologies

Les technologies de production d'électricité suivantes sont considérées comme «nouvelles»: la méthanisation hydrothermale de la biomasse aqueuse, les nouvelles technologies géothermiques, la fusion nucléaire et la production de courant thermoélectrique visant une utilisation stationnaire des rejets de chaleur.

Dans cette évaluation des technologies, l'expression «nouvelle» se réfère au fait que ces technologies sont comparativement bien loin d'être commercialisées et en sont à un stade de développement précoce; pour l'heure, il est impossible d'estimer de façon fiable si elles parviendront un jour à percer et pourront être utilisées à grande échelle pour la production d'électricité en Suisse. De plus, il est très difficile et incertain, voire pure spéculation, en l'état actuel des connaissances, de chiffrer les coûts, les potentiels et les aspects environnementaux.

La méthanisation hydrothermale de la biomasse aqueuse est activement développée en Suisse et a déjà été démontrée en laboratoire. Cette technologie permet une utilisation plus efficace de la biomasse présentant une forte teneur en eau et peut servir à transformer les algues, le marc de café et les boues d'épuration en électricité. Au regard de la biomasse adéquate qui est disponible en Suisse, il serait possible de produire 2 à 5 TWh d'électricité par an.

Les nouvelles technologies géothermiques comprennent des concepts qui vont plus loin que les systèmes EGS. Deux approches sont discutées ici: 1) l'utilisation d'un autre fluide d'échange thermique que l'eau ou les solutions salines; 2) une augmentation supplémentaire de la température des fluides géothermiques. La première approche se fonde sur le recours au CO_2 et/ou au N_2 comme fluide d'échange thermique, ce qui permettrait d'utiliser les ressources géothermiques à des températures plus basses. La seconde est basée sur l'utilisation de fluides préchauffés par des procédés géothermiques et qui pourraient servir à la production d'électricité avec une source de chaleur secondaire (ou un combustible supplémentaire).

La fusion nucléaire en est encore au stade de la recherche, avec ITER comme principal projet d'infrastructure. Il s'agit d'un projet de recherche international visant à construire le premier réacteur à fusion nucléaire du monde. Ce sera le premier où le rendement électrique dépassera clairement les besoins de chaleur (facteur 10). Avec la construction d'ITER et l'étude conceptuelle DEMO, la recherche sur la fusion évolue loin de la recherche fondamentale en se consacrant à un projet où les obstacles de nature technique doivent être levés dans la pratique. On s'attend à ce que la fusion nucléaire soit opérationnelle dans la seconde moitié du siècle.

La technologie thermoélectrique permet une transformation directe de la chaleur (des rejets de chaleur) en électricité et peut être vue comme une alternative aux circuits de vapeur ou aux processus ORC traditionnels. Il est aussi possible de produire davantage d'électricité en utilisant les rejets de chaleur. La technologie thermoélectrique présente aujourd'hui de très faibles rendements électriques et n'est donc pas une alternative compétitive. D'un point de vue actuel, la production thermoélectrique restera une application de niche.

3.2 Potentiels de la production et de l'approvisionnement électriques

La Figure 3.1 montre la production actuelle[92] d'électricité en Suisse. Le gaz naturel[93] n'est pour l'heure utilisé à cette fin que dans les installations de CCF et non dans les grandes centrales à gaz à cycle combiné. La production d'électricité par le biais des centrales géothermiques et des piles à combustible est encore inexistante ou négligeable à l'heure actuelle.

[92] 2015; il n'y avait pas de statistiques cohérentes plus récentes lors de la rédaction du présent rapport.

[93] La catégorie «combustibles fossiles» est intégralement imputée aux CCF au gaz naturel. Ce n'est pas tout à fait juste, car une quantité minime d'électricité est produite par des CCF au diesel. On ne dispose toutefois pas de chiffres précis.

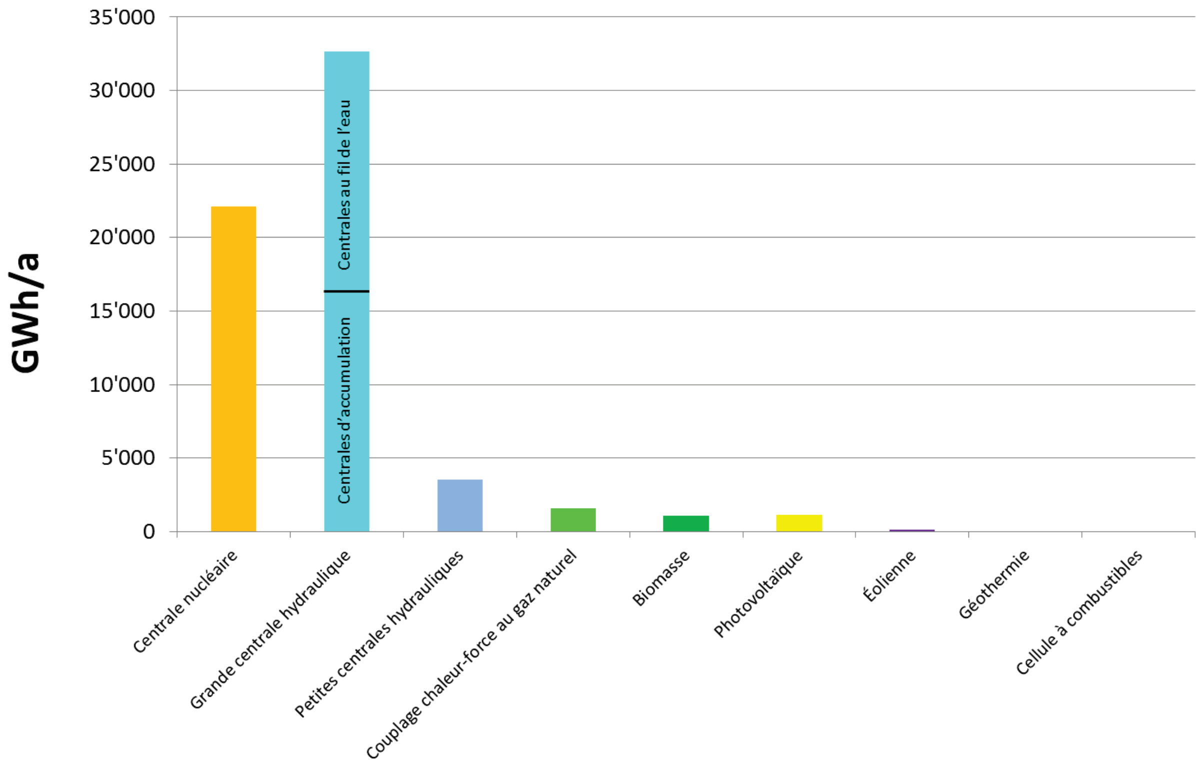


Figure 3.1: Production d'électricité en Suisse en 2015 (BFE/SFOE 2016e, BFE/SFOE 2016g).

La Figure 3.2 montre les «potentiels exploitables»[94] identifiés pour la production et l'approvisionnement électriques avec différents combustibles et technologies en Suisse ainsi que pour les importations d'électricité en 2050. Les potentiels techniques sont sujets à certaines restrictions, que ce soit pour des raisons économiques, écologiques, politiques ou sociétales. Ces restrictions les réduisent. Conformément à la terminologie de l'OFEN, le potentiel exploitable est défini comme l'intersection entre potentiel écologique et potentiel économique élargi. Pour les technologies qui utilisent des combustibles fossiles, la production d'électricité est uniquement limitée techniquement par les capacités d'importation de gaz naturel; dans la pratique, les facteurs politiques et économiques sont aussi contraignants. Les importations d'électricité sont limitées par l'infrastructure de transport; les quantités d'électricité issues des centrales houlomotrices et marémotrices ainsi que des centrales solaires thermiques s'entendent comme de premières estimations rudimentaires. Les chiffres pour les potentiels estimés en 2020 et 2035 sont indiqués dans les fiches de données sur les différentes technologies.

Les installations photovoltaïques présentent le plus grand potentiel parmi les énergies renouvelables en Suisse; les incertitudes sont toutefois assez grandes et se reflètent dans la fourchette indiquée. Les incertitudes sont encore un peu plus importantes pour la géothermie, car le système EGS doit d'abord faire ses preuves et réussir son implantation en Suisse. Les potentiels de la production d'électricité par les centrales à gaz à cycle combiné, les CCF et les piles à combustible ne sont pas chiffrés, car l'utilisation de ces technologies dépend surtout du cadre politique et économique. Les importations des centrales CSP, houlomotrices, marémotrices et à charbon seront limitées par l'infrastructure de transport

[94] Terminologie sur les potentiels: section 5.1.

existante et les conditions politiques, raison pour laquelle elles sont aussi grevées d'incertitudes.

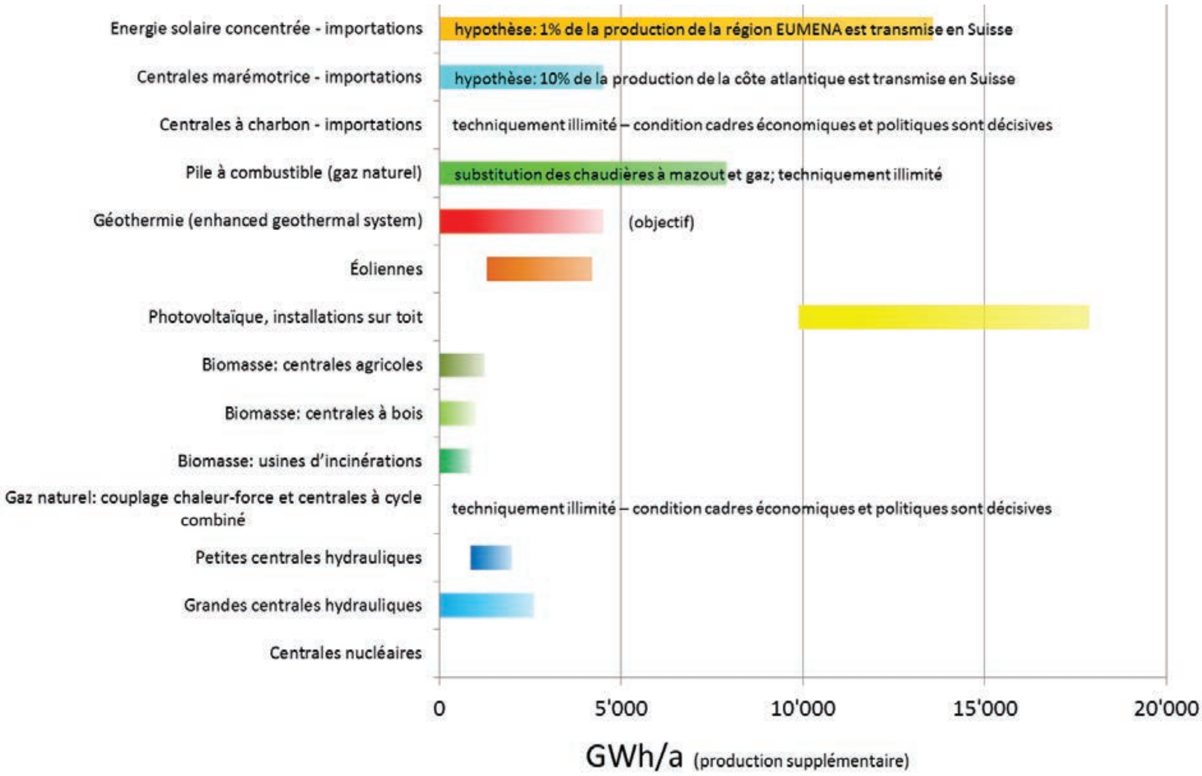


Figure 3.2: «Potentiels exploitables» pour une production et un approvisionnement électriques supplémentaires en 2050 (par rapport à 2015). GuD: centrale à gaz à cycle combiné; CCF: couplage chaleur-force; EGS: *enhanced geothermal systems*; CSP: *concentrated solar power*; EUMENA: Europe, Moyen-Orient, Afrique du Nord; «charbon» comprend la houille et le lignite. *Le potentiel photovoltaïque ne comprend que les installations sur toiture et non sur façade – le potentiel technique illimité des installations sur façade en Suisse est estimé entre 3 et 5.6 TWh/a.

Ces potentiels technologiques sont expliqués ci-après.

3.2.1 Grande hydraulique

La fourchette indiquée pour la grande hydraulique se fonde sur certaines estimations concordantes de ces dernières années (BFE/SFOE 2012b, BFE/SFOE 2013c, Filippini and Geissmann 2014). Elles identifient une série de sites potentiels pour de nouvelles grandes centrales hydrauliques. La réalisation de ces projets et l'agrandissement des installations existantes sont souvent entravés faute d'acceptation. De plus, la situation actuelle du marché de l'électricité diminue la rentabilité des centrales hydrauliques. Le développement de la force hydraulique dépendra principalement des conditions économiques et politiques. Les estimations du potentiel doivent tenir compte de la nouvelle législation sur les débits résiduels, qui réduit la production d'électricité des centrales existantes et des nouvelles centrales.

3.2.2 Petite hydraulique

Le potentiel de l'électricité produite par les petites centrales hydrauliques est relativement faible mais non négligeable (BFE/SFOE 2012b). Les nouvelles centrales ne voient souvent pas le jour faute d'acceptation. De plus, l'électricité provenant des petites centrales hydrauliques est généralement chère et guère compétitive sans subventions. Le développement de la petite hydraulique dépendra donc principalement de la conception de la rétribution de l'injection et de l'acceptation par l'opinion publique.

3.2.3 Energie éolienne

Les conditions de vent sont moins avantageuses en Suisse pour la production d'électricité que dans d'autres pays. Il existe toutefois un potentiel substantiel pour le développement de l'éolien (BFE, BAFU et al. 2004a, BFE, BAFU et al. 2004b, BFE, BAFU et al. 2004c, ARE 2015b, ARE 2015a). Comme pour la force hydraulique, les nouvelles éoliennes échouent souvent en raison de l'opposition locale. Les restrictions économiques doivent aussi être prises en compte. Globalement, le développement de l'énergie éolienne dépendra surtout du cadre législatif et des mesures d'incitation financières.

3.2.4 Photovoltaïque

Le potentiel de l'électricité photovoltaïque est le plus fort parmi les technologies renouvelables en Suisse, même si l'on ne considère que les installations sur toiture. Cette fourchette correspond à la production supplémentaire d'électricité à partir de nouvelles installations placées sur des toitures qui se prêtent au photovoltaïque (Cattin, Schaffner et al. 2012, swisstopo 2012); les restrictions techniques, sociétales et économiques sont prises en compte, tout comme le développement technique escompté. Contrairement aux autres énergies renouvelables, il y a moins de problèmes d'acceptation pour le photovoltaïque et une large exploitation du potentiel semble plus réaliste. Comme l'électricité photovoltaïque est comparativement chère, son développement dépendra ces prochaines années encore des mesures de soutien de l'Etat et d'une réglementation adéquate. Il faut aussi tenir compte du fait qu'une intégration réussie de grandes quantités d'électricité photovoltaïque issue d'installations décentralisées dont la production est irrégulière nécessite des mesures appropriées d'un point de vue systémique; il s'agit par exemple de développer le réseau électrique ou d'utiliser des accumulateurs électriques.

3.2.5 Electricité issue de la biomasse

Le plus grand potentiel pour l'électricité issue de la biomasse réside dans une meilleure utilisation du lisier et de la biomasse ligneuse. Pour l'instant, seule une petite partie du lisier généré par l'agriculture est exploitée sur le plan énergétique. Pour la biomasse ligneuse également, il est possible d'utiliser une certaine quantité de biomasse supplémentaire et de produire par ailleurs de l'électricité avec une partie du bois utilisé aujourd'hui à des seules fins de chauffage dans les CCF.

L'exploitation du potentiel de la biomasse fait face à certains obstacles, principalement d'ordre logistique et économique. Contrairement à d'autres énergies renouvelables telles que le photovoltaïque et l'éolien, on ne s'attend pas à ce que les coûts de production de l'électricité diminuent notablement pour les technologies de biomasse, ce qui tient aussi aux prix assez élevés de la biomasse. De plus, il faut tenir compte du fait que la biomasse n'est pas seulement utilisée pour la production d'électricité, mais aussi comme carburant et source de chaleur.

Les importations potentielles de biomasse ne sont pas examinées dans la présente étude.

3.2.6 Géothermie

Le potentiel indiqué pour l'électricité géothermique soulève la plus grande incertitude parmi toutes les options de production d'électricité en Suisse. Il faut d'abord démontrer la fonctionnalité des installations EGS en Suisse d'un point de vue technique, économique et sociétal. Le potentiel correspond à l'objectif politique à long terme, qui ne peut être réalisé que si les obstacles géologiques, légaux, techniques, économiques et sociétaux existants peuvent être surmontés (Hirschberg, Wiemer et al. 2015). L'aspect économique central est l'utilisation de grandes quantités de rejets de chaleur. Il s'agit d'identifier des sites appropriés où cela fait sens.

3.2.7 Centrales houlomotrices et marémotrices

L'électricité produite par les centrales houlomotrices et marémotrices dans l'Atlantique sur les côtes du Portugal, d'Espagne et de France pourrait être importée en Suisse. Mais la technologie n'est pas encore viable commercialement, son potentiel est incertain. La production est aussi comparativement minime: l'estimation maximale correspond à 10% de la production d'électricité potentielle des centrales houlomotrices et marémotrices sur les côtes occidentales de l'Europe.

3.2.8 Centrales solaires thermiques

Par rapport à l'électricité issue des centrales houlomotrices et marémotrices, le potentiel semble nettement plus élevé pour l'électricité produite par les centrales solaires thermiques à une distance intéressante pour la Suisse (sud de l'Europe, Afrique du Nord et Moyen-Orient). La technologie est aussi plus développée et a déjà gagné des parts de marché dans plusieurs pays comme l'Espagne. Une application à grande échelle semble toutefois difficile, en particulier dans les pays hors UE, et la disponibilité pour la Suisse d'électricité issue des centrales d'Afrique du Nord et du Proche- et Moyen-Orient est discutable d'un point de vue actuel. Par conséquent, la présente analyse mise tout au plus sur une disponibilité de 1% du potentiel technique des centrales solaires thermiques de la région EUMENA[95] pour la Suisse.

3.2.9 Energie nucléaire

Le potentiel nul indiqué reflète la position actuelle de la politique suisse, car on part du principe qu'aucune nouvelle centrale nucléaire ne sera constuite dans notre pays.

3.2.10 Centrales au gaz naturel et à charbon

La production d'électricité à partir de gaz naturel en Suisse – dans les centrales centralisées à gaz à cycle combiné ou les CCF décentralisées – ainsi que l'importation d'électricité produite par les centrales à charbon ne sont guère limitées d'un point de vue technique, mais dépendent des conditions économiques, politiques, réglementaires, sociétales et écologiques; par exemple de la détermination des prix des émissions de CO_2 et de la politique climatique nationale et internationale. De tels facteurs dépassent le cadre de la présente analyse, aucun potentiel n'est donc indiqué pour l'électricité issue du gaz naturel et du charbon. Les facteurs limitants concernant la protection du climat pourraient être en partie éliminés par la capture de CO_2 des émissions des centrales et le stockage géologique.

[95] EUMENA: Europe, Moyen-Orient et Afrique du Nord.

Mais il est tout à fait incertain si et quand le CCS pourra être pleinement concrétisé en Suisse et en Europe.

3.2.11 Piles à combustible

Comme pour les centrales à gaz à cycle combiné et les CCF, la production d'électricité à partir de piles à combustible est principalement limitée sur le plan technique en Suisse par les capacités d'importation de gaz naturel. Le potentiel maximal indiqué correspond à la production d'électricité à partir des piles à combustible qui remplaceraient tous les chauffages actuels au mazout et au gaz dans notre pays. Dans la pratique, les restrictions économiques notamment détermineront l'utilisation des piles à combustible.

3.3 Coûts de la production d'électricité

La Figure 3.3 montre les coûts de la production d'électricité (*levelised costs of electricity*, LCOE) pour des nouvelles installations qui seraient construites aujourd'hui[96], à l'exception des nouvelles technologies. Les coûts des importations des centrales houlomotrices et solaires thermiques par courant continu, entre 0,5 et 2 ct./kWh, doivent être additionnés aux coûts indiqués. Ces fourchettes reflètent la variabilité des coûts de production en raison des conditions spécifiques aux sites (p. ex. rendements annuels des installations photovoltaïques et éoliennes), des caractéristiques des technologies (p. ex. rendements et puissances des centrales) et des coûts de la biomasse. Les coûts des émissions de CO_2 ne sont pas pris en compte.[97] Les coûts de production comprennent les crédits attribués pour l'exploitation des rejets de chaleur pour les CCF au gaz naturel, les piles à combustible et les CCF à biomasse; ces technologies sont en général exploitées de sorte qu'une partie des rejets de chaleur puisse être vendue ou remplace la chaleur achetée à l'extérieur.

[96] Pour les grandes centrales hydrauliques et les centrales nucléaires, les coûts actuels de la production d'électricité des installations en exploitation sont aussi indiqués (Centrales nucléaires : Gösgen et Leibstadt). Dans le cas de l'énergie nucléaire, les coûts indiqués pour des nouvelles centrales se réfèrent aux réacteurs de troisième génération.

[97] Les coûts des certificats de CO_2, au prix actuel de près de 10 €/tCO_2, sont négligeables pour les coûts de production de l'électricité. Une estimation des futurs prix du CO_2 n'entre pas dans le cadre de la présente analyse; les prix du CO_2 sont fixés en premier lieu par la politique climatique nationale et internationale.

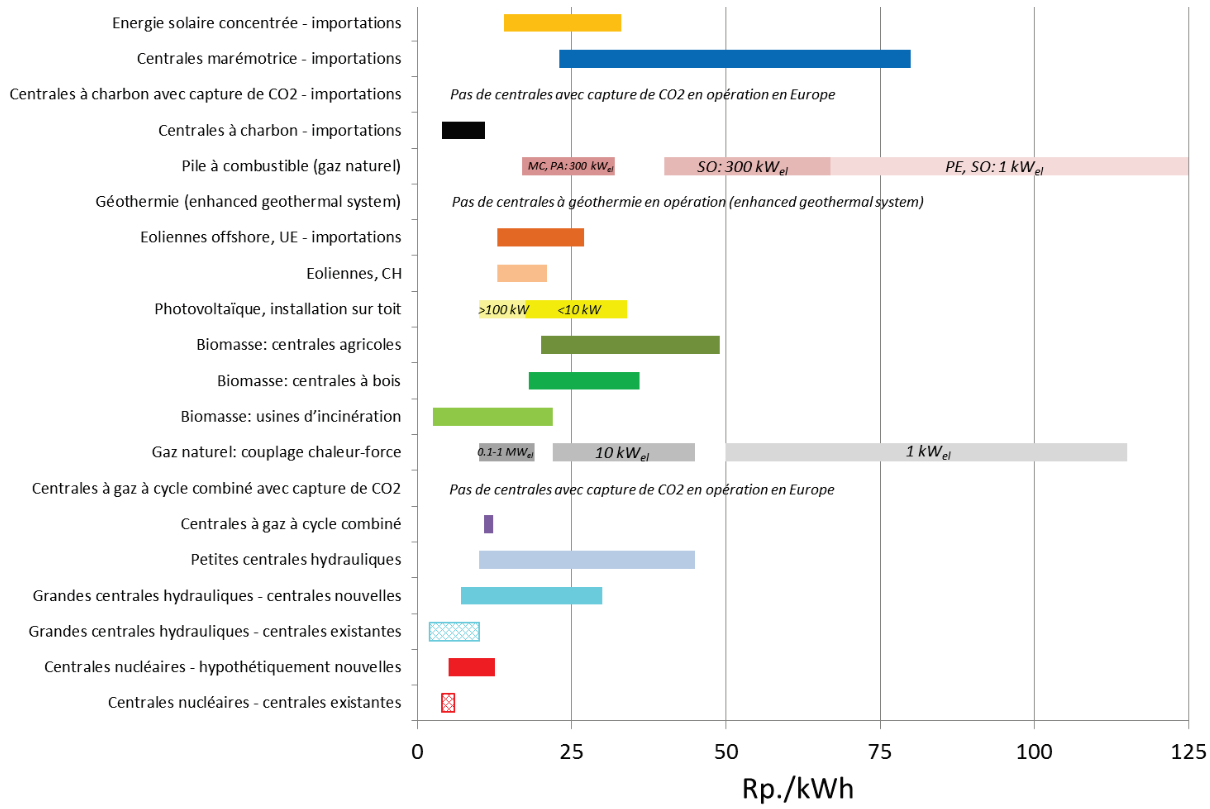


Figure 3.3: Coûts de la production d'électricité (LCOE) actuelle (2015/2016) avec différentes technologies. Les fourchettes indiquées reflètent la variabilité due aux facteurs spécifiques aux sites, aux caractéristiques des technologies et aux coûts de la biomasse. Les fourchettes pour les piles à combustible, les installations photovoltaïques et les CCF au gaz naturel résultent principalement de la puissance des installations; les valeurs pour certaines puissances sont indiquées dans les fiches de données et les différentes sections. Il est nécessaire d'ajouter les coûts des importations d'électricité en courant continu, de l'ordre de 0,5 à 2 ct./kWh. Les coûts des émissions de CO_2 ne sont pas pris en compte.[58] Les crédits attribués pour l'exploitation des rejets de chaleur sont pris en compte pour les piles à combustible et les CCF au gaz naturel et à biomasse. LCOE: *levelised costs of electricity*; GuD: centrale à gaz à cycle combiné; CCF: couplage chaleur-force; CSP: *concentrated solar power*; EGS: *enhanced geothermal systems*; MC: *molten carbonate*; SO: *solid oxide*; PE: *polymer electrolyte*; PA: *phosphoric acid*; «charbon» comprend la houille et le lignite.

Globalement, les centrales à charbon, les grandes centrales hydrauliques existantes, les centrales nucléaires et les installations de biomasse qui servent en premier lieu au traitement des déchets et sont payées pour leur élimination[98] présentent les coûts de production les moins élevés, les CCF au gaz naturel de faible puissance et les piles à combustible les plus élevés à l'heure actuelle. La grande fourchette pour les centrales houlomotrices et marémotrices résulte de la palette de technologies et des incertitudes liées à la maturité commerciale hésitante. Les fourchettes pour l'électricité issue des installations photovoltaïques, des piles à combustible et des CCF au gaz naturel reflètent les économies d'échelle, c.-à-d. les coûts en forte baisse en cas d'augmentation de la puissance; les coûts pour certaines puissances sont présentés schématiquement dans le graphique – les chiffres exacts figurent dans les fiches de données et les sections dédiées aux technologies. Pour les installations photovoltaïques, la fourchette des coûts comprend aussi les variations possibles dans la production annuelle en fonction du lieu d'implantation en

[98] Les UIOM et les stations d'épuration sont payées pour le service de traitement des déchets.

Suisse.[99] Les fourchettes importantes pour l'électricité issue de la biomasse découlent d'une combinaison entre les différents coûts des combustibles et des technologies, qui peuvent fortement varier en fonction de la ressource et de la technologie de conversion: la production d'électricité dans les UIOM et les stations d'épuration, par exemple, revient bien moins cher que dans les petites installations à biogaz agricoles et les CCF à bois. Les détails figurent dans les fiches de données et la section dédiée à la biomasse.

La Figure 3.4 montre les coûts de la production d'électricité pour 2050. Les fourchettes indiquées reflètent la variabilité des coûts de production en raison des conditions spécifiques aux sites (p. ex. rendements annuels des installations photovoltaïques et éoliennes), des caractéristiques des technologies (p. ex. rendements et puissances des centrales), des coûts de la biomasse et des incertitudes liées aux coûts technologiques escomptés. Les coûts des importations par ligne à courant continu des centrales houlomotrices et solaires thermiques, entre 0,5 et 2 ct./kWh, doivent être additionnés aux coûts indiqués. Les coûts des émissions de CO_2 ne sont pas pris en compte.[58] Aucun crédit attribué pour l'exploitation des rejets de chaleur n'est imputé pour la géothermie.[100] Les coûts de production comprennent toutefois lesdits crédits pour les piles à combustible et les CCF au gaz naturel et à biomasse; ces technologies sont en général exploitées de sorte qu'une partie des rejets de chaleur puisse être vendue ou remplace la chaleur achetée à l'extérieur. Pour toutes les technologies, les coûts de production avec ou sans lesdits crédits sont indiqués dans les fiches de données et les différentes sections.

Par rapport aux coûts de production actuels, la plus forte réduction peut être escomptée pour l'électricité issue des piles à combustible et des centrales houlomotrices et marémotrices, suivie du photovoltaïque et des centrales solaires thermiques. L'électricité produite par les centrales hydrauliques sera généralement plus chère, car il n'y a qu'une quantité limitée de site favorables. L'électricité issue des installations de biomasse et des centrales au gaz naturel et à charbon coûtera aussi plus cher qu'aujourd'hui de manière générale, car il faut s'attendre à une hausse des prix des combustibles qui ne pourra pas être compensée par une baisse des coûts technologiques. Le même modèle est identifiable pour les grandes CCF au gaz naturel, alors que les coûts de l'électricité des CCF de petite puissance diminueront d'ici 2050; pour ces dernières, la hausse des prix des combustibles sera plus que compensée par la baisse des coûts technologiques. L'électricité produite par les centrales géothermiques restera comparativement chère s'il n'est pas possible de compter sur les crédits pour l'exploitation des rejets de chaleur.

[99] La production annuelle des installations photovoltaïques sur toiture en Suisse oscille entre 850 et 1500 kWh/kW$_p$. La présente étude table sur une production de référence de 970 kWh/kW$_p$. La plupart des bâtiments se trouvent sur le Plateau, où les rendements annuels sont comparativement faibles.

[100] L'influence des profits des ventes de chaleur sur la faisabilité économique des installations EGS est importante, car de grandes quantités de (rejets de) chaleur sont produites en raison de rendements électriques assez faibles. D'un point de vue actuel, il semble peu probable, en particulier dans une perspective de perception des risques, que les centrales géothermiques puissent être souvent construites à proximité de grands consommateurs de chaleur.

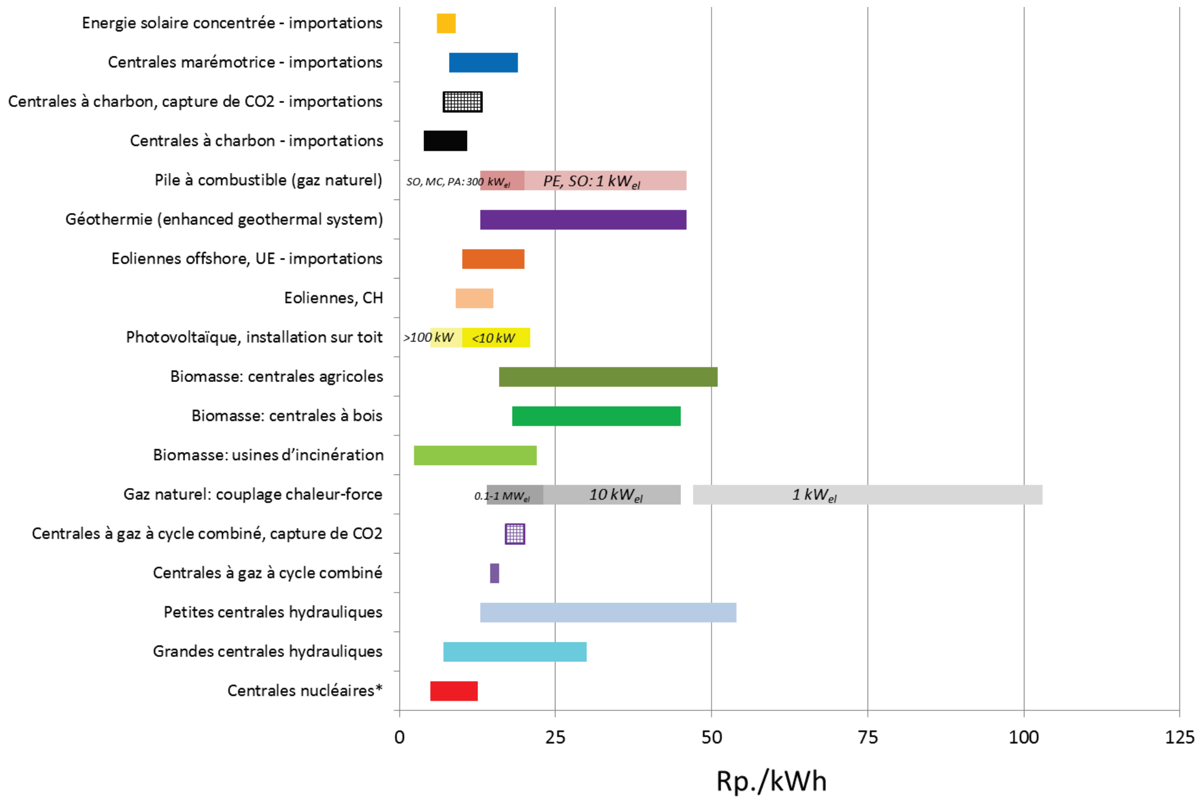


Figure 3.4: Coûts de la production d'électricité (LCOE) avec différentes technologies en 2050. Les fourchettes indiquées reflètent la variabilité due aux facteurs spécifiques aux sites, aux caractéristiques des technologies, aux coûts de la biomasse et aux coûts technologiques escomptés. Les fourchettes pour les piles à combustible, les installations photovoltaïques et les CCF au gaz naturel résultent principalement des différences de puissance des installations; les valeurs pour certaines puissances sont indiquées dans les fiches de données et les différentes sections. Il est nécessaire d'ajouter les coûts des importations d'électricité en courant continu, de l'ordre de 0,5 à 2 ct./kWh. Les coûts des émissions de CO_2 ne sont pas pris en compte.[58] Les crédits attribués pour l'exploitation des rejets de chaleur sont pris en compte pour les piles à combustible et les CCF au gaz naturel et à biomasse, non pour la géothermie.[62] LCOE: *levelised costs of electricity*; GuD: centrale à gaz à cycle combiné; CCF: couplage chaleur-force; CSP: *concentrated solar power*; EGS: *enhanced geothermal systems*; MC: *molten carbonate*; SO: *solid oxide*; PE: *polymer electrolyte*; PA: *phosphoric acid*; «charbon» comprend la houille et le lignite. *Les coûts de l'énergie nucléaire sont valables pour les réacteurs de génération 3+ et les *small modular reactors*, car on ne dispose pas de chiffres exploitables pour les réacteurs de génération 4, qui pourraient être une option en 2050.

Les aspects des coûts sont discutés ci-après en fonction des différentes technologies.

3.3.1 Grande hydraulique

Les coûts de capital et l'amortissement constituent les principaux postes des coûts de production de l'électricité pour les grandes centrales hydrauliques exploitées à l'heure actuelle; les coûts de l'électricité dépendent par conséquent assez fortement des intérêts. D'autres facteurs de coûts importants sont l'exploitation, l'entretien et la redevance hydraulique. Les coûts de revient de l'électricité produite par les nouvelles centrales construites aujourd'hui et à l'avenir seront plus élevés que ceux des installations existantes et dépendront fortement du site. Avec de nouvelles centrales et une extension des installations existantes, il est possible de produire du courant à hauteur de 2 TWh/a pour des coûts inférieurs à 15 ct./kWh (BFE/SFOE 2013c).

3.3.2 Petite hydraulique

Les frais d'investissement sont aussi le principal facteur des coûts de revient de l'électricité pour les petites centrales hydrauliques. Ils présentent des variations importantes d'une installation à l'autre, en fonction du site et de la taille. Les installations d'une puissance inférieure à 1 MW ont des coûts nettement plus élevés que celles d'une puissance de 1 à 10 MW. D'un point de vue économique, les installations qui peuvent être intégrées dans une infrastructure existante ont des avantages évidents. De manière générale, les centrales sur eau potable, au fil de l'eau et sur eaux usées sont les plus avantageuses. Des réductions de coûts sensibles sont peu probables à l'avenir. Au contraire, comme les sites avantageux seront sans doute utilisés en premier, la petite hydraulique présentera une tendance des coûts à la hausse.

3.3.3 Energie éolienne

Les coûts de capital sont le principal facteur des coûts de production de l'électricité éolienne; les intérêts et les coûts technologiques sont donc déterminants. Le rendement des turbines en fonction du lieu d'implantation est aussi un facteur d'influence important. Par rapport à des technologies moins développées, il faut s'attendre à une baisse de coûts relativement minime pour l'éolien (du moins pour les installations *onshore*). Un relèvement de la hauteur de moyeu peut conduire à une hausse du rendement des turbines et, ainsi, à une réduction des coûts de production. Les coûts de production des installations *offshore* sont généralement plus élevés qu'*onshore* et on peut supposer que cette situation perdurera.

3.3.4 Photovoltaïque

Les frais d'investissement sont le principal facteur des coûts de revient de l'électricité photovoltaïque. Dans ce cadre, les coûts des modules photovoltaïques jouent un rôle prépondérant, avec une part moyenne de 50%. Les coûts liés au travail de planification et de montage sont un facteur non négligeable. L'exploitation et l'entretien concourent pour près d'un tiers aux coûts de revient. La production d'électricité photovoltaïque est nettement plus avantageuse plus l'installation est grande. Comme pour les éoliennes, le rendement spécifique au site a aussi un grand impact sur les coûts de production de l'électricité photovoltaïque. On peut supposer que les coûts des installations photovoltaïques diminueront encore de manière significative à l'avenir, principalement en raison d'une réduction des coûts des cellules et des modules, qui suivent une courbe d'apprentissage raide par rapport à d'autres technologies.

3.3.5 Electricité issue de la biomasse

Pour la transformation de la biomasse en électricité, les coûts de la biomasse sont souvent le principal facteur des coûts de revient de l'électricité, et les coûts des matières premières varient fortement en fonction du type de biomasse. La production d'électricité dans les installations de traitement des déchets pouvant générer des recettes par la valorisation des déchets de biomasse est la plus avantageuse (elles bénéficient de coûts de «combustible» négatifs); les UIOM et les stations d'épuration entrent dans cette catégorie. Pour les installations qui produisent aussi bien de l'électricité que des rejets de chaleur exploitables (p. ex. CCF à bois et à biogaz), les recettes de la vente de chaleur (ou les économies réalisées en évitant des coûts de combustibles) sont déterminantes pour la faisabilité économique.

Sans utilisation économiquement intéressante de la chaleur, il est peu probable que de telles installations soient mises en service. Les futurs coûts de l'électricité produite par les installations de biomasse devraient rester à peu près au niveau actuel et dépendront principalement des coûts des combustibles.

3.3.6 Géothermie

Les coûts de production de l'électricité dans les centrales géothermiques EGS dépendent surtout de la géologie et des recettes potentielles de la vente des rejets de chaleur – les incertitudes et les marges de fluctuation sont importantes pour ces deux facteurs. Il apparaît que les coûts des forages profonds constituent de loin la part la plus importante des coûts de l'installation. De manière générale, il semble peu probable que les centrales EGS puissent être exploitées de façon rentable sans une utilisation économiquement intéressante des rejets de chaleur. Il s'agit donc d'identifier des sites géothermiques potentiels où la géologie et la proximité des consommateurs de chaleur permettent une exploitation rentable et où l'opinion publique est favorable. Les principaux facteurs individuels des coûts de revient de l'électricité sont la profondeur des forages (étant donné que les coûts de forage augmentent de manière exponentielle avec la profondeur) et le gradient de la hausse de température sous la surface de la terre. Par rapport à d'autres technologies, les coûts technologiques sont en soi bien moins déterminants pour les coûts de production de l'électricité.

3.3.7 Centrales houlomotrices et marémotrices

Les coûts de production de l'électricité diffèrent fortement en fonction du type de centrale houlomotrice ou marémotrice. Les frais d'investissement sont de loin le facteur principal des coûts de revient de l'électricité. Plus la puissance de l'installation est grande, plus les coûts spécifiques sont faibles. On s'attend à l'avenir à des frais d'investissement en forte baisse. Ces effets d'apprentissage escomptés impliquent toutefois une production de masse très développée.

3.3.8 Centrales solaires thermiques

L'estimation des coûts de revient de l'électricité des actuelles centrales solaires thermiques souffre du manque de données exploitables qui reflètent la réalité; les coûts des centrales ne sont guère accessibles au public. Dans la présente étude, les coûts de production de l'électricité se fondent sur plusieurs rapports récemment publiés par des organisations internationales et révèlent des incertitudes en la matière. Une chose est sûre: les principaux facteurs de coûts sont les frais d'investissement, le rayonnement solaire, la durée de vie des installations, les taux d'intérêts, les frais d'exploitation et d'entretien. On s'attend à ce que les coûts soient nettement plus bas à l'avenir grâce à trois facteurs: des coûts technologiques réduits, de meilleurs rendements avec une plus grande disponibilité des centrales et de plus grandes installations.

3.3.9 Energie nucléaire

Les centrales nucléaires sont une technologie à forte intensité en capital; les taux d'intérêt et les frais d'investissement ont donc un grand impact sur les coûts de revient de l'électricité. Même des retards substantiels pendant la phase de planification, d'autorisation et de construction peuvent entraîner des coûts de production nettement plus élevés qu'initialement prévu. Contrairement aux centrales à gaz et à charbon, les coûts du combustible sont un facteur de moindre importance s'agissant des coûts de revient. Faute de données exploitables, la présente étude a renoncé à quantifier les coûts de production de l'électricité des réacteurs de quatrième generation, même s'ils pourraient être disponibles en 2050 comme nouvelle technologie.

3.3.10 Centrales au gaz naturel et à charbon

Les coûts de revient de l'électricité produite par les centrales à cycle combiné au gaz naturel sont dominés par le combustible, c.-à-d. le gaz naturel. C'est aussi le cas pour les grandes CCF au gaz naturel d'une puissance de plus de 100 kW_{el}. Plus la CCF est petite, plus la part des frais d'investissement dans les coûts de revient est grande. Comme le rendement électrique est comparativement plus faible, les petites CCF dépendent plus fortement d'une utilisation économiquement intéressante des rejets de chaleur. Pour les centrales à charbon, les frais d'investissement, l'exploitation, l'entretien et le combustible concourent à parts à peu près égales aux coûts de production de l'électricité. Les coûts du combustible sont moins déterminants pour les centrales au lignite que pour celles à la houille. Equiper les centrales d'un système de capture du CO_2 augmente les coûts de production des centrales au gaz naturel et à charbon de 25 à 60% selon la technologie, les taux de capture et les coûts du combustible. Un stockage géologique permanent du CO_2 augmenterait encore les coûts de production; comparés à la capture du CO_2, les coûts liés au transport et au stockage sont minimes. Les coûts de production de l'électricité des centrales au gaz naturel et à charbon augmenteraient de 5 à 10%.[101]

3.3.11 Piles à combustible

Les coûts de production de l'électricité à partir des piles à combustible sont déterminés dans une large mesure par les frais d'investissement, surtout pour les installations de faible puissance. On s'attend à ce qu'ils diminuent fortement à l'avenir. En plus des frais d'investissement, la durée de vie des piles à combustible est aussi un facteur important pour les coûts de production. Le rendement et les coûts du combustible ont comparativement peu d'influence.

3.4 Aspects environnementaux

La quantification et l'évaluation de l'impact environnemental en lien avec la production d'électricité se fondent sur la méthode de l'écobilan (*life cycle assessment*, LCA) et comprennent donc les chaînes énergétiques complètes, y c. l'extraction et la mise à disposition des agents énergétiques, l'infrastructure, etc. (ISO 2006a, ISO 2006b, EC 2010, Hellweg and Milà i Canals 2014, Astudillo, Treyer et al. 2015, Astudillo, Treyer et al. 2016). Les émissions de gaz à effet de serre (GES) et leur effet sur le changement climatique sont utilisés dans le présent rapport comme indicateur environnemental primaire pour les

[101] Cette hausse correspond à une estimation grossière qui s'appuie sur des données non spécifiques à la Suisse; on ne dispose pas de données pour la Suisse, mais les coûts devraient être similaires. Tandis que les coûts liés au transport du CO_2 sont assez bien connus, ceux du stockage géologique du CO_2 sont très incertains, car il n'y a pas encore de valeurs empiriques. S'il est possible de vendre et d'utiliser ce CO_2, p. ex. pour produire des carburants synthétiques, il faudrait tenir compte de «crédits de CO_2». Une telle analyse sort toutefois du cadre de cette étude.

technologies de production d'électricité actuelles et futures. D'autres impacts environnementaux des technologies actuelles sont présentés et discutés de façon moins détaillée; on ne dispose pas d'un set de données d'inventaire cohérent pour les futures technologies qui permettrait une analyse au même niveau que pour les émissions de gaz à effet de serre, et l'établissement de nouvelles données d'inventaire correspondantes dépassait le cadre de cette étude.

La méthode de l'écobilan permet de quantifier l'impact environnemental d'une «exploitation normale» des centrales et des chaînes d'approvisionnement en combustible. Les conséquences possibles d'accidents graves ne sont pas prises en compte. La méthode ne permet pas de mesurer l'impact environnemental local et spécifique aux sites, à l'instar des écosystèmes locaux pour les petites centrales hydrauliques. Le bruit et l'impact visuel ne font pas non plus partie des écobilans. Ces aspects sont discutés dans les différentes sections en complément des résultats de l'écobilan.

3.4.1 Emissions de gaz à effet de serre

La Figure 3.5 montre les émissions de gaz à effet de serre (GES) de la production d'électricité avec d'actuelles technologies représentatives en Suisse (et à l'étranger pour les importations d'électricité potentielles).[102] Les fourchettes indiquées reflètent la variabilité des facteurs d'implantation (p. ex. rendement annuel des installations photovoltaïques et éoliennes en Suisse), des caractéristiques des technologies (p. ex. rendement, puissance de l'installation) et des propriétés des combustibles. En cas de production simultanée d'électricité et de chaleur utile dans les CCF et les piles à combustible, l'impact environnemental est réparti (alloué) grâce à la teneur en exergie de l'électricité et de la chaleur. La disponibilité des résultats des écobilans est restreinte pour les technologies de biomasse.[103] Les résultats se réfèrent à la production d'électricité «au départ de la centrale», c.-à-d. que le transport et la distribution d'électricité ne sont pas pris en compte. Les aspects systémiques, comme le besoin potentiel en technologies de *back-up* pour compenser les fluctuations de production, ne sont pas pris en considération, car un tel besoin dépend de la composition du système global d'approvisionnement en électricité.

Dans la comparaison des technologies, la production d'électricité des centrales hydrauliques, des centrales nucléaires et des éoliennes génère le moins d'émissions de gaz à effet de serre. L'électricité produite par les centrales à charbon implique le plus d'émissions. Les grandes fourchettes pour les centrales à charbon, les CCF au gaz naturel et les piles à combustible s'expliquent par les différentes technologies et puissances des installations. Celles pour la biomasse reflètent la variabilité des technologies de conversion et des catégories de matières premières. On procède de l'idée que le bois est récolté de manière durable; c.-à-d. que le cycle du carbone est fermé et que les émissions de CO_2 biogènes ne sont pas prises

[102] Dans le cadre des aspects environnementaux, l'expression «technologies actuelles» se réfère aux centrales modernes qui sont aujourd'hui sur le marché. Une différenciation entre les installations exploitées à l'heure actuelle et les nouvelles installations à construire pour la grande hydraulique et l'énergie nucléaire – comme pour les coûts de revient de l'électricité – ne fait guère sens et n'a donc pas été entreprise.

[103] La «biomasse agricole» est représentée dans l'écobilan par de petites installations agricoles de biogaz approvisionnées en lisier; les émissions de gaz à effet de serre sont principalement générées par le méthane («émanations de méthane») dues à la fermentation du lisier. Les installations modernes générant peu d'émanations de méthane produiraient nettement moins d'émissions GES.

en compte dans le bilan. La fourchette pour les centrales houlomotrices et marémotrices découle du grand nombre de modèles de centrales possibles.

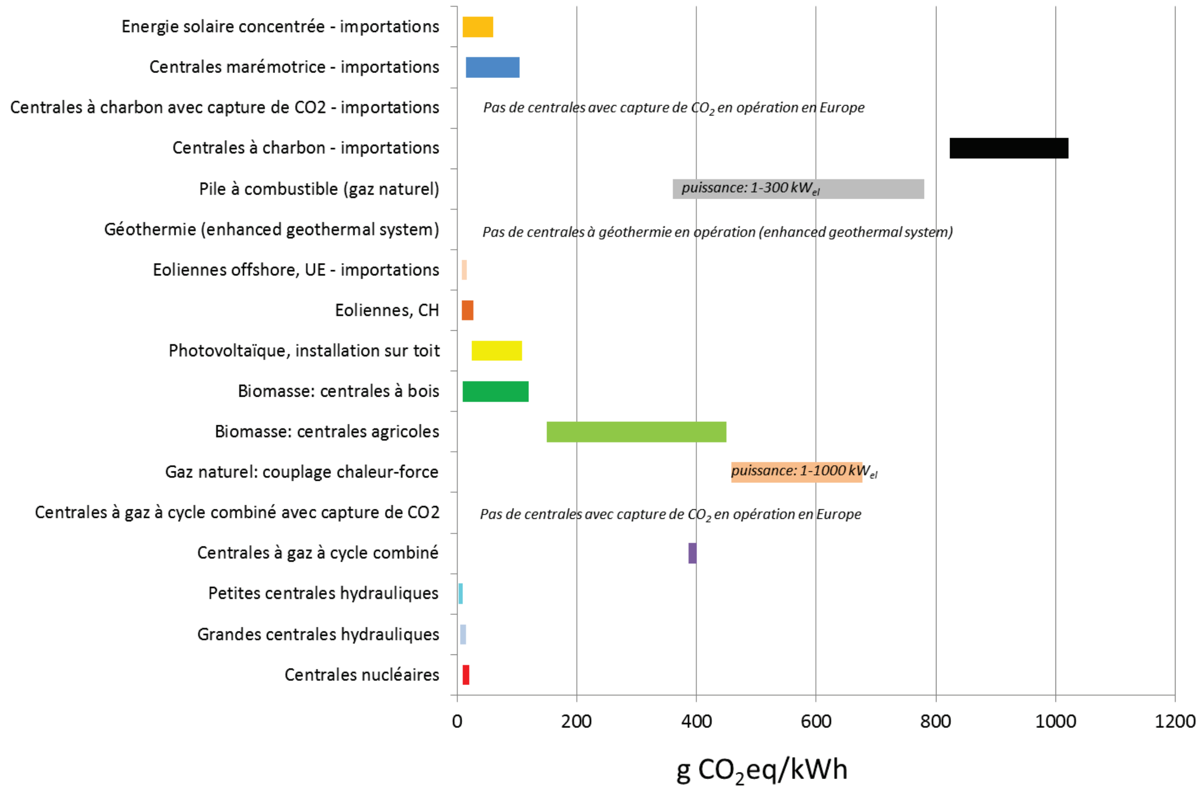


Figure 3.5: Emissions de gaz à effet de serre (tout le cycle de vie; électricité au départ de la centrale) des technologies actuelles de production d'électricité pour l'approvisionnement électrique de la Suisse. Les fourchettes reflètent la variabilité des facteurs d'implantation, des caractéristiques des technologies et des propriétés des combustibles. Les émissions d'une production combinée d'électricité et de chaleur utile sont allouées à l'aide de leur teneur en exergie. La disponibilité des données sur les technologies de biomasse est limitée. GuD: centrale à gaz à cycle combiné; CCF: couplage chaleur-force; CSP: *concentrated solar power*; EGS: *enhanced geothermal systems*; «charbon» comprend la houille et le lignite.

La Figure 3.6 montre les émissions de gaz à effet de serre des technologies de production d'électricité pour l'approvisionnement électrique de la Suisse en 2050. Les fourchettes reflètent la variabilité des facteurs d'implantation, des caractéristiques des technologies et des propriétés des combustibles. Les émissions d'une production combinée d'électricité et de chaleur utile sont allouées grâce à leur teneur en exergie. La disponibilité des données sur les technologies de biomasse est limitée.

Pour la plupart des technologies, on peut supposer que les émissions de gaz à effet de serre diminueront d'ici 2050. A l'exception de la force hydraulique et de l'énergie nucléaire – où il n'y a guère de potentiel de réduction. Au contraire, la réduction des concentrations en uranium pourrait en rendre l'extraction plus onéreuse et conduire à une hausse des émissions; l'autre aspect est le progrès technologique escompté dans toute la chaîne de processus, p. ex. dans l'enrichissement de l'uranium. Le facteur de la moins bonne disponibilité des ressources pourrait aussi entraîner une augmentation des émissions pour les centrales au gaz naturel et à charbon; mais la présente étude n'a pas pu le quantifier. Les technologies du gaz naturel et du charbon montrent une diminution des émissions proportionnelle à la hausse des rendements des centrales et CCF. La capture du CO_2 réduirait les émissions de manière substantielle – presque au niveau de certaines énergies renouvelables selon le taux de capture et le combustible.[104,105,106] Parmi les énergies renouvelables, les émissions diminuent le plus pour l'électricité photovoltaïque grâce aux progrès escomptés dans les processus de production des cellules et des modules photovoltaïques et aux meilleurs rendements.

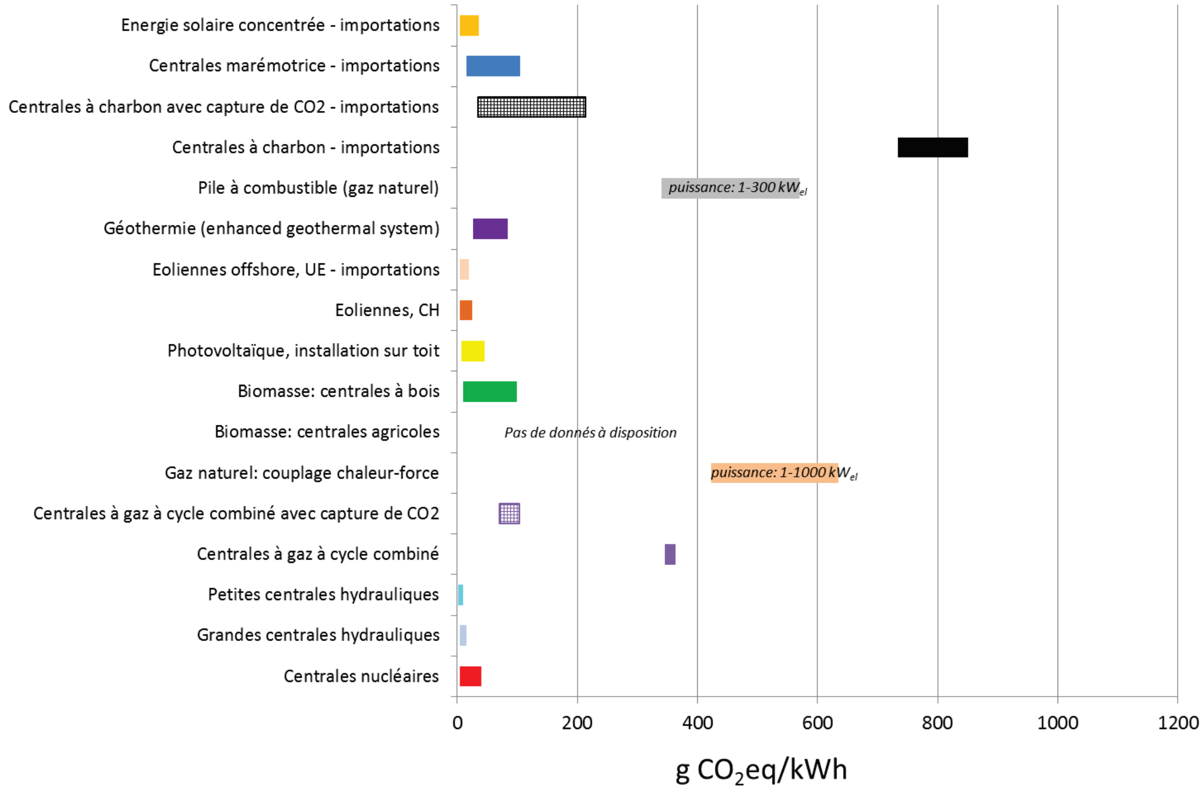


Figure 3.6: Emissions de gaz à effet de serre (tout le cycle de vie; électricité au départ de la centrale) des technologies de production d'électricité pour l'approvisionnement électrique de la Suisse en 2050. Les fourchettes reflètent la variabilité des facteurs d'implantation, des caractéristiques des technologies et des propriétés des combustibles. Les émissions d'une production combinée d'électricité et de chaleur utile sont allouées grâce à leur teneur en exergie. La disponibilité des données sur les technologies de biomasse est limitée. GuD: centrale à gaz à cycle combiné; CCF: couplage chaleur-force; CSP: *concentrated solar power*; EGS: *enhanced geothermal systems*; «charbon» comprend la houille et le lignite.

3.4.2 Autres résultats des écobilans

La Figure 3.7 montre les résultats des écobilans d'autres indicateurs environnementaux pour des technologies de production actuelles. Les résultats sont gradués sur une valeur de 1 pour le premier résultat d'une technologie (plus grand impact environnemental) pour chaque indicateur; à titre de comparaison, l'impact environnemental du mix énergétique actuel de la Suisse est aussi représenté (y c. importations). Le choix des indicateurs

[104] La mise en œuvre de toute la chaîne CCS, c'est-à-dire la capture, le transport et le stockage géologique du CO_2, n'augmenterait les émissions de gaz à effet de serre de l'électricité issue des centrales au gaz naturel et à charbon dotées d'un système CCS que de façon marginale.

[105] La conversion de la biomasse en électricité avec un système CCS impliquerait des émissions de gaz à effet de serre négatives. Elle n'apparaît néanmoins pas dans le graphique récapitulatif, car une implémentation de grandes centrales de biomasse dotées d'un système CCS en Suisse semble plutôt peu probable d'un point de vue actuel.

[106] Si le CO_2 capturé était utilisé dans d'autres processus, les effets de substitution devraient être pris en compte dans l'écobilan; cela dépasse toutefois le cadre du présent rapport.

environnementaux et des méthodes d'évaluation s'appuie sur les recommandations de Hauschild, Goedkoop et al. (2013). Cette comparaison utilise les données d'inventaire de la banque de données LCA ecoinvent (ecoinvent 2016). La plupart des sections ont des graphiques similaires avec davantage de technologies.[107]

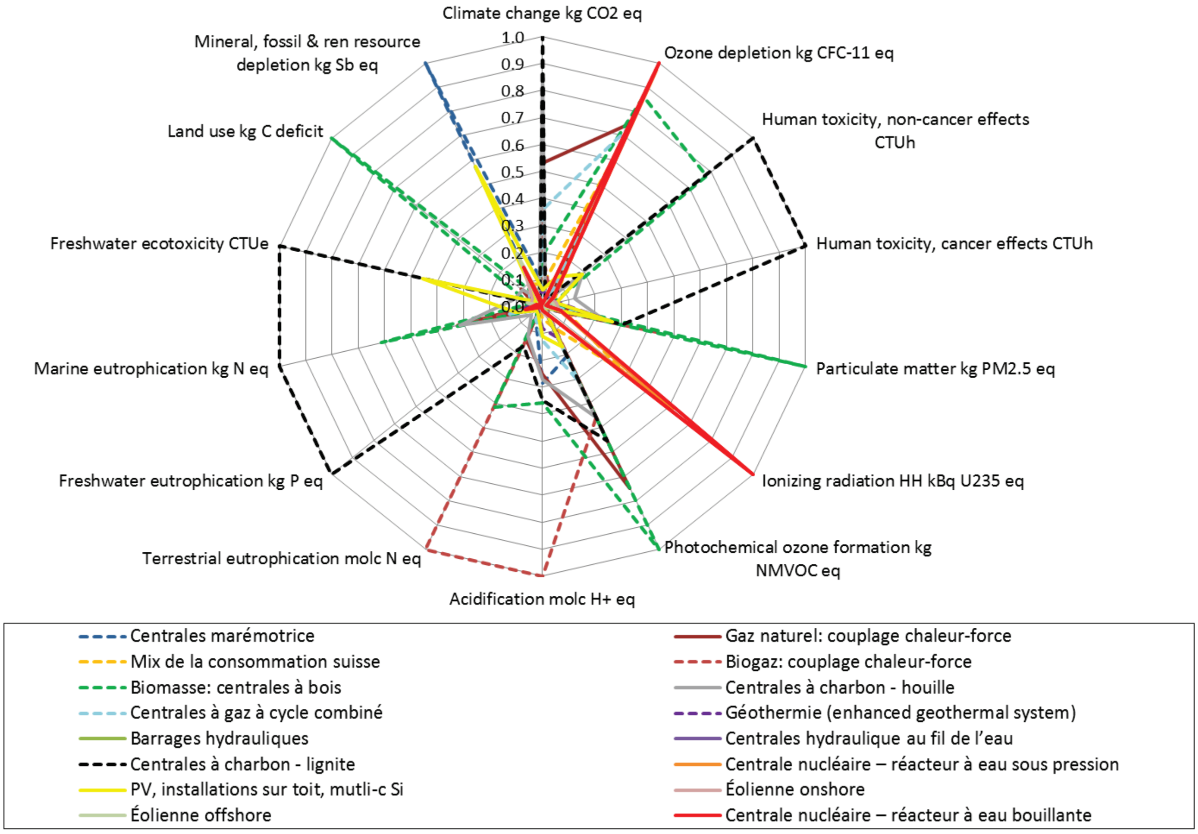


Figure 3.7: Résultats des écobilans pour les technologies de production d'électricité actuelles, gradués par rapport au résultat le plus élevé (=le plus mauvais, 1) d'une technologie par indicateur (au départ de la centrale[108]). Choix d'indicateurs basé sur (Hauschild, Goedkoop et al. 2013); données d'inventaire de l'écobilan tirées de (ecoinvent 2016). Toutes les technologies sont représentatives des installations actuelles en Suisse, à l'exception de l'énergie houlomotrice, de la houille, de l'éolien *offshore* et du lignite (importation d'électricité). Les données d'inventaire pour les centrales solaires thermiques, les piles à combustible et la petite hydraulique ne sont pas disponibles sous une forme cohérente. CCF: couplage chaleur-force; PV: photovoltaïque; multi-c Si: cellules photovoltaïques en silicium multicristallin; GuD: centrale à gaz à cycle combiné; EGS: *enhanced geothermal system*; REP: réacteur à eau sous pression; REB: réacteur à eau bouillante.

[107] Dans le présent résumé, la Figure 3.7 sert à donner une vue d'ensemble de l'impact environnemental des différentes technologies dans une comparaison globale. En d'autres termes, il est nécessaire de renoncer à certains détails qui figurent dans les sections dédiées aux technologies. Nombre de résultats ne concordent pas entièrement avec les résultats des différentes sections, car la Figure 3.7 utilise des données d'inventaire de technologies moyennes et représentatives, alors que les sections comprennent souvent des résultats d'écobilans de technologies spécifiques afin de donner un aperçu plus précis des aspects technologiques et de leur impact sur l'écobilan. Les sections dédiées aux technologies utilisent en partie aussi des données d'inventaire plus récentes pour lesquelles le set d'indicateurs environnementaux présenté à la Figure 3.7 n'est pas disponible. Les différences entre les résultats des écobilans présentés dans ce cadre et dans les sections sont toutefois minimes et ont un impact négligeable sur la comparaison des technologies s'agissant de l'impact environnemental.

[108] Le transport et la distribution d'électricité ne sont pas pris en compte dans ces résultats.

Les résultats montrent que globalement, l’impact environnemental le plus important (avec une pondération équivalente des indicateurs) est causé par l’électricité produite dans les centrales au lignite et les installations de combustion du bois; principalement en raison des émissions directes générées par la combustion du charbon et du bois, et en partie aussi du fait de l’approvisionnement en combustible. L’électricité issue des centrales hydrauliques a l’impact environnemental le plus limité, car leur exploitation ne génère presque pas d’émissions et que l’intensité matérielle de l’infrastructure par kilowattheure d’électricité est faible. La force éolienne et les centrales géothermiques présentent aussi un impact environnemental minime. Le courant produit par les centrales à cycle combiné au gaz naturel, les centrales nucléaires, les installations photovoltaïques ainsi que les centrales houlomotrices et marémotrices a un impact environnemental un peu plus important, avec de mauvais résultats pour un ou plusieurs indicateurs. L’électricité issue des CCF au biogaz et au gaz naturel de même que les centrales à la houille génère comparativement un impact environnemental élevé, comparable à celui des centrales au lignite et des CCF à bois, mais de manière moins marquée.

3.5 Fiches de données sur les différentes technologies

Les fiches de données donnent un aperçu, en une ou deux pages par technologie, des principaux résultats de l’évaluation technologique. Elles comprennent l’estimation des potentiels exploitables pour la production d’électricité, les coûts de la production d’électricité et les résultats des écobilans pour les émissions de gaz à effet de serre comme indicateur de l’impact environnemental de la production. Les chiffres sont indiqués pour «aujourd’hui» (2015/16), 2020, 2035 et 2050. En complément, il y a certains paramètres technologiques et une explication des résultats.

Les résultats sont aussi présentés sous forme de fourchettes qui reflètent les incertitudes et les possibles marges de fluctuation dues aux caractéristiques des technologies et au développement technologique attendu, aux rendements annuels en fonction des sites (p. ex. pour le photovoltaïque et l’éolien) et aux propriétés des combustibles (mais pas de leurs prix). Pour chaque technologie, les fourchettes tiennent compte des principaux facteurs d’influence. Les commentaires sur les chiffres sont indiqués sous forme de notes au bas des différents tableaux. Les informations complètes sur la genèse de ces chiffres se trouvent ensuite dans les sections dédiées aux technologies.

Fiche de données – grande hydraulique

Technologie: les centrales hydrauliques produisent du courant en convertissant en électricité l'énergie potentielle ou cinétique contenue dans l'eau. Les centrales d'une puissance de plus de 10 MW sont considérées comme «grandes» en Suisse et se répartissent dans les catégories suivantes:

- centrales à accumulation: l'eau est retenue par un barrage dans un lac de retenue
- centrales au fil de l'eau: ne possèdent pas de barrage; le régime hydrologique n'est pas ou presque pas modifié
- centrales à pompage-turbinage: produisent de l'électricité en période de charge de pointe en pompant et en turbinant l'eau entre les lacs de retenue à différentes altitudes

Les grandes centrales hydrauliques sont une technologie «au développement achevé». Les rendements des turbines ne pourront être augmentés à l'avenir que de façon minime.

Grandes centrales hydrauliques			Nouvelles installations: aujourd'hui[1]	2020	2035	2050
Potentiel[2]	TWh/a		32.7	~32.7	33.9-35.3	33.9-35.3
					32.7-34.0	32.7-34.0
Coûts d'investissement[3]	CHF/kW		3500 (2000-10000)	2000-10'000	2000-10'000	2000-10'000
Coûts de production de l'électricité[4,5]	ct./kWh	Centrale au fil de l'eau[8]	7-30	7-30	7-30	7-30
		Centrale à accumulation[9]				
Emissions de gaz à effet de serre[6,7]	g éq-CO_2/kWh	Centrale au fil de l'eau	5-10	~5-10	~5-10	~5-10
		Centrale à accumulation	5-15	~5-15	~5-15	~5-15

[1] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne sur le marché; les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui; le potentiel actuel correspond à la production escomptée en 2016 (la production effective dépend des précipitations, du climat, etc.).

[2] Etant donné que la rentabilité de la force hydraulique n'est en partie pas donnée aujourd'hui en Suisse, on ne peut pas miser sur un développement substantiel d'ici 2020. Et cela en dépit des contributions d'investissement destinées aux agrandissments et aux rénovations notables de la grande hydraulique à partir du 1.1.2018. Ces contributions sont issues du fond alimenté par le supplément perçu sur le réseau. La future expansion de la force hydraulique dépendra principalement des conditions-cadres économiques et de l'acceptation de nouvelles centrales. Les nouvelles centrales et l'extension de centrales existantes peuvent contribuer à peu près autant à une augmentation de la production. La ligne du haut pour 2035 et 2050 porte sur la production possible sans tenir compte des nouvelles dispositions légales (loi sur la protection des eaux); la ligne du bas prend en compte une réduction de la production de 1260 GWh/a en raison de la LEaux (réduction globale: 1400 GWh/a; 90% sont imputés à la grande hydraulique, 10% à la petite hydraulique – proportionnellement à la production actuelle).

[3] Les données disponibles ne permettent pas de faire la distinction entre les centrales au fil de l'eau et les centrales à accumulation. 3500 CHF/kW représente une moyenne pondérée pour des investissements visant à augmenter la production d'électricité (dans de nouvelles centrales ou l'extension d'installations existantes) sans tenir compte des constructions visant principalement à régler la problématique des éclusées.

[4] Les coûts de production de l'électricité comprennent les frais d'investissement, les frais d'exploitation et d'entretien ainsi que d'autres coûts. Les fourchettes reflètent les facteurs spécifiques aux sites.

[5] En supposant que les sites économiquement intéressants sont utilisés en premier, les coûts de production de l'électricité des nouvelles installations tendent à passer de la limite inférieure à la limite supérieure de la fourchette. Dans l'ensemble, près de 1,6 TWh/a d'électricité peut être produit en plus à des coûts de production inférieurs à 15 ct./kWh (sans tenir compte de la LEaux).

[6] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent des facteurs d'influence spécifiques aux sites. A titre de

comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh (haute tension).

[7] On suppose que l'impact environnemental de nouvelles centrales correspond à peu près à celui des actuelles, parce qu'il est comparativement faible et que la technologie n'évoluera pas de manière substantielle.

[8] Coûts de la production d'électricité des centrales existantes avec un capital en partie amorti: 5-6 (2-10) ct./kWh.

[9] Coûts de la production d'électricité des centrales existantes avec un capital en partie amorti: 6 (3-9) ct./kWh.

Fiche de données – petite hydraulique

Technologie: les centrales hydrauliques produisent du courant en convertissant en électricité l'énergie potentielle ou cinétique contenue dans l'eau. Les centrales d'une puissance de moins de 10 MW entrent dans la catégorie «petite hydraulique» en Suisse. Les petites centrales hydrauliques peuvent aussi être intégrées dans des infrastructures existantes, par exemple des conduites d'eau potable. On distingue selon le type d'utilisation de l'eau:

- centrales à accumulation: l'eau est retenue par un barrage dans un lac de retenue
- centrales au fil de l'eau: ne possèdent pas de barrage; le régime hydrologique n'est pas ou presque pas modifié

Les petites centrales hydrauliques traditionnelles sont en général une technologie «au développement achevé». Les rendements des turbines n'augmenteront à l'avenir que de façon minime. La recherche actuelle vise néanmoins à renforcer l'efficacité des petites centrales hydrauliques avec de faibles débits et de faibles dénivelées exploitables pour pouvoir mieux exploiter de nouveaux sites.

Petites centrales hydrauliques		**Nouvelles installations: aujourd'hui[1]**		**2020**	**2035**	**2050**
Potentiel[2]	TWh/a		3.5	~3.5	~4.3-5.5	~4.3-5.5
Coûts d'investissement[3]	CHF/kW	Centrales sur eaux usées/au fil de l'eau	6160 (5200-13 700)	~6160	~7150	~7400
		Centrales sur eau potable	11 150 (9600-25 100)	~11 150	~13 000	~13 400
Coûts de production de l'électricité[4,5]	ct./kWh	Centrales sur eaux usées/au fil de l'eau	12-28	~12-28	~14-33	~14-34
		Centrales sur eau potable	17-42	~17-42	~20-49	~20-50
Emissions de gaz à effet de serre[6,7]	g éq-CO_2/kWh	Centrales sur eaux usées/au fil de l'eau	~5-10	~5-10	~5-10	~5-10
		Centrales sur eau potable	~2-5	~2-5	~2-5	~2-5

[1] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne sur le marché; les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui; le potentiel actuel correspond à la production escomptée en 2016 (la production effective dépend des précipitations, du climat, etc.).

[2] Les fourchettes des futurs potentiels reflètent les estimations de certaines études actuelles. L'OFEN mise sur un potentiel supplémentaire de 1,3 à 1,6 TWh/a. On suppose que ces chiffres devront être réduits de près de 140 GWh/a en conséquence de la loi sur la protection des eaux. L'extension effective de la production des petites centrales hydrauliques dépendra des mesures de soutien financier.

[3] Les coûts d'investissement actuels ont été estimés à l'aide de la «liste RPC» (rétribution du courant injecté à prix coûtant). L'échantillon évalué comprend des projets pour 1049 nouvelles petites centrales hydrauliques. Les coûts d'investissement auront tendance à augmenter, car les centrales sont d'abord construites sur des sites favorables et que les réglementations risquent plutôt de se multiplier dans le domaine de l'environnement.

[4] Les coûts de production de l'électricité comprennent les frais d'investissement, les frais d'exploitation et d'entretien ainsi que d'autres coûts. Les fourchettes reflètent les facteurs spécifiques aux sites.

[5] En supposant que les sites favorables sont utilisés en premier, les coûts passeront de la limite inférieure à la limite supérieure de la fourchette indiquée entre 2020 et 2050.

[6] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent des facteurs d'influence spécifiques aux sites. A titre de comparaison: le mix d'approvisionnement de la Suisse (y c. importations) présente une intensité de GES de près de 100 g éq-CO_2/kWh.

[7] On suppose que l'impact environnemental des nouvelles centrales correspond à peu près à celui des actuelles, parce qu'il est comparativement faible et que la technologie n'évoluera pas de manière substantielle.

Fiches de données – éoliennes

Technologie: les éoliennes à axe horizontal dominent le marché actuel. Le courant est produit à l'aide de pales de rotor par la conversion en électricité de l'énergie cinétique du flux d'air. Les turbines actuelles peuvent produire de l'électricité avec une vitesse de vent de 3 à 34 m/s.

Eoliennes			**Nouvelles installations**			
			aujourd'hui[9]	**2020**	**2035**	**2050**
Puissance		Onshore	1-3 MW (70% de la puissance installée) Nouvelles turbines: 2-4 MW	Plus grande turbine aujourd'hui: 8 MW (on-/offshore), 164 m diamètre de rotor, 220 m hauteur de moyeu. La faisabilité de turbines de 20 MW a été démontrée.		
		Offshore	>3 MW (2/3 de la puissance installée)			
Facteur de capacité (cf)[1]		Général	0.1-0.55; Moyenne mondiale ~0.23 (2013)	Les facteurs de capacité augmenteront un peu grâce à l'amélioration des turbines et aux prévisions plus précises des vitesses de vent pour un choix optimal du lieu d'implantation.		
		Onshore	CH: 20.8 (2015); Allemagne: 22.3 (2015)			
		Offshore	Jusqu'à 0.55; DK: 0.43 (2012)			
Potentiel	TWh/a	Suisse	0.1	0.1-0.6	0.7-1.7	1.4-4.3
	TWh/a	Europe[6]	~260	580-630	2030: 604-988	Pas de données
Coûts de production de l'électricité[2,3]	ct./kWh	Suisse	13-21	11-19	10-17	9-15
		Europe, onshore	4-18	4-16	3-13	3-10
		Europe, offshore	13-27	13-25	12-23	10-20
Emissions de gaz à effet de serre[2,4,5]	g éq-CO_2/kWh	Suisse	~15 (8-27)	5-30	5-30	5-30
		Europe, onshore[7]	8-21	5-25	5-25	5-25
		Europe, offshore[8]	8-16	5-20	5-20	5-20

[1] «Heures de pleine charge» annuelles divisées par 8760 h/a. Elles correspondent au temps qui découle de la production annuelle à la puissance nominale.
[2] Les coûts de production de l'électricité comprennent les frais d'investissement, les frais d'exploitation et d'entretien ainsi que d'autres coûts. Le rendement annuel est le principal facteur d'influence sur les coûts de production de l'électricité et les résultats des écobilans. Sur les sites ayant de très bonnes ou de très mauvaises conditions de vent, les coûts et les émissions de GES peuvent se situer en dehors des fourchettes indiquées.
[3] Les coûts futurs sont des estimations grossières sur la base de la littérature et des tendances actuelles.
[4] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent les facteurs d'influence spécifiques aux sites et les classes de puissance des turbines. A titre de comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh (haute tension).
[5] On ne s'attend pas à ce que l'impact environnemental change considérablement à l'avenir. Une diminution résulterait d'une meilleure utilisation du vent; une augmentation d'une détérioration des sites disponibles.
[6] Aucune distinction possible entre les turbines *onshore* et *offshore*.
[7] Pour des facteurs de capacité de 0,15 à 0,35.
[8] Sur la base de la banque de données ecoinvent, v3.3, «allocation – cut-off by classification», cf de 0,30 à 0,55.
[9] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne sur le marché; les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui.

Fiche de données – photovoltaïque (PV)

Technologie: les cellules photovoltaïques transforment directement le rayonnement solaire en électricité. En Suisse, les installations sur toiture sont courantes. Les installations photovoltaïques peuvent être catégorisées comme suit:

- 1re génération: cellules en silicium cristallin (Si monocristallin et Si polycristallin); prédomine aujourd'hui
- 2^{e} génération: cellules à couche mince – CdTe, Si amorphe, CIGS; déjà sur le marché
- 3^{e} génération: cellules à concentration, cellules organiques; en développement

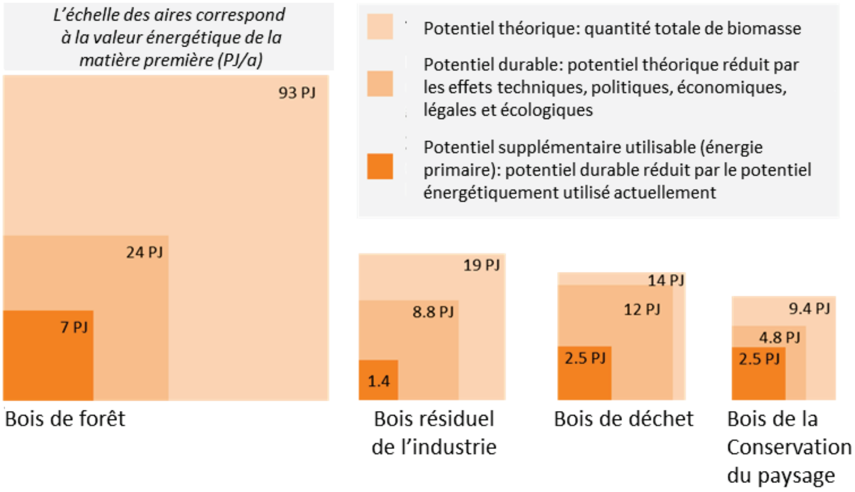
Le développement technologique vise principalement à augmenter les rendements et à diminuer les coûts de production.

Notes du tableau

[1] Toutes les données se réfèrent ici à des installations photovoltaïques sur des bâtiments existants. Les installations isolées ne sont pas examinées, car leur acceptation n'est pas considérée comme acquise en Suisse.
[2] Supposé ici d'après (Nowak and Biel 2012) et (Frischknecht, Itten et al. 2015); utilisé comme valeur de référence pour les calculs des coûts et les écobilans.
[3] Y c. les modules photovoltaïques, les onduleurs, les autres éléments de construction, les coûts du travail et les autres coûts. Les fourchettes pour les futurs prix reflètent une estimation d'évolution optimiste et pessimiste.
[4] Comprennent les coûts d'investissement et d'élimination, d'exploitation et d'entretien ainsi que de remplacement des onduleurs et autres éléments de construction. Les fourchettes découlent de la variation des rendements annuels (850-1500 kWh/kW/a). Les coûts futurs comportent un scénario avec une estimation d'évolution optimiste et pessimiste; les variations des rendements annuels (850-1500 kWh/kW/a) sont prises en compte entre parenthèses.
[5] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent des facteurs d'influence spécifiques aux sites. Elles découlent de la variation des rendements annuels (850-1500 kWh/kW/a). A titre de comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 100 g éq-CO_2/kWh (basse tension).
[6] Les valeurs de référence actuelles sont calculées avec un rendement de 970 kWh/kW/a. Les chiffres pour les futures cellules ribbon-Si, a-Si et CIS ne sont pas disponibles. Les fourchettes pour les futures technologies reflètent les incertitudes dans le développement des technologies à l'avenir et la variabilité des rendements annuels (850-1500 kWh/kW/a).
[7] Les estimations du PSI ne tiennent compte que des surfaces de toiture appropriées (Cattin, Schaffner et al. 2012), conformément au «potentiel technique limité». Il est difficile d'estimer le développement futur de la production photovoltaïque en Suisse, raison pour laquelle des fourchettes larges sont indiquées. L'évolution dépendra des conditions-cadres, dont la rétribution de l'injection et les autres incitations, l'évolution de la technologie photovoltaïque et des prix de l'électricité, le soutien politique, les réglementations de la consommation propre, etc. La plupart de ces facteurs dépassent le cadre de la présente analyse.
[8] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne sur le marché; les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui avec des données sur les coûts datant de 2015/2016.
[9] Les potentiels illimités des installations en façade ne sont pas directement comparables avec les chiffres des installations sur toiture; on ne dispose pas d'estimations au regard des facteurs de restriction économiques et sociétaux. Les potentiels des installations sur toiture et en façade ne peuvent donc pas être simplement additionnés.
[10] Correspond aux surfaces sur toiture disponibles compte tenu des restrictions techniques, économiques et sociétales (Cattin, Schaffner et al. 2012); en d'autres termes, c'est le «potentiel technique limité».

Photovoltaïque				**Nouvelles installations**			
				aujourd'hui[8]	**2020**	**2035**	**2050**
Potentiel[1]	Potentiel sur les toits et les façades	Surface (km^2)	Maximale	Façades[9]: 52			
				Toits[10]: 79			
		Puissance installée (GW_p)	Maximale	Façades[9]: 7-13			
				Toits[10]: 11-20			
			Estimation PSI[7]	1.4	~2.9-3.4	~5.7-16	~7.1-20
		Production d'électricité (TWh/a)	Maximale	Façades[9]: 4-8			
				Toits[10]: 11-19			
			Estimation PSI[7]	1.1	~2.8-3.3	~5.5-16	~6.9-19
Paramètres techniques[1]	Rayonnement solaire ($kWh/m^2/a$)			Suisse: 1100 (Plateau)			
	Rendement		Module (%)	14-16	15-18	20-26	23-27
			Onduleur (%)	98			
	Surface par kW de puissance installée (m^2/kW)			7.0-8.0	6.3-7.5	4.3-5.6	4.2-4.9
	Degré d'utilisation (%)			80			
	Rendement moyen annuel[2] ($kWh/kW_p/a$)			970			
	Durée de vie des modules (a)			30	30	35	35
Coûts[1]	Coûts d'investissement dans le système[3] (CHF/kW)		6 kW	2583	1791-2194	1052-1746	908-1545
			10 kW	2092	1543-1874	917-1488	771-1294
			30 kW	1815	1339-1626	796-1291	665-1118
			100 kW	1410	1040-1263	618-1003	538-886
			1000 kW	1350	996-1209	592-960	515-849
	Coûts de production de l'électricité[4] (ct./kWh)		6 kW	31 (20-35)	24-27 (15-31)	15-21 (10-24)	14-19 (9-21)
			10 kW	27 (18-31)	22-25 (14-28)	14-19 (9-22)	13-17 (8-19)
			30 kW	22 (14-26)	18-20 (12-23)	11-16 (7-18)	10-14 (7-16)
			100 kW	15 (10-18)	12-14 (8-16)	8-11 (5-12)	7-10 (4-11)
			1000 kW	12 (8-13)	9-11 (6-14)	6-8 (4-10)	5-7 (3-9)
Emissions de gaz à effet de serre[1,5,6]	(g éq-CO_2/ kWh)		Si multicristallin	60 (39-69)	35-66	21-55	7-45
			Si monocristallin	95 (62-109)	56-104	33-88	11-71
			CdTe couche mince	38 (25-43)	23-42	15-36	8-30
			ribbon-Si	67 (43-76)	NN	NN	NN
			Si amorphe	63 (41-72)	NN	NN	NN
			CIS couche mince	53 (34-61)	NN	NN	NN

Fiche de données – biomasse ligneuse



Potentiel de la biomasse ligneuse en Suisse (Erni, Thees et al. in preparation, status: 16.11.2016).[109]

Technologie: le bois de forêt, le bois résiduel de l'industrie, le bois de déchet et le bois de maintien de la conservation du paysage entrent dans la catégorie de la biomasse ligneuse. Seule une partie de ces ressources est actuellement exploitable sur le plan énergétique pour des raisons juridiques et économiques. Cette biomasse peut être convertie en électricité par des technologies de combustion ou de gazéification. Les installations de combustion de biomasse produisent le plus souvent à la fois de l'électricité et de la chaleur par le biais du couplage chaleur-force (CCF). Le gaz issu de la gazéification du bois permet par exemple de produire de l'électricité avec des moteurs, turbines ou piles à combustible. Sur la base de la Statistique suisse des énergies renouvelables de l'OFEN, on peut catégoriser les technologies de conversion comme suit:

- **Chauffages à bois automatiques avec CCF:** combustion de bois laissé à l'état naturel avec CCF d'une puissance supérieure à 50 $kW_{combustible}$.
- **Combustion de bois de déchet et de déchets biogènes:** combustion industrielle de bois de déchet et de déchets biogènes qui peuvent être utilisés à des fins énergétiques.
- **UIOM**: grandes installations avec pour vocation première l'élimination des déchets.
- **Gazéification du bois avec CCF**: installations de CCF exploitées au gaz issu de la gazéification du bois.

CCF avec chauffage au bois automatique à Felben-Wellhausen (TG) © Schmid

Combustion de bois de déchet et de déchets biogènes, Spiez (BE) © Eicher + Pauli

UIOM, Bâle (BS) © IWB

Gazéificateur, Stans (NW) © Korporation Stans

Les technologies de gazéification du bois ne sont pas aussi souvent utilisées aujourd'hui que celles de combustion du bois. La plupart des systèmes de combustion du bois ne produisent que de la chaleur. Le rééquipement de ces installations pour une production combinée d'électricité et de

[109] Le potentiel durable du bois de forêt vaut pour un seuil de prix (sans subventions) de 5,9 ct./kWh. Le potentiel serait plus grand avec des subventions.

chaleur et l'exploitation des ressources de biomasse actuellement inutilisées sont les principales contributions à l'augmentation de la production d'électricité à partir de la biomasse ligneuse.

Biomasse ligneuse		**Nouvelles installations**			
		aujourd'hui	**2020**	**2035**	**2050**
Potentiel, production d'électricité[1] [GWh/a]	CCF bois automatique[2]	126	126-225	126-614	126-1142
	Combustion de bois de déchet et de déchets biogènes[3]	70	70	70	70
	UIOM[4,5]	1065	1065-1072	1065-1105	1065-1262
Coûts de production de l'électricité[6] [ct./kWh_{el}] *(en italiques: sans crédits attribués pour l'exploitation des rejets de chaleur)*[7]	CCF bois automatique[2]	18-36 *(35-71)*	18-37 *(35-73)*	18-41 *(35-80)*	18-45 *(35-87)*
	Combustion de bois de déchet et de déchets biogènes		18-36 *(35-71)*	18-36 *(35-71)*	18-36 *(35-71)*
	Gazéification du bois[8] CCF[2]	18-31 *(25-44)*	18-32 *(25-44)*	17-33 *(24-47)*	16-35 *(23-49)*
	UIOM[4]	2.5-16[9] *(2.6-17)*	2.5-16 *(2.5-16)*	2.4-15 *(2.5-16)*	2.3-15 *(2.5-16)*
Emissions GES[10,11] [g éq-CO_2/kWh]	Combustion et gazéification	˜10-120	˜10-120	˜10-100	˜10-100 (moins ˜1300)[12]

[1] Les fourchettes pour les futurs potentiels sont grandes, car il s'agit en partie de technologies relativement nouvelles. La limite inférieure correspond à la production d'électricité actuelle, la limite supérieure à une hausse linéaire de l'utilisation des ressources de biomasse, avec une utilisation de 100% en 2050. On table aussi sur une plus grande efficacité de la conversion de la biomasse en électricité grâce à une utilisation de ressources supplémentaires par gazéification. La section dédiée comprend un scénario comparativement plus conservateur.

[2] CCF: centrale à couplage chaleur-force.

[3] Cette catégorie n'augmentera pas, car on suppose que les ressources seront plutôt utilisées dans la catégorie «CCF bois automatique», où les rendements sont nettement plus élevés.

[4] UIOM: usine d'incinération des ordures ménagères.

[5] Cette catégorie est aussi mentionnée dans la fiche de données sur la biomasse «non ligneuse». Il ne doit pas y avoir de doublons pour le potentiel global.

[6] Le calcul des coûts futurs se fonde sur les valeurs actuelles. La structure des coûts de toutes les technologies (investissements, combustible, exploitation et entretien, etc.) est déterminée à l'aide d'études de cas; pour tous ces composants, des hypothèses sont admises sur l'évolution future. L'augmentation des coûts de production découle de la hausse des prix du bois, car il y a davantage de bois utilisé à des fins énergétiques.

[7] Les coûts de production de l'électricité sont également indiqués sans les crédits attribués pour l'exploitation des rejets de chaleur, sur la base de la structure des coûts dans la section dédiée à la biomasse (les autres composants des coûts restent inchangés). Dans la pratique, de telles installations ne sont exploitées que si la chaleur peut être utilisée de façon rentable.

[8] Les technologies de gazéification et de combustion sont réunies dans la catégorie «CCF bois automatique» pour les potentiels; les coûts sont indiqués séparément.

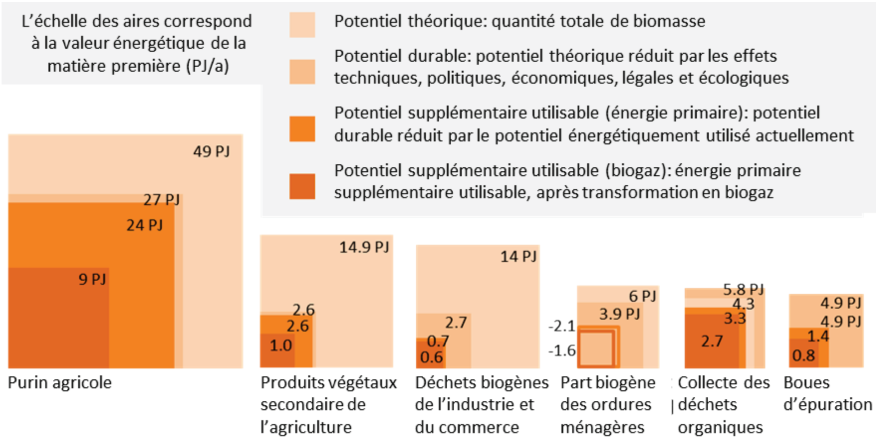
[9] La limite inférieure correspond aux «UIOM standard» pour l'élimination des déchets, la limite supérieure à des installations spéciales qui brûlent plus de bois que de déchets, comme l'installation à Bâle (UIOM/centrale à bois).

[10] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes reflètent différentes technologies et combustibles. Faute de données, les valeurs ne sont pas spécifiques à la Suisse et ne peuvent pas être indiquées séparément pour toutes les technologies. A titre de comparaison: le mix d'approvisionnement de la Suisse (haute tension, y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh.

[11] La diminution supposée des émissions est imputable à l'accroissement des rendements.

[12] Les émissions de GES négatives sont possibles en cas d'exploitation durable du bois en rapport avec la capture et le stockage du CO_2.

Fiche de données – biomasse non ligneuse



Potentiels[110] de la biomasse non ligneuse en Suisse (Burg, Bowman et al. in preparation, status: 2.2.2017).

Technologie: plusieurs substances avec des teneurs en eau très différentes entrent dans la catégorie de la biomasse non ligneuse, à l'instar des parts biogènes des ordures ménagères, des déchets biogènes de l'industrie et du commerce, des produits secondaires de l'agriculture, des déchets organiques, du lisier et des boues d'épuration. Les substances présentant une forte teneur en eau (boues d'épuration, lisier, etc.) font d'abord l'objet d'une fermentation anaérobie. Le biogaz qui en résulte peut être utilisé dans les moteurs, turbines ou piles à combustible pour produire de l'électricité. Les substances avec une faible teneur en eau peuvent être brûlées et faire fonctionner des circuits de vapeur ou *organic rankine cycles* (ORC). La gazéification des déchets est aussi possible techniquement. Il existe aujourd'hui une installation commerciale de gazéification à Lahti, en Finlande. Sur la base de la Statistique suisse des énergies renouvelables de l'OFEN, on peut catégoriser les technologies de conversion comme suit:

- **UIOM**: grandes installations avec pour vocation première l'élimination des déchets.
- **STEP communale:** biogaz issu de la fermentation anaérobie des boues d'épuration dans les stations d'épuration.
- **STEP industrielle:** biogaz issu de la purification nécessaire des eaux usées de certaines industries, à l'instar de la transformation des fruits et légumes.
- **Biogaz industriel:** production de biogaz à partir des déchets organiques et des déchets alimentaires et d'abattoir de source communale et industrielle.
- **Biogaz agricole**: production de biogaz dans des fermes à partir de lisier et de co-substrats.

UIOM, Bâle (BS) © IWB

STEP communale (SG) © morgenthal.ch

STEP industrielle Rickenbach (LU) © Gefu Produktion

Biogaz industriel KBA Hard, Beringen (SH) © abfall-sh.ch

Biogaz agricole Guin (FR) © ZHAW

[110] La part biogène des ordures ménagères devrait diminuer à l'avenir, car de plus en plus de déchets verts sont collectés à la source. Il en découle des valeurs négatives pour le potentiel restant de la part biogène des ordures ménagères.

La fermentation anaérobie est une technologie à grande échelle arrivée à un certain degré de maturité (p. ex. pour les stations d'épuration), mais à petite échelle dans l'agriculture. Le lisier représente aujourd'hui le plus grand potentiel de biomasse non ligneuse qui n'est pas utilisé, mais il n'est disponible dans les fermes que de façon décentralisée. Les petites installations dépendent fortement d'un soutien économique (rétribution du courant injecté à prix coûtant, RPC); pour être compétitifs, les coûts d'investissement devraient nettement diminuer. Les rendements électriques pour l'incinération des déchets vont augmenter, car les installations sont optimisées au regard de la production d'électricité.

Biomasse non ligneuse		**Nouvelles installations**			
		aujourd'hui	**2020**	**2035**	**2050**
Potentiel, production d'électricité[1] [GWh/a]	UIOM[2,3]	1065	1065 – 1072	1065 – 1105	1065 – 1262
	STEP communale[4]	119	119 – 129	119 – 170	119 – 225
	STEP industrielle[4,5] Biogaz industriel[5]	84	84 – 149	84 – 381	84 – 668
	Biogaz agricole	100	100 – 232	100 – 718	100 – 1342
Coûts de la production d'électricité[6] [ct./kWh_{el}] *(en italiques: sans crédits attribués pour l'exploitation des rejets de chaleur)*[7]	UIOM[2]	2.5 – 16[9] *(2.6-17)*	2.5 – 16 *(2.5-16)*	2.4 – 15 *(2.5-16)*	2.3 – 15 *(2.4-16)*
	STEP communale[4] STEP industrielle[4]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]
	Biogaz industriel Biogaz agricole	20 – 49 *(23-55)*	20 – 49 *(22-55)*	18 – 50 *(20-56)*	16 – 51 *(18-57)*
Emissions GES[10,11] [g éq-CO_2/kWh]	Biogaz agricole	150-450	150-450	Pas de donnés à disposition	

[1] La limite inférieure correspond à la production d'électricité actuelle, la limite supérieure à une hausse linéaire de l'utilisation des ressources de biomasse, avec une utilisation de 100% en 2050. On table aussi sur une meilleure efficacité de la conversion de la biomasse en électricité grâce à un plus grand recours aux piles à combustibles. La section dédiée à la technologie comprend un scénario comparativement plus conservateur.

[2] UIOM: usine d'incinération des ordures ménagères.

[3] Cette catégorie est aussi mentionnée dans la fiche de données sur la biomasse ligneuse. Il ne doit pas y avoir de doublons pour le potentiel global.

[4] STEP: station d'épuration des eaux.

[5] Ces catégories sont réunies au regard du potentiel futur, car elles utilisent des substances de départ similaires.

[6] Le calcul des coûts futurs se fonde sur les valeurs actuelles. La structure des coûts de toutes les technologies (investissements, combustible, exploitation et entretien, etc,) est déterminée à l'aide d'études de cas; pour tous ces composants, des hypothèses sont admises sur l'évolution future. On suppose des coûts constants pour les STEP, car on ne s'attend guère à des développements techniques ayant un effet sur les coûts de production.

[7] Les coûts de production de l'électricité sont également indiqués sans les crédits attribués pour l'exploitation des rejets de chaleur, sur la base de la structure des coûts dans la section dédiée à la biomasse (les autres composants des coûts restent inchangés). Dans la pratique, certains systèmes dépendent fortement des recettes provenant des ventes de chaleur.

[8] On suppose qu'une grande partie de la chaleur issue des STEP est directement consommée sur place et que les ventes de chaleur ne génèrent donc pas de recettes substantielles.

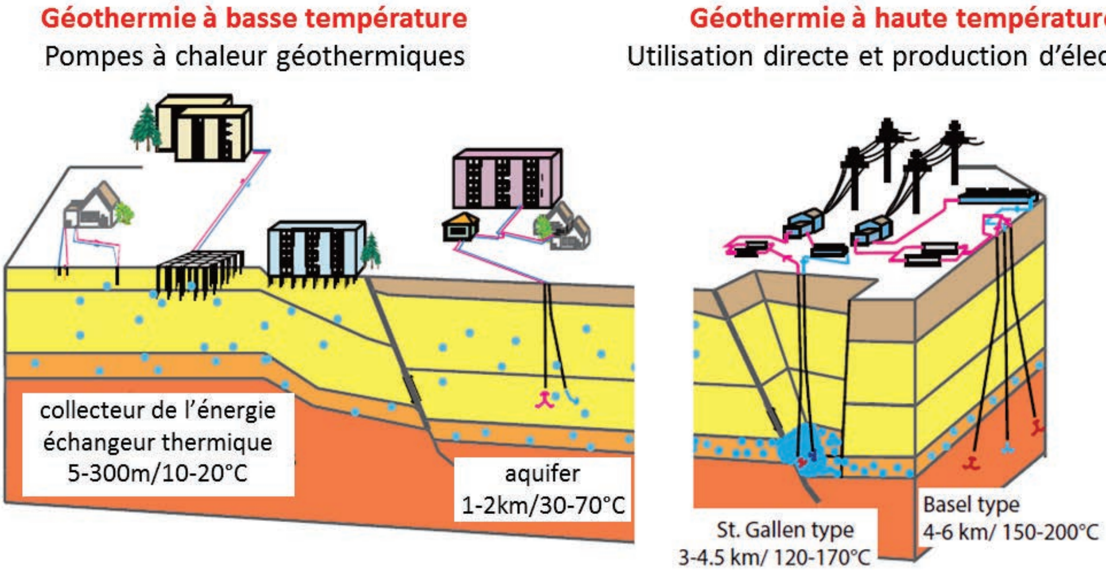
[9] La limite inférieure correspond aux «UIOM standard» pour l'élimination des déchets, la limite supérieure à des installations spéciales qui brûlent plus de bois que de déchets, comme l'installation à Bâle (UIOM/centrale à bois).

[10] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Des données d'écobilan cohérentes sont rares pour la biomasse non ligneuse. Ces fourchettes sont des estimations grossières pour les petites CCF à biogaz dans l'agriculture. A titre de comparaison: le mix

d'approvisionnement de la Suisse (haute tension, y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh.
[11] La diminution supposée des émissions est imputable à l'accroissement des rendements.

Fiche de données – géothermie

Technologie: électricité produite par géothermie profonde. Les forages ont généralement une profondeur de plus de 400 mètres et les températures dans le sous-sol doivent être supérieures à 120°C. Comme il n'y a pas de ressources géothermiques de faible profondeur en Suisse, la profondeur des forages atteint 4 à 6 km.



Les technologies sont classées selon le type d'utilisation des ressources géothermiques:

- Installations *flash steam*, *dry steam*, *back pressure*: de telles installations existent de par le monde et sont réalisables quand il y a des gisements d'eau chaude ou de vapeur (pas en Suisse).
- Installations hydrothermales (HT): ces installations sont exploitées dans le monde entier. Leur potentiel est limité, car il doit y avoir dans le sous-sol des températures élevées (>100°C), des couches géologiques aquifères et une quantité suffisante d'eau chaude.
- *Enhanced geothermal systems* (EGS): les installations EGS seraient la technologie de choix pour la Suisse. Pour l'instant, aucune n'est encore exploitée commercialement dans le monde. Leur potentiel est élevé, car elles ne dépendent pas autant de conditions naturelles opportunes et spéciales que les autres types. Elles dépendent davantage d'aspects techniques tels que des forages réussis et une stimulation efficace du sous-sol. Elles fonctionnent avec deux forages ou plus, dont l'un sert à presser l'eau froide dans le sous-sol. Celle-ci se réchauffe dans la chaleur du sous-sol et est pompée à la surface par un ou plusieurs autres forages. L'eau chaude est utilisée pour produire de l'électricité au moyen d'un générateur.

La puissance (nette) d'une centrale EGS est déterminée par le gradient de température souterrain, la profondeur des forages et l'impédance du réservoir et dépend donc du site. La modélisation de telles installations pour la Suisse donne en moyenne des puissances de l'ordre de 1,5 à 3 MW_{el}, la puissance par triplet peut même atteindre 10 MW_{el} en cas de conditions exceptionnelles. Les installations pourraient être réalisées avec plus d'un triplet dans de tels lieux d'implantation.

Géothermie profonde – EGS		**Nouvelles installations**			
		aujourd'hui	**2020**	**2035**	**2050**
Potentiel[1]	TWh/a	Aucune production d'électricité géothermique en Suisse	NN	NN	~4.5
Emissions de gaz à effet de serre[2,3,4,5]	g éq-CO_2/kWh		27 - 84		
Coûts d'investissement					
Forage	Millions de CHF/forage			18 - 30	15
Stimulation	Millions de CHF/forage			3.3	3.3
Centrale	CHF/kW_{el}			4000	3500
Coûts de la production d'électricité[3,4,6,7] (sans crédits attribués pour l'exploitation des rejets de chaleur)	ct./kWh			16 - 58	13 - 47 (~10)
Coûts de la production d'électricité[3,4,8] (avec crédits attribués pour l'exploitation des rejets de chaleur)	ct./kWh			-3 - 33	-4 - 27

[1] La Stratégie énergétique suisse table sur un objectif de 4 à 5 TWh/a d'ici 2050. L'indication pour 2050 correspond à cet objectif et à un potentiel réaliste à long terme, qui ne peut être concrétisé que si les actuels obstacles économiques, techniques, géologiques, légaux et sociétaux peuvent être surmontés.

[2] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent des facteurs d'influence spécifiques aux sites. A titre de comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh (haute tension).

[3] Ces indications sont les résultats d'un modèle couplé spécifique à la Suisse pour l'évaluation économique et écologique des installations EGS; la variation des paramètres spécifiques aux sites (gradient de température, perméabilité, etc.) est prise en compte. Les fourchettes indiquées pour les coûts de production de l'électricité et les émissions de GES reflètent cette variabilité.

[4] Les coûts de production de l'électricité et les résultats des écobilans dépendent fortement du site. Comme on ne dispose pas encore de valeurs empiriques, seule une estimation grossière de l'évolution future est possible.

[5] Les émissions sont imputées à 100% à l'électricité, car on ignore si les rejets de chaleur peuvent être utilisés à grande échelle.

[6] Les coûts de production de l'électricité sont d'abord indiqués sans les crédits attribués pour l'exploitation des rejets de chaleur, car la plupart des installations EGS ne sont sans doute pas exploitées à proximité de grands consommateurs de chaleur. Plus de détails dans la section dédiée à la géothermie.

[7] En cas de conditions géologiques extrêmement favorables, les coûts de production de l'électricité pourraient se situer autour de 10 ct./kWh.

[8] Les recettes provenant de la vente de chaleur peuvent nettement améliorer la rentabilité des installations EGS (conduire dans le meilleur des cas à des coûts de production négatifs). Plus de détails dans la section dédiée à la géothermie.

Fiche de données – centrales houlomotrices (et marémotrices)

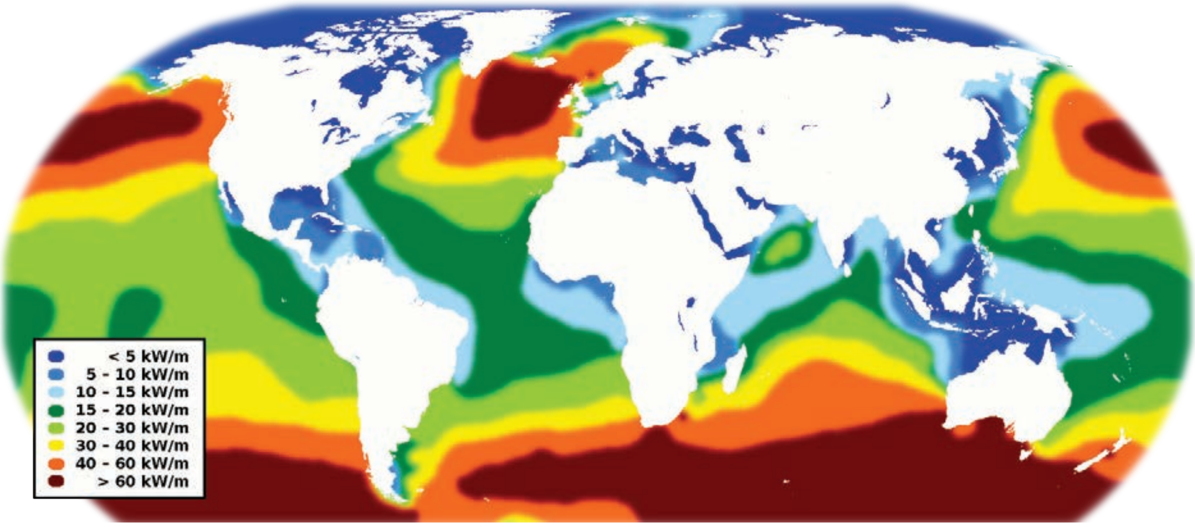
Technologie: le vent qui souffle sur les mers transmet une partie de son énergie aux vagues, et cette énergie peut être utilisée pour produire de l'électricité. C'est ce qui se passe avec les centrales houlomotrices. Les centrales marémotrices peuvent convertir en électricité l'énergie que recèlent les marées. Les centrales houlomotrices peuvent être catégorisées en installations ***onshore*** et ***offshore***.

Centrales houlomotrices. De gauche à droite: *Pelamis*; *SINN*; *Wave roller*; *Atlantis turbine*; *Wave dragon*.

Les centrales houlomotrices et marémotrices en sont encore à une phase de développement relativement précoce; il n'existe que quelques installations de démonstration et expérimentales dans le monde. Le développement se concentrera probablement sur les types *offshore*, car la densité énergétique est plus forte en mer et il y a moins de restrictions, p. ex. pour des raisons visuelles.

Ressources: les lieux avec le plus grand potentiel pour l'énergie houlomotrice sont les côtes occidentales de l'Europe, les côtes septentrionales de la Grande-Bretagne et les côtes du Pacifique en Amérique du Nord et du Sud, de même que le sud de l'Afrique, l'Australie et la Nouvelle-Zélande. Les latitudes Nord et Sud moyennes conviennent le mieux aux centrales houlomotrices. Les vents plus forts permettent de produire plus de courant l'hiver que l'été.

L'électricité produite par les centrales houlomotrices devrait être importée en Suisse, sans doute de la côte atlantique de la France, de l'Espagne et du Portugal.



Carte de la distribution de l'énergie houlomotrice dans le monde.

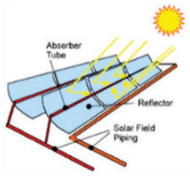
Electricité produite par les centrales houlomotrices et marémotrices			Nouvelles installations			
			aujourd'hui[1]	2020	2035	2050
Potentiel[2]	TWh/a	offshore	NN	30	30	30
		onshore	NN	10-15	10-15	10-15
Coûts d'investissement[3]	CHF/kW	offshore & onshore	4000-9500	3000-7000	2100-5000	1900-3500
Coûts de production de l'électricité[3,4,5]	ct./kWh	offshore & onshore	~38 (23-80)	~30 (14-42)	~17 (9-24)	~11 (8-19)
Coûts d'importation[6]	ct./kWh	~1000 km	NN	~0.5	~0.5	~0.5
Emissions de gaz à effet de serre[7,8]	g éq-CO_2/kWh	Energie houlomotrice	15-105			
		Energie marémotrice	15-70			

[1] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne (au stade de démonstration); les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui.
[2] Production d'électricité sur la côte atlantique avec transport en Suisse.
[3] Les données disponibles ne permettent aucune distinction entre installations *onshore* et *offshore*.
[4] Les coûts de production de l'électricité comprennent les investissements, l'exploitation et l'entretien; les détails sur les coûts figurent dans la section correspondante.
[5] Les fourchettes se fondent sur des indications de la littérature et reflètent des incertitudes concernant le développement futur et les variations du modèle de centrale possible.
[6] Coûts du transport de l'électricité de l'Atlantique jusqu'en Suisse.
[7] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent des différences entre les modèles de centrale possibles. A titre de comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh (haute tension).
[8] Les fourchettes indiquées valent pour une série de modèles de centrale possibles; des estimations plus détaillées sur le développement technologique futur et ses conséquences sur les résultats des écobilans ne sont pas possibles à l'heure actuelle.

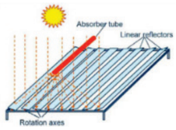
Fiche de données – centrales solaires thermiques
(*concentrated solar power* – CSP)

Technologie: la production d'électricité solaire thermique fonctionne par le biais de la concentration du rayonnement solaire direct pour faire chauffer un fluide caloporteur liquide, gazeux ou solide; celui-ci fait fonctionner un circuit (vapeur) pour produire l'électricité. Il existe des systèmes qui focalisent le rayonnement solaire de façon linéaire et atteignent des températures de 550°C, d'autres qui le focalisent en points avec des températures et des rendements plus élevés. Les centrales solaires thermiques sont exploitées à des endroits où le rayonnement normal direct (DNI) est supérieur à 2000 kWh/m^2/a, ce qui correspond à des latitudes géographiques inférieures à 35-40° (donc pas en Suisse). Un accumulateur d'énergie thermique, qui permet aussi de produire de l'électricité en charge de base, fait, en général, partie des installations. Les dimensions de ces accumulateurs permettent de produire entre une et quinze heures d'électricité avec la chaleur qu'ils contiennent. L'électricité produite dans le bassin méditerranéen pourrait être importée en Suisse par une ligne de transport à haute tension en courant continu avec des pertes relativement faibles (3%/1000 km).

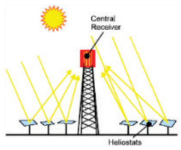
Il existe les technologies CSP suivantes:



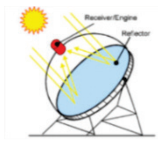
- Miroir cylindro-parabolique (*parabolic trough*, PTC): des miroirs cylindro-paraboliques qui suivent le soleil permettent de concentrer les rayons du soleil sur des tubes. Ceux-ci contiennent un fluide caloporteur qui est chauffé et transmet la chaleur à un circuit de vapeur pour produire de l'électricité.



- Concentrateur de Fresnel (*linear Fresnel reflector*, LFR): le concept est semblable aux miroirs cylindro-paraboliques; la forme parabolique de ses miroirs n'est toutefois qu'imitée, un grand nombre de miroirs plats ou légèrement courbes sont alignés de sorte à concentrer le soleil sur un capteur dirigé vers le bas.



- Récepteur central (power tower, CRS): un grand nombre de miroirs (solar field) concentrent le rayonnement solaire sur un récepteur central monté sur une tour. La chaleur générée fait fonctionner à son tour un circuit de vapeur pour produire de l'électricité.



- Parabole (parabolic dish, PDC): à chaque capteur, la chaleur du rayonnement solaire concentré permet de faire fonctionner un moteur pour produire de l'électricité (moteur Stirling ou microturbine). Ces moteurs se situent dans le foyer du miroir parabolique. Inconvénient: la chaleur ne peut être stockée que de façon limitée.

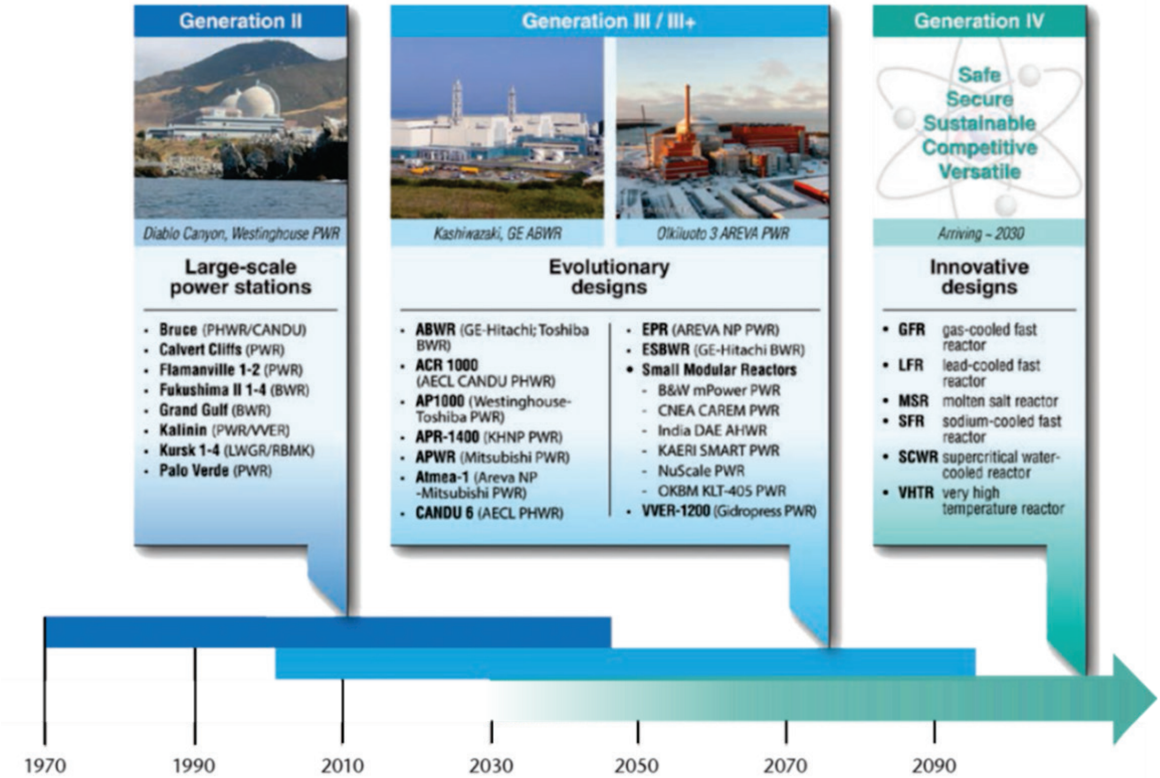
Aujourd'hui, seules quelques centrales solaires thermiques sont en exploitation à titre commercial, surtout en Espagne et aux USA. Les plus grandes installations d'une puissance jusqu'à 750 MW se trouvent aux USA. Les miroirs cylindro-paraboliques et les récepteurs centraux sont les technologies dominantes et les plus développées à l'heure actuelle. Les installations paraboliques ont presque disparu du marché, car elles sont comparativement chères et qu'il est difficile d'intégrer des accumulateurs de chaleur. Le potentiel d'amélioration est important pour les centrales solaires thermiques. Les coûts de production de l'électricité peuvent être diminués grâce à une production de masse et à des centrales de plus grande puissance. Le développement de la technologie nécessitera des mesures de soutien et d'incitation substantielles. Pour pouvoir importer en Suisse de l'électricité produite dans le bassin méditerranéen, il est nécessaire de construire une infrastructure de transport appropriée, avec des câbles courant continu haute tension ou un raccordement à un futur réseau européen élargi.

Centrales solaires thermiques			Nouvelles installations			
			Aujourd'hui[1]	2020	2035	2050
Potentiel	TWh/a	Monde	˜25[2]	31-466	NN	222-9'348
		EUMENA[3]	NN	<99	<660	<1358
		MENA[4]	NN	<69	<490	<1150
Données d'exploitation	Heures de pleine charge par an	(Suisse)	NN	(1250)	(1375)	NN
		Espagne[5] (y c. TES; max. 6400h)	˜5000	˜5500	˜5500	˜5500
		Algérie[6] (y c. TES; max. 8000h)	˜5500	˜6000	˜6000	˜6000
Rendement annuel («solar-to-electricity»)	%	PTC (y c. accumulateur)	13-15	NN	˜19	˜19
		LFR (<10min accumulateur)	9-13	NN	˜12	˜12
		CRS (y c. accumulateur)	14-18	NN	˜18	˜18
		PDC (sans accumulateur)	22-24	NN	NN	NN
Coûts d'investissement[7]	CHF/kW	PTC (sans accumulateur)	3100-8000	3100-8000	3000-5900	2000-5900
		PTC (0,5-8h accumulateur)	3400-12 800			
		CRS (0,5->8h accumulateur)	3400-12 800			
		LFR (0,5-4h accumulateur)	3400-6700			
Coûts de production de l'électricité[8,9]	ct./kWh	Sans accumulateur	16-33	NN	NN	NN
		Avec accumulateur (4-15h)	14-28	6-23	7-11	6-9
Coûts d'importation[10]	ct./kWh		NN	NN	˜2	˜2
Emissions de gaz à effet de serre[11]	g éq-CO_2/ kWh	PTC	13-55	13-55	5-44	5-36
		CRS	9-42	9-42	5-25	5-21
		PDC	5-60	5-60	3-36	3-30

[1] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne; les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui.
[2] Estimation grossière sur la base de la puissance installée.
[3] Europe, Moyen-Orient et Afrique du Nord. Seule une petite partie serait disponible pour la Suisse.
[4] Moyen-Orient et Afrique du Nord. Seule une petite partie serait disponible pour la Suisse.
[5] DNI 2000 kWh/m^2/a; TES=accumulateur d'énergie thermique. Estimation grossière; dans la pratique, les données d'exploitation dépendent des dimensions concrètes de l'installation.
[6] DNI 2500 kWh/m^2/a; TES=accumulateur d'énergie thermique. Estimation grossière; dans la pratique, les données d'exploitation dépendent des dimensions concrètes de l'installation.
[7] Les données disponibles ne permettent aucune différenciation entre les diverses technologies CSP.
[8] Les coûts de production de l'électricité comprennent les investissements, l'exploitation, l'entretien et les coûts du gaz naturel comme combustible supplémentaire. Les fourchettes reflètent les données de la littérature – les détails figurent dans la section correspondante.
[9] Les données disponibles ne permettent aucune différenciation entre les diverses technologies CSP.
[10] Coûts du transport de l'électricité des pays MENA jusqu'en Suisse.
[11] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent les différences entre les modèles de centrale possibles et les incertitudes concernant l'évolution future. A titre de comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh (haute tension).

Fiche de données – énergie nucléaire

Technologie: dans les centrales nucléaires actuelles, l'électricité est produite par la fission d'atomes d'uranium 235; l'U-235 est enrichi dans le combustible, c.-à-d. présent en plus grande proportion que les 0,7% naturels. Une réaction en chaîne est générée au moyen de produits de désintégration et d'un nombre suffisant de neutrons. Il existe de nombreuses variations technologiques: plusieurs cycles de combustible (concernant la substance de départ, le degré d'enrichissement, etc.), différentes méthodes de contrôle des neutrons, plusieurs matériaux en guise de modérateur (eau légère ou lourde, graphite, etc.), différents fluides de refroidissement pour produire de la vapeur (eau, gaz ou sels liquides) et plusieurs configurations de réacteur. Les modèles de réacteur dominants se basent sur l'oxyde d'uranium en tant que combustible, enrichi à 3-5%, l'eau légère comme modérateur pour les neutrons thermiques (*light water reactors*; LWR) et la production de vapeur par évaporation directe de l'eau (réacteurs à eau bouillante) ou sous une pression élevée (réacteurs à eau sous pression). L'illustration suivante montre les générations de réacteur dans le temps, qui se distinguent dans le design et la technologie utilisée. Le développement visait et vise à améliorer la rentabilité et à renforcer la sécurité.



Générations de modèles de réacteur dans le temps (d'après (OECD/NEA/IEA 2015)).

Les réacteurs à eau légère qui dominent le marché peuvent être considérés comme une technologie relativement avancée. Les modèles évolutifs (génération 3+) sont développés dans le but d'une sécurité accrue, mais la compétitivité doit être préservée. Cette évolution comprend aussi une tendance à de petits réacteurs modulaires (*small modular reactors*, SMR) fabriqués en plus grandes quantités et à un coût moindre dans des procédés standardisés. Des estimations de coûts actuelles et fiables sont toutefois rares et grevées d'incertitudes. Les coûts d'investissement spécifiques pour les SMR semblent similaires à ceux des réacteurs actuels et les obstacles à la mise en place d'une ligne de production, sous forme de coûts plus élevés pour les premières installations, sont importants en cas de carnet de commandes incertain. A l'avenir, des réacteurs de quatrième génération pourraient être commercialisés. Selon le type de réacteur, plusieurs modèles promettent une sécurité inhérente, des améliorations en termes de prolifération, moins de déchets radioactifs ou une meilleure exploitation de l'uranium en tant que ressource.

Une série de modèles de réacteur actuels et futurs peuvent être exploités avec du thorium. Au contraire de l'U-235, le thorium n'est pas fissible, c'est une «matière fertile» (comme l'U-238), si bien qu'il est transformé en U-233 dans le réacteur (surgénérateur) et que le cycle du combustible doit être activé au début par un autre matériau fissible ou un accélérateur de neutrons. Par rapport aux combustibles nucléaires actuels, le thorium est disponible en plus grandes quantités, génère moins de déchets radioactifs et est moins fragile en termes de prolifération. Le recours accru au thorium est toutefois limité par son taux de surgénération, et il existe encore des incertitudes techniques et scientifiques.

Ressources: la disponibilité de l'uranium ne sera pas le principal facteur limitant pour l'énergie nucléaire à l'avenir. L'exploitation des réserves d'uranium avérées avec les réacteurs actuels pourrait restreindre une croissance potentielle de l'énergie nucléaire à l'échelle mondiale au siècle prochain; il existe néanmoins d'autres cycles de combustible, modèles de réacteur, méthodes d'enrichissement et sources de combustible (p. ex. l'uranium extrait de l'eau de mer), ce qui signifie que les facteurs limitants relèveront plutôt des domaines de la compétitivité, de l'acceptation, de la prolifération et de la sécurité.

Energie nucléaire		**Aujourd'hui** Centrales existantes en Suisse	**«Nouvelles installations»[1]** (hypothétiques nouveaux réacteurs Gen III/III+)	**2035** (SMR[6])	**2050** (Gen IV)
Potentiel[2]	TWh/a	Non applicable			
Coûts d'investissement[3]	CHF/kW	1300-6000	4000-7000	3000-9000	pas de données
Coûts de production de l'électricité[4]	ct./kWh	4-6 [7]	7.5 (5.1 - 12.5)	7.4 (5.1 - 12.2)	pas de données
Emissions de gaz à effet de serre[5]	g éq-CO_2/kWh	10-20	10-20	5-40	

[1] «Nouvelles installations» se réfère ici à des centrales dont la planification serait engagée aujourd'hui. Après l'acception par le Peuple suisse le 25 mai 2017 de la stratégie énergétique 2050, la construction nouvelles centrales nucléaires est, d'après la loi sur l'énergie nucléaire révisée, interdite.
[2] Guère limité techniquement; déterminé par des considérations économiques et des questions d'acceptation.
[3] *Overnight capital costs*. La fourchette pour les centrales exploitées à l'heure actuelle comprend les mises à niveau réalisées jusqu'ici. Les coûts d'investissement pour d'hypothétiques nouvelles centrales valent pour les modèles actuels (Gen III/III+), construites en Suisse. Ceux pour 2035 valent pour les SMR; les coûts des réacteurs Gen III/III+ seraient aussi applicables à 2035. La plus grande fourchette pour les SMR résulte de plus grandes incertitudes. Les coûts des modèles Gen IV en 2050 ne peuvent pas être estimés correctement aujourd'hui faute de données exploitables et en raison d'incertitudes importantes.
[4] Comprennent les coûts d'investissement, d'exploitation, d'entretien, de démantèlement et d'élimination des déchets. Les fourchettes pour «aujourd'hui» et 2035 se fondent sur des analyses de sensibilité où les principaux facteurs de coûts varient de 50 à 200% par rapport aux valeurs de départ. De plus amples détails figurent dans la section dédiée. Les valeurs centrales («cas de base») et les limites inférieures et supérieures des domaines calculés sont indiquées pour les réacteurs Gen III/III+ et SMR.
[5] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent la variabilité possible des données d'inventaire de la chaîne nucléaire suisse. A titre de comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh (haute tension). Les chiffres pour 2035 et 2050 ne sont que des estimations grossières, car les résultats des écobilans sont limités; il n'y a pas de résultats exploitables pour les modèles Gen IV.
[6] *Small modular reactors*.
[7] Pour les coûts de production d'électricité des centrales exploitées à l'heure actuelle, les coûts de capital sont en grande partie amortis, les coûts de l'électricité tirés des rapports annuels de KKG et KKL.

Fiche de données – centrales au gaz naturel et à charbon

Technologie: le gaz naturel peut être utilisé dans de grandes centrales à gaz à cycle combiné (GuD) et de petites centrales décentralisées à couplage chaleur-force (CCF) pour produire de l'électricité. La puissance des installations varie entre 1 kW_{el} et quelques centaines de MW_{el}. L'électricité est produite à partir de houille et de lignite dans de grandes centrales d'une puissance allant jusqu'au GW_{el}. La capture, l'utilisation et/ou le stockage géologique du CO_2 (*carbon capture, utilization and storage* CCUS) pour les grandes centrales à gaz et à charbon en sont aujourd'hui au stade expérimental et de la recherche. Les technologies des centrales en sont à un stade de développement avancé; les futures améliorations visent à augmenter les rendements et à réduire les émissions polluantes.

Abréviations

NGCC – GuD	Natural gas combined cycle – centrale à gaz à cycle combiné
NGCC post	Centrale GuD avec capture du CO_2 «post-combustion»
NGCC pre	Centrale GuD avec capture du CO_2 «pre-combustion»
NG-Turbine	Turbine à gaz naturel
CCF 1kW_{el}	CCF au gaz naturel avec moteur à piston 1 kW_{el}
CCF 10kW_{el}	CCF au gaz naturel avec moteur à piston 10 kW_{el}
CCF 100kW_{el}	CCF au gaz naturel avec moteur à piston 100 kW_{el}
CCF 1000kW_{el}	CCF au gaz naturel avec moteur à piston 1000 kW_{el}
IGCC hard coal	Centrale GuD à la houille avec gazéification du charbon intégrée
IGCC hard coal pre	Centrale GuD à la houille avec gazéification du charbon intégrée et capture du CO_2 «pre-combustion»
SCPC hard coal	Centrale à la houille supercritique
SCPC hard coal post	Centrale à la houille supercritique avec capture du CO_2 «post-combustion»
SCPC hard coal oxy	Centrale à la houille supercritique avec capture du CO_2 «oxyfuel combustion»
IGCC lignite	Centrale GuD au lignite avec gazéification du charbon intégrée
IGCC lignite pre	Centrale GuD au lignite avec gazéification du charbon intégrée et capture du CO_2 «pre-combustion»
SCPC lignite	Centrale au lignite supercritique
SCPC lignite oxy	Centrale au lignite supercritique avec capture du CO_2 «oxyfuel combustion»
SCFBC lignite	Centrale au lignite avec combustion en lit fluidisé supercritique
FBC lignite post	Centrale au lignite avec combustion en lit fluidisé supercritique, capture du CO_2 «post-combustion»

Notes du tableau

[1] Sont pris en compte les coûts d'investissement, de combustible, d'élimination, d'entretien et d'exploitation. Les fourchettes reflètent une spécification et un développement optimiste et pessimiste de la technologie et l'évolution supposée des coûts par rapport à aujourd'hui.

[2] D'après le tableau 4.3: prix du gaz naturel pour les ménages et l'industrie suisses; prix du charbon pour l'industrie.

[3] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent les disparités dans les paramètres des centrales et les possibles développements futurs. A titre de comparaison: le mix d'approvisionnement actuel de la Suisse (y c. importations) présente une intensité de GES de près de 90 g éq-CO_2/kWh (haute tension).

[4] Pour les CCF, les émissions sont réparties grâce à la teneur en exergie de l'électricité et de la chaleur.

[5] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne; les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui.

[6] La production et les importations d'électricité sont surtout limitées techniquement par les capacités d'importation de gaz naturel ou d'électricité; dans la pratique, les facteurs économiques, écologiques et sociétaux jouent principalement un rôle.

Electricité à partir de gaz naturel et de charbon		**Nouvelles installations**			
		aujourd'hui[5]	**2020**	**2035**	**2050**
Potentiel	TWh/a	1.6	NN[6]		
Coûts de production de l'électricité[1] (avec crédits attribués pour l'exploitation des rejets de chaleur pour les CCF) (ct./kWh_{el})	GuD	11.3 (10.8 - 12.3)	11.7 (11.1 - 12.6)	13.4 (12.9 - 14.2)	15.2 (14.5 - 16.0)
	GuD post	14.1 (13.0 - 15.8)	14.4 (13.4 - 16.1)	16.3 (15.3 - 17.7)	18.4 (17.3 - 19.8)
	GuD pre	14.2 (13.3 - 16.0)	14.3 (13.4 - 16.0)	16.1 (15.3 - 17.6)	18.1 (17.3 - 19.6)
	NG-Turbine	18.5 (16.8 - 20.9)	19.6 (17.9 - 22.0)	21.3 (19.6 - 23.8)	23.6 (21.8 - 26.1)
	CCF 1kW_{el}	71.8 (50.2 - 114.6)	70.6 (49.5 - 112.5)	67.0 (47.4 - 106.0)	65.6 (46.9 - 103.1)
	CCF 10kW_{el}	29.6 (22.2 - 45.3)	29.5 (22.2 - 45.6)	29.5 (22.5 - 44.8)	30.2 (23.4 - 45.3)
	CCF 100kW_{el}	14.2 (9.6 - 19.2)	14.9 (9.6 - 20.4)	16.5 (11.1 - 21.9)	18.3 (12.7 - 23.9)
	CCF 1000kW_{el}	12.0 (9.9 - 14.6)	12.7 (10.4 - 15.7)	14.5 (12.1 - 17.4)	16.6 (14.0 - 19.6)
	IGCC hard coal	7.1 (6.5 - 8.3)	7.2 (6.6 - 8.4)	7.5 (6.9 - 8.7)	7.7 (7.3 - 8.9)
	IGCC hard coal pre	9.5 (8.3 - 11.2)	9.3 (8.2 - 10.9)	9.0 (8.2 - 10.3)	9.4 (8.5 - 10.6)
	SCPC hard coal	5.5 (5.2 - 5.9)	5.7 (5.4 - 6.1)	6.3 (5.9 - 6.7)	6.8 (6.5 - 7.3)
	SCPC hard coal post	8.5 (7.6 - 9.6)	8.3 (7.5 - 9.3)	8.8 (8.0 - 9.7)	9.4 (8.6 - 10.3)
	SCPC hard coal oxy	8.5 (7.1 - 10.2)	8.5 (7.2 - 10.1)	8.6 (7.5 - 10.0)	8.9 (8.0 - 10.1)
	IGCC lignite	6.6 (5.6 - 7.6)	6.5 (5.6 - 7.5)	6.8 (5.8 - 7.7)	7.1 (6.1 - 8.0)
	IGCC lignite pre	8.6 (7.3 - 10.1)	8.4 (7.2 - 9.9)	8.6 (7.4 - 10.1)	9.0 (7.7 - 10.4)
	SCPC lignite	4.6 (4.0 - 5.6)	4.7 (4.1 - 5.6)	4.8 (4.2 - 5.8)	5.1 (4.4 - 6.0)
	SCPC lignite oxy	8.9 (7.4 - 10.6)	8.6 (7.1 - 10.5)	7.4 (6.3 - 10.4)	6.6 (5.5 - 10.4)
	SCFBC lignite	4.5 (3.9 - 5.3)	4.6 (4.0 - 5.4)	4.8 (4.3 - 5.6)	5.1 (4.6 - 5.9)
	FBC lignite post	7.7 (6.6 - 9.2)	7.8 (6.7 - 9.3)	8.0 (6.8 - 9.6)	8.3 (7.0 - 10.0)
Coûts de production de l'électricité[1] (sans crédits attribués pour l'exploitation des rejets de chaleur pour les CCF) (ct./kWh_{el})	CCF 1kW_{el}	93.2 (72.7 - 131.5)	92.4 (72.4 - 129.6)	91.6 (73-1 - 125.8)	89.3 (71.9 - 121.6)
	CCF 10kW_{el}	48.8 (40.3 - 63.3)	49.1 (40.7 - 63.3)	51.5 (43.5 - 65.0)	51.3 (43.5 - 64.3)
	CCF 100kW_{el}	22.3 (19.2 - 26.2)	22.2 (19.2 - 26.5)	25.4 (22.3 - 29.6)	26.2 (23.2 - 30.3)
	CCF 1000kW_{el}	17.1 (15.5 - 19.3)	17.1 (15.5 - 19.2)	20.1 (18.4 - 22.2)	21.0 (19.3 - 23.1)
Coûts du combustible: gaz naturel[2] (CHF/MWh)	CCF 1 kW_{el}, 10 kW_{el}	84	87	103	110
	Autres technologies	56	58	75	82
Coûts du combustible: houille / lignite[2] (CHF/MWh)	Toutes les technologies	13/6	18/8	20/9	22/10
Emissions de gaz à effet de serre[3,4] (g éq-CO_2/kWh_{el})	GuD	393 (387 - 400)	380 (374 - 386)	365 (359 - 371)	357 (346 - 363)
	GuD post	104 (94 - 114)	99 (90 - 109)	90 (81 - 103)	83 (75 - 100)
	GuD pre	97 (81 - 120)	91 (76 - 112)	86 (72 - 107)	83 (70 - 103)
	NG-Turbine	570 (556 - 585)	570 (556 - 584)	520 (509 - 533)	500 (489 - 511)
	CCF 1kW_{el}	643 (611 - 677)	636 (605 - 670)	618 (589 - 648)	606 (578 - 635)
	CCF 10kW_{el}	611 (583 - 633)	605 (575 - 632)	586 (558 - 613)	575 (546 - 601)
	CCF 100kW_{el}	506 (476 - 529)	500 (464 - 530)	482 (448 - 511)	474 (441 - 503)
	CCF 1000kW_{el}	481 (459 - 500)	473 (450 - 498)	452 (429 - 476)	445 (423 - 468)
	IGCC hard coal	841 (823 - 860)	820 (803 - 838)	807 (790 - 824)	748 (734 - 764)
	IGCC hard coal pre	205 (177 - 255)	190 (164 - 237)	172 (148 - 213)	156 (135 - 194)
	SCPC hard coal	845 (827 - 864)	825 (807 - 843)	803 (786 - 820)	785 (768 - 801)
	SCPC hard coal post	240 (223 - 268)	229 (214 - 256)	204 (181 - 234)	181 (159 - 214)
	SCPC hard coal oxy	158 (123 - 215)	153 (119 - 208)	145 (113 - 197)	137 (106 - 187)
	IGCC lignite	912 (892 - 934)	871 (852 - 891)	842 (824 - 861)	832 (815 - 850)
	IGCC lignite pre	128 (103 - 178)	121 (94 - 170)	109 (85 - 154)	107 (83 - 151)
	SCPC lignite	965 (942 - 1022)	929 (902 - 980)	837 (803 - 874)	801 (785 - 835)
	SCPC lignite oxy	83 (43 - 152)	79 (38 - 149)	71 (33 - 133)	67 (34 - 122)

Fiche de données – piles à combustible

Technologie: les piles à combustible sous revue produisent électrochimiquement de l'électricité et de la chaleur à partir de méthane (gaz naturel ou biogaz). Les systèmes fonctionnant à l'hydrogène comme combustible sont équipés d'un reformeur afin de produire de l'hydrogène sur place à partir de gaz naturel. Les puissances des systèmes de piles à combustible peuvent fortement varier, de moins de 1 kW_{el} à des centaines de kW_{el}. Des piles à combustible très flexibles sont en service, présentant des rendements élevés à charge partielle; selon le type de pile à combustible, les temps de démarrage varient entre la minute et les heures.

Les piles à combustible sont disponibles sur le marché. Mais la plupart des installations dépendent de mesures du soutien dans le cadre de projets de démonstration. On suppose que les coûts d'investissement diminueront à l'avenir et que les durées de vie et les rendements augmenteront de manière substantielle.

Electricité à partir de piles à combustible			**Nouvelles installations**			
			aujourd'hui[1]	**2020**	**2035**	**2050**
Potentiel[2]	TWh/a		<0.01	~1.2	~6.1	~7.9
Coûts de production de l'électricité[3,4] (avec crédits attribués pour l'exploitation des rejets de chaleur)	ct./kWh	PEFC 1 kW_{el}	96 (65 - 125)	37 - 95	24 - 64	20 - 46
		SOFC 1 kW_{el}	96 (65 - 124)	35 - 98	23 - 60	19 - 44
		SOFC 300 kW_{el}	54 (40 - 70)	24 - 57	15 - 37	14 - 23
		MCFC 300 kW_{el}	23 (17 - 32)	15 - 30	16 - 31	14 - 24
		PAFC 300 kW_{el}	22 (17 - 32)	14 - 29	14 - 22	13 - 20
Coûts de production de l'électricité[3,4] (sans crédits attribués pour l'exploitation des rejets de chaleur)	ct./kWh	PEFC 1 kW_{el}	108 (77 - 136)	49 - 106	36 - 75	30 - 57
		SOFC 1 kW_{el}	107 (76 - 134)	46 - 108	33 - 70	29 - 53
		SOFC 300 kW_{el}	58 (44 - 73)	27 - 60	18 - 39	17 - 25
		MCFC 300 kW_{el}	29 (23 - 37)	20 - 35	21 - 35	18 - 27
		PAFC 300 kW_{el}	29 (24 - 38)	21 - 35	22 - 30	21 - 28
Coûts du combustible: gaz naturel	CHF/MWh	1 kW_{el} / 300 kW_{el}[9]	84/56	87/58	103/75	110/82
Coûts du combustible: biogaz	CHF/MWh	1 kW_{el} / 300 kW_{el}[9]	159/131	162/133	178/150	185/157
Emissions de gaz à effet de serre[5,6,8]	g éq-CO_2/kWh	PEFC 1 kW_{el}	690 (590 - 780)	540 - 700	490 - 620	450 - 570
		SOFC 1 kW_{el}	610 (560 - 670)	520 - 630	480 - 560	440 - 520
		SOFC 300 kW_{el}	490 (360 - 540)	340 - 500	350 - 440	340 - 420
		MCFC 300 kW_{el}	560 (370 - 610)	360 - 580	380 - 490	360 - 450
		PAFC 300 kW_{el}	590 (500 - 650)	480 - 620	460 - 580	440 - 550
Emissions de gaz à effet de serre[5,7,8]	g éq-CO_2/kWh	PEFC 1 kW_{el}	440 (350 - 530)	330 - 470	320 - 430	300 - 410
		SOFC 1 kW_{el}	430 (350 - 520)	330 - 470	310 - 420	300 - 390
		SOFC 300 kW_{el}	390 (330 - 460)	310 - 420	300 - 380	290 - 370
		MCFC 300 kW_{el}	410 (340 - 490)	320 - 450	310 - 400	290 - 370
		PAFC 300 kW_{el}	410 (340 - 500)	320 - 460	310 - 420	300 - 400

[1] «Aujourd'hui» se réfère aux informations disponibles à l'heure actuelle et à une technologie moderne; les coûts de production de l'électricité se réfèrent à des nouvelles centrales construites aujourd'hui.

[2] Guère limité techniquement; estimation valable pour le remplacement des chauffages à mazout et à gaz actuels dans les ménages.

[3] Sont pris en compte les coûts d'investissement, de combustible, d'élimination, d'entretien et d'exploitation. Les fourchettes reflètent une spécification et un développement optimiste et pessimiste de la technologie et l'évolution supposée des coûts par rapport à aujourd'hui.

[4] Les résultats sont valables pour le gaz naturel comme combustible. Les coûts augmentent de 8 à 14 ct./kWh avec le biogaz.

[5] Les émissions de gaz à effet de serre figurent ici comme indicateur principal de l'impact environnemental; la section dédiée à la technologie comprend d'autres indicateurs. Tous les indicateurs sont calculés par des écobilans. Les fourchettes indiquées reflètent les disparités dans les spécifications des différents types de piles à combustible et les possibles développements futurs. A titre de comparaison: le mix d'approvisionnement

actuel de la Suisse (y c. importations) présente une intensité de GES de près de 100 g éq-CO_2/kWh (basse tension).
[6] Les émissions sont réparties grâce à la teneur en exergie de l'électricité et de la chaleur.
[7] Emissions de gaz à effet de serre calculées avec une extension du système: les émissions de la quantité de chaleur correspondante d'un chauffage au gaz sont déduites des émissions globales des piles à combustible.
[8] On ne dispose pas des émissions de gaz à effet de serre pour l'exploitation au biogaz.
[9] D'après le tableau 4.3: prix du gaz naturel pour les ménages et l'industrie suisses; majoration de 75 CHF/MWh pour le biométhane.

3.6 Comparaison avec des études antérieures

3.6.1 Cadre de l'étude et démarche

Par rapport à l'étude précédente (Hirschberg, Bauer et al. 2005), le cadre de la présente analyse est nettement plus large:

- Plusieurs autres technologies sont prises en compte: grande hydraulique, centrales à cycle combiné au gaz naturel, CCF au gaz naturel et piles à combustible, centrales au gaz naturel et à charbon avec capture du CO_2 et nouvelles technologies.
- La présente analyse comprend une évaluation de l'impact environnemental de la production d'électricité, c.-à-d. les résultats des écobilans.
- Dans la mesure du possible, des fourchettes spécifiques à la Suisse sont indiquées pour les coûts de production de l'électricité et l'impact environnemental, de manière cohérente pour toutes les technologies.
- La sensibilité des coûts de production de l'électricité est analysée de manière largement cohérente pour toutes les technologies.
- L'évaluation des technologies est réalisée d'une façon plus systématique, globale et transparente; cela concerne la différenciation des différentes technologies, les références tirées de la littérature, les données et les hypothèses.
- L'étude a été soumise à une évaluation détaillée par des experts des offices fédéraux, de l'industrie et des institutions académiques.
- Les résultats – potentiels, coûts de production de l'électricité et impact environnemental – sont présentés dans le contexte d'autres études nationales et internationales.

3.6.2 Potentiels et coûts de production de l'électricité

Les coûts de production de l'électricité et les potentiels déterminés dans la présente étude peuvent être comparés avec les résultats des études antérieures (Figure 3.8 et Figure 3.9). La base en est (Hirschberg, Bauer et al. 2005, Hirschberg, Bauer et al. 2010, Densing, Hirschberg et al. 2014, Densing, Panos et al. 2016): les potentiels maximaux pour la production d'électricité[111] et les coûts de production d'électricité en 2050 sont utilisés en l'espèce. Les technologies et leurs applications ne sont pas toujours spécifiées concrètement dans les différentes études. S'agissant des potentiels, seuls peuvent être comparés la force hydraulique, la biomasse, la géothermie, l'éolien et le photovoltaïque, car ces études ne contiennent sinon pas de chiffres cohérents. Quant aux coûts de production de l'électricité en 2050, seules les installations photovoltaïques, les éoliennes, les centrales à cycle combiné au gaz naturel et les centrales nucléaires peuvent être comparées – il manque les coûts de production des autres technologies et des combustibles dans les autres études.

L'estimation du potentiel de la force hydraulique dans la présente étude comprend la grande et la petite hydraulique; on ne sait pas si c'est aussi le cas des autres études ou si elles ne se réfèrent qu'à la grande hydraulique. Les valeurs comparativement faibles (Barmettler, Beglinger et al. 2013, Teske and Heiligtag 2013) s'expliquent par des restrictions écologiques. Les différents potentiels de l'électricité à partir de biomasse sont

[111] Des valeurs cohérentes d'études comparatives ne sont disponibles que pour la force hydraulique, la biomasse, le photovoltaïque, l'éolien et la géothermie. Elles sont valables pour le «potentiel accepté sur le plan économique et sociétal» des différentes technologies.

une conséquence de la disparité des sources de données primaires, des hypothèses différentes s'agissant des technologies de conversion et de l'utilisation alternative de la biomasse (pour la chaleur utile et la circulation routière). (Hirschberg, Bauer et al. 2005) ne comprend pas les potentiels de la grande hydraulique et de la biomasse. Les potentiels de l'électricité éolienne sont assez semblables dans toutes les études, car la plupart des estimations reposent sur la même source. Pour l'électricité produite par les centrales géothermiques, la plupart des études (dont celle-ci) se réfèrent à l'objectif à long terme formulé par la Confédération, mais cette quantité d'électricité géothermique ne peut être réalisée que si les obstacles actuels et les incertitudes concernant les aspects géologiques, sociétaux, législatifs et économiques peuvent être levés. Les plus grandes disparités entre les études résident dans les potentiels du photovoltaïque, mais on ignore quelles études ne tiennent compte que des installations photovoltaïques sur toiture et lesquelles se concentrent sur les façades.[112]

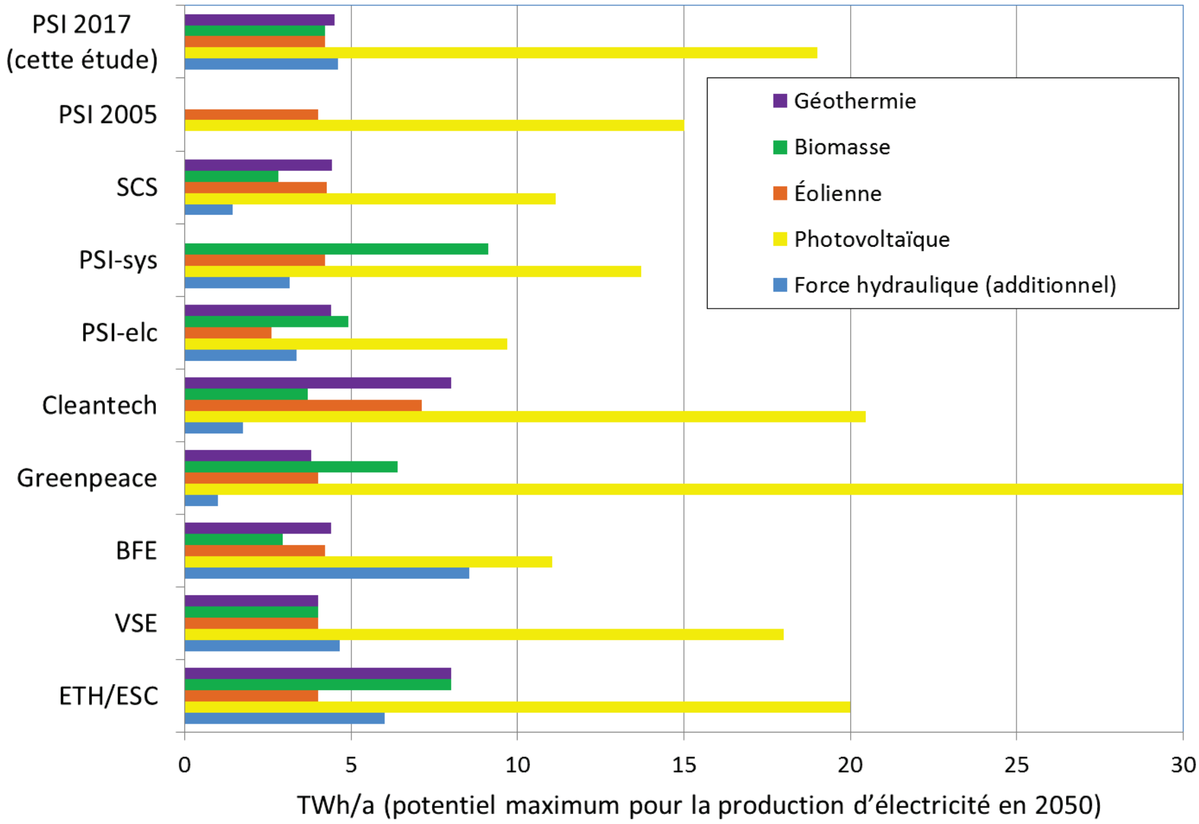


Figure 3.8: Potentiels maximaux pour la production d'électricité avec différentes technologies en Suisse en 2050, selon diverses études. On ne dispose pas de données cohérentes pour d'autres technologies. Pour la force hydraulique, seule est représentée la production supplémentaire par rapport à la production possible à l'heure actuelle; pour toutes les autres technologies, les barres portent sur la production actuelle. ETH/ESC: (Andersson, Boulouchos et al. 2011); AES: (VSE 2012); OFEN: (Prognos 2012a); Greenpeace: (Teske and Heiligtag 2013); Cleantech: (Barmettler, Beglinger et al. 2013); PSI-elc: (Kannan and Turton 2012b, Kannan and Turton 2012a); PSI-sys: (Weidmann 2013); SCS: (SCS 2013); PSI 2005: seuls les potentiels de l'éolien et du photovoltaïque ont été estimés pour 2050 (Hirschberg, Bauer et al. 2005); PSI 2010: (Hirschberg, Bauer et al. 2010); «PSI 2017» ne comprend que les installations sur toiture pour le photovoltaïque.

[112] Le potentiel des installations sur toiture déterminé dans la présente étude est exposé dans cette comparaison.

Une comparaison plus précise avec (Hirschberg, Bauer et al. 2005) montre que le potentiel de la petite hydraulique se révèle un peu plus faible dans la présente étude. Le potentiel éolien reste pratiquement inchangé, car il n’y a pas de nouvelles estimations. Le potentiel photovoltaïque bénéficie d’une estimation plus élevée dans la présente étude, car il existe une nouvelle estimation concernant la surface en toiture durablement disponible et tenant compte des futurs développements technologiques. Les nouvelles estimations pour l’importation de l’électricité issue des centrales solaires thermiques et des centrales houlomotrices sont un peu plus élevées, mais elles restent dans le même ordre de grandeur.

La comparaison entre les coûts de production de l’électricité déterminés dans la présente étude pour 2050 et ceux des autres études révèle que la fourchette pour le photovoltaïque est la plus grande dans la présente étude; et ce notamment parce qu’elle tient compte d’une très large gamme de puissances et que l’électricité issue des petites installations est nettement plus chère que celle produite par les grandes installations; de plus, la présente étude prend en compte la variabilité possible en Suisse dans le rendement annuel. Les coûts de l’électricité photovoltaïque chiffrés par la plupart des autres études se situent dans cette nouvelle fourchette. Les coûts de production de l’électricité pour les éoliennes, recalculés dans la présente étude, sont dans la fourchette de coûts prévus par les autres études. En comparaison, les coûts de l’électricité calculés dans ce cadre pour les centrales à cycle combiné au gaz naturel sont relativement élevés, ce qui semble principalement dû aux prix du gaz présumés.

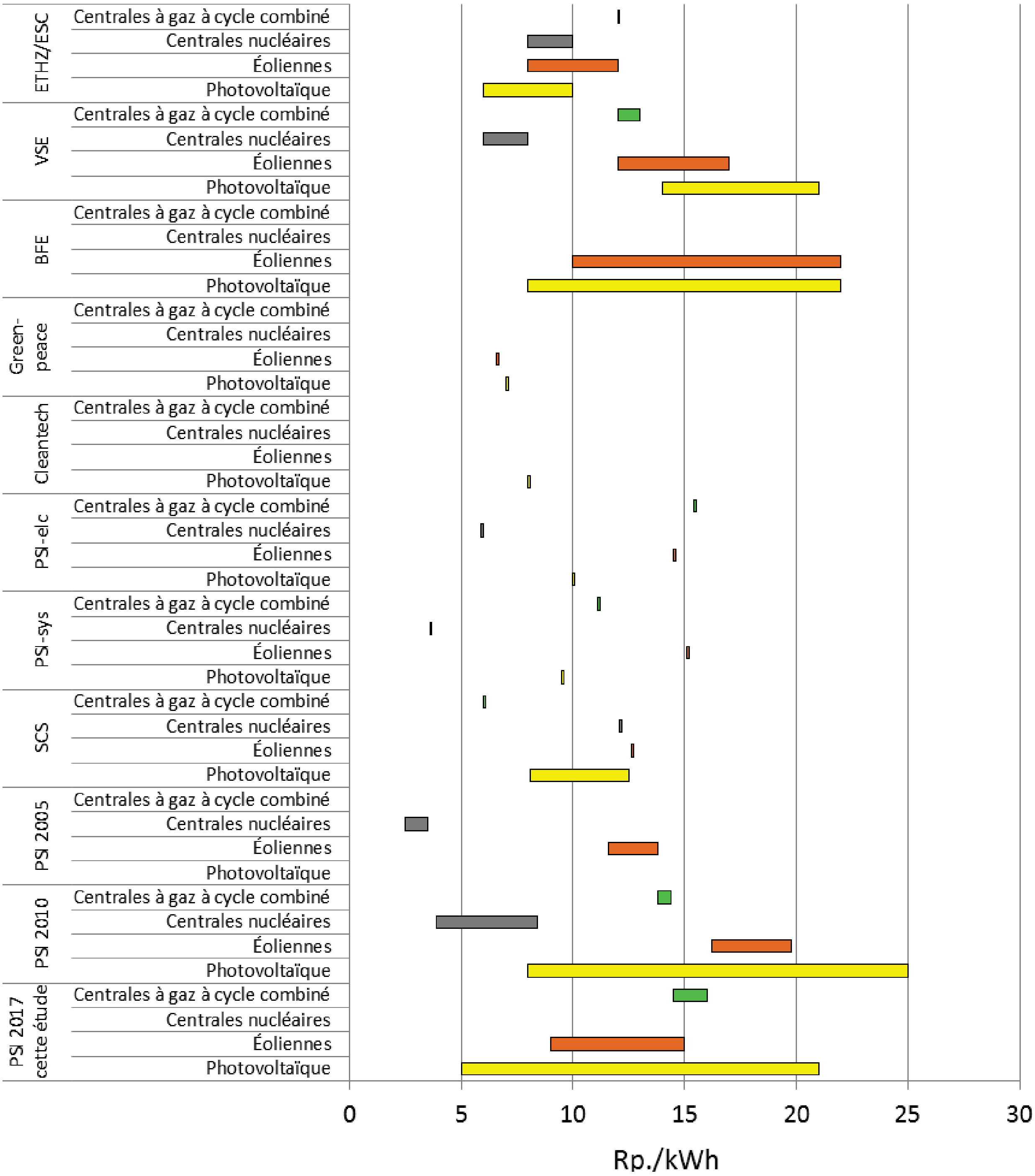


Figure 3.9: Coûts de production de l'électricité en 2050 selon diverses études. ETH/ESC: (Andersson, Boulouchos et al. 2011); AES: (VSE 2012); OFEN: (Prognos 2012a); Greenpeace: (Teske and Heiligtag 2013); Cleantech: (Barmettler, Beglinger et al. 2013); PSI-elc: (Kannan and Turton 2012b, Kannan and Turton 2012a); PSI-sys: (Weidmann 2013); SCS: (SCS 2013); PSI 2005: (Hirschberg, Bauer et al. 2005); PSI 2010: (Hirschberg, Bauer et al. 2010); NN: aucune donnée disponible.

Une comparaison plus précise avec (Hirschberg, Bauer et al. 2005) montre que les coûts de production de l'électricité estimés pour 2050 pour les petites centrales hydrauliques ont quelque peu augmenté. Les nouveaux coûts de production pour le photovoltaïque sont nettement plus bas, ce qui reflète la baisse drastique des prix des installations photovoltaïques ces dernières années. Les nouveaux coûts de production de l'électricité éolienne sont similaires à ceux prévus par (Hirschberg, Bauer et al. 2005), tandis que ceux estimés pour l'énergie nucléaire ont augmenté, tout comme pour l'électricité issue des centrales géothermiques. Les nouvelles estimations des coûts de l'électricité produite par les centrales solaires thermiques sont plus faibles. Toutes les autres technologies évaluées dans la présente étude ne sont pas comprises dans (Hirschberg, Bauer et al. 2005). De manière générale, la comparaison des coûts de production de l'électricité à l'aune de diverses études montre très clairement l'importance élémentaire d'une présentation transparente et compréhensible des données et des calculs.

3.7 Besoins de la recherche, perspectives et recommandations

Malgré la littérature abondante qui sert de base à la présente étude et même si une grande équipe de chercheurs aux horizons et à l'expertise variés a contribué à cette analyse, certaines questions restent en suspens, importantes dans le cadre de l'approvisionnement et de la politique énergétiques de la Suisse:

- **Courbes coûts-potentiel:** les informations et données disponibles sur les coûts et potentiels de la production d'électricité en Suisse ne permettent pas de chiffrer les coûts de production de l'électricité par rapport à la possible production annuelle supplémentaire. Ce serait souhaitable pour les technologies pour lesquelles le site, les conditions-cadres et le type d'agent énergétique jouent un rôle important pour les coûts de production; parmi ces technologies, il y a la force hydraulique[113], les centrales à cycle combiné au gaz naturel intégrées aux bâtiments et les piles à combustible, les éoliennes, les installations photovoltaïques, les centrales géothermiques et les installations de conversion de la biomasse en électricité. Les coûts de production de l'électricité pour toutes ces technologies peuvent (fortement) fluctuer dans le cadre des potentiels déterminés et les moyennes et fourchettes indiquées dans la présente étude pour les coûts de revient de l'électricité ne sont pas toujours pertinentes.
- **Données sur les coûts spécifiques pour la Suisse**: en Suisse, les prix sont d'ordinaire plus élevés que dans les pays voisins, ou en Europe de manière générale, et sur le marché international. Cela a une influence sur les coûts de revient de l'électricité, car les prix de l'infrastructure des centrales sont plus élevés dans notre pays. Les données disponibles sur les coûts et les prix ne se réfèrent souvent pas à la Suisse, mais doivent être utilisées faute d'alternatives. Dans cette étude, ce facteur n'a pu être pris en compte qu'à un certain point – principalement sous forme d'analyses de sensibilité sur les coûts de revient de l'électricité.
- **Aspects systémiques et stockage de l'électricité**: cette évaluation se réfère exclusivement à certaines technologies. S'agissant des coûts et des aspects environnementaux de l'approvisionnement en électricité et en énergie, il faudrait examiner et évaluer l'ensemble du système pour obtenir des conclusions pertinentes. Cela concerne par exemple des facteurs tels que les variations journalières et annuelles de la production d'électricité de certaines technologies par rapport à la consommation, la répartition géographique de la production et de la consommation d'électricité en Suisse, les extensions éventuellement nécessaires du réseau électrique ou le stockage potentiel de l'électricité. De tels aspects doivent être analysés à l'aide de modèles portant sur l'ensemble du système électrique ou énergétique.

[113] Une telle courbe est disponible pour les grandes centrales hydrauliques, voir la section 6.

- **Aspects environnementaux**: conformément au mandat de l'OFEN, l'impact environnemental de la production d'électricité a été déterminé en grande partie à l'aide des données d'inventaire des écobilans disponibles. Certains résultats ne sont par conséquent plus tout à fait actuels; certaines lacunes dans les données d'inventaire et certaines incohérences étaient inévitables. Cela concerne surtout les futures technologies, qui ne peuvent être évaluées globalement à l'heure actuelle faute de données d'inventaire cohérentes.

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4 Preface and introduction

On behalf of the Swiss Federal Office of Energy (SFOE), a core team of researchers at the Paul Scherrer Institute (PSI), supported by individual authors from the Swiss Federal Institute for Forest, Snow and Landscape Research (WSL), and Swiss Federal Institutes of Technology in Zurich (ETHZ) and Lausanne (EPFL), carried out an update and extension of the previous PSI-study "New renewable energies and nuclear power plants: Potentials and Costs" ("Neue erneuerbare Energien und Nuklearanlagen: Potenziale und Kosten" (Hirschberg, Bauer et al. 2005). The current report is simultaneously a contribution to the ongoing research activities within the two Swiss Competence Centers for Energy Research (SCCER) "Supply of Electricity" (SoE)" [114] and "Biomass for Swiss Energy Future (BIOSWEET)"[115]. The analysis will serve the purpose of technology monitoring by the SFOE and the results will be used as technology performance input to the upcoming Swiss energy perspectives.

The majority of PSI authors belong to the Laboratory for Energy Systems Analysis (LEA)[116]. Biomass related contributions are from authors from the Thermal Processes and Combustion Laboratory (LTV)[117] with additional contributions from WSL, concentrated solar power related ones from the Solar Technology Laboratory (LST)[118]. Draft versions of this report were reviewed by various experts at or associated with SFOE, and by researchers from ETHZ, EPFL and University of Applied Sciences and Arts Northwestern Switzerland (FHNW).

4.1 Goal and scope

The main goal of this work was a comprehensive update and extension of technology-specific potentials and costs of electricity generation in Switzerland as a follow-up of PSI's previous corresponding study (Hirschberg, Bauer et al. 2005). This includes the evaluation of selected technologies that potentially could contribute to the Swiss supply through electricity imports from the European neighborhood. In addition, environmental aspects of these power generation technologies were investigated. Potentials, costs and environmental aspects are quantified for today, 2020, 2035 and 2050, which facilitates using these data within the Swiss energy perspectives and the federal technology monitoring. Future technology performance and associated potentials, costs and environmental burdens were estimated based on PSI's experience from relevant recent and current projects as well as use of learning curves, expert consultations and literature. Depending on the technologies, uncertainties in these estimates can be substantial – as far as reasonable, these uncertainties are reflected by the provided ranges of potentials, costs and environmental burdens.

The following technologies are included in this report:

- Large hydropower (LHP)
- Small hydropower (SHP)
- Wind power (onshore and offshore)

[114] http://www.sccer-soe.ch/
[115] http://www.sccer-biosweet.ch/
[116] https://www.psi.ch/lea/
[117] http://crl.web.psi.ch/
[118] https://www.psi.ch/lst/

- Solar photovoltaics (PV)
- Electricity from biomass
- Deep geothermal power
- Wave and tidal power
- Solar thermal power (concentrated solar power, CSP)
- Nuclear power
- Natural gas and coal power
- Fuel cells
- Novel technologies: hydrothermal methanation of wet biomass; novel geothermal technologies; nuclear fusion; thermoelectrics.

Since novel technologies are far from maturity we abstain in this work from performing evaluations of their potentials, costs and environmental impacts.

System aspects, i.e. the interaction of different power generation technologies as part of the overall electricity supply system, are out of the scope of this work and have not been addressed. Out of scope of this analysis are also external costs[119].

This report is structured in the following way: The executive summary and the "Zusammenfassung" in German contain the most important technology-specific information and data in a concentrated form (as summarized in "fact sheets") as well as a comparative overview of current and future potentials, generation costs and environmental burdens. The Methodology section provides insights into methodological aspects: specification of potentials, procedures for quantification of generation costs and environmental impacts as well as some relevant background information on these topics. Next, all generation technologies are presented in chapters dedicated to each resource and the associated technologies; each chapter includes a section with technology-specific references. At the end, all references quoted in this report are listed.

[119] External costs are costs that affects a party who did not choose to incur that cost (Buchanan and Craig 1962); i.e., often society has to bear these costs. External costs in the context of electricity generation can e.g. be due to health impacts as a consequence of combustion-related air pollution or due to potential costs as consequences of potential accidents not covered by insurances.

5 Methodology, data inputs and common assumptions

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5.1 Potentials for electricity generation

One central goal of this work – as specified by the SFOE – was the quantification of "technical potentials" for electricity generation in Switzerland (plus potential imports from ocean energy, concentrated solar power, offshore wind power, coal power and possibly centralized gas power) in 2020, 2035 and 2050. However, providing only technical potentials is of limited use: Without consideration of practical constraints in addition to technical limitations, potentials are hardly meaningful and therefore, this analysis provides "exploitable potentials"[120] for domestic electricity generation and electricity imports. These potentials are predominantly based on existing estimates from literature, expert consultations and own judgements. New estimates are provided for biomass (in collaboration with WSL) and partially for solar photovoltaics.

The specification of "exploitable potentials" is based on the terminology used by the Swiss Federal Office of Energy, distinguishing between different potentials for electricity generation (BFE/SFOE 2007b, BFE/SFOE 2007a, BFE/SFOE 2012a):

1. "Theoretical potential": Refers to the physically available energy within certain geographical boundaries (e.g., within Switzerland) without any further limitations.
2. "Technical potential": Refers to the share of the theoretical potential, which can be used considering technical limitations. Due to potential technology development, this technical potential might change over time.
3. "Ecological potential": Fraction of the technical potential, which does not cause any permanent, irreversible harm to the environment; i.e. environmental constraints are considered.
4. "Economic potential" and "extended economic potential": Fractions of technical potentials, which can be economically used; i.e. economic constraints are taken into account. While the economic potential can be interpreted as a business-oriented perspective without considering any subsidies, the extended economic potential does include incentives and subsidies such as feed-in tariffs at production cost[121] for renewable electricity generation and can be interpreted as national economy perspective.
5. "Exploitable potential": This potential is defined as overlap of the ecological and extended economic potential; i.e. the technical potential reduced by environmental and economic constraints. Social concerns are, however, not taken into account as limiing factors.

These terms can only be partially used and applied within this report in a completely consistent way: In general, (constrained) technical potentials are somewhat ambiguous for certain technologies and energy carriers. Fuels for fossil (natural gas) and nuclear power plants in Switzerland are imported and import capacities can hardly be considered as limiting factor for the generation potential, at least not to a decisive extent; therefore,

[120] In the context of this analysis, the term "exploitable" corresponds to the German term "ausschöpfbar". Exploitable potentials for electricity generation can also be interpreted as "constrained technical potentials".
[121] "Kostendeckende Einspeisevergütung", KEV.

technical potentials for fossil and nuclear power are not useful in the context of this work (and are not quantified). Furthermore, available literature is often ambiguous and does not quantify technical, but rather "expected potentials" (or somewhat limited technical potentials), e.g., for hydropower and wind power, without explicitly addressing limiting environmental, economic and social factors. In such cases, these expected potentials are directly provided in this report as they are considered as most relevant given the Swiss boundary conditions with e.g. limited acceptance of new hydropower plants or large, open-ground photovoltaic installations. Whenever possible, environmental, economic and social constraints are provided and discussed in detail in the respective technology chapters of this report.

5.2 Electricity generation costs

5.2.1 Overall Goal and Purpose

The overall goal of PSI's update to the previous report on costs and potentials for SFOE Energy Perspectives (BFE Energieperspektiven; (Hirschberg et al. 2005)) is to provide a broad, objective and impartial analysis of the relative characteristics, potential, and cost of the full range of future electricity generation technologies. The purpose of the economic analysis effort within the PSI update is to analyze the internal generation costs of the different technologies, based upon the trajectory of costs and generation over the lifetime of each unit. The economic analysis also has the goal of analyzing each technology with a common methodology, and using a common framework of shared data assumptions. As far as possible, the economic analysis also has the goal of applying a consistent level of moderate optimism to expected technological learning and advances based on the current maturity of technologies.

5.2.2 Procedure

5.2.2.1 Levelized generation costs

The levelized cost methodology (also called "Life Cycle Costing", LCC) uses financial discounting to bring all construction costs forward, and all future costs backward, to the date of the plant's start of operation (Figure 5.1). A uniform discount rate of 5% has been used for quantification of LCOE of all technologies.[122] Future costs include operating costs (fuel, and fixed and variable operation and maintenance costs), as well as costs for plant dismantling, site restoration and waste treatment and storage costs. The net present value is then amortized over the generation lifetime of the plant, as shown in the Figure 5.1 below. The annualized cost is then divided by the expected annual generation, based on an expected capacity factor or dispatch simulation.

[122] Evaluation of LCOE of biomass conversion technologies includes external case studies for comparison; these case studies partially use different discount rates, which are explicitly mentioned.

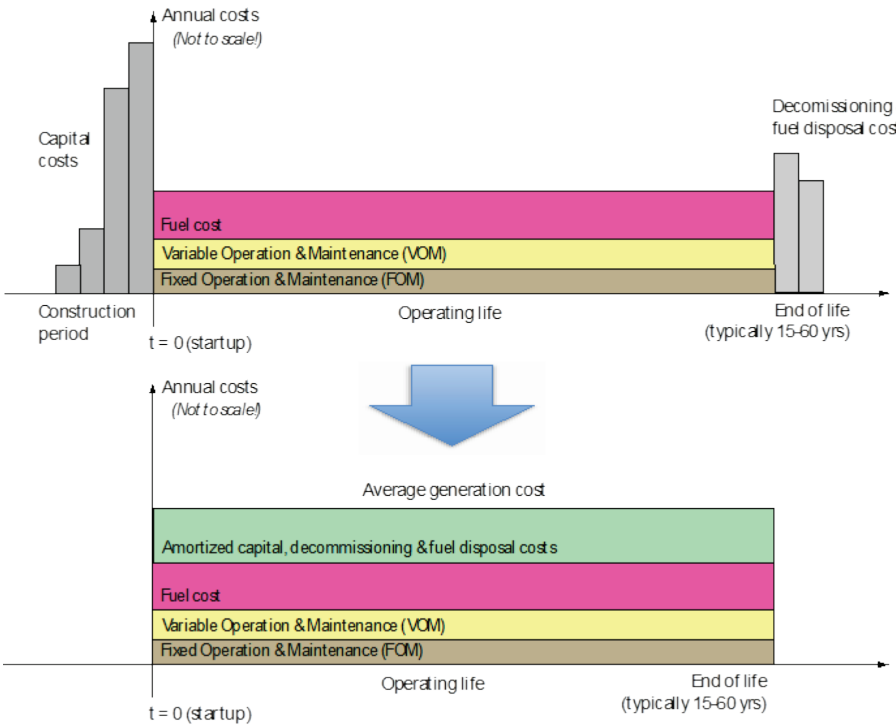

Figure 5.1: Scheme of LCC methodology, resulting in average generation costs per kWh of electricity, equal to "Levelized Cost of Electricity - LCOE".

Both current and future LCOE are quantified. Current LCOE refer to hypothetical new power generation units "to be built today" purchasing new technology on the market. In case of large hydropower and nuclear power, also the generation costs of the currently existing power plants in Switzerland are provided, since these plants contribute the vast majority to the current domestic generation will be part of the Swiss generation mix for many more years. In addition, "to be built today" is a theoretical concept for nuclear and (to some extent) large hydropower, since new power plants require extensive planning and licensing, are subject to complex approval procedures, and construction periods are substantial.

5.2.2.2 Cogeneration

In cases where electricity is produced by cogeneration (that is, both electricity and heat are produced as co-products), it is assumed that some of the heat can be sold, or that the heat can replace heat or fuel that would otherwise be purchased. In either case an appropriate heat credit is applied. This heat credit will generally be larger for avoided costs (e.g., natural gas fuel or district heating not purchased) than it will be for heat sales (heat is sold back to a district heating network for a much lower credit than the district heat purchase price). The heat credit is based on the expected annual heat revenue or avoided cost, as there may be no need or market for heat produced during some months.

For example, a geothermal plant with an electric capacity of 5 MW will produce about 35 MW of heat at about 14% electric efficiency. Annual heating demand has a load factor of about 20%, which means that about 60 GWh of heat could be used or sold annually. If the geothermal plant can replace 40 GWh of heat from a district heating loop at about 70 CHF/MWh (by direct self-use or direct sale to a nearby customer), and sell the remaining 20 GWh back to the district heating system at 10 CHF/MWh, then the annual heat credit will be about 2.8 MCHF from the savings and 0.2 MCHF from the sell-back. Obviously, depending upon how much of the heat can be used onsite or sold nearby, the heat credit could vary widely from 0.6-4.2 MCHF. Likewise, if more of this low temperature heat could be used per year to displace district heat (e.g. an 80% load factor preheating material in a cement kiln or another industrial process), then the value could be about 240 GWh at 70 CHF/MWh, or almost 17 MCHF.

In general, LCOE both with and without heat credits are provided. Whether these are likely to be credited will in reality mainly depend on generation plant locations and amounts of heat generated; also economic incentives and regulations could play a role. Technology specific factors in this respect are discussed in the technology chapters and results are discussed from this perspective as well.

5.2.2.3 Applicability and potential limitations

By using the average cost per kWh, the levelized cost method allows comparison between small and large plants, as well as comparison between inexpensive plants with relatively high fuel costs and low capacity factor (e.g., gas turbines) and expensive plants with cheap fuel and high capacity factors (e.g., nuclear). The method does omit site and jurisdiction specific factors, including taxes, depreciation, insurance, regulatory costs, etc., but it does provide a commonly accepted benchmark for cost comparison. The focus of this method is on costs rather than revenue, but if different technologies produce electricity sold at different prices this can also be taken into account. Sensitivity analysis is used to show the dependence of the average cost upon variation in the difference cost components, as well as the plant life, interest rate, capacity factor and other variables. Figure 5.2 shows an example of sensitivity analysis performed for photovoltaics.

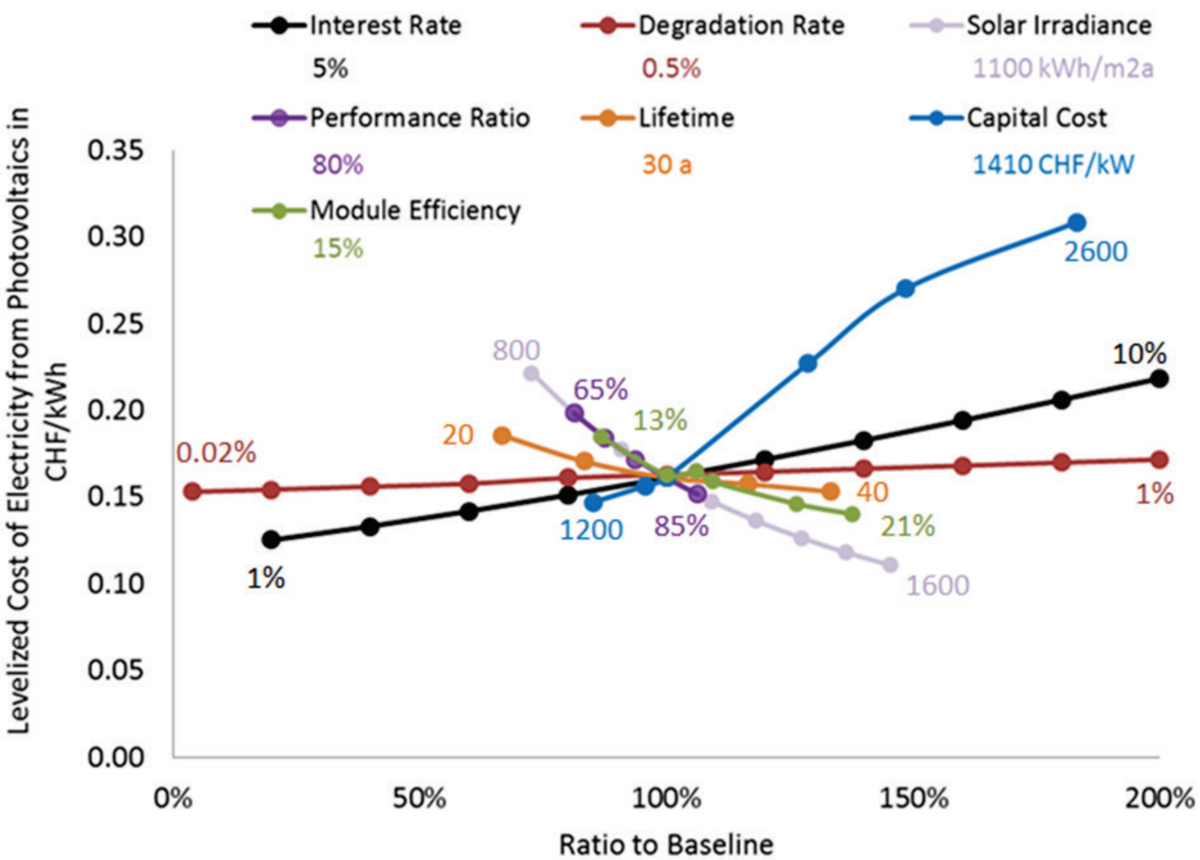

Figure 5.2 Example of sensitivity analysis: LCOE of photovoltaics.

Within PSI's framework for energy systems analysis, the average cost of generation is used as the chief economic indicator of internal system costs, but other economic indicators (e.g. total cost related to financing risks, or the fuel cost fraction related to energy dependence risk) are also calculated. The economic indicators are combined with environmental and social indicators for overall sustainability analysis. This includes tradeoff analysis between competing indicators, total costs based on monetization of environmental burdens (external costs) and multi-criteria decision analysis.

5.2.3 Estimation of future development of fuel prices

"It's difficult to make predictions, particularly about the future" (variously attributed to Yogi Berra, Niels Bohr, Mark Twain, Samuel Goldwyn, and many others).

In order to place the economic evaluation of different generation technologies on a consistent basis, it is necessary to have appropriate and consistent fuel price assumptions for the major fuels used for thermal generation, in particular natural gas, coal, (oil) and nuclear. Biomass fuels (wood and non-woody) are dominated by more local pricing, due to lower energy density and lower economic transportation radius and are not further discussed in this section.

This section surveys the available future fossil and nuclear fuel price scenarios, describes their comparative results and chooses future price trajectories for use by the individual technology analyses and in the unified comparison presented in this chapter. It is important to realise that future price projections represent the best efforts of each projecting agency, but they are not firm predictions. Likewise, in this survey PSI is choosing price trajectories that are a scenario for future prices, recognising their uncertainty without estimating any associated probability.

5.2.3.1 Requirements

The major characteristics desired in the fuel price scenarios surveyed included the following:

- Long term. For long-term generation sector planning based on plant lifetimes, demand growth, technology changes, etc., it is necessary that the fuel price scenarios should also be quite long-term (out to 2040 or beyond). The majority of price scenarios are dominated by the short and mid-term time horizons due to commercial needs, which can also lead to shifts in definition of terms (some sources consider 5 years to be long-term).
- Multi-fuel. For consistency, it is by far the best if price projections are taken from a single, coordinated modeling effort, reflecting consistent assumptions for demand, resources, demand, substitution, etc.
- Regional differences. Fossil fuels have regional price differences (oil least, and gas most), based on quality differences and transport costs. Nuclear fuel is more energy dense, and so any regional cost differences are smaller, and more related to markets than fuel quality. These regional differences would again be accounted for in a proper integrated model environment.

These requirements imply that a long-term, multi-region or global, multi-fuel energy sector model will be required. Long-term demand growth is driven by assumptions about population growth, economic growth, energy intensity and price elasticity. Energy supply is driven by known and estimated resources, their costs of production, and the costs and efficiencies to refine, transport and transform energy into services. Models find the prices at which supply meets demand, taking into account fuel and technology substitutions, price feedbacks, investment constraints, and other factors. Such models are complex, data intensive and require expertise, such that they are likely to be performed (or at least funded) by either a major country or an international agency.

5.2.3.1.1 International organizations/energy models

Two main, major energy models providing long-term price scenarios/projections were already known in advance. These were:

1. the OEDC/IEA World Energy Outlook (IEA 2016d)
2. the US DOE/EIA Annual Energy Outlook (US EIA 2016)

Such scenarios present a weighted reflection of past experience, as well as the assumptions that they contain for the future. As such, they 'digest' historic price swings that can be extreme (and appear random or stochastic), to produce much smoother curves of future supply, demand and prices. The challenge is to correctly see with hindsight through the historical noise that obscures the underlying trends, and then to extend these trends into the future. It is always an exercise in humility to compare the jagged historical cost data with the smooth future curves, and to know "the forecast is always wrong," but that significant lessons can also be learned about different future strategies, and their tradeoffs, risks and resiliency.

Oil, gas and coal prices have all declined significantly in the last several years, reflecting both the drop in demand due to economic slowdown (including China), and increased production capacity and expected reserves due to the revolution in fracking for tight oil and natural gas. Darwinian competition in fracking for oil and gas has driven the technology forward, while increased Saudi production and dropping oil prices have left only the best surviving. This has provided the US oil and gas sectors with a base of known geology and already drilled wells (with well costs already liquidated by the failures of the weakest producers) ready to increase production with higher prices. As a result, discussion of peak oil fears has significantly subsided, and long-term price expectations have declined. This can be seen, for example, in (IEA 2016d), where an additional year of low energy prices for 2015 has slightly reduced the long-term projection slightly below the 2015 scenario. Nuclear fuel prices have also declined precipitously, reflecting a drop in fuel demand following Fukushima, as well as other factors (see below).

The main concern and effort of the fuel price survey was to find other long-term projections that would improve or supplement (IEA 2016d, US EIA 2016). The three main sources considered were: 1) other government or international agencies, 2) energy industry companies and associations, and 3) energy sector consultants and/or data service providers. Individual sources within these groups are discussed below.

5.2.3.1.2 Other Government / International Agencies

Beyond (IEA 2016d, US EIA 2016), an effort was made to survey other government and international agencies. For the fossil fuel prices in particular, these included the following:

- United Nations (UN) – The UN has policy concerns and goals regarding energy, including economic development, sustainability and climate change. These are reflected through the UN-Energy interagency mechanism, the UN Environment Program, the UN

Foundation and other agencies. The UN Energy Statistics Division collects historic national data from more than 190 countries and maintains the Energy Statistics Database. However no actual energy price scenarios were found.

- European Commission (EC) – The EC performs energy modeling for the EU, and the EU Reference Scenario 2016 contains a graph of future fuel prices (but few numbers, or any tables of projected prices) (EC 2016a). However, the report states that the Reference Scenario 2016 is based on the PROMETHEUS model of international price projections, which is consistent with the New Policies Scenario of (IEA 2015g) for the medium and long term, and the WEO projections for all scenarios were already in hand.
- UK Department of Energy and Climate Change (DECC) – Fuel prices were taken from the DECC 2015 Fossil Fuel Price Assumptions (DECC 2015), which however states the caveat that the projections are "not forecasts of future energy prices." This is typical of the reservations by modelers that scenarios are not the future, and there is no necessary probability associated with different scenarios.
- World Bank – Publishes the World Bank Commodities Price Forecast, including oil, natural gas and coal to the year 2025 (World Bank 2016).
- International Monetary Fund (IMF) – Publishes the IMF Commodities Price Outlook, but only to 2018 (IMF 2016).

It is possible that this survey may have missed some other government/agency fuel price projections (particularly possible non-English, national modeling efforts, such as China). However, (IEA 2016d, US EIA 2016) both contain their own internal comparisons with other projections, and also do not mention any other major government or agency fuel price scenarios.

For nuclear fuel, the following government sources for price projections were reviewed:

- IAEA/OECD – The preeminent resource data source is the uranium Red Book (OECD/NEA/IAEA 2014, OECD/NEA/IAEA 2016) issued jointly by the International Atomic Energy Agency (IAEA) and the OECD Nuclear Energy Agency (NEA). The Red Book contains uranium resources by resource certainty, country, geology, and the method and cost to produce. It also contains two nuclear demand scenarios to 2035, but does not combine supply and demand data to quantify future prices.
- EC Euratom Supply Agency (ESA) – The ESA focuses on nuclear energy in the EU, including markets, EU supply and demand, security of supply, and medical isotopes (EC 2016b). It follows EU prices for 1) spot uranium prices, 2) the long-term price paid by utilities under multi-year contracts. Multi-year contracts are the dominant form of purchase (~90%), but the ESA only reports historical price data and does not report future prices on its website or in the ESA Annual Report. In general, "long-term" means "multi-year contracts" in relation to nuclear fuel prices, and does not refer to price projections into the long-term future (e.g., 2040 or 2050).
- OECD/IEA WEO – The World Energy Outlook issued by the OECD's International Energy Agency does not give prospective uranium prices as it does for fossil fuels. The OECD's other primary scenario document is the Energy Technology Perspectives 2016 (ETP), which only refers to the Red Book.
- USDOE/EIA – The Annual Energy Outlook includes nuclear generation, but does not include future price data as it does for fossil fuels.

- DECC – The DECC Energy Markets Outlook (DECC 2016) focuses on the supply and demand of nuclear fuel in the UK and globally, but does not provide long-term prices, and is based on the Red Book and the NEA Nuclear Energy Outlook.

5.2.3.1.3 Energy industry companies and associations

The major oil and gas companies do their own future supply and demand modeling, and sometimes publish quite detailed supply and demand projections by region and demand sector. The modeling required to produce these projections presumably must also produce the prices necessary to balance the supply and demand, but the industry apparently does not believe that it is to their advantage to publish these. The oil and gas companies or associations surveyed included:

- OPEC – Tuture prices are published in and taken from the World Oil Outlook 2015 (OPEC 2016), which contains no future natural gas or coal price scenarios for comparison.
- British Petroleum (BP) – Detailed supply and demand projections are published in the BP Energy Outlook, 2016 edition, but no prices (BP 2016).
- Exxon Mobil – Publishes The Outlook for Energy: A View to 2040. Also includes detailed region and sector demand projections but no future price data (ExxonMobil 2016).
- Shell – Publishes the New Lens Scenarios: A Shift in Perspective for a World in Transition (Shell 2016), which describes two qualitative scenarios. The Mountains scenario envisages maintaining the status quo and stability with limited market forces and social mobility, while the Oceans scenario contains more devolved and competing interests with more economic productivity but possibly destabilized social cohesion and political stability. Future fuel prices are not quantified, but qualitatively the prices are "moderate" and "higher" for the two scenarios, respectively.
- Eurogas – Publishes the Natural Gas Demand and Supply – Outlook to 2030, which gives supply and demand projections, but no prices (eurogas 2016).

Coal market price projections were sought, but the search results were generally either too short-term (circa 2020), or referred to other commodities price scenarios already mentioned ((IEA 2016d, IMF 2016, US EIA 2016).

In general, the industry survey of future fossil fuel prices shows that the strong emphasis is first on global crude oil prices, only second on natural gas prices and future coal prices are a distant third. Due to the goal of having coordinated, coherent price projections for all three fossil fuels, the industry sources are of less interest than the government/agency sources.

- World Nuclear Association (WNA) – The WNA website provides basic descriptive information about the nuclear fuel cycle, including historic uranium prices, historic cost supply curves, etc., but does not show fuel price projections. The WNA sells the Nuclear Fuel Report (WNA 2016a), including supply and demand scenarios to the year 2035, but does not provide any open future fuel prices.
- Nuclear fuel industry companies – Similar to the fossil industry, the nuclear industry fuel companies focus on either historical or short term future fuel price information.

5.2.3.1.4 Consultants and industry service providers

There is a very active industry of consultants and industry data providers that serve the fossil and nuclear fuel sectors. The problems here however are twofold. First, the commercial emphasis of the market means that there is a short time horizon, and second, the data providers are very definitely for-profit, and serving a market that pays well. This means that any long-term, publically available price projections are rather meager. The following consultant/industry sources were surveyed.

- Deloitte – Deloittes' Oil and Gas Price Forecast, September 30, 2016 (Deloitte 2016) contains oil and natural gas prices to 2035 for different benchmark types and/or locations.
- Bloomberg – The Bloomberg New Energy Outlook 2016 (Bloomberg 2016) focuses on new renewable energies and the power generation sector rather than fossil fuels.
- Lazard – Lazard's Levelized Cost of Energy Analysis (Lazard 2016) focuses on forecasting levelized costs of competing conventional and renewable electricity generation technologies, with some fuel price assumptions, but does not contain any real long-term, comprehensive fuel price data.
- Wood Mackenzie – Wood Mackenzie is a well-established energy sector consulting company that produces its own commodity price projection, but the only publically available projection (Wood Mackenzie 2016) does not include prices.

A small number of price projections from the fossil sector were obtained by the fuel price scenario comparisons published within (IEA 2016d, US EIA 2016). Often these comparisons have been based on direct personal contacts (either by phone or email) or from sources that are not publically available, or are available only by purchase (generally at expensive consulting company rates). These sources include ArrowHead Economics (arrowhead 2016), Strategic Energy and Economic Research (SEER) (SEER 2016), Energy Security Analysis Inc. (ESAI) (ESAI 2016), ICF (ICF 2016), and Energy Ventures Associates (EVA)(EVA 2016), and are also shown in the legends of the fuel price scenario graphs shown below.

In the nuclear industry, some consultants like UxC publish cost studies, e.g. the Uranium Production Cost Study 2015, for $6000 (UXC 2017), but again these are generally historic, analytic, and short-term.

5.2.3.2 Results of the survey

The results of the price projections surveyed are shown below in graphs for the oil, natural gas, coal and nuclear sectors. Most of the projections say (as noted above) something like "we do not assign any probability to these scenarios," or "these are consistent scenarios of the way things *could* happen." Nevertheless, where there are three or more scenarios, there is generally at least some expectation that the central price scenario, or the one labeled "reference" or "base" may be somewhat more likely.

Projections may be found that are given in either nominal ("real") or constant year currencies (with a given base currency year). Projections are dominantly given in dollars (particularly for oil), but are also often given in Euros. Currency conversion is made as necessary at the currency base year rate. Models generally include an assumed rate of inflation tied to the projection of economic activity on which the model is based, but constant 2015 USD have been used below. Relatively low USD inflation rates in the last couple years, and use of the most recent projections available means that this is a relatively minor issue. Oil prices are given per barrel, natural gas prices are given per unit of energy (GJ), and coal prices are given per metric ton. Uranium prices are generally given either in USD/kgU or USD/lb U_3O_8, but as discussed below, nuclear fuel prices include uranium, conversion, enrichment, and fabrication costs.

5.2.3.2.1 Oil Price scenarios

In general, the focus in the present analysis is on future electricity generation technologies, and there is little prospect that oil will be a potential fuel for future generation in Switzerland. Oil prices do vary somewhat regionally due to light vs. heavy crude, sweet vs. sour crude (sulfur content), and transport costs, but the regional price variation is relatively smaller for oil than for either natural gas or coal, as it is more value and energy dense, and tanker transport is relatively inexpensive.

Within the transport sector, there is significant potential that electric vehicles, natural gas, or hydrogen could substitute for future gasoline and diesel use, but this is unlikely to significantly affect natural gas prices for power generation. Rail transport in Switzerland is already dominantly electrified, so oil is also not a significant factor there. For both the air and marine transport sectors, fuel substitution is much more problematic and there remain few economically foreseeable alternatives. This could affect the Swiss air transport sector, and the marine sector only affects the gray CO_2 content of imported goods.

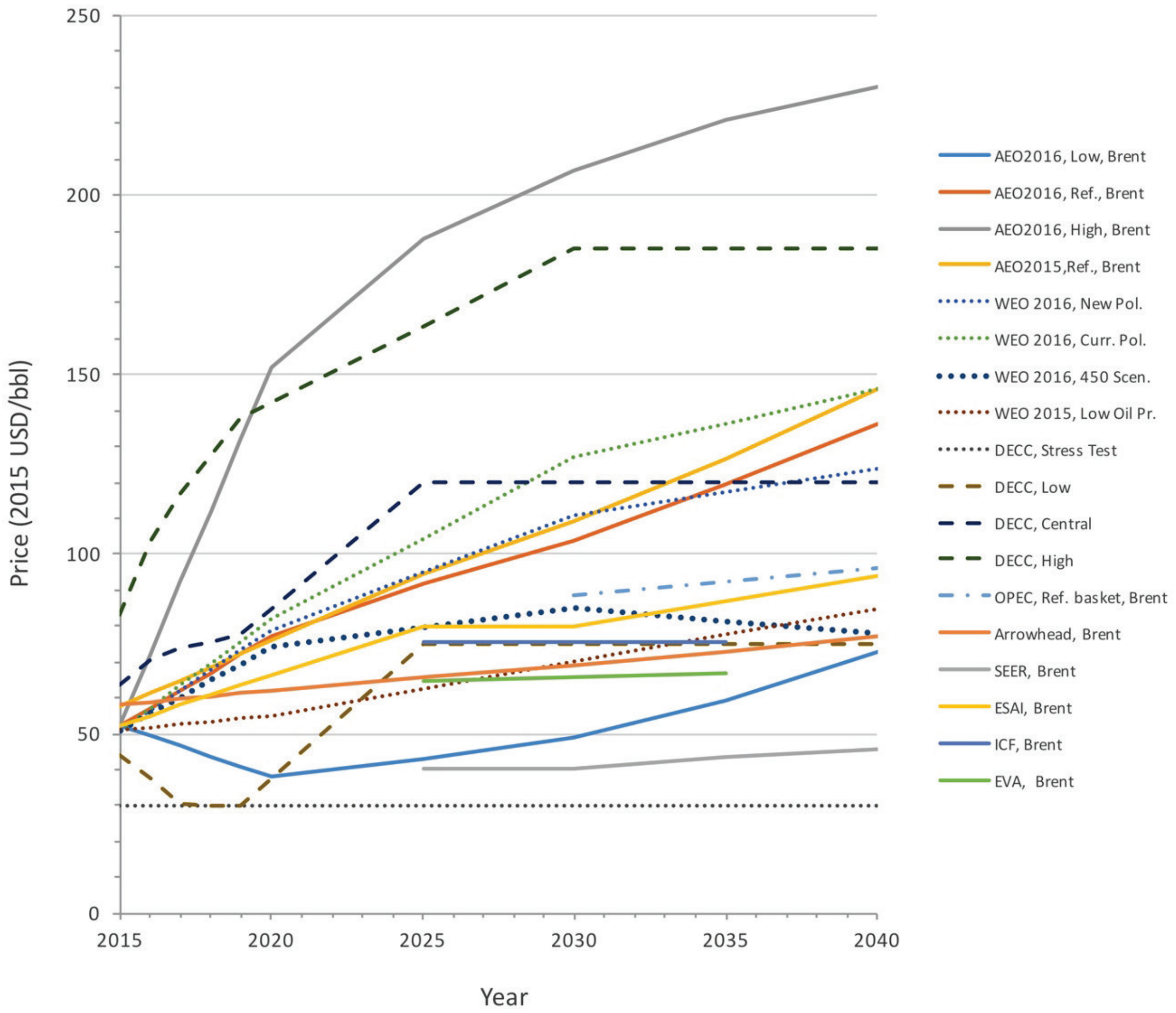

Figure 5.3: Surveyed oil price projections. Sources: (DECC 2015, arrowhead 2016, ESAI 2016, EVA 2016, ICF 2016, IEA 2016d, OPEC 2016, SEER 2016, US EIA 2016). AEO: US EIA 2016 Annual Energy Outlook; WEO: IEA 2016 World Energy Outlook.

Overall, the oil price scenarios have a very broad spread, ranging from the (DECC 2015) stress test scenario of 30 USD/bbl in 2040, up to the (US EIA 2016) price of 230 USD/bbl

(Figure 5.3). However, the broad range of the projections largely overlap, and the mid-range scenarios (DECC 2015) central, (US EIA 2016) reference and the (IEA 2016d) current and new policies all cluster in the range of 120 to 140 USD/bbl by 2040. The (US EIA 2015) reference scenario is slightly higher than the (US EIA 2016) reference, and has been included to illustrate the effect that the continued low oil prices of 2015 had in reducing the long-term AEO scenarios (US EIA 2016).

The (OPEC 2016) reference price increases to about 95 USD/bbl, which is significantly lower than the government consensus, and the 5 private consulting company projections are lower yet, in the range from approximately 45-90 USD/bbl by 2040.

It is worth noting that the graph legend references the Brent benchmark price as the most regionally relevant. Even though North Sea production is declining and other sources of imports are significant, this benchmark price remains dominant in the prices surveyed.

5.2.3.2.2 Natural Gas Price scenarios

The future fuel prices for natural gas show several obvious and important patterns (Figure 5.4). First and foremost is that the American price scenarios, including the various consulting company projections, are for the benchmark Henry Hub price. The (IEA 2016d) and (DECC 2015) prices are the much higher EU import prices. The (DECC 2015) prices from low to high span the range from about 5.6 to 12.2 USD/GJ by 2040, whereas the various WEO 2016 scenarios range from about 9 to 12.4 USD/GJ by 2040.

Natural gas has the highest regional cost differences of all three fossil fuels, due to the high transport costs and energy losses involved in shipping via Liquefied Natural Gas (LNG) tank ship. Natural gas prices in Asia are usually quoted with a Japanese benchmark price that is much higher than for Europe, but this has not been shown here. LNG terminals once intended for import to the US have now been converted for export, but there is still insufficient capacity to further reduce European gas prices, and the energy losses and shipping costs for LNG ships and terminals will always maintain a significant cost differential.

Over the long term, the big question for European gas prices is whether Europe could duplicate the American success in fracking to produce tight gas. The great increase in American gas production and the drop in prices and CO_2 emissions is not particularly due to exceptional American geologic formations, but rather to a combination of other factors, including (Zeihan 2016);

- technology (including horizontal drilling, fracking, and IT for formation imaging),
- the skilled labor expertise in relevant fields,
- capital markets for financing,
- the legal framework for subsurface mineral ownership rights,
- the pipeline infrastructure for gas collection and distribution.

The drilling and fracking technology and the manpower expertise are presumably the most mobile assets, but capital markets and the collection/distribution pipeline infrastructure have longer time to put in place. The legal framework for subsurface ownership and development incentives may be the longest and most restrictive. All of these factors, combined with higher environmental and political opposition the regional premium in natural gas prices is likely to remain.

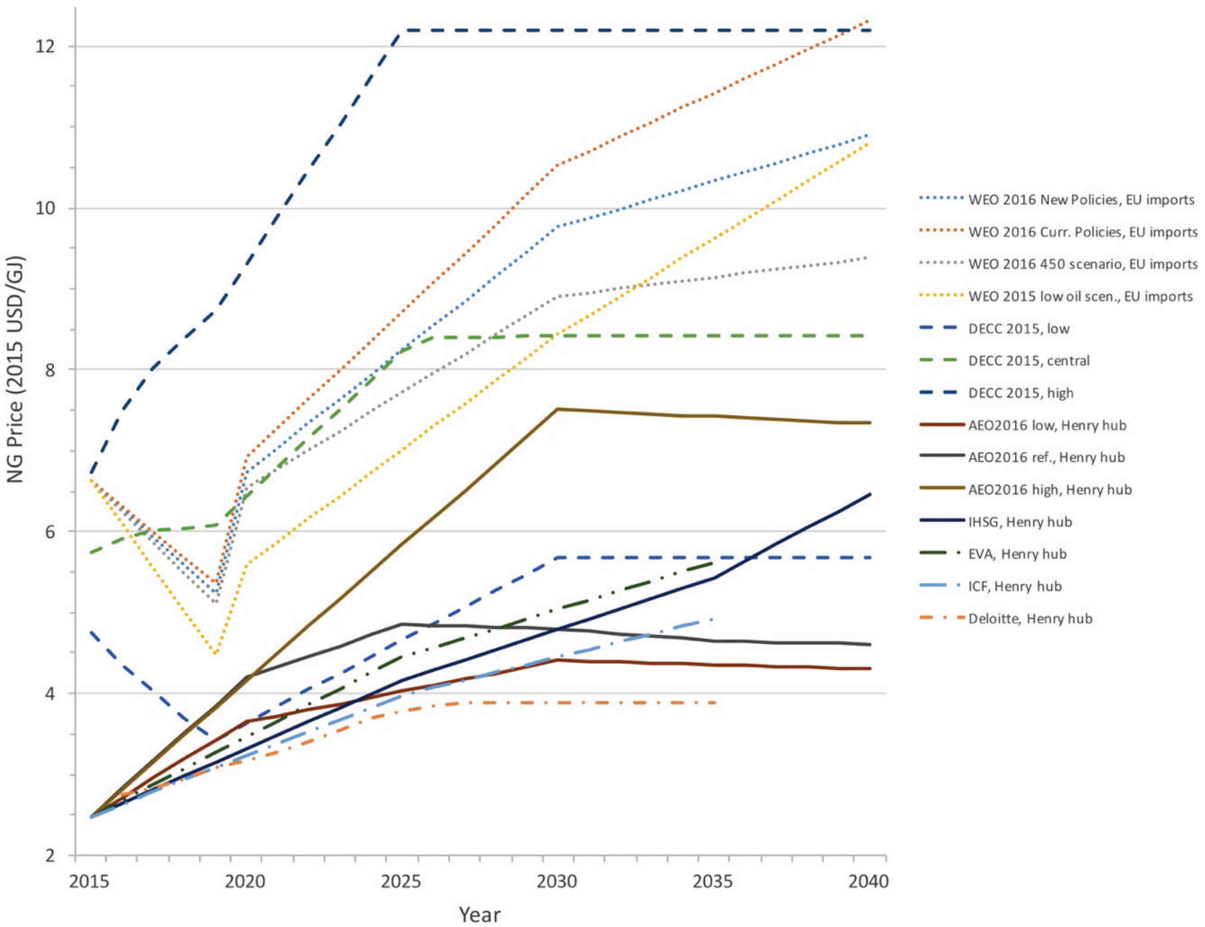

Figure 5.4: Surveyed natural gas price projections. Sources: (DECC 2015, US EIA 2015, Deloitte 2016, EVA 2016, ICF 2016, IEA 2016d). AEO: US EIA 2016 Annual Energy Outlook; WEO: IEA 2016 World Energy Outlook.

5.2.3.2.3 Coal Price scenarios

Figure 5.5 shows 2015 USD/ton for steam coal. Prices have been adjusted where necessary from American short tons (2000 lbs.) to metric tons (1000 kg), and also using an average heat content of 19 million Btu/ton[123] when needed.

As with natural gas, there is a regional price difference for coal delivered to Europe versus within the USA. The lowest 7 lines on the graph above show the AEO 2016 prices for the US. The 3 lines starting at about 37 USD/ton are the low, reference and high future mine-mouth prices, while the 3 lines starting near 44 USD/ton and the volume-weighted, delivered prices for non-metallurgical (i.e. steam) coal. The orange solid line is the (US EIA 2016) reference scenario price for coal delivered to the power plant.

For the European delivery price scenarios, (DECC 2015) has a relatively wide spread from about 70 to 110 USD/ton by 2040. The (IEA 2016d) prices for the current policies, new policies and low oil scenarios range from about 87 to 102 USD/ton by 2040, with the CO_2 constrained 450 scenario has a much lower price of about 57 USD/ton by 2040 due to constrained coal demand.

[123] Btu: British thermal unit.

Overall, these prices generally reflect coal's dominant use still being in power generation, and also an overall perceived drop in demand due to its high carbon content and the decreasing price of renewables substituting into generation market.

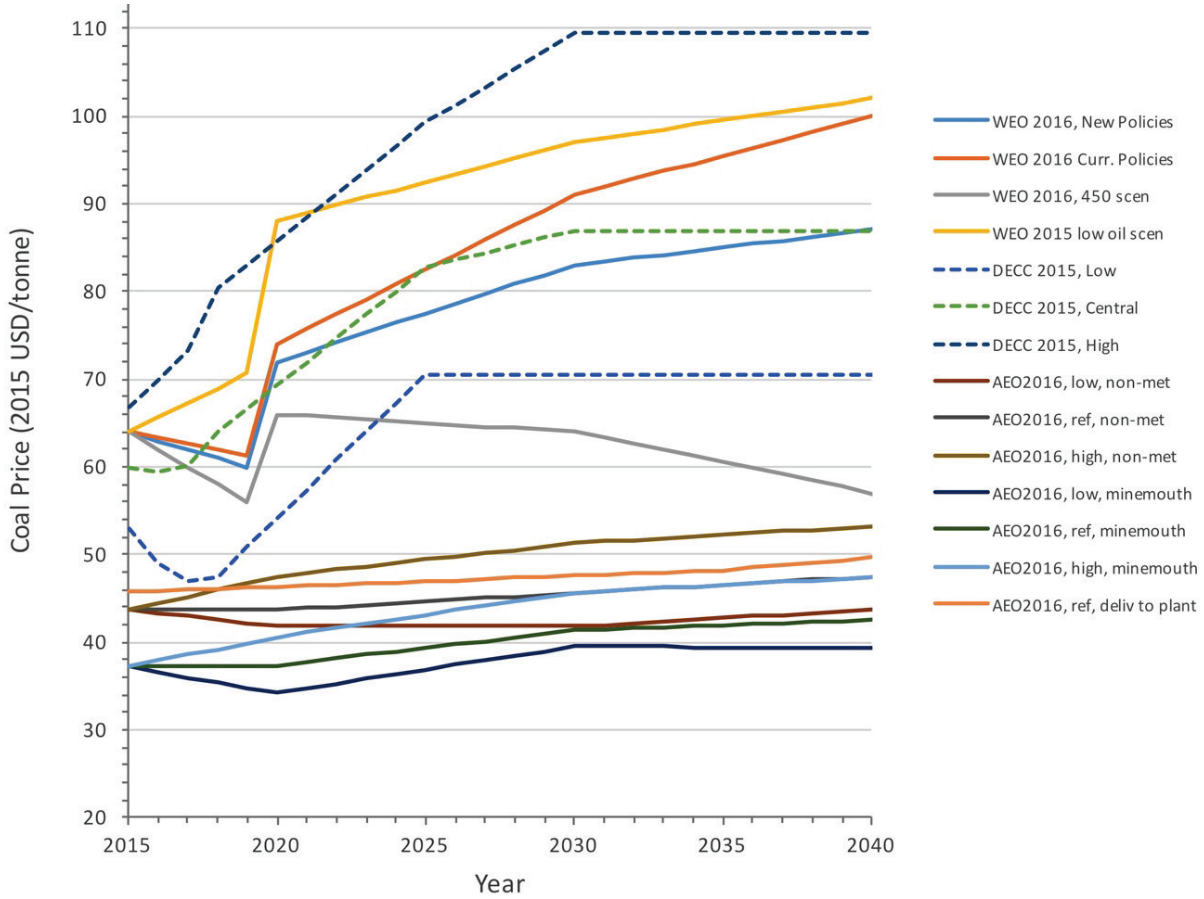

Figure 5.5: Surveyed coal price projections. Sources: (DECC 2015, IEA 2016d, US EIA 2016). AEO: US EIA 2016 Annual Energy Outlook; WEO: IEA 2016 World Energy Outlook.

Although somewhat unlikely, it is possible that coal could be delivered up the Rhine by barge to Basel for thermal generation or gasification, so the closest regional price is the most reasonable.

5.2.3.2.4 Nuclear fuel price scenarios

While fossil fuel markets are certainly not simple, nuclear fuel prices are in some ways both more complex and less important. This is because fossil fuels are produced, refined (oil), transported and burned. For nuclear fuel uranium is mined, concentrated or purified to yellowcake (U_3O_8), converted to uranium hexafluoride (UF_6), enriched to approximately 3-5% U235, and fabricated into fuel pellets in fuel rod bundles. Table 5.1 shows the approximate breakdown of these costs as of July 2015 to obtain 1 kg of UO_2 reactor fuel. This fuel produces 360 MWh at a burn-up of 45,000 MWd/t to give a fuel cost of 0.52 US¢/kWh.

Table 5.1: Nuclear fuel cost components (WNA 2016a).

Uranium:	8.9 kg U_3O_8 x \$97	US\$ 862	46%
Conversion:	7.5 kg U x \$16	US\$ 120	6%
Enrichment:	7.3 SWU x \$82	US\$ 599	32%
Fuel fabrication:	per kg (approx)	US\$ 300	16%
Total, approx:		US\$ 1880	

However, average nuclear generation costs are dominated by plant capital costs (60% or more), and fuel costs are only about 10%, so the final average price of electricity is quite insensitive to the price of uranium. This is in strong contrast to gas-fired generation, where the capital costs are low, and the fuel costs relatively high, while coal falls in the middle.

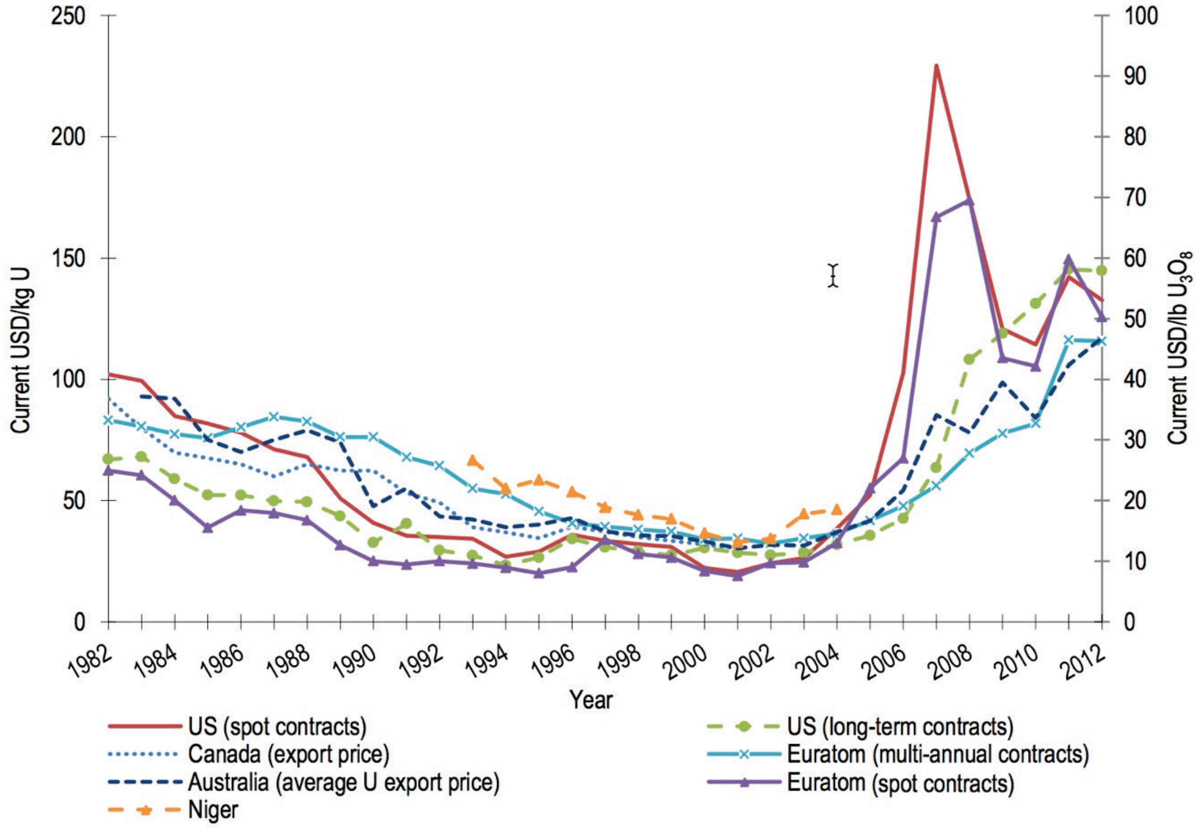

Figure 5.6: Historic uranium prices: 1982 – 2012 (OECD/NEA/IAEA 2014).

The low impact of uranium prices has some benefit, as uranium prices have been even more volatile than fossil prices. Figure 5.6 shows historical uranium prices over the 30 years from 1982 to 2012 for both spot market and multi-year contracts. The spot market price is much more volatile (as expected), with the US spot price ranging from about 20-240 \$/kg U. The multi-year contract prices are less volatile, but they are also less certain, as many companies do not disclose the prices of private contracts. These swings in prices reflect the increase in demand due to de-militarized weapons materials coming to an end and the increase in new nuclear construction (chiefly in Asia), followed by a drop in demand following Fukushima when all Japanese reactors where taken offline and some other countries also decided to exit nuclear generation.

The uranium Red Book (OECD/NEA/IAEA 2014) does not supply future prices, but they do provide estimates of future supply and demand. Figure 5.7 shows two trajectories for low and high demand scenarios, based on projected growth in the global reactor fleet. These two trajectories are compared to two trajectories for uranium supply from identified resources producible at less than 130 $/kg U.

(OECD/NEA/IAEA 2014) does not give the cumulative, global production required until 2035, but by using simple approximation, these totals are approximately 1.6 and 2.1 million tons of uranium for the low and high scenarios. As can be seen, even in the high demand case demand is almost met by identified resources at less than 130 $/kg U.

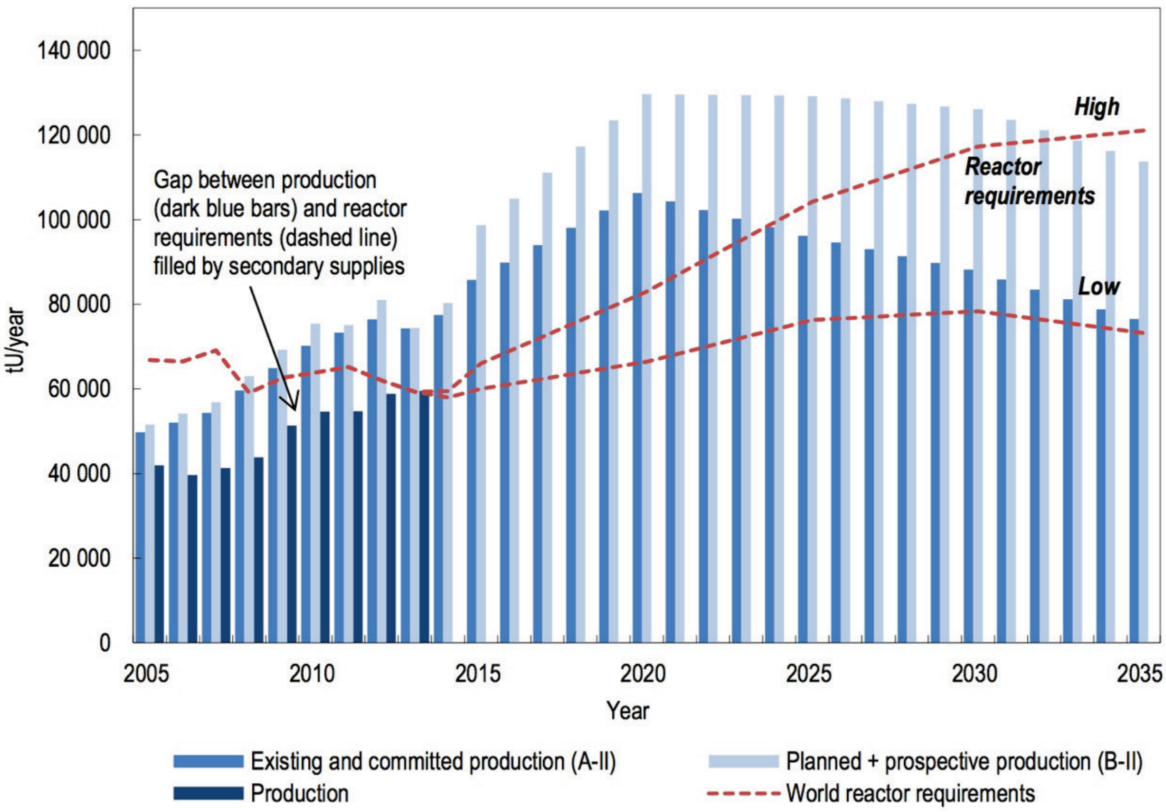

Figure 5.7: Projected annual world uranium production capability to 2035 compared to projected world reactor requirements (OECD/NEA/IAEA 2014).

(OECD/NEA/IAEA 2014) also gives global uranium resources, categorized by the cost to produce, and the degree of knowledge or certainty about the geology of the ore deposits. Identified resources are divided into RAR (reasonably assured resources) and inferred resources, while undiscovered resources are divided into prognosticated and speculative resources. The numbers in Table 5.2 and Figure 5.8 are in units of thousands of tons, and are cumulative, so for example reasonably assured resources with production costs between 40 and 80 $/kg U would be 1211.6 – 507.4 = 704.2 thousand tons. When the cost category was not specified for the speculative resources, they were assumed to fall in the highest category between 130 and 260 $/kg U.

Table 5.2: 2013 Uranium Resources by Cost and Certainty (kT) (OECD/NEA/IAEA 2014).

	Identified		Undiscovered	
Category	RAR	Inferred	Prognos-ticated	Speculative
< 40 $/kgU	507.4	175.5		
< 80 $/kgU	1211.6	745.1	665.4	
< 130 $/kgU	3698.9	2204	1222.8	2639.3
< 260 $/kgU	4587.2	3048	1755.5	5942.2

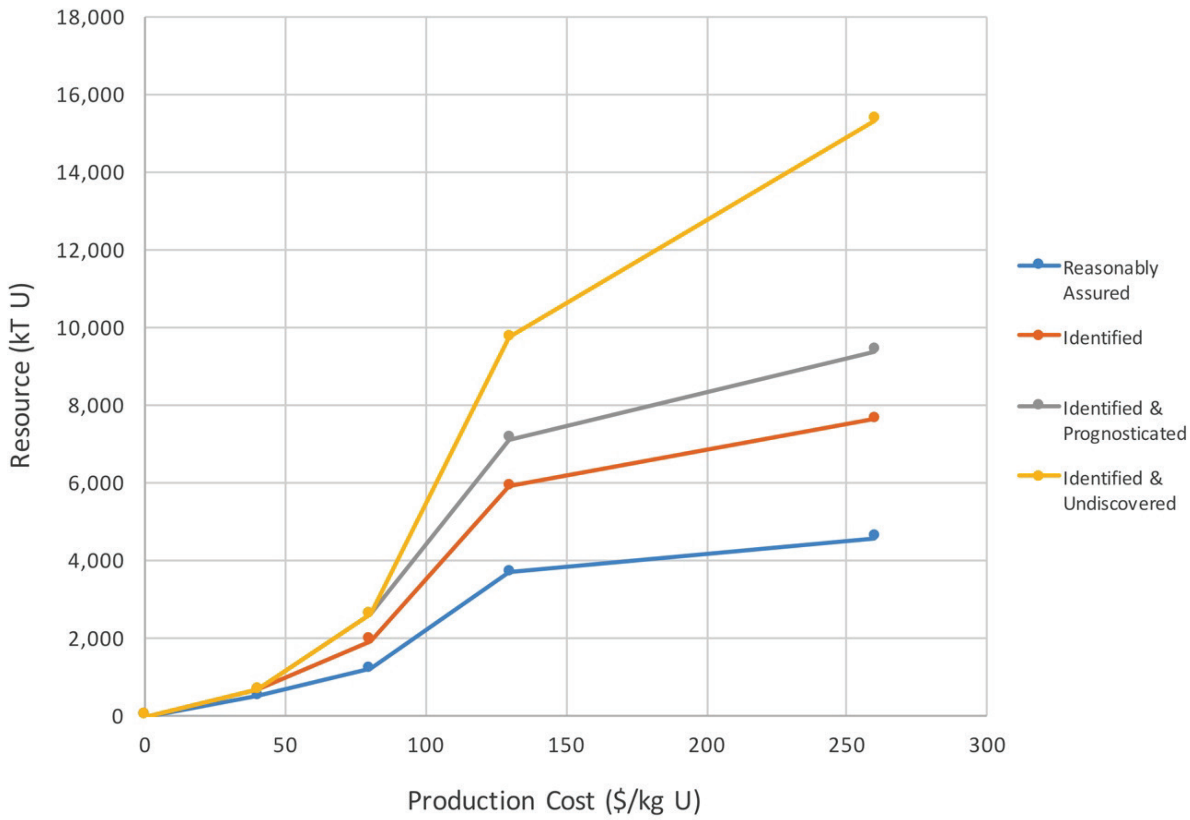

Figure 5.8: Global Uranium Resources by Cost and Certainty (OECD/NEA/IAEA 2014).

If only reasonable assured resources are assumed, and *if* these resources have a cost distribution that is linear across the intervals given (as shown above), then for the low and high growth scenarios, the cost in 2035 would be 88 and 98 $/kg U, respectively. If all four categories are included (RAR through speculative), then the prices in 2035 would be 59 and 69 $/kg U for the low and high cases, respectively. If the 2015 costs for conversion, enrichment and fabrication remain unchanged, then the final fuel cost would be approximately in the range from 0.42-0.49 US¢/kWh, lower than the current price. Obviously the Red Book (OECD/NEA/IAEA 2014) production costs do not include all production related costs or profits, but the point remains that even out past 2035 to 2050, it is not very extreme to assume that nuclear fuel will remain close to current prices.

This is also true because there are a number of other factors that will also tend to reduce future prices. First, it is likely that the Red Book resources given (OECD/NEA/IAEA 2014) understate the abundance of the uranium resource. This is based on the relative elemental abundance of uranium (tin and uranium are ranked 49 and 51 in elemental abundance in the earth's crust, as 2.2 and 1.8 ppm, respectively), and to the fact there has not been a very intensive global search for uranium (certainly not compared to other mineral resources). More exploration would almost certainly shift resources from the undiscovered to identified categories, improve the undiscovered estimate, and improve the cost of recovery data.

Second, it is likely that improvements in enrichment will eventually reduce fuel prices. Nuclear fuel enriched to about 4% U235 requires about 0.8-0.9 SWU/kg U. Laser enrichment of uranium (the SILEX process (Silex 2017) is currently the most advanced) will likely reduce both capital costs and the average cost per separative work unit (SWU), compared to centrifuge enrichment. The economics of the SILEX process are still uncertain (or obscured) but the first plant is being built at a contract price of 120 $/SWU with an estimated cost of 60 $/SWU, and would likely have to reduce prices to 30 $/SWU to beat centrifuge enrichment (cost range of 10-60 $/SWU). Opponents suggest that target costs between 30 and 45 $/SWU for SILEX are very optimistic.

There is also a secondary effect, as lower enrichment costs will also lower the economically optimal concentration of the depleted tailings, which SILEX is technically well-suited to do. This means that more enriched uranium can be extracted from the same feedstock, reducing the requirements for uranium mined. This also means that uranium can be economically extracted from the tailings from previous enrichment (diffusion, and to a lesser extent, centrifuge). The company developing the SILEX process (Global Laser Enrichment, or GLE) has recently purchased 300,000 tons of depleted UF6 from the US DOE, showing further potential to reduce uranium demand (World Nuclear News 2017). However, laser separation also has opponents due to concerns about proliferation, as the smaller size of the enrichment plant (~4x) and more widespread availability of laser vs. centrifuge expertise means that it could be easier to build and conceal an enrichment facility for weapons production.

Third and finally, costs to extract uranium from seawater have declined significantly over the recent years, from approximately 1000 to 2000 $/kg U in 2010 to a reviewed range of 400 to 1000 $/kg U in 2015 (Lindner and Schneider 2015). US national labs ORNL and PNNL reported in 2016 a 4x drop in the last 5 years to near 200 $/lb U_3O_8 (~520 $/kg U), with optimistic statements that market prices might be possible. These costs depend on how effectively the coated polymer adsorbent material adsorbs uranium from the seawater, how long the material remains in the ocean current, and how many times the material can be reused. Uranium is present in seawater at a concentration of 3.3 ppb (or 3.3 mg/m^3) with a total resource of approximately 4.5 billion tons. This means even without optimistic assumptions of further progress, the cost of production from seawater serves as a cap or backstop to the possible production price from resources on land. The present day cost of scarce mineral resources depends both on their production costs and their expected future costs, so the prospect of a future backstop price of uranium from seawater will reduce the scarcity rent over the whole future price trajectory.

5.2.3.3 Choice of fuel price projections selected

Given the regional dependence of fuel costs that is illustrated above, especially for natural gas and coal, and the fact that there are only two dominant long-term, coordinated multi-fuel projections with regional resolution, then the choice between the US DOE/EIA's Annual Energy Outlook (US EIA 2016) and the relatively more European-focused OECD World Energy Outlook (IEA 2016d) is relatively easy to make. However, as mentioned above, the

OECD also publishes the Energy Technology Perspectives 2016 (IEA 2016b), which contains price scenarios closely linked to the World Energy Outlook, but which extend to 2050, eliminating the need to extrapolate from 2040 onward. Work at PSI in the Energy Economics Group is also based on use of the ETP price scenarios.

Given this choice, the OECD ETP projection (IEA 2016b) is shown in Figure 5.9, proceeding by regional specificity from the prices for NW Europe to the Rotterdam spot prices for the different fuels to sector specific prices for industry, residential, and transport demand. Note that the units for this graph have been changed from USD to CHF, and also from physical units (barrels for oil and tons for coal) to the common energy units of GJ for the purpose of comparing prices on a single graph.

Figure 5.9 shows well the energy prices shocks of the last decade, in particular. Recall that first energy price drop was due to the financial crisis of 2008/09 with the large drop in economic activities and energy demand, while the second price drop was due rather to technological development (in the oil and gas industry) and oil cartel action (by the Saudis) to increase production rates during a continued sickly recovery. Coal price drops have been basically due to the substitution of natural gas for coal in US power generation, with a concomitant increase in exports to decrease cost in other markets. This graph also shows well the contrast (mentioned above) between the jaggy price disruptions of known history, and the smooth (and hence wrong) projection for the future. However, if the smooth projection embodies (or distills) the correct insights from the past, it still contains valuable guidance for the future.

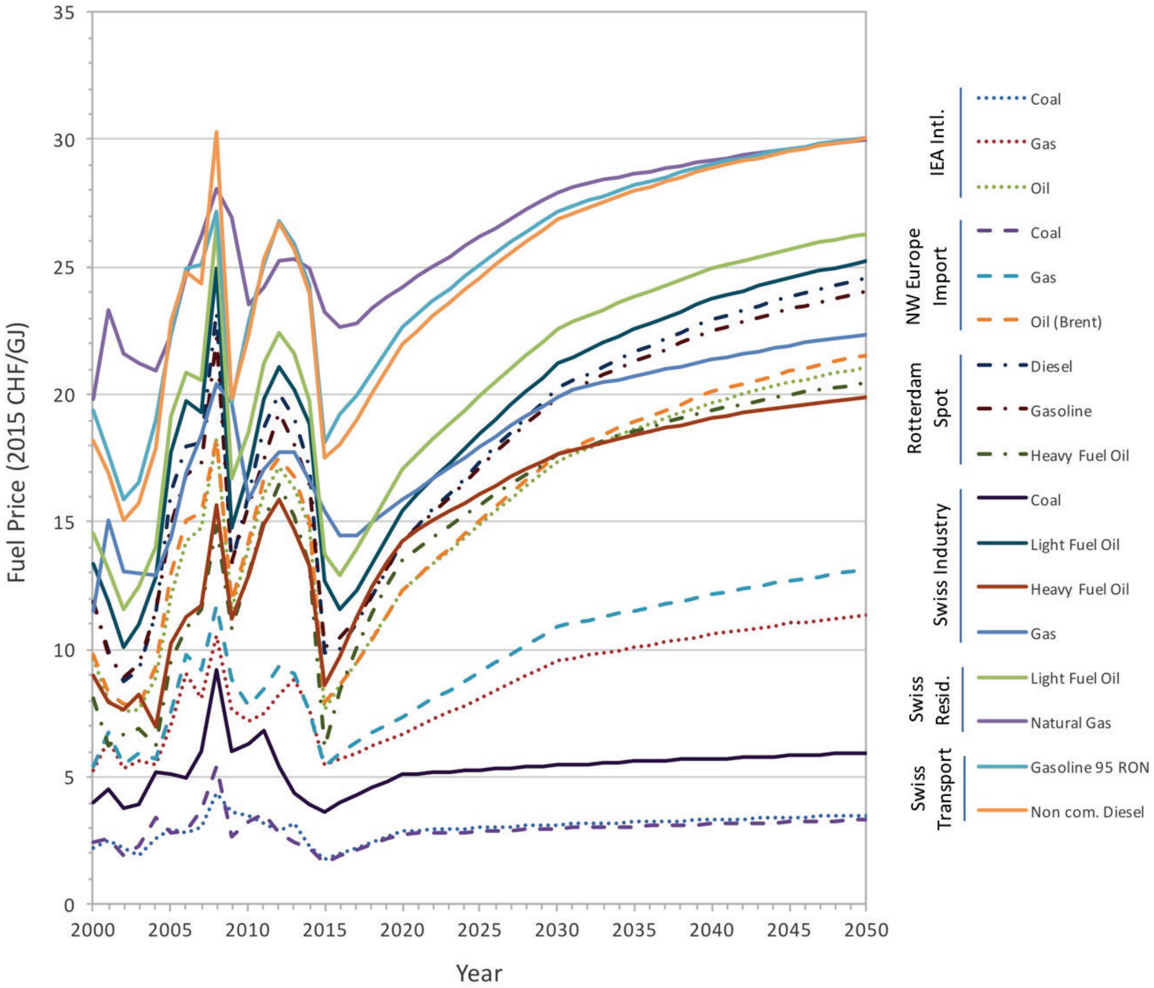

Figure 5.9: OECD/IEA Energy Technology Perspectives 2016 fuel price projections for Scenario 4DS (IEA 2016b, OECD 2017).

5.2.3.4 Conclusions

In general, the results of the fuel price survey are much as initially expected with the following conclusions:

- Closest regional results from the (IEA 2016b) should be used
- This is because regional variations are especially important for gas and coal prices, and
- We also gain the benefit of consistency with past and future work performed by the LEA Energy Economics Group for Swiss energy modeling scenarios
- That biomass prices remain Swiss or location-specific, with green and manure waste being more site-specific than wood. Consideration must be given for biomass to transport radii, and the “waste depletion” as a limited resource gains market value.
- Like the various fuel price projections we have surveyed, the authors regard the projections we have adopted as a future scenario, but not as a firm prediction.

Table 5.3 shows the fuel price development scenarios as used in this technology evaluation; projections are based on (IEA 2017) (without taxes). Figures for “Swiss industry” and “Swiss households” correspond to fuel prices used for centralized and decentralized units, respectively. Fuel prices in Switzerland are higher than on the European/international fuel markets; and prices for Swiss residential consumers are higher than those for Swiss industry. These differences reflect the increasing costs of transportation and distribution from major shipping hubs to Switzerland and then to industrial and individual consumers. Non-commercial diesel is more expensive than light fuel oil (both not used within the scope of this study) due to slightly different product quality and lower quantities to be purchased.

Table 5.3: Fuel price development scenarios as used in this technology evaluation; projections based on (IEA 2017) (without taxes). Figures for "Swiss industry" and "Swiss households" correspond to fuel prices used for centralized and decentralized units, respectively. Prices by sector in CHF_{2015}/GJ.

	IEA International Price			NW Europe Import Price			Rotterdam Spot Prices		
Year	Coal	Gas	Oil	Coal	Gas	Oil (Brent)	Diesel	Gasoline	Heavy Fuel Oil
2015	**1.78**	**5.50**	**7.68**	1.66	5.44	7.90	9.88	10.11	6.15
2020	**2.89**	**6.66**	**11.80**	2.76	7.35	11.79	13.65	13.64	13.04
2025	**3.02**	**8.12**	**14.31**	2.87	9.12	14.42	16.62	16.47	15.19
2030	**3.14**	**9.57**	**16.67**	2.98	10.90	16.90	19.39	19.12	17.07
2035	**3.23**	**10.08**	**17.85**	3.07	11.53	18.14	20.78	20.44	17.95
2040	**3.32**	**10.60**	**18.88**	3.15	12.17	19.23	21.98	21.59	18.76
2045	**3.42**	**11.02**	**19.62**	3.24	12.70	20.00	22.84	22.41	19.33
2050	**3.51**	**11.36**	**20.21**	3.32	13.13	20.63	23.53	23.07	19.78

	Swiss Industry				Swiss residential		Swiss Transport	
Year	Coal	Light Fuel Oil	Heavy Fuel Oil	Gas	Light Fuel Oil	Natural Gas	Gasoline 95 RON	Non com. Diesel
2015	3.63	12.67	8.61	15.46	13.73	23.24	18.09	17.49
2020	5.10	14.87	13.89	15.87	16.51	24.22	22.18	21.45
2025	5.29	17.76	15.70	17.95	19.31	26.18	24.55	24.01
2030	5.47	20.41	17.23	19.91	21.83	27.92	26.60	26.23
2035	5.60	21.72	17.94	20.72	23.05	28.63	27.58	27.29
2040	5.72	22.85	18.58	21.37	24.11	29.18	28.41	28.19
2045	5.83	23.65	19.02	21.92	24.86	29.65	28.98	28.82
2050	5.94	24.29	19.38	22.35	25.45	30.01	29.44	29.32

5.3 Environmental aspects: burdens and potential impacts

This report contains an evaluation of environmental burdens and potential impacts caused by the different electricity generation technologies to be used for Swiss electricity supply. The evaluation is primarily based on Life Cycle Assessment (LCA; in German: "Ökobilanzen"). LCA provides a comprehensive perspective taking into account the complete life cycle of products and services; in the case of energy services such as power generation all parts of the so-called "energy chains": fuel supply, infrastructure manufacturing, power plant operation and end-of-life (EOL). This includes extraction of energy and material resources, land use, material and energy conversion, transport services as well as disposal and recycling (Figure 5.10).

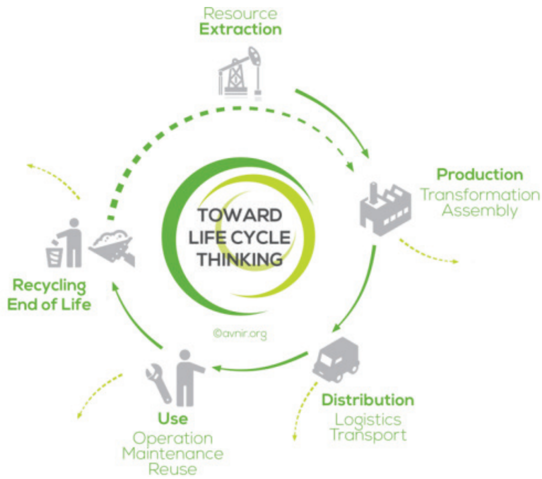

Figure 5.10: Schematic representation of LCA (avnir 2016).

LCA considers emissions of potentially harmful substances into air, water bodies and soil as well as land transformation and occupation and resource depletion. So-called “direct” emissions and other burdens are caused by the operation of the generation units (power plants and CHP units), while “indirect” emissions and other burdens are caused by other processes in the energy chain (e.g., fuel supply) as well as consumption of fuels, electricity, materials and transport services for all processes within the energy chain (so-called “background processes” from a background LCA database like ecoinvent[124]) (Figure 5.11).

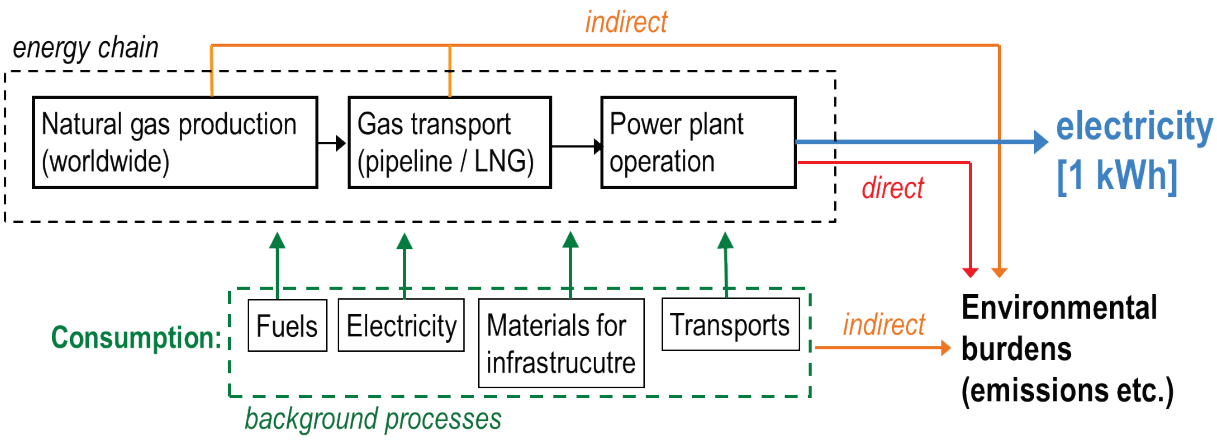

Figure 5.11: Schematic representation of the LCA process model for electrciity generation with a natural gas power plant; [1 kWh] indicates the functional unit of the LCA.

Quantitative environmental assessment results provided in this report are based on attributional, process-based LCA as specified by ISO (ISO 2006a, ISO 2006b). The results provided in this report are supposed to represent Swiss specific boundary conditions in the sense that – as long as data are available – parameters and technology characteristics with high impact on the environmental technology performance reflect Swiss-specific energy chains. That includes e.g. annual yields of photovoltaic and wind power plants, origin of natural gas imports as well as subsurface geology relevant for geothermal power generation.

Potential impacts on climate change – measured in terms of life-cycle Greenhouse Gas (GHG) emissions – are in the center of national and international energy and environmental

[124] www.ecoinvent.org

policy and at the same time represent the most important burden of the current global electricity supply (IPCC 2011, Schweizerische Eidgenossenschaft 2013, IPCC 2014a). These GHG emissions are therefore the burden most frequently addressed by LCA studies and literature provides the most reliable LCA results concerning this issue. Potential ranges and variations in technology-specific results can therefore most consistently be addressed; furthermore, life-cycle GHG emissions correlate well with many other environmental indicators representing impacts on human health and ecosystem quality such as particulate matter formation, acidification and eutrophication, ozone depletion and formation, etc. (Huijbregts, Rombouts et al. 2006); biomass related land-use represents an important exception (Hertwich, Gibon et al. 2015), which is however not relevant in the context of this analysis, since biomass (wood) is harvested at sustainable rates in Switzerland and biomass imports are not evaluated. Therefore, potential impacts on climate change are used as the key environmental indicator in this report. In addition and depending on availability of data, selected additional environmental indicators are quantified for most of the technologies; most current technologies are evaluated using the broad range of Life Cycle Impact Assessment (LCIA) indicators recommended by ILCD (EC 2010, Hauschild, Goedkoop et al. 2013). In order to provide a meaningful perspective, technology-specific LCIA results are compared to the ones of the average electricity consumption mix in Switzerland according to the latest version of the ecoinvent LCA database (ecoinvent 2016).

The environmental evaluation of current technologies predominantly uses existing LCA with the ecoinvent database (ecoinvent 2015, ecoinvent 2016) as most reliable and consistent source of LCIA results.[125] In addition, new LCA has been performed for a few technologies with previously insufficient LCA data. The evaluation of future technologies is mainly based on previous LCA of PSI authors, extrapolations from current technologies considering expected future technology development and some additional external literature. Due to limited availability of LCIA results beyond GHG emissions for future technologies, the evaluation of future environmental technology performance is mostly limited to the impact on climate change. As far as the available LCA data allow, technology-specific ranges for GHG emissions of electricity generation are provided, reflecting uncertainties and variability in both LCA input data and modeling as well as technology performance. These ranges are supposed to represent potential variability of results for Swiss electricity supply. Available data does not allow for such an approach for other LCIA indicators. Swiss-specific LCIA results (mainly concerning GHG emissions) for current technologies from ecoinvent, PSI and a few other sources are compared to those provided by "review-type", external references (IPCC 2011, Burkhardt, Heath et al. 2012, Dolan and Heath 2012, Hsu, O'Donoughue et al. 2012, Kim, Fthenakis et al. 2012, Schreiber, Zapp et al. 2012, Warner and Heath 2012, Whitaker, Heath et al. 2012, Hertwich 2013, Turconi, Boldrin et al. 2013, Whitaker, Heath et al. 2013, O'Donoughue, Heath et al. 2014, Asdrubali, Baldinelli et al. 2015, Uihlein 2016) as a measure of quality control.

"Current" in the LCA context of this analysis refers to modern technologies on the market today and their associated fuel chains. As opposed to the quantification of electricity generation costs, LCA of current technologies does not differentiate between currently operating power plants and plants "to be built today" in case of nuclear and large hydropower. Such a differentiation is not meaningful: LCA methodology does not allow for

[125] Most energy system related LCA data in the ecoinvent database originate from previous work performed by PSI authors.

"going back in time", i.e. quantifying burdens and impacts of infrastructure built decades ago and operated during long time periods in a consistent way; LCA usually represents a "snapshot in time" (ISO 2006a, ISO 2006b, EC 2010). Furthermore, the life-cycle burdens of currently operating nuclear and hydropower plants and hypothetical new power plants are expected to be similar and within the common ranges of uncertainty and variability.

LCA does not include certain, mostly site specific aspects potentially relevant for some technologies such as visual impacts and noise for wind turbines, local effects on ecosystems for hydropower, potential induced seismicity for geothermal energy, etc. Such issues are qualitatively discussed in the individual technology-specific chapters of this report. Consequences of potential accidents are in general not evaluated by LCA and also not addressed in this report.

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6 Large hydropower

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6.1 Introduction

6.1.1 Definition

According to the common Swiss definition, hydropower plants are categorized as „large", if the installed capacity is above 10 MW (BFE/SFOE 2012b). Power plants with capacities below 10 MW are categorized as "small hydro". Internationally, this capacity threshold can vary between 1.5 MW (Sweden) and 50 MW (China and Canada) (IHA 2015).

6.1.2 Global status of hydropower

Worldwide, currently (end of 2014) installed hydropower capacity amounts to 1'036 GW (IHA 2015). Total hydropower generation for the year 2014 is estimated at 3'900 TWh, contributing 16% to global overall electricity generation. New hydro installations (excluding pumped storage hydropower plants) in 2014 amount to 36 GW (China: 22 GW, Brazil: 3.3 GW; Canada: 1.7 GW; Turkey: 1.4 GW; Russia: 1.2 GW; India: 1.2 GW) (IHA 2015). Figure 6.1 shows installed capacities per country; Figure 6.2 shows total hydropower generation per country in 2014 by area. Norway, Switzerland and Austria are on top of this ranking.

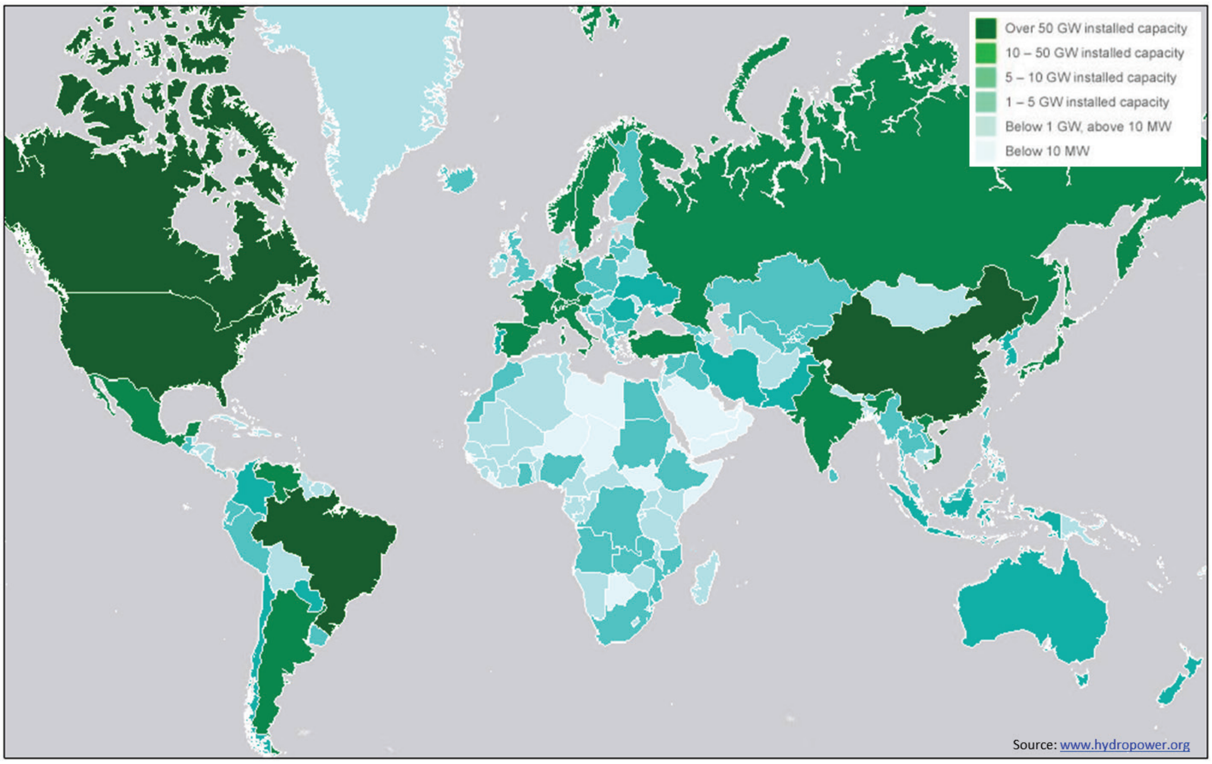

Figure 6.1: Installed hydropower capacities worldwide.[126]

[126] www.hydropower.org (20.11.2015)

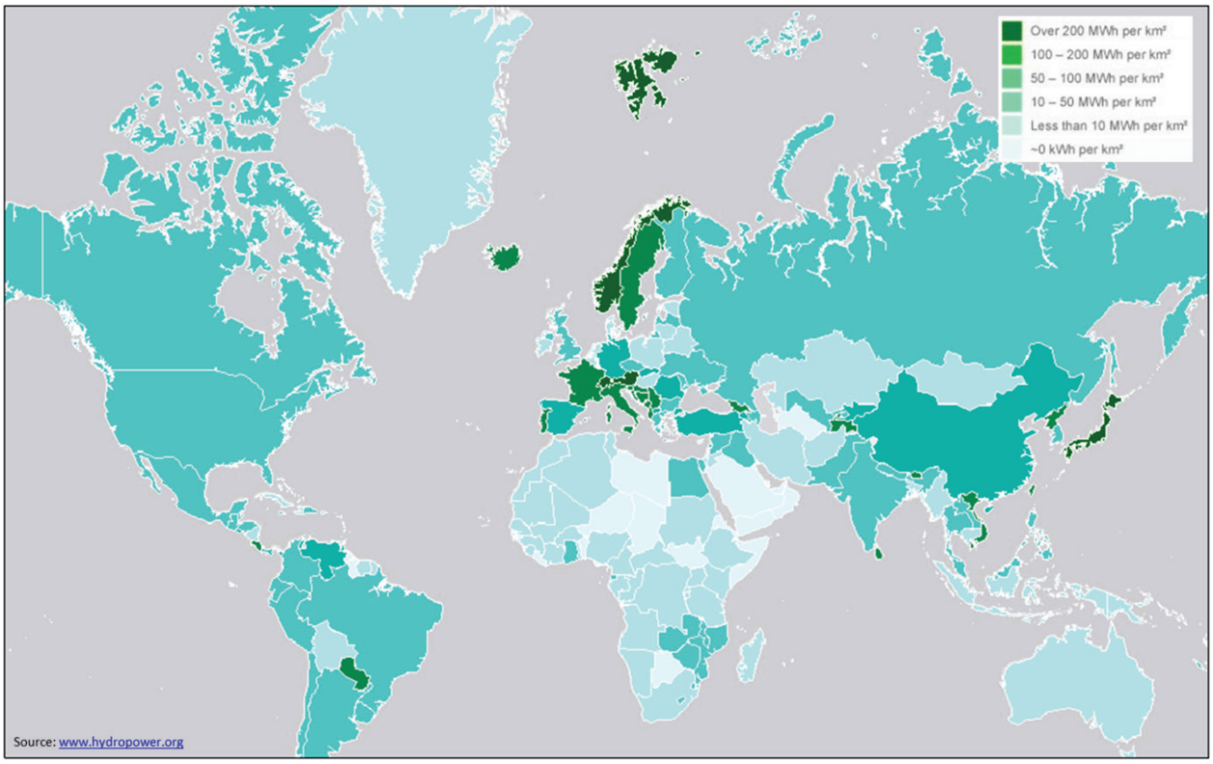

Figure 6.2: Total electricity generation of hydropower plants by area.[127]

6.1.3 Status of large hydropower in Switzerland

Large hydropower plants with capacities above 10 MW contribute around 91% to Swiss hydropower production, small hydropower plants with capacities of 1-10 MW around 8%, and power plants with capacities <1 MW about 1% (BFE/SFOE 2016h).

Figure 6.3 shows the current status of large hydropower in Switzerland in terms of operating power plants (as of 1st of January 2016). Installed capacities and expected annual generations are summarized in Table 6.1.

Total installed capacity amounts to 13’760 MW (at generator), of which 3’641 MW are categorized as run-of-river power plants (“Laufkraftwerke”), 7’966 MW as storage power plants (“Speicherkraftwerke”), 1’184 MW as pumped storage power plants using natural inflow and pumped water (“Pumpspeicherkraftwerke”), and 469 MW as pumped storage hydropower plants using only previously pumped water (“Umwälzwerke”) (BFE/SFOE 2016h).

Total annual expected electricity production amounts to 36’175 GWh without using pumped water (“Umwälzbetrieb”), 48% provided by run-of-river power plants, 48% by storage power plants and 4% by pumped storage power plants (excl. use of pumped water) (BFE/SFOE 2016h). However, hydro generation is not evenly distributed throughout the year. On average monthly generation in summer is almost twice as high as in spring (Figure 6.4). Monthly variation is also higher due to weather conditions (Piot 2014).

[127] www.hydropower.org (20.11.2015).

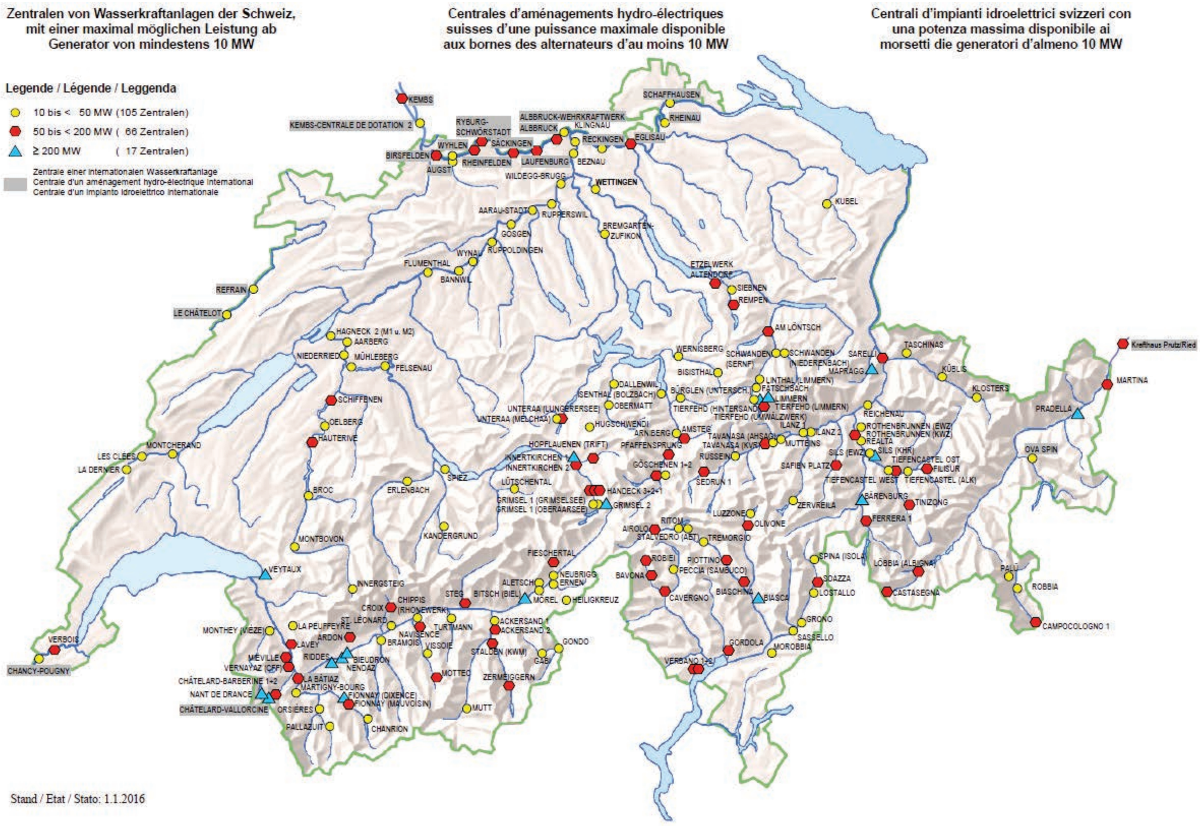

Figure 6.3: Currently operating large hydropower plants in Switzerland, as of 1st of January 2016 (BFE/SFOE 2016h).

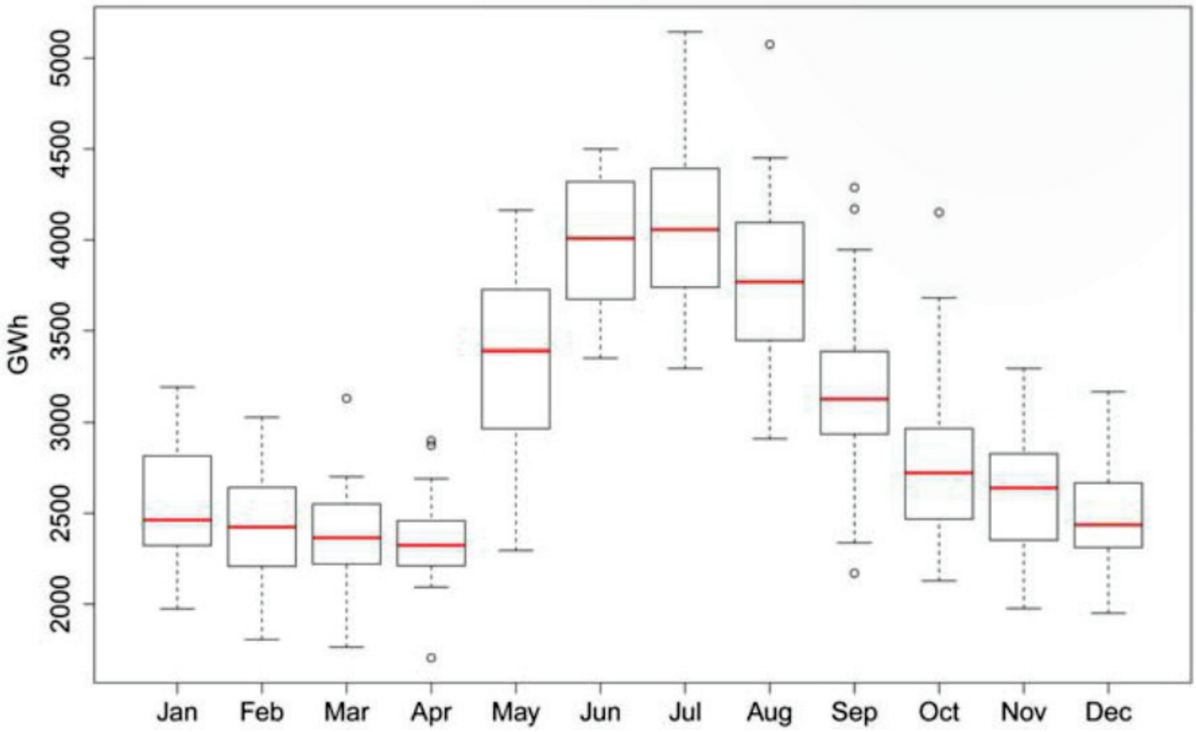

Figure 6.4: Average monthly hydropower generation 1990-2013 (Piot 2014).

Few new large hydropower plants are currently under construction: Gletsch-Oberwald (14 MW installed capacity, generation: 27 GWh/a), Krafthaus Prutz/Ried (12 MW installed capacity, generation: 57 GWh/a), Limmern (1000 MW installed capacity, generation: 7.8 GWh/a) and Nant de Drance (900 MW installed capacity, generation: 9 GWh/a) (BFE/SFOE 2016e).[128] In addition, the capacity of one pumped storage hydropower station (Veytaux) is being upgraded from 240 MW to 480 MW.

Table 6.1: Installed capacities and expected annual generation of (large) hydropower plants in Switzerland, as of 1st of January 2016 (BFE/SFOE 2016h).

Power plant type		Overall hydropower installed capacity (generator) [MW]	Overall hydropower expected annual production [GWh]	*Expected winter production[4] [GWh]*	*Expected summer production[4] [GWh]*	Large hydropower installed capacity (generator) [MW]	Large hydropower expected annual production [GWh]
Run-of river	Laufwasser	3’941	17’312	*6’173*	*11’139*		
Storage	Speicher	7’966	17’295	*8’083*	*9’212*		
Pumped storage[1]	Pump-speicher	1’384	1’568	*936*	*631*		
Pumped storage[2]	Umwälz	469	0	*0*	*0*		
Total[3]		13’760	36’175	*15’192*	*20’982*	12’874	32’652

[1] Using natural inflow of water and pumped water for power generation.

[2] Using pumped water for power generation only.

[3] Without generation from pumped water.

[4] Expected winter and summer generation is only provided for Swiss hydropower plants in total, i.e. for large (>10 MW) and small (<10 MW) hydropower.

6.2 Technology description

6.2.1 Current technologies

Hydropower is power derived from the energy of falling water or fast running water, which is harnessed for electricity generation. Large hydropower plants can be categorized according the way the water is used:

Storage power plants: damming the water and creating a reservoir lake. These power plants use the potential energy of dammed water driving water turbines and generators. The power extracted from the water depends on the volume and on the difference in height between the water source and the water's outflow. This height difference is called the head. Large pipes (the "penstock") deliver water from the reservoir to the turbine.

Run-of-river (RoR) power plants: those without reservoir capacity, so that only the water in the rivers coming from upstream is available for generation and the hydrological regime remains unchanged. These power plants are therefore subject to seasonal river flows and generation can only be regulated to a minor extent. However, the use of the term "run-of-river" for power projects varies around the world. In some countries like India and Buthan

[128] For all power plants: Expected annual generation (excl. pumped water).

projects might be specified as run-of-river, if power is produced with minor water storage capacities but still substantial short-term changes of the hydrological regime.

Pumped storage power plants: these produce electricity to supply high peak demands by moving water between reservoirs at different elevations using pumps. Often, pumped storage and reservoirs are combined using pumped water plus natural inflows to reservoirs for electricity generation. Power plants which are using only pumped water are essentially electricity storage systems and do not provide any net generation. Efficiency of a storage cycle is around 80%.

Hydropower plants use water turbines for electricity generation. Water turbines are rotary engines converting kinetic and potential energy of water into mechanical work.

Different turbine types (Figure 6.5) are used depending on useable water heads and flow rates, as shown in Figure 6.6.

Figure 6.5: Various types of water turbine runners. From left to right: Pelton Wheel; Francis Turbine; Francis Turbine; Kaplan Turbine.[129]

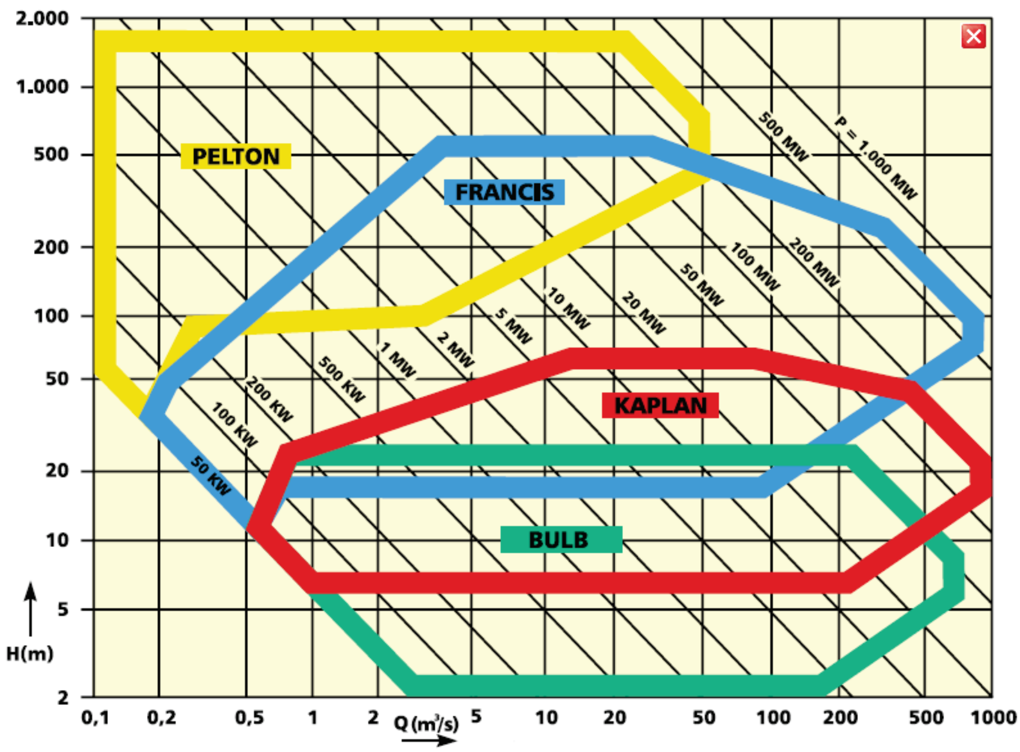

Figure 6.6: Application of different turbine technologies, depending on useable water head and flow rate.[130]

[129] Source: https://commons.wikimedia.org/wiki/File:Water_turbine_runners.jpg (19.11.2015).

6.2.2 Future technologies

The three main turbine technologies – Francis, Kaplan and Pelton – were invented between 1850 and 1920 and today and optimized designs achieve efficiencies of 90% or more (Figure 6.7) (OECD/IEA 2012). Further improvements in terms of generation efficiency will be marginal and technology breakthroughs cannot be expected.

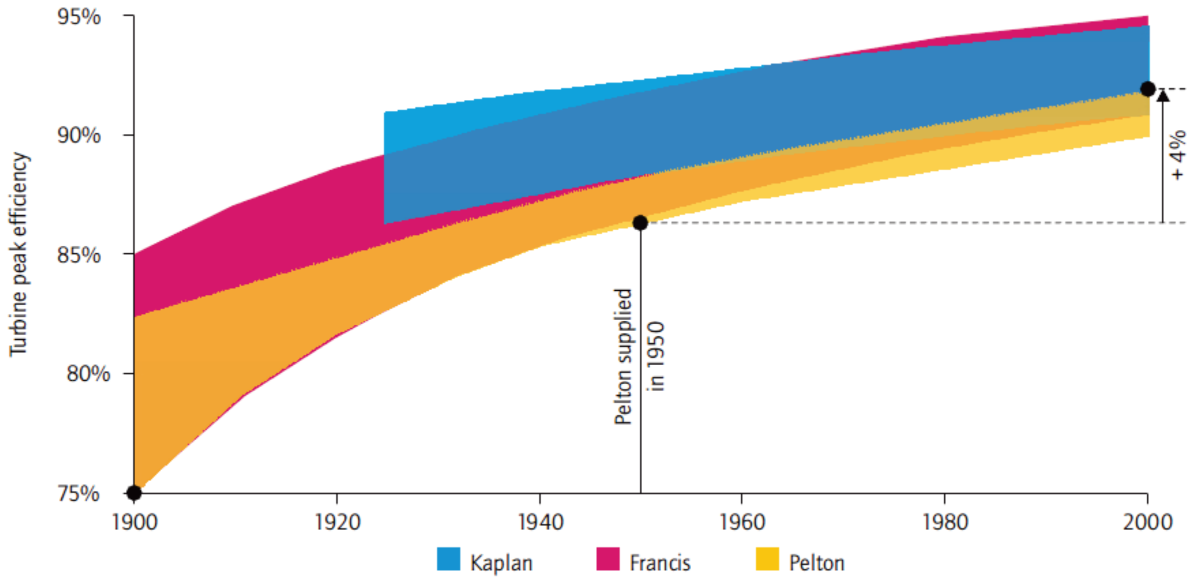

Figure 6.7: Improvement of hydraulic performance over time (OECD/IEA 2012).

6.3 Electricity generation potential worldwide

As shown in Figure 6.8, the still unexploited technical potential for hydropower generation is large and amounts to more than 10'000 TWh per year (OECD/IEA 2012). The overall technical potential of 14'576 TWh/a corresponds to around two thirds of current overall global annual electricity generation. Both, already installed hydropower as well as undeveloped potential, are regionally unevenly distributed. While in Europe more than half of the technical potential is already in operation, more than 90% of the African hydro potential is still undeveloped.

On the global scale, expansion of hydropower is considered as one of the important elements in climate change mitigation scenarios. According to (OECD/IEA 2012), hydropower generation is supposed to almost double until 2050 in a 2°C scenario, with increasing generation mainly in Asia and South America (Figure 6.9).

[130] Source: http://vip.water.hu/Galai/Antal/pub/reservoir/hydropower/pp/unesco.htm (19.11.2015).

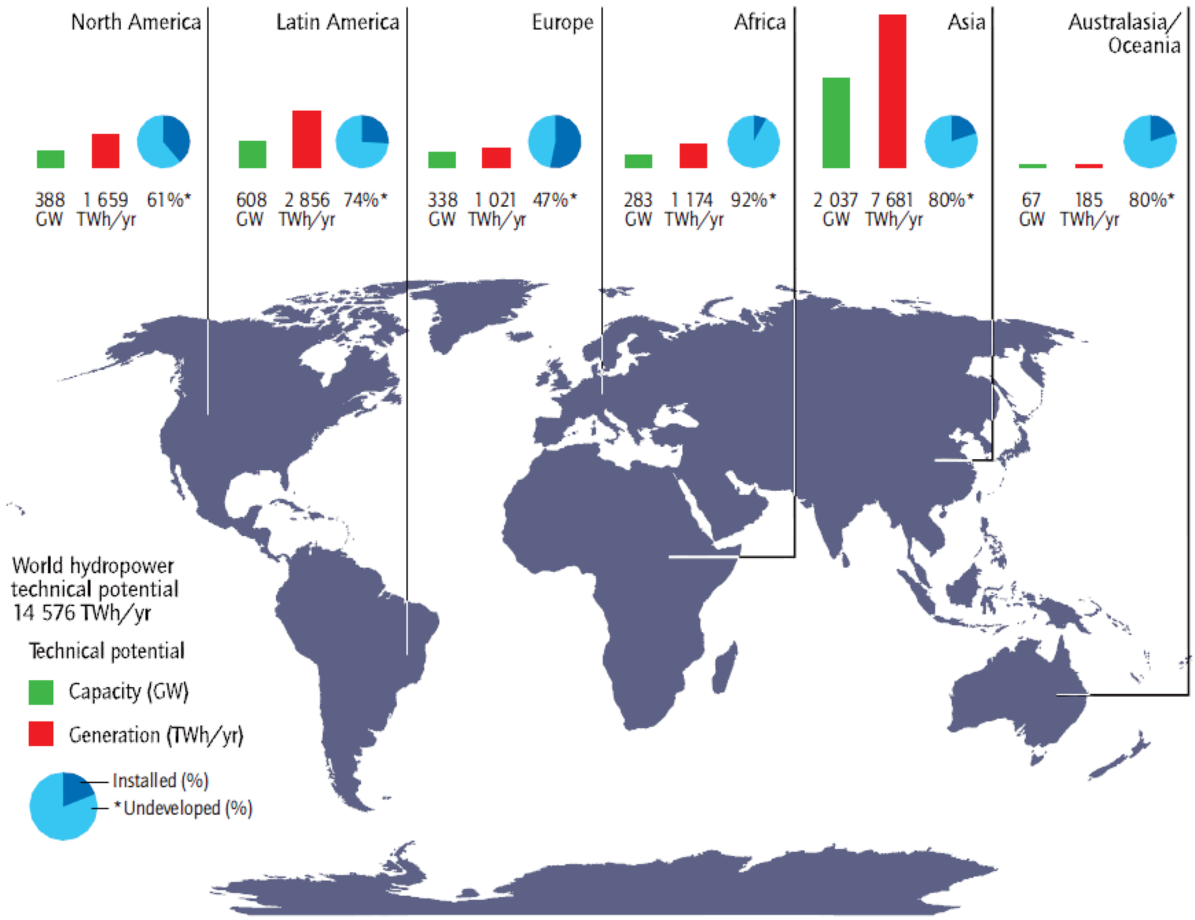

Figure 6.8: Regional technical hydropower potential and percentage of undeveloped technical potential (2009) (OECD/IEA 2012).

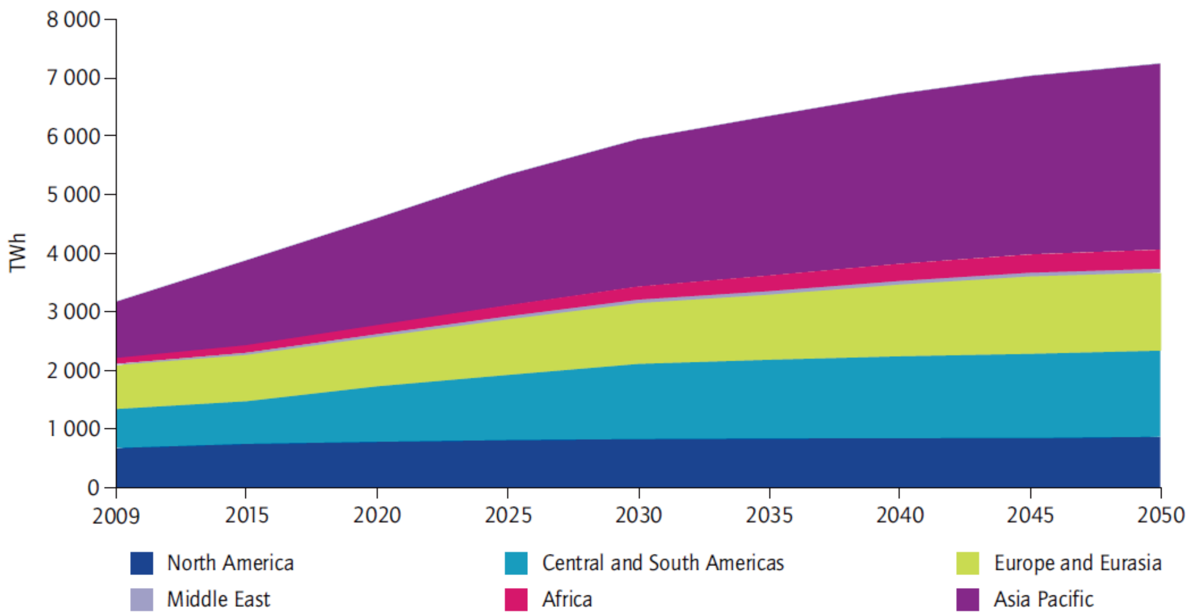

Figure 6.9: Hydroelectricity generation till 2050 in the Hydropower Roadmap vision (OECD/IEA 2012).

6.4 Electricity generation potential in Switzerland

6.4.1 Current estimations

Switzerland is using hydropower already in an extensive way and the undeveloped potential is relatively small. A few studies have recently evaluated the expansion of large hydropower in Switzerland and these estimate similar potentials, in line with the goal of the government of 37.4 TWh annual hydro generation in 2035 and of an additional annual generation of 4 TWh (relating to an expected annual generation of 35.8 TWh/a as of 1st of January 2012) until 2050 (including small hydropower) (BFE/SFOE 2012b).

According to (BFE/SFOE 2013c), additional large hydro production amounts to 3’271 GWh per year, corresponding to an additional hydro capacity of almost 1.1 GW. This estimate is based on an economic evaluation of 25 specific large hydro projects currently in the planning phase of large Swiss utilities representing 80% of current large hydro generation in Switzerland (16 run-of-river power plants, 9 storage power plants). Increasing production of existing units represents 18% of this additional potential, 82% are supposed to be contributed by new power plants. According to the utilities’ judgement, most of the evaluated projects would likely be realized given sufficient economic profitability (Figure 6.10). However, considering the current boundary conditions, only one out of 25 evaluated projects would be economically viable (BFE/SFOE 2013c).

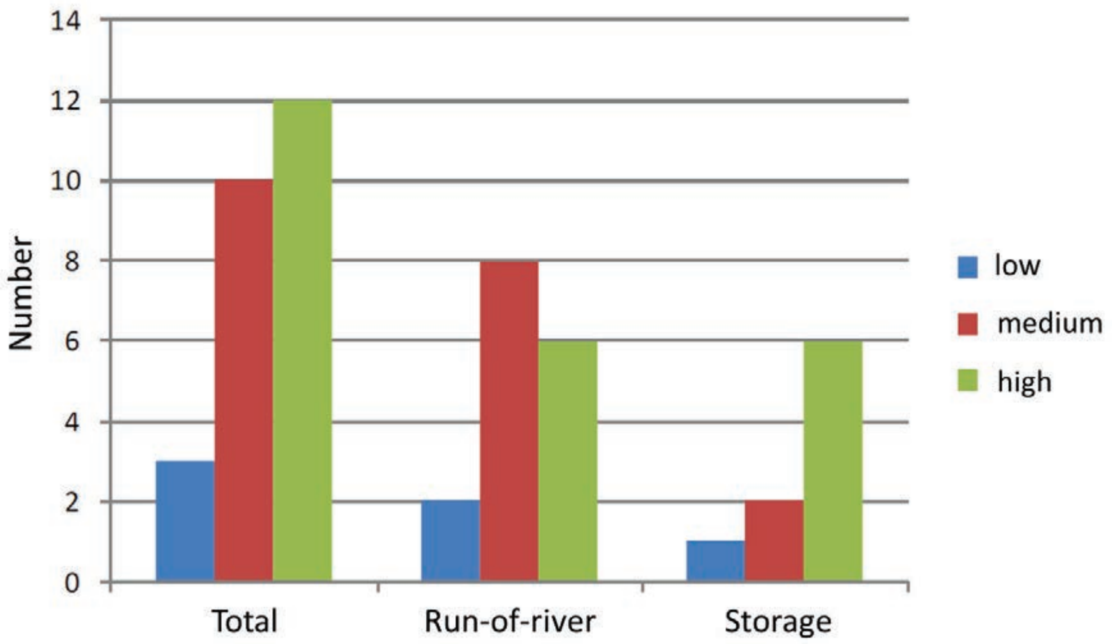

Figure 6.10: Utilities’ judgement of the likelihood of project implementation given sufficient economic profitability of 25 large hydropower projects (BFE/SFOE 2013c).

According to the latest hydro potential evaluation of the SFOE (BFE/SFOE 2012b), additional generation crucially depends on the economic and social boundary conditions. Given the current boundary conditions, new large hydropower plants could generate additional 770 GWh per year, expansion and modernization of current power plants result in additional annual generation of 870 GWh until 2050. Under optimized boundary conditions, i.e. prioritizing hydropower over current obstacles such as negative visual impacts, impacts on ecosystems and recreation areas and providing appropriate economic incentives, new large hydropower plants could generate additional 1’430 GWh per year, expansion and modernization of current power plants result in additional annual generation of 1'530 GWh until 2050 (all numbers relating to an expected annual generation of 35.8 TWh/a as of 1st of January 2012)[131].

In both scenarios, a reduction in overall hydropower generation of 1'400 GWh per year (incl. small hydro)[132] due to the effects of new legislation ("Gewässerschutzgesetz") until 2050 is estimated. Furthermore, it is stated that impacts of climate change on hydropower generation – considering the high associated uncertainties – are not expected to change annual electricity production in a substantial and quantifiable way.

Table 6.2: Estimated additional large hydropower potential in Switzerland, relating to an expected annual generation of 35.8 TWh/a as of 1st of January 2012 (BFE/SFOE 2012b, BFE/SFOE 2013c).

additional generation potential [GWh/a]				
		BFE/SFOE 2012		**BFE/SFOE 2013**
		Current boundary conditions	Optimized boundary conditions	
large hydro	new construction	770	1430	2682
	renovation & extension	870	1530	589
impact of waters protection legislation		*-1260*	*-1260*	*not addressed*
large hydro	total additional generation	**380**	**1700**	**3271**

Figure 6.11 shows the estimated additional large hydropower potential in Switzerland, as summarized in Table 6.2 according to the two most relevant recent evaluations.

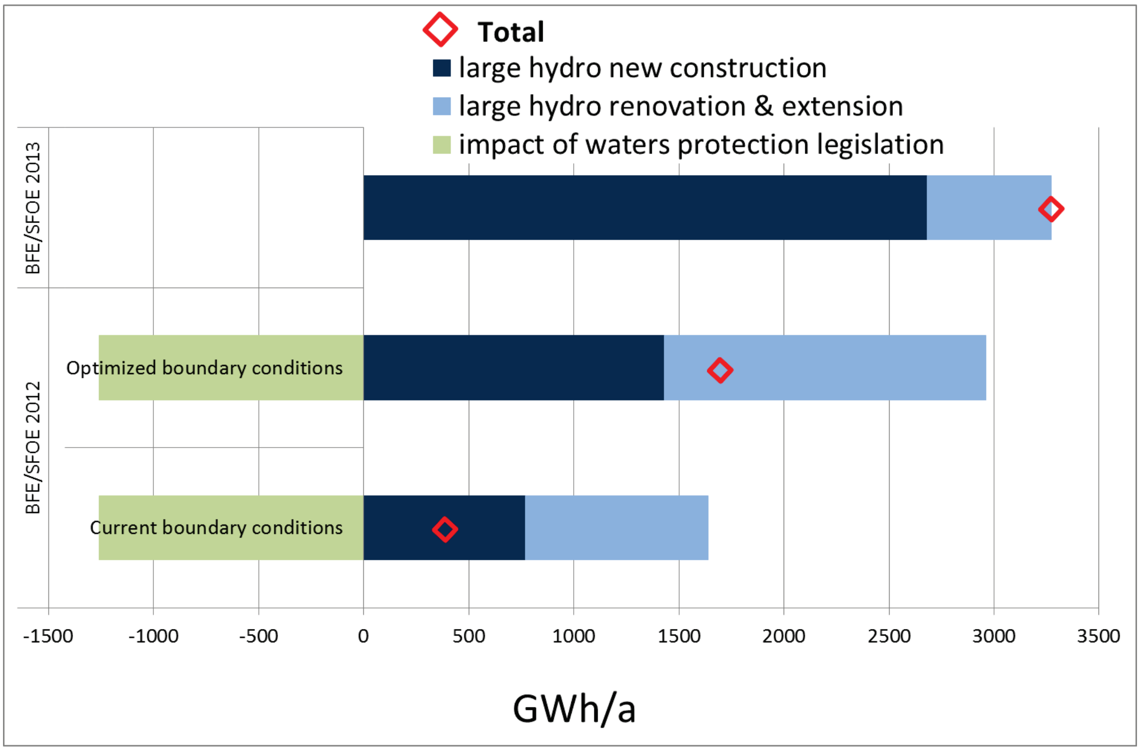

Figure 6.11: Overview of estimated additional large hydropower potential in Switzerland according to latest evaluations, relating to an expected annual generation of 35.8 TWh/a as of 1st of January 2012 (BFE/SFOE 2012b, BFE/SFOE 2013c).

[131] Note that these figures for the additional LHP generation potential – summarized in Table 6.2 – must not be added to the expected LHP generation of 36.2 TWh/a in 2016, but to the expected generation in 2012, i.e. 35.8 TWh/a (confirmed by (Bühlmann 2017)). The difference between 2012 and 2016 corresponds to already realized expansion of LHP.

[132] In proportion to current production, 90% of this reduction is assigned to large hydropower, 10% to small hydropower.

However, the way the additional large hydro potential is quantified in (BFE/SFOE 2012b) requires some discussion: each specific project for new hydropower plants is assigned with a probability of implementation (higher for optimized than for current boundary conditions) of 0, 0.25, 0.5, 0.75 or 1 (Annex 2 in (BFE/SFOE 2012b)). The cumulative, additional annual generation is calculated as sum of power plant specific expected annual generation multiplied with the power plant specific probability of implementation. E.g. a power plant with an annual generation of 100 GWh, to be implemented with a probability of 0.5, contributes 50 GWh/a.

An alternative way of estimating the additional generation potential of new hydropower plant constructions is shown in Figure 6.12. Power plant projects are categorized according to the probability of their implementation and their complete expected annual generation is added up independently of their probability of implementation (as long as >0). For example, this procedure results in case of project implementation for all power plants with a probability ≥0.5 in almost 1100 GWh or about 1400 GWh of additional annual generation under today's or future optimized boundary conditions, respectively.

Figure 6.13 shows the locations, expected (increase in) annual production and probability of implementation of potential future hydropower projects (Boes 2016).

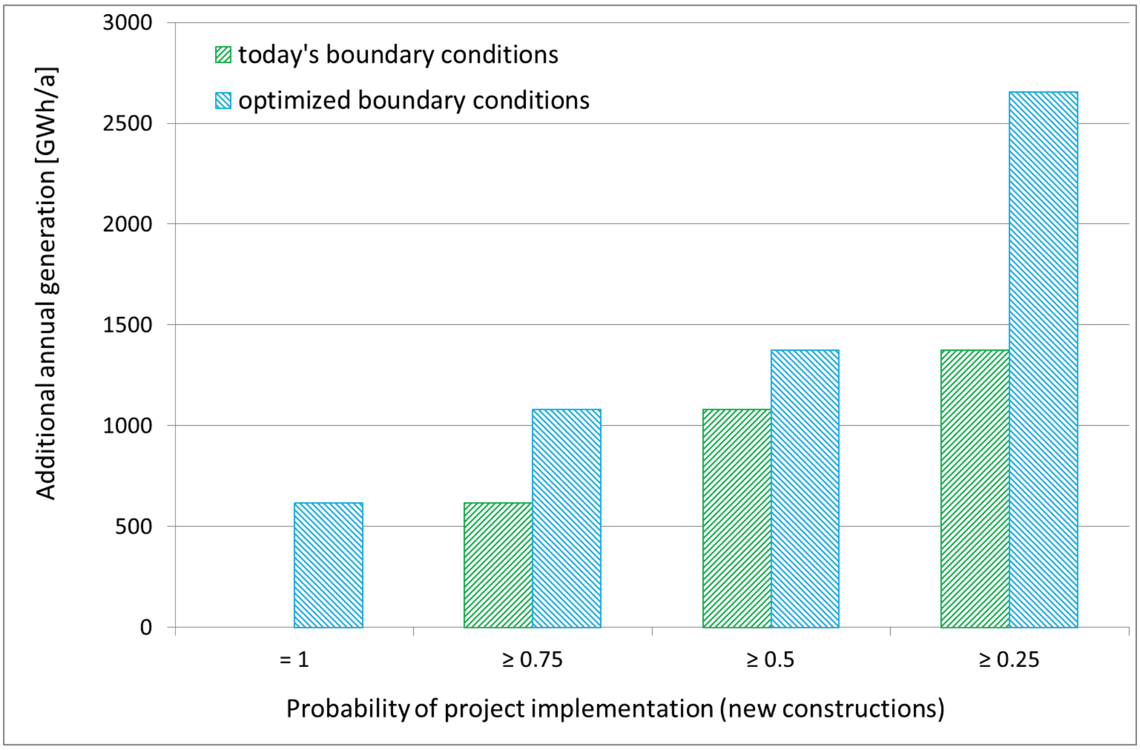

Figure 6.12: Alternative estimation of additional electricity generation with new hydropower plant constructions, relating to an expected annual generation of 35.8 TWh/a as of 1st of January 2012 according to project specific data in Annex 2 of (BFE/SFOE 2012b).

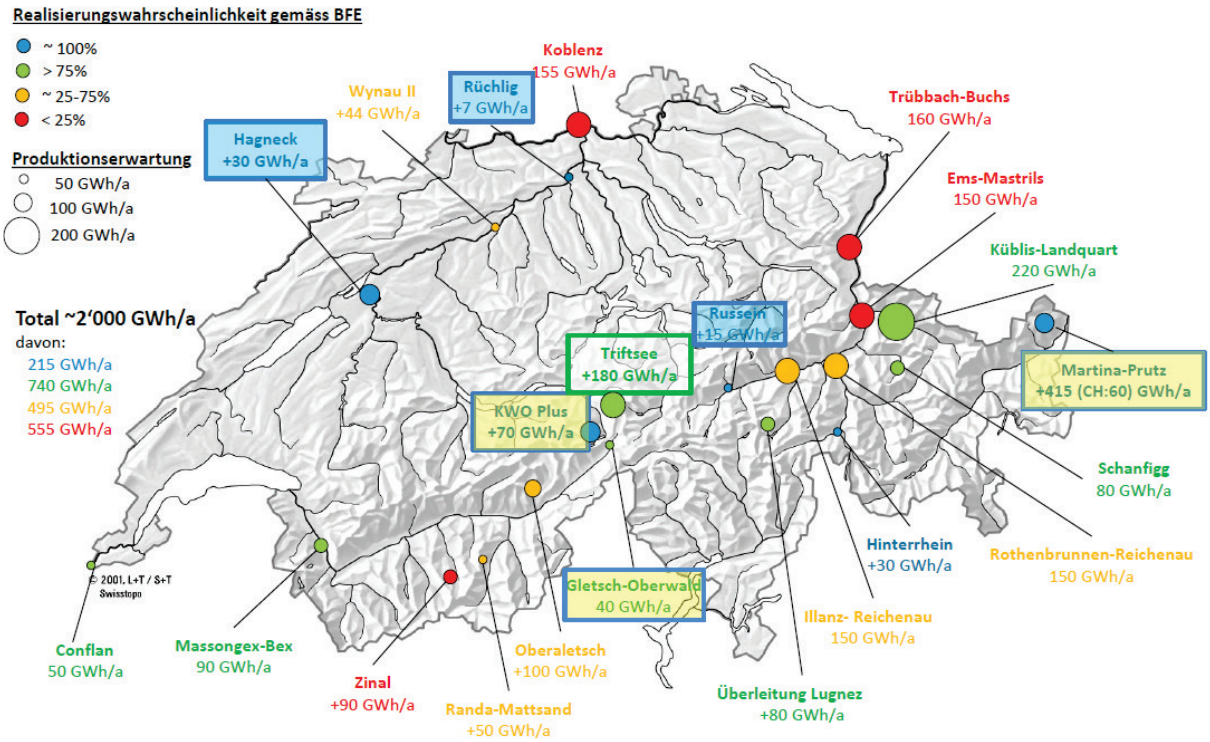

Figure 6.13: Locations and expected (increase in) annual production of specific potential future hydropower projects (Boes 2016).

The "Schweizerische Wasserwirtschaftsverband (SWV)" does not believe in increasing hydro generation given the current boundary conditions; the association rather expects slightly decreasing overall hydro generation in the long term in Switzerland (Pfaffmatter and Piot 2014).

(Schleiss 2012b) and (Schleiss and Oberrauch 2014) stress the importance of increasing flexibility in hydro generation and the importance of reservoirs considering the increasing amounts of intermittent electricity on the market and Swiss dependence on electricity imports in winter. According to (Schleiss 2012b), an increase of the heights of 20 Swiss reservoir dams by less than 10% could increase Swiss winter electricity production by roughly 2 TWh, i.e. around 10%. Increasing heights further could yield 15% increase of Swiss winter electricity production (Schleiss 2016).

Even if pumped storage hydropower plants do not contribute to net generation, they are supposed to become more important counterbalancing supply and demand in case of substantial expansion of intermittent sources such as photovoltaics or wind power. The sites Linth-Limmern, Nant de Drance and Veytaux recently finalized or currently under construction are adding and will add, respectively, a capacity of 2.1 GW until 2017. Lago Bianco and Grimsel 3 would further add 1.6 GW capacity, summing up to a potential total capacity of pumped storage hydropower plants of 5.2 GW (Piot 2014).

The potentials identified in these recent studies do not take into account frequently occurring obstacles, be it from the economic, legislative, spatial planning, or acceptance perspectives. (Walter, Scheuchzer et al. 2013) have discussed these issues and proposed some measures for realizing hydro potentials in Switzerland in a sustainable way.

6.4.2 Impact of climate change on future hydropower generation

Recent studies (Terrier, Jordan et al. 2011, Weingartner and Zappa 2011) provide a perspective of the future potential impacts of global warming on Swiss hydropower generation. (Weingartner and Zappa 2011) emphasize the high uncertainties in this context and advise against generalization of local estimates, in line with (Schaefli 2015).

Climate models predict temperature increases in the Alps above global average and only small changes in annual precipitation, slightly increasing in Northern Switzerland and slightly decreasing in Southern Switzerland. Less rainfall is expected in summer (especially in Northern Switzerland), slightly more in the other seasons. Snow cover and glaciers will be reduced, substantially until 2100 (Figure 6.14).

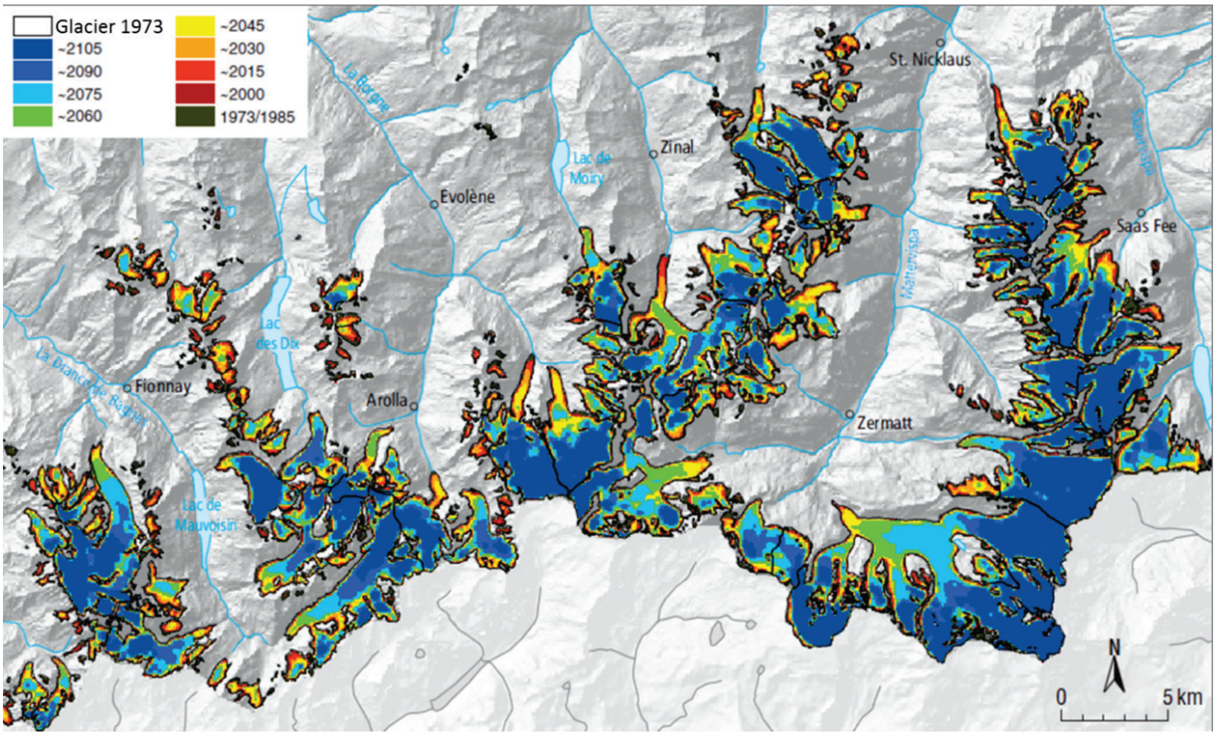

Figure 6.14: Modeled development of glaciers in Southern Wallis over time (Paul, Linsbauer et al. 2011).

While in the short term, reservoirs with glaciated and snow-influenced water catchment areas will profit from accelerated melting of glaciers, average annual runoff tends to decrease in the long term. While annual average runoff volumes will only be affected to a minor extent, seasonal runoff patterns will change more substantially: the runoff maximum will shift from summer to late spring; average runoff volumes will decrease in summer and autumn and increase in winter (Terrier, Jordan et al. 2011, Schaefli 2015).

(Weingartner and Zappa 2011) conclude that until 2035, the impact of climate change on hydro generation in Switzerland will be minor and can be positive or negative. However, they expect negative impacts in the longer term (until 2085), most pronounced in the Wallis with average reductions between four and eight percent and "worst case" reductions for single plants of up to 20%.

The meltdown of alpine glaciers will lead create new lakes in former glaciated areas (Terrier, Jordan et al. 2011, Haeberli, Schleiss et al. 2012). Figure 6.15 shows potential locations of these lakes, their water volumes and the time periods in which they are expected to be created. These lakes represent both opportunities and risks: chances in terms of new reservoir lakes for power generation and risks in terms of causing flood waves and rockslides. Therefore, these lakes have to be managed with care. First estimates of additional potential for power generation are in the order of 1 TWh/a by 2050 (Boes 2016)[133].

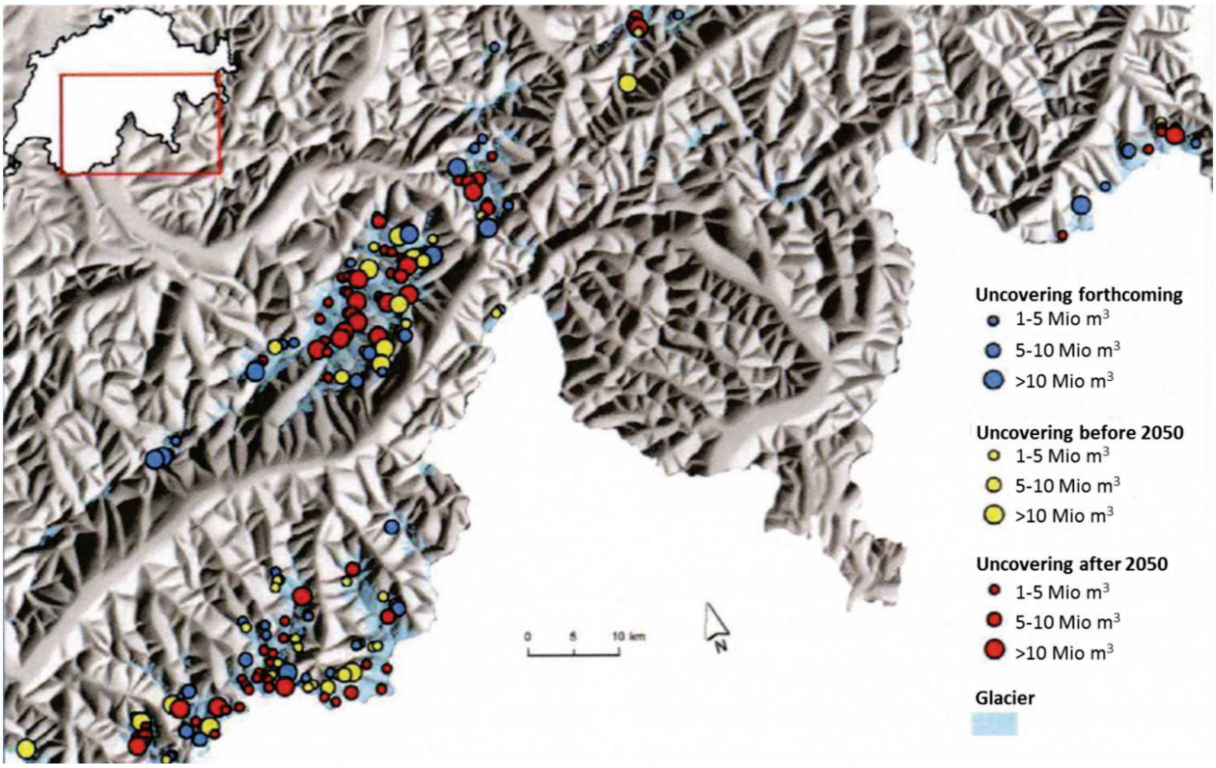

Figure 6.15: Potential locations and sizes of new lakes in currently glaciated areas due to global warming (Haeberli, Schleiss et al. 2012).

6.5 Electricity generation costs in Switzerland

6.5.1 Current generation costs

(Filippini and Geissmann 2014) differentiate between different hydro plant types. Their analysis of large hydro generation costs of existing plants includes data from 60 Swiss hydro operators, which are split into four different categories: utilities mainly operating a) low pressure run-of-river power plants, b) high-pressure run-of-river power plants, c) storage power plants and d) pumped storage power plants. However, a specific categorization does not imply that these utilities only operate a certain plant type. Overall, the sample represents Swiss hydropower well, both in terms of installed capacities as well as in terms of annual electricity production.

Figure 6.16 shows that – on average – generation costs of low pressure run-of-river power plants (around 5 Rp./kWh) are slightly below those of the other categories (around 6 Rp./kWh for high-pressure run-of-river and storage power plants, and 6-8 Rp./kWh for pumped storage plants).

[133] Due to the large uncertainties, this additional potential is not accounted for in the estimates of total hydropower potentials.

Figure 6.17 shows that capital costs contribute most to average generation costs.

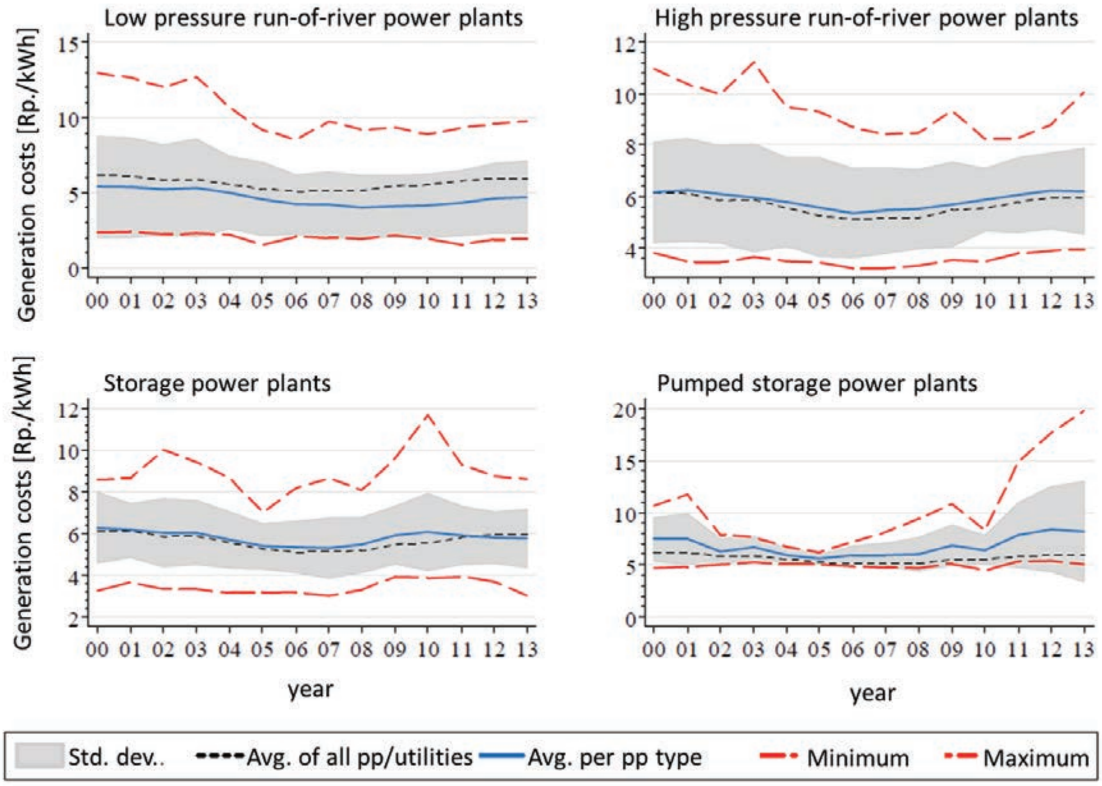

Figure 6.16: Electricity generation costs of current Swiss large hydropower plants between 2000 and 2013, split into different hydropower plant types (Filippini and Geissmann 2014); pp=power plant.

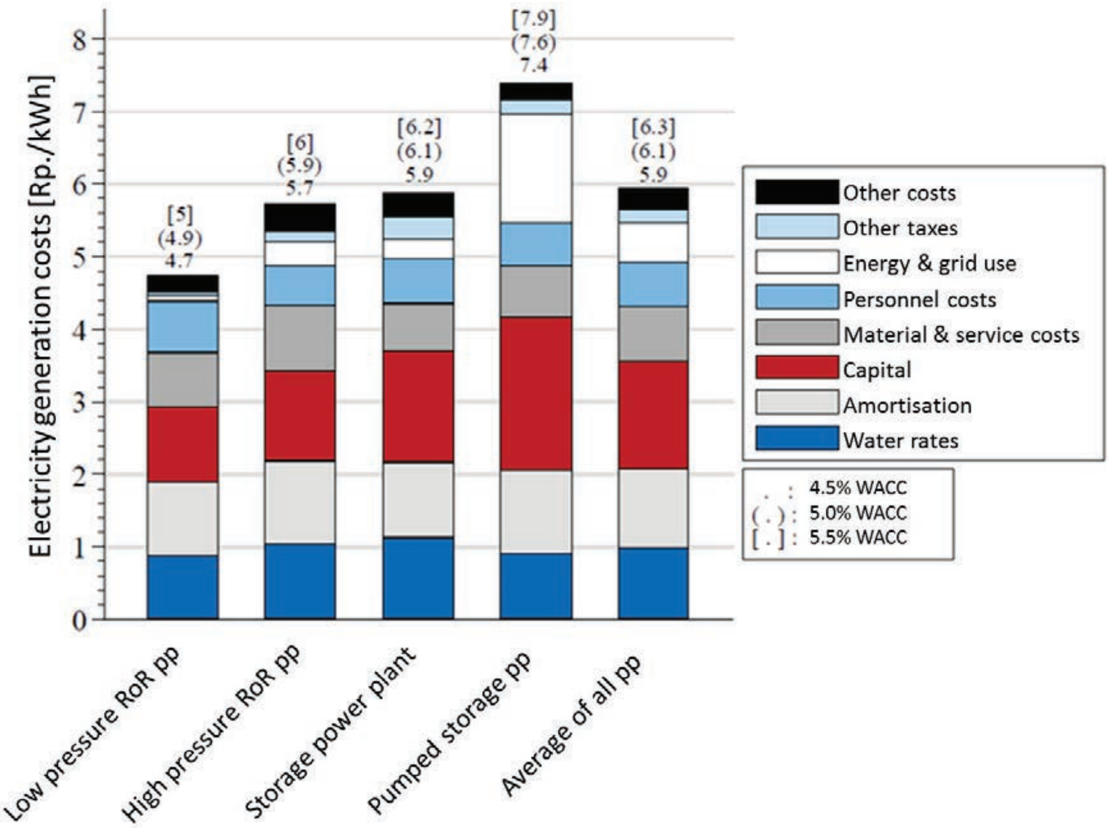

Figure 6.17: Breakdown of average generation costs of current Swiss large hydropower plants in 2013, split into four different categories (Filippini and Geissmann 2014); RoR=run-of-river, pp=power plant.

6.5.2 Future generation costs

According to (BFE/SFOE 2013c), electricity generation costs of new large hydropower plants amount on average to 14.1 Rp./kWh, while existing large hydropower plants generate for 5-6 Rp./kWh. These generation costs of new power plants were estimated based in a sample of 25 potential new power plants (16 run-of-river, 9 storage power plants). Project plans of utilities exist for these power plants; however, they have not (yet) been built due to various reasons, lacking profitability as the most prominent one. Since input data for this quantification have been provided by the utilities, the results can be judged as reliable. Unfortunately, the data provided in (BFE/SFOE 2013c) do not allow for differentiation between storage and run-of-river power plants.

Specific investment costs of all projects are in the range of 2'000-10'000 CHF per kW with a generation weighted average of 5'995 CHF/kW. If projects with focus on modification of hydropeaking (so-called "Schwall-Sunk Sanierung") (which are not primarily carried out for increase of electricity generation) are excluded, the average investment costs go down and amount to 3'466 CHF/kW. Larger power plants tend to exhibit lower specific investment costs (Figure 6.18).

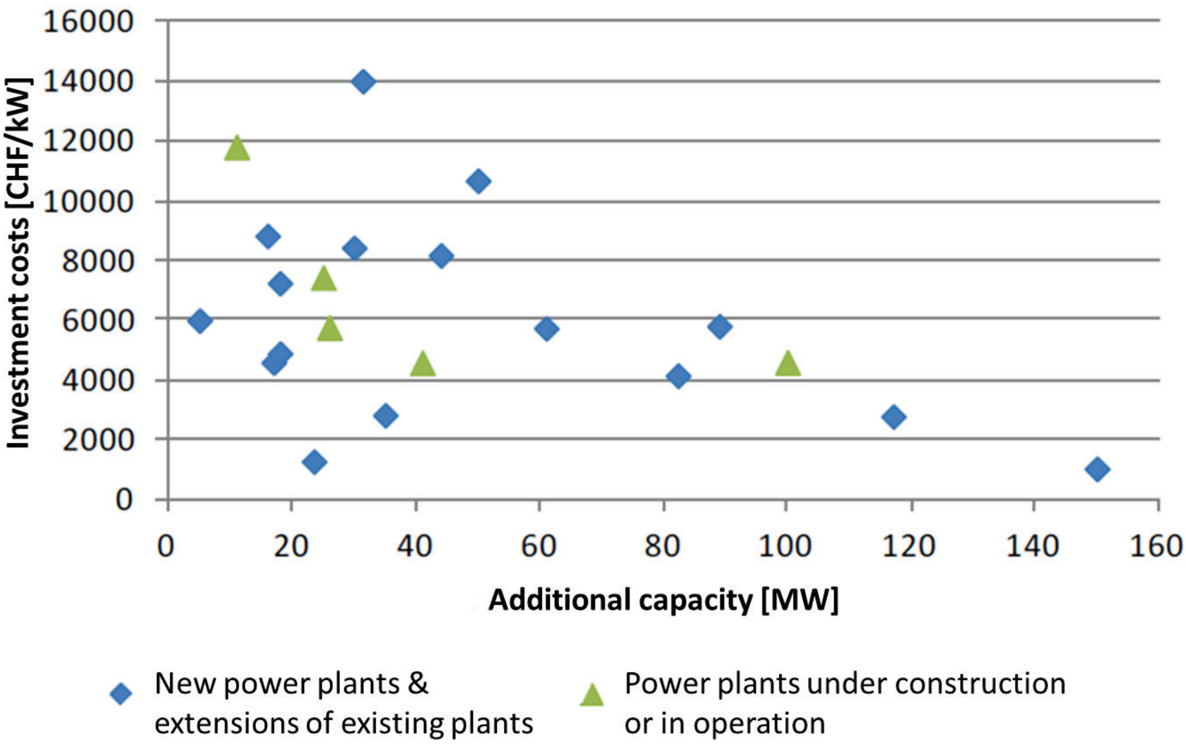

Figure 6.18: Specific investments costs of new large hydropower plants, as analyzed in (BFE/SFOE 2013c).

Excluding the projects focusing on "Schwall-Sunk Sanierung" reduces average electricity generation costs of new power plants to 12.9 Rp./kWh. Capital costs are the main contributor to average generation costs with an average share of 70%.

(BFE/SFOE 2013c) provide a "cumulative additional generation – generation cost" curve (Figure 6.19) showing that up to an additional annual generation of 2'000 GWh the generation costs are below 15 Rp./kWh and substantially increase above 2000 GWh/a.

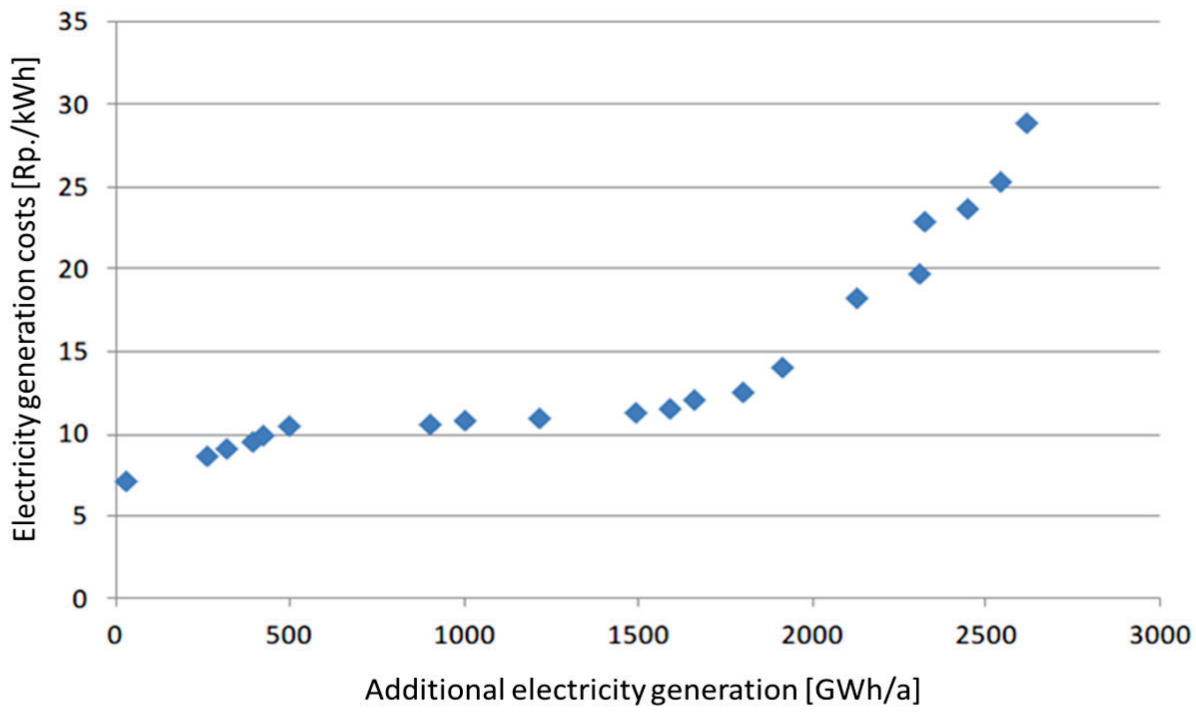

Figure 6.19: Cumulative additional large hydropower electricity production ranked according to increasing generation costs (BFE/SFOE 2013c).

Concerning pumped storage hydropower plant generation, (BFE/SFOE 2013a) state that while in the short term pumped storage hydropower plant projects will hardly be profitable, the long term perspectives are much better due to further expansion of intermittent wind power and photovoltaics and higher electricity prices at times of lacking wind and photovoltaics generation (as a consequence of expected increasing cost of fossil generation).

6.6 Environmental aspects

6.6.1 Life Cycle Assessment (LCA)

Recent LCA literature (Sathaye, Lucon et al. 2011, Bauer, Frischknecht et al. 2012, Masanet, Chang et al. 2013, Turconi, Boldrin et al. 2013, ecoinvent 2015) shows that hydropower is generally generating electricity with a very good environmental profile, i.e. compared to other generation technologies, the life cycle burdens of hydropower are minor. One potentially problematic issue is the generation of GHG emissions due to degradation of organic material in reservoir lakes; resulting net GHG emissions per kWh of electricity generated can be substantial (Hertwich 2013, Fearnside 2015). However, these high net GHG emissions of hydropower only occur in tropical regions. Climatic conditions in Europe and vegetation patterns in the Alps do not allow for substantial biomass degradation resulting in noteworthy GHG emissions (Hertwich 2013, ecoinvent 2015), and therefore, this issue is not relevant for Switzerland.

Figure 6.20 shows life cycle GHG emissions of storage and run-of-river hydropower in Switzerland (at the power plant) representing impacts on climate change, quantified using GWP factors of IPCC 2007 (Solomon, Qin et al. 2007) according to different studies.

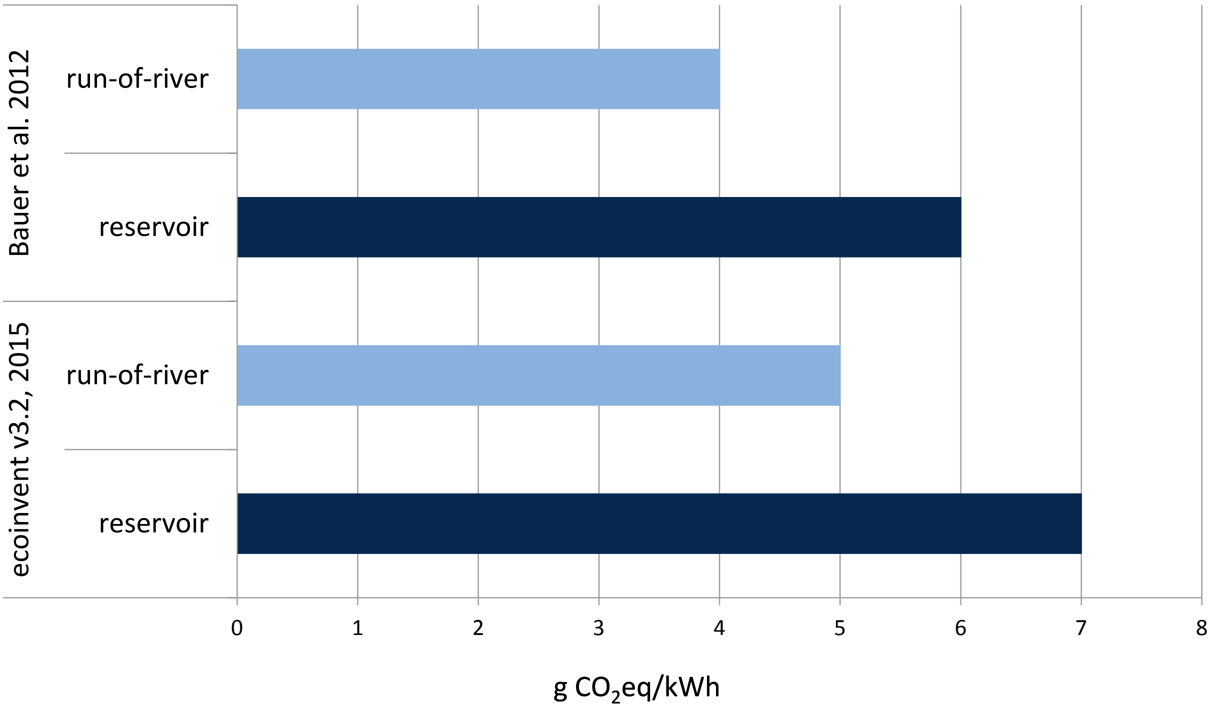

Figure 6.20: Life cycle GHG emissions (GWP 100a) due to electricity production at different hydropower plant types in Switzerland (Bauer, Frischknecht et al. 2012, ecoinvent 2015).

GHG are predominantly caused (directly and indirectly via material supply chains) by infrastructure construction of the hydropower plants.

Further environmental LCA indicators recommended by the Joint Research Centre of the European Commission (JRC) (Hauschild, Goedkoop et al. 2013) are quantified for Swiss hydropower plants according to (ecoinvent 2015) in comparison to the Swiss high voltage electricity consumption mix (Figure 6.21): electricity from hydropower in Switzerland generates much less environmental burdens than the average Swiss consumption mix in all impact categories.

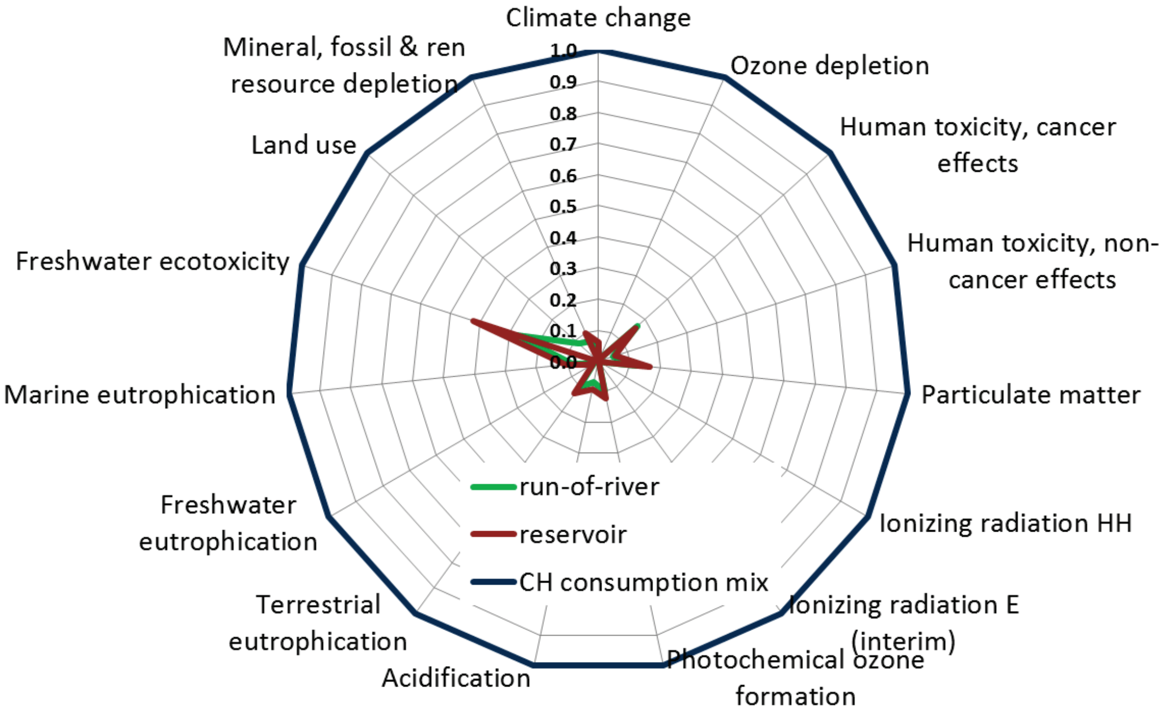

Figure 6.21: Comparison of LCIA indicators for the average Swiss consumption mix, Swiss storage and run-of-river power plants, relative to the Swiss consumption mix (=1).

6.6.2 Other environmental issues

Hydropower can, however, have negative impacts on ecosystems not measured with LCA methodology. Such impacts are location specific and depend on local and regional hydrology. Impacts on local scale, e.g. negative effects on biodiversity, or visual disturbance, need to be evaluated on a case-by-case basis and weighted against the benefits of electricity generation. Impacts on ecosystems can basically be attributed to three different types of interventions induced by hydropower plants (Weber and Schmid 2014):

- Interruption of river networks ("Längsvernetzung") due to dams
- Reduction of water flow (residual water)
- Up- and downsurge / hydro-peaking ("Schwall-Sunk")

Interruption of river networks leads to reduced transport of river bed loads, which changes habitats for fish and other organisms. Furthermore, travel of fish and mammals negatively affected. Reduced residual water and regulated water flows due to hydropower plants (i.e., lack of flooding) shows negative effects on floodplains; self-purification is reduced and water temperatures tend to increase, both with negative impacts on organisms. Also artificially regulated and quickly fluctuating downstream water flows lead to changes in water temperatures. Reservoir lakes can also be used to shift runoff from summer to winter. All these changes affect fish, insects and plants, i.e. local ecosystems (Weber and Schmid 2014).

6.7 Abbreviations

a	year
avg	average
BFE/SFOE	Bundesamt für Energie/Swiss Federal Office of Energy
CAPEX	capital expenses
CH	Switzerland
CHF	Swiss francs
CO_2 eq.	carbon dioxide equivalent
EQ	ecosystem quality
GHG	greenhouse gas
GIS	geographic information system
GWP	global warming potential
HH	human health
KEV	Kostendeckende Einspeisevergütung/compensatory feed-in renumeration
LCA	life cycle assessment
LCI	life cycle inventory
LCIA	life cycle impact assessment
LCOE	levelized cost of electricity
LHP	large hydropower
MHP	mini hydropower
O&M	operation & maintenance
OPEX	Operating and maintenance expenses
pp	power plant
PSI	Paul Scherrer Institut
RoR	run-of-river
Rp.	Rappen (Swiss cents)
SHP	small hydropower
Std. dev.	standard deviation
WWAC	weighted average capital costs
yr	year

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7 Small hydropower

Maxim Lehnert, Christian Bauer, Warren Schenler (Laboratory for Energy Systems Analysis, PSI)

7.1 Introduction

The utilization of the energy potential of running water in small scale has an unexpectedly long tradition. In the form of water mills, first small hydropower applications date back to pre-Christian eras and prevailed throughout ancient and medieval ages.

In Switzerland small hydropower maintained its importance even after in most other European nations, hydropower applications had been replaced by emerging steam power. So, for example, in 1914 about 6’700 small hydropower plants were registered in Switzerland. With the development of the electricity grid and the rise of cheap and reliable energy from large power stations many small hydropower applications were shut down.

This decline prevailed until several political initiatives assisted the small hydropower industry to reach a turnaround in the 1990s. As an emission-free electricity source with an inexhaustible fuel, hydropower had regained a lot of its attractiveness under modern assessment criteria.

With respect to the Swiss energy strategy 2050 the potential contribution of small hydropower to the Swiss electricity generation mix should be evaluated in consideration of technical, economic, environmental and social constraints.

7.1.1 Definition

7.1.1.1 Installed capacity

According to the commonly applied Swiss definition, hydropower plants are categorized as „small“, if the installed capacity is below 10 MW (BFE/SFOE 2012b). Plants[134] with capacities above 10 MW are categorized as “large hydro”. Although a capacity threshold of 10 MW is also internationally mostly accepted, the threshold varies among countries between 1.5 MW (Sweden) and 50 MW (China and Canada) (IHA 2015).

Within the overall definition of small hydropower further differentiations can be made. In Switzerland hydropower plants with an installed capacity below 300 kW are defined as “mini hydro”, whereas internationally this threshold is typically set to 500 kW (Crettenand 2012).

This report always uses the Swiss disambiguation. “Mini hydropower” (MHP) refers to power plants with an installed capacity below 300 kW. “Small Hydropower” (SHP) refers to all power plants with an installed capacity below 10 MW also including, if not specified otherwise, mini hydropower.

7.1.1.2 Differentiation according to the type of power plant

Besides the definition according to installed capacity, SHP can also be distinguished with respect to the type of the power plant. Different factors such as head, kind of construction and runoff medium are useful criteria to define different groups of SHP plants.

[134] In the context of this report, the term “plant” is used as synonym for “power plant” or “hydropower plant”.

Differentiation according to **hydraulic head** (UVEK/DETEC 2007):

- Low head power plants (head < 40 m)
- Middle head power plants (head between 40 and 200 m)
- High head power plant (head > 200 m)

Differentiation according to **construction type** (UVEK/DETEC 2007):

- Run-of-river power plant (a river is dammed and the water is returned directly to the river after the turbine, without ever leaving the natural flow channel)
- "Ausleitkraftwerk"/diversion power plant (a part of the flow is diverted from the river and fed to the turbines via a headwater channel. Afterwards the water is returned to the river)[135]
- Storage hydropower plants (water is stored for a certain period of time in a reservoir)
- "Umwälzwerke"/circulation power plants (Turbine and pump form a cycle. Water is pumped from a lower reservoir to a higher one and can then feed a turbine)
- Pumped-storage plants (combination of storage plants and circulation plants)

Differentiation according to **runoff medium** (Hirschberg, Bauer et al. 2005):

- River fed hydropower (a natural stream is used for power generation)
- Wastewater power plant (power generation related to wastewater treatment. Either before, within or after wastewater treatment plant)
- Drinking water power plant (water, which is captured and distributed for drinking purposes, is used for power generation in the process)
- "Dotierkraftwerk"/discharge power plant (the residual water of larger power plants and weirs is harnessed)

7.1.2 Global status of small hydropower

SHP is a widespread technology, being used in most countries of the world. Figure 7.2 shows the proportion of the global installed capacity, state of 2013. The total amount is in the order of 75'000 GW. The total potential is given as 173'000 GW (Liu, Masera et al. 2013).

Asia, especially China (36.9 GW installed, 3.76 TWh annual production), contributes largely to the global SHP generation. Currently about 45'000 SHP stations are installed in China, accounting for 25% of the domestic hydropower production. As shown in Figure 7.1, other important holders of installed SHP capacity are the USA (6.8 GW), Japan (3.5 GW), India (3.2 GW), Italy (2.7 GW), France (2.1 GW), Spain (1.9 GW), Norway (1.8 GW), Germany (1.7 GW), Russia (1.3 MW), Sweden (1.2 GW), Canada (1.0 GW) and Brazil (1.0 GW). The installed capacity of Switzerland is given as 760 MW.

The International Center on Small Hydropower (ICSHP) provides an online map that offers a clear interactive overview over the used and unused SHP potential for most countries of the world.[136] However, this display is rather an approximation and lacks accuracy on national level. The SHP potential of Switzerland, for instance, is indicated as fully exploited. This is not correct, as will be shown in part 7.4.

[135] http://www.bfe.admin.ch/kleinwasserkraft/03875/03876/index.html?lang=en (23.04.2016)
[136] http://www.smallhydroworld.org/ (09.06.2016)

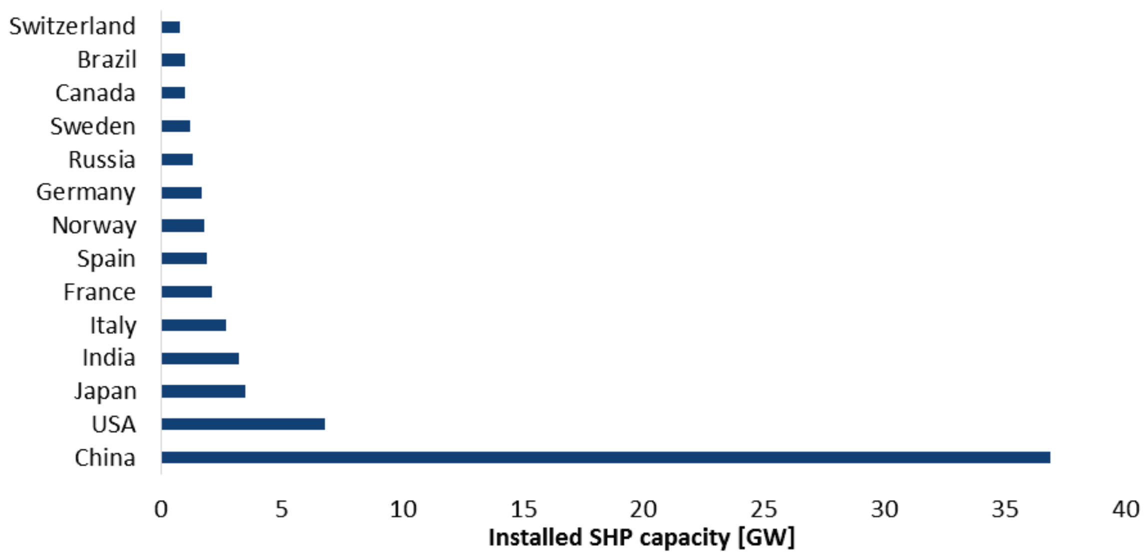

Figure 7.1: Main SHP producers. Source: (Liu, Masera et al. 2013)

The aggregation of international data on SHP can be problematic since many countries have different thresholds for the SHP definition. Thus, often no separate data is available for plants with an installed capacity up to 10 MW (Liu, Masera et al. 2013).

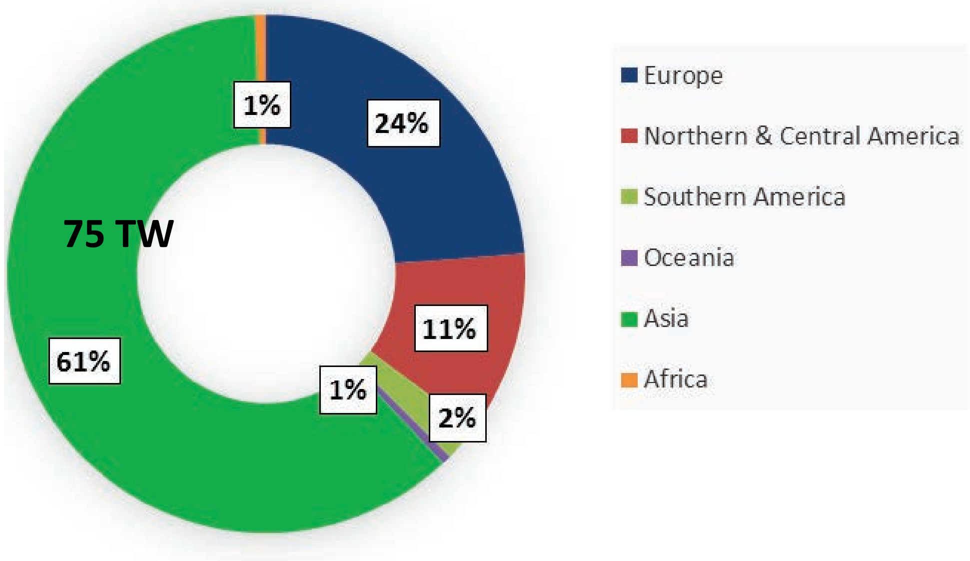

Figure 7.2: Global installed SHP. Source: (Liu, Masera et al. 2013)

7.1.3 Status of small hydropower in Switzerland

Small hydro plants with capacities between 300 kW and 10 MW generate around 8.7% of the total Swiss hydropower production. Mini hydro plants with capacities below 300 kW generate further 0.5%. SHP therefore holds a share of nearly 5% of the total Swiss electricity generation (Pfaffmatter and Piot 2014, BFE/SFOE 2016h).

In absolute numbers this corresponds to an annual production of around 3.5 TWh, 64%[137] of which is generated during the summer half-year (BFE/SFOE 2015c). Table 7.1 provides an overview of the SHP status in Switzerland.

Table 7.1: Operating small hydropower plants in Switzerland for different size categories as of 1st of January 2016 (BFE/SFOE 2016h) for power plants with capacities above 0.3 MW[138] and as of 2012 for power plants with capacities below 0.3 MW (Pfaffmatter and Piot 2014).

Plant categorization	Number of plants [-]	Installed capacity [MW]	Expected annual production [GWh/a]	Share in total Swiss hydropower production
SHP 1-10 MW	204	714	2’728	7.1%
SHP 0.3-1 MW	226	131	605	1.6%
MHP <0.3 MW	700	41	190	0.5%

As of 1st of January 2016, 30 new SHP plants were under construction and six under revision, with a total capacity of about 83 MW (BFE/SFOE 2016h).

7.2 Technology description

7.2.1 Current technologies

7.2.1.1 General structure

A small hydro plant usually consists of a weir made of concrete to dam up water, with an integrated intake into the weir, feeding a turbine. The turbine uses the potential energy of the water to drive a generator for electricity production. A gearbox can be installed to operate the generator at its optimum. However, the increased construction costs are a tradeoff which is subject to economic considerations. For ecological reasons a residual flow stretch and a fish by-pass are implemented (Hirschberg, Bauer et al. 2005).

For high head hydro plants a settling basin is placed after the intake to remove sand particles from the water. The settling basin is connected to a forebay via a headrace canal. The penstock, a pressure pipe of steel or other pressure resistant material, connects the forebay to the turbine in the power house downhill (Crettenand 2012).

For drinking and wastewater power plants the turbine can be integrated into the existing piping.

7.2.1.2 Turbines

There is a range of mature turbine types on the market, each designed for different flow characteristics. Figure 7.4 on page 238 shows for different combinations of flow rate and head the particular turbine type with the optimal efficiency.

The Pelton turbine is an impulse type water turbine, i.e. it extracts energy from the impulse of moving water. It is designed for high heads and achieves maximum efficiency even when operating at only 30% of the nominal capacity.

The Francis and Kaplan turbines are reaction type turbines, i.e. they extract energy from the hydrodynamic pressure of water. Francis Turbines are designed for medium heads and can’t be operated at partial loads below 40% of the nominal capacity. Kaplan turbines have their

[137] Stated value is given for large hydropower. Assuming that value also holds true for small hydropower

[138] The list of power plants from SFOE does not include units with capacities below 0.3 MW; therefore, an alternative source had to be used for this category.

maximum efficiency in the low head regime. Their blades can adjust to the flow rate allowing this turbine to achieve maximum efficiency even when operating at only 40% of its nominal capacity. All of these turbine types underwent at least a century of development and optimization, allowing efficiencies of 90% or more (UVEK/DETEC 2007).

For SHP Francis and Kaplan type turbines are the most commonly used worldwide. Pelton turbines are only used in rare occasions when the topography favors very high heads (Lorenzoni, Pecchio et al. 2001), but in Switzerland these are the more common ones.

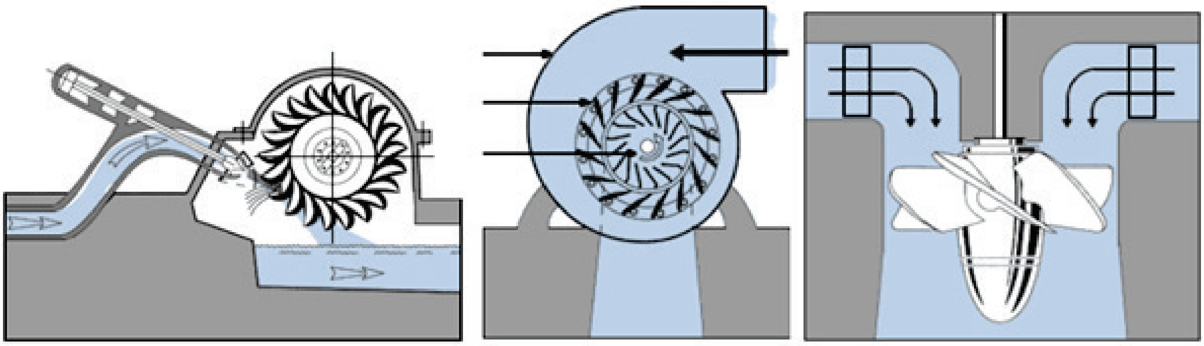

Figure 7.3: Schematic representation of a Pelton (left), Francis (middle) and Kaplan (right) turbine. Source: (Hirschberg, Bauer et al. 2005).

For low heads and power outputs of less than 3 MW cross flow turbines represent a possible alternative. In a cross flow turbine, water passes transversely through the turbine, interacting with the runner on its way in and on its way out. Thanks to its simple design, the cross-flow turbine is less expensive in installation and maintenance than the main turbine types, making it an interesting option for SHP. High reliability and very good partial load behavior are further characteristics. The main disadvantage on the other hand is the comparatively low peak efficiency.[139]

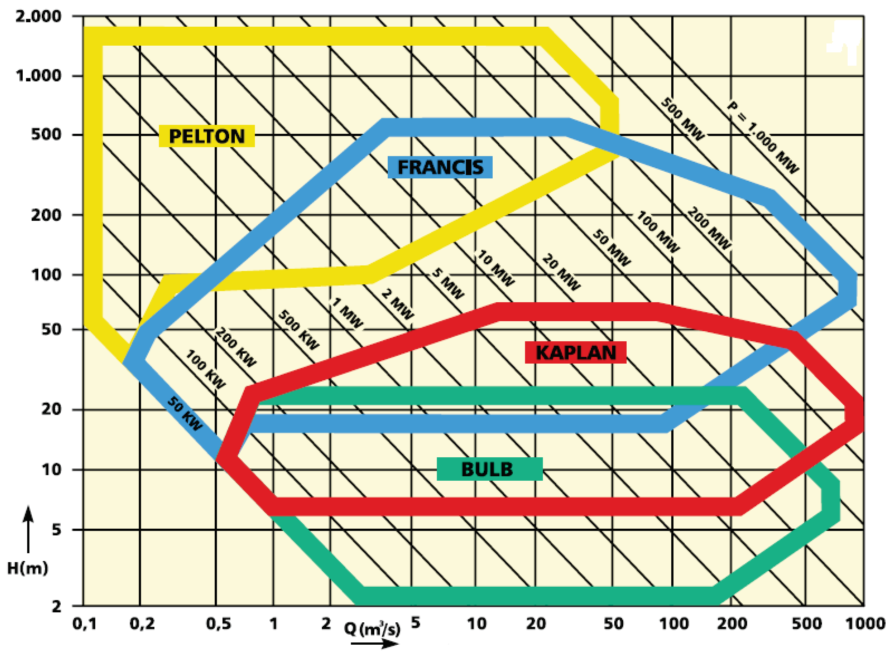

Figure 7.4: Optimal efficiency regime, as a function of flow rate and head, for different turbine types.[140]

[139] https://en.wikipedia.org/wiki/Cross-flow_turbine (13.04.2016)
[140] http://vip.water.hu/Galai/Antal/pub/reservoir/hydropower/pp/unesco.htm (06.03.2016)

7.2.1.3 Generator and gearbox

A generator converts the kinetic energy of the turbine into electrical energy. The depends on the rotational speed, which can be regulated by a gearbox. However, the gearbox itself comes with additional investment costs and mechanical losses. Therefore some SHP owners prefer low-speed generators, which are more expensive but at the same time very robust and achieve efficiencies close to 100% even without gearboxes (Pelikan 2009b).

7.2.2 Future technologies

7.2.2.1 Research focus in Switzerland

The three main turbine technologies – Francis, Kaplan and Pelton – represent mature technologies. They all achieve efficiencies beyond 90% (OECD/IEA 2012). No major technological breakthroughs are expected in this field. Some potential SHP sites do not have enough head or flow discharge to operate a conventional turbine efficiently. Current research, performed in the framework of the SCCER SoE Task 3.2, aims at providing alternative solutions for medium head and low-head respectively low-runoff applications.[141] Two exemplary SHP research projects deal with the development of turbines that are installed inline of a pressurized pipe to provide between 300W and 30 kW. Those types of turbine will be installed in drinking water supply networks, which is an emerging field of SHP (Biner 2015, Samora, Hasmatuchi et al. 2016).[142]

Other research efforts aim at exploiting ultra-low heads of rivers on the Swiss Plateau. Ten alternative SHP technologies (7 pilot projects and 3 machine concepts) were evaluated by (BFE/SFOE 2011) with respect to their environmental, constructional, electromechanical and operational properties. It was concluded that

- for some plants very few operational experience is on-hand
- the technologies are still facing teething troubles and require further development
- none of the analyzed concepts represents a generally optimal solution
- the requirements of each potential site have to be thoroughly analyzed before the most suitable concept can be identified

Among these concepts for ultra-low head hydropower are for example screw turbines, which are basically reversed Archimedes screw pumps (Figure 7.5). This turbine type is only suitable for low flows (0.25-5 m^3/s) and low heads (1-6 m) and achieves an average overall efficiency of 69% in praxis. As a result all currently installed screw turbines have a capacity of less than 300 kW and are therefore considered MHP plants. Currently they are a niche technology. Only 2 out of about 75 screw turbines in Europe are installed in Switzerland. The rest is situated mainly in Germany, Great Britain and Austria. Potential applications can be found in wastewater power plants because screw turbines are hardly affected by impurities in the water (Lashofer and Kaltenberger 2013).

Due to their flow invariability screw turbines are mostly suited for applications with constant and low flow rates, such as residual water stretches of larger power plants or the before-mentioned waste water power plants (Pelikan 2009b).

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[141] Cécile Münch, Hdroelectricity group, HES-SO Valais; Irene Samora, Laboratory of Hydraulic Constructions (LCH), École Polytechnique Fédérale de Lausanne (EPFL)

[142] http://www.hevs.ch/de/afe-instituts/institut-systemtechnik/projets/duo-turbo-8924 (2.8.2016)

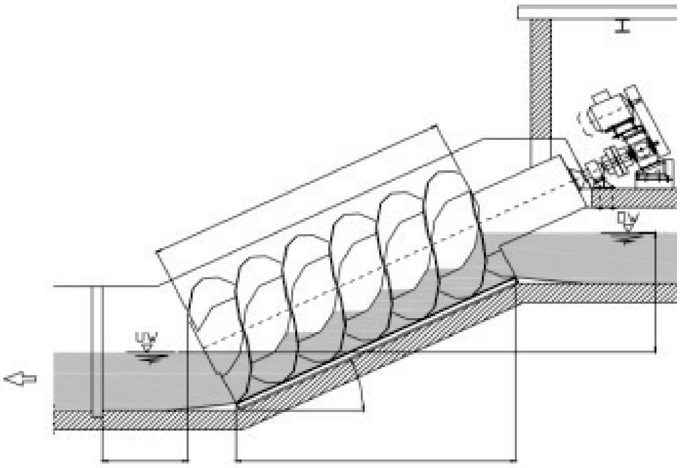

Figure 7.5: Concept of archmiedes screw turbine. Source: (BFE/SFOE 2011).

Isokinetic turbines for artificial waterways (Figure 7.6) are also in development in Switzerland. A first prototype of 1 kW will be installed in the tailrace channel of Lavey Power Plant.

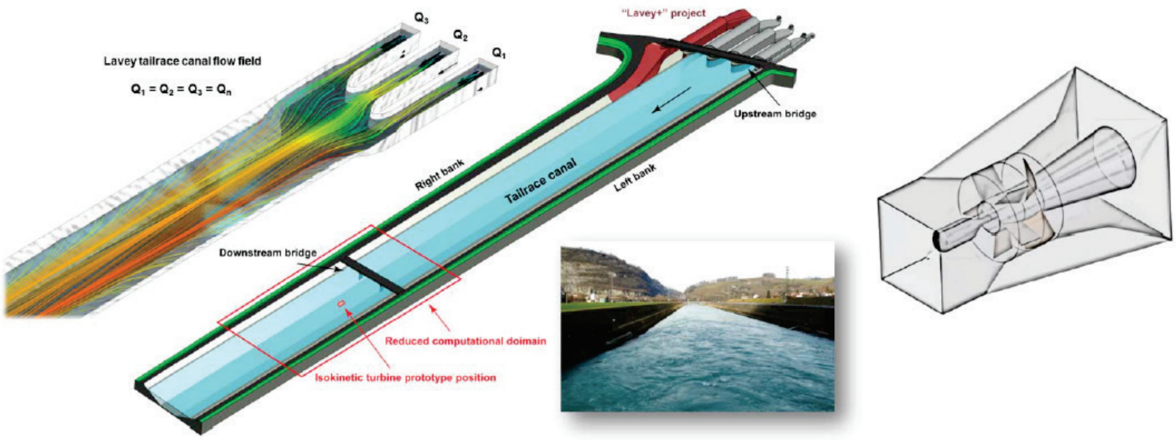

Figure 7.6: Concept of an Isokinetic turbine. Source: http://www.hevs.ch

Another active field of research investigates the ecological impact of SHP plants and trade-offs between electricity production and ecosystem services in order to design efficient mitigation measures and assist decision makers with respect to licensing and defining minimum flow requirements.[143]

7.2.3 Research outlook in Switzerland

The efficiency of particular SHP plants is optimized to a high degree. The total electricity generation can only be substantially increased by making more sites exploitable. Hence the most dominant research trend in the field of SHP is the utilization of low heads. This field already experienced noticeable development, yet most concepts are still not commercially available. Research in this field still has some way to go.

[143] http://www.sccer-soe.ch/research/hp/Task-2.4/ (07.05.2016)

The Swiss Competence Center for Energy outlined a roadmap for hydropower research and development in Switzerland (SCCER-SoE 2015). For SHP in particular they identified two important research needs: Development of criteria for careful site selection as well as strategies to optimize power production while at the same time minimizing negative impacts on the river ecology. Further key research directions stated by (SCCER-SoE 2015) apply to small as well as to large hydropower. Figure 7.7 shows a graphic depiction of the roadmap.

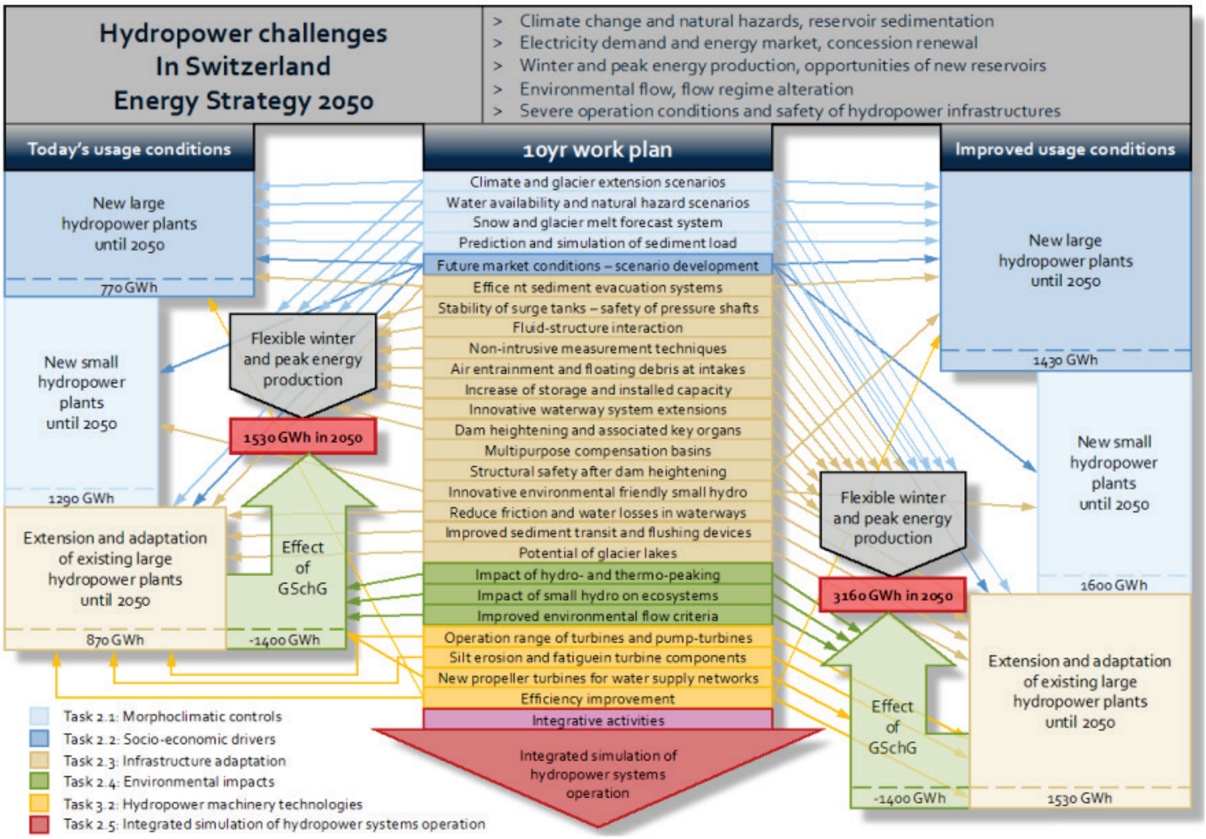

Figure 7.7: Research and development roadmap for hydropower in Switzerland. Source: (SCCER-SoE 2015)

7.2.3.1 International Research

In 2010 the International Energy Agency published a report, summarizing "Innovative Technologies for Small-Scale Hydro". In the scope of this task 78 SHP technology submissions were reviewed and 31 of them were considered to meet the criteria for being innovative. They were categorized as in Figure 7.8. 17 of these innovations addressed new or improved turbine technologies, 12 of which were related to power outputs of less than 1 MW. The presented innovations varied to a large extent, including for example utilization of common turbine types for ultra-low heads, improved construction procedures of structural parts or means to decrease the environmental impact of operation (IEA 2010a).

Figure 7.8: Number distribution of innovative technologies according to topic. Source: (IEA 2010)

The U.S. Department of Energy presented an overview of funded SHP research projects at the state of 2011. It is noticeable that among these projects there are currently generally two dominating research trends: Turbine development for utilization of ultra-low heads and modular design of SHP systems.[144] This development of modular SHP applications eventually can lead to cost reduction and make more sites profitable. It remains to be seen how well modular construction is compatible with integral project requirements in Switzerland.

Although these sample innovations are dated back to 2010 respectively 2011, they are also representative for current improvement approaches as well. The development potential of SHP is distributed among all system components and project stages. Though none of the prospective research projects promises major breakthroughs, the combined effect of various rather small technological improvements is expected to make SHP become more cost competitive and environmentally as well as socially acceptable.

7.3 Electricity generation potential worldwide

The term *potential* describes the amount of an existing resource that can be made accessible. However, the actual degree of availability depends on underlying technical, economic, environmental and social constraints. Therefore different kinds of potential are distinguished. The *theoretical potential* refers to the unconstrained physical height potential of water. The *technological potential* is the remaining portion of the theoretical potential in which technological constraints are factored in. The portion of the technological potential complying with economic, environmental and social criteria, is denoted as *expected potential* (BFE/SFOE 2012b).

In 2013 the International Center on Small Hydropower (ICSHP) published under the auspices of the United Nations Industrial Development Organization (UNIDO) the World Small Hydropower Development Report (Liu, Masera et al. 2013). The report derives data from various national sources to provide an insight on used and unused SHP potential of nearly all nations worldwide. As capacity threshold 10 MW was used, even if the particular country uses another definition. Therefore the applied threshold is in line with the Swiss definition. Since some of the used sources, did not denote whether theoretical, technical or expected potential is specified, the World SHP Development Report makes no distinction either. Because of that all presented numbers must be seen as a rough estimate. Table 7.2 and Figure 7.9 provide an overview of the data of regions and selected countries.

[144] http://energy.gov/articles/16-projects-advance-hydropower-technology (11.03.2016)

According to the World Small Hydropower Development Report 2013 Africa has more than 90% of its SHP potential unused. Especially Eastern African countries such as Kenya, Ethiopia and Mozambique hold a large unused potential.

Canada and the USA harness more than 80% of their 9 TW SHP potential. The potential of Central America is denoted as 4 TW, 15% of which is exploited.

Southern America has a total potential, comparable to Northern Americas'. However, only 18% is used. The majority of the potential sites is located in Chile.

Of all continents Asia has in absolute numbers the largest used, as well as unused SHP reserves. Most Asian countries use less than 20% of their potential. Exceptions are China (58%) and Japan (34%). Turkey (6.5 TW) and Kazakhstan (2.7 TW) both hold a large potential, which is almost completely unexploited.

Europe as a whole uses 68% of its 26 TW potential. Northern and Western European countries tend to have a slightly larger portion of their potential exploited than Southern and Eastern Europe.

Table 7.2: Installed capacity and estimated potential of SHP for regions and selected countries. Percentages in brackets refer to the total global SHP production or potential respectively.

Region/selected countries	SHP installed [GW]	SHP potential [GW]	Used potential [%]
Africa	525 (1%)	7'900 (5%)	7
Kenya	33	3'000	1
Northern & Central America	8'565 (11%)	13'467 (8%)	64
USA	6'785	8'041	84
Southern America	1'735 (2%)	9'390 (5%)	18
Chile	117	7'000	2
Asia	45'972 (61%)	112'705 (65%)	41
China	36'889	63'429	58
India	3'198	15'000	21
Europe[1]	17'812 (24%)	26'220 (16%)	68
France	2'110	2'615	81
Norway	1'778	1'778	100
Oceania	412 (1%)	1'238 (1%)	33
Total World	**75'000**	**173'000**	**43**

[1] Including Russian Federation

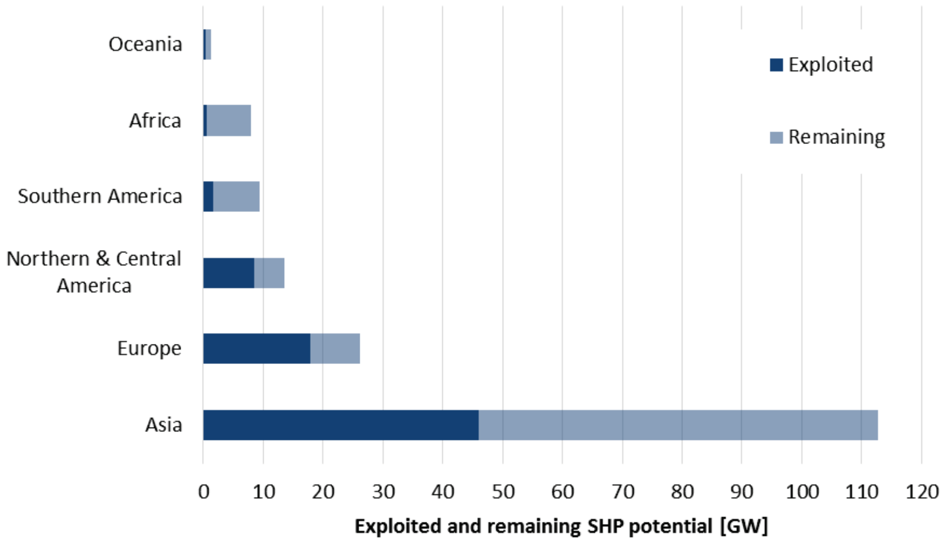

Figure 7.9: Global distribution of used and unused SHP potential. Source: (Liu, Masera et al. 2013).

7.4 Electricity generation potential in Switzerland

7.4.1 Current estimation

The Swiss Federal Office of Energy indicates an additional SHP potential of 1’290 GWh/a, assuming current usage conditions, and an additional potential of 1’600 GWh/a, assuming optimized usage conditions (Table 7.3). *Optimized usage conditions* describes a scenario, in which economic and social framework conditions are altered in favor of a moderate expansion of hydropower, without infringing the constitutional standards regarding sustainability and environmental protection. These values are based on the aggregated estimations of the responsible department of the respective cantons. Many estimates are based on the KEV (“Kostendeckende Einspeisevergütung”/cost-covering feed-in remuneration) application list[145] for SHP plants (BFE/SFOE 2016b). The stated potentials are roughly in line with estimations from the Swiss Water Management Association (SWV) and the École Polytechnique Fédérale de Lausanne (EPFL) (BFE/SFOE 2012b). All estimations are in the range of 1’000 to 2’000 GWh/a. Based on a current annual generation of 3’500 GWh/a (section 7.1.3), a remaining potential of 1’000-2’000 GWh/a means that 20-35% of the Swiss SHP potential are undeveloped.

Table 7.3: Undeveloped SHP potential in Switzerland, estimated by different institutions. Source: (BFE/SFOE 2012b)

Institution	Estimation of additional Potential [GWh/a]
BFE[1]	1'290[4] - 1'600[5]
EPFL[2]	1'000 - 1'400
SWV[3]	1'000 - 2'000

1 Swiss Federal Office of Energy
2 Swiss Federal Institute of Technology of Lausanne
3 Swiss Water Management Association
4 Under current usage conditions
5 Assuming optimized usage conditions

[145] This “KEV-list” was provided by BFE, reflects the status as of 23rd of March 2016 and is subject of a non-disclosure agreement.

Furthermore in (BFE/SFOE 2012b) it is estimated, that changes of the water protection legislation (“Gewässerschutzgesetz”) will decrease the expected overall hydropower generation by 1’400 GWh/a until 2050. This number refers to the total national output, including large and small hydropower. It is not stated which portion of the production shortfall will concern SHP. If we assume the respective reduction to be proportional to the expected annual production in 2050, about 10% or 140 GWh/a respectively of the shortfall will be accounted to SHP.

In another approach to estimate the SHP potential of Switzerland, geographic information systems (GIS) were applied. The Swiss elevation model in combination with runoff data was used to determine the theoretical hydropower potential. In the next step general exclusion criteria were factored in with help of GIS-layers of protected nature reserves. As a result, the amount of already developed, undeveloped and, due to environmental constraints, excluded hydropower potential for all SHP-relevant waters was calculated (Table 7.4). It stands out, that the stated potential, which is already exploited (4’649 MW), clearly exceeds the value of 745 MW, given by (Pfaffmatter and Piot 2014). This is not solely, but mainly, owing to three simplifications, respectively assumptions:

- Residual water flows were not taken into account
- Perfect energy conversion efficiency was assumed
- The 10 MW threshold was not applied. Instead every potential source of hydropower, which does not belong to the three largest Swiss (Rhine, Rhone, Aare), was defined as SHP.

Especially the third factor makes direct comparisons with estimated remaining potentials by (BFE/SFOE 2012b) impossible because different definitions of SHP were applied. Also It has to be pointed out, that the calculated remaining potential (6’739 MW) should be seen as theoretical potential and may serve only as a first approximation.

Table 7.4: SHP potential in Switzerland, calculated with the help of GIS. Source: (Schröder, Hemund et al. 2012)

Parameter	Capacity [MW]
Theoretically available potential	11'992
Already used potential	4'649
Available potential	7'343
Affected by exclusion criteria	603
Remaining unaffected potential	6'739

7.4.2 Impact of climate change on future hydropower generation

According to (Weingartner and Zappa 2011) climate change will lead to decreased precipitation in summer and increased precipitation during the rest of the year in Switzerland. Total annual precipitation to the north of the Alps will increase slightly while to the south of the Alps a slight decrease is expected. At the same time evaporation will increase to a negligible extent. Snow cover and size of glaciers are expected to shrink drastically until 2100. As a result the runoff will increase temporarily in strongly glaciated areas. In 2100, the total annual precipitation will not have changed significantly in the northern alpine region but will have decreased slightly in Ticino and southern Valais.

It has to be considered, that SHP plants generally are run-of-river plants, rather than storage plants. Thus, changes of the flow regime directly result in changes of the temporal distribution of power generation. A modified flow regime can either have a positive or negative effect, depending on whether the new flow regime will be more or less fluctuating. As climate change will lead to a runoff decrease in summer and increase in winter, the Swiss flow regime will be more evened out, allowing on average higher load factors of power plants. On the long term (2085) the net power output in most parts of Switzerland will be hardly affected by climate change while a reduction of 4-8% is expected in Valais (Weingartner and Zappa 2011).

7.5 Electricity generation costs in Switzerland

7.5.1 Current generation costs

7.5.1.1 Investment costs

The investment costs of SHP plants strongly depend on the site of construction and can therefore vary strongly. In (Pelikan 2009a) the range of investment costs in Switzerland is given as 4’000 -10’000 €/kW. Also, the breakdown of SHP costs by source cannot be generalized precisely. While for LHP the largest share of construction costs arises from civil works, for SHP the share of the electro-mechanical equipment is significantly larger (18% to 50% of total cost). In the case of remote or difficult to access SHP projects, infrastructure costs can also dominate the total costs (IRENA 2012a).

Data from specific SHP projects in Switzerland provide a good source to specify the costs of SHP plants more precisely. The status overview list of KEV (cost-covering feed-in remuneration) is a representative source, containing information about installed capacity and investment costs of all planned and realized SHP projects in Switzerland (BFE/SFOE 2016b). After 87 out of 1’470 plants were excluded as outliers[146] from the data series, 1383 projects were statistically analyzed, 1049 of which are new constructions and 334 are extensions or renovations of existing plants.

Considering all SHP projects, an average[147] investment cost of 6’350 CHF/kW has been calculated. If only new constructions are taken into account, the resulting costs will amount to 6’735 CHF/kW. These values fit well into the range of about 4’000-10’000 CHF/kW given by (Pelikan 2009a) as well as by (Hirschberg, Bauer et al. 2005). However, the stated typical cost range of 4’000-10’000 CHF/kW covers only one third of the actual projects. As can be seen in Figure 7.10, a range of 2’000-18’000 CHF/kW represents the current cost of new SHP plants better and includes 75% of all newly constructed plants. It stands out that a significant portion of SHP projects has costs beyond 30’000 CHF/kW, although extreme outliers were already excluded from the data series in the first step.

[146] Projects were defined as outliers if specific investment costs are lower than 40 CHF/kW or higher than 130’000 CHF/kW.
[147] Average calculated as weighted average with annual expected electricity production.

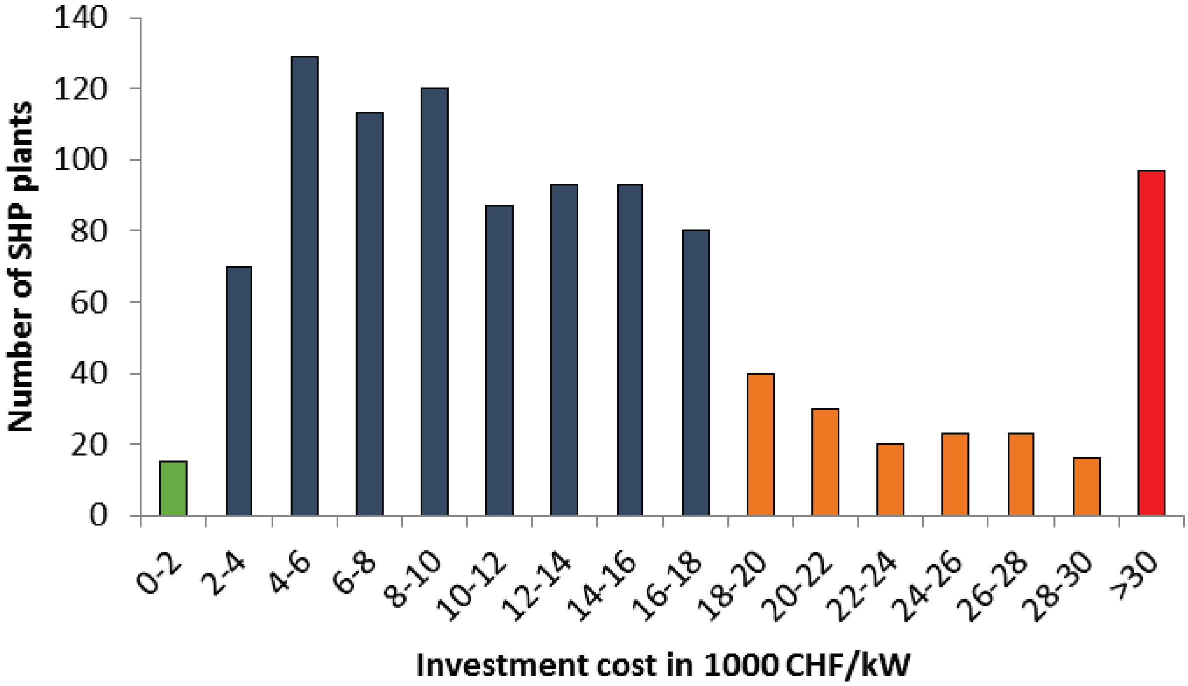

Figure 7.10: Number of SHP plants (new constructions only) according to investment cost range. 4 regimes were designated. Green: Low cost regime (1%). Blue: Typical cost range (75%). Orange: High cost regime (13%). Red: Very high cost/outliers (11%). Total number of SHP plants: 1049.

The KEV-list (BFE/SFOE 2016b) includes information about the type of every particular plant, allowing to analyze the costs of different plant types separately, as displayed in Table 7.5. An explanation of the plant types can be found in Section 7.1.1.

Diversion and run-of-river power plants tend to be associated with lower costs of about 6’000 CHF/kW, whereas all other types come with investment costs beyond 10’000 CHF/kW on average. The costs of all plant types generally vary strongly, resulting in broad cost ranges.

Furthermore it can be observed, that all plant types except ‘Others/Not specified’ have higher specific investment costs when the capacity lies below 1 MW and lower costs when the capacity is above 1 MW. The deviation from the average is particularly large in the case of diversion, drinking water and run-of-river power plants. Figure 7.11 shows that the specific investment cost tend to decrease with higher installed capacities. The fact that costs for plants with capacities <1MW are often substantially higher than for plants >1MW has recently been taken into account by the Swiss parliament: The Federal Assembly has decided to stop feed-in remuneration for plants with capacities <1 MW with reference to the less attractive cost-benefit ratio of these SHP plants.[148]

[148] http://www.ee-news.ch/de/article/33669/energiestrategie-2050-auch-der-standerat-will-die-wasserkraft-unterstutzen&page; http://www.ee-news.ch/de/wasser/article/33670/swiss-small-hydro-kritisiert-forderuntergrenze-fur-neue-kleinwasserkraft (09.06.2016)

Table 7.5: Investment costs of SHP plants according to plant type (BFE/SFOE 2016b). Rounded values. The typical cost range indicates the cost range, in which at least 75% of all respective plant types can be found.

Type of power plant	Number of plants [-]	Average investment cost [CHF/kW] < 1 MW	1-10 MW	All plants	Typical cost range [CHF/kW]
Discharge p. p.	39	11’990	8’890[1]	11'000	6’000 – 17’000
Diversion p. p.	218	9’660	5’790	6'300	2’000 - 16’000
Run-of-river p. p.	287	9’140	5’350	6'050	1’000 - 16’000
Drinking water p. p.	463	12’390	1’610[1]	11'150	4’000 - 30’000
Wastewater p. p.	19	26’530	19’860[1]	23'650	13’000 - 32’000
Others/Not specified	23	6’460	14’830[1]	11'900	6’000 - 14’000
Total	1049	10’420	5’720	6'750	2’000 - 18’000

[1] Sample size less than 4 plants.

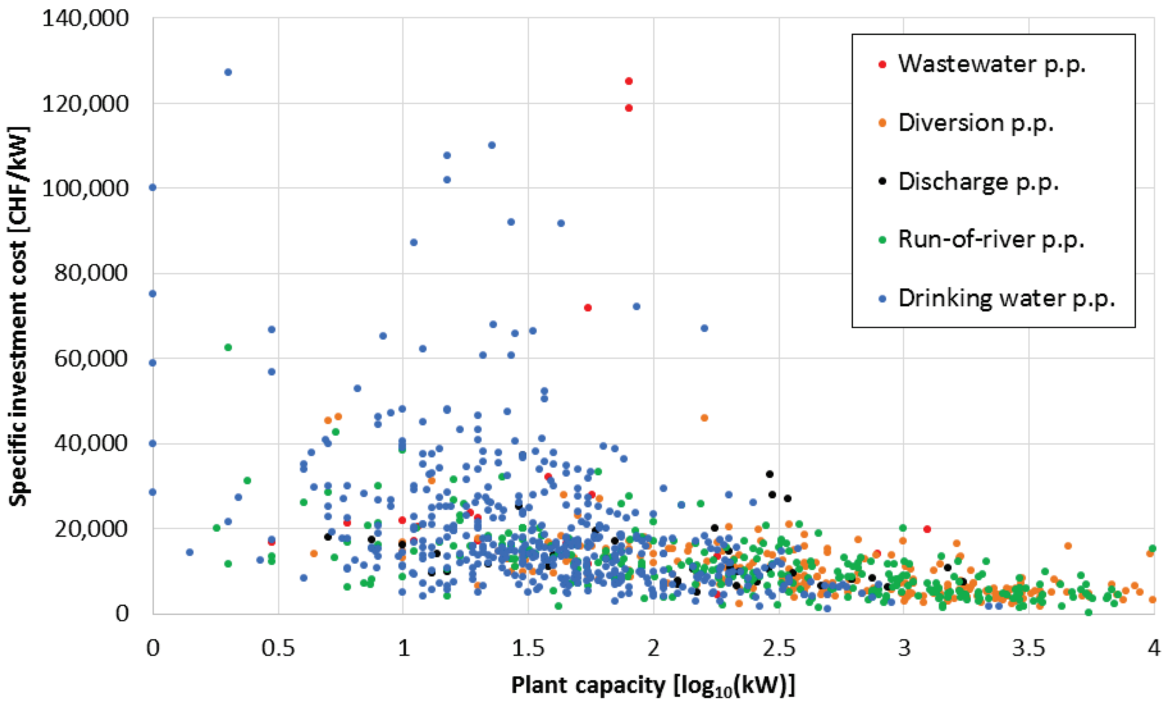

Figure 7.11: Specific investment cost as a function of installed capacity for different power plant types (BFE/SFOE 2016b).

7.5.1.2 Levelized cost of electricity

The data from KEV-list (BFE/SFOE 2016b) was also used to determine the levelized cost of electricity (LCOE) of SHP in Switzerland.

Regarding capital costs a low cost and a high cost scenario were investigated. In the high cost scenario the applied capital costs correspond to the 25% percentile of the investment costs, as found in the KEV-list. For the high cost scenario, the 75% percentile of the investment costs was used. In order to cover the most important SHP plant types in Switzerland, drinking water, diversion and run-of-river power plants were analyzed. The latter two were combined in one group due to their similar cost characteristics. An amortization period of 60 years was chosen in correspondence with typical lifespans from (Flury and Frischknecht 2012). The data about installed capacity and expected annual power generation were used to deduct the operation hours per year of every plant. The average value of standalone (4673 hours/year) respectively integrated (5503 hours/year) power plants was used for the cost calculation.

The annual costs for operation and maintenance (O&M) can be modelled as a certain percentage of the investment costs. The International Energy Agency (IEA) assumes a percentage of 2.2% - 3%, whereby 2.5% corresponds to the global average (IRENA 2012a). For diversion power plants and run-of-river power plants a percentage of 2.5% was chosen. For drinking water power plants a slightly lower value of 2.2% was used. In this way it is taken into account, that some typical cost factors, such as abrasion of turbines due to suspended particles or removal of bedload, are less applicable in drinking water operations.

The Swiss water rates ("Wasserzins") have to be accounted on top of the standard O&M costs. The water rates may not exceed 110 CHF per kW installed capacity until end of 2019. This corresponds to about 1.6 Rp./kWh (Pfaffmatter and Piot 2014). Interest rate was assumed to be 6%.

The results of the cost calculation are presented in Table 7.6. These values correspond to the "current" category of future cost outlook (Figure 7.12); ranges in Figure 7.12 correspond to high and low investment cost and LCOE, respectively. Differentiating average values according to plant capacities (<1MW and 1-10MW, respectively) is only meaningful for diversion and run-of-river plants, as the sample of drinking water plants >1MW is too small. The LCOE, calculated for diversion and run-of-river power plants, accord well with the electricity generation cost of 10-25 Rp./kWh for new SHP projects, given by (BFE/SFOE 2008b). However, the LCOE of drinking water plants is significantly higher due to their high investment costs.

Table 7.6: Overnight investment costs and levelized cost of electricity (LCOE) of SHP in Switzerland for new constructions.

Power plant type	Investment costs [CHF/kW]					LCOE [Rp./kWh]				
	Low	Average			High	Low	Average			High
Diversion and run-of-river		All plants	<1MW	1-10MW			All plants	<1MW	1-10MW	
	5'200	6'160	9'370	5'540	13'700	11.7	13.5	19.8	12.3	28.2
Drinking water	9'600	11'150			25'100	16.9	19.4			41.6

7.5.2 Future generation costs

The investment costs, and thus the strongly interlinked LCOE as well, of SHP in Switzerland are expected to increase in the future. This is mainly due to exhaustion of favorable SHP sites (VSE/ASEC 2014) and tightening of environmental regulations (UVEK/DETEC 2012). Cost reductions by technological innovations will not be sufficient to compensate these factors.

In comparison to 2013 levels (VSE/ASEC 2014) estimates an increase of investment costs of 16% until 2035 and of 20% until 2050. These relative changes were used to estimate future cost development. The LCOE follows a similar trend because the capital costs account for the majority (approx. 70%) of the LCOE and O&M is also modelled as a function of the investment costs. Results of the future cost estimation are presented in Figure 7.12.

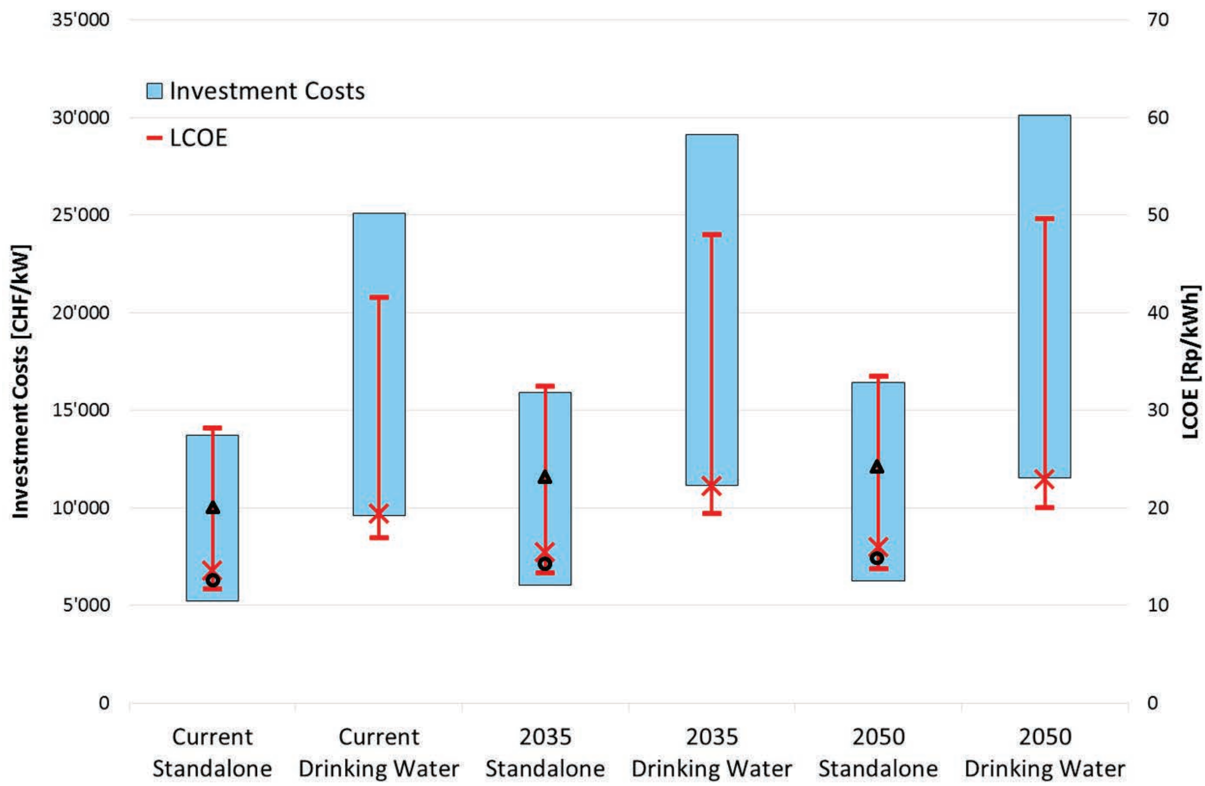

Figure 7.12: Range of overnight investment costs and levelized cost of electricity (LCOE) of SHP in Switzerland for current and future new constructions. Average LCOE, calculated as weighted average with annual expected electricity production, is marked as red "X". LCOE of standalone plants <1MW are marked as black triangles; those of plants 1-10 MW are marked as black circles.

7.6 Environmental aspects

SHP, as well as hydropower in general, is a renewable form of electricity generation and considered environmentally friendly. In fact there are clearly positive effects related to hydropower compared to other power generation technologies – primarily because SHP doesn't require any kind of fuel during operation, which is very beneficial. (Bauer, Frischknecht et al. 2012) and (VSE/ASEC 2014) confirm, that the life cycle assessment (LCA) of small and large hydropower indicates the lowest environmental impacts of all renewable and non-renewable energy sources.

7.6.1 Life Cycle Assessment (LCA)

Within the scope of this report an LCA of SHP plants in Switzerland was accomplished, using the new version 8.5.0.13 of the LCA-software SimaPro and the underlying database ecoinvent v3.1. The inventory analysis was adapted from (Flury and Frischknecht 2012), who collected complete inventory data of the construction and operation of SHP plants in Switzerland. Two general kinds of plants were differentiated: Standalone hydropower stations (e.g. run-of-river or diversion power plants) and power stations integrated in waterworks infrastructure (drinking water or wastewater power plants). The study examined several SHP plants with a total capacity of 1.2 MW and an average capacity of 193 kW. The expected net production of the modelled reference plant amounts to 1.1 GWh/a for standalone and to 1.2 GWh/a for integrated power plants. The assumed lifespan amounts to 70 years[149]. This corresponds to conservative estimations of typical lifespans of constructional parts of the plants (Flury and Frischknecht 2012). The deconstruction of the plant after its lifespan is included, following the assumptions of (Flury and Frischknecht 2012).

Figure 7.13 displays the potential impact on climate change in terms of life cycle Greenhouse Gas (GHG) emissions of electricity generated by SHP and visualizes the main contributing materials, respectively processes.

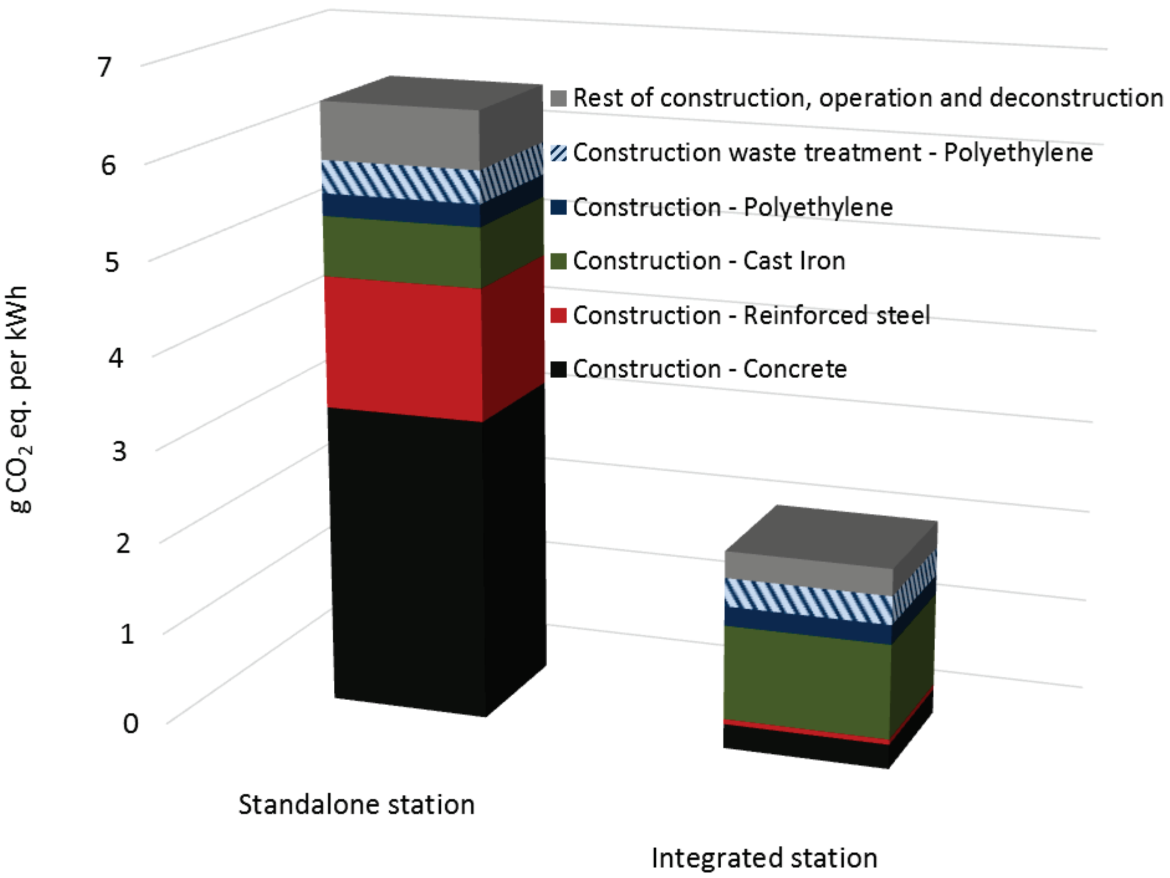

Figure 7.13: CO_2 equivalent assigned to the process of providing 1 kWh high voltage with small hydropower in Switzerland. Impact assessment method: IPCC GWP 100a.

There is a distinct difference in the greenhouse gas emitting from electricity generated in standalone (6.5 g CO_2 eq./kWh) and integrated (2.1 g CO_2 eq./kWh) power plants. This lies near to the 2-5 g CO_2 eq./kWh for run-of-river power plants given by (Turconi, Boldrin et al. 2013). Figure 7.13 shows that the difference is mainly due to significantly reduced building material requirements of power plants, which are integrated into waterworks infrastructure. This synergy saves great amounts of concrete and steel, which otherwise account for around 70% of all GHG emissions. Cast iron and polyethylene are required to about equal amounts in both plant types, whereas the latter mainly causes emissions due to waste treatment in municipal incineration. The relative absolute difference (4.4 g CO_2 eq./kWh) of standalone and integrated plants however, is insignificant when compared to the emissions associated

[149] 70 years was chosen as lifetime, since this is the best estimate as average lifetime of the plant components, using a higher weighting factor for civil works compared to electromechanic infrastructure.

with the average Swiss electricity consumption mix (100 g CO_2 eq./kWh at low voltage level (ecoinvent 2016)). The impact of the operation phase on climate change is negligible for both kinds of power station.

Figure 7.14 shows that not only regarding climate change, but also with respect to all other covered impact categories, electricity from SHP plants causes distinctly lower environmental impacts than the Swiss consumption mix. The impacts were assessed with the ILCD 2011 Midpoint+ V1.06 method. The impact category 'water resource depletion' was excluded from the assessment because of a mismatch between inventory data and impact assessment method resulting in an incorrect assignment of water used in turbines as resource depletion.

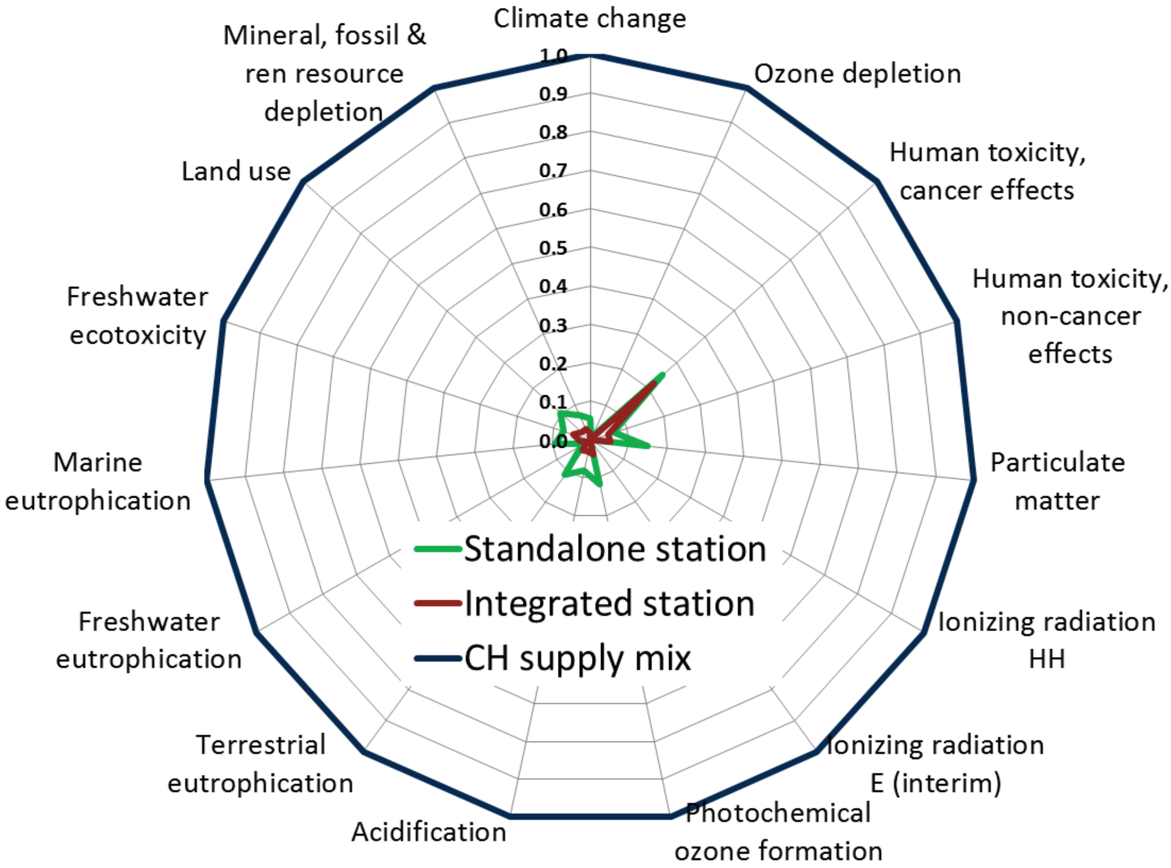

Figure 7.14: Environmental impact of electricity generated by standalone and integrated SHP power stations, values relative to the average Swiss electricity consumption mix (=1). Impact method: ILCD 2011 Midpoint+ V1.06 / EU27 2010, equal weighting.

7.6.2 Further environmental impacts

Not all negative impacts of SHP are captured by an LCA. Especially local effects on the utilized waterbody are not taken into consideration. This is due to the fact that such impacts are difficult to quantify and very location-specific. From several literature sources (Lorenzoni, Pecchio et al. 2001, Hirschberg, Bauer et al. 2005, UVEK/DETEC 2012, Weber and Schmid 2014) and from Swiss Water Management Association (SWV)[150] a non-exhaustive list of potentially negative impacts, which are usually not within the scope of an LCA, can be aggregated and divided into two main impact categories.

[150] https://www.swv.ch/Fachinformationen/Wasserkraft-Schweiz/Umweltauswirkungen (07.06.2016)

1.) Impairment of river ecology and biodiversity

- Reduction of the residual water flow
- Longitudinal separation of river networks/disturbance of fish migration
- Hydropeaking
- Increased sedimentation upstream of SHP plant
- Interference with bedload transport

2.) Reduction of the cultural and recreational value

- Visual disturbance of the landscape
- Impairment of fishery
- Noise emission

These impacts are exclusively relevant for natural waterbodies and do not come into effect in drinking- or wastewater power plants. Since many impacts of an SHP plant are not within the scope of an LCA, an integrated cost-benefit analysis for each potential power plant location has to be performed before construction.

Nevertheless, SHP is a renewable source of energy, which can replace other more harmful technologies, and its implementation should generally be encouraged.

7.6.3 Impact mitigation

In this section some approaches to reduce the negative local impacts of SHP plants are introduced.

7.6.3.1 Fish migration

To allow fish migration through a weir different types of fish ladders (Figure 7.15) or fish bypasses can be set up. Several designs can be used, according to species and local factors, to allow upstream migration of aquatic organisms. As fish follow the mainstream on their upstream migration, a flow velocity of 0.8-2 m/s at the outflow of the fish ladder is required to guide the fishes. On the downstream migration screens must prevent fishes from descending through the turbine (Patt, Jürging et al. 2010). In Switzerland the water protection law (GSchG, SR 814.20) forces waterworks structures to establish fish migration systems.[150]

Figure 7.15: Fish ladder at mini hydropower plant Lotzwil. Source: Elaqua Ag

7.6.3.2 Minimum residual water flow

Power plant operators in Switzerland are obliged to leave a certain amount of water, which may not be diverted, in the natural riverbed. In Switzerland the amount is depending on the flow rate, which is reached or exceeded in 347 days of the year (Q_{347}).[151] The residual flow should guarantee the ecological function of the river. It must be high enough to provide sufficient water depths and flow velocities, natural temperature conditions and interconnectedness of waterbodies.[152]

7.6.3.3 Measures against hydropeaking

Hydropeaking leads to extreme short term variations of the water flow. When the water discharge reaches a peak, aquatic organisms are washed away. Furthermore hydropeaking decreases the period of clear water in winter and interferes with the sedimentation behavior of the river.[152] According to (Schleiss 2012a) the adverse impacts of hydropeaking on the river ecology and morphology can be reduced by following measures

- Restitution directly into a lake
- Construction of a compensation basin
- Limitation of maximum discharge and increase of minimum discharge
- Start and shutdown of turbines in sequences
- Coordinated operation of several power plants
- Shelters for aquatic life

7.6.3.4 Restoration of bed-load balance

Water infrastructures influence the bed-load balance of rivers. This can reduce the quality of habitats downstream as well as upstream of the power plant.[152] To compensate these negative effects to some extent (AWEL/WWEA 2015) suggests following measures:

- Removal of bed-load on the upstream side of the weir and addition downstream
- Addition of gravel to the riverbed
- Structural reconstruction of weirs in order to allow passage of bed-load
- Reactivation of bank erosion

7.6.3.5 Mitigation of visual and audible impacts

Every component of a hydropower plant has the potential to alter the visual appearance of the landscape. Especially the penstock is mainly perceived visually intrusive and can be an obstacle for wildlife. The ideal solution is to inter the penstock, or any other component such as the power house or the grit chamber. If this is not possible they can be at least kept in near-natural colors. Proper sound insulation of the machine hall and other noisy components is a mandatory requirement (ESHA 2004).

Alternatively to interring, the power plant can also be aesthetically integrated into the landscape. Various examples exist where weir, spillway or other structural components of the plant are either pristinely or artfully designed and contribute to the local recreational value. For instance the Fonte River Dam (Figure 7.16) in Guam with its brick-covered

[151] Swiss water protection law (GSchG, SR 814.20).
[152] Fact sheet from EAWAG: https://www.eawag.ch/fileadmin/Domain1/Beratung/Beratung_Wissenstransfer/Publ_Praxis/Faktenblaetter/fb_Wasserkraft_und_Oekologie_Sept2011.pdf

spillway is mostly overgrown by vegetation and perceived as a scenic site, which is included in the United States National Register of Historic Places.[153]

Figure 7.16: Fonte river dam, Guam. Source: (Ioannidis 2016)

[153] http://npgallery.nps.gov/nrhp/Download?path=/natreg/docs/All_Data.html

7.7 Abbreviations

a	year
avg	average
BFE/SFOE	Bundesamt für Energie/Swiss Federal Office of Energy
CAPEX	capital expenses
CH	Switzerland
CHF	Swiss francs
CO_2 eq.	carbon dioxide equivalent
EQ	ecosystem quality
GHG	greenhouse gas
GIS	geographic information system
GWP	global warming potential
HH	human health
IRENA	International Renewable Energy Agency
KEV	Kostendeckende Einspeisevergütung/compensatory feed-in renumeration
LCA	life cycle assessment
LCI	life cycle inventory
LCIA	life cycle impact assessment
LCOE	levelized cost of electricity
LHP	large hydropower
MHP	mini hydropower
O&M	operation & maintenance
OPEX	Operating and maintenance expenses
pp	power plant
PSI	Paul Scherrer Institut
RoR	run-of-river
Rp.	Rappen (Swiss cents)
SHP	small hydropower
Std. dev.	standard deviation
WWAC	weighted average capital costs
yr	year

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8 Wind power (onshore and offshore)

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8.1 Introduction and definitions

Wind energy is the renewable energy source with the highest increase in installed capacity worldwide in the last years. The total capacity by the end of 2015 amounted to 435 GW, out of it 12 GW offshore (GWEC 2015, WWEA 2016). This covered about 3-5% of the world's electricity needs.[154] Wind power is supposed to have a huge potential in the electricity supply in many countries, and is supported by manifold governmental incentives.

Windmills have been making use of the kinetic energy of wind for centuries now. Starting with pumping water or grinding grain, these mills have developed in the late nineteenth century to produce electricity (Burton, Jenkins et al. 2011). The first wind turbines showed capacities of 5 to 10 kW, developing to a 1 MW turbine in 1941 in Vermont, US.[155] The 1980ties came along with intensive research in the wind sector due to increased oil prices, which led to wind turbines of about 4 MW capacity. The latest wind turbines demonstrate capacities of up to 8 MW on- and offshore.[156] The first offshore wind farm was commissioned in 1991 with a total capacity of 5 MW (Burton, Jenkins et al. 2011). In 2015, the largest offshore wind parks are located in the United Kingdom with installed capacities of 500 to 630 MW.[157]

In the following some definitions are given.

The harvest of **electrical energy** with a wind turbine is possible due to rotation of blades using kinetic energy from moving air. In lingual terms there is a difference between individual **wind turbines** standing alone and **wind farms**, which represent an assembly of wind turbines. The wind turbines and farms can be located **onshore** on firm land or **offshore** in a body of water. Whereas it is technically more challenging to build offshore plants, stronger wind speeds at such locations can drive higher harvest of energy.

The **efficiency** of a wind farm can be defined as the relation between the energy supplied with the blowing wind and the harvested electrical power. The theoretical maximum power which can be extracted is defined by the Betz's law to be 16/27 (59.3%) of the kinetic energy of the wind (Betz 1926). However, this maximal efficiency is not reached by modern rotors, which can use up to 50% of the kinetic energy. Losses of other parts of the wind turbine such as gear, generator or transformer have to be subtracted in addition, which reduces the efficiency to around 30%.[158] Wind speed and wind supply over the year determine the actual electricity production.

The **full load (equivalent) hours** correspond to the number of hours a wind turbine would have to run at rated capacity in order to produce the amount of electricity delivered in a year. The **capacity factor** of a wind turbine or park is calculated by dividing these full load

[154] http://www.gwec.net/global-figures/wind-in-numbers/, http://www.wwindea.org/new-record-in-worldwide-wind-installations/
[155] http://www.energy.gov/eere/wind/history-wind-energy
[156] http://www.windpowermonthly.com/10-biggest-turbines
[157] https://en.wikipedia.org/wiki/List_of_offshore_wind_farms
[158] http://www.weltderphysik.de/gebiet/technik/energie/gewinnungumwandlung/windkraft/physik-der-windenergie/

hours by 8760 hours. The capacity factor varies with location and includes downtime due to ordinary and unforeseen maintenance. Common capacity factors are between 0.1 and ca. 0.55 (IRENA 2012c) with a world average of ca. 23% in 2013 (calculated from (GWEC 2015, IEA 2015c, WWEA 2016)). In general, offshore wind parks show considerably higher capacity factors (up to 0.52[159]) than onshore wind parks (see chapter 8.4.6). Onshore availabilities are usually around 95%, while offshore availabilities have increased up to 92% to 98% in the past few years (IEA 2013a) (see chapter 8.4.8).

8.2 Wind power worldwide

8.2.1 Status Quo worldwide

Key facts and figures and time series of wind power are presented yearly by the Global Wind Energy Council (GWEC), the World Wind Energy Association (WWEA), and other Wind Associations such as the European Wind Energy Association (EWEA) or the American Wind Energy Association (AWEA). According to (WWEA 2016), a total of 435 GW wind capacity was installed by the end of 2015 on the world in around 105 countries (Figure 8.1). Another 60 GW are estimated to be added in 2016 (GWEC 2016).

Total electricity production with the installed capacity of 372 GW in 2014 corresponded to 717 TWh, which was ca. 4% of the world's electricity supply. The share of wind power in the electricity supply of OECD countries went up to 5.3% in 2015, which is 22.9% of the renewable power in these countries (IEA 2016c). The countries with the largest shares of electricity from wind in their production mix in 2014 have been Denmark (41% of domestic production mix), Portugal (23%), Ireland (20%), and Spain (19%) (OECD 2015). Note that the actual share in the electricity consumption mix might be lower if electricity is imported.

Out of the 435 GW wind power installed by the end of 2015 worldwide, 12 GW are offshore – half of these are installed in the United Kingdom (WWEA 2015, EWEA 2016). Detailed data for installed capacities in the end of each year 2010 to 2014, growth rate 2014, and installed capacity per capita and per square km are given for all countries in the appendix of this chapter (Table 8.14). The largest market for new turbine capacity in 2015 was China with 33 GW, followed by the USA (8.6 GW, ca. 4000 new turbines) and Germany (4.9 GW). These are also the regions with largest installed capacities: 148 GW in **China**, 74 GW in the **USA**, and 45 GW in **Germany**. Most of the remaining capacity is installed in **Europe,** which hosts a total of ca. 142 GW (GWEC 2016, WWEA 2016).

[159] http://cf01.erneuerbareenergien.schluetersche.de/files/smfiledata/3/1/7/2/7/1/V2BC37NhCFWindDK.pdf

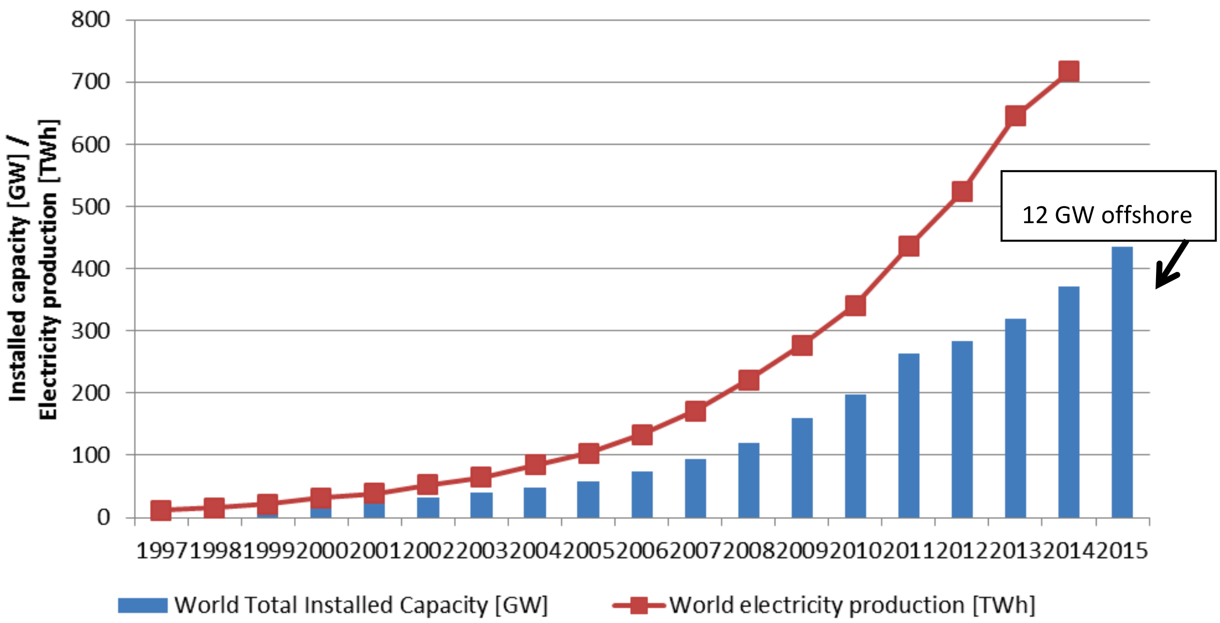

Figure 8.1: World total installed capacity [GW] and world electricity production [TWh] between 1997 and 2015 (OECD 2016, WWEA 2016). No worldwide electricity data are available for 2015 yet.

8.2.2 Projections: Technical potential of wind power worldwide

The theoretical worldwide potential of wind power is huge. However, manifold factors narrow down the actual locations where wind energy can be harvested. Examples are too low or too high wind speed, distance to land on the high seas or other water bodies, urban areas, mountains and other regions which are difficult to access, or social and political factors.

Figure 8.2 shows an example of the decrease from the theoretical to the practical wind power potential. Archer and Jacobson (2013) define the technical wind power potential to include all areas where it is technically possible to install a wind turbine. This excludes polar regions, offshore locations deeper than 200 m, and mountainous areas above 2000 m. The practical potential then excludes areas with practical restrictions, such as conflicting land and water uses or remoteness, and areas with wind speed lower than 7 m/s, as only high-wind locations are considered in the study.

The regions with highest wind speeds are ocean waters, the Sahara desert, the lowest part of Southern America, central parts of Northern America, Himalaya, and parts of the eastern coast of Africa (Archer and Jacobson 2013, IEA 2013a).

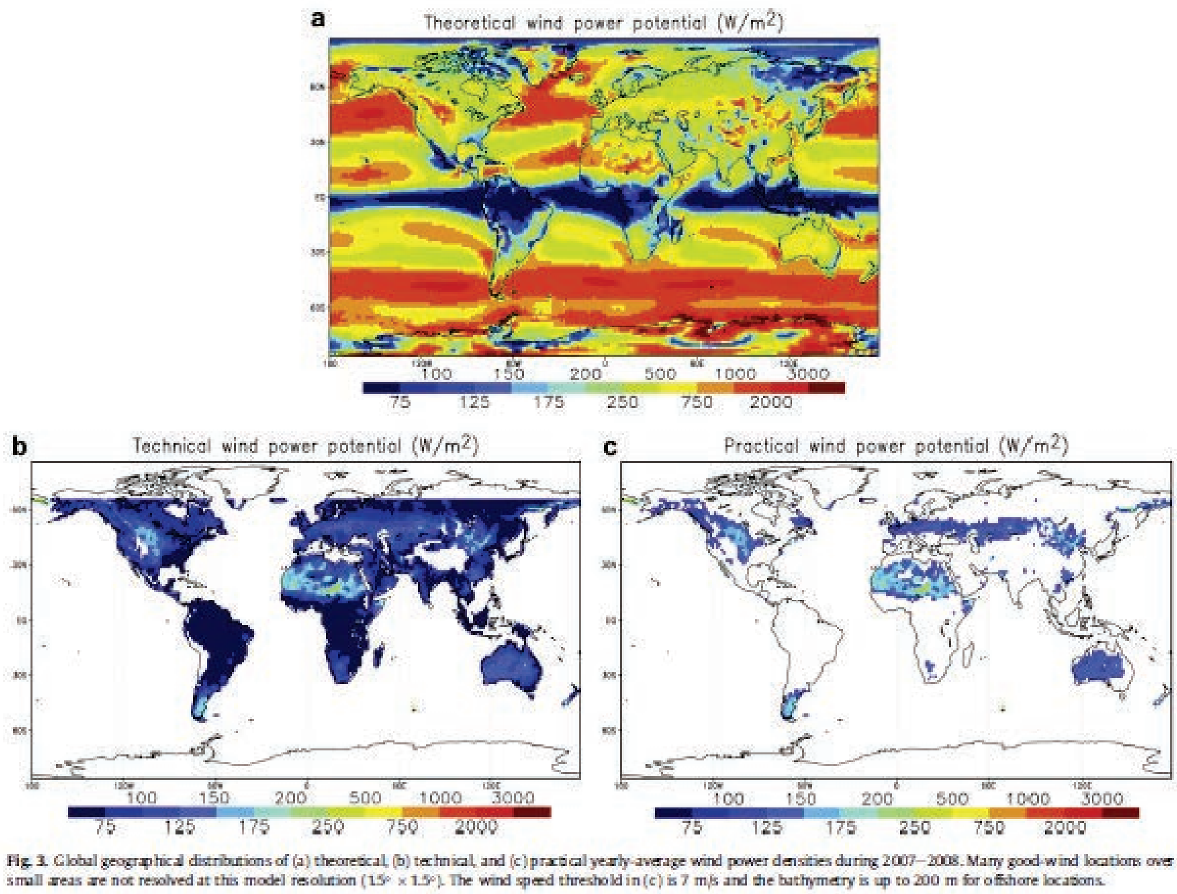

Figure 8.2: Theoretical, technical and practical global wind power potential. Taken from (Archer and Jacobson 2013).

Archer and Jacobson (2013) estimate that the practical potential is between 68 and 115 TW, while the global installed electricity demand in 2012 was 2.44 TW. They comment that the practical potential is a theoretical exercise and in any case exceeds the world's electricity demand if it could be exploited and the intermittency challenge could be solved. The highest potentials are modelled to be in Northern and Western Africa (26-33 TW), former USSR (9-18 TW), Oceania (5.5-11.6 TW), East Asia (7-11 TW), US (6.5-11 TW), and Eastern Africa (6-8 TW). As will be shown in chapter 8.4.2, the availability of these potentials varies over the seasons. Further, the regions with the highest potentials are not the regions where high wind power deployment is expected until 2050 (see below). The offshore potential is modelled to be rather low in Archer and Jacobson (2013). The regions with highest potential are the former USSR, South America and the US, Oceania, and OECD Europe. Besides the excluding criteria of seawaters deeper than 200 m, it is not discussed in the paper why the potential is not higher.

Depending on such influences and resulting assumptions, projections of installed global wind capacities vary a lot (see Figure 8.3).

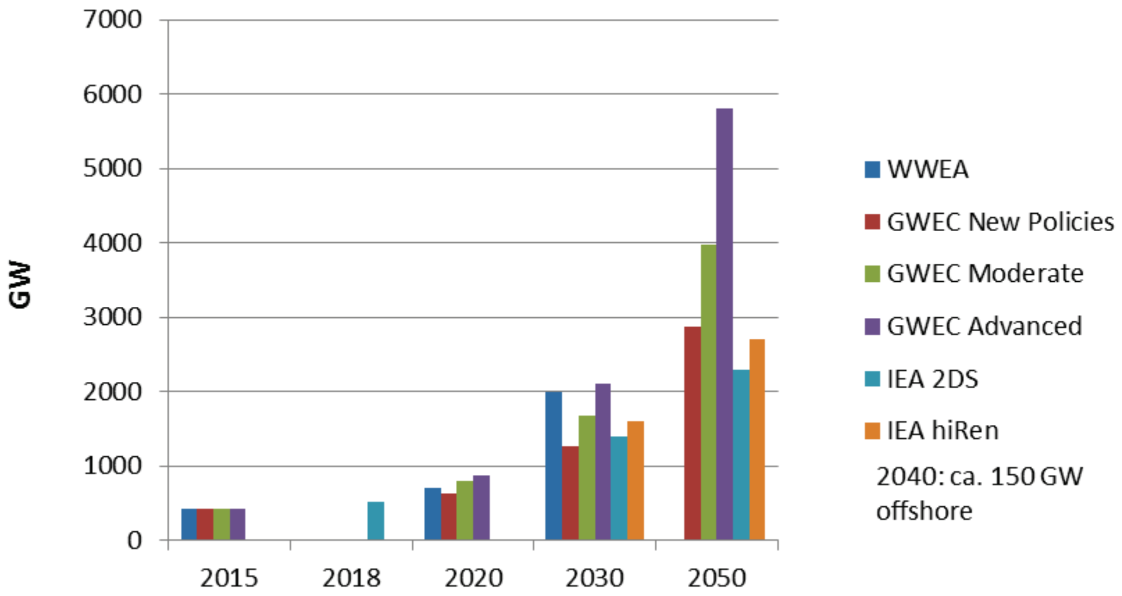

Figure 8.3: Expected installed wind capacity until 2050 modelled by (IEA 2013a, WWEA 2015, GWEC 2016). The GWEC models four different scenarios up to 2050 (of which one intermediate is not displayed), the IEA shows two scenarios up to 2050, while the WWEA only gives an estimate up to 2030. 2DS = 2 degree scenario; hiRen = high renewables scenario.

According to the World Wind Energy Association (WWEA 2015), expected global installed wind capacity will be larger than 500 GW by 2017, exceed 700 GW in 2020 and reach 2000 GW in 2030. The Global Wind Energy Council (GWEC) has corrected its estimates from the report 2014 to the report 2016, rising the estimates for 2030 from 1000-2000 GW to 1261-2110 GW, and from up to 4000 GW in 2050 (2014 estimate) to 5806 GW (2016 estimate)(GWEC 2016). The GWEC projections are based on the official IEA/OECD World Energy Outlook scenario "New Policies" (IEA 2015g). They see the largest potential in **China** with around 30% of the worldwide installed capacity, followed by the **OECD Europe** (20 to 27%) and **OECD North America** with close to 20%, depending on the scenario. The scenarios from the International Energy Agency IEA support these estimates of country potentials. However, they don't support the GWEC Advanced scenario with over 4000-5800 GW, and project the total capacity to reach at most 2700 GW in 2050. As shown in chapter 8.2.1, the European Wind Energy Association projects a total capacity installed in the EU-27 by 2020 of 230 to 265 GW, which corresponds to around one third of the projected worldwide capacity. Most of this capacity will be installed onshore. Estimates in the World Energy Outlook 2015 (IEA 2015g) say that by 2040, the European Union will have more than 65 GW of offshore capacity, China will have close to 50 GW installed, and no other region in the world will have more than 10 GW of offshore capacity.

Europe: Estimates by the European Wind Energy Association (EWEA 2011) project 40 to 55 GW of offshore wind power by 2020, which would be 17% to 21% of total installed capacity. As a result, it can be concluded that offshore wind power will not play a major role in the wind power sector in the next decades. Given that the theoretical potential is high, it might catch up in far future.

China: The 12th 5-year Plan for Renewable Energy (2012) foresees a governmental goal of 30 GW installed offshore wind power in China by 2020 (Korsnes 2014). However, the latest news postulate that this target will be lowered to 12 GW in the 13th 5-year Plan[160]. Also in China, the "main barriers for the offshore wind industry […] are two things: price and the approval process is not quick enough." (Korsnes 2014)

In 2015, 4% of the **global electricity demand** was covered by wind power plants. The IEA and GWEC estimates for the share of wind power in global electricity demand vary between 7-9% for 2020, 11-20% (2030) and 18-41% (2050), with IEA always being more conservative than GWEC (GWEC 2016). The **main obstacles** to reaching higher capacities despite of the large theoretical physical potential, are considered to be complicated permission processes, low political support, public acceptance, or areas suitable for wind power but prohibited for one or the other reason. Costs higher than costs for established (fossil) technologies also hinder a quick penetration of wind power into the power markets and therefore, financial support by the government is often required. On top, negative spot prices occur at the spot market when periods of suitable wind strengths happen in parallel to high electricity production and low power needs. Further to be mentioned is the challenge of the intermittent nature of wind power and the related design questions for a reliable electricity grid.

8.2.3 Status quo and projections up to 2020 in the EU-27

Wind energy has grown steadily in the EU-27 in the last decade, reaching 130 GW of installed capacity in 2014 (WWEA 2015) and an average load factor of close to 23% (JRC 2014a). In its goal of increasing the share of renewables to 20% by 2020 (EU 2009), the European Union will focus on wind power and biomass. The reason for this is that the potential for large hydropower is more or less exploited already.

Detailed numbers for 2010, 2014 and projections for 2020 for the EU-27 countries are shown in Table 8.1. Data have been taken from a report from the European Wind Energy Association (EWEA), which shows a baseline scenario for the EU requiring an average annual increase in capacity of 14.6 GW between 2011 and 2020; and a "high scenario" requiring an average annual increase in capacity of 18.1 GW. Data for the remaining (European) countries are shown in the appendix in Table 8.14.

The offshore installed capacity amounts to 3.5% of total installed capacity in 2010 and is responsible for 5.8% of electricity produced. The highest offshore installed capacity share is found in the United Kingdom (25.8%), Denmark (22.5%) and Belgium (21.4%), where offshore wind produces about one third of consumed electricity. Offshore wind is projected to rise up to 58.8% of installed capacity or 65.6% of electricity production in the UK by 2020 (high scenario), followed by the Netherlands. The countries with highest projected increase rates in installed capacity are Germany, France, Spain, and the United Kingdom with rates of up to 2880 MW per year until 2020.

[160] http://www.windpoweroffshore.com/article/1351718/analysis-china-reevaluate-offshore-new-five-year-plan

Table 8.1: Installed capacities and electricity production of on- and offshore wind power in the end of 2010 in the EU-27. The table also includes projections up to 2020 in the EU-27 for a baseline (lower range) and a high (higher range) scenario. Taken from (EWEA 2011), data for 2014 and 2030 scenarios from (EWEA 2015), data for projections from (JRC 2013). On = Onshore, Off = Offshore.

	MW installed end 2010			MW installed end 2014			GW installed end 2020: Baseline - High			GW installed end 2030: Low - High			Electricity production end 2010 (TWh)			Electricity production end 2020: Baseline - High (TWh)		
	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total
Austria	1011	0	1011	2095	0	2095	3.5-4	0 - 0	3.5-4	5-6.65	0	5-6.65	2	0	2	7.5-8.6	0	7.5-8.6
Belgium	716	195	911	1247	713	1659	2.1-2.5	1.8-2	3.9-4.5	2.65-4.0	2.2-3.8	4.85-7.8	1.5	0.7	2.2	4.7-5.6	6.1-7.3	10.8-12.9
Bulgaria	375	0	375	690	0	690	3-3.5	0	3-3.5	1-1.44	0	1-1.44	0.8	0	0.8	7-8.2	0	7-8.2
Cyprus	82	0	82	147	0	147	0.3-0.5	0	0.3-0.5	0.45-0.58	0	0.45-0.58	0.2	0	0.2	0.7-1.2	0	0.7-1.2
Czech Republic	215	0	215	282	0	282	1.6-1.8	0	1.6-1.8	1.04-4.32	0	1.04-4.32	0.5	0	0.5	3.5-3.9	0	3.5-3.9
Denmark	2944	854	3798	3603	1271	4845	3.7-4	2.3-2.5	6-6.5	3.3-6	2.65-5.32	5.95-11.32	6.6	3.1	9.7	8.5-9.2	6.2-9.1	14.7-18.3
Estonia	149	0	149	303	0	303	0.5	0-0.1	0.5-0.6	0.67-0.5	0-1.5	0.67-2	0.3	0	0.3	1.2	0-0.4	1.2-1.6
Finland	171	26	197	601	26	627	1.5-2	0.4-1	1.9-3	5-12	0.03	5.03-12.03	0.4	0.1	0.5	3.6-4.9	1.4-3.7	5.1-8.6
France	5660	0	5660	9285	0	9285	19-20	4-6	23-26	19-28	6-15	25-43	11.9	0	11.9	45.8-48.3	14.7-22.1	60.5-70.4
Germany	27122	92	27214	38369	1049	39165	41-42	8-10	49-52	60-65	15-22.5	75-87.5	49.2	0.3	49.5	77.1-79.2	29.2-36.8	106.3-115.9
Greece	1208	0	1208	1980	0	1980	6.5-8.3	0-0.2	6.5-8.5	8-12	0-0.5	8-12.5	3	0	3	17.4-22.3	0-0.7	17.4-23
Hungary	295	0	295	329	0	329	0.9-1.2	0	0.9-1.2	0.93-1.05	0	0.93-1.05	0.6	0	0.6	2.1-2.8	0	2.1-2.8
Ireland	1403	25	1428	2246	25	2272	5-6	1	6-7	5.5-8.39	0.03-1.2	5.53-9.6	3.8	0.1	3.9	13.9-16.7	3.6-3.7	17.5-20.4
Italy	5797	0	5797	8665	0	8865	15-17	0.5-1	15.5-18	10.8-16.8	0-0.5	10.8-17.3	11.6	0	11.6	32.5-37.1	1.8-3.7	34.4-40.8
Latvia	31	0	31	62	0	62	0.2	0-0.1	0.2-0.3	0.23-0.43	0	0.23-0.43	0.1	0	0.1	0.5	0-0.4	0.5-0.8
Lithuania	154	0	154	279	0	279	1	0-0.1	1-1.1	0.88-1.2	0-1	0.88-2.2	0.4	0	0.4	2.4	0-0.4	2.4-2.7
Luxembourg	42	0	42	58	0	58	0.3-0.7	0	0.3-0.7	0.12-0.17	0	0.12-0.17	0.1	0	0.1	0.6-1.5	0	0.6-1.5
Malta	0	0	0	0	0	0	0.1-0.2	0	0.1-0.2	0.03-0.08	0	0.03-0.08	0	0	0	0.2-0.4	0	0.2-0.4
Netherlands	1998	247	2245	2565	247	2805	5-5.4	4.5-6	9.5-11.4	5.88-6.39	6-7	11.9-13.4	4.2	0.9	5.1	11-11.9	15.9-22.1	26.9-34
Poland	1107	0	1107	3834	0	3834	10-12	0.5	10.5-12.5	7.9-13.5	0.5-2.2	8.4-15.7	2.4	0	2.4	23.5-28.2	1.8	25.3-30
Portugal	3898	0	3898	4913	2	4915	7.5-9	0	7.5-9	5.92-7.01	0.03	5.95-7.04	8.6	0	8.6	16.8-20.2	0	16.8-20.2
Romania	462	0	462	2954	0	2954	3-3.5	0	3-3.5	4.5-6	0	4.5-6	1	0	1	7-8..2	0	7-8.2
Slovakia	3	0	3	3	0	3	0.8-1	0	0.8-1	0.3-0.49	0	0.3-0.49	0	0	0	1.8-2.3	0	1.8-2.3
Slovenia	0.03	0	0.03	3	0	3	0.5-0.7	0	0.5-0.7	0.03-0.08	0	0.03-0.08	0	0	0	1.1-1.6	0	1.1-1.6
Spain	20676	0	20676	22982	5	22987	39-41	1-1.5	40-42.5	35-52	0.01-0.5	35.01-52.5	45.5	0	45.5	90.4-95.3	3.7-5.5	94.1-100.8
Sweden	1999	164	2163	5220	212	5425	6-8	3	9-11	8.6-18	0.2-2	8.8-20	4.2	0.6	4.8	13.3-17.9	10.6-11	23.9-28.9
UK	3863	1341	5204	7953	4494	12440	13-14	13-20	26-34	12.3-20	12-35	24.3-55	10.2	4.8	15	35.8-38.6	44.2-73.5	80-112
EU-27	81380	2944	84324	121021	8044	128744	190-210	40-55	230-265	206-294	45-98	250-392	171.1	10.6	181.7	4323-278	148-204	581-628
Projection by JRC, EU-27							204	51	255									
Projection by JRC, all countries							221	53	274									

The total potential in the EU-27 by 2020 is estimated to reach 230-265 GW of installed capacity and 581-628 TWh of electricity produced, which is estimated to cover 15.7% to 18.4% of the electricity needs.

Another projection for all European countries by 2020 and 2050 is presented by the Joint Research Council (JRC) by means of the JRC-EU-TIMES model (JRC 2013). The total installed capacity is projected to reach 274 GW by 2020 (with a share of 19% offshore) and 481 GW by 2050 (with a share of 34% offshore). The greatest potentials are also seen in Germany, Spain, France, and the United Kingdom by 2020. By 2050, the Netherlands is projected to catch up by installing large amounts of offshore capacity (73 GW).

8.3 Wind Energy in Switzerland

8.3.1 Status Quo

The installed capacity of wind turbines in Switzerland has been growing slowly within the last ten years and has reached 60 MW as to the end of 2013 with no new installations in 2014 and 2015. In 2016, another 15 MW were added. The resulting electricity production amounted to 109 GWh in 2016, which covers ca. 0.1% of the total electricity production and also electricity consumption in Switzerland (Figure 8.4).

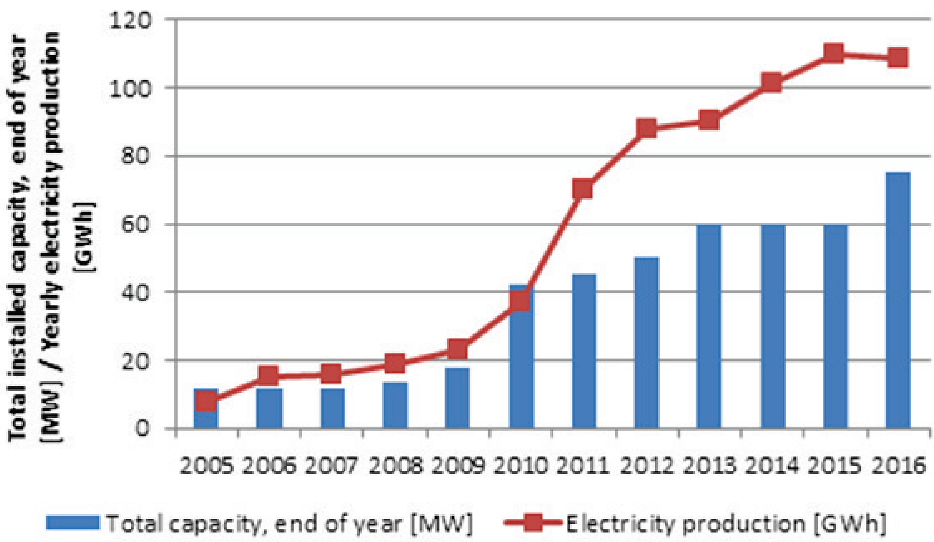

Figure 8.4: Installed total capacity of and electricity production with wind turbines from 2005 to 2016 in Switzerland (WWEA 2011, BFE/SFOE 2015a, BFE/SFOE 2015b, WWEA 2015).

A typical wind turbine with 2 MW capacity in Switzerland can supply a total amount of electricity to cover the needs of ca. 800-1500 households, depending on the location and assumed household needs (though the intermittency nature of wind power has to be considered). The largest and most productive wind turbines in Switzerland produced 4.5-7 GWh in 2016 each, which covered the needs of ca. 1200-1700 households (Martigny and Charrat). The largest wind park in Jura (Mt. Crosin) produced ca. 57 GWh in 2016 (ca. 14'000 households with 2 persons).

The average capacity factor of large wind turbines in Switzerland amounted to 20.8% in 2015.[161]

Figure 8.5 shows where wind turbines are present in Switzerland as of today (2016). Information shown by (SuisseEole 2017) is summarized in Table 8.2.

[161] Own calculation based on http://wind-data.ch/wka/list.php

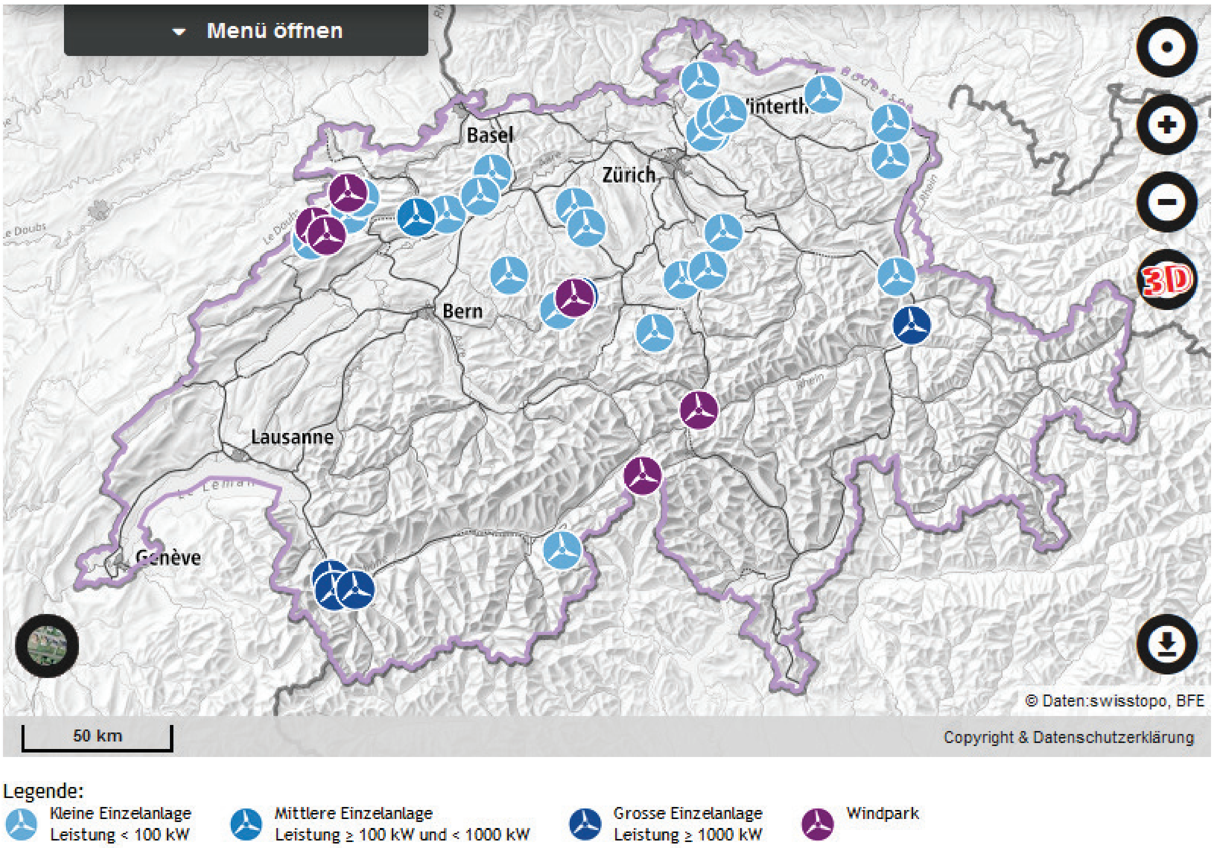

Figure 8.5: Wind turbines installed in Switzerland mid 2017 (BFE/SFOE 2016i).

As shown in Table 8.2, a total of 64 wind turbines existed in Switzerland at 37 locations as per the end of 2016, out of which 28 have a capacity lower than 100 kW. Wind parks are defined as locations with more than three wind turbines.

The largest wind park is Mt. Croisin in the Jura with 16 wind turbines and a total capacity of 37.2 MW after repowering some of the older wind turbines in 2016. The other wind parks are located on the Gütsch (4 turbines), Gries (4 turbines), and Peuchapette (3 turbines) with a total capacity of 19.5 MW. Most large wind turbines have been built in the last ten years.

Medium to big single plants and wind parks are located in the region of the Jura and in the mountains (Wallis, Uri, Graubünden). Small single plants are more scattered over Switzerland, but still more to be found in the Northern part.

The turbine types most used are Aventa for small turbines with 6.5 kW (0.1% of total installed capacity, 26% of small capacity), Vestas (53%) and Enercon (43%) with capacities between 0.9MW and 3MW. Tower height is between 45 and 119 m with a rotor diameter of around 40 to 112 m for the >100kW turbines. As can be seen in Figure 8.4, most of the turbines with larger capacity have been built in the last 10 years and represent improved technology. The largest wind turbines have a capacity of 3 MW.

Table 8.2: Wind energy capacity installed (end of 2016) and electricity produced (2016) in Switzerland (BFE/SFOE 2016i).

	Total	<100kW	>100kW			
			Total, >100kW	Medium	Large	Wind park
Number of wind turbines	64	28	*36*	1	9	27
Capacity installed, end of 2016 [MW]	75.5	0.4	*75.15*	0.15	18.2	56.8
Shares		*0.5%*	*99.5%*	*0.2%*	*24.1%*	*75.2%*
Electricity production, 2016 [GWh]	110	0.2	*108.4*	0.1	30.4	78.0
Shares		0.2%	99.8%	0.1%	28.0%	71.8%

8.3.2 Potential of wind power in Switzerland

According to the new Swiss wind energy concept, 4.3 TWh/a are supposed to be generated with wind turbines in Switzerland in 2050 (BFE/SFOE 2017). However, this new concept does not contain any basis for the expected generation in 2050.

This potential is in line with earlier estimates: The Swiss Energy Strategy 2050 contains an electricity production of 4222 GWh from wind turbines in 2050 in all scenarios except of Variant C with 1372 GWh. This would cover around 7% of the projected electricity demand in Switzerland. The increase is projected to be 624 GWh by 2020 and 1723 GWh in 2035 (Prognos 2012b) (see Table 8.3). Based on a simplified calculation with an assumed average capacity of 3 MW per turbine and on average 1500 to 1800h wind load hours per year, achievement of this goal would require 800-1000 wind turbines with current technology. This is roughly consistent with the projections of the updated federal wind energy concept (ARE 2015b, ARE 2015a), who project the need of 600-800 wind turbines or 60-80 wind parks with around 10 wind turbines each to reach the goal. As shown above, today there are 34 large wind turbines in Switzerland. The Umweltallianz Schweiz states that there is space and capacity for around 400 wind turbines à 2MW in Switzerland capable to produce 1.5 TWh/a of electricity by 2035, based on average wind load hours of 1875 h/year (Umweltallianz 2012). This number is estimated to be higher by the Suisse Eole association.

(Cattin, Schaffner et al. 2012) have provided different estimates for the wind power potential in Switzerland: According to their prospective scenario with 3 MW turbines, the sustainable potential taking into account noise and acceptance related constraints is only 1.7 TWh/a and 2.2 TWh/a, respectively, for sites with average wind speeds above 5 m/s and 4.5 m/s, respectively.

Based on recent measurements, (Kruyt, Lehning et al. 2017) have not provided any numbers for generation potentials, but a few important qualitative conclusions:

- Due to the complex terrain, cross-correlations as a function of distance between stations are significantly lower in Switzerland than values reported in literature for Europe and the US, meaning that smoothing the output from combinations of wind farms can be achieved over much shorter distances than those commonly reported in literature.
- Wind farms that are located at higher elevation are less likely to suffer from long periods without power production.

- The mean wind speed is higher in winter, and the relative difference between winter and summer is also more pronounced with increasing elevation. Moreover, power production also appears to increase with elevation, despite the negative effects of lower air density on electricity yield.

Table 8.3 summarizes projections of Swiss wind power potentials according to different studies.

Table 8.3: Projections and estimates of annual electricity production from wind power in Switzerland up to 2050 (GWh/a). VSE = Verband Schweizerischer Elektrizitätsunternehmen (Association of Swiss electric utilities); nd = no data.

	2020	2035	2050
Swiss wind energy concept (BFE/SFOE 2017)	nd	nd	4300
Meteotest (Cattin, Schaffner et al. 2012)	nd	nd	1500-2200[162]
Energy Strategy (Prognos 2012b)	624	1723	4222
Energy Strategy, Variant C (Prognos 2012b)	108	738	1372
VSE (VSE 2013)	nd	700-1500	2000-4000
Energie Trialog Schweiz (VSE 2013)	nd	1500 (+-500)	2000-3000
Suisse Eole (SuisseEole 2012)	2000	6000	nd
Umweltallianz (Umweltallianz 2012)			2000 (400 turbines)[163]

The new Swiss wind energy concept basically specifies the legislative boundary conditions for further development of wind power in Switzerland. Based on average wind speeds (Figure 8.6) and various constraints (Figure 8.7), areas with high wind potential for further evaluation of wind turbine installations are identified (Figure 8.8).

[162] (Cattin, Schaffner et al. 2012) do not provide a time horizon, but just quantify the sustainable potential for wind power in Switzerland. The range provided here corresponds to the sustainable potential taking into account noise and acceptance related constraints, turbine capacities of 2-3 MW and locations with average wind speeds of 4.5-5 m/s.

[163] http://www.suisse-eole.ch/media/redactor/Windrose_CongresEolien_WWF_Martinson_20160406_bO09dWo.pdf

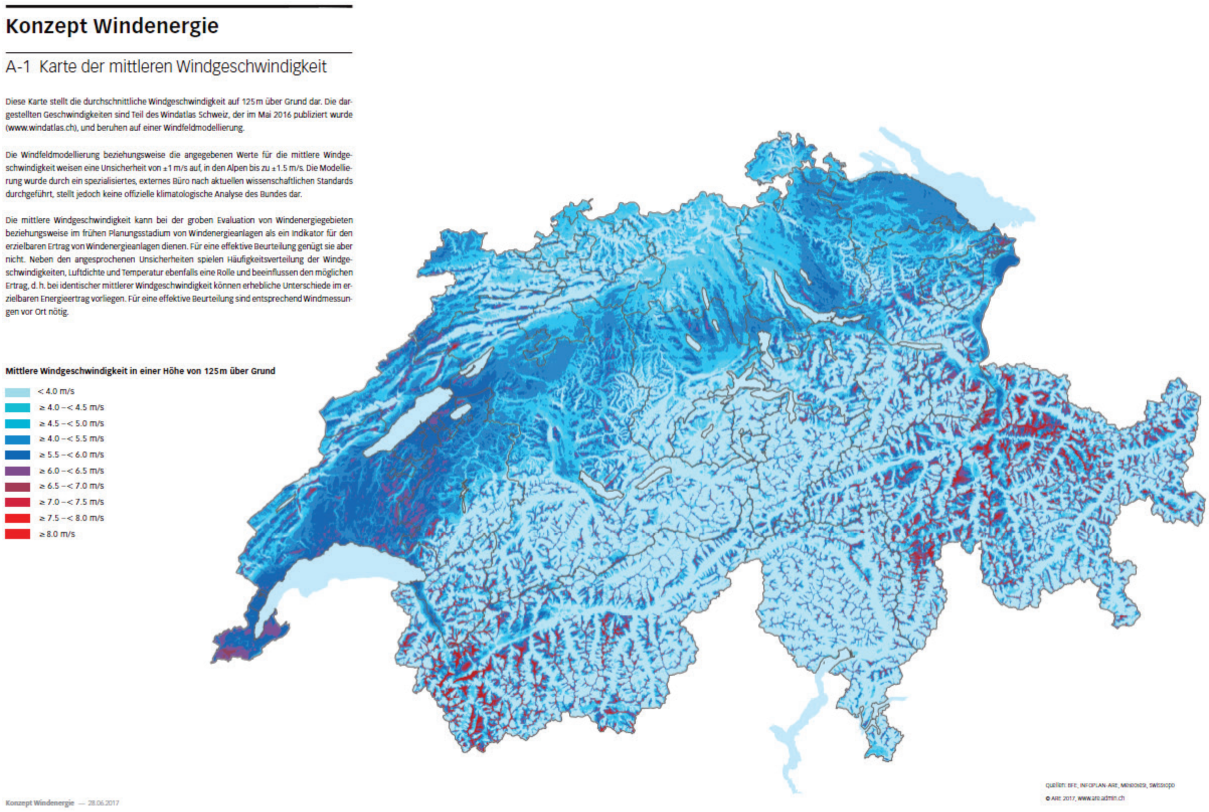

Figure 8.6: Map of average wind speeds in Switzerland (BFE/SFOE 2017).

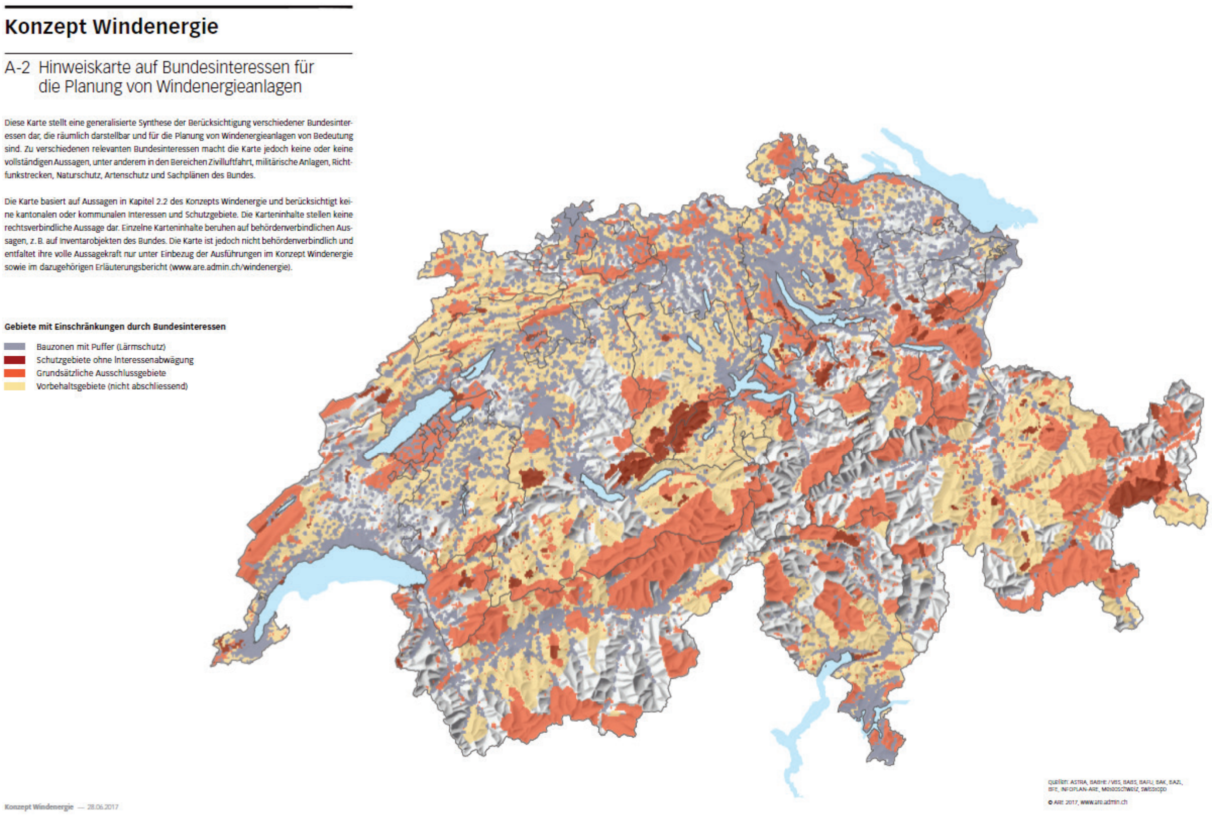

Figure 8.7: Map of constraints for wind power development (BFE/SFOE 2017).

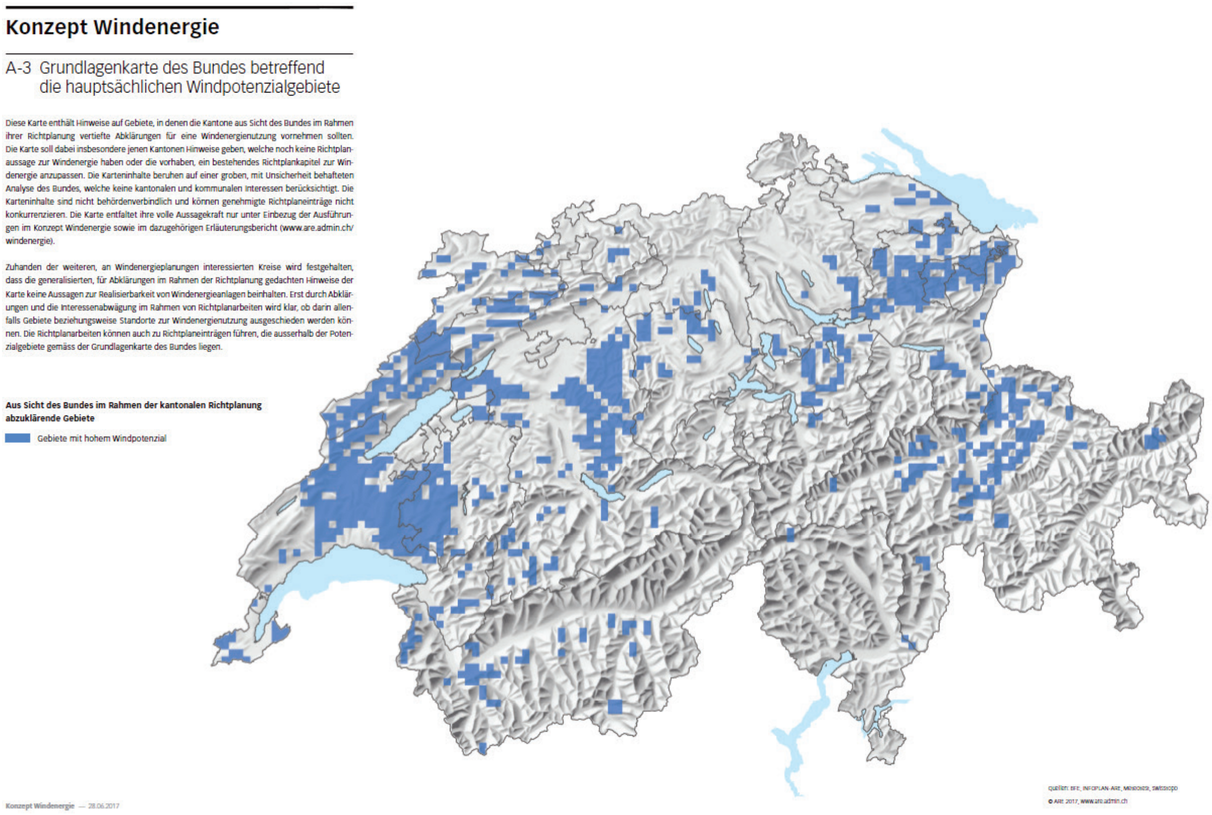

Figure 8.8: Map of high potential areas for wind power development (BFE/SFOE 2017).

Various research institutes are active in the field of Swiss wind power, e.g. FHNW, ZHAW, NTB, EPFL[164] and ETHZ[165]. Research institutes are working on refining the modeling of suitable wind power plant locations and wind park designs. As an example, the Laboratory for Energy Conversion at ETH Zürich[166] is performing field experiments, controlled experiments, and simulation of wind turbines and wind farms. In this way, new potential locations in Switzerland might be found, and costs could be reduced.

According to the "Stiftung KEV", a total of 554 **wind turbine projects** with a capacity of 1159 MW were accepted as per 1st of July 2016 (KEV 2016). It is estimated that this will result in a production of 2069 GWh/a. Further 350 wind turbine projects with a total capacity of 804 MW have been on the waiting list, resulting in estimated 1480 GWh/a. Together with today's electricity production, wind turbines on the KEV list might produce a theoretical total of ca. 3600 GWh/a. However, note that projects with a positive decision ("accepted projects") have to undergo all necessary approval and concession procedures and so far often don't materialize. The projects with a positive approval are mostly situated in the cantons of Bern (ca. 20% of estimated capacity and electricity production) and Vaud (ca. 30%). Another 10% each are situated in the cantons of Graubünden, Neuchâtel and St. Gallen.

8.3.3 Imports

Already today and probably also in future, Swiss utilities will buy electricity from or produce electricity with wind power plant installations abroad. According to (Stolz and Frischknecht

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[164] http://wire.epfl.ch/
[165] http://www.lec.ethz.ch/research/wind-energy.html
[166] http://www.lec.ethz.ch/

2015), 0.6% of the electricity consumption in Switzerland in 2011 was supplied by imports of wind power. 14% of the consumption was of non-specified origin and type, which might include wind power. Also in the future, wind power from abroad might complement the Swiss electricity mix. However, when counting on imports, the wind potentials, policies and plans of all neighboring countries have to be taken into account.

Table 8.4 shows the estimated wind resource potentials in 2050 in Austria, Switzerland, Germany, France and Italy.

Table 8.4: Assumptions on wind resource potentials in 2050 in Switzerland and neighboring countries (Pattupara 2016).

	Resource potentials (2050) (TWh)				
	AT	CH	DE	FR	IT
Wind (Onshore)	6.9	3.9	132	65	17.8
Wind (Offshore)	n.a.	n.a.	128	92	12936

Swiss electricity utilities have already invested into wind parks abroad in the past few years (Table 8.5 and Figure 8.9).

Table 8.5: Swiss wind electricity abroad. Electricity production of selected Swiss electricity utilities in wind parks in Europe, in Million kilowatt hours (Mio. kWh) per year, as per 2015. Adapted from[167].

Company	Yearly electricity production in Mio. kWh	Percent of it abroad
Alpiq	450	> 95%
Axpo	900	100%
BKW Energie	700	> 90%
EBM (Elektra Birseck)	200	> 95%
EW Canton of Zurich	250	> 95%
EW City of Zurich	250	100%
IW Basel-Stadt	500	> 95%
Repower	100	> 95%
Swisspower	400	> 95%
Total	**3750**	**> 95%**

This article estimates that all these wind turbines produce 3.75 TWh/a as per 2015, of which more than 95% abroad.

Even if the compilation in Figure 8.9 is not complete, it is clearly visible that the number of wind turbines, installed capacity and electricity produced are much larger abroad than in Switzerland. Investments in wind parks in Germany, France or in Sweden are interesting because of portfolio diversification, good local wind conditions, political constraints and subsidies. Furthermore the authorization processes are much faster abroad (ca. 4 years) compared to Switzerland (up to 10 years). Planning in Switzerland is also more difficult due to wind conditions, topography, and population density.

[167] http://www.tageswoche.ch/de/2015_39/schweiz/699285/

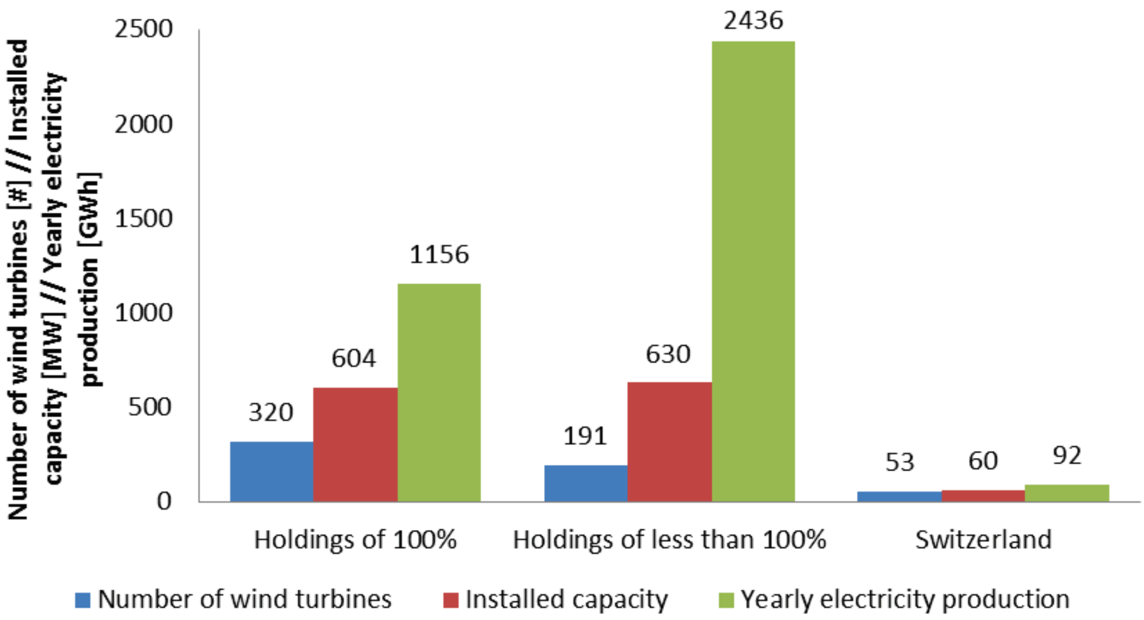

Figure 8.9: Total number, capacity and yearly electricity production of wind turbines installed abroad (partially) owned by Swiss electricity utilities. Own compilation based on various sources[168]. Data for Switzerland are not complete in this compilation.

8.4 Technology description

8.4.1 General

There exist various types of wind turbines. The two main categories are **horizontal axis wind turbines (HAWT)** and **vertical axis wind turbines (VAWT).** VATW claim to have the advantage of less impact on the landscape and cheaper design. In addition, they can always face the wind. However, they show much lower efficiencies than common HAWT, partly because they are situated at lower wind speeds as they are closer to the ground (see Figure 8.10). In order to reach a similar production capacity as HAWT, they would have to be placed higher up so that visual impact would be similar to HAWT. There exist the rotor types "Savonius", "Darrieus", and "H-rotor". In the following text, VAWT are not considered and explained in detail as they don't play a role on the wind power market today due to economic and technical reasons, which is not projected to change until 2050. All information therefore concerns HAWT.

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[168] http://www.alpiq.com/de/alpiq-gruppe/unsere-anlagen/windkraftwerke/wind-power-plants.jsp
http://www.bkw.de/produktionsanlagen.html
http://www.snee.ch/beteiligung/
http://www.strom.ch/de/verband/politik/news/news-detail/news/helvetic-wind-uebernahme-eines-windparks-in-italien.html
https://www.ewz.ch/de/ueber-ewz/unternehmen/energieproduktion.html

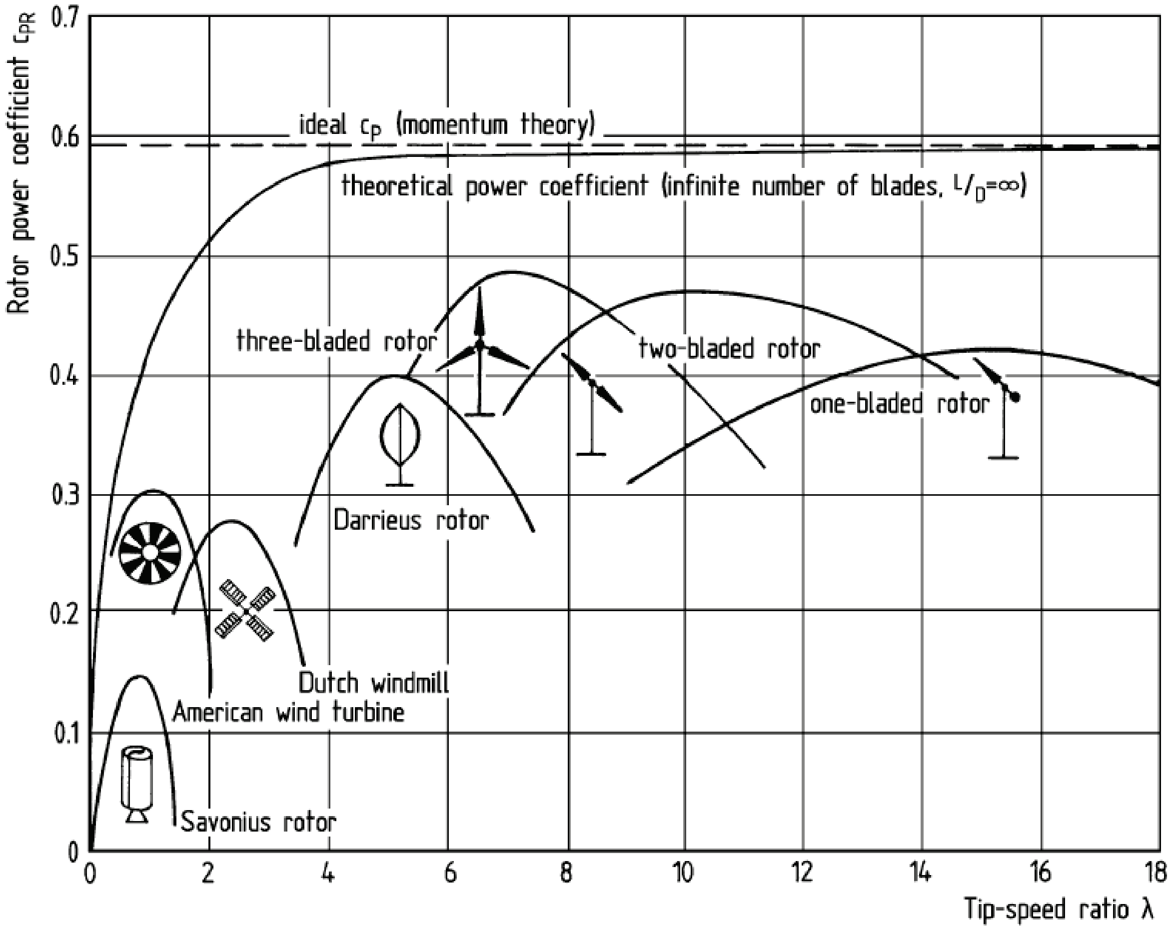


Figure 8.10: Power coefficients of wind rotors of different designs. Taken from (Hau 2013).

Figure 8.11: Example of a vertical axis wind turbine.[169]

[169] http://verticalaxiswindturbines.blogspot.ch/2010/10/how-efficient-are-vertical-axis-wind.html

Within the HAWT category, there exist downwind (pointing out of the wind) and upwind (pointing into the wind) rotor wind turbines, and various designs of rotor blades. The most commonly applied wind turbine today is HAWT with three rotor blades (see Figure 8.10) as shown in Figure 8.14. They make use of higher wind speeds at higher heights by installing the rotor shaft and electrical generator at the top of a tower. Improved developments go towards better use of the kinetic energy through optimization of the aerodynamic efficiency, so that also lower wind speed can be of use and full load hours can be increased. The resulting electricity production is mostly dependent on the full load hours, i.e. the number of hours the wind turbine is running at its rated capacity. Full load hours times the capacity of the wind turbine therefore gives the electricity produced. The load hours can go up to ca. 4600 hours per year[170] for an offshore location and ca. 3000 hours for an onshore location, depending on specific location and wind turbine type.

Modern wind turbines reach a capacity of up to 8 MW (Vestas 164-8.0 prototype for offshore or Enercon E126-7.5 for onshore installation[171]). The diameter of the rotor can be as large as 164 m and the hub height up to 220 m[172]. However, around 72% of the installed capacity worldwide are wind turbines between 1 and 3 MW. 15% of installed capacity are turbines with less than 1 MW, and 14% are turbines with more than 3 MW (calculated based on (Pierrot 2015)) (See Figure 8.12). The average size of offshore wind turbines in Europe is 4.2 MW (EWEA 2016).

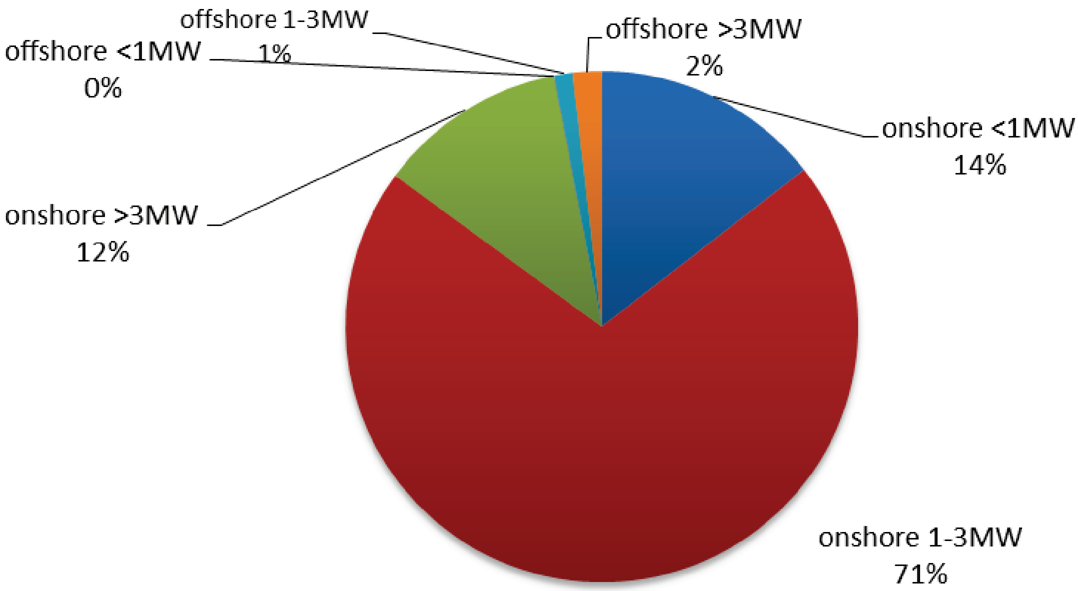


Figure 8.12: Installed capacity of wind power worldwide in turbine size classes, separated into onshore and offshore installations. Based on (Pierrot 2015) with data for the end of 2014.

It should be mentioned that the WWEA also publishes a report on small wind turbine installations on the world for turbines with a capacity of up to 100 kW[173]. However, this market is still very small with only 678 MW installed capacity in 2012 (WWEA 2014). The

[170] E.g. http://cf01.erneuerbareenergien.schluetersche.de/files/smfiledata/3/1/7/2/7/1/V2BC37NhCFWindDK.pdf
[171] http://www.windpowermonthly.com/10-biggest-turbines
[172] http://www.enercon.de/produkte/ep-8/e-126/
[173] The definition of small wind is still disputed and is discussed in (WWEA 2014).

leading markets are China (39% of global capacity), USA (31%) and United Kingdom (9.4%). Small wind turbines are not treated further in this report.

8.4.2 The intermittent nature of wind power

Wind is not steadily blowing. It is of intermittent nature at different time scales – from hourly over diurnal to seasonal changes. As a result, there need to be either backup power plants based on other energy sources, or energy storage items connected to the wind power plant. These may lead to hidden costs or environmental impacts, which is not yet extensively addressed on a regular basis in assessments of wind power. Further, it is important to estimate wind loads in advance so that baseload power plants can adjust their power production in order to prevent blackouts in the electricity grid. However, forecasting the wind speed and direction is not trivial.

As the data in Table 8.6 show, wind power is least available in summer and most available in wintertime in European countries.

Table 8.6: Capacity factors of onshore (and offshore) wind power in Switzerland and surrounding countries (Pattupara 2016).

	Austria	France		Italy	Germany		Switzerland
	Onshore	Onshore	Offshore	Onshore	Onshore	Offshore	Onshore
Spring	27%	21%	41%	14%	21%	47%	19%
Summer	19%	17%	34%	13%	13%	29%	8%
Fall	25%	22%	43%	43%	21%	48%	12%
Winter	25%	29%	58%	31%	30%	68%	18%

Note that the data for Switzerland are valid for the period before 2010, while the data for Germany are for the period 2011-2015. The average capacity factor 2015 of big wind turbines in Switzerland was about 21%[174], and it amounted to 23% for onshore wind turbines in Germany[175]. However, the seasonal patterns as shown in Table 8.6 are still valid. As already described in chapter 8.2.2, Archer and Jacobson (2013) did a research on the "geographical and seasonal variability of the global "practical wind resources" at a height of 100 m. They find that the highest capacity factors on the Northern Hemisphere are generally found in the winter months from December to February, and lowest are present in the period from June to August. On the Southern Hemisphere, the strongest winds happen in their winter period from June to August with lowest wind from December to February. However, as also described in (Archer and Jacobson 2013), this can vary a lot on a regional level. As example, the Environmental Agency in the United States evaluated the seasonality of wind power in various regions in the US. They find that the capacity factor is highest in summer for California, while the other regions show a similar (but not identical) pattern as described above[176]. In general, (Archer and Jacobson 2013) conclude that despite these seasonal variations, the wind energy source would be suited to cover today's electricity needs in all regions of the world (except Japan) even during weak wind periods.

[174] Own calculation based on http://wind-data.ch/wka/list.php.

[175] http://windmonitor.iwes.fraunhofer.de/windmonitor_en/3_Onshore/5_betriebsergebnisse/1_volllaststunden/

[176] https://www.eia.gov/todayinenergy/detail.cfm?id=20112

The intermittent nature of wind power is not only present at seasonal level, but also at hourly and even lower level, which can decrease the power quality in an electricity grid. Storage possibilities and/or backup power plants then have to level out these fluctuations. Today, there are various energy storage options in discussion for electricity grids less depending on nuclear or fossil fuels. These are of different types based on different physical conditions (e.g. chemical, kinetic energy, magnetic fields, electric fields, compressed air, gravitational potential energy, electrochemical). They act on various time and size scales. Not all of these are equally suited for wind power. (Díaz-González, Sumper et al. 2012) did a review of energy storage technologies for wind power applications. They found a variety of publications discussing appropriate storage technologies. Still, spinning reserves will have to be present to even out fluctuations in wind power production. Simulations of the need for such reserves should be as accurate as possible in order to save money without underestimating the needs.

8.4.3 Power output

A wind turbine generator is driven by rotor blades rotating due to kinetic energy from wind. When the wind is blowing with a minimal wind speed set through the design of the wind turbine, the rotor blades start rotating. This mechanic rotating drives the shaft drive, handing the energy over to the gearbox. "Gearboxes turn the slow rotation of the blades into a quicker rotation that is more suitable to drive an electrical generator"[177]. Most wind turbines make use of a gearbox which converts the lower turning speed from the rotor blades into a higher speed. However, companies strive to build more and more gearless wind turbines. This decreases downtime and therefore makes the wind turbines more reliable at less (maintenance) cost.

The **power output** of a wind turbine is mainly a function of the wind speed and the rotor swept area, as given in the following formula:

$$P = \frac{1}{2} C_p \rho A U^3$$

P	Power Output [kW]
ρ	Density of air [kg/m^3]
C_p	Maximum power coefficient (efficiency) [-]
A	Rotor swept area [m^2]
U	Wind speed [m/s]

The density of the air changes with altitude, temperature and humidity. At sea level, T=15°C and standard atmospheric pressure, it is 1.225 kg/m^3. As described in the introduction part of this chapter, the maximum power coefficient (ratio of power extracted by the turbine to the total contained energy in the wind resource) can theoretically reach 59%, but in reality is between 25%-45%. The rotor swept area is an important parameter for the yield and increases with larger rotor blades. The wind speed parameter value is within a certain range: The so-called "cut-in speed" and "cut-out speed". Below the cut-in speed, the rotor blades do not receive enough energy to move – typically, this is below 3.5 m/s. The wind speed then quickly reaches the rated output speed. Power output has a maximum for a tip

[177] http://www.turbinesinfo.com/types-of-wind-turbines

speed ratio (the ratio of rotor tip speed to free wind speed) which is unique to each wind turbine type. Higher wind speed then does not increase the power output, but the wind turbine has to be shut down at a certain cut-out speed in order to prevent damage. An example of a typical power output curve is shown in Figure 8.13 for the Enercon E82 / 2 MW, as built in Martigny and St. Brais. The start-up wind speed is 2 m/s, nominal wind speed is at 12.5 m/s, and the cut-out wind speed is at 34 m/s.

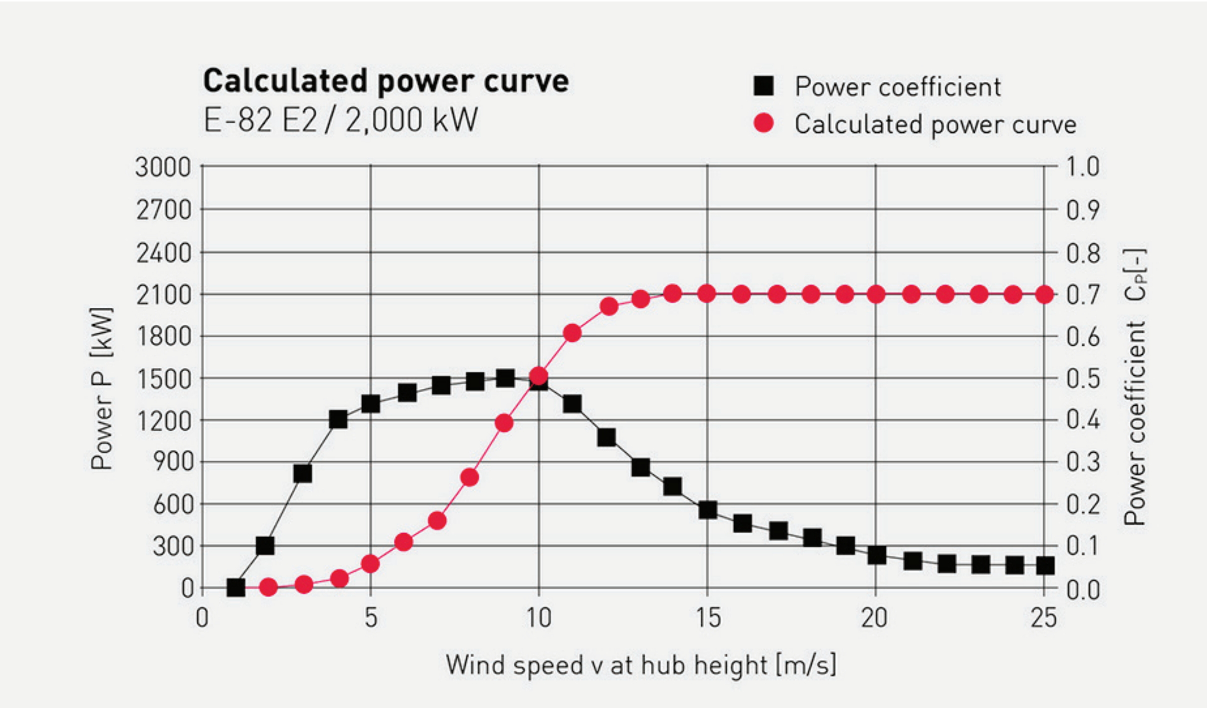


Figure 8.13: Calculated power curve and power coefficient curve for the Enercon E-82 E2 / 2000kW wind turbine.[178]

The actual power output on site is influenced and potentially decreased by manifold parameters, though. First, the density of the air is lower in mountain regions or cold regions. Second, the flow conditions (and with it wind velocity) can be influenced by the landform, the placement of wind turbines within a wind park, or other turbulence phenomena. In cold regions, wind turbines can suffer from icing. Last, maintenance of all turbine parts ensures the maximum power output possible at actual conditions and prevents downtime.

8.4.4 Onshore wind turbines

Today's wind horizontal-axis three-bladed wind turbines are composed of a foundation, a tower, a nacelle, and the rotor blades. These typical components of an onshore HAWT are shown in Figure 8.14.

[178] http://www.enercon.de/en/products/ep-2/e-82/

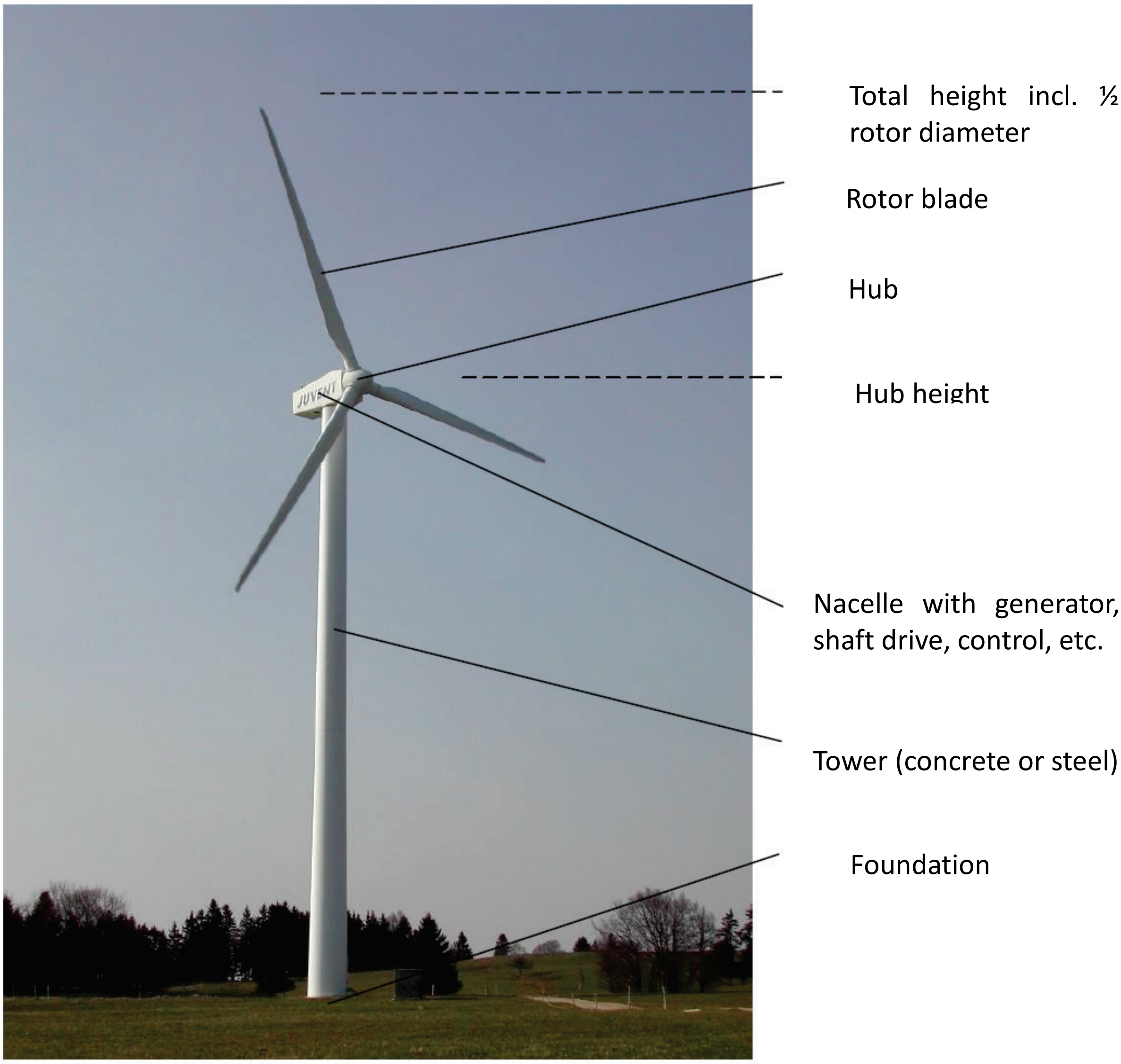


Figure 8.14: Components of a wind turbine. Adapted from (BFE, BAFU et al. 2004a).

The **foundation** is the anchor of the wind turbine, usually made of concrete with reinforced steel. The size of it is determined by the size of the wind turbine and local ground conditions. In weak soils, the foundation can be enforced with piles. The **tower** is made of steel-reinforced concrete or steel. Free-standing tubular steel towers as shown in the figure today dominate the installed towers. They are easily transported in small parts and quickly erected. However, new towers unify the tubular geometry with the concrete material due to increasing height of the towers and steel prices. Tests have also been made with concrete-steel hybrid towers, which should keep costs reasonable with increasing tower height while still allowing to withstand the dynamic stress a tower is exposed to (Hau 2013, Eymann, Stucki et al. 2015). They can be prefabricated and transported in parts to the location of installation. **Rotor blades** are aimed to be lightweight and are usually made of carbon fibers or alloys. All other parts and components of the wind turbine are mostly iron or steel-based.

8.4.5 Offshore wind turbines

Offshore wind plants usually show a higher capacity factor than similar plants onshore. The main reasons for this are larger swept area, higher average wind speeds, less turbulences, and larger wind farms. The main differences between onshore and offshore wind power plants are the support structures (foundation) and network connection. Besides this, offshore wind turbines are mostly further developments of onshore wind turbines and therefore follow the established onshore design. It is potentially possible that the design might deviate from the one for onshore plants in future. The average distance to shore in Europe is 43 km, average water depth is 27 m, average size of connected offshore wind farms is 338 MW (EWEA 2016).

There exist five different types of sub-structures for offshore wind power plants to date: Monopiles, jacket structures, tripods, tripiles and gravity bases. They are being used depending on water depth and other location-specific and technological considerations. Monopiles are most used today (Burton, Jenkins et al. 2011, IRENA 2012c, JRC 2014a). Advantages and disadvantages of each of these foundations are summarized in table 2.2 in (IRENA 2012c) or in (Hau 2013).

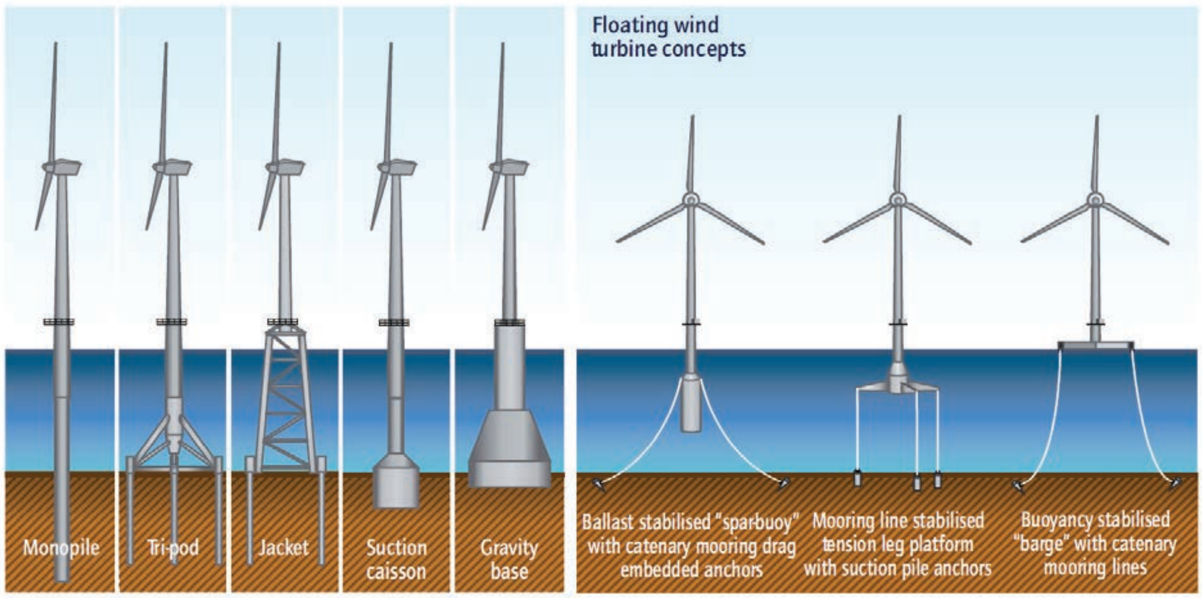


Figure 8.15: Types of fixed-bottom and floating offshore support structures. Taken from (IEA 2013a).

Jacket structure can be installed at deeper water depths. Besides this, floating platforms are being discussed and tested for installation of wind turbines at deep water depths (>60 m) and thus exploiting the wind potential over the sea better. They would come along with easier installation and lower material needs. In this design, the platform is attached to the sea floor with lines. However, this concept is not yet economic as per today and faces some physical challenges, e.g. changed dynamics due to the floating underground. Test installations are present on the world, but it is not estimated by (IEA 2013a) that the testing phase is finalized before 2025.

In Europe, 80% of the existing and under construction wind turbine foundations are monopiles, 9.1% are gravity foundations, 5.4% are jackets, 3.6% are tripods and 1.7% are tripiles (EWEA 2016).

8.4.6 Capacity factor and full load hours

”The capacity factor of a wind turbine is the amount of energy delivered during a year divided by the amount of energy that would have been generated if the generator were running at maximum power output throughout all the 8760 hours of a year” (EWEA 2009). This represents the same idea as the “full load hours”, which represent the time that a wind turbine would spend at peak power in order to produce the energy delivered throughout a year. The capacity factor multiplied with 8760 hours equals the full load hours. These two parameters should not be confused with the power coefficient (efficiency), which is limited at 59.3%, while the capacity factor could theoretically reach 100%.

Capacity factors have been steadily increasing in the last decade and can reach nearly 50% (see Figure 8.16). The main reason for this is improved technology, so that also locations with lower wind speeds can be exploited with a decent capacity factor.

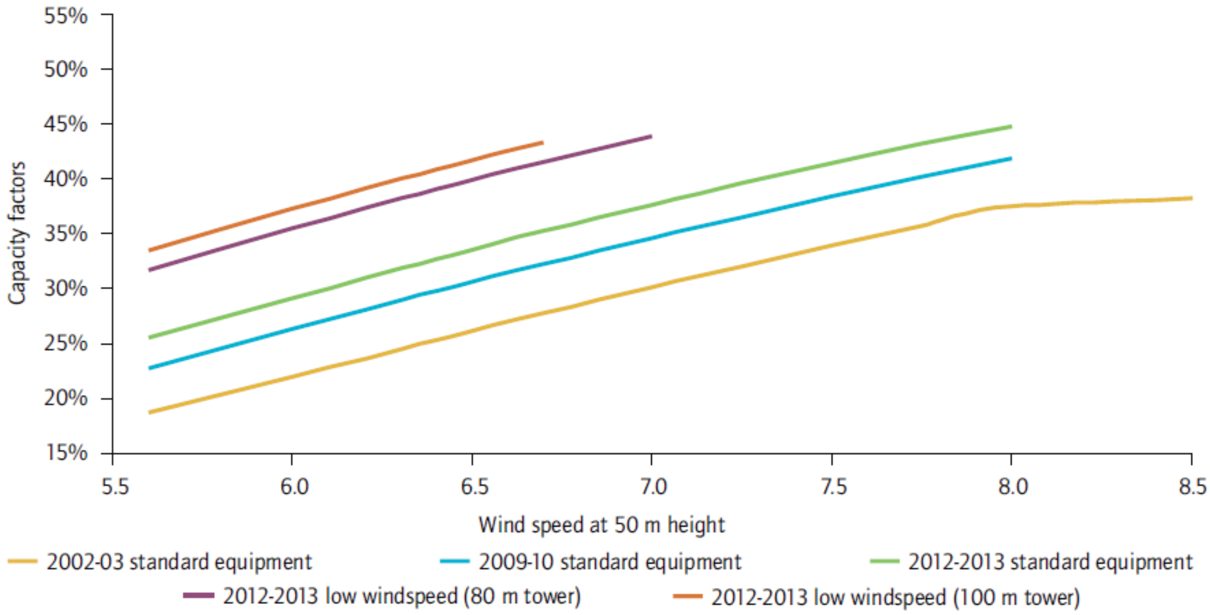


Figure 8.16: Evolution of the wind capacity factor in the last 15 years (IEA 2013a).

A compilation of on- and offshore capacity factors in 18 countries[179] by (IEA 2015d) shows that onshore capacity factors are between 20% and 49%, those of offshore plants are between 30% and 48%.

Actual capacity factors and full equivalent load hours are shown in Table 8.7. Germany’s onshore plants show a 10 year average of 18.8% (2005-2015). The capacity factor in Switzerland in 2015 is calculated to be 20.8%. In Denmark, the offshore wind park with the highest capacity factor performed at 52%, with a DK offshore average of 42.6% in 2012.

[179] Representative European countries, United States, China, Japan, Korea, New Zealand, South Africa.

Table 8.7: Capacity factors and load hours for selected countries. The most recent available data were chosen.

Country	Year	onshore, offshore, average	Capacity factor	Load hours	Source
AU	Sep 2014-Sep2015	average (no offshore)	0.29	2540	(a)
CN		average	0.23	2015	(b)
US 2014 peak	2014	average	0.43	3767	(b)
US 2014 lowest	2014	average	0.225	1971	(b)
US	2013	average	0.323	2830	(e)
DE	2005-2015	onshore	0.188	1650	(c)
DE	2015	onshore	0.223	1950	(c)
DK	2012	offshore	0.426	3733	(d)
DK	2012	onshore	0.239	2098	(d)
DK	2012	average	0.281	2463	(d)
DK Hornsrev offshore highest offshore	2012	offshore	0.52	4555	(d)
DK Vindeby offshore lowest offshore	2012	offshore	0.202	1770	(d)
CH	**2015**	**onshore**	**0.208**	**1828**	**(f)**

(a) https://bravenewclimate.com/2015/11/08/the-capacity-factor-of-wind/
(b) https://carboncounter.wordpress.com/2015/07/24/what-are-the-capacity-factors-of-americas-wind-farms/
(c) http://windmonitor.iwes.fraunhofer.de/windmonitor_en/3_Onshore/5_betriebsergebnisse/1_volllaststunden/
(d) http://cf01.erneuerbareenergien.schluetersche.de/files/smfiledata/3/1/7/2/7/1/V2BC37NhCFWindDK.pdf
(e) http://www.commdiginews.com/environment/solar-and-wind-electric-a-matter-of-land-area-10383/
(f) http://wind-data.ch/wka/list.php

The 10-year average of onshore wind plants in Germany lies at 1650 h/year, while they reached 1950 h/y in 2015. The Swiss average for big wind turbines in the year 2015 lies at 1828 h/year. This number is expected to increase, as more modern wind turbines will be planted in future which are able to better exploit the wind resources. However, good locations might be exploited soon, so that locations of less good quality have to be used.

Differences between regions on the world are shown in Figure 8.17. Average load hours are highest in Brazil and South America. Medium load hours are found in Africa with rather high capacity projects, Central America, Eurasia, North America and Oceania. Lower average load hours are shown for China, Europe, India, and other Asia. This is in general in agreement with the potentials shown in Figure 8.2.

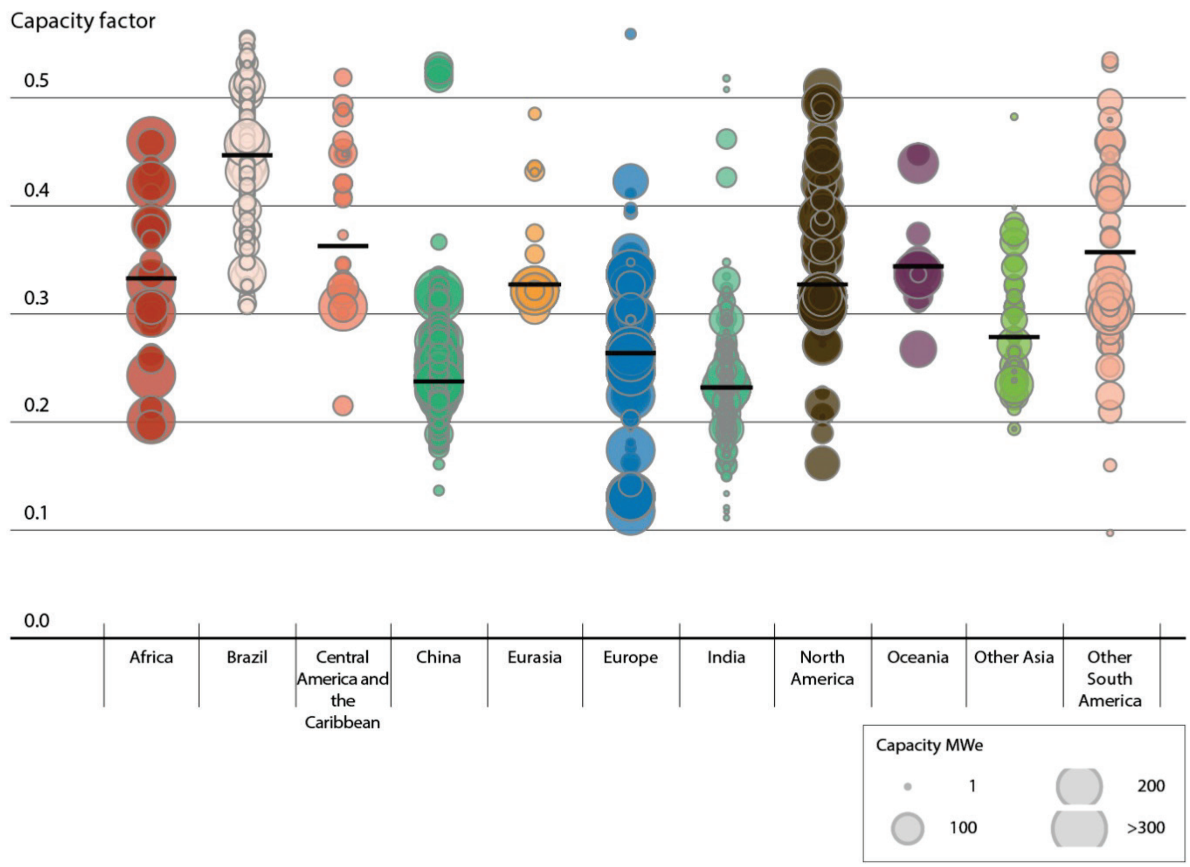


Figure 8.17: Capacity factors by project and weighted averages for commissioned and proposed wind farms in world regions, 2010-2014. Taken from (IRENA 2012c).

8.4.7 Parameters: Lifetime, performance decline with age

Economic life is often assumed to be 20 years. This assumption was contested in the past by a prominent study by Hughes in 2012 on the performance decline of wind turbines in the United Kingdom and Denmark statistically analyzed monthly output data of 282 installations in the UK and 823 installations in DK with an age range from 0 to 19 years. He found a huge decline from 24% to 11% load factor after 15 years already in the UK (ca. 5.5% of load factor lost per year). His conclusion was that wind turbines reach their end of life the latest after 15 years. However, this study was heavily criticized and statistical analysis by other authors based on the same data revealed major flaws in the study (MacKay 2013, Staffell and Green 2014). They claim (based on the same data set) that wind turbines probably lose 1.85% (MacKay) or 1.6 +- 0.2% (Staffell) of their output per year.

8.4.8 Availability, failures, downtime and replacement of parts

Onshore availabilities are usually around 95%, while offshore availabilities have increased up to 92% to 98% in the past few years (IEA 2013a). The availability depends heavily on age and type of the wind turbine, wind conditions, service quality and other factors. 2009 data for Swedish wind turbines with a capacity higher than 1.5 MW of four operators (Enercon, Siemens, Vestas, NEGMicon) report availabilities between 93.2% and 97.8% (data collected by (Sheng 2013) from Vindstat database valid for Sweden with entries for ca. 800 wind turbines out of total 1300 wind turbines). Based on the Vindstat database, there is no indication that availability changes with turbine size (Sheng 2013). Electrical and other systems are most probable to fail, but in general don't lead to a long downtime (see Figure 8.18). Mechanical and moving parts (rotor blades, gearbox, drive train) are less likely to fail, but require longer time for repair.

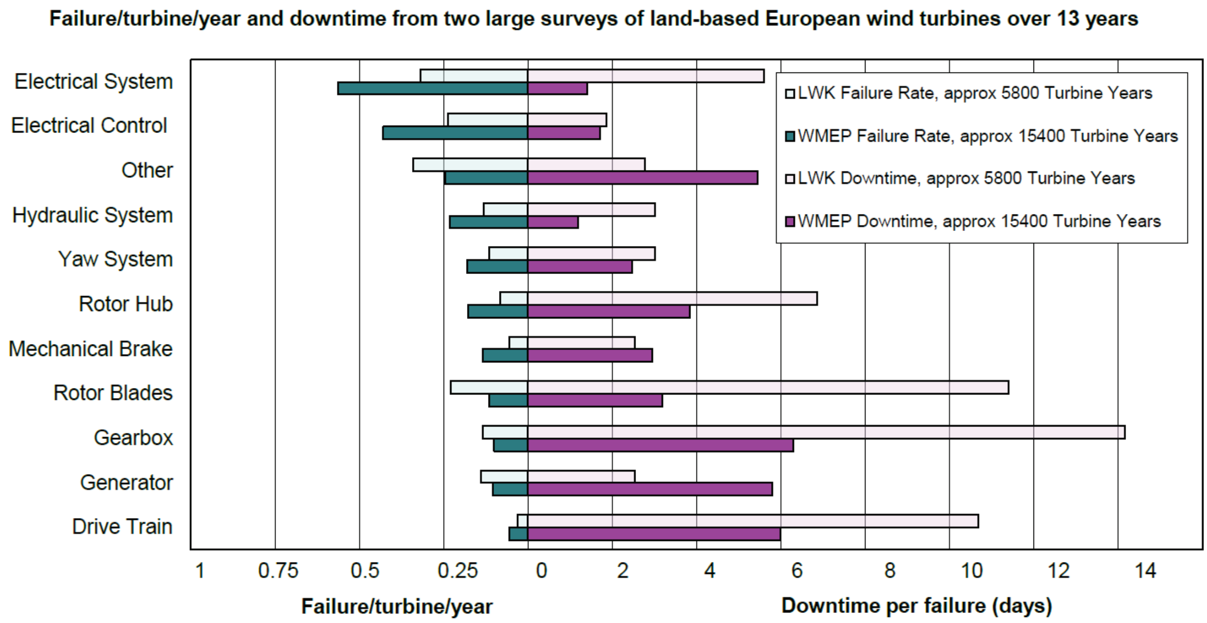


Figure 8.18: Failure types and related downtime of wind turbines. Taken from (Sheng 2013). Data are taken from two European databases with a sample of 5800 and 15400 turbine years, respectively, over 13 years of operation. The databases closed in 2006, so that the data are at least 10 years old.

According to (Sheng 2013), 75% of the failures caused only 5% of the downtime, while the remaining 25% of the faults caused 95% of the downtime. More recent data (2008-2012) collected by (Sheng 2013) suggest that gearbox, generator, rotor and electric systems still cause the longest downtimes. However, downtime has decreased from the period 2003-2007 to 2008-2012 by ca. 30% ((Sheng 2013) based on the international quarterly WindStats Newsletter with data from ca. 30'000 turbines in Sweden, Denmark, Germany and Finland).

According to (Sheng 2013), causes for failures are most often wearout (mechanical and moving parts) or wearout/malfunction of control system/others for electrical and other systems.

In general, parts are designed to last for 20 year and are maintained by scheduled maintenance. As shown above, failures are mostly due to the electrical system. Such costs are integrated in the scheduled O&M cost. Unscheduled maintenance is due to larger failures which take more time to fix. The moving parts (rotor blades, gearbox) are most prone to such failures. According to data collections in (Sheng 2013), **rotor blades** failures typically happen in years 1 and 2 due to manufacturing defects or due to transport and construction damage. About 2% of turbines per year in North America require blade replacements through 10 years of operation, mostly due to lightning strikes. Such incidents are not seen as normal life and are not considered in the below cost calculations. For **gearboxes**, data for North America suggest that there is an average failure rate of 5% of turbines per year over 10 years of operation, peaked in years 4, 5 and 8 (Sheng 2013). Another source supports this finding by claiming that gearboxes only have an average lifetime of 8-10 years, and thus have "to be replaced or extensively repaired at least once during the plants lifetime" (Andersen 2015). **Generator** failure rate is estimated at 3.5%

turbines per year over 10 years of operation, peaked in years 6 and 7 ((Sheng 2013) based on (Lantz 2013)).

8.4.9 End of life and recycling

During decommissioning, the wind turbine is removed and the land is set back to the original state. The foundation usually remains underground. As described above, the economic lifetime of a wind turbine is usually set to 20 years. However, wind turbines are also being replaced by more modern turbines (so-called "Repowering") before reaching 20 years of life due to economic reasons. Such wind turbines are often sold and exported abroad, as there exists a stable market for such wind turbines in e.g. Eastern countries in Europe. Actual recycling of wind turbine parts therefore has not yet taken place on a large scale, and experience with final decommissioning is scarce in Europe. Damaged rotor blades which have to be replaced or rotor blades from wind turbines at the end of their lifetime are usually sent to incineration, as there does not yet exist an industrial scale recycling method for rotor blades (Woidasky and Seiler 2013, Andersen 2015).

Typical mass shares of a wind turbine are concrete for the foundation (60-65%, including some 3-6% of reinforcing steel), steel for the tower (30-35%), compound materials (glass fiber reinforced plastics) in the rotor blades and nacelle (2-3%), electrical components, copper, aluminum and PVC in the electrical systems (<4%), and operation liquids (<1%) (Woidasky and Seiler 2013, Andersen 2015). A large share of these materials is recyclable. The metals (steel, aluminum and copper) can be sold to the scrap market for recycling. In contrast, the blade composite materials are more difficult to separate, and as mentioned above, there does not yet exist a large-scale recycling method. Incineration of these composites with a high calorific value can be turned into electricity and heat. However, the ash content is significant (Andersen 2015). Alternatively, shredded rotor blades are being used as thermal source and filler material in the cement production process[180].

It is evident that the material amounts from out of order wind turbines will increase in the next years and decades. There exist various studies which estimate the (waste) material flows over time from the wind industry (e.g. (Woidasky and Seiler 2013, Andersen 2015))[181].

In Switzerland, the end of life conditions are usually regulated in the building license. There exists an obligation to restore original condition of premises including a contractual guarantee.

8.4.10 Future technology improvements

Future improvements in the wind power technology can be twofold: Better exploitation of the wind resource with today's wind turbines, and upscaling or break-through changes of wind turbines. In addition, coupling of the wind power with suitable storage items will be important for proliferation of the technology. Storage options are discussed in chapter 8.4.2.

The size of wind turbines has been continuously increasing over the last years, and tends to further increase (see Figure 8.19).

[180] E.g. http://www.iswa.org/uploads/tx_iswaknowledgebase/Schmidl.pdf, http://www.ewea.org/fileadmin/files/our-activities/policy-issues/environment/research_note_recycling_WT_blades.pdf

[181] http://www.windpower.org/en/knowledge/statistics/the_danish_market.html

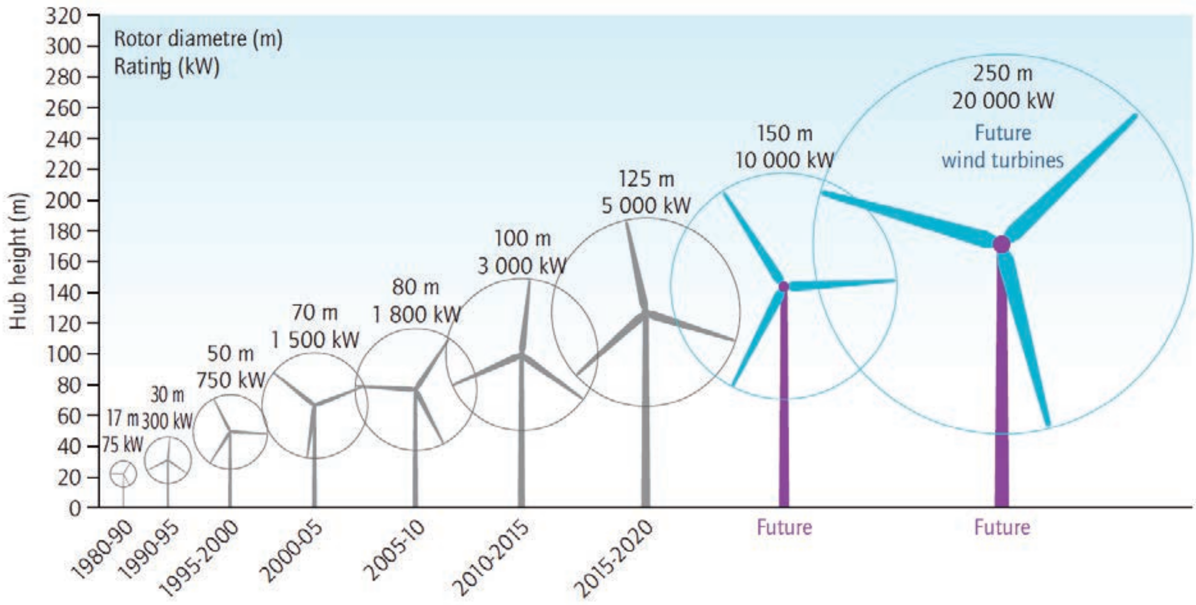


Figure 8.19: Evolution of hub height, rotor diameter and rating of wind turbines over time. Taken from (IEA 2013a)

Projections assume that future wind turbines can reach 20 MW of capacity (IEA 2013a). A EU-project called "UpWind" has shown that this is feasible, without focusing on if this is actually an optimal design size (UpWind 2011). The main challenges in upscaling are changes in physical phenomena at the wind turbine which have to be tackled with adapted materials, control and measurement instruments. The project has not investigated in detail the consequences on cost of wind power, but showed the feasibility of upscaling. Upscaling from 5 MW to 20 MW leads to an estimated quadrupling of the electricity output.

Today's wind turbines can exploit wind speeds between 3 and 34 m/s (IEA 2013a), which might also be improved in the future. A certain potential is present by increasing the availability of the wind turbines, which is today at around 95% for onshore installations and 92-98% for offshore installations, with some fluctuations over the years (IEA 2013a). Further general technical engineering improvements and advanced components can lead to better exploitation of the wind resource.

Another goal for the future is to be able to more precisely predict wind regimes at specific locations in order to install the best-suited wind turbine type and size. Further, wind turbine designs should be adjusted to special conditions in very warm, humid or icy climates.

Acceptance of wind turbines could be improved by making the wind turbines more silent during operation. However, such turbines only exist on the kW level yet [182]. Research is also done for completely other designs for using wind power. An example of this is the bladeless Vortex wind turbine.[183]

8.5 Costs of wind power

There exist several extensive recent studies investigating the (levelised) cost of wind power today and partly in future, e.g. (EIA 2009, IRENA 2012c, Kost, Mayer et al. 2013, Wallasch, Lueers et al. 2013, Lueers, von Zengen et al. 2014, EIA 2015, IEA 2015d, NREL 2015). They all

[182] http://buildipedia.com/aec-pros/engineering-news/future-improvements-in-wind-power
[183] http://www.vortexbladeless.com

agree that the decisive factors for the levelised cost of electricity (LCOE) are the location specific conditions and the full load hours which can be reached. The latter depend on wind conditions, but also on the technological specifications and maturity of a wind turbine. Further, availability and failures including replacements needed influence the LCOE. These topics are discussed in the following chapters.

8.5.1 Levelised Cost of Electricity (LCOE) of wind power - overview

As mentioned above, the main drivers of LCOE of wind power are the location-specific wind conditions and how these are exploited (technical matureness). As a result, the LCOE of wind power at different locations or in different countries vary a lot. Current continued development of wind turbines therefore focuses on higher yield, mainly through higher towers or higher rotor sweep. The increased material use has to be outbalanced by a significant increase in full load hours in order to make the higher investment costs profitable. It is expected that these improvements can especially support low-wind turbines in their deployment.

In general, electricity from onshore wind turbines has lower LCOE than offshore wind power (see Figure 8.20). The higher full load hours at offshore locations are outbalanced by higher planning, material, installation and operation & maintenance cost.

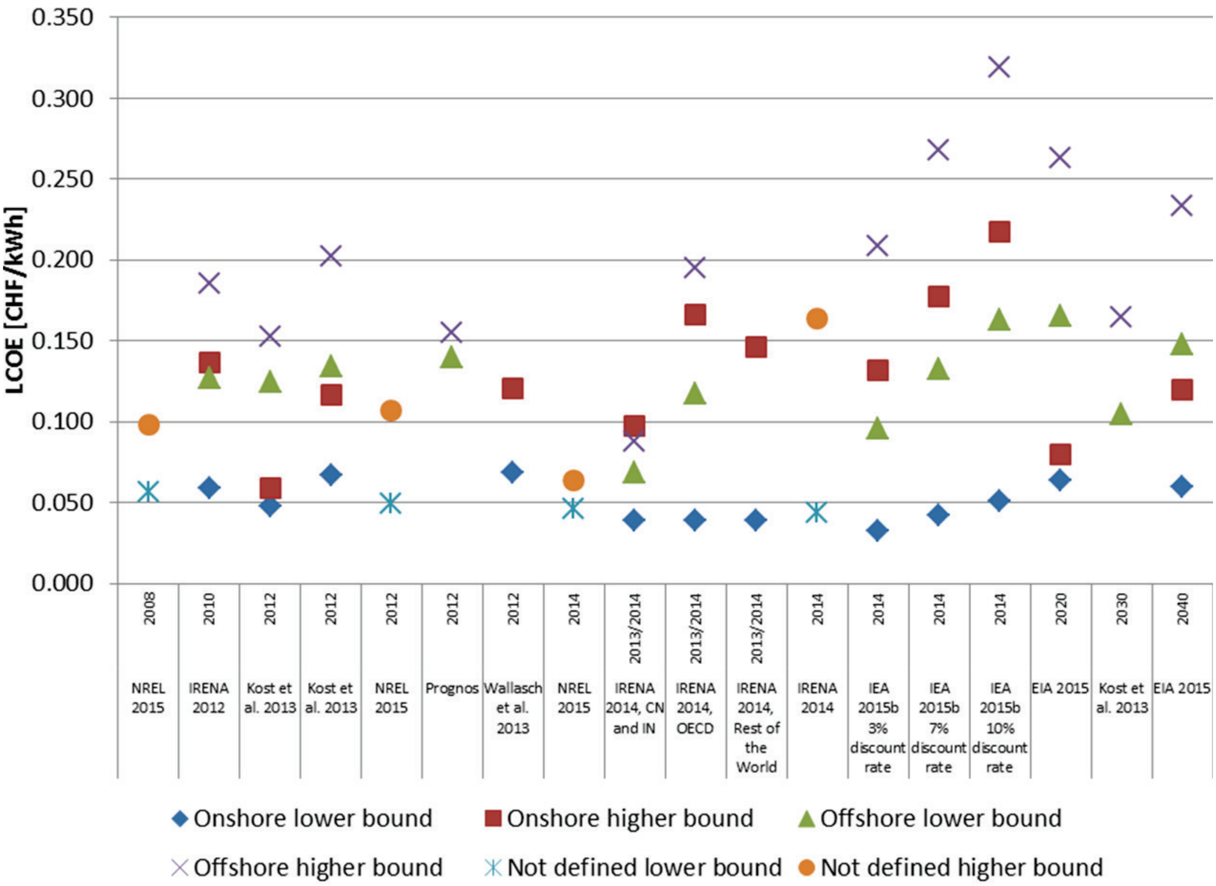


Figure 8.20: Literature review on LCOE of wind power. Costs are converted to and given in CHF/kWh. 1USD=0.976CHF; 1EUR=1.092CHF. The x-axis shows the source and the year for which the values are given. Not all references differentiate between on- and offshore turbines, so that the corresponding values are provided under the category "not defined", i.e. it is unknown whether they represent on- or offshore conditions.

LCOE literature data for today's onshore plants vary between 3.2 Rp./kWh and 21.8 Rp./kWh. Offshore plants show higher LCOE with a range of 6.8 Rp./kWh to 31.9 Rp./kWh. Data points from (IRENA 2012c) indicate that higher costs for onshore plants are expected in Europe compared to LCOE of wind in China/India or Northern America. (IRENA 2012c) supports again the claim that the cost for wind power in China/India are lower than in OECD countries, while the spread is quite large for so-called "Rest-of-the World". In contrast, (NREL 2015) doesn't show general lower LCOE for the United States compared to the European countries Denmark, Germany, Ireland, and Norway.

Data in (IEA 2015d) are presented for 21 onshore and 12 offshore wind power plants situated in 18 countries in Europe, Asia, Northern America and Southern Africa and calculated with three different discount rates (3%, 7%, 10%). Here, LCOE in the United States show again a tendency to be lower than those in European countries. The capacity factor is also assumed to be much higher than in other regions of the world with 35%-49% for onshore in the US compared to 26%-40% in the other countries.

In the future, the projections have a decreasing tendency if compared within each reference. The various references all operate with ranges and do not completely contradict each other. The main outcome is that onshore wind power can compete with electricity produced from natural gas or coal, given that optimal locations and large, modern wind turbines are chosen. Projections for the future agree that the LCOE of onshore plants will further decrease due to reduced turbine costs, improvements in the technology and resulting higher yields. It is not sure if offshore plants have already reached their plateau in LCOE.

The report on "Projected Cost of generating electricity 2015" by the IEA (IEA 2015d) presents a compilation of LCOE for a sample of 21 onshore and 12 offshore plants in 18 countries (ranges see Figure 8.20), split into investment cost, operation & maintenance (O&M) cost, and refurbishment & decommissioning cost. The values are provided based on three interest rates of 3%, 7% and 10%. For most countries and scenarios, the **investment costs** are most important, while **O&M cost** are responsible for 14% to 39% (9.5 CHF/MWh in China to 86.2 CHF/MWh in Portugal) of the LCOE at a discount rate of 7% (IEA 2015d). O&M costs are in general higher for offshore plants than for onshore plants. Though, there exist offshore plants with rather low O&M cost (30 CHF/MWh in the United States, 26 CHF/MWh in Denmark, 9.5 CHF/MWh in China). The two non-OECD countries in the list (China and South Africa) show lowest LCOE values as well as lowest O&M shares with 13% to 16%. **Refurbishment & decommissioning costs** are negligible. These findings are supported by (IRENA 2012c), which lists data for 7 countries including Switzerland.

The next chapter investigates in more detail the largest part of the LCOE, i.e. the investment cost.

8.5.2 Investment cost

The investment cost of wind power plants include the wind turbine components, electrical components, foundation, grid connection, installation, and planning & miscellaneous. Wind turbine components are the tower, rotor blades, generator, gearbox, transformer, nacelle, power converter, controller, and some other small parts. There exist extensive compilations of investment and wind turbine cost on a country-specific level in (IRENA 2012c, IEA 2015g). A summary of these and other references is given in Table 8.8.

Table 8.8: Investment cost of onshore and offshore plants according to various sources. Figures given in CHF/kW. 1USD=0.976CHF; 1EUR=1.092CHF

Source	Year	Onshore		Offshore		Not specified		Switzerland
		Lower bound	Higher bound	Lower bound	Higher bound	Lower bound	Higher bound	
(IRENA 2012c)	2003-2010	1658	2390	3219	4878			
GWEC 2014	2013					1365		
GWEC 2014	2015					1332	1354	
GWEC 2014	2020					1245	1365	
GWEC 2014	2030					1201	1365	
GWEC 2014	2050					1201	1365	
IEA 2015	2013	1533	2926	3612	5788			
Kost et al. 2013	2013	1092	1965	3712	4913			
WindGuard 2014	2010					634	2049	
IRENA 2014	2013					1392	2829	
Various								2000-2500 (see chapter 8.5.5.1)

All sources agree that offshore investment costs are higher than costs for onshore plants. Differences are discussed in chapters 8.5.2.1 and 8.5.2.2. Due to the fact that the figures originate from different sources, they do not necessarily include the same cost components.

8.5.2.1 Investment cost - Onshore

The investment costs (or capital costs) of onshore wind power installations are driven by the wind turbine and its components (Figure 8.21 and Table 8.9). This major cost driver includes production, transportation and installation of all wind turbines parts (tower, rotor blades, gearbox, power converter, transformer and generator, and other). Depending on location and turbine type, the share of wind turbine cost can go as high as 84% (IRENA 2012c). Investment cost shares for the foundation and the network connection are usually in the same range (Wallasch, Lueers et al. 2013). Generally spoken, three quarters of the investment costs are related to the physical wind turbine, whilst one quarter accounts for the grid connection and planning activities.

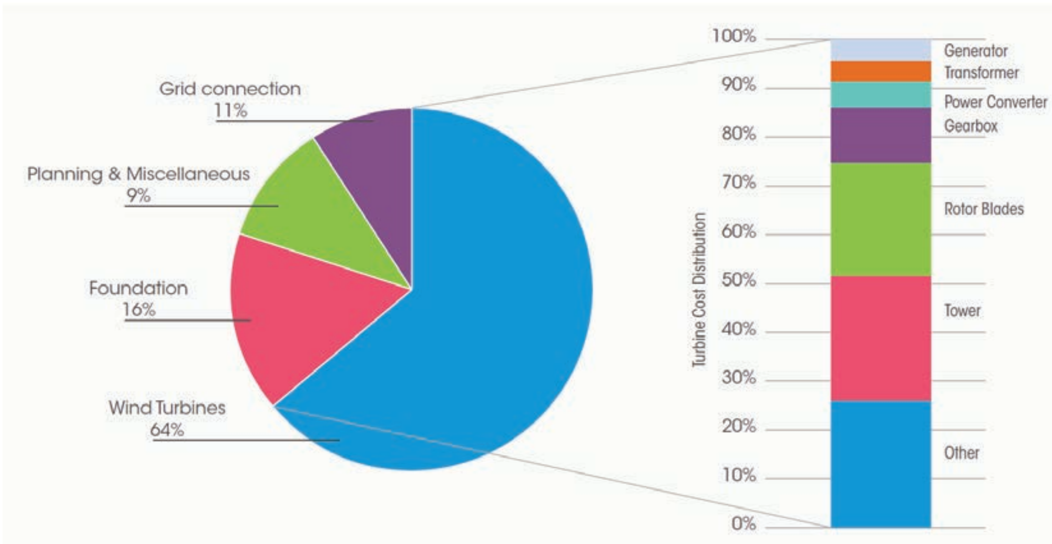


Figure 8.21: Capital cost breakdown for a typical onshore wind power system and turbine. Taken from (IRENA 2012c).

The total investment cost for onshore wind plants shows a decreasing tendency in the past few years (IRENA 2012c, IEA 2013a). The wind turbine prices exhibit a decreasing tendency over the last few years. They vary between the countries, e.g. (IRENA 2012c) shows a range between 644 USD/kW in China and 2123 USD/kW in Australia. Switzerland is situated within the higher range with 1924 USD/kW.

8.5.2.2 Investment cost - Offshore

Investment costs for offshore wind power plants are also driven by the wind turbine cost, but less than for onshore installations (see Figure 8.22 and Table 8.9). Foundation and grid connection increase in importance.

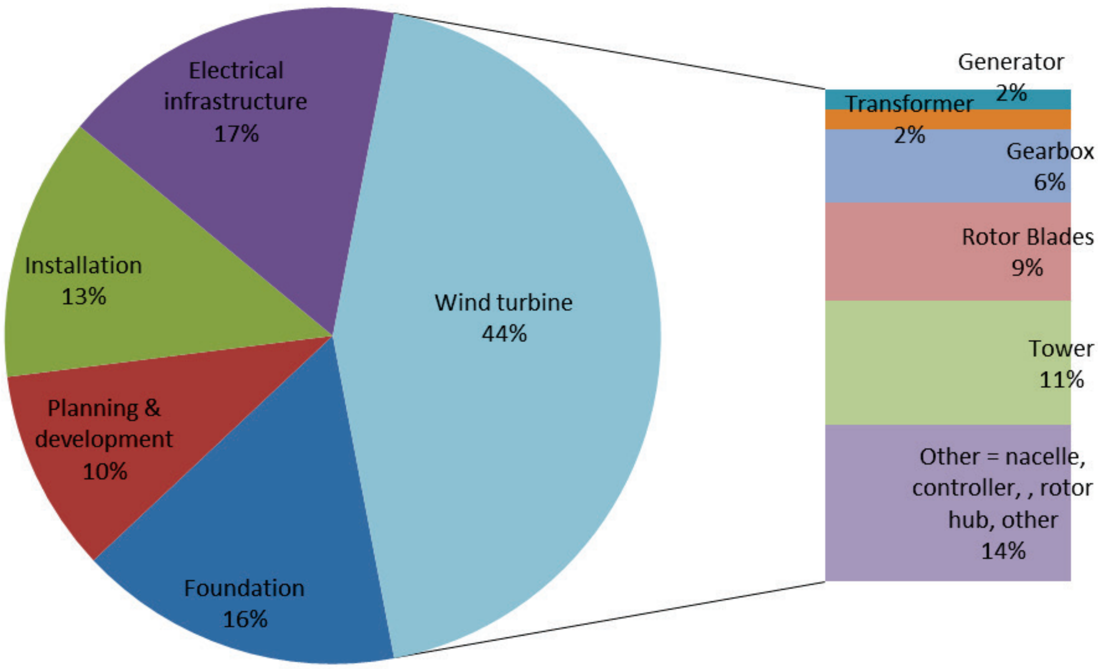


Figure 8.22: Capital cost breakdown for a typical offshore wind power system and turbine (IRENA 2012c).

According to (Burton, Jenkins et al. 2011, IRENA 2012c), the wind turbine cost are around 30-51% of the total investment cost, the foundation and grid connection cost hold a share of ca. 15-30% each, while installation cost are a higher for offshore plants with around 10-13%. The investment cost for offshore wind plants have probably not yet reached their plateau. Exploitation of deeper locations in the sea even out the technical improvements of offshore plants (IEA 2013a).

Table 8.9: Comparison of capital cost breakdown for typical onshore and offshore wind power systems in developed countries. Taken from (IRENA 2012c).

	Onshore	Offshore
Capital investment costs (USD/kW)	1 700-2 450	3 300-5 000
Wind turbine cost share (%)[1]	65-84	30-50
Grid connection cost share (%) [2]	9-14	15-30
Construction cost share (%) [3]	4-16	15-25
Other capital cost share (%) [4]	4-10	8-30

[1] *Wind turbine costs includes the turbine production, transportation and installation of the turbine.*
[2] *Grid connection costs include cabling, substations and buildings.*
[3] *The construction costs include transportation and installation of wind turbine and tower, construction wind turbine foundation (tower), and building roads and other related infrastructure required for installation of wind turbines.*
[4] *Other capital cost here include development and engineering costs, licensing procedures, consultancy and permits, SCADA (Supervisory, Control and Data Acquisition) and monitoring systems.*

8.5.3 Operation and maintenance (O&M) costs

O&M costs are rather low for wind turbines, in the range of 2-5% of investment costs onshore and 5-8% offshore (VSE 2013, Lueers, von Zengen et al. 2014).

Operation costs include non-equipment costs of operation, land lease, insurance, monitoring, management, administration, and similar cost items.

Maintenance costs are of scheduled and unscheduled type. Scheduled maintenance includes the planned routine activities so that everything runs optimally. Unscheduled maintenance is due to random failures as discussed in chapter 8.4.8.

8.5.4 Decommissioning cost

See chapter 8.4.9 for details on end of life and recycling. The general economic lifetime of a wind turbine is 20 years. Often, wind turbines are being replaced before or at the end of these 20 years, and often sold and exported to less developed countries (e.g. from Germany to Poland, or from Switzerland to Belarus).

Profit from sales of steel, copper and aluminum on the scrap markets depend on the actual prices on the markets. (McCarthy 2015) shows these price time series from 1990 to 2015 including future projections by the World Bank until 2025.

Decommissioning costs in literature are between 14 to 64 CHF/kW (Aldén and Engberg Ekman 2015, McCarthy 2015). These can decrease a lot if the wind turbine can be sold or if components can be sold on the scrap market.

8.5.5 LCOE in Switzerland

8.5.5.1 Assumptions

A compilation of **investment cost** of wind turbines projects in Switzerland is shown in Table 8.10. The available data on investment cost don't show a clear rising or decreasing tendency. Most recent data for specific installations indicate that investment costs are around 2000-2500 CHF/kW. As shown in Table 8.8, this is rather at the higher bound of worldwide investment cost. This may be explained by higher labor cost in Switzerland; in addition the currently long durations of proceedings and high standards for environmental impact assessments act as cost drivers. The collected values support the conclusion in (IRENA 2012c) that the average investment cost of wind power installed in Switzerland is within the globally observed range, i.e. around 2533 USD_{2010}/kW compared to 1360 to 3318 USD_{2010}/kW. **Operation and maintenance costs** are low, in the range of few percent of investment cost. For Switzerland, they are around 4.5 Rp./kWh or ca. 49-100 CHF/kW (IRENA 2012c, VSE 2013, Lueers, von Zengen et al. 2014). This is in the middle range of international data (1-9 Rp./kWh).

Table 8.10: Compilation of investment cost for existing wind turbines in Switzerland, sorted by year. Values used for calculation of Swiss-specific LCOE are marked with grey shadows. n.d. = no data available.

Location	Year	Source	Capital cost [CHF/kW]	Capacity of turbine [MW]
Wind cost calculator	2000(?)	(WeisskopfPartnerAG 2000)	1900-1949	0.75, 1.75
Entlebuch	2005	(KEV 2014)	889	0.9
Mt. Crosin West	1998 and 1996	(Hirschberg, Bauer et al. 2005)	2000	600kW, 660kW
Mt. Crosin East	2001	(Hirschberg, Bauer et al. 2005)	1500	Probably 850 kW
Collonges	2005	(BFE/SFOE 2016i) and webpage[184]	2500	2
General	2008	(IRENA 2012c)	2107	n.d.
General	2010	(IRENA 2012c)	1877	n.d.
General	2008	(Lueers, von Zengen et al. 2014)	2146	n.d.
General	2009	(Lueers, von Zengen et al. 2014)	2049	n.d.
General	2010	(Lueers, von Zengen et al. 2014)	1853	n.d.
Gries	2011	(BFE/SFOE 2016i) and webpage [185]	2391	2.3
Charrat	2012	Webpage [186]	2500	3
Haldenstein	2012	(KEV 2013)	2333	3
Lutersarni	2013	(CKW 2014, BFE/SFOE 2016i)	2174	2.3
General	2013	(VSE 2013)	2000-2500	n.d.
Average of these values			2190	n.d.

The breakdown of investment cost to the different deployment steps and wind turbine parts is taken from Figure 8.21.

There are few limitations to be noted for the cost calculations for Switzerland as presented in the next chapter.

- The first part of the calculations is presented for specific operating plants in Switzerland based on available information on the investments spent for those plants and current load hours of those plants. The calculations don't account for any amortization of turbines which have already been running for a long time (e.g. Mt. Crosin).
- Sensitivity analyses are performed based on an average state-of-the art case (definition see below). However, the LCOE results are not presented on a geographic resolution for different specific locations in Switzerland with varying wind conditions[187]. Further, the

[184] http://www.drgoulu.com/2008/08/30/rentabilite-des-eoliennes/#.Vop0KytF1cM
[185] http://www.ee-news.ch/de/wind/article/23101/gries-hoechstgelegenen-windturbine-europas
[186] http://www.lenouvelliste.ch/articles/valais/martigny-region/la-plus-puissante-eolienne-de-suisse-inauguree-a-charrat-235230
[187] As mentioned in chapter 8.3.2, the updated maps with wind potential areas in Switzerland will be published in 2017.

cost calculations don't differentiate between single-standing wind turbines and wind parks.

- As shown in chapter 8.3.3, Swiss utilities hold significant shares of wind parks abroad. Costs of electricity from offshore plants can be assumed to be in the range as presented in chapter 8.5.1. Electricity from wind power abroad (on- and offshore) can be imported to Switzerland, which causes additional costs. However, specific calculations for such import costs have not been performed. As outlined in chapters 12.5 and 13.4, imports with dedicated HVDC transmission lines would cause additional costs of 0.5-2 Rp./kWh, depending on the distance and whether comparatively expensive offshore cables are required (Dii 2013).

8.5.5.2 LCOE calculations for Switzerland

LCOE calculations for Switzerland are performed for all wind power plants where data were available on capital costs (investment costs) and load hours. A "state-of-the-art" case aims at representing a new wind turbine to be built in 2017 at a reasonable location with best available technology (3.3 MW capacity, load hours 2300 h/year, and capital cost of 2500 CHF/kW). Load hours were calculated using information from (BFE/SFOE 2016i). Calculations are made based on an interest rate of 5% and an annual degradation rate (in terms of annual yield) of 0% or 1.2%. The degradation rate is derived from the discussion in chapter 8.4.7, where a decline of performance of 1.4-1.8% per year is stated in (Staffell and Green 2014). No replacements are assumed. Decommissioning costs are assumed to be 30 CHF/kW. Annual O&M costs vary with capacity size of the wind turbine, they are roughly in the order of 50-100 CHF/kW/year. Note that costs for installation of potential electricity storage or power grid adaptation have not been integrated in the cost calculations, as such data depend on the overall system configuration and are thus in the present work not considered on the level of individual technologies.

Table 8.11 shows the major input data for the LCOE case calculations shown in the last column in the table and in Figure 8.23 including the breakdown to capital cost, O&M and decommissioning cost. Only turbines with consistent data available have been used. Wind turbine size is between 2-3.3 MW. The investment costs are in a range of 2000-2500 CHF/kW. Higher (or lower) load hours are possible at specific locations. The resulting LCOE if no degradation is included are in the range of 13-30 Rp./kWh, with the highest value being rather an outlier in the case of the Gries plant, where load hours are low[188]. If an annual degradation rate of 1.2% is assumed (see discussion in chapter 8.4.7), the costs increase by about 10% to 14-32 Rp./kWh. Excluding the non-representative turbine in Gries results in LCOE ranges of 13-19 Rp./kWh and 14-21 Rp./kWh, without and with 1.2% annual degradation, respectively. The Swiss state-of-the-art case is at 14.2 Rp./kWh (considering degradation).

These results are higher than the LCOE collection presented in chapter 8.5.1 from (IEA 2015d) between 4.2 Rp./kWh and 14.7 Rp./kWh for a discount rate of 7%. KEV tariffs for wind power lie around 20 Rp./kWh (based on KEV Cockpit Quartal reports 2015 and 2016).

[188] This turbine cannot be considered as representative, since it was installed as pilot plant at this site and not adapted to average local wind conditions, which results in a very low number of full load hours (Geissmann 2017).

Table 8.11: LCOE of selected[189] operating wind power plants in Switzerland. Results are given for 0% annual degradation rate and for a 1.2% annual degradation rate. WLH = wind load hours. "CH state-of-the art" represents a new wind turbine to be built today at a site with good wind conditions.

Case	Year built	Capacity (kW)	Load hours 2015 (h/year)	Capital cost (CHF/kW)	LCOE (CHF/kWh) 0% annual degradation	LCOE (CHF/kWh) 1.2% annual degradation
Lutersarni	2013	2300	1200	2200	0.188	0.206
Gries[188]	*2011*	*2300*	*750*	*2400*	*0.295*	*0.323*
Collonges	2005	2000	2300	2500	0.130	0.142
Charrat	2012	3000	2250	2500	0.132	0.145
Haldenstein	2012	3000	1450	2300	0.173	0.190
CH state-of-the-art		3300	2300	2500	0.130	0.142
(VSE 2013)					2013: 0.14-0.2 2035: 0.12-0.18 2050:0.12-0.17	
KEV tariffs					0.155-0.215[190] 0.16-0.2 (KEV 2016)	
(Prognos 2012b)					0.1-0.22, limited potential for decrease in future.	
(Hirschberg, Bauer et al. 2005) Mt. Crosin West Mt. Crosin East				2500 2000	0.2 0.12	

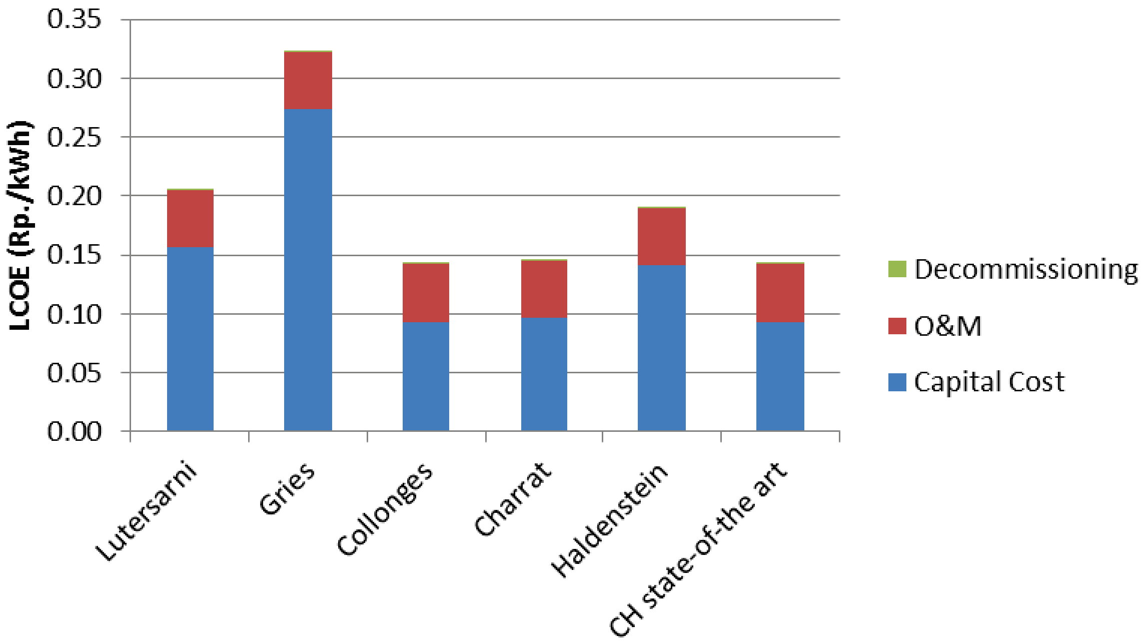


Figure 8.23: LCOE of Swiss case studies for selected locations in Switzerland, including a theoretical average Swiss case and a state-of-the-art Swiss case, calculated with an annual degradation rate of 1.2%.

[189] Provided for those wind power plants with consistent available data.
[190] http://www.suisse-eole.ch/de/windenergie/planung-und-bewilligung/kev/

8.5.5.3 Sensitivity analysis

The sensitivity analysis is performed for the following hypothetical state-of-the art Swiss average case: 3.3 MW capacity, 2300 load hours per year, capital cost of 2500 CHF/kW, interest rate of 5, annual degradation rate of 1.2%, economic lifetime of 20 years, annual O&M cost of 102 CHF/kW*year, decommissioning cost of 30 CHF/kW.

Sensitivity analysis was performed for the following parameters:

Interest rate: The interest rate was varied from 5 down to 1% and up to 10%.

Load hours: The load hours were varied from 800 h/year to 3800 h/year.

Lifetime: Default lifetime of all components is 20 years. This was varied down to 5 years and up to 40 years. It has to be considered that these are not very realistic scenarios: If parts like gearbox or rotor blades break before 20 years, they will probably be replaced. In the same way, it is likely that these have to be replaced if the lifetime of a wind turbine would be extended to 40 years.

Default **capital costs** are set to 2500 CHF/kW. This was varied down to 1700 CHF/kW and up to 4100 CHF/kW. The main reasons of variations are the steel and concrete price fluctuations on the markets influencing the price of the tower.

O&M cost: As default, O&M cost of 0.45 CHF/kWh were assumed, or in other words 102 CHF/kW/year for the base case. This was varied down to 25 CHF/kW and up to 203 CHF/kW.

Decommissioning cost: Cost for the end-of-life of a wind turbine can decrease significantly if the turbine or its materials can be sold for second use of the turbine or on the scrap market. Default costs of 30 CHF/kW were assumed, which was varied between 0 CHF/kW and 300 CHF/kW.

Degradation rate: See chapter 8.4.7 for explanations. Variation is made between 0% and 3.0% as yearly degradation rate.

Results from these sensitivity analyses are shown in Figure 8.24.

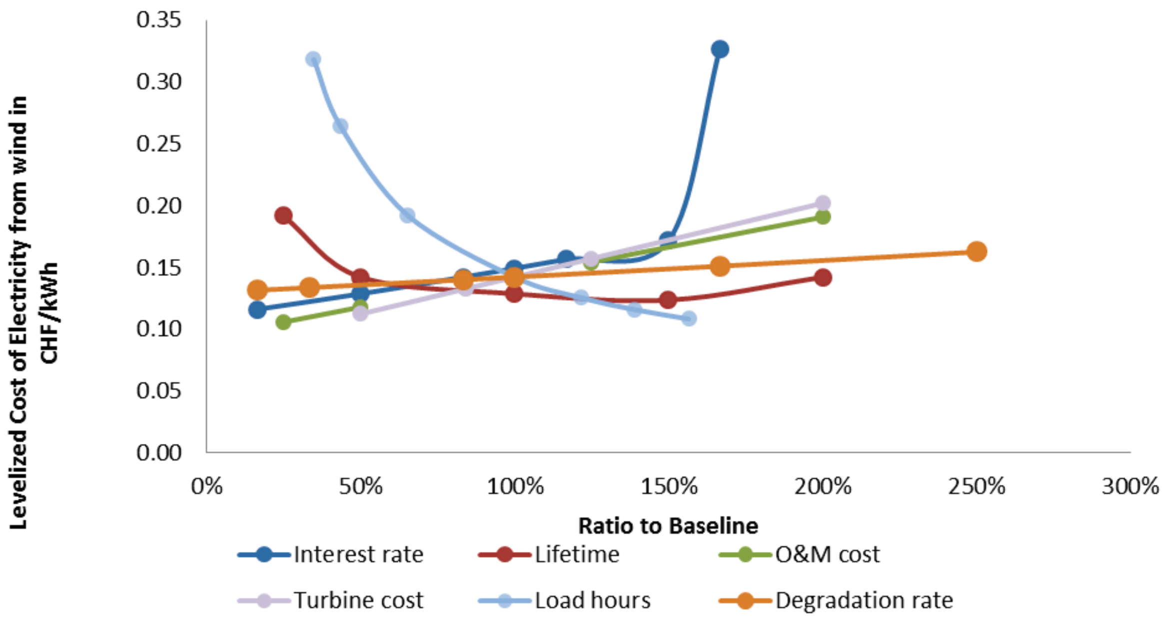


Figure 8.24: Sensitivity analyses of key cost factors in LCOE of wind power. Results for decommissioning costs are not shown in the graph (see explanation in the text).

The most important factors are the **lifetime and the capacity factor (load hours)** of the wind turbine. Early failure of the whole wind turbine (e.g. after 5 years) leads to very high LCOE. However, it has to be mentioned that this is a rather hypothetical case, as individual components such as gearbox or rotor blades can be replaced after failure. Such cases will be presented further below. The cost curve for load hours also shows an exponential shape, which indicates that reaching a minimum amount of load hours is crucial for lowering the related cost. Costs go down 10.8 Rp./kWh if load hours as high as 3600 h/year would be reached. With the wind resources in Switzerland not being of best quality, this seems only to be possible with break-through improved technology.

If the **interest rate** is 1% only, LCOE decrease to 11.6 Rp./kWh. This goes up to 18 Rp./kWh for an interest rate of 10%. Together with annual degradation rate, O&M cost and turbine cost this parameter shows a linear behavior. If turbine cost would be halved, LCOE goes down to 11.2 Rp./kWh. When doubling the turbine cost, the cost linearly increases to 20.2 Rp./kWh. O&M cost are also important and can vary the LCOE from 10.6 Rp./kWh to 19.1 Rp./kWh. Annual degradation of 3% would lead to higher LCOE (16.3 Rp./kWh) than if no degradation is included in the calculation (13.0 Rp./kWh).

If the rotor blades or the gearbox or both have to be replaced once in the life of wind turbine, the LCOE will increase. We assume the cases that (a) the gearbox has to be replaced in year 10 for 250’000 CHF; (b) the rotor blades have to be replaced in year 10 for 150’000 CHF; (c) the rotor blades as well as the gearbox have to be replaced in year 10 for 250’000 CHF plus 150’000 CHF. The resulting LCOE increase only marginally from 14.2 Rp./kWh to 14.3-14.4 Rp./kWh, which indicates that even in case of several replacement needs, the LCOE don’t increase dramatically.

Similarly, the decommissioning costs only increase the LCOE to 14.6 Rp./kWh even if they are increased by a factor of 10 from 30 CHF/kW to 300 CHF/kW. This is not shown in the graph due to the low variability even if the x-axis would display the factor 10.

8.5.6 Future cost of on-and offshore wind power – investment

As shown above, the main cost drivers of wind power are the wind turbine components, the foundations, connection to the grid, and installation/planning cost. Further, choosing appropriate locations and technologies for maximizing the full load hours and therefore electricity yield is also crucial.

In the last six years, wind turbine prices have in general been decreasing steadily (IRENA 2012c, JRC 2014a). Reasons for this are maturity of the technology, and low-cost Chinese manufacturers entering the market. (IRENA 2012c) describes economies of scale for wind parks with capacities below 5 MW, while no further effect is observed above 5 MW. The trend towards wind turbines with a larger capacity is also favorable, as the relation between higher material input for larger wind turbines and their increased yield is not linear.

In general, it is expected that cost of wind power will decrease in the future due to upscaling, standardization and economies of scale. Main uncertainty factor is the steel price. Estimates by various sources for how much the decrease might be for onshore wind power plants are summarized in (IRENA 2012c) and shown in Table 8.12.

Table 8.12: Compilation of estimates of the potential for cost reductions in the installation cost of onshore wind. Taken from (IRENA 2012c).

	2015	2020	2025	2030	2035	2040	2045	2050
				(%)				
IEA				-18				-23
EWEA	-11	-22	-28	-29				
GWEC	-5 to -6	-9 to -12		-16 to -18				
Mott MacDonald		-12				-23		
US DOE				-10				

All sources estimate a reduction potential. It should be noted that IEA 2009 has been updated in 2013 and corrected the estimate up to -25% by 2050. In summary of these estimates, the IRENA report estimates a medium- to long-term cost reduction potential in the order of 10% to 30%. Cost reductions seem to be a result of increasing competition with Chinese manufacturers as well as learning and economies of scale effects in wind turbine manufacturing. Tower prices might decrease by 2020 by 15%-30% due to lightweight materials and competition – however, the major decisive aspect is steel price (IRENA 2012c). The same source predicts a decrease of 10%-20% for blades due to weight minimization, and 15% decrease of gearbox cost due to improved reliability or gearless drive generators. The costs for grid connections are not likely to decline for onshore plants, but might become cheaper for offshore plants. The foundations are again heavily influenced by cement and steel prices.

For **Switzerland**, the above estimates would decrease today's average **wind plant capital cost** of 2500 CHF/kW to ca. 2200-2350 CHF/kW by 2020 (6% to 11% decrease, respectively) and 2060-2270 CHF/kW by 2035 (9% to 18% decrease, respectively). For the year 2050, a decrease of 16-28% of capital cost is assumed.

8.5.7 Future cost – LCOE

As a result of the discussions above and combined with an increase of *average* Swiss load hours of 2500 h/year (2020, plus 9%) and 2800 h/year (2030, plus 22%) (see chapter 8.4.10 for discussion), the resulting **LCOE** decrease from 14.2 Rp./kWh to 12.5-13 Rp./kWh (2020) and 11.2-11.8 Rp./kWh (2030). This is a decrease of 9-12% (2020) and 17-21% (2030). Lifetime, annual degradation rate and O&M cost are assumed to be constant.

These decrease rates are in line with numbers found by (Wiser, Jenni et al. 2016) in an expert elicitation survey with 163 respondents. For a 3.25 MW turbine in 2030, they predict a decrease of ca. -10% to 35% in LCOE of onshore wind until 2030. The main drivers are higher capacity factor (+10%), project life (+10%), and lower Capital cost (-12%), operating cost (-9%), at identical interest rate. Larger rotors, rotor design advancements, taller towers, lower financing costs, and improved component durability and reliability are considered as cost driving factors.

Further general trends and aspects of LCOE reductions are discussed in the following. Drivers of cost reduction are improvements of performance via various elements, advancements in design, turbines upscaling, competition in key supply markets, and economies of scale (details presented in e.g. (IRENA 2012c, Lantz, Hand et al. 2012, NREL 2015)). Cost reduction might be slowed down by utilization of less attractive locations as the best quality locations will quickly be exploited. However, examples of cost targets in the United States and in the United Kingdom show that a decrease of LCOE in these countries is expected for both onshore and offshore plants until the year 2020 (Figure 8.25 for onshore plants and Figure 8.26 for offshore plants), and further until 2050 as discussed above due to decrease of investment cost and advancements in performance.

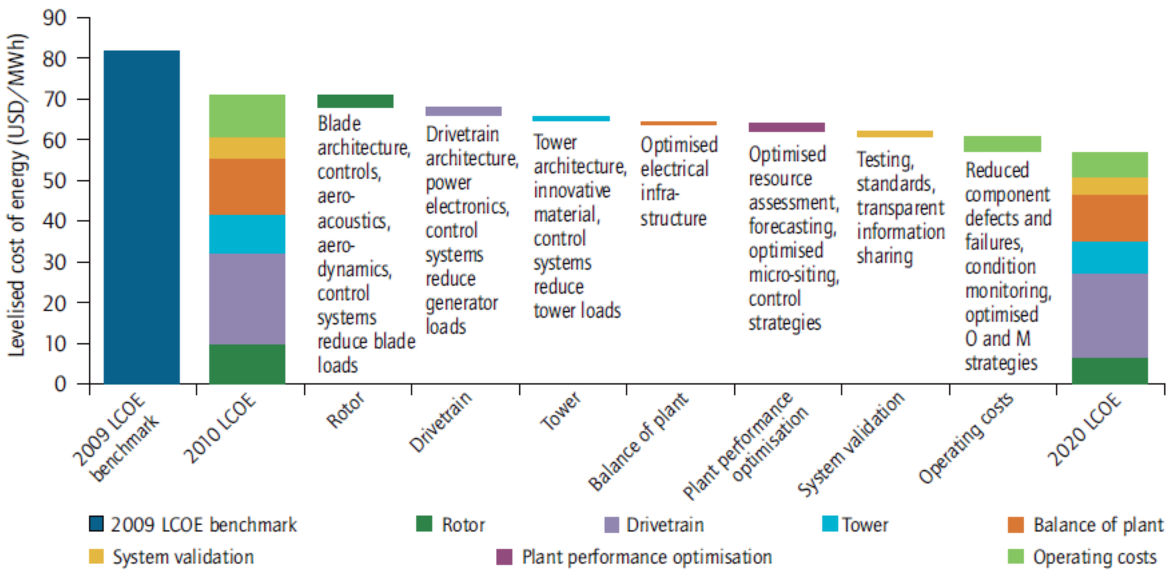
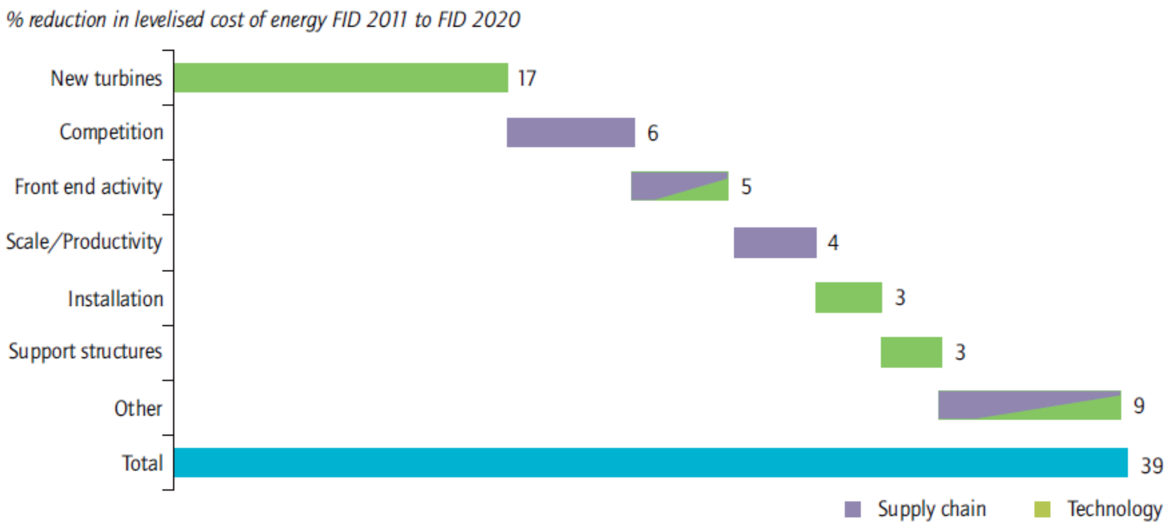


Figure 8.25: Target for cost reductions of onshore wind power in the United States (IEA 2013a).

Main reduction potential is seen in rotor, drivetrain, operating costs and plant performance optimization. Combined with some smaller reduction potentials, a reduction from 7.8 Rp./kWh (2009) to around 5.8 Rp./kWh is projected until 2020. Projections for offshore plants in the United Kingdom give a decrease of 39%, mainly due to new turbine types, other issues and competition (see Figure 8.26).



Source: Crown Estate, 2012b.

Figure 8.26: Target for cost reductions of offshore wind power in the United Kingdom (IEA 2013a).

Cost reductions can be achieved with reductions in the supply chain (ca. 17%), while technology improvements will be the major part of reduction (ca. 28%).

8.6 Environmental aspects

Direct environmental impacts of producing electricity with wind turbines include use of (agricultural) land, landscape, bird strike, or noise and are usually small and local. Therefore, Life Cycle Assessment is an important tool to identify impacts from the life cycle chain of a wind turbine.

8.6.1 Life Cycle Assessment

(Eymann, Stucki et al. 2015) have recently published a study which includes LCA for all main wind plant sites and wind turbine types present in Switzerland today. Further, they have created scenarios for environmental impacts in 2035. This chapter is therefore heavily based on this study, as it covers exactly the needs of this chapter.

As mentioned in chapter 8.3.1, the main turbine types in Switzerland are Aventa for small capacity turbines and Enercon and Vestas for larger capacities. Life Cycle Inventories have been built for the following turbine types:

- Vestas V52-850 kW and V66-1750 kW (Mt. Crosin)
- Vestas V90-2.0 MW (Mt. Crosin)
- Vestas V112-3.0 MW (Haldenstein)
- Enercon E-82 (various locations)
- Enercon E-70 and E-101 (Gries, Charrat)
- Enercon E-40 and E-44 (Gütsch)
- Aventa V-7 (small capacity turbines)

Future scenarios for the year 2035 mainly include changes in materials for the hub, nacelle, and a tendency towards cement instead of steel for the tower. Another scenario assumes production of the wind turbine components in China, which implies another energy mix during production with a rather high share of fossil fuels, and longer transport. Future large wind turbines in Switzerland are assumed to have capacities of 3-4 MW. The assumed full load hours are between 1456 h/year and 2073 h/year. Average wind speed at suitable locations in the Jura, Mittelland, and the alps are between 5 and 6 m/s. All components and materials needed to produce the wind turbine are taken into account, including their manufacturing. The main parts shown are the rotor, the nacelle, the tower, electronics and grid connection, and foundation. The main materials which are being used are steel, copper, glass fibers, aluminum, and concrete. Energy use for material processing, assembly and installations as well as land use and transports are also included. As default, it is assumed that the turbine is produced in Germany, Spain or Denmark. Metal recycling at the end of the life is being assumed based on the so-called “cut-off approach”. This means that the burdens related to the recycling process are allocated to the user of the secondary metals. For other details, please consult the report by (Eymann, Stucki et al. 2015).

The results of this study for impacts on climate change are in a range of around 10-40 g CO_2eq/kWh for wind turbines with a capacity higher than 1 MW with an average of about 15 g CO_2eq/kWh, and are higher for small wind turbines with around 80 g CO_2eq/kWh (see Figure 8.27).

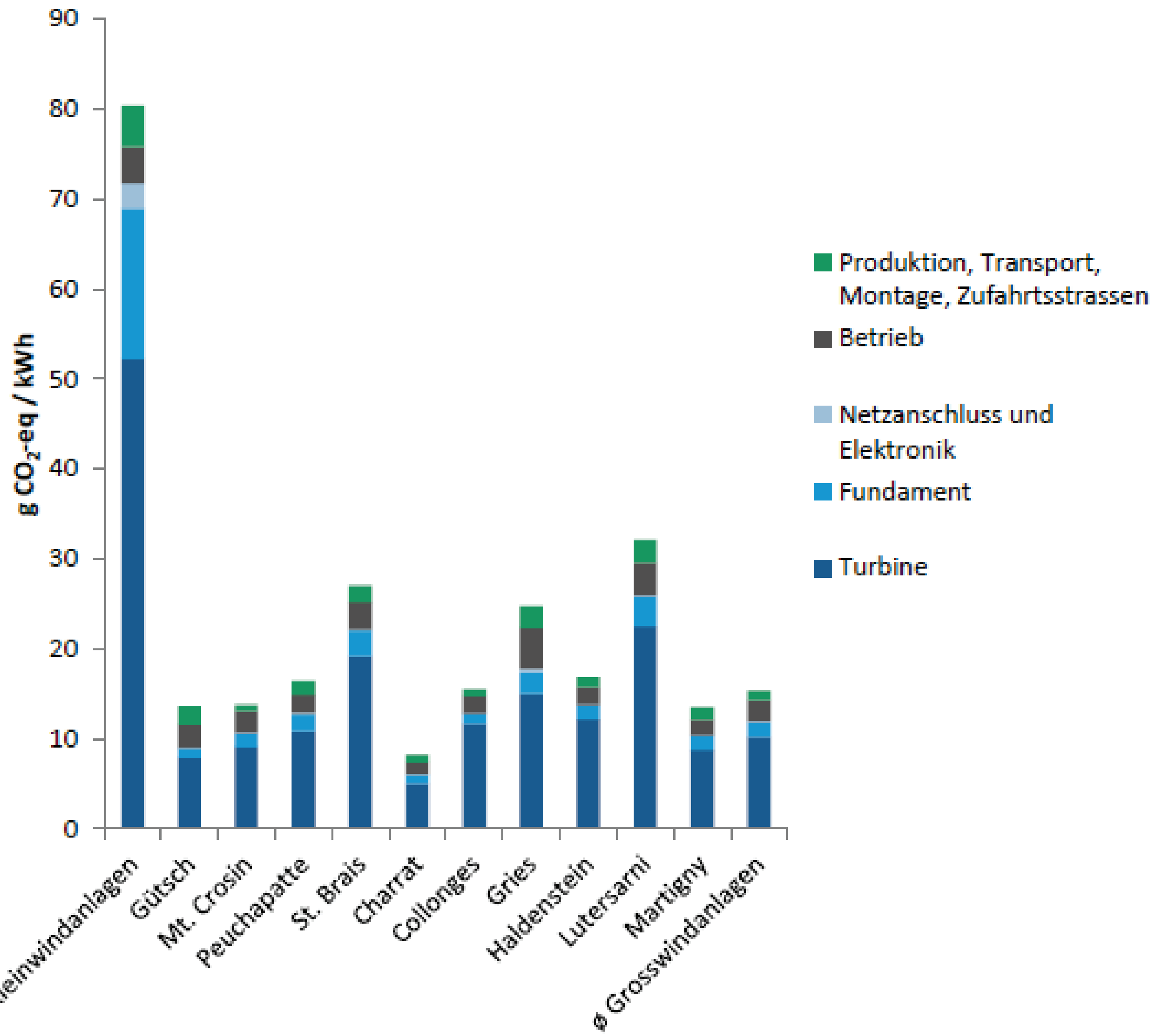


Figure 8.27: Life cycle GHG emissions of electricity from wind turbines in Switzerland. Taken from (Eymann, Stucki et al. 2015).

The main share of the impacts comes – in parallel to the LCOE – from the wind turbine components and installation. Fundament, grid connection and construction have a lower impact. The main materials and processes responsible for the GHG emissions are steel and chromium steel production, emissions of SF_6 during operation, road construction, concrete production and epoxy resin.

Transport of the electricity to the consumer can be as important as 30% to 50% of total impacts (depending on the impact category).

Table 8.13 shows selected LCIA results for the wind power installations in Switzerland as of today.

Table 8.13: Environmental impacts of the production of 1 kWh electricity at various locations in Switzerland (Eymann, Stucki et al. 2015). Figures in the last column represent averages (weighted by electricity production) of all large wind turbines and wind parks.

Umweltauswirkungen pro kWh Strom ab Anlage/Park			Klein-wind-anlagen	Grosswindanlagen										Ø Gross-wind-anlagen
				Gütsch	Mt. Crosin	Peucha-patte	St. Brais	Charrat	Col-longes	Gries	Halden-stein	Luter-sarni	Mar-tigny	
Methode der ökologischen Knappheit		UBP 2013	162	33.2	30.2	39.0	58.9	21.2	33.3	54.9	39.6	69.2	32.4	34.5
Treibhausgas-Emissionen		g CO_2-eq	80.4	13.7	13.8	16.4	27.1	8.24	15.5	24.8	16.8	32.1	13.6	15.4
Kumulierter Energieaufwand	Nicht-erneuerbar	MJ	1.12	0.201	0.173	0.208	0.369	0.100	0.203	0.298	0.225	0.448	0.172	0.198
	erneuerbar	MJ	3.92	3.88	3.88	3.88	3.89	3.88	3.88	3.89	3.89	3.90	3.88	3.88
Feinstaub		mg PM2.5 eq	40.5	7.82	7.29	9.96	16.3	4.75	8.50	14.2	9.96	19.5	8.13	8.62
Abiotischer Ressourcenverbrauch		µg Sb eq	977	231	164	324	434	163	201	479	246	507	258	226
Ionisierende Strahlung		Bq U^{235} eq	13.5	2.02	2.27	2.51	4.13	1.18	2.15	3.54	2.98	4.94	2.06	2.42
Hochradioaktive Abfälle		mm^3	0.123	0.0184	0.0212	0.0232	0.0384	0.0109	0.0200	0.0327	0.0279	0.0458	0.0190	0.0225

Ionizing radiation originates from the use of nuclear power in the background of the system.

Wind turbines with a higher electricity yield perform better (Charrat). Wind turbines with a steel tower perform worse (Lutersarni, St. Brais) than those with concrete towers.

Environmental impacts are not projected to decrease significantly until 2035 according to (Eymann, Stucki et al. 2015). Concrete towers seem to be more beneficial than steel towers. However, short transport distances are important because of the higher weight of the concrete towers.

As described in chapter 8.4.4, steel and concrete are the major materials used for wind turbines in terms of mass. However, the electronic installations further use other metals and rare earth oxides. (IEA 2013a) investigated if abundant propagation of wind power would quickly exploit such rare earth metals (oxides). They claim that “the wind power industry will continue to represent less than 1% of the global demand”. However, China is under control of 95% of the current rare earth oxides production, so that mining should be started also in other parts of the world. But the reverse of the medal is that the Chinese population also bears the environmental and social problems from mining of the rare earth metals.

(Wilburn 2011) wrote a report on projected material use until 2030 from wind turbines in the United States. Materials included are e.g. steel, concrete, glass fiber reinforced plastic, carbon fiber composite, aluminum, copper, or Neodymium used in the magnet. According to the Suisse Eole association, Neodymium is only used in one wind turbine in Switzerland so far.[191]

[191] http://www.suisse-eole.ch/de/news/2014/7/1/kaum-seltene-erden-in-schweizer-windturbinen-recycling-losungen-werden-intensiv-gesucht-31/

8.6.2 Local impacts

8.6.2.1 Land use

Direct land use is small for wind power plants. Except for the access roads, the area can be used for agricultural or other purposes. However, habitats requiring special protection may be affected by a wind park. Offshore plants must carefully be planned in order not to destroy important sea life habitats. The wind power plant locations as well as access roads are usually set back to the original condition after decommissioning of the plant.

8.6.2.2 Landscape

Wind turbines are well visible within a landscape. Landscapes which need special protection should be identified, and careful regional planning has to be performed. One solution is to build clustered wind parks in contrast to individual wind turbines spread over a large area.

Offshore wind parks are usually placed far from the coast, so that they are not well visible or not visible at all from the shore.

8.6.2.3 Birds: Strike, migration, habitat loss

Birds and also bats may collide with the rotating rotor blades. Migration corridors have to be identified, so that bird strike is mitigated by choosing the correct location and orientation of the wind turbine. Alternatively, the wind turbines can include a mechanism to shut down the plant when intensive bird migration is taking place. Some species avoid being close to wind turbines. The habitat of sensitive (protected) species should therefore not be used for wind turbines.

Studies suggest that the share of bird mortality due to wind turbines is very small compared to other anthropogenic activities, mainly buildings/windows, cats, high tension lines, vehicles, pesticides[192]. A recent study performed by the Vogelwarte Sempach at the wind park Le Peuchapette with three turbines found that during the investigated time slot between March 2015 and November 2015, the median of bird strike per turbine amounts to about 21 birds/turbine (Aschwanden and Liechti 2016). The authors state that these results might be valid for similar topographic locations, but should not be transferred to locations in alpine or the Swiss plateau and that further such investigations are required.

8.6.2.4 Noise

Noise from wind turbines comes from the gearboxes and generators (mechanical noise) and from the blades (aerodynamic noise). Mechanical noise has been eliminated by recent developments of wind turbines integrating noise reduction, e.g. from insulating materials in the nacelle. Further research now strives to a reduction of the aerodynamic noise. In general, recently wind turbines have become more efficient and convert more of the wind into rotational torque. Noise is prevented in this way. In general, new wind turbines are less noisy than older ones.

[192] http://www.wind-energy-the-facts.org/onshore-impacts.html

8.6.2.5 Other

Electromagnetic interferences and shadow flicker are discussed as potentially disturbing effects from wind turbines. Such effects have to be evaluated and discussed with the local population.

8.6.2.6 Wind regime and climate effects

Large-size (offshore) wind parks slow down the wind speed and increase turbulences, as the turbines represent an obstacle on the relatively smooth surface of the sea[193]. Possible effects on the climate are not well-explored. Recent and ongoing research projects aim to bring more light to this topic. As example, the project "WIPAFF" (Wind Park Far Field) coordinated by the Karlsruhe Institute of Technology (KIT) investigates local climate effects. With more than 500 offshore wind turbines installed in 2015 alone in Germany, research will include measurements rather than only modelling.

Another project finalized mid 2016 in the UK did measurements on UK's largest array of onshore turbines with 54 turbines and a total installed capacity of 124 MW (Armstrong, Burton et al. 2016). Due to major maintenance of the wind park, effects with and without turbines rotating could be compared. They found that the wind park actually did have a climatic effect, but they also state that this effect is very small in the range of 0.2-1°C increase in temperature. Further, they say that it is not a warming effect as such, but simply mixing air layers up. Open research questions are formulated in the field of effects of the ground-level microclimate changes on biogeochemical processes and ecosystem carbon cycling. These findings are supported by (Vautard, Thais et al. 2014), who modelled a small climatic effect of operational and planned European wind farms on temperature and precipitation. Both studies find that the effects of wind parks on climate are smaller than the natural climate interannual variability.

[193] http://www.kit.edu/kit/english/pi_2016_028_offshore-wind-parks-interactions-and-local-climate.php

8.7 Abbreviations

ARE	Bundesamt für Raumplanung
BAFU	Bundesamt für Umwelt
BFE	Bundesamt für Energie
CAPEX	Capital expenses
CH	Switzerland
CHF	Swiss Francs
EU	European Union
EWEA	European Wind Energy Agency
GHG	Greenhouse gas
GWEC	Global Wind Energy Council
HAWT	Horizontal Axis Wind Turbines
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
KEV	Kostendeckende Einspeisevergütung/compensatory feed-in renumeration
LCA	Life Cycle Assessment
LCIA	Life Cycle Impact Assessment
LCOE	Levelised Cost of Electricity
O&M	Operating and maintenance
OPEX	Operating and maintenance expenses
Rp.	Rappen
UK	United Kingdom
US	United States
USD	United States Dollar
USSR	Union of Soviet Socialists Republics
VSE	Verband Schweizerischer Elektrizitätsunternehmen
WWEA	World Wind Energy Association

8.8 APPENDIX

Table 8.14: Detailed data on installed wind capacity by the end of 2014, 2013, 2012, 2011 and 2010 including the added capacity 2014, growth rate 2014, and installed capacity per capita and per square km. Taken from (WWEA 2015).

Position 2014	Country/Region	Total capacity end 2014 [MW]	Added capacity 2014 [MW]	Growth rate 2014 [%]	Installed Capacity per Capita W/person	Installed Capacity per sqkm kW/sqkm	Total capacity end 2013 [MW]	Total capacity end 2012 [MW]	Total capacity end 2011 [MW]	Total capacity end 2010 [MW]
1	China	114'763.0	23'350.0	25.7	84.7	12.0	91'324.0	75'324.0	62'364.0	44'733.0
2	United States	65'754.0	4'854.0	7.6	206.2	6.7	61'108.0	59'882.0	46'919.0	40'180.0
3	Germany	40'468.0	5'808.0	16.8	499.6	113.3	34'660.0	31'315.0	29'075.0	27'215.0
4	Spain	22'986.5	27.5	0.1	481.5	45.5	22'959.0	22'796.0	21'673.0	20'676.0
5	India *	22'465.0	2'315.1	11.5	18.2	6.8	20'150.0	18'321.0	15'880.0	13'065.8
6	United Kingdom	12'440.3	1'736.4	16.1	195.2	51.0	10'710.9	8'635.9	6'018.0	5'203.8
7	Canada	9'694.0	1'871.0	25.9	278.3	1.0	7'698.0	6'201.0	5'265.0	4'008.0
8	France	9'296.0	1'042.0	12.6	140.3	14.4	8'254.0	7'499.8	6'607.6	5'628.7
9	Italy	8'662.8	107.5	1.3	140.4	28.7	8'551.0	8'144.0	6'737.0	5'797.0
10	Brazil	5'961.6	2'495.5	72.0	29.4	0.7	3'466.1	2'507.0	1'429.0	930.0
11	Sweden	5'425.0	1'050.0	21.4	557.9	12.0	4'470.0	3'745.0	2'798.0	2'052.0
12	Portugal *	4'953.0	229.0	4.0	454.4	53.4	4'724.0	4'525.0	4'083.0	3'702.0
13	Denmark	4'883.0	111.0	2.3	876.8	113.3	4'772.0	4'162.0	3'927.0	3'734.0
14	Poland	3'834.0	444.0	13.1	100.0	12.3	3'390.0	2'497.0	1'616.4	1'179.0
15	Australia	3'806.0	757.0	24.8	169.1	0.5	3'049.0	2'584.0	2'226.0	1'880.0
16	Turkey	3'763.0	804.0	27.2	46.1	4.8	2'959.0	2'312.0	1'799.0	1'274.0
17	Romania	3'220.0	437.0	15.7	148.2	12.6	2'783.0	1'905.0	826.0	591.0
18	Netherlands	2'805.0	141.0	4.2	166.2	67.5	2'693.0	2'391.0	2'328.0	2'269.0
19	Japan *	2'788.0	130.4	4.5	21.9	7.4	2'669.0	2'614.0	2'501.0	2'304.0
20	Mexico	2'551.0	559.0	28.1	21.2	1.3	1'992.0	1'348.0	929.0	521.0
21	Ireland	2'272.0	222.0	10.9	470.1	32.1	2'049.0	1'738.0	1'631.0	1'428.0
22	Austria	2'095.0	411.0	24.4	254.8	25.0	1'684.0	1'378.0	1'084.0	1'010.6
23	Greece	1'980.0	114.0	6.2	183.7	15.0	1'865.0	1'749.0	1'626.5	1'208.0
24	Belgium	1'959.0	308.0	18.7	187.5	64.2	1'651.0	1'375.0	1'078.0	886.0
25	Norway	856.0	88.0	11.5	166.3	2.6	768.0	703.0	520.0	434.6
26	Chile	836.0	502.0	149.6	48.1	1.1	335.0	190.0	190.0	170.0
27	Morocco	787.0	300.0	61.6	23.9	1.8	487.0	291.0	291.0	286.0
28	Bulgaria	691.0	10.0	1.5	99.8	6.2	681.0	674.0	503.0	499.0
29	Chinese Taipei	633.0	18.8	3.1	27.1	17.6	614.2	563.8	563.8	518.7
30	Finland	627.0	179.0	40.0	119.0	1.9	448.0	288.0	197.0	197.0
31	New Zealand	623.0	0.0	0.0	141.5	2.3	623.0	622.8	622.8	506.0
32	Egypt	616.0	66.0	12.0	7.1	0.6	550.0	550.0	550.0	550.0
33	Korea, South	609.0	47.7	8.5	12.4	6.1	561.3	482.6	406.3	379.3
34	South Africa	570.0	468.0	458.8	11.8	0.5	102.0	10.1	10.1	10.0
35	Uruguay	529.4	470.0	792.7	158.8	3.0	59.3	55.7	40.5	30.5
36	Ukraine	409.5	126.3	34.0	9.2	0.7	371.0	276.0	151.1	87.4
37	Croatia	347.0	45.0	14.9	77.6	6.1	302.0	180.0	131.0	89.0
38	Hungary	329.4	0.0	0.0	33.2	3.5	329.4	329.4	329.4	295.0
39	Estonia	302.7	22.7	8.1	240.6	6.7	280.0	269.0	184.0	149.0
40	Czech Republic	283.0	14.0	5.2	26.6	3.6	269.0	260.0	217.0	215.0
41	Lithuania	279.0	0.0	0.0	79.6	4.3	279.0	225.0	179.0	163.0
42	Argentina	271.0	53.0	24.8	6.3	0.1	217.1	140.9	129.2	54.0
43	Pakistan	256.0	150.0	141.5	1.3	0.3	106.0	106.0	6.0	6.0
44	Tunisia	245.0	141.0	135.6	22.4	1.5	104.0	104.0	54.0	54.0
45	Thailand	223.0	30.0	15.5	3.3	0.3	193.0	112.0	8.0	0.0
46	Philippines	216.0	183.0	554.5	2.0	0.7	33.0	33.0	33.0	33.0

Position 2014	Country/Region	capacity end 2014 [MW]	capacity 2014 [MW]	Growth rate 2014 [%]	Capacity per Capita W/person	Capacity per sqkm kW/sqkm	capacity end 2013 [MW]	capacity end 2012 [MW]	capacity end 2011 [MW]	capacity end 2010 [MW]
47	Costa Rica	198.0	50.0	33.6	41.6	3.9	148.2	148.2	148.2	123.0
48	Nicaragua	186.0	44.4	31.4	31.8	1.4	141.6	102.0	63.0	63.0
49	Ethiopia	171.0	0.0	0.0	1.8	-	171.0	51.0	30.0	0.0
50	Honduras	152.0	50.0	49.0	17.7	1.4	102.0	102.0	70.0	0.0
51	Peru	148.0	147.3	∞	4.9	0.1	0.7	0.7	0.7	0.7
52	Cyprus	147.0	0.0	0.0	125.4	15.9	147.0	147.0	134.0	82.0
53	Puerto Rico	125.0	0.0	0.0	34.5	13.7	125.0	125.0	0.0	0.0
54	Iran	117.5	17.5	17.5	1.5	0.1	100.0	100.0	100.0	100.0
55	Dominican Republic	85.3	0.0	0.0	8.2	0.7	85.3	33.6	33.6	0.2
56	Latvia	68.0	0.0	0.0	31.4	1.1	68.0	68.0	31.0	30.0
57	Switzerland	60.3	0.0	0.0	7.5	1.5	60.3	50.0	45.5	42.3
58	Luxembourg	58.0	0.0	0.0	111.4	22.4	58.0	58.0	44.0	44.0
59	Mongolia	50.9	0.0	0.0	17.2	-	50.9	1.3	1.3	1.3
60	Jamaica	47.7	0.0	0.0	16.3	4.3	47.7	47.7	47.7	29.7
61	New Caledonia	38.2	0.0	0.0	1426.2	2.1	38.2	38.2	38.2	38.2
62	Vietnam	31.0	0.0	0.0	0.3	0.1	31.0	31.0	31.0	31.0
63	Aruba	30.0	0.0	0.0	271.1	168.5	30.0	30.0	30.0	30.0
64	Venezuela	30.0	0.0	0.0	1.0	-	30.0	30.0	0.0	0.0
65	Guadeloupe	26.8	0.0	0.0	5.90	16.5	26.8	26.8	26.8	26.8
66	Cabo Verde	25.5	0.0	0.0	47.4	6.3	25.5	25.5	25.5	2.8
67	Reunion Island	23.4	0.0	0.0	27.8	9.3	23.4	23.4	23.4	23.4
68	Colombia	19.5	0.0	0.0	0.4	-	19.5	19.5	19.5	19.5
69	Ecuador	19.0	0.0	0.0	1.2	0.1	19.0	2.5	2.5	2.5
70	Faroe Islands	18.3	14.3	357.5	366.4	13.1	4.0	4.0	4.0	4.0
71	Russia	16.8	0.0	0.0	0.1	-	16.8	16.8	16.8	15.4
72	Guyana	13.5	0.0	0.0	18.4	0.1	13.5	13.5	13.5	13.5
73	Curacao	12.0	0.0	0.0	81.7	27.0	12.0	12.0	12.0	12.0
74	Cuba	11.7	0.0	0.0	1.1	0.1	11.7	11.7	11.7	11.7
75	Bonaire	10.8	0.0	0.0	652.9	36.7	10.8	10.8	10.8	10.8
76	Algeria	10.1	0.0	0.0	0.3	-	10.1	0.1	0.1	0.1
77	Fiji	10.0	0.0	0.0	11.1	0.5	10.0	10.0	10.0	10.0
78	Dominica	7.2	0.0	0.0	98.0	9.6	7.2	7.2	7.2	7.2
79	Israel	6.0	0.0	0.0	0.8	0.3	6.0	6.0	6.0	6.0
80	Belarus	3.4	0.0	0.0	0.4	-	3.4	3.4	3.4	3.4
81	Nigeria	3.2	1.0	45.5	-	-	2.2	2.2	2.2	2.2
82	Iceland	3.0	1.2	66.7	9.5	-	1.8	1.8	0.0	0.0
83	Slovakia	3.0	0.0	0.0	0.6	0.1	3.0	3.0	3.0	3.0
84	Vanuatu	3.0	0.0	0.0	11.2	0.2	3.0	3.0	3.0	3.0
85	St. Kitts and Nevis	2.2	0.0	0.0	40.6	8.4	2.2	2.2	2.2	0.0
86	Azerbaijan	2.0	0.0	0.0	0.2	-	2.0	2.0	2.0	0.0
87	Kazakhstan	2.0	0.0	0.0	0.1	-	2.0	2.0	2.0	0.5
88	Antarctica	1.6	0.0	0.0	-	-	1.6	1.6	1.6	1.6
89	Jordan	1.5	0.0	0.0	0.2	-	1.5	1.5	1.5	1.5
90	Indonesia	1.4	0.0	0.0	-	-	1.4	1.4	1.4	1.4
91	Madagascar	1.2	0.0	0.0	0.1	-	1.2	1.2	1.2	0.0
92	Martinique	1.1	0.0	0.0	2.8	1.0	1.1	1.1	1.1	1.1

Position 2014	Country/Region	Total capacity end 2014 [MW]	Added capacity 2014 [MW]	Growth rate 2014 [%]	Installed Capacity per Capita W/person	Installed Capacity per sqkm kW/sqkm	Total capacity end 2013 [MW]	Total capacity end 2012 [MW]	Total capacity end 2011 [MW]	Total capacity end 2010 [MW]
93	Mauritus	1.1	0.0	0.0	0.8	0.5	1.1	1.1	1.1	0.0
94	Falkland Islands	1.0	0.0	0.0	341.1	0.1	1.0	1.0	1.0	1.0
95	United Arab Emirates	0.9	0.0	0.0	0.2	-	0.9	1.0		
96	Eritrea	0.8	0.0	0.0	0.1	-	0.8	0.8	0.8	0.8
97	Grenada	0.7	0.0	0.0	6.4	2.0	0.7	0.7	0.7	0.7
98	St. Pierre-et-M.	0.6	0.0	0.0	101.9	2.5	0.6	0.6	0.6	0.6
99	Syria	0.6	0.0	0.0	-	-	0.6	0.6	0.6	0.6
100	Samoa	0.5	0.5	∞	2.5	-	0.0	0.0	0.0	0.0
101	Namibia	0.2	0.0	0.0	0.1	-	0.2	0.2	0.2	0.2
102	North Korea	0.2	0.0	0.0	-	-	0.2	0.2	0.2	0.2
103	Afghanistan	0.1	0.0	0.0	-	-	0.1	0.1	-	-
104	Bolivia	0.1	0.0	0.0	-	-	0.1	0.1	0.1	0.1
105	Nepal	0.1	0.0	0.0	-	-	0.1	0.1	-	-
	Total	371'374	52'565	16.4			318'530	282'608	236'803	197'004

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9 Solar photovoltaics (PV)

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9.1 Introduction

Solar energy is the source of nearly all energy on the earth, directly or indirectly. The intense nuclear activity in the center of the sun produces huge amount of radiation, which generates light energy called photons (Boxwell 2012). Photons have no physical mass but carry huge amount of energy and momentum. It would take a long time for a photon to push out from the center to the surface of the sun, and once it has reached the surface, it will travel at the speed of 300,000 meters per second, and will reach the earth in about 8 minutes (Boxwell 2012). The photovoltaics effect was first observed by French physicist Edmond Becquerel in 1839, who managed to produce electric current between two plates of platinum and gold, by immersing them into a solution and exposing the device to light (Palz 2010). However, the understanding and application of this effect was not further explored until the development of quantum mechanics and semiconductor technology in the 20th century, as well as the first photovoltaics module being built by Bell Laboratories in 1954 (Corkish, Green et al. 2013), with a cell efficiency up to 6% (Antchev 2009).

Renewable energy has played a key role in climate change mitigation strategy, and it stimulates the rapid boom of solar photovoltaics (PV) in the past decade. Since 2005, average annual growth rates of around 50% have been observed in the market of photovoltaics, which has surpassed the most optimistic predictions (Hernández-Moro and Martínez-Duart 2015). Since 2010, the world has installed more capacity of solar photovoltaics than in the previous four decades, and the total global capacity has reached 227 GW at the end of 2015. This is at least 10 times higher than in 2009, and it corresponds to about 1.3% of the global electricity demands (IEA 2016a). In Switzerland, according to the latest Energy Statistics published by the Federal Office of Energy, the total generation of electricity from solar photovoltaics in 2015 was about 1119 GWh per year, which represents 1.9% of the national electricity demand at the end users. The annual capacity installed in Switzerland in 2015 was 333 MW, and the cumulative installed capacity has reached 1394 MW (BFE/SFOE 2016e). Assuming the current annual capacity installation of around 300 MW will continue, and given an average annual yield of 970 kWh/kWp (Nowak and Biel 2012), about 4-5% of demand would be met by electricity generation from PV by 2020 in Switzerland.[194]

9.1.1 Definition and working principle of PV

The word “photovoltaics” derives from the Greek word “phos”, meaning light, and the word “volt”, unit for electrical voltage named by Alessandro Volta, who is a pioneer in the study of electricity (GoSolarCalifornia 2015). Photovoltaic is a technology that does exactly what it tells by its name: it directly converts solar irradiance into direct-current (DC) electricity. This is different from solar thermal technology, which concentrates the power from the sun to obtain thermal energy (and can further convert this to electricity).

The process of converting solar energy into electricity is achieved by the photovoltaics effect using semiconductor materials (Luque and Hegedus 2011). The solar cell is the basic

[194] At an annual electricity consumption of 60-65 TWh.

element of a PV system, and it is composed of a p-type and an n-type semiconductor. When solar cells are exposed to sunlight, the absorption of light results in incident photons that have greater energy than the band-gap energy, which generate electron-hole pairs that are oppositely charged, and they gather around the n-type and p-type of semiconductor, respectively. When loads are connected, electric current flows through the external circuit between two electrodes (Figure 9.1).

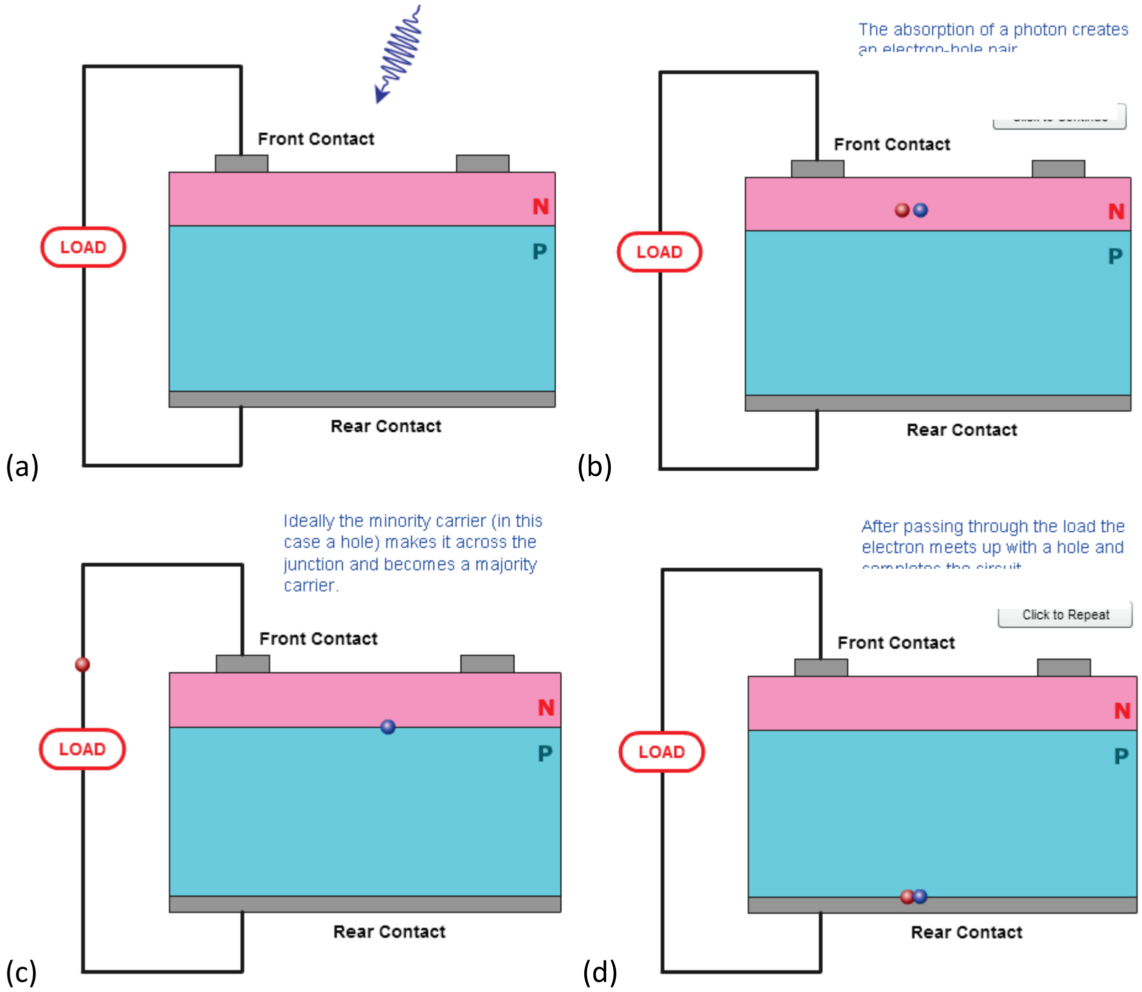


Figure 9.1: Illustration of The Photovoltaics Effect Formation (PVEducation 2015b).

9.1.2 Global and European development and trends

Global and European trends of photovoltaics are discussed in terms of installed capacity, installed system types, and production of PV system components (e.g. modules, inverter, etc.). Trends for PV system and component costs are briefly discussed in this section, and more details can be found in section 9.4.

The global installations of solar photovoltaics have been rapidly growing in recent years. By the end of 2015, the cumulated PV installations worldwide have reached 227 GW, and the electricity generation from these PV systems meets 1.3% of the global electricity consumption (IEA 2016a). A breakdown of the global cumulative installed capacity is shown in Figure 9.2, which shows that China has the biggest share in the global installed capacity of 19%, which is followed by Germany with 17%, Japan with 15%, USA with 11% and Italy with 8%. It is shown that the top seven countries contributed 78% of the installations in 2015.

The contribution of Switzerland is not shown in the chart, but given the Swiss cumulative installed capacity in 2015 at about 1394 MW, it is about 0.6% of the globally installed capacity. In regard to percentage of electricity demand met by generation from PV, Italy is the highest of the world with 8%, followed by Greece of 7.4%, and Germany with 7.1% in 2015 (IEA 2016a).

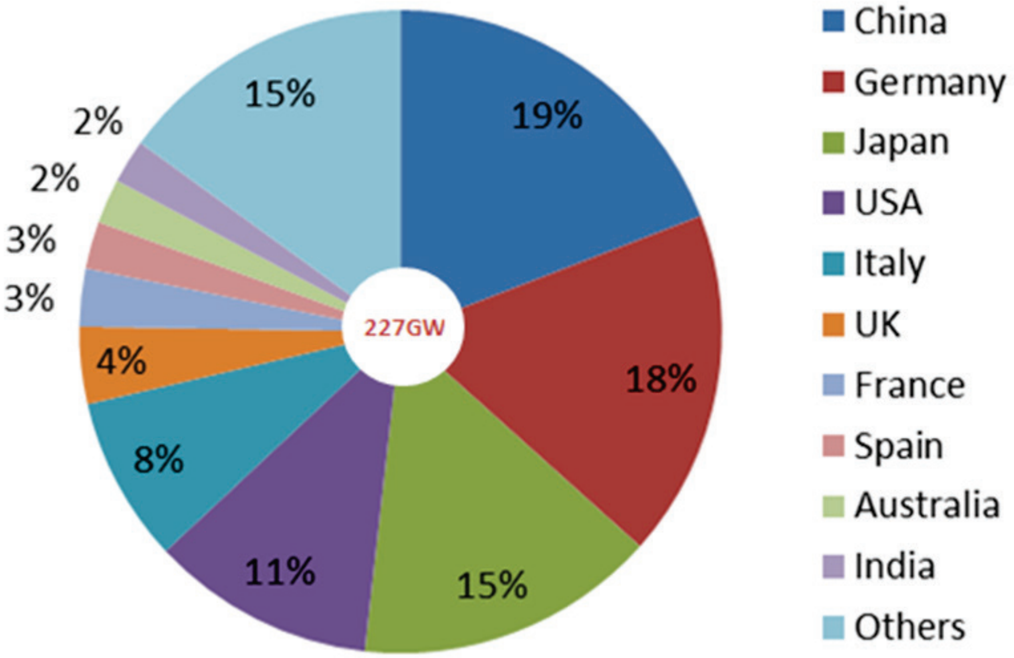


Figure 9.2: Breakdown of cumulative PV capacity installed by the end of 2015 (IEA 2016a).

A general increasing trend of PV installations worldwide can be observed from the annual installed capacity since 2000, as shown in Figure 9.3. However, the breakdown of the annual installed capacity by region shows that the trends are different from region to region; the main increase recently occured in general outside of the European market, with around 60% of the global PV market (IEA 2016a). The two giants in Asia continue to grow, with China installed 15.3 GW, and Japan installed 11 GW of additional capacity in 2015. The US market increased again by 7.3 GW, dominated by large-scale systems and third-party ownership (IEA 2016a). The European solar PV market remains quite varied, with very diverse segmentation from one country to another, but in general, there is a clear trend that, after Europe reaching the peak of annual installed capacity in 2011, the largest contributor in the growth of annual installed capacity has gradually shifted from Europe to Asia Pacific and the United States in the past few years.

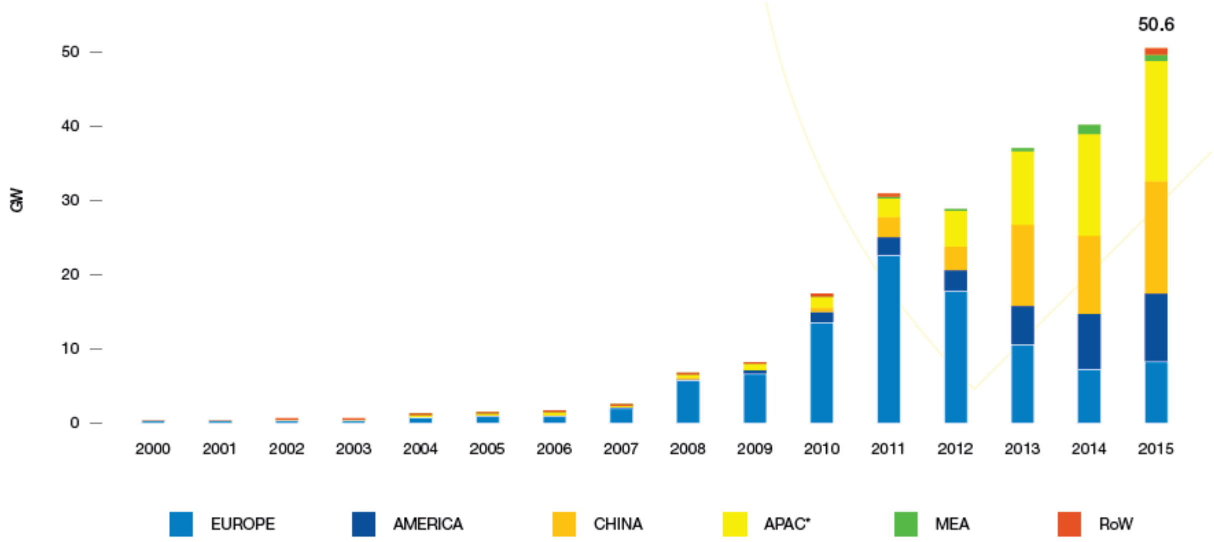


Figure 9.3: Annual Installed Capacity by Region from 2000 to 2015 (Schmela, Masson et al. 2016).

This is an effect of the decreasing annual installed capacity in some major European PV market players (Figure 9.4), including Germany, which used to be the global leader in annual installed capacity, and Italy, which deployed the highest annual installed capacity in Europe back in 2011 of 9.3 GW (IEA 2016a). There are other European countries with rising trends in annual installed capacity, such as UK, but due to its relatively small percentage of the global market, the general decreasing trend of annual installed capacity in Europe had not stopped from 2011 to 2014. However, the European market started to slightly grow again from 2015, thanks mainly to the growth of the UK market with 3.5 GW of installed capacity in 2015 (IEA 2016a). In terms of the type of installed systems, most of the PV systems installed are grid-connected rather than off-grid, especially in Europe, only limited remote areas are equipped with off-grid systems. The grid-connected systems can be further divided into decentralized and centralized systems. Size is not a decisive factor to determine whether it is a distributed system or centralized system, but rather the functions or installed locations are. The distributed systems are usually on or integrated to the customer’s premises on the demand side, while a centralized system functions similar as a centralized power plant (IEA 2015f). The percentage of centralized systems has globally raised to almost 60% from around only 10% in 2009 (IEA 2015f).

Concerning PV system production, the annual manufacture of PV has always been slightly more than the amount being installed, but when a closer look is taken at the annual production capacity, it is only around 57% to 65% of the total manufacture capacity since 2010, as shown in Figure 9.5 (IEA 2015f).

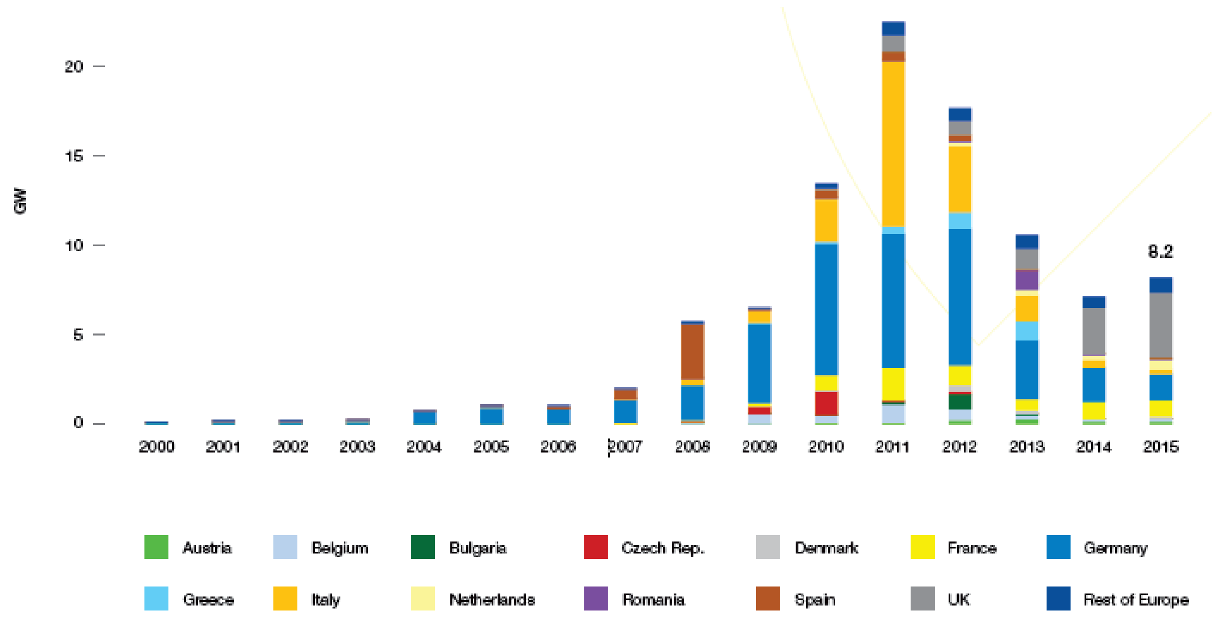


Figure 9.4: Annual Installed Capacity by Region in Europe from 2000 to 2015 (IEA 2016a).

The majority of PV cells and modules are produced in Asia: in 2014, more than 60% of the PV modules and cells are manufactured in China, followed by Taiwan (16% of cells), Japan (6% of cells, 8% of modules), and Malaysia (6% of cells and modules) (IEA 2015f). Production of inverters is increasing due to the main contribution of grid-connected system installations. But since it is mainly influenced by country-specific regulations, usually domestic manufacturers tend to dominate the domestic PV markets.

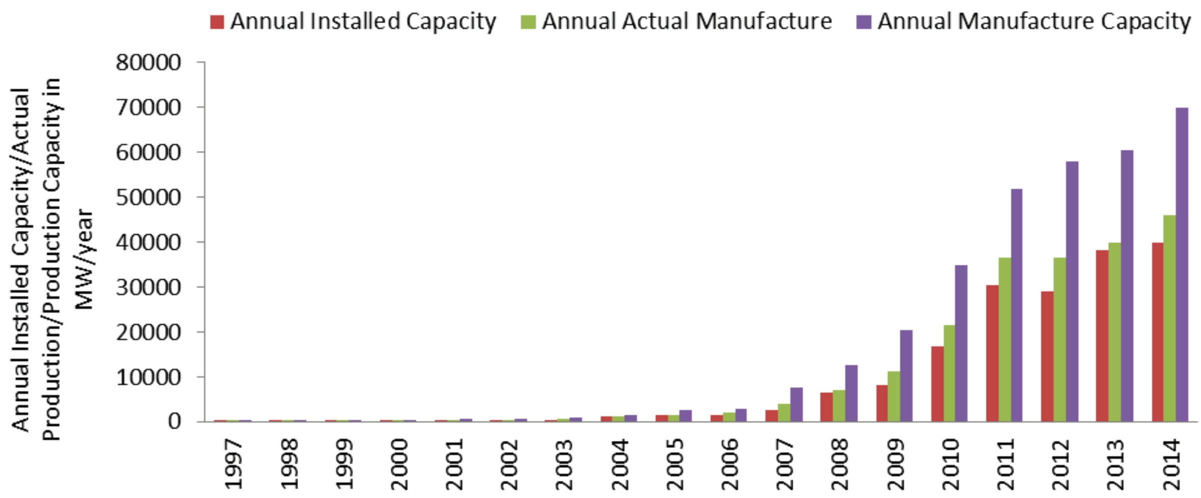


Figure 9.5: Annual Installed Capacity, Annual Actual PV Production and Annual PV Production Capacity (IEA 2015f).

9.1.3 Swiss PV development and trends

In Switzerland, the annual installed capacity continues to increase again, to about 333 MW of PV installed in 2015, after a slight decrease in 2014 in comparison with 2013 (Figure 7.6), which is caused by the decreasing Feed-in-Tariff (FiT, or Kostendeckende Einspeisevergütung, KEV) and more importantly, the long waiting list of KEV applications due to limited amounts of total FiT (more details in section 9.3.3.1). By 2014, the cumulative installed capacity in Switzerland has exceeded 1 GW, and according to the Swiss general energy statistics in 2015 (Figure 9.7), the percentage of electricity generation from PV is further increased to 1.8%, with 1394 MW of total installed capacity in Switzerland (Kaufmann 2016a).

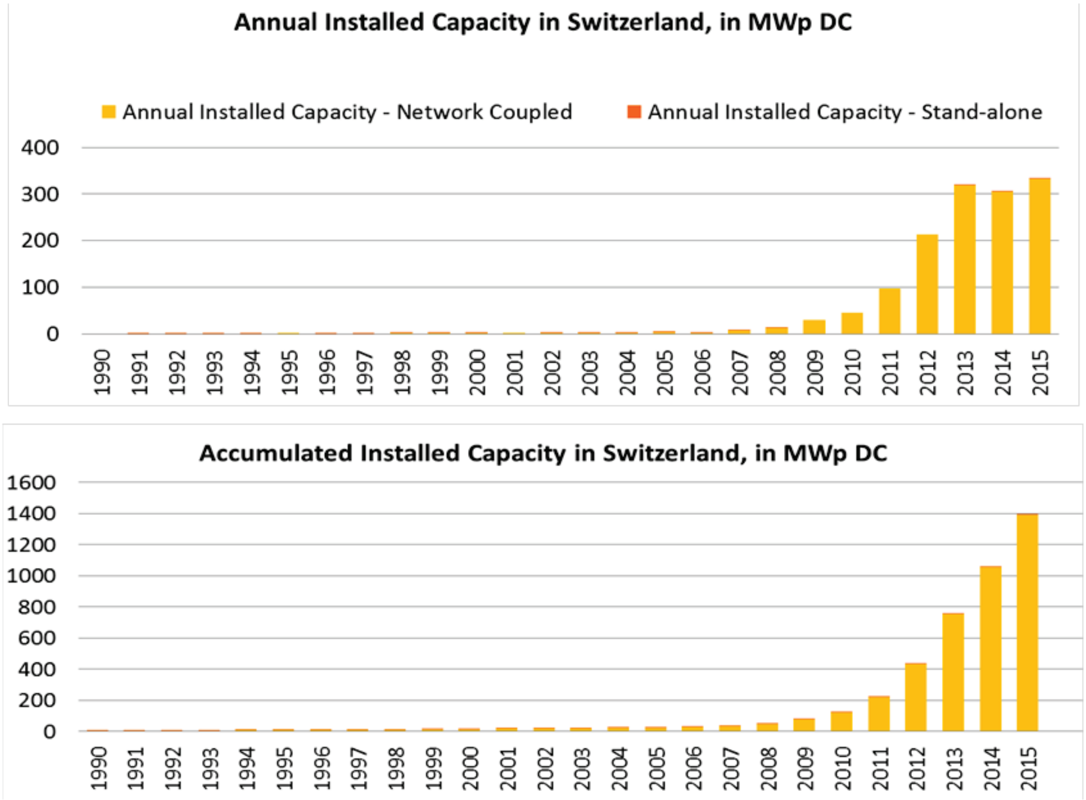


Figure 9.6: The PV Installations in Switzerland from 1990 to 2015: Annual Capacity Installed and Accumulated Capacity Installed (BFE/SFOE 2016f).

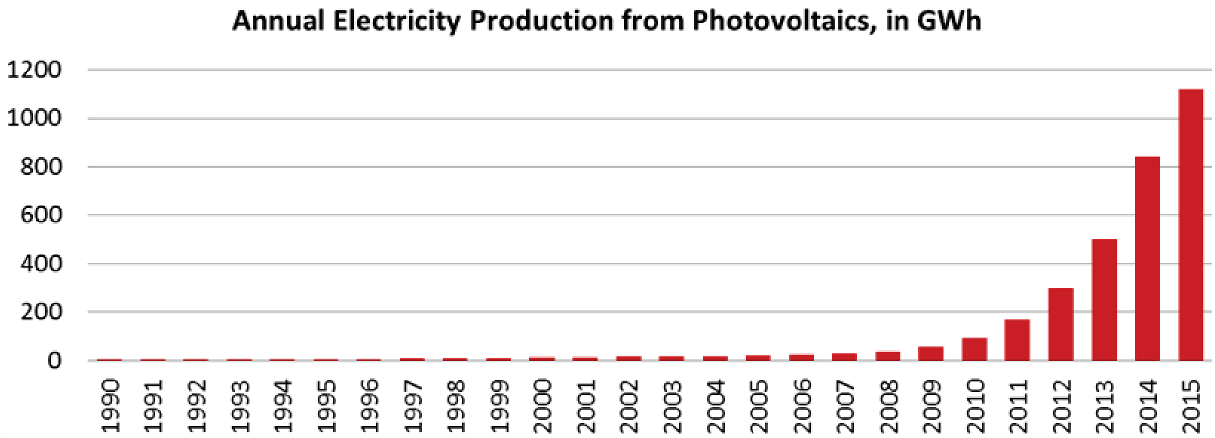


Figure 9.7: Annual generation of electricity from PV in Switzerland 1990-2015 (BFE/SFOE 2016f).

The percentage of PV generation in total electricity demand in Switzerland is also above the average world level of 1%, according to IEA (2015f) (Figure 9.8), but lower in comparison with countries such as Italy (8%), Greece (7-8%), Germany (6-7%), Bulgaria, Spain, Belgium and Czech Republic (3-4%). Figure 9.8 further breaks down the percentage into more details by: self-consumed electricity, self-consumed electricity under net-metering, PV electricity injected into the grid for IEA PVPS countries and PV electricity production for other countries. It is shown that in Switzerland, most of the electricity generated from PV is fed into the grid, whereas only a small portion of electricity generated is self-consumed, and it is rather low in comparison with the other countries.

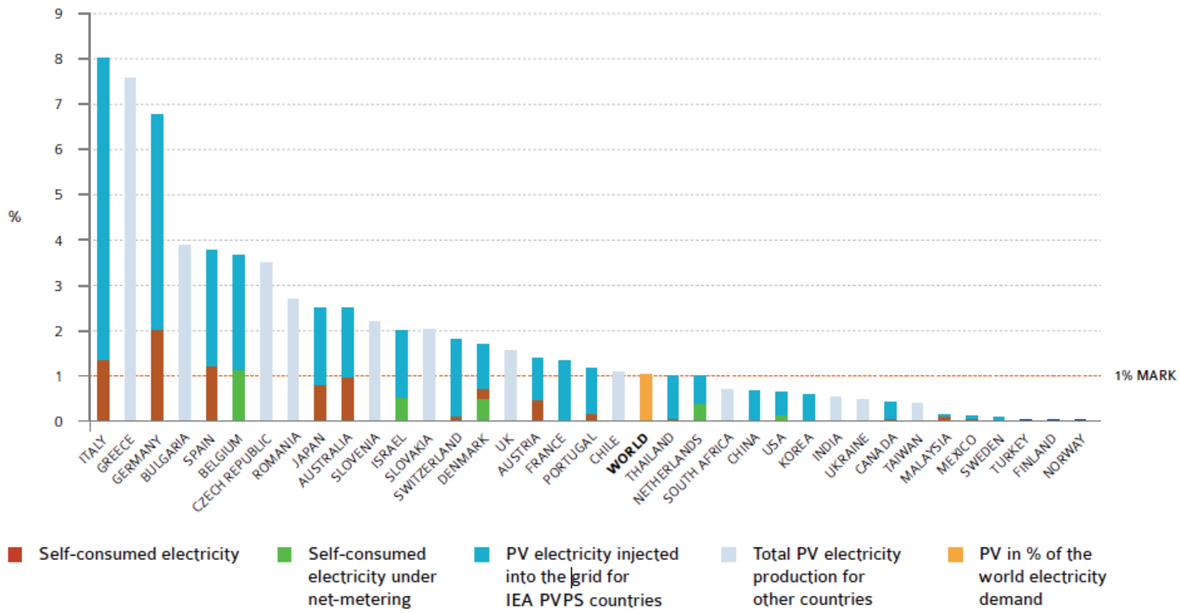


Figure 9.8: Percentage of Electricity Generation from PV in Total Electricity Demand (IEA 2015f).

The installed PV systems can be also categorized by sector, as shown in Figure 9.9 (BFE/SFOE 2001-2015). The pie charts show the breakdown by installed capacity and number of installations. It can be observed that more than half of the systems are installed on residential houses, but their sizes are rather small, which contribute for about less than a quarter of the total installed capacity. In contrary, the number of systems installed in industry and agriculture sector is about a quarter of all installed system, but they are accounted for more than 60% of installed capacity, which indicates that the average system size is much higher than that of residential systems.

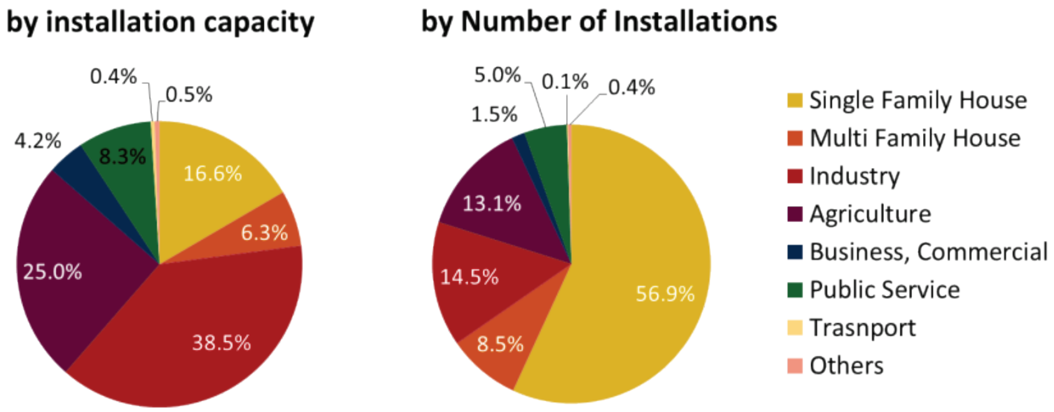


Figure 9.9: Installation of PV Systems in Switzerland by Installed Capacity and by Number of Installations (BFE/SFOE 2001-2015).

The grid-connected systems installed up to 2015 are also shown by range of size in Table 9.1 (BFE/SFOE 2001-2015). It shows that, up to 2015, about half of the systems have installed capacities of more than 100 kW, and the remaining systems have installed capacities of less than 100 kW.

Table 9.1: Grid-connected system by range of size in Switzerland in 2014 (BFE/SFOE 2001-2015)

	up to 4 kW	4 to 20 kW	20 to 50 kW	50 to 100 kW	over 100 kW
Installed Capacity by 2014 (kW)	2,646	51,126	45,873	36,852	200,688
Percentage (%)	2%	17%	13%	14%	55%

9.2 Technology description

9.2.1 Photovoltaics technologies and market shares

There are many ways to categorize the photovoltaics technologies. One of the most common ways is to divide them by generation, based on the basic material used and the level of commercial maturity (IRENA 2012b). The first-generation refers to the crystalline silicon (c-Si) technologies. Depending on how a wafer is produced, it can be further divided into mono-crystalline silicon (mono c-Si, or single crystalline silicon), multi-crystalline silicon (multi c-Si, or polysilicon), and ribbon-sheet grown silicon. The second-generation refers to the thin-film technologies, in which amorphous silicon or amorphous/microcrystalline silicon (a-Si, also known as nanocrystalline silicon), cadmium telluride (CdTe), and Copper Indium Gallium (di)Selenide (CIGS or CIS) are the three types that have been commercially developed (IRENA 2012b).

The current global production of PV modules is mainly dominated by the first-generation technologies. A breakdown of their productions is shown in Figure 9.10. It can be observed that up until today, the first-generation PV technologies are still the most mature and commonly-applied PV technologies in the market, with 93% of the market share, and mono-Si and multi-Si PV panels being the main contributors. Multi-Si in general shows an increasing trend in market share, while mono-Si shows a decreasing trend since 1994. There is a drop of market share of thin-film PV modules since 2009, and until 2015, it has dropped to below 10% of the market share, with 4.2 GW of annual production.

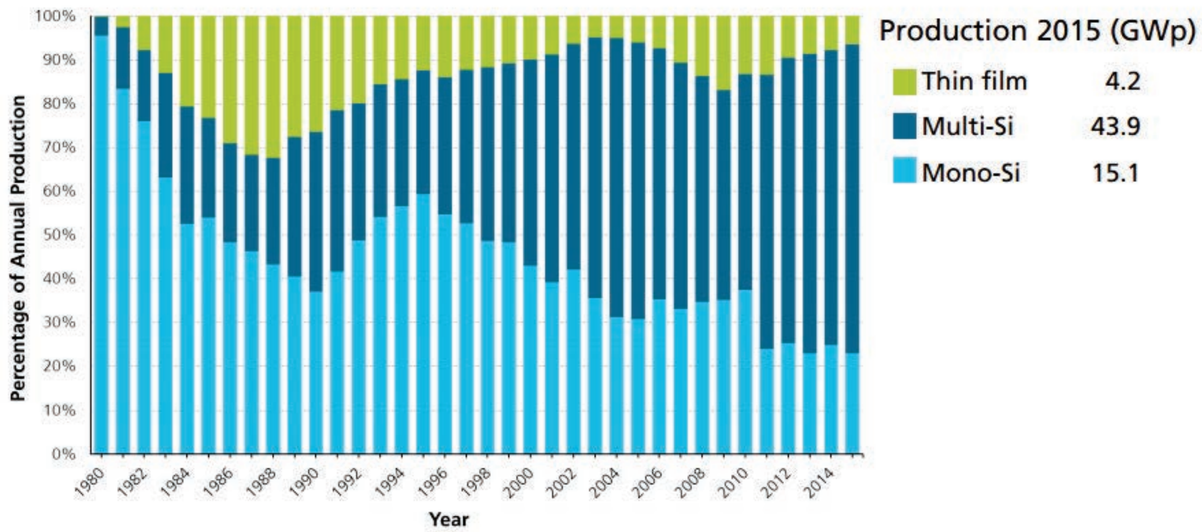


Figure 9.10: Global production of PV modules by technology from 1980 to 2015 (Fraunhofer 2016)

The third-generation of PV technologies refers to the emerging and novel PV technologies such as concentrating PV, dye-sensitized PV, organic PV and other advanced thin-film PV technologies. These technologies are also referred to as the technologies that are potentially able to overcome the Shockley–Queisser limit (maximum theoretical efficiency of a solar cell using a p-n junction to collect power from the cell) of 31 to 41% efficiency for single bandgap solar cells (Conibeer 2007). They use multi-layer cells and abundant, non-toxic, durable materials (Lamont 2013), such as nano-tubes, organic dyes, silicon wires, conductive plastics and solar inks using conventional printing press technologies. Although it was expected that the second- and the third-generation technologies would overtake the first-generation, so far it has not been so, and most of all the third-generation PV technologies have not yet been commercialized or are still under R&D and demonstration, while second-generation technologies holding a relatively small market share. PV technologies and their technology characteristics are summarized in Table 9.2.

Table 9.2: Overview of PV Technologies by Generation (unless otherwise specified, the information in the following table refer to single-junction PV).

		1st Generation PV		2nd Generation PV			3rd Generation PV		
Technology	Unit	Multi-crystalline silicon (multi-Si)	Mono-crystalline silicon (mono-Si)	Amorphous silicon/Amorphous microcrystalline silicon	Copper Indium Gallium Diselenide (CIS/CIGS)	Cadmium Telluride (CdTe)	III-V Compound Multi-junction concentr. PV (CPV)	Dye-sensitized (DSSC)	Organic or Polymer (OPV)
Best research cell efficiency	%	21.3 (Trinasolar) (NREL 2016)	25.2 (SunPower 2016)	14 (AIST) (NREL 2016)	22.6 (ZSW 2016)	22.1 (FirstSolar 2016a)	46% (Fraunhofer 2014)	11.9% (Sharp 2016)	11.5 (HKUST) (Yan 2016)
Best research module efficiency	%	19.86 (Trinasolar 2016b)	24.1 (SunPower 2016)	12.34 (TEL Solar) (Cashmore, Apolloni et al. 2015)	-	-	-	-	-
Best commercial PV module efficiency	%	17 (REC Twinpeak Series) (REC 2016)	21.5 (SunPower X-Series) (SunPower 2013)	10.4 (Meillaud, Boccard et al. 2015)	14.5 (Stion 2013)	17 (FirstSolar 2016b)	>30% (Soitec) (Philipps and Bett 2016)	-	-
Global market share in 2015 (Fraunhofer 2016)	%	69	24	1	2	4	-	-	-
Average area needed per kW	m^2	8	7	15	10	11	-	-	-
State of commercialization	n.a	mature with large-scale production	mature with large-scale production	mature with small-scale production	mature with small-scale production	mature with small-scale production	R&D and demon-stration	R&D and demon-stration	R&D and demon-stration

9.2.1.1 *Crystalline Silicon (c-Si) PV technologies*

Crystalline silicon PV is the most widely used technology in the world (Figure 9.10). The main material required for the c-Si PV is silicon, an element that is the second abundant in the earth's crust, with concentration of 27.7% by weight. Its energy band gap (minimum change in energy required to excite the electron so that it can participate in conduction) of 1.1 eV makes it a suitable material for PV applications (Streetman and Banerjee 2014). On average, the efficiency of mono-crystalline silicon PV is higher than that of multi-crystalline silicon PV. NERL has verified that SunPower's mono-crystalline PV module has reached efficiency of 24.1%, while its cell efficiency in lab has reached 25.2% (SunPower 2016), which is close to the world's highest record of cell efficiency achieved in lab by Panasonic of 25.6% in 2014 (Panasonic 2014). The record of cell efficiency in lab for multi-crystalline PV was achieved by Trinasolar recently at 23.5% (Trinasolar 2016).

The manufacturing process of wafer-based silicon PV cells consists of five steps: metallurgical-grade silicon production from silicon dioxide (SiO_2), solar-grade silicon (silicon that has intermediate grade (99.999999 or 6N) of impurity, and this requirement of impurity is between metallurgical-silicon (98%) and semiconductor- or electronic-grade silicon (99.999999999% or 9N)) production, ingot and wafer production, cell production, and module assembly. Solar-grade silicon is manufactured from metallurgical-grade silicon via chemical purification, and the most commonly-used technology is the “Siemens process”. This process distillates volatile silicon compounds, from which decomposition forms silicon at high temperatures. Although the Siemens process is quite energy intensive, in its recrystallization process, high energy and cost reduction can be achieved by increasing the size of the Siemens reactor. Another alternative technology that has been developed more recently is using a fluidized bed reactor, which needs only a fraction electricity demand of the Siemens process, reduces the material waste, and is able to effectively control the granules that might cause pollution during the purification process. It had a market share of nearly 10% of global multi-silicon production in 2014, and IHS projected a market share of 16.7% by 2020 (Segundo 2014). Continued cost reductions are possible through improvements in materials and manufacturing processes, and from economies of scale if the market continues to grow.

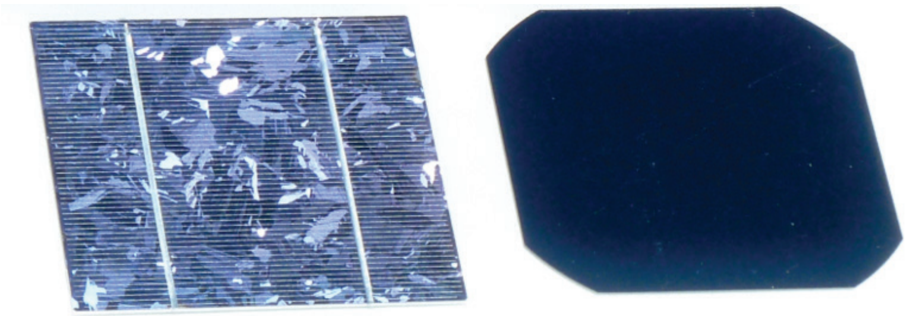


Figure 9.11: Solar PV cells made of multi-crystalline silicon (left) and mono-crystalline silicon (right) (Müller 2014).

9.2.1.2 Thin-film PV technologies

Thin-film PV is generally consisting of three types: amorphous (a-Si) and microcrystalline silicon (µc-Si), CdTe, and CIS or CIGS. Market share of thin-film PV has been no more than 20% in the last two decades (Figure 9.10) and has been declining to less than 10% of worldwide annual photovoltaic production in 2015 (Fraunhofer 2016). The market share of thin-film PV modules by technology from 2000 to 2015 is shown in Figure 9.12 (Fraunhofer 2016).

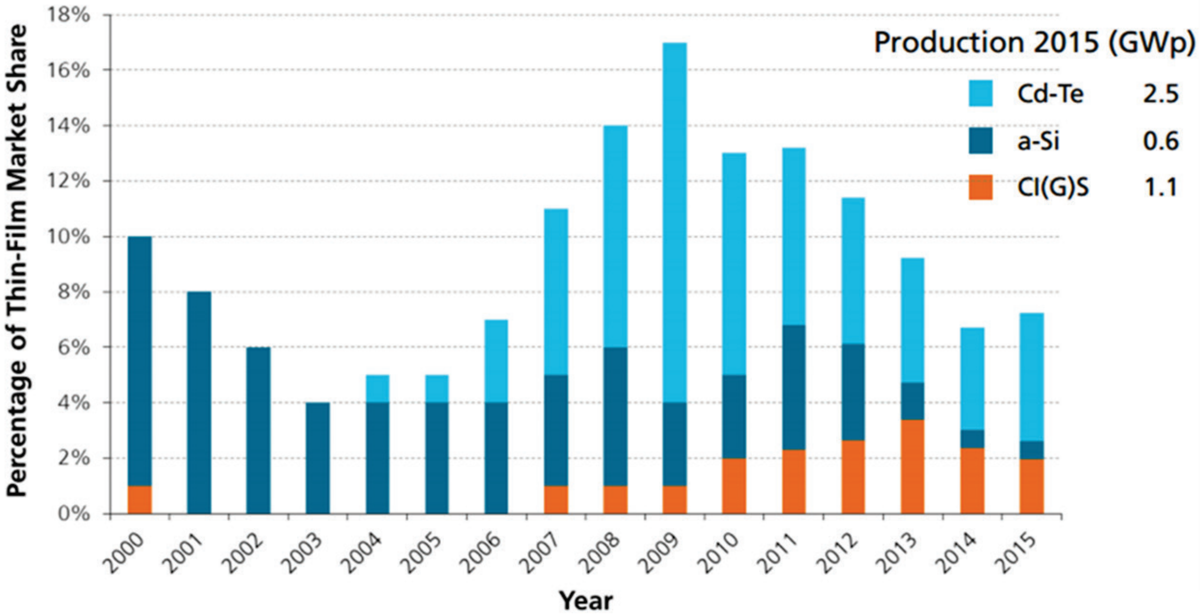


Figure 9.12: Thin-film PV market share from 2000 to 2015 (Fraunhofer 2016).

Thin-film solar cells are made by depositing successive thin layers with thickness of a few nanometers (nm) to tens of micrometers (µm) (whereas traditional crystalline silicon solar cells have wafers up to 200 µm) onto an inexpensive substrate, such as glass, polymer, or metal. As a consequence, they require a lot less semiconductor material and are much lighter than crystalline silicon solar cells. However, the benefits of lower capital costs are often offset by the lower efficiencies (IRENA 2012b) and faster degradation rates. But in recent years, more and more research has been conducted to investigate the cell design of thin-film PV to further reduce the cost, and to understand the relationship between the cell efficiency and its materials and designs. Thin-film solar PV also perform relatively well under poor lighting conditions and are not affected as much by shading issues (Maehlum 2013). Thin film PV cells can be also made to be more flexible and lighter in weight, making it a good candidate to be integrated into the buildings as flat or curved surface such as in roof and facades. This type of PV is also called building-integrated PV or BIPV. An overview of thin-film PV cell structure of difference types is shown in Figure 9.13 (Jung 2008).

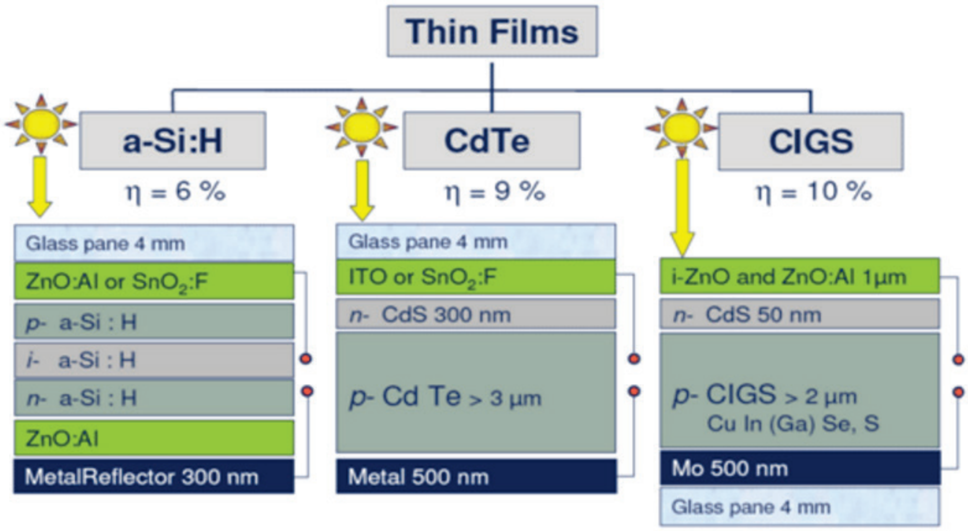


Figure 9.13: Types of thin-film solar cells and their structure (Jung 2008).

9.2.1.2.1 Amorphous silicon (a-Si) and microcrystalline silicon (μc-Si)

Amorphous silicon (a-Si) PV is shapeless, in other words, it is not structured or crystalized on a molecular level. It had dominated the thin-film PV market for some time in the last decade due to its low production cost. However, low conversion efficiency and long-term stability are often the challenges for traditional single-junction a-Si PV cells. The low efficiency on the other hand also indicates that it requires a much larger area given the same power output than crystalline silicon PV. Although remarkable improvements were achieved in production technologies with associated cost reduction, the lower efficiency and long-term stability issues have limited a-Si PV to gain market share.

A variant of amorphous silicon solar cells is multi-junction cells with micro-crystalline silicon (μc-Si) applied onto the substrate, also known as micromorph cells. The advantage of the μc-Si layer is that it absorbs more light from the red and near infrared part of the light spectrum, thus increasing the efficiency. The thickness of the μc-Si layer is in the order of 3 μm and makes the cells thicker and more stable (IRENA 2012b). The average module efficiency of micromorph PV is in the range of 4-10%; the highest stabilized cell efficiency of 13.6% was achieved in laboratory conditions by Sai, Matsui et al. (2015).

9.2.1.2.2 CdTe

The lower production costs and higher cell efficiency compared to other thin-film technologies makes CdTe thin-film PV the most economical thin-film technology currently available (IRENA 2012b). With about 4% of worldwide PV production in 2015, it accounts for more than half of the thin-film PV market. The average module efficiency of CdTe PV is about 13% (Fraunhofer 2016), and the lab-scale cell efficiency of CdTe PV has been increased significantly in recent years, with level close to the efficiency of multi-crystalline silicon in 2013 (Fraunhofer 2016). First Solar has announced so far the highest cell efficiency for CdTe PV, with 22.1% cell efficiency and 18.6% of module efficiency (FirstSolar 2016).

There is however public skepticism about the materials of cadmium used in CdTe PV cells, which is primarily produced as a by-product of zinc mining, due to its toxicity, although Fthenakis (2004) claims that encapsulating cadmium as CdTe in PV modules is a safer option than being disposed to landfill or as hazardous waste, and the recycling of CdTe PV module at the end of its lifetime would completely resolve the environmental concerns. First Solar produces several GW of such modules per year, and have been one of the most successful companies on the PV market so far.

9.2.1.2.3 CIGS

CIGS PV is manufactured by depositing a thin layer of copper, indium, gallium and selenide on glass or plastic backing, along with electrodes on the front and back to collect current. CIGS has an exceptionally high absorption coefficient of more than 10^5/cm for 1.5 eV and higher energy photons. Current module efficiencies are in the range of 7% to 16% (IRENA 2012b), but higher efficiencies were achieved in the lab, with efficiency of 20.4% by Swiss Federal Laboratories for Materials Science and Technology in 2013 (Nideröst 2013), and efficiency of 21.7% by The Centre for Solar Energy and Hydrogen Research Baden Württemberg in 2014 (Brusdeylins 2014), close to that of c-Si cells.

9.2.1.3 Emerging and novel PV technologies

First- and second-generation panels are still the most widely applied in industry but with the motivation of further increasing the efficiency and reducing the cost, the third-generation PV technologies emerged, hoping to overcome the these problems and combine the advantage of first- and second-generation technologies through multi-junction devices or the use of different materials and technologies (Lamont 2013). Selected third-generation PV technologies, together with their performance, developments, advantages and challenges are briefly introduced in the following sections.

9.2.1.3.1 Concentrating PV

Concentrating PV (CPV) systems utilize lenses and curved mirrors to focus direct solar radiation onto very small, highly efficient multi-junction solar cells made of a semiconductor material. CPV systems often uses solar trackers orienting the lenses permanently towards the sun, using a single- or double-axis tracking system for low and high concentrations, respectively. It is also common that CPV systems are equipped with cooling systems. These system requirements often result in expensive CPV modules in comparison with conventional PV. On the other hand, their higher efficiency and the smaller surface area of active material required may eventually compensate for the higher costs, depending on the evolution of costs and efficiency (IRENA 2012b). Low- to medium-concentration systems can be combined with silicon solar cells, but higher temperatures will reduce their efficiency, while high concentration systems are usually associated with multi-junction solar cells made by semiconductor compounds from groups III and V of the periodic table (e.g. gallium arsenide), which offer the highest PV conversion efficiency. Multi-junction (also referred as cascaded or tandem (Lamont 2013)) solar cells consist of a stack of layered p–n junctions, each made from a distinct set of semiconductors, with different band gap and spectral absorption to absorb as much of the solar spectrum as possible (Figure 9.14). Most commonly employed materials are Ge (0.67 eV), GaAs or InGaAs (1.4 eV), and InGaP (1.85 eV). A triple-junction cell with band gaps of 0.74, 1.2 and 1.8 eV would reach a theoretical efficiency of 59%. Commercial CPV modules with silicon-based cells offer efficiency in the range of 20% to 25%. Commercial multi-junction devices have efficiencies of around 35%, which is significantly higher than conventional single-junction c-SI solar cells. Because CPV modules rely on direct sunlight, they need to be used in regions with clear skies and high direct solar irradiation to maximize performance (IRENA 2012b).

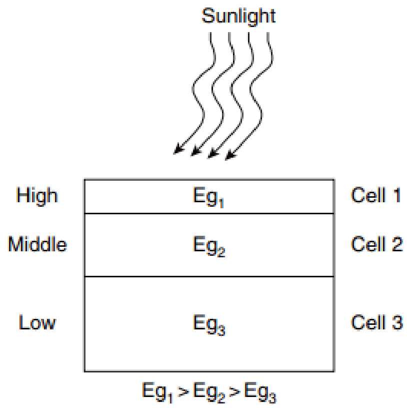


Figure 9.14: Operation of a three-layer multi-junction PV (Lamont 2013).

9.2.1.3.2 Dye-sensitized PV

Dye-sensitized PV cell, also known as the “Grätzel cell”, is a type of low-cost thin-film cell that was first invented by O'Regan and Gratzel (1991). The main principle of dye-sensitized solar cells (DSSC) is that organic dyes can generate electricity at oxide electrodes in electrochemical cells. In DSSC, sunlight passes through the transparent electrode into the dye layer where it can excite electrons that then flow into the titanium dioxide. The electrons flow toward the transparent electrode where they are collected for powering a load. After flowing through the external circuit, they are re-introduced into the cell on a metal electrode on the back, flowing into the electrolyte. The electrolyte then transports the electrons back to the dye molecules. Dye-sensitized solar cells separate the two functions provided by silicon in a traditional cell design. Normally the silicon acts as both the source of photoelectrons, as well as providing the electric field to separate the charges and create a current. In the dye-sensitized solar cell, the bulk of the semiconductor is used solely for charge transport, the photoelectrons are provided from a separate photosensitive dye. These cells are attractive due to the use of low-cost materials and easy manufacturing. They release electrons from titanium dioxide covered by a light absorbing pigment. However, performance degradation can occur over time (Ahuja 2015). Efficiency of 15% has been achieved via sequential deposition and formation of the perovskite pigment within the porous metal oxide film (Burschka, Pellet et al. 2013). However, commercial efficiencies are low, typically under 4-5%. The low efficiency of DSSC is caused by the fact that only a few dye can absorb a broad spectral range (IRENA 2012b). Another challenge of DSSC is that it uses liquid electrolyte, which raises stability issues at high and low temperatures, and its liquid property requires good sealing of the panel. However, in comparison with conventional crystalline silicon PV technologies, DSSC has also some advantages, such as expected lower cost, better performance during bad weather and higher temperature.

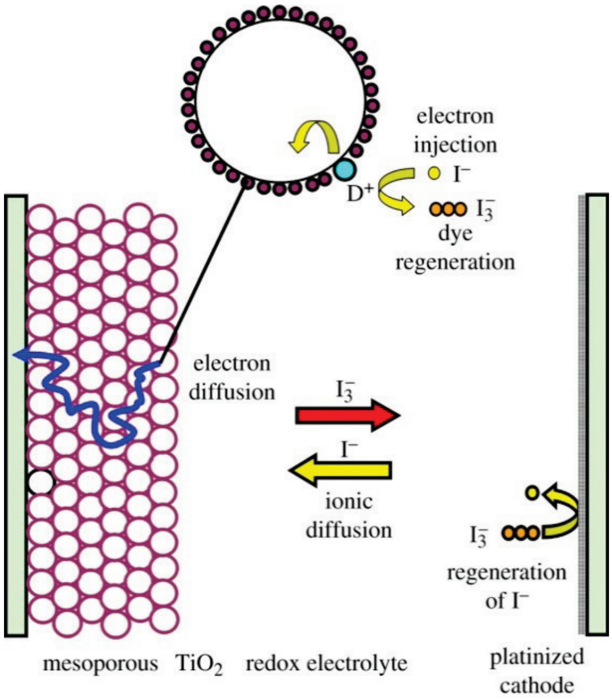


Figure 9.15: Working principal of dye-sensitized solar cells (Peter 2011).

9.2.1.3.3 Organic PV

Another third-generation technology is organic solar cells, which is made of organic or polymer materials. The absorber is used in conjunction with an electron acceptor, such as a fullerene, which has molecular orbital energy states that facilitate electron transfer. Upon absorbing a photon, the resulting exciton migrates to the interface between the absorber material and the electron acceptor material. At the interface, the energetic mismatch of the molecular orbitals provides sufficient driving force to split the exciton and create free charge carriers (Liu and Bashir 2015). High-speed and low temperature roll-to-roll printing technology can be applied in the production of organic PV cell, which makes it cheaper than conventional crystalline silicon PV technologies. The organic solar cells are also light and flexible, thus they are suitable for portable and building-integrated applications. Another advantage is that organic solar cells use abundant, non-toxic materials and is based on a very scalable production process with high productivity. But the commercialization of it has been hindered by inefficiency. Organic PV module efficiencies are now in the range of 4-5% for commercial systems and up to 10% in the laboratory (Mulligan et al. 2014).

9.2.1.3.4 Perovskite PV

The word “perovskite” refers to a group of compounds characterized by the general formula ABX_3. It is a material class with organic–inorganic metal halide perovskite semiconductors, with A containing organic cation, B as metal cation, and X as halide anion. The most attractive feature of perovskite PV is its low cost, due to both cheap materials and ease of manufacturing. With the potential of achieving even higher efficiencies and the very low production costs, perovskite solar cells have become commercially attractive, with some start-up companies already raised investment for commercialization (Gifford 2015). The most common material for perovskite PV is $CH_3NH_3PbI_3$, and the highest record efficiency was achieved by a research team from EPFL at 21% (Overton 2015).

9.2.2 PV systems and installations

PV systems and installations vary between applications, and depending on whether there is a connection to a utility grid, the installed PV systems can be divided into grid-connected and stand-alone system. A grid-connected system often includes: 1) PV modules, 2) inverters, 3) meters, 4) connection to utility grid, as shown on the right side of Figure 9.16. An inverter is required in the PV system, as it converts the direct-current electricity generation from PV modules to alternative-current, which is needed to meet the electrical demand of, for example, home appliances. A meter is often installed before the PV system is connected to the grid, so the electricity fed into the utility grid can be always accurately recorded. Some other components of the PV system are optional, but can further improve the performance of system, for instance, systems with a sun tracker are much more efficient than fixed systems because they track and face the modules to the sun all the time so they can capture the increased amount of incoming solar radiations. A battery can be also considered as an optional component of the system in order to increase self-consumption.

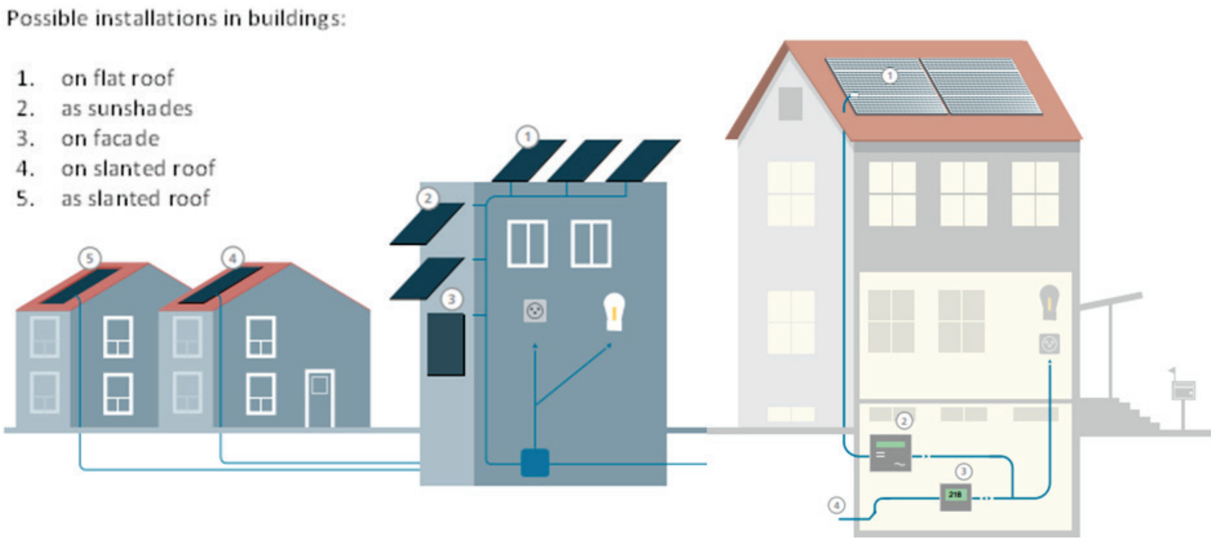


Figure 9.16: left: Applications of building attached photovoltaics (BIPV) system; right: Grid-connected PV system installation (Swissolar 2014)

When PV systems are installed on buildings, depending on whether the PV system has been integrated as part of the building, it can be categorized into Building Attached PV system (BAPV) and Building Integrated PV system (BIPV). BAPV systems can be installations on flat or slanted roof tops, while BIPV systems can replace windows and roofs of buildings (illustration on the left of Figure 9.16). BAPV system requires a mounting structure to support the installation of PV modules, and the costs of mounting structure are different when PV is installed on rooftop and on ground.

9.2.3 System efficiency

System efficiency of PV reflects the ability to convert sunlight into usable energy for consumption. It is estimated by the ratio of electricity generated from PV system and the solar energy hit onto the PV modules.

9.2.3.1 Losses and efficiencies of system, module and cell

PV cells are the basic elements of the PV module, and are usually in a round or square shape with about 5 to 15 centimeters in dimension. To increase utility, a number of individual PV cells are interconnected together in a sealed, weatherproof package called modules. For instance, a 12V module has 36 cells connected in series and a 24V module has 72 PV cells connected in series. A PV system (or array) is consisting of several PV modules, connected to electricity network and/or to a series of loads. It comprises various electric devices, such as inverters and charge controller, which adapt the electricity output of modules to the requirement of the network or load (Figure 9.17).

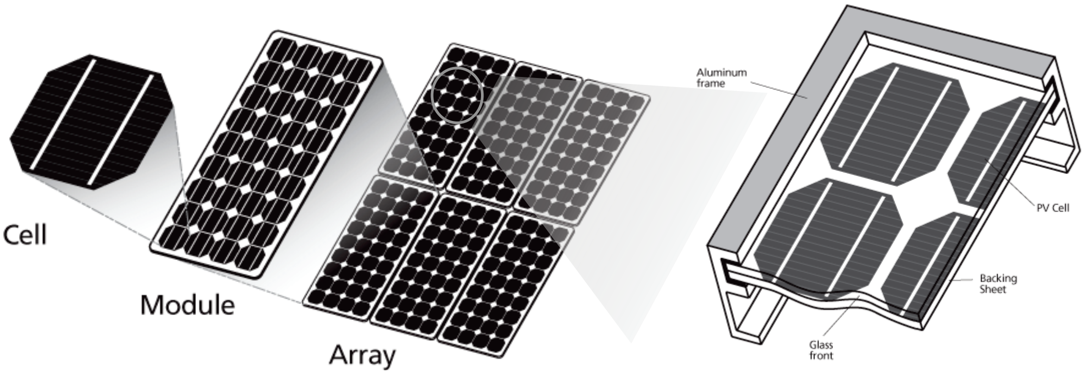


Figure 9.17: PV cell, module and array (Samlexsolar 2015).

Differentiation should be made between system efficiency and module efficiency: system efficiency considers all different types of losses, including pre-photovoltaic losses from shading, dirt, snow and reflection, system losses from electrical components including wiring, inverters and transformers, and module losses reflecting the efficiency and temperature dependence of PV modules, whereas module efficiency only considers module losses. Different losses and their contributions to reducing system efficiency are illustrated in Figure 9.18.

System efficiency can be estimated by multiplying the module efficiency and performance ratio. Performance ratio shows the proportion of energy that is actually available after deduction of losses such as thermal and conduction losses. It describes the relationship between the actual and theoretical energy outputs of the PV, and is largely independent of the orientation, location, and inclination of the panel. It includes pre-photovoltaic losses and system losses other than the losses from PV modules. The performance ratio differs from system to system, and modern high-performance PV systems have performance ration around 80% . Module efficiency is the nominal efficiency given by the manufacturer, and measured under the standard condition of 25^{o}C and 1000 W/m^{2} of total irradiance. Cell efficiency is determined as the fraction of power that is converted to electricity to the incident power. Module efficiency is always 12-25% lower than cell efficiency based on the best module and cell efficiencies according to Fraunhofer (2016).

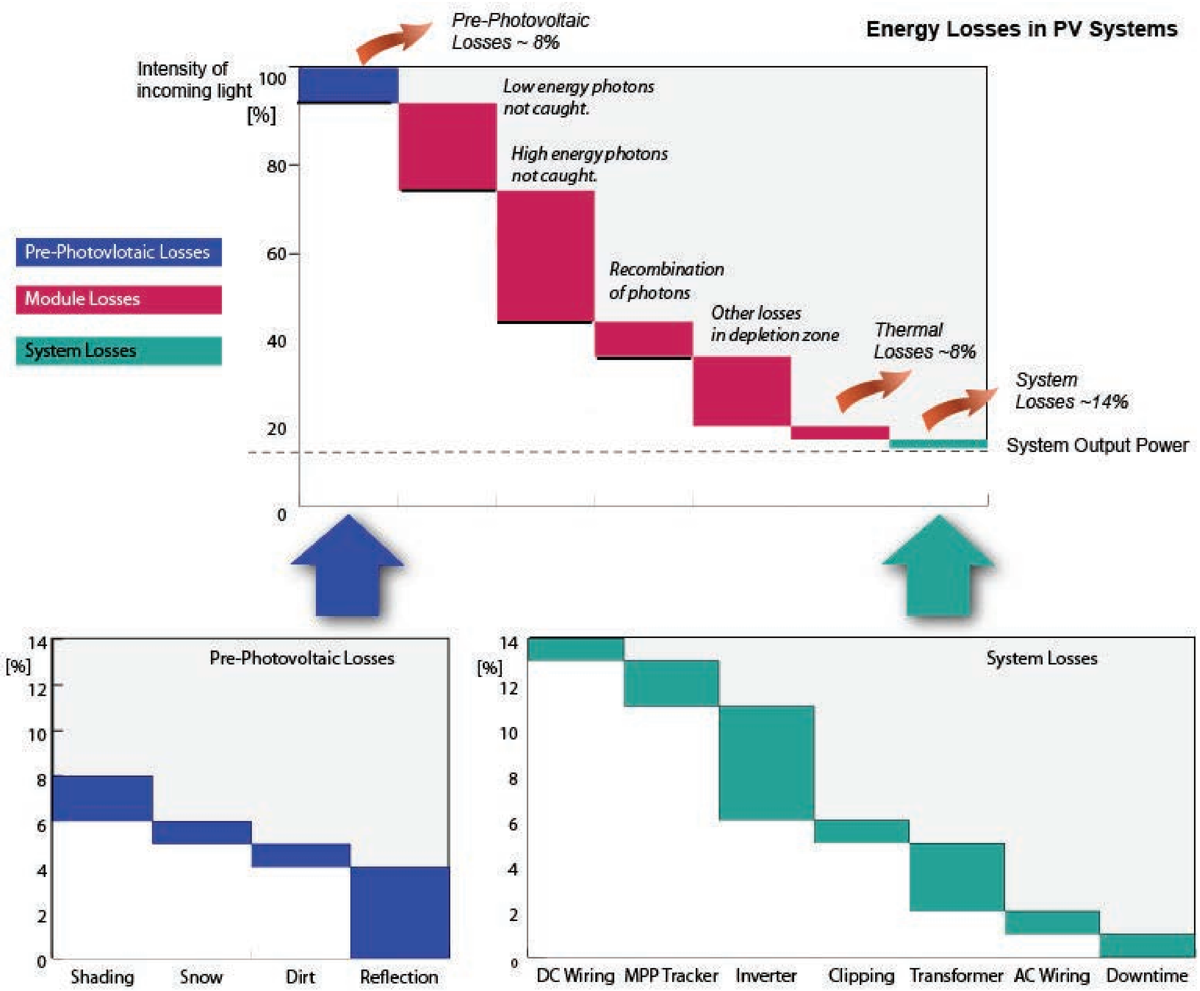


Figure 9.18: Energy losses in PV system: factors reducing the system efficiency (GreenRhinoEnergy 2015).

9.2.3.2 Efficiency in lab and efficiency of commercialized modules

Efficiency also varies when it is demonstrated under different circumstances. Efficiency found at laboratory scale is often much higher than the highest efficiency that can be achieved at commercial level. Highest commercial module efficiency is usually higher than the representative efficiency reflecting all the systems installed.

The National Renewable Energy Laboratory (NREL) maintains a plot of compiled values of highest confirmed conversion efficiencies for research cells, from 1976 to the present, for a range of photovoltaic technologies and several families of semiconductors, including multi-junction cells, single-junction gallium arsenide cells (GaAs), crystalline silicon cells, thin-film technologies, and emerging photovoltaics, as shown in Figure 9.19 (NREL 2016). It shows that the multi-junction cell technologies have demonstrated the highest efficiencies in lab, of up to 46%. This is followed by some other third-generation PV technologies (e.g. concentrated PV, advanced thin-film PV), conventional crystalline silicon based PV technologies, and conventional thin-film PV technologies, while emerging PV technologies such as dye-sensitized PV and organic PV remain on the lower end of the efficiency range.

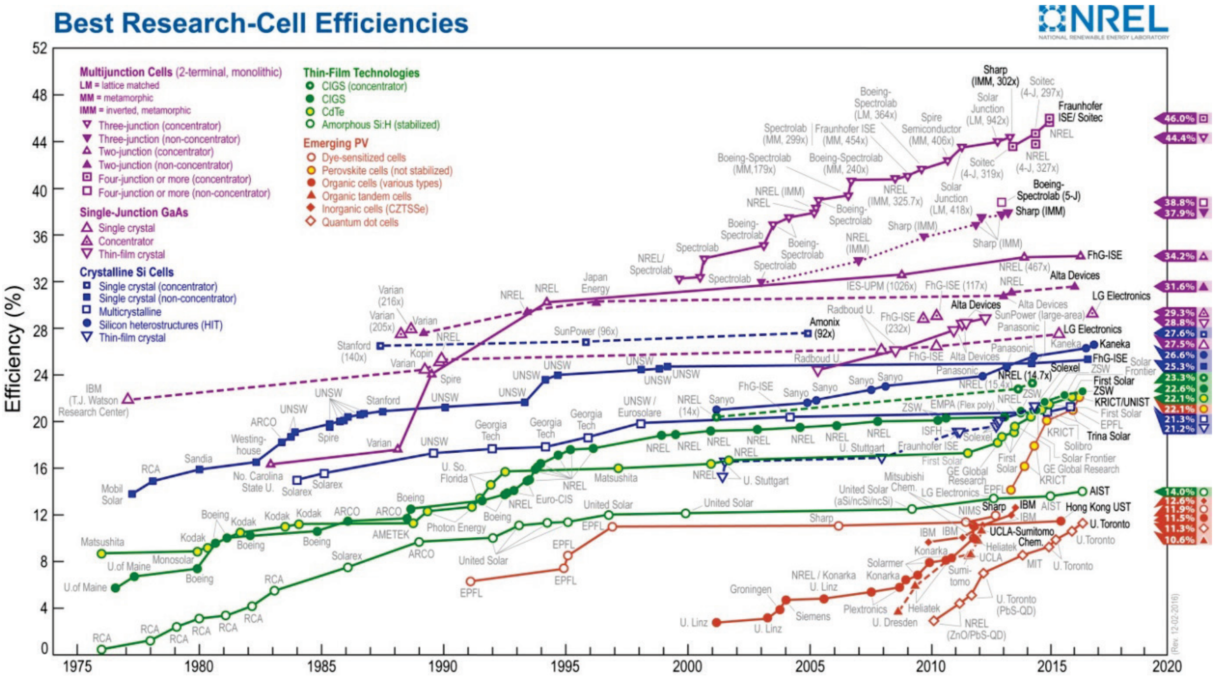


Figure 9.19: Best research cell efficiencies (NREL 2016).

9.2.3.3 *Impact of temperature on cell efficiency*

A typical PV module converts 5-20% of the incident solar radiation into electricity, depending upon the type of solar cells and climatic conditions. The rest of the incident solar irradiance is converted into heat, which significantly increases the temperature of the PV module and reduces the efficiency of the PV cell (Dubey, Sarvaiya et al. 2013). Increase in temperature reduces the band gap, and thereby affects most of the other material parameters. The most significant effect is that the intrinsic carrier concentration is increased by the lower band gap, and the open-circuit voltage will be decreased by higher carrier concentration, which further reduces the power output and efficiency (Figure 9.20). PV modules with less sensitivity to temperature are preferable for the high temperature regions.

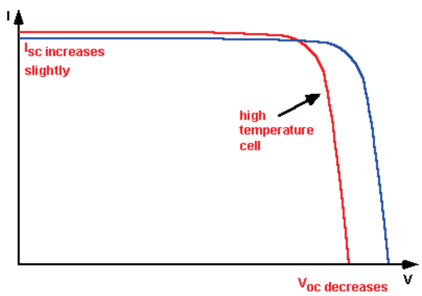


Figure 9.20: Impact of increased temperature on I-V curve (PVEducation 2015a).

9.2.4 Future technology development

The future developments of PV technologies mainly focus on two aspects: manufacturing cost reduction and efficiency improvement.

The manufacturing cost reduction has been observed in the past decade due to the significant expansion in PV production and systems installed worldwide. Many studies have predicted continuous drop in PV module price in the future, but this at the same time requires more innovation and research in PV technologies as well as manufacturing process than before. There are many factors that could reduce the cost of modules. Tour, Glachant et al. (2013) predicted a 67% decrease of module price from 2011 to 2020 based on the learning curve model, and showed that the cost of electricity from PV will be comparable with conventional electricity by 2020 in the countries with good resource of solar irradiance, with 75% of this evolution being attributed to increased cumulative capacity (which results in technology improvement and mass manufacturing), and 25% to the decline of silicon price. With current power purchase agreement in sunny countries reaching 4.5-6 Rp./kWh, the prediction of Glachant have already been reached in 2016. There are also researchers such as Mayer (2015) which are in the viewpoint that the technological breakthrough in other PV technologies is promising, but the impact of such technology development to the overall PV market and cost is usually not quantified, and future research is required to further assess possible implications.

The development of efficiency improvement of PV cell is highly dependent on material, since different materials have different band gaps and usable voltage, which determines cell efficiency. The cell efficiency has been constantly increased on both lab-scale and commercial-scale in the past few years. On the other hand, there has been also research investigating the maximum possible efficiency of PV technologies. Shockley-Queisser limit is the most common parameter to show the maximum theoretical efficiency of a solar cell using single p-n junction, which was first calculated by William Shockley and Hans Queisser at Shockley Semiconductor in 1961 (Shockley and Queisser 1961). It is reported that single-junction crystalline silicon based PV cell has a maximum theoretical cell efficiency of around 30% (Richter, Hermle et al. 2013). The commercial-scale efficiency development is in general lower than efficiency achieved at lab scale, and is discussed into more details in section 9.4.2.1.

9.2.5 Disposal and recycling

While the PV technologies and worldwide installations have experienced a fast development in the last decade, more and more countries will be at the same time facing the challenge of proper disposing and recycling of end-of-life PV modules. PV modules have many components and materials that can be recycled, including glass, semiconductor materials, ferrous and non-ferrous metals, among which glass is the most common material to be recycled due to its high percentage in the module material composition of about 74-95% by weight in conventional crystalline silicon and thin-film PV cells (Table 9.3).

Table 9.3: Composition of materials in crystalline silicon and thin-film modules in terms of weight (BINE 2010).

	c-Si	a-Si	CIS	CdTe
Glass	74%	90%	85%	95%
Aluminum	10%	10%	12%	<0.01%
Silicon	~3	<0.1		
Polymers	~6.5	10	6	3.5
Zinc	0.12%	<0.1%	0.12%	0.01%
Lead	<0.1%	<0.1%	<0.1%	<0.01%
Copper (cables)	0.6%		0.85%	1%
Indium			0.02%	
Selenium			0.03%	
Tellurium				0.07%
Cadmium				0.07%
Silver	<0.06%			<0.01%

The value of glass per unit weight is nevertheless much lower than that of metals and semiconducting materials (e.g. silicon). Figure 9.21 shows a breakdown of material value for conventional crystalline silicon and thin-film PV cells.

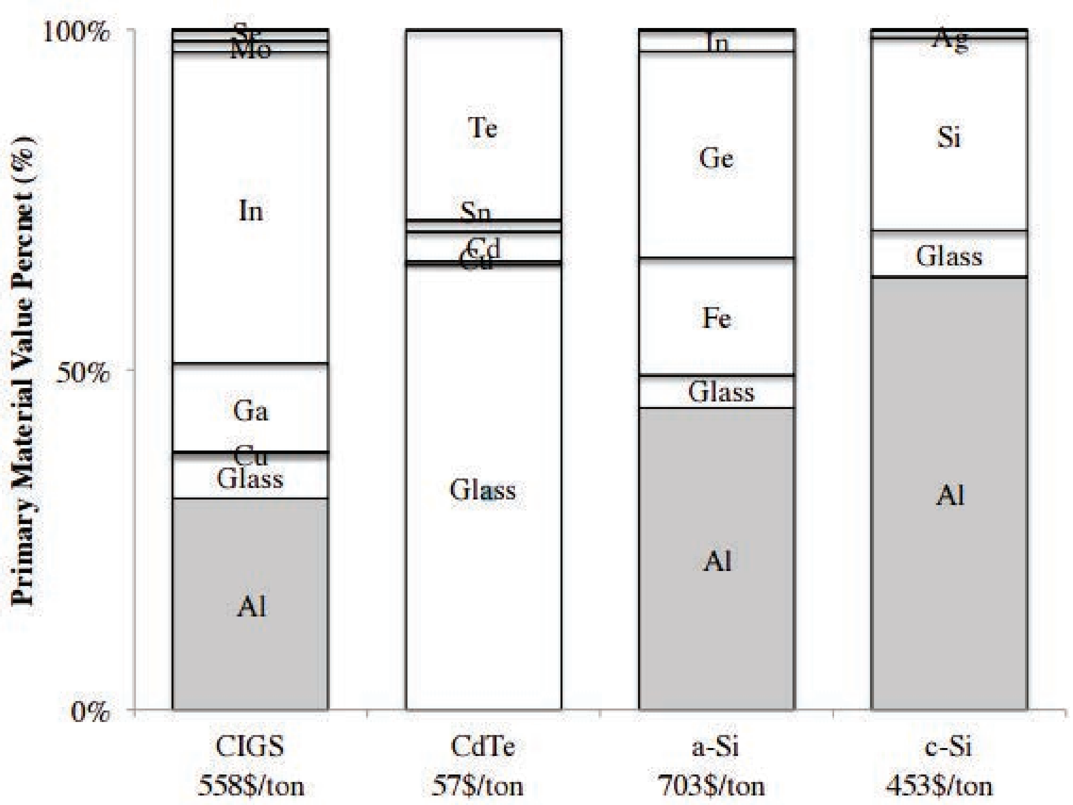


Figure 9.21: Material value breakdown in crystalline silicon and thin-film modules (Goe 2014)

Since most of the installed PV modules are still in use, recyclers specialized in PV module recycling are rare, interest from large scale specialized recyclers won't be expected in processing PV modules due to limited volume available in the near future, and end-of-life PV modules are not expected to hit the market in a significant amount before 2030 to 2035. But the reuse of some materials used in PV module manufacturing, for example, silicon, is technically possible (Pathan, Ministerråd et al. 2013). It would be advisable to include some minimum requirements for the treatment processes into national legislations, including the separation and removal of some key components, such as frames, glass, polymers, plastics, metals, and cables. The PV industry is already working on such requirements with the European Committee for Electro-technical Standardization (CENELEC), an organization mandated by the European Commission to develop a European standard for the treatment of Waste Electrical and Electronic Equipment (WEEE), including PV modules. It is recommended to collect PV modules separately from other products to take into account their specificities and independent recycling targets for PV modules shall be set.

At the moment, most of the PV modules in Europe are recycled under the scheme of the WEEE directive. The modules present on today's market belong to two different categories, silicon and non-silicon based, which determine the recycling process to be used.

(1) Silicon-based modules: aluminum frames and junction boxes are dismantled manually at the beginning of the process. The module is subsequently crushed and its several components are separated, allowing recovering up to 80% of the modules. Since a large quantity of these modules is composed of glass, it is common for glass recyclers to be involved in the recycling process.
(2) Non-silicon based modules: due to various types of non-silicon based modules, diverse recycling technologies are required. Cadmium telluride (CdTe) modules, for instance, are first crushed into different fractions, and then passed through chemical baths to separate the various semiconductor materials, allowing for the recovery of 95% of components. Recycling technologies for this type of panels have been widely increasing in recent years. Similar chemical bath treatment applies also to copper indium selenide (CIS), copper indium gallium (di)selenide (CIGS), and other type of thin-film PV modules.

In Europe, the organization PV Cycle[195], founded by PV manufacturers on the volunteering basis in 2007, takes back and recycles PV modules at the end of their lifetime in EU and EFTA countries. The members of it today represent more than 90% of the European PV market. In Switzerland, Swissolar and SENS eRecycling have signed a cooperation agreement that from after 2014, relevant aspects in regard to the collection and disposal of photovoltaic modules in Switzerland are regulated (Swissolar 2013). This agreement entitles SENS eRecylcing to collect and recycle PV modules and accessories for Swissolar members. The revision to the regulation on the Return and Disposal of Electrical and Electronic Equipment (Rücknahme und die Entsorgung elektrischer und elektronischer Geräte, VREG) is currently revised by the Federal Office for Environment (FOEN), and it is expected that corresponding regulations would be put in force on PV module recycling.

[195] More information can be found at: www.pvcycle.org

9.3 Potential for electricity generation

The future potential for electricity production by solar PV in Switzerland can be discussed with regard to several aspects. In order to provide a reasonable and realistic potential, considerations have to be taken into account concerning solar irradiance available, surface available for PV installation, as well as capacity that can be installed, and electricity that can be generated given the future technology development (e.g., efficiency improvement).

A study in 2012 by BFE (BFE/SFOE 2012a) has defined three types of potential for renewable energy production considering these aspects: theoretical potential, technical potential and expected potential. Theoretical potential refers to the entire energy source that is available under the study area without considering any actual limitations. For Switzerland, this equals to the product of total area of Switzerland and its available solar irradiance. Solar irradiance is measured by the Global Horizontal Irradiance (GHI), which equals to the terrestrial irradiance falling on a surface horizontal to the earth, expressed in W/m^2. The theoretical potential usually serves as an upper cap of energy that is available for renewable electricity production, and cannot be met due to conversion losses in the actual production. Technical potential is less than the theoretical potential: it is the potential estimate considering technical restrictions and technology development. Other considerations can be introduced on top of technical potential to estimate more “realistic” potentials, such as limitations from ecological, economic and social perspectives.

The electricity generation potentials from PV in Switzerland are reviewed and discussed in the following sections, with focus on theoretical and technical potential. In addition, technical potentials considering some economic and social aspects are included, and a comparison with the historical trend is performed to check how these potentials could be possibly achieved. In the end, the Swiss policy related to photovoltaics, in particular the incentive schemes are introduced and its future perspective is briefly discussed. However, since the influence of future policy on expected electricity production is highly uncertain and hard to quantify, it is not taken into account in the expected potential estimate. In terms of geography, the following discussion is mainly focused on Switzerland, but some related parameters are discussed with extension to the European and global scope, for the purpose of comparison (e.g., solar irradiance).

9.3.1 Theoretical potential (based on available solar irradiance)

In Switzerland, the total energy from sunlight corresponds to 220 times the national energy consumption (Swissolar 2014). Given the total energy consumption of about 233 TWh in 2015 (BFE/SFOE 2016f), this is about 51’000 TWh/year. According to a study from Meteotest in 2012, the theoretical potential considering 85% of maximum power conversion of PV in Switzerland is about 41’000 TWh/year. According to the definition of theoretical potential in this study, this is equivalent to about 49’000 TWh/year (Cattin, Schaffner et al. 2012). The geographical distribution of solar irradiance in Switzerland from 1981 to 2000 shows higher potential on the southern part of the nation (Figure 9.22). However, most of the available roof surface areas are in the north, which provides potential space for solar PV installation.

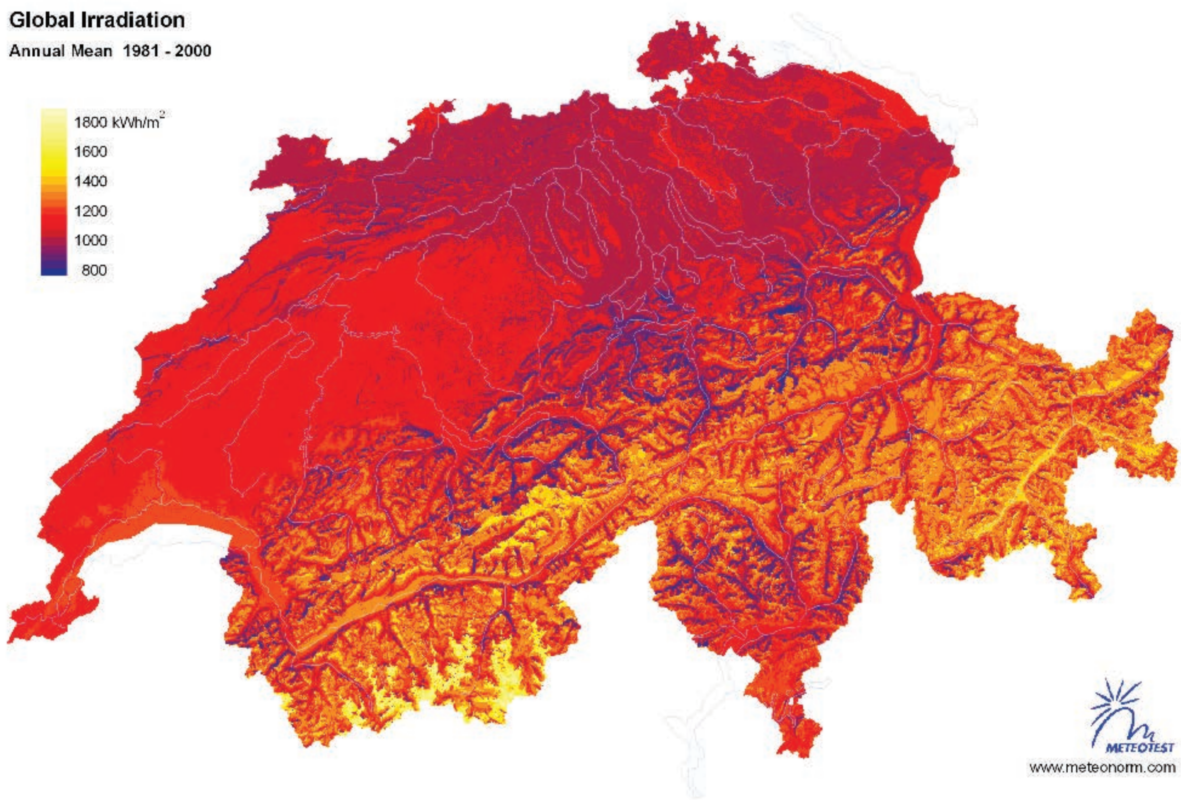


Figure 9.22: Average annual global horizontal irradiance in Switzerland (MeteoTest 2016).

The solar irradiance at the Swiss Plateau (Schweizer Mittelland) is about 1100 kWh/m^2 per year, while at higher altitude in the Alps it can reach up to 1400-1600 kWh/m^2 per year (Swissolar 2014). According to the satellite data, the Cantons of Valais and Grisons had the highest global solar irradiance in 2012 (MeteoSchweiz 2012).

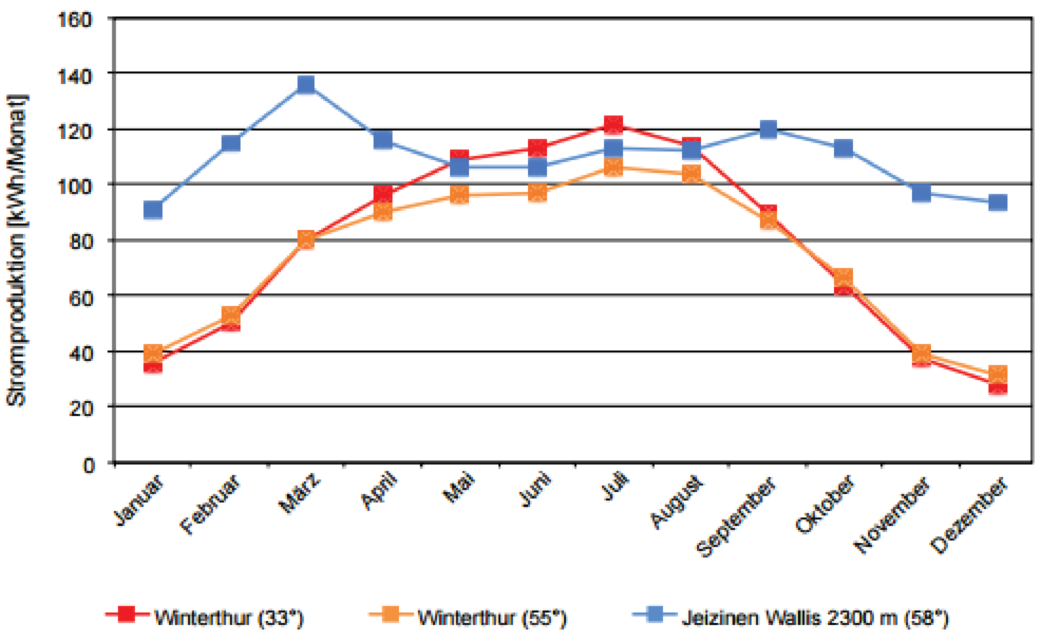
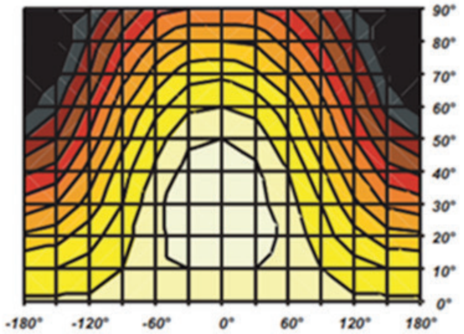


Figure 9.23: Comparison of electricity production from PV systems installed in the Swiss Plateau and the Alps: PV system of 1 kWp power, with 33° and 55° inclined installation in Winterthur (Swiss Plateau), and 58° inclined installation in the Alps at an altitude of 2300 m; Solar irradiance in the Alps is on average about 1320 kWh/m^2 year (WWF 2016).

The installed PV modules are usually inclined, and different locations have different suitable tilt and azimuth ranges for the inclination in order to generate the maximum annual yield. One such example is given in Figure 9.24. In Switzerland, the average best inclination for installation is at approximately 35° facing the south (Hirschberg, Bauer et al. 2005).



Place	Flat roof	Sloped roof	Façade
Zurich Latitude: 47.4° N Longitude: 8.6° W Altitude: 556 m Best solar yield: 1 167 kWh/m^2	Solar yield: 91%	Best tilt: 30° Good yield area on south axis: 0° to 75° Good yield area for 30° tilt: -110° to +110°	Best azimuth: 0° Best yield: 65% Good yield area: -100° to +100°

Figure 9.24: Annual solar yield for roof and façade PV installations in Zurich (IEA 2002).

For comparison, the following table also lists the yield and capacity factor[196] in Swiss Mittelland, Swiss Alps, southern Europe and the desert of Sahara.

Table 9.4: Annual yield and capacity factor for various locations in the world (average multi-C PV performance).

Location	Yield (kWh/kWp per year)	Capacity Factor
Swiss Mittelland	920-970 (Jungbluth, Stucki et al. 2012b, Nowak and Biel 2012)	11%-12%
Swiss Alps	1200-1400[197]	14%-16%
Southern Europe	1400-1700 (Kost, Mayer et al. 2010)	14%-19%
Sahara	2500 (IEA 2015a)	29%

Figure 9.25 shows the average global solar irradiance in Europe. In comparison with other European countries, the average solar irradiance in Switzerland is in the middle range: it is not as abundant as in southern European, African and mid-East countries, but it is better than countries like Germany, the UK, the Netherlands, and other European countries on the north.

[196] Capacity factor = annual yield (kWh/kW per year)/(nameplate capacity*8760 hours per year).
[197] estimated based on solar irradiance of 1400-1600 kWh/m^2 per year and rounded.

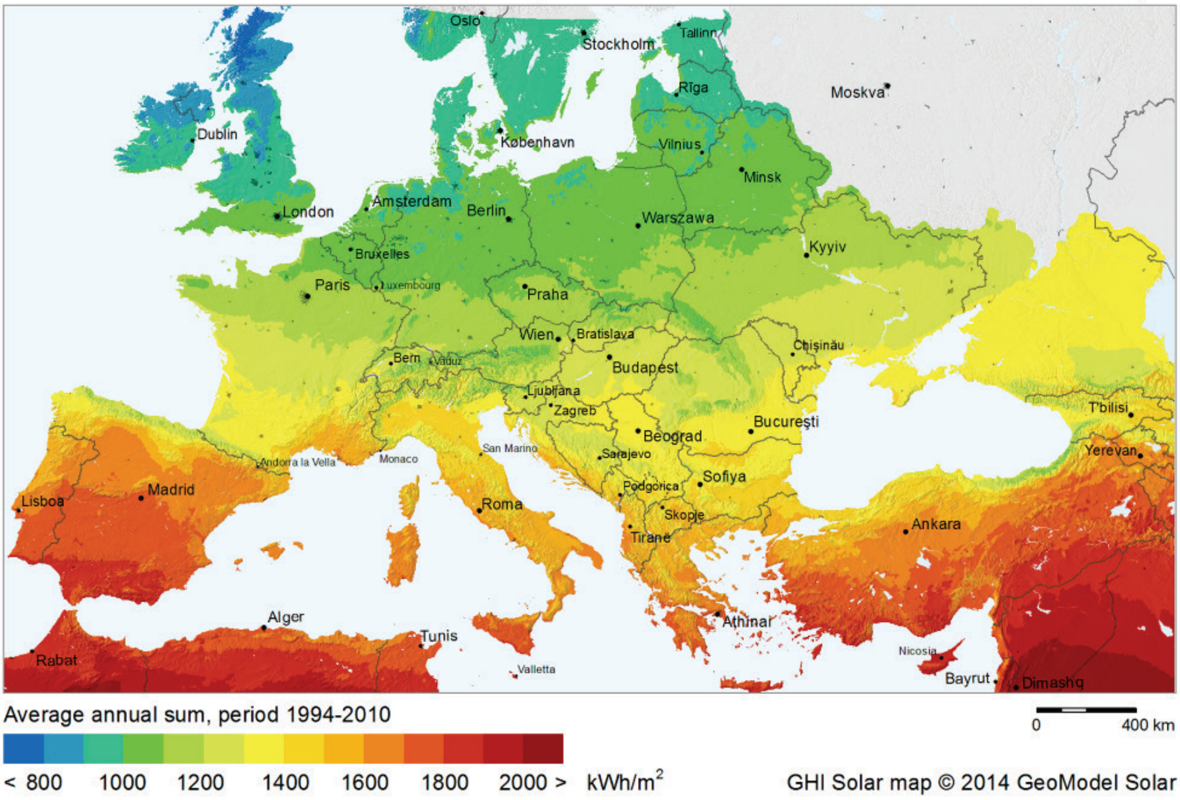


Figure 9.25: Average European Global Horizontal Irradiation, 1994-2010 (SolarGIS 2014).

9.3.2 Technical potential

The PV systems installed in Switzerland are almost all rooftop applications and there are only a few ground-mounted PV applications, which are comparatively small in size. Large-scale ground mounted systems are almost non-existent in Switzerland (IEA 2015). It is not expected that the dominant preference for roof-top installations will change in the future in Switzerland, mainly due to the visual impacts of PV installation on the landscape, for instance in the Alps. Therefore, estimating the rooftop (and facade) surface available for PV installations is essential, and ground-mounted PV installations are not investigated in this study.

In 2012, MeteoTest conducted a study on the potential of wind and solar energy in Switzerland (Cattin, Schaffner et al. 2012). Although the study estimated potential for electricity production from PV per year, in order to use consistent assumptions in the present analysis, only roof area estimated from the Meteotest study is referred to; assumptions of annual yield and area required per kWp installed capacity are based on our own estimations and other sources. The Meteotest study shows that in total there are about 1.8 million buildings in Switzerland. If it is assumed that all the buildings under the current planning are fully built out (based on the data in swissBuilding 3D (swisstopo 2012)), the total area of buildings will be 545 km^2, in which about 405 km^2 are for buildings less than 1000 m^2 (small building), and 140 km^2 are for buildings that are more than 1000 m^2 (large building). Total roof area that can be used for solar PV installations is therefore estimated based on the total area of buildings above, of about 396 km^2, with the following assumptions:

1) Roof area by large and small buildings:
   for large buildings, 80% of the roof area is flat roof, and 20% is slanted roof;
   for small buildings, 40% of the roof area is flat roof, and 60% is slanted roof
2) Utility rate of roof area by roof type: 50% of the flat roof area can be used (because between every two rows of installations, a row of space needs to be left empty to reduce shading effect), while 100% of slanted roof can be used
3) Consideration of area reserved for solar thermal installations: 2 m^2 per person.

This gives the area used to estimate the **technical potential** of roof-top installations. Given the average area of 4-7.5 m^2 required for 1 kWp of crystalline silicon PV, in which 4 m^2/kWp corresponds to future efficiency development[198], and 7.5 m^2/kWp corresponds to the average area requirement for current single and multi c-Si PV technology (Table 9.2), this corresponds to 53-99 GW of installed capacity. If it is assumed that on average 970 kWh/year would be generated per kWp of PV installed (Nowak and Biel 2012)[199], this corresponds to an electricity production from PV installed on rooftops of **51-96 TWh/year**.

On top of this technical potential, several other considerations have been taken into account to estimate a more "realistic" technical potential. Table 9.5 lists out these considerations that further narrow down the surface area used for technical potential estimates to more realistic values, with their corresponding assumptions. Note that only one consideration is included to estimate the remaining surface area under each of the estimates below.

Table 9.5: Limiting considerations on top of available surface area used for technical potential estimates (Meteotest, 2012)

Considerations	Assumptions	Remaining Surface Area After Reduction (km^2)
Economic aspects (obstacle structure and not ideal slanted roof orientation)	Buildings larger than 1000 m^2 – 20% reduction due to obstacle structures on roof Buildings smaller than 1000 m^2 – 50% reduction due to obstacle structures on roof Slanted roof: 50% reduction by excluding slanted roof with little solar irradiance, and not ideal orientation	182
Protected heritage buildings	5% reduction to exclude protected roof area for heritage buildings	376
Social aspects (likelihood of buildings to be built according to the master planning) (highly-uncertain)	Buildings larger than 1000 m^2 – 60% will be built Buildings smaller than 1000 m^2 – 40% will be built	175

All these limitation factors are then considered in one scenario, and a **"sustainable technical potential"** (corresponding to a constrained technical potential) is estimated based on 79 km^2 roof area available in Switzerland (Cattin, Schaffner et al. 2012). Note that since the reductions for these three considerations may overlap with each other, the roof area for sustainable technical potential is not the total roof area (396 km^2) excluding the sum of

[198] The Sunpower X-Series monoscrystalline PV today has reached 4.9m^2/kW, with more than 21% efficiency; therefore, with future efficiency increase up to more than 26%, the area required per kWp is assumed to decrease to around 4 m^2/kWp.

[199] The annual yield in kWh/kWp will not change with efficiency improvement, due to the fact that efficiency increase results in an area decrease per kWp to receive solar irradiance.

individual reductions. The assumptions of how these reductions are combined are not explained in details of the Meteotest study. This is so far the lowest estimate of roof surface available for PV installation found for Switzerland. However, there is no detailed timeframe of when and how this potential could be met in the future. Given the assumption of an area requirement of 4-7.5 m^2/kWp, this corresponds to about 11-20 GW of installed PV capacity. With the average annual yield of 970 kWh/kWp, the total **constrained technical potential** (or exploitable potential) for electricity generation of **rooftop PV installations** would be about **11-19 TWh per year**.

Another study by Nowak and Gutschner (2011) shows the estimate for available rooftop area for PV installations of 150 km^2 by 2020, with a contribution of 50% from crystalline silicon PV and the remaining from thin-film PV. This corresponds to a total installation of about 20.3 GW[200], and electricity production of about 18.2 TWh/a[201].

The latest estimate of the PV potential in Switzerland has been released in January 2017 (Remund 2017). Electricity generation for two different scenarios is quanitified: the first one with solar thermal collectors and PV installations on buildings, the second one with the available building surface used for PV modules only. In the first scenario, (Remund 2017) estimates a sustainable PV generation potential of 17 TWh/a on rooftops and about 3 TWh/a on facades; in the second scenario, sustainable PV generation potential is 24.6 TWh/a on rooftops and 5.6 TWh/a on facades.

Considering all the uncertainties involved, these latest estimates are well in line with the maximum potential of 19 TWh/a from rooftop PV installations as estimated here in this study.

International estimates for Switzerland are rather outdated: IEA (2002) had estimated a potential of BIPV in Switzerland with 190 km^2 of area for installation, in which 52 km^2 is on facade and 138 km^2 is on rooftop. With the area required per kWp from 4-7.5 m^2 (for crystalline silicon-based PV), and the annual yields of 970 kWh/kWp (Nowak and Biel 2012) for roof-top integrated installation and 620 kWh/kWp (Jungbluth, Stucki et al. 2012a) for facade integrated installation, the annual electricity production would be 18-34 TWh/year for BIPV on roof, and 4-8 TWh/year for BIPV on facades. If only the buildings with good solar yield are equipped with PV systems, IEA estimated that BIPV systems installed both on roofs and facades in Switzerland are able to produce 18.4 TWh of electricity per year (IEA 2002).

Given these numbers for sustainable technical PV electricity generation potentials, which are supposed to represent the maximum PV generation on buildings in Switzerland, the actual development of generation over time in the future remains very uncertain and will depend on factors such as feed-in tariffs, market and price development, incentives, etc. Nevertheless, different scenarios are developed here: Figure 9.26 shows the cumulative installed capacity in Switzerland, with the historical trend from 1990 to 2015 and “PSI scenarios 2016” (i.e. estimates for this report). Potential annual electricity generations are estimated in TWh per year, using an average annual yield of 970 kWh/kWp. This yield remains constant regardless of future efficiency improvement, because the PV area per kWp decreases proportionally as efficiency increases which results in constant electricity generation per kWp per year. However, this also indicates that with the same available area

[200] Reduced area required per kWp as a result of future efficiency improvement might not have been considered.
[201] An average annual yield of about 900 kWh/kWp per year was used in this reference.

for PV installation, the electricity generation potential will increase in the future as more capacity could be installed. The annual yield assumed here is higher than the current average annual yield calculated based on electricity generation from PV and capacity installed in Switzerland in 2015 (804 kWh/kWp, Figure 9.26), because it is expected that modern PV systems with higher performance ratio will gradually replace the old systems.

The cumulative installed capacity is estimated using the S-curve method, also known as the sigmoid function. It is widely applied to approximate the technology life-cycle, which usually follows four phases: research and development, ascent, maturity, and eventually decline, which leads to the maximum cumulative installed capacity. To define an S-curve, three parameters are required: the year when peak annual installation occurs, the maximum cumulative installed capacity, and the growth rate. The formula for an S-curve is:

$$C_T = \frac{C_{max}}{1 + e^{\left(r*\left(T_p - T\right)\right)}}$$

in which,

C_T is the cumulative installed capacity in year T;

C_{max} is the maximum cumulative installed capacity (upper limit of S-curve);

r is the growth rate;

T_p is the year when the annual installed capacity peaks;

T is the year.

Comparing historical data with the scenarios from (Hirschberg, Bauer et al. 2005), it is clear that the installations from 2005 to 2015 were above the expectations. But the faster-than-expected development in the past decade might also indicate an earlier-than-expected peak of annual installed capacity that might occur in the next 8 to 10 years (2025 to 2028), if the growth of PV installation in Switzerland will more or less follow an S-curve.

Three scenarios are provided in this study, based on the range of PV electricity generation potential on rooftop, namely an “optimistic”, a “moderate” and a “pessimistic” scenario. The potential estimates for BIPV on facades is not considered in these scenarios, as a systematic basis for dealing with the constraints for facade BIPV and to derive an equivalent “sustainable technical potential” that is consistent with rooftop installations is missing. The optimistic projection is based on the maximum sustainable technical potential of 20 GWp installed capacity or 19 TWh/year of electricity generation estimated in section 9.3.2. The moderate projection is given using the minimum sustainable technical potential of 11 GWp or 11 TWh/year. The pessimistic projection is based on the assumption that Switzerland has reached the peak of annual installation in 2015, and the percentage of decline from 2013 to 2014 (about 4% annually, estimated based on Figure 7.6) will continue.

The specific cumulative installed capacity and annual electricity generation in 2020, 2035 and 2050 in the “PSI 2016” scenarios for Switzerland are listed in Table 9.6. It shows that the projections by Swiss energy perspectives in year 2020 have been already met by the end of 2015; in other words, the Swiss energy perspectives have underestimated the speed of PV expansion. Comparing the “PSI 2016” scenarios with Swiss energy perspectives, most of the projections of solar electricity production between 2020 and 2050 from “PSI 2016” scenarios are higher than the ones given by Swiss energy perspectives, except the highest projection in 2020 is slightly lower than the highest projection from Swiss energy perspectives.

Note that the historical and future PV installation in Switzerland is strongly related to the incentive schemes (feed-in tariff and one-time compensation scheme). With decreasing feed-in tariffs and the gradual phase-out of incentives, future trends might exhibit different patterns compared to historical records, and thus the key question falls on how to maintain the growth of PV in Switzerland without the incentives at some point. In any case, any assumptions for future growth rates of PV installations are to some extent arbitrary, since growth rates will (especially in the short-term future) crucially depend on political incentive schemes, measures for PV integration into the electricity grid as well as development of costs not only for PV modules and their installation, but also for electricity storage, as well as regulations for self-consumption of PV generation.

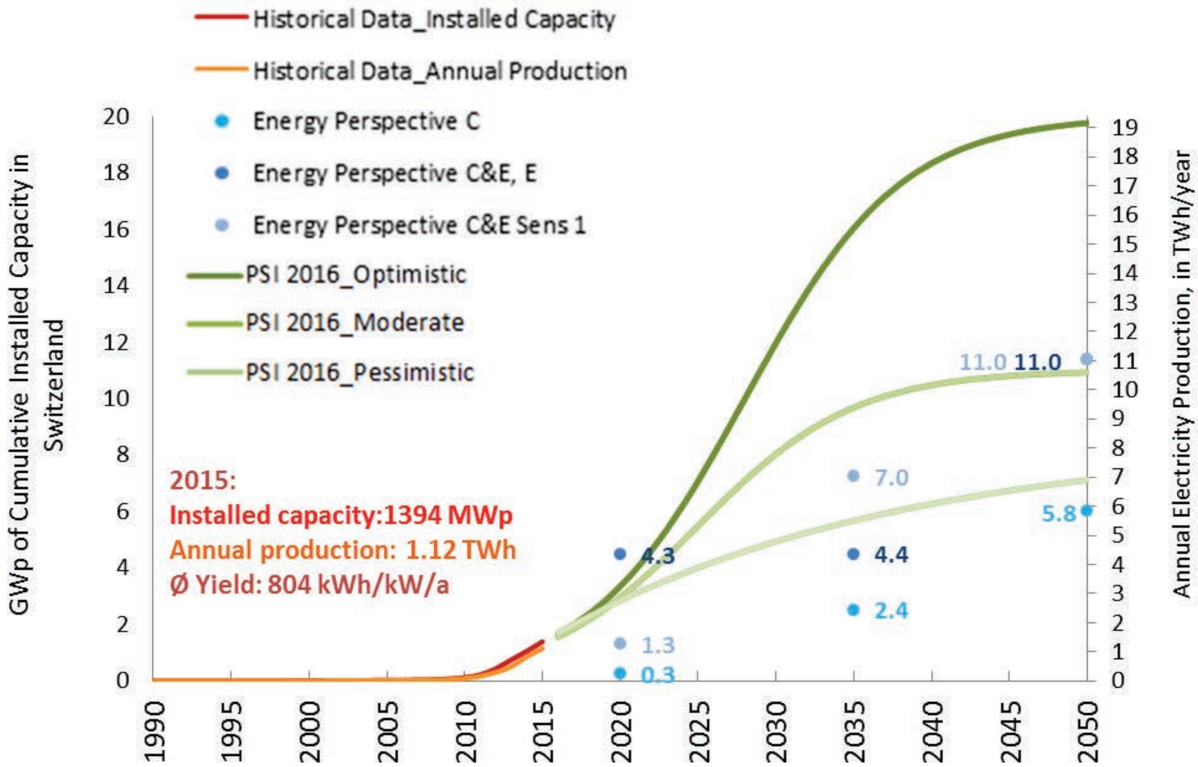


Figure 9.26: Cumulative installed capacity in GWp (y axis on the left) and projected electricity production from solar PV in TWh/year (y axis on the right) in Switzerland: historical trend, PSI scenarios in 2016, and projections from Swiss energy perspectives in 2020, 2035 and 2050 for variant C, C&E, C&E Sens 1, E (annual production only) (BFE/SFOE 2013b). Projections of electricity production from PSI 2016 are estimated based on an average annual yield of 970 kWh/kWp.

Table 9.6: Projections of cumulative installed capacity (in GW) and annual projected electricity generation (TWh/year) on rooftop PV based on an annual yield of 970 kWh/kWp (Nowak and Biel 2012), from 2020 to 2050 by PSI 2016.

Year	PSI 2016_Pessimistic		PSI 2016_Moderate		PSI_2016_Optimistic	
Unit	GWp	TWh/year	GWp	TWh/year	GWp	TWh/year
2020	2.9	2.8	3.0	2.9	3.4	3.3
2035	5.7	5.5	9.7	9.4	16	15.6
2050	7.1	6.9	11	10.6	20	19.2

9.3.3 Policy-related drivers

9.3.3.1 Feed-in tariff and one-time compensation

As many other countries, Switzerland supports renewable electricity generation by providing an incentive scheme. For photovoltaics, there are two schemes at the federal level depending on the size of the systems installed: one-time compensation (also known as Einmalvergütung, or EIV) and Feed-in-Tariff (FIT, also known as Einspeisevergütung, or KEV). The FIT has different sets of tariffs for stand-alone systems (e.g., ground mounted systems), building attached systems (BAPV) and building integrated systems (BIPV), without any limit of size. According to the Swiss regulation of 730.01 EnV (Energieverordnung)[202], systems commissioned before the end of 2013 can receive FIT up to 25 years, while systems commissioned after the end of 2013 can receive FIT up to 20 years. The one-time compensation provides incentive funding of about 30% of the investment costs of a reference system. For systems larger than 30 kWp, Feed-in-Tariff applies. For systems ranging from 2-10 kWp, only one-time compensation is available. For systems from 10-30 kWp, a choice can be made between one-time compensation and Feed-in-Tariff.

A long waiting time is however expected for FiT, as Swissgrid on average receives 1000 applications for FiT per month, most of which are for PV systems. By the end of May 2016, about 37’600 projects are on the waiting list, of which only 1200 projects are not PV systems. There is quota for successful applications for FiT. For example, in July of 2016, the first 27 out of 91 ready-to-construct projects are taken into the incentive scheme, which corresponds to 27 MW installed capacity that potentially could generate 157 GWh of electricity. The quota for 2017 has not yet been specified, and it all depends on the development of market prices (BFE/SFOE 2016c).

According to Swissgrid, systems applied for the FiT scheme from 2010 to 2011 were taken into the scheme in 2014, and with the increasing applications in recent years, the waiting time has increased. The tariff also keeps decreasing, in line with the decreasing system cost. From 2014 to 2015, the tariff has declined by 8-23%, depending on the size of the system (Figure 9.27), and it is expected to continue to decrease. In terms of general political support, according to Rekinger, Thies et al. (2015), the situation in Switzerland, together with other European countries like Austria, Denmark, Netherland, UK and Turkey, is relatively positive. It is expected that the long waiting time for FiT may reduce the interest for large (more than 30 kW_p installed capacity) new PV systems installation, but on the other hand, the decreasing module price and the fast-in-return one-time compensation would continue to encourage small PV system installations.

[202] See under “4 Jährliche Absenkung, Dauer der Vergütung“: https://www.admin.ch/opc/de/classified-compilation/19983391/index.html

KEV-Vergütungssätze gültig für neue Bescheide
inkl. MWST 8%

Anlagenkategorie Leistungsklasse	Vergütungssätze ab 1.1.2014 [Rp./kWh]	Vergütungssätze ab 1.4.2015 [Rp./kWh]	Vergütungssätze ab 1.10.2015 [Rp./kWh]	Vergütungssätze ab 1.04.2016 [Rp./kWh]	Vergütungssätze ab 1.10.2016 [Rp./kWh]	Referenzkosten Okt. 2016* Investitionskosten CHF/kW
Freistehend ≤10 kW		Eigene Kategorie "Freistehend" gibt seit 01.04.2015 nicht mehr. Vergütung erfolgt gemäss Kategorie "Angebaut".		Eigene Kategorie "Freistehend" gibt es seit 01.04.2015 nicht mehr. Vergütung erfolgt gemäss Kategorie "Angebaut".		Eigene Kategorie "Freistehend" gibt es ab 01.04.2015 nicht mehr. Vergütung erfolgt gemäss Kategorie "Angebaut".
≤ 30 kW	23.8					
≤ 100 kW	19.8					
≤ 1000 kW	19.2					
> 1000 kW	17.2					
Angebaut ≤10 kW	Einmalvergütung	Einmalvergütung**		Einmalvergütung**		
≤ 30 kW	26.4	23.4	20.4	19.5	19.0	1815
≤ 100 kW	22.0	18.5	17.7	16.6	15.6	1410
≤ 1000 kW	21.3	18.8	17.6	16.4	15.2	1350
> 1000 kW	19.1	18.5	17.6	16.5	15.3	1350
Integriert ≤10 kW	Einmalvergütung	Einmalvergütung**		Einmalvergütung**		
≤ 30 kW	30.4	27.4	24.0	22.4	21.9	
≤ 100 kW	25.3	21.1	20.1	19.1	17.9	
≤ 1000 kW	21.3					
> 1000 kW	19.1					

Quelle: Energieverordnung, Anhang 1.2 (EnV, 730.01)

Für Anlagen mit Nennleistung > 10 kW wird die Vergütung anteilsmässig über die Leistungsklassen berechnet.

Für integrierte Anlagen > 100 kW gelten die KEV-Tarife der angebauten Anlagen.

* Gültig für das 3. Quartal 2016, Investitionskosten können um +/- 20 % abweichen.

** Für Anlagen zwischen 2 und 10 kW gibt es seit 01.04.2014 eine Einmalvergütung (EIV) (max. 30 % der Investitionskosten von Referenzanlagen), zwischen 10 und 30 kW besteht eine Wahlmöglichkeit zwischen KEV und EIV.

Tarifrechner Swissgrid
Energieverordnung

	Angebaute und freistehende Anlagen		Integrierte Anlagen	
Inbetriebnahme	Grundbeitrag (CHF)	Leistungsbeitrag (CHF/kWp)	Grundbeitrag (CHF)	Leistungsbeitrag (CHF/kWp)
Ab 01.10.2015	1400	500	1800	610
01.04.2015 – 30.09.2015	1400	680	1800	830
Ab 2014	1400	850	1800	1050
Ab 2013	1500	1000	2000	1200
Ab 2012	1600	1200	2200	1400
Ab 2011	1900	1450	2650	1700
Bis Ende 2010	2450	1850	3300	2100

Einmalvergütung-Vergütungssätze inkl. MWST 8%, Quelle: Swissgrid

Figure 9.27: KEV Tariffs in Switzerland, from 2011 to 2015 (Swissolar 2016).

In general, financial incentives such as FiT can boost demand to encourage manufacturers' investment; for example, the solar installation in Germany had been increased for years since the country introduced high FiT in 2004. Nevertheless, installations started to drop in recent years due to lower FiT and domestic financial difficulties. The similar situations also take place in Italy and Japan, proving that the changes in policy influence the market development.

9.3.3.2 Self-consumption

Self-consumption refers to the electricity consumption at the location where it is generated. Self-consumption of electricity generated from PV is to reduce the demand for grid supply, and often it can co-exist with grid feed-in tariff if excess electricity is generated. Electricity fed back to the grid is sold at different rates. Depending on the country, it can be lower or higher than the retail price of electricity. Other than policy regulating how the feed-in electricity could be remunerated and whether self-consumption is allowed, a self-consumption scheme also has other requirements. A report from IEA PVPS has reviewed the self-consumption schemes for about 20 countries, and a set of key parameters used to define schemes is summarized below (Masson, Briano et al. 2016).

Table 9.7: Key parameters defining a self-consumption scheme (Masson, Briano et al. 2016).

PV Self-consumption	1	Right to self-consume
	2	Revenues from self-consumed PV
	3	Charges to finance T&D
Excess PV electricity	4	Revenues from excess electricity
	5	Maximum timeframe for compensation
	6	Geographical compensation
Other system characteristics	7	Regulatory scheme duration
	8	Third party ownership accepted
	9	Grid codes and additional taxes/fees
	10	Other enablers of self-consumption
	11	PV System Size Limitations
	12	Electricity System Limitations
	13	Additional features

Self-consumption is legally allowed in most countries. Some countries differentiate the schemes between residential and industrial/commercial application of PV system, such as Belgium. In Switzerland, self-consumption is legally allowed since April 1, 2014. Excess electricity sold to the grid is remunerated at rates lower than variable prices of electricity, although some local utilities provide higher tariff for excess electricity than the feed-in tariffs. As self-consumption might increase in the future, it is possible that the system operators will introduce charges for self-consumers due to decreasing revenue from grid-related charges based on kWh of electricity sold (Masson, Briano et al. 2016). Overall, regulations including remuneration tariffs and grid charges (and eventually also costs of storage) will have an important impact on the expansion of PV generation in Switzerland. However, since these aspects are hard to foresee, they have not been taken into account in the current estimates for future PV generation in Switzerland.

9.4 Costs

The remarkable increase of PV installations and development of manufacturing technology in recent years result in a substantial drop of PV module prices (Figure 9.28). Such decrease is also known as cost decrease driven by learning curve. A similar curve is also followed by inverters (Table 9.11).

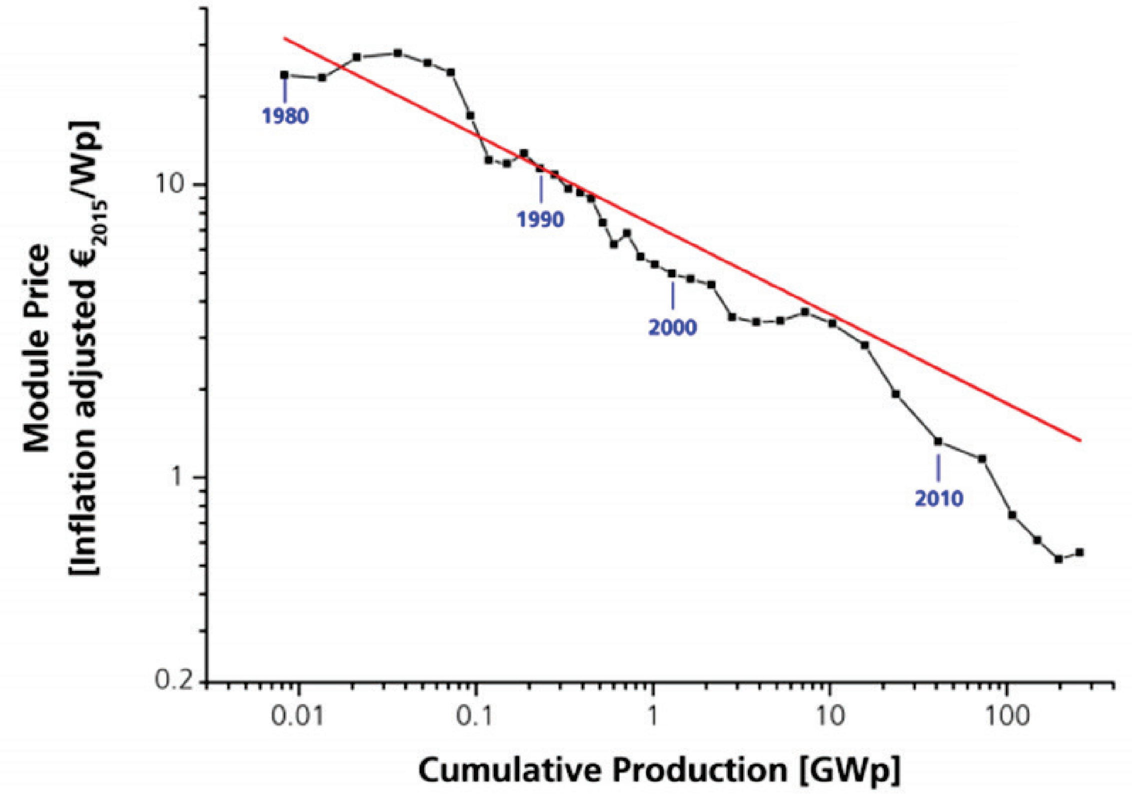


Figure 9.28: Module price learning curve from 1980 to 2015 (Fraunhofer 2016).

To estimate the current and future levelized cost of electricity (LCOE) from PV, the cost components and trends of how these cost components would develop have to be specified. The life cycle cost of a PV system includes capital cost, annual operation and maintenance cost, replacement cost and decommissioning cost. The capital cost is further divided into module cost, inverter cost, balance of system cost, planning and installation labor cost, and other miscellaneous cost. These cost components are listed in Table 9.8 with the major assumptions for current and future cost assumptions and calculations. Due to data availability, the “costs” in this section always refers to the investment that PV system owners have to make, or in other words, the price at which they need to pay for their systems (instead of the manufacturing costs).

Table 9.8: Cost components and major assumptions.

Cost Category	Cost Component	Major Asssumption on Current Cost	Major Assumption on Future Cost Development
Capital Cost	Module cost	based on system investment costs below: - 6 kW: derived based on the average of selected module price offers in Switzeraland ranging from 5.2 to 7.2 kWp (PSI 2016) - 10 kW: interpolated based on cost difference for different sizes in (Nowak and Biel 2012) - 30 kW-1000 kW: reference system investment cost as in KEV, Oct, 2016 (Swissolar 2016) and percentages of module, inverter, BOS, labor and other costs in system investment cost (Perch-Nielsen, Märki et al. 2014); percenatage breakdown is assumed to be the same for all system sizes.	future cost driven by learning curve
	Inverter cost		future cost driven by learning curve
	Balance of system (BOS) cost		future cost driven by efficiency improvement which results in reduced area per kW[1]
	Planning and installation, labor cost		future cost driven by efficiency improvement which results in reduced area per kW[1]
	Other miscellaneous cost (e.g. transportation, etc.)		future cost driven by efficiency improvement which results in reduced area per kW[1]
Annual O&M cost	Cost for maintenance, monitoring, regular check, etc.	based on median O&M cost (excluding replacement of inverter) from figure 2.3.6 in (Basler & Hofmann AG und ZHAW Winterthur 2015, Baumgartner, Toggweiler et al. 2015, BFE/SFOE 2017)	future cost driven by efficiency improvement which results in reduced area per kW[1]
Replacement cost	Replacement cost of inverter and BOS	every 15 years: - inverter replacement - 10% of BOS replacement	
	Replacement labor cost	every 15 years: 10% of replacement cost for inverter and BOS	
Decommissioning cost	Decommissioning labor cost	- 50% of planning and installation labor cost - disposal is free of charge	

[1] In reality, these cost components are driven by learning curves as well. However, the learning rates are different from the ones used for modules and inverters, and the reduction of area per kWp as a result of efficiency improvement causes only part of the reduction of these cost components. Other factors do have an impact decreasing these costs, but in this analysis, it is assumed that costs of these components are reduced in line with the decreasing PV area per capacity installed, due to lack of data that can be used to estimate other factors.

The analysis does not differentiate between PV technologies (e.g., c-Si, thin-film, etc.), as the cost of the same technology can vary a lot depending on the quality and efficiency of the product. No consideration is made on differentiating system types of BIPV and BAPV due to the uncertainty of system cost (Perch-Nielsen, Märki et al. 2014). The cost input to the analysis is in general the average PV system cost in Switzerland to be installed in specific years. It is attempted to avoid cost data from global market or other countries, as different countries do have different prices, for example, of modules (Figure 9.29). It is shown that although the difference of price exists between countries, this difference kept decreasing over the past few years due to the more and more competitive international PV market. But the price difference of modules and other components of PV system are not expected to be completely eliminated, just like for any other commercial products today.

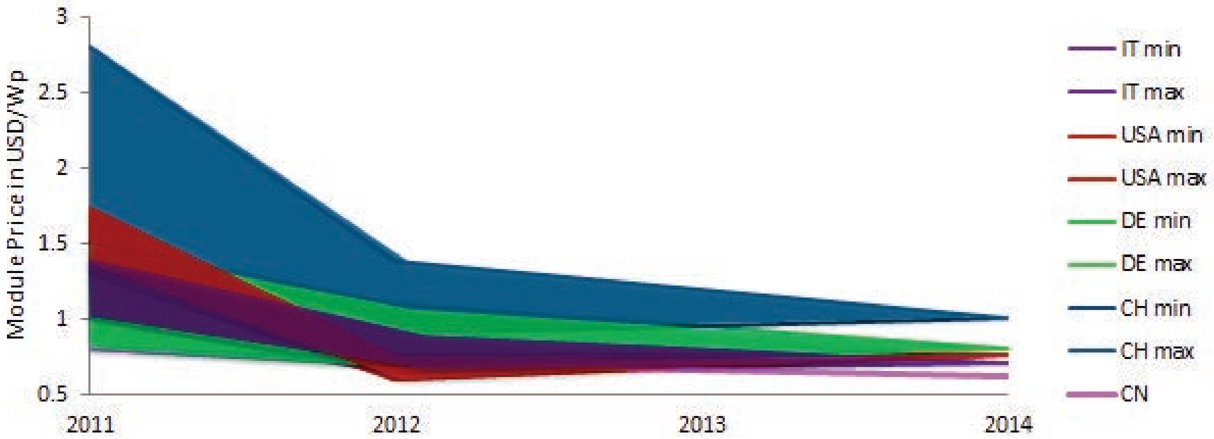


Figure 9.29: Module price in Italy, the USA, Germany, Switzerland and China, 2011-2014; based on data reported in IEA PV Applications Trend Report 2010-2014; price in USD per Wp excl. VAT; in 2014, only one value is reported for the selected countries, therefore no minimum and maximum values are illustrated

It is however believed that the results are dominated by the conventional crystalline silicon PV applications on rooftop, since it is the major PV application in Switzerland so far. Other assumptions related to the LCOE calculation for (current[203]) systems are listed below:

- interest rate: 5%
- annual electricity production degradation rate: 0.5%
- area required per kWp installation: 7.5 m^2/kWp
- average module efficiency: 15%
- average inverter efficiency: 98%
- lifetime: 30 years
- performance ratio: 80%
- average annual solar irradiance: 1100 kWh/m^2 per year
- annual yield: 970 kWh/kWp

The electricity production degradation rate of 0.5% per year is based on the study by NERL (Jordan and Kurtz 2012), and is considered in the electricity production during the module lifetime when calculating LCOE. The area required per kWp installation is taken based on the current average area requirement for multi- and mono-crystalline silicon PV (Table 9.2). Average module efficiency of 15% is assumed, and might be "relatively low" in comparison with the state-of-art c-Si technology development (both in lab and best commercialized module efficiency), but this conservative value is assumed for efficiency in order to reflect the representative efficiency of average PV systems installed in Switzerland today. The efficiency of the inverter is estimated based on the efficiency and market share of three main types of inverters (Table 9.9). Lifetime is assumed to be 30 years as most of PV resellers in Switzerland provide warranty of 80% or 85% efficiency after 20 or 25 years of operation, and therefore the lifetime is assumed a bit longer than the warranty period, which is also consistent with the assumption in ecoinvent version 3.1 (ecoinvent 2014b), the background database used for environmental impact assessment in section 9.5. Performance ratio is also assumed based on ecoinvent version 3.1 (ecoinvent 2014b).

[203] Factors changing for calculation of future LCOE are described in the associated, subsequent sections.

Average solar irradiance of Swiss Plateau (Mittelland) is used as that is the area where most of the buildings are. Annual yield is estimated by the product of annual solar irradiance, area required per kWp installation, module efficiency, performance ratio and inverter efficiency and is in line with (Nowak and Biel 2012).

Table 9.9: Main inverter types and market shares (Fraunhofer 2016).

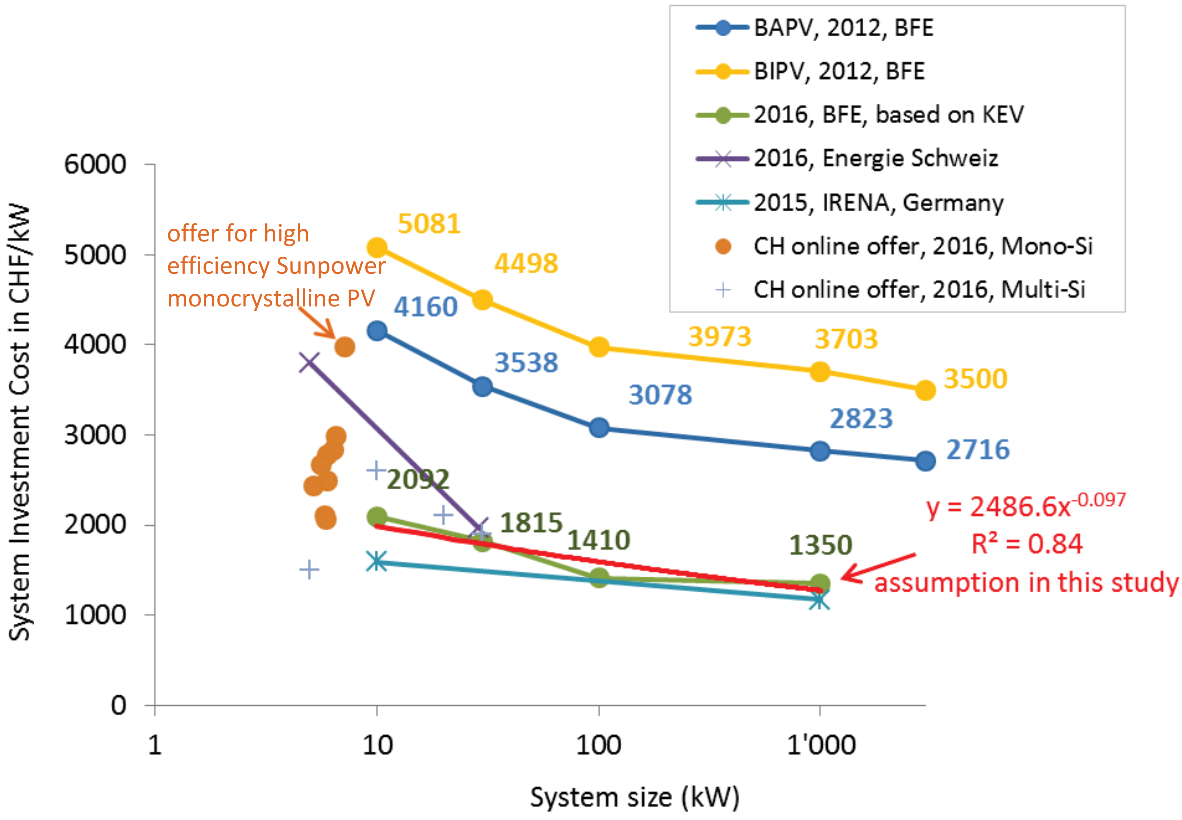
Inverter Type	Power Range	Market Share	Inverter Efficiency	Price (CHF/kWp)
String inverter	<= 100 kW	37%	up to 98%	120 - 207
Central inverter	> 100 kW	61%	up to 98.50%	~109
Micro inverter	Module Power Range	2%	90% - 95%	382
DC/DC converter (power optimizer)	Module Power Range	n.a.	up to 98.8%	~109

9.4.1 Current costs

9.4.1.1 Assumptions

The current costs of PV systems in Switzerland depend on the size of the systems due to the economies of scale. Based on the study by Nowak and Biel (2012), the system investment costs for BAPV and BIPV at various sizes in 2012 are illustrated in the figure below. It shows that in the example of BAPV, the system investment costs drop from 10 kWp to 30 kWp is about 31 CHF/kWp of size increase; from 100 kWp to 1000 kWp, the cost drop per kW is greatly reduced to 0.3 CHF/kWp of size increase, and from 1000 kWp to 3000 kWp, the decrease in investment costs per kWp of size increase is almost insignificant. A similar trend of system cost decrease due to upscale of size can be observed for BIPV. Given these cost differences for different system sizes, the current capital investment cost for BAPV systems of 10 kWp is derived based on the investment costs for 30 kWp system. System investment cost for 6 kWp is derived from selected Swiss online offers for PV modules ranging from 5.2 to 7.2 kWp (PSI 2016). System investment costs for other sizes from 30 to 1000 kWp are taken from the system investment cost used for KEV, October 2016 (Swissolar 2016).

These system investment costs are the key inputs for this analysis, and therefore they are compared with other sources, including a study from IRENA in 2016 by Gielen, Kempener et al. (2016) as well as Energie Schweiz (Energieschweiz 2016), and they are all illustrated in Figure 9.30.



Notes:
BAPV (2012, BFE): (Nowak and Biel 2012)
BIPV (2012, BFE): (Nowak and Biel 2012)
2016, BFE, based on KEV: (Swissolar 2016)
2016, Energie Schweiz: (Energieschweiz 2016)
2015, IRENA, Germany: (Gielen, Kempener et al. 2016)
CH online offer, 2016, Mono-Si & CH online offer, 2016, Multi-Si: these data are estimated based on the sampled online offers in Switzerland, with size range from 5-30 kW. Some of the offers are only for module costs; these system investment costs are therefore scaled up by dividing the module cost by 46% (as shown in the figure below) (Bögli 2016, Solarenergy-shop 2016)

Figure 9.30: System investment costs for various system sizes in Switzerland and Germany from various data sources and years.

With the breakdown of system capital investment shown in Figure 9.31, capital costs of specific components are derived for different system sizes.

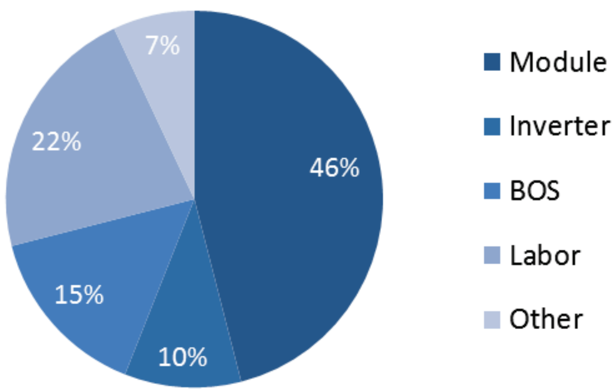


Figure 9.31: Average breakdown of capital cost for Swiss PV systems (Perch-Nielsen, Märki et al. 2014).

O&M costs are based on the median O&M cost surveyed from various of system sizes in 2015 (excluding the replacement of inverter as it is already considered as part of replacement costs) (Basler & Hofmann AG und ZHAW Winterthur 2015, Baumgartner, Toggweiler et al. 2015, BFE/SFOE 2017). Replacement required for the system is assumed to occur every 15 years, which includes the replacement of the inverter as well as 10% of BOS in terms of cost. The labor costs required for replacement are assumed to be 10% of the total replacement costs. Decomissioning costs are is assumed to be 50% of the labor cost for planning and installation in capital investment costs. Disposal of waste generated from decommissioning is assumed to be covered in the system capitcal investment.

9.4.1.2 Levelized cost of electricity produced from photovoltaics

The average current levelized costs of electricity produced from different sizes of PV systems are shown in Figure 9.32. The LCOE for system less than 6 kWp is the highest, of about 30 Rp./kWh. The LCOE for system at 100 kWp is reduced by half. Due to the small difference in system cost, the LCOE for system at 1000 kWp is not much cheaper, with only 4 Rp. reduction compared with the 100 kWp system, but this is in line with the utility-scale LCOE of around 0.1-0.2 USD/kWh by IRENA in 2015 (Taylor, Ralon et al. 2016). The breakdown of levelized costs into different cost components shows that levelized capital costs are the major contribution to total LCOE. This is followed by the contribution of O&M cost. The contribution from replacement and decommissioning cost are rather small, of less than 6% of total LCOE.

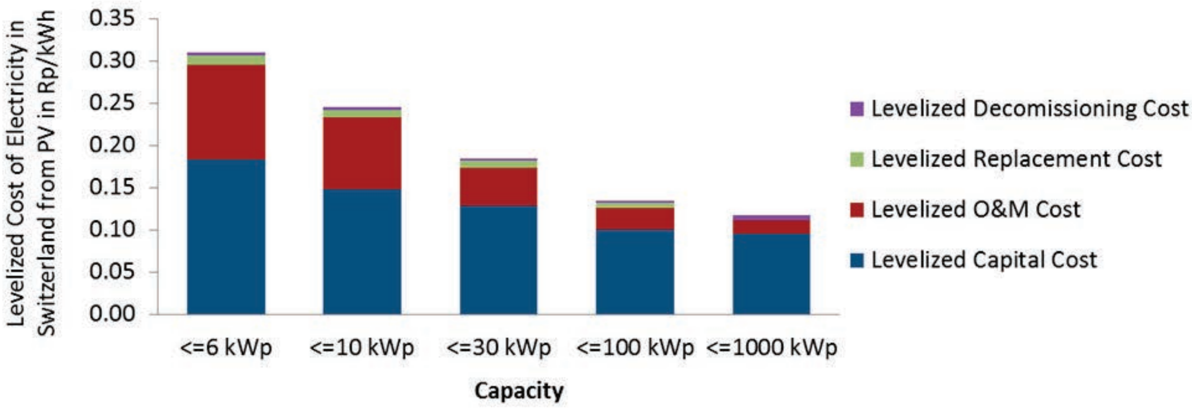


Figure 9.32: Current LCOE for Swiss PV systems at various sizes, under average performance (generation, efficiency).

9.4.1.3 Sensitivity analysis

The size of 100 kWp is selected as the base size for the sensitivity analysis. Based on trends of reduction shown in the economies of scale curve above, cost of other sizes can be interpolated if necessary. The size of 100 kWp is chosen due to the fact that about half of the currently installed Swiss PV capacity is above 100 kW, and the other half is below (Table 9.1), so it is regarded as an appropriate median size to show the relative sensitivity of system parameters except for the sensitivity of capital costs, which is related to system size.

The sensitivity analysis is performed with interest rate, degradation rate, module efficiency, solar irradiance, performance ratio, capital costs and lifetime, and it is shown in the figure below. Although it is known that the module efficiency has some influence on module cost, in order to investigate the sensitivity of each individual parameter, it is assumed the module cost does not change as efficiency changes. Variations of efficiency also result in variations in the area of PV required per Watt, and the relation of these two parameters is based on various types of PV modules sold on the Swiss market (Solarmarkt 2016). Sensitivity of capital cost takes into account the capital cost of various system sizes ranging from 6 kWp to 1000 kWp. For each parameter, a base value is selected and shown below the corresponding legend, while the ratios of variations (limited by the potential range of each parameter) to the base values are shown on the x-axis.

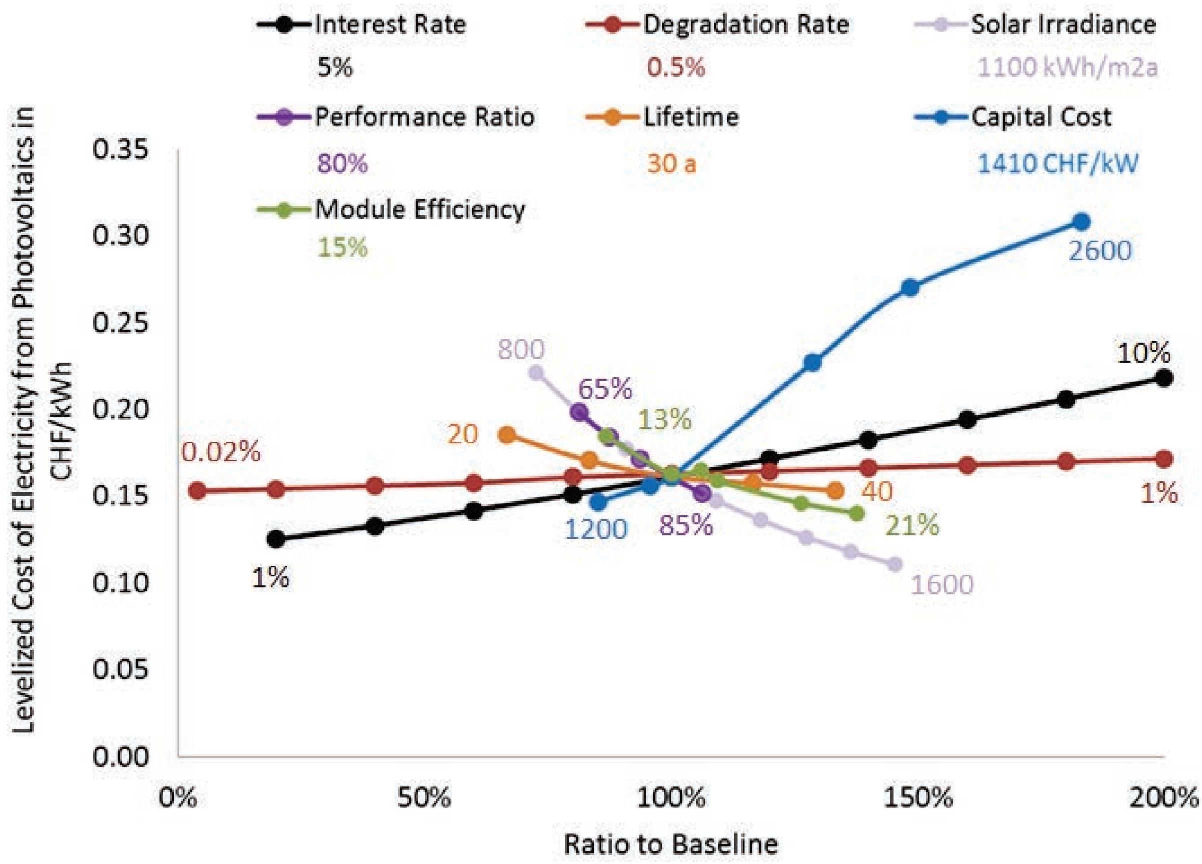


Figure 9.33: Sensitivity analysis of current LCOE, center point represents current LCOE of a 100 kWp system.

It can be seen that the sensitivities of solar irradiance and performance ratio have some overlap, as both of these two parameters have an impact on the electricity generation, but they are not fully overlapped with each other, as solar irradiance has more variation than performance ratio in comparison with base values. The sensitivity results of efficiency do not fall on a smooth curve, since the data points correspond to a mixture of technologies (e.g., mono-crystalline, multi-crystalline, CIS). Although in general, as the efficiency increases, the area required for certain installed capacity (power) decreases, the product of area required per Watt and efficiencies of different PV technologies are not equal due to different PV technologies, which affects the electricity generation per Watt as well as the LCOE. LCOE at different lifetimes also do not fall on a straight line. This is because replacement is assumed to occur every 15 years, so when the system lifetime is 25 years or 35 years, the components that require replacements (i.e. inverter and BOS parts) are not fully utilized throughout the end of their lifetime yet. This therefore results in slightly higher sensitivity for certain lifetime values than the reference plifetime assumed. The figure also shows that LCOE has higher sensitivity to the interest rate than to performance degradation.

Note that the sensitivities shown in the figure reflect the impact of individual parameters, and do not show the combined impacts of variation of the various parameters. With the combined impacts of all parameters to form the best-case and worst-case, the LCOE can go as low as 6 Rp./kWh, or as high as almost 60 Rp./kWh, whereas when only individual parameter variation is considered, the range of LCOE would be about 11-31 Rp./kWh.

9.4.2 Future cost

9.4.2.1 Assumptions

The future cost of PV systems will drop further, given the continuous increase of production and installation, and the ongoing research and development of PV technologies and advancement in manufacturing. The study by Perch-Nielsen, Märki et al. (2014) shows that almost all cost components of a PV system will drop in the future, but since they have different driving factors for cost reduction, the long-term system costs will exhibit different trends for various cost components. As shown in Table 9.8, the cost reductions of modules and inverters are assumed to be driven by learning curves, while the BOS cost, installation and planning labor cost, other miscellaneous cost and O&M costs are assumed to be driven by the area reduction per kWp due to the future module efficiency improvement. As for the other costs such as replacement cost and decommissioning cost, since they are assumed to be a percentage of capital cost, they will also decrease in the future as the capital cost decreases. The lifetime is assumed to increase to 35 years from year 2035 onwards.

In order to project the future module and inverter costs, a review on projections of future cumulative PV production was performed. Due to limited data availability, it is assumed that the cumulative production is the same as the cumulative installation, although there might be a slight difference in the future (Mayer 2015). The projections reported in literature vary a lot by institution and organization, and often, different scenarios are developed. In order to capture all these different projections, a range of cumulative production with minimum and maximum values is reported for each year in 2020, 2035 and 2050. There are even variations for the cumulative PV production today between different sources, but in this study it is assumed to be 177 GW (by the end of 2014, based on (IEA 2015f)). It is assumed that the maximum and minimum projections of selected years are triggered by Fraunhofer's scenario with Compound Annual Growth Rate (CAGR) of 10% (Mayer 2015) (also known as "the third scenario") and World Energy Outlook's scenario with current policies (IEA 2015g), respectively.

Table 9.10: Global maximum and minimum cumulative production capacity from 2020 - 2050, in GWp.

	Min Cumulative Production (GW)	Max Cumulative Production (GW)
2020	360	850**
2035	670*	6'900**
2050	980*	16'700

*: Since the cumulative production capacities are not reported in the year needed for this study, these values are inter- and extrapolated based on the reported data in 2030 and 2040.

**: Since the cumulative production capacities are not reported in the year needed for this study, these values are approximately taken from figure 66 in the reference (Mayer 2015).

The learning rate of PV modules has been around the range of 19-23% since 1980 (Mayer 2015); therefore, three learning rates were selected in this study: 19%, 21% and 23%. The formula of learning rate, and future cost estimate based on learning rate are shown below:

$$LR = 1 - 2^b$$

$$C(X_t) = C(X_o)(\frac{X_t}{X_o})^{-b}$$

in which, LR is learning rate; it is the fractional cost reduction for a doubling of cumulative production capacity; b is learning rate exponent; X_t and X_0 are cumulative production capacity at time t and o; $C(X_t)$ and $C(X_o)$ are costs when cumulative production capacities are at X_t and X_o.

Based on the range of cumulative production capacities and the current cost of modules, the future costs are calculated and shown in Figure 9.34. It shows that in 2020, the module costs of a 6 kWp system is going to decrease to 1032 CHF per kWp, and by 2050, the module costs of a 100 kWp system can be as low as 123 CHF per kWp. As the more it goes into the future, the uncertainties and ranges of the cumulative production capacity become higher, thus differences between the maximum and minimum projected module cost become larger for the same system size. It can also be observed that due to the large ranges selected for the cumulative production capacity as well as for different system sizes, the maximum module cost (corresponding to the higher estimate of the smallest system) in a year are always higher than the minimum costs (corresponding to the lower estimate of the largest system) in an earlier year, which in return proofs the important influence of size and installation/production development on the future module costs.

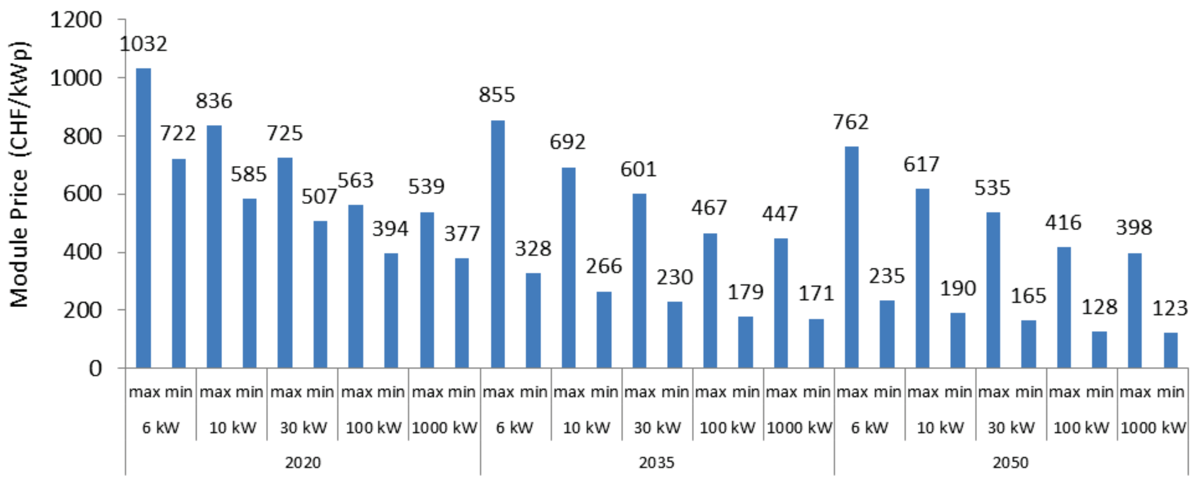


Figure 9.34: Future estimated maximum and minimum module cost for various installation sizes in Switzerland, 2020-2050.

The estimation of future inverter cost follows the similar methodology as applied for module cost, based on learning curves. It is assumed that the inverter for PV applications has its own market, and its cost will decrease according to the market growth of PV modules, therefore the same range of cumulative production capacity of PV is applied. However, from the historical data, it shows that the decrease of inverter cost has a slower trend than that of module costs; therefore, a learning rate of 19% is assumed (Mayer 2015) and future inverter costs are listed in Table 9.11.

Table 9.11: Future inverter costs: minimum and maximum values, in CHF/kWp.

Size	2020		2035		2050	
	max	min	max	min	max	min
6 kWp	224	173	186	91	166	70
10 kWp	182	140	150	74	134	57
30 kWp	158	121	131	64	116	49
100 kWp	122	94	101	50	90	38
1000 kWp	117	90	97	48	87	37

The other costs that are area-dependent will be reduced as efficiency improves. However, the assumption that area reduction is the only driving factor for cost reduction in BOS costs, installation and planning labor costs, other miscellaneous costs and O&M costs, is a limitation of this analysis. In reality, other non-area dependent factors might reduce these costs too, but these non-area dependent factors were not considered due to lack of appropriate, Swiss-specific data. There are recent studies exploring how these costs might reduce in the future (Vartiainen, Masson et al. 2015, Taylor, Ralon et al. 2016); however, these studies exhibit completely different pictures of how these costs would develop in the future, and they are mainly focused on utility-scale ground mounted PV, whereas in Switzerland, roof-top mounted smaller scale PV systems have the main potential. Previous studies also have a relatively short-term time horizon, usually until 2025-2030. In addition, many of these costs such as installation costs, transportation costs, electrical system and structure costs, etc., vary widely from country to country (Taylor, Ralon et al. 2016). In other words, cost data from other regions or countries cannot be simply adopted and applied to Switzerland. This simplification should definitely be refined in the future if more local data is available.

The area required for certain capacity installation is closely related to the efficiency development. Since the study is focused mainly on crystalline silicon PV, the historical efficiency of selected commercial crystalline silicon modules was reviewed (Figure 9.35). It shows that the historical efficiency improvement of main market players from 1997 till 2015 exhibits a range of annual efficiency increase of about 0.26-0.5%. This is also in line with the finding by the Fraunhofer institute that the efficiency of average commercial wafer-based silicon modules increased from about 12% to 16% in the last 10 years (Fraunhofer 2016). The range of annual efficiency increase from 0.26% to 0.5% per year is thus used in the projections of minimum and maximum efficiency in the future. However, it should also be noted that there is a theoretical maximum efficiency of single-junction crystalline silicon PV cells not to be exceeded, which according to Richter, Hermle et al. (2013) is 29.4%. Since usually the module efficiency will be around 10% less than the cell efficiency, the cap of module efficiency used in this study for single-junction crystalline silicon PV is 27%. Note that it is assumed that the shift of dominant PV technology from single-junction to multi-junction will not occur before 2050, which might not be the case. In the projection of maximum efficiency, when the annual efficiency increase of 0.5% is applied, an efficiency of 33% would be reached by 2050, which exceeds the above mentioned limit. Therefore the maximum of 27% is applied in this case, and thus resulting in a smaller difference between maximum and minimum efficiency in 2050 than in 2035. Both minimum and maximum efficiency projection scenarios until 2050 used in the analysis are shown in Figure 9.35, with the values of projected module efficiencies, area requirement per kW, and area-dependent costs from 2014 to 2050 listed in Table 9.12 to Table 9.16.

Please note that the efficiency ranges projected for each time horizon are the representative efficiency ranges rather than the best- and worst-performed PV modules available on the market in the future. These representative ranges are used for future cost calculation, in order to be consistent with the future projection of other representative costs (e.g., capital cost, BOS cost, etc.).

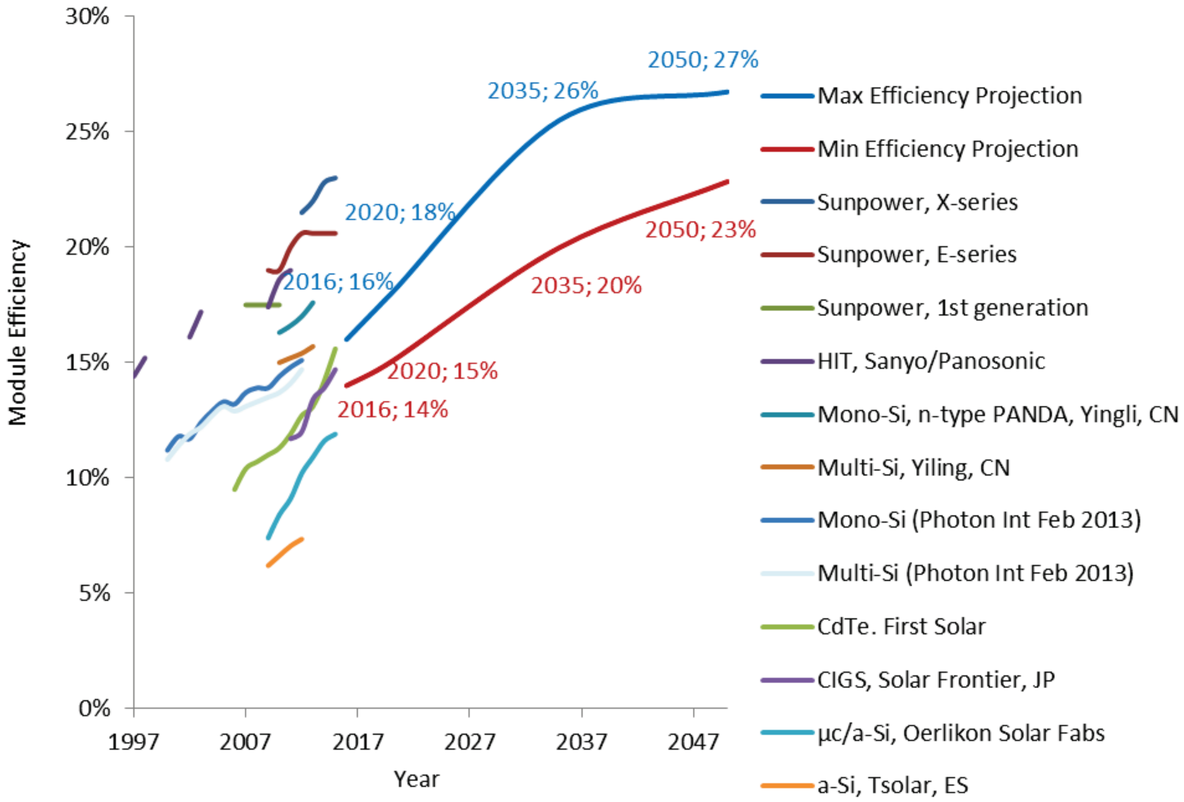


Figure 9.35: Historical commercial module efficiency development (Wim 2014), maximum and minimum module efficiency projections used in this study; efficiency curves within the circle represent wafer based crystalline silicon PV module; note that Sunpower 1st generation is not referred when calculating the minimum efficiency improvement as it was a product series that manufacturing was stopped and just included here for illustration.

Table 9.12: Future module efficiency, area per kWp and other area-dependent costs, 2014-2050, 6 kW.

	Module Efficiency		Area per kWp (m2/kWp)		BOS Cost (CHF/kWp)		Labor Cost (CHF/kWp)		Other Cost (CHF/kWp)		Annual O&M Cost (CHF/kWp/year)	
Year	min	max	max	min	max	min	max	min	max	min	max	min
2016	14%	16%	7.5	7.5	258	258	568	568	181	181	103	103
2020	15%	18%	7.0	6.7	240	230	529	505	168	161	96	91
2035	20%	26%	5.3	4.7	181	162	398	357	127	113	72	65
2050	23%	27%	4.6	4.5	158	155	348	340	111	108	63	62

Table 9.13: Future module efficiency, area per kWp and other area-dependent cost, 2014-2050, 10 kW.

	Module Efficiency		Area per kWp (m2/kW)		BOS Cost (CHF/kWp)		Labor Cost (CHF/kWp)		Other Cost (CHF/kWp)		Annual O&M Cost (CHF/kWp/year)	
Year	min	max	max	min	max	min	max	min	max	min	max	min
2016	14%	16%	7.5	7.5	314	314	460	460	146	146	103	103
2020	15%	18%	7.0	6.7	292	279	428	409	136	130	96	91
2035	20%	26%	5.3	4.7	220	197	323	289	103	92	72	65
2050	23%	27%	4.6	4.5	192	188	282	276	90	88	63	62

Table 9.14: Future module efficiency, area per kWp and other area-dependent cost, 2014-2050, 30 kW.

	Module Efficiency		Area per kWp (m2/kW)		BOS Cost (CHF/kWp)		Labor Cost (CHF/kWp)		Other Cost (CHF/kWp)		Annual O&M Cost (CHF/kWp/year)	
Year	min	max	max	min	max	min	max	min	max	min	max	min
2016	14%	16%	7.5	7.5	272	272	399	399	127	127	78	78
2020	15%	18%	7.0	6.7	253	242	372	355	118	113	72	69
2035	20%	26%	5.3	4.7	191	171	280	251	89	80	54	49
2050	23%	27%	4.6	4.5	167	163	245	239	78	76	48	46

Table 9.15: Future module efficiency, area per kWp and other area-dependent cost, 2014-2050, 100 kW.

	Module Efficiency		Area per kWp (m2/kW)		BOS Cost (CHF/kWp)		Labor Cost (CHF/kWp)		Other Cost (CHF/kWp)		Annual O&M Cost (CHF/kWp/year)	
Year	min	max	max	min	max	min	max	min	max	min	max	min
2016	14%	16%	7.5	7.5	212	212	310	310	99	99	42	42
2020	15%	18%	7.0	6.7	197	188	289	276	92	88	39	37
2035	20%	26%	5.3	4.7	148	133	217	195	69	62	29	26
2050	23%	27%	4.6	4.5	130	127	190	186	60	59	26	25

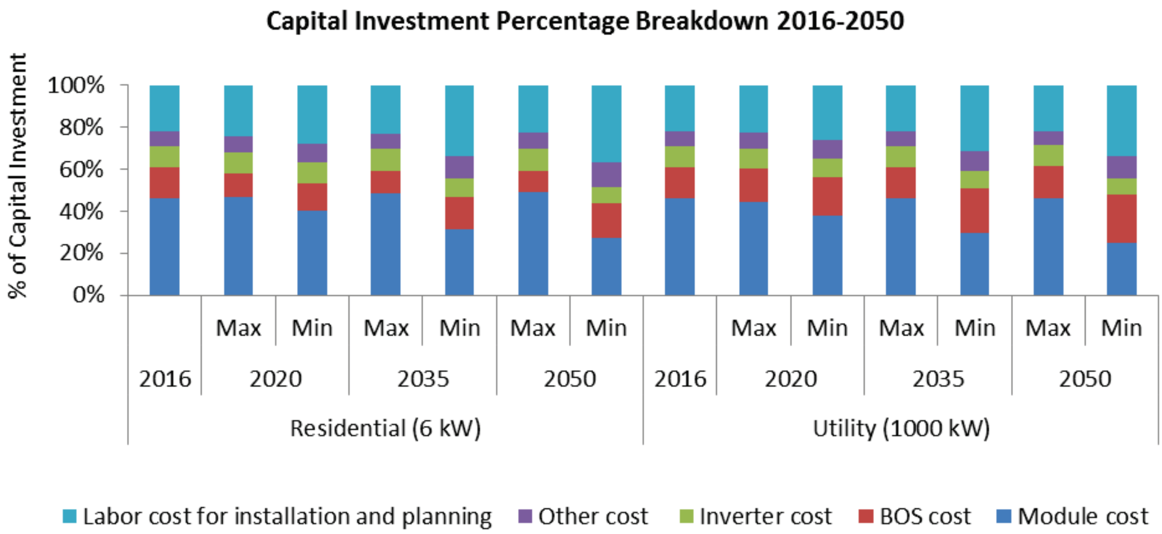
Table 9.16: Future module efficiency, area per kWp and other area-dependent cost, 2014-2050, 1000 kW.

	Module Efficiency		Area per kWp (m2/kW)		BOS Cost (CHF/kWp)		Labor Cost (CHF/kWp)		Other Cost (CHF/kWp)		Annual O&M Cost (CHF/kWp/year)	
Year	min	max	max	min	max	min	max	min	max	min	max	min
2016	14%	16%	7.5	7.5	203	203	297	297	95	95	15	15
2020	15%	18%	7.0	6.7	188	180	276	264	88	84	14	13
2035	20%	26%	5.3	4.7	142	127	208	186	66	59	10	9
2050	23%	27%	4.6	4.5	124	121	182	178	58	57	9	9

With all the above assumptions, the current and future capital cost breakdown by component from 2016 to 2050 is shown in Figure 9.36, in terms of both percentage breakdown and absolute investment cost in CHF per kWp, and for both the utility-scale system (represented by 1000 kWp) as well as the residential-scale system (represented by

6 kWp). It is shown that while the contribution of different capital cost components in pessimistic projections stay more or less the same, in the optimistic projection of large systems (minimum cost), the contributions of module and inverter to capital cost become less important as the total cost decreases. This on the other hand indicates the potential of module and inverter cost reduction will become less important in the future, whereas on the other hand BOS cost, labor cost for installation and planning, and other costs will gradually become dominant in the future.

The capital cost breakdown in CHF per kWp shows that in 2016, depending on the size of the system, the system capital cost is in the range of about 1350-2583 CHF/kWp, with module and inverter contributing more than half of the investment cost. This will be reduced to about 992-2198 CHF/kWp in 2020, and to 583-1761 CHF/kWp in 2035, and further down to 493-1561 CHF in 2050. In comparison with other references, the module cost for large system used in this study for 2016 (621 CHF/kWp, corresponding to the 1000 kWp system) is slightly higher than the assumption used in a study by European PV Technology Platform Steering Committee, of about 610 Euro/kWp by the end of 2014 in Germany for 50 MWp systems (Vartiainen, Masson et al. 2015). But given the year, country and size difference, this assumption is considered to be reasonable. Regarding the system investment cost, Vartiainen, Masson et al. (2015) reported the cost for system less than 10 kWp is about 120% higher than the 1 MW ground-mounted system, which is higher than what is assumed in this study (91%).



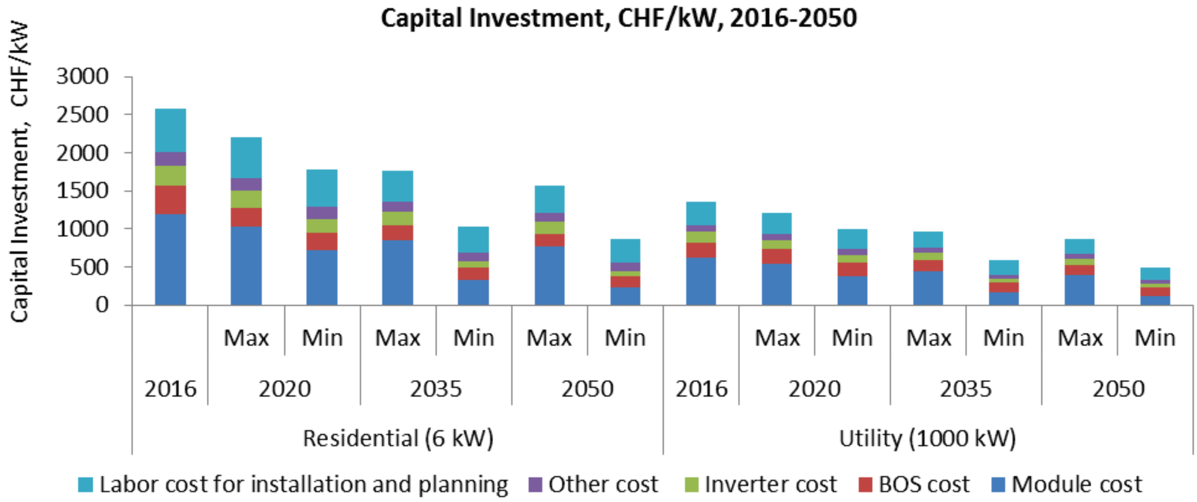


Figure 9.36: Current and future capital cost breakdowns for both residential-scale PV system (represented by a typical size of 6 kWp) and utility-scale PV system (represented by a size of 1000 kWp) by cost component.

9.4.2.2 Levelised cost of electricity produced from photovoltaics in the future

The levelized costs of future electricity generation from PV are presented in Figure 9.37. It shows that the LCOE for a 100 kWp PV system in 2020 may drop to below 20 Rp./kWh, at around 12-14 Rp./kWh, and until 2050, the LCOE could go below 10 Rp./kWh, with the range of 7-10 Rp./kWh. The difference between the maximum and minimum cost estimates exhibits similar increasing trend as in the other scenarios of capital cost and cumulative production capacity, due to the increasing uncertainties in the future scenarios.

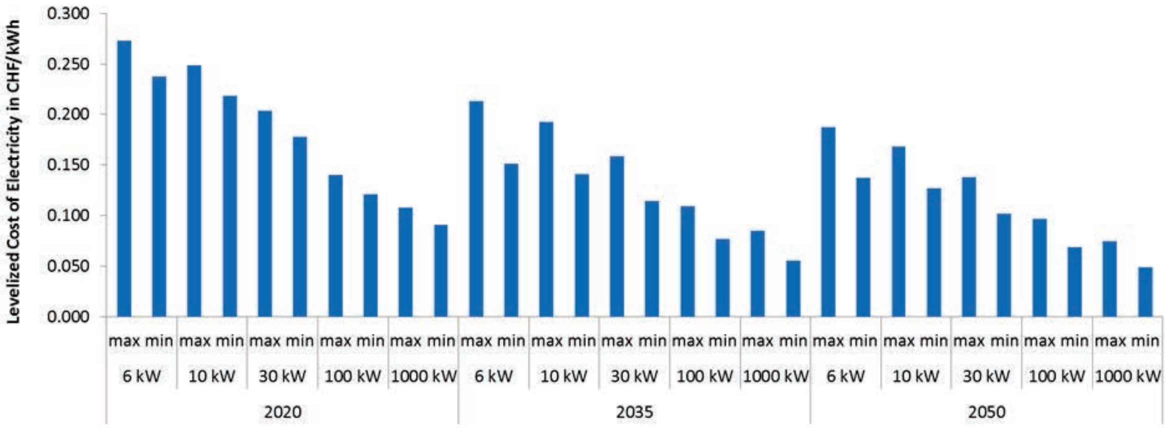


Figure 9.37: Future levelized costs of electricity from PV power in Switzerland: minimum and maximum values, 2020-2050.

To investigate the contribution of cost components in future LCOE reduction, the cost for 100 kWp system in 2016 and its lower estimate in 2035 are taken as an example, and it is compared with the LCOE in 2016 (Figure 9.38). It shows that the learning curve based cost components, in particular the module cost and inverter contribute about 56% of cost reduction, while the area dependent cost components including annual operation and maintenance, installation and planning labor, and BOS contribute 44% of the reduction in LCOE due to the improvement in module efficiency.

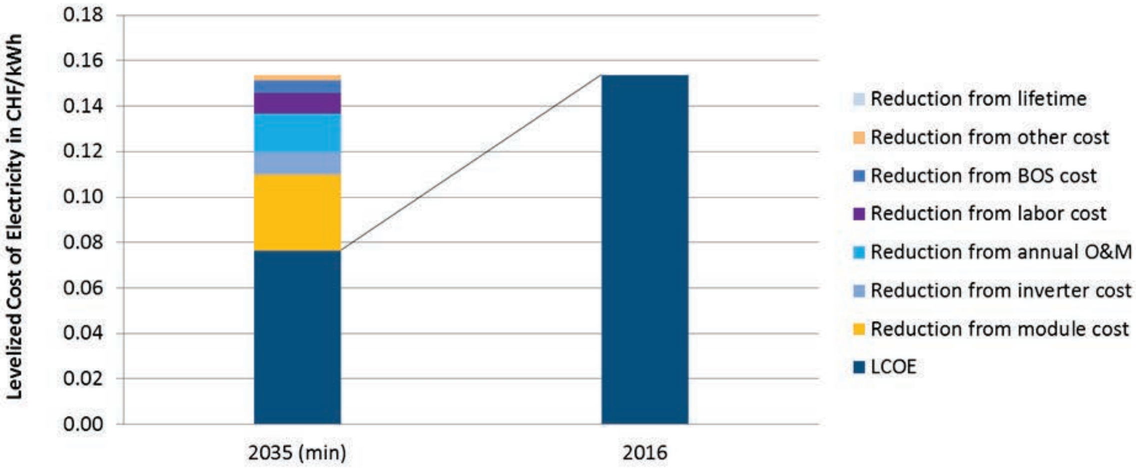


Figure 9.38: Contribution of future LCOE reduction by cost component: example from lower estimate of LCOE in 2035 (minimum) vs. LCOE in 2016 for a 100 kWp system.

In comparison with other references, Vartiainen, Masson et al. (2015) show for Munich, Germany, that the LCOE for a typical PV system in 2030 would range from 0.06-0.08 Euro/kWh, corresponding to a utility size system of up to 1 MW, and a residential system as small as 5 kW, respectively. This range matches with the LCOE of systems up to 1000 kW in this study (around 0.07 CHF/kWh in 2035). However, it is much lower than the LCOE for systems smaller than 6 kW obtained in this study (0.18 CHF/kWh), mostly because of the relatively more important role of other cost coponents (i.e. O&M cost, replacement and decommissioning labor cost) for small systems, and these cost components differ between countries. A recent study by ITRPV (Cellere, Forstner et al. 2015) shows that at an annual yield of 1000 kWh/kW, the future LCOE for large-scale systems in the US and Europe by

2020 would reach around 0.09 USD/kWh, which is comparable with the results of this study for the 1000 MW system in 2020 (0.09-0.11 CHF/kWh).

9.5 Environmental aspects

Evaluation of the environmental performance of electricity generation from PV requires Life Cycle Assessment (LCA) quantifying environmental burdens along the complete supply and manufacturing chain. Life-cycle Greenhouse gas (GHG) emissions with the associated impact on climate change are used as main performance indicator and are discussed in detail. Further environmental LCIA (Life Cycle Impact Assessment) indicators are provided in a less detailed way with PV results in comparison to the current Swiss electricity consumption mix.

It is found in many previous studies, e.g. (Turconi, Boldrin et al. 2013, Liu, Kent Hoekman et al. 2015), that the life-cycle GHG emissions of electricity produced from PV are a lot lower than those of conventional electricity production technologies using fossil fuels. Different from some conventional electricity generation technologies, in which the infrastructure has relatively low contribution to most of the environmental impacts while operation (especially fuel combustion and supply) has large impacts on the environment, the manufacturing of PV modules is the major contributor to total life-cycle impacts of a solar PV system (Liu, Kent Hoekman et al. 2015). Therefore, it is important to assess the environmental burdens, from a life cycle perspective, i.e. perform LCA.

The process system of electricity produced from PV can be divided into a few stages: the manufacturing of metallurgical-grade silicon from silica sand (MG-silicon), purification of MC-silicon to electronic-grade silicon and solar-grade silicon, the casting and production of silicon ingot, sawing of wafer, PV cell production, PV panel production, PV panel transportation, and installation, as well as electricity production (Figure 9.39). All the processing energy consumption, air- and waterborne process-specific pollutants at all production stages, materials, auxiliary chemicals, transport of materials, energy carriers, semi-finished products and the complete power plant, waste treatment processes for production wastes, dismantling of all components, infrastructure for all production facilities with its land use, are considered (Jungbluth, Stucki et al. 2012a).

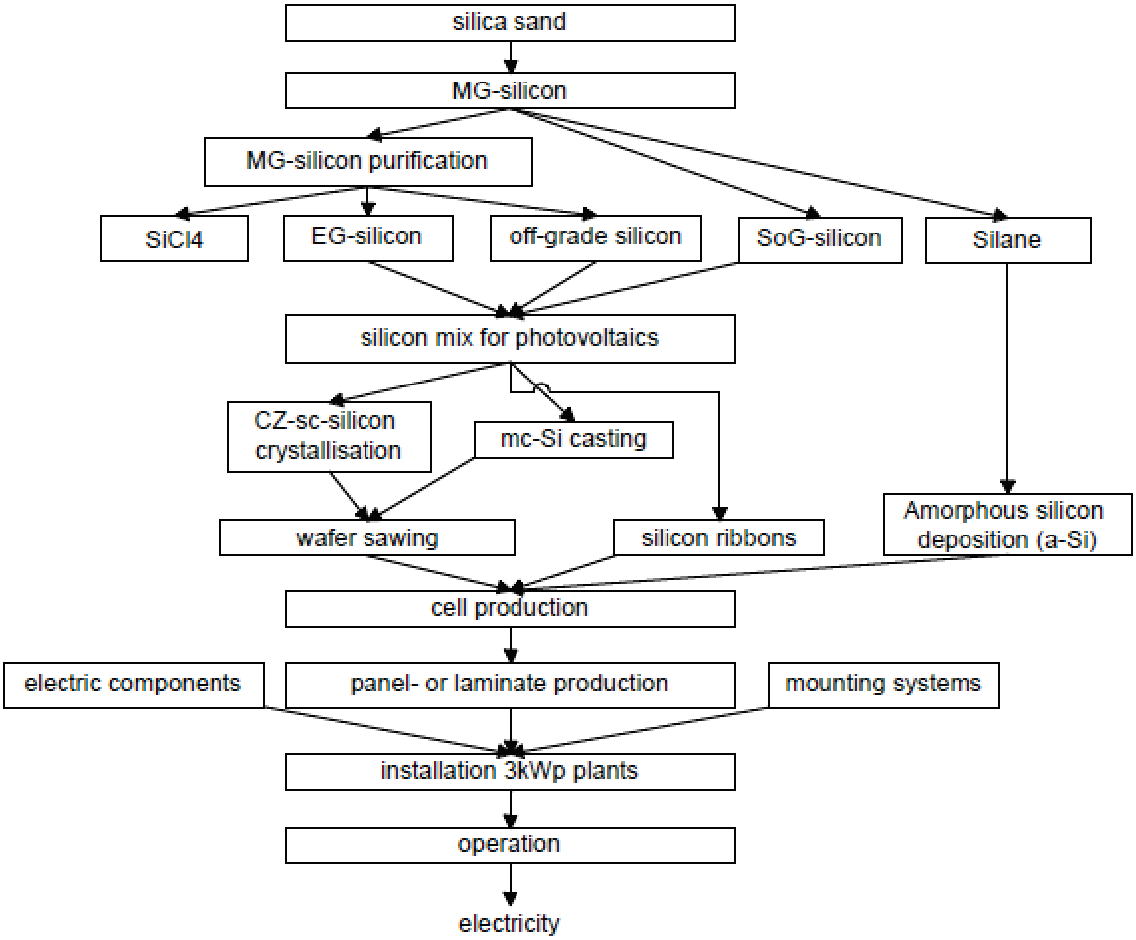


Figure 9.39: Process system in the LCA of PV. Different sub systems investigated for the production chain of silicon cells based photovoltaic power plants installed in Switzerland. MG-silicon: metallurgical grade silicon, EG-silicon: electronic grade silicon, SoG-silicon: solar-grade silicon, a-Si: amorphous silicon (Jungbluth, Stucki et al. 2012a).

9.5.1 Environmental performance of current technologies

9.5.1.1 Life-cycle GHG emissions of photovoltaics manufacture in Europe

The GHG emissions of electricity produced from different PV technologies based on (ecoinvent 2016) are presented in Figure 9.40. In general, thin-film PV technologies (a-Si and CIS) show lower GHG intensities than crystalline silicon PV, although they have a much lower efficiency. However, thin-film PV production chains exhibit a lower energy and material consumption than crystalline silicon production chains, resulting in lower emissions per kWh of electricity production.

Since multi-crystalline Si is globally the most commonly used PV technology (Figure 9.10), the environmental performance of PV is further discussed based on multi-crystalline Si modules. The environmental impact of electricity generation from PV will differ depending on the annual electricity generation affected by location-specific factors (such as solar irradiance) and technology parameters, as well as the lifetime of PV panels. Ranges of life-cycle GHG emissions are estimated by considering Swiss-specific ranges of annual yields from 850-1500 kWh/kWp (Borgna, Geissbühler et al. 2007). For multi-crystalline-Si PV, this results in GHG emissions of 46-81 gCO_2eq/kWh of electricity production.[204]

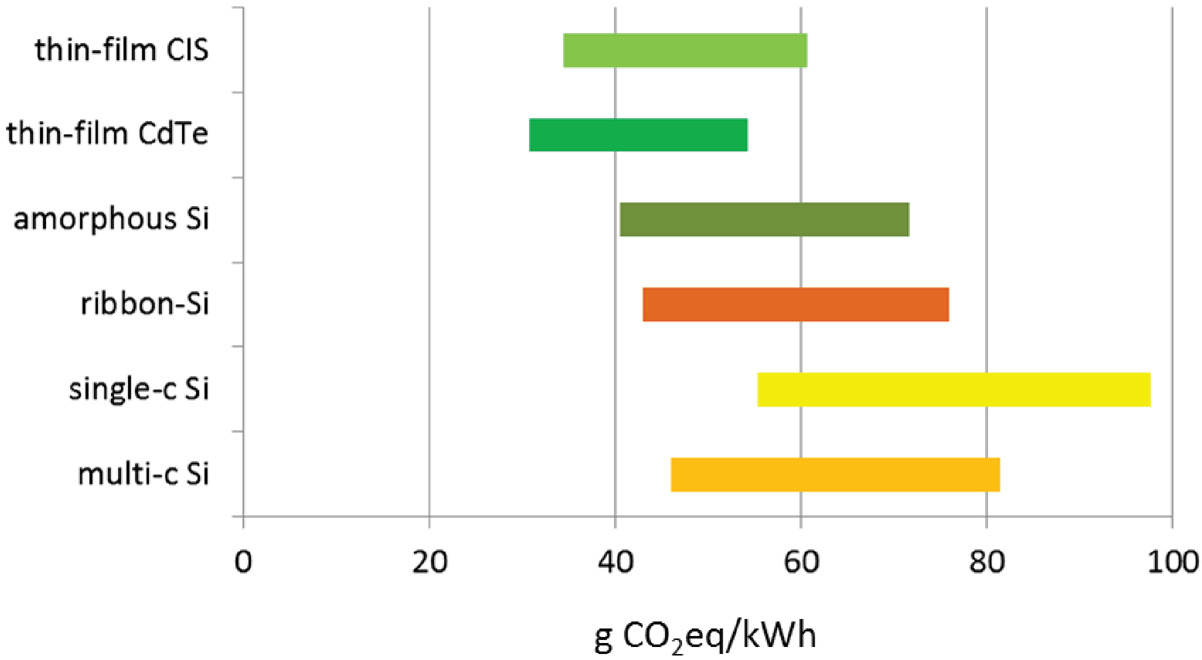


Figure 9.40: Life cycle GHG emissions of different PV technologies in Switzerland (laminates on slanted roof-tops), based on (ecoinvent 2016); ranges of emissions using potential annual yield ranges of 850-1500 kWh/kW (with a reference yield of 922 kWh/kW). Inventory data mostly represent European (and US) production and manufacturing of PV modules.

Inventory data upon which these life-cycle GHG emissions are based are somewhat outdated, namely in terms of manufacturing technology represented and in terms of representation of global PV manufacturing chains. However, compilation of new inventory data was out of scope of this work. Therefore, we refer in the following discussion to further, more recent references reflecting both aspects.

Recent technological progress consists e.g. in reduction of silicon-wafer thickness, implementation of factory-internal recycling processes and minimization of material losses. Such technological progress against the inventory data in (ecoinvent 2016) has been considered in e.g. (Bauer, Frischknecht et al. 2012, Jungbluth, Stucki et al. 2012a, Itten and Frischknecht 2014). However, reductions of environmental impacts due to progress in average production technology are relatively small – in the order of 15-20% for GHG emissions of average panels produced in Europe (Bauer, Frischknecht et al. 2012, Jungbluth, Stucki et al. 2012a) – and partially more than compensated by increasing shares of Asian manufacturers on the European and Swiss markets for PV modules with the associated comparatively worse environmental performance (Itten and Frischknecht 2014). The fact that the life-cycle emissions of PV depend on the origin of cells and modules is mainly caused by two reasons: a) PV manufacturing technologies are different from country to country, and manufacturer to manufacturer, and require different material and energy consumption; b) the mix of electricity supply is very different between countries, so even

[204] Applying the yield range to the global warming impact of the dataset “electricity production, photovoltaic, 3kWp slanted-roof installation, multi-Si, laminated, integrated” of the ecoinvent database (ecoinvent 2016) Same yield range applied to other PV technologies available (building-integrated) in the ecoinvent database.

the same manufacturing technology will have different indirect emissions if the plants are located in different regions of the world. Based on current global market share of PV cells and panels, it is known that many Asian countries such as China, Japan, Taiwan and Malaysia are most important in terms of PV manufacturing. Similar market shares can be observed in Switzerland, and an example of module origin of a major Swiss dealer is shown in Figure 9.41, based on the study by Perch-Nielsen, Märki et al. (2014).

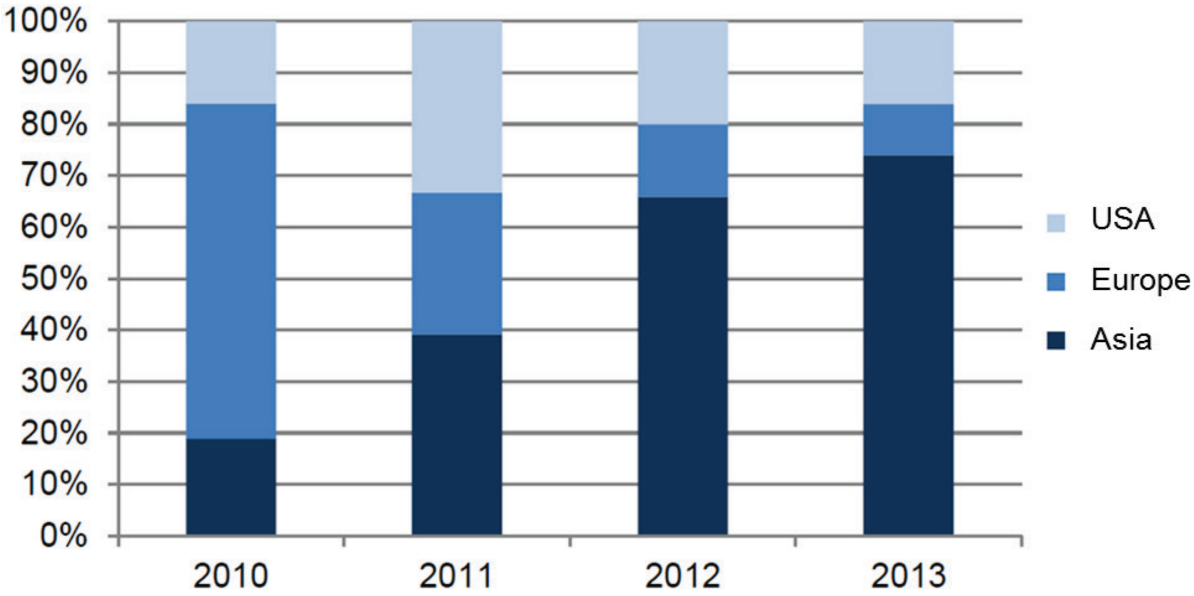


Figure 9.41: Module origin of a major dealer on the Swiss market (Perch-Nielsen, Märki et al. 2014).

According to (Itten and Frischknecht 2014), “single and multi-crystalline silicon, wafers and photovoltaic cells, laminates and panels are mainly produced in China, having a share on the world market of between 73% and 81% (reference year 2011). Multi-crystalline silicon production is more evenly spread in China having a market share of 41%. While production is mainly concentrated in Asia, three out of four photovoltaic panels and laminates are sold and mounted in Europe.” Modelling supply chains according to the market shares of the four world regions China, Europe, Americas and Asia & Pacific and only partially considering region-specific inventories for PV manufacturing (and therefore underestimating environmental burdens[205]), Itten and Frischknecht (2014) calculate GHG emissions of 94-97 g CO_2eq/kWh for single-crystalline Si and 58-62 g CO_2eq/kWh for multi-crystalline Si modules in Switzerland, at an annual yield of 975 kWh/kW. Taking into account the location-specific variation in annual yields in Switzerland (850-1500 kWh/kW), these results correspond to ranges of about 60-110 g CO_2eq/kWh for single-crystalline Si (slightly higher than the numbers in Figure 9.40) and 40-70 g CO_2eq/kWh for multi-crystalline Si PV modules (slightly lower than the numbers in Figure 9.40).

Most recent LCA results for CdTe are reported in (Jungbluth, Stucki et al. 2012a): Electricity from CdTe modules causes life-cycle GHG emissions of ~40 g CO_2eq/kWh at an annual yield of 922 kWh/kWp, which corresponds to a range of about 25-45 g CO_2eq/kWh considering the location-specific variation of annual yield in Switzerland (850-1500 kWh/kWp).

[205] (Itten and Frischknecht 2014) The authors show that the approximated data used in their calculation underestimates the GHG emissions of actual Chinese mainstream and best technology multi-Si panel production by about 35% and 10%, respectively.

Alternative technologies such as micromorphous solar modules and Amorphous thin film plastic PV modules could partially substantially reduce the life-cycle GHG emissions of electricity from PV (Frischknecht, Stucki et al. 2013). However, these technologies are not (yet) commercially mature with established long-term performance records.

9.5.1.2 Life-cycle GHG emissions of photovoltaics manufacture in China

It is reported in many statistics and reports that China has a big market share in PV manufacturing. According to the IEA PV trend report in 2015 (IEA 2015f), the global PV cells (crystalline silicon PV cells and thin-film PV cells) production in 2014 has reached 46.7 GW, out of which China contributes the largest production of PV cells with about 28 GW. China is also the largest producer of polysilicon in the world, which is the main material required for silicon-based PV cells. China reported that it produced 136’000 tons of polysilicon (EG- and SoG- silicon) in 2014, accounting for around 50% of total global production. However, China has also imported 96’000 tons of polysilicon (MG-silicon) mainly from Germany, Korea, USA and Malaysia. China is also the largest producer of wafers for solar cells in the world, with wafer production capacity of 50.4 GW and actual production of 38 GW in 2014.

The life cycle inventory of electricity production from Chinese-manufactured PV varies by source. There are three major studies including Diao and Shi (2011), Yue, You et al. (2014) and Frischknecht, Itten et al. (2015), while the other studies investigating Chinese-manufactured PV mainly refer to these studies. The study by Diao and Shi (2011) is conducted based on the Chinese industrial data in processes of SoG silicon production, silicon ingot and wafer production, PV cell and panel production, with Chinese electricity production, glass, aluminum, EVA and chemical production referred from ecoinvent version 2.2 (ecoinvent 2013). The study mentioned the technology variation between manufacturers in China, and has therefore included two streams of technologies: the mainstream technology and the best technology. The study by Yue, You et al. (2014) refers to the PV production datasets in ecoinvent version 2.2 (ecoinvent 2013). The methodology mainly uses European-based inventory data for PV manufacturing with some process datasets replaced from Chinese Core Life Cycle Database (CLCD) (IKE SCU-ISCP 2013). Since this study is mainly based on PV manufacturing process data in Europe, it is excluded from this process. The study by Frischknecht, Itten et al. (2015) is the most recent publication, and it is based on the previous study by Diao and Shi (2011) with some more up-to-date inventory data mainly obtained from personal communication with Chinese Academy of Science. The GHG emissions of the electricity produced from mainstream- and best-performing PV manufacturing technologies in China are shown in Figure 9.42, together with the GHG emissions of electricity produced from European-manufactured PV in ecoinvent version 3.1 (ecoinvent 2014b).

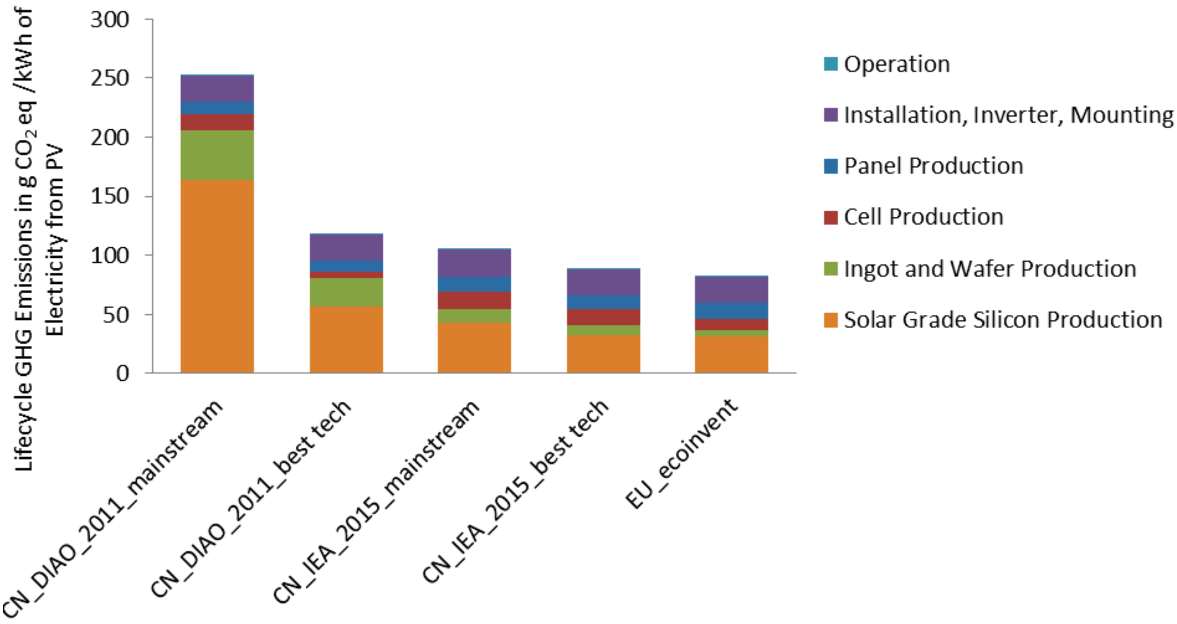


Figure 9.42: Comparison of GHG emissions based on various sources of Chinese manufactured PV life cycle inventory input (Diao and Shi 2011, Frischknecht, Itten et al. 2015); results based on LCI datasets constructed by PSI referring to the inventory data published, using ecoinvent version 3 (ecoinvent 2014b) as background database.

It is shown that the highest emissions are from the Chinese dataset by Diao and Shi (2011), with emissions more than two times higher compared to the electricity produced from European-manufactured PV, which is consistent with the conclusion reached by the study by Yue, You et al. (2014), although the absolute values differ from each other due to different sources of background database (ecoinvent v3 vs. ecoinvent v2 in combination with CLCD). The lowest emissions are from the electricity produced from best PV manufacturing technology published by Frischknecht, Itten et al. (2015), which is slightly more than the emissions of electricity produced from European-manufactured PV. Since both sources are mainly based on the study from Diao and Shi (2011), with limited amount of updated entries in Frischknecht, Itten et al. (2015) with more up-to-date data from Chinese Academy of Science, this large variation is investigated further by comparing the difference between the LCI inputs of these two sources. It is found that this variation is mostly caused by the highly varied electricity and steam input required for wafer and SoG silicon production, as shown in Figure 9.43. This difference in inputs results in large differences in the GHG emissions, because the purification process of silicon to solar-grade is known to be energy intensive, and has a relatively important contribution to the life cycle GHG emissions of electricity produced from PV. In addition, it is also know that the electricity supply in China is mainly dominated by coal power plants, which makes the life cycle emissions of electricity production from PV even more sensitive to the energy intensive processes. The cause of these variations in inputs is however pending further investigation. The large variations in LCA results show the difficulties in compiling inventory data representative for Chinese (and most likely also Asian) manufacturing chains and reflect associated uncertainties in the LCA results.

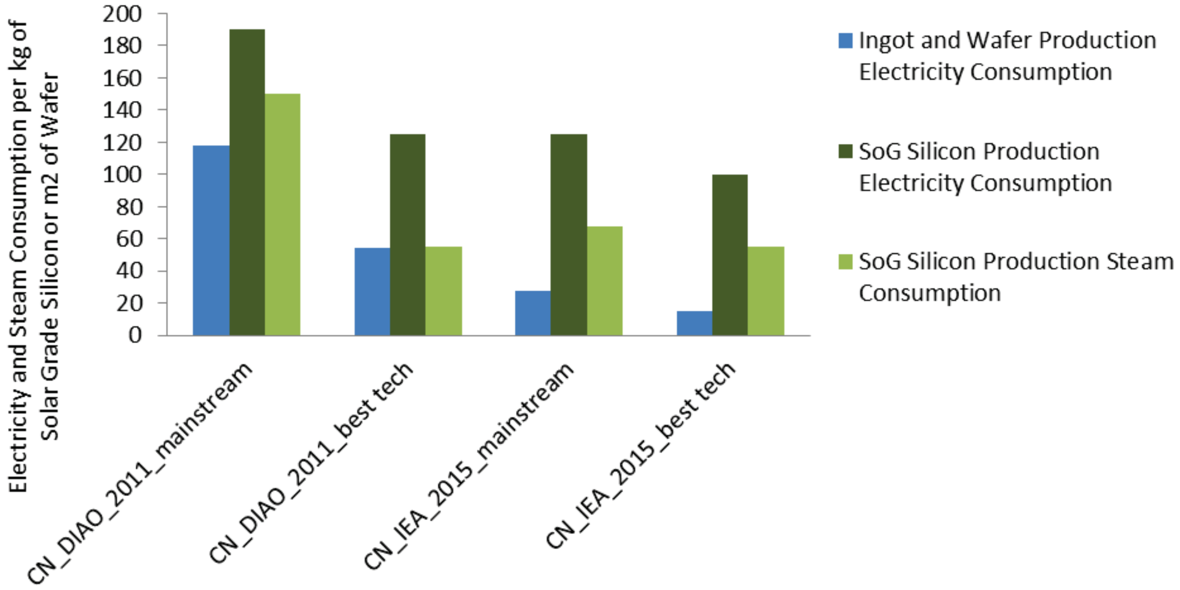


Figure 9.43: Comparison of electricity and steam consumption in manufacturing of wafer and SoG silicon in China based on various sources (Diao and Shi 2011, Frischknecht, Itten et al. 2015).

9.5.1.3 Quantification of current life-cycle GHG emissions of electricity from PV in Switzerland

Based on the references previously cited in section 9.5.1, current life-cycle GHG emissions of electricity from PV in Switzerland can be estimated, as listed in Table 9.17 and visualized in Figure 9.44.

Table 9.17: Life-cycle GHG emissions (g CO_2eq/kWh) of electricity from current PV technologies in Switzerland: slanted roof-top laminate installations, 30 years lifetime, reference annual yield 970 kWh/kWp (range: 850-1500 kWh/kWp per year).

PV technology	best estimate	range	source
multi-c Si	60	39-69	(Itten and Frischknecht 2014)
single-c Si	95	62-109	(Itten and Frischknecht 2014)
ribbon-Si	67	43-76	(ecoinvent 2016)
amorphous Si	63	41-72	(ecoinvent 2016)
thin-film CdTe	38	25-43	(Jungbluth, Stucki et al. 2012a)
thin-film CIS	53	34-61	(ecoinvent 2016)

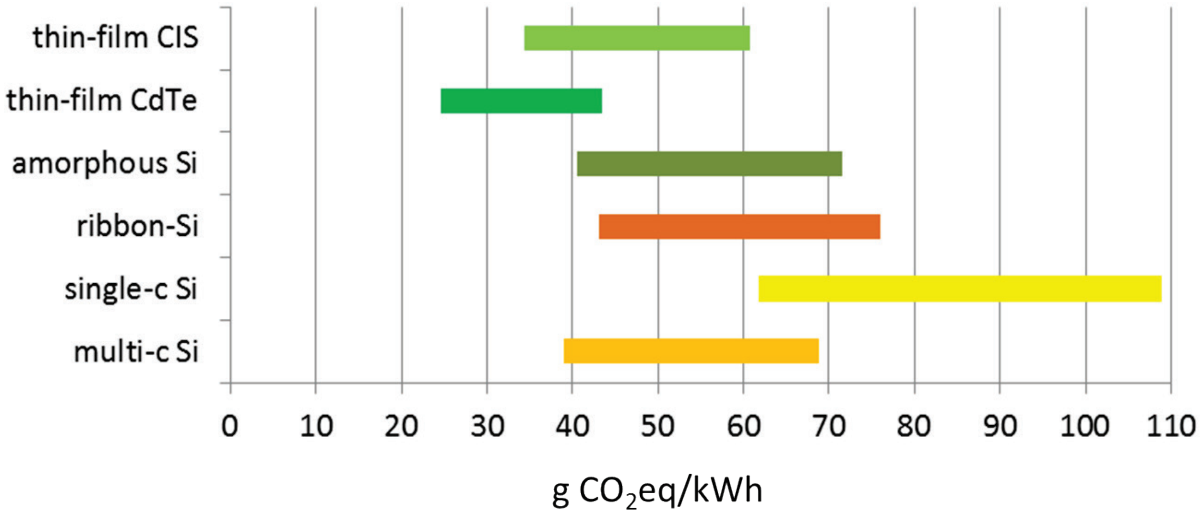


Figure 9.44: Life-cycle GHG emissions of electricity from current PV technologies in Switzerland: slanted roof-top laminate installations, 30 years lifetime, reference annual yield 970 kWh/kWp (range: 850-1500 kWh/kWp per year).

9.5.1.4 Other environmental indicators

In addition to GHG emissions, further LCIA indicators representing other impacts of electricity from PV than those on climate change are provided in Figure 9.45. The indicators are selected based on the recommendations by Hauschild, Goedkoop et al. (2013). Results for PV are based on the inventory data from (ecoinvent 2016); these are compared to those of the current Swiss low-voltage electricity consumption mix according to (ecoinvent 2016).

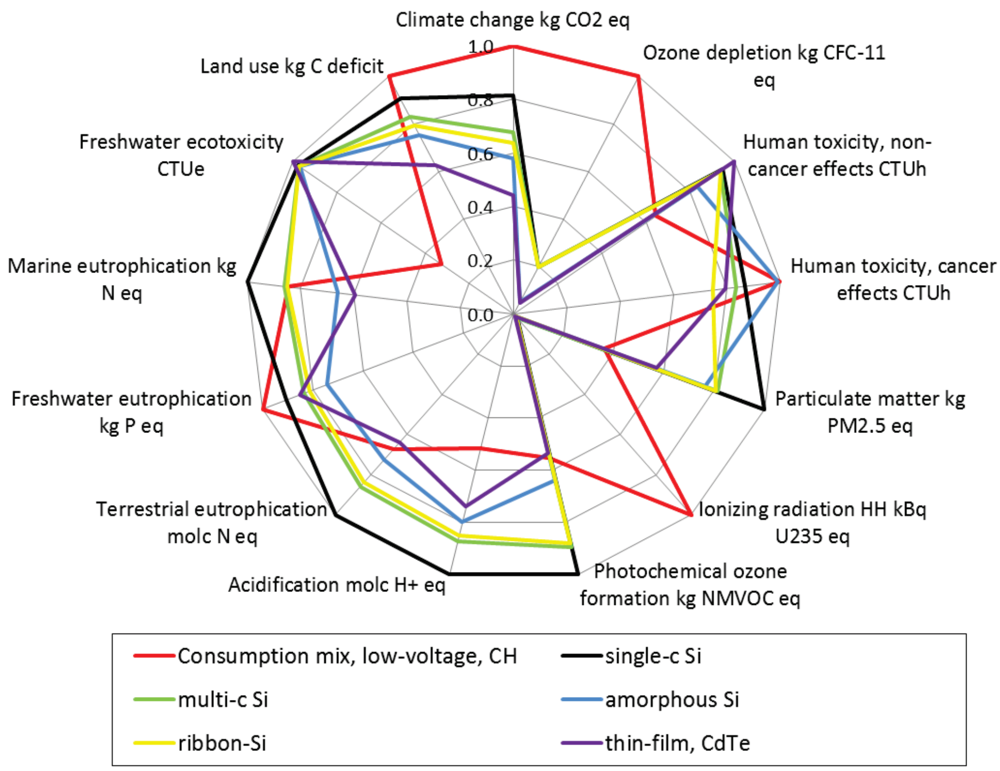


Figure 9.45: LCIA results for electricity from Swiss roof-top PV plants (all slanted roof-top, laminated and integrated installations) according to (ecoinvent 2016) in comparison with the current Swiss low-voltage electricity consumption mix (ecoinvent 2016) using LCIA indicators recommended by Hauschild, Goedkoop et al. (2013). Maximum for each indicator equal to 1.

9.5.2 Environmental performance of future technologies

The environmental performance of future PV technologies will improve mainly due to technology advancement in manufacturing process (wafer thickness, cutting losses, kerf losses, silver use, glass thickness), cell and module efficiency improvement, lifetime of modules, and reduced impacts of indirectly caused burdens via energy supply in the whole manufacturing and supply chain. Frankl, Menichetti et al. (2006) have estimated the main lifecycle emissions (and land-use) of PV systems in year 2025 and 2050 (Table 9.18), assuming three scenarios: pessimistic, optimistic realistic, and optimistic.

By converting the emissions shown in Table 9.18 into global warming potential based on the GWP factors given in IPCC 2013, it is found that by 2025, 1 kWh of electricity generation will create the climate change impact of 17-35 g of CO_2eq, while in 2050, the impact will be further reduced to 2-12 g of CO_2eq.[206] However, these results reflect the future life cycle emissions of the average PV application in Europe, with assumptions of: 1) technology market share (crystalline-Si of 50% in 2025 and 15% in 2050, thin-film of 45% in 2025 and 35% in 2050; other novel PV technologies of 5% in 2025 and 50% in 2050); 2) ground-mounted PV and roof-integrated PV (10% and 90% respectively); 3) contribution of central Europe and southern Europe (in 2025, 50% for Central and Southern Europe, in 2050, 25% for Central Europe and 75% for Southern Europe). Some technology-specific life cycle emissions in 2050 optimistic realistic scenario were also reported, and with the adjusted solar irradiation to be consistent with the assumption in this study (1100 kWh/m^{2}year), it shows general life cycle emissions per kWh of electricity for future PV applications to be below 10 g CO_2eq per kWh, with GaInP/GaAs of about 9 g CO_2-eq per kWh, integrated CdTe PV of about 3 g CO_2eq per kWh, ground-mounted crystalline-Si of about 8 g CO_2eq per kWh, and roof-integrated crystalline-Si of about 9 g CO_2eq per kWh.

Table 9.18: Projections of key emissions and land use of 1 kWh of electricity production from PV systems, NEEDS project (Frankl, Menichetti et al. 2006).

Parameter	Path	Unit	2025 Very Optimistic	2025 Optimistic realistic	2025 Pessimistic	2050 Very Optimistic	2050 Optimistic realistic	2050 Pessimistic
Occupation, agricultural and forestal area	resource	m^2a	3,99E-04	4,15E-04	8,94E-04	1,55E-04	4,80E-03	3,34E-04
Occupation, built up area incl. mineral extraction and dump sites	resource	m^2a	5,13E-04	5,15E-04	9,00E-04	1,81E-03	1,33E-05	4,36E-04
Carbon dioxide, fossil	air	kg	8,85E-03	9,31E-03	1,96E-02	3,25E-03	1,69E-05	5,79E-03
Methane, fossil	air	kg	1,77E-05	2,02E-05	4,28E-05	9,29E-06	1,08E-05	1,57E-05
Nitrogen oxides	air	kg	2,47E-05	2,59E-05	5,36E-05	1,12E-05	6,95E-06	2,27E-05
NMVOC total	air	kg	1,98E-05	2,01E-05	4,67E-05	5,40E-06	3,93E-06	1,78E-05
PM2.5-10	air	kg	6,06E-06	6,19E-06	1,06E-05	5,72E-06	1,96E-05	5,27E-06
PM2.5	air	kg	4,58E-06	4,93E-06	8,52E-06	3,06E-06	2,21E-04	4,31E-06
Sulfur dioxide	air	kg	3,82E-05	4,08E-05	8,11E-05	1,15E-05	1,57E-03	4,17E-05

[206] Results from NEEDS project, 2008, final report on technical data, costs and life cycle inventories of PV applications; error contained in the optimistic scenario, therefore it is not included here; values for the "expected" scenario were taken from "optimistic realistic"; original results published in emissions of CO_2 and CH_4; conversion of CH_4 to CO_2 equivalents performed using CH_4 GWP of 25; the same is applicable to results in 2050.

Another study by Raugei and Frankl (2009) has estimated the future life cycle emissions for electricity production from system based on ribbon-Si, CdTe and dye-sensitized PV, with the following technological characteristics.

Table 9.19: Key assumptions on selected future PV systems

Year	2025		2050		
Technology	c-Si ribbon	CdTe	c-Si ribbon	CdTe	DSC
c-Si layer thickness (μm)	150	–	100	–	–
Efficiency (%)	20	13	22	16	17
Lifetime	35	35	40	40	15

However, the study was performed under the following assumptions: performance ratio of 75% and solar irradiation of 1700 kWh/m^{2}year. With adjusted assumptions of performance ratio and solar irradiation that are consistent with the assumptions applied in this study for Switzerland, the results on future projected GHG emissions obtained by Raugel and Frankl are scaled up by 45%, leading to life cycle emissions for CdTe PV of about 12 g CO_2eq/kWh in 2025 and 9 g CO_2eq/kWh in 2050, for ribbon-Si PV of about 19 g CO_2eq/kWh in 2025 and 13 g CO_2eq/kWh in 2050, and dye-sensitized PV of about 15 g CO_2eq/kWh in 2050.

The estimates for future environmental burdens from PV electricity generation in Switzerland in this report are based on the most recent prospective LCA of PV (Frischknecht, Itten et al. 2014). In line and largely based on the previously cited NEEDS project (PV report by Frankl, Menichetti et al. (2006)), Frischknecht, Itten et al. (2014) compiled inventory data for single-crystalline Si and CdTe PV modules for three different scenarios (“business as usual” – BAU, “realistic improvement” – REAL, and “optimistic improvement” – OPT), representing different future technology development for both PV manufacturing chains as well as background economy (e.g. electricity supply). Key assumptions concerning future technology specification (manufacturing in 2050) are reproduced in Table 9.20.

Based on the projected changes to key parameters and the background system, life cycle GHG emissions could be reduced by 35-82% for sc-Si and by 30-68% for CdTe modules, installed on European roof-tops in 2050. Multi-crystalline Si modules are not addressed in (Frischknecht, Itten et al. 2014). For the purpose of this study (i.e., in order to provide figures for 2020, 2035 and 2050), potential reductions until 2050 are assumed to be linear and reductions for mc-Si are assumed to be equal to those for sc-Si. Resulting future life-cycle GHG emissions are provided in

Table 9.21 and Figure 9.46.

Table 9.20: Key parameters of future PV technology manufactured in 2050 according to (Frischknecht, Itten et al. 2014). Year 2050 scenarios: BAU "business as usual"; REAL "realistic improvement"; OPT "optimistic improvement".

Parameter	Single-Si				CdTe			
	TODAY	BAU	REAL	OPT	TODAY	BAU	REAL	OPT
Cell efficiency	16.5 %	25.0 %	27.0 %	29.0 %	15.6 %	22.8 %	24.4 %	26.0 %
Derate cell to module efficiency	8.5 %	8.5 %	6.8 %	5.0 %	13.9 %	10.0 %	7.5 %	5.0 %
Module efficiency	15.1 %	22.9 %	25.2 %	27.6 %	13.4 %	20.5 %	22.6 %	24.7 %
Wafer thickness / layer thickness	190 µm	150 µm	120 µm	100 µm	4.0 µm	2.0 µm	1.0 µm	0.1 µm
Electricity demand in CdTe laminate manufacture	-	-	-	-	100 %	86 %	81 %	74 %
Kerf loss	190 µm	150 µm	120 µm	100 µm	-	-	-	-
Silver per cell	9.6 g/m^2	9.6 g/m^2	5.0 g/m^2	2.0 g/m^2	-	-	-	-
Fluidized-bed reactor (FBR) Share of Poly Si Production	0 %	20 %	40 %	100 %		-	-	
Glass thickness	4.0 mm	4.0 mm	3.0 mm	2.0 mm	3.5 mm	3.5 mm	3.0 mm	2.0 mm
Operational lifetime	30 years	30 years	35 years	40 years	30 years	30 years	35 years	40 years

Table 9.21: Life-cycle GHG emissions (g CO_2eq/kWh) of electricity from future (and current) PV technologies in Switzerland: slanted roof-top laminate installations, reference annual yield 970 kWh/kWp (range: 850-1500 kWh/kWp per year), future technology specifications according to Table 9.20.

PV technology	2016	2020	2035	2050
multi-c Si	39-69	35-66	21-55	7-45
single-c Si	62-109	56-104	33-88	11-71
thin-film CdTe	25-43	23-42	15-36	8-30

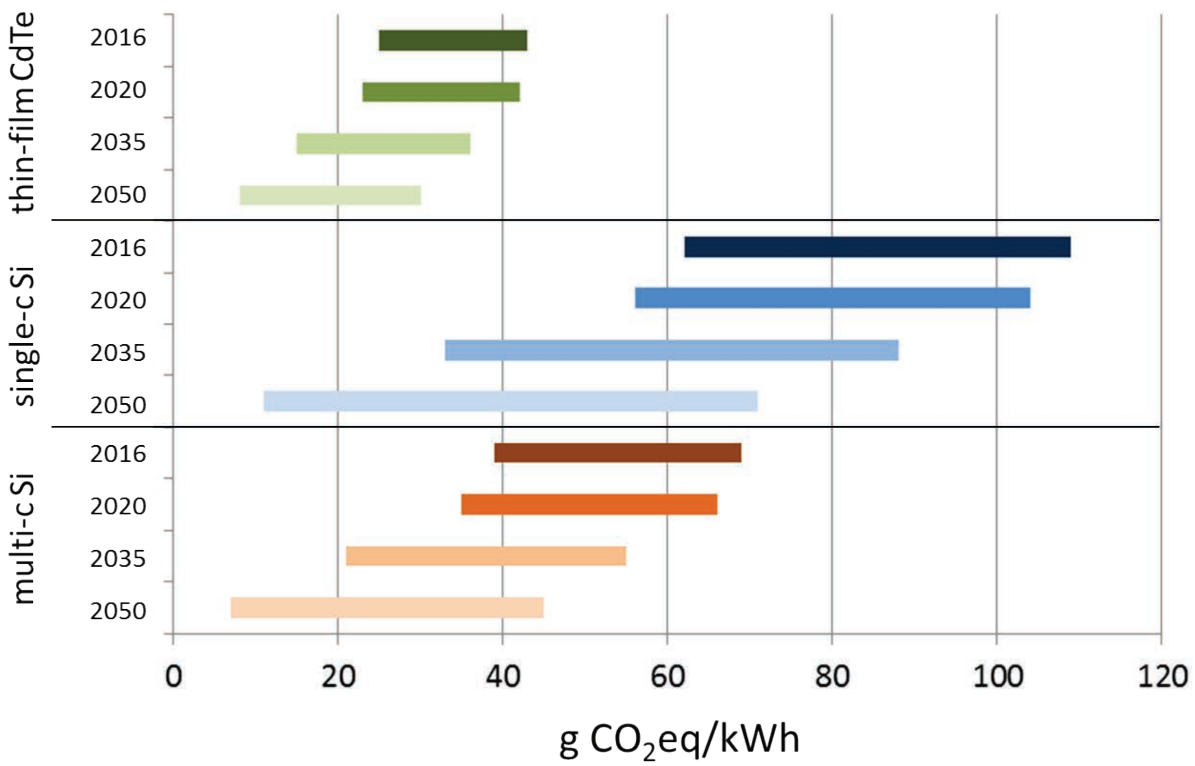


Figure 9.46: Life-cycle GHG emissions of electricity from future (and current) PV technologies in Switzerland: slanted roof-top laminate installations, reference annual yield 970 kWh/kWp (range: 850-1500 kWh/kWp per year), future technology specifications according to Table 9.20.

9.6 Open questions, limitations and research needs

The present analysis has provided an overview of the current status and the potential future development of PV in Switzerland. However, there are a few aspects in the analysis that could be refined and further investigated. For example, other than module and inverter costs, all the other costs (BOS, labor cost for installation and planning, other cost) are assumed to be reduced by the decreasing area required for installation, as a result of future efficiency improvement. Other factors that will reduce these costs such as improved practices are not considered, as they could be different from region to region, and appropriate local data are lacking, which makes projections impractical. There are many references on the future cost development of PV systems with most data from Germany and US, and usually for utility-scale systems, which cannot be easily adopted for the cost analysis for Switzerland. Concerning environmental burdens of electricity from PV (LCA), inventory data for current technologies could be improved to better reflect the real conditions. Due to the complexity of global PV manufacturing chains and trading of components and materials between countries, further investigations are needed with more detailed inventory data. Inventory data for emerging manufacturing technologies not covered in the present analysis (such as fluidized bed reactor (FBR)), and market share analyses need to be updated to capture the fast development of the industry. Uncertainty ranges of environmental performance with consideration of performance and resource parameters should be analyzed by category of PV technology.

Future PV installations in Switzerland will not only be affected by global cost developments, but also by political driving factors, such as incentive schemes and regulations concerning self-consumption. These factors are not covered in the present study.

Research is required in exploring new materials, how to improve the performance of novel PV technologies, and how to speed up the commercialization of low-cost PV technologies. In Switzerland, the cost of modules, inverters, and BOS will eventually decrease following the global market trend, and as the contribution of other "soft costs" (such as labor cost for installation and planning, and other costs) becomes more important, policies that facilitate the reduction in these costs are crucial for the future development of photovoltaics. Collection of local data as well as more detailed research in understanding the region-related costs and supply chain is needed.

9.7 Abbreviations

a	year
a-	amorphous
ac	alternate current
APAC	Asian and pacific countries
ARE	Bundesamt für Raumplanung
BAFU	Bundesamt für Umwelt
BAPV	building attached photovoltaics
BFE	Bundesamt für Energie
BIPV	building integrated photovoltaics
BOS	balance of system
-c	crystalline
CAPEX	capital expenses
CdTe	Cadmium telluride
CH	Switzerland
CHF	Swiss Francs
CIS	copper indium selenide
CIGS	copper indium gallium selenide
CO_2eq	carbon dioxide equivalent
CZ-Si	Czochralski Silicon
DC	direct current
EIV	Einmalvergütung
EU	European Union
GHG	Greenhouse gas
HH	human health
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
KEV	Kostendeckende Einspeisevergütung/compensatory feed-in renumeration
LCA	life cycle assessment
LCIA	life cycle impact assessment
LCOE	Levelised Cost of Electricity
max	maximum
mc-	multi-crystalline
MEA	Middle East and Africa
MG	metallurgical-grade
min	minimum
O&M	operation and maintenance
OPEX	Operating and maintenance expenses
p	peak
PV	photovoltaics
RoW	rest of the world
Rp.	Rappen (Swiss cents)
sc-	single-crystalline
Si	silicon
SoG	solar grade
UK	United Kingdom
US	United States
USD	United States Dollar
WEEE	Waste Electrical and Electronic Equipment
yr	year

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10 Electricity from biomass

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10.1 Introduction

10.1.1 Definition

This chapter considers the potential for electricity generation from domestic biomass resources in Switzerland. When reading this chapter, it is important to remember that unlike for most other electricity generating resources, biomass can also be used in other energy sectors such as for heat only or transportation, and for non-energy sectors. This creates a competing situation for the feedstock. In other countries, this has historically included the competition between biomass for food and for fuel, but this is not an issue in Switzerland as energy crops use are of minor importance here. However, the use of biomass as a material (e.g. forest wood for furniture) and for heat generation continue to be relevant. Synergies, not only competition, can also exist between mobilization of woody feedstock (energy/non-energy). For example, the energy wood can be harvested at the same time as – or as a by-product of – wood collection for material uses. Finally, there are close ties between electricity generation and heat generation for many biomass uses, and these are addressed throughout the chapter.

The use of biomass for electricity generation encompasses a varied range of feedstocks, processing steps, and electrical conversion technologies. Very broadly, electricity can be generated from biomass following the pathways shown in Figure 10.1. The direct conversion pathways from biomass to electricity are shown on the left-hand side. Alternatively, biomass can also be transformed first to biomethane, which is chemically similar to natural gas and can therefore be transported through the natural gas grid. The biomethane can then be used to generate electricity (and heat) as needed, without needing to be tied geographically or in time to the original biomass resource.

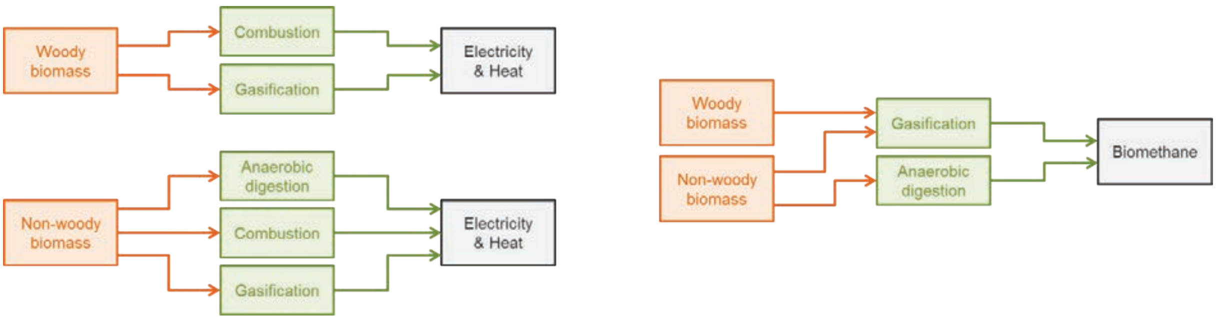


Figure 10.1: Broad overview of conversion pathways from biomass resources to electricity.

Feedstocks can be broadly categorized as “woody” or “non-woody” biomass. Woody biomass consists of forest wood, industrial wood residues, waste wood, and wood from landscape maintenance. These resources can be directly converted to electricity either by combustion or gasification pathways. Combustion is followed by a combined heat and power system (CHP) to directly produce electricity and heat. Gasification is followed by any technology that can take gaseous fuel as an input for various CHP systems (internal combustion engine, turbine or fuel cells[207]).

Non-woody biomass consists of several feedstocks of varying liquid content, including organic parts of household waste, industrial bio-waste, agricultural crop by-products, green waste, animal manure, and sewage sludge. Feedstocks with high liquid content (sewage sludge, manure, etc.) are first processed through an anaerobic digester. The resulting biogas can be used directly to generate electricity and heat in an engine, turbine, or fuel cell. Feedstocks with lower liquid content can be combusted to drive a steam or organic Rankine (ORC) cycle. Gasification of waste feedstocks is also technically feasible, and one commercial waste gasifier exists today (in Lahti, Finland).

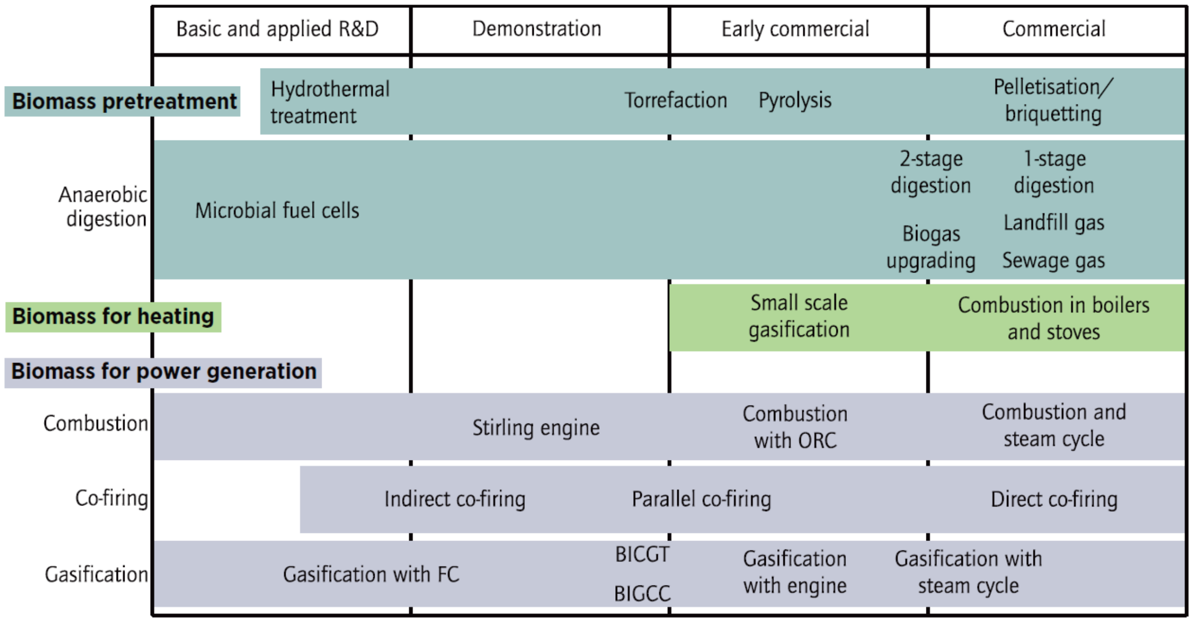
An alternative to direct electricity is via the production of biomethane, as depicted schematically in Figure 10.1. The biomethane produced can then be injected into the natural gas grid, where it can be converted to electricity as needed by any of the conversion paths that are open to natural gas[208]. The process chain for producing biomethane generally needs at least two main process steps. First, a gas must be generated from the biomass resource. Then, this gas must be upgraded to reach the quality required for grid injection. In Switzerland the gas grid requirement is that the gas must be >96% CH_4 (SVGW/SSIGE 2014).

For non-woody biomass, the first step is done by anaerobic digestion. For woody biomass, it is by gasification. The second step can be done in several ways. For biogas the gas upgrading takes place in a gas separation unit (e.g., amine scrubbing or membrane) to separate gases such as CO_2 from the methane in the biogas. In biomass gasification, the gas also contains CO and H_2. In a methanation reactor, additional CH_4 is produced from the H_2 and carbon compounds (CO, CO_2) present in the syngas. The resulting methanated syngas is similar to biogas and can be upgraded with the same gas separation unit (e.g., amine scrubbing or membrane).

The technology portfolio for bioenergy relevant for direct heat and electricity production is large and on different development status, as can be seen in Figure 10.2 (Lako, Koyama et al. 2015). Since 2009, the date of the original publication of this figure, some progress has been achieved. Technologies positioned at that time as “early commercial” are now commercial. This is the case for biogas upgrading, combustion with Organic Rankine Cycle (ORC) and gasification with engine (small scale systems). Other technologies such as Stirling engine, biomass internal combustion gas turbine (BICGT) and biomass integrated gasification combined cycle (BIGCC) have not yet had a technical breakthrough, and no early commercial plants exist.

[207] Fuel cells operated with biomethane are part of chapter 16.

[208] Alternatively, it can also be used for other, competing purposes, e.g. as vehicle fuel. Such other purposes are not within the scope of this study.



Note: ORC = Organic Rankine Cycle; FC = fuel cell; BICGT = biomass internal combustion gas turbine; BIGCC = biomass internal gasification combined cycle

Source: Modified from Bauen et al., 2009

Figure 10.2: Overview of biomass conversion technologies and their current development status which are relevant for heat and power production. Figure is from (Lako, Koyama et al. 2015).

Concepts for processes for the conversion of woody biomass to biomethane differ in scale, from 1 MW up to several hundreds of MW. Multitudes of gasification processes exist to produce a syngas suitable for biomethane production. Nevertheless, dual fluidized bed (DFB) gasification is the dominant design for biomethane production. Also for gas cleaning multitudes of processes exist to produce a (ultra) clean syngas suitable for biomethane production, as well as multitude of methanation processes. There is no dominant design, neither for gas cleaning nor for methanation. Technical solutions in consideration for individual steps such as gasification, methanation and gas upgrading differ considerably in scale (see Figure 10.3).

A first industrial scale plant from woody biomass to biomethane has been built in Gothenburg and has been in operation since 2014 (see Figure 10.4). The scale of the GoBiGas installation is of 32 MW_{wood} with an output of 20 $MW_{biomethane}$.

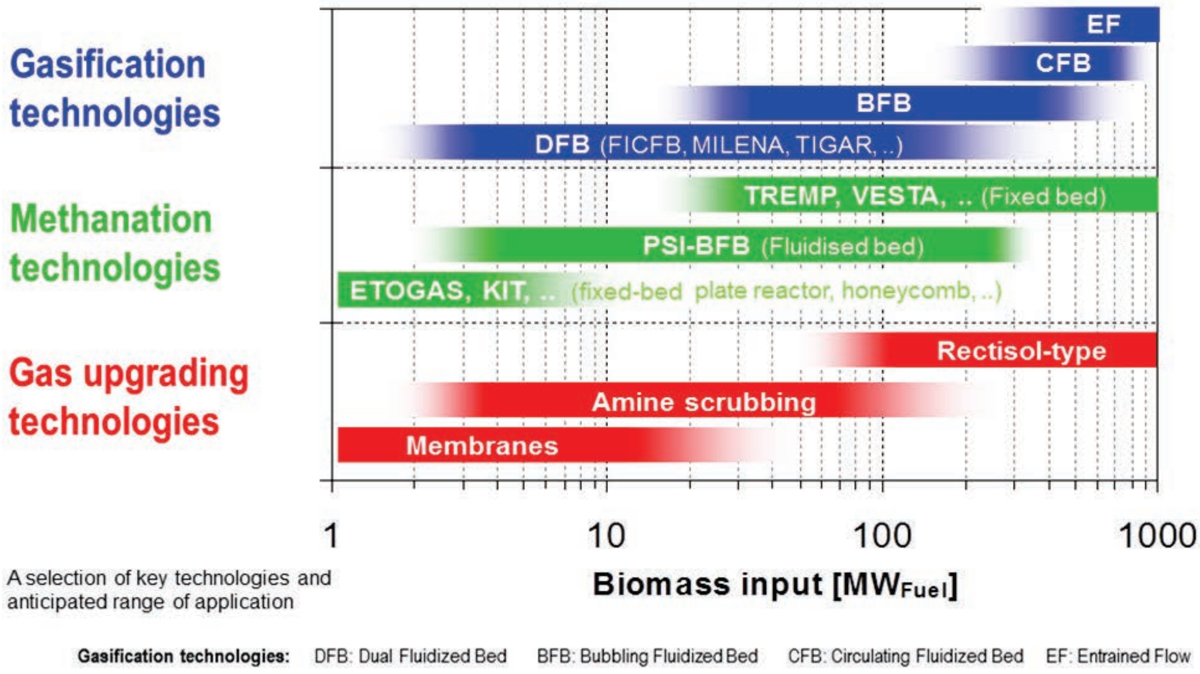


Figure 10.3: A selection of key technologies for biomethane production from woody biomass (Biollaz, Schildhauer et al. 2015).

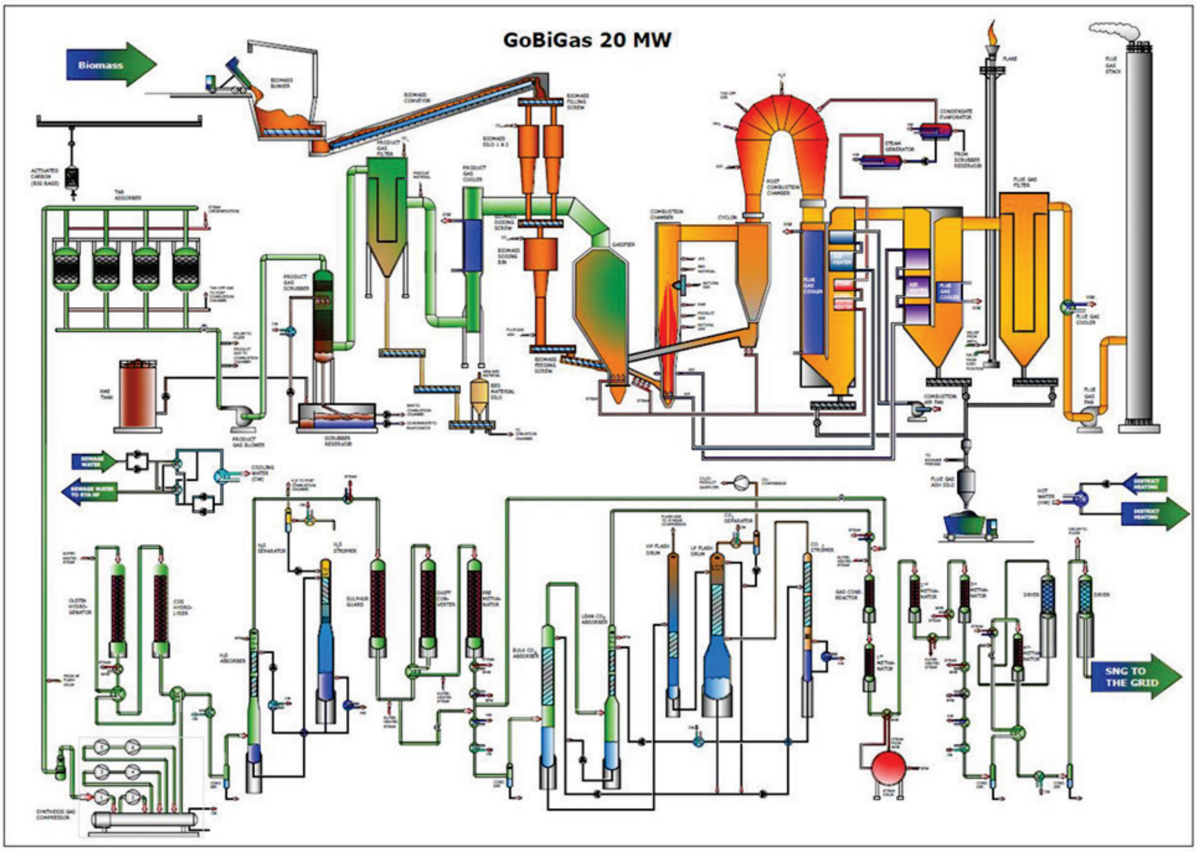


Figure 10.4: Schematic overview of the GoBiGas-plant (Thunman, Larsson et al. 2015).

Additional biomethane or more general renewable methane can be generated by the use of Power-to-Gas technologies. In these technologies, CO_2 can be combined with hydrogen gas in a methanation reactor to produce methane. The hydrogen gas is supposed to be produced from electrolysis of water by electricity produced with renewable technologies (solar, wind, hydro and geothermal). The CO_2 source can be from biomass resources (biogas from anaerobic digestion is 40-50% CO_2) or from non-biomass resources such as from industrial processes or from the atmosphere. Additional biomethane production could therefore be envisaged in the long term, if CO_2 from biomass conversion is used in Power-to-Gas processes.

10.1.2 Global and European trends

10.1.2.1 Global trends

The International Energy Agency (IEA) publishes the results of its climate and energy modelling efforts on a yearly basis in the Energy Technology Perspectives (ETP) report (Elzinga, Bennett et al. 2015). In the 2015 edition, the IEA's 2°C scenario (2 DS) shows bioenergy becoming the largest primary energy carrier by 2050, as seen in Figure 10.5. This includes contributions from biomass directly for industry (high temperature heat), for residential use (low temperature heat), and for biofuels, in addition to electricity production. Overall, this scenario represents a tripling of the bioenergy contribution to the global energy supply by 2050 relative to 2015 in order to avoid exceeding the 2°C target.

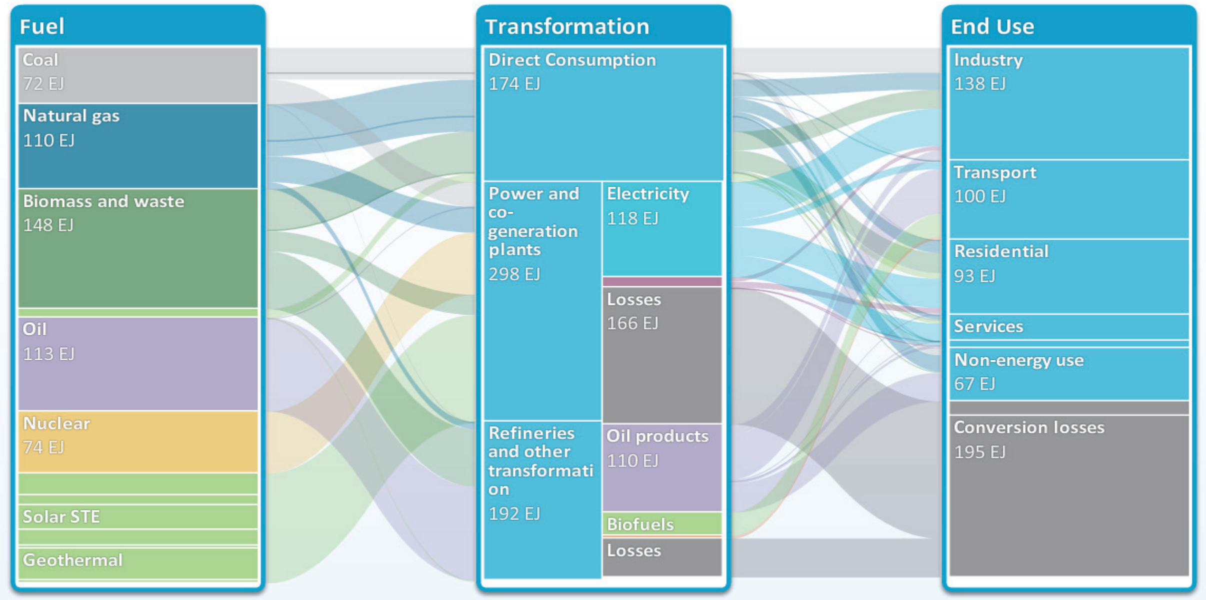


Figure 10.5: Role of bioenergy in IEA Energy Technology Perspectives 2015. Bioenergy is largest primary energy carrier in IEA's 2 DS scenario in 2050. Figure is from (Elzinga, Bennett et al. 2015).

The effect of this scenario on regional electricity supply is shown in Figure 10.6. By 2050 – and even by 2030 – there will need to be a significant increase in the share of electricity that is generated from biomass, across all regions. In 2012 (the year of the current data given in Figure 10.6), the European Union already has a larger share of electricity produced from biomass than any other region.

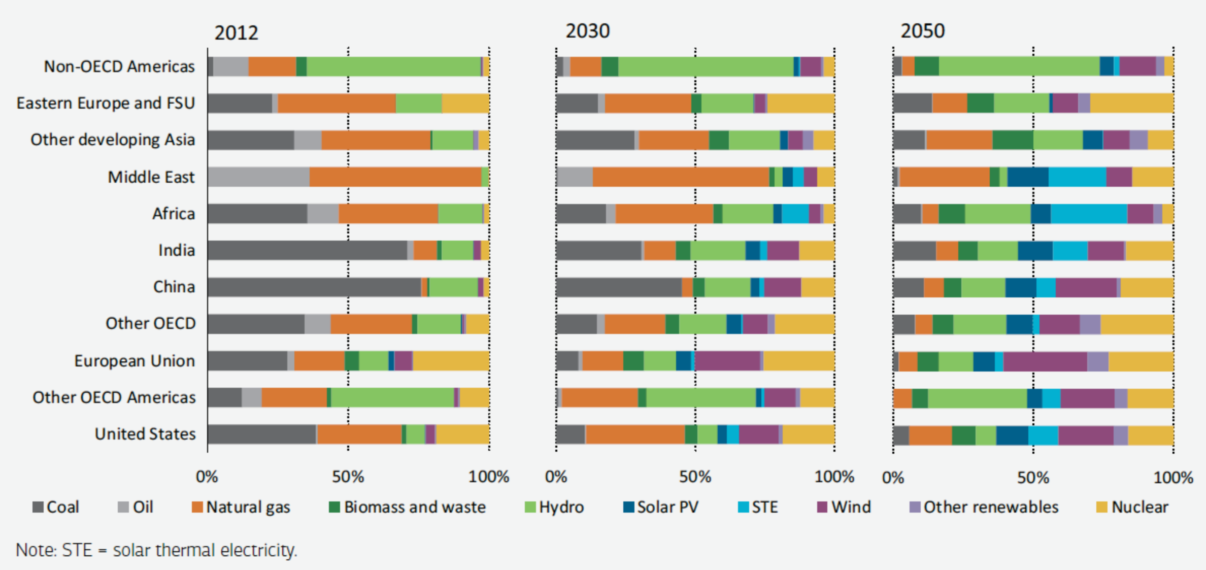


Figure 10.6: Evolution of regional electricity generation mixes in the IEA's 2 DS over time. Figure is from (Elzinga, Bennett et al. 2015).

10.1.2.2 European trends

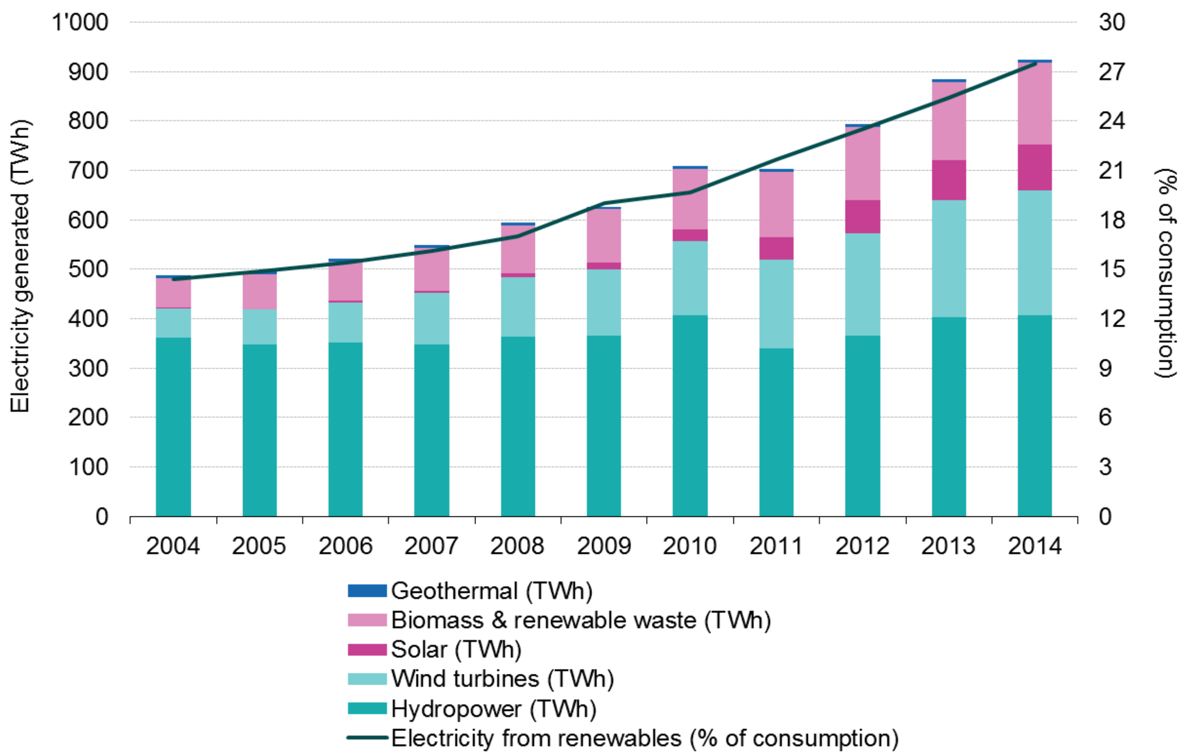


Figure 10.7: Electricity generated from renewable energy resources in the EU-28, 2004-2014. Source: (EUROSTAT 2016).

Electricity generation from biomass sources has been steadily increasing in Europe over the past decade along with the overall increase in renewable electricity, as seen in Figure 10.7. However, electricity from biomass still represents a small fraction of the total electricity mix in Europe (at just over 5% of the total electricity consumption). By far, the leading European country for electricity generation from biomass is Germany, representing about one third of the total generation in the EU (see Figure 10.8 and Figure 10.9). The situation in Germany is discussed in detail in the following section, both due to its leadership role in bioelectricity and because its market bears several similarities to the Swiss one.

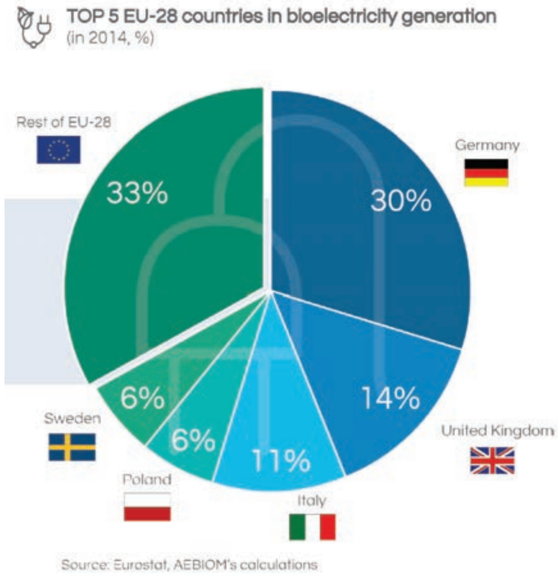


Figure 10.8: Top 5 EU-28 countries in bioelectricity generation. Source: (Calderón, Gauthier et al. 2016).

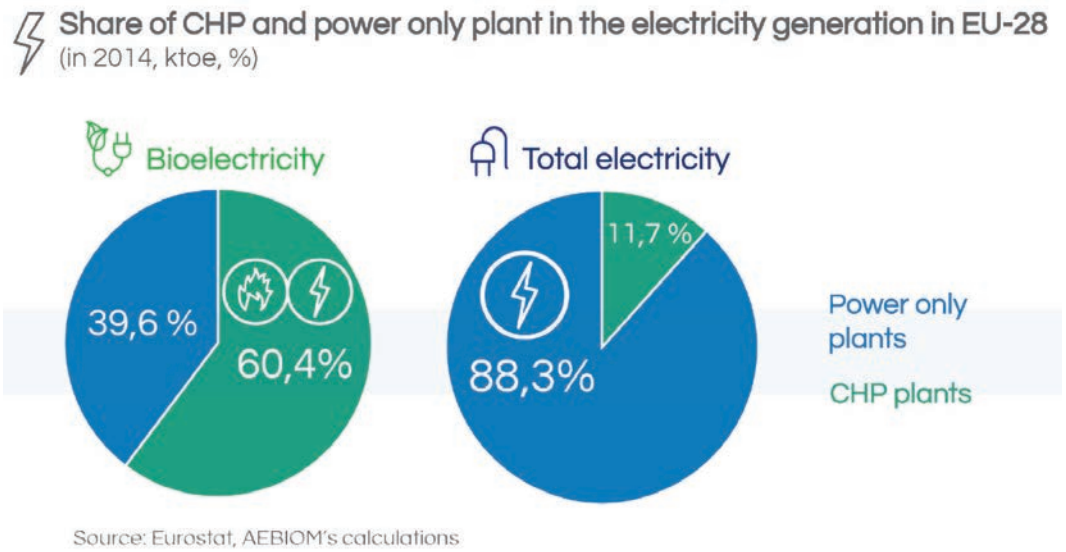


Figure 10.9: Share of CHP and power only plants in the electricity generation in EU-28. Source: (Calderón, Gauthier et al. 2016).

Although biomass still generates only a small fraction of the electricity in Europe, it is also used to generate useful heat – often at the same time as generating electricity. As seen in Figure 10.9, 60% of bioelectricity production in Europe also generates heat, while only 12% of other electricity production does the same. This creates significant added value for bioelectricity plants when the heat is sold.

Electricity production from biomass can be either from woody biomass or from non-woody biomass. The types of non-woody biomass used can be quite different depending on the needs and resources of each country, as shown in Figure 10.10. This figure shows the profile of biogas plants (i.e. anaerobic digestion based plants) by biomass resource type in European countries. Relative to other European countries, existing Swiss biogas plants are much more focused on sewage than agricultural resources. This reflects both the current underutilization of Swiss manure and the fact that other countries – Germany in particular – have installed energy crop (e.g., maize) based systems which are currently of minor importance in Switzerland.

Finally, European countries also produce grid-injectable biomethane from biomass resources as an alternative to direct bioelectricity production. Once again, Germany has a clear leading role in this category, as seen in Figure 10.11.

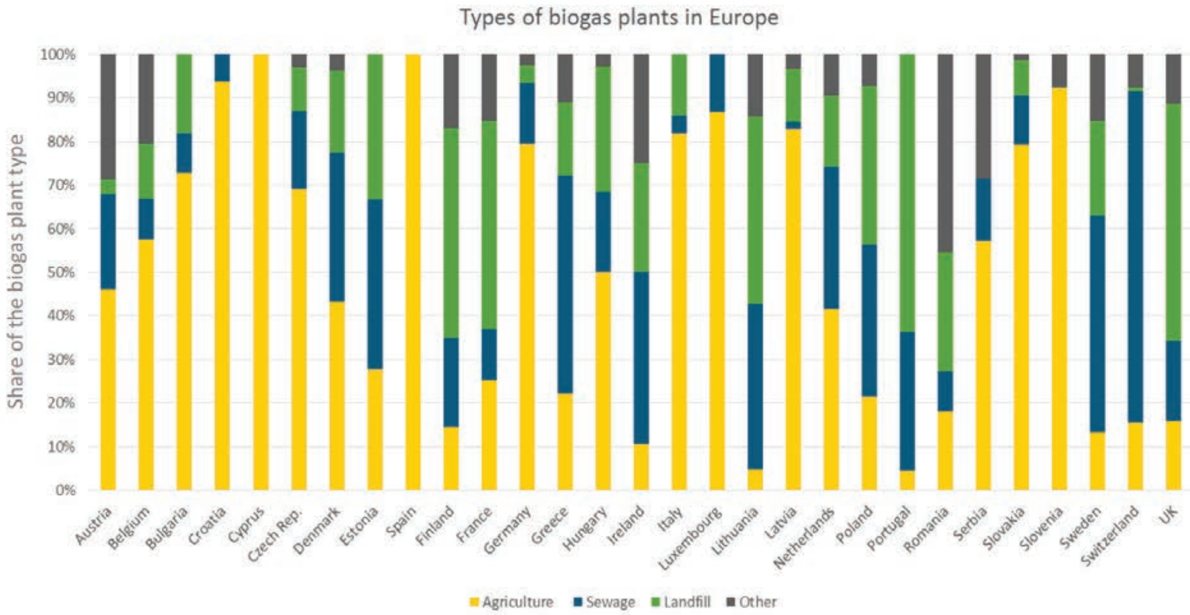


Figure 10.10: Fraction of biogas plants by feedstock category across Europe. Source: (Štambaský, Prządka et al. 2015).

Estimates for sustainable biomass resources for energetic use in the EU are shown in Figure 10.12. This figure, which comes from a recent review of different EU biomass resource potential assessments in the literature, shows that the remaining biomass potential is in the range of 10’600-21’350 PJ in 2020, and 10’850-22’700 PJ in 2030 (Khawaja and Janssen 2014). This is relative to the 7’750 PJ of biomass used energetically in 2012, which represents >60% of renewable energy use in the EU (Khawaja and Janssen 2014).

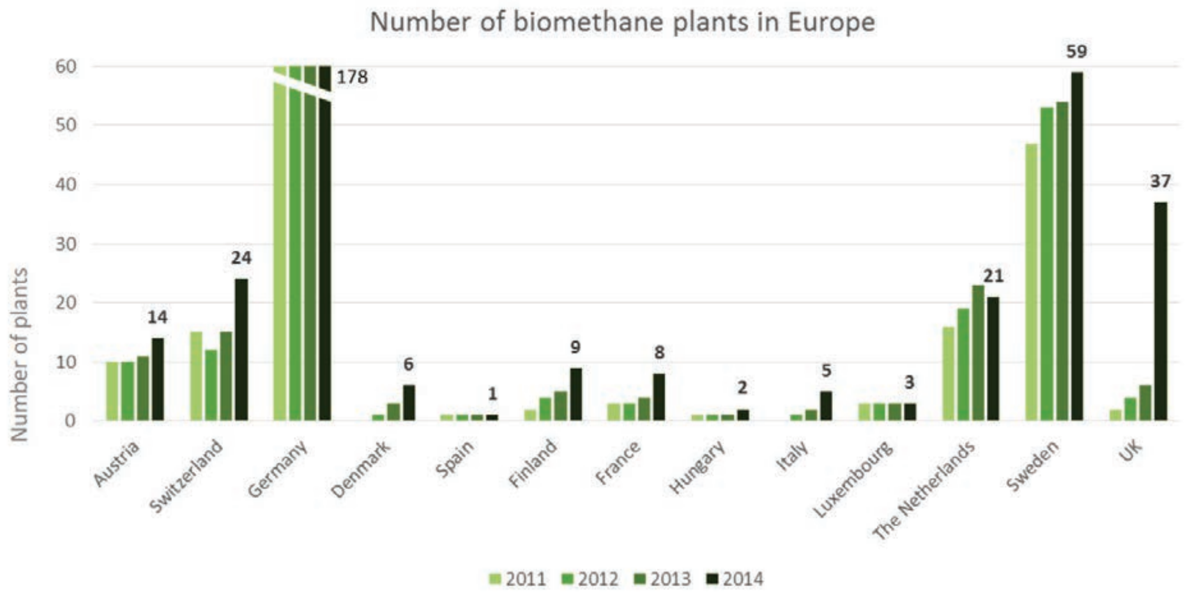


Figure 10.11: Development of biomethane plants in European countries. Source: (Štambaský, Prządka et al. 2015).

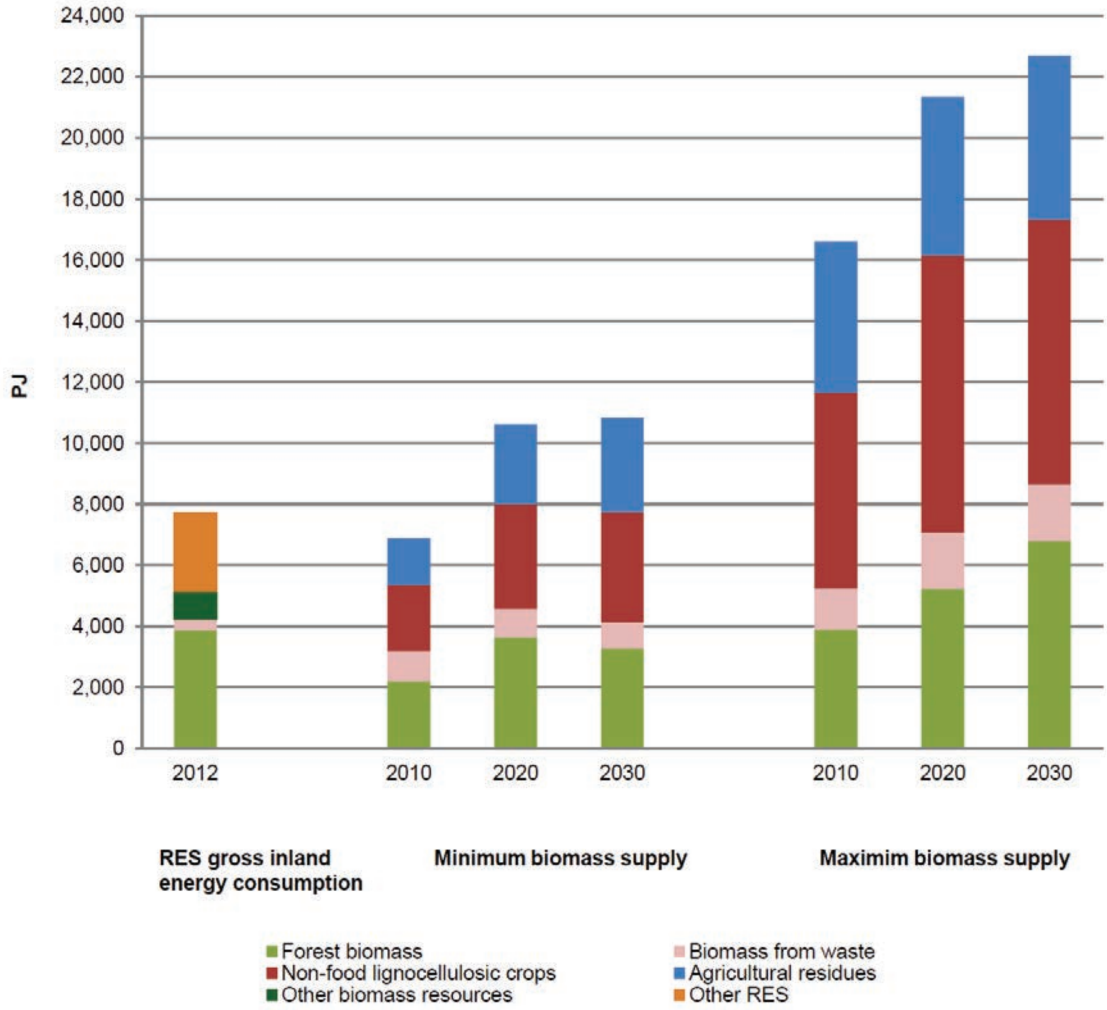


Figure 10.12: Minimum and maximum estimation values of biomass potential supply for bioenergy use in the EU. Source: (Khawaja and Janssen 2014).

10.1.2.3 German trends

On a European level, the case of Germany is the most important one to consider in detail. Germany is one of the largest markets for technologies for the production of bioelectricity and biomethane. Moreover, most of the technologies implemented in Germany are relevant for Switzerland, and the markets have many similarities. Figure 10.13 and Figure 10.14 demonstrate the importance of biomass for electricity generation in Germany today. In 2015, electricity from biomass represented 27% of the total electricity generation from renewables. Meanwhile, both the installed capacity and the total yearly generation of electricity have been increasing nearly linearly since 2004 (BMWi 2016).

The development in Germany was stimulated by the German Renewable Energy Act, which was implemented in the year 2000 (German: "Erneuerbare-Energien-Gesetz, EEG"). In the year 2001, 28% of the bioelectricity produced was supported by the EEG, and by the year 2014 it was 75% (calculated from data in (BMWi 2016)). This shows that without attractive feed-in tariffs, most likely such a development would not have been possible under the current market conditions. Nevertheless, for wind and solar PV the EEG support is even more important, as wind is supported by the EEG at 100%, and photovoltaics are supported at 90%. Moreover, the strong development of bioelectricity installations in Germany should contribute to cost reductions in both Germany and Switzerland, as economies of scale for mass production of bioelectricity components develop.

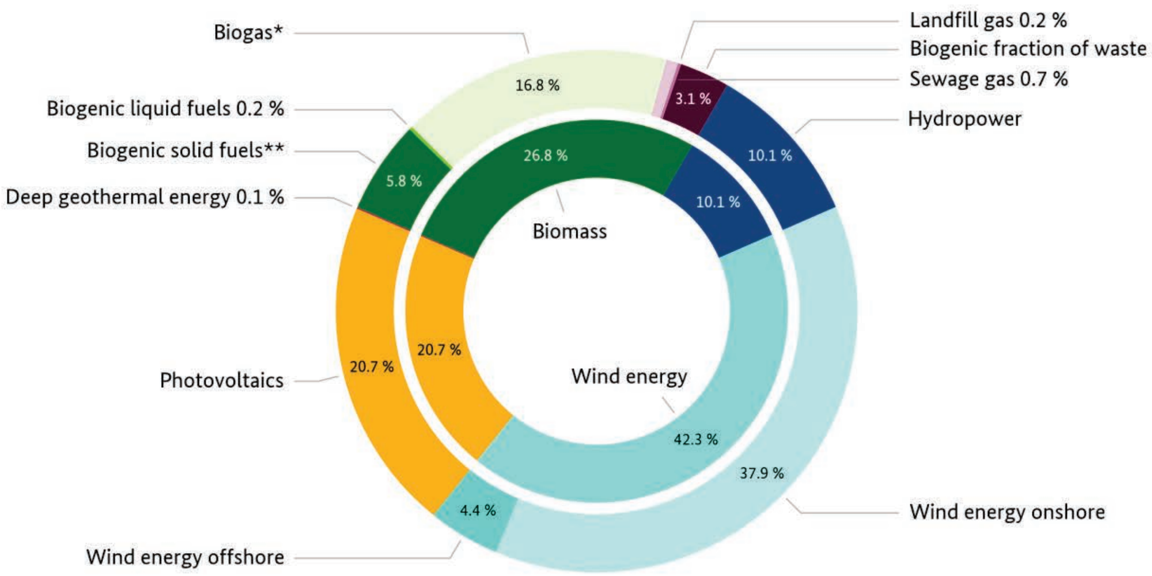


Figure 10.13: Share of electricity generation from all renewables in Germany 2015; total production of renewable electricity: 187.3 TWh. Figure is from (BMWi 2016).

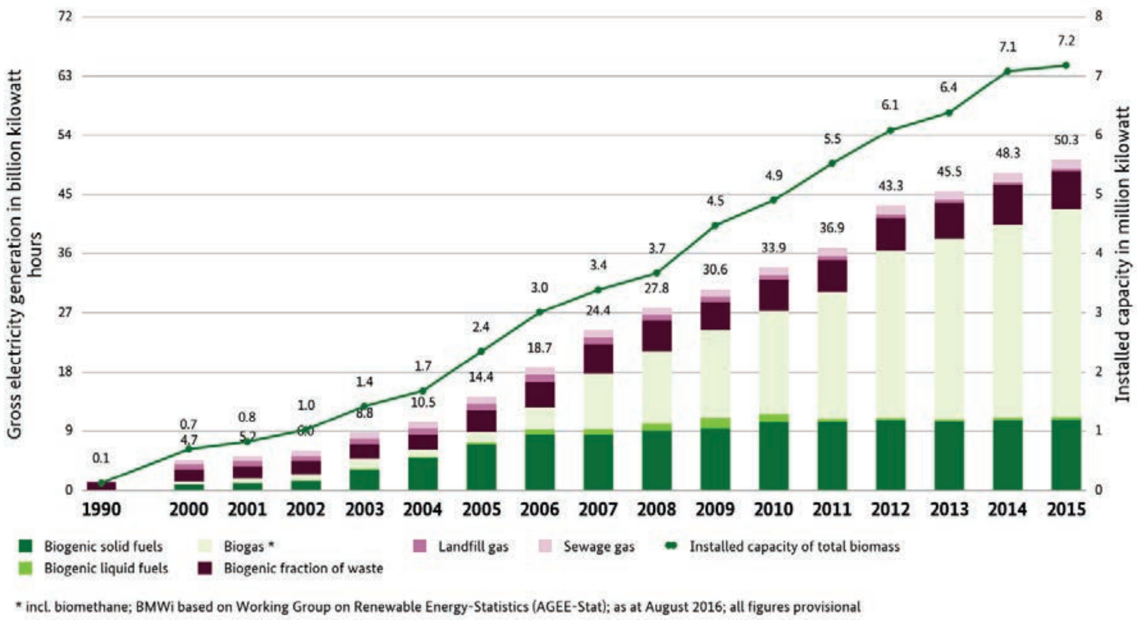


Figure 10.14: Development of power generation from biomass and installed capacity in Germany. Figure is from (BMWi 2016).

10.2 Feedstock

"Biomass" is a broad term that covers a wide variety of different feedstocks, which then follow various conversion pathways to produce electricity. In most cases, the choice of conversion pathway depends on the properties of the type of feedstock available – including its liquid content, its particle size and its chemical composition. This study considers all biomass from the sectors of forestry, agriculture and waste management in Switzerland.

To describe the biomass feedstock potentials, the feedstock categorisation system used in this study is the one used by WSL (Eidg. Forschungsanstalt für Wald, Schnee und Landschaft) in the study "Renewable Energies Aargau" (Ballmer, Thees et al. 2015). This system is described in the following sub-sections. The assessment of the potentials and the cost estimations presented here were carried out by WSL researchers, who also wrote the text describing the potential types and feedstock categories.

10.2.1 Description of potential categories

The evaluation of the biomass potential that can be used sustainably is a multi-step process, depicted graphically in Figure 10.15. Four potential categories are used in this chapter.

- **Theoretical potential**: Represents the total quantity of that feedstock that exists in Switzerland today.
- **Sustainable potential**: Represents the theoretical potential, minus a range of technical, political, economic, legal, and environmental constraints.
- **Used potential**: Refers to the portion of the sustainable potential that is already used energetically (i.e. for heat, electricity, or fuel production) today.
- **Remaining sustainable potential** [209]: Refers to the difference between the sustainable potential and the used potential. This describes the potential that can still be used energetically in the current Swiss environment. This potential can be

[209] Corresponds to „constrained technical potential" or "exploitable potential".

expressed as primary energy on a heating value basis for the raw feedstock, or on a heating value basis for the biogas that would be produced from the raw feedstock. The biogas basis is relevant for the non-woody biomass resources.

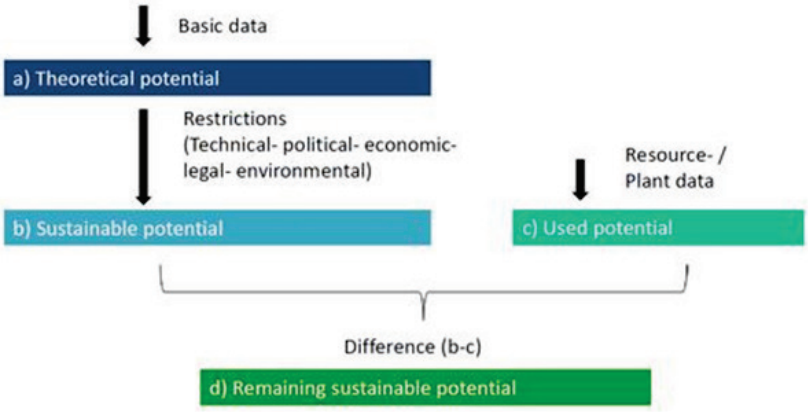


Figure 10.15: Graphical description of different potentials described in this section. Figure is from http://www.wsl.ch/fe/waldressourcen/projekte/fps_biosweet/index_EN.

10.2.2 Woody biomass potentials in Switzerland[210]

Woody biomass resources in Switzerland are categorised according to the following descriptions. The quantification of the potentials of each of these categories follows the descriptions.

- **Forest wood:** Wood directly from the forest for energetic use (Deutsche Bezeichnung: "Waldholz").
  This category includes parts of merchantable wood, as well as stems and branches, twigs (brushwood) and bark. Needles and leaves are not included.

- **Wood residues:** Wood residues from woodworking and processing industries (Deutsche Bezeichnung: "Restholz").
  Wood residues arise as by-products of primary production of wood items, mainly in sawmills, carpentries and joineries. In sawmills, semi-finished products such as cuttings and squares are produced. In carpentries and joineries, finished products, trusses and furniture are manufactured. The by-products are mainly rinds, splinters, shavings and sawdust.

- **Waste wood:** Wood which has already been used (Murer 2015) (Deutsche Bezeichnung: "Altholz").
  This especially includes wood of construction sites, demolitions, renovations, rebuilding as well as crushed wood waste. It also includes problematic wood waste and bulky waste from wood.

- **Wood from landscape maintenance** (Deutsche Bezeichnung: "Flurholz").
  This includes wood from trimming and maintenance activities, for example on meadows, pastures in agricultural and horticultural sectors, parks, cemeteries, along roads and field borders, bank slopes, along railways, orchards, vineyards, private gardens or allotments, etc. (BFS 2006, Ernst Basler + Partner and Interface 2009, Kaltschmitt, Hartmann et al. 2009).

[210] Feedstock descriptions and resource potentials are from (Erni, Thees et al. in preparation, status: 16.11.2016)

For each of these woody biomass categories, the assessed potentials are shown in Figure 10.16. It is important to note the theoretical potentials from all woody biomass categories should not be added together to give a total value. This is because the theoretical potential of the waste wood and the wood residues are already included, in part, in the theoretical potential of the forest wood. For wood residues, the entirety of the theoretical potential overlaps with the forest wood theoretical potential. For waste wood, only a part of the theoretical potential overlaps with forest wood. The rest of the waste wood originates from materials that were imported as wooden products such as furniture into Switzerland. In 2014, these imports represented around 420'000 tonnes of wood (according to (BAFU 2015)).

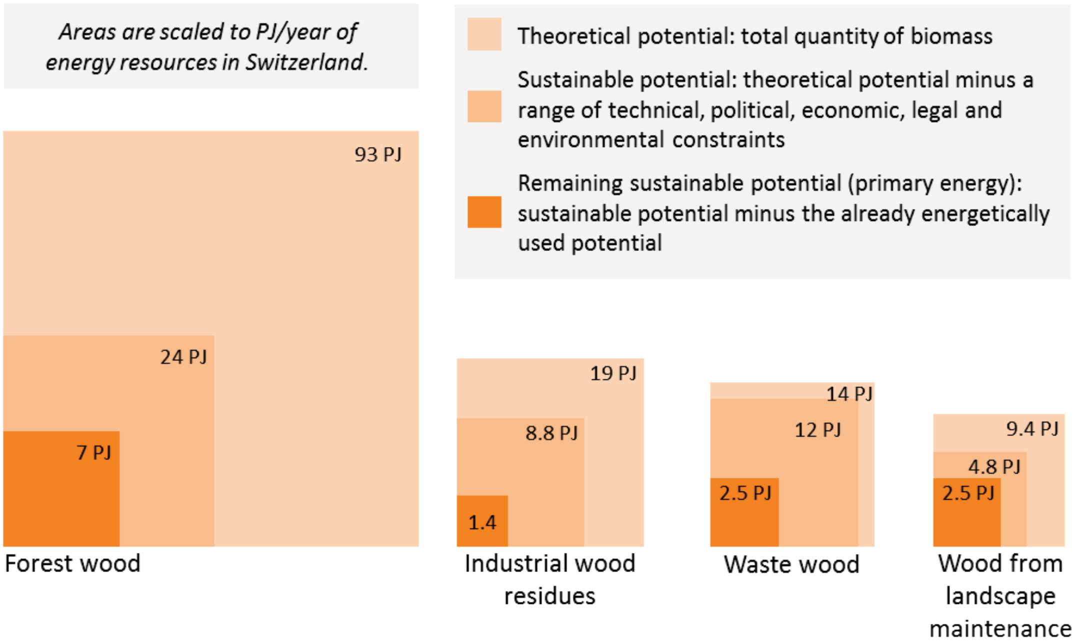


Figure 10.16: Potentials of domestic woody biomass resources in Switzerland, from (Erni, Thees et al. in preparation, status: 16.11.2016)[211].

The sustainable potential is particularly interesting for the design of the Swiss energy system. This potential is the sum of the resource that is already used energetically and the additional usable potential. These potentials can be added over the different resource categories, unlike the theoretical potential, as no double counting would occur in this case. Sustainable potentials are assessed by a combination of different types of harvesting/gathering restrictions, market situations, or cost considerations. Reductions in the potential occur due to reserves or protected areas, harvest losses, material use, and an assumed upper limit of feedstock costs.

[211] The sustainable potential of forest wood from WSL 2017 (2017-2026) shown here is the quantity using 2015/2016's price of 5.9 Rp./kWh. If considering subsidies to the costs, a larger potential would result.

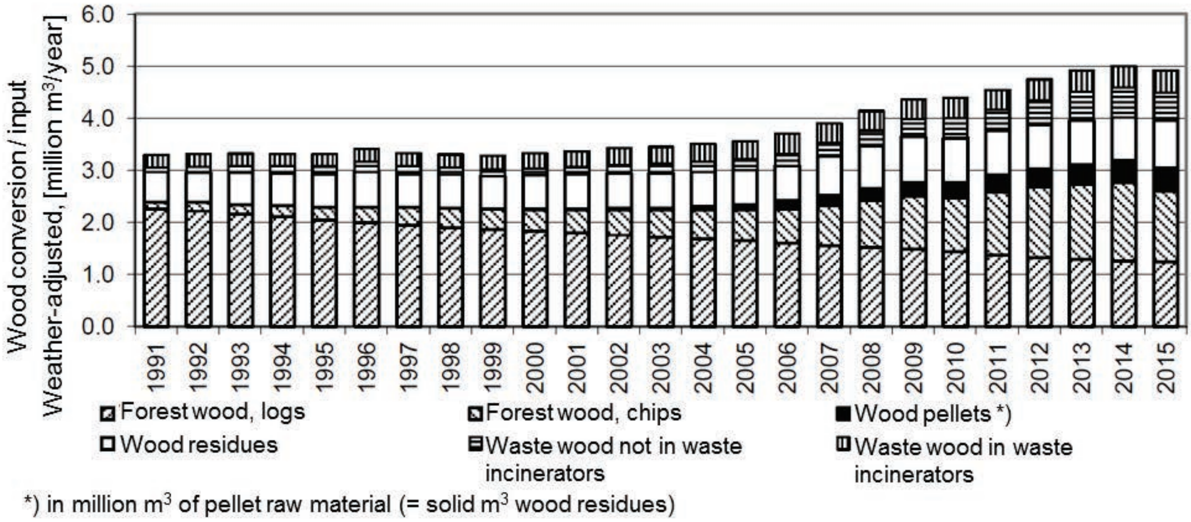


Figure 10.17: Wood used energetically by product type, in millions m^3 (weather-compensated), 1990 to 2015. Figure is translated from (Stettler and Betbèze 2016).

Figure 10.17 shows the chronological development of energetic wood utilization by product type (Stettler and Betbèze 2016). From this it can be seen that the quantity of forest wood logs ("Waldholz, Stückholz") has decreased steadily, but the quantity of forest wood chips ("Waldholz, Schnitzel") has increased significantly. Wood pellets have been used for around 10 years. The energetic use of waste wood has also increased significantly. The amount of wood residues used has increased slightly.

The largest part of the remaining potential of woody biomass comes from forest wood. New technologies for the highly efficient generation of electricity or biomethane production from wood must therefore be capable of processing wood chips in particular. However, assorted fuels such as waste wood or residual wood should also continue to be used.

10.2.3 Non-woody biomass potentials in Switzerland[212]

Non-woody biomass resources in Switzerland are categorized according to the following descriptions. The quantification of the potentials of each of these categories follows the descriptions.

- **Manure:** Liquid manure and dung from livestock (Deutsche Bezeichnung: "Hofdünger aus der landwirtschaftlichen Tierhaltung").
  Manure refers to all dejections (both liquid and solid forms) from livestock farming. Farm animal excrements and urines form the basic components of this biomass category. Depending on the husbandry installation type, they are produced without any additional material (except water in some cases) – it is then called slurry – or they are mixed with straw bedding material – which is then called manure.
- **Agricultural crop by-products:** Residues left on the field after the normal harvest and intermediate crops (Deutsche Bezeichnung: "Nebenprodukte aus dem landwirtschaftlichen Pflanzenbau").

[212] Feedstock descriptions and resource potentials are from (Burg, Bowman et al. in preparation, status: 2.2.2017)

This comprises the residues that are left on the fields after the main crop harvest, as well as the intermediate crops sown to cover the soil. The crop residues can be for example stalks, leaves or straws. It should be noted that hay (pastures, meadows) as well as wheat hay, which are today used mostly as animal feed or litter, are not taken into account in the calculations. As part of a cascading use system, this biomass is first supplied to the livestock and its energy potential is included in the manure category. Considering these as part of the theoretical potential would lead to a usage conflict and a double counting.

- **Sewage sludge:** Organic matter from central water treatment plants (Deutsche Bezeichnung: "Klärschlamm aus zentralen Abwasserreigungsanlagen").
  The energy potential concerns the fresh sludge that is produced during the waste water treatments in Swiss central waste water treatment plants. Fresh sludge refers to the untreated sewage sludge. Organic matter, which decomposes quickly under controlled conditions, can be subsequently degraded. Anaerobic digestion is a proven and common method to stabilize fresh sludge. The fresh sludge is transformed into digested sludge. It has the advantage of making available a valuable energy source thanks to the biogas emitted.

- **Organic part of household garbage:** Organic part of domestic garbage (Deutsche Bezeichnung: "Organischer Anteil im Hauskehricht").
  The calculated energy potential refers to the organic part of Swiss household garbage. Household garbage comprises all municipal waste from household which are not separately collected or further used as material. Small quantities of similar waste from firms using the common municipal garbage waste collection are also part of it. Waste from industrial production or catering as well as construction waste, sewage sludge and hazardous waste are not considered here. Waste disposal is carried out by the public authorities and the cantons are responsible for the planning (cantonal structure plan, exploitation plan). We consider as organic part all matter coming from plant, animal or microbes which land in the household garbage. As about half of the garbage heating value comes from the organic wastes, 50% of the electricity produced in the incineration plants is counted as renewable electricity.

- **Green waste:** All non-ligneous waste collected separately by local authorities during landscape maintenance, as well as household biogenic wastes (Deutsche Bezeichnung: "Grüngut aus Haushalt und Landschaft").
  Green waste refers to general non-woody, biogenic waste coming from household or landscape maintenance and collected separately within the communal waste management. Small quantities of similar waste from firms using the common municipal separate waste collection are also part of it. Waste from industrial production or catering as well as mixed communal waste or garbage are not considered here. Today in Switzerland the biogenic wastes collect and exploitation is regulated differently in each commune. In the same way, the green spaces maintenance practices cannot be generalized. Theoretical additional possibilities linked to changes in the public green spaces exploitation are not considered in this study.

- **Industrial and commercial biowaste:** Biogenic residue from food processing, catering waste, retailers, tobacco industry, pharma-industry, textile industry and paper industry (Deutsche Bezeichnung: "Abfälle in der Industrie und Gewerbe").
  Industrial waste refers to the potential for organic, non-woody wastes from the industry production and restauration. This includes for example slaughterhouses wastes, leftovers from the food industry production and supply, paper, cardboard, etc. Wood wastes are studied separately. Although solid organic wastes such as paper or cardboard are taken into account, the occurrence of this organic matter is mostly characterized by high nutrient and water contents.

For each of these non-woody biomass categories, the assessed potentials are shown in Figure 10.18. Biogas conversions from primary resources were calculated following recommendations in (KTBL 2014). The organic part of the household garbage is expected to decrease in future, as more green waste is separated at source. This is the reason for the negative value of the remaining potential for organic part of household garbage. Similarly, the projected sustainable potential for green waste is larger than its current theoretical potential.

By a significant ratio, the largest remaining sustainable potential is from animal manure. The sustainable potential from biogas produced from manure is larger even than the sustainable potential for any of the woody biomass categories. Therefore, a future energy strategy should focus on the potential to mobilise this resource.

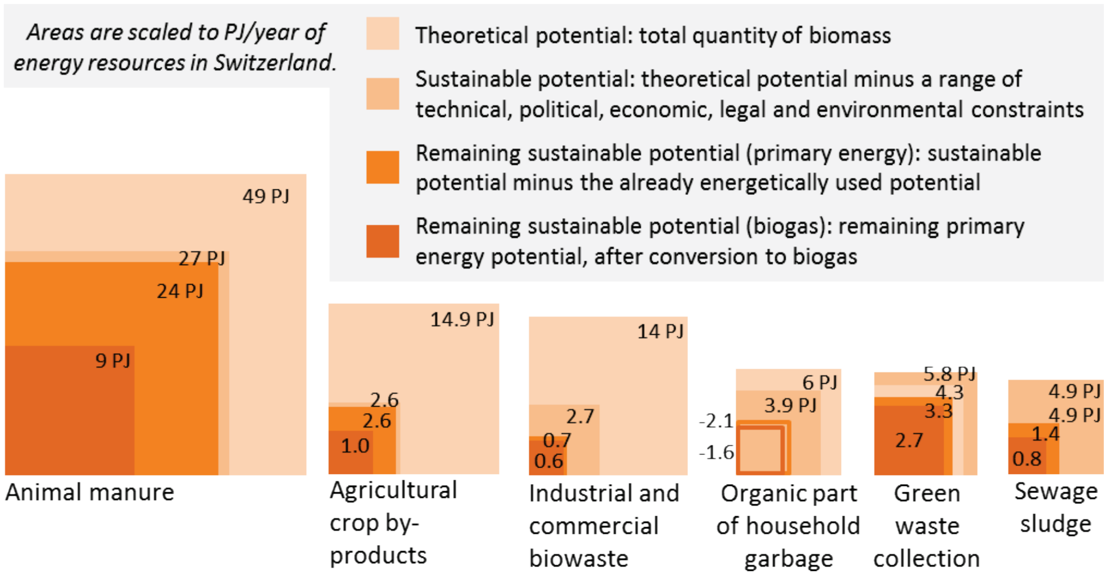


Figure 10.18: Potentials of domestic non-woody biomass resources in Switzerland, from (Burg, Bowman et al. in preparation, status: 2.2.2017).

10.2.4 Comparison of feedstock potentials with previous studies

The biomass feedstock potentials which are presented in Sections 10.2.2 and 10.2.3 can be compared to previously published studies of Swiss biomass resources, especially references (Oettli, Blum et al. 2004), (Steubing, Zah et al. 2010), and (Kirchner and Prognos AG Sept. 2012).

These comparisons are shown in Figure 10.19, which compares the current study to the results of (Oettli, Blum et al. 2004) and (Kirchner and Prognos AG Sept. 2012) and in Figure

10.20, which compares the current study to the results of (Steubing, Zah et al. 2010). These comparisons are separated into two independent figures due to the slightly different biomass categories used in each of the studies.

Figure 10.19 shows a comparison of the theoretical biomass potential evaluations for Switzerland's domestic resources. The main difference here is the vastly different theoretical potential for crops and crops residues. Apart from this biomass category, the theoretical potentials are very similar. The cited 2004 study (Oettli, Blum et al. 2004) has included pastures, meadows, and other grasslands in this theoretical potential, but these were excluded from the current study as their main purpose is animal feeding. Moreover, INFRAS considered that energy crops would be included in the theoretical potential, which was not assumed for the current study.

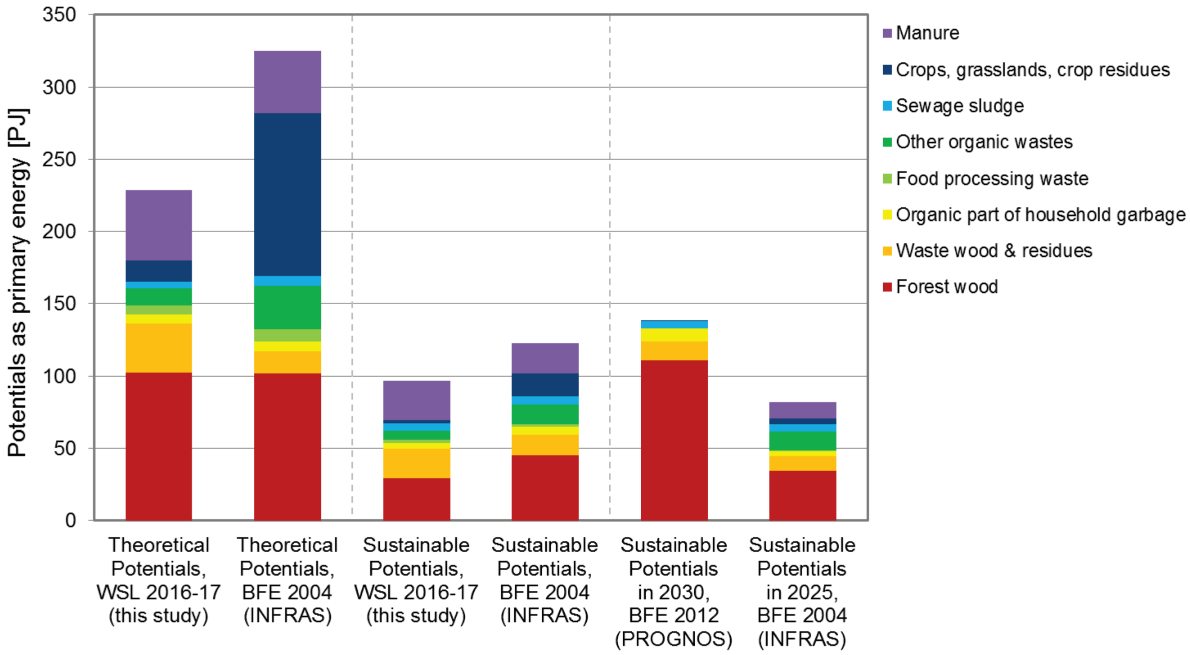


Figure 10.19: Comparison of theoretical and sustainable potentials[213] for Swiss domestic biomass resources. WSL 2016-17 refers to (Burg, Bowman et al. in preparation, status: 2.2.2017, Erni, Thees et al. in preparation, status: 16.11.2016). BFE 2004 (INFRAS) refers to (Oettli, Blum et al. 2004) and BFE 2012 (PROGNOS) refers to (Kirchner and Prognos AG Sept. 2012).

Sustainable potentials evaluated in the current study are compared to (Oettli, Blum et al. 2004) in Figure 10.19 and to (Steubing, Zah et al. 2010) in Figure 10.20. The sustainable potential results of (Steubing, Zah et al. 2010) and the current study are quite similar, with the exception that the current study assumes that more wood residues and waste woods are sustainably recoverable. The sustainable potential for manure is also higher due to a more detailed approach in the evaluation. Relative to (Oettli, Blum et al. 2004) in Figure 10.19, the current study includes the effect of economic restrictions for the recovery of crop residues, as was the case for the theoretical potential. The current study also restricts the sustainable use of forest wood relative to (Oettli, Blum et al. 2004) for competing uses as a material rather than an energy resource.

[213] The sustainable potential of forest wood from WSL 2017 (2017-2026) shown here is the quantity using 2015/2016's price of 5.9 Rp./kWh. If considering subsidies to the costs, a larger potential would result.

Finally, the remaining portion of the sustainable potentials are shown in Figure 10.20. These are found by subtracting the biomass resources that already used energetically from the sustainable potentials. There has been an increase in the energetic use of biomass from 2010 to 2016, as shown in Figure 10.20 as the "already used" potentials.

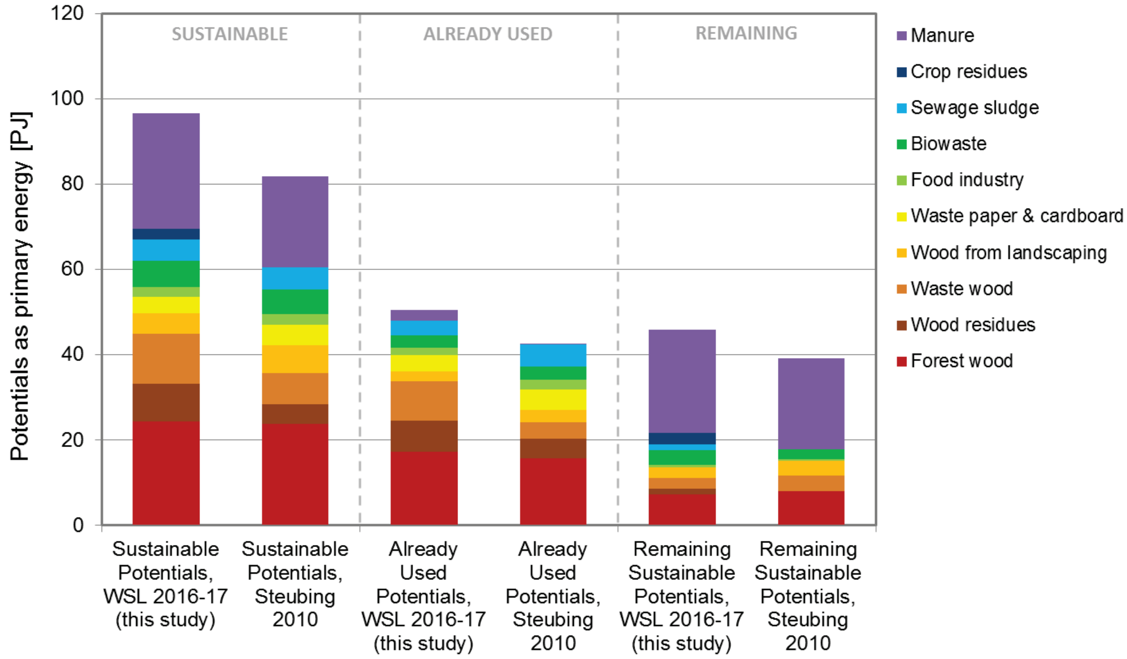


Figure 10.20: Comparison of sustainable, already used sustainable, and remaining sustainable potentials[214] for Swiss domestic biomass resources. WSL 2016-17 refers to (Burg, Bowman et al. in preparation, status: 2.2.2017, Erni, Thees et al. in preparation, status: 16.11.2016). Steubing 2010 refers to (Steubing, Zah et al. 2010).

10.2.5 Estimation of feedstock costs

Feedstock costs were also estimated by WSL, and are shown in Figure 10.21 for woody biomass and Figure 10.22 for non-woody biomass. The principal message to understand from these figures is the large range of feedstock costs that exists currently.

For woody biomass, forest wood burns more cleanly and has a larger heating value than waste wood. However, it is also more expensive, as seen in Figure 10.21. If we begin to use more of the sustainable woody biomass resources, we can expect an increase in the average feedstock price, which will affect the cost of the secondary bioenergy (electricity, heat and fuels).

For non-woody biomass, several effects can be seen in Figure 10.22. First, household garbage is indicated to have a negative price because of gate fees paid for its collection. Manure often has very low costs if used on site (for example, in a farm-scale digester). However, the transportation of manure, if collection from several farms is needed to feed to a larger digester, adds significantly to the supply cost of the feedstock. Similarly, the primary difference between sewage sludge as a feedstock to be used in the wastewater treatment plant (yellow bar) and sewage sludge to an incinerator (brown bar) is the cost of transportation and taxes from the incineration units.

[214] The sustainable potential of forest wood from WSL 2017 (2017-2026) shown here is the quantity using 2015/2016's price threshold without subsidies of 5.9 Rp./kWh. If considering subsidies to the costs, a larger potential would result.

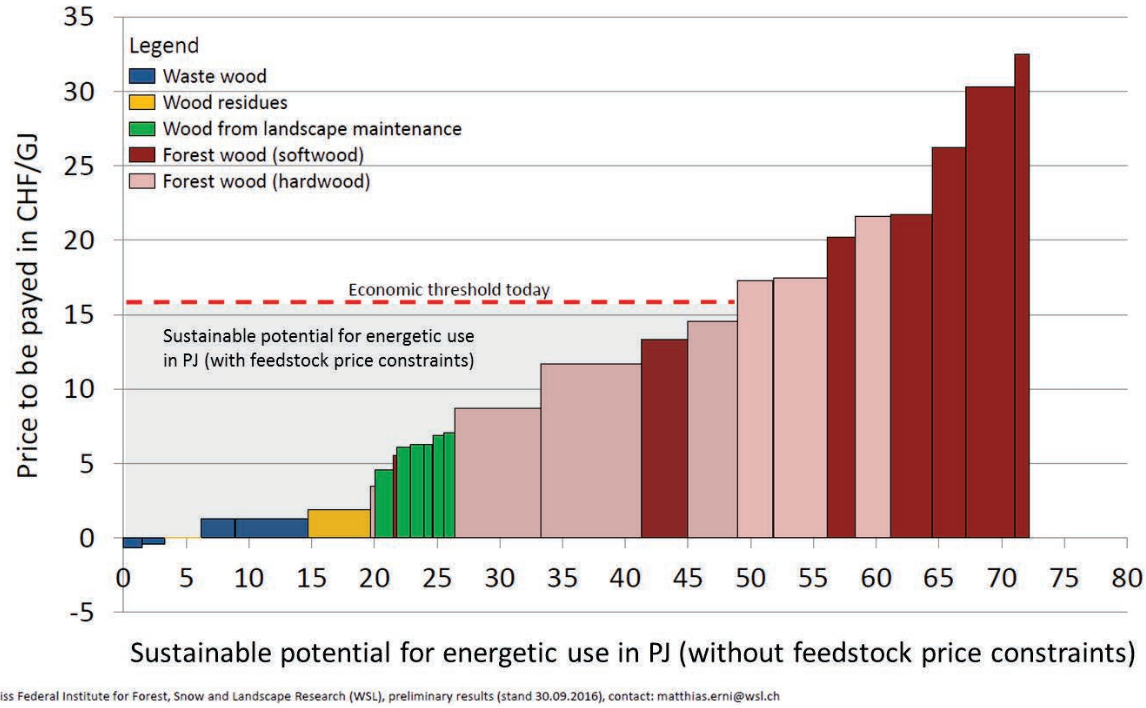


Figure 10.21: Potentials for energetic uses of woody biomass and corresponding costs. The sustainable potential is determined by a price threshold, set here at 5.9 Rp./kWh. All feedstocks in the grey shaded region are thus considered the actual sustainable potential as seen in Figure 10.16. If more expensive feedstocks were considered economically acceptable, the sustainable potential would increase.[215] Figure is from (Erni, Thees et al. in preparation, status: 16.11.2016).

10.2.6 International biomass trade

One observation on the international level is that biomass trade would need to grow significantly to boost the global share of bioenergy. In IRENA's REmap analysis, 20-40% of the global bioenergy demand by 2030 is suggested to be from international trade (IRENA 2014a). For the purposes of this report, the use of domestic Swiss resources only is considered for making predictions of additional electricity generation in the future. Some import of bioenergy takes place already today as biomethane imports, imports of biofuels and imports of pellets.

[215] The sustainable potential of forest wood from WSL 2017 (2017-2026) shown here is the quantity using 2015/2016's price threshold without subsidies of 5.9 Rp./kWh. If considering subsidies to the costs, a larger potential would result.

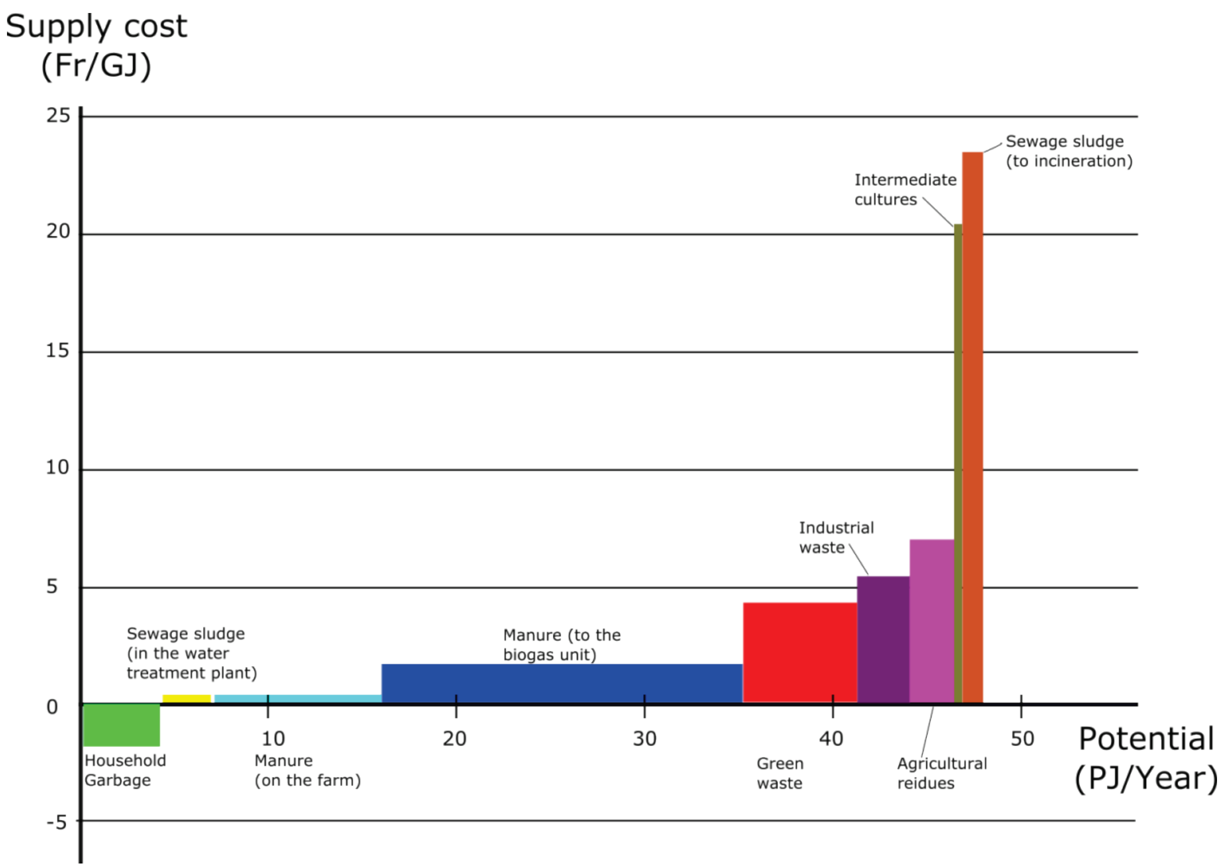


Figure 10.22: Sustainable potential for energetic uses of non-woody biomass and corresponding costs. Figure is from (Burg, Bowman et al. in preparation, status: 2.2.2017).

10.3 Current (2015) electricity generation

10.3.1 Description of technological pathways

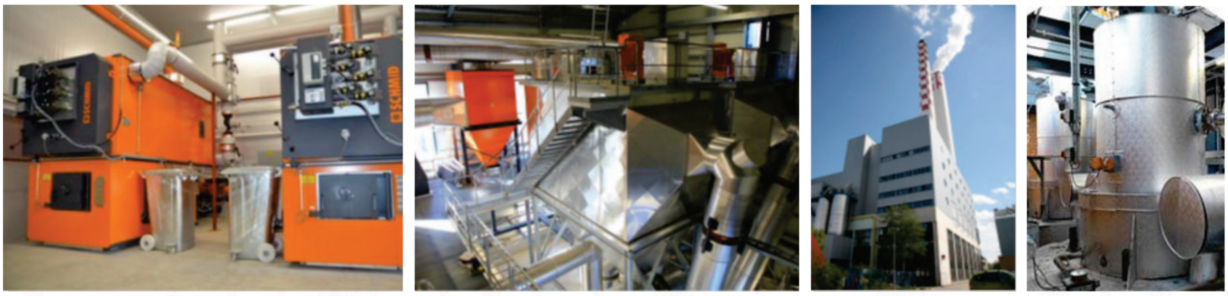
The conversion of biomass to electricity can follow a variety of pathways. In order to structure the analysis of current and future electricity generation and costs, these many possible pathways are organised into categories based on those used by SFOE in the Swiss Renewable Energy Statistics (Kaufmann 2016a).

The conversion pathway categories are shown in Figure 10.23, and their brief description will follow. Broadly, this figure can be understood to cover technologies that process non-woody biomass on the top row, and woody biomass on the bottom row. Because waste incineration plants (KVA) can accept both woody biomass and certain types of non-woody biomass as a feedstock, it is included on both rows.

The wood gasifier category is not used by SFOE in the Swiss Renewable Energy Statistics, as wood gasification technologies are included in the "wood combustion CHP" systems. In this chapter, wood gasification is treated as an independent category for the purposes of discussing current and future costs of electricity generation. Also, the SFOE uses landfill gas ("Deponiegasanlagen") as a separate category. This category is used in this chapter when describing current generation of electricity. However, it is not otherwise used for future predictions because landfills are not in active use in Switzerland, and therefore no significant new capacity is assumed to be added.

The conversion pathway categories considered for non-woody and woody biomass can be described briefly as follows. A more detailed description of the categories can be found in the Swiss Renewable Energy Statistics (in German) (Kaufmann 2016a).

Municipal WWTP Morgental (SG) © morgenthal.ch | **Industrial WWTP Rickenbach (LU) © Gefu Produktions** | **Industrial biogas KBA Hard, Beringen (SH) © abfall-sh.ch** | **Agricultural biogas Düdingen (FR) © ZHAW** | **KVA, Basel (BS) © IWB**



Autom. wood combustion CHP in Felben-Wellhausen (TG) © Schmid | **Combustion of wood & organic wastes, Spiez (BE) © Eicher + Pauli** | **KVA, Basel (BS) © IWB** | **Wood gasifier, Stans (NW) © Korporation Stans**

Figure 10.23: Examples of the technological pathways described. Photos are originally from the sources listed, but were collected from the SFOE report on renewable energies in 2015 (Kaufmann 2016a) with the exception of the gasifier photo.

10.3.1.1 Non-woody biomass:

- **Municipal wastewater treatment plant, WWTP** (Deutsche Bezeichnung: "Klärgasanlagen")**:** Biogas produced by anaerobic digestion of municipal sewage sludge.
- **Industrial wastewater treatment plant, WWTP** (Deutsche Bezeichnung: "Biogasanlagen Industrieabwässer")**:** Biogas produced as a result of required pre-purification of effluents in some industries, especially in the processing of fruits and vegetables.
- **Industrial biogas** (Deutsche Bezeichnung: "Biogasanlagen Gewerbe/Industrie")**:** Production of biogas from green waste, food waste, slaughter waste, etc. from municipal, commercial and industrial sources.
- **Agricultural biogas** (Deutsche Bezeichnung: "Biogasanlagen Landwirtschaft")**:** Production of biogas on farms from manure and co-substrates.
- **KVA – waste incineration** (Deutsche Bezeichnung: "Kehrichtverbrennungsanlage, KVA")**:** Large installations with the primary purpose of incinerating wastes.

10.3.1.2 Woody biomass:

- **Automatic wood combustion CHP (Combined Heat and Power)** (Deutsche Bezeichnung: "Automatische Feuerungen mit Holz, WKK")**:** Combustion of clean wood chips and logs for CHP use starting at 50 kW_{fuel}. In the Renewable Energy Statistics, this category includes CHP and heat-only units. For this chapter, only the CHP units are considered, using the Swiss Wood Energy Statistics (Stettler and Betbèze 2016) to separate heat-only from CHP.
- **Combustion of wood and organic wastes** (Deutsche Bezeichnung: "Feuerungen mit Holzanteilen und erneuerbare Abfälle")**:** Industrial-scale combustion of waste woods and organic wastes, which can be used for energetic uses.
- **KVA – waste incineration** (Deutsche Bezeichnung: "Kehrichtverbrennungsanlage, KVA")**:** Large installations with the primary purpose of incinerating wastes.
- **Wood gasification CHP** (Deutsche Bezeichnung: "Holzvergasung WKK")**:** Combined heat and power unit based on the gasification of wood, instead of its combustion.

10.3.2 Performance indicators in 2015

In 2015, a total of 1.6 TWh of electricity were generated from biomass resources in Switzerland, as shown in Figure 10.24. Based on the Swiss Renewable Energy Statistics for 2015 (Kaufmann 2016a), the electrical and thermal efficiency of the different biomass conversion pathways can be quantified. The results are shown in Figure 10.25, and details about capacity factors and plant size are listed in Table 10.1.

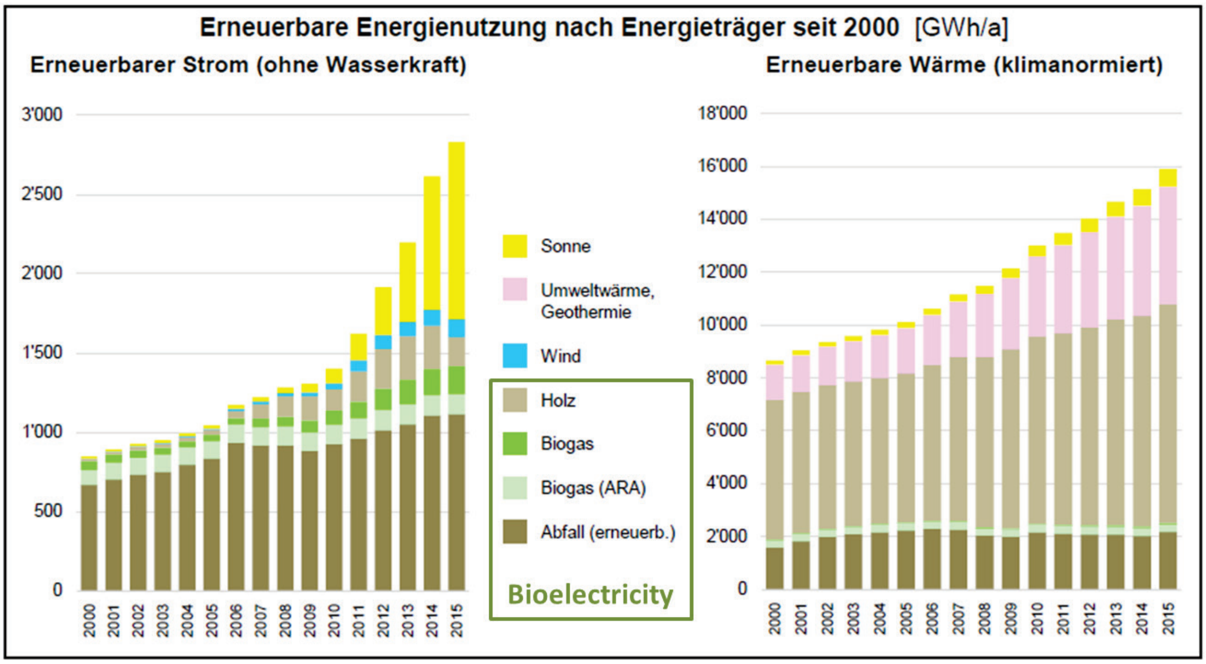


Figure 10.24: Electricity and heat production from renewable resources in Switzerland in the past 15 years. Figure is adapted from SFOE, Swiss Renewable Energy Statistics (Kaufmann 2016a).

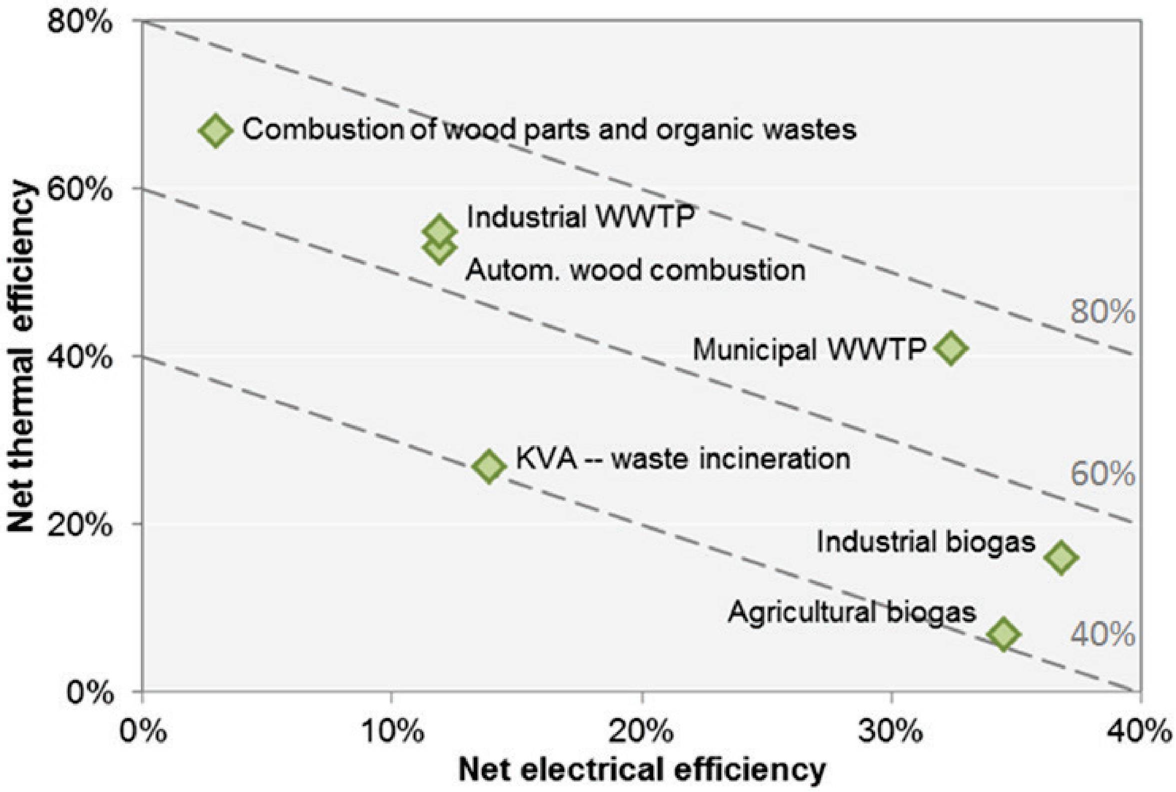


Figure 10.25: Efficiencies[216] of the biomass-to-electricity conversion pathways in Switzerland in 2015. Values are calculated from (Kaufmann 2016b, Kaufmann 2016a, Stettler and Betbèze 2016).

In these figures and table, the electricity production given is the net electricity injected into the grid. Similarly, the term "useful heat" is defined as encompassing any heat that is sold to a third party, and any heat used on site that would have been necessary even if the electricity were not produced. For example, in agricultural biogas units, the useful heat does not include heat needed to maintain the operation temperature of the digester, because the digestion process is not needed except for the creation of biogas for electricity. By contrast, the heat produced by the CHP and then used for the digestion process in industrial wastewater treatment plants is generally counted as useful. This is because many of these plants would need to digest their waste products for sanitation purposes regardless, and so the heat would need to be supplied from another resource if the CHP were not operating.

[216] For electricity, this refers to the net electricity produced divided by the the heating value of the fuel (where fuel is biogas for anaerobic digestion processes, and raw biomass feedstock for combustion processes).

Table 10.1: Performance indicators of the biomass-to-electricity conversion pathways in Switzerland in 2015. Values are calculated from (Kaufmann 2016a, Kaufmann 2016b, Stettler and Betbèze 2016).

<table>
<tr><th></th><th>Number of installations</th><th>Installed capacity, MW_e total</th><th>Average installed capacity, kW_e avg.</th><th>GWh_e total</th><th>Full-load equivalent h/yr</th><th>% of fuel[217] converted to electricity</th><th>% of fuel[217] converted to useful heat</th></tr>
<tr><td>Autom. wood combustion (CHP)</td><td>11</td><td>26.8</td><td>2'437</td><td>125.7</td><td>4'689</td><td>11.9%</td><td>53%</td></tr>
<tr><td>Combustion of wood parts and organic wastes[218]</td><td>67 [218]</td><td>16.9</td><td>252</td><td>69.8</td><td>4'135</td><td>2.9%</td><td>67%</td></tr>
<tr><td>KVA – waste incineration</td><td>30</td><td>211 [219]</td><td>7'021 [219]</td><td>1065 [219]</td><td>5'056</td><td>13.9%</td><td>27%</td></tr>
<tr><td>Landfill gas installations</td><td>3</td><td>0.4</td><td>120</td><td>1.6</td><td>4'361</td><td>26.7%</td><td>1.9%</td></tr>
<tr><td>Municipal WWTP</td><td>351</td><td>28.9</td><td>82</td><td>119</td><td>4'118</td><td>32.4%</td><td>41%</td></tr>
<tr><td>Industrial WWTP</td><td>23</td><td rowspan="2">17.3 [220]</td><td rowspan="2">353 [220]</td><td>8.5</td><td rowspan="2">4'850 [220]</td><td>11.9%</td><td>55%</td></tr>
<tr><td>Industrial biogas</td><td>26</td><td>75.4</td><td>36.8%</td><td>16%</td></tr>
<tr><td>Agricultural biogas</td><td>99</td><td>15.4</td><td>156</td><td>99.8</td><td>6'479</td><td>34.5%</td><td>7.4%</td></tr>
</table>

Overall, the information in Figure 10.25 and Table 10.1 shows that most wood-based systems are built primarily to supply heat. The heat utilization is quite high, and these systems are generally put in place on sites where heat is needed as part of a process. The efficiency of waste incinerators is relatively low, because the primary purpose of these installations is to incinerate waste. Producing heat for district heating and electricity for grid injection are secondary purposes. Finally, the useful heat utilization is low for industrial and agricultural biogas plants. This is caused by two effects. A portion of the heat is used for the anaerobic digestion process, but this is not counted as "useful". Then, these installations – especially the agricultural installations – are often at small sites that have no built heat distribution network, either at the local (farm) or district scale. Therefore, the heat cannot yet easily be valorised without building additional infrastructure.

Finally, the production of biomethane in Switzerland and its subsequent injection into the natural gas grid is shown for the past 15 years in Figure 10.26.

There has been a marked increase in the production of biomethane over this time period. Small biogas installations would not be able to economically upgrade biogas to grid quality.

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[217] The fuel is defined as biogas for anaerobic digestion processes and raw biomass feedstock for combustion processes, in agreement with the information in the SFOE Swiss renewable energy statistics.

[218] Note that not all of these produce electricity; some produce only heat. The statistics do not allow to isolate the
electricity-producing systems from the heat-only systems. This explains the low electrical efficiency.

[219] Only the renewable portion (~50%) is included.

[220] These values are calculated from the 2015 WKK (CHP) Statistics. All other values calculated from 2015 Renewable Energy Statistics and 2015 Wood Energy Statistics.

This explains the fact that most biomethane today is produced at municipal or industrial sites, which can be larger than agricultural installations.

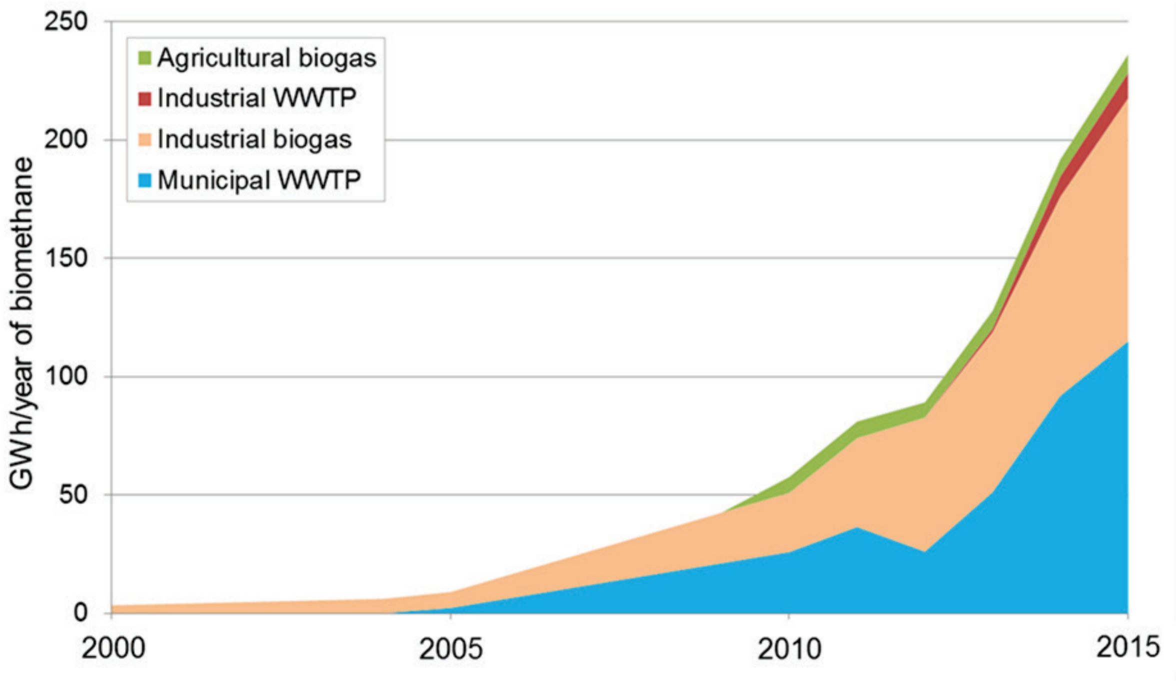

Figure 10.26: Biomethane production for injection into the Swiss natural gas grid (LHV basis). Data is from (Kaufmann 2016a).

10.4 Future Electricity Generation

Increasing the future use of biomass for electricity generation in Switzerland will depend on several technical, economic, and societal factors, not all of which can be easily predicted or addressed directly. This section has a technical focus, answering the question "How much electricity could be generated from Swiss biomass resources?" using several sets of assumptions about the performance of the conversion technologies available. Economic aspects are then considered in Section 10.5, which focuses on the costs of electricity production from biomass.

Future direct electricity generation from Swiss biomass resources is estimated through two scenarios, which are introduced in Section 10.4.1. The first scenario, designated as "Technology-as-Usual (TAU)", assumes that the use of biomass feedstocks is gradually increased while technology metrics remain essentially constant. The second scenario, designated as "New Technologies (NT)", assumes that new technologies (fuel cells for biogas, gasification and small-scale high-efficiency combustion systems) are brought online gradually as well as increasing the feedstock utilisation. Alternatively, a "Biomethane Scenario" is considered for the eventual indirect generation of electricity via the production of grid-quality methane. This scenario is described in more detail along with its results in Section 10.6.

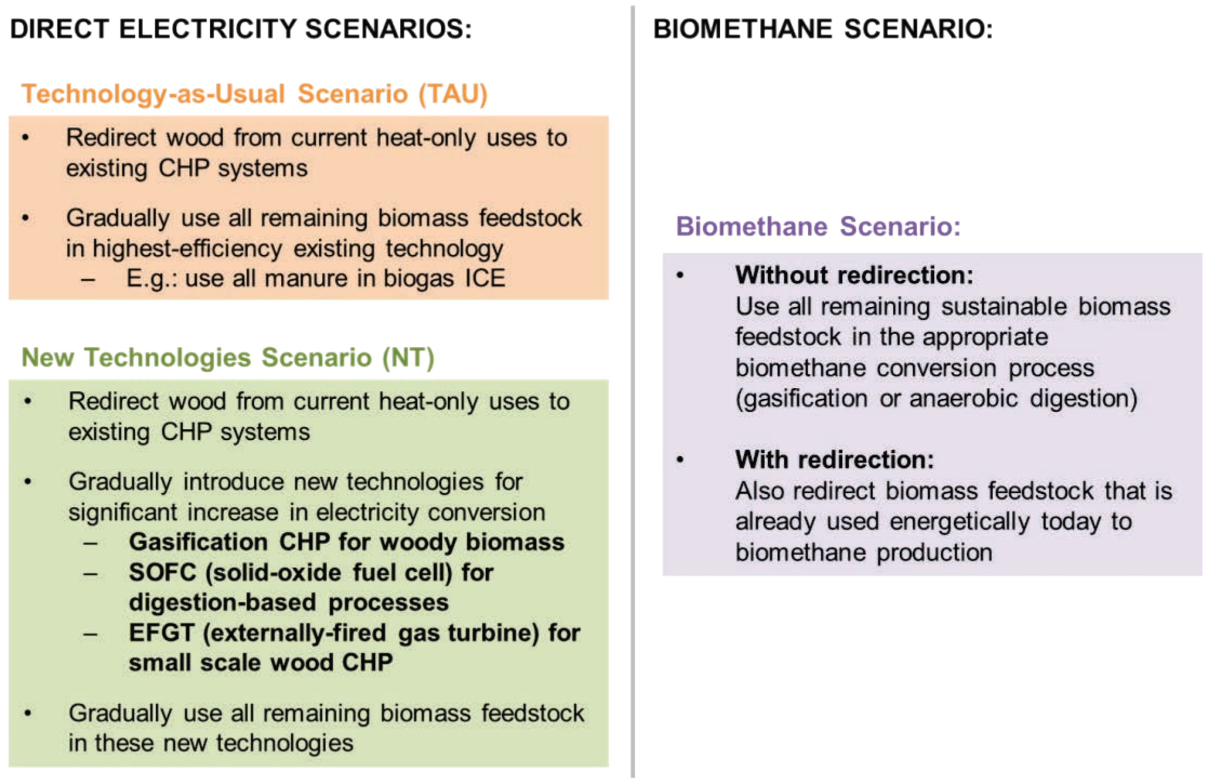

Figure 10.27: Short overview of the scenarios considered for future bioelectricity and biomethane generation. Direct electricity scenarios are treated in this section. The biomethane scenario is explored in Section 10.6.

10.4.1 Description of the direct electricity scenarios

The TAU and NT scenarios are summarised in Figure 10.27. Both scenarios assume the same time profile for the future utilization of the feedstock. First, the remaining sustainable potential for each resource (as described in Section 10.2) is assumed to be gradually utilized for electricity generation, until the entirety of the feedstock is used by 2050. This gives the maximum end of the range for future feedstock utilization. For the transition to 2050, a linear increase in the utilised feedstock is assumed.

Furthermore, both scenarios include the assumption that the large already-utilised potential of woody biomass could produce more electricity in the future. In 2015, the majority of this already-utilised potential is used for heat production only (Stettler and Betbèze 2016). Using these resources in CHP units instead would allow the generation of electricity as well. However, many of these woody biomass resources are burned at small-scale installations. These small-scale installations would be unlikely to be retrofitted to have a CHP. It would also be unlikely that the feedstock from these small installations would be redirected to a single large new CHP. Therefore, we consider that only the woody biomass currently burned in heat-only installations with a size larger than 500 kW_{th} would be redirected to CHP units. In 2015, 2.5 TWh/a of woody biomass fulfilled these criteria (Stettler and Betbèze 2016). If all of this wood were redirected to wood CHP systems in Switzerland – which had an average electrical efficiency of 12% in 2015 (see Table 10.3) – then 0.3 TWh of electricity could be produced per year. Both scenarios assume that this redirection potential is fully achieved by 2050, and increases linearly from 2015 to 2050.

The TAU scenario assumes a substantial increase in the biomass feedstock utilization, but no technology improvements relative to 2015. The remaining sustainable potential of each type of biomass resource is assumed to be converted to electricity in the highest-efficiency process currently available for its use in Switzerland. The technically allowable pathways for each resource are shown in Table 10.2. Landfills are no longer actively used for waste disposal in Switzerland since the year 2000. While a small amount of landfill gas is currently used for electricity generation (Kaufmann 2016a), no new electricity generation will be possible via this pathway. The efficiency and other performance indicators for each of the conversion paths in 2015 are shown in Table 10.3.

Table 10.2: Allowable conversion pathways for each type of biomass resource.

	Forest wood	Industrial wood residues	Waste wood	Wood from land-scape maint.	Organic part of house-hold garbage	Industrial biowaste	Animal manure	Agricult. crop by-products	Green waste collection	Sewage sludge
Autom. wood combustion CHP	✓	✓	✓	✓	×	×	×	×	×	×
Combustion of wood parts and organic wastes	×	✓	✓	✓	✓	✓	×	×	×	✓
KVA -- waste incineration	×	✓	✓	×	✓	✓	×	×	✓	(✓)
(Landfill gas installations)	-	-	-	-	-	-	-	-	-	-
Municipal WWTP	×	×	×	×	×	✓	×	×	×	✓
Industrial WWTP	×	×	×	×	×	✓	×	×	×	✓
Industrial biogas	×	×	×	×	×	✓	×	✓	✓	×
Agricultural biogas	×	×	×	×	×	✓	✓	✓	✓	×

The NT scenario assumes that, in addition to the increase in feedstock utilization from 2015 to 2050, there is also an increase in the efficiency of conversion pathways as newer technologies replace existing installation at their end of technical life. The ranges of possible efficiency increases considered are shown in Table 10.3. These correspond to increased use of gasification as the primary conversion step for wood-based CHP, and to increased use of high-temperature fuel cells (SOFC in particular) as the electricity generation step in anaerobic digestion steps. It is also assumed that the electrical efficiency for waste incineration plants would improve as steam parameters are optimised. Once again, the landfill gas pathway is not relevant any more as no new capacity is added. Finally, the category of “combustion of wood parts and organic wastes”, which mainly focuses on heat production and only produces electricity occasionally, is assumed to disappear in favour of additional wood CHP systems.

An additional potential would be possible from the use of technology that can considerably increase the biogas yield of wet biomass resources. This includes, for example, two-step digestion, pre-treatment of the substrates in some cases, and the use of hydrothermal gasification (HTG) instead of anaerobic digestion. The HTG concept is discussed in Chapter

17.2 (Vogel 2016a) as an emerging technology, as it is still in the research phase and is not yet commercially available. Because the NT scenario is already very optimistic, it is assumed that the partial implementation of HTG and other technologies by 2050 would not significantly alter this scenario's results. However, it is important to note that these technologies are being developed, especially since the biogas yield from manure through anaerobic digestion is quite low at the moment. A future prospect of increasing this yield would be attractive for Switzerland.

Table 10.3: Efficiency improvements considered in the NT scenario due to increased use of gasification of woody biomass, optimized steam parameters at KVA plants, and high-temperature fuel cells for biogas.

	2015 status in Switzerland (Kaufmann 2016b, Kaufmann 2016a, Stettler and Betbèze 2016)			2020 efficiency (estimated)		2035 efficiency (estimated)		2050 efficiency (estimated)	
	Number of installa-tions	Full-load equivalent h/yr	% of fuel[221] sold as electricity	Min	Max	Min	Max	Min	Max
Autom. wood CHP	11	4'689	12%	13%	14%	17%	19%	20%	25%
Combustion of wood parts and organic wastes	67	4'135	3%	–	–	–	–	–	–
KVA – waste incineration	30	4'576	14%	16%	17%	20%	24%	25%	32%
Landfill gas installations	3	4'361	27%	–	–	–	–	–	–
Municipal WWTP	351	4'118	32%	32%	35%	33%	42%	34%	50%
Industrial WWTP	23	4'850	12%	15%	17%	25%	34%	34%	50%
Industrial biogas	26		37%	37%	39%	37%	44%	37%	50%
Agricultural biogas	99	6'479	35%	35%	37%	35%	44%	35%	50%

10.4.2 Technology-as-Usual (TAU) scenario results

The results of the TAU scenario are shown in Figure 10.28 for 2050 and Figure 10.29 for 2035. Several effects are combined into these overall ranges. The range of additional electricity production from wood CHP includes the combined effect of redirecting feedstock from the heat production sector and of utilising currently-unused woody biomass feedstock potential. The waste incineration range includes additional electricity production from waste woods and wood residues that cannot be used in clean-wood CHP system. However, it also includes a subtraction of electricity production due to the predicted increase in at-source green waste sorting in future, leading to a reduction in household garbage as a feedstock (see Section 10.2). The net additional electricity generation for this category remains positive.

The category with the largest additional production is the agricultural biogas category, due to the large unused potential of manure remaining in Switzerland today. It is important to

[221] The fuel is defined as biogas for anaerobic digestion processes and raw biomass feedstock for combustion processes, in agreement with the information in the SFOE Swiss renewable energy statistics.

remember that the results in Figure 10.28 and Figure 10.29 show a *range* of additional added capacity for each category. The top of the range is the maximum technically possible under the scenario's constraints. Significant mobilisation of the available manure feedstock will be a considerable challenge, but it will be necessary in order to significantly increase the share of electricity production from biomass in Switzerland. Small, farm-scale installations for digestion of manure are currently quite expensive and are heavily supported by feed-in tariffs (KEV, see Section 10.5). Some alternative ideas are being explored for mobilisation of this resource for electricity production, including the work being done by Fleco Power[222] to create a "virtual power plant" that pools several small installations into one (Zahnd 2016).

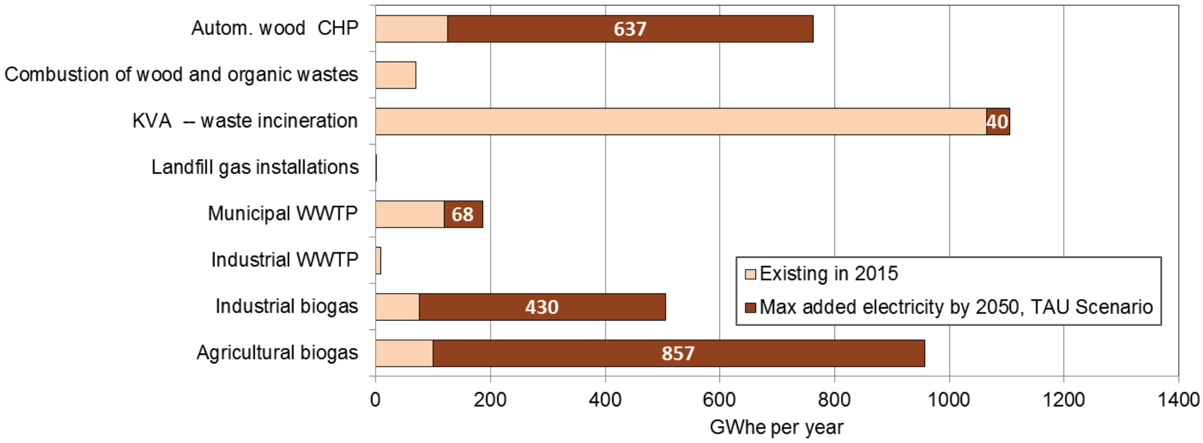

Figure 10.28: Maximum potential electricity generation to be added by 2050 under the TAU scenario, relative to the electricity produced in 2015. The maximal added electricity production is of 2.0 TWh (7.3 PJ) relative to 2015.

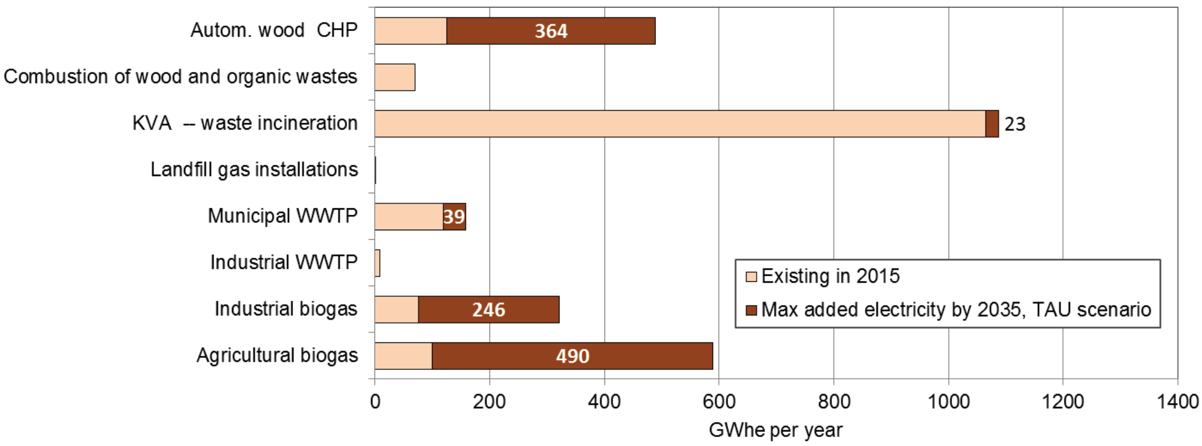

Figure 10.29: Maximum potential electricity generation to be added by 2035 under the TAU scenario, relative to the electricity produced in 2015. The maximal added electricity production is of 1.2 TWh (4.2 PJ) relative to 2015.

10.4.3 New Technologies (NT) scenario results

The results of the NT scenario are shown in Figure 10.30 for 2050 and Figure 10.31 for 2035. Once again, the same effects described in Section 10.4.2 are combined in these figures – namely, the redirection of woody biomass from heat-only to CHP and the change in the

222 http://flecopower.ch/

amounts of feedstock supplied to waste incineration plants. Comparing the results from these figures to those from Figure 10.28 and Figure 10.29 gives an indication of the possible effect of bringing new technologies online.

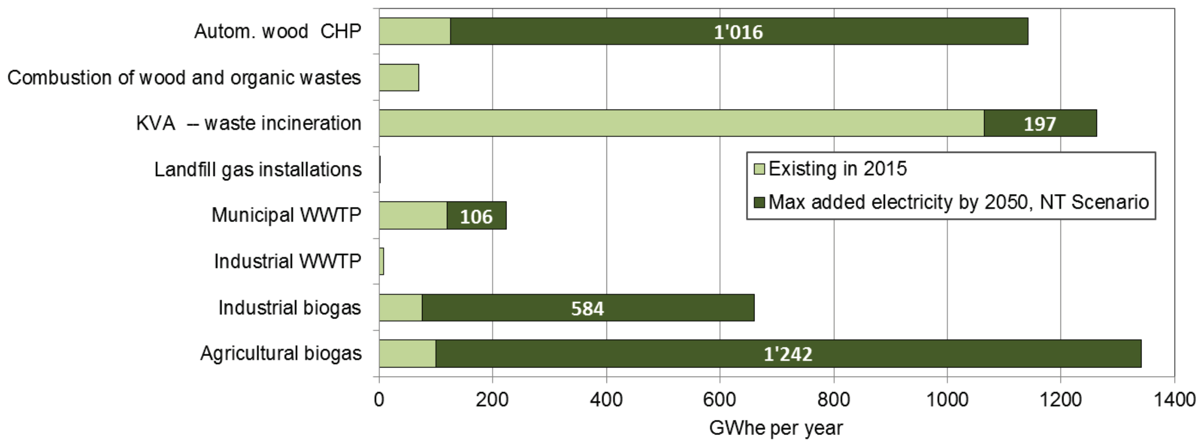

Figure 10.30: Maximum potential electricity generation to be added by 2050 under the NT scenario, relative to the production in 2015. The maximal added electricity production is of 3.1 TWh (11.3 PJ) relative to 2015.

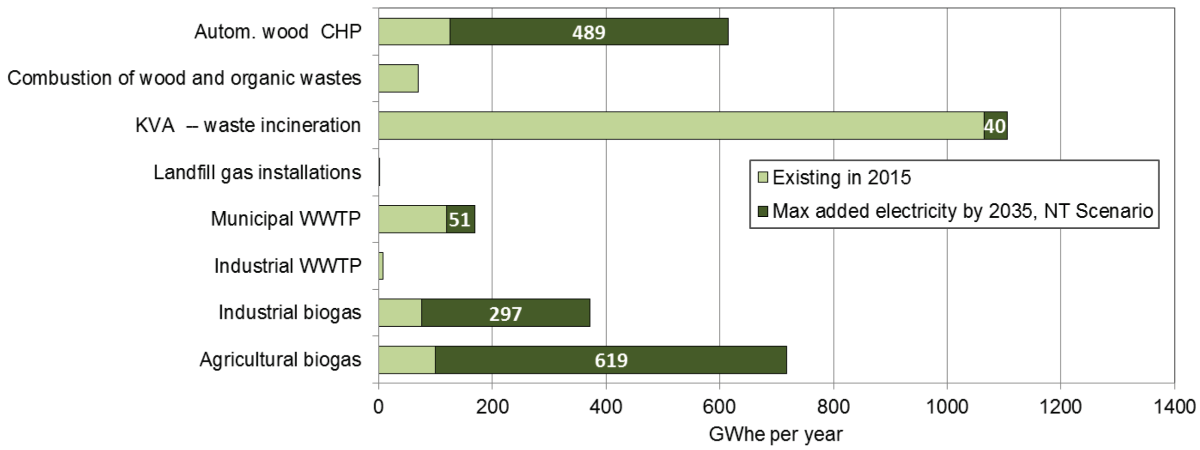

Figure 10.31: Maximum potential electricity generation to be added by 2035 under the NT scenario, relative to the electricity produced in 2015. The maximal added electricity production is 1.5 TWh (5.4 PJ) relative to 2015.

This scenario is quite optimistic, as it requires a remarkable increase in the mobilisation of resources and in market development of two conversion technologies – gasifiers and solid-oxide fuel cells. At the moment, very few commercial wood gasifier units exist in Switzerland. The use of biogas for fuel cells is in the demonstration phase for wastewater treatment installations (see the ongoing DEMOSOFC project in Italy (Gandiglio, Lanzini et al. 2014), for example), and for manure farm-scale systems the economic feasibility is still the subject of study (Majerus 2016). However, the value of this scenario is to give the maximum upper range of electricity generation that is possible from Swiss biomass resources. Only importing feedstock from other countries could result in any higher electricity generation from biomass. And regardless of the scenario considered, the trend is clear. The three main areas of focus that are necessary to bring more bioelectricity online are, in order: (1) the significant mobilisation of manure; (2) the redirection of wood from heat-only to CHP systems; and (3) the mobilization of currently unused wood resources.

10.5 Costs of Electricity Generation

10.5.1 Introduction and approach

The trends for the costs of bioelectricity in Switzerland are presented in this section. A selection of representative case studies (including built plants and concept studies) are first analysed to give an indication of the current costs and cost structure of the production of electricity from biomass. There were two principal goals in analyzing the case studies: (1) to determine broad trends in the cost structure of different types of bioelectricity installations, including the effects of feedstock costs and heat credits; and (2) to determine the costs of electricity production at the selected case studies.

One challenge in the assessment of costs for electricity production from biomass is the complexity of the biomass-to-electricity chain. Costs vary strongly, not just by scale of installation as is true for other electricity generation technologies, but also based on the type of biomass feedstock and on the local conditions at each plant (including the possibility for heat sales, existing infrastructure, etc.). By contrast, other renewables such as solar PV and wind are less site specific. The case studies presented in this section were selected to provide a representative overview of biomass-based electricity generation plants in Switzerland and in other countries.

Rather than following a single business model centered purely around electricity sales, biomass plants generally follow one of three business models, as outlined in Figure 10.32. In one business model, income for providing a waste processing service (such as waste incineration or wastewater treatment) is significant. In a second business model, heat sales are considered to be a primary source of income. In a third business model, neither income from a waste processing service nor from heat sales is significant, and electricity sales are then the dominant source of income. Each business model results in different costs and cost structures for the production of electricity.

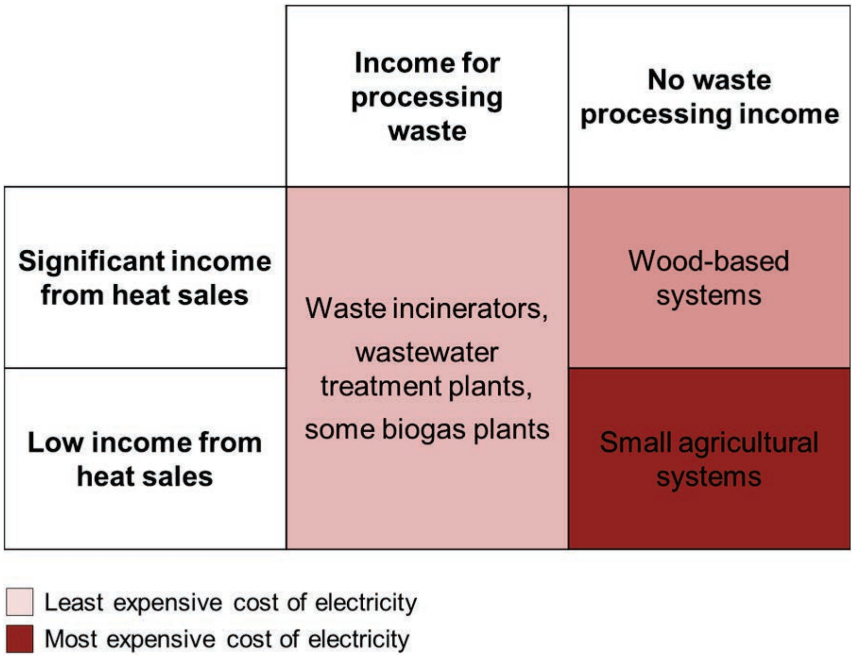

Figure 10.32: Business models for electricity production from biomass. Darker red represents options that are generally more expensive than lighter red options.

At the moment, a significant percentage of bioelectricity production plants in Switzerland receive feed-in tariffs at cost (Deutsch: “Kostendeckende Einspeisevergütung, KEV”; français: “rétribution à prix coûtant du courant injecté, RPC”). Because this system represents a significant source of income for Swiss bioelectricity plants today, the statistics of the feed-in tariffs are presented and compared with the costs of electricity generation in the case studies.

A range of costs of electricity production today are synthesized from the case studies and, where relevant, from information from the feed-in tariff statistics. Finally, future costs of electricity generation from biomass systems are estimated based on today’s cost ranges and cost structures and on expected changes in capital costs, operating costs, feedstock costs, and heat credits.

This section only considers direct electricity production from biomass. Electricity production by creation of biomethane for grid injection is discussed in Section 10.6.

10.5.2 Case studies: Systems in the agricultural sector

Finding detailed cost information for individual agricultural biogas sites in Switzerland is not straightforward, because many are run by individual farmers as small family operations. One exception is a 16 kW_e farm-scale biogas operation in Reichenbach, whose farmer/biogas operator has provided a detailed cost analysis of his installation online[223] (Hari 2015). Moreover, a 2015 study by SFOE and Oekostrom Schweiz reports average techno-economic values for a selection of 20 operational agricultural biogas installations in Switzerland (Anspach and Bolli 2015). In addition, a recent conceptual study examined the general feasibility of building small-scale (25 kW_e) installations in Switzerland (Bakx, Boéchat et al. 2014). Finally, several German cases (one reported existing installation (Stinner, Stur et al. 2015), and three conceptual studies performed by FNR (FNR 2016)) are included, because Germany currently has the largest development of agricultural biogas installations in Europe.

The cost structures of these case studies are shown in Figure 10.33. In this figure, the top line shows the cost of electricity production, with and without the inclusion of any heat credits reported for each case study. The bottom line shows the cost structure, with costs as positive values and income as negative values.

Detailed values of cost parameters for each case study are listed in the appendix of this chapter. Contributions to costs of electricity production are found according to the data directly given by each of the studies, where available. Specifically, interest rates are in the range of 2-4% with plant life of either 10 or 15 years, depending on the study. Operating and maintenance costs are separated into variable (per-kWh_e of production) and fixed (per-kW of installed capacity) where possible, and are otherwise combined. In all cases, biomass feedstock costs are considered separately from operating and maintenance costs. Heat credits are also calculated based on information given in each of the studies. In the Swiss cases, the value of external heat sales range from 6-9 Rp./kWh_{th} (Bakx, Boéchat et al. 2014, Anspach and Bolli 2015, Hari 2015).

[223] http://www.quh-energie.ch/biogas.html

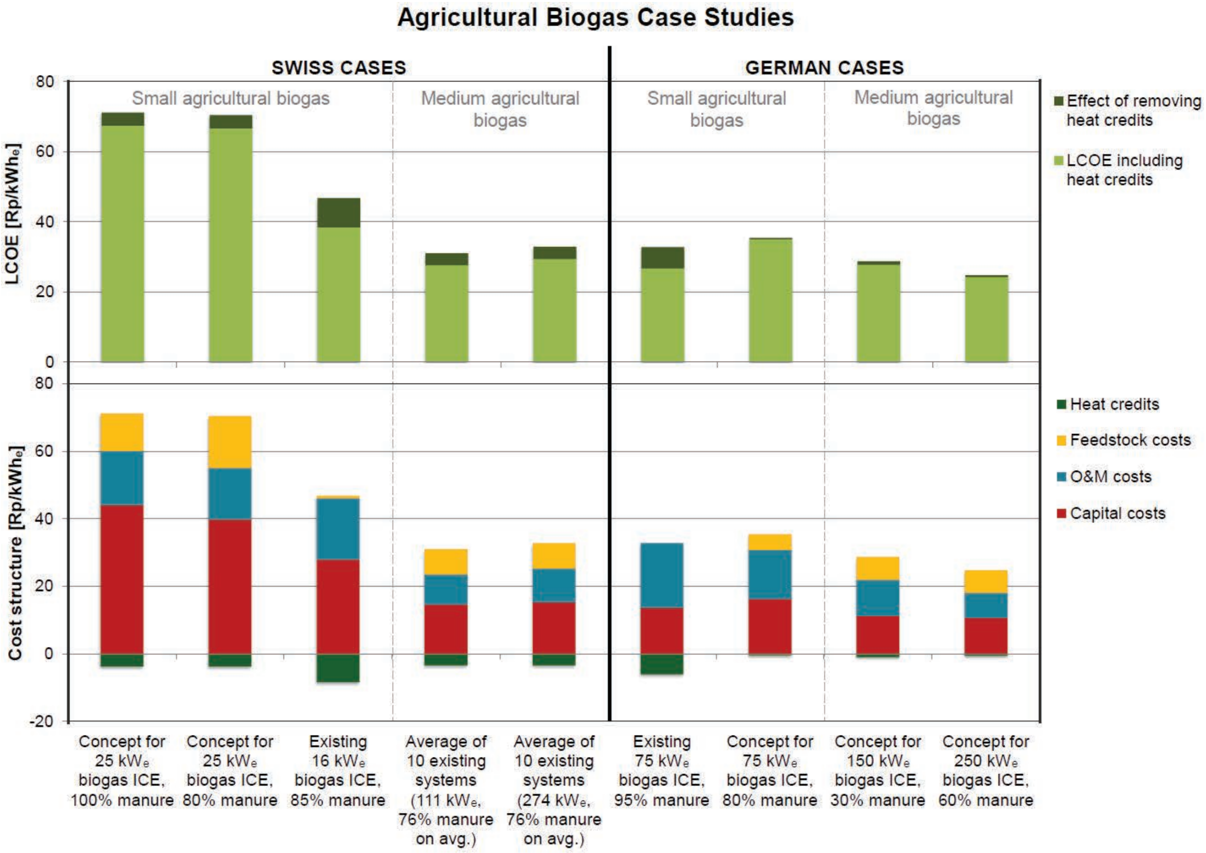

Figure 10.33: Cost structure for selected case studies using agricultural biogas. Data is adapted from (Bakx, Boéchat et al. 2014, Anspach and Bolli 2015, Hari 2015, Stinner, Stur et al. 2015, FNR 2016) and from own estimations. Details of parameters can be found in the appendix. ICE = internal combustion engine; O&M = operation and maintenance.

The following conclusions can be drawn about agricultural biogas systems from Figure 10.33:

- Costs of electricity production from agricultural biogas systems in Switzerland are high (~30 Rp./kWh$_e$ and higher), and capital costs are still the largest hurdle. A detailed analysis (Bakx, Boéchat et al. 2014) has shown that the digester and digestate[224] storage – not the CHP – are the most important parts of the capital costs. The CHP installation contributes about 20% to the total investment cost. Importantly, small-scale systems have particularly high capital costs. Swiss manure resources are distributed at many small farms, with the average farm's manure corresponding to a 3 kW$_e$ biogas engine (Bakx, Boéchat et al. 2014). Even though the average capital costs of <150 kW$_e$ systems are not significantly different from those of >150 kW$_e$ systems, the capital costs in the <30 kW$_e$ range do increase considerably. Reducing capital costs at small scales will be important for increasing the use of Swiss manure resources.
- Capital costs, in practice, are highly variable depending on what infrastructure already exists at the farm, especially for manure/digestate storage. The evaluated 75 kW$_e$ German installation was able to have low capital costs because the construction of the biogas installation was combined with an already-planned expansion of his

[224] The digestate is the sludge that remains after biogas production in the digester. It must generally be stored for weeks or months for sanitation or transport collection purposes.

farm (Stinner, Stur et al. 2015). Similarly, the reported capital costs are significantly lower in the real 16 kW_e Swiss installation (Hari 2015) than in the 25 kW_e Swiss conceptual study (Bakx, Boéchat et al. 2014), indicating that agricultural biogas installation feasibility varies on a case-by-case basis.

- However, there is a need for more detailed cost survey of very small Swiss biogas installations. An existing benchmarking study (Anspach and Bolli 2015) has performed a survey of the costs of several biogas installations, but the two size categories considered were >150 kW_e and <150 kW_e, with no smaller size category. There is a large difference between reported costs of an existing small installation (Hari 2015) and a conceptual feasibility study for a similar unit (Bakx, Boéchat et al. 2014). The reason for this difference is not yet fully understood, but could result from conservative assumptions in the feasibility study, optimistic assumptions at the farm site, or simply due to favorable conditions at the farm site.
- On-site manure is free except for the cost of additional collection and storage. Therefore, feedstock costs are very small. Co-substrates are more expensive if they must be transported from off-site. Valorisation of heat as a co-product is not very significant in agricultural biogas installations. A portion of the heat produced by the CHP unit is needed to heat the digester. The remaining heat is typically used at the farm rather than sold externally, such that the value of the heat is only as a replacement of other heating costs (e.g. heating oil, natural gas). This would vary on a case-by-case basis depending on location in particular, as not all plants could sell heat to a district heating network. For similar system sizes, the costs and cost structure are not significantly different in Germany and in Switzerland.

10.5.3 Case studies: Systems in the wood sector

In Figure 10.34, the cost structures of selected case studies using combustion or gasification are shown. In this figure, the top line shows the cost of electricity production, with and without the inclusion of any heat credits reported for each case study. The bottom line shows the cost structure, with costs as positive values and income as negative values.

The case studies shown here are for installations that use woody biomass as a feedstock. The Swiss case studies shown here include an 11 MW_e wood combustion system (Aubrugg in Wallisellen, ZH) (Jenni 2012, Jenni 2015) a 1.4 MW_e wood gasification system (in Stans, NW) (Schaub and Gemperle 2008, Keel 2013, Genossenkorporation Stans 2016, Hrbek 2016), a 600 kW_e wood combustion system (in Nesslau, SG) (Keel 2013), a 180 kW_e wood gasification system (planned for Rheinfelden, AG based on existing German systems) (Burkhardt 2014, St.Peter-Bioenergie 2014)[225], and an 83 kW_e wood combustion system using an externally-fired gas turbine (Vogel and Schibli 2012). These cover gasification-based commercial systems in Switzerland and a representative selection of the wood combustion systems. A conceptual study for a small-scale externally-fired gas turbine is also shown (Griffin, Winkler et al. 2015), because future trends in increased wood utilisation will require the construction of more small-scale units.

Additionally, several case studies from other EU countries are shown for comparison. These include a 5.7 MW_e Austrian wood combustion plant and a 130 kW_e Slovakian wood

[225] As the unit in Rheinfelden is not yet built, the production data from a similar German site which uses the same gasifier by the company Burkhardt was used, while the economic data for the planned Rheinfelden case was used..

combustion plant, both of which were case studies in a recent IEA report on the techno-economics of biomass CHP (Obernberger, Hammerschmid et al. 2015). Detailed values of cost parameters for each case study are listed in the appendix of this chapter. Contributions to costs of electricity production are found according to the data directly given by each of the studies, where available. Specifically, interest rates are in the range of 2-4% with plant life of either 10, 15, or 20 years, depending on the study and on the type of plant. Operating and maintenance costs are listed separately from biomass feedstock costs in all cases. Heat credits are reported based on the information in the studies where available, and on assumptions based on similar systems when not directly available. The assumptions about heat sales were quite variable. On the low end, the 180 kW_e system assumes a heat sale price of 0.5 Rp./kWh_{th} (Burkhardt 2014). Most other Swiss case studies assume a heat sale price around 8 Rp./kWh_{th}. Variability in these values can come from whether the heat is sold directly to a customer or first to a heat distribution network, and whether the end user is industrial or residential (with direct sales to residential customers having the highest acceptable heat price). A heat price of 0.5 Rp./kWh_{th} is considered to be unusual, typically indicating a competing heat source with inexpensive heat production in the same or neighboring distribution network.

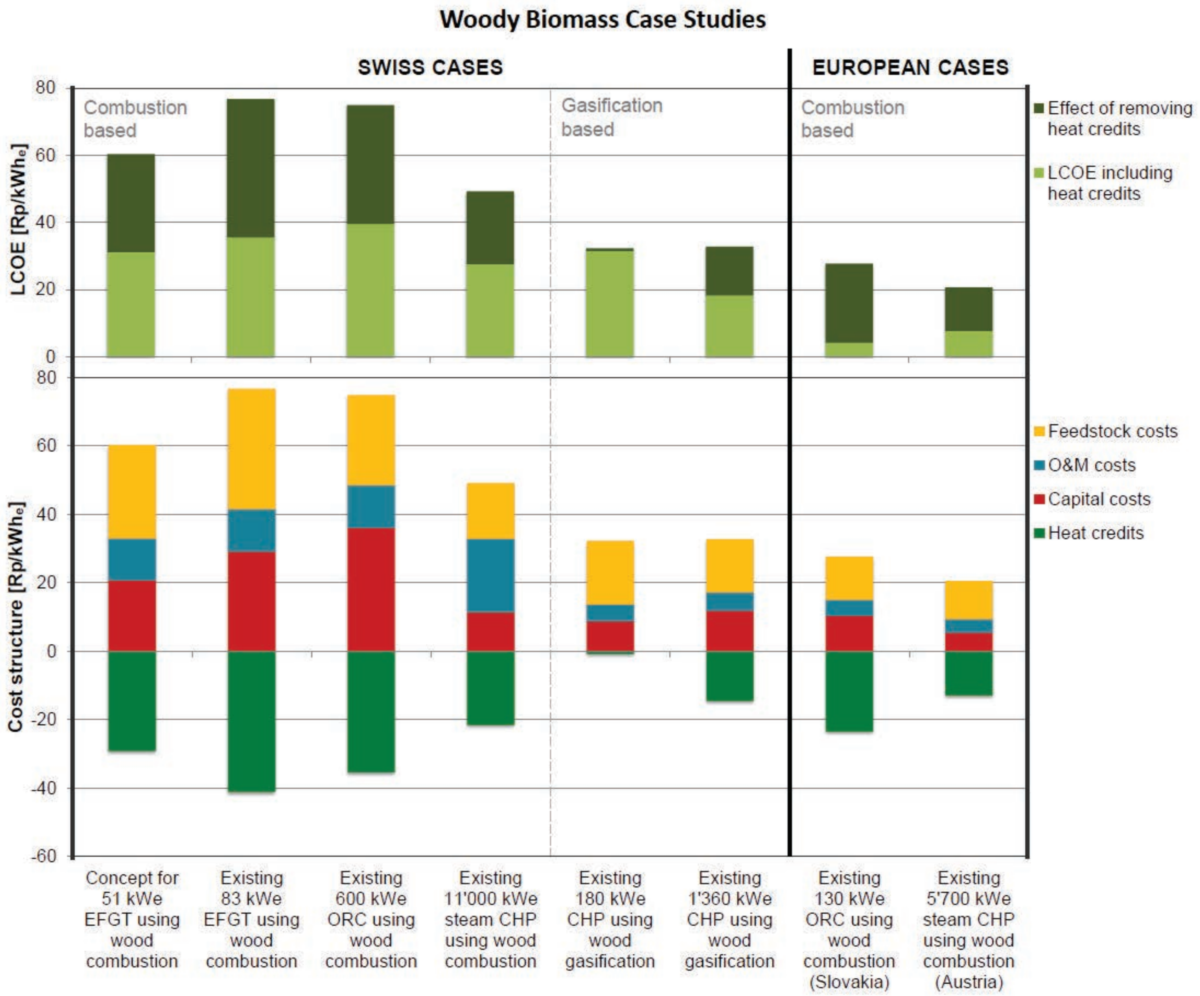

Figure 10.34: Cost structure for selected case studies using combustion or gasification of woody biomass. Data is adapted from (Schaub and Gemperle 2008, Jenni 2012, Vogel and Schibli 2012, Keel 2013, Burkhardt 2014, Griffin, Winkler et al. 2015, Jenni 2015, Obernberger, Hammerschmid et al. 2015, Wandschneider + Gutjahr Ingenieurgesellschaft mbH and SWU Energie GmbH 2015, Dirner 2016, Genossenkorporation-Stans 2016, Hrbek 2016) and from own estimations. Details of parameters can be found in the appendix. EFGT = externally-fired gas turbine; CHP = combined heat and power; ORC = organic Rankine cycle; O&M = operation and maintenance.

From Figure 10.34, the following conclusions can be drawn about combustion and gasification systems for woody biomass:

- The costs for producing electricity from combustion and gasification systems are also still quite high in Switzerland (~20 to ~40 Rp./kWh$_e$ for the case studies shown here). However, the cost structure for these plants looks fundamentally different than the agricultural biogas plants, as described in the next points.
- The primary costs for wood combustion and gasification systems are feedstock costs. These are even higher than capital costs, on average. Wood is an expensive feedstock with a large range of prices depending on the quality of the wood, as discussed in Section 10.2. The future of wood prices will therefore have a significant effect on the costs of electricity production from wood combustion and gasification.
- Heat sales are a significant source of revenue for wood combustion and gasification systems. The cost of electricity generation is very sensitive to heat valorisation.

Without the ability to sell heat at a reasonable price level, these systems would not be economically attractive. Any future systems will thus need to be built in locations where heat can be sold through an existing district heating network, or where a district heating network can be built, or where there is significant need for self-use of heat (e.g. for drying wood chips).

- Based on the case studies considered, gasification systems can have lower capital costs than wood combustion based systems. This is promising for the future of wood gasification systems in Switzerland.

10.5.4 Case studies: Systems in the waste management sector

For systems which are in the waste management sector, the cost structures look quite different from systems which use woody biomass or agricultural biomass as feedstocks. These installations receive gate fees or other income for providing a waste processing service, which means that their feedstock "costs" are effectively negative. This effect applies to municipal wastewater treatment plants, waste incinerators, and some industrial biogas or industrial wastewater treatment plants. Gasification of waste feedstocks is also technically feasible. One commercial large-scale waste gasifier exists today in Lahti, Finland (160 MW_{fuel}).

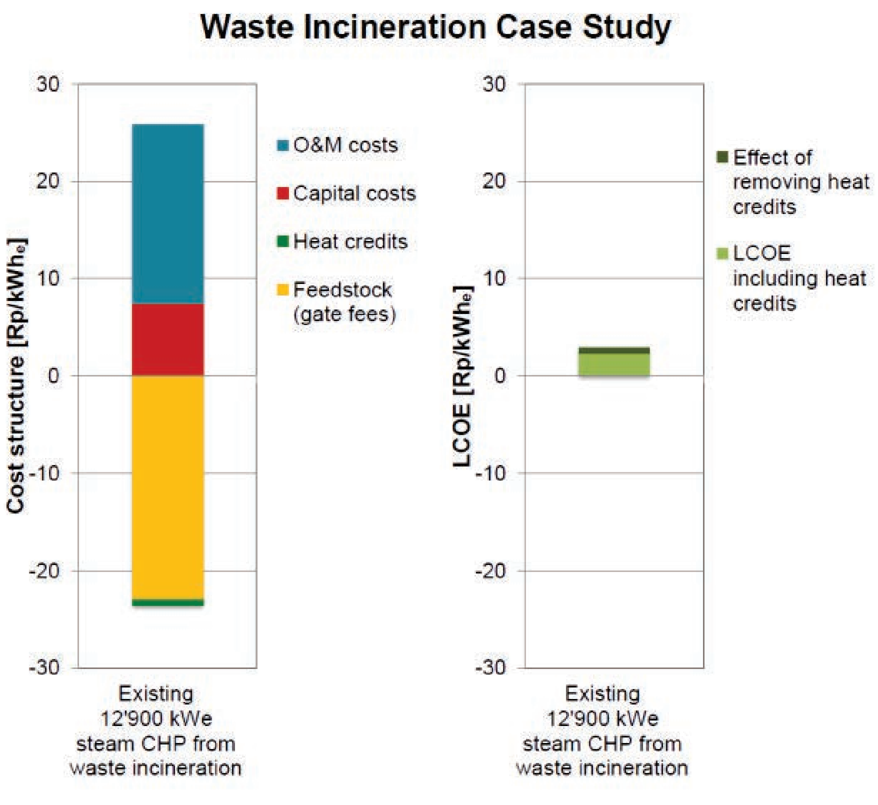

Figure 10.35: Cost structure for a waste incineration plant (KVA) in Switzerland. Credits received for heat utilization (in green) as well as negative feedstock costs (in yellow) are used to shift the cost baseline down, while capital costs (in red) and operating & maintenance costs (in blue) are positive. The top of the stacked bars therefore represents the net cost of electricity. Data is adapted from (KVA Turgi 2015).

Figure 10.35 shows the cost structure for an existing municipal waste incineration system: the KVA in Turgi, AG (KVA Turgi 2015). In this figure, the right side shows the cost of electricity production, with and without the inclusion of any heat credits reported for the case study. The left side shows the cost structure, with costs as positive values and income as negative values. This case is shown as an example of a waste incinerator which receives no feed-in tariffs for electricity sold, and instead sells electricity directly to the grid. In this case study, electricity was produced at a cost of 2.3 Rp./kWh and sold it at 4.7 Rp./kWh in 2015 (KVA Turgi 2015). This plant sells heat to the local district heating system as well, but it sells it very cheaply at 0.66 Rp./kWh_{th} (KVA Turgi 2015). Detailed values of cost parameters for the case study are listed in the appendix of this chapter.

For plants which are in the waste management sector, the following statements apply:

- The feedstock prices are effectively negative. This is because the installations receive a gate fee or other income for providing a waste processing service.
- Heat produced at waste incinerators (KVAs in German) is often sold to district heating grids, so it can be used to offset some of the production costs of electricity. However, the gate fees for these waste incinerators are a much more significant source of income than heat sales.
- Heat produced at wastewater treatment plants is utilized to a large extent on-site to heat the digester (Zutter, Nijsen et al. 2015).
- Some plants in the waste management industry do receive feed-in tariffs today for selling electricity, although many do not. This is discussed in the following section.

10.5.5 Feed-in tariffs for bioelectricity in 2015

As long as bioelectricity plants fulfil certain conditions[226], they receive a feed-in tariff for the electricity fed into the grid. These feed-in tariffs are higher than the electricity market price, and are intended to offset the higher costs of producing electricity from renewable resources until the technologies become more highly developed and the costs of production decrease. Each year, the list of all installations receiving feed-in tariffs in Switzerland is published online by SFOE[227] (BFE 2016), which are given in accordance with the Energieverordnung (Schweizer Bundesrat 2017, Stand 1. Januar). From this list, the biomass installations can be identified. Figure 10.36 shows these data plotted as a function of plant size for the four major bioenergy categories identified in the feed-in tariff data tables from SFOE.

[226] And as long as money is still available from the government to provide the feed-in tariffs; at the moment, a waiting list exists for feed-in tariffs for new installations.

[227] http://www.bfe.admin.ch/php/modules/publikationen/stream.php?extlang=de&name=de_58802254.xlsx&endung=Liste%20aller%20KEV-Bez%FCger%20im%20Jahr%202015

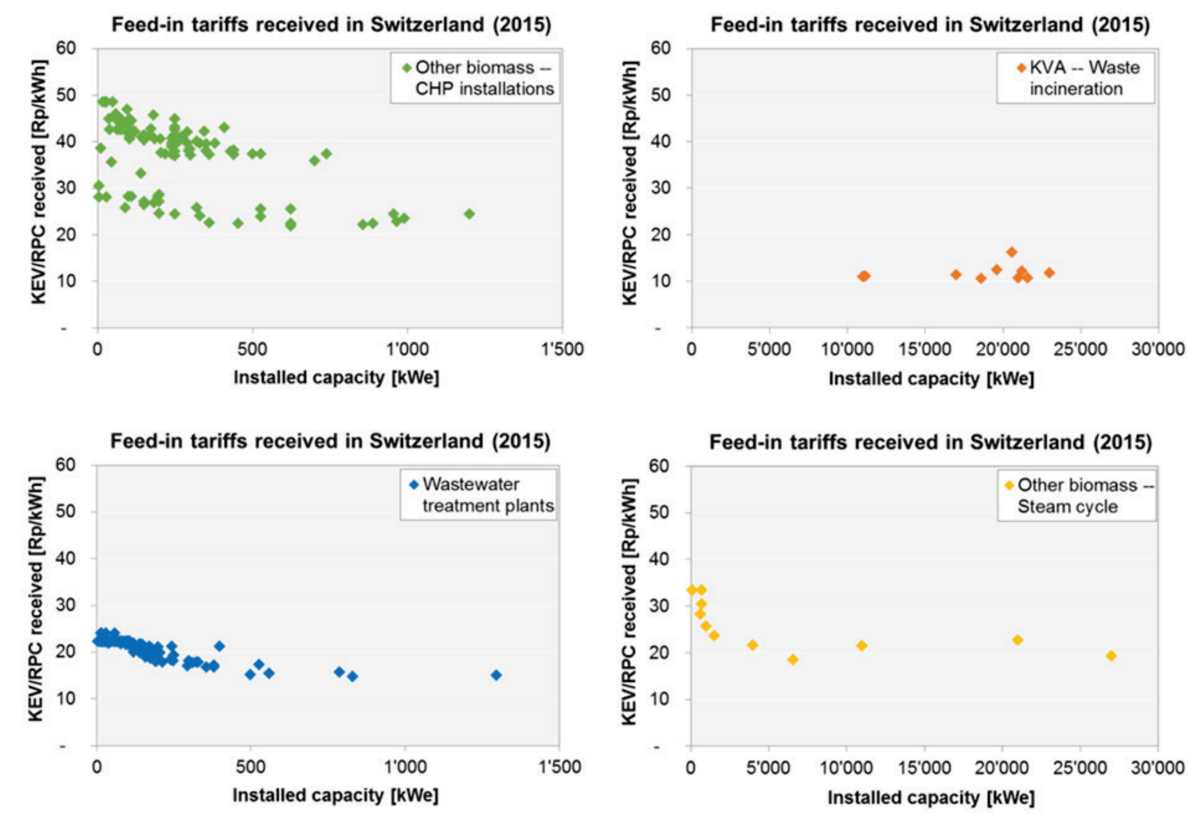

Figure 10.36: Distribution of feed-in tariffs (KEV/RPC) received for bioelectritcty in Switzerland in 2015. Data is adapted from (BFE 2016), which is based on (Schweizer Bundesrat 2017, Stand 1. Januar). The category "Other biomass – CHP installations" is the category name used by SFOE ("Übrige Biomasse – übrige WKK-Anlage"), and the majority of these installations are agricultural or industrial biogas and industrial WWTP. The category "Other biomass – Steam cycle" ("Übrige Biomasse – Dampfprozess") includes combustion and gasification of woody biomass, and includes both traditional steam cycles as well as organic Rankine cycles.

Plants that receive the highest feed-in tariffs are agricultural biogas installations. The range of feed-in tariffs received for biogas installations is quite large, depending primarily on the size of the plant and the percentage of manure in the digester feedstock. Small plants whose substrate is at least 80% manure (by mass) and who utilise at least 20% of the heat produced externally to the digestion process receive a maximum feed-in tariff of 48.5 Rp./kWh$_e$. These comprise the cluster of data points in the top left corner of the "Other biomass" subplot of Figure 10.36. The lower cluster, in the 20-30 Rp./kWh$_e$ range, are mainly installations that have more than 20% of non-agricultural substrates, and most of them would be categorised as "industrial biogas".

In order to preserve consistency in the biomass chapter of this report, the data in Figure 10.36 was also sorted into the technological pathway categories described in Section 10.3 and used throughout this chapter. The result of this sorting process gives a range of feed-in tariffs received for each category, as seen Figure 10.37.

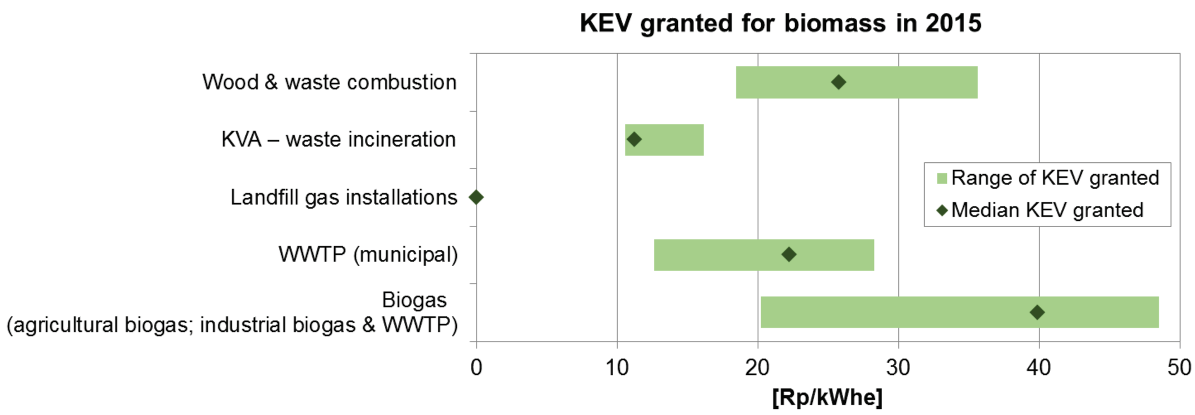

Figure 10.37: Range of feed-in tariffs (KEV/RPC) received for bioelectricity in Switzerland in 2015. Data is adapted from (BFE 2016), which is based on (Schweizer Bundesrat 2017, Stand 1. Januar).

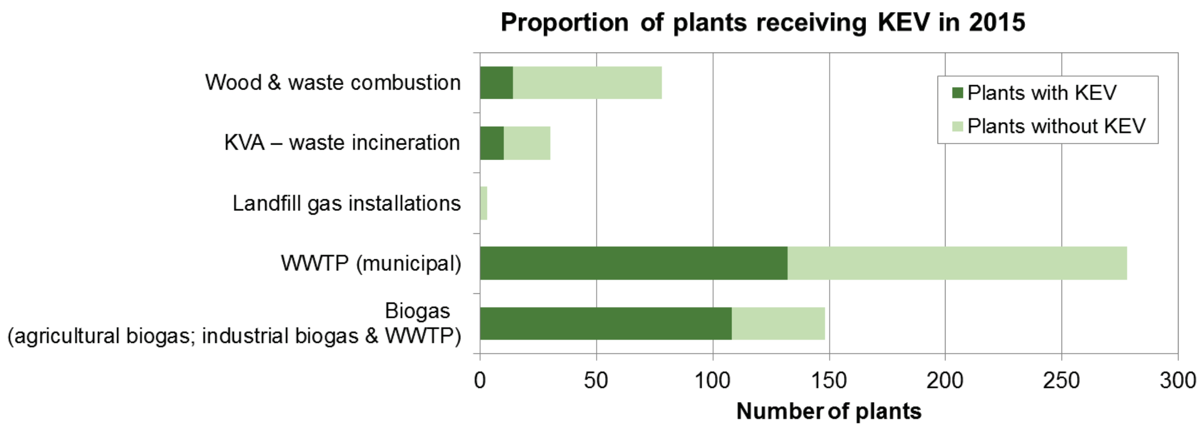

Figure 10.38: Proportion of plants receiving a feed-in tariff (KEV/RPC) in Switzerland in 2015. Data adapted from (BFE 2016, Kaufmann 2016a, Kaufmann 2016b, Stettler and Betbèze 2016). For wood and waste combustion, it was not possible to separate the installations that produce heat only from those that produce electricity and heat. It is assumed that the majority of the plants producing electricity do receive a feed-in tariff.

However, not all bioelectricity installations receive feed-in tariffs. In Figure 10.38, we show the number of plants that received feed-in tariffs in 2015 relative to those that did not. For the “wood & waste combustion” category, it was not possible to separate electricity-producing installations from those producing electricity and heat given the categories in the statistics. This was already mentioned in Table 10.1 as the reason for the apparent low electrical efficiency of this category. For this category, we can therefore make the assumption that the installations that do produce electricity are also the ones who receive feed-in tariffs.

The waste incineration plants and wastewater treatment plants are similar in the sense that some of them receive feed-in tariffs, while others do not. These are the two categories in which the purpose of the plant is firstly to process waste, rather than generate heat or electricity. Therefore, these plants receive gate fees or other income for providing a waste processing service, and thus have effectively negative costs for the feedstock used to generate electricity. This creates a cost structure that can result in affordable electricity generation without a feed-in tariff in some cases, as shown in the case study in Figure 10.35. Several modern incinerators receive feed-in tariffs of 10 Rp./kWh$_e$, and some may even receive higher feed-in tariffs when wood is valorized more strongly.

10.5.6 Costs of electricity production in 2015

The cost ranges for electricity production from biomass from the selected case studies were ~28-38 Rp./kWh$_e$ for built plants in the agricultural sector, ~18-40 Rp./kWh$_e$ for built plants in the wood sector, and 2.5 Rp./kWh$_e$ for one waste incinerator.

These case studies provide some information about the costs of producing electricity from biomass today, especially as they come from real plants and as they give information about the cost structure. However, there are limitations in considering only these case studies.

First, a small selection of cases will not give a full picture of the range of costs at all plants in the country. This is especially true for biomass plants, which are still largely built on a case-by-case basis in accordance with local needs. This leads to a wide variety in scale, in heat utilization, in heat sales price, and in capital costs depending on what is locally available. All of these factors have a significant effect on electricity production costs.

Second, even for the case studies considered there are still uncertainties in the cost structures presented. The cost data were compiled from a mix of pre- or post-construction engineering and budgeting presentations from conferences, newspaper articles, yearly financial reports, academic and governmental studies, along with some additional assumptions about plant lifetime and interest rates. The value is that the numbers used are real, publicly available values to the extent possible. The limitation is that the assumptions made by these various sources may not always be consistent, and that numbers given at different stages of plant life (planning, building, commissioning, …) may change with progress in the plant's construction and operation. There is therefore an inherent uncertainty in the final results for the cost of electricity production.

The cost ranges for electricity production from biomass are therefore extended by including statistics from the feed-in tariffs where relevant. Including statistics from the feed-in tariffs allows us to cover a much larger number of cases without having to analyze each one in detail. The principal assumption when using feed-in tariff data in this way is that feed-in tariffs are indeed provided *at cost* for the production of electricity, as is their purpose. Specifically, it should be shown that the difference between the feed-in tariff received and the cost of electricity production is of a similar magnitude than the expected uncertainty in the cost of electricity calculation. If this is true, the feed-in tariff ranges can be used to provide information about the cost of electricity production – at least for plants which receive feed-in tariffs.

Figure 10.39 and Figure 10.40 show the differences between the estimated[228] feed-in tariffs and the costs of electricity production for the case studies considered in this chapter. With the exception of the smaller existing agricultural cases, the Swiss cases shown in Figure 10.39 and Figure 10.40 have feed-in tariffs that match the production costs within ±35%, and often less. A maximum of 35% uncertainty in the cost of electricity production would not be unexpected, considering case-specific differences as well as the uncertainties in reported costs.

[228] Estimated using the online feed-in tariff calculator, https://www.guarantee-of-origin.ch/swissforms/TarifBioWKK.aspx?Language=De, which is based on the rules set out in (Schweizer Bundesrat 2017, Stand 1. Januar).

For the agricultural cases in Figure 10.39, one point should be discussed. The case "Average of 10 existing systems" is, as indicated, based on reported aggregated values rather than on a specific plant. The average manure content in these plants is 76% (Anspach and Bolli 2015). The feed-in tariff is estimated based on a hypothetical plant with the characteristics of these averaged values. The use of aggregated values results in uncertainties both in the real cost data and in the ability to compare this data with an estimated feed-in tariff. For this reason, the feed-in tariffs resulting for plants with >80% manure and <80% manure are shown.

Given the close match between the costs of electricity and the feed-in tariffs, feed-in tariffs can be taken to be reasonable indicators for the cost of electricity productions in cases where feed-in tariffs are received. Mainly wood-based and agricultural based systems were discussed here, but wastewater treatment plants receiving feed-in tariffs are also expected to receive these feed-in tariffs at cost (as stated in a recent study of Swiss wastewater treatment plants (Zutter, Nijsen et al. 2015).

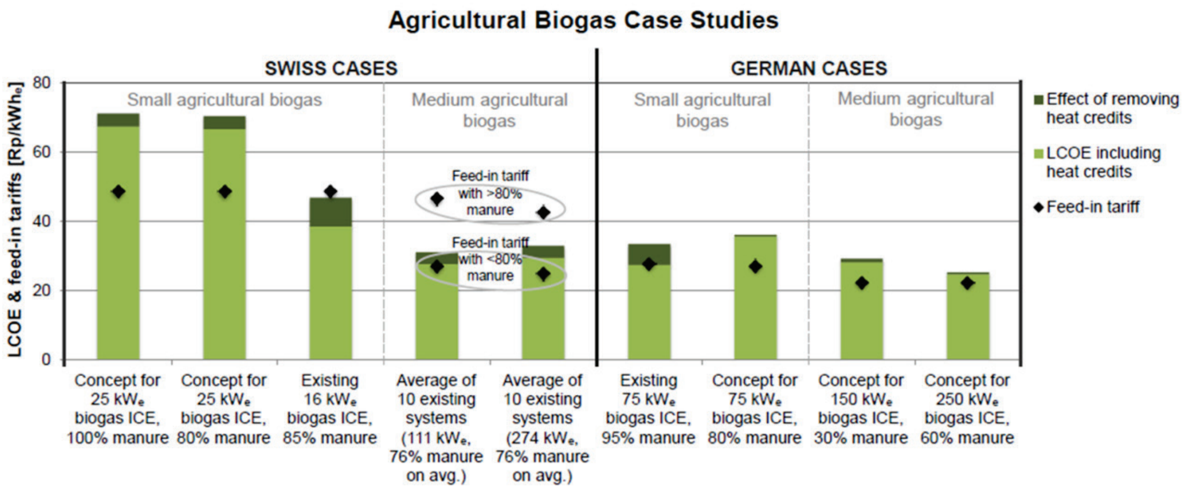

Figure 10.39: Comparison of the agricultural case studies from Section 10.5.2 with an estimate of the feed-in tariffs that they would receive. Feed-in tariffs in Switzerland are estimated using the online feed-in tariff calculator[229]. Feed-in tariffs in Germany are from (Bakx, Boéchat et al. 2014, Anspach and Bolli 2015, Hari 2015, Stinner, Stur et al. 2015, FNR 2016). Cost structure information is shown in Figure 10.33 and detailed in the appendix of this chapter.

[229] Estimated using the online feed-in tariff calculator, https://www.guarantee-of-origin.ch/swissforms/TarifBioWKK.aspx?Language=De, which is based on the rules set out in (Schweizer Bundesrat 2017, Stand 1. Januar)

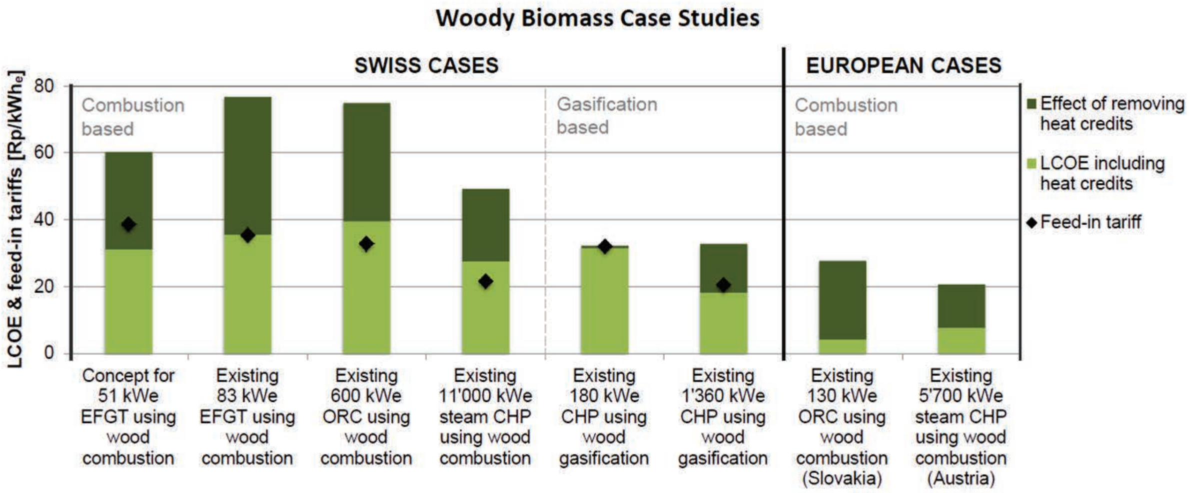

Figure 10.40: Comparison of the wood sector case studies from Section 10.5.3 with an estimate of the feed-in tariffs that they would receive. Feed-in tariffs in Switzerland are estimated using the online feed-in tariff calculator[229]. Cost structure information is shown in Figure 10.34 and detailed in the appendix of this chapter.

The ranges of costs of electricity production from biomass in Switzerland in 2015 are shown in Figure 10.41. All of the case studies presented in this chapter have costs of electricity that are within the ranges shown in Figure 10.41, but the ranges have been expanded beyond the results of the individual case studies using feed-in tariff data to provide more complete information.

The upper end of each range is the highest feed-in tariff received for the designated technology category. Therefore, the upper ends of the ranges in Figure 10.41 correspond to the upper ends of the ranges in Figure 10.37. The key assumption here is that plants which produce electricity at a higher cost than the feed-in tariff (and are therefore unprofitable) would either not be built, would stop operation, or would change cost structure to match the feed-in tariff (e.g. by increasing the valorization of heat).

The lower end of the ranges in Figure 10.41 is the lowest feed-in tariff received for the categories of wood CHP, combustion of wood and organic wastes, and biogas installations. For these technology categories, it is assumed that the majority of today's plants cannot be built without feed-in tariffs, as seen by the high costs of electricity production in the case studies of Figure 10.33 and Figure 10.34. For waste incinerators and wastewater treatment plants, the lower end is estimated to be around market price for electricity to represent the plants that do not receive feed-in tariffs. For the waste incinerators, the lower end refers to data from the KVA Turgi, which reports electricity production costs of 2.3 Rp./kWh$_e$ (calculated from data given in (KVA Turgi 2015). For municipal wastewater treatment plants, the estimate of 4 Rp./kWh$_e$ (around market price for electricity) is used for the lower end. Industrial wastewater treatment plants are assumed to have electricity production costs that are similar to municipal wastewater treatment plants, and are therefore included in the same category.

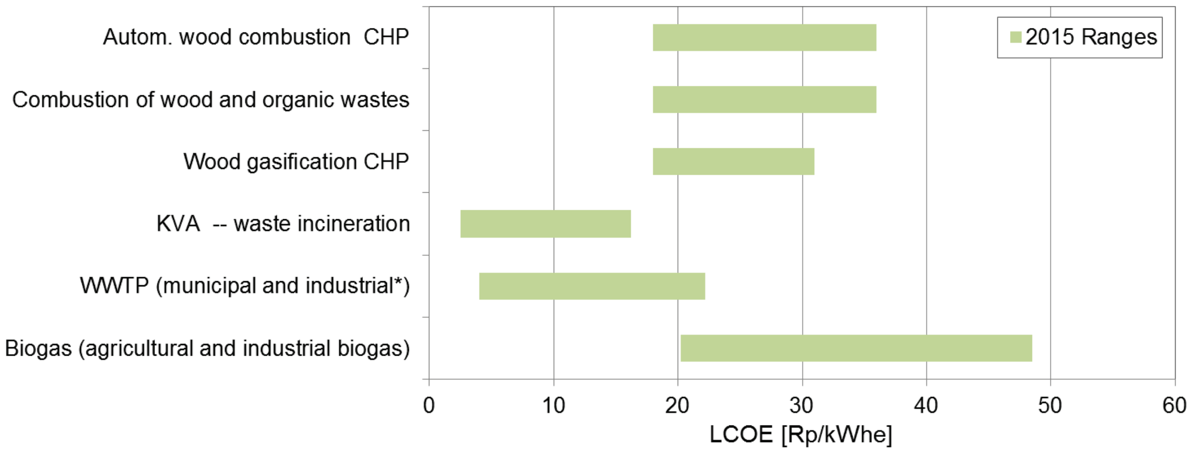

Figure 10.41: Range of costs for production of electricity from biomass in Switzerland. *It is assumed that industrial wastewater treatment plants have electricity production costs that are similar to municipal wastewater treatment plants.

Several conclusions can be drawn by observing the results in Figure 10.41 and the case studies in Figure 10.33, Figure 10.34, and Figure 10.35:

- The biomass-based installations with the cheapest costs of electricity production are all in the waste management sector. This is because of a key difference between the business model of these and other biomass-based systems: plants in the waste management sector receive gate fees or other income for providing a waste management service. This leads to an easier path to profitability than for systems in the wood sector (where the wood must be purchased) or in the agricultural sector (at the local farm scale, farmers do not pay themselves for use of their own manure).
- Plants in the wood sector do have to purchase their feedstock, but they are also generally built at locations where significant heat sales can be made (as shown in the case studies in Figure 10.34). The profitability of these plants depends very strongly on the heat sales, and electricity is (for the moment) a side product.
- The plants which have the highest costs of electricity production are small-scale agricultural installations. The feedstock (manure and agricultural by-products, in addition to some co-substrates) typically does not bring an income for waste management services, although there are some exceptions. The feedstock cannot be transported easily to areas where heat demand is high, so the heat credits are often small. Without easy transportation of the feedstock, small scale plants are built, which also means that the capital costs contribute heavily to the total costs (as seen in the case studies in Figure 10.33).

10.5.7 Estimated projections to 2050

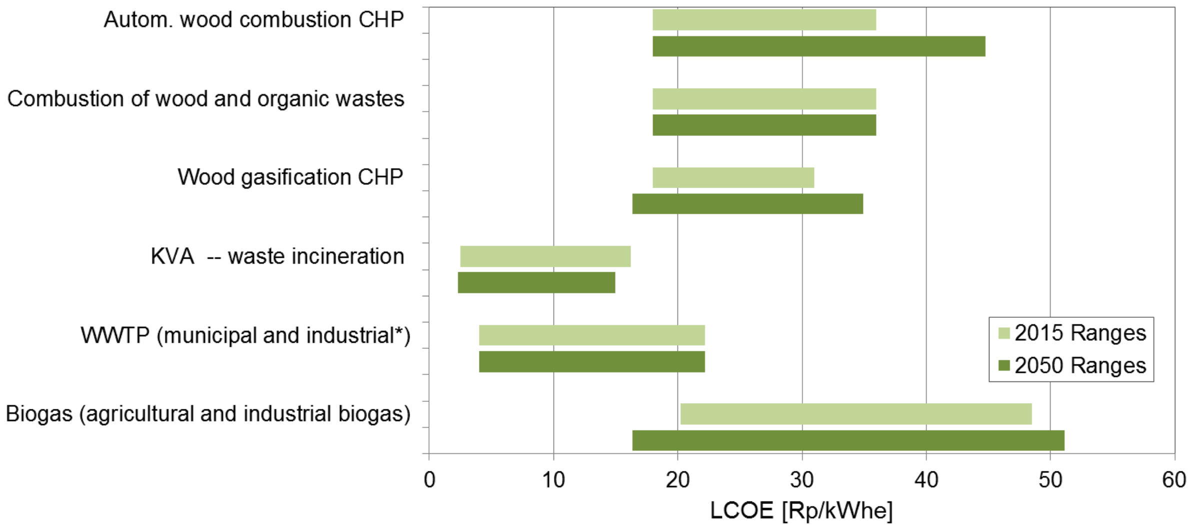

Figure 10.42: Projected future range of costs for production of electricity from biomass in Switzerland. *It is assumed that industrial wastewater treatment plants have electricity production costs that are similar to municipal wastewater treatment plants.

The estimated ranges of costs of electricity production from biomass in Switzerland in 2050 are shown in Figure 10.42. The bases for these estimations are as follows:

- Assume that wood feedstock prices could increase by up to 30%. This affects clean wood combustion and gasification systems. Price increases will happen naturally as more wood feedstock becomes utilized. Today, the cheaper wood feedstocks are used, but increasing electricity generation from wood will require using more expensive wood as well (Figure 10.21).
- Assume that wood combustion capital costs, operating costs, and heat utilization will not change significantly. It is likely that future plants will have a smaller average capacity than today's plants, which would generally lead to more expensive per-kWh capital costs. However, it is assumed that technological development will offset this effect, resulting in no net change.
- Assume that waste incineration plants could valorise their heat by an additional 20% relative to today (more heat utilization; similar heat sale price).
- Assume that waste incineration plants will see no other net change in costs. Gate fees for waste material could change in future. However, this is controlled by the plant itself, which will raise gate fees if its incineration process becomes more expensive. Therefore, no net change would result.
- Assume that capital costs for wood gasification processes can decrease by up to 20% as these technologies begin to become mass produced. These technologies would also see the same 30% feedstock price increase as other wood-based technologies. Assume no changes in operation and maintenance costs or in heat credits received.
- Assume that technologies at wastewater treatment plants are technologically mature, and will see no change in costs.
- Assume that capital costs for biogas systems can decrease by up to 30% as small-scale digesters become mass-produced. Assume that heat valorisation in these systems could be increased by up to 30% of current amounts. Finally, assume that

feedstock costs can increase by up to 30% as more transportation of feedstock is required.

These assumptions about increases are then applied to the 2015 costs of each conversion pathway category. The relative weighting of capital costs, feedstock costs, operating and maintenance costs, and heat credits for each category are taken from the cost structures analysed in Sections 10.5.2, 10.5.3 and 10.5.4. These weighting factors – and the assumed maximal relative change of each category – are listed in Table 10.4.

Table 10.4: Cost weighting factors and predicted relative changes from 2015 to 2050. The contributions are listed as percentages of LCOE, with positive values for costs and negative values for credits. Therefore, the individual cost contributions can be >100% when the credits are also high.

	Cost structure [% contribution to total costs]				Maximum relative change from 2015 to 2050 [% increase]			
	Capital costs	O&M costs	Feedstock costs	Heat credits	Capital costs	O&M costs	Feedstock costs	Heat credits
Autom. wood combustion	36%	24%	40%	-49%	0%	0%	30%	0%
Combustion of wood & organic wastes	36%	24%	40%	-49%	0%	0%	0%	0%
Gasification	33%	16%	51%	-29%	-20%	0%	30%	0%
KVA – waste incineration	29%	71%	-89%	-2%	0%	0%	0%	20%
WWTP	*No change assumed*							
Biogas	56%	28%	16%	-11%	-30%	0%	30%	30%

Overall, these assumptions will not result in very substantial changes in costs of electricity from biomass. Incremental changes can be expected as described in the list of assumptions. One persistent reality is the nature of the Swiss bioenergy system: installations will continue to be relatively small and location specific. The greatest Swiss biomass resource – manure – is distributed over the country at many small farms and is expensive to transport at the moment[230]. Woody biomass is more easily transported, but will always be best utilized at sites where heat is in high demand.

10.6 Biomethane production

10.6.1 Introduction

Instead of direct electricity generation as considered in the NT and TAU scenarios (Section 10.4.1), Switzerland's biomass resources could be used to produce biomethane. Biomethane, as opposed to biogas, refers to a gas that is primarily methane and can thus be injected into the natural gas grid. In Switzerland, biomethane must reach >96% methane content (by mole or volume) to satisfy requirements for grid injection (SVGW/SSIGE 2014). After injection into the natural gas grid, biomethane can be used to generate electricity and heat or used as a transportation fuel in vehicles. Therefore, biomethane production represents an indirect pathway to generate electricity from biomass. The value of biomethane as an energy carrier for electricity generation is that it can be used when and where electricity is

[230] Therefore, there are ongoing research efforts to separate the different fractions of manure in order to transport a fraction with a smaller water content (Hersener, Meier et al. 2014).

needed. Therefore, the biomass resource availability can be decoupled in time and place from the electricity (and heat) demand. Biomethane can be produced through different technology pathways, depending on the moisture content of the biomass, as described in Section 10.1.1.

10.6.2 Current biomethane production

The trends in biomethane production in Switzerland over the past 15 years were shown in Figure 10.26 in Section 10.3.2. Today, a total of 236 GWh of biomethane are produced in Switzerland. The GWh are given on the basis of lower heating value (LHV). This is still a small proportion of the total natural gas transported in Switzerland, at 0.7% of the gross natural gas energy used in Switzerland in 2015 (33'172 GWhLHV (VSG 2016)). Approximately half of the biomethane is produced at wastewater treatment plants, and the other half is produced from anaerobic digestion of food wastes and industrial waste (such as from sugar production). No biomethane is produced from woody biomass resources in Switzerland today.

10.6.3 Biomethane potential from Swiss resources

The potential for producing biomethane directly from biomass resources in Switzerland is shown in Figure 10.43. If all remaining sustainable biomass resources in Switzerland were used to produce biomethane, an additional 6.0 TWh/a of biomethane (LHV basis) could be generated. It is important to note that this figure therefore presents an *alternative* pathway to the ones presented in the TAU and NT scenarios in Section 10.4. The scenarios are not additive. It is considered that the biomass resources could be used either for direct electricity generation in the TAU and NT scenarios, or for biomethane production in this section.

If biomethane were considered to be preferable to other ongoing energetic uses of biomass, we could also consider additional biomethane generation from resource redirection. This is also shown in Figure 10.43. A total of 8.6 TWh/a of additional biomethane (LHV basis) could be generated if all biomass resources that are currently energetically utilised were redirected to produce biomethane, for a total of 14.6 TWh/a of additional biomethane relative to today's generation. Of course, these numbers only represent upper limits on the amount of biomethane which would be ever produced in Switzerland from domestic biomass resources. However, it is worth noting that even these maximal values still represent only a fraction of the 33'172 GWhLHV of natural gas used each year in Switzerland today (VSG 2016). A complete replacement of today's natural gas demand with biomethane is thus only possible with imports.

Using this biomethane for electricity generation only with decentralized CHP units or large NGCC power plants – applying the generation efficiencies provided in Table 14.9 – would result in an additional electricity generation of about 1.7-3.7 TWh/a by 2050 without biomass resource redirection, and 4.2-9.2 TWh/a when including resource redirection. The lower end of these ranges is calculated using the efficiencies of 1 kW_{el} CHP units, which would in addition generate 3.8 TWh of heat per year without resource redirection, or 9.2 TWh of heat with resource redirection. The higher end of these ranges is calculated using the efficiencies of NGCC plants without additional useful heat supply.

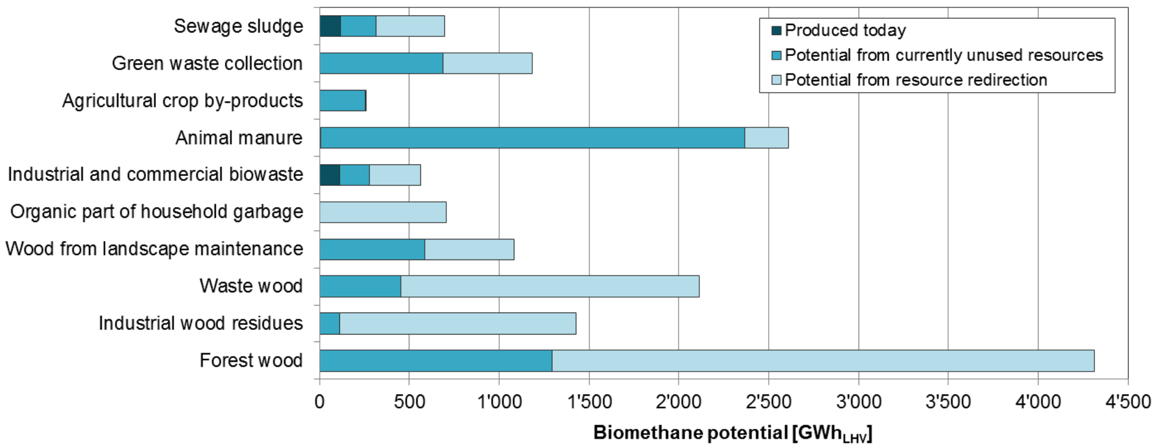

Figure 10.43: Potential for biomethane production in Switzerland, not including Power-to-Gas technologies.

Several assumptions about technology conversion pathways were used to generate Figure 10.43. It is assumed that a gasification pathway to biomethane would be used for all wood categories including forest wood, industrial wood residues, waste wood, wood from landscape maintenance, but also for the organic part of household garbage. Anaerobic digestion and upgrading of biogas is assumed for industrial biowaste, animal manure, agricultural crop by-products, green waste collection, and sewage sludge. The values of remaining sustainable resources and already energetically used sustainable resources are given in Section 10.2. Finally, only direct biomethane production is considered here.

Conversion processes using gasification are assumed to have a 65% chemical conversion efficiency, which is defined as the ratio between LHV of the produced biomethane and the heating value of the biomass resource. This efficiency is consistent with assumptions in the literature (Kopyscinski, Schildhauer et al. 2010). Biogas upgrading is assumed to have a conversion efficiency of 95%. In cases where biogas is produced, there is a much lower efficiency for conversion of the biomass resource to biogas, but this is already considered in the resource assessment in Section 10.2.3. Eventually, the use of new technologies such as hydrothermal gasification (described in 17.2) could also increase the biogas yield from the raw biomass relative to today's anaerobic digestion technologies.

10.6.4 Costs of biomethane production

The costs of biomethane production from different biomass resources are shown in Figure 10.44. There is a large range of biomethane costs, even for the same feedstock. The costs for biomethane production in Switzerland from forest wood range from 18.3-25.5 Rp./kWh$_{LHV}$ (16.5-23 Rp./kWh$_{HHV}$) (Seifert 2015). The range is due to the different plant sizes that are considered in the original sources, from 1.3 MW$_{SNG}$ to 2.7 MW$_{SNG}$ (SVGW/BFE/Holdigaz 2014, Seifert 2015). It is important to note that this range of sizes is small for woody biomass. The costs of biomethane production from wood resources could still decrease beyond the values in Figure 10.44 if larger plants were built, which are of one order of magnitude larger.

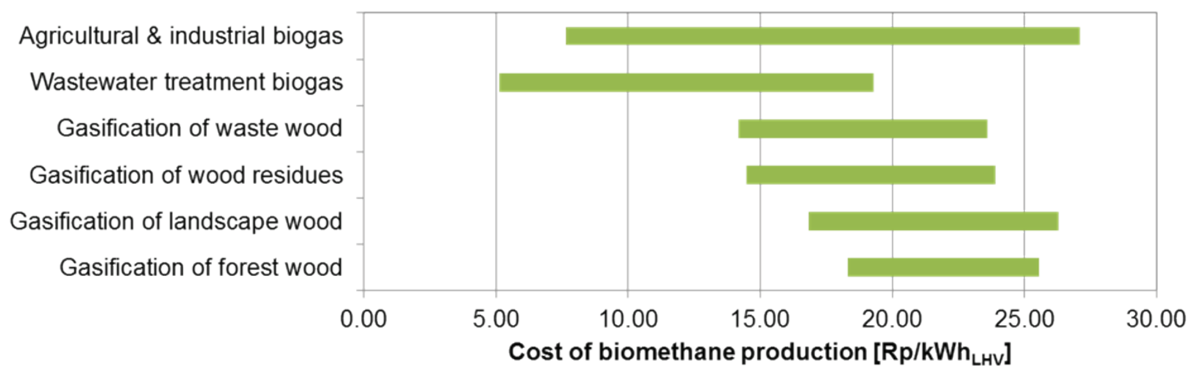

Figure 10.44: Costs of producing biomethane in Switzerland from different feedstocks and with different technologies. The size of the ranges correspond in some cases to a range of plant scales considered in the studies quoted in the main text, with smaller scale plants being more expensive. For the wood-based plants, a production range from 1.3 MW$_{SNG}$ to 2.7 MW$_{SNG}$ is considered. The cost range would broaden if the scale range were extended. For biogas plants, the range of costs correspond partly to scale and partly to the feedstock price. Large plants with feedstocks which are waste products and therefore have a negative price (or gate fee) – i.e., large wastewater treatment plants – are the least expensive.

The range of costs from forest wood, which comes from an existing study (Seifert 2015), was then used as the basis to calculate costs for other woody biomass resources. It is assumed that when switching feedstock from forest wood to waste wood, wood residues, or landscape wood, feedstock costs will decrease while operating and maintenance (O&M) costs will increase. The increase in O&M costs would be due to higher levels of impurities in the feedstock.

First, the contributions of feedstock costs and O&M costs to the final biomethane cost from forest wood were assessed. For the smaller plant sizes, 32% of the biomethane costs (8 Rp./kWh$_{LHV}$) are due to feedstock costs, while 50% (12.9 Rp./kWh$_{SNG}$) are due to non-feedstock O&M costs (calculated from (SVGW/BFE/Holdigaz 2014)). For the larger plant sizes, 44% of the biomethane costs (8.0 Rp./kWh$_{LHV}$) are due to feedstock costs, while 41% (7.3 Rp./kWh$_{SNG}$) are due to O&M costs (calculated from (Seifert 2015)).

Having found the relative contribution from feedstock and O&M costs, these could be adjusted for different feedstocks. The feedstock price used in the study with forest wood was 12.8 CHF/GJ$_{wood}$ (calculated from (Seifert 2015)). Following the feedstock prices given in Figure 10.21 in Section 10.2.4, the midpoint price is approximately 5.8 CHF/GJ$_{wood}$ for landscape wood, 2 CHF/GJ$_{wood}$ for wood residues, and 0.5 CHF/GJ$_{wood}$ for waste wood. These represent reductions of 55%, 84%, and 96%, respectively, from the price of forest wood. Finally, it was assumed that O&M costs would be up to 40% higher for other woody biomass resources than for forest wood. Applying these modifications to the range of biomethane costs from forest wood, it was found that biomethane costs would range from 16.8-26.3 Rp./kWh$_{LHV}$ for landscape wood, 14.5-23.9 Rp./kWh$_{LHV}$ for wood residues, and 14.2-23.6 Rp./kWh$_{LHV}$ for waste wood.

Costs of biomethane from non-woody biomass resources are found by starting by the range in cost of electricity for these resources, which are listed in Section 10.5. Producing biomethane from these resources instead of electricity requires three process modifications: (1) the removal of the CHP unit, (2) the addition of biogas upgrading and grid injection process steps, and (3) the addition of an alternate heat source for the digester, now that the

CHP unit no longer exists. From the cost of electricity, the cost of biogas is calculated by multiplying by a CHP efficiency of 28-38%.

However, this cost of biogas still includes capital and operating costs for the CHP unit, and includes neither the biogas upgrading and injection units nor the additional heating for the digester. A SwissPower study has given an estimate of these costs (Zutter, Nijsen et al. 2015), and these are used here as well. From this study, the credits received for elimination of the CHP unit amount to 1-5 Rp./kWh_{HHV}, the costs of upgrading and injection are 3.5-6 Rp./kWh_{HHV}, and the costs for additional heating of the digester are 1-4 Rp./kWh_{HHV}. This results in costs of biomethane production from wastewater treatment plants that range of 5.1-19.3 Rp./kWh_{LHV} (4.6-17.4 Rp./kWh_{HHV}).

For biomethane from agricultural and industrial wastes, the same procedure was used – with one exception. The credits for elimination of the CHP unit are assumed to range from 0.8-3.2 Rp./kWh_{HHV}, as calculated from the contribution of the CHP unit to overall bioelectricity costs from agricultural biogas units in Switzerland (Anspach and Bolli 2015). The resulting range of biomethane costs from agricultural & industrial biomass resources is 7.7-27.1 Rp./kWh_{LHV} (6.9-24.4 Rp./kWh_{HHV}).

10.7 Environmental aspects

Environmental aspects of electricity generation from biomass feedstocks are discussed from a life-cycle perspective, i.e. covering complete energy chains including biomass harvesting, processing, transport and conversion into electricity, and based on available Swiss-specific as well as broader “review-type” literature.

Available transparent and high-quality literature does not entirely match biomass feedstock and conversion technology classification of the previous sections and does by far not cover all potential feedstocks and conversion technologies. Moreover, scientifically sound literature concerning future biomass-based electricity generation is extremely scarce. However, carrying out new Life Cycle Assessment (LCA) in order to ensure complete consistency between environmental assessment and quantification of potentials and electricity generation costs was out of scope of this study and therefore, environmental aspects can only be discussed based on a few selected feedstocks and conversion technologies. Based on these and review LCA literature, relatively broad ranges of environmental impacts of “biopower” are provided.

10.7.1 Life cycle Greenhouse gas (GHG) emissions of current and future technologies

Cumulative life cycle GHG emissions represent the impact on climate change and are quantified aggregating all contributing emissions to air weighted by their 100-year global warming potentials (GWP 100a). Figure 10.45 shows GHG emissions of electricity generation with current and future technologies. Data for current technologies – CHP generation from wood chips and from biogas from small-scale, agricultural manure digestion, respectively – are taken from the LCA database (ecoinvent 2013, ecoinvent 2016)[231] data for potential future technologies from (Volkart, Bauer et al. 2013). In the context of this environmental

[231] Due to the fact that version 2.2 of the ecoinvent database contained more biogas-to-electricity LCI data than the most recent version v3.3, which allows to provide a range for life-cycle GHG emissions (with emissions mainly depending on the type of biomass feedstock used, procedures for anaerobic digestion and CHP unit technology), results from version 2.2 are used for biogas.

assessment, “future technologies” refers to rather large-scale, dedicated biomass power plants (wood and biomethane combustion) with and without carbon capture and storage (CCS[232]), which could be an option in Switzerland in the long-term (2050), if negative GHG emissions[233] are required in order to reach stringent climate goals.[234] Conventional biomass electricity generation chains can basically be carbon-neutral, since the CO_2 emitted during wood combustion has been extracted from the atmosphere before during biomass growth and therefore, it is common LCA practice to not consider biogenic CO_2 emissions (Christensen, Gentil et al. 2009), as long as harvesting and growth rates are on equal levels, i.e. in case of “sustainable forestry”. “Above-zero” life-cycle GHG emissions are due to indirect CO_2 (and other GHG) emissions from fuel supply chains and from carbon released as methane, which has a much higher GWP than CO_2, during biomass conversion and combustion. For example, methane emissions from anaerobic manure digestion can be such a source of substantial GHG emissions of electricity from biogas CHP units. New technologies, e.g. hydrothermal gasification processes (section 17.2), are in development in order to eliminate such unintended methane leakage. Fuel cells operated with biomethane are addressed in chapter 16. In addition to Swiss-specific results from (ecoinvent 2013, ecoinvent 2016) and (Volkart, Bauer et al. 2013), life-cycle GHG emissions of biomass electricity generation from few recent international review studies can be provided.

Turconi, Boldrin et al. (2013) report 8.5-118 g CO_2eq/kWh for direct combustion technologies and 17-117 g CO_2eq/kWh for IBGCC[235] plants. Sathaye, Lucon et al. (2011) report a median value of about 35 g CO_2eq/kWh for biopower and also negative figures in the range of minus 600-1300 g CO_2eq/kWh for electricity from biomass combustion with CCS. [236] Swiss-specific results (Figure 10.45) for wood combustion are within these ranges; emissions from biogas chains are higher, mainly due to methane emissions during biogas production, i.e. anaerobic digestion of biomass. ecoinvent (2013) provides LCA results for several biogas pathways using different feedstocks and different digestion systems as well as CHP units – some of those might not represent current state-of-the-art technologies. This variety is used for quantifying a range of potential emissions; uncertainties regarding potential methane leakage are high. Considering potential future development of the technologies shown as “current” in Figure 10.45 taking into account the future efficiency increases of CHP technologies envisaged in chapter 15.2, it is likely that GHG emissions of wood combustion CHP units will be reduced by about 20% until 2050. On the other hand

[232] CCS is not further discussed here. It is addressed as part of chapter 15.

[233] Biomass power plants with CCS can achieve negative GHG emissions, since they permanently remove CO_2 from the atmosphere which was fixed during biomass growth and is permanently stored in suitable geological formations.

[234] Referring to “large-scale, dedicated” wood power plants as future technologies in Switzerland might seem to be a contradiction to what has previously been discussed is sections 10.4 and 10.5, in which distributed, small-scale systems are specified as most promising technologies for expansion of biomass power generation in Switzerland in the future. It should be noted that CCS would only be implemented at relatively large power plants and won’t be an option for distributed generation due to technical and economic reasons. The intention here is to show the potential of biomass in connection with CCS to achieve negative GHG emissions, which are – according to a broad range of energy-climate scenarios – one of the key components in order to achieve a “1.5/2°C climate goal” as well as the associated environmental trade-offs.

[235] Integrated biomass gasification combined cycle.

[236] The types of biomass fuels considered in these review studies are not further specified. However, based on the content of the studies and the results, it is likely that only solid biomass (wood) is considered in (Turconi, Boldrin et al. 2013), whereas all kinds of biomass seem to be taken into account by Sathaye, Lucon et al. (2011).

and as outlined in sections 10.4 and 10.5, mobilization of biomass potentials is likely to require a large amount of small CHP units in a decentralized way, which have comparatively lower electric efficiencies and therefore higher associated emissions compensating for future efficiency gains. Modern biogas production technologies might substantially reduce methane emissions from biomass digestion in the future.

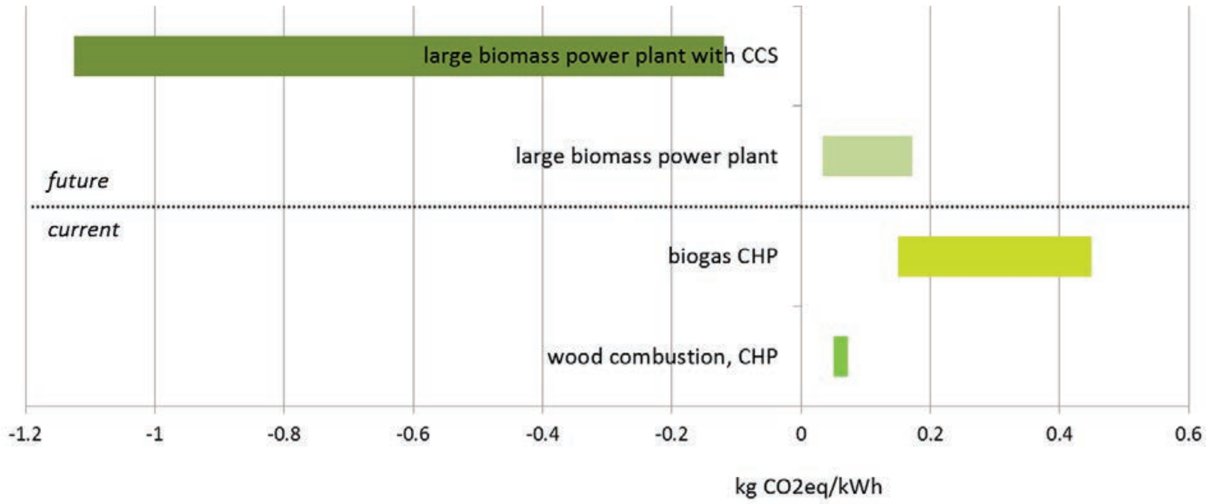

Figure 10.45: Life cycle GHG emissions of current (bottom) and future (top) biomass electricity generation systems in Switzerland. CCS: Carbon Capture and Storage; CHP: Combined Heat and Power. Large biomass power plants include conventional wood combustion as well as combined cycle plants using synthetic natural gas from wood gasification. Data sources: (ecoinvent 2013, ecoinvent 2016)[237] for current systems, (Volkart, Bauer et al. 2013) for future systems (reference year 2050).

10.7.2 Other environmental burdens of current and future technologies

The same technologies as above in Figure 10.45 are evaluated in terms of further environmental indicators in addition to impact on climate change, i.e. GHG emissions. Selection of indicators is based on Hauschild, Goedkoop et al. (2013), results are shown in Figure 10.46, relative to the impacts caused by the current Swiss high voltage consumption mix (incl. electricity imports) according to (ecoinvent 2016). The results show that the 2 MW CHP unit causes comparatively high impacts for many indicators, due to its relatively low electric efficiency. Depending on their capacity, new wood combustion systems installed today have to comply with higher particulate matter and NO_x emission standards than the average installed units, which substantially reduces their impacts for particulate matter formation and Photochemical ozone formation. The comparison of future systems with and without CCS shows that CCS comes along with environmental trade-offs between GHG emissions and other environmental burdens, since the energy demand for CO_2 capture reduces power plant net efficiencies, i.e. more fuel is required per unit of electricity delivered to the grid and burdens associated to fuel supply increase accordingly.

[237] Wood combustion, CHP: ecoinvent v3.3; biogas CHP: ecoinvent v2.2.

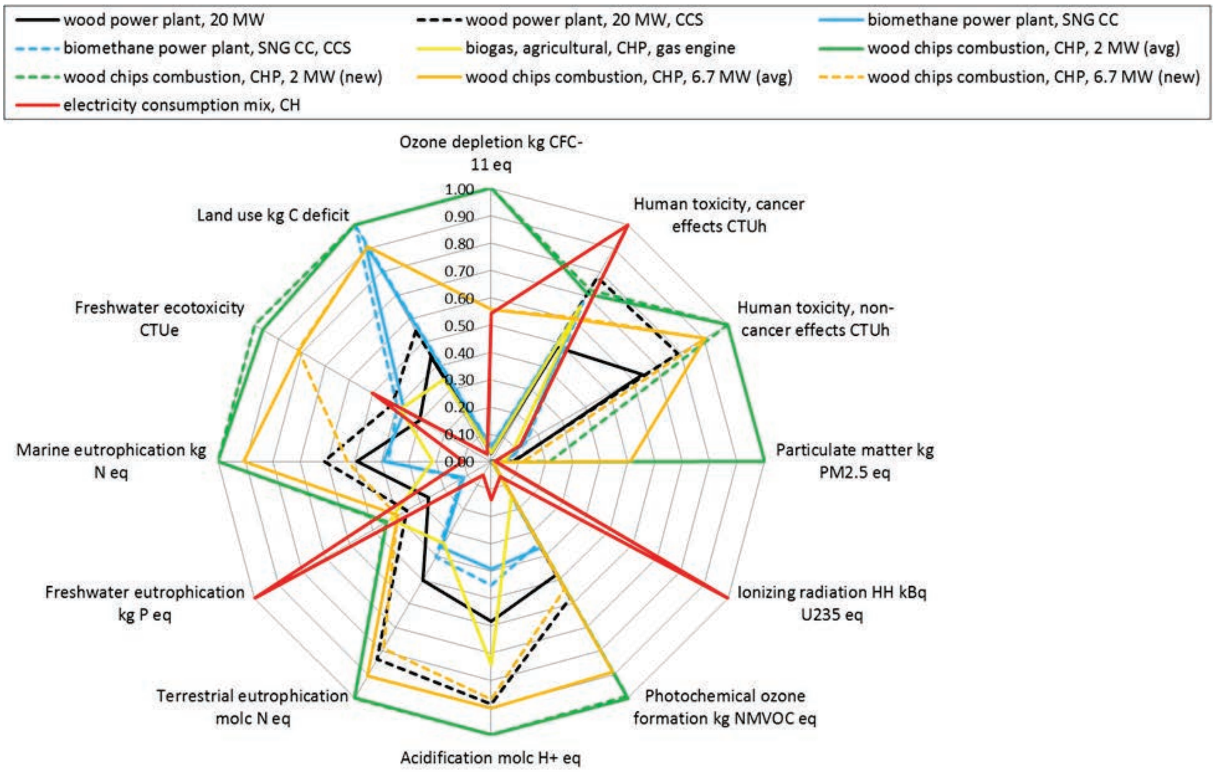

Figure 10.46: Selected life cycle environmental impacts of current and future biomass electricity generation systems in Switzerland, relative to the maximum for each indicator (=1). Indicators are selected based on (Hauschild, Goedkoop et al. 2013). SNG: Synthetic Natural Gas; CCS: Carbon Capture and Storage; CC: Combined Cycle; "new" refers to new CHP technology as installed today in Switzerland; "avg" refers to the average of the currently installed CHP units. Data sources: (ecoinvent 2015) for current systems, (Volkart, Bauer et al. 2013) for future systems.

10.8 Conclusions and Outlook

10.8.1 Conclusions

In Switzerland, 1.6 TWh of electricity were generated from biomass resources in 2015. These resources are a heterogeneous group, comprising feedstocks ranging from wastewater and manure, to municipal and industrial waste products, to forest wood. Non-woody biomass feedstocks with a high liquid content, such as wastewater or manure, are first processed through an anaerobic digestion step in which biogas is produced. Then, the biogas can be used in a combined heat and power (CHP) unit, such as an engine, a gas turbine or a fuel cell. Woody biomass feedstocks and non-woody biomass feedstocks with a low water content (such as municipal waste) can be combusted directly to drive steam cycles at large scales or organic Rankine cycle (ORC) at medium scales. At small scales, externally-fired gas turbines (EFGT) are also considered. Finally, the woody and dry non-woody feedstocks can be gasified, creating a syngas that can be burned in an engine or other CHP unit to produce electricity. An alternative pathway for all feedstocks is the creation of biomethane for injection into the natural gas grid. In 2015, 0.2 $TWh_{CH4,LHV}$ of biomethane were produced in Switzerland and injected into the natural gas grid.

Most of the bioelectricity generation in Switzerland today comes from waste incineration plants, which generate steam for electricity generation from the heat produced in the waste incinerator. Condensation heat is then used for district heating. The largest potential for future additional generation, however, is from the mobilization of manure and woody biomass resources. The potential from manure comes from mobilising the large resource that is currently not utilised energetically. Meanwhile, the potential from woody biomass comes from a combination of utilising unused resources and redirecting wood from heat-only systems to CHP systems. If all of the remaining sustainable potential for Swiss biomass resources were used to generate electricity with technology existing today, a maximum of 2.0 TWh/year of electricity could be added to today's generation. If we allow the use of new technologies, especially the increased use of gasification for woody biomass and increased use of high-temperature fuel cells for biogas, this value could increase to a maximum of 3.1 TWh/year of additional electricity generation.

The costs of producing electricity from biomass in Switzerland are still relatively high, especially for agricultural biogas installations. Many bioelectricity installations still rely strongly on feed-in tariffs. Waste incinerators have the least expensive costs of producing bioelectricity today, in the range of 2.5-16 Rp./kWh$_e$. Less than half of the installations receive feed-in tariffs. This is largely because of a key advantage in the cost structure of waste incinerators relative to other bioelectricity systems: waste incinerators receive gate fees for accepting the waste materials, and therefore have negative feedstock costs. Agricultural biogas installations have costs of electricity in the range of 20-48.5 Rp./kWh$_e$, which is the highest feed-in tariff that can be received in Switzerland for bioelectricity today. These systems are expensive mainly because of the current high capital costs of building small-scale anaerobic digestion systems. Finally, current wood-based electricity generation systems have costs that are in between those of agricultural biogas and of waste incinerators, in the range of 18-36 Rp./kWh$_e$. For these systems, the two key elements of the cost structure are the price of the feedstock, which can be quite high, and the ability to sell heat at a good price to offset some of the electricity generation costs.

Overall, very substantial changes in costs of electricity from biomass are not foreseen. Incremental changes can be expected as described in Section 10.5. These include, among others, the effects of increasing feedstock price for woody biomass and of decreasing the capital costs of small-scale anaerobic digestion units. One persistent reality is the nature of the Swiss bioenergy system: installations will continue to be relatively small and location-specific. The greatest Swiss unused biomass resource – manure – is distributed over the country at many small farms and is expensive to transport. Therefore, there are ongoing research efforts to separate the different fractions of manure in order to transport a fraction with a smaller water content (Hersener, Meier et al. 2014). Woody biomass is more easily transported, but will always be best utilized at sites where heat is in high demand.

Finally, the key indicators for each biomass conversion pathway are summarized in

Table 10.5.

Table 10.5: Summary of key indicators for woody and non-woody biomass in Switzerland.

Woody biomass		**Current**	**2020**	**2035**	**2050**
Electricity generation potential, GWh/a	Autom. wood CHP	126	126-225	126-614	126-1142
	Combustion of wood & organic wastes	70	70	70	70
	KVA – waste incineration	1065	1065-1072	1065-1105	1065-1262
Electricity generation costs, Rp./kWh$_e$	Autom. wood combustion	18 – 36	18 – 37	18 – 41	18 – 45
	Combustion of wood & organic wastes		18 – 36	18 – 36	18 – 36
	Wood gasification CHP	18 – 31	18 – 32	17 – 33	16 – 35
	KVA – waste incineration	2.5 – 16	2.5 – 16	2.4 – 15	2.3 – 15

Non-woody biomass		**Current**	**2020**	**2035**	**2050**
Electricity generation potential, GWh/a	KVA – waste incineration	1065	1065 – 1072	1065 – 1105	1065 – 1262
	Municipal WWTP	119	119 – 129	119 – 170	119 – 225
	Industrial WWTP	84	84 – 149	84 – 381	84 – 668
	Industrial biogas				
	Agricultural biogas	100	100 – 232	100 – 718	100 – 1342
Electricity generation costs, Rp./kWh$_e$	KVA – waste incineration	2.5 – 16	2.5 – 16	2.4 – 15	2.3 – 15
	Municipal WWTP	4 – 22	4 – 22	4 – 22	4 – 22
	Industrial WWTP				
	Industrial biogas	20 – 49	20 – 49	18 – 50	16 – 51
	Agricultural biogas				

10.8.2 Outlook

Looking at the outlook for the future, some of the difficult questions to address will be (1) How can manure and wood resources be mobilised economically to fully utilise their potential? and (2) How can the demand for electricity and heat from biomass be managed in a synergistic way?

Ongoing research and development is currently addressing these questions. One possible path focuses on the potential to maximise the electricity that can be produced from the same amount of feedstock. Hydrothermal gasification is one such technology, and it is described in chapter 17.2 (Vogel 2016a). Broadly, the concept focuses on recovering a significantly larger fraction of the primary energy content of non-woody biomass than is done with today's technology, by processing the biomass in a medium of supercritical water

(water above 218 atm and 374°C). In standard anaerobic digestion processes, a considerable amount of this primary energy is lost in the digestate – a waste product, from the point of view of electricity generation – instead of being converted to biogas. Another research approach is to increase the yield of standard anaerobic digestion by pretreatment, as for example in a new SFOE project (Mikroaerobe Hydrolyse (HYDROFIB), SI / 501228).

Similarly, a completed research project supported by SFOE demonstrated the technical feasibility of increasing the biogas yield from manure by performing a phase separation of the feedstock into a solid and liquid fraction (Hersener, Meier et al. 2014). Each fraction can then be digested in operation conditions that are optimised for that fraction alone. The biogas yield from the liquid fraction in particular is increased by the use of a Membrane Bio-Reactor (MBR). This technology chain is now being developed for commercial application.

The question of managing demand for electricity and heat from biomass is also being addressed, by attempting to decouple the two. One approach is to recognise that, in locations where heat cannot be easily transported due to lack of heat distribution infrastructure, technologies with the highest electrical efficiency should be used. This is a motivation for using fuel cells at small agricultural biogas sites. Microbial fuel cells are also being studied to produce electricity directly from household waste water (for example, in the SFOE project "Mikrobielle Brennstoffzelle", SI/501243).

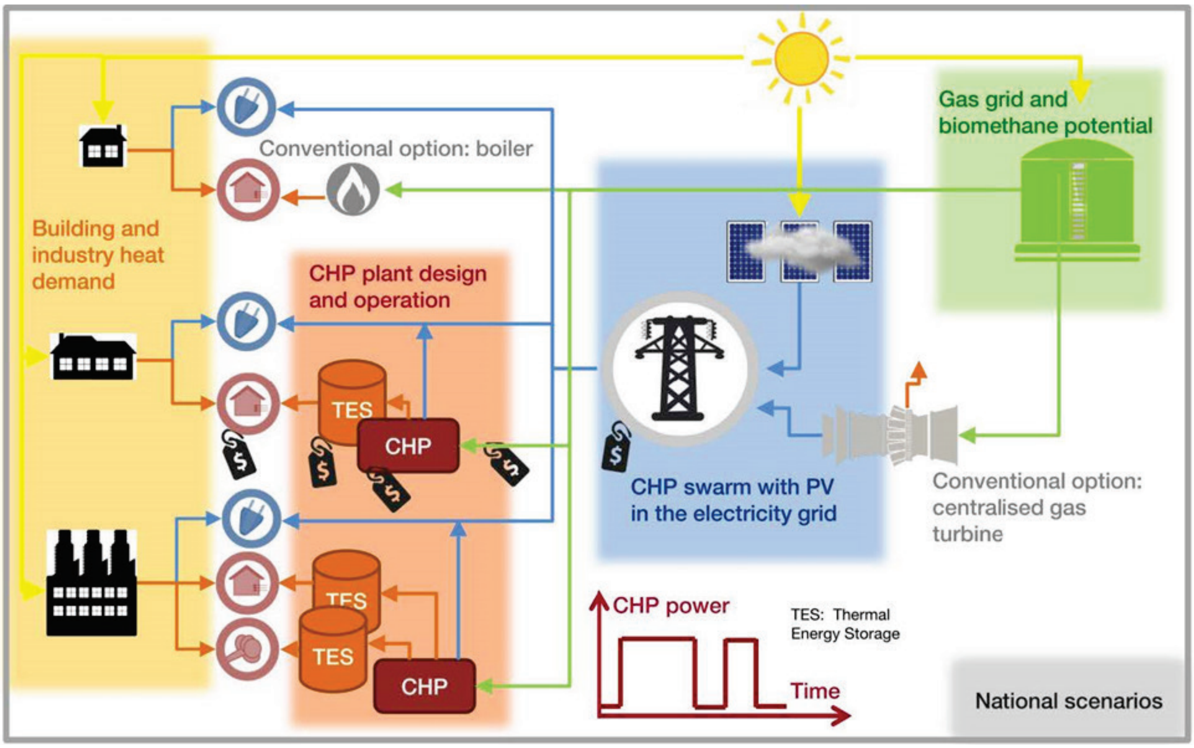

Figure 10.47: Operational strategy of the biomass swarm. Centralised swarm controller, local storage of heat and balancing the electrical grid on demand (Vögelin, Georges et al. 2016).

On a larger system scale, the decoupling of heat and electricity can be achieved by the storage of either of these two products, or by the creation of biomethane for injection into the natural gas grid. The use of a "biomass swarm" is one such approach. This concept is the result of recently completed research project supported by SFOE (Vögelin, Georges et al. 2016). In Figure 10.47, the operational strategy of the biomass swarm is shown. Biomethane is produced at large, centralised locations and injected into the natural gas grid. Then, microCHP plants distributed through Switzerland are controlled by a centralised swarm controller in order to balance the electrical grid on demand. Heat produced is either used directly locally, or it is stored in a thermal energy storage device for use on demand.

Ultimately, the outlook for bioelectricity in Switzerland rests on a few key facts. The remaining domestic resource potential is large and could be used to generate up to 3.1 TWh per year of electricity, in addition to the 1.6 TWh/a already produced today. In order to utilise it correctly and economically, some technological or logistical innovations will likely be necessary, and these should continue to be studied.

10.9 Acknowledgements

Raphael Haymoz and Prof. Dr. Timothy Griffin, both of FHNW, are thanked for contributing the economic analysis of the EFGT systems. Prof. Dr. Urs Baier of ZHAW is acknowledged for many helpful inputs to our understanding of anaerobic digestion systems. Discussions with collaborators within SCCER-BIOSWEET (Swiss Competence Centre for Energy Research, Biomass for Swiss Energy Future) and with external academic and industrial partners have been essential to understanding the current situation in Switzerland.

10.10 Abbreviations

a	year
ARA	Abwasserreinigungsanlage
ARE	Bundesamt für Raumplanung
avg	average
BAFU	Bundesamt für Umwelt
BICGT	biomass internal combustion gas turbine
BIGCC	biomass integrated gasification combined cycle
BFE	Bundesamt für Energie
CAPEX	capital expenses
CCS	carbon capture and storage
CH	Switzerland
CHF	Swiss Francs
CHP	combined heat and power
CO_2eq	carbon dioxide equivalent
EEG	Erneuerbare-Energien-Gesetz
EFGT	Externally Fired Gas Turbine
ETP	energy technology perspectives
EU	European Union
FHNW	Fachhochschule Nordwestschweiz
GHG	Greenhouse gas
GWP	global warming potential
HH	human health
HHV	higher heating value
HTG	hydrothermal gasification
ICE	internal combustion engine
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
KEV	Kostendeckende Einspeisevergütung/compensatory feed-in renumeration
KVA	Kehrichtverbrennungsanlage
LCA	life cycle assessment
LCIA	life cycle impact assessment
LCOE	Levelised Cost of Electricity
LHV	lower heating value
max	maximum
min	minimum
NT	New Technologies
O&M	operation and maintenance
OPEX	Operating and maintenance expenses
ORC	organic Rankine cycle
Rp.	Rappen (Swiss cents)
RPC	rétribution à prix coûtant du courant injecté
SFOE	Swiss Federal Office of Energy
SNG	synthetic natural gas
SOFC	solid oxide fuel cell
SCCER	Swiss competence center for energy research
TAU	Technology-as-Usual
UK	United Kingdom
US	United States
USD	United States Dollar

WKK	Wärme-Kraft-Kopplung
WSL	Eidg. Forschungsanstalt für Wald, Schnee und Landschaft
WWTP	wastewater treatment plant
yr	year
ZHAW	Zürcher Hochschule für angewandte Wissenschaften

10.11 Appendix

Table 10.6: Agricultural biogas case studies in Switzerland: parameters considered with their sources, and resulting LCOE with and without heat credits. ICE = internal combustion engine; O&M = operation and maintenance.

	Concept for 25 kW_e biogas ICE	Concept for 25 kW_e biogas ICE	Existing 16 kW_e biogas ICE	Average of 10 existing plants	Average of 10 existing plants
Capacity [kW_e]	25	25	16	111[238] (avg.)	274[239] (avg.)
Operating hours [h/y]	8'000[240]	8'000[240]	3'991[241]	7'506[238]	5'932[239]
% of electricity used for plant's own needs	15%[240]	15%[240]	15% (est.)	11%[242]	11%[242]
Plant life [y]	15[245]	15[245]	15 (est.)	15 (est.)	15 (est.)
Capital costs [CHF/kW_e]	38'000[243]	34'400[252]	12'020[241]	11'611[244]	9'532[244]
Interest rate [%]	2%[245]	2%[245]	2%[246]	3%[247]	3%[247]
O&M costs [CHF/kW_e]	1095[243]	1034[252]	617[241]	598[248]	538[248]
Heat value [Rp./kWh_{th}]	9[249]	9[249]	6[241]	8[250]	8[250]
Heat [kWh_{th}/y]	70'660[240]	70'660[240]	75'566[241]	322'157[251]	628'474[251]
Feedstock costs' effect on LCOE [Rp./$kWh_{e,net}$]	11.1[243]	15.4[252]	0.74[241]	7.6[248]	7.6[248]
Feedstock details	100% manure; transport costs	80% manure; transport costs	85% manure; co-subs. costs	76% manure[253]	76% manure[253]
LCOE [Rp./$kWh_{e,net}$]	**67.4[254]**	**66.6[254]**	**38.4[246]**	**27.6**	**29.4**
LCOE without heat credits [Rp./$kWh_{e,net}$]	71.1	70.4	46.8	31.0	32.8

Table 10.7: Agricultural biogas case studies in Germany: parameters considered with their sources, and resulting LCOE with and without heat credits. ICE = internal combustion engine; O&M = operation and maintenance.

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238 From Table 5, pg 25 of (Anspach and Bolli 2015).
239 From Table 6, pg 26 of (Anspach and Bolli 2015).
240 From pg 82 of (Bakx, Boéchat et al. 2014).
241 From (Hari 2015).
242 From Table 9, pg 31 of (Anspach and Bolli 2015).
243 From pg 83 of (Bakx, Boéchat et al. 2014).
244 From Table 14, pg 35 of (Anspach and Bolli 2015).
245 Estimated from pg 84 of (Bakx, Boéchat et al. 2014).
246 Note that the capital costs' contribution to LCOE reported by (Hari 2015) are slightly lower because no interest rate was considered by (Hari 2015).
247 From pg 15 of (Anspach and Bolli 2015).
248 Calculated based on information in pgs. 39-41 of (Anspach and Bolli 2015).
249 From pg 81 of (Bakx, Boéchat et al. 2014).
250 From pg 16 of (Anspach and Bolli 2015).
251 Calculated based on information in Fig. 6 and Fig. 7 of (Anspach and Bolli 2015).
252 From pg 79 of (Bakx, Boéchat et al. 2014).
253 From pg 27 of (Anspach and Bolli 2015).
254 Note that the costs reported by (Bakx, Boéchat et al. 2014) are slightly lower because CO_2 credits were included.

	Existing 75 kW_e biogas ICE	**Concept for 75 kW_e biogas ICE**	**Concept for 150 kW_e biogas ICE**	**Concept for 250 kW_e biogas ICE**
Capacity [kW_e]	75	75	150	250
Operating hours [h/y]	7'945[255]	7'911[256]	8'032[256]	7'912[256]
% of electricity used for plant's own needs	8% (est.)	7.3%[256]	7.3%[256]	7.3%[256]
Plant life [y]	10[257]	10[256]	10[256]	10[256]
Capital costs [CHF/kW_e]	9'515[255]	10'182[256]	7'165[256]	6'663[256]
Interest rate [%]	2%[257]	4%[258]	4%[258]	4%[258]
O&M costs [CHF/kW_e]	1'393[255]	1'151[256]	856[256]	589[256]
Heat value [Rp./kWh_{th}]	4.5 (est.)[259]	Results in a credit of 0.43 Rp./kWh_e.[260]	Results in a credit of 0.95 Rp./kWh_e.[260]	Results in a credit of 0.54 Rp./kWh_e.[260]
Heat [kWh_{th}/y]	731'078[261]			
Feedstock costs' effect on LCOE [Rp./$kWh_{e,net}$]	0[261]	4.7[262]	6.8[262]	6.8[262]
Feedstock details	95% manure[261]	80% manure[256]	30% manure[256]	60% manure[256]
LCOE [Rp./$kWh_{e,net}$]	**26.7**	**35.0**	**27.8**	**24.2**
LCOE without heat credits [Rp./$kWh_{e,net}$]	32.8	35.4	28.7	24.8

255 From pg 49 of (Stinner, Stur et al. 2015).
256 From Chapter 8 of (FNR 2016).
257 From pg 32 of (Stinner, Stur et al. 2015).
258 From pg 161 of (FNR 2016).
259 This is an assumption about the minimum heat value needed to be profitable given the feed-in tariff in Germany.
260 From Table 8.13 on pg 162 of (FNR 2016).
261 From pg 48 of (Stinner, Stur et al. 2015).
262 From pg 153 of (FNR 2016).

Table 10.8: Wood combustion case studies in Switzerland: parameters considered with their sources, and resulting LCOE with and without heat credits. EFGT = externally-fired gas turbine; ORC = organic Rankine cycle; CHP = combined heat and power; O&M = operation and maintenance.

	Concept for 51 kW_e EFGT	**Existing 83 kW_e EFGT**	**Existing 600 kW_e ORC**	**Existing 11'000 kW_e steam CHP**
Capacity [kW_e]	51	83	600	11'000
Operating hours [h/y]	7'500[263]	7'500[264]	4'444[265]	3'789[266]
% of electricity used for plant's own needs	10%[263]	18%[264]	10% (est.)	9%[267]
Plant life [y]	10[263]	10[264]	15 (est.)	20[268]
Capital costs [CHF/kW_e]	11'765[263]	15'060[264]	18'333[265]	6'364[268]
Interest rate [%]	3%[263]	3%	2% (est.)	2% (est.)
O&M costs [CHF/kW_e]	824[263]	759[264]	500 (est.)[269]	742 (est.)[270]
Heat value [Rp./kWh_{th}]	8[263]	8[264]	8 (est.)	8 (est.)
Heat [kWh_{th}/y]	1'256'250[263]	2'625'000[264]	10'625'000[265]	102'649'000[268]
Feedstock costs' effect on LCOE [Rp./$kWh_{e,net}$]	27.4[263]	35.2[264]	26.4	20.9
Feedstock details	Wood at 5 Rp./kWh_{wood} (250 CHF/tonne)[263]	Wood at 3.9 Rp./kWh_{wood} (195 CHF/tonne)[264]	Wood at 3.9 Rp./kWh_{wood} (195 CHF/tonne) (est.)[271]	Wood at 3.9 Rp./kWh_{wood} (195 CHF/tonne) (est.)[271]
LCOE [Rp./$kWh_{e,net}$]	**31.1**	**35.6**	**39.5**	**32.2**
LCOE without heat credits [Rp./$kWh_{e,net}$]	60.3	76.7	74.9	53.8

[263] From (Griffin, Winkler et al. 2015).
[264] From (Vogel and Schibli 2012).
[265] From pg 21 of (Keel 2013).
[266] From pg 2 of (Jenni 2015).
[267] Calculated from (Jenni 2015) and (Holzheizkraftwerk-Aubrugg 2016).
[268] From pg 12 of (Jenni 2015).
[269] From assuming that the resulting contribution to LCOE should be similar to the EFGT cases.
[270] From assuming similar fixed (per kW_e) and variable (per kWh_e) O&M costs as the KVA Turgi, see waste case study.
[271] By similarity with the EFGT case.

Table 10.9: Other combustion and gasification case studies used in this chapter: parameters considered with their sources, and resulting LCOE with and without heat credits. ORC = organic Rankine cycle; O&M = operating and maintenance; CHP = combined heat and power; CH = Switzerland; SK = Slovakia; AT = Austria.

	CH: Existing CHP; wood gasification	**CH: Existing CHP; wood gasification**	**SK: Existing ORC; wood comb.**	**AT: Existing steam CHP; wood comb.**	**CH: Existing waste incinerator**
Category	**Swiss wood gasification cases**		**EU wood combustion cases**		**Waste case**
Capacity [kW$_e$]	180	1'360	130	5'700	12'900
Operating hours [h/y]	7'778[272]	7'059[273]	7'500[274]	7'807[275]	6'228[276]
% of electricity own consumption	10% (est.)	10%[277]	20%[274]	5.2%[275]	20.4%[276]
Plant life [y]	10[278]	20 (est.)	15[279]	15[279]	20 (est.)
Capital costs [CHF/kW$_e$]	6'667[278]	11'765[280]	7'277[281]	4'780[282]	6000[283]
Interest rate [%]	2% (est.)	2% (est.)	3%[284]	4%[285]	2%[283]
O&M costs [CHF/kW$_e$]	350[278]	341[280]	281[286]	295[287]	911[288]
Heat value [Rp./kWh$_{th}$]	0.5[278]	8.3[280]	3.5[289]	6.1[290]	0.66[291]
Heat [kWh$_{th}$/y]	2'100'000[272]	15'200'000[280]	5'212'350[274]	90'000'000[275]	58'250'000[291]
Feedstock costs' effect on LCOE [Rp./kWh$_{e,net}$]	18.6	15.6	12.7	11.2	-23.0
Feedstock details	Wood at 5.6 Rp./kWh$_{wood}$ (265CHF/tonne)[278]	Wood at 3.75 Rp./kWh$_{wood}$ (180CHF/tonne)[280]	Wood residues	Bark, wood chips, sawdust	Gate fee for waste, 119 CHF/tonne[291]
LCOE [Rp./kWh$_{e,net}$]	**31.4**	**18.2**	**4.2**	**7.7**	**2.2**
LCOE without heat credits [Rp./kWh$_{e,net}$]	32.2	32.7	27.7	20.6	2.9

272 By analogy with an existing plant using the same technology in Germany (St.Peter-Bioenergie 2014).
273 Calculated from (Genossenkorporation-Stans 2016).
274 From pg 42 of (Obernberger, Hammerschmid et al. 2015).
275 From pg 30 of (Obernberger, Hammerschmid et al. 2015).
276 Calculated from pg 24 of (KVA Turgi 2015).
277 From pg 62 of (Schaub and Gemperle 2008).
278 From pg 13 of (Burkhardt 2014).
279 From pg 29 of (Obernberger, Hammerschmid et al. 2015).
280 From pg 64 of (Schaub and Gemperle 2008).
281 From pgs 43 and 45 of (Obernberger, Hammerschmid et al. 2015).
282 From pgs 32 and 34 of (Obernberger, Hammerschmid et al. 2015).
283 Back-calculated from a 7 Rp./kWh$_e$ contribution of capital costs, from (KVA Turgi 2015).
284 From pg 43 of (Obernberger, Hammerschmid et al. 2015).
285 From pg 32 of (Obernberger, Hammerschmid et al. 2015).
286 From pgs 44 and 46 of (Obernberger, Hammerschmid et al. 2015).
287 From pgs 32 and 34 of (Obernberger, Hammerschmid et al. 2015).
288 From pg 15 of (KVA Turgi 2015).
289 From pg 47 of (Obernberger, Hammerschmid et al. 2015).
290 From pg 35 of (Obernberger, Hammerschmid et al. 2015).
291 From pg 24 of (KVA Turgi 2015).

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11 Deep geothermal power

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11.1 Introduction

Electricity generation from deep geothermal energy resources in Switzerland was extensively evaluated in a recent research project carried out by PSI in collaboration with ETH Zurich and further partners. The study "Energy from the earth's interior: Deep geothermal energy as the energy source of the future" funded by TA-Swiss describes the Swiss-specific and Swiss-relevant aspects for deep geothermal power in the areas of resources, technology, economy, environment, risks, regulation, public opinion, and integrated assessment of these aspects (Hirschberg, Wiemer et al. 2015). This comprehensive evaluation of geothermal energy is used as basis for the geothermal chapter in this report. Further discussions with experts in the field and new boundary conditions resulted in some extensions in terms of cases analyzed and in updates in the evaluation of costs and environmental impacts of deep geothermal electricity generation in Switzerland.

A wide range of policy support measures have been developed to implement Switzerland's Energy Strategy. In the case of geothermal energy they are based on a scenario which envisages a contribution of 4.5 TWh/a to the 2050 electricity supply (Prognos 2012b). Deep geothermal plants are defined as to be located at depths of at least 400 m down to a few thousand meters with surrounding rock temperatures high enough to extract heat suitable for conversion to electricity (generally speaking temperatures in excess of 80-100^{o}C). However, as of today, no such installation exists in Switzerland to produce electricity. Being a promising technology for baseload power supply, there are still a number of challenges to overcome for successful deployment of deep geothermal plants in Switzerland. Hydrothermal plants for heat and/or power production are already deployed at several locations around the world and have been successfully operated. However, their potential in Switzerland is limited. Economically operating Enhanced Geothermal Systems (EGS) do not exist yet worldwide, but are a promising option for the future power supply. Hence, public opinion in Switzerland tends to be rather neutral or even positive towards geothermal power (Hirschberg, Wiemer et al. 2015). The main concerns are seismic events, use of toxic chemicals, and risk of failure with potentially substantial economic implications.

In addition to EGS, some other geothermal technologies could be used for electricity generation. These are subject to ongoing research activities and discussed in chapter 17.3.

11.2 Technology description

Shallow geothermal heat can be harvested e.g. via energy piles, energy collectors, or downhole heat exchangers (see Figure 11.1). Such systems are widely used in Switzerland and have produced 3037 GWh in 2014 of which 2277 GWh of heat are attributable to renewable geothermal energy sources, but are not suited for electricity production (Imhasly, Signorelli et al. 2015). They are not treated further in this report, as the focus is power supply.

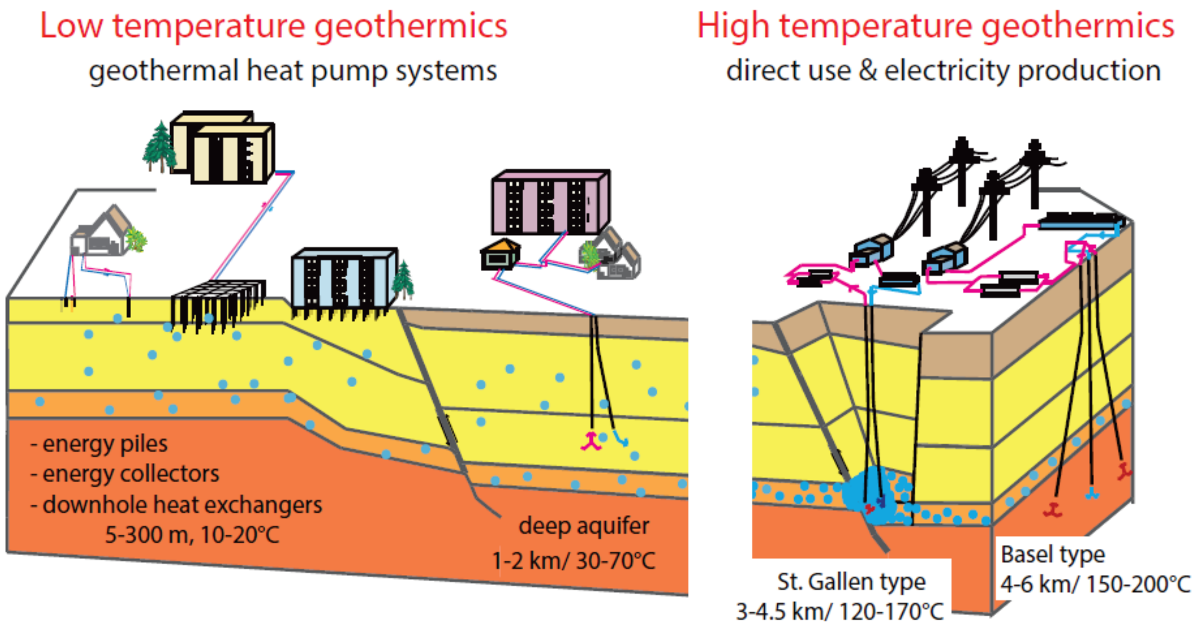

Figure 11.1: Different types of systems using geothermal energy. Taken from (Hirschberg, Wiemer et al. 2015).

Energy from deep geothermal installations (>400 m depth, >120°C) can be harvested in two different forms: From hydrothermal systems and from so-called Enhanced Geothermal Systems (EGS) or petrothermal systems (Figure 11.1). Hydrothermal systems require high underground temperatures (>100°C), water-bearing geological formations and structures, and adequate generation of hot water in these formations. While these pre-conditions are often met in specific geological formations (e.g. in Southern Germany), they seem to be present only at few places in Switzerland. EGS can therefore step in, as these are not dependent on hot water in the underground, but simply make use of the natural temperature gradient towards the Earth's interior and the resulting hot rock in the underground. By drilling two or more wells and connecting them, cold water can be injected to these high-temperature formations, warm up there and then be pumped up through one or two other well(s). The resulting hot water will drive a generator with or without the help of an organic working fluid in a binary cycle. EGS only need a high temperature gradient from a geological point of view, but are more dependent on technical issues such as the drilling and the stimulation phase, or adequate treatment of mineral scaling during operation. The plants can be driven with a doublet (one injection well, one production well) or a triplet (one injection well, two production wells) setting.

Besides hydrothermal and petrothermal systems running on binary systems there also exist hydrothermal back pressure, flash steam (single, double or triple cycle) and dry steam geothermal plants. These make use of very hot reservoirs at selected geological sites (which are not present, or only to a very limited extent in Switzerland). Today, most capacity of geothermal power installed worldwide is of flash or dry steam type, so that these technologies are mature. Also a number of hydrothermal plants are in operation around the world. In contrast, the EGS technology has only been tested at few locations worldwide, and pilot projects have not yet reached an economical level of development. As of 2015, 14 EGS[292] research or commercial pilot projects were ongoing in France (1), Germany (6),

[292] The authors state that based on the available documentation the differentiation between EGS and hydrothermal plants is not always obvious.

Austria (1), United Kingdom (2), USA (3), and El Salvador (1) (Sigfusson and Uihlein 2015). A total of 32 ongoing, abandoned or finished EGS projects have been identified by (Sigfusson and Uihlein 2015).

11.3 Potential

11.3.1 Global

Installed capacity of geothermal electricity production has been increasing over the last half of the last century until today (Figure 11.2).

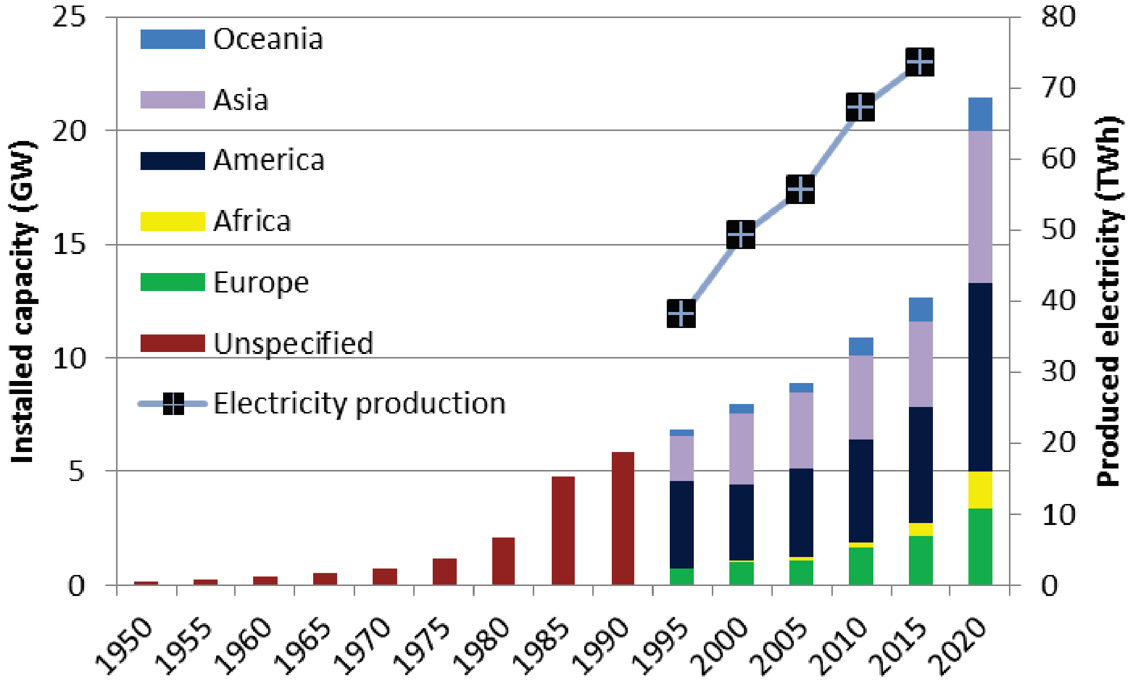

Figure 11.2: Installed capacity of geothermal electricity production between 1950 and 2015 with an estimate for 2020. For the years 1995 to 2015, the corresponding electricity production is shown. Based on (Bertani 2015).

With a total installed capacity of 12.6 GW, 73.5 TWh of electricity were produced in 2015. Leading countries are the USA, the Philippines, Indonesia, Mexico, and New Zealand, as shown in Figure 11.3. According to (Bertani 2015), 40% of this installed capacity is of Single Flash type. This is followed by dry steam plants (22.7%), double flash plants (20.1%) and binary plants (14.2%). Naturally occurring hot water sources (or steam) are therefore dominating today's geothermal power plant portfolio.

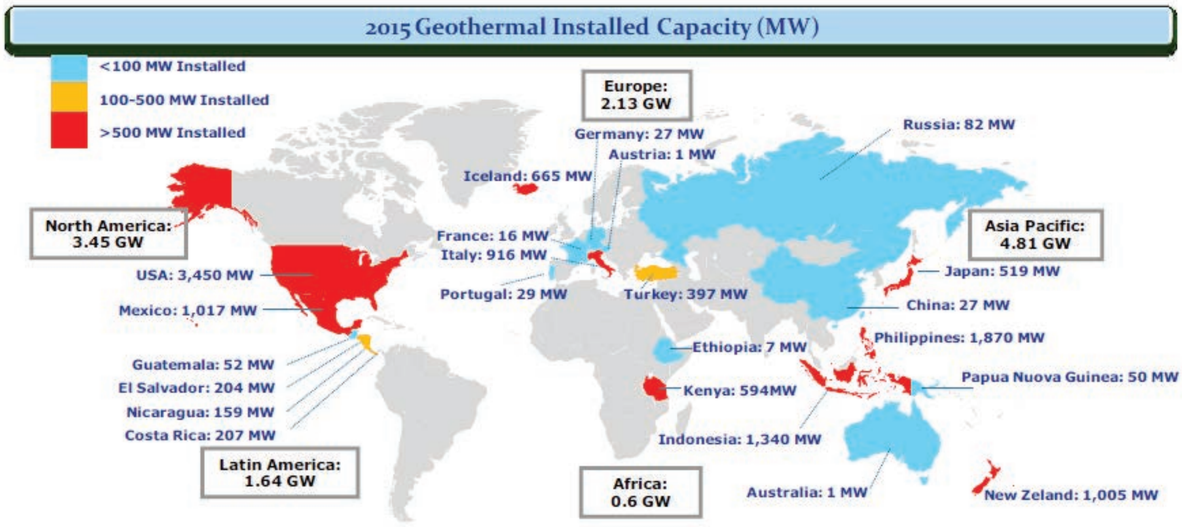

Figure 11.3: Installed geothermal capacity for electricity production in 2015. The total amounts to 12.6 GW. Taken from (Bertani 2015).

Bertani estimates an increase of close to 9 GW within the next five years, with a high potential in Asia and America (Figure 11.2). IEA and IPCC estimates for the global potential for electricity from deep geothermal plants reach 1180-1400 TWh per year in 2050. Heat from geothermal systems might increase to 1600-2100 TWh per year in 2050 (5.8-7.6 EJ/year) (Goldstein, Hiriart et al. 2011, IEA 2011a). The most promising systems are projected to be the EGS systems, as the potential for other plant types is limited. Scenarios for geothermal electricity production in the EU28 for 2050 vary between ca. 180-1100 TWh per year (Sigfusson and Uihlein 2015). A steep increase in installed capacity is projected in the period between 2030 and 2050, finally using 6-41% of the geothermal potential.

11.3.2 Switzerland

Today, geothermal power is only used in rather shallow systems and for heat production in Switzerland. These sources of 3037 GWh of heat in Switzerland in 2014 are described in detail in the report "Statistik der geothermischen Nutzung in der Schweiz – Ausgabe 2014" (Imhasly, Signorelli et al. 2015). No electricity is produced with geothermal power so far. The potential for hydrothermal plants in Switzerland is low. Therefore, the goal is to exploit the vast theoretical potential of underground heat with EGS plants. This is estimated to be in the order of 10^{23}J, or 100 thousand times higher than Switzerland's 2013 energy demand. However, this potential is massively reduced by geological, technical, legal, environmental, social and economic aspects. The target of 4-5 TWh electricity per year from geothermal sources in the Swiss Energy Strategy can only be met if these constraints can be overcome and plants with sufficiently high capacities can technically be built – in other words, if these resources can be exploited in a reasonable way. The individual constraints are discussed in the following.

11.3.2.1 Technological aspects

EGS plants are technically and theoretically feasible. However, there is no economically running EGS plant worldwide yet due to engineering challenges. First, it is not sure that ***drilling*** will be ***successful***. This means for example that the heat gradient may not be as high as estimated based on calculations and test drillings, so that the underground rock temperature is not high enough to heat the water up to a minimum necessary temperature.

Second, the huge experience from oil-gas well engineering is used today as a basis for geothermal ***drilling technology***, but cannot entirely be transferred to geothermal conditions: downhole conditions are different due to hard abrasive rocks, larger well diameters, great depths, elevated pressures, higher temperatures and the presence of corrosive fluids. On top of that, to reduce the cost of a well, the useful lifetime of a geothermal well needs to be longer than that of an oil/gas well. This imposes additional constraints on casing and cementing, which result from substantial thermal and mechanical loads. These technical challenges during the well construction have to be overcome.

Last, ***stimulation*** is associated with uncertainties and risks concerning technical, health and environmental aspects. It may be unsuccessful when the wells cannot be connected via cracks in the reservoir rock in a reasonable way. They are then either poorly connected or only with a large crack, so that the heat resource will decline quickly around this crack. Stimulation can also lead to unaccepted seismic events. However, the stimulation step (together with the given gradient) is crucial for the success of the project. Successful connection of the wells and formation of the reservoir is decisive for getting a reasonable temperature, flow rate, low pumping losses, net capacity and reservoir lifetime. New techniques such as multiple horizontal stimulation aim to increase the success rate and to reduce seismic risk. These advantages still have to be proven in practice.

11.3.2.2 Economic aspects

The uncertainties discussed above, the low calorific value of water, as well as the high well cost lead to unit technical costs (CHF/MWh) that are substantially higher than those of oil and gas wells. As a result, well costs and associated Swiss labor costs are the most important cost drivers for heat and power derived from geothermal energy.

Besides electricity, an EGS plant can provide a substantial amount of heat. Selling this heat is important to reach a reasonable economic performance. However, this can be difficult due to remote location of potential plants and non-existing heat customers. The economic aspects of EGS plants are presented in detail in chapter 11.4.2.2.

11.3.2.3 Social aspects

Public opinion mainly focuses on the problems of seismic events and potential use of chemicals during the stimulation phase. However, perception is rather neutral or positive among Swiss residents (Hirschberg, Wiemer et al. 2015).

11.3.2.4 Legal aspects

Geothermal developments (subsurface and surface) are primarily subject to cantonal laws and regulations. These exist in rudimentary form, but are not yet tailored to the geothermal sector. Although a major topic in cantonal legislations (2-4 cantons per year pass new laws governing the use of the subsurface and explicitly mention geothermal energy), one of the main barriers for geothermal developments is that "an exploration permit to find geothermal resources that is issued by cantonal authorities does not necessarily confer an automatic right to a subsequent development license or concession to exploit the geothermal resource" (Hirschberg, Wiemer et al. 2015). Furthermore, individual legal and concession processes are not yet fully clear in some cantons.

11.3.2.5 Projects in Switzerland

Several projects are underway that aim to supply heat (and partially power) from geothermal resources in Switzerland (Figure 11.4). However, only few of them are for electricity production. The most advanced of these is located in Haute-Sorne (JU), where the canton has granted a permit for the development of the project in June 2015[293] with the remaining objections currently working their way through the Swiss judicial system. The goal is to reach an installed capacity of 5 MW_{el}, and if possible make use of and sell the excess heat. A seismic monitoring system will be installed in 2016, and the drilling for the exploration well is expected to be started in 2017. The timeline foresees operation of the plant by 2020.

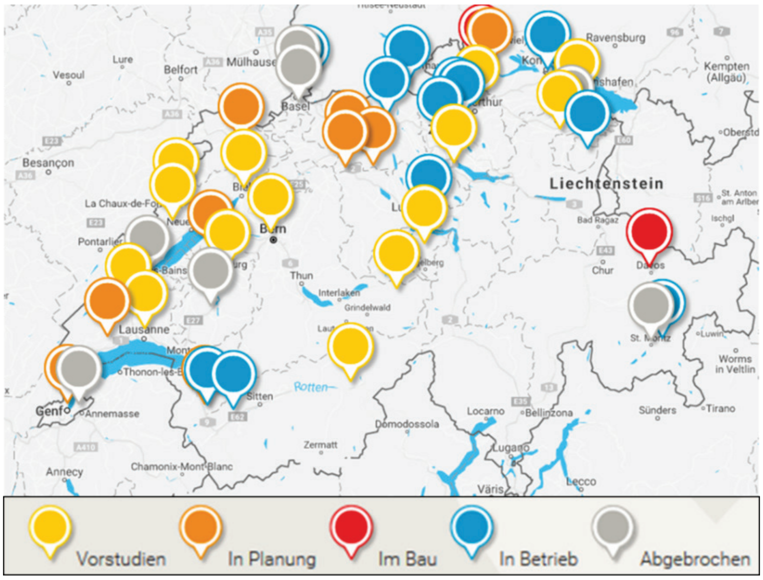

Figure 11.4: Geothermal projects in Switzerland for heat and/or electricity production in pre-study phase, planned, in construction, running, or discontinued. Taken from http://geothermie-schweiz.ch/, accessed 01.09.2016.[294]

11.4 Combined assessment: power generation costs and environmental aspects

A model for the coupled assessment of power generation costs and environmental impacts of future EGS projects in Switzerland was developed (Hirschberg, Wiemer et al. 2015). This model is summarized in the following sections and further details can be found in Hirschberg et al. 2015.

11.4.1 The PSI deep geothermal model for Switzerland

The PSI model for deep geothermal power in Switzerland is a physically based model which allows for adjustment of key parameters and calculation of LCOE and LCA results at the same time (Figure 11.5). The working scheme is a binary, Organic Rankine Cycle EGS system, and the physical model is based on geothermal fluid circulation. Flow rate and downwell pressure values can be chosen, and physical phenomena such as turbulent friction losses are

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[293] http://www.geo-energie.ch/de/projekte/hautesorne.php, accessed 14.01.2016

[294] Note that the well in St. Gallen well has encountered a natural gas reservoir and has been declared as a geothermal failure. Currently shut-in, the future of the well is uncertain. In 2016, discussions are underway to assess the suitability of the well as a research infrastructure.

accounted for. The amount of heat which can be extracted from the production well is based upon the reservoir temperature (from the geothermal gradient and well depth) and the fluid flow rate. The model includes plant-internal power consumption and explicitly shows the downwell pump electricity demand.

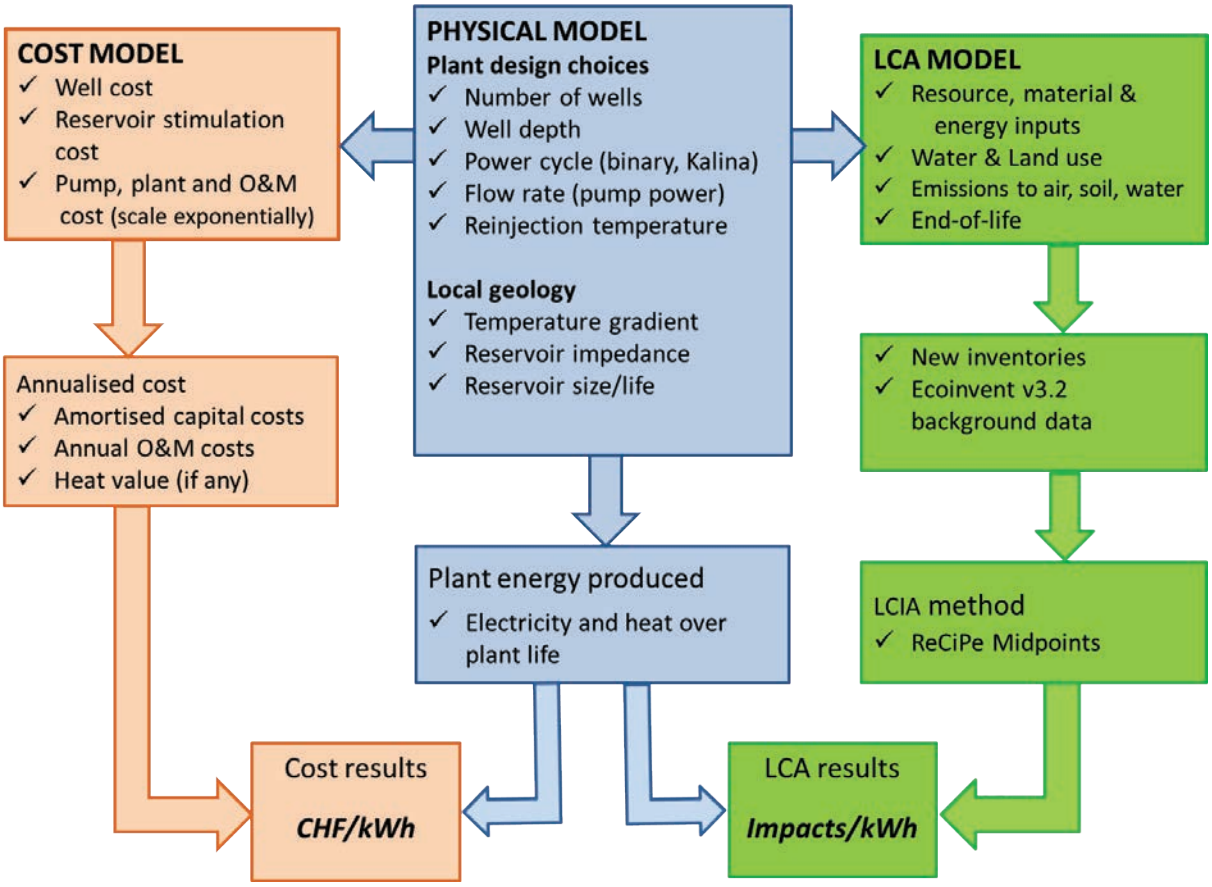

Figure 11.5: Scheme of the PSI deep geothermal physical model with the coupled cost and LCA parameters (adapted from (Hirschberg, Wiemer et al. 2015)

There are plant design choices which can be actively made, while local geological conditions cannot be changed. Active physical inputs to the system are therefore:

- Wells: Location, number depth, diameter
- Stimulation: Duration, pressure
- Operation: Flow rate, input temperature, power cycle

Important uncertainties are present in terms of:

- gradient (drives fluid temperature and thermal efficiency)
- success of stimulation (low impedance reduces pump losses, big reservoir size increases well life)
- brine chemistry (affects well and plant O&M, and return temperature)
- well cost (experience is mainly based on oil and gas wells that are typically in different geology and to shallower depths than for EGS)
- energy use for drilling

Three cases are shown in (Hirschberg, Wiemer et al. 2015), which are supposed to represent a wide range of potential outcomes of an EGS plant in Switzerland. Compared to this previous evaluation, several system parameters have been adjusted in the current assessment. Table 11.1 summarizes the key parameters and outcomes of the assessed cases from (Hirschberg, Wiemer et al. 2015); "TA Swiss cases") and the new cases for this report ("Doublet" and "Triplet" case). For each of these, a medium, a good and a poor setting have been specified. These new cases represent plants which might potentially be operated, while the TA Swiss cases intend to show the potential range of plant performances. The "poor" cases intend to show what happens if the conditions met in the underground or for the generation unit are not as beneficial as expected. This concerns mainly a lower gradient, low flow rate, only partly successful stimulation, or short well lifetime. The "medium" cases simulate (expected) average conditions. The "good" cases simulate especially beneficial conditions, e.g. high gradient and completely successful stimulation. Otherwise, the most important changes compared to the TA Swiss cases are the following: Apart from well triplets, also doublets are considered; the diameter of the wells has been reduced from 0.254 m to 0.216 m (10 to 8.5 inches); the heat gradients have been modified; and the reservoir impedance has been varied.

Table 11.1: Selected key parameters and outcomes of the deep geothermal model developed in (Hirschberg, Wiemer et al. 2015) (TA Swiss – triplet cases) and adjusted for this report (Doublet and Triplet case); n.s.: not specified.

Characteristic	Unit	Doublet			Triplet			TA Swiss cases			Sensitivity range
Scenario		Medium	Good	Poor	Medium	Good	Poor	Medium	Good	Poor	
Plant design choices											
Well depth	km	5	5	5	5	5	5	5	6	5	3-8
Well pipe inside diameter (0.216=8.5 inches)	m	0.216	0.216	0.216	0.216	0.216	0.216	0.254	0.254	0.254	3-20 inches
Geological/local conditions											
Geothermal gradient	°C/km	30	35	30	30	35	30	35	40	30	20-50
Reservoir impedance - absolute	Mpa per L/s	0.2	0.15	0.25	0.2	0.15	0.25	0.2	0.2	0.2	0.05-0.5
Reservoir temperature	°C	165	190	165	165	190	165	190	255	165	n.s.
Plant design & geological conditions											
Flow rate (injection) per well set	L/s	50	75	40	100	100	80	146.7	146.7	147	49-294
Well/reservoir lifetime	a	20	20	20	20	20	20	20	30	20	5-50
Surface plant lifetime	a	20	20	20	20	20	20	30	30	20	20-45
Economic assumptions											
Well cost	Million CHF/well	24	18	30	24	18	30	21	34	21	10-57
Plant capital cost	CHF/kW$_{el}$	4000	4000	4000	4000	4000	4000	4200	4200	4200	2500-5500
Interest rate	#	5%	5%	5%	5%	5%	5%	5%	5%	5%	0.02-0.1
Fracturing cost	Million CHF /well	3.30	3.30	3.30	3.30	3.30	3.30	1.00	1.00	1.00	
Other assumptions											
Rig power source		Electricity from the Swiss grid									Diesel, various electricity sources
Energy use, drilling	kWh/m	2713	2713	2713	2713	2713	2713	3934	4295	3934	1750-11650
Surface system		Organic Rankine Cycle with benzene as working fluid									n.s.
Cooling system		Air cooling									n.s.
Stimulation	m3	40000	40000	40000	40000	40000	40000	40000	40000	40000	10000-200000
Outcomes											
Gross plant power	MW$_{el}$	2.2	4.6	1.7	4.4	6.1	3.5	8.9	17.3	6.4	
Net plant power	MW$_{el}$	1.47	3.3	1.2	2.8	5.3	2.3	5.5	14.6	2.9	
Avg annual net electricity generation	GWh	11.8	27.0	9.6	22.7	42.6	18.6	49.6	131.1	25.6	
Average generation cost w/o heat credit	Rp./kWhe	41.4	18.4	58.1	33.6	16.2	45.4	38.0	19.7	67.5	
Average generation cost with heat credit	Rp./kWhe	15.8	-2.9	32.7	6.9	-1.8	19.4	17.7	7.7	37.1	
Climate Change	g CO_2eq/kWh	67	30	84	51	27	61	26	6	42	

The parameters are briefly discussed in the following section. Sensitivity analysis in chapter 11.5 illustrates the effect of selected parameters on plant capacity, cost and environmental aspects.

Well depth: In Switzerland, a well depth of 5 km is most likely in terms of expected reservoir temperature and well cost. The PSI model also finds that this depth is the optimum in terms of net generation vs. well costs. We assume that the well depth is equal to the well length. This will not exactly be true at locations where horizontal drilling and stimulation is planned.

The well for the EGS system planned in Haute-Sorne is planned to go down to 4 km depth and then turning more horizontally for ca. 1 km in order to allow multi-stage stimulation.

Well diameter: Compared to the TA Swiss cases, the diameter was reduced from 10 inches to 8.5 inches (21.6 cm). This represents casing schemes which have been considered for the wells in Basel and St. Gallen. Larger casing dimensions require increases in rig capacity (and hence are associated with higher cost). In contrast, the flow velocity increases as well diameter goes down eventually causing turbulent flow and large pressure drops.

Thermal gradient: We assume an average gradient of 30°C per 1000 m, which is the expected average Swiss gradient (Hirschberg, Wiemer et al. 2015). This gradient can significantly deviate at specific locations depending on geology and water circulation at depth. The sensitivity analysis will show that a lower gradient quickly leads to very poor conditions for a potential plant. If an exploration well indicates a gradient lower than 30°C, we assume that such a project would not be completed. A gradient of 40-50°C/1000 m represents a "very good" case and if at all mostly to be found in high potential regions such as the Rhône Valley and the Gros du Vaud.

Reservoir impedance: The reservoir impedance is the ratio between the pressure drop across the reservoir (MPa) divided by the production rate (liter/s). Higher impedance requires higher pump power and hence reduces net generation from the plant. In contrast to the TA Swiss cases, the new cases operate with varying reservoir impedance. Reservoir impedance depends upon the distance between the wells, the reservoir geology and the reservoir stimulation. Impedance during stimulation (injectivity) is not necessarily constant (see Figure 11.6), but the PSI model assumes that the impedance is constant between two wells during the production phase, so that flow is proportional to pumping pressure. This reflects a linear approximation of limited parts of the curves in Figure 11.6.

Reservoir temperature: Values of 165°C and 190°C have been assumed, which is more conservative than the TA Swiss «good» case with 255°C.

Flow rate per production well: In a doublet there is only one production and injection well each, while an additional production well in a triplet may be able to double the production flow rate if conditions are favorable. Based on experience in Switzerland and Germany in hydrothermal plants, we assume flow rates between 40 to 75 l/s per production well.

The **interest rate** is assumed to be 5%, which is the discount rate used for financial calculations, reflected the weighted average cost of capital (WACC). This is a figure that is used by many established Swiss energy utilities for project screening purposes. This figure is also used in the calculation of pay-outs in Switzerland's governmental geothermal guarantee scheme in case of failed or partially failed geothermal power projects.

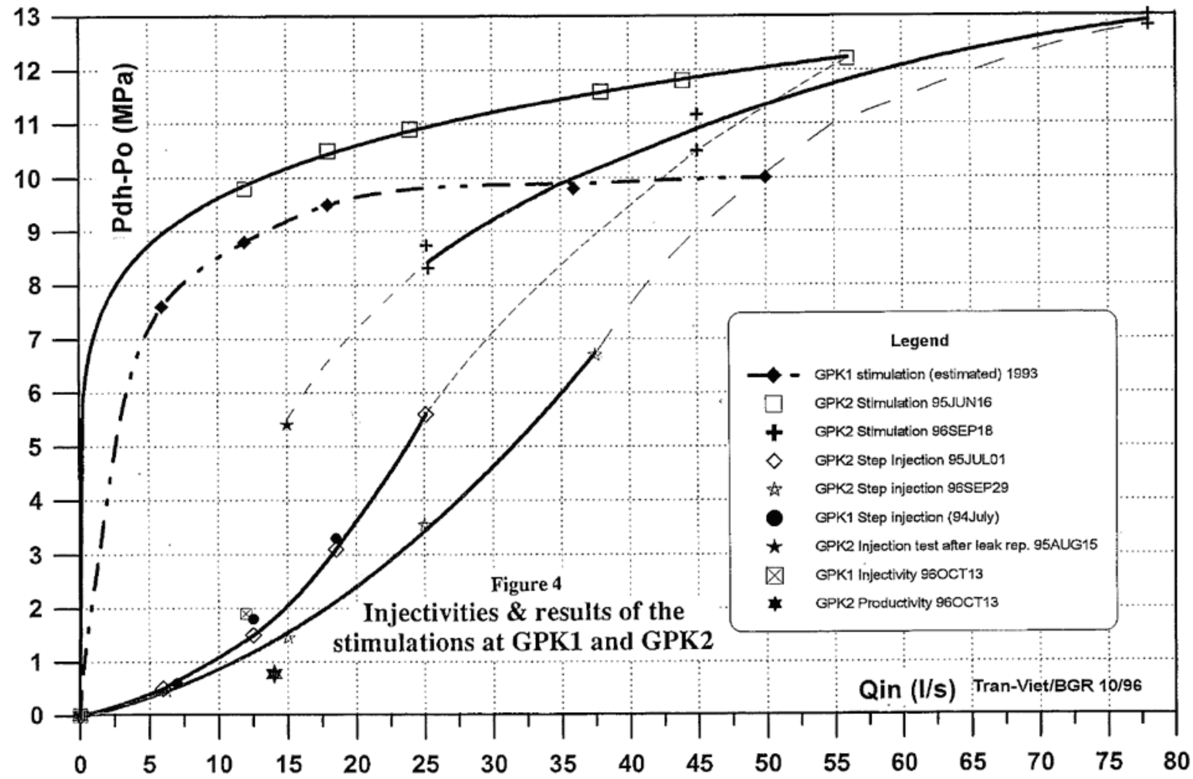

Figure 11.6: Behavior of pressure vs. injection rate at two experimental wells in Soultz-Sous-Forêts (GPK1, GPK2) shown over several years (Gerard, Baumgärtner et al. 1997). For a certain range, the injectivity improved after applying high pressures to the underground.

The **useful lifetime** of an EGS well is assumed to be a function of initial temperature combined with the amount of heat taken out from the underground. Successful stimulation is additionally important for a long lifetime, i.e. stimulation which does not lead to only one large water channel between injection and production well(s). Such a cracking system would decrease the temperature of channel surrounding rock quickly. Furthermore, well integrity and outflow depend primarily on the quality of the completion and casing, as well as scaling and corrosion during the well's lifetime. The PSI model reduces such reactions by keeping the return temperature of the fluid rather high, so that minerals stay in soluble state. It is assumed that a lifetime of 20 years can be reached. The **plant lifetime** has been set equal to the well lifetime. Note that the reservoir lifetime may be longer, which means that potentially the well and plant could be used for a longer time, or a new doublet/triplet set could be established and reservoir exploitation could continue. However, the reservoir can also cool down faster, so that well and plant would have to be abandoned unless other sections of the reservoir are developed. The model includes a factor taking into account the reservoir temperature decline when calculating the average net electricity and heat generation.

The **well cost** show an exponential behavior with well depth and well diameter. Due to the decrease of the well diameter in the new cases, new costs had to be estimated. However, these parameter values are uncertain, as there are only very few field data in Switzerland. Comparable data for wells in other countries are hard to find, as they are often only available for hydrothermal plants with less depth and less solid underground conditions.

Additionally, labor rules, labor cost, cost of procuring services and so on are different in Switzerland. Today's cost seems to be in a range of ca. 15-40 Million CHF for a 5 km well[295].

The **specific capacity cost of the power plant** has been slightly reduced compared to the TA Swiss cases, while the **fracturing cost** has been increased.

Similar to the well cost, the **energy required for drilling** is an exponential function of well depth and well diameter. Due to the lower well diameter, the energy demand has decreased compared to the TA Swiss cases.

The **rig power source** in Switzerland is electricity from grid with a diesel backup. The **surface system** is assumed to be **air-cooled** with an Organic Rankine Cycle with benzene as working fluid.

The **poor cases** in the doublet and triplet setting represent wells with an average gradient of 30 °C, but in the end perform badly due to low fluid flow rate together with high impedance. Nevertheless it is assumed that such plants would be operated as the infrastructure would already have been set up. Operators might try to improve the flow performance and/or the reservoir impedance by stimulating again. In the poor case, we assume that all these investments don't result in an improved situation.

The **good cases** represent favorable conditions in view of gradient (35°C), impedance (0.15 MPa per L/s), reservoir temperature (190°C) and flow rate.

The outcomes of the model as presented in Table 11.1 are discussed in detail in the next chapter.

11.4.2 Outcomes of the model

11.4.2.1 Net capacity

With the parameter values shown above, the net electrical capacity of the modelled **doublet plant** varies between **1.2 MW_{el} and 3.3 MW_{el}** (see Table 11.1). The **triplet plants** show net capacities between **2.3 MW_{el} and 5.3 MW_{el}**. The main reason for the better performance of the triplets is the higher flow rates due to two production wells in a triplet design. This suggests that a successful doublet design can be improved by enlarging it to a triplet, provided that a successful connection to the new well can be established. The net capacities of the new cases are substantially lower than those in TA Swiss with 2.9 MW_{el} to 14.6 MW_{el}. The main reasons for this are lower gradient, reservoir temperature and flow rate per well set. In other words, it is assumed that less thermal energy can be harvested.

A productive well set can be enlarged by creating a geothermal well field, i.e. adding more well sets to a reservoir. The endpoints of the wells within a well set have to have a distance of at least 500 m and a certain distance between well sets needs to be maintained as well. Note that drillings can partially start from the same point and then be directed underground to reach these distances.

[295] Personal contacts, own calculations based on St. Gallen (http://www.nzz.ch/schweiz/stadt-st-gallen-stoppt-geothermie-projekt-1.18302266), Haute-Sorne projections (http://www.geo-energie.ch/de/projekte/hautesorne.php), http://www.energie.tg.ch/documents/Broschuere_-_Geothermie_im_Kanton_Thurgau1382102321736.pdf

11.4.2.2 Levelised cost of electricity

The costs of electricity generation are calculated without and with a heat credit of 7 Rp./kWh, when the heat can be sold for 2500 hours per year as additional revenue allocated to the electricity cost[296]. The theoretical potential for heat sales would be higher, but it cannot be assumed that customers can be found (see discussion below).

The costs of electricity generation **without any heat credit** are between **18.4 Rp./kWh and 58.1 Rp./kWh for the doublet case** and **16.2 Rp./kWh and 45.4 Rp./kWh for the triplet case** (see Table 11.1). If it is assumed that all surplus **heat can be sold**, this decreases to **-2.9 to 32.7 Rp./kWh (doublet) and -1.8 to 19.4 Rp./kWh (triplet).** These negative LCOE call for explanation.

In an EGS plant, the thermal efficiency is rather low and the ratio of electricity to heat is low as well (around 1:6). Still, if all this heat could be sold (during estimated 2500 hours per year), the costs of electricity would become negative. This means that "the plant could pay customers to take the electricity or operate at a loss on a purely electric basis and still break even (Hirschberg, Wiemer et al. 2015)". Any type of combined heat and power geothermal plant would therefore be beneficial in terms of costs. However, there are several obstructions for such an unlikely case:

- The PSI model does not account for heat losses. This means that "the available waste heat is the heat that comes up the well minus the heat in the reinjection fluid and the electric energy produced".
- Due to public concerns about seismic events, EGS plants will probably be built at a certain distance from densely populated areas. The heat source is therefore situated at a place where such a high heat demand might not be present, and/or a grid for delivering the heat has to be built. Such costs are not integrated into the PSI model.
- There might be competing other (surplus) heat sources.

The heat credit might also be lower than 7 Rp./kWh, which represents the price for heat sold to a (large) customer. If the heat has to be sold in wholesale, the price might be significantly lower (e.g. around 1.5 Rp./kWh) and with this the heat credit.

Hence, it should not be taken for granted that some of the surplus heat can be sold and the figures for the cases without heat credit are more likely.

The costs are dominated by the well cost and can substantially be decreased with the heat sales (Figure 11.7). Details on the individual cost components are explained in (Hirschberg, Wiemer et al. 2015).

[296] Annual load factor for space heating, for comparison: ca. 2000 hours.

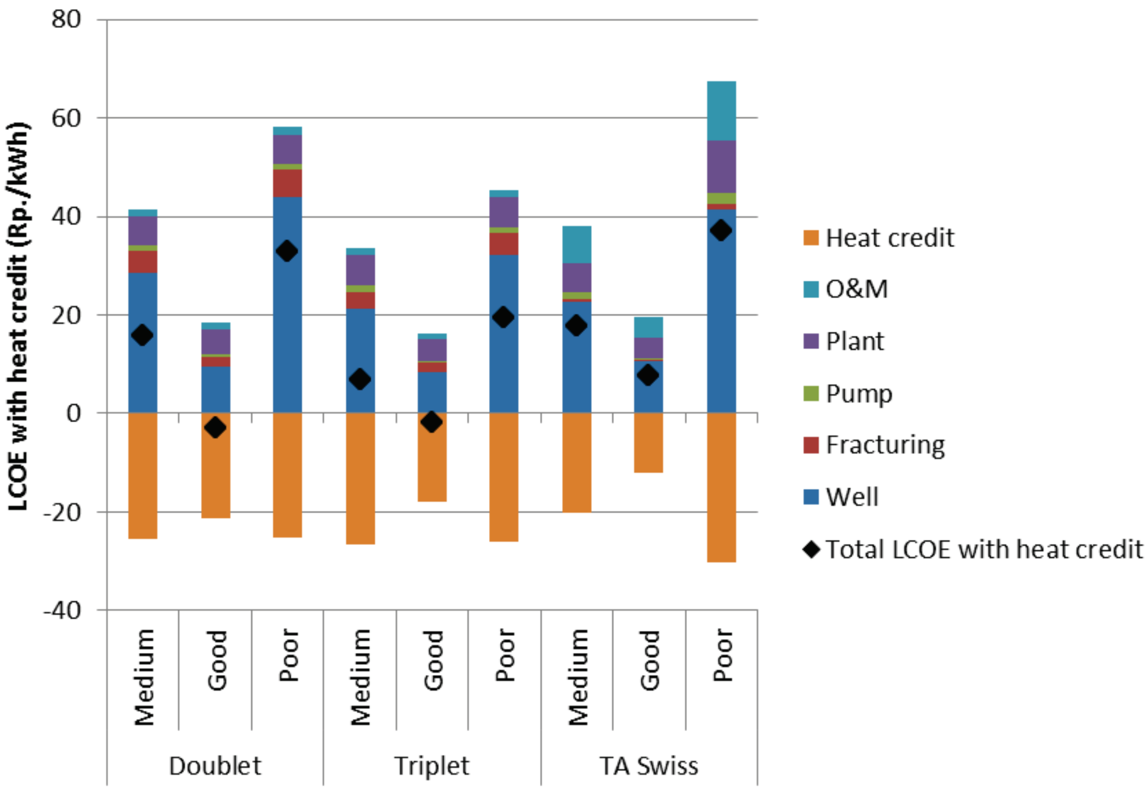

Figure 11.7: LCOE composition for the various cases of electricity from deep geothermal electricity production.

The **well costs (drilling costs)** are driven by infrastructure and labor costs, treatment of drill cutting and mud, etc. These costs are expected to be higher in Switzerland than abroad due to aspects such as higher labor costs, more stringent (environmental) regulations, or less experience in vertical drilling. Well costs have an exponential behavior, i.e. they increase fast with increasing depth due to longer tripping time, higher material needs and higher rig capacity needed. The well costs include exploratory wells – which are most likely being used as production or injection well if measured parameters are promising for setting up a plant. The current cases assume costs of 24 million dollar per well of 5 km depth.

The **fracturing costs** are very uncertain. They might be substantially lower or higher.

A lifetime of 5 years has been assumed for the **production pumps**, so that they have to be replaced four times in a lifetime of 20 years at costs of 900 $/kW each time. Even despite this fact, the pump costs are minor in total LCOE. The model chooses between a line shaft pump if the pump can be place between 0-600 m down in the well, or a submersible pump if the pump needs to be placed lower than 600 m down. However, the use of line shaft pumps is in reality more practical due to longer lifetime in high temperature and better suitability for many times of switching on and off cycles.

As shown in Table 11.1, plant capital costs are assumed to be 4000 $/kW_e$. Also these costs are rather minor in total LCOE, and so are O&M costs.

As described above, the heat credit is rather unsure, but may decrease the resulting LCOE significantly. Generally spoken, plants which reach a certain capacity may have rather low LCOE even without heat credit. Sensitivity analysis of parameters influencing the net capacity is presented in chapter 11.5.2.

11.4.2.3 Life-cycle environmental impacts

The life-cycle impacts are quantified without allocation of impacts between electricity (the main product of the deep geothermal plant) and the by-product heat, since it is highly uncertain if the heat can be used.

The life cycle related **environmental burdens** are dominated by the drilling phase in most impact categories.

The **life cycle CO_2 equivalent emissions** per kWh are in the range of 30-84 g CO_2eq/kWh (doublet) and 27-61 g CO_2/kWh (triplet) (see Figure 11.8).

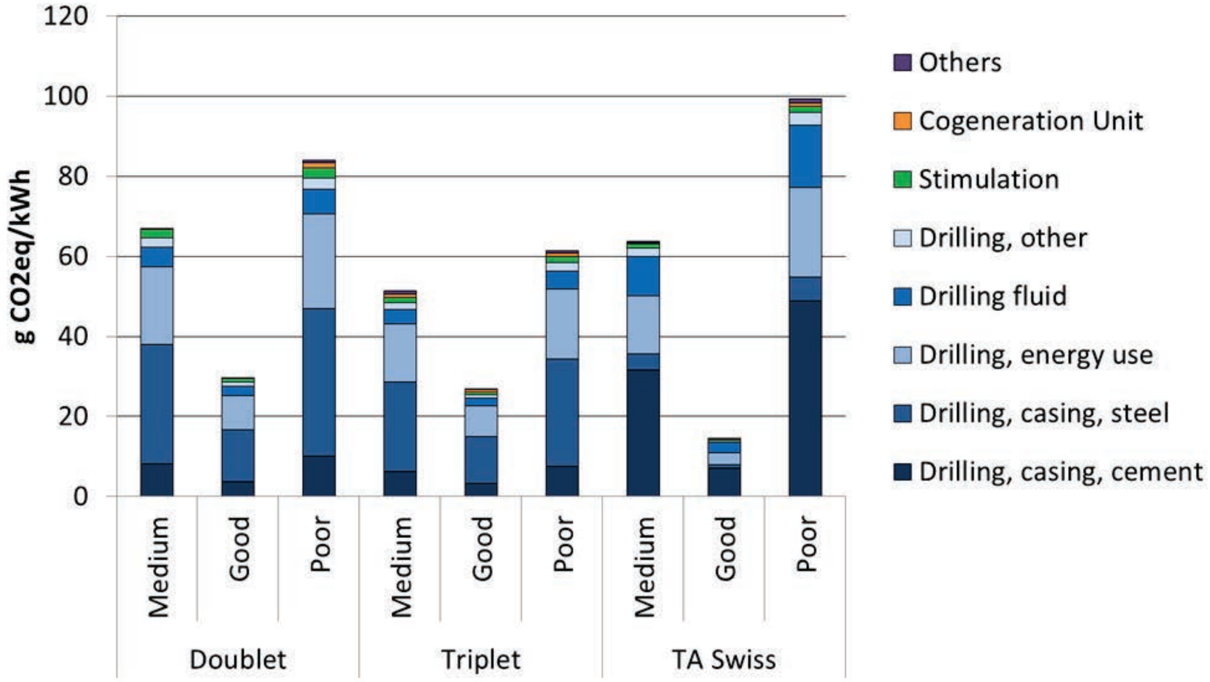

Figure 11.8: Impact on climate change (g CO2eq/kWh) for the six cases in this report.

Within the drilling phase, the steel used for the casing as well as the energy use are most important. Energy source in Switzerland is electricity from grid, with a small diesel backup. This picture is the same also for most other impact categories, i.e. the drilling phase is dominating the results. Within the drilling, material use for the casing (mainly steel and cement) as well as the energy use are most important. Stimulation, cogeneration unit, drilling fluid and others play a minor role in all cases.

The life cycle inventories (LCI) and life cycle impact assessment (LCIA) results are shown and discussed in detail in (Hirschberg, Wiemer et al. 2015).

11.5 Sensitivity analyses

The sensitivity analyses are performed for the medium doublet case. Most parameters tested are the same for cost and environmental impacts, with some specific parameters for each of the areas. The parameter ranges tested are shown in Table 11.1. Certain parameter values lead to negative net capacities, which do not reflect plants actually built. Such cases are not discussed in the following – the effect can be observed by means of the steep curves in the figures.

Only one parameter each time is changed in the sensitivity analyses. This might not reflect reality, e.g. when the reservoir life is kept constant even if the fluid flow rate is varied. The only exception is variation of the well cost with changing well depth. The same would be necessary for a changing well diameter. However, data were not available for doing this. Hence, results for this parameter have to be judged with care. On a qualitative level, we expect lower well costs for a lower diameter, but also a lower net capacity due to higher pumping losses. Costs will increase with increasing diameter, so that at some point they will overbalance the benefits from higher capacity. The curve will therefore show an optimum.

11.5.1 Sensitivity analysis - net capacity

The net capacity is important for both LCOE and environmental impacts per kWh, as it determines the life cycle electricity generation of a plant. The behavior of this parameter is shown in Figure 11.9. The reference values from the medium doublet case are shown in brackets.

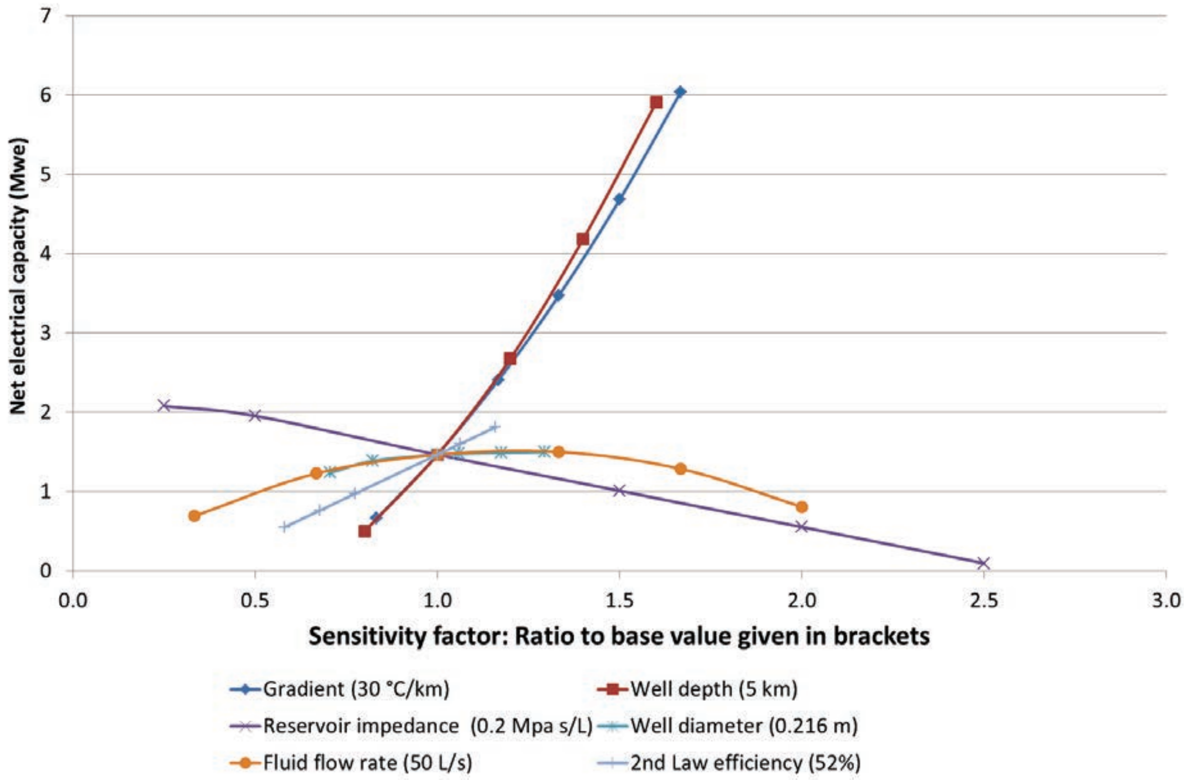

Figure 11.9: Influence of variation of the sensitivity parameters on the net electrical capacity for the medium double wells case (1.5 MW_{el}). Parameters not having an impact on the net electrical capacity are not shown.

It is directly visible that the **gradient** and the **well depth** have the highest influence on the net capacity, being the determining factors for heat resource at the bottom of the well. With a well depth of 8 km or a gradient of 50°C/km, a capacity of 6 MW_{el} can be reached. However, such a high gradient is not realistic, and the costs for a well of such a depth would outweigh the benefits from the higher capacity (see chapter 11.5.2). On the contrary, lower gradient and well depth quickly lead to zero capacity. Exploration drillings indicating a gradient lower than 25°C would probably lead to project stop, while it might be possible to increase the well depth a little if maximizing the plant output is the goal without economic constraints, e.g. in case of subsidies.

The **reservoir impedance** has a close to linear behavior with a decreasing capacity in case of higher impedance. This is due to higher pumping load needs to keep the fluid flowing. Measurements from test sites showed that the impedance can be very high. The target value should however be at ca. 0.1-0.3 MPa/l/s to reach good conditions. The **well diameter** is "linked to increasing flow impedance, pressure drops and pumping losses due either to the reservoir impedance or fluid velocity" (Hirschberg, Wiemer et al. 2015). As a result, increasing the diameter from 8 to 10 inches does not bring any benefit for the net capacity (only in the range of ca. 0.1 MW), but increases the costs.

The **fluid flow rate** has an optimum after which the capacity decreases due to higher pump power needed not outweighing the benefit from additional heat brought up. This optimum point is around 60 l/s. Even if this does not lead to a significantly higher capacity in the double medium case, sensitivity tests for the triplet good case showed an increase in capacity of 1 MW when increasing the flow rate from 100 l/s (as is in the base case) to 177 l/s. Note that in reality the fluid flow rate is coupled to the reservoir life, which is not accounted for in this analysis, as predictions are complex.

The assumed value for the **second law efficiency** is rather uncertain, but as the sensitivity analysis shows, this parameter does not have a huge influence on the net capacity. In any case the energy available underground is for free and available in a large amount, so that efficiency is not an as big topic as for other technologies.

11.5.2 Sensitivity analyses – Cost

The results for the sensitivity of costs are shown in Figure 11.10. The reference values from the medium doublet case are shown in brackets. Details on the importance of the individual cost components (drilling, fracturing, pump, plant, O&M) are shown and discussed in detail in (Hirschberg, Wiemer et al. 2015). These are not repeated here, as the behavior of the sensitivity analyses in this study is similar to the one in the report.

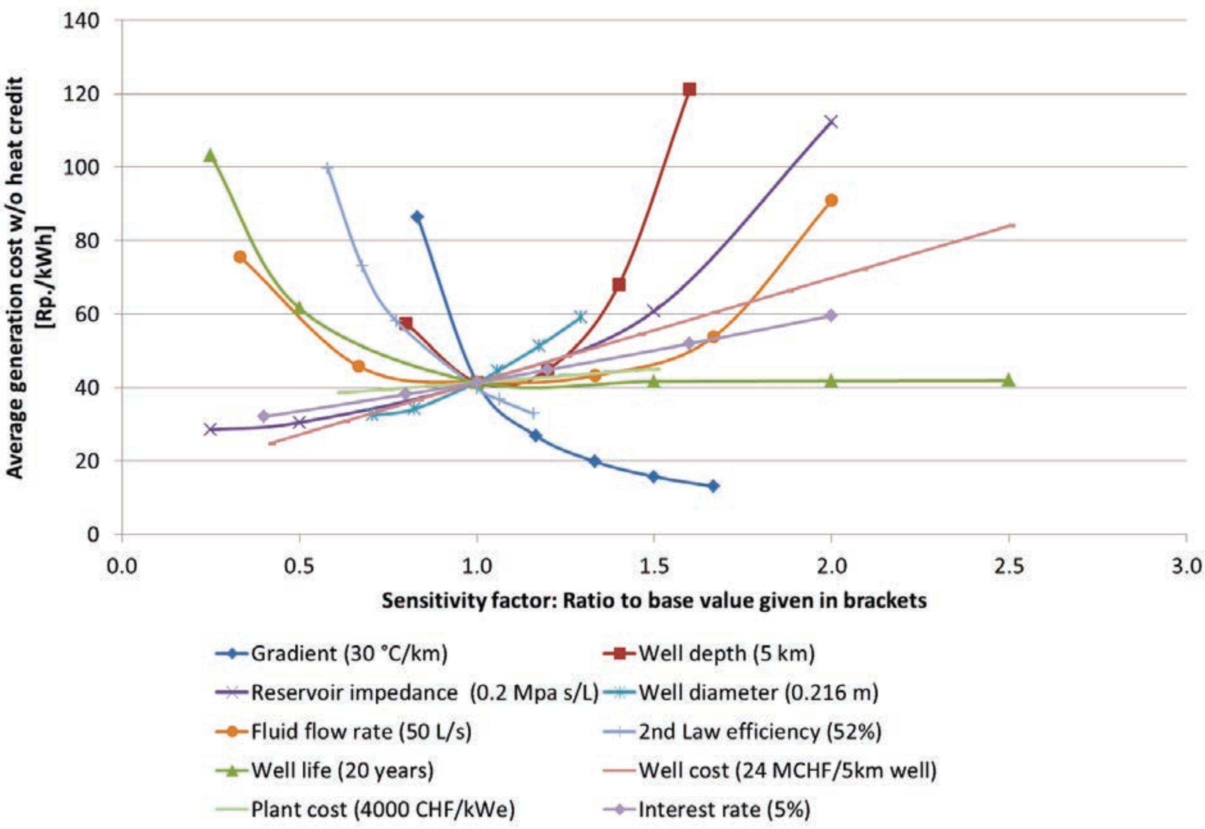

Figure 11.10: Sensitivity analysis for LCOE without heat credit in Rp./kWh.

An increasing **gradient** leads to increased net capacity, as the resource temperature is higher. A gradient of 40°C/km results in a net capacity of 3.5 MW_{el} instead of 1.5 MW_{el} as in the base case assumed here. On the contrary, a gradient of 20°C/km is already way too low for extraction of heat, so that the resulting capacity is zero. With a gradient of 25°C/km, the resulting capacity is as low as 0.66 MW_{el} and the cost are as high as 86 Rp./kWh.

The drilling cost and energy use increase exponentially with **depth**, which is represented by the right side of the well depth curve. We see an optimum point because a more shallow well would not bring enough heat and therefore lead to a lower capacity. In our model, a well depth of 5 km is most beneficial from an economic perspective, even if deeper wells would lead to a much higher capacity (see Figure 11.9).

Well life: The well lifetime may be lower than the actual reservoir lifetime, which means that after decline of a well, another one might be drilled for further exploration of the reservoir.

Same as for the net capacity, there is an optimum point for the **fluid flow** rate.

Interest rate, well cost and plant cost and related LCOE behave linearly: The higher these cost, the higher the resulting LCOE.

11.5.3 Sensitivity analyses – Environment

A similar graph as shown for the costs can be produced for each individual impact category in the model. However, their behavior is similar, so that a selected graph for impacts on climate change is shown in Figure 11.11 (see (Hirschberg, Wiemer et al. 2015) for details).

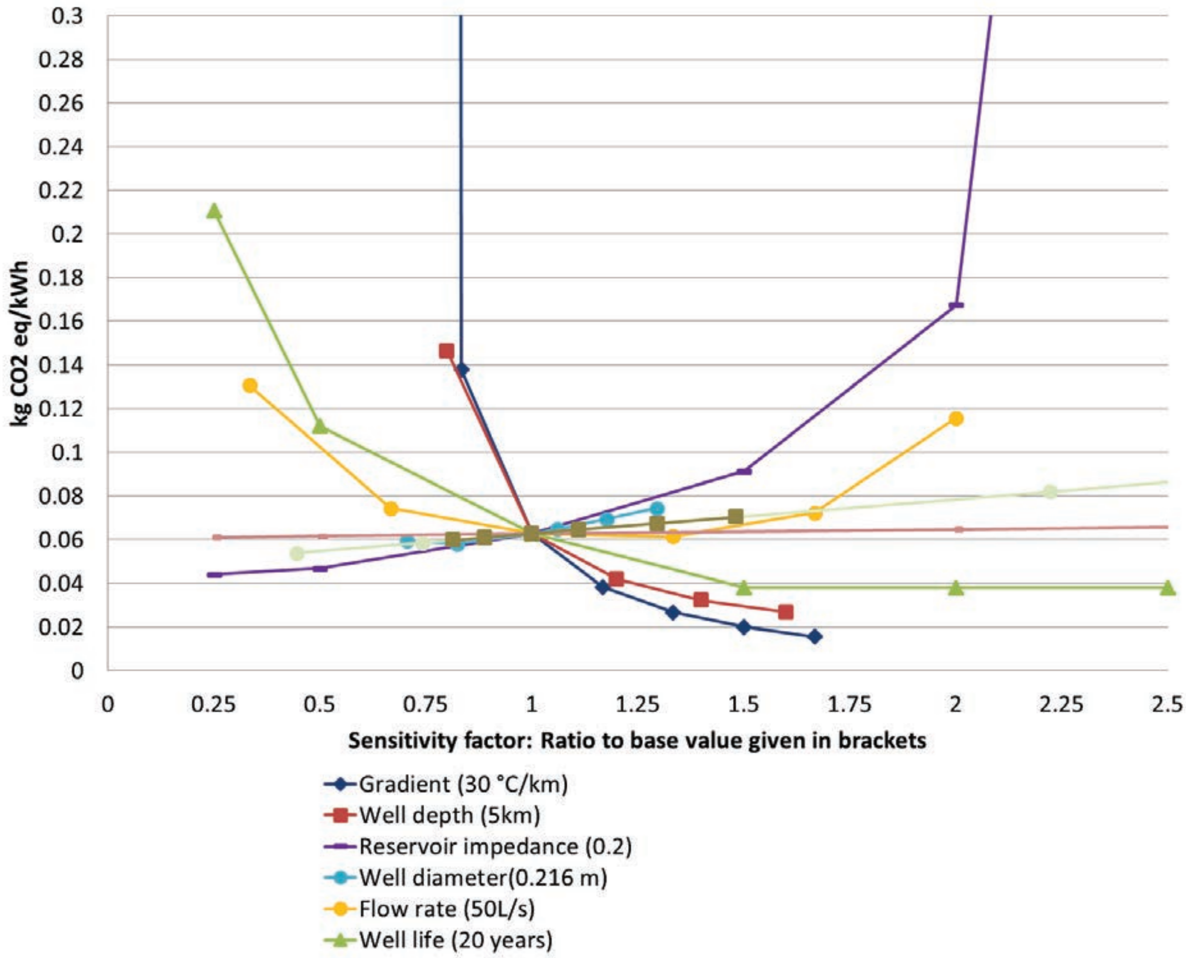

Figure 11.11: Sensitivity analysis for impacts on climate change.

Again, the environmental impacts per kWh are most sensitive to changes in the **gradient and the well depth**. Even in very low capacity and high cost cases which would maybe be kept running once they have started despite low performance, the emissions of CO_2 over the whole lifetime remain lower than ca. 150 g CO_2eq/kWh.

The **drilling energy consumption** is increasing exponentially with well depth, but is difficult to estimate exactly. However, even if it is increased by a factor 2.5, the impacts only go up from 60 g CO_2eq/kWh to a bit more than 80 g CO_2eq/kWh. On the other hand, working on decreasing the energy consumption does not improve the environmental performance a lot. This effect would be larger or smaller depending on the energy source (see Figure 11.12). Energy and water use for stimulation are also parameters which are difficult to estimate as field data are missing. However, the influence on the final result is negligible.

The **flow rate** again shows an optimal point, which has been assumed for the base case. If this rate cannot be reached or is exceeded, CO_2 emissions can even more than double.

Increasing the **well life** is beneficial, but the curve flattens quickly with a longer lifetime. Even if energy and material consumption increase exponentially with well depth, these negative effects on CO_2 emissions are outweighed by the higher net capacity and lifetime electricity production.

Sensitivity results for reservoir impedance and gradient changes again reflect the important changes in plant net capacity, while the increasing the water and energy use for the stimulation phase does not even change the results for water depletion a lot.

A broader view on sensitivities in the environmental area are presented in (Hirschberg, Wiemer et al. 2015) for several selected environmental impact categories and sensitivity parameters. The behavior of all shown impact categories is similar. They react most on changes in parameters which influence the net capacity most. These are namely the gradient, well depth and reservoir impedance.

With the drilling phase being so important for the results, a variation of the **drilling energy source** is shown in Figure 11.12.

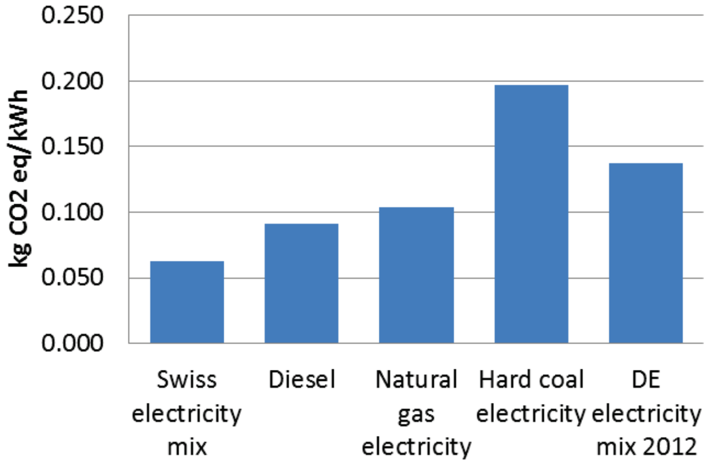

Figure 11.12: Sensitivity analysis for the climate change indicator with the drilling energy source.

Depending on the energy source for the drilling, the CO_2eq/kWh of electricity from an EGS plant can vary significantly. An EGS plant with identical conditions as in Switzerland, but built in Germany with German grid electricity, would increase the impacts from 63 gCO_2eq/kWh to 137 gCO_2eq/kWh.

11.6 Future costs and environmental aspects

11.6.1 Costs

As shown in the sensitivity analyses section, the costs and environmental impacts depend mostly on the **net capacity** which can be reached with a specific drilling and plant design. The most important factors for this are the temperature gradient, the reservoir impedance, the fluid flow rate, and the well depth. The first is entirely physical and cannot be influenced. The impedance can be influenced by stimulation, but the technology knowledge on stimulation in EGS is not yet advanced. The fluid flow rate actually shows an optimum point which should be reached. This way the full amount of thermal energy possible to use is exploited while not exceeding natural heat recharge rate much. Increasing well depth results in a steep increase of the net capacity, but also in much higher LCOE.

For the net capacity (and with this for LCOE and environmental impacts), actual conditions at site are most important for EGS projects. The net capacity therefore does not depend that much on the point of time of construction (today or future). Improved drillings technology and experience will probably lead to a decrease in the well cost, so that overall costs will tend to decline. However, there might also be an effect that the most promising sites will be explored first, with lower gradient or less beneficial conditions for further plants.

Cost drivers for the drilling are discussed in chapter 11.5. It is not expected that the costs will decrease significantly in the near future, as this would "require the development of new and improved drilling technologies" (Hirschberg, Wiemer et al. 2015). A small decrease might come from increasing experience. Further, drilling of several well sets in the same area might profit from experience from the first drillings at a certain location.

A fictive example of LCOE related to a future plant was set up with the following parameters:

- Successful stimulation leads to an impedance of 0.15 MPa per l/s and a flow rate of 75 l/s per production well. The gradient is 35°C/km.
- Well cost decrease to 15 Million CHF/well.
- Plant cost decrease from 4000 CHF/kW$_e$ to 3500 CHF/kW$_e$.
- The capacity factor of the plant increases from 86% to 95%

These assumptions lead to a **capacity of 3.3 MW$_{el}$ for the doublet and 6.3 MW$_{el}$ for the triplet**. The related LCOE go down **to 14.5 Rp./kWh and 12.9 Rp./kWh**, respectively. As the well cost are most important (up to ca. 75%) for the LCOE, decreasing them is most important for reducing the LCOE in future by means of more experience, standardization, and other learning effects. Increasing the capacity factor is also likely to happen and decreases the LCOE by several Rappen.

If the gradient would happen to be 40°C/km, the plant net capacity would reach **5 MW$_{el}$ (doublet) and 9.4 MW$_{el}$ (triplet)** with related costs of **10.8 Rp./kWh and 9.6 Rp./kWh**, respectively.

11.6.2 Environmental impacts

The Swiss electricity mix will change, which is relevant for environmental impacts since electricity is used for drilling. If more renewables or nuclear electricity imports will be part of this mix, environmental impacts will decrease in most impact categories. If more electricity from natural gas or imports from Germany will be part of the mix, environmental impacts will increase in most impact categories – partly significantly (see Figure 11.12).

11.7 Abbreviations

a	year
ARE	Bundesamt für Raumplanung
BAFU	Bundesamt für Umwelt
BFE	Bundesamt für Energie
CAPEX	capital expenses
CH	Switzerland
CHF	Swiss Francs
CO_2eq	carbon dioxide equivalent
DE	Germany
EGS	Enhanced Geothermal System
EU	European Union
GHG	Greenhouse gas
HH	human health
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
KEV	Kostendeckende Einspeisevergütung/compensatory feed-in renumeration
LCA	life cycle assessment
LCIA	life cycle impact assessment
LCOE	Levelised Cost of Electricity
max	maximum
min	minimum
O&M	operation and maintenance
OPEX	Operating and maintenance expenses
Rp.	Rappen (Swiss cents)
UK	United Kingdom
US	United States
USD	United States Dollar
WACC	weighted average cost of capital
yr	year

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12 Wave and tidal power

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12.1 Introduction

The purpose of this section is to describe the potential for electrical generation from wave power. There have been many research developments in this field, and a very large increase in the number of interested organizations, but there has been less advancement in actual commercial development than was hoped for at the time of the publication of (Hirschberg, Bauer et al. 2005). The range of potential wave power technologies is still very wide, and no single technology has emerged as the dominant solution. This chapter updates (Hirschberg, Bauer et al. 2005), in particular including the new actors in this sector, some new technologies, advances in various research areas, cost estimates and environmental burdens. However, the description of former technologies and the overall approach to the estimation of resource potential remain largely unchanged. Other specific advances and changes since publication of (Hirschberg, Bauer et al. 2005) are mentioned throughout.

One major change in the overall area of ocean energy that has occurred however is that wave energy is no longer perceived quite so much as the dominant resource. Other sources of ocean energy also include ocean currents, tidal power, ocean thermal energy conversion (OTEC), and salinity gradient power. There are active research and development activities in these areas, and the tidal and current technologies in particular are seen as challengers to the former dominance of wave power. This introduction sketches the basics of these different ocean energy resources very briefly before turning to concentrate on its original mandate in the area of wave power.

12.1.1 Wave Power

Figure 12.1 shows a schematic diagram of the physical characteristics of this energy resource that contribute to its challenges and potential.

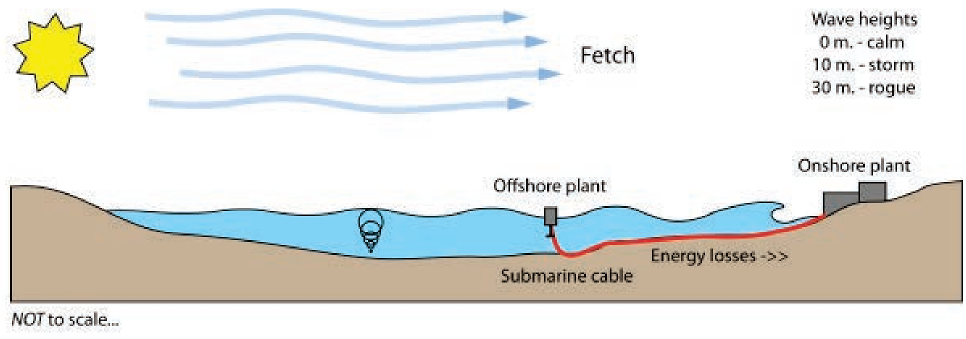

Figure 12.1: Schematic diagram of wave power fundamentals (Source: PSI).

First, ocean wave energy is an indirect form of solar energy. The sun drives weather systems and their associated winds. Wind blowing over the ocean causes waves to build up. The size of the waves depends upon the strength of the wind, how long it blows, its consistency of direction, and the distance of water over which the waves have a chance to build up (the „fetch" in English). The dominant ocean wave patterns therefore follow the predominant weather patterns. Wave heights tend to be the highest in the southern ocean, where both wind and waves are unimpeded by land between the southern capes and Antarctica. Ordinary maximum wave heights during severe storms can reach approximately 10 meters, and extraordinary „rogue“ waves can reach heights of 30 meters. Relevant wave characteristics include amplitude (size), frequency (or distance between waves) and direction. The statistical distribution and maximum values of these variables will determine the wave energy resource, and the maximum damage potential which any wave power installation will have to withstand.

As waves pass, individual water molecules move or oscillate in a roughly circular motion that decreases with depth. As a wave approaches the shore, its energy begins to dissipate against the ocean bottom, and the remaining energy is concentrated in the form of increased wave size at the surface. These waves may break, and finally dissipate against the beach or rocks of the shoreline. Wave height in shallow water is limited (to approximately 80%, or even as low as 55%) the depth of the water. The shape of shoreline can also concentrate or focus the wave energy on a particular location.

Seawater is of course much denser than air, by a factor of approximately 800 (1022-1029 kg/m^3 vs. 1.25-1.29 kg/m^3). This means that the size and cost of wave generator structures necessary to harvest wave power can be much smaller than wind power installations, although this is somewhat countered by the fact that on average the waves move more slowly than the wind and wind power is related to the cube of wind speed. This leads to another relevant difference between wind and wave energy implied by the density of water. The mass and momentum of moving waves means that they build up and dissipate more slowly than the wind, effectively averaging the wind speed over the upwind fetch of the ocean where they build up. This reduces the variability in the wave energy available, and can increase the average generation over time (the capacity factor) for a given size of generator, thus reducing the size and cost of generator necessary for the amount of energy produced.

Technologies to collect the wave power may be either onshore or offshore. Energy from offshore installations is usually delivered as electricity by submarine cables, or less commonly by pipelines that deliver compressed air or water to onshore generators. The increased offshore energy resource must therefore be balanced against the cost to deliver it ashore. Desalinated water or other chemical products may also be produced offshore and shipped to land. Wave power is generally less limited by site than current or tidal power.

12.1.2 Ocean Current Power

Ocean currents are also driven by the meteorological engine of the weather, although over even longer distances and time scales than wave power. As ocean surface water is warmed by the sun, water vapor evaporates and makes the water saltier. When the current reaches colder latitudes, the saltier and denser water sinks to great depths and circulates again to the tropics where it rises to complete the cycle. This so-called thermo-haline conveyor is intimately linked to global climate, including the storage of heat from the greenhouse effect. Ocean currents can depend strongly on local seabed topography, and can achieve speeds of up to around 1 meter/second, but deep ocean currents may only achieve around 1-2 meters/day. The total energy resource size of an ocean current is generally measured in units of Sverdrups (1 Sv = 1 million m^3/s, or an average speed of 1 m/s across an area of 1 km^2). For example, the Gulf Stream that warms northern Europe increases in size from about 30 Sv offshore from Florida to a maximum of about 150 Sv near Newfoundland. Ocean current power collection technologies include various styles of turbines anchored to the seabed, or asymmetric drogues (drag devices) on cables. The advantages of ocean current power are the large resource scale and the constant availability, while the disadvantages are generally the availability within economic distance of shore.

12.1.3 Tidal Power

The power of the tides has of course been appreciated since ancient times, but in the more recent past this resource was considered limited to locations with high tidal range (height differences) and appropriate coastline (e.g. the Bay of Fundy or Normandy) to contain or impound the water. Power was then generated using hydropower turbines, similar to low head run-of-river turbines. Even more recently, attention has focused on extracting energy directly from tidal currents in much the same way as from ocean currents using anchored submarine turbines. Locations where tidal streams are focused to higher speeds by coastal features like bays or islands may therefore be especially favorable. Tidal power has daily and seasonal variations that are not always in synchronization with power demand, but they do have the advantage of being perfectly predictable in advance, rather than stochastic like wind, solar and (to a lesser extent) wave power.

12.1.4 Ocean Thermal Energy Conversion (OTEC)

This concept uses the temperature difference between sun-warmed surface water and deep, cold water to vaporize an organic working fluid with a lower boiling temperature to drive a rankine cycle engine. In the past, this technology has suffered from biological fouling of the large heat exchangers necessary, leading to poor economic results. However, there has been renewed interest in OTEC globally. In general, OTEC is not an ocean energy technology that is of interest to Europe because the western coast does not have the tropical surface water temperatures that are required.

12.1.5 Salinity Gradient Power

Where freshwater rivers run into the sea it is possible to use a semi-permeable membrane between the fresh and salt water to generate an osmotic pressure difference that can be used to generate power. This is the reverse process of osmotic membrane desalination that is used to produce freshwater from seawater. The resource is of course limited by the annual flow and variation in European rivers that run to the sea, and the competing needs for navigation and preservation of estuary ecosystems.

12.2 Global and European Electricity Supply and Trends

Wave power generation is, if not in its infancy, certainly still in adolescence, with a relatively small number of demonstration scale installations, widely scattered around the globe. However, there has been a very large increase in the number of wave-related organizations, including companies, grant-making institutions, research institutes, test facilities, and universities. Table 12.2 at the end of this chapter summarizes a wide, updated range of research and development activities and installations, totaling over 400 different organizations.[297] Although this table has been compiled from a number of sources and covers the main types of wave power technologies, it is not claimed to be absolutely complete and comprehensive. It may also be noted by the relative sparsity of the data entered in the table that not all data is available or applicable for each of the categories

[297] Complete data file available upon request.

listed. A number of the designs or installations have been decommissioned or retired, either due to poor economic results or physical failure. Other projects have had a succession of installations at a single site, and in this case the year and unit size columns may include more than one value.

Overall, this table reflects the fact that there are more research universities, more test centers, more commercial companies, and more wave power installations that at the time of the previous Energieperspektiven report. But as alluded to in the introduction, the wave power sector has not still not really taken off or fulfilled prior hopes or expectations. This is evidenced by articles in the popular and trade press, e.g. (Levitan 2014, Richard 2014), and also by the reduction in forecasts or predictions of future capacity and generation (WEC 2013).

The largest current wave power designs are on the order of a MW in size, with the current largest demonstration projects on the order of 10's of MW. The EU Energy directive of 2008 indicated a planned global waver power capacity of about 75 MW by 2012, with a target of over 1500 MW by 2020. Northern Europe remains a leading center of global wave power technology, reflecting both high resource levels (especially around the British Isles) and local expertise with the offshore oil and gas industries, but other active regions include the US and Australia. Many of the test sites are on islands, where the ocean current resource is also good. The small demand and high price of competing electricity sources on islands not connected to the mainland grid make these locations the best niche markets for wave power. All these factors came together to result in the location of the European Marine Energy Center on the Orkney Islands, north of Scotland, which is one of the premier organizations and test facilities, and it is one of the best measures of growth in the field that over 30 different test facilities are listed in Table 12.2.

12.2.1 Swiss Electricity Supply and Trends

Being landlocked, Switzerland of course does not have any current or prospective wave power resources of its own. Any wave energy would have to be imported, probably from the Atlantic coast of Spain, Portugal or France.

12.3 Technology Description

12.3.1 Current Technologies

Wave power technologies are basically divided into two broad categories, onshore and offshore. Onshore installations are (of course) in the surf zone, and this category more nearly includes near-shore designs that are installed in relatively shallow depths. This section discusses the major categories of wave power generation technologies belonging to these two major classes. It is not possible to discuss all individual designs within each category within this report, but the major advantages and disadvantages of each type, as well as some specific examples are described below.

It is also possible to categorize wave power technologies using an alternate typology that separates each technology by its elements, including a) power absorber, b) power takeoff, and c) the infrastructure needed for siting or anchoring. Figure 12.2 shows an alternative typology or categorization based on the type of power absorber. In general, there are no really new classes of power absorbers, power takeoffs or infrastructure since the prior BFE report (Hirschberg, Bauer et al. 2005), and the body of this section still follows the original onshore/offshore division, with only a few new technology examples added.

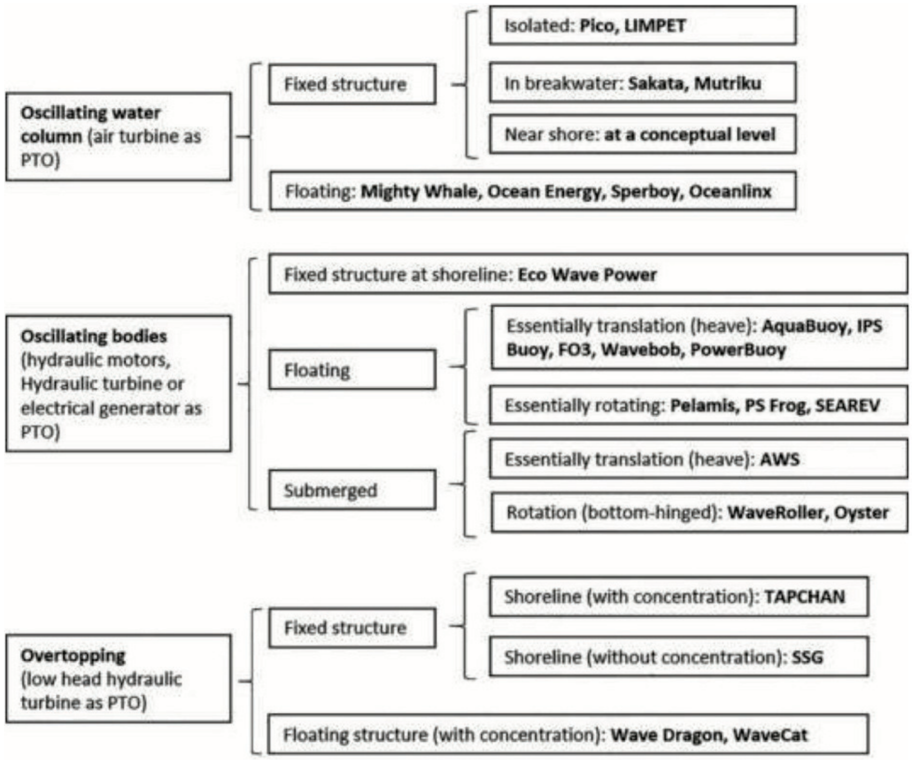

Figure 12.2: Classification of wave power devices by type of power absorber.

12.3.1.1 Onshore Technologies

Onshore generation is obviously dependent upon the weaker strength of waves that reach the shore, and shoreline features that may focus or dissipate wave strength. Onshore facilities are also more site-limited, partly by suitability but also partly by competing site uses. Although not all onshore technologies are visually obtrusive, the major competing use for such sites may be simply to preserve them for their scenic beauty. The major advantages of onshore technologies also include the lack of any need for submarine power cables to deliver the energy onshore, and reduced potential for storm damage. While onshore siting has some clear advantages, good wave generation sites are obviously in exposed locations that may make construction more time consuming or hazardous. Construction time will generally be limited to the calmer summer season, and individual site variations will limit the amount of standardization possible to reduce costs.

12.3.1.1.1 Oscillating Water Column Designs (OWC)

In this approach, the wave action makes the water level oscillate within a chamber that has only one outlet. The air above the water is compressed as each wave raises the water level, and the compressed air is used to drive a turbine generator. As each wave recedes the airflow is reversed. The air turbine (called a Wells turbine) uses a special blade design that allows it to keep turning in the same direction and extract energy during both halves of the wave cycle. The difference between large surface area of the water within the chamber and the small size of the air hole means that the relatively slow wave velocity is multiplied into a much larger air velocity. A schematic diagram of this approach is shown below in Figure 12.3.

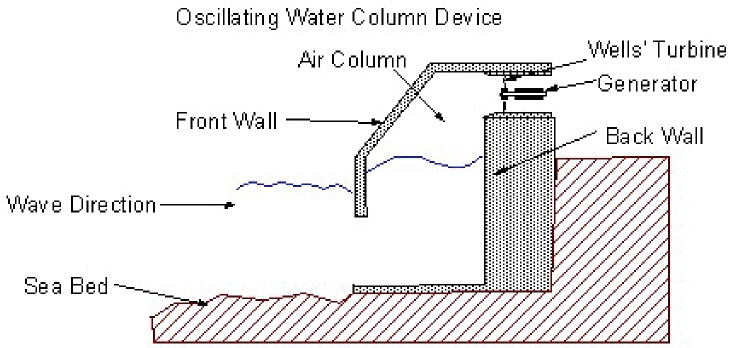

Figure 12.3: Schematic Drawing of Oscillating Water Column Design.[298]

The OWC design is one of the more popular onshore approaches and has had several pilot installations, which have met with mixed success. One installation at Dounreay, Scotland was destroyed by a storm in 1995. Other examples have been built in Pico, Portugal and on the Scottish island of Islay, with sizes of 400 kW and 500 kW, respectively. Figure 12.4 below shows a cutaway picture of the Islay plant.

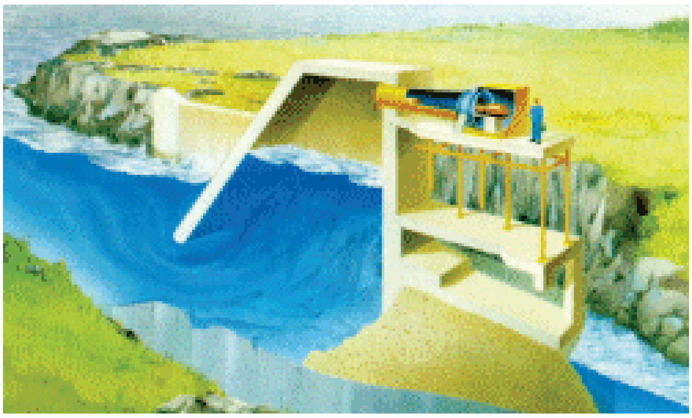

Figure 12.4: Cutaway Diagram of Oscillating Water Column Design at Islay.[299]

In many ways, the OWC approach is similar to natural coastal formations where waves enter existing sea caves or channels and create a natural blowhole or spout. It has been proposed that OWC installations could also be built into existing sea cliffs. This would however raise costs significantly, and current plans are for the plants to be built in exposed, often remote, locations. While not large, they will have at least some visual impact.

It should be noted that OWC installations can also be constructed in shallow water, with the turbine and exhaust pipe above sea level. This may technically make them offshore, or more accurately near shore, installations, but in this report they are classified as onshore designs. However, floating OWC designs also exist, and are included under the offshore discussion.

12.3.1.1.2 Pendulum Designs

As expected from the name, this design uses a suspended pendulum to extract the energy of the incident wave striking it. The pendulum hangs below its hinge, and the waves drive it back and forth. Its oscillating motion operates a hydraulic cylinder that in turn is used to drive a hydraulic motor and generator. A schematic diagram of this approach is shown in

[298] http://europa.eu.int/comm/energy_transport/atlas/assets/images/Image14.gif
[299] http://europa.eu.int/comm/energy_transport/atlas/assets/images/wave3.gif

Figure 12.5 below. One such design has been proposed by a group at the Muroran Institute of Technology in Japan, and is called the Pendulor. In this instance the pendulum is located in front of a submerged, solid back wall that reflects wave from the shore or oblique incident waves. The Pendulor design has been estimated to absorb 40% of the incident wave energy. Pendulum designs have also been tested in China.

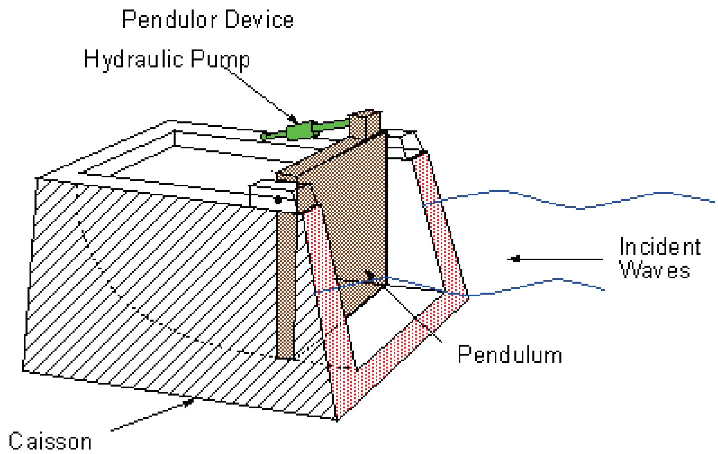

Figure 12.5: Schematic Drawing of Pendulum Design.[300]

12.3.1.1.3 Tapered Channel Designs

This design uses a tapered channel to focus the oncoming wave and divert it upwards into a reservoir. The water flows out from this reservoir through a conventional low-head hydro generator turbine to produce power. One specific design uses the abbreviated name „TAPCHAN". A schematic figure that shows this design is shown below in Figure 12.6.

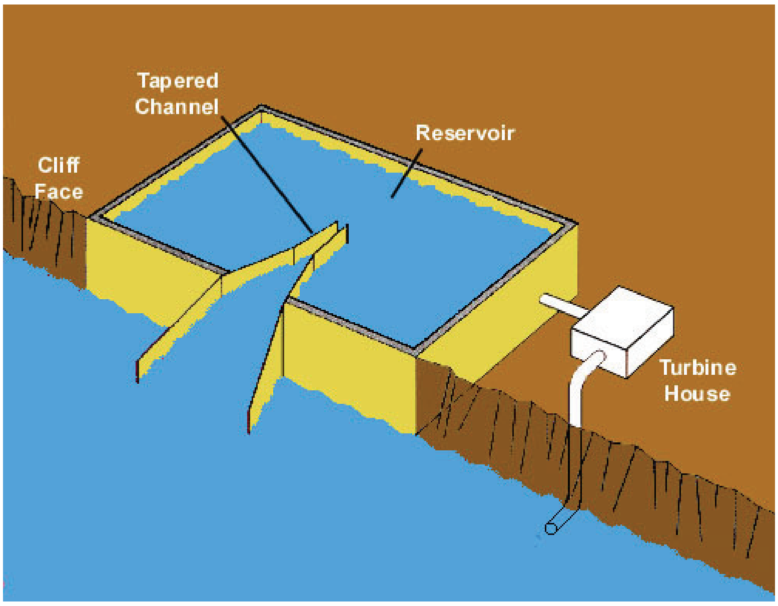

Figure 12.6: Schematic Drawing of Tapered Channel Design.[301]

Several facts are obvious from the basic design. Low head hydro plants require large flow rates, and the tapered channel focuses the wave energy so that only a relatively small

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300 http://europa.eu.int/comm/energy_transport/atlas/assets/images/Image29.gif
301 http://www.acre.murdoch.edu.au/ago/ocean/wfigure_3.jpg

fraction of the water from the incident wave is lifted into the reservoir. This means that generator size is limited, or that multiple channels may be needed to feed a relatively large reservoir. In any case the civil engineering costs for the channel and reservoir will dominate overall costs. Overall installation size will be relatively large and visually obtrusive, relative to other onshore designs. A large tidal range will reduce or stop water being driven into the reservoir at low tide, but will also increase the turbine head (height difference) at the same time.

12.3.1.2 Offshore

Offshore generation can take advantage of stronger waves, has a much wider range of possible sites, and is visually unobtrusive or even invisible to view from shore. Some designs can be built in either shallow or deep water. The major disadvantage of deeper water of course is that the energy generated must be collected from a widespread array of generators and then transmitted to shore using submarine power cables or pipes. This means that there is a tradeoff between increased energy further from shore and the increased cost to anchor the generator and transmit the power back to shore. In general, the best compromise appears to be a sea depth of between 30 and 90 m, because power is reduced at depths of less than 30 m, and mooring or anchoring costs increase unnecessarily in depths greater than 90 m. Naturally sites where these depths are close to shore are preferred, and typical sites may be located between one and five kilometers from shore. Offshore installations must occasionally withstand very severe conditions, but technologies developed in the offshore oil and gas industry for construction, anchoring and cabling appear to be suitable for this new application. Offshore wave power construction also has a cost advantage in that individual units can be identical, allowing them to be mass-produced under shipyard conditions and then towed into place for anchoring.

12.3.1.2.1 Hinged Float Designs

Hinged flat designs ride on the surface of the water, and the motion of the water causes the floats to move, driving a hydraulic pump to generate power. There are a number of different designs in this class, including the Salter Duck, the Pelamis and the McCabe wave pump.

One of the oldest designs, stemming from the University of Edinburgh in the late 1970’s is the Salter Duck, as shown below in Figure 12.7. The floats, or ducks, are arranged in rows of eight floats on the linked spines of the supporting structure and face transversely across the wave front. Each duck bobs up and down as the wave passes. Unfortunately, this design was decided to be inefficient and uneconomic.

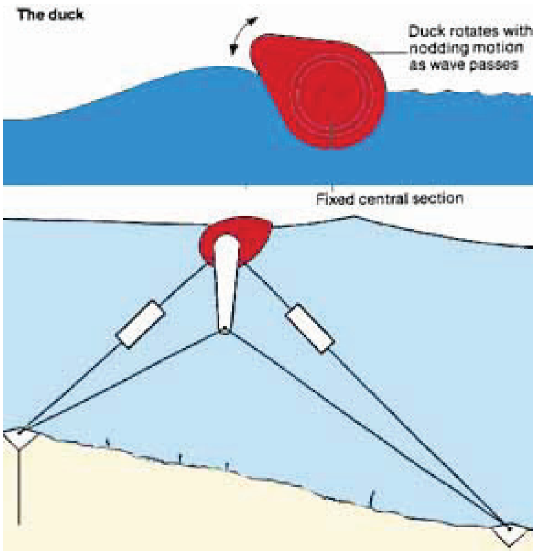

Figure 12.7: Schematic Diagram of Salter Duck Design.[302]

The Salter Duck was succeeded by another design from Ocean Power Delivery, Ltd. (a spin-off from the Ocean Engineering department at the University of Edinburgh). This design is called the Pelamis, named after a kind of sea snake. This design faces into the wave longitudinally, and the segments of the snake flex relative to each other as each wave moves down its length, driving hydraulic pumps. Figure 12.8 below shows a schematic diagram of the Pelamis (left), and a photo of a full-scale prototype (right).

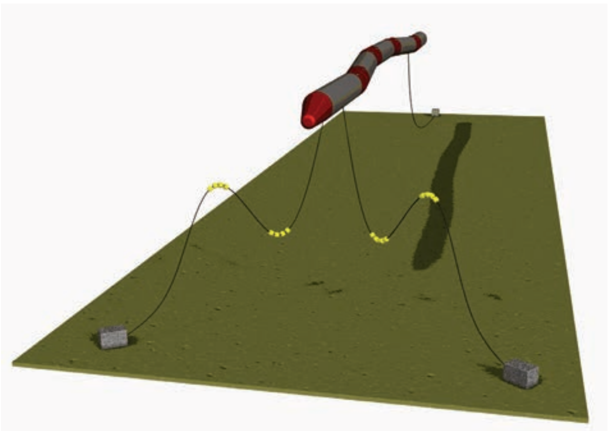


Figure 12.8: Schematic Diagram of Pelamis Design[303] **and photo of Full Size Pelamis Prototype.**[304]

This design measures 3.5 m in diameter by 130 m in length, and was installed in summer 2004 for testing at the European Marine Energy Center in the Orkney Islands. Each Pelamis unit has an output similar to a medium wind turbine (750 kW), and it is projected that a „wave farm“ of 40 units covering a square kilometer would produce 30 MW of generating capacity. This design was installed at the world's first wave commercial farm in Portugal in 2008, but was shut down after two months of operation due to the technical and financial difficulties. Further second generation machines were tested off Orkney between 2010 and

302 http://www.acre.murdoch.edu.au/ago/ocean/wfigure_4.jpg
303 http://www.worldenergy.org/wec-geis/publications/reports/ser/wave/Image57.gif
304 http://www.oceanpd.com/images/Dscf0324.jpg

2014, but the company went into administration in 2014, with intellectual property transferred to Wave Energy Scotland.

The McCabe wave pump is yet another hinged float design, shown below in Figure 12.9. There are three linked pontoons, with the fore and aft floats being hinged to the center float that holds the generation equipment. The key aspect of the design is the damping plate below the central float. Since the wave amplitude decreases with depth, the damping plate stabilizes the center float relative to the fore and aft floats.

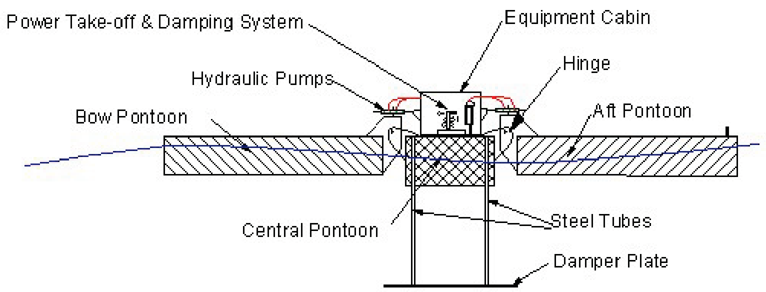

Figure 12.9: Schematic Diagram of McCabe Wave Pump Design.[305]

This design was originally intended for to produce fresh water by desalination using reverse osmosis, but the hydraulic pumps can also be used to drive a hydraulic motor and generator.

12.3.1.2.2 Float Pump Devices

While flexing float devices derive their energy from the wave contour on the sea's surface, float pump devices derive their energy from the wave motion relative to the seabed, or at least relative to the quieter water below the surface. This section discusses several variations on this family of designs.

The first is the Danish wave power float pump, where the float is attached to a piston pump located on the ocean floor. The rise and fall of the float drives a pump which forces water into the concrete body of the anchor and out through a turbine (or motor) to drive the generator. This design is shown below in Figure 10.

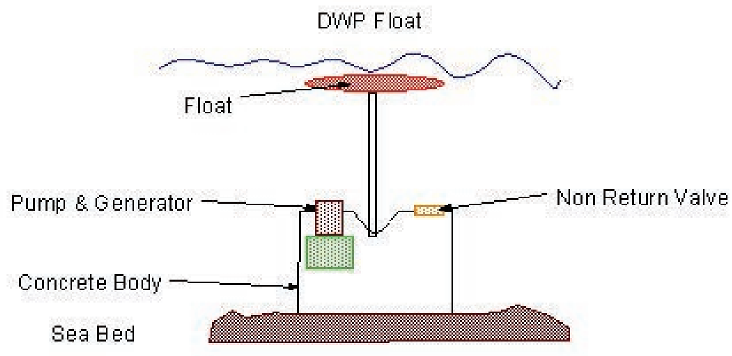

Figure 12.10: Schematic Diagram of Seabed Piston Pump Design.[306]

An alternate approach to the float pump design is the Swedish hose pump, which has been under development since 1980. In this case, the float moves relative to a reaction or

305 http://europa.eu.int/comm/energy_transport/atlas/assets/images/Image45.gif
306 http://europa.eu.int/comm/energy_transport/atlas/assets/images/Image310.gif

damping plate, which is deeper in quieter water. The unique feature of this design is that a hose is used to anchor the float to the reaction plate. As the float bobs up and down, the hose relaxes and then constricts, forcing water through one-way valves to drive a generator. The schematic diagram shown below in Figure 12.11 shows that compressed water is sent to drive a central generator on the seabed. In a sufficiently large design the generator could be mounted on the reaction plate if the costs of the compressed water hose and pumping losses are greater than for electric cable.

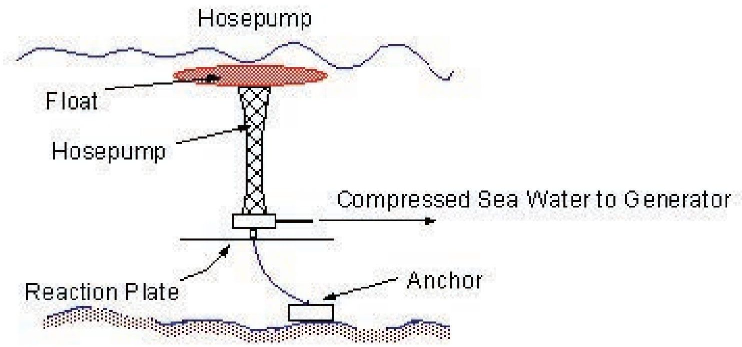

Figure 12.11: Schematic Diagram of Hosepump Pump Design.[307]

The hosepump design above uses the vertical float action to relax and constrict the hose to produce its pumping action. An alternate variation of this hosepump action is to float the hose horizontally on the ocean surface. As it rises and falls on the surface waves, this generates a pressure pulse toward the downwave end of the hose, and the addition of a ducks-beak check valve to prevent return flow completes the pumping actions. This technology can thus be seen as somewhat of a hybrid of the Pelamis and vertical hosepump technologies also described above.

There are several other variations on the float pump theme. Figure 12.12 below shows a diagram of the Archimedes Wave Swing. This design has a piston that is moved up and down by the jellyfish-like umbrella, driving a hydraulic motor-generator in the head of the standpipe. The standpipe may be anchored directly to the seabed, or fastened to a reaction plate in deeper water.

Figure 12.12: Schematic Diagram of Archimedes Wave Swing Design[308]

[307] http://europa.eu.int/comm/energy_transport/atlas/assets/images/Image310.gif

Another variation includes buoy designs with a captured float that oscillates within a tube. One buoy manufacturer's design (Ocean Power Technology) is referred to in the literature as using flexible piezoelectric plastic strips to generate electricity directly. However other references (including the company's US Senate testimony) are quite vague and seem to indicate a shift to a more conventional hydraulic pump design.

12.3.1.2.3 Floating OWC Designs

As well as being a relatively popular onshore design, oscillating water column designs have also been proposed for offshore use. Examples include the Mighty Whale design in Japan (110 kW), and devices where the exit duct for the air is curved away from the wave in the so-called „backward bent duct" design.

12.3.1.2.4 Floating Tapered Channel Designs

The tapered channel design has also been tried for offshore power. One such design was called the WaveDragon, built by the Norwegian University of Science and Technology in the 1980's, tested in a fjord and since decommissions. In this design, the floating wave power vessel has a steel platform containing a sloping ramp that gathers incoming waves into a raised internal basin. The water flows back into the sea through low-head turbines. Unlike onshore Tapchan designs, the floating vessel is not sensitive to tidal variations.

12.3.1.3 Combined Wind/Wave Generation

The idea for combined wind/wave designs, of course, is that once an offshore wave power generator has been built, anchored and connected to shore, the marginal cost to add a wind generator on top is relatively small (or vice versa, it is relatively cheap to add a wave power generator below an offshore wind turbine). Such designs may be more susceptible to storm damage. They are also more visually obtrusive, which is an environmental drawback but may also reduce hazards to shipping.

As can be seen, the technical range and inventiveness of wave generation designs is broad, reflecting several decades of serious research in many countries (although some of the designs do tend to have rather jolly carnival names). The range of maturity is also quite broad, from proposals that are rather vaguely theoretical, to designs that reached demonstration phase (often without commercial success). Considerable learning progress has been achieved, with design prototype increasing in size. Onshore designs have been dominated by OWC designs, while offshore designs have been more varied. Hinged float (such as the Pelamis) and float pump buoy designs (such as the OPT design) dominate the more current literature. This paper takes the position that offshore designs will come to dominate proposed future designs, due to their advantages in having a higher energy resource and less restricted siting possibilities.

12.3.2 Future Technologies

As can be seen from the survey of current and currently proposed technologies outlined above, there is a wide variety of approaches to wave generation. It seems most likely that future technologies will fall within this already existing spectrum of designs, rather than the invention of some new and radically different device. To date, the offshore oil and gas

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[308] http://easyweb.easynet.co.uk/~friendly/Archimedes.gif

industry have driven advances in a number of technologies that contribute to wave generation designs, including construction, submarine cabling, anchoring and overall durability. This development of component technologies contributing to wave power devices will continue, but it is not certain which design will benefit the most. However, as experience with wave power technologies increases, the driving force will shift (at least somewhat) from oil and gas related needs to advances driven by actual wave power technology needs. Increasing experience should also decrease the current cost advantage of onshore designs, and along with the offshore advantages of larger energy density, less restricted siting and no visual disturbance, this should lead the dominance in wave power designs to shift from onshore to offshore devices. At the present, there is no clearly dominant design (or design family) that will benefit by the industry concentrating on it and driving it down the learning curve over other designs. There does seem to be some dominance for electrical versus hydraulic power takeoff schemes, which seems likely to continue.

12.4 Resource Potential

12.4.1 Physical Potential

As noted in the introduction, wave energy is an indirect form of solar energy, driven by the wind and averaging out much of the wind's variation over time. The wave energy resource depends upon the water depth, decreasing as energy is dissipated on the ocean floor and shore. This dependence means that there is approximately three to eight times the available energy offshore compared to onshore locations.[309]

Data from the University of Edinburgh confirm this more concretely, with the following figures for the decrease in available UK wave resource at decreasing depths.

Depth (m)	100	40	20	0 (onshore)
UK Resource (GW)	80	45	36	< 30

Although the global variation in the offshore wave energy resource is significant, the average resource depends upon the prevailing wind, which does not vary much locally over short distances. While wind patterns are no longer of primary importance to naval shipping, the hazards to ships of storm and wave damage continue to be the driving force behind information gathered on wave patterns. Luckily, the data that is needed for predicting average or seasonal wave hazards, and the short-term data needed for estimation of real-time hazards can also be used for estimating the average wave energy resource.

Early data was of course more or less limited to visual observation along routes or areas favored for fishing, commerce or naval purposes. Even when direct observation became supplemented by buoys to collect wind and sea state data, the data collected continuously over extended periods was still limited to specific locations. Only when satellite data on wave states became available was truly comprehensive information available.

The two satellite measurement systems that have been directly used to date for direct wave measurement are the satellite radar altimeter (RA) and synthetic aperture radar (SAR). Radar altimetry uses a vertical, pulsed radar signal to measure the range to the ocean surface within a few centimeters. Signal distortion and backscatter is related to surface

[309] http://www.energy.ca.gov/development/oceanenergy/

roughness and wave height. Synthetic aperture radar achieves high resolution by tracking the phase and amplitude of the return signal as the satellite moves. SAR is also the only means of tracking wave direction by satellite. Both methods of satellite observation provide either partial or indirect imaging of the ocean surface, so it is necessary to correlate them to more direction observations of sea state by using various computer algorithms. For this reason, these algorithms are typically calibrated using buoy data at specific locations.

Satellite data are offered to end users in various forms for different purposes, and by a range of different vendors. There exist several global wave atlases based on satellite data. The World Wave Atlas (WWA) is in fact a composite collection of different types of wave data at the highest resolution and accuracy available, divided into smaller areas of interest to individual maritime countries. The current version of WWA may contain data from GEOSAT (1986-1989), Topex/Poseidon (1992-1997), available buoy data, and global wave model results calibrated to satellite data, depending upon the area in question. Wave data is available on-line and in CD-ROM form from various organizations, including:

- The National Oceanic and Atmospheric Administration (NOAA) National Environmental Satellite, Data and Information Service (NESDIS).[310]
- University of California at San Diego Coastal Data Information Program.[311]
- Scripps Oceanographic Institution wave surf information.[312]
- Committee on Earth Observation Satellites (CEOS).[313]
- Southampton Oceanography Centre.[314]
- Satellite Observing Systems.[315]
- Oceanor ASA (World Wave Atlas sales).[316]

Since the publication of the last SFOE Energieperspektiven (Hirschberg, Bauer et al. 2005), there has significant research on and advances in resource estimation. This research has included better modeling of the wave resources, including more detailed wave spectrum analysis. This is particularly important for wave power technology survivability, since the design durability and cost of each installation is largely affected by the most severe wave conditions expected.

One research area of technology development that is linked to this improved spectral modeling is in the area of adaptive resistance for the power absorber elements. By making it possible for the power absorber to adaptively adjust its own “stiffness” (e.g. between the linked floats of a Pelamis device), it is possible to improve both energy absorption efficiency and device survivability under more extreme wave conditions (Nunes, Valério et al. 2010, Bacelli and Ringwood 2013).

Other areas of research have included an increased focus on smaller-scale, site-specific wave resource modeling. This modeling is more suitable for evaluating specific wave project sites for their generation potential and cost (Azzellino, Ferrante et al. 2013, Morandeau,

[310] http://ns.noaa.gov/NESDIS/NESDIS_Home.html
[311] http://cdip.ucsd.edu
[312] http://facs.scripps.edu/surf
[313] http://ceo-www.jrc
[314] http://www.soc.soton.ac.uk
[315] http://www.satobsys.co.uk
[316] http://oceanor.no/wwa

Walker et al. 2013). However, for the scale and detail of estimating the overall onshore European wave potential analysis (as explained below), such detailed modeling was judged to be inappropriate.

Although it would have been possible to purchase compiled wave energy data for the European coastline from one of these vendors, it was not judged that this level of detail was necessary. Instead, reference was made to published wave energy maps. Figure 12.13 below shows one such map from the World Energy Council (WEC), and Figure 12.14 shows another from Oceanor ASA. It should be noted that the highest wave energy resources occur on western shores with long distances of open ocean upwind from the shore, and at higher latitudes.

Both of these maps indicate wave energy densities between 40 and 60 kW/m (MW/km) on the western shores of Europe. This is averaged over seasonal variation, and for areas at least several kilometers offshore, before decreasing depths can dissipate wave energy. The wave energy decreases from north to south, with the most intense areas offshore from England and Scotland. For coastal areas offshore from France, Portugal and Spain which might be of interest for generating power to be exported to Switzerland, it would be more reasonable to use an average wave energy figure in the neighborhood of 45 kW/m.

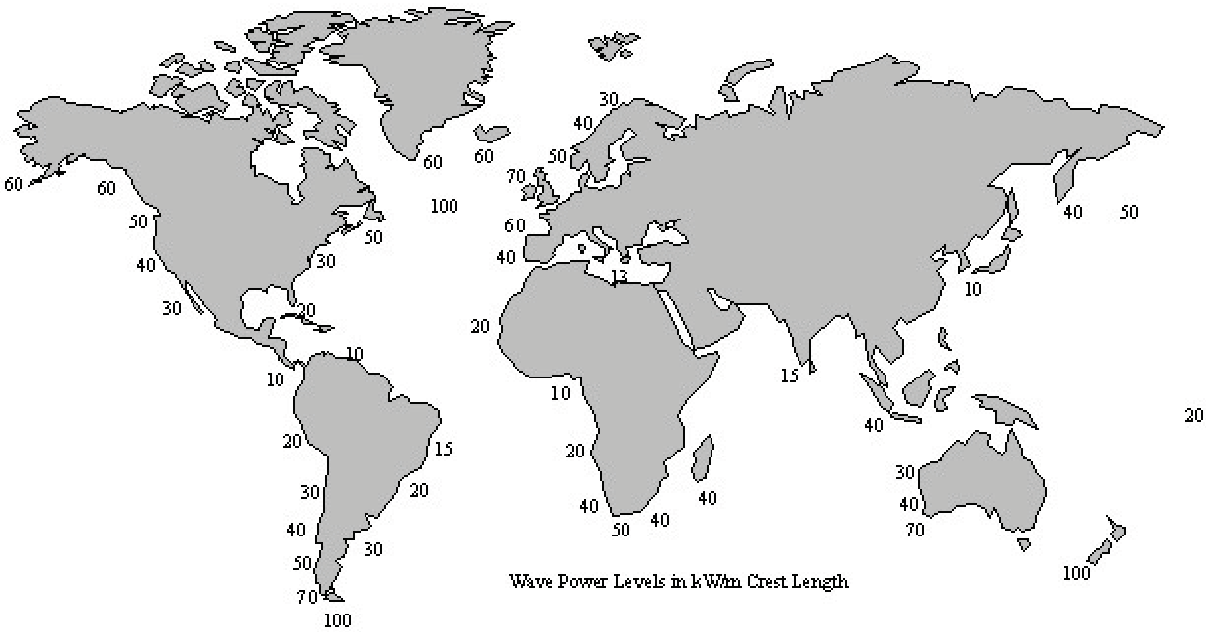

Figure 12.13: Wave Energy Resource Map 1.[317]

[317] http://www.worldenergy.org/wec-geis/publications/reports/ser/wave/Image55.gif

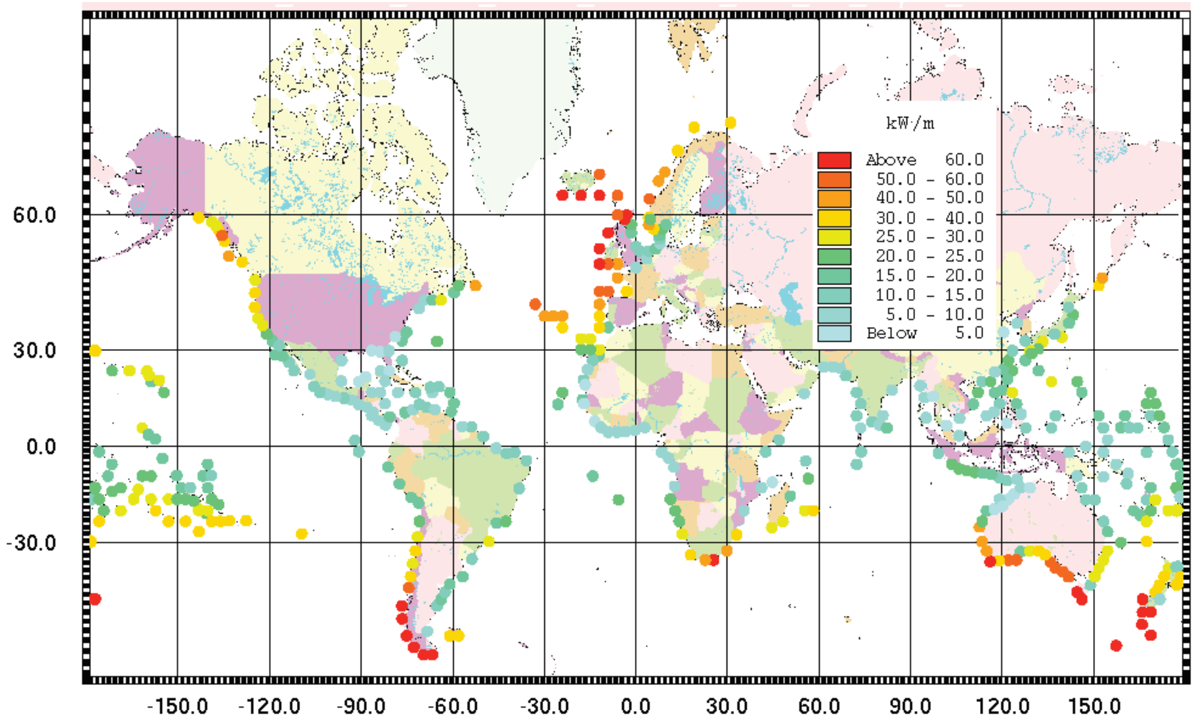

Figure 12.14: Wave Energy Resource Map 2.[318]

12.4.2 Technical Potential

Given a certain level of wave resource potential incident upon the coast of Europe, the amount of potential wave power generation depends upon a series of factors. These can be expressed by the equation:

Wave energy potential per year = wave energy potential (MW/km) * distance offshore coastline (km) * energy recovery factor * annual capacity factor.

These factors are addressed individually below:

- Wave energy potential – As stated above, an approximate value of 45 MW/km seems appropriate for the southern European Atlantic coast.
- Distance of offshore coastline – The European Atlantic coast of interest stretches from the southern end of the Iberian peninsula (approximately 37º N latitude) across the Bay of Biscay to the tip of Normandy (approximately 48º N latitude). The waves may bend around the top of the Iberian Peninsula, but to estimate the total energy coming onshore the total north-south distance of 11º latitude is appropriate. The mean radius of the earth is approximately 6370 km, so π*6370 km*(11˚/180˚) equals about 1220 km. This means that total wave power onshore is about 45 MW/km*1220 km, or about 55 GW of power. This compares to a global total energy resource estimated at 2-3 TW.[319] Wave power installations would not be placed in a single line N-S along this entire distance, as they would then be uneconomically far from the coast, but it is the total transverse distance perpendicular to the oncoming wave energy which gives the total resource.

[318] http://www.oceanor.no/projects/wave_energy/images/globb3.gif
[319] http://www.eere.energy.gov/RE/ocean.html

- Energy recovery factor – Wave energy generators cannot absorb 100% of the wave energy incident upon them, or the sea would be dead calm to leeward of the generator. The recovery factor will obviously vary for different designs. For example, the Pendulor design described above claims about 40% conversion of the incident wave energy. Other designs claim 10-25% efficiency (Danish Wave Energy Program in the World Energy Council Survey of Energy Resources), while the Salters Duck design claims more than 80% conversion efficiency. The IRENA Wave Energy Technology Brief (IRENA 2014b) uses an average conversion efficiency of 40% in its resource estimation calculations. In addition, it is obviously necessary to have some spacing between generators, not to mention keeping sea lanes and fishing areas free for navigation. Generators can have a staggered spacing in several rows to extract the maximum energy. The Pelamis design estimates a power of 30 MW for each square kilometer, while the OPT buoy design estimates 100 MW in two square miles (or 19 MW/km^2). These claims are made for offshore the Scottish coast (about 60-70 MW/km) and the US west coast (about 30-40 MW/km). Adjusting for the wave resource, this means that about 40-50% of the offshore wave energy might be generated. Combined with a rather arbitrary assumption for maximum deployment of 40% of the north-south distance gives an energy recovery factor of 16-20%.
- Annual capacity factor – The waves vary in power, according to the seasonal variation of the wind, so a wave generator cannot work at 100% of its peak power for the entire year. Based on a review of the literature, an approximate capacity factor of 40% (3500 h/a) seems appropriate (EPRI 2004). It is unfortunate that much of the more popular literature found in the press on wave power often confuses power and energy, and often implies capacity factors which are too high (greater than 100%, which is impossible) or too low. One specific example given[320], is that 150 km of the Danish North Sea could produce 5 TWh/year at 25% conversion efficiency. If the average resource there is about 50 MW/km, this would imply a capacity factor of about 30%.

Combining these factors together indicates that a reasonable maximum potential capacity for offshore wave power generation should be in the neighborhood of 8800 MW_{el}, based on an estimate of (45 MW/km)*(1220 km)*(16% MW generated per MW incident wave power). A capacity factor of about 40% or 3500 h/a implies an annual generation energy of about 31 TWh.

This contrasts with global estimates of 2000 TWh/a[321], and University of Edinburgh estimates for all of Europe of 34-46 TWh/year onshore, and 120-190 TWh/year offshore[322]. This latter reference also breaks down European wave potential by country, and the totals for France, Portugal and Spain are 10-16 TWh/yr onshore and 34-52 TWh/year offshore.

It is clear by the calculations above that estimates of technical potential are based on some relatively crude assumptions about how many wave generating units could actually be built and sited, their energy recovery factor and their capacity factor, which is why more accurate data on the actual wave energy resource was not pursued. Nevertheless, the estimate of about 30 TWh per year agrees with the lower range of the offshore generation estimates found in the literature. The range of the estimates in the literature also provides some

[320] http://www.worldenergy.org/wec-geis/publications/reports/ser/wave/wave.asp
[321] http://www.sciencenews.org/articles/20010414/bob12.asp
[322] http://helios.bto.ed.ac.uk/resman/nrm/wave_power.htm

indication that they also contain uncertainties similar to those stated more explicitly above. In either case, these numbers provide an order of magnitude estimate of how much wave energy could be generated if wave power was pursued on a large scale.

Transmission losses to Switzerland would reduce this potential energy, but this loss is relatively low relative to the uncertainty in other factors. In fact, although a dedicated high voltage direct current (HVDC) transmission line would have transmission losses on the order of 3-7%[323], if the building of wave power generation can shift the siting of new French or Spanish generating units closer to the Swiss border then actual losses could be even lower.

12.5 Technology Costs

12.5.1 Current Costs

12.5.1.1 Generation costs

As noted above, most current wave power generation designs are still in the stages of research and development, with only a few prototype or demonstration units actually installed and tested. In addition, there is a wide range of designs, many of which do not have (or have not published) cost estimates. This section therefore presents a survey of cost estimates from the literature of overall wave power costs for both current and potential future technologies. This survey is summarized in Table 12.1 below, with both dollar and Euro costs converted to Swiss Francs. Note that some sources give capital costs (CAPEX) per kW, other give average generation cost per kWh, and most give both. Also note that some sources give cost ranges, other best estimates, and also costs for future dates vs. future stages of technology development.

[323] http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/2_2_08.asp

Table 12.1: Current Estimates of Wave Power Cost. CAPEX: Capital expenses; OPEX: Operating and maintenance expenses; LCOE: Levelized Cost of Electricity.

Reference	Source	Date	Size			CAPEX			OPEX			Cap. Factor			LCOE		
			Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
				MW			(CHF/kW)			(CHF/kW/a)			(%)			(CHF/MWh)	
JRC Ocean Energy Status Report	EC Joint Research Center	2014															
2010			1		5	8349	9988	11770	301	360	424		20		*554*	*662*	*780*
2020			5		20	5566	6369	7029	228	261	288		23		*335*	*383*	*423*
2030			30		40	4279	4928	6039	201	232	284		28		*222*	*255*	*313*
2040			40		50	2816	2915	2970	163	169	172		32		*139*	*144*	*146*
2050			50		400	2255	2530	2816	131	147	163		36		*98.8*	*111*	*123*
International Levelised Cost Of Energy for Ocean Energy Technoogies	Ocean Energy Systems-An IEA Technology Initiative	May 2015															
First project/array			1	-	3	3880	-	17557	136	-	1455						
Second project/array			1	-	10	3492	-	14841	97	-	485	30	-	35	204	-	650
First commercial project			2	-	75	2619	-	8827	68	-	369	35	-	40	116	-	456
Wave Energy Technology Brief	IRENA-International Renewable Energy Agency	Jun 2014															
Exec summary, 10 MW farm															363	-	693
Exec summary, > 2 GW cum.															124	-	249
IEA - 2010-2012							6215			94.6							
IEA - 2020							4477									315	
IEA - 2030							3685									228	
IEA - 2050							1925			51.7						189	
UK - 2010-2012						5500	-	9900							234	-	550
UK - 2020						3300	-	5500									
UK - 2030						3300	-	5500							124	-	249
UK - 2050						2750	-	3300							96.8	-	138
UTI/UKERC - 2010-2012						5324	-	10648	53	-	107	25	-	35	266	-	666
UTI/UKERC - 2020						2995	-	4659	33	-	80	32	-	40	133	-	266
UTI/UKERC - 2030						2330	-	2995	20	-	33	35	-	42	93.5	-	133
UTI/UKERC - 2050						1664	-	2330	13	-	26	37	-	45	67.1	-	107
World Energy Perspective - Cost of Energy Technologies	World Energy Council, with Bloomberg New Energy Finance	2013															
						5.3	8.5	15.5		145.5		25	30	35	275	481	1026
Wave and Tidal Energy in the UK Conquering Challenges, Generating Growth	Renewable UK	Feb 2013															
First generation arrays																39	
Second generation arrays																16.1	
Cost of and financial support for wave, tidal stream and tidal range generation in the UK	Ernst & Young and Black & Veatch	Oct 2010															
Pre-demo						8540	10220	12040	728	882	1036		31				
Demo						5740	6860	7980	336	406	490		33				
Commercial						3920	4760	5460	238	280	336		34				
2020															248	300	354
2035															136	165	199
2050															99	120	147

The data from Table 12.1 are summarized in Figure 12.15 below, which shows both the current and future estimates of capital costs and the average cost of generation (LCOE).

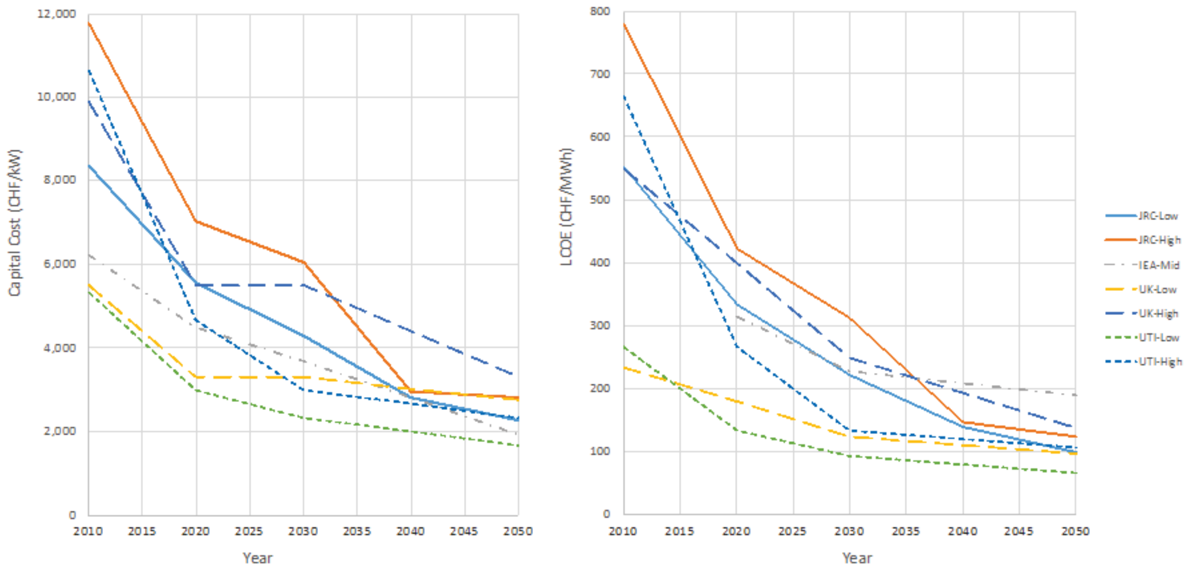

Figure 12.15: Estimated current and future capital and generation costs from major sources.

As can be seen, current estimates of both capital and average wave power costs vary widely. The capital costs for 2010 range from about 5500 up to 12'000 CHF/kW, while the average generation costs range from about 230 to 800 CHF/MWh. Much of this spread also depends upon the size of the individual wave energy converters. Figure 12.16 below from the IEA shows some of this variation, and gives curve fits for estimated economies of scale based on questionnaire responses, historical prototypes, planned projects and reference reports and/or models. It is clear from the graph that historical prototypes and specific planned projects have significantly higher capital costs than the questionnaire responses and reference reports.

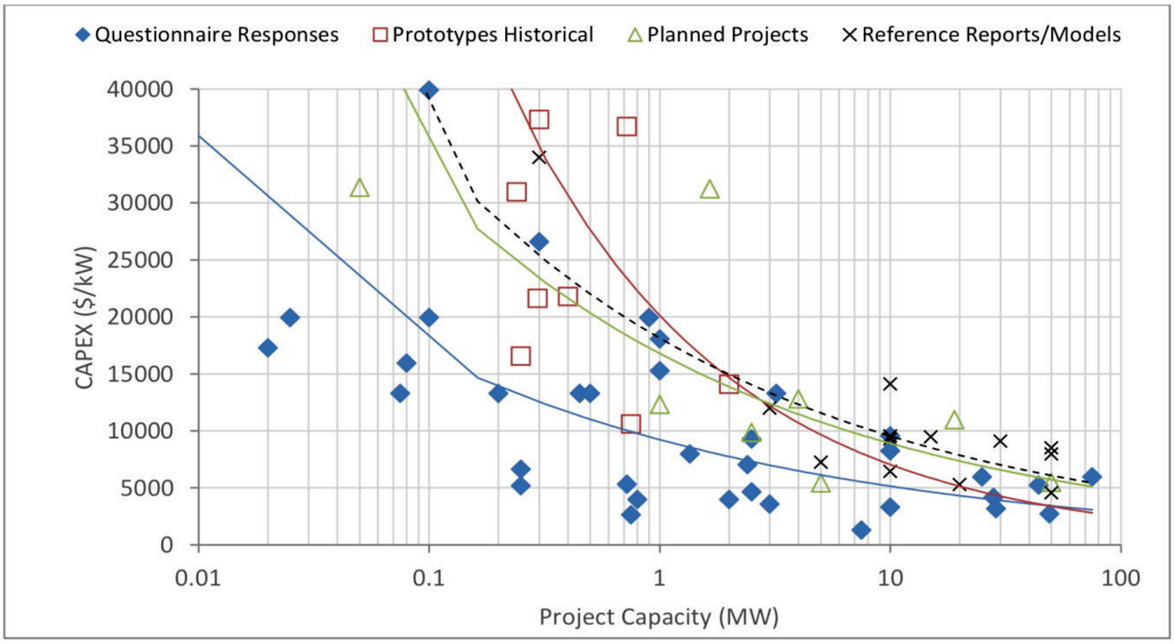

Figure 12.16: Estimated economies of scale based on different data sources (IEA 2015b).

The same reference also shows the expected breakdown of the average cost as it shifts from current to commercial target status.

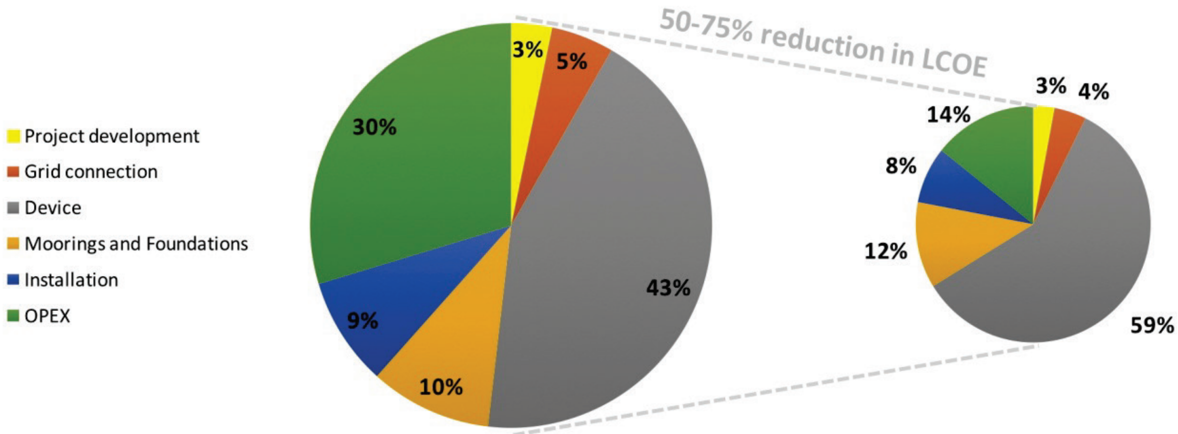

Figure 12.17: Wave cost breakdowns for current and commercial target development (chart area corresponds to total LCOE) (IEA 2015b).

The decrease in area also show the expected 50-75% overall decrease in levelized cost, while also showing that the actual wave energy converter device decreases less (increasing from 43% to 59% relative share) while the other costs decrease more (particularly the operating and maintenance expenses (OPEX)). While these economies of scale and cost breakdown are for individual plants, estimates for the cumulative industry learning curve are shown in Figure 12.18 below.

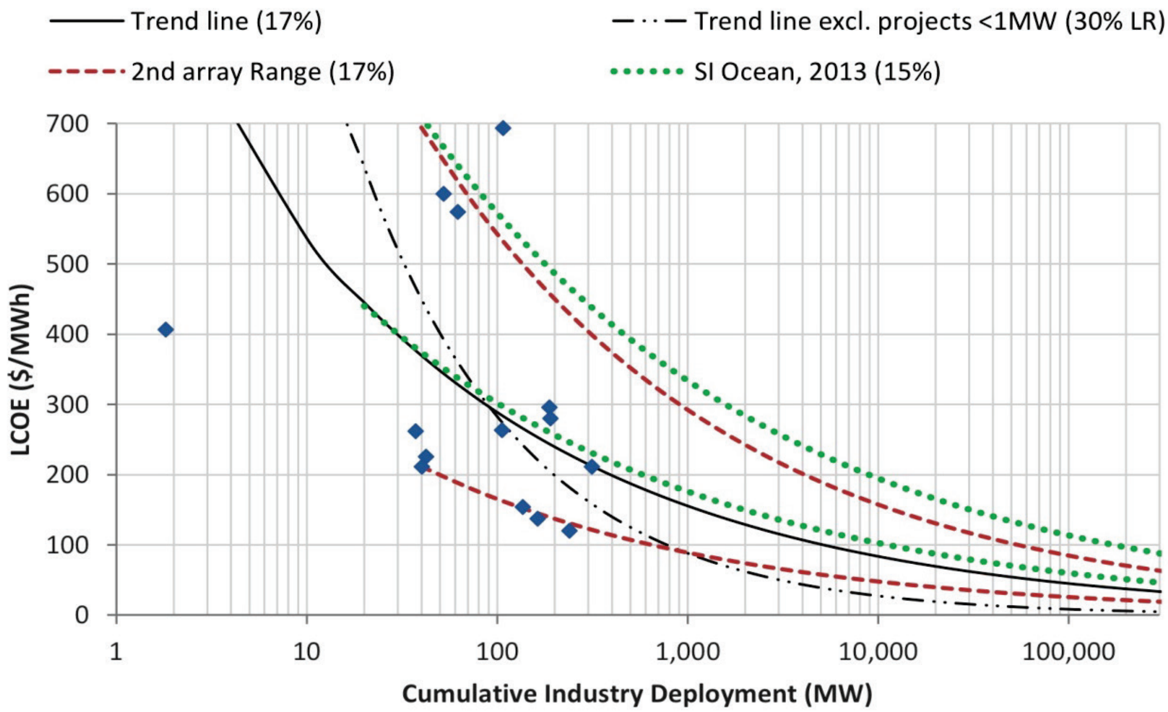

Figure 12.18: Learning curve trends from survey responses (blue diamonds are developer data points) (IEA 2015b).

The base of experience to date is sufficiently small that these curves should be taken quite conservatively, but at least they do show that there is considerable optimism about the possibility for future cost reductions.

Several comments on the data in Table 12.1 are appropriate here. Capital cost for wave power generation is typically higher than for fossil or nuclear plants because the energy resource is less concentrated. This was formerly also the case for wind and solar power, but the relatively rapid learning curves for wind and solar technologies have meant that they have achieved very competitive costs on a per kW basis. However, the problem for wind and solar remains that the stochastic, non-dispatchable nature of the resource means that the overall capacity factor remains low, and so the costs on an energy basis can range from competitive to still expensive.

Representative technology-specific cost numbers for the OPT power buoys are 6200 US$/kW and 2300 US$/kW for 1 MW and 100 MW units, respectively, and the Pelamis units are estimated at between 2 to 3 million US$ (2667-4000 US$/kW), without mooring costs.[324] Capital costs are typically amortized over relatively long lifetimes, which are definitely still unproven in the hostile marine environment (the OPT system claims an expected lifetime in excess of 30 years). Capital amortization and maintenance are the entire cost, since there is of course no fuel cost. All the offshore plant costs already include the cost to transmit the electricity to shore using submarine cable (typically at about 30 kVDC). If the optimum depth

[324] http://www.oceanpd.com/PDFS/E21 EPRI Assessment.pdf

for energy recovery is farther offshore, then this component of the overall cost will increase. Also, costs are naturally lower for large plant sizes, although only a few estimates were found that compared different sizes of the same design.

As mentioned, the marine environment is particularly hostile, which affects not only the technology life for cost amortization, but also O&M costs. Offshore O&M is much more costly due to the need to either make repairs offshore or to tow generating units to shore (which can also be seen for onshore v. offshore wind power). Technology lifetimes remain both unproven and uncertain.

12.5.1.2 Transmission Costs

In addition to estimating the cost of wave power generation, it is also necessary to estimate the cost of importing it to Switzerland. The wave resource estimation given above was based on the assumption that the western shores of France, Spain and Portugal would be the most likely possible locations for wave power that might be imported to Switzerland. The map shown below in Figure 12.19 indicates that these locations cover a distance range of between at least 500 and 1500 km from Switzerland.

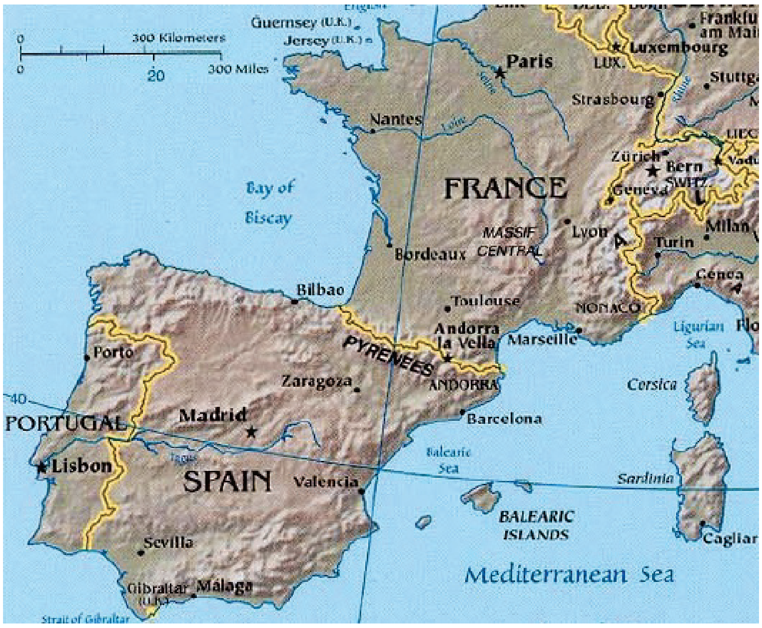

Figure 12.19: Transmission Distance for Importing Wave Power to Switzerland.

The nature of power flow in the long distance transmission network means that if wave power is added to the grid in the west, it will go primarily to more local loads and divert (now excess) power from other generators in eastern France towards Switzerland. In the end, it is unimportant to track the flow of actual electrons, except for the security and expansion of the transmission network. Pricing of the transmission is determined by the utilities and their regulation in the intermediate countries. This pricing is not yet tied to actual transmission costs based on network constraints and changes in generation dispatch. The cost of future power transmission pricing is uncertain, and will depend strongly upon changes in European electricity regulatory policies.

Therefore, the best way to estimate long-term transmission costs seems simply to find the upper limit, which should be represented by the cost of a dedicated transmission line to Switzerland. Such a high voltage line could be either AC or DC. AC lines only need transformers at each end, but they are more costly per km of wires, need reactive power compensation and have higher losses. DC lines are cheaper per km (fewer towers, wires and less land), but need voltage converter substations using high power semiconductors at each end of the transmission line. DC is also more efficient and has network stability advantages. The breakeven distance where HVDC becomes more economical is usually around 400 to 600 miles (650 to 1000 km), depending upon the power, and hence the converter substation prices.

For the purposes of this upper bound cost estimate, it was assumed that a HVDC transmission line would be used. Figure 12.20 below shows estimates of transmission cost and efficiency for HVDC lines, depending upon the parameters of power and distance.[325] Although the total wave power resource estimated about was around 8.8 GW_{el} this would not be carried on a single transmission line, but rather require a number of lines, probably of capacity between one and two GW each. Based on the cost figure below, this means that a HVDC transmission line between 500 and 1000 km long, and carrying between 1000 and 2000 MW of power is likely to cost in the range of 4-6 mill$/kWh (at current exchange rates, about 4-6 CHF/MWh). Efficiency losses for such line would be in the range of 3-7%, as also noted above. Thus, an upper bound estimate of the cost of transmission mean that bringing the power to Switzerland would add (at most) approximately between 5% and 20% to the range of different estimates of wave power generation costs given above.

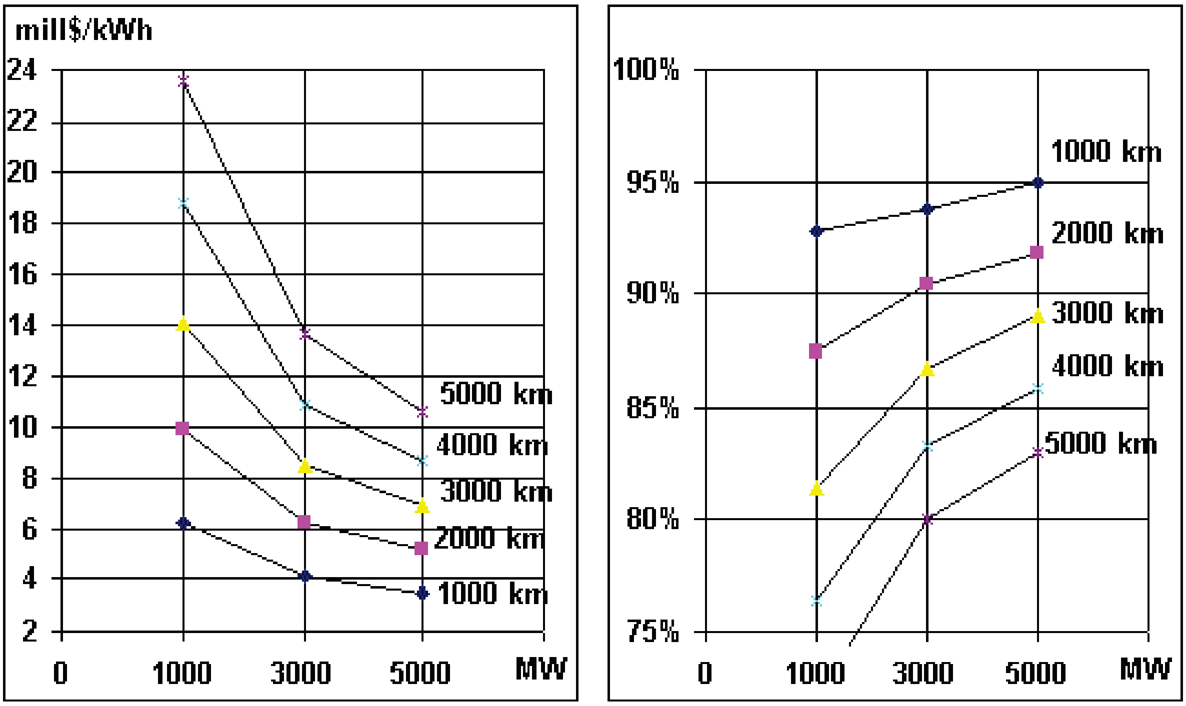

Figure 12.20: Cost and Efficiency of HVDC Transmission.

As a comparison, the above cost estimates (from the prior Energieperspektiven) can be compared to more recent estimates for power transmission from North African solar thermal generation (the Desertec project), which are higher and in the range from 15-20 USD/MWh (Dii 2013, SolarPACES 2013). HVDC power line costs have been driven down in part due to the large growth in Chinese HVDC transmission capacity, so the primary

[325] http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/2_2_08.asp

difference must be attributed to the submarine cable costs from Africa to Europe, while in the present case submarine cable costs from the wave power location to shore are already included in the surveyed cost estimates presented above in Table 12.1.

Wave power generation seems in a state that is still relatively analogous to where wind power was approximately 20 years ago, so a learning curve similar to those shown above should apply for both unit size and cumulative installed capacity. Whereas the wind industry will climbed the learning curve to mass markets, wave power can still benefit from niche markets. The predominant niche still appears to be generating power for remote areas (mostly islands) with a strong wave energy resource, no grid connection and expensive alternate generation resources. However other niche applications also exist. As mentioned above, the McCabe wave pump was originally designed for reverse osmosis desalination of seawater, and other designs could naturally serve this purpose as well. In addition, offshore power for navigation and weather buoys is a natural niche market. One company (Offshore Wave Power) also has indicated that offshore generation could be used to power naval drone vehicles. Such military applications are often leading niche markets, because of the high value the military is willing to pay for them.

12.5.2 Optimization Factors

As has been previously noted, the chief factor in optimizing wave generation costs lies in the balance between increased wave energy offshore and increased submarine cable costs to deliver the power to shore. Only the cable costs are subject to technological improvement, so the economically optimal distance offshore will tend to increase over time. The best wave power sites have a strong wave resource close to shore at depths of about 30-90 meters. As these sites are used up or reserved for navigational or fishing purposes, it will be necessary to move to sites further offshore, thus creating a wave energy supply curve over increasing costs. Improved capital and transmission technologies will tend to lower the entire curve over time as the learning curve decreases costs.

Two other areas of wave power optimization include the choice of a specific site, based on detailed local resource analysis and modeling, and also the related issue of optimizing the wave power converter design to balance durability and life expectancy against expected wave intensity and damage to achieve minimum expected costs.

12.5.3 Future Costs

As noted above, the future estimates of wave power capital and average generation costs shown in Table 12.1 are based several major published sources. It is a mark of the progress in the field that such sources are now available (as they were not before). The projection to 2050 show that costs are to drop significantly in absolute terms, and the range of estimates both between and within the different sources also decreases significantly. The estimated capital costs for 2050 range from about 1800 to 3500 CHF/kW, while the average cost of generation ranges from about 70 to 190 CHF/MWh, about a fourfold decrease compared to 2010.

These expected cost decreases are based both on climbing the learning curve and on expected economies of scale as units increase in size. But because the installed base is still very small, future cost estimates should still be regarded as speculative and probably optimistic.

12.6 Environmental aspects

12.6.1 Life cycle assessment

Environmental burdens of wave and tidal power generation are shown based on the analysis recently performed by Uihlein (2016), which is the most up-to-date and comprehensive LCA of these technologies. Uihlein (2016) analyzed "all ocean energy technologies currently being proposed", setting up life cycle models with "detailed technical information on the components and structure of around 180 ocean energy devices". The results shown here are supposed to represent environmental burdens associated with current and future ocean energy from a life-cycle perspective, even if technology progress until 2050 will go beyond currently proposed technologies; since wave and tidal power plants are relatively simple mechanical devices, proposed concepts are often not yet proven and associated uncertainties therefore high. Since associated life cycle burdens are comparatively minor, it is fair to assume that – for the purpose of this study – environmental burdens will not substantially change in the next three decades. According to (Magagna and Uihlein 2015), ocean wave and tidal current represent the most promising ocean energy technologies in the European context. These two are therefore in focus of this section.

Figure 12.21 shows impacts on climate change in terms of cumulative GHG emissions due to electricity generation with different wave and tidal power concepts, with a breakdown into contributions from different components. The range of GHG emissions per kWh is about 15-105 g CO_2eq. with an average of 53 g CO_2eq/kWh. Mooring and foundation elements are most important structural elements in terms of GHG emissions for most device types.

Uihlein (2016) states "for tidal energy converters, a design consensus seems to emerge in favor of horizontal axis turbines". Point absorbers (PTA) are the dominating design for wave energy devices. Therefore, the analysis of further impacts in addition to climate change is limited to horizontal axis turbines (HAT) and PTA. Figure 6.20 shows relative contributions of different structural elements to various environmental burdens (Hauschild, Goedkoop et al. 2013), according to (Uihlein 2016).

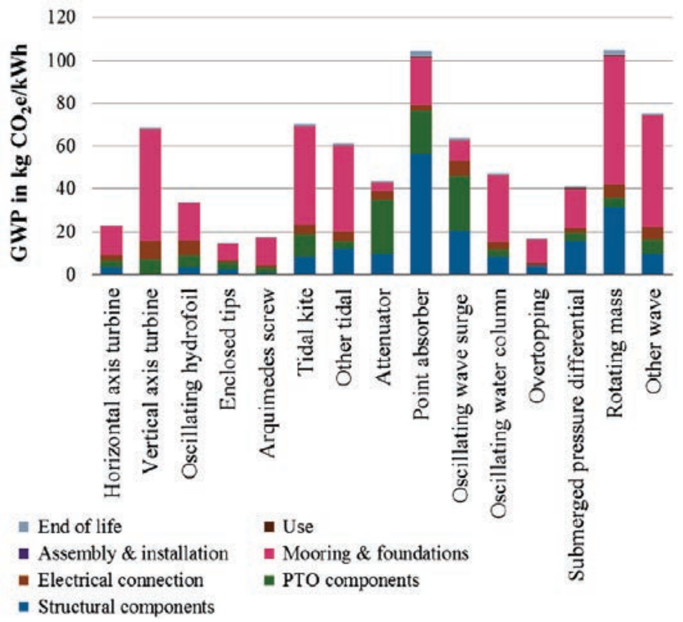

Figure 12.21: Life cycle GHG emissions (GWP 100a) due to electricity production with different wave and tidal power concepts according to (Uihlein 2016).

The environmental performance of wave and tidal power – represented by HAT and PTA – according to (Uihlein 2016) is evaluated against the current Swiss electricity consumption mix (low voltage) (ecoinvent 2016) in Figure 12.23 using the same LCIA[326] indicators (Hauschild, Goedkoop et al. 2013) as above. Environmental burdens of tidal power are in general below those of wave power as well as below those of the Swiss electricity consumption mix. Wave power performs worse than the Swiss mix for some indicators.

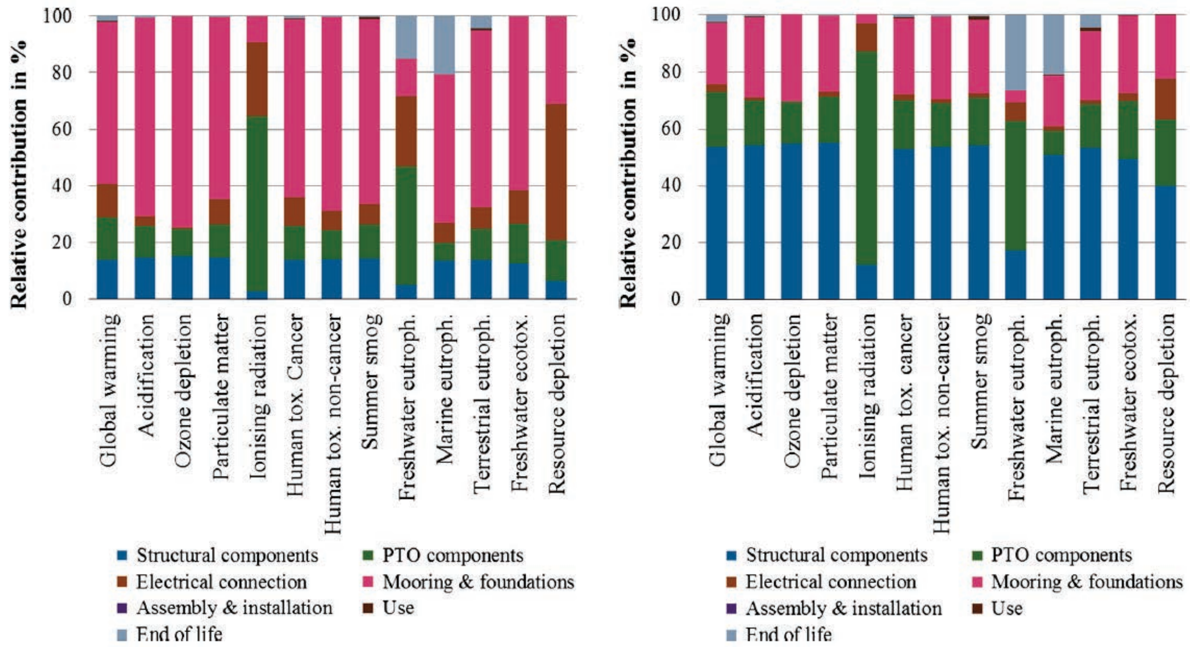

Figure 12.22: Relative contribution of different structural elements to various environmental burdens (Hauschild, Goedkoop et al. 2013), according to (Uihlein 2016). Left: horizontal axis turbines; right: point absorbers.

[326] Life Cycle Impact Assessment.

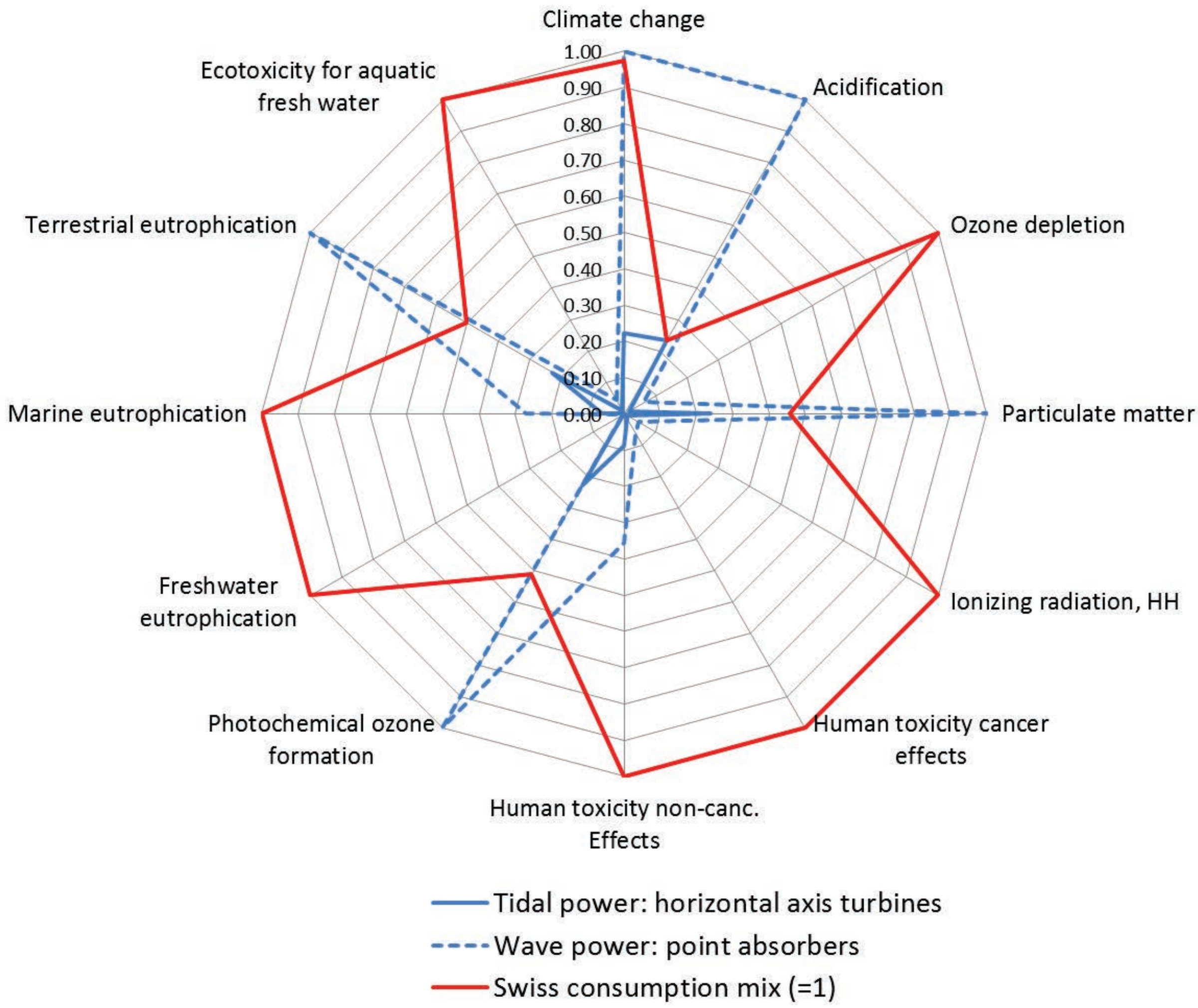

Figure 12.23:Relative environmental performance of wave and tidal power – represented by HAT and PTA – according to (Uihlein 2016) against the current Swiss electricity consumption mix (low voltage) (ecoinvent 2016). Maximum for each indicator equal to 1.

12.6.2 Other environmental issues and potential risks

Wave generation technology is basically benign in most environmental aspects. There are no emissions, no solid waste, no fossil resource depletion, and it is a local resource that is not susceptible to import restrictions. On the other hand it does have its own particular environmental issues, which are briefly summarized below.

Water Pollution – Some wave generation plants use hydraulic fluids that could conceivably escape during accidents or maintenance. Some pollution can also be expected from normal boat use for placing and maintaining offshore units. Overall however, the risks of pollution from these sources seem relatively low.

Visual impact – Onshore plants can detract visually from sites that are often very scenic. The buildings are not necessarily very obtrusive, but the site is no longer pristine. Paradoxically, if the site is very remote there may be too few people to appreciate the scenery and the implicit value of the scenic beauty is reduced. The onshore power terminal for the submarine cable from an offshore location will be less obtrusive than for an onshore installation, but both types must connect to a regular power line that will also be noticeable. Combined wave and wind buoys would present a larger visual impact, but this is not likely to be very significant unless the wind turbines are large and relatively close to shore. The Poseidon wave wind hybrid is one example of such a combined wind and wave power design.

Hazards to Navigation – Naturally, offshore units present a possible hazard to navigation for fishing, shipping and naval military purposes. Offshore wave and wind generation sites must be prominently marked on navigation charts, and also of course clearly marked by visible, lighted buoys. If tidal turbines can be located at sufficient depth, they may be able to avoid requiring such markers.

Onshore Erosion – Because offshore wave generation reduces the energy of each wave as it passes, there is a reduction of onshore wave action and associated beach erosion. This effect depends upon whether the shore is rocky or sandy. If the reduced erosion increases the sand present on the beach that is directly affected this may be considered beneficial, but it may also reduce the amount of sand present further down the beach since wave action drives the transport of sand. In addition, reduced wave action may preferentially influence different species of fish relative to each other, and thus affect certain fishing stocks. Some wave generation designs like the Japanese Big Whale have been specifically intended to reduce onshore wave action to promote aquaculture. The Japanese Pendulor design has specifically recognized this in its cost estimation, where a generation cost of 46 ¥/kWh (53 Rp./kWh) was partially offset by an erosion control credit of 12.5 ¥/kWh (14 Rp./kWh) to give a net cost estimate of approximately 34 ¥/kWh (39 Rp./kWh).

Accidents – Occupational risk and safety of wave power generation will depend primarily upon whether the design in question is onshore or offshore. Onshore designs will have occupational risk levels similar to those for small hydro construction and operation. Offshore designs will have occupational risk levels that reflect some weighted average between the risks present in shipyard construction and offshore activities like oil platform construction and operation, deep-sea tug towing and buoy tending.

12.6.3 Future developments

It is expected that future technologies will be more advanced and mature, but they should fall within the range of current technology, so that the environmental and safety aspects will be basically the same. Because suitable onshore wave power sites are limited, it is expected that possible future wave power installations will be increasingly dominated by offshore sites (continuing to follow the trend since the previous Energieperspektiven). The major possible impacts of wave power will therefore have to do with the increased offshore areas where wave generation is sited, in particular the increased hazards to navigation, the effects of reduced wave energy reaching the shore and occupational risk to increased numbers of employees in this sector.

12.7 Factors influencing development and market introduction

12.7.1 Demand factors

The factors influencing the demand for wave power generation are naturally related to its unique characteristics. The lack of CO_2 emissions is likely to be the key consideration for Swiss customers. If Swiss CO_2 emissions policy demands continued negligible emissions from the power sector, and construction of future nuclear design generations does not occur, then this would obviously promote demand for zero CO_2 sources like wave power. Many of the other advantages and disadvantages mentioned above, like visual impact, navigation, pollution, etc. would be of basically no interest in Switzerland unless they affect the price, since they are otherwise local to the producing country.

12.7.2 Obstacles

The obstacles to wave power generation naturally appear to be the reverse of factors which would promote demand. If CO_2 emissions become less important in Swiss energy policy, or other zero CO_2 sources like nuclear power are approved, this would present a relative obstacle to wave power imports. Also, the cost and regulation of high voltage power transmission to Switzerland across the intervening countries could be a key factor. If siting of power lines, compensatory siting of new generation outside Switzerland, or regulation of power wheeling (transmission) become problems, this will be reflected in the price of imported wave power and may significantly decrease its attractiveness.

12.7.3 Government promotion

In contrast status at the time of the previous Energieperspektiven, government support of wave power research and development has increased significantly. This includes support via the following areas.

Government research programs – The largest European specific government policy survey is contained in (JRC 2014b, JRC 2015). This covers basic and applied research for knowledge creation, diffusion and transfer, including academic networks, spinoffs, and public-private partnerships, with emphases on market formation and resource mobilization. For the UK, (Renewable-UK 2013) also examines current sector status, potential, and benefits, with an emphasis on current policy, commercialization pathways, and risk mitigation strategies.

Grant programs – There has been a significant increase in the number of grant programs and development funds, with 21 different programs that are listed in Table 12.2.

Technology development contests – In the US one of the methods of encouraging wave technology development that is being implemented is in the form of a contest or competition, similar to the X-prize for vehicle development. This program is sponsored by the US DOE, and designed to encourage development of a diverse range of designs, currently in an intermediate stage. The initial field of designs was been narrowed down to a group of 10 competitors in August 2015, who then submitted 1/50 scale prototype models. These models were tank tested and ranked results were announced in November 2016.

12.7.4 Requirements for Future Development and Market Readiness

The primary requirement for the future development of wave power generation, and its readiness to compete in the marketplace, continues to be the demonstration of wave power installations that can drive down prices as they increase in size. The existence of several global demonstration platforms, including the European Marine Energy Center in the Orkney Islands and continued commercial interest mean that it is likely that costs will continue to drop. This is supported by the various promotional actions (grants, programs, contests) mentioned above. If a learning curve similar to the wind market can be followed, then the cost of wave power may well drop to levels that will be of interest. Swiss action or investments are unlikely to be key or necessary requirements for this development, so a wait-and-see policy appears most reasonable.

12.8 Open questions, research activities and research needs

There appears to be relatively little need for Swiss involvement in wave power research and development. However, it is important that any Swiss legislation that penalizes the CO_2 content of power sold should also apply to Swiss imports, so that CO_2-free wave power imports will receive the relative price credit that they would deserve.

12.9 Conclusions

While there has been significant development in the area of wave power, and also in the related areas of other ocean energy resources (in particular tidal and current energy), the basic conclusions of (Hirschberg, Bauer et al. 2005) are largely unchanged. The potential for wave power imports to Switzerland is substantial, but not really that large when compared to several other renewable energy resources. Costs seem quite promising, but estimates are based on a very small base of installations to date, and could turn out to be optimistic. The cost of importing wave power to Switzerland seems bearable, but would represent an extra burden both in cost and in bureaucratic overhead. In the end, Switzerland does not currently have any leading strength in the wave power area, and it seems unlikely that it will be a real contributor in the future. Even if Swiss companies wish to invest in this area, there is no real driving reason for them to import the power back home.

12.10 Abbreviations

a	year
AC	alternate current
BAFU	Bundesamt für Umwelt
BFE	Bundesamt für Energie
CAPEX	Capital expenses
CH	Switzerland
CHF	Swiss Francs
CEOS	Committee on Earth Observation Satellites
CO_2eq	carbon dioxide equivalent
EU	European Union
DC	direct current
GHG	Greenhouse gas
HAT	horizontal axis turbines
HH	human health
HV	high voltage
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
LCA	life cycle assessment
LCIA	life cycle impact assessment
LCOE	Levelised Cost of Electricity
LR	learning rate
max	maximum
min	minimum
NESDIS	National Environmental Satellite, Data and Information Service
NOAA	National Oceanic and Atmospheric Administration
O&M	operation and maintenance
OPEX	Operating and maintenance expenses
OTEC	ocean thermal energy conversion
OWC	Oscillating Water Column
PTA	point absorber
RA	radar altimeter
Rp.	Rappen (Swiss cents)
SAR	synthetic aperture radar
SV	Sverdrup
UK	United Kingdom
US	United States
USD	United States Dollar
WACC	weighted average cost of capital
WEC	World Energy Council
WWA	World Wave Atlas
yr	year

12.11 Appendix

Table 12.2: Overview of ocean power and activities worldwide. Categories include companies, grant programs, institutes (government and other), test facilities and universities. Sources: 1 = www.emec.org.uk, 2 = EPRI, 3 = JRC, 4 = www.ocean-energy-systems.org, 5 = www.openwaveenergy.org, 6 = www.wikipedia.org.

Index	Group	Organization/Actor	Device/facility name	Capture method	Power takeoff	Location	Status/scope	Country	Size (MW_{el})	Source
7	Company	Fred. Olsen Ltd.	BOLT Lifesaver	Point absorber			Operating/operated	US	0.03	6
112	Company	Fred. Olson, Ghent University	SEEWEC	Point absorber				NO, EU		1
113	Company	GasNatural Fenosa	OWC	Osc. water column				ES		1
114	Company	G Edward Cook	Under the Bottom Wave Generator, Syphon Wave Generator	Submerged pressure differential, OWC				US		1, 5
631	Company	GL Garrad Hassan (now DNV GL)						UK		3
116	Company	Globalone Sciences						US		1
117	Company	Gmax Tidal Energy						US		1
118	Company	Grays Harbor Ocean Energy Company	Titan Platform	Osc. water column				US		1, 5
383	Company	Green Ocean Energy Ltd	Wave Treader / Ocean Treader	Osc. Water Column				UK		5
384	Company	Green Ocean Wave Energy	Ocean Wave Air Piston	Point Absorber				US		5
119	Company	Greencat Renewables	Wave Turbine	Other				UK		1, 5
120	Company	Greenfield Techonolgies LLC								1
121	Company	Greenheat Systems Ltd	Gentec WaTS	Other				UK		1
122	Company	Grey Island Energy Inc						CA		1
123	Company	Group Captain SM Ghouse	Free Floating Wave Energy Convertor (FFWEC)	Attenuator				India		1
635	Company	Guinard Energies						FR		3
124	Company	Gyrodynamics Co Ltd						JP		1
125	Company	Gyrogen (DNS)	GyroWaveGen	Other				US		1, 5
127	Company	Hann-Ocean	Drakoo	Point absorber				Singapore		1, 5
128	Company	Havkraft	Evolver (Havkraft Wave Energy Converter – H-WEC)	Osc. water column				NO		1
129	Company	Healy's Wave Energy Convertor						US		1
130	Company	HidroFlot SA	Hidroflot	Point absorber				ES		1, 5
678	Company	Hidromod (spinoff)						PT		3
131	Company	Hui Nalu						US		1
649	Company	HYDAC Electronic GmbH						DE		3
533	Company	Hydam Technology	McCabe Wave Pump	Osc. Water Column				IE		2, 5
132	Company	Hydrocap Energy SAS	Seacap	Point absorber				FR		1
666	Company	HydrOcean (spinoff)						FR		3
390	Company	HydroGen	HydroGen 10	Osc. Water Column				FR		5
133	Company	Hydrokinetic Energy Solutions						US		1
134	Company	IHC Tidal Energy	Wave Rotor	Other				NL		1
681	Company	IHFOAM (spinoff)						ES		3
135	Company	Independent Natural Resources	SEADOG – water pump	Point absorber				US		1, 2, 5
136	Company	Indian Wave Energy Device	IWAVE	Point absorber				India		1, 5
137	Company	Inerjy	WaveTORK	Overtopping				US		1, 5
394	Company	Ing Arvid Nesheim	Oscillating Device	Point Absorber				NO		5
665	Company	INNOSEA (spinoff)						FR		3
138	Company	Innova Foundation	Penwest							1
139	Company	Intentium AS	Intentium Offshore Wave Energy Convertor	Quasi Point Absorber/Terminator, Other			Full-scale	NO		1, 3, 5
397	Company	Interproject Service (IPS) AB	IPS OWEC Buoy	Point Absorber				SE		5
18	Company	Islay LIMPET	Islay LIMPET	oscillating water column	Air turbine	Onshore	Proposed/prototype, operating/operated	UK, Scotland	0.5	6
141	Company	James F Marino (DNS)						US		1
142	Company	JAMSTEC	Mighty Whale	Osc. Water Column				JP		1, 5
143	Company	Jetty Joule						US		1
144	Company	Jospa Ltd	Irish Tube Compressor (ITC)	Overtopping/Other				IE		1, 5
146	Company	Joules Energy Efficiency Services Ltd	TETRON	Point absorber				IE		1, 5
145	Company	Joules Energy Efficiency Services Ltd	Wave Train	Osc. water column				IE		1
672	Company	Kepler Energy (spinoff)						UK		3
147	Company	Kinetic Wave Power	PowerGin	Overtopping				US		1, 5
148	Company	KN Ocean Energy Science & Development	KNSWING					DK		1
149	Company	Kneider Innovations	Wave Energy Propulsion	Other (direct boat propulsion)				FR		1, 5
151	Company	Kozoriz Franklin California Maglev Inc						US		1
565	Company	kymaner	Kymanos				Part-scale	PT		3
152	Company	Kymogen						US		1
153	Company	Laminaria	Laminaria					Belgium		1
155	Company	Langlee Wave Power, Canary Islands	Langlee System Rubusto	Osc. wave surge converter			Demo array N/A , then full-scale	NO	0.5	1, 3, 5
636	Company	Le Gaz Intégral						FR		3
156	Company	Leancon Wave Energy	Multi Absorbing Wave Energy Convertor (MAWEC)	Osc. water column			Small-scale	DK		1, 3, 5
157	Company	Leviathan Energy Waves						US		1
158	Company	Limerick Wave Ltd						UK		1
159	Company	M3 Wave LLC	DMP Device	Submerged pressure differential				US		1
160	Company	M4Wave Power	M4					UK		1
161	Company	MakerStrong	eBuoy					US		1
673	Company	Manchester Bobber (spinoff)	Manchester Bobber	Point Absorber				UK		3, 5
162	Company	Marine Energy Corporation	Wave Catcher	Point absorber/Other				US		1
163	Company	Marine Hydroelectric Company						US		1
164	Company	Marine Power Systems	WaveSub	Point absorber				UK		1
165	Company	Marine Power Technologies Pty Ltd	Energy Island					AU		1
166	Company	Martifer Energia	FLOW	Attenuator				PT		1, 5
167	Company	Maruthi Power						US		1
596	Company	Mhk System Performance Advancement					Under dev.	US	N/A	3
168	Company	Mighty Waves Energy Team						US		1
169	Company	Mocean Energy						US		1
170	Company	Motor Wave	Motor Wave	Point absorber				HK		1, 5
410	Company	Nautilus	Wave Energy Convertor for near shore deployment. Buoy driven piston driving pressurised air to onshore energy convertor	Point Absorber				Israel		5
674	Company	Nautricity Ltd (spinoff)						UK		3
172	Company	Navatek Ltd	Navatek WEC	Attenuator				US		1, 5
667	Company	Nemos (spinoff)						DE		3
173	Company	NEMOS GmbH	NEMOS	Other				DE		1
412	Company	Neptune Renewable Energy Ltd	Triton	Osc. Wave Surge Converter				UK		5
413	Company	Neptune Systems	MHD Neptune	Other				NL		5
568	Company	Neptune Wave Power	Neptune WECD				Part-scale	US		1, 3

Index	Group	Organization/Actor	Device/facility name	Capture method	Power takeoff	Location	Status/scope	Country	Size (MW_{el})	Source	Start date
28	Company	40South Energy	R38/50 kW, R115/150 kW, y series, D series	Underwater attenuator	Electrical conversion	Offshore	Proposed/prototype, now full-scale	UK, IT?		1, 3, 6	2010
44	Company	Abengoa Seapower						ES		1	
45	Company	Able Technologies LLC	Electric Generating Wave Pipe	Point absorber				US		1, 5	
46	Company	Acubens	REWAB					ES		1	
47	Company	AdapWave						US		1	
48	Company	Advance Ocean Energy @ Virginia Tech	MULLET					US		1	
49	Company	AeroVironment Inc	Eel Grass	Point absorber				US		1, 5	
4	Company	Agucadoura Wave Farm	3x Pelamis				Operating/operated	PT	2.25	6	2008, Decommissioned 2008
50	Company	Aimmer UK	Aimmer	Other				UK, HK		1	
51	Company	Aker Solutions ASA	Aker WEC							1	
8	Company	Albatern	WaveNET SQUID	Multi-point absorber array	Hydraulic / electric / DC	Offshore	Proposed/prototype, part-scale	UK Scotland		1, 3, 5, 6	2010
53	Company	Alternative Energy Engineering Associates	AEEA-WECS					US		1	
32	Company	Alvin Smith (Dartmouth Wave Energy)\Ecotricity	SeaRaser	Buoy	Hydraulic ram	Nearshore	Proposed/prototype	UK		6	2008
54	Company	AOE (Accumulated Ocean Energy)						CA		1	
55	Company	Applied Technologies Company, Ltd (ATC)	Float Wave Electric Power Station (FWEPS)	Point absorber				RU		1, 5	
58	Company	Aqua-Magnetics Inc	Electric Buoy	Point absorber				US		1, 5	
60	Company	Aqua-Shift						US		1	
530	Company	AquaEnergy	AquaBuOY					US		2	
56	Company	Aquagen Technologies	Rig Drive, SurgeDrive	Point absorber			Small-scale	AU		1, 3	
57	Company	AquaHarmonics						US		1	
2	Company	Aquamarine Power	Orkney Wave Power Station, 50x Oyster 'farm'				Operating/operated	UK	2.4	6	proposed
25	Company	Aquamarine Power (spinoff)	Oyster, Oyster 800, Oyster 801	Osc. wave surge converter	Pump-to-shore (hydro-electric turbine)	Nearshore	Proposed/prototype, then full-scale. Single device/ 2015 Demo array	UK Scots-Irish	0.8 (up to 1.6)	1, 3, 5, 6	2005, upcoming
346	Company	Arlas Invest	TUVALU	Point Absorber				ES		5	
61	Company	ATA Engineering						US		1	
16	Company	Atargis Energy Corporation	Cycloidal Wave Energy Converter	Other, Fully Submerged Wave Termination Device	Direct Drive Generator	Offshore	Proposed/prototype, small-scale	US		1, 3, 6	2006
63	Company	Atlantic Wavepower Partnership						US		1	
64	Company	Atlas Ocean Systems	SQ5					US		1	
11	Company	Atmocean Inc.	WES - Wave Energy System	Point Absorber array, attenuator	Pump-to-shore	Nearshore & offshore	Proposed/prototype	US, subsid in Peru		1, 5, 6	2006
66	Company	Avium AS	Yeti Cluster System	Other				Turkey		1	
67	Company	AW Energy	WaveRoller	Osc. wave surge converter	Hydraulic	Nearshore	Proposed/prototype, full-scale	FI		1, 3, 5, 6	1994
68	Company	AWECS Attenuator						US		1	
69	Company	AWS Ocean Energy	AWS-III, Archimedes Wave Swing	Point absorber (subsurface)	Air turbine	Offshore	Proposed/prototype, full-scale	UK Scotland		1, 3, 5, 6	2010
637	Company	AZTI Tecnalia (foundation)						ES		3	
70	Company	Balkee Tide and Wave Electricity Generator	TWPEG	Point absorber				Mauritius		1, 5	
71	Company	BioPower Systems Pty Ltd	bioWave	Osc. wave surge converter/Overtopping			Small-scale	AU	0.25	1, 3, 5	Under development
72	Company	Blue Power Energy Ltd		Point absorber				NL		1	
73	Company	Bombora Wave Power	Bombora WEC	Submerged pressure differential			Small-scale	AU		1, 3	
352	Company	Bourne Energy	OceanStar ocean power system	Osc. Water Column				US		5	
74	Company	Brandl Motor	Brandl Generator	Point absorber				DE		1, 5	
75	Company	Brimes Energy	Jellyfish					US		1	
76	Company	Buoyant Energy						US		1	
360	Company	C-Wave	C-wave	Osc. Water Column				UK		5	
77	Company	Cal Poly-Protean Wave Energy Inc						US		1	
78	Company	Caley Ocean Systems	Wave Plane	Other				UK, DK		1, 5	
79	Company	Calwave						US		1	
614	Company	Carnegie Wave Energy Ltd	CETO5, CETO6 (Cylindrical Energy Transfer Oscillator)	Point absorber (buoy)	Pump-to-shore	Offshore	Prototype, demo array 2014, 2016	AU	0.72, 3	1, 3, 6, 5	1999, Upcoming
81	Company	Checkmate Seaenergy UK Ltd	Anaconda Wave Energy Converter	Bulge wave surface-following attenuator	Hydroelectric turbine	Offshore	Proposed/prototype	UK		1, 5, 6	2008
359	Company	Coastal Hydro LLC	Coastal Hydro Hydrogenerator	Other				US		5	
82	Company	College of the North Atlantic	SARAH Pump	Submerged pressure differential				CA		1, 5	
83	Company	Columbia Power Technologies	StingRAY, Manta, SeaRay	Attenuator/Point absorber			Part-scale	US		1, 3, 5	
559	Company	COPPE Subsea Technology Laboratory	COPPE subsea wave energy device		Compressed air	Onshore	Part-scale	BR	0.05	1, 3	
85	Company	CorPower Ocean AB	CPO2	Point absorber				SE		1	
86	Company	Costas Wave	Costas Wave					US		1	
15	Company	Crestwing ApS	Crestwing	Surface-following attenuator	Mechanical	Offshore	Proposed/prototype	DK		6	2011
87	Company	Daedalus Informatics Ltd	Wave Energy Conversion Activator	Osc. wave surge converter				GR		1, 5	
362	Company	Dartmouth Wave Energy	SeaRaser Buoy (seawater pump)	Point Absorber				UK		5	
88	Company	Delbuoy	Wave Powered Desalination	Point absorber				US		1, 5	
89	Company	DexaWave A/S	DexaWave	Attenuator			Small-scale	DK		1, 3, 5	
90	Company	Dolphin Energy						UK? United Arab Emirates?		1	
365	Company	Dresser-Rand	HydroAir	Osc. Water Column				US		5	
91	Company	Earth by Design						US		1	
92	Company	Eco Wave Power	Wave Clapper, Power Wing	Other			Part-scale	Israel		1, 3	
366	Company	Ecofys	Wave Rotor	Other				NL		5	
95	Company	Ecomerit Technologies	Centipod	Attenuator				US		1, 5	
96	Company	Ecotricity	Searaser	Point absorber				UK		1	
97	Company	ELGEN Wave	Horizon Platform	Point absorber				US		1, 5	
98	Company	Embley Energy Limited	Sperboy	Point absorber/Osc. water column				UK		1, 5	
595	Company	EMEC, Green Theme, Tension Technology International					Under dev.	Scotland	N/A	3	N/A
531	Company	Energetech	Offshore OWC					AU		2	
372	Company	Energias de Portugal	Foz do Douro breakwater	Osc. Water Column				PT		5	
664	Company	Energie de la Lune (spinoff)						FR		3	
99	Company	Energystics						US		1	
100	Company	Enorasy Labs						US		1	
101	Company	Ensea						IT		1	
669	Company	EolPower Group (spinoff)						IT		3	
35	Company	Erik Friis-Madsen	Wave Dragon	Overtopping device	Hydroelectric turbine	Offshore	Proposed/prototype	DK		6	2003
597	Company	ESB Intl. Ocean Energy WestWave Project	Wave Roller Pelamis Oyster				Demo array 30/06/2018, Deployment proj.	IE	5	3	30/06/2018
102	Company	Etymol Ocean Power SpA	Etymol WEC - Alfa Series	Other				Chile		1, 5	
103	Company	Euro Wave Energy	Floating absorber	Point absorber				NO		1, 5	
104	Company	Fetzer Wave						US		1	
10	Company	Finavera Wind Energy, later SSE Renewables Limited	AquaBuOY	Buoy	Hydroelectric turbine	Offshore	Proposed/prototype	IE, CA, UK (Scotland)		6	2003
105	Company	Finima - Aimmer						HK		1	
17	Company	FlanSea (Flanders Electricity from the Sea)	Wave Pioneer	Buoy	Hydroelectric turbine	Offshore	Proposed/prototype	Belgium		1, 6	2010
532	Company	Float Inc.	Rho-Cee Pneumatic Stabilized Platform	Point absorber				US		1, 2, 5	
108	Company	Floating Power Plant AS	Poseidon – Wave wind hybrid	Attenuator			Part-scale	DK		1, 3, 5	
109	Company	Fobox AS	FO3	Osc. water column				NO		1, 5	
110	Company	Fred Olsen Ltd	B1 Buoy, FO3, Bolt Lifesaver, Bolt 2 Lifesaver	Point absorber			Full-scale	NO, UK		1, 3, 5	

Index	Group	Organization/Actor	Device/facility name	Capture method	Power takeoff	Location	Status/scope	Country	Size (MW_{el})	Source	Start date
414	Company	New Energy Solutions LLC	Oscillating Cascade Power System (OCPS)	Osc. Water Column				US		5	
175	Company	Next Gen						US		1	
176	Company	Nodding Beam	Nodding Beam	Other				UK		1	
177	Company	Norvento	Wavecat					ES (Galicia)		1	
179	Company	Nualgi Nanobiotech	Rock n Roll wave energy device	Attenuator/Point absorber				India		1	
1	Company	NW Energy Innovations (NWEI)	Azura wave power device				Operating/operated	US Hawaii	0.2	6	2015
180	Company	Ocean Electric Inc	Wave platform	Point absorber				US		1	
23	Company	Ocean Energy	OE buoy	Buoy	Air turbine	Offshore	Proposed/prototype	IE		6	2006
181	Company	Ocean Energy Industries Inc	WaveSurfer	Point absorber				US		1, 5	
185	Company	Ocean Energy Ltd	Ocean Energy Buoy	Osc. water column			Part-scale	IE		1, 3, 5	
186	Company	Ocean Harvesting Technologies	Ocean Harvester	Point absorber			Full-scale	SE		1, 3, 5	
187	Company	Ocean Hydropower Systems Ltd	OHS Wave Energy Array	Point absorber				UK		1	
188	Company	Ocean Motion International	OMI Combined Energy System	Point absorber				US		1, 5	
420	Company	Ocean Navitas	Aegir Dynamo	Point Absorber				UK		5	
27	Company	Ocean Power Technologies (OPT)	PowerBuoy / victorian waver power station	Point absorber (buoy)	Hydroelectric turbine	Offshore	Proposed/prototype, deployment proj.	US, UK?	19	1, 2, 3, 5, 6	1997, closed 20/06/2014
190	Company	Ocean RusEnergy	Ocean 3, 160, 640	Other				RU		1	
194	Company	Ocean Wave and Wind Energy (OWWE)	OWWE-Rig (Hybrid Technology)	Overtopping				NO		1, 5	
193	Company	Ocean Wave and Wind Energy (OWWE)	Wave Pump Rig	Point absorber				NO		1, 5	
205	Company	Ocean Wave Energy Company	Ocean Wave Energy Converter	Point absorber				US		1, 2, 5	
24	Company	Ocean Wave Energy Ltd	OWEL	Wave Surge Converter	Air turbine	Offshore	Proposed/prototype	UK		6	2013
423	Company	Ocean Wavemaster Ltd	Wave Master	Other				UK		5	
195	Company	Oceanic Power	SeaHeart	Point absorber				ES		1, 5	
196	Company	Oceanlinx	GreenWAVE / BlueWAVE ? ogWave?	Osc. water column	air turbine	Nearshore & Offshore	Proposed/prototype, deployment proj.	AU	1	1, 3, 5, 6	1997, closed 20/06/2014
199	Company	Oceantec Energias Marinas SL	Oceantech Energy Convertor	Attenuator (gyroscopic precession)			Small-scale	ES		1, 3, 5	
538	Company	Ocenergy	Wave Pump					US		2	
427	Company	Offshore Islands Limited	Wave Catcher	Other				US		5	
200	Company	Offshore Wave Energy Ltd (OWEL)	OWEL WEC	Osc. wave surge converter			Small-scale	UK		1, 3, 5	
201	Company	Open Wave Energy Project Intentium	Intentium					NO		1	
429	Company	ORECon Ltd	MRC 1000	Osc. Water Column				UK		2	
574	Company	Oscilla Power	TDB (Magnetostrictve Wave Energy Harvester)	Point absorber			Small-scale	US		1, 3	
203	Company	Ovsiankin Energy Group						US		1	
204	Company	OWC Power AS	OWC Power	Osc. water column				NO		1	
206	Company	PAULEY (Phil Pauley Innovation)	Solar Marine Cells	Other				UK		1	
207	Company	Pelagic Power AS	W2Power	Point absorber				NO		1, 5	
26	Company	Pelamis Wave Power, was Ocean Power Delivery (spinoff)	Pelamis Wave Energy Converter	Surface-following attenuator	Hydraulic	Offshore	Proposed/prototype, then full-scale	UK Scotland		1, 2, 3, 5, 6	1998
209	Company	Perpetuwave Power	Hybrid Float Xtracta	Attenuator			Part-scale	AU		1, 3, 5	
599	Company	Perth Wave Energy Project (Carnegie)					Deployment proj.	AU	1 (up to 2)	3	Construction completed
577	Company	Pico Plant EU Consortium, Wave Energy Centre (WavEC)	Pico Plant OWC	Osc. water column			Full-scale	PT		1, 3, 5	
435	Company	PIPO Systems	APC-PISYS and WELCOMÉ	Point Absorber				ES (Galicia)		1, 5	
213	Company	Polygen Ltd	Ocean WaveFlex, Volta WaveFlex	Osc. wave surge converter				UK		1	
214	Company	Pontoon Power	Pontoon Power Converter	Point absorber array, attenuator				NO		1, 5	
215	Company	Portsmouth Innovation Limited	WAVESTORE	Overtopping				UK		1	
216	Company	Poseidon’s Kite						US		1	
217	Company	Principle Power						US		1	
218	Company	Protean Energy Limited	Protean	Point absorber				AU		1, 5	
437	Company	Purenco AS formerly Straumekraft	Winch Operated Buoy	Point Absorber				NO		5	
219	Company	Purneco AS	The “Fisherman” WEC	Point absorber				NO		1	
220	Company	Renewable Energy Pumps	Wave Water Pump (WWP)	Point absorber				US, Lebanon		1, 5	
221	Company	RESEN ENERGY	Resen Waves LOPF buoys	Point absorber/Other			Small-scale	DK		1, 3	
222	Company	Resolute Marine Energy Inc	SurgeWEC	Osc. wave surge converter			Full-scale	US		1, 3	
440	Company	Resolute Marine Energy, Inc	Resolute WEC	Point Absorber				US		5	
223	Company	Rohan Patel						US		1	
224	Company	Rotary Wave SL	Rotary					ES		1	
225	Company	Royal Wave						US		1	
226	Company	RTI Ocean Wave Energy	RTI F2/F2D Ocean WEC	Submergible surface float				US		1	
441	Company	RWE nPower renewables	OWC	Osc. Water Column				DE		5	
442	Company	Ryokuseisha	WAG Buoy	Osc. Water Column				JP		5	
229	Company	SAi Orbit Wave Power						US		1	
230	Company	SARA Inc	MHD Wave Energy Conversion (MWEC)	Other				US		1, 5	
580	Company	SDE Energy Ltd.	Sea Wave Power Plant	Buoy, Osc. Wave Surge Converter	Hydraulic ram	Nearshore	Proposed/prototype, operating/operated	Israel	0.04	3, 5, 6	2009, 2010
231	Company	SDK Marine	SDK Wave Turbine	Osc. water column				ES (Madrid)		1	
232	Company	Sea Energies Ltd						IE		1	
233	Company	Sea Green Technologies						US		1	
445	Company	Sea Power International AB	Streamturbine					SE		5	
235	Company	Sea Wave Energy Ltd (SWEL)	Waveline Magnet	Other				UK		1	
31	Company	Seabased AB (spinoff)	WEC S2.7 / Islandberg Project, Sotenäs SE	Point absorber (buoy)	Linear generator on seabed	Offshore	Proposed/prototypek full-scale, array 2016	SE	10	1, 3, 5, 6	2015
237	Company	SeaFoil						US		1	
238	Company	Seamax Energy	Triton	Other				Korea		1	
239	Company	SeaNergy	Turbo Outburst Power/Top Desalination System	Submerged pressure differential				Israel		1, 5	
540	Company	SeaPower Group	Floating Wave Power Vessel					SE		2	
30	Company	Seapower Ltd.	Sea Power Platform	Surface-following attenuator	RO Plant or Direct Drive	Offshore or Nearshore	Proposed/prototype	IE		1, 5, 6	2008
240	Company	Seatricity Ltd.	Oceanus, Oceanus 2	Point absorber (buoy)	Pump-to-shore	Nearshore and Offshore	Proposed/prototype, then full-scale	UK		1, 3, 5, 6	2007
450	Company	SeaVolt Technologies	Wave Rider	Point Absorber				US		5	
451	Company	Seawood Designs Inc	SurfPower	Quasi Point Absorber/Terminator				CA		1, 5	
242	Company	SEEWEC Consortium	FO3	Point absorber				UK, EU		1, 5	
453	Company	SeWave Ltd	OWC	Osc. Water Column				UK Faroe Islands		5	
454	Company	Sieber Energy Inc	SieWave					Canada		5	
244	Company	Sigma Energy	MD wave power converting device					Slovenia		1	
33	Company	SINN Power GmbH	SINN Power Wave Energy Converter	Buoy	Linear generator	Offshore	Proposed/prototype	DK		6	2014
245	Company	Slow Mill	Slow Mill					NL		1	
246	Company	Snapper Consortium	Snapper	Point absorber				UK		1	
247	Company	Spar Buoy	Spar Buoy	Osc. water column				PT		1	
248	Company	Spindrift Energy	Spindrift Energy Device	Point absorber			Small-scale	US		1, 3	
660	Company	SPOK ApS						DK		3	
34	Company	SRI International	Unnamed Ocean Wave-Powered Generator	Buoy	Electroactive polymer artificial muscle	Offshore	Proposed/prototype	US		1, 5, 6	2004
456	Company	Straumekraft AS now Purenco AS	Winch operated buoy	Point Absorber				NO		5	
250	Company	Super Watt Wave Catcher						US		1	
679	Company	Swanturbines (spinoff)						UK		3	
598	Company	Swell	Wave Roller				Deployment proj., Demo array 01/01/2018	PT	5.6	3	Upcoming 01/01/2018

Index	Group	Organization/Actor	Device/facility name	Capture method	Power takeoff	Location	Status/scope	Country	Size (MW_{el})	Source	Start date
458	Company	SyncWave	SyncWave Power Resonator	Point Absorber				Canada		5	
459	Company	T Sampath Kumar	Rock n Roll	Osc. Water Column				India		5	
251	Company	TAMU-OSSL						US		1	
252	Company	Team FLAPPER						US		1	
253	Company	Team Treadwater						US		1	
541	Company	Teamwork Tech	Archimedes Wave Swing					NL		2	
254	Company	Tecnalia, Oceantec Energias Marinas	MARMOK-A-5	Osc. Water Column buoy				ES	0.03	1, 3, 5	
255	Company	The CyanWave Wave Energy Converter	CyanWave4							1	
256	Company	Tremont Electric	nPower WEC	Point absorber				US		1, 5	
257	Company	Trident Energy Ltd, Direct Thrust Designs Ltd	PowerPod Linear Generator	Point absorber			Full-scale	UK		1, 3, 5	
542	Company	U.S. Wave Energy	Wave Energy Module					US		2	
463	Company	Union Electrica Fenosa of Spain	OWC	Osc. Water Column				ES		5	
258	Company	Uniturbine Corporation						US		1	
260	Company	VERT Labs						UK, RU		1	
261	Company	Vigor Wave Energy AB	Vigor Wave Energy Convertor	Attenuator (floating hose)				SE		1, 5	
650	Company	Voith Hydro Ocean Current Technologies	Limpet OWC, Mutriku OWC	Osc. water column				DE, UK		1, 3, 5	
263	Company	Vortex	VIVACE Converter	Cylinder vortex oscillation				US		1	
264	Company	Vortex Oscillation Technology Ltd	Vortex Oscillation Technology	Other (?)				RU		1, 5	
265	Company	Wave Dragon	Wave Dragon	Overtopping			Part-scale	UK Wales, DK		1, 2, 3, 5	
266	Company	Wave Electricity Renewable Power Ocean (WERPO)	SDE	Osc. wave surge converter				Israel		1	
267	Company	Wave Energy AS	Seawave Slot-Cone Generator	Overtopping				NO		1, 5	
677	Company	Wave Energy Centre (spinoff)						PT		3	
269	Company	Wave Energy Conversion Corporation of America (WECCA)	Advanced Wave Energy Conversion System (AWECS)	Attenuator				US		1	
587	Company	Wave Energy Technology New Zealand (WET-NZ)	WET EnGen	Point absorber			Part-scale	NZ, CA?		1, 3, 5	
668	Company	Wave for Energy Srl (spinoff)						IT		3	
474	Company	Wave Power Group	Salter Duck, Sloped IPS	Osc. Water Column				UK		5	
680	Company	Wave Power Solutions (spinoff)						NL		3	
36	Company	Wave Star Energy A/S	Wave Star	Multi-point absorber	Hydroelectric turbine	Offshore	Proposed/prototype	DK		1, 5, 6	2000
274	Company	Wave Water Works						US		1	
275	Company	Waveberg Development	Waveberg	Attenuator				US		1, 2, 5	
37	Company	WaveBob Ltd	WaveBob	Point absorber (buoy)	Direct Drive Power Take off	Offshore	Proposed/prototype	IE		1, 2, 3, 5, 6	1999
277	Company	Waveenergyfyn	Crestwing	Attenuator				DK		1	
278	Company	WaveFlex 1						US		1	
279	Company	WaveFlo						US		1	
546	Company	WaveGen	Offshore OWC					UK		2	
280	Company	WavElectric Inc	WE 10/WE 50/WE 125	Rotating Mass				US		1	
478	Company	Wavemill Energy	Wavemill					Canada		5	
281	Company	WavePiston ApS	WavePiston	Oscillating wave surge converter, attenuator?	Pump-to-shore (hydro-electric turbine)	Nearshore	Proposed/prototype	DK		1, 5, 6	2013
282	Company	WavePlane Production	WavePlane	Overtopping device		Offshore	Proposed/prototype	DK		1, 5, 6	Scrapped 2012
588	Company	WaveRider Energy	WaveRider Platform				Part-scale	AU		1, 3	
284	Company	Waves for Energy	ISWEC	Rotating Mass				IT		1	
285	Company	Waves Ruiz						FR		1	
286	Company	Waves2Energy						US		1	
38	Company	Waves4Power	WaveEL	Point absorber (buoy)	Hydroelectric turbine	Offshore	Proposed/prototype	SE		1, 6	2010
288	Company	Waveset Ltd						IE		1	
589	Company	WaveStar Energy	WaveStar				Part-scale	DK		3	
289	Company	Waveswing America						US		1	
290	Company	Wavetricity								1	
291	Company	Wavetube						SE		1	
292	Company	Wavewatts						US		1	
293	Company	Wavy Turbine						US		1	
590	Company	Wedge Global					Part-scale	ES		3	
294	Company	Wello OY	Penguin	Rotating Mass			Full-scale	FI		1, 3, 5	
295	Company	Weptos	WEPTOS WEC	Other			Part-scale	DK		1, 3	
296	Company	Wind Waves And Sun	WaveBlanket	Other				US		1, 5	
670	Company	Wirescan AS (spinoff)						NO		3	
297	Company	Wizards of Energy						US		1	
298	Company	Yu Energy Corp	Yu Oscillating Generator "YOG"	Osc. wave surge converter				US		1, 5	
13	Company	Zyba Renewables	CCell	Oscillating wave surge converter	Hydraulic	Nearshore & offshore	Proposed/prototype	UK		6	2015
638	Grant program	ADEME Renewable Energy Grant Programme						FR		3	3/9/2010
647	Grant program	Carbon Trust Marine Energy Accelerator						UK		3	12/18/2008
713	Grant program	Carbon Trust Marine Renewables Proving Fund						UK		3	9/22/2009
701	Grant program	Danish Wave Energy Programme						DK		3	1997
706	Grant program	Dansk Research Council						DK		3	
719	Grant program	DECC Clean Tech Start Up Programme						UK		3	10/19/2009
718	Grant program	EMEC – European Marine Energy Centre						UK Scotland		3	
712	Grant program	Innovation Norway						NO		3	2012
720	Grant program	Marine Energy Accelerator Grant Programme						UK		3	10/10/2006
715	Grant program	Marine Renewable Deployment Fund						UK		3	8/2/2004
704	Grant program	Marine Renewable Energy and the Environment (MaREE)						UK		3	6/23/2009
707	Grant program	Norway Energy Fund						NO		3	2011
705	Grant program	Prototype Development Fund						IE		3	2006
714	Grant program	Scottish Government Waters Fund						UK		3	3/23/2010
702	Grant program	Scottish Marine Energy Grant						UK		3	10/24/2006
710	Grant program	Scottish Marine Renewables Commercialisation Fund						UK		3	10/24/2011
711	Grant program	Sitra Innovation Fund						FI		3	2010
703	Grant program	Supergen Array Demonstration						UK		3	2012
717	Grant program	The Marine Energy Array Demonstrator (MEAD) scheme						UK		3	2011
721	Grant program	UK 2007 Marine Power Grant Programme						UK		3	2007
716	Grant program	UK DTI Marine Renewables Deployment Fund						UK		3	8/1/2004
708	Institute/govt.	CIEMAT (Centro de Investigaciones Energéticas, Mediambientales y Tecnológicas)						ES		3	
709	Institute/govt.	Federal Maritime and Hydrographic Agency						DE		3	
325	Institute/org.	Danish Wave Energy Society						DK		5	
326	Institute/org.	EMEC – European Marine Energy Centre						UK Scotland		4, 5	
327	Institute/org.	Eurocean						Europe		5	
328	Institute/org.	Fraunhofer						DE		5	
329	Institute/org.	IEA-OES						World Wide		5	
330	Institute/org.	IFE						NO		5	
331	Institute/org.	INORE						World Wide		5	
332	Institute/org.	Instituto Tecnológico de Canarias – ITC						ES		5	

333	Institute/org.	Ocean Renewable Energy Group, OREG						CA		5	
334	Institute/org.	PLOCAN Oceanic Platform of the Canary Islands						ES		5	
335	Institute/org.	Scottish Marine Institute						UK Scotland		5	
336	Institute/org.	SINTEF						NO		5	
338	Institute/org.	Wave Energy Centre, WavEC						PT		5	
723	Test facility	Aalborg Universitet	Deep water wave basin				Small lab	DK		3	
724	Test facility	Aalborg Universitet	Nissum Bredning Test Site				Small lab	DK		3	
699	Test facility	Aguçadoura					Array	PT		3	2007
606	Test facility	Atlantic Marine Energy Test Site (AMETS)						IE	20	3	T.B.A.
528	Test facility	AWATEA	NZ-MEC				Planned	NZ		4	
690	Test facility	BIMEP					Array	ES		3	2013
607	Test facility	Biscay Marine Energy Platform (BIMEP)						ES	20	3	Operational
519	Test facility	California Polytechnic State University	California Wave Energy Test Center (CalWave)				Planned	US		4	
725	Test facility	Centro Nazionale Ricerca	Wave Tank				Large lab	IT		3	
504	Test facility	Claire Gibson	WaveHub				Operating	UK		4	
684	Test facility	Danish Benign Test Site					Scale	DK		3	2000
727	Test facility	Danmarks Tekniske Universitet	Mechanical test facilities				Large lab	DK		3	
726	Test facility	Danmarks Tekniske Universitet	PowerLabDK				Large lab	DK		3	
683	Test facility	DanWEC					Full scale	DK		3	2009
728	Test facility	Ecole Central de Nantes	Hydrodynamic and marine Engineering Tank				Large lab	FR		3	
686	Test facility	EMEC - nursery					Nursery	UK, Scotland		3	2011
729	Test facility	EMEC – European Marine Energy Centre	Real Sea Test Sites, Orkney				Medium-scale site	UK		3	
608	Test facility	EMEC – European Marine Energy Centre					Full scale , operating	UK, Scotland	Six grid-connected berths	3	Operational , 2002
493	Test facility	Enondas	OceanPlug				Existing	PT		4	
527	Test facility	ERI@N with ClassNK & EMEC	REIDS-Offshore (TMEC)				Planned (2017)	Singapore		4	
526	Test facility	ERI@N with Sentosa Dev't Corp	Sentosa Tidal Test Bed				Existing	Singapore	50 kW. Grid conn. planned	4	
525	Test facility	ERI@N with Singapore Cruise Centre	TMFT Marine RE Test Bed				Existing	Singapore		4	
731	Test facility	EVE (Ente Vasco de la Energia)	Biscay Marine Energy Platform - BIMEP				Operational, Large-scale site	ES	20 MW grid connection	3, 4	
730	Test facility	EVE (Ente Vasco de la Energia)	Mutriku Breakwater Wave Plant				Large-scale site, operating/operated	ES	0.3	3, 4, 6	2009
688	Test facility	FaB Test					Nursery	UK, England		3	2011
506	Test facility	Falmouth Harbour Commissioner/Mark Samson	FaBTest				Operating	UK		4	
512	Test facility	Florida Atlantic University	Southeast National Renewable Energy Center				Planned	US		4	
509	Test facility	FORCE	Fundy Ocean Research Centre for Energy (FORCE) - Tidal Energy				Operational	CA	64 MW grid connection	4	
732	Test facility	Fraunhofer Institute	Offshore Field Test Facilities				Large-scale site	DE		3	
693	Test facility	Galway Bay					Nursery	IE		3	2006
486	Test facility	Hans Jorgen Brodersen	DanWEC				Two wave and current Datawell buoys	DK		4	
734	Test facility	IFREMER	Deep Seawater Wave Tank				Large lab	FR		3	
733	Test facility	IFREMER	Materials in Marine Environment Laboratory				Large lab	FR		3	
735	Test facility	IFREMER	Wave/Current Circulation Tank				Large lab	FR		3	
505	Test facility	John Buckland/Mark Francis	PTEC				Under development	UK		4	
498	Test facility	Lysekil wave power research site		Point absorber (buoy)	Electrical generator	Offshore	Operational	SE		4	
692	Test facility	Mutriku					Operational	ES		3	2011
736	Test facility	Narec	CPTC Energy Link Labs				Large lab	UK		3	
738	Test facility	Narec	Large Scale Wave Flume				Large lab	UK		3	
737	Test facility	Narec	Nautilus Rotary Test Rig				Large lab	UK		3	
739	Test facility	Narec	South West Mooring Test Facility				Medium-scale site	UK		3	
520	Test facility	National wave energy full scale test site					Planned	CN		4	
515	Test facility	NNMREC	Pacific Marine Energy Center - North Energy Test Site				Operational	US		4	
514	Test facility	NNMREC	Pacific Marine Energy Center - South Energy Test Site				Planned	US		4	
522	Test facility	NOTC	National small scale test site				Under development	CN		4	
694	Test facility	Ocean Plug					Array	PT	80 (up to 250)	3	In progress, 2007
494	Test facility	Oceanic Platform of the Canary Islands (PLOCAN)	PLOCAN				Operational	ES	10 (up to 100)	3, 4	Operational
518	Test facility	Oregon Military Department	Camp Rilea Test Site				Operational	US		4	
698	Test facility	Peniche test site					Array	PT		3	2007
697	Test facility	Pico Test Plant					Operational	PT		3	1999
691	Test facility	PLOCAN Oceanic Platform of the Canary Islands					Array	ES		3	2013
740	Test facility	Plymouth University	Coastal marine and Sediment Transport Laboratories				Large lab	UK		3	
490	Test facility	Politecnico di Torino/wave for energy s.r.l.	ISWEC				Planned (2016)	IT	100 kW grid connection	4	
489	Test facility	Ponte di Archimede International Spa	KOBOLD				Deployed 2000	IT	60 kW grid connection	4	
485	Test facility	Port of Ostend	FlanSea test site at Ostend				Ready	Belgium		4	
742	Test facility	Queen's University Belfast	Portaferry Tidal Test Centre				Medium-scale site	UK		3	
741	Test facility	Queen's University Belfast	Shallow Water Wave Tank				Small lab	UK		3	
492	Test facility	Runde Environmental Centre (REC)					Operational, full scale	NO		3, 4	2008
488	Test facility	SEAI	Atlantic Marine Energy Test Site				Planned	IE		4	
487	Test facility	SEAI/Marine Institute/Smart Bay Ltd	National quarter scale Test Site				Operational	IE		4	
491	Test facility	SEAPOWER Scarl	GEM				Planned (2016)	IT	200 kW grid connection	4	
695	Test facility	SEM-REV					Array	FR		3	2007
611	Test facility	Site d'Expérimentation en Mer pour la Récupération de l'Energie des vagues (SEM-REv)						FR	8	3	Operational
743	Test facility	Strathclyde University	Kelvin Hydrodynamics Laboratory				Small lab	UK		3	
744	Test facility	Sustainable Energy Authority of Ireland	Galway Bay 1/4 Scale Wave Energy Test Site				Medium-scale site	IE		3	
745	Test facility	Sustainable Energy Authority of Ireland	Wave Energy Test Site, Belmullet				Large-scale site	IE		3	
746	Test facility	Tecnalia	Electrical PTO lab				Small lab	ES			
511	Test facility	U.S. Navy	U.S. Navy Wave Energy Test Site				Operational	US		4	
524	Test facility	Uldolmok TEC Test Bed					Planned	KR		4	
749	Test facility	Universita di Firenze	Wave/Current Flume				Small lab	IT		3	
750	Test facility	Universität Stuttgart	Turbine Test rigs				Small lab	DE		3	
747	Test facility	University College Cork	Beaufort marine Wave Basin				Small lab	IE		3	
748	Test facility	University College Cork	Beaufort Rotating Test Rig				Small lab	IE		3	
513	Test facility	University of Alaska Fairbanks AHERC	Pacific Marine Energy Center - Tanana River hydrokinetic Test Site				Operational	US		4	
751	Test facility	University of Edinburgh	Curved Wave tank				Small lab	UK		3	
752	Test facility	University of Exeter	Dynamic Marine Component Test Facility				Small lab	UK		3	
510	Test facility	University of Manitoba	Canadian Hydrokinetic Turbine Test Centre (CHTTC) - River Current Energy				Operational	CA		4	

Index	Group	Organization/Actor	Device/facility name	Capture method	Power takeoff	Location	Status/scope	Country	Size (MW_{el})	Source	Start date
753	Test facility	WAVEC	WAVEC OWC Pico				Large-scale site	PT		3	
523	Test facility	Yongsoo WEC Test Bed					Planned	KR		4	
301	University	Aalborg University						DK		3, 5	
639	University	Centro de Investigaciones Energéticas						ES		3	
662	University	Chalmers University of Technology						SE		3	
319	University	Delft University of Technology						NL		5	
94	University	Ecole Centrale de Nantes	SEAREV	Osc. water column				FR		1, 3, 5	
369	University	Edinburgh University	Sloped IPS Buoy	Osc. Water Column				UK		5	
317	University	Gent University						Belgium		5	
304	University	Heriot-Watt University						UK Scotland		5	
634	University	Institut français de recherche pour l'exploitation de la mer						FR		3	
648	University	Institut für Fluid- und Thermodynamik Siegen						DE		3	
395	University	Instituto Superior Técnico, Technical University of Lisbon	Pico Plant OWC	Osc. Water Column				PT		1, 3, 5	
150	University	Korean Institute of Ocean Science and Technology (KIOST)						KR		1	
646	University	Laboratório Nacional de Energia e Geologia						PT		3	
154	University	Lancaster University	PS Frog	Point absorber				UK England		1, 3, 5	
171	University	Muroran Institute of Technology	Pendulor	Other				JP		1, 5	
643	University	National University of Ireland, Maynooth						IE		3	
178	University	Norwegian University of Science and Technology	CONWEC	Point absorber				NO		1, 3, 5	
321	University	Oregon State University						US Oregon		5	
656	University	Politecnico di Torino						IT		3	
313	University	Queen's University Belfast						UK IE		5	
228	University	Rutgers Wave Power	Cyclic pitch paddle wheel					US		1	
314	University	Swansea University						UK Wales		5	
316	University	Technische Universität München						DE		5	
320	University	Universidad de La Laguna, Tenerife						ES		5	
655	University	Università di Padova						IT		3	
632	University	Université de Toulouse + Institut de Mécanique des Fluides de Toulouse						FR		3	
312	University	University College Cork, Hydraulics and Maritime Research Centre						IE		3, 5	
640	University	University of Almería						ES		3	
653	University	University of Bologna						IT		3	
259	University	University of Edinburgh	Salter's Duck	Attenuator				UK Scotland		1, 3, 5	
306	University	University of Exeter						UK England		5	
20	University	University of Groningen	Ocean Grazer	Buoy	hydraulic multi-piston pump	Offshore	Proposed/prototyp e	NL		6	2011
323	University	University of Iowa						US Iowa		5	
309	University	University of Manchester						UK England		5	
654	University	University of Naples Federico II						IT		3	
310	University	University of Oxford						UK England		3, 5	
311	University	University of Plymouth						UK England		3, 5	
307	University	University of Southampton						UK England		3, 5	
305	University	University of Strathclyde						UK Scotland		3, 5	
322	University	University of Texas at Austin						US Texas		5	
19	University	Uppsala University	Lysekil Project	Point absorber (buoy)	Linear generator	Offshore	Proposed/prototyp e	SE		6	2002
302	University	Uppsala University, Division for Electricity	Uppsala/Seabased AB Wave Energy Convertor	Point Absorber				SE		3, 5	
270	University	Wave Energy Team at Virginia Tech						US		1	
182	University, govt.	Ocean Energy Laboratory of Guangzhou Institute of Energy Conversion (GIEC), Chinese Academy of Sciences	Duck	Attenuator				China		1	
184	University, govt.	Ocean Energy Laboratory of Guangzhou Institute of Energy Conversion (GIEC), Chinese Academy of Sciences	Eagle	Attenuator				China		1	
183	University, govt.	Ocean Energy Laboratory of Guangzhou Institute of Energy Conversion (GIEC), Chinese Academy of Sciences	Neza II	Point absorber				China		1	

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13 Solar thermal power generation – concentrated solar power (CSP)

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13.1 Introduction

Solar energy is the most abundant energy resource on earth, with about 885 million terawatt hours (TWh) reaching the surface of the planet every year – 6200 times the commercial primary energy consumed by humankind in 2008, and 3500 times the energy that humankind would consume in 2050 according to the Energy Technology Perspective 6DS (6˚C) scenario (IEA 2014a, IEA 2014b). In fact, merely 1% of the Sahara desert used for concentrating solar power (CSP) systems would be sufficient to satisfy today's world electricity demand (Pitz-Paal 2008). Such CSP plants use mirrors to concentrate the sun's rays and produce heat for electricity generation via a conventional thermodynamic cycle. Unlike solar photovoltaics (PV), CSP uses only the direct component of sunlight (DNI)[327] and can provide carbon-free heat and power in regions with high DNI >2000 kWh/m^2/a, as shown in Figure 13.1 (IRENA 2013). These Sunbelt regions include the Middle East and North Africa (MENA), South Africa, the southwestern United States, Mexico, Chile, Peru, Australia, India, western China, southern Europe and Turkey. The technical potential of CSP-based electricity generation in most of these regions is typically many times higher than their electricity demand, resulting in opportunities for electricity export through high voltage direct current (HVDC) lines.[328] Thus, solar thermal electricity import from the Mediterranean area may be an interesting future option for Switzerland.

Since 2010, generation of solar thermal electricity (STE) from concentrating solar power (CSP) plants has grown strongly worldwide, though more slowly than expected in the first IEA CSP roadmap (IEA 2010b). The first commercial plants were deployed in California in the 1980s. A resurgence of solar power in Spain was limited to 2.3 gigawatts (GW) by the government in the context of the financial and economic crisis. Deployment in the United States was slow until 2013 because of long lead times and competition from cheap unconventional gas and from photovoltaic (PV) energy, whose costs decreased rapidly[329]. Deployment in other places took off only recently. Global deployment of STE, 4.9 GW at the end of 2015 (Teske 2016), pales in comparison with the 227 GW of PV[330]. Costs of CSP plants have dropped but less than those of PV. However, new CSP components and systems are

[327] Sunlight consists of direct and indirect (diffused) components. The direct component (i.e. DNI or Direct Normal Irradiance) represents up to 90% of the total sunlight during sunny days but is negligible on cloudy days. Direct sunlight can be concentrated using mirrors or other optical devices (e.g. lenses). CSP plants can provide cost-effective energy in regions with DNI >2000 kWh/m^2/a, typically arid and semi-arid regions at latitudes between 15° and 40° North or South of the Equator. Note that equatorial regions are usually too cloudy. High DNI can also be available at high altitudes where scattering is low. In the best regions (DNI >2800 kWh/m^2/a), the CSP electricity generation potential is 100-130 GWh/km^2/a. This is roughly the same electricity generated annually by a 20 MW coal-fired power plant with a 75% capacity factor.

[328] HVDC is the technology of choice for transmitting power efficiently and reliably over long distances. It is ideally suited for integrating renewable energy sources situated in remote locations. ABB has developed new technologies that make viable low-loss HVDC power transmission of 10 GW over distances up to 3,000 km (ABB 2014).

[329] (IEA 2014b)

[330] *Snapshot of Global Photovoltaic Markets 2015*. Report IEA PVPS T1-29:2016, ISBN 978-3-906042-42-8.

coming to commercial maturity, holding the promise of increased efficiency, declining costs and higher value through increased dispatchability.

The recent IEA roadmap (IEA 2014b) envisions STE's share of global electricity to reach 11% by 2050 – almost unchanged from the goal in the previous IEA roadmap (IEA 2010b). Thus, the goal for PV is not increased at the detriment of STE in the long term. Adding STE to PV, solar power could provide up to 27% of global electricity by 2050, and become the leading source of electricity globally as early as 2040. Achieving this roadmap's vision of 1000 GW of installed CSP capacity by 2050 would avoid the emissions of up to 2.1 gigatonnes (Gt) of carbon dioxide (CO_2) annually.

From a system perspective, STE offers substantial advantages over PV, mostly because of its built-in thermal storage capabilities (IEA 2014b). STE is firm and can be dispatched at the request of power grid operators, in particular when demand peaks in the late afternoon, in the evening or early morning, while PV generation is at its best in the middle of the day. Both technologies, while being competitors on some projects, are ultimately complementary.

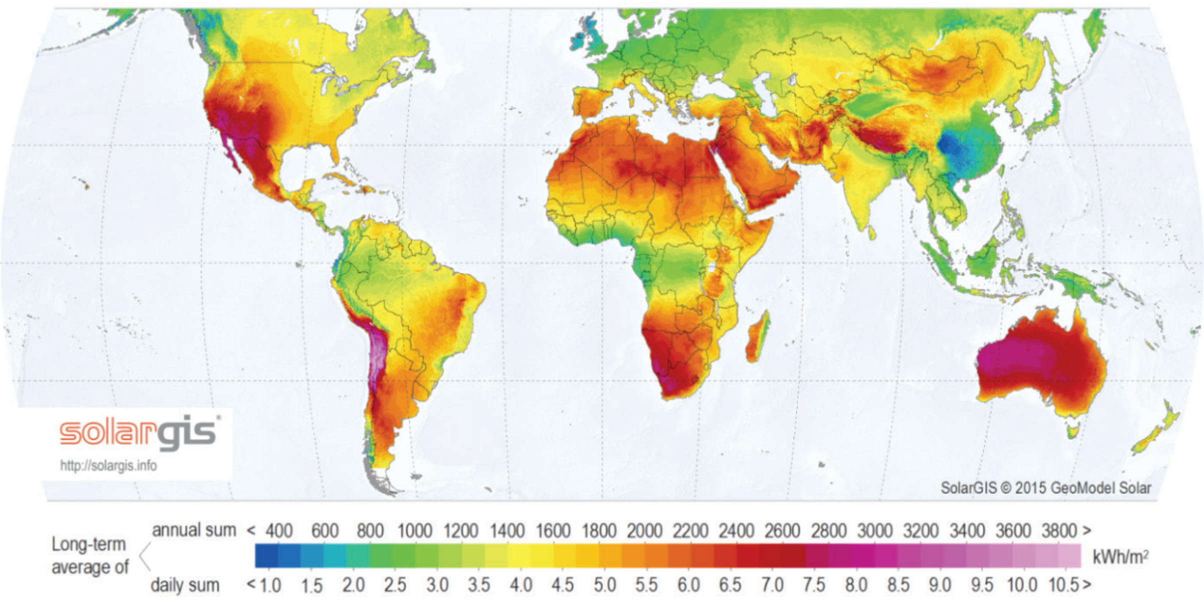

Figure 13.1: World map of direct normal irradiation (DNI). Source: (SolarGIS 2015).

Combined with long lead times, deployment of CSP plants will remain slow in the next ten years compared with previous expectations (IEA 2010b). Deployment is expected to increase rapidly after 2020 when STE becomes competitive for peak and mid-merit power in a carbon-constrained world, ranging from 30 GW to 40 GW of new-built plants per year after 2030 (IEA 2014b).

Appropriate regulatory frameworks – and well-designed electricity markets, in particular – will be critical to achieve the vision in the IEA roadmap (IEA 2014b). Most STE costs are incurred up-front, when the power plant is built. Once built, CSP plants generate electricity almost for free, except for minor operation and maintenance (O&M) and balance of system (BoS) cost. This means that investors need to be able to rely on future revenue streams so that they can recover their initial capital investments. Market structures and regulatory frameworks that fail to provide robust long-term price signals beyond a few months or years are thus unlikely to attract sufficient investment to achieve timely decarbonization of the global energy system.

13.1.1 Definition

Concentrating Solar Power (CSP) plants use mirrors to concentrate sunlight onto a receiver, which collects and transfers the solar energy to a heat transfer fluid that can be used to supply heat for end-use applications or to generate electricity through conventional steam turbines (IRENA 2013). CSP plants can be equipped with a heat storage system to generate electricity even with cloudy skies or after sunset. For example, during sunny hours, solar heat can be stored in a high thermal-capacity fluid, and released upon demand (e.g. at night) to produce electricity. Thermal storage can significantly improve the *capacity factor* and *dispatchability*[331] of CSP plants, as well as their grid integration and economic competitiveness. To provide the required heat storage capacity, the *solar field* (i.e. mirrors and heat collectors) of the CSP plant must be oversized[332] with respect to the nominal electric capacity (MW) of the plant. There is a trade-off between the incremental cost associated with thermal storage and increased electricity production. Current research efforts focus on thermal storage for CSP plants.

Figure 13.2 shows the four CSP technologies, namely *Parabolic Trough Concentrator* (PTC)*, Linear Fresnel Reflector* (LFR)*, Central Receiver System* (CRS) *and Parabolic Dish Concentrator* (PDC), which differ depending on the design, configuration of mirrors and receivers, heat transfer fluid used and whether or not heat storage is involved. The first three types are used mostly for power plants in centralized electricity generation, with the parabolic trough system being the most mature commercial technology. Solar dishes are more suitable for distributed generation.

CSP plants generate electricity while producing almost no greenhouse gas (GHG) emissions[333], so it could be a key technology for mitigating climate change (IEA 2014b). In addition, the flexibility of CSP plants enhances energy security. Unlike solar photovoltaic (PV) technologies, CSP plants use steam turbines, and thus inherently provide all the needed ancillary services. Moreover, they have an inherent capacity to store thermal energy for later conversion to electricity. CSP plants can also be equipped with backup from fossil fuels delivering additional heat to the system.[334] When combined with thermal storage capacity

[331] The *capacity factor* is the amount of electricity produced in a year (GWh) divided by the product of nominal capacity of the plant (MW) multiplied by the number of hours in a year (8760 hours), while *dispatchability* is the ability of the plant to provide electricity on the operator's demand.

[332] The *solar multiple* is the ratio of the actual size of the solar field to the solar field size needed to feed the turbine at nominal design capacity with maximum solar irradiance (about 1 kW/m^2). To cope with thermal losses, plants with no storage have a solar multiple between 1.1-1.5 (up to 2.0 for LFR) while plants with thermal storage may have solar multiples of 3-5.

[333] During the electricity production phase, almost no greenhouse gases are emitted. Compared to other energy technologies, minor environmental impacts are related to the construction of components (e.g., heliostats).

[334] Whether CSP plants are equipped with fossil backup for additional heat production or not and to which extent this is used mainly depend on the layout of the plants including heat storage and national regulation. Back-up combustion of natural gas with the associated GHG emissions mainly affects the environmental performance of CSP. Modern plants are usually equipped with sufficient thermal storage in order to cover the usual periods without sunshine and therefore hardly require any fossil back-up. The trend towards larger thermal storage is expected to continue in the future and therefore, the focus of this report is on CSP plants without fossil back-up.

of several hours of full-capacity generation, CSP plants can continue to produce electricity even when clouds block the sun, or after sundown or in early morning when power demand steps up.

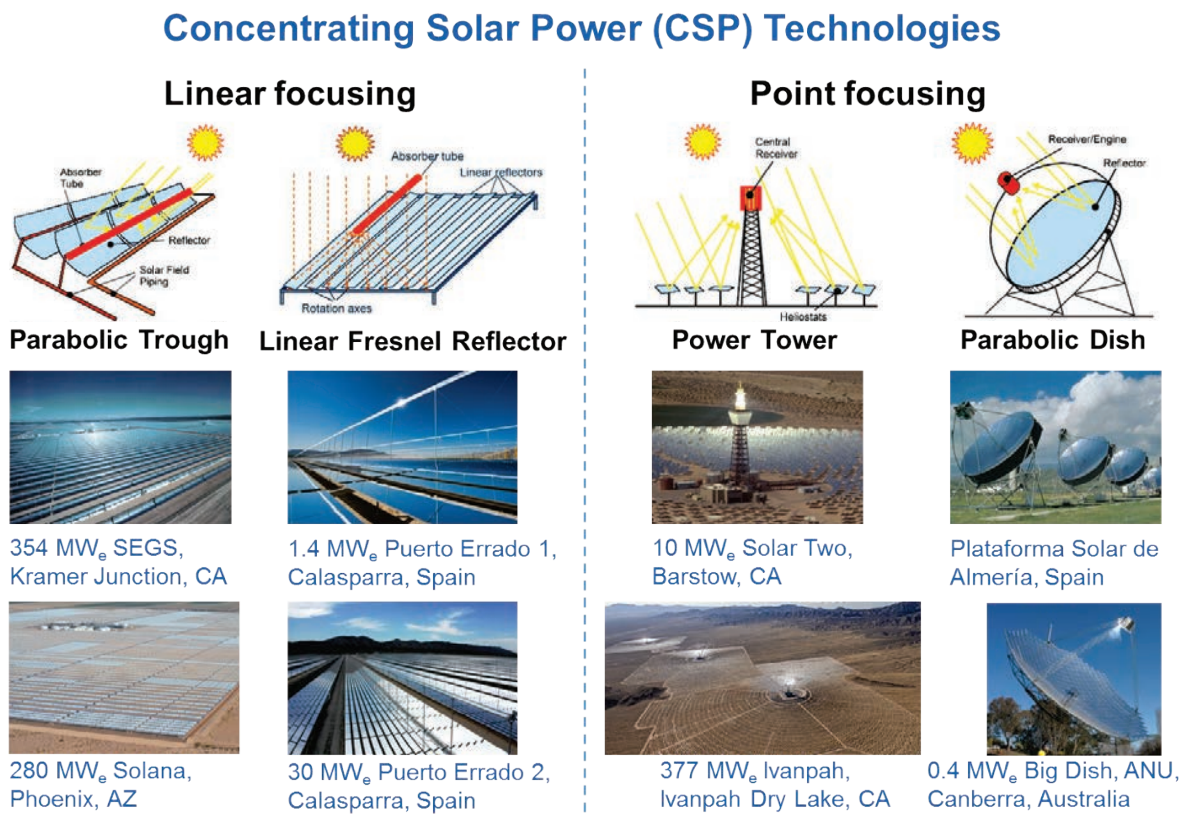

Figure 13.2: Schematics of CSP Technologies (SolarPACES 2016a): Linear focusing systems include Parabolic Trough Collectors (PTC) and Linear Fresnel Reflectors (LFR); point focusing systems include Central Receiver Systems (CRS) or "solar power towers" and Parabolic Dish Concentrators (PDC). Examples of commercial parabolic troughs are the 354 MW_e SEGS[335] plants in California (constructed in 1985-91) and the 280 MW Solana plant in Arizona (2013); Fresnel reflector systems are operational in Spain as 1.4 MW prototype (2009) and 30 MW commercial plant (2012); Solar power towers have been built in California as 10 MW prototype (1996) and 377 MW commercial plant (2013); Parabolic dish prototypes with Stirling engines are being tested in Spain (25 kW modules constructed in 1996-97) and Australia (400 kW big dish erected in 2011).

The technologies deployed in CSP plants to generate electricity also show significant potential for complying with specialized demands such as process heat for industry; co-generation of heating, cooling and power; and heat-based water desalination processes that are particularly important in sunny (and often arid) regions. They could also produce concentrating solar fuels such as hydrogen and other energy carriers (see Box 1) – an important area for further research and development (IEA 2014b). Solar-generated hydrogen can help decarbonize the transport and other end-use sectors by mixing hydrogen with natural gas in pipelines and distribution grids, and by producing cleaner liquid fuels. Solar fuels could also be used as zero-emission back-up fuel for generating STE. Another option is solar-fossil hybridization by adding a small solar field to a traditional fossil-fired

[335] SEGS – Solar Electricity Generation System.

thermal power plant – either a gas-fired combined cycle or a coal-fired plant – because both technologies can share a common turbine generation device.

BOX 1 – Solar thermochemical fuels and materials*

Solar energy can be efficiently stored in liquid or gaseous fuels using concentrated solar radiation as the source of high-temperature heat for endothermic thermochemical processes (Yadav and Banerjee 2016). There are a number of potential pathways to solar fuels (Meier and Steinfeld 2012). The straightforward thermolysis of water is the most difficult, as it requires temperatures above 2200°C and may produce an explosive mixture of hydrogen and oxygen. The division of the single-step water-splitting reaction into a number of sub-reactions opens up the field of so called thermochemical cycles for H_2 production (Steinfeld 2005). The necessary reaction temperature can be decreased to temperatures even below 1000°C, resulting in intermediate solid products like metals (e.g., aluminum, magnesium, or zinc), metal oxides, metal halides or sulphur oxides. The different reaction steps can be separated in time and place, offering possibilities for long-term storage of the solids and their use in transportation. These thermochemical cycles are also able to split CO_2 into CO and oxygen. If mixtures of water and CO_2 are used, even synthesis gas (mainly H_2 and CO) can be produced (Agrafiotis, Roeb et al. 2015), which can be further processed to synfuels, for example by the Fischer-Tropsch process. Thermochemical cycles are reported to have theoretical efficiencies above 60%. If coupled to a solar tower, efficiencies up to 25% are expected (IEA 2014b).

In a similar way, high-temperature solid oxide electrolyzers can be used to generate hydrogen and synthesis gas (Houaijia, Roeb et al. 2015). Coupled to a solar tower, solar-to-hydrogen efficiencies above 20% seem possible, a significant improvement over using solar electricity in low-temperature steam electrolyzers, which achieves an efficiency of only about 12% (IEA 2014b). All the solar thermochemical and electrochemical processes described above offer an additional environmental benefit if water and atmospheric CO_2 are used to produce H_2 and synthesis gas, thus making the products CO_2 emission-neutral (Reich, Yue et al. 2014).

Concentrated solar radiation can also be used to upgrade carbonaceous materials (Piatkowski, Wieckert et al. 2011). One of the most developed processes is steam reforming of methane to produce synthesis gas (Agrafiotis, von Storch et al. 2014, Sheu, Mokheimer et al. 2015). Sources are either natural gas or biogas. Methane can also be cracked into hydrogen and carbon, thus producing a gaseous and a solid product (Rodat, Abanades et al. 2009). However, the required process temperature is very high and a homogeneous carbon product is unlikely to be produced because of the intermittent solar radiation conditions. Additionally, there is a discrepancy between the huge demand for hydrogen and the low demand for high-value carbon, such as carbon black or advanced carbon nano-tubes (IEA 2014b).

Another environmentally beneficial use of concentrated solar radiation is the gasification of biomass or carbonaceous waste material to produce synthesis gas more efficiently than by burning part of the biomass or waste for providing high-temperature process heat (Wieckert, Obrist et al. 2013). Using concentrating solar gasification technologies in sunny countries would reduce the land and water requirement of current or future advanced biofuels. Solid and liquid biofuels enhanced from solar heat could be used in virtually all transport and industry applications (IEA 2014b).

Hydrogen produced in concentrating solar chemical plants could be blended with natural gas and thus used in today's energy system (IEA 2014b). Town gas, which prevailed before natural gas spread out, included hydrogen up to 60% in volume or about 20% in energy content. This blend could be used for various purposes in industry, households and transportation, reducing emissions of CO_2 and nitrous oxides. Gas turbines in integrated gasification combined cycle (IGCC) power plants can burn a mix of gases with 90% hydrogen in volume. Many existing pipelines could, with some adaptation, transport such a blend from sunny places to large consumption centers (e.g. from North Africa to Europe).

Solar-produced hydrogen could also find niche markets today in replacing hydrogen production from steam-reforming of natural gas in its current uses, such as manufacturing fertilizers and removing sulphur from petroleum products (IEA 2014b). Regenerating hydrogen with heat from concentrated sunlight to decompose hydrogen sulphide into hydrogen and sulphur could save significant amounts of still gas in refineries for other purposes.

Coal could be used together with methane gas as feedstock, and deliver dimethyl ether (DME), after solar-assisted steam reforming of natural gas, coal gasification, and two-step water splitting (IEA 2014b). DME could be used as a liquid fuel, and its combustion would entail similar CO_2 emissions to those from burning conventional petroleum products, but significantly less than the life-cycle emissions of other coal-to-liquid fuels (IEA 2014b).

Besides solar fuels, CSP technology could find a great variety of uses in providing high-temperature process heat or steam, such as for enhanced oil recovery, and mining applications (where CSP is already in use), production of lime and cement, smelting of aluminum and other metals, and in industries such as food and beverages, textiles and pharmaceuticals. Various forms of cogeneration with STE can also be considered. For example, sugar plants require high-temperature steam in spring, when the solar resource is maximal but electricity demand minimal. Solar fields providing steam for sugar plants could run a turbine and generate STE for the rest of the year (IEA 2014b).

* Based on the contribution of Anton Meier (PSI) to the STE Technology Roadmap 2014 (IEA 2014b).

13.1.2 Global and European trends for solar thermal electricity supply

Between 1984 and 1991, the first commercial CSP plants without thermal storage (i.e. SEGS plant, 354 MW) were built in California in the context of tax incentives for renewable energy (IRENA 2013). After a period of stagnation due to low fossil fuel prices, the interest in CSP resumed in the 2000s, mainly in Spain and the United States, as a consequence of energy policies and incentives to mitigate CO_2 emissions and diversify the energy supply. With 2.3 GW of cumulative CSP capacity, of which 300 MW was added in 2013, Spain leads the world in STE, but will soon be overtaken by the United States (IEA 2014b). Spain is the only country where STE is "visible" in national statistics, with 2% of annual electricity coming from CSP plants (RED 2014). Maximum instantaneous contribution in 2013 was 7.6%, maximum daily contribution 4.6%, and maximum monthly contribution 3.6% (IEA 2014b). The United States ranks second, with 900 MW at the end of 2013 and 750 MW added in early 2014. More than 20 large projects are being promoted or are in early development but not all will survive the permitting process or negotiations with utilities for appropriate remuneration. While Spain and the United States are leading countries in CSP installations, CSP plants are in operation, under construction or planned in many Sunbelt countries. The largest plants in the rest of the world are in the United Arab Emirates, South Africa and India, but others are under construction in Chile, China, Israel, and Morocco. Smaller solar fields, often integrated in larger fossil fuel plants, also exist in Algeria, Australia, Egypt, Iran, Italy, and Morocco. In 2015, the global installed CSP capacity amounted to about 4.9 GW with an additional 1.4 GW under construction and 2-4 GW planned, mostly in the United States (SolarPACES 2016b).

In summary, the STE industry has experienced robust growth since 2009, although from low initial levels (IEA 2014b). This growth has been concentrated in Spain and the United States, but can also be observed now in many other countries. Market prices, which have been slow to diminish, finally seem to be falling. New technologies have reached commercial maturity and new concepts have emerged. Thermal storage in molten salts is routinely used in parabolic trough configurations and has been demonstrated in solar towers.

Solar electricity generated by concentrating solar thermal power stations in Middle East and North Africa (MENA) and transferred to Europe via high-voltage direct current (HVDC) transmission can provide firm capacity for base load, intermediate and peaking power, effectively complementing European electricity sources (Pitz-Paal 2008). This option is under consideration in the Mediterranean Solar Plan[336] and the DESERTEC Industrial Initiative[337] (Figure 13.3). Starting between 2020 and 2025 with a transfer of 60 TWh/a, solar electricity imports could subsequently be extended to 700 TWh/a in 2050. High solar irradiance in MENA and low transmission losses of 10-15%[338] might yield competitive imported solar electricity cost of around 50 EUR/MWh (Pitz-Paal 2008).

[336] Mediterranean Solar Plan: http://www.plansolairemediterraneen.org
[337] Website of DII consortium: www.dii-eumena.com
[338] HVDC lines show only 3% electricity losses per 1000 km, plus 0.6% losses in conversion at both ends, and have a smaller footprint than on-shore high voltage alternate current (HVAC) lines (IEA 2011b).

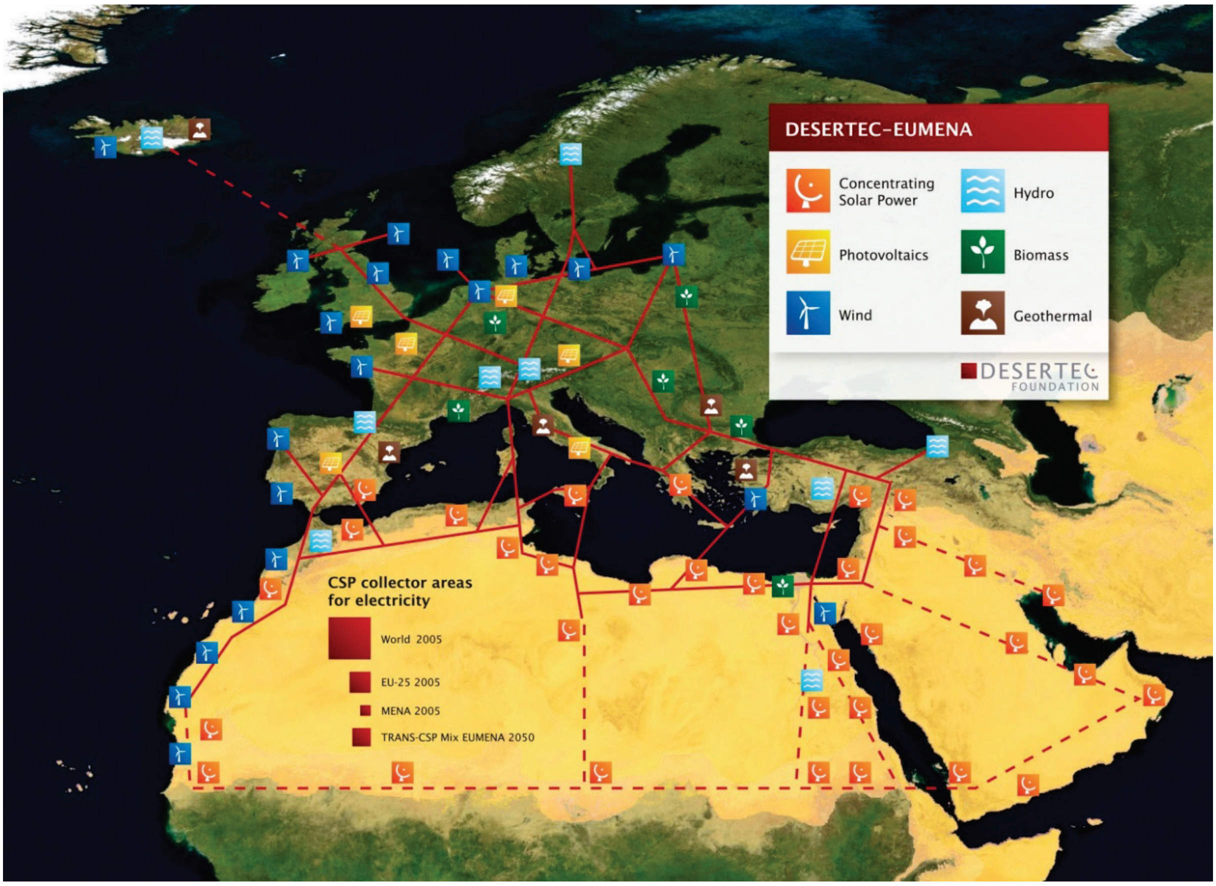

Figure 13.3: Vision of a European Mediterranean electricity grid based on HVDC lines for the use of the most efficient renewable energy resources, such as CSP, biomass, hydro, geothermal, wind, and solar PV. Indicated are possible power lines and future grid expansion. Also shown is the CSP collector area needed to cover the annual electricity demand of various world regions. Source: the DESERTEC foundation[339].

13.1.3 Swiss trends for solar thermal electricity supply

In Switzerland, solar thermal power plants for the generation of electricity or the production of high temperature process heat[340] presumably will not be economically attractive due to the lack of sufficient direct solar irradiation (DNI)[341].

In the medium term, the import of electricity generated in CSP plants in the Mediterranean region may become an interesting option for supplying Switzerland with environmentally benign renewable electricity. In fact, the Swiss Federal Council has approved a postulate by National Councilor Bastien Girod concerning "Desert power in Switzerland" ("Wüstenstrom in der Schweiz")[342]. In particular, the Swiss government was requested to consider measures for supporting DESERTEC and similar initiatives in promoting the utilization of the enormous solar energy potential in the Sahara desert. However, in order to realize this potential, both investment security on site and electricity transport to Europe should be ensured. The report investigated the technical possibilities of DESERTEC and alternative projects, such as

[339] Website of DESERTEC foundation: www.desertec.org

[340] In 2016, ten pilot plants for low temperature solar process heat (temperature range between 90 and 190 °C), among them three using parabolic troughs, are under evaluation and an economic analysis is ongoing.

[341] In the Swiss Alps, maximum annual direct normal irradiance (DNI) is about 1500 kWh/m^2/a (MeteoWallis 1995).

[342] (BFE/SFOE 2014)

the feasibility of long-range transport of renewable energies, aspects related to economically and politically instable North African countries, ecological and social boundary conditions, as well as impacts on the Swiss energy strategy 2050.

In the long term, also chemically stored solar energy from CSP plants in the form of solar thermochemical fuels (such as hydrogen, synthesis gas or liquid hydrocarbon fuels) may contribute to the energy supply in Switzerland. Indeed, PSI's Solar Technology Laboratory (STL) and ETH's Professorship of Renewable Energy Carriers (PREC) are recognized worldwide as leading groups in high-temperature solar chemistry research. The mission of STL is to develop the science and technology that is required for transforming, at an industrial scale, solar energy into chemical fuels with a thermochemical process that effects this conversion more competitively than any other solar-to-fuel process. PREC is committed to excellence in research and education. It performs pioneering R&D projects in emerging fields of renewable energy engineering, operates state-of-the-art experimental laboratories, offers advanced courses in fundamental/applied thermal sciences, and produces qualified scientists and engineers with expertise in renewable energy technologies.

Switzerland has a long-lasting research tradition in the field of high-temperature solar technology, which is substantially supported by the Swiss Federal Office of Energy (SFOE), the Swiss State Secretariat for Education, Research and Innovation (SERI), the Commission for Technology and Innovation (CTI), the Swiss National Science Foundation (SNSF) and other public institutions. Therefore, it is expected that Switzerland will play an important role in transferring solar thermal and solar thermochemical technologies to Mediterranean countries (Southern Europe, North Africa, and Middle East). This constitutes an opportunity for the Swiss export industry and may have a beneficial effect on the Swiss Economy.

13.2 Technology description

13.2.1 Current CSP technologies

A CSP plant produces electricity by using mirrors to concentrate sunlight onto receivers which produce steam to generate electricity. The system (Figure 13.4) consists of (1) the solar field converting solar energy into thermal energy; (2) the thermal energy storage (TES) using molten salt as heat-storage medium; (3) the power block generating electricity through a steam turbine with steam produced by solar energy. Traditional technologies used in fossil-fuel power plants can be applied to the power block, which utilizes solar thermal energy instead of fossil fuel.

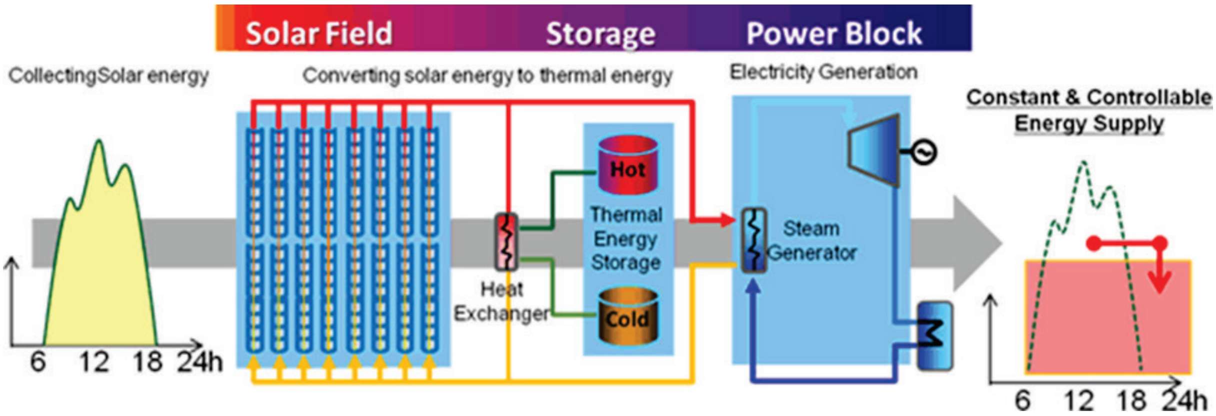

Figure 13.4: Schematic of a CSP system consisting of solar field, storage system and power block (Chiyoda 2016).

13.2.1.1 Technology categorization

The four CSP technologies are *Parabolic Trough Collector* (PTC), *Linear Fresnel Reflector* (LFR), *Central Receiver System* (CRS) and *Parabolic Dish Concentrator* (PDC). While PTC and LFR plants concentrate the sun's rays on a focal line and reach maximum operating temperatures between 300-550°C, CRS and PDC plants focus the sunlight on a single focal point and can reach higher temperatures. PTC is currently the most mature and dominant CSP technology. In PTC plants, synthetic oil, steam or molten salt are used to transfer the solar heat to a steam generator, and molten salt is used for thermal storage. Among other CSP variants, CRS is presently under commercial demonstration, while LFR and PDC are less mature.

Parabolic Trough Collector (PTC) - Most installed capacities today replicate the design of the first commercial plants built in California in the 1980s, which are still operating (IEA 2014b). Long parabolic troughs (Figure 13.5) track the sun on one axis, concentrate the solar rays on linear receiver tubes isolated in an evacuated glass envelope, heat oil to 390°C, and then transfer this heat to a conventional steam cycle. Almost half the capacities built in Spain since 2006 have been equipped with thermal energy storage comprised of two tanks of molten salts, with 7 hours of nominal capacity (i.e. with full storage they can run seven hours at full capacity when the sun does not shine). This is now fully mature technology. In the United States, three 280 MW (gross capacity) plants using PTC technology were built and connected to the grid in 2013 and early 2014: two without storage, the Genesis and the Mojave projects in California, another with six-hour storage, the Solana generating station in Arizona.

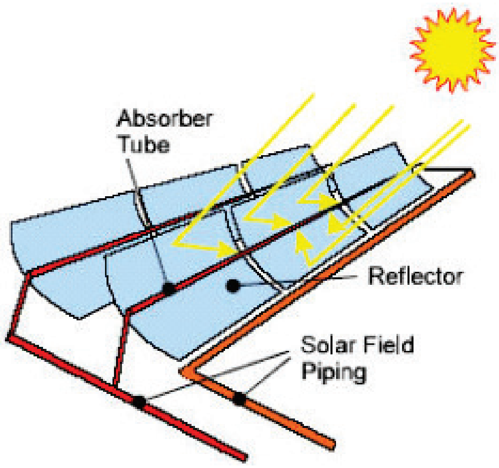

Figure 13.5: Schematic of parabolic trough concentrator (SolarPACES 2016a).

Central Receiver System (CRS) – Among the technologies making considerable progress since the publication of the previous IEA roadmap (IEA 2010b), central receiver systems (CRS), or solar towers, in particular, have emerged as a major option (Figure 13.6). After Abengoa Solar built two tower plants based on direct steam generation (DSG) near Seville, Spain, two much larger plants began operating in the United States. One large plant was built by BrightSource at Ivanpah in California, totaling 377 MW (net capacity) – the largest CSP capacity so far at a single place. The plant gathers three distinct towers – each with its own turbine – based on DSG technology and no storage. The other is the largest single tower plant ever built, with a capacity of 110 MW and 10 hour thermal storage. It was built by Solar Reserve at Crescent Dunes, Nevada, and uses molten salts as both heat transfer fluid and heat storage medium. Tower technology comes second to parabolic dishes with respect to concentration ratio and theoretical efficiency, and offers the largest prospects for future cost reductions.

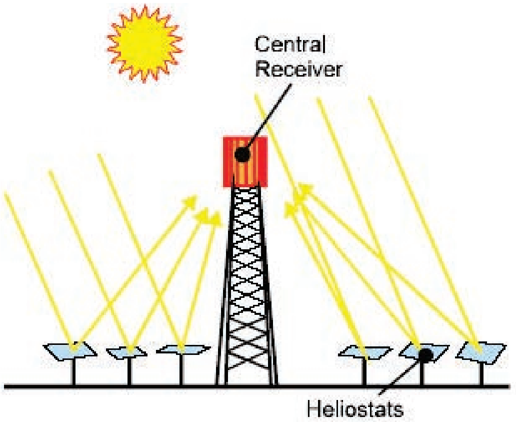

Figure 13.6: Schematic of central receiver or solar tower system (SolarPACES 2016a).

Linear Fresnel Reflector (LFR) - While in 2010 only a couple of prototypes using Linear Fresnel reflectors (LFR) were operating, a 30 MW LFR plant built in Calasparra, Spain, by the German company Novatec Solar started up in early 2012, and a 125 MW commercial LFR plant built in Rajasthan, India, by AREVA Solar, subsidiary of the French nuclear giant, began operating in 2014 (IEA 2014b). None of them have storage. LFR approximate the parabolic shape of trough systems but use long rows of flat or slightly curved mirrors to reflect the sun's rays onto a downward-facing linear, fixed receiver (Figure 13.7). LFR are compact and their almost flat mirrors easier to manufacture than parabolic troughs. The mirror aperture can be augmented more easily than with troughs, and secondary reflection makes possible higher concentration factors, reducing thermal losses. However, LFR have greater optical losses than troughs when the sun is low in the sky. This reduces generation in early morning and late afternoons, and also in winter, but can be overcome in part by the use of higher operating temperatures than trough plants. All LFR plants currently use DSG, as does one small parabolic trough plant in Thailand.

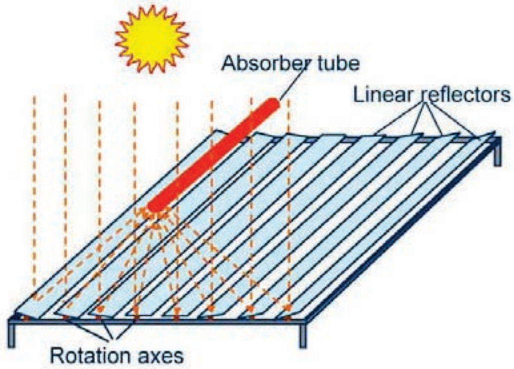

Figure 13.7: Schematic of Linear Fresnel Reflector system (SolarPACES 2016a).

Parabolic Dish Collector (PDC) - Parabolic dishes (Figure 13.8) supporting individual heat-to-electricity engines (Stirling motors or micro-turbines) at their focal points have almost disappeared from the commercial energy landscape, despite having the best optical efficiency (IEA 2014b). It has not proved possible to reduce the higher costs and risks of the technology, which also does not easily lend itself to storage, and thereby suffers from competition by PV, including CPV. Meanwhile an alternative type, called "Scheffler dish" after the name of its inventor, is being used by hundreds as a source of heat in community kitchens and other service or small industry facilities in India (IEA 2011b). A Scheffler dish is less efficient but more convenient, as it concentrates the sunrays on a fixed receiver.

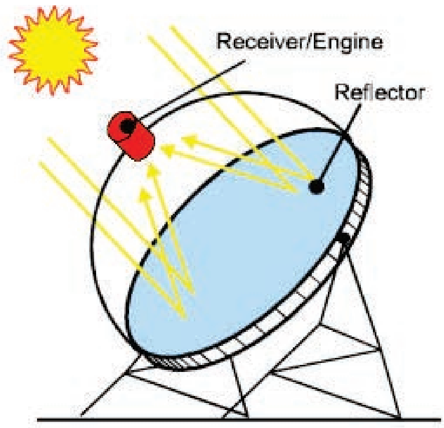

Figure 13.8: Schematic of parabolic dish concentrator system (SolarPACES 2016a).

13.2.1.2 Power cycles for CSP technologies

The most common power cycle used in solar power systems is the Rankine cycle, very similar to that used for many coal, nuclear or natural gas-fired steam power plants (IPCC 2011). The working fluid is usually either water or an organic liquid. Steam turbines are most efficient and most cost effective if they are built as large units and run at full load. Most, but not all, of the size efficiency advantage is achieved at the 50-100 MW scale. For a CSP application, a large turbine requires a large field, which results in extended thermal line losses, and so there is a trade-off against turbine size, with a 250 MW unit being suggested by many observers as offering the lowest cost of energy (Lovegrove and Stein 2012).

The most efficient state-of-the-art steam turbines work at steam inlet temperature of up to 700°C. Trough and linear Fresnel concentrators are, however, limited to around 400°C if the heat transfer fluid (HTF) is thermal oil and up to 500°C if an alternative HTF such as direct steam generation (DSG) is used. Tower and dish systems are able to reach the temperatures needed for the highest possible steam turbine inlet temperatures and pressures; the limitation in that case becomes survival of materials either in the turbine or in the solar receiver.

Present trough plants using oil as HTF are limiting steam turbine temperatures to 370°C and turbine cycle efficiencies to around 37%, which leads to design-point solar-to-electric efficiencies in the order of 18% and annual average efficiency of 14% (IPCC 2011). To increase efficiency, alternatives to the use of oil as the heat transfer fluid – such as producing steam directly in the receiver or using molten salts – are being developed for troughs.

CSP plants may also be integrated with fossil fuel-fired plants such as displacing coal in a coal-fired power station or contributing to gas-fired integrated solar combined cycle (ISCC) systems. In ISCC power plants, a solar parabolic trough field is integrated in a modern combined cycle gas and steam power plant; the waste heat boiler is modified and the steam turbine is oversized to provide additional steam from a solar steam generator. Better fuel efficiency and extended operating hours make combined solar/fossil power generation much more cost-effective than separate CSP and combined cycle plants (IPCC 2011). However, without including thermal storage, solar steam could only be supplied for some 2’000 of the 6’000-8’000 combined-cycle operating hours of a plant in a year. Furthermore, because the solar steam is only feeding the combined cycle turbine – which supplies only one-third of its power – the maximum solar share obtainable is under 10%. Nonetheless, this concept is of special interest for oil- and gas-producing Sunbelt countries, where solar power technologies can be introduced to their fossil-based power market (Teske 2009).

Hybrid solar/fossil plants have received increasing attention in recent years, and several integrated solar combined-cycle (ISCC) projects have been either commissioned or are under construction in the Mediterranean region and the USA (IPCC 2011). The first plant in Morocco (Ain Beni Mathar: 470 MW total, 22 MW solar) started operation in June 2010, and two additional plants in Algeria (Hassi R’Mel: 150 MW total, 30 MW solar) and Egypt (Al Kuraymat: 140 MW total, 20 MW solar) are in operation since 2011. In Italy, another example of an ISCC plant is Archimede with a 31’000-m^2 parabolic trough solar field that is the first using molten salt as the heat transfer fluid (Teske 2009).

13.2.1.3 Thermal energy storage systems

Most CSP plants have some ability to store heat energy for short periods of time and thus have a “buffering” capacity that allows them to smooth electricity production considerably and eliminate the short-term variations of other intermittent renewable energy sources like PV or wind.

The two main parameters that influence the solar capacity factor of a CSP plant are the solar irradiation and the amount of storage or the availability of a gas-fired boiler as an auxiliary heater, for example, in the SEGS plants in California (Fernández-García, Zarza et al. 2010). In case of solar-only CSP plants, the capacity factor is directly related to the available solar irradiation. With storage, the capacity factor could in theory be increased to 100%; however, this is not an economic option and parabolic trough plants are now designed for 6-7.5 hours of thermal energy storage (TES) and a capacity factor of 36-41%. Tower plants, with their higher temperatures, can charge and store molten salt more efficiently, and projects have been designed and constructed for up to 15 hours of storage, giving a 75% annual capacity factor.

When thermal storage is used to increase the capacity factor, it can reduce the levelised cost of solar thermal electricity (LCOE). The extra investments needed – in a larger solar field and in the storage system – are spread over more kWh, as the power block (turbine and generators) and many auxiliaries run for more hours. By contrast, storage that first takes electricity from the grid (such as pumped-storage hydropower, or battery storage) always increases the LCOE shifted in time (IEA 2014c). Thermal storage also has remarkable “return” efficiency, especially when the storage medium is also used as heat transfer fluid. It may then achieve 98% return efficiency – i.e., energy losses are limited to about 2% (IEA 2014b).

The most established storage medium is molten salt, typically stored in a "cold" tank (e.g., at 290°C) and a hot tank (e.g., at 565°C), between which the molten salt is transported (Figure 13.9). Large amounts of salt are required[343] and it has to be ensured that the salt temperature is kept above the melting point at all times.[344] Most plants use heat exchangers from the heat transfer fluid, typically thermal oil, to molten salt (Figure 13.10). In some recent plants, molten salt serves directly as heat transfer fluid (Tian and Zhao 2013).

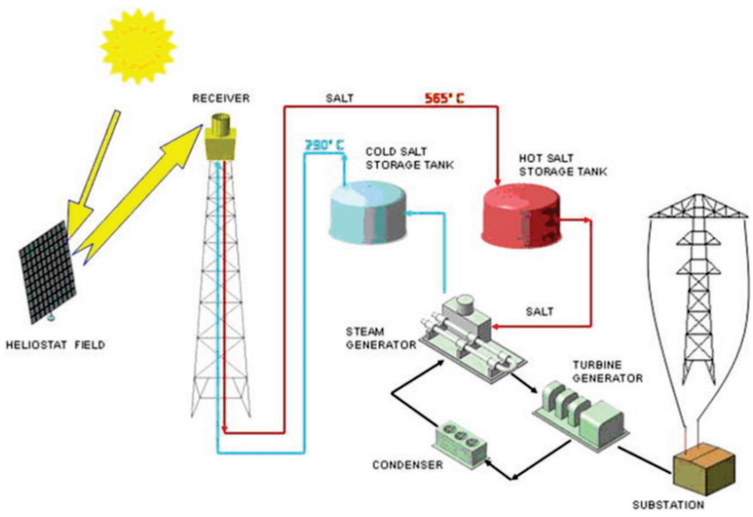

Figure 13.9: Solar tower power plant with two tank thermal energy storage (TES) using molten salt (Ortega, Burgaleta et al. 2008).

In a few CSP plants with steam as heat transfer fluid, the steam is directly used as storage medium for short term storage up to about one hour (e.g., in the solar tower plants PS10 and PS20 near Seville, Spain).

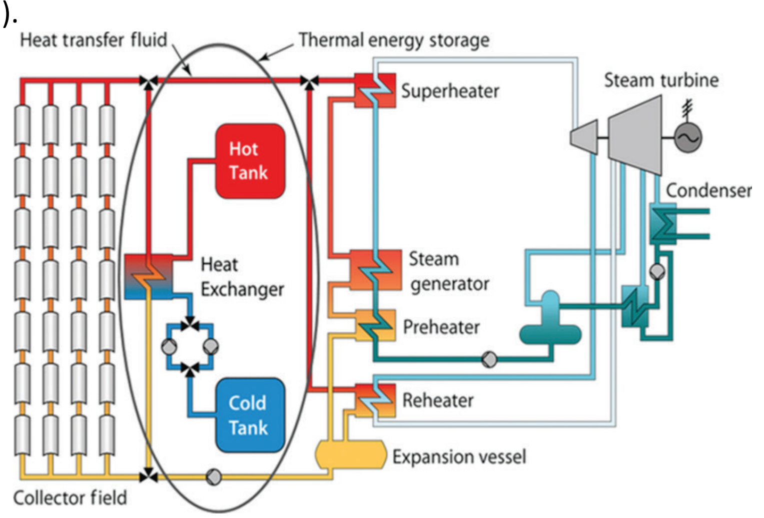

Figure 13.10: Parabolic through plant with two tank indirect heat storage (Siegel 2012).

13.2.2 Future technologies

CSP is a proven technology at the utility scale (IPCC 2011). The longevity of components has been established over two decades, O&M aspects are understood, and there is enough operational experience to have enabled O&M cost-reduction studies not only to recommend, but also to test, those improvements. In addition, field experience has been fed back to industry and research institutes and has led to improved components and more advanced processes. Importantly, there is now substantial experience that allows researchers and developers to better understand the limits of performance, the likely

[343] For example, the 50 MW parabolic trough plant ANDASOL 1 uses 28'500 tons of molten salt allowing for 7.5 hours of electricity production after sunset.

[344] Standard „solar salt" consists of a mixture of 60wt% $NaNO_3$ and 40wt% KNO_3. It has a melting point of 220°C and starts to decompose above 565°C.

potential for cost reduction, or both. Studies (Sargent and Lundy 2003) have concluded that cost reductions will come from technology improvement, economies of scale and mass production. Other innovations related to power cycles are discussed below.

13.2.2.1 Power cycle for future CSP technologies

CSP is a technology driven largely by thermodynamics. Thus, the thermal energy conversion cycle plays a critical role in determining overall performance and cost (IPCC 2011). In general, thermodynamic cycles with higher temperatures will perform more efficiently. Of course, the solar receivers that provide the higher-temperature thermal energy to the process must be able to perform efficiently at these higher temperatures, and today, considerable R&D attention is on increasing the operating temperature of CSP systems. Although CSP works with turbine cycles used by the fossil-fuel industry, there are opportunities to refine turbines such that they can better accommodate the duties associated with thermal cycling invoked by solar inputs.

State-of-the-art steam turbines are now produced that work at supercritical conditions, for maximum conversion efficiency (Lovegrove and Stein 2012). Supercritical steam power plants operate at pressures and temperatures above the critical point (22 MPa, 374°C); at these conditions, the phase-change occurs continuously rather than via nucleate boiling, at higher temperatures. Viable only at very large scales, these turbines have not yet been applied to CSP plants.

Two commercial solar tower system configurations are in active commercial development today (Kearney 2013). In one configuration, called the indirect configuration, a working fluid other than water or gas is heated in the receiver, held in a TES system if present, and then sent to a steam generator train to produce steam that, in turn, drives a conventional turbine generator to produce electricity. Current commercial designs based on this concept are using molten nitrate salts as the working fluid because of its superior heat-transfer and energy-storage capabilities. In the other configuration, called the direct steam generation (DSG), water/steam is used as the working fluid, heated in the receiver and sent directly to the Rankine turbine inlet. The direct steam solar receiver may have separate receiver sections for steam generation, superheating, and even reheating if applicable. Another direct configuration, not yet commercialized, is to use a gas working fluid like air or CO_2 to drive a Brayton or Rankine cycle power system.

Areas with sufficient direct irradiance for CSP development are usually arid and many lack water for condenser cooling. Dry-cooling technologies for steam turbines are commercially available, so water scarcity is not an insurmountable barrier, but it leads to an efficiency penalty and an additional cost (IEA 2014b). Wet-dry hybrid cooling can significantly improve performance, with water consumption limited to heat waves. For large CSP plants, dry cooling could be further improved and the efficiency penalty reduced or suppressed with a modified “Heller system”, using condensing water in a closed system with a cooling tower tall enough to allow for natural updraft (Bonnelle, Siros et al. 2010).

Heat transfer fluids such as molten salts and others are already preferred for central receivers (IPCC 2011). Central receivers and dishes are capable of reaching the upper temperature limits of these fluids (around 600°C for present molten salts) for advanced steam turbine cycles, whether subcritical or supercritical, and they can also provide the temperatures needed for higher-efficiency cycles such as gas turbines (Brayton cycle) and

Stirling engines. Such high-temperature cycles have the capacity to boost design-point solar-to-electricity efficiency to 35% and annual average efficiency to 25%. The penalty for dry cooling is also reduced, and at higher temperatures thermal storage is more efficient.

Besides integrating solar parabolic trough fields in a modern gas and steam power plant, highly efficient ISCC power plants using a solar central receiver system with combined Brayton and Rankine cycles are conceivable in future (Figure 13.11).

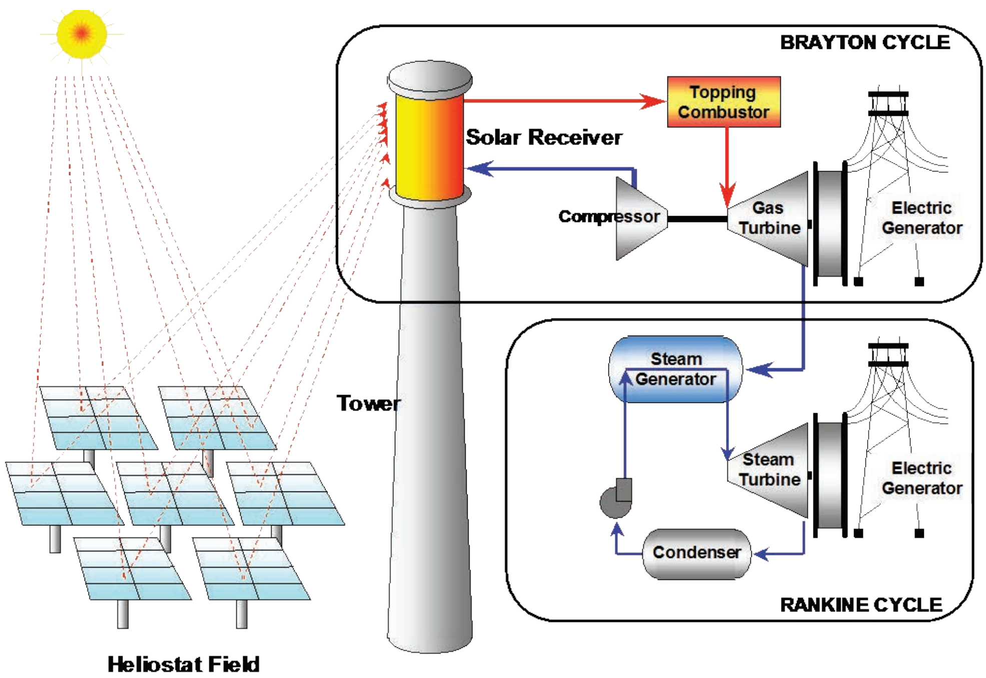

Figure 13.11: Highly efficient, solar-driven integrated solar combined cycle (ISCC) power plant. Source: ETHZ/PSI.

13.2.2.2 Future thermal energy storage systems

Up to now TES systems are making use of sensible heat storage, typically in two tank molten salt systems. Numerous R&D activities are ongoing for alternative thermal storage systems (Gil, Medrano et al. 2010, Siegel 2012, IRENA 2013) including (1) improved molten salt systems, e.g. using other molten salt mixtures including Ca and/or Li salts, allowing for lower melting points and/or higher upper operation temperatures; (2) phase change materials (Liu, Saman et al. 2012); (3) packed bed thermal storage systems (Singh, Saini et al. 2010) based on natural rocks, specific glass qualities, metallurgical slags and others; (4) chemical storage systems working on reversible chemical reactions (Pardo, Deydier et al. 2014).

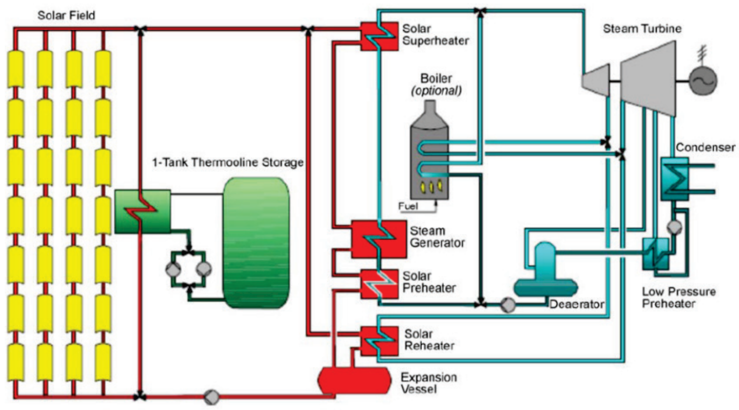

Figure 13.12: Parabolic trough plant with one tank thermocline storage, e.g. from a packed bed (Gil, Medrano et al. 2010).

While even improved molten salt mixtures are typically limited to operation temperatures of below 600-700°C, the other listed alternatives have the potential to be used at higher temperatures in case appropriate storage materials are chosen. This is specifically relevant for future central receiver plants targeting higher operation temperatures. They also avoid the issue of freezing prevention inherent to molten salt systems. Furthermore, many systems can be realized with one tank only, in which a "thermocline" front separates the hot from the cold sector within the tank, as shown in Figure 13.12 (Mira-Hernández, Flueckiger et al. 2015).

13.2.3 System efficiency of solar thermal technologies

The performance of a CSP plant is characterized by its annual solar-to-electric conversion efficiency. This metric includes all of the energy losses that affect the annual electricity produced by the plant, including optical, thermal, and electrical parasitic losses, as well as forced and planned outages for maintenance (USDOE 2012). According to the SunShot Vision Study (USDOE 2012), the current design-point solar-to-electric efficiency – the net efficiency in the ideal case when the sun is directly overhead – for a parabolic trough plant ranges from 24–26%, and the overall annual average conversion efficiency is about 13-15%.[345] The annual average solar-to-electric conversion efficiency of a power tower is about 14-18%, with direct-steam towers slightly higher than molten-salt towers. The design-point efficiency is about 20-24%. Dish/Stirling systems have demonstrated the highest recorded CSP design-point solar-to-electric efficiency (31.4%) and have estimated annual conversion efficiencies in the low 20% range. Other studies report efficiency values in a similar range (Table 13.1). For example, Viehbahn, Kronshage et al. (2008) argue that for current parabolic trough systems the maximum conversion efficiency will be reached at 16% because of technology reasons. The change to direct steam generation will enable a higher efficiency assumed to reach 19% as maximum. Linear Fresnel reflector systems will reach 12% and therefore only two thirds of the parabolic trough, while the central receiver's efficiency will increase to 18%. Viehbahn, Kronshage et al. (2008) assume that the 2050 values will be the same as in 2025, because the most important development will take place before.

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[345] The design-point values represent an ideal case that is useful for comparing between different components, such as two different receiver designs. This metric is also used for evaluating photovoltaic (PV) panels. The annual average efficiency provides a better assessment of actual operation (USDOE 2012)

Table 13.1: Annual solar-to-electricity efficiency of STE plants.

Annual solar-to-electricity efficiency [%]	2005	2015	2020	2035	2050
Solar thermal technology	-	15-17 [a]	17-19 [a]	-	19-22 [a]
Parabolic trough collector	10-15 [b]	13-15 [c] ~15 [e]	-	19 [d]	19 [d]
Linear Fresnel reflector	9-11 [b]	9-13 [c] ~11 [e]	-	12 [d]	12 [d]
Central receiver system	8-11 [b]	14-18 [c] ~17 [e]	-	18 [d]	18 [d]
Parabolic dish concentrator	15-20 [b]	22-24 [c] ~22 [e]	-	-	-

[a] (Pitz-Paal and Elsner 2015); [b] (Pitz-Paal 2008); [c] (Liu, Steven Tay et al. 2016); [d] (Viehbahn, Kronshage et al. 2008); [e] (MIT 2015).

13.3 Technical realization and potential for electricity generation

13.3.1 Physical potential

According to (Gantner and Hirschberg 1997) the theoretical solar energy potential for Switzerland is $4.8 \cdot 10^7$ GWh/a, while in 2015 the total energy consumption was about $2.33 \cdot 10^5$ GWh or 838,360 TJ (BFE/SFOE 2016f), and the electricity consumption reached about $5.82 \cdot 10^4$ GWh or 209,690 TJ (BFE/SFOE 2016e). In comparison, the theoretical potential of solar thermal electricity generation in North Africa is nearly unlimited, attaining $1.3 \cdot 10^6$ TWh/a (Broesamle, Mannstein et al. 2010), which corresponds to more than 60 times the estimated World's total electricity consumption of $21 \cdot 10^3$ TWh/a in 2012 (CIA 2016).

13.3.2 Technical potential

The technical electricity generation potential of CSP plants in the Swiss Alps is in the range of 5'000 TJ/a ((EGES 1988), for 2025) or 10'000 ± 3'000 TJ/a (2'800 ± 830 GWh/a) (SGS 1996). The latter value corresponds to the amount of electricity that can be produced per year, assuming reasonable boundary conditions but neglecting economic viability (Gantner and Hirschberg 1997). Worldwide, the technical potential of CSP plants in 2050 is around 8'000 EJ/a (IPCC 2011), if all land areas with high direct-normal irradiance (DNI) – minimum DNI of 2,000 kWh/m^2/a is required – were defined as suitable for CSP, and just 20% of that land was excluded for other uses.

Table 13.2 summarizes the cumulated installed capacity between 2005 and 2050 using data from selected international studies published between 2003 and 2016. For example, Viehbahn, Kronshage et al. (2008) distinguish between three scenarios, shown in Figure 13.13. The "very optimistic" CSP deployment scenario is built upon a study of Greenpeace and the European Solar Thermal Industry Association (ESTIA) published in 2003 (Aubrey 2003) and updated in 2005 (Baker 2005). Their long-term scenario describes an ambitious solar thermal power development starting from 1.6 GW in 2010 and reaching 630 GW in 2040. These figures are combined with data from the World Energy Assessment of the

United Nations Development Program (UNDP 2000), which reports only two figures for future solar thermal electricity capacity (15 GW in 2020 and 1'000 GW in 2050) but illustrates a smooth continuation to the 2040 figure reported by (Aubrey 2003). To reach this ambitious goal, UNDP assumes growth rates similar to the development of wind power plants and calculates with an average rate of 20-25% per year after 2010 and 15% per year between 2020 and 2050. Under "optimistic-realistic" conditions, where the worldwide CSP capacity development is assumed to be compatible with the 2DS (2°C) scenario, an installed capacity of around 400 GW is expected in 2050. After a slow development until 2020 (160 GW), a strong increase during the next decades determines the development path until 2050 (with a growth rate of 17% per year until 2030 and an average rate of 5.5% per year between 2030 and 2050). The "pessimistic" scenario is assuming that only 40% of the CSP capacity installed within the "optimistic-realistic" scenario will be reached from 2010 to 2025. After this time the share is continuously decreased to 30% in 2050. This results in a low capacity of 14 GW in 2020 and up to 120 GW in 2050.

Table 13.2: Technical global potential of solar thermal power plants (GW installed capacity). Comparison of selected studies on CSP deployment until 2050.

Year	GP-ESTIA 2003 [a]	NEEDS 2008 [b]	GP-ESTELA-SP 2009 [c]	IEA 2010 [d]	GP-EREC-GWEC 2012 [e]	IEA 2014 [f]	GP-ESTELA-SP 2016 [g]
2005	0.5	0.35	-	-	-	-	-
2010	1.6	0.8-2	1.6-4	1	-	-	-
2015	6	-	4-29	-	5-34	5	5-6
2020	21	14-40	7-84	147	11-166	(11)[h]	11-42
2025	48 [i]	26-89	10-187	-	-	(115)[h]	-
2030	106	47-200	13-342	337	24-714	261 (260)[h]	27-350
2035	260 [j]	-	15-550	-	-	(450)[h]	-
2040	630	83-630	16-818	715	40-1362	664 (650)[h]	54-940
2045	-	-	17-1144	-	-	(830)[h]	-
2050	-	120-1000	18-1524	1089	62-2054	982 (980)[h]	90-1660

[a] (Aubrey 2003); [b] (Viehbahn, Kronshage et al. 2008) (low: pessimistic; high: very optimistic); [c] (Teske 2009) (low: reference; high: advanced); [d] (IEA 2010b); [e] (Teske 2012) (low: reference; high: energy [r]evolution); [f] (IEA 2014b); [g] (SolarPACES 2016b) (low: reference; high: advanced); [h] (IEA 2014b) (fold-out) [i] Own interpolation of data from 2020 and 2030 (average growth rate 17.3%); [j] Own interpolation of data from 2030 and 2040 (average growth rate 19.5%).

Greenpeace, the European Solar Thermal Electricity Association (ESTELA), and IEA SolarPACES present three different scenarios for the future growth of solar thermal electricity around the world (Teske 2009, Teske 2016). The "reference" scenario in the updated version (2016), derived from (IEA 2014a, IEA 2014b), foresees cumulative global STE capacity of 11 GW in 2020 and 90 GW in 2050. Under the "moderate" scenario, growth rates are expected to be substantially higher than in the reference scenario, resulting in solar thermal power capacity as high as 22 GW by 2020 and 781 GW by 2050. This would represent around 5% of global electricity demand in 2050. The analysis based on the assumptions of the "advanced" scenario, with high shares of solar electricity from CSP plants, shows that concentrating solar power could meet up to 12% of the world's power needs in 2050.

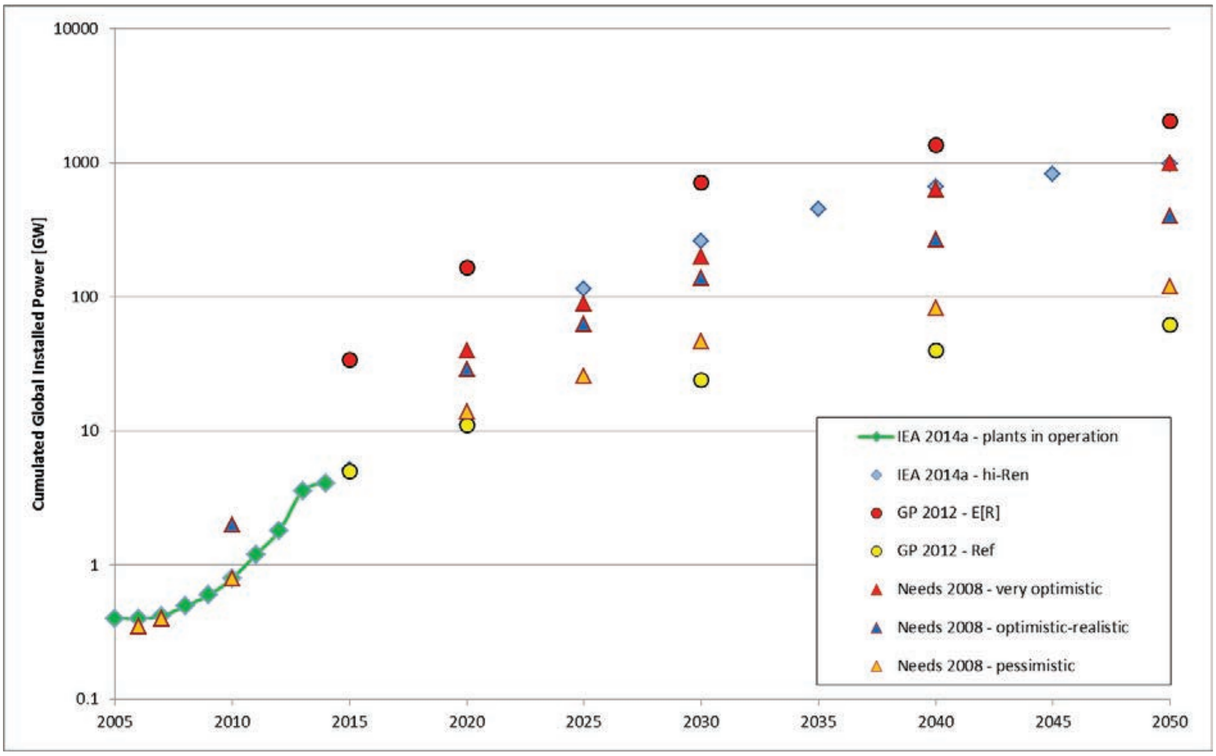

Figure 13.13: CSP plants in operation (green diamonds) and forecast cumulated global installed power for STE according to selected studies and scenarios (Viehbahn, Kronshage et al. 2008, Teske 2012, IEA 2014b).

Another study of Greenpeace, the European Renewable Energy Council (EREC), and the Global Wind Energy Council (GWEC) presents two scenarios to show the wide range of possible pathways in each world region for a future energy supply system (Teske 2012). The "reference" scenario, based on (IEA 2011a, IEA 2011b) is reflecting a continuation of current trends and policies, while the "energy [r]evolution" scenario is designed to achieve a set of environmental policy targets such as the reduction of worldwide carbon dioxide emissions from energy use down to a level of below 4 Gt per year by 2050 in order to hold the increase in global temperature under +2°C. Actual and predicted CSP capacities are depicted in Table 13.3 and Figure 13.13. (Teske 2012) foresees cumulated installed STE capacity for different world regions, both according to the "reference" and "energy [r]evolution" scenarios. Table 13.3 depicts values for selected regions from 2015 to 2050.

Table 13.3: Technical potential of solar thermal power plants (GW installed capacity) for selected world regions. According to (Teske 2012).

Installed capacity [GW]	2015	2020	2030	2040	2050
Global	*5-34*	*11-166*	*24-714*	*40-1362*	*62-2054*
North America	2-13	3-46	7-218	12-467	22-651
Latin America	0-5	0-8	1-21	2-44	3-69
Europe	1-2	2-12	4-32	5-55	6-82
Africa	0-1	1-13	4-42	8-101	14-161
Middle East	1-4	1-25	3-102	4-146	6-235
India	0	0-4	0-79	0-142	1-223
China	0-1	1-42	2-138	2-203	3-295
Other world regions [a]	1-8	3-18	3-82	7-204	7-338

[a] Eastern Europe/Eurasia; Non-OECD Asia; OECD Asia Oceania.

Since 2010, CSP deployment has been slower than expected in the first CSP roadmap developed by IEA (IEA 2010b). The 147 GW of cumulative capacity expected to be reached by 2020 is now likely to be achieved seven to ten years later at best (IEA 2014b). As STE becomes competitive on more markets, however, its deployment is likely to accelerate after 2020, potentially reaching impressive growth in a carbon-constrained world.

13.3.2.1 Interconnection of electricity grids

The CSP roadmap of IEA (IEA 2010b) foresees long-range transportation of electricity as an important way of increasing the achievable potential of CSP. Large countries such as Brazil, China, India, South Africa and the United States will have to arrange for large internal transmission of CSP-generated electricity.

The transfer of large amounts of solar energy from desert areas to population centers has been promoted, in particular, by the DESERTEC Foundation. The DESERTEC Industrial Initiative (Dii 2012, Dii 2013) aims to establish a framework for investments to supply the Middle East, North Africa and Europe (EUMENA) with solar and wind power. The long-term goal is to satisfy a substantial part of the energy needs of the Middle East and North Africa (MENA), and meet as much as 15% of Europe's electricity demand by 2050.

Dii (2012) analyzed an integrated power system for EUMENA in the year 2050 based on a share of 90% renewables. The focus was on electricity exchange between regions and cost benefits from power system integration between MENA and Europe. All scenarios investigated show that an integrated EUMENA power system is highly beneficial for both MENA and Europe in the long term. In the follow-up report "Getting started" (Dii 2013), a sophisticated model was used to analyze the transition to the 2050 target picture considering the years 2020, 2030, 2040 and 2050, with a focus on the time aspect of transition. Generation, transmission and storage are all part of the cost-optimal power system to be produced under the constraints that load and supply must be matched in each country in all 8760 hours of the year.

The development of grid infrastructure was derived with a two-step procedure. First, a cost-optimal grid development path was derived. Then, a gradual and feasible build-up of all interconnections between the 2020 starting point and the 2050 target grid was applied to the years 2030 and 2040. A valuable insight of the modelling was that the utilization of grids is high at all times in the process of building the EUMENA super-grid 2050.

It is apparent in Figure 13.14 that strong electricity exchange is expected to occur along the West-East axis in MENA. This facilitates, for example, the combination of the good wind conditions and associated potentials in Egypt with the strong build-up of CSP in Saudi Arabia, and the wind-dominated system in Libya. In summer, Egypt exports electricity during the middle of the day to Libya while importing at the same time from Saudi Arabia. At night, exports to Saudi Arabia take place, powered by wind in Egypt. Similarly, strong East-West balancing can be observed between France, Italy and Greece.

In the 2050 perspective, a number of countries in Europe emerge as hubs for electricity exchange. These hubs include Greece, Italy and Spain in the South as well as France in the center of Europe. Desert power is passed on from Italy to France, Switzerland and Austria. In France, it merges with desert power from the western corridor and goes further to the UK, Belgium, and Germany. These connections show a much higher gross exchange in the annual balance than the net trade balance. This means that desert power also plays a crucial role for these countries further north. In summer, they are served by desert power from the South, while wind and hydro power from the North go towards the South in winter. In the East, Turkey, Saudi Arabia and Egypt are the three pillars of strong electricity exchange and desert power exports.

The purpose of grids is to facilitate electricity trade. This role becomes even more important as more electricity is generated from (fluctuating) renewables. Yet at different stages of the transition to a power system with a renewable energy share of more than 90%, grids will facilitate different situations of demand and supply. It is therefore crucial for grids to be managed in an efficient and flexible way during this transition.

The abundant sunlight in the Middle East and North Africa will lead to lower costs, compensating for the additional expected transmission costs of about 21-63 USD/MWh (IRENA 2013) and electricity losses via HVDC transmission.

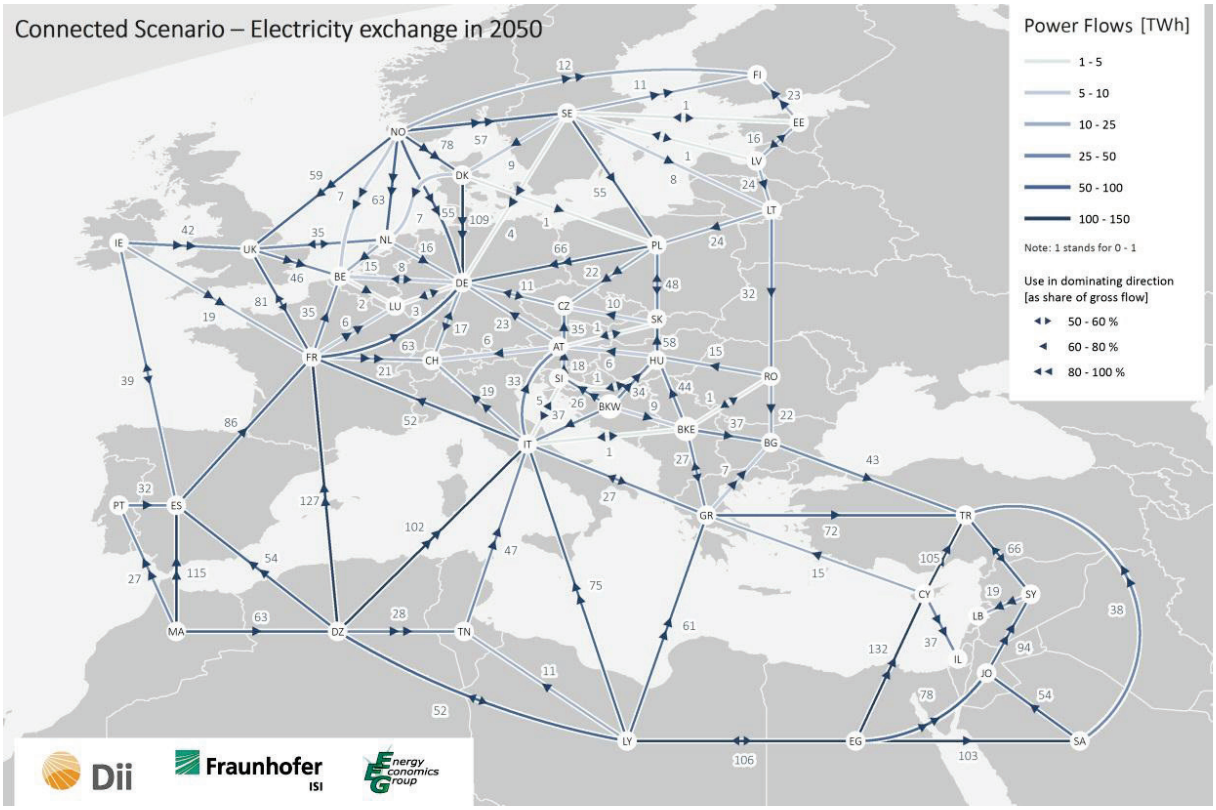

Figure 13.14: EUMENA electricity exchange in 2050 (Dii 2013).

13.4 Costs

Because the current globally installed capacity is limited and the technology is still under development, the cost of CSP plants and CSP electricity varies substantially depending on local labor and land cost, the size of the plant, the thermal storage system (if any), and – last but not least – the level of maturity (i.e. demo, pilot, commercial) of the project (IRENA 2013).

The cost of CSP electricity includes investment costs, operation and maintenance costs (O&M) and financing costs, the latter often being included in the investment costs. CSP plants with thermal storage are usually more expensive because of the larger solar field and the storage system, but they allow higher capacity factors and/or the possibility to generate electricity at peak demand times when electricity prices are higher (IRENA 2013).

Since 2010, thermal energy storage has been routinely used in 40% of Spanish plants and in a growing number of plants in the United States and elsewhere. The rapid cost reduction of PV systems seems to have made CSP without storage almost irrelevant, while the expected roll-out of PV will increase the need for flexible, dispatchable “mid-merit” technologies, i.e. technologies that may be optimally run for about 4,000 hours per year. CSP plants with five to ten hours of storage, depending on the DNI, seem best fitted to play this role (IEA 2014b).

In the electricity market, CSP technologies can be competitive with conventional technologies based on fossil fuels as well as with other renewable energies, as long as market incentives exist and substantial cost reduction occurs. The competitiveness of CSP technologies is measured by electricity generation cost (so-called “levelised cost of electricity" or LCOE[346] specified in USD/kWh[347]) that comprise total investment cost as well as operation and maintenance (O&M) cost.

13.4.1 Current costs

The available cost information refers mainly to the dominant parabolic trough technology, while much less information is available for other CSP options (IRENA 2013). The published investment costs of CSP plants are often confused when compared with other renewable sources, because varying levels of integrated thermal energy storage (TES) increase the investment, but also improve the annual output and capacity factor of the plant (IPCC 2011). Virtually no data are available in the public domain on the actual O&M costs of recently built CSP plants (IRENA 2015). Key elements for the LCOE of CSP plants are investment and financing costs, capacity factors, lifetimes, local DNIs, discount rates and O&M costs. Caution is advised in drawing general conclusions from the available information as very often data from most recent projects are not in the public domain or are based on different assumptions (IRENA 2013).

13.4.1.1 Investment costs

Despite around fifteen solar tower projects or more in operation, the current CSP market is dominated by PTC technologies, both in terms of number of projects and total installed capacity (around 85% of capacity). PTC technology's share of total installed capacity will decline slowly in the near future, as around one-third of the capacity of plants currently under construction are either solar tower projects or linear Fresnel systems (IRENA 2015).

According to (IRENA 2015), current investment costs for parabolic trough plants without storage in the OECD countries are typically between 4'600 and 8'000 USD/kW, which compares closely with bottom-up engineering cost estimates. PTC plants without storage in non-OECD countries have been able to achieve a lower cost structure, with investment costs between 3'500 and 7'300 USD/kW. A few PTC, CRS and LFR projects around the world with modest storage capacity of 0.5-4 hours have estimated investment costs of 3'400-6'700 USD/kW. The costs of PTC and CRS plants with thermal energy storage of 4-8 hours are typically between 6'800 and 12'800 USD/kW, with a slight downward trend over time, for projects for which data are available. For first-of-a-kind CRS projects with more than 8 hours of storage, cost estimates suggest a range of around 7'600-10'700 USD/kW.

IEA reports investment costs for large, state-of-the-art parabolic trough plants as 4'200-8'400 USD/kW (IEA 2010b) and 4'000-9'000 USD/kW (IEA 2014b), respectively, depending on labor and land costs, technologies, the amount and distribution of DNI and, above all, the amount of storage and the size of the solar field.

13.4.1.2 Operation and maintenance (O&M) cost

The O&M costs of CSP plants are low compared to those of fossil fuel-fired power plants (IRENA 2013). A typical 50 MW parabolic trough plant requires about 30-40 employees for

[346] LCOE depends on many different factors such as configuration and site of the solar power plant, size effects, full load hours, thermal storage, as well as solar and fossil shares.

[347] In the following, cost data are given in USD. In case the original costs are given in EUR, average currency conversion is used either for the year indicated as cost basis or for the year of publication. At current exchange rates, and considering the intrinsic uncertainties of LCOE calculations, figures provided in USD can be considered as corresponding to figures in CHF.

operation, maintenance and solar field cleaning[348]. In the California SEGS plants, the O&M costs are estimated at 40 USD/MWh (Cohen, Kearney et al. 1999), the most important components being the substitution of broken receivers and mirrors, and mirror washing. Technology improvements have reduced the requirement to replace mirrors and receivers, while increased automation has reduced the cost of other maintenance procedures by as much as 30%. As a result, the range of 20-40 USD/MWh seems to be a robust estimate of the total O&M costs, including all other miscellaneous costs, but costs will vary substantially by plant size. In contrast, IEA (2014b) states that O&M costs have been assessed in the Spanish plants at 50 USD/MWh, including fuel costs for backup and water consumption for mirror cleaning, feed-water make-up and condenser cooling.

13.4.1.3 Levelised cost of electricity (LCOE)

IRENA (2014a) is reporting a downward trend of the LCOE between 2012 and 2014. The LCOE for recent parabolic trough plants without storage is in the range of 190-380 USD/MWh. Adding storage narrows this range to 200-360 USD/MWh. The weighted average LCOE of CSP by region varied from a low of 200 USD/MWh in Asia to a high of 250 USD/MWh in Europe in recent years, with the LCOE of individual projects varying significantly depending on location and level of storage. However, as costs are falling, recent projects are being built with LCOE of 170 USD/MWh, and power purchase agreements (PPA) are being signed at even lower values of 140-190 USD/MWh where low-cost financing is available. Future cost reductions can be expected if deployment accelerates, but policy uncertainty is hurting growth prospects.

Liu, Steven Tay et al. (2016) summarize representative features of different CSP technologies for current (2015) and near-future (2020) CSP plants, among them investment cost, O&M cost, and LCOE for parabolic trough, tower, and linear Fresnel plants, based on information available from various international organizations (Table 13.4).

[348] Estimates carried out in Germany, Spain and the US show that some 8-10 jobs are created for each MW of installed CSP capacity, including manufacturing, installation, operation and maintenance.

Table 13.4: Current (2015) and near-future (2020) investment cost, operation and maintenance (O&M) cost, and levelised cost of electricity (LCOE) of various CSP technologies: Average values without storage and 4-15 hours of storage. Also, the 2020 SunShot targets are included (USDOE 2012).

Solar thermal electricity (STE) cost	Parabolic Trough	Central Receiver	Linear Fresnel	2020 SunShot Target
Investment cost (USD/kW)				
no storage (OECD [e] countries)	4700-7300 [a]			3,770 [b]
	4600-8000 [c]			*SunShot assumptions:*
no storage (non-OECD)	3100-4050 [a]			solar field (< 75 USD/m^2)
	3500-7300 [c]			receiver and
with storage (all sizes)	6400-10700 [a]	6400-10700 [a]		HTF [f] (< 150 USD/kW) [a]
0.5-4 h storage	3400-6700 [c]	3400-6700 [c]	3400-6700 [c]	power block
4-8 h storage	6800-12800 [c]	6800-12800 [c]		(< 1200 USD/kW) [a]
> 8 h storage		7600-10700 [c]		storage (< 15 USD/kWh$_{th}$) [a]
O&M cost				
variable (USD/MWh)	20-40 [c]	20-40 [c]		
	50 [d]	50 [d]		
fix (USD/kW-yr)				40 [b]
LCOE (USD/MWh)				
no storage	260-370 [a]		190-380 [a]	
	190-380 [c]			
with storage (all sizes)	220-340 [a]		170-370 [a]	
	200-360 [c]			
6-7.5 h storage		200-290 [a]		
12-15 h storage		170-240 [a]		60 [b]

[a] (Liu, Steven Tay et al. 2016); [b] (USDOE 2012); [c] (IRENA 2015); [d] (IEA 2014b); [e] OECD: Organization of Economic Cooperation and Development; [f] HTF: heat transfer fluid.

13.4.2 Future Costs

13.4.2.1 Cost reduction potential

STE systems constitute a complex technology operating in intricate resource and financial environments, so many factors affect the LCOE (Gordon 2001). A study for the World Bank (WorldBank 2006) suggested four phases of cost reduction for CSP technology and forecast that cost competitiveness with non-renewable fuel could be reached by 2025. Figure 13.15 shows that cost reductions for CSP technologies are expected to come from plant economies of scale, reducing costs of components through material improvements and mass production, and implementing higher-efficiency processes and technologies (IPCC 2011).

A detailed study about the cost reduction potential till the year 2025 for the different CSP technologies (PTC, CRS and LFR) is provided in (KIC-InnoEnergy 2015). It surveys the major technological improvement options and their anticipated cost reduction. The calculated costs are for a site with a moderate DNI of 2050 kWh/a as available in Southern Spain, therefore they result in relatively high LCOE values, but are also relevant in the context of potential imports to Switzerland.

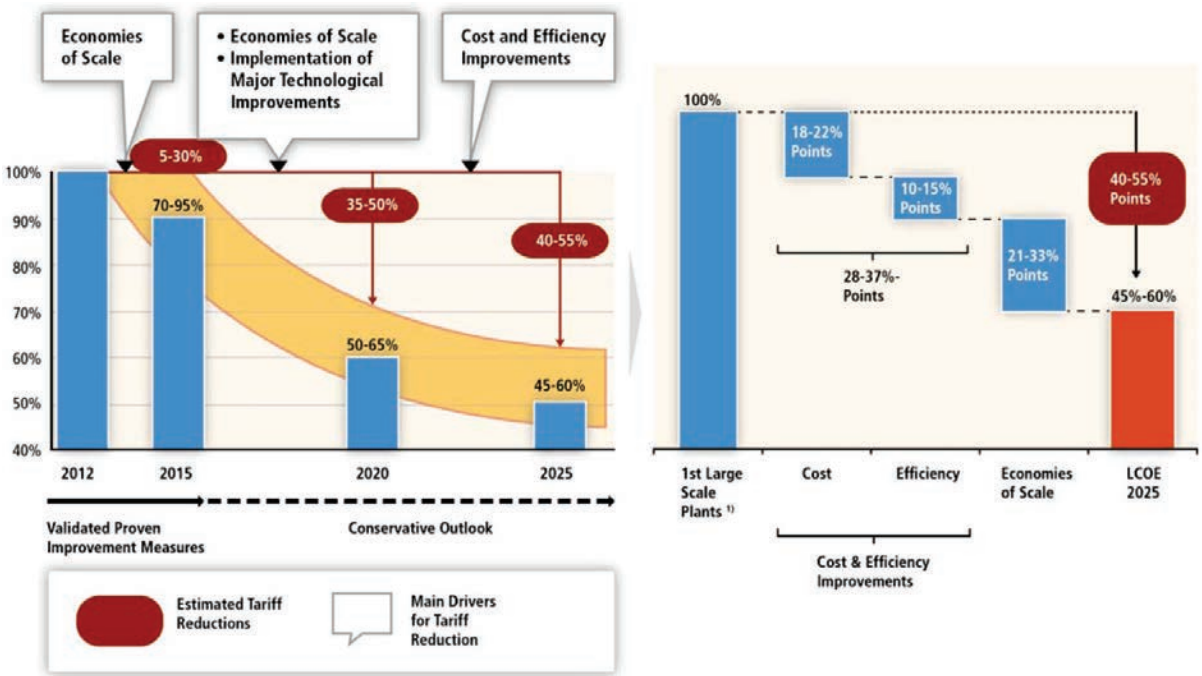

Figure 13.15: Expected cost decline for CSP plants from 2012 to 2025. The cost number includes the cost of the plant plus financing (Kearney 2010). As reduction ranges for cost, efficiency and economies of scale in the right panel overlap, their total contribution in 2025 amounts to less than their overall total. From (IPCC 2011).

For all the technology types, the impacts from STE technology innovations (excluding transmission, decommissioning, supply chain and finance effects) contribute an anticipated reduction in the LCOE by around 25% between 2014 and 2025. The savings are generated through a balanced contribution of reduced capital expenditure (CAPEX) and operational expenditure (OPEX) and increased annual energy production (AEP). To calculate a realistic LCOE for each scenario, real-world effects of supply chain dynamics, risks, cost of finance, transmission and decommissioning are considered in addition to technology innovations.

Telsnig (2015) investigated current and expected future costs mostly till the year 2030 for CSP plants in South Africa.

The learning rate for CSP, excluding the power block, is given as 10±5% by Neij (2008) and 10% by IEA (2014b). Other studies provide learning rates according to CSP components: Trieb (2011) gives 10% for the solar field, 8% for storage, and 2% for the power block, whereas Viehbahn, Kronshage et al. (2008) and Viebahn, Lechon et al. (2011) state 12% for the solar field, 12% for storage, and 5% for the power block. Cost reductions for parabolic trough plants in the order of 30-40% within the next decade are considered achievable. Central receiver technology is less commercially mature than troughs and thus presents slightly higher investment costs than troughs at present time; however, cost reductions of 40-75% are predicted for central receiver technology (IEA 2010b).

13.4.2.2 Investment costs

CSP technologies have come under pressure in recent years due to the price reductions of PV. The learning rate per doubling of cumulated installed capacities for CSP is smaller with only 10-12% (Hernández-Moro and Martínez-Duart 2013), and the global production has increased much more slowly compared to PV. IEA (2014a) anticipates that investment costs would follow a 10% learning rate (i.e., diminish by 10% for each doubling of cumulative capacities), and in the hi-Ren scenario fall by 2050 to a range of 2'800-4'100 USD/kW for a plant with six-hour storage – allowing for up to 4'500 full-load hours per year. The weighted average would be about 3'100 USD/kW by 2050. A comparison made by DIW (2013) shows that such prices are in the upper range of the current literature. Their proposed price projections for CSP without storage are all slightly above the median of the literature review and reflect current experiences and growth rates. A strong argument for market growth might be the good complementarity of CSP with heat storage (e.g., concrete, sand, or molten salts) and natural gas power plants for security of supply. Table 13.5 and Figure 13.16 compare current and future investment cost of solar thermal power plants until 2050 as predicted in selected studies.

Table 13.5: Investment cost of solar thermal power plants (USD/kW installed capacity). Comparison of selected studies on CSP deployment and cost until 2050. Currency of original cost data indicated in table footnotes.

Year	NEEDS 2008 [a]	GP-ESTELA-SP 2009 [b]	GP-EREC-GWEC 2012[c]	US DOE 2012 [d]	DIW 2013 [e]	IEA 2010[f]; 2014[g]	GP-ESTELA-SP 2016 [h]
2005	4100-7300	5200					
2010	6400	4000-4900	9300	5000 [i] 9200 [j]	5300-8000	4200-8400 [f]	
2015	5900	3950-4400	8100	4800 [i] 7900-8800 [j]		4600-7000 [g]	4800
2020	5500	3500-3900	6600	4600 [i] 3400-8500 [j]	5300	3100-5000 [g]	3900
2025	4800-5900	3200-3800		4400 [i] 3400-7500 [j]			3400
2030	4200	3250-3600	5750	4200 [i] 3400-6700 [j]	4600	2400-3800 [g]	3100
2035	3800	3100-3600		4100 [i] 3400-5900 [j]			3000
2040	3700	3000-3350	5300	3900 [i]	4000	2200-3300 [g]	3000
2045	3600	2900-3350		3700 [i]			2950
2050	3300-4500	2800-3100	4800	3500 [i] 3400-5900 [j]	3300	2000-3100 [g]	2900

[a](Viehbahn, Kronshage et al. 2008) (EUR_{2007}/kW; for year 2005, low: US plants; high: Andasol-1); [b] (Teske 2009) (EUR_{2008}/kW); [c] (Teske 2012) (USD_{2012}/kW); [d] (USDOE 2012) (USD_{2010}/kW); [e] (DIW 2013) (EUR_{2010}/kW); [f] (IEA 2010b) (year 2010: USD_{2010}/kW); [g] (IEA 2014b) (USD_{2014}/kW; weighed average; low: no TES; high: 6h TES); [h] (SolarPACES 2016b) (EUR_{2015}/kW); [i] without TES; [j] with TES (11 hours, solar multiple 2.4), lower value US DOE SunShot goal.

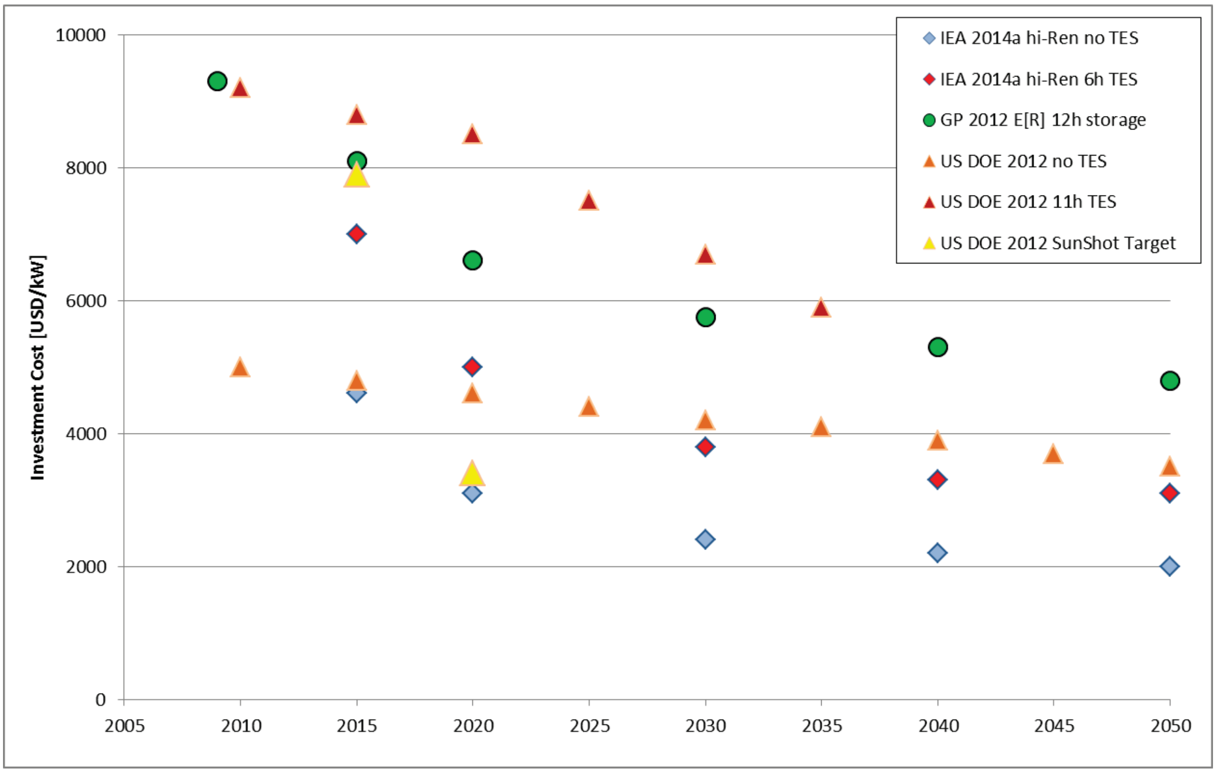

Figure 13.16: Forecast for CSP plant investment costs according to different studies, scenarios and technologies ((IEA 2014b); (Teske 2012); (USDOE 2012)).

13.4.2.3 Operation and maintenance (O&M) cost

In modern CSP plants, automation can reduce the O&M costs, including fixed and variable costs, and insurance by more than 30%. Further significant reductions are expected in the coming years (Turchi 2010b, Turchi 2010a). Overall, given recent experience and as a result of improved O&M procedures, in the long run it should be possible to reduce total O&M costs of CSP plants to 25 USD/MWh or less, even in OECD countries (IRENA 2015).

13.4.2.4 Levelised cost of electricity (LCOE)

USDOE (2012) states its CSP goals for the USA in terms of USD/MWh, rather than USD/kW, because the Solar Energy Technologies Program is designed to affect the LCOE and includes significant storage. The specific CSP goals are the following: 90-110 USD_{2005}/MWh by 2010; 60-80 USD_{2005}/MWh (with 6 hours of thermal storage) by 2015; and 50-60 USD_{2005}/MWh (with 12-17 hours of thermal storage) by 2020 (USD_{2005}, assumed 2009 base). The EU is pursuing similar goals through a comprehensive R&D program (IPCC 2011).

Pitz-Paal and Elsner (2015) state that the electricity generation costs of CSP plants with and without TES have decreased within the past five years by half to about 110-180 USD/MWh, depending on the location and financing scheme. According to IEA (2014b), the LCOE has the potential to be reduced to 50-80 USD/MWh by 2050. An important reason for the expected cost reduction is the increase in efficiency due to the rise of the upper process temperature. This also leads to more effective and thus cost-efficient storage systems. In addition, economies of scale are expected for this emerging technology, in particular for collector and receiver systems, which will lead to substantial reduction of production costs, while costs will only slightly adapt through scaling and standardization. Thus, in the long term, cost-efficient, renewable electricity would be available on demand, which could support the extension of electricity supply towards high shares of renewable energies.

The results for the temporal development of the LCOE are shown in Table 13.6 and in Figure 13.17 together with results from selected studies with a time horizon up to 2050. Table 13.7 provides a summary of the predicted investment cost, O&M and LCOE for the different CSP technologies.

Table 13.6: Levelised cost of electricity (LCOE) of CSP plants (USD/MWh). Comparison of selected studies on CSP deployment until 2050.

Year	NEEDS 2008 [a]	GP-ESTELA-SP 2009 [b]	IEA 2010 [c]	US DOE 2012 [d]	FISE 2013 [e]	IEA 2014 [f]	GP-ESTELA-SP 2016 [g]
2005	141-190						
2010		190-290	200-295	204			
2015				144-194	206	146-213	150-200
2020		150-200	100-130	98-116 60 [h]	173	116-169	120-180
2025	79-95				146	96-124	
2030			60-75		126	86-112	
2035						72-105	
2040			50-60			69-101	
2045						66-96	
2050	59-75		40-55			64-94	

[a] (Viehbahn, Kronshage et al. 2008) (EUR_{2007}/MWh; for year 2005, low: hybrid operation; high: solar-only operation); [b] (Teske 2009) (EUR_{2008}/MWh); [c] (IEA 2010b) (USD_{2010}/MWh, low: DNI 2600; high: DNI 2000); [d] (USDOE 2012) (USD_{2010}/MWh, low: CRS; high: PTC); [e] (FISE 2013) (EUR_{2013}/MWh); [f] (IEA 2014b) (USD_{2014}/MWh; hi-Ren scenario); [g] (Teske 2016) (EUR_{2015}/MWh); [h] (USDOE 2012) goal.

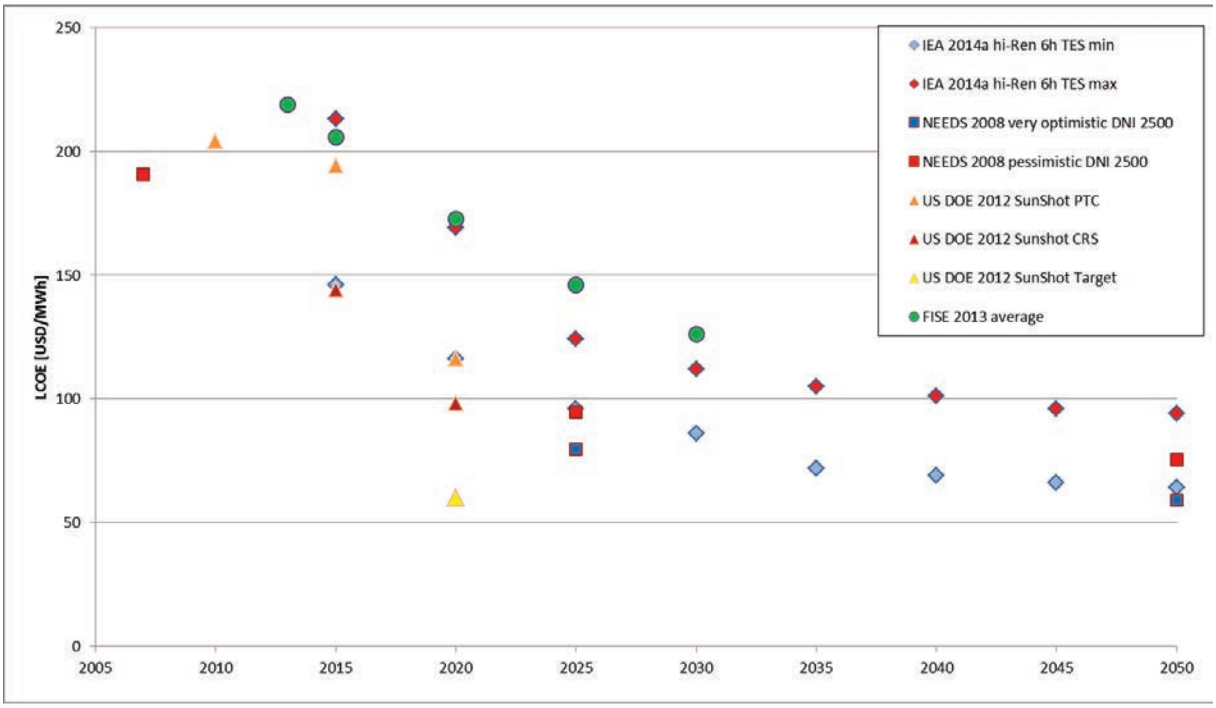

Figure 13.17: Forecast for LCOE according to different studies, scenarios and technologies (Viehbahn, Kronshage et al. 2008, IEA 2010b, USDOE 2012, FISE 2013, KIC-InnoEnergy 2015).

Table 13.7: Investment cost, operation and maintenance (O&M) cost, and levelised cost of electricity (LCOE) of CSP technologies until 2050: Average values without storage and 4-15 hours of storage, respectively.

Solar thermal electricity (STE) cost	2005	2015	2020	2035	2050
Investment costs (USD/kW)					
no storage		4600 [a]	3100 [a]	4100 [d]	2000 [a]
		3300-6500 [b]			
4 h storage		4800-5400 [c]	4500-5100 [c]		
6 h storage		7000 [a]	5000 [a]		3100 [a]
		5900-7900 [d]			
8h storage		6900-9200 [b]			3500 [b]
12h storage		8100 [e]	6600 [e]	3400-5900 [d]	4800 [e]
			6500 [d]		
14/15h storage	10400 [f]	7400 [f]	3800-6400 [d]		4250 [f]
O&M cost					
fix (USD/kW-yr)		60-65 [d]	40-50 [d]		58 [g]
LCOE (USD/MWh)					
no storage		160-331 [b]			
4 h storage		248-267 [c]	212-231 [c]		
6 h storage		144-194 [d]	116-169 [d,a]	72-105 [a]	64-94 [a]
8h storage		187-277 [b]	153 [b]		64 [g]
14/15 h storage			60-98 [d]		

[a] (IEA 2014b); [b] (FISE 2013); [c] (KIC-InnoEnergy 2015); [d] (USDOE 2012); [e] (Teske 2012); [f] (Trieb, Schillings et al. 2009); [g] (Trieb, Schillings et al. 2009, Dii 2012).

13.4.2.5 Value of solar thermal electricity

Thermal storage allows CSP to achieve higher capacity factors and dispatch electricity when the sun is not shining. This can make CSP a competitor of conventional power plants (IRENA 2013).

Several analyses focus on the impact of thermal storage on the electricity generation cost. It is clear that there is a trade-off between the incremental investment cost for thermal storage and the reduction of the electricity cost due to the improved capacity factor. Available analyses agree that for a given plant, the minimum LCOE is achieved with a solar multiple of about three and twelve hours of energy storage. However, this assumes that electricity always has the same economic value while in most actual markets the electricity prices vary over by day and season and are higher during peak demand periods. Therefore, the economic optimization of CSP services and thermal storage depends heavily on local conditions. If the production of the CSP plant coincides with peak demand and price periods, little or no storage may be more convenient, while if peak demand occurs in the early evening, thermal storage allows electricity to be dispatched when the electricity price is higher. If this is the case, the CSP plant with thermal storage not only offers a higher capacity factor, but is also more flexible to capture market opportunities. The economic value of the ability to dispatch CSP electricity during peak-demand periods depends on the specific country and project.

Although STE from CSP plants is not broadly competitive today, on-demand STE has higher value than PV electricity (IEA 2014b). Even in areas where afternoon peak time matches well with PV output, CSP plants offer a variety of ancillary services that are becoming increasingly valuable as shares of PV and wind (both variable renewables) increase in the electricity mix. CSP plants' thermal inertia and relatively small storage capacities are likely to be sufficient for them to provide these services. To some extent, these added values are able to compensate for higher costs. Utilities in the southwestern United States that are choosing CSP plants to comply with renewable energy portfolio standards appear to be aware of these advantages of STE — and adverse to the potential risks arising from the variable output of PV systems that have been deployed too rapidly.

Researchers at NREL have studied the future total values (operational value plus capacity value)[349] of STE with storage and PV plants in California in two scenarios: one with 33% renewables in the mix (the renewable portfolio standard by end 2020), including about 11% PV, another with 40% renewables (under consideration by California's governor), including about 14% PV. In both cases there is over 1 GW of electricity storage available on the grid. The main results indicate that at 33% renewable penetration, the bulk of the gap in favor of STE (94.6-107 USD/MWh vs. 47.1-58.2 USD/MWh) comes from its greater capacity value (47.9-60.8 USD/MWh vs. 15.2-26.3 USD/MWh), which avoids the costs of building additional thermal generators to meet demand. At 40% renewable penetration, the value of STE increases slightly to 96.0-109 USD/MWh, but the value of PV drops significantly to 2.4-17.6 USD/MWh, mostly reflecting the drop of its own capacity value (Jorgenson, Denholm et al. 2014). For investment decisions and planning, system values are as much important as LCOE.

Compared to non-dispatchable PV, the combined operational and capacity value translates to an increase in value of 50 USD/MWh to utility-scale solar energy in California under the 2020-mandated 33% renewable portfolio standard (RPS), or 60 USD/MWh under a 40% RPS (Jorgenson, Denholm et al. 2014).

13.5 Environmental aspects

13.5.1 Environmental Impacts

For electricity from CSP plants, the environmental consequences vary depending on the technology and site of the power plant. In general, compared to fossil fuel power generation, GHG emissions and other pollutants are strongly reduced without incurring additional environmental risks (IPCC 2011). Each square meter of CSP concentrator surface is enough to avoid the annual production of 0.25 to 0.4 t of CO_2. The energy payback time of CSP systems can be as low as five months, which compares favorably with their lifespan of about 25 to 30 years. Most CSP solar field materials can be recycled and reused in new plants (Geyer 2008).

Operation of CSP plants is unproblematic as long environmentally friendly heat transfer fluids (HTF) are used in trough plants, thus, limiting the technology options to more

[349] The "operational value" represents the avoided costs of conventional generation and includes fuel costs, start-up costs, variable operation and maintenance costs, and emission costs. The "capacity value" reflects the ability of to avoid the cost of building new conventional thermal generators in systems that need capacity in response to growing energy demands or conventional power plants retirement.

innovative designs, such as DSG or molten salts as HTF (IEA 2014b). For future CSP plants no special risks are known of the materials used (Pitz-Paal and Elsner 2015).

Land consumption and impacts on local flora and wildlife during the build-up of the heliostat field and other facilities are the main environmental issues for CSP systems (Pregger, Graf et al. 2009). A 100 MW CSP plant with a solar multiple of one would require 2 km^2 of land. However, the land needs to be relatively flat (particularly for linear trough and Fresnel systems), ideally near transmission lines and roads for construction traffic, and not in an environmentally sensitive area. Although the mirror area itself is typically only about 25-35% of the land area occupied, the site of a solar plant will usually be arid. Thus, it is generally not suitable for other agricultural pursuits, but may still have protected or sensitive species[350]. For this kind of system, sunny deserts close to electricity infrastructure are ideal.

13.5.1.1 Life-cycle GHG emissions current CSP plants

NREL has conducted a systematic literature review and harmonization of CSP lifecycle assessments (Burkhardt, Heath et al. 2012). Harmonization concerns the following parameters (figures used for harmonized GHG calculations in brackets): solar fraction (1)[351]; direct normal irradiance (2400 $kWh/m^2/a$)[352]; lifetime (30a); solar-to-electric efficiency (15% and 20% for trough and tower technologies, respectively); removal of auxiliary natural gas combustion and electricity consumption. Harmonized life-cycle GHG emissions are summarized in Table 13.8.

Table 13.8: Harmonized life-cycle GHG emissions of different current solar-thermal power generation technologies according to (Burkhardt, Heath et al. 2012).

	Parabolic trough			Power tower			Parabolic dish		
	min	mean	max	min	mean	max	min	mean	max
g CO_2eq/kWh	13	23	55	9	22	42	5	20	60

Ranges of life-cycle GHG emissions according to (Burkhardt, Heath et al. 2012) are shown in Figure 13.18.

[350] Relatively minor issues seem able to create disproportionate concerns. One example is the media hype on birds killed by solar heat in CRS configurations in the southwestern United States (ESTELA 2015) If killing birds had to be avoided at all costs, then windows, pet cats and roads should all be prohibited, as commented by (IEA 2014a) A recent study on avian mortality concludes that the number of birds killed every year by solar tower plants is insignificant compared to other sources of bird deaths (Walston Jr, Rollins et al. 2016).

[351] A solar fraction of 1 corresponds to “solar-only” operation without fossil back-up (natural gas combustion).

[352] A DNI of 2400 $kWh/m^2/a$ can be considered as representative for sites in e.g. North Africa.

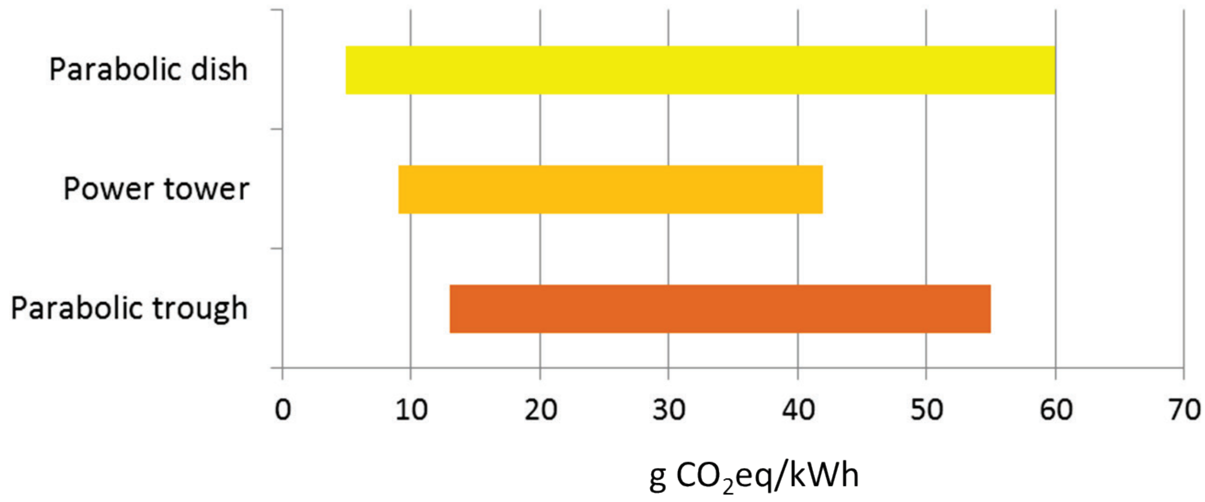

Figure 13.18: Ranges of life-cycle GHG emissions of different current solar-thermal power generation technologies according to (Burkhardt, Heath et al. 2012).

Telsnig (2015) analyzed CSP at two different sites in South Africa with DNI of slightly above 2000 kWh/m^2/a (similar to Southern Spain) and around 2500 kWh/m^2/a (similar to good sites in North Africa). Life-cycle GHG emissions calculated in this analysis are (excluding fossil back-up) within the ranges provided by (Burkhardt, Heath et al. 2012).

According to Pitz-Paal and Elsner (2015), the GHG emissions of CSP plants without fossil back-up are in the range of 15-20 g CO_2-eq/kWh and are comparable to wind power.

13.5.1.2 Life-cycle GHG emissions of future CSP plants

A dynamic study of the GHG emissions associated with electricity from CSP plants in Europe and Algeria (DESERTEC concept) resulted in current specific emissions of about 31 g CO_2eq/kWh (plants in Spain), which are expected to reduce to about 18 g CO_2eq/kWh in 2050 (case study: 90% production in Algeria, 10% in Spain) (Viebahn, Lechon et al. 2011). The decrease in emissions is mainly due to better solar irradiation conditions in Algeria, diminished by the higher burden resulting from the need to transmit the electricity to Europe.

The most detailed LCA of potential future CSP technologies was carried out by Viehbahn, Kronshage et al. (2008). They estimate reduction potentials for GHG emissions of parabolic trough plants of 20-60% by 2025 and 35-65% by 2050 compared to current plants, depending on the heat storage technology. For central receiver plants, they estimate reductions of GHG emissions of around 40% until 2025 and 50% until 2050 compared to current plants. These reduction potentials applied to the figures for current CSP plants in Table 13.8 are used as basis for estimating the life-cycle GHG of future plants[353], as summarized in Table 13.9.

[353] From the current point of view and considering the somewhat “slower-than-expected” expansion of CSP installations in recent years, the figures provided by (Viehbahn, Kronshage et al. 2008) for 2025 can be considered as quite optimistic and are therefore used representing potential development until 2035 in this study. Figures for 2020 are assumed to be equal to today (2016).

Table 13.9: Estimated life-cycle GHG emissions of different future solar-thermal power generation technologies applying reduction potentials from (Viehbahn, Kronshage et al. 2008) to figures from (Burkhardt, Heath et al. 2012).

	Parabolic trough			Power tower			Parabolic dish		
	2020	2035	2050	2020	2035	2050	2020	2035	2050
g CO_2eq/kWh	13-55	5-44	5-36	9-42	5-25	5-21	5-60	3-36	3-30

Ranges of potential life-cycle GHG emissions of future CSP technologies are shown in Figure 13.19.

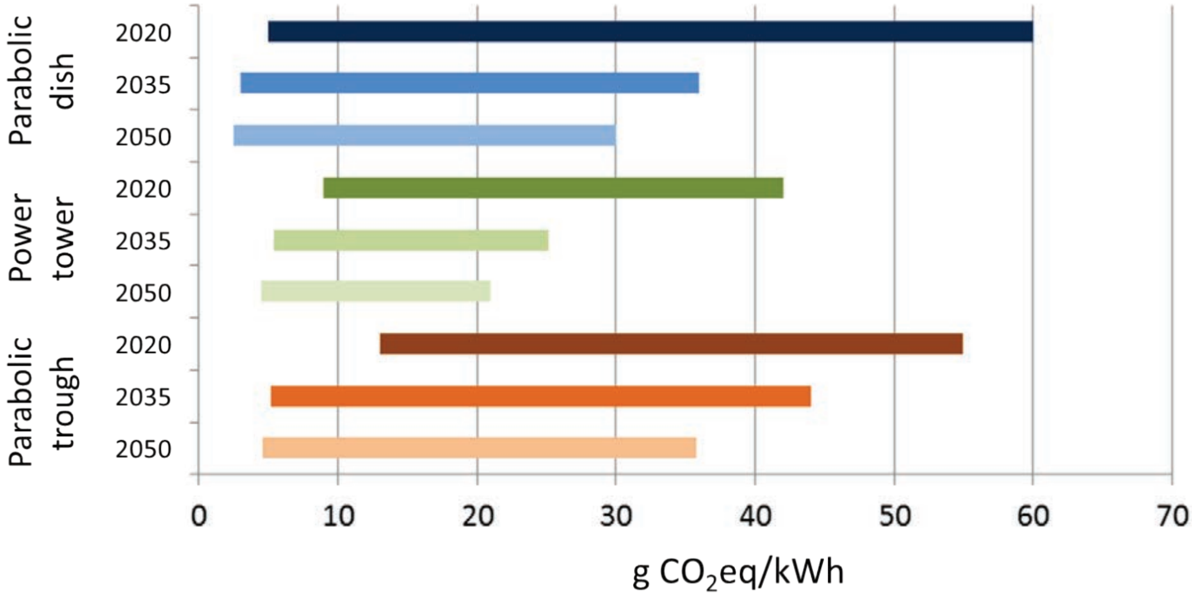

Figure 13.19: Ranges of life-cycle GHG emissions of different future solar-thermal power generation technologies.

13.5.1.3 Other environmental burdens

Besides GHG emissions, environmental impacts are associated with the construction of the steel-intensive infrastructure for solar energy collection due to mineral and fossil resource consumption, as well as discharge of pollutants related to today's steel production technology (Felder and Meier 2007).

In the near term, water availability may be important to minimize the cost of Rankine cycle-based CSP systems. Water is also needed for steam-cycle make-up and mirror cleaning, although these two uses represent only a few percent of that needed if wet cooling is used. However, there will be otherwise highly favorable sites where water is not available for cooling. In these instances, water use can be substantially reduced if dry or hybrid cooling is used, although at an additional cost. The additional cost of electricity from a dry-cooled plant is 2-10% (USDOE 2009), although it depends on many factors such as ambient conditions and technology. For example, tower plants operating at higher temperatures require less cooling per MWh than troughs. Tower and dish Brayton and Stirling systems are being developed for their ability to operate efficiently without cooling water.

13.5.2 Safety aspects

Except for the usual safety measures in power plants, no special precautions are necessary.

13.5.3 Social aspects

Solar energy has the potential to meet rising energy demands and decrease GHG emissions, but solar technologies have faced resistance due to public concerns among some groups (IPCC 2011). The land area requirements for centralized CSP plants raise concerns about visual impacts, which can be minimized during the siting phase by choosing locations in areas with low population density, although this will usually be the case for suitable solar sites anyway.

In recent years, a number of assessments concerning the employment effects of CSP have been carried out in Germany, Spain and the US. In their analysis, Teske (2016) assumes that for every MW of new capacity, the annual market for STE will create ten jobs through manufacturing, component supply, solar project development, installation and indirect employment. A study comparing job impacts across energy technologies showed that CSP yielded an average of 0.23 job-years per GWh, which exceeded estimated job creation for fossil technologies (Wei, Patadia et al. 2010).

13.6 Development and market

13.6.1 Facilitators

To support CSP deployment, it is vital to build investor confidence by setting a sufficiently high price for the electricity generated, and in a predictable manner (IEA 2010b). Feed-in tariffs and premiums have proven effective for CSP deployment in Spain, and for other renewable energy technologies in many countries. The levels of feed-in tariffs or premiums must be carefully studied and agreed upon with everyone involved, however, as they are ineffective if too low and economically inefficient if too generous. Renewable energy standards might be effective if they are sufficiently ambitious and “binding” for utilities – that is, if the financial penalties or safety bounds are set at appropriate levels in case of no or limited compliance.

Regardless of whether the electricity sector belongs to state-owned or partially state-owned monopolies or is fully deregulated, governments could encourage all utilities to bid for CSP capacities. Governments should also consider other options to help initiate or develop CSP capacities, such as: offering suitable land or connection to the grid or to water resources; waiving land property taxes; and helping ensure the availability of low-cost or at least reasonably priced loans.

Utilities, for their part, should reward the flexibility of CSP plants, i.e. their ability to dispatch electricity when needed. Capacity payments represent a simple option for doing this. Storage has a cost, and should be valued at grid level, not plant level. Policy frameworks should encourage this necessary evolution.

13.6.2 Barriers

Developers have encountered several barriers to establishing CSP plants. According to (IEA 2014b), these include insufficiently accurate DNI data; inaccurate environmental data; policy uncertainty; difficulties in securing land, water and connections; permitting issues; and expensive financing, leading to difficult financial closure. Inaccurate DNI data can lead to significant design errors. Ground-level atmospheric turbidity, dirt, sand storms and other weather characteristics or events may seriously interfere with CSP technologies. Permits for plants have been challenged in courts because of concerns about their effects on wildlife, biodiversity and water use. Some countries prohibit the large-scale use of heat-transfer fluids (HTF) such as synthetic oil or some molten salts.

The most significant barrier is the large up-front investment required (IEA 2014b). The most mature technology, PTC with oil as HTF, with over 200 cumulative years of running, may have limited room for further cost reductions, as the maximum temperature of the HTF limits the possible increase in efficiency and imposes high costs to thermal storage systems. Other technologies offer greater prospects for cost reductions but are less mature and therefore more difficult to obtain finance for. In countries with no or little experience of the technology, financing circles fear risks specific to each country.

In the United States, the loan guarantee program of the DoE has played a key role in overcoming financing difficulties and facilitating technology innovation. National and international development banks have helped finance CSP plants in developing countries, such as Morocco.

The rapid decrease of the cost of PV modules and systems has led some project developers to consider switching from STE to PV, especially in California, where PV offers a good match with consumption peaks, so that the value of thermal storage is less. This has in turn led some CSP technology providers to broaden their offer and sell hybrid PV-STE plants (Green, Diep et al. 2015).

13.6.3 Framework for future development and market readiness

STE is not broadly competitive today, and will not become so until it benefits from strong and stable frameworks, and appropriate support to minimize investors' risks and reduce capital costs (IEA 2014b). Deploying STE requires strong, consistent and balanced policy support. The main areas of policy intervention include: 1) Removing or alleviating non-economic barriers such as costly, lengthy and heavy permitting and connecting procedures; 2) Recognizing the value of STE for electric systems, due to its dispatchability, and ensuring it is duly rewarded; 3) Creating or updating a policy framework for market deployment, including tailoring incentive schemes and reconsidering electricity market design to accompany the transition to market competitiveness; basing policy frameworks on targets for deployment set at country level; making regulatory changes that are as predictable as possible; and avoiding retroactive changes; 4) Providing innovative financing schemes to reduce costs of capital for a great variety of potential customers.

13.7 Open questions and research activities

Over the last three decades, public R&D efforts have taken place mostly in Australia, Europe and the United States. China and South Korea are building new R&D programs, while other countries have expressed interest, in particular Abu Dhabi through Masdar[354] (IEA 2010b). Recent global public R&D investments in CSP have been assessed at less than USD 100 million per year. The CSP deployment in the BLUE Map scenario (IEA 2008b) would imply building about 20 GW of new CSP capacity each year on average during the next four decades. This represents investment expenses of about 56 billion USD per year. R&D expenditures are typically 1% of total investments, giving 560 million USD as the necessary

[354] Masdar Initiative: http://masdar.ae/en/

level of public and private R&D expenditures. Even if 50% of this were to come from industry, the global public R&D expenses still need to be almost tripled.

IEA (2014b) sees a need for more open access to R&D tower facilities like those at the Platform Solar de Almería (Spain), as the few others available are all overloaded in experiments.[355] Scalable demonstration plants in the 5 MW range also need to be built, possibly via public-private partnerships. These developments would easily add further 300 million USD per year to the public R&D funding already mentioned.

Since its inception in 1977, the IEA Implementing Agreement SolarPACES[356] has been an effective vehicle for international collaboration in all CSP fields (IEA 2014b). Of all IEA Implementing Agreements, SolarPACES has the largest participation from non-IEA members. It has been a privileged place for exchanging information, sharing tasks and, above all for sharing experience. The SolarPACES START teams (Solar Thermal Analysis, Review and Training) have carried out missions to support the introduction of CSP to developing countries. By sending international teams of experts, independent technical advice was made available to interested countries. In solar chemistry research[357], where the commercialization goals are more long term, SolarPACES has succeeded in building up and supporting international interest, defining research priorities and facilitating co-operative international research.

13.8 Conclusions

The following summary remarks include CSP technologies, current cost and future cost reduction potential, market potential, future markets, next steps, impact on Switzerland, and final recommendations.

13.8.1 CSP technologies

Concentrating solar power (CSP) technologies produce electricity by concentrating direct-beam solar irradiance to heat a liquid, solid or gas that is then used in a downstream process for electricity generation. The majority of the world's electricity today—whether generated by coal, gas, nuclear, oil or biomass—comes from creating a hot fluid. CSP simply provides an alternative heat source. Therefore, an attraction of this technology is that it builds on much of the current know-how on power generation in the world today. And it will benefit not only from ongoing advances in solar concentrator technology, but also as improvements continue to be made in steam and gas turbine cycles. Some of the key advantages of CSP include the following: 1) it can be installed in a range of capacities to suit varying applications and conditions, from tens of kW (dish/Stirling systems) to multiple MWs (tower and trough systems); 2) it can integrate thermal storage for peaking loads (less than one hour), intermediate loads (three to six hours), and base loads (up to 15 hours); 3) it has modular and scalable components; and 4) it does not require exotic materials (IPCC 2011).

[355] These include CNRS-Odeillo and Themis (France), the Paul Scherrer Institute (Switzerland), Sandia National Laboratory (USA), DLR Jülich (Germany), ENEA (Italy), and the CSIRO Energy Centre (Australia).

[356] Solar Power and Chemical Energy Systems: http://www.solarpaces.org/tasks/task-ii-solar-chemistry-research

[357] SolarPACES Task II (Solar Chemistry Research) has been coordinated by PSI's Solar Technology Laboratory from the beginning until July 2016, and since then by the ETH's Professorship of Renewable Energy Carriers.

CSP is a scalable renewable technology that can provide either baseload or dispatchable power. It allows great flexibility in planning a balanced electricity system, and therefore is especially valuable (Pfenninger, Gauche et al. 2014).

13.8.2 CSP cost

Following the analysis of (Teske 2016), generating increased volumes of STE electricity will require a significant investment over the next 35 years. At the same time, the increase in installed STE capacity will have tremendous economic and environmental benefits. In each of their outlook scenarios, the investment value of the future STE market has been assessed on an annual basis: 1) Because of a rather flat market volume projection over the next decades ("reference scenario"), the annual investment level would remain between 1.2 and 1.5 billion EUR until 2050; 2) In the "moderate scenario", the annual value of global investment would be 16.8 billion EUR in 2020, increasing to 53 billion EUR by 2030 and peaking at 162 billion EUR in 2050; 3) In the "advanced scenario", the annual value of global investment reaches 41.6 billion EUR in 2020, increasing to 140 billion EUR by 2030 and increasing further to 209 billion EUR in 2050.[358] The cost of generating electricity from concentrated solar power currently ranges from approximately 150 EUR/MWh at high DNI sites up to approximately 200 EUR/MWh at sites with a low average solar resource. With increased plant sizes, better component production capacities and more suppliers and improvements from R&D, costs are expected to fall to 120-180 EUR/MWh by 2020. Besides the estimation of further price drops in the long run, the gap with generation costs from conventional fuels is expected to decrease due to increased prices for conventional fuels in global markets. The competitiveness with mid-load plants might be achieved in the next 10 to 15 years.

13.8.3 Cost reduction potential

The roadmap of IEA (2014b) requests that CSP industry action in the short term, with support from research institutions, should focus on reducing cost of components: 1) develop new light-weight low-cost reflectors; 2) demonstrate large-scale use of molten salts as HTF in linear systems; 3) further develop and optimize solar tower concepts; 4) introduce supercritical steam turbines in CSP plants; 5) bring to market CSP technologies for high-temperature process heat.

13.8.4 Market potential

A detailed examination of the main markets and project pipelines anticipates the deployment of 11 GW of CSP plants by 2020 (IEA 2014b). While this is well below the expectations in the previous roadmap (IEA 2010b), it nevertheless represents a dramatic increase over the installed capacities at the end of 2009, which were about 600 MW. It is expected that global capacities will jump to 260 GW by 2030 and reach 980 GW by 2050. This represents capacity increases of 27 GW per year on average, with a five-year peak of 40 GW per year from 2040 to 2045. Thermal storage is a key feature of CSP plants all along, and capacity factors will grow regularly with increased solar field sizes and storage capacities,

[358] These figures may appear large, but they represent only a portion of the total level of investment in the global power industry. During the 1990s, for example, annual investment in the power sector was running at some 158-186 billion EUR each year.

reaching on average 45% in 2030. This allows the amount of STE to reach about 1000 TWh/a by 2030, and 4380 TWh/a by 2050, thus providing 11% of the global electricity mix.

13.8.5 Future markets

Currently, there are no new CSP projects in Spain, as incentives have been cut, even though the national renewable energy action plan (NREAP) envisages CSP capacity of 5 GW by 2020. New projects would have to be designed for export to other European countries in the framework of reaching the European Union’s 20% renewable energy target. Projects that would produce several GW are still under consideration or development in the United States, although not all will succeed in obtaining the required permits, PPAs, connections, and financing.

Besides Spain and the United States, and a few countries where small solar fields are used as boosters in larger-scale fossil fuel plants, hardly any countries have installations of commercial size, say above 50 MW. India and the United Arab Emirates have plants already connected to the grid; Morocco and South Africa are finalizing their first plants. Other countries are implementing or have announced ambitious development plans, including India, Israel, Jordan, Kuwait, Morocco, Saudi Arabia and South Africa, while in northern Chile development is taking place on a market basis. In 2012, Saudi Arabia announced that it would build CSP plants with a capacity of 32 GW by 2032, creating considerable hope in the industry. Some early achievements in these countries will come to fruition before the end of the decade.

13.8.6 Next steps

To reach a share of global electricity of as much as 11% in 2050, the roadmap developed by IEA (2014b) implies a set of milestones by different stakeholders over 35 years. In a nutshell, they are the following: 1) Governments establishing or updating targets for CSP deployment and implementing stable regulatory and market framework ensuring predictable financing environment and remuneration reflecting the value of STE at time of delivery; 2) Industry further reducing STE costs through technology improvements; 3) Industry and research institutions making R&D efforts commensurate with the potential role of STE and CSP technologies in climate-friendly energy future.

13.8.7 Impact on Switzerland

Only after CSP plants will be deployed in large quantities and the electricity generation costs will be competitive with other technologies, import of solar thermal electricity from CSP plants in the Mediterranean area is expected to gain importance for Switzerland. As in the case exemplified for Germany (Elsner, Fischedick et al. 2014), the electricity import from MENA to central Europe (Germany and Switzerland) requires the construction of additional transmission lines. The best strategy still has to be elaborated, being either point-to-point HVDC transmission or connection to the future European super-grid. Such grid expansion in any case requires social acceptance and legal frameworks, not only in the destination countries (Germany and Switzerland), but also at the CSP plant sites and in all countries affected by the transmission lines. Furthermore, the implications on the security of supply would have to be examined if a large portion of the electricity demand was covered by imports from MENA countries.

Pitz-Paal, Amin et al. (2012) summarize the findings of a study undertaken by the European Academies Science Advisory Council (EASAC) to evaluate the development challenges of CSP and its potential to contribute to low carbon electricity systems in Europe, the Middle East and North Africa (the MENA region) up to 2050. Key factors which will determine CSP's contribution in Europe and the MENA region over the period until 2050 are electricity generating costs, physical constraints on construction of new plants and transmission lines, and considerations of security of supply. The study makes recommendations to European and MENA region policy makers on how the associated issues should be addressed.

13.8.8 Final recommendations

In the framework of the new Swiss energy strategy 2050, the future energy systems need to be fundamentally revisited and all technical options should be evaluated (BFE/SFOE 2014). Among others, electricity import from CSP plants in the Mediterranean area could be part of the future renewable energy portfolio. In this regard, it is important that Switzerland continues its cooperation with MENA countries and supports RD&D on energy production in desert areas. Above all, such activities should serve the supply of the local population and industries. In these regions, markets for renewable energies will open up and offer Switzerland to position itself thanks to its technological know-how in these fields. Therefore, it is important to maintain existing instruments such as development cooperation, technological research, export risk insurance and credit assets.

SFOE is coordinating research activities in the field of industrial solar energy utilization, such as the development of innovative CSP technologies, the application of medium temperature concentrating solar thermal collectors, as well as the thermochemical conversion and storage of solar energy in chemical energy carriers (syngas, hydrogen) with subsequent industrial scale-up in demonstration projects for the production of solar fuels. Continuing support of SFOE is warranted for technological RD&D projects that may contribute to the DESERTEC initiative.

Table 13.10 provides an overview on main characteristics and indicators of concentrating solar thermal power plants.

Table 13.10: Characteristics and indicators for electricity generation in solar thermal power plants.

Characteristics of CSP plants	Solar thermal electricity (STE) generated by concentrating solar power (CSP) plants: Parabolic Trough Collector (PTC) Linear Fresnel Reflector (LFR) Central Receiver System (CRS) Parabolic Dish Concentrator (PDC) Minimum amount of direct normal irradiance (DNI): DNI > 2000 kWh/m^2/a. Latitude < 35-40°			
Physical potential				
Switzerland (CH)	$4.8 \cdot 10^7$ GWh/a [a] (Swiss electricity demand $5.8 \cdot 10^4$ GWh/a in 2015) [b]			
Mediterranean (MENA) region	$1.3 \cdot 10^6$ TWh/a [c] (World electricity consumption $21 \cdot 10^3$ TWh/a in 2012) [d]			
Technically viable potential (GW)	2015	2020	2035	2050
World min.	5 [e]	11 [e] - 14 [f]	-	62 [e] - 120 [f]
avg.	5.2 [g]	29 [f]	450 [g]	405 [f]
max.	34 [e]	40 [f] - 166 [e]	-	1000 [f] - 2054 [e]
Technically viable potential (TWh/a)	2015	2020	2035	2050
World min.	15 [e]	31 [e] - 77 [f]	-	222 [e] - 660 [f]
avg.		160 [f]	1760 [g]	2228 [f]
max.	92 [e]	220 [f] - 466 [e]	-	5500 [f] - 9348 [e]
EUMENA	6.9 [p]	- 99 [n]	(100) - 660 [n]	(357) - 1358 [n]
MENA	0.6 [p]	- 69 [n]	- 490 [n]	(281) - 1150 [n]
Performance (full load hours): Location-dependent	2015	2020	2035	2050
Switzerland (max.)	-	(1250)	(1375)	-
Spain DNI 2000 kWh/m^2 (incl. TES; max. 6400 [f])	5000 [f]	5500 [f]	5500 [f]	5500 [f]
Algeria DNI 2500 kWh/m^2 (incl. TES; max. 8000 [f])				
State of the art	Largest plants to date (2015):			
Parabolic trough collector (PTC)	Solana USA (2 x 125 MW) / 6h storage (molten salt) Mojave USA (2 x 125 MW) Genesis USA (2 x 125 MW)			
Linear Fresnel reflector (LFR)	Dhursar India (125 MW)			
Central receiver system (CRS)	Ivanpah USA (3 x 125 MW)			
Parabolic dish concentrator (PDC)	Maricopa USA (60 x 25 kW)			
Technology (future developments)				
Solar thermal technology	Supercritical CO_2 combined cycle tower plant [h] Brayton cycle power plant with gas working fluid [o]			

Annual solar-to-electricity efficiency (%)	2015	2020	2035	2050
Solar thermal technology	15-17 [i]	17-19 [i]	-	19-22 [i]
Parabolic trough collector (including storage)	13-15 [j]	-	19 [f]	19 [f]
Linear Fresnel reflector (< 10 min storage)	9-13 [j]	-	12 [f]	12 [f]
Central receiver system (including storage)	14-18 [j]	-	18 [f]	18 [f]
Parabolic dish concentrator (no storage)	22-24 [j]	-	-	-
Market maturity				
Solar thermal technology	Market development, current state:			
Parabolic trough collector (PTC)	Market proven (3750 MW); reliable in operation			
Linear Fresnel reflector (LFR)	Market proven (440 MW); in operation			
Central receiver system (CRS)	Market proven (182 MW); reliable in operation			
Parabolic dish concentrator (PDC)	Demonstrated (10 kW); currently non-operational			
Environmental burdens	See chapter 8.5			
Lifetime	25-30 years			
Planning timeframe	Location-dependent; within months			
Investment costs (USD/kW)	2015	2020	2035	2050
No storage	3300 - 6500 [k]	3100 [g]	4100 [h]	2000 [g]
Storage (4-15 h)	4800 - 9200 [e,g,h,k,l,m]	3800 - 6600 [e,g,h,l]	3400 - 5900 [h]	3100 - 4800 [e,g,l,m]
Typical O&M costs (USD/kW-yr)	2015	2020	2035	2050
Solar thermal technology	60-65 [h]	40-50 [h]	-	58 [q]
Levelised cost of electricity (LCOE) (USD/MWh)	2015	2020	2035	2050
No storage	160-331 [k]	-	-	-
Storage (4-15 h)	144 - 277 [h,k,l]	60-231 [h,k,l]	72-105 [g]	64-94 [g,q]
Costs for distribution (USD/MWh)				
Electricity distribution				
(HVDC transmission lines; incl. MENA to Europe)	About 15-20 USD/MWh (average) [n,p]			
Decommissioning (USD/kW)	unknown			
Learning curve	Learning rate: 10±5% (Neij 2008); 10% (IEA 2014b)			

[a] (Gantner and Hirschberg 1997); [b] (BFE/SFOE 2016e); [c] (Broesamle, Mannstein et al. 2010); [d] (CIA 2016); [e] (Teske 2012); [f] (Viehbahn, Kronshage et al. 2008); [g] (IEA 2014b); [h] (USDOE 2012); [i] (Pitz-Paal and Elsner 2015); [j] (Liu, Steven Tay et al. 2016); [k] (FISE 2013); [l] (KIC-InnoEnergy 2015); [m] (Trieb, Schillings et al. 2009); [n] (Dii 2013) (connected scenario; in brackets: inertia scenario; 2035: interpolated); [o] (IPCC 2011) [p] (Teske 2016); [q] (Dii 2012); [p] (Trieb 2011).

13.9 Abbreviations

AEP	Annual Energy Production
ABB	Asea Brown Boveri (ABB Ltd)
BFE	Bundesamt für Energie (SFOE)
BoS	Balance of System
CAPEX	Capital Expenditure
CPC	Compound Parabolic Concentrator
CPV	Concentrating Photovoltaics
CSP	Concentrating Solar Power
CRS	Central Receiver Systems
CTI	Commission for Technology and Innovation
DESERTEC	DESERTEC Foundation: Clean Power from Deserts
Dii	DESERTEC Industrial Initiative
DIW	Deutsches Institut für Wirtschaftsforschung
DME	Dimethyl Ether
DOE	Department of Energy
DNI	Direct Normal Irradiation
DSG	Direct Steam Generation
EGES	Expertengruppe Energieszenarien
EREC	European Renewable Energy Council
ESTIA	European Solar Thermal Industry Association
ESTELA	European Solar Thermal Energy Association
ETHZ	Eidgenössische Technische Hochschule Zürich
ETP	Energy Technology Perspective
EU	European Union
EUMENA	Europe (EU), Middle East (ME), and North Africa (NA)
EUR	Euro
FISE	Fraunhofer Institute for Solar Energy Systems
GHG	Greenhouse Gas
GP	Greenpeace
Gt	Gigatonne
GW, GWh	Gigawatt, Gigawatt-hour
GWEC	Global Wind Energy Council
HTF	Heat Transfer Fluid
HVAC	High Voltage Alternate Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	International Panel on Climate Change
IRENA	International Renewable Energy Agency
ISCC	Integrated Solar Combined Cycle
kW, kWh	Kilowatt, Kilowatt-hour
LCOE	Levelised Cost of Electricity
LFR	Linear Fresnel Reflector
MENA	Middle East (ME) and North Africa (NA)
NEEDS	New Energy Externalities Developments for Sustainability
NREAP	National Renewable Energy Action Plan
NREL	National Renewable Energy Laboratory
OECD	Organization of Economic Cooperation and Development
O&M	Operation and Maintenance
OPEX	Operational Expenditure

PDC	Parabolic Dish Concentrator
PPA	Power Purchase Agreement
PREC	Professorship of Renewable Energy Carriers at ETHZ
PSI	Paul Scherrer Institute
PTC	Parabolic Trough Collector
PV	Photovoltaics
RD&D	Research, Development and Demonstration
R&D	Research and Development
REE	RED Electrica de España (Spanish Electricity Grid)
SEGS	Solar Electricity Generation System
SERI	State Secretariat for Education, Research and Innovation
SFOE	Swiss Federal Office of Energy
SGS	Schweizerische Greina-Stiftung
SNSF	Swiss National Science Foundation
SolarPACES	Solar Power and Chemical Energy Systems
SP	SolarPACES
STL	Solar Technology Laboratory at PSI
STE	Solar Thermal Electricity
TES	Thermal Energy Storage
TW, TWh	Terawatt, Terawatt-hour
UNDP	United Nations Development Program
US	United States
USD	US Dollar

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14 Nuclear power[359]

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14.1 Introduction

This chapter reviews current and future nuclear reactor technologies with emphasis on their safety, economy and environmental impacts. The evolution of reactor generations is described and each generation is evaluated with respect to the performance criteria of interest. Comparison is made between different nuclear technologies.

The present work builds partially on published literature and partially on recent interdisciplinary studies carried out by PSI. The extent and depth of the existing knowledge on the advanced future designs is much more limited in comparison with the existing ones, and further investigation on these advanced technologies is therefore recommended.

Worldwide, 450 nuclear power plants, with a total electricity generation capacity of about 392 GW, are currently operating in 31 countries as of beginning of January 2017 (IAEA 2017). The share in OECD countries is substantially higher, at 19.3% (NEA 2015). 63 reactors with a combined generation capacity of 62 GWe are currently under construction in 16 countries, and 90 additional reactors are planned in 9 countries (IAEA 2016, WNA 2016c, WNA 2016b).

Earlier nuclear accidents, i.e. Three Mile Island in 1979 and Chernobyl in 1986, had a strongly negative influence on the penetration of nuclear energy. Nuclear power programs slowed down due to these events but also due to a number of other factors such as low fossil fuel prices and regained confidence in security of supply. This was followed by a period of partial revival of nuclear energy driven by the mostly good performance of nuclear units in operation in terms of availability and economic competitiveness, renewed concerns about security of supply and increased awareness about the threat of global climate change. However, following the Fukushima accident, Germany decided to phase out its nuclear program by 2022. In four countries (apart from Germany also in Switzerland, Italy and Venezuela) political decisions were made ruling out construction of new nuclear power plants. In addition, Japan decided to scale back the plans to increase nuclear generation of electricity, and to review the future role of nuclear energy in the national electricity supply. In the opposite direction, the deadline for phasing out nuclear generation was postponed for some years in Belgium. Sweden recently revised its nuclear policy, abolishing the nuclear tax and allowing again the construction of new plants.

In countries pursuing construction projects these are in principle not being contested though the public debate has become more polarized. Delays in the nuclear projects due to public opposition and/or possible changes in regulation during construction, particularly in areas exposed to natural disasters, may result. Also, slower implementation or even withdrawal of some of the planned projects is a possible outcome.

The main drivers for the continued substantial contribution of nuclear energy globally are: security of supply, a transition to low-carbon fuels and the potential to use nuclear energy for other applications than electricity, i.e. hydrogen production, process heat and water

[359] This chapter builds on an earlier report on the assessment of current and future nuclear energy technologies (Hirschberg, Eckle et al. 2012), prepared by PSI for the Swiss Federal Office of Energy.

desalination. The conditions for positive nuclear development include: safe operation, licensing harmonization, radioactive waste management with implementation of deep geological disposal, a solid environmental protection framework, assured economic competitiveness, robust financing schemes, assurance of high competences on both the operational and regulatory sides, sufficient capacities in uranium and component supply, nuclear non-proliferation, strong R&D capacities, public acceptance and involvement, and political support. Meeting these requirements is definitely a major challenge for the future nuclear energy.

From 2011 until 2016, the total number of reactors shut down was compensated for by new reactors coming on-line or restarted from long-term shut-down. Overall, the total operational generation capacity increased by 15.8 GW (IAEA 2016). For more details, see Table 14.1.

Table 14.1: Evolution of Nuclear Reactor Population between 2011 and 2015 (IAEA 2016).

Year	Region	Construction		Grid Connection		Permanent Shutdown		Long Term Shutdown		Restart from LTS	
		#	MW	#	MW	#	MW	#	MW	#	MW
2011	Asia - Far East			3	1'646	4	2'719				
	Asia - Middle East and South	4	1'890	3	1'417						
	Europe - Central and Eastern			1	950						
	Europe - Western					9	8'639				
2011	**World**	**4**	**1'890**	**7**	**4'013**	**13**	**11'358**				
2012	America - Northern					1	635			2	1'696
	Asia - Far East	5	4'530	3	2'963						
	Asia - Middle East and South	1	1'345								
	Europe - Central and Eastern	1	1'109								
	Europe - Western					2	707				
2012	**World**	**7**	**6'984**	**3**	**2'963**	**3**	**1'342**			**2**	**1'696**
2013	America - Northern	4	4'468			4	3'576				
	Asia - Far East	4	4'330	3	3'143	2	1'827				
	Asia - Middle East and South	1	1'345	1	917						
	Europe - Central and Eastern	1	1'109								
	Europe - Western							1	446		
2013	**World**	**10**	**11'252**	**4**	**4'060**	**6**	**5'403**	**1**	**446**		
2014	America - Northern					1	605				
	America - Latin	1	25	1	692						
	Asia - Far East			3	3'018						
	Asia - Middle East and South	1	1'345								
	Europe - Central and Eastern	1	1'109	1	1'011						
2014	**World**	**3**	**2'479**	**5**	**4'721**	**1**	**605**				

Year	**Region**	**Construction**		**Grid Connection**		**Permanent Shutdown**		**Long Term Shutdown**		**Restart from LTS**	
		#	MW	#	MW	#	MW	#	MW	#	MW
2016	America - Northern			1	1'165	1	482				
	Asia - Middle East and South	1	2’000	2	1’232						
	Asia - Far East	2	1’014	6	5’968	1	528				
	Europe - Central and Eastern			1	1’114	1	385				
2016	**World**	**3**	**3’014**	**10**	**9’479**	**3**	**1’405**				
2011 - 2016	**World**	**32**	**30'964**	**39**	**34'603**	**33**	**23'976**	**1**	**446**	**2**	**1'696**

		Reactors	
		∆#	**MW**
2011 - 2016	**World Balance Nuclear Generation Capacity**	**7**	**15'860**

Currently nuclear power provides more than a quarter of the electricity supply in 16 countries. France generates around 75% of its power from nuclear energy, while nuclear generation in Belgium, Bulgaria, Czech Republic, Finland, Hungary, Slovakia, Sweden, Slovenia, South Korea, Japan, and Ukraine amounts to around one-third or more. The USA, UK, Spain, Romania and Russia all have about 20% of the electricity demand met by nuclear power. Among countries which do not host nuclear power plants such as Italy and Denmark, almost 10% of their electricity is supplied from imported nuclear power (WNA 2016b).

Switzerland has four nuclear power plants with five reactors in Beznau (2 units), Gösgen, Leibstadt and Mühleberg, for a total capacity of about 3.3 GW. They generate about 39% of the country’s annual electricity supply, and up to about 45% in winter during peak demand. The nuclear power plants in Switzerland operate with the following cumulative availability factors (BFE/SFOE 2016d), calculated for the whole operating life up to 2016 and the period from 2006 to 2016.

Table 14.2: Cumulative Energy Availability Factors of Swiss Nuclear Power Plants.

Nuclear Power Plant	Type	Net Power Generation [MW]	Cumulative Energy Availability Factor for whole period of operation up to 2016 [%]	Cumulative Energy Availability Factor for 2006-2016 [%]
Beznau I	PWR	365	81.8	77.3
Beznau II	PWR	365	87.2	89.0
Mühleberg	BWR	373	86.9	89.4
Gösgen	PWR	1010	88.8	90.9
Leibstadt	BWR	1220	85.4	87.7
Weighted Average			86.4	87.8

n.a. = not available

14.2 Safety requirements

The nuclear fission process liberates approximately 200 MeV of energy with each fission and produces two fission fragments together with 2 – 3 fast neutrons that enable the chain reaction to continue (after due moderation in thermal reactors). The mass of the two fission fragments is distributed according to a double hump curve of the fission yield with the two modes of the distribution coinciding with the mass numbers 93 (Zr, ~6.3%) and 133 (Cs ~6.8%), but many more isotopes appear as fission products with a high fission yield of > 1%, including isotopes of Zr, Cs, I, Xe, Mo, Tc, Pm, and Sm.

The key safety goals derive naturally from these key aspects of nuclear fission, i.e. to:

1. Control reactivity
2. Maintain cooling
3. Contain the activity

The specific safety requirements supporting the fulfillment of these goals developed and became stricter over time, e.g. the acceptance criteria related to the fuel integrity during reactivity and loss-of-coolant accidents were tightened in light of new results from respective large experimental programs. Also the three severe accidents in Harrisburg (Three Mile Island, 1977), Chernobyl (1986) and more recently Fukushima (2011) each stimulated considerable safety research programs that had impact on the mitigation of severe accidents and led to back-fitting. In Switzerland filtered containment venting systems (FCVS) were installed in all nuclear power plants. Separate bunkered emergency control rooms for reaching and maintaining safe shutdown conditions were built in the two early nuclear power plants Beznau and Mühleberg. Such systems were present in the Gösgen and Leibstadt plants as originally built and operated.

The evolution of the different reactor and plant designs for a given technology (e.g. light water reactors) can hence be understood as an attempt to continuously better fulfill the requirements of these safety goals, considering an ever widening spectrum of incidents and accidents.

Naturally, another important vector for the evolution of the reactor and plant designs is of economic nature: Only an economic plant can be operated safely in the long run.

14.3 Technology

14.3.1 Technology development of nuclear generations

While initially there prevailed a largely exaggerated optimism with respect to the expected low cost of electricity generated by nuclear technology, the increasing understanding of the possible consequences after postulated severe accidents has guided reactor developers to improve the safety systems considerably (separation, redundancy, diversity, inherent safety features, passive systems, etc.), Furthermore, experience from plant operation (e.g. extended burnup, uprated power, etc.) and related new research results (e.g. a loss of coolant accident (LOCA) for high-burnup fuel) prompted the regulators to enhance the safety requirements . Evidently, such actions contributed to increased construction costs. A further element of enhancing the safety requirements is represented by the revised limits for radio-protection that are based on new rules from the International Commission on Radiological Protection (ICRP)[360].

Nuclear reactor technology has gone through continuous development for more than 50 years, and the evolution of it can be explained by “generations,” each of which represents significant advancements in terms of performance, cost and safety. Figure 14.1 shows an overview of nuclear technology development as an evolution of these generations.

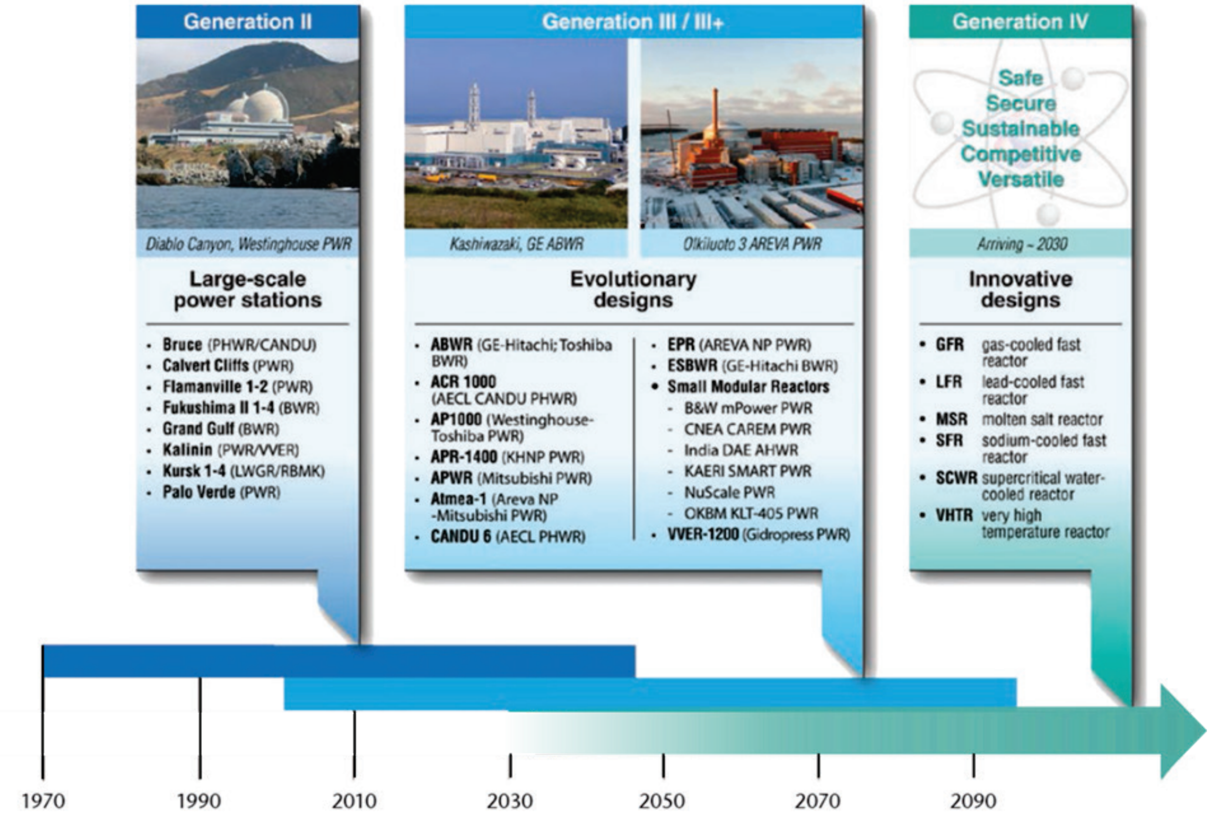

Figure 14.1: Evolution of fission reactor technology; adapted from (OECD/NEA/IEA 2015).

The second generation (Gen II) reactors in general refer to a class of commercial reactors designed to be economical and reliable, with a designed lifetime of around 40 years (Goldberg and Rosner 2011). A few technologies were widely established, with the bulk of installed systems being light water reactors (LWRs). The fleet of light water reactors (LWRs) comprises boiling water reactors (BWRs) and pressurized water reactors (PWRs). The LWR fleet represents 82% of the total reactor population and provides 89% of the generation capacity, with PWRs contributing 78% of the LWR generation capacity, and BWRs only 22% (OECD/NEA 2011, IEA 2015c, NEA 2015, OECD/NEA 2015, OECD/NEA/IEA 2015). There are also heavy-water reactors (HWRs), primarily in Canada, India and East Asia, and a few gas-cooled reactors (GCRs) in the UK. The Soviet-designed graphite-moderated, water-cooled reactors (RBMKs) play only a minor role on the world market today.

The liquid metal-cooled fast reactors (LMFBRs, or often just FBRs) currently in operation in Russia and China represent a technology that will be further developed by Russia, China and Japan within the framework of the Generation IV International Forum (GIF), of which Switzerland is also a member.

[360] http://www.icrp.org/

The third generation (Gen III) are nuclear reactors that have been developed on the basis of the Gen II reactors with (at the time) state-of-the-art design improvements (Goldberg and Rosner 2011) in the areas of modularized construction, safety systems, longer lifetimes and thermal efficiency.

The results of LWR-related safety research as well as the operating experience of the American, Japanese, and Western European LWR fleets together with requirements from the economic optimization process to improve the economic competitiveness provided additional input for new reactor designs. The Gen III+ reactors represent a further evolutionary development based on Gen III reactors, offering significant improvements in safety over Gen III reactor designs. The designers/vendors of Gen III+ systems began this development in the 1990’s. Among all the improvements of Gen III+ reactors, the most significant one is the incorporation of passive safety features, which do not require active controls or operator intervention, but instead rely on gravity or natural convection to mitigate the impact of abnormal events (Goldberg and Rosner 2011), particularly the removal of the decay heat.

It should be noted that due to the evolutionary improvement process the allocation of specific designs to Gen III and Gen III+ is somewhat arbitrary and may be disputed.

With regard to nuclear safety, the development of Generation IV (Gen IV) plants designs has been aimed at further decreasing the core damage frequency and excluding the necessity of off-site emergency response measures. The development of Gen IV systems was intended to explore the benefits of new coolants, which become necessary for achieving the sustainability goals of high conversion, transmutation, higher thermal and fuel efficiency, proliferation resistance and competitive economic parameters. It is an essential feature of the Gen IV development that it excludes the use of pressurized light water below the thermodynamic critical point as a coolant.

The following sections discuss the generations of nuclear reactor technologies in more details.

14.3.1.1 Generation I and Generation II

In the 50’s and 60’s, a variety of prototype reactors of the first generation (Gen I, not shown in Figure 14.1) was built worldwide. From these reactors, the different lines of technology emerged that are now called Generation II (Gen II), which were then pursued commercially. Most of the currently operating reactors belong to Gen II and represent close to 17,000 reactor-years of operating experience (Krivit, Lehr et al. 2011). The safety of these reactors is based on the principles of Defense in Depth, i.e. the creation of a system of nested barriers, completed by systems and measures to protect them against attack by internal (decay heat, pressure…) and external (earth quakes, floods, extreme weather) threats, where the attention given to the latter has increased continuously. Concepts like redundancy, diversification and conservative design were already established and applied in the design phase. The design was checked by a deterministic safety analysis, the results of which was compared to quantitative and qualitative acceptance criteria. The goal consisted of excluding the destruction of the fuel rods. A core melt accident was considered very unlikely (“hypothetical accident”) and countermeasures were first limited to external emergency measures, like evacuation of the population or the distribution of iodine pills.

Within the fleet of Gen II reactors, significant differences exist with regard to the level of plant safety. In addition, the current (Gen II) reactors are operated under a variety of licensing regimes and economic boundary conditions that may also contribute to the different safety levels.

Nuclear plants commissioned later were designed with a stronger focus on spatial separation of redundant and diversified systems, a better man-machine interface, improved operator instruction and stronger containment structures. The introduction of the single failure criterion has led to more redundancy. A comprehensive list of design basis accidents, was taken into account in the deterministic safety analysis. The method of probabilistic analysis was established and helped to identify weak points and to optimize the allocation of safety improvements.

In particular, after the Three Mile Island accident, a core melt was no longer considered hypothetical. Severe Accident Research was established as a broad research discipline. Results from partially large-scale experiments tackling all phases of accidents beyond the design criteria (e.g. hydrogen tests, fuel element degradation and destruction, core melt formation, pressure vessel failure by the attack of the core melt, core-melt concrete interaction, aerosol transport and deposition) provided the basis for Severe Accident Management, which includes both engineered components and Severe Accident Management Guidelines (SAMG) for the operators. Today, operators are trained not only to respond to design basis accidents (DBA), but also to mitigate the consequences of severe accidents that are Beyond Design Basis Accidents (BDBA).

After initially mainly coping with internal initiating events, like Reactivity Induced Accidents (RIA) and Loss-of-Coolant Accidents (LOCA) and the decreasing probability of a core damage in similar accident sequences due to the improved safety, probabilistic analyses showed the growing relevance of external initiating events for a further reduction of the core damage frequency. Research started to focus on related phenomena. Programs like the German HDR research project were conducted, simulating air plane crashes and earthquakes (among other events). As a result, the protection of the plants against external threats was improved, a process which is still ongoing. The mentioned huge R&D activities related to both internal and external initiating events created the basis for the development of Generation III systems.

Newer plants commissioned in the 80's were already equipped with most of the innovations that were available as a result of the mentioned R&D efforts. Plants of Gen II that were built before requirements to be backfit to meet today's standards. A good example are the Swiss NPPs, which all belong to Gen II, with extensive retro-fitting of the oldest plants (Beznau (KKB) and Mühleberg (KKM)). Table 14.3 below shows the key data and characteristics of the Swiss plants.

Table 14.3: Facts and figures of the Swiss nuclear reactors (ENSI 2014)

	KKB 1	KKB 2	KKG	KKL	KKM
Reactor type	PWR	PWR	PWR	BWR	BWR
Reactor vendor	W	W	KWU	GE	GE
Thermal power [MW_{th}]	1130	1130	3002	3600	1097
Total electrical power [MW]*	380	380	1060	1275	390
Net electrical power [MW]*	365	365	1010	1220	373
Start of commercial operation	1969	1971	1979	1984	1972
Holder of operating license	Axpo AG	Axpo AG	Kernkraftwerk Gösgen-Däniken AG	Kernkraftwerk Leibstadt AG	BKW FMB Energie AG
Number of coolant loops	2	2	3	2	2
Turbine vendor	BBC	BBC	KWU	BBC	BBC
Generator power [MW]	2 x 228	2 x 228	1250	1360	2 x 214
Main heat sink	River	River	Cooling tower	Cooling tower	River
Spent Fuel Pool (SFP)	2 SFPs in separate building	2 SFPs in separate building	1 fuel pool in prim. containment; 1 fuel pool (loading pool) in sec. containment	1 SFP in primary containment; 1 SFP in separate building	1 SFP in secondary containment
intermediate storage	Intermediate storage (air cooled)	Intermediate storage (air cooled)	External intermediate storage (water cooled)	External intermediate storage (water cooled)	External intermediate storage (water cooled)
Containment type	Full pressure containment with filtered venting system	Full pressure containment with filtered venting system	Full pressure containment with filtered venting system	Mark III containment with filtered venting system	Mark I containment with filtered venting system

* Total electrical power includes the consumption of the nuclear power plant. Only the net electrical power is delivered to the grid.

14.3.1.2 Generation III and Generation III+

Passive safety systems that do not depend on the availability of external energy sources have been developed for the so-called revolutionary design line (Figure 14.2). In passive safety systems, rotating (turbines, pumps) and reciprocating machinery (e.g. diesel generators) are explicitly excluded. Gravity driven flows such as natural circulation and flooding fed from high-lying tanks are considered acceptable, as are pressurized tanks and on-site direct current batteries. Passive system valves may only accept one single switching action and require stored energy for their activation. The reactor operator is not required to interfere with the initiation of the safety function.

A Gen III+ system is characterized by the requirement that all required safety systems necessary for the reactor protection are passive systems. For example, Figure 14.2 shows in the leftmost diagram three separate systems for depressurizing the reactor, flooding the core and cooling the containment).

The so-called evolutionary design line still relies on classically active systems powered by emergency diesel generators. The required level of safety is achieved by a strong enhancement of the containment function, especially with regard to the protection from off-site risks, like earthquakes, floods and airplane crashes, as well as enhanced redundancy and diversification. The most prominent example of this approach is the EPR of AREVA. Some Gen III concepts combine enhanced active safety with passive systems, in particular with regard to long-term cooling tasks, see for instance the Russian AES-2006, but also newer editions of the Advanced Boiling Water Reactor (ABWR).

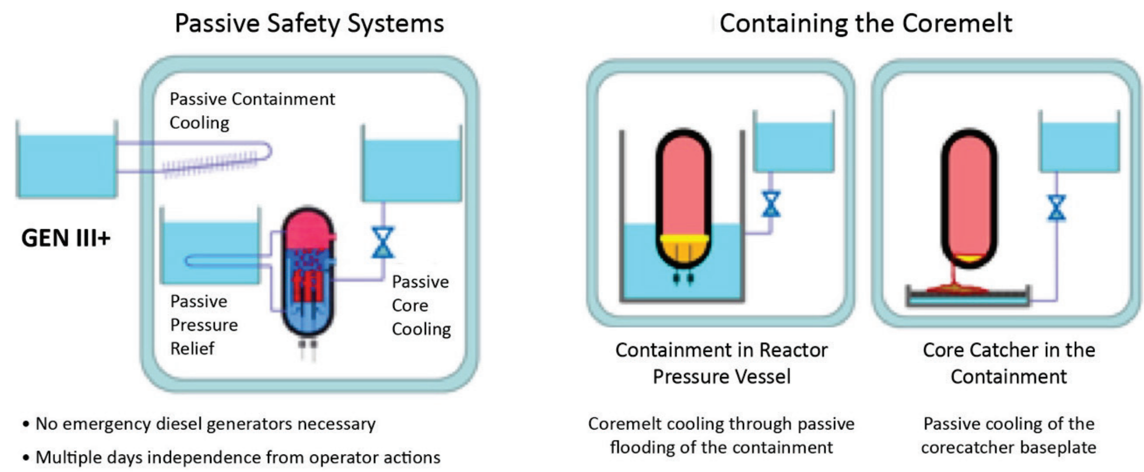

Figure 14.2: Examples of passive safety systems and features for core melt retention in the containment of light water reactors (Hirschberg, Eckle et al. 2012).

Two alternative solutions for core melt retention are implemented for Gen III/III+ reactors:

One of the targets of the development of Gen III consisted in decoupling a core damage event from a large release of radioactive material from the plant that led to the introduction of core melt retention system. A melted core can be retained within the reactor pressure vessel below a critical power density of the core (rated reactor power over core volume) if the reactor pressure vessel can be cooled from the outside by flooding the reactor cavern (Figure 14.2, middle). A previous depressurization, preferably by a passive safety system, is a necessary prerequisite for the success of such an action. The AP1000 by Westinghouse and the KERENA by AREVA are examples of this approach.

Reactors with higher power density, such as the EPR by AREVA, the ABWR by GE-Toshiba or GE-Hitachi and the ESBWR by GE, require an external core-catcher. The melted core, once outside the reactor pressure vessel, spreads on a resistant baseplate that is cooled by water flooding (Figure 14.2, right).

In both approaches, no reactor operator intervention is necessary to initiate the cooling water injection that relies on passive systems only.

Standardized construction should reduce the construction period and promises a higher reliability (measured by the equivalent availability fator, or EAF). Furthermore, these plants are designed for a longer lifetime than current Gen II reactors. Neutron embrittlement, which often limits lifetime in older Gen II plants, is significantly delayed by a reduction of the neutron flux arriving at the pressure vessel wall. As a result, Gen III+ plants should benefit from improved economy. Slightly improving the thermal efficiency also helps to better utilize the fuel and produce less waste per unit of energy generated.

The deployment of Gen III reactors is well underway: the first two reactors were connected to the grid in 1996 in Japan. Four EPR's are currently under construction in Finland, France and China, and 4 AP1000's are under construction in the US. During the period between 2011 and 2015, 32 new reactors were under construction, most of them belonging to Gen III, with the majority in Asia (China, India, Korea), but also in Russia and the United Arab Emirates.

A survey of selected Gen III/III+ reactor designs that are either in operation or under construction can be found in (OECD/NEA 2011, IEA 2015c, NEA 2015, OECD/NEA 2015, OECD/NEA/IEA 2015). In addition, there are numerous concepts in the design stage.

Table 14.4: Overview of generation III/III+ large reactor designs (OECD/NEA 2011, IEA 2015c, NEA 2015, OECD/NEA 2015, OECD/NEA/IEA 2015).

Vendor	Country	Design	Type	Net capacity (MW)	In operation*	Under construction*
AREVA	France	EPR	PWR	1600	0	**4 (Finland, France, China)**
AREVA/MHI	France / Japan	ATMEA	PWR	1100	0	**0**
CANDU Energy	Canada	EC6	PHWR	700	0	**0**
CNNC-CGN	China	Hualong-1	PWR	1100	0	**0**
GE Hitachi – Toshiba **GE Hitachi**	US / Japan	ABWR ESBWR	BWR BWR	1400-1700 1600	4 (Japan) 0	**4 (Japan, Taiwan)** **0**
KEPCO/KHNP	Korea	APR1400	PWR	1400	1	**7 (Republic of Korea, United Arab Emirates)**
Mitsubishi	Japan	APWR	PWR	1700	0	**0**
ROSATOM	Russia	AES-92, AES-2006	PWR	1000-1200	1	**10 (Russia, Belarus, China, India)**
SNPTC	China	CAP1000, CAP1400	PWR	1200-1400	0	**0** **2 (China)**
	US / Japan	**AP1000**	**PWR**	**1200**	**0**	**8 (China, United States)**

* As of 31 December 2016.

14.3.1.3 Generation IV

The Generation IV International Forum (GIF) was founded in 2000 by nine countries including Switzerland and a related multi-national contract was signed in 2005. The objective of GIF is to support the development of generation IV reactor systems to achieve the goals of sustainability, safety and reliability, economic competitiveness, proliferation resistance and physical protection. Since closing of the fuel cycle is a target under the sustainability goal, three of the six reactor systems are fast-spectrum concepts.

Six systems were selected out of an initial set of approximately 100 concepts. The key characteristics of the 6 GIF systems are given in Table 14.5.

Table 14.5: Overview of Generation IV designs under development by GIF (WNA 2015)

Name	Neutron spectrum	Cooling medium	temperature	Pressure*	Fuel	Fuel cycle	Size [MW]	Uses
Gas-cooled fast reactor	fast	helium	850	high	U-238***	closed on site	1200	electricity & hydrogen
Lead-cooled fast reactor	fast	lead or Pb-Bi	480-570	low	U-238***	closed regional	20-180** 300-1200 600-1000	electricity& hydrogen
Molten salt reactor	fast	fluoride salts	700-800	low	UF in salt	closed	1000	electricity& hydrogen
Molten salt reactor - Advanced high-temperature reactor	thermal	fluoride salts	750-1000		UO2 particles in prism	open	1000-1500	hydrogen
Sodium-cooled fast reactor	fast	sodium	500-550	low	U-238 and MOX	closed	30-150 300-1500 1000-2000	electricity
Supercritical water-cooled reactor	thermal or fast	water	510-625	very high	UO2	open (thermal), closed (fast)	300-700 1000-1500	electricity
Very high temperature reactor	thermal	helium	900-1000	high	UO2 prism or pebbles	open	250-300	hydrogen & electricity

* high= 7-15 MPa

** battery model with long cassette core life (15-20 years) or replaceable reactor module

*** with some U-235 or Pu-239

The degree of maturity of the different systems can be assessed by the end of the so-called viability phase that is defined as the development phase during which basic concepts, technologies and processes are tested under relevant conditions, and all potential technical show-stoppers are identified and resolved (GIF 2014). A corresponding overview can be found in Table 14.6 where the participation of the different GIF-partners is also shown (Kelly 2016). Since 2014, Switzerland has terminated the project agreement on the GFR and has signed a Memorandum of Understanding for the MSR, while the VHTR agreement remains active.

Table 14.6: Status of the GIF Active R&D Collaborations as of July 2016 (Kelly 2016(GIF 2014).

Generation IV Systems	Canada	China	France	Japan	Korea	Russia	Switzerland	U.S.A.	EU
Sodium-cooled Fast Reactor (SFR)		●	●	●	●	●		●	●
Very-high Temperature Gas cooled Reactor (VHTR)		●	●	●	●		●	●	●
Gas-cooled Fast Reactor (GFR)			●	●					●
Supercritical-water cooled Reactor (SCWR)	●	●		●		●			●
Lead-cooled Fast Reactor (LFR)				●	●	●			●
Molten Salt Reactor (MSR)			●			●	●		●

● *Participating member, signatory of a System Arrangement as of July 2016*

Table 14.7: Parties to GIF framework agreement and system arrangements.

Member	Framework Agreement	System Arrangements				Memoranda of Understanding (MOU)	
		GFR	SCWR	SFR	VHTR	LFR	MSR
Argentina							
Australia							
Brazil							
Canada[1]	X		X				
Euratom[2]	X	X	X	X	X	X	X
France	X	X		X	X		X
Japan	X	X	X	X	X	X	
People's Republic of China	X		X	X	X		
Republic of Korea	X			X	X	X	
Republic of South Africa	X						
Russian Federation	X		X	X		X	X
Switzerland[3]	X				X		X
United Kingdom[4]							
United States	X			X	X		

* Among the signatories to the Charter, ten Members (Canada, Euratom, France, Japan, the People’'s Republic of China, the Republic of Korea, the Republic of South Africa, Russian Federation, Switzerland and the United States) have signed or acceded to the Framework Agreement (FA) as shown in the table above, other signatories to the Charter are Non-Active Members.

1. Canada was a signatory to the VHTR System Arrangement from 11/2006 to 12/2012.
2. The European Atomic Energy Community (Euratom) is the implementing organisation for development of nuclear energy within the European Union.
3. Switzerland was a signatory to the GFR System Arrangement from 11/2006 to 11/2015.
4. United Kingdom participates in GIF activities through Euratom.

14.3.2 Other future innovative reactor technologies and fuels

Due to the large variety of options and limited knowledge, Small Modular Reactors (SMRs), High-Temperature Reactors (HTRs), Molten Salt Reactors (MSRs) and the use of thorium as an alternative fuel for suitable reactors, are treated here separately. A further in-depth investigation of these technologies is recommended.

14.3.2.1 Small Modular Reactors (SMRs)

Historically, all early reactors were smaller in size compared to those deployed today. However, in the past the general trend toward larger unit sizes (with lower specific costs because of the economies of scale) has led to nuclear power plants (NPPs) with an electrical capacity of up to 1800 MW. According to the classification in use by the IAEA, small sized reactors have electrical power less than 300 MW, whereas medium sized reactors are reactors with the electric power between 300 MW and 700 MW (IAEA 2012b). Since 2008, small modular reactor designs, which are less than 125 MW, have gained attention worldwide.

In the context of SMRs, the term modular refers to a single reactor that can be grouped with other modules to form a larger (multi-unit) nuclear power plant on the same site. It is expected that SMRs require limited on-site preparation as they are designed to be ready for operation when they arrive from the factory. Modular reactors provide simplicity of design and offer more flexibility (in financing, siting, sizing, etc.) compared to larger nuclear power plants (USDOE 2010). The economic advantage of SMRs over larger reactors will only be realized in niche markets, particularly if 1-3 GW must be constructed with a minimum delay time between the construction of the individual modules, and if an adequate carbon tax has been adopted (Locatelli, Bingham et al. 2014). In this way, maximum benefit from learning, co-siting and self-financing can be obtained. For demands smaller than 1 GW, careful evaluation is necessary in view of competitive generation technologies and related tax/funding schemes. In general, SMRs allow greater flexibility for the construction of additional capacity, which leads to lower financial risks, so that such reactors are potentially attractive for investors, and for countries which are going to start a new nuclear program (OECD/NEA 2011).

Although plants with small modular reactors rely on the same basic principles as applied with large reactors, the simplified design (e.g. recirculation pumps and steam generator internal to the reactor pressure vessel) that becomes feasible due to the lower power ratings needs special consideration. There are potential benefits of SMRs for niche applications where the grid demand is small and/or electrical grids are poorly developed or absent. This can be the case in remote or isolated areas, where there may also be a market for cogenerated heat). The upfront capital investment for one SMR is significantly smaller than for a large reactor. The flexibility in incremental capacity increases for SMRs results in smaller financial risks, making such reactors potentially attractive to investors and for countries initiating a nuclear program (OECD/NEA 2011).

14.3.2.2 Small and Medium-sized Reactors (SMRs)

Since the mid-1980s, there is a continued interest among Member States of the IAEA (IAEA 2009) and OECD (OECD/NEA 2011) in the development and applications of small and medium-sized reactors (confusingly also referred to as SMRs). This development of SMRs is primarily aimed at niche markets that cannot accommodate larger nuclear power plants. Compared to large conventional reactors SMRs often exhibit some innovative features implemented in their designs to meet specific conditions and requirements of the target markets. Such reactors are not in general modular (modular designs are a subset), which means total plant capacity is likely to be less flexible, and remote construction may be more difficult. While the upfront capital investment for unit of a small to medium reactor is significantly smaller than for a large reactor, the financial flexibility is also less and there is less potential for economies of scale for the non-nuclear balance of plant.

The R&D work on SMR designs is oriented towards providing increased benefits in the areas of safety, security, non-proliferation, waste management and resource utilization and economy, as well as to offer a variety of energy products and flexibility in design, siting and fuel cycle options (IAEA 2012b). SMRs address deployment needs for smaller grids and lower rates of increase in demand.

Today there are several dozen SMR designs based on the technology of the principal reactor lines (PWR, BWR) and non-conventional technologies. As can be seen from Table 14.8, most of the near-term designs (deployment time of ~10 years) are based on the well-known pressurized water reactor technology. Moreover, there is one high temperature reactor (HTR-PM), one advanced heavy water reactor (AHWR) and three liquid metal cooled SMRs (two lead-bismuth cooled and one sodium cooled), although prototypes are only expected by 2020 because a higher degree of innovation is required.

Table 14.8 Design status and possible timeframe for the deployment of SMRs (Hidayatullah, Susyadi et al. 2015).

SMR designs	Type	Power rating (MW)	Designers	Status
CAREM-25	Integral PWR, natural circulation	27	CNEA, Argentina	**One unit prototype under construction near Atucha-2 site**
CNP-300	2 loop PWR	315	CNNC, China	**Three units in operation, two units under construction**
ACP-100	Integral PWR	100	CNNC, China	Detailed design
CAP-150	Integral PWR	150	SNERDI, China	Conceptual design
Flexblue	Seabed-moored small modular reactor	160	DCNS, France	Conceptual design
AHWR300-LEU	Pressure tube	304	BARC, India	Detailed design
IMR	Integral modular PWR, natural circulation	335	MHI, Japan	Conceptual design
SMART	Integral PWR	100	KAERI, Korea	**Standard design approval received in July 2012**
ABV-6M	Integral PWR, natural circulation	8.6	OKBM Afrikantov, Russian Federation	Detailed design
VBER-300	Integral PWR	325	OKBM Afrikantov, Russian Federation	Detailed design
RITM-200	Integral PWR	50	OKBM Afrikantov, Russian Federation	Under construction
KLT-40S	Barge mounted - floating nuclear power plant	70	OKBM Afrikantov, Russian Federation	**2 units in final stage of construction**
VVER-300	Integral PWR	300	OKB Gidropress, Russian Federation	Detailed design
VK-300	BWR	250	RDIPE, Russian Federation	Conceptual design

SMR designs	Type	Power rating (MW)	Designers	Status
UNITHERM	Very Small, Integral PWR, with Natural Circulation	2.5	RDIPE, Russian Federation	Conceptual design
SHELF	Seabed-moored small modular reactor	6	RDIPE, Russian Federation	Conceptual design
IRIS	Integral PWR	335	IRIS International Consortium, Italy	Conceptual design
mPower	Integral PWR (twin-pack of 180 MW)	360	B&W Generation mPower, USA	Detailed design
NuScale	Integral natural circulation PWR (12 x 50 MW)	570 (nominal)	NuScale Power, USA	Detailed design
Westing-house SMR	Integral PWR	225	Westinghouse Electric Corporation, USA	Detailed design
SMR-160	Integral PWR	160	Holtec Corporation, USA	Detailed design

Small and modular reactors offer a number of different ways to improve economic performance (IAEA 2007, USDOE 2010), including:

Reduction of plant complexity. In some advanced SMRs it may be possible to achieve significant design simplification through broader incorporation of size-specific, inherent safety features that would not be possible for large reactors. Some vendors and designers estimate that such design simplification could reduce the capital costs for near-term pressurized water small modular reactors by at least 15%.

Reduction of construction time and costs. It may be possible to obtain a faster return on investment by sizing the reactor for transport and using a standardized design with no site-specific modifications. Most of the SMR developers claim that SMRs could be built in approximately 3 years. Capital costs could be reduced by up to 20%, if the discount rate is high.

"Economies of Mass Production" instead of "Economies of Scale". "Economies of Scale" are replaced by "Economies of Mass Production" by taking advantage of cost reductions through factory mass production associated with serial manufacture of transportable plants or equipment modules incorporating standardized structures, systems and components.

Matching electrical capacity additions to system size. By combining small reactor size and short construction times, it is possible better match the load growth of smaller utility systems. Smaller reactor modules can reduce excess capacity, interest costs and investment risk, compared to large, conventional reactors. Additional savings may be available by building a series of multiple reactors as needed on a single shared site.

Barge-mounted reactors. Some vendors and designers claim that a full, factory-fabricated, barge-mounted nuclear power plant could be 20% less expensive than an SMR of the same size built on land. Designs are typically based on naval reactors like those used in icebreakers and would be produced in shipyards. Delivery is obviously limited to navigable coasts and rivers, but population density is usually highest in such areas, leading to high electricity demand.

Cogeneration. Small reactors may often provide a good size match not only for electricity but also for heat demand. In some remote (often northern) locations, the generally low-temperature heat can be a valuable co-product that may match well to the local district heating grid.

An analysis of levelized cost of electricity (LCOE) for small modular reactors has been recently published by the IAEA (OECD/NEA 2011). This analysis also includes a comparison with larger nuclear power plants, fossil based plants and wind turbines, using cost data from a global survey of generation costs. The costs reported in this survey do not have any uniform quality or common assumptions, but it is very instructive to observe the variation in costs both within and across three regions, i.e. Europe, North America and Asia. Estimated LCOEs for all land-based SMRs are slightly higher than for large nuclear power plants, while the corresponding costs for the barge-mounted SMRs are significantly higher than for land-based SMRs, with the exception of the Russian twin barge-mounted units. It should be noted, though, that a more recent analysis of (Locatelli, Bingham et al. 2014) arrives at somewhat more pessimistic conclusions with respect to the economic viability of SMRs and especially restricts the range of economically viable power ratings from approximately 1-3 GW.

14.3.2.3 High Temperature Reactors (HTRs)

The high-temperature reactor (HTR) represents one of the most advanced SMR designs. Due to the special fuel design and small power rating, it also offers a high level of safety because the decay heat can be passively removed. Because it operates at a higher temperature level than the water-cooled LWR-based designs, the HTR offers a much higher thermal efficiency. This higher level of temperature also opens opportunities to provide process heat for a wider range of industries.

The unique characteristics of passive safety of the HTR are the following:

The ceramic fuel is composed of many small fuel particles (UO_2 or UC) embedded in a pebble shaped graphite matrix. This is the pebble-bed design that was used in Germany and is currently used in China (HTR-10, HTR-PM). The fuel particles are coated with several layers of PyC and SiC that inhibit the transfer of radioactive isotopes out of the particles. The pebbles can withstand temperatures up to 1600°C. With such pebbles, continuous refueling is possible. This minimizes the excess reactivity necessary to operate the reactor and thereby minimizes the potential for reactivity induced accidents.

Another design option is to embed the fuel particles into so-called compacts made of graphite that then will be put into channels in prismatic graphite blocks. This is the so-called block design, used in France, Russia and USA. The Japanese design represents a variant by using cladding made of graphite to contain the compacts with the fuel particles.

This fuel features a strong negative temperature feedback that keeps the power within limits (similar to the LWRs). In fact, the HTR will absorb a total, unprotected loss of cooling accident (i.e. combined with a failure of the reactor shutdown systems, as happened to the LWRs in Fukushima) without consequences outside of the power plant due to its capability for inherent shutdown and for passive decay heat removal (through radiation, conduction and convection and finally external air cooling of the pressure vessel); the maximum acceptable fuel temperature of 1600°C will not be violated, and furthermore, due to the absence of zirconium, no hydrogen will be generated. No auxiliary systems are needed. This benign behavior has been experimentally demonstrated in several test reactors (AVR, Germany, HTR-10, China and HTTR in Japan).

A further benign safety feature is the sluggishness of the HTR that is caused by the high heat capacity of the graphite used as moderator and reflector combined with the low power density that is mandated by the use of the inert He gas as coolant.

In summary, modular HTRs clearly show an increased level of inherent and passive safety features.

The development and the realization of HTRs is mainly going on in Asia: Since the late nineties of the last century, Japan has operated the High Temperature Test Reactor (HTTR) rated at 30 MW_{th}. Korea is developing a very high temperature reactor concept (VHTR) that optimally supports hydrogen production.

Finally, at the Tsinghua University, China has successfully operated its HTR-10 pilot plant rated at 10 MW_{th} for many years. This pebble bed reactor is based on German technology that was developed for the AVR and THTR reactors. Currently, the demonstration reactor HTR-PM (High Temperature Reactor – Pebble-Bed Module) is being constructed at Shidaowan (Shandong province). The plant includes two units rated each at 250 MW_{th}, which are connected to a single 200 MW_e turbine. The first reactor pressure vessel has been installed in April 2016, and the second in September 2016.

A current overview on the different HTR concepts, their application for process heat generation, and the related research on fuel technologies including irradiation experiments is documented in (IAEA-TECDOC-CD-1682 2012).

For the last 15 years, HTR related research has been organized in Europe through the network HTR-TN and the EU technology platform "Sustainable Nuclear Energy Technology Platform" (www.snetp.eu). The most recent EU projects have been ARCHER (www.archer-project.eu, for technology development) and EUROPAIRS (www.europairs.eu, on industrial applications). The demonstration reactor (ALLEGRO) should also be constructed in Poland with the help of structural funds. In addition, GIF also serves as a coordinating platform.

The possible use of a thorium fuel cycle in an HTR is today still a topic of research. The reprocessing of the coated fuel particles is not yet established.

14.3.2.4 Molten Salt Reactors (MSRs)

Molten salt reactors represent a quite different design line that has been explored in parallel to the more traditional LWRs since the beginning of the development of nuclear technology. Today, the MSR is being developed within two different families of reactor concepts.

The less ambitious family of MSR concepts relies on some form of solid fuel as it is known from LWRs or HTRs and uses the molten salt only as coolant, and typically relies on (epi-) thermal neutron spectra. With this choice, a higher coolant temperature can be reached, thereby increasing the thermal efficiency of the reactor concept. At the same time, it minimizes the developmental risks. Therefore, this concept is considered as a next step towards to the fluid fuel MSR variant. It being is pursued in the US (the Fluoride salt-cooled High-temperature Reactor, or FHR) and also recently in China (SINAP, Shanghai). The US and China have also entered a related cooperation.

In the more ambitious family of MSR concepts exploiting the full potential of benefits, the nuclear fuel is dissolved in fluoride salts for (epi-) thermal spectra and chloride salts for fast spectra. On-line separation of fission gases, and possibly also other fission products such as lanthanides, helps to minimize neutron absorption, thereby also minimizing the necessary excess reactivity. The on-site and on-line separation of actinides allows for efficient use of the nuclear fuel, as it can be easily fed back to the fluid stream passing through the core. It also helps to minimize the radioactive inventory in the reactor core. In some designs, drain tanks below the reactor loop are accessible via frozen plugs. These plugs will melt at excessive temperatures or if refrigeration power is lost, and the drain tank will receive the fuel salt to assure reactor shutdown by passive means.

If thorium is used as the fuel, breeding can be achieved even in a thermal neutron spectrum. At Oak Ridge, the MSBR design concept was completed in 1972. The breeding ratio was estimated to be 1.06.

Currently, many different MSR reactor concepts are pursued worldwide, and it is noteworthy that several of these concepts are developed by private (start-up) companies, among them Terrestrial Energy (Canada), Terrapower (US), and Transatomic Power Inc. (US).

In Asia (Japan and China) the graphite-moderated breeder developed at Oak Ridge National Laboratory (ORNL) is favored (Perry and Bauman 1970). Reactor systems with small capacities up to 200 MW are considered, such as the mini-FUJI or FUJI MSR.

In Europe, CNRS in France has been developing a fast-spectrum MSR reactor for the last 2 decades and is a key partner to the EU project SAMOFAR that after EVOL continuously provides the framework for MSR research.

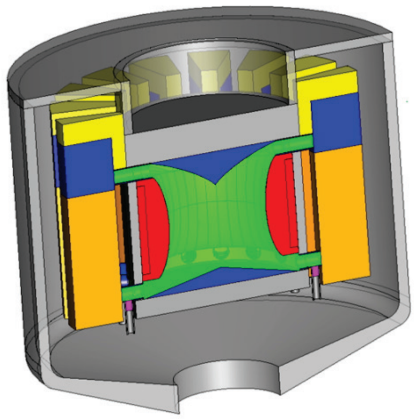

Figure 14.3: Lay out of conceptual Molten Salt Fast Reactor (MSFR), reference design of the EU SAMOFAR project, with the fluoride-based fuel salt in green and the fertile blanket salt in red (GIF 2014).

A very characteristic feature of fluid-fuel molten salt reactors is their capability of on-separation of actinides and fission products. Figure 14.4 shows a schematic of the continuous reprocessing.

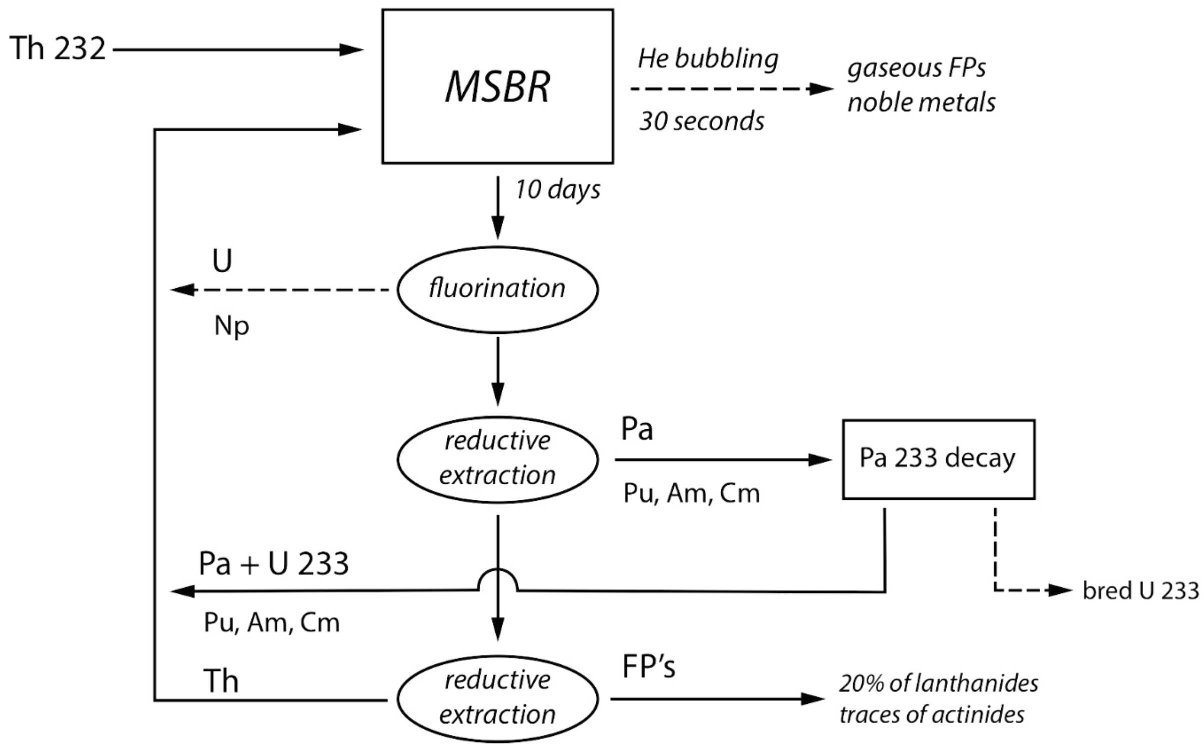

Figure 14.4: Simplified diagram of the continuous reprocessing of the MSBR concept of ORNL.

The continuous processing of the molten salt is essentially a four step process. In the first step, noble gases and precious metals are separated using gaseous helium in the so-called bubble chamber. In the second step, uranium is separated by means of fluoridizing. In the third step, protactinium and transuranic elements that are present in very small quantities are separated by electrolytic fractionation or reductive extraction from the liquid salt. The protactinium itself is stored in a tank, where it decays to U-233, and is then returned as fuel to the salt cycle. In another reductive extraction, the lanthanides (Ce, La, etc.) are separated.

It is clear that the MSR poses a number of research challenges in the area of materials, chemistry and also that a new licensable approach to safety needs to be developed.

14.3.2.5 Thorium

Introduction and review: Since the beginning of the development of nuclear age, industrial nuclear power generation has been based on the uranium or uranium/plutonium fuel cycles. The uranium fuel cycle is used worldwide in all nuclear power plants with a thermal spectrum and its economic viability has been demonstrated. The alternative thorium fuel cycle has been explored in parallel and related research programs were carried out between the 1950s and 1980s. However, commercial use of thorium as nuclear fuel has not materialized to date.

Basic R&D work has been performed in England, USA, Russia, Japan, Germany and India. Since the 80s, relevant work has been abandoned in the countries listed, with the exception of India. India has very large reserves of thorium and is implementing a long-term strategy to exploit the domestic thorium resources in a sustainable manner, and has accordingly made great efforts to develop a thorium fuel cycle.

Since the new millennium, a growing interest in the thorium fuel cycle can be observed in many countries. This has, inter alia, led to extensive reviews conducted by international and national organizations, such as OECD/NEA (IAEA-TECDOC-1450 2005), the Norwegian government (ThoriumReportCommittee 2008) and the American Nuclear Society. Within the framework of these reviews all aspects of the fuel cycle (from thorium extraction to final storage of radioactive waste) were considered to assess the potential and benefits of such a fuel cycle.

Whether a thorium fuel cycle is more advantageous compared to a uranium fuel cycle is controversial, partly due to the complex scientific, technological and economic aspects. Recently, new research (Taiwo, 2016) and reviews (OECD/NEA 2015) provide a more rational basis to answer this question. Taiwo, Kim et al. (2016) reviewed the different thorium fuel cycles analyzed in the framework of the large “Nuclear Fuel Cycle Evaluation and Screening” study (Wigeland, Taiwo et al. 2014). This latter study included a total of 40 different fuel cycle options, 15 of which use thorium and evaluated all options based on a metric that covers several figures of merit for each of the criteria of “Nuclear Waste Management”, “Proliferation Risk”, “Nuclear Material Security Risk”, “Safety”, “Environmental Impact”, “Resource Utilization”, “Development and Deployment Risk”, “Institutional Issues and Financial Risk” and “Economics.” Taiwo, Kim et al. (2016) concluded that there are indeed some worthwhile fuel cycle options using thorium, but similar performance in term of the applied metric can be obtained with less effort with uranium-based fuel cycles using continuous recycling of U/Pu or U/TRU in fast reactors. Hence, the often published opinions of thorium advocates on the superiority of the thorium fuel cycle over the more traditional fuel cycle options cannot be corroborated with scientific analysis. In fact, while advantages of the thorium fuel cycle undeniably exist, there are at the same also disadvantages that have impeded the deployment of this fuel cycle option at the commercial scale to date (OECD/NEA 2015). Among them is the higher level of radioactivity (due to U-232) that requires remote handling in the fuel cycle facilities, but this is mostly seen as an advantage related to the risk of proliferation as it complicates unauthorized fuel handling. On the other hand, some critics point to the potential for chemical extraction of pure protactinium, which is a precursor to fissile uranium 233. The Pa-233 converts into very pure weapons grade U-233 by its radioactive decay, which is not contaminated by U-232. An overview on the pros and cons can be found in Table 14.9.

Table 14.9: Advantages and disadvantages of thorium PWR fuel compared to UO2-based fuel (OECD/NEA 2015).

Aspect	**Pro**	**Con**
Thorium characteristics	• High-thermal capture cross-section results in high ^{233}U breeding ratio. • Stable element, no oxidation or corrosion.	• Requires high amount of initial fissile material for initiation of the thorium cycle. • Doppler coefficient is less negative than of ^{238}U. • (n,2n) process results in high production of ^{232}U and its daughter product ^{208}Tl.
Thorium fuel characteristics	• Higher melting temperature and higher thermal conductivity.	

Aspect	Pro	Con
^{233}U	• Highest neutron reproduction factor in thermal region of all fissionable nuclides. • High content of fissile material at discharge makes recycling attractive.	• In situ fission of ^{233}U is smaller than Pu in U/Pu cycle ($\sigma_{f,\ U233} < \sigma_f$, Pu).
Highly enriched uranium (HEU)	• Highest thorium content in fuel.	• Not available for commercial use. Proliferation concerns.
Low enrichment uranium (LEU) (<20% ^{235}U)	• May avoid proliferation concerns to some extent.	• Significant reduction of thorium usage compared to HEU. • Results in significant plutonium production.
Plutonium	• Available from reprocessing. • Significant reduction of amount and denaturing of plutonium.	• Could compromise plutonium inventories required to deploy future fast reactors.
^{233}Pa	None.	• Significant reduction of conversion ratio at high neutron flux.
^{232}U	• Contamination of fuel increases proliferation resistance of Th-232/U-233 cycle.	• Intensive gammas by daughter nuclides (^{208}Tl).
Once-through fuel cycle	• Non-proliferation aspect: low solubility of thorium fuel. • In Th/Pu fuel high degradation and mass reduction rate of plutonium. • No further production of plutonium in Th/HEU and Th/Pu cycles.	• High content of fissionable material at discharge. • The Th/U cycle exhibits only minor savings in natural uranium – if any – compared to U/Pu cycle.
Closed fuel cycle	• Higher conversion factor than U/Pu fuel cycle (10%-15% higher). • THOREX process is similar to PUREX process.	• Thorium fuel more difficult to dissolve, needs addition of hydrofluoric acid. • THOREX process needs to be industrially developed. • With no countermeasures, breeding of highly fissionable 233U in high-quality (countermeasures result in reduction of attractiveness for thorium fuel cycle). • No experience with reprocessing of Th/Pu fuels.
Manufacturing	• Known technology.	• Th/U assembly manufacturing might need shielding. • Th/U/Pu fuel (recycling option) manufacturing is even more penalized. • Th/Pu/U fuel not developed.

The use of thorium in existing Gen II/III reactors, such as light-water moderated reactors (LWRs) and heavy water moderated reactors (HWR), is currently mainly restricted to theoretical studies. Thorium has been investigated also for deployment in Generation IV concepts, like molten salt reactors, high temperature reactors and fast reactor systems.

Major research projects: There are currently no reactors operated with thorium. Four reactors using thorium fuel are permanently shut down. However, approximately 300 thorium fuel rods were employed in Pressurized Heavy Water Reactors (PHWR) under the Indian research program (Anantharaman and Rao 2011).

The Norwegian Thor Energy (Asphjell 2011) has launched a significant R&D program. A related irradiation program has been launched in the OECD Halden reactor in 2013, and at the end of 2015 a second round of tests were launched. This campaign is supported by a consortium including Thor Energy (Norway), Westinghouse, Fortum (Finland), NNL (UK), ITU (Germany) and KAERI.

Advantages of thorium over uranium: The use of thorium has several advantages over the established industrial use of uranium: There is the possibility of sustainable nuclear energy generation with reduced production of very long-lived highly radioactive waste, as only very small amounts of plutonium, americium and curium are produced.

A significant reduction or elimination of weapons-grade and/or civilian plutonium by burning plutonium and thorium together is possible, because almost no plutonium is produced using thorium. On the other hand, U-233 can be used for nuclear weapons, which was demonstrated by a small number of successful tests conducted by the USA. Furthermore, pure U-233 can potentially be produced by the decay of chemically extracted Pa-233, which is the precursor of U-233 in the Th-232 to U-233 conversion process. This is a specific property of Th-U cycle, because the half-life of Pa-233 is long enough to conduct this kind of separation process. If safeguards can exclude early access to the fuel from a nuclear power plant, then the proliferation resistance of the Th-232/U-233 cycle is higher than for the U-235 cycle, because of the contamination of U-233 by U-232, as discussed above.

The radioactive element thorium is about 3 to 4 times more abundant in the earth's crust than uranium. Physical studies of different reactor systems (LWR, HTR, SFR, etc.) have shown that safety-related reactor physics parameters are more favorable if thorium is used.

An interesting industrial application of Th-232 is the possibility of replacing gadolinium as a burnable neutron poison. A related development is underway in Norway by THOR Energy.

Economy and constraints:

As mentioned above, thorium fuel can be used in very different reactors and accordingly, the costs vary greatly.

Earlier cost estimates of the construction of molten salt reactors led to similar costs as for today's LWRs. Current overnight LWR costs are estimated to center on the range of 4000-5000 USD/kW, except for Asia which is in the range of 2000-3000 USD/kW[361]. However, the uncertainty of the MSR cost is higher than for LWR. For the LWR the primary hazards are cost and schedule overruns due to project management, quality control,

[361] Discussion later in this chapter focuses on the cost of a future EPR where cost overruns to date have raised expected prices.

regulatory opposition and other delaying factors. Some MSR designs have the potential to be economical, but the risk of unproven technological problems cannot be excluded.

The economic aspects also include the necessary R&D costs, construction of demonstration plants, building a prototype system, the development and implementation of all necessary infrastructure facilities and, last but not least, the fulfillment of all regulatory requirements.

14.4 Fuel Cycle

The nuclear fuel cycle, also known as the nuclear fuel chain, is a series of industrial processes that involves the processing and production of fuels, the production of electricity from uranium in nuclear power reactors, and the processing and disposal of nuclear waste. The most common nuclear fuel today is uranium, which is used in over 400 operational nuclear reactors worldwide for power generation (OECD/NEA/IAEA 2016). In order to process and produce uranium from raw material to fuel assemblies that can be used for power generation, the fuel cycle steps below need to be followed:

- Uranium mining and milling: extraction of uranium and conversion to yellowcake
- Conversion of yellow cake to uranium hexafluoride (UF_6)
- Enrichment of uranium-235 content
- Fuel assembly fabrication (including conversion to uranium dioxide (UO_2), production of fuel pellets, fuel rods)
- Consumption of fuel in the reactor to produce power
- Intermediate storage of spent nuclear fuel
- Reprocessing of spent nuclear fuel (optional)
- Spent nuclear fuel and high level waste disposal

Fuel cycles can be separated into two main categories: if the spent fuel is not reprocessed, the fuel cycle is referred to as an “open fuel cycle” (also known as a “once-through” cycle); if spent fuel is reprocessed and partly reused, it is referred to as a “closed fuel cycle”. Within each fuel cycle, the preparation of the fuel before it is consumed in the reactor is called the “front end”, and correspondingly, there is the “back end”, which refers to the processes dealing with spent nuclear fuel, including the reprocessing, reuse and disposal of the spent fuel. The consumption of the fuel in the reactor is called the “service period” (IAEA 2011).

There are four classes of fuel cycles: (1) the once-through fuel cycle, (2) a fuel cycle with partial recycling of the plutonium, (3) a fuel cycle with full plutonium recycling, and (4) a fuel cycle with full recycling of transuranic elements (GIF 2002).

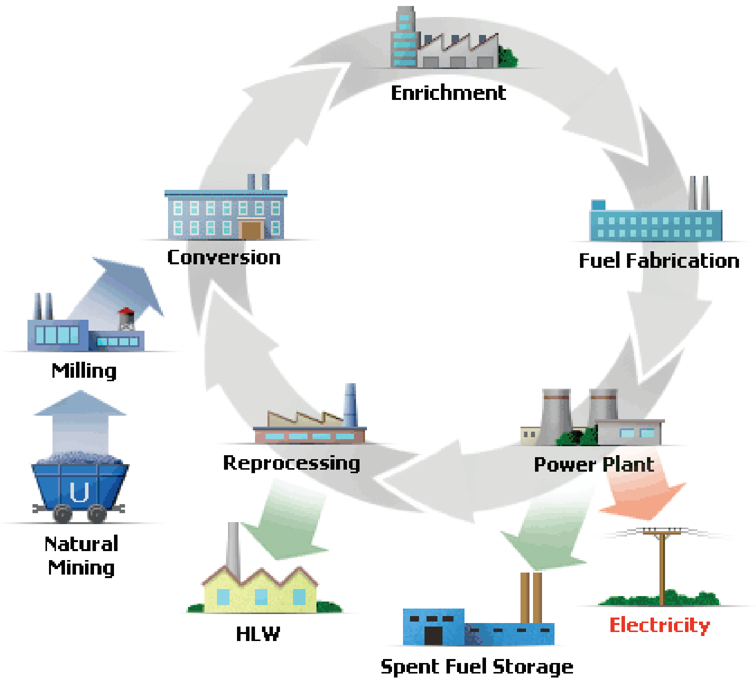

Figure 14.5: Fuel cycle using uranium as a fuel (Rohlf, VanSchepen et al. 2010).

Once-through cycle: The fuel is manufactured, used in the reactor, stored at the plant during a cooling period, and then directly disposed of as waste. The light water reactors in the USA presently use this cycle, particularly due to concerns based on protection from weapons proliferation.

Partial recycle: The burned fuel is partially reprocessed, and new fuel manufactured from the recycled resource. This fuel is used once again to gain the additional energy. In France and England, uranium and plutonium are recovered and used to manufacture mixed-oxide fuel elements. These are put back in a reactor and finally disposed of directly.

Full recycle: The entire burned fuel is recycled with near total recovery of plutonium and uranium, with multiple or almost total reuse of the fissile material. The higher actinides and fission products are sent to final storage. An example of this process is the Liquid Metal (sodium-cooled) Fast Reactor (LMFR).

Full actinide recycle: All fission products and actinides are recycled multiple times, to use all the fissile material. To achieve such a cycle, an integrated combination of different reactor types is necessary that burn or breed the respective fission products and fertile materials, with the goal of minimizing are far as possible the both amount of waste and its radiotoxicity so that almost no final, long-term storage is necessary.

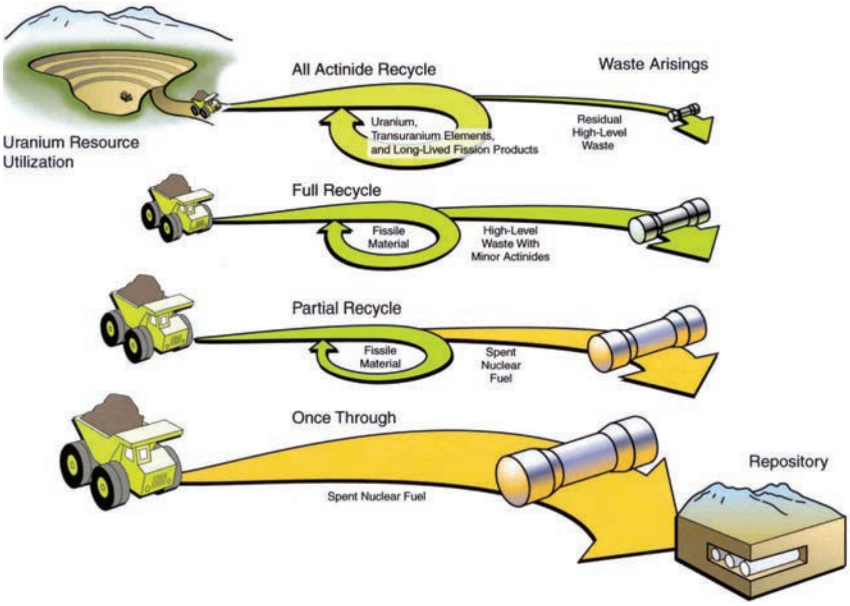

Figure 14.6: Types of fuel cycles (GIF 2002).

14.5 Fuel supply

14.5.1 Resources

The identified uranium resources refer to the uranium that can be recovered at a cost of less than 260 USD/kg U, and it can be categorized into two types: reasonably assured resources (RAR) and inferred resources (IR) (OECD/NEA/IAEA 2016). RAR refers to uranium in known mineral deposits that can be recovered within a given production cost range with currently proven mining and processing technologies, whereas IR is in general less certain than RAR, and refers to uranium that is inferred to occur based on based on direct geological evidence, in extensions of well-explored deposits, or in deposits where specific data and knowledge are inadequate to classify the resource as RAR (Geoscience Australia 2017). In the beginning of 2015, the total uranium resource identified that is recoverable under the cost of 260 USD/kg U is about 7642 thousand tons of uranium. When the recovery cost is reduced to 130 USD/kg U, the uranium resources amounted to 5718 thousand tons of uranium. A significant increase of 21% compared to 2013 is reported for inferred resources that can be extracted under 80 USD/kg U, mainly from the addition of 208 thousand tons of inferred resources from China and Kazakhstan. In addition, there are about 73 thousand tons of resource reported by companies that are not yet included in the national resource total above. Based on the uranium demand for power generation in 2015 (56 thousand tons per year), the identified resources are sufficient to meet the power generation demand for more than 100 years (OECD/NEA/IAEA 2016).

Table 14.10: Identified uranium resources in 2013 and 2015 (OECD/NEA/IAEA 2016).

Resource category	2013	2015	Change (1 000 tU)[(a)]	% change
Identified (total) (1 000 tU)				
<USD 260/kgU	7 635.2	7 641.6	6.4	0.1
<USD 130/kgU	5 902.9	5 718.4	-184.5	-3.1
<USD 80/kgU	1 956.7	2 124.7	168.0	8.6
<USD 40/kgU[(b)]	682.9	646.9	-36.0	-5.3
Reasonably assured resources (1 000 tU)				
<USD 260/kgU	4 587.2	4 386.4	-200.8	-4.4
<USD 130/kgU	3 698.9	3 458.4	-240.5	-6.5
<USD 80/kgU	1 211.6	1 223.6	12.0	1.0
<USD 40/kgU(b)	507.4	478.5	-28.9	-5.7
Inferred resources (1 000 tU)				
<USD 260/kgU	3 048.0	3 255.1	207.1	6.8
<USD 130/kgU	2 204.0	2 260.1	56.1	2.5
<USD 80/kgU	745.1	901.1	156.0	20.9
<USD 40/kgU[(b)]	175.5	168.4	-7.1	-4.0

(a) Changes might not equal differences between 2013 and 2015 because of independent rounding.

(b) Resources in the cost category of <USD 40/kgU are likely higher than reported, because some countries have indicated that detailed estimates are not available, or the data are confidential.

In addition to the conventional resources from mining mentioned above, there are discussions on utilizing the large amount of uranium in seawater (4 billion tonnes of U, which is equivalent to the fuel demand of 1000 reactors of 1000 MW for 100 thousand years of operation (Conca 2016)) as an alternative resource for global uranium supply. The drawback of this potential source is its extremely low concentration (3 ppb), which makes it a challenge to develop economic attractive extraction technology. Many countries have explored this potential source by conducting research since the 1950s, including Germany, Italy, the UK, and Japan, with the US being the leading country, and China and Japan showing great interest. In 2012, US researchers from the Oak Ridge National Laboratory (ORNL) and Pacific Northwest National Laboratory (PNNL) announced that, based on the fiber stack technology developed by Japan in 2001, they had doubled the amount of uranium recovered from seawater using polyethylene fibers coated with amidoxime which has much higher surface area, and reduces the production cost of uranium from seawater by half to 660 USD/kg of uranium (OECD/NEA/IAEA 2016). In April 2016, a special issue introducing the latest research on uranium in seawater was published by the journal of Industrial & Engineering Chemistry Research (Alexandratos and Kung 2016). Most recently, work at Stanford has focused on making the adsorbent fibers electrically conductive to improve surface ion transport and adsorption, projecting that a price of 400 USD/kg may be possible (Liu et al 2017).

The spot price of uranium varies widely, from a historical high of about 135 USD/lb U_3O_8 in 2007 to about 25 USD/lb U_3O_8 in January 2017 (uraniumminer.net 2017). Long-term contracts comprise about 85% of uranium sales, with a price premium that is generally unstated but recently estimated to be in the range of 30 to 50% (Cameco 2017).

Obviously, a large cost reduction is still required for extracting uranium from seawater in order to compete on the market with conventional mining. However, the cost of uranium only makes up about 5% of the total average cost of nuclear generation, so even if the cost of uranium was ten times the present cost, this would only represent a total average cost increase of about 50%. In the meanwhile, the potential of uranium from seawater acts as a backstop resource that limits the potential upper bound of prices from more conventional resources.

14.5.2 Exploration and mine development

Because the price of uranium has declined since 2007, uranium exploration and mine development has slowed down and expenditures reduced in many countries, such as Argentina, Australia, Canada, Finland, Kazakhstan, Russia, South Africa, Spain and the United States. Despite the decrease in expenditure for domestic exploration and mine development, the current expenditure in most countries has been maintained above the expenditures before 2007. In contrast, other countries like Brazil, China, the Czech Republic, Jordan, Mexico and Turkey exhibit increased expenditures in uranium exploration and mine development, with the most significant expenditure increase of about 50% observed in China from 2012 to 2014, showing their strong commitment in the growth of nuclear power. Four countries (China, France, Japan and Russia) reported their non-domestic exploration and development expenditures, which showed more than a fourfold increase from 2012 to 2015 from 185 million USD to 846 million USD, of which more than 90% is contributed by investment in the Husab mine in Namibia by China (IAEA 2016, OECD/NEA/IAEA 2016).

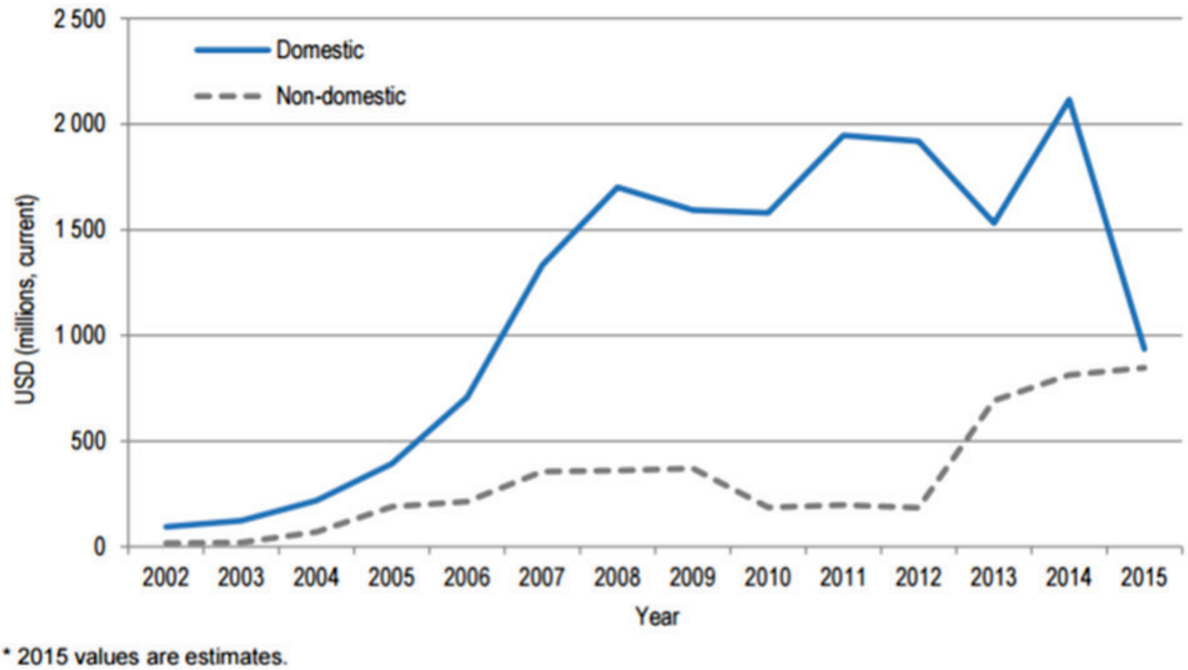

Figure 14.7: Trends in exploration and development expenditures (IAEA 2016).

14.5.3 Production

In terms of uranium production, as of January 2015, about 56 thousand tonnes of uranium were produced worldwide from 21 countries, which showed a decrease of 4% compared to 2012, mainly due to the reduced production in Australia, and lower uranium production from mining in countries including Brazil, Czech Republic, Malawi, Namibia and Niger. Despite the overall decreasing trend of world uranium production, Kazakhstan continued to grow and remained the largest producer of uranium in the world, with about 23 thousand tons of uranium production in 2014. This is more than the combined production from the second and the third largest producers, namely Canada and Australia (Figure 14.8). However the increase of uranium production in Kazakhstan has slowed. Countries like Germany, Hungary and France produce uranium from mine remediation.

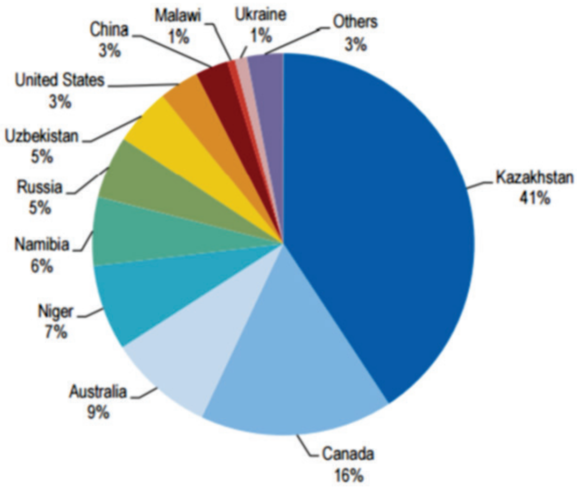

Figure 14.8: Uranium production in 2014, totaling of 56 thousand tonnes (IAEA 2016).

In terms of the market share of uranium mining technologies, historically uranium was mainly produced from conventional underground or open-pit mining. In recent years the dominant technology for uranium production has gradually shifted from conventional mining to in-situ leaching (ISL), where uranium dissolving solutions are injected into and then recovered from the ore deposit. In 2014, 51% of uranium was produced by in-situ leaching (ISL), followed by underground mining (27%), open-pit mining (14%), production as a by-product from the mining of copper, gold and phosphate (7%), and heap leaching and other technologies (less than 1%) (IAEA 2016). The amount of energy used in mining varies between 240 MJ and almost 2000 MJ per kg of uranium.

After the uranium is mined, it must be converted from U_3O_8 to UF_6. According to the global conversion capacity, about 63% of the uranium conversion occurs in the USA and Europe, 33% in Russia and 4% in China. Enrichment must be carried out after conversion, and the most common enrichment technologies are enrichment by centrifuge and diffusion. In addition, uranium can be enriched using laser isotope separation. In 2013, the US Department of Energy (DOE) and Global Laser Enrichment agreed to further explore laser enrichment by applying Silex laser enrichment technology to a portion (about 115 thousand tons) of high assay uranium tails at the closed Paducah gaseous diffusion enrichment plant. However, technological hurdles remain before commercial deployment can be achieved, and in 2015, Global Laser Enrichment announced it would slow development of laser enrichment technology due to poor market conditions (IAEA 2016).

Due to a lack of information about the fuel supply for Swiss reactors, in this study enrichment has been modeled according to global installed capacity, namely 42.5% and 22.9% via centrifuge in Russia and Europe, respectively, and 19.7% and 14.8% via diffusion in the USA and France, respectively. The average degree of enrichment in fuel assemblies used in Switzerland is assumed to be 4.43% for BWRs and 4.75% for PWRs. The fuel burn-up has increased in recent years to 57 $MW_{th}d$/kg U for BWRs and to 60 $MW_{th}d$/kg U for PWRs.

14.6 Costs

14.6.1 Costs of current Swiss nuclear plants

Due to the post-Fukushima decision by the Swiss parliament, no new Swiss nuclear plants using current technology are permitted (and three new units that were in the planning stages were cancelled). The present Swiss nuclear plants are allowed to continue operation as long as they are safe to operate. This remains true after a proposed Swiss constitutional amendment failed that would have limited the life of currently operating plants to 45 years. These current nuclear plants still play an important role in Swiss electricity production in the short and medium time frame until their future retirement dates. Therefore the construction costs of Generation II plants may be of historical interest, but the operating cost of these current plants is still important.

The older and smaller Beznau 1 and 2 (KKB) and Mühleberg (KKM) plants are wholly owned by individual utility companies, and so their operating costs are difficult to extract from the companies' annual reports. However the newer and larger Gösgen (KKG) and Leibstadt (KKL) plants are jointly owned by utility and government shareholders through their own holding companies, which do publish their own annual reports.

The average generation costs of the current Swiss nuclear power plants over the past decade have been in the range of 4-6 Rp./kWh, with the capital costs largely amortized. The figure below shows the average production costs for KKG and KKL since 2005 and 2006, respectively.

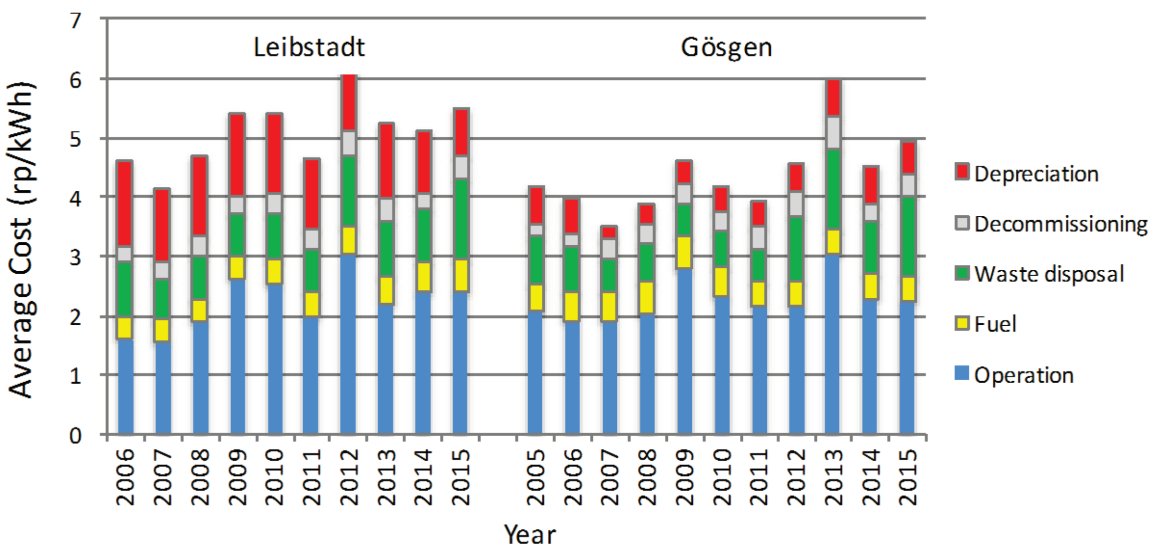

Figure 14.9: Average Cost Components for the Leibstadt (KKL) and Gösgen (KKG) plants. Source: Annual corporate reports available online from plant websites.

It can be seen from this figure that the nuclear waste disposal costs (Entsorgungskosten) dominate the plant decommissioning costs (Stilllegungskosten). Both of these costs are reviewed every 5 years, and it can be seen that the waste disposal costs increased in 2012 following 2011 cost study (swiss*nuclear*, 2011). This cost study was updated in 2016 (swiss*nuclear*, 2016) and is currently in the review process prior to approval in 2017. For the purposes of the cost analysis in this report the fuel supply costs are assumed to be 40%, and the waste disposal costs are considered to be 60% of the total fuel costs. The decommissioning costs are treated as a fixed future cost (even though the utilities pay an annual amount towards funding this cost).

Since the majority of the plant costs are fixed, the annual plant generation has a large impact on the average costs. The annual operation is generally measured by the plant capacity factor, which is the annual generation divided by the rated capacity times the number of hours per year (i.e. the actual generation/potential generation). Swiss plants generally operate at a capacity factor of over 90% (Table 14.2), which is good by international standards. The annual capacity factors for Leibstadt and Gösgen are shown in Figure 14.10 below, showing their relatively good and consistent output, except for 2012 and 2013, where these plant had major upgrade and repair periods. These years also correspond to the peak average cost years.

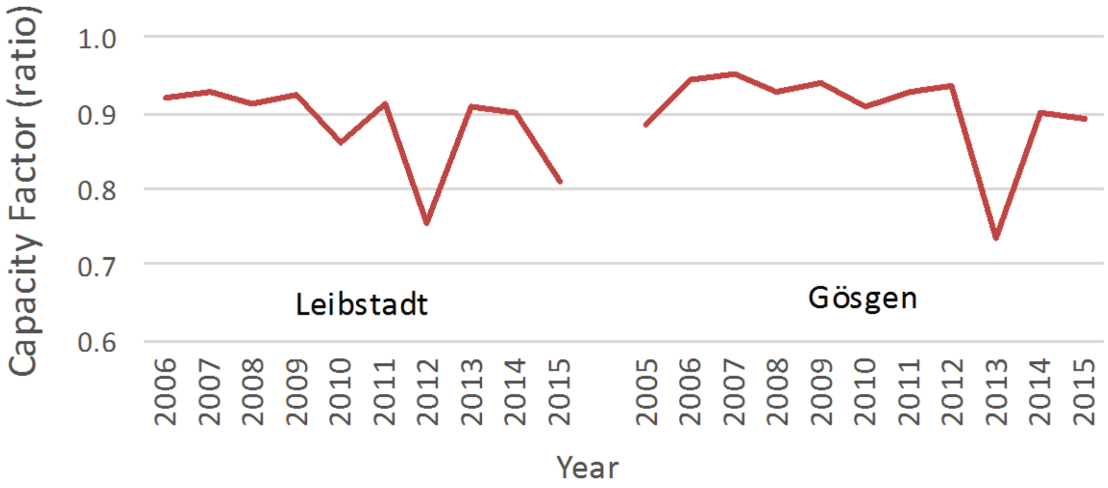

Figure 14.10: Annual capacity factors for the Leibstadt (KKL) and Gösgen (KKG) plants. Source: Annual corporate reports available online from plant websites.

Another slight but relatively consistent trend that tends to reduce the average cost per kilowatt hour is that incremental capacity improvements have gradually increased the rated power of the nuclear plants. This is shown in Figure 14.11.

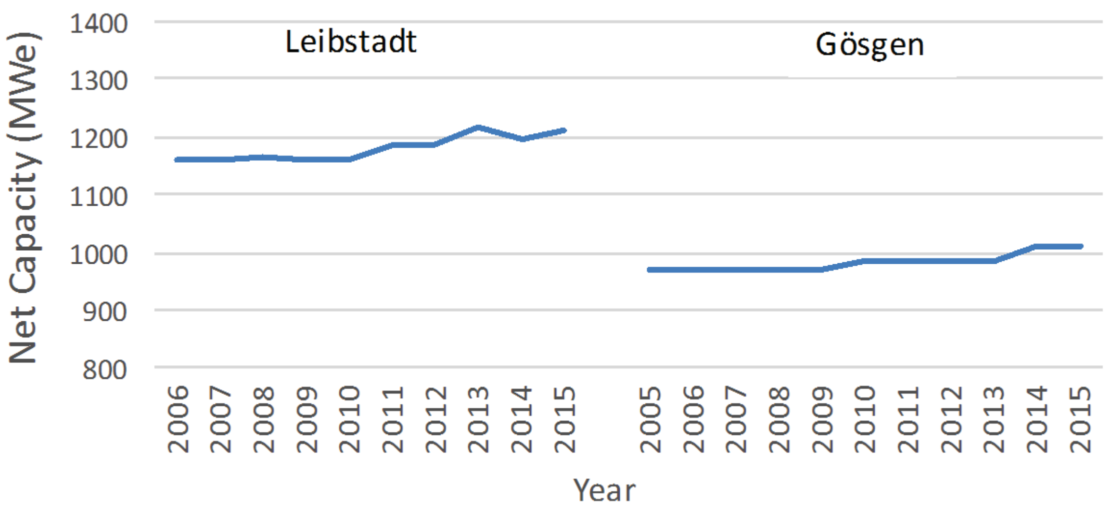

Figure 14.11: Annual net generation capacity for the Leibstadt (KKL) and Gösgen (KKG) plants. Source: Annual corporate reports available online from plant websites.

Although it is hard to obtain reliable, recent financial costs for the Beznau and Mühleberg plants without data broken out in the companies' annual reports, it is still possible to see an older, historic comparison of Beznau and Mühleberg versus Gösgen and Leibstadt. In general, Swiss plants followed the international trend of increasing capital costs over time, due to increased safety standards, diseconomies of scale, etc. However in Switzerland, the three older reactors (KKB and KKM) were subject to safety-related retrofits in the early 1990's that brought their average costs approximately equal with the two newer and larger plants.

The NANO project at the Beznau plant (KKB) and SUSAN project at Mühleberg (KKM) installed additional diesel emergency generators for secure power backup, an emergency control room, and in the case of Beznau, wells for an independent cold water supply. NANO is the German acronym for „Nachrüstung für den Notstand", meaning Retrofit for Emergencies, while SUSAN is short for „Spezialles unabhängiges System zur Abfuhr der Nachzerfallwärme", meaning Special Independent System for Disposal of Decay Heat.) Due to a lack of groundwater on the site of Mühleberg, the SUSAN project relies on a water supply from the Aare river. In addition to providing additional redundancy for the avoidance of core damage, NANO and SUSAN were also designed to reduce the consequences of severe accidents as part of the Severe Accident Management (SAM) system. This scheme also installed air filtration systems in all Swiss reactors during the 1990's for filtering any air released for emergency pressure relief.

Table 14.11 shows the construction-related costs of the Swiss nuclear fleet and the NANO and SUSAN projects. The average cost columns for the NANO 1, NANO 2 and SUSAN lines reflect the total costs for both the original construction and the upgrade. The final column shows the plant costs adjusted by the Swiss consumer price index to 2016 CHF. (This final column is not in the original reference, but is based on the same costs and original installed gross capacities, without subsequent capacity increases). Table 14.12 shows the influence of the large plant revisions on the average production cost.

Table 14.11: Construction, renovation, interest and total plant costs. Renovation includes costs that were already planned in 1985 for the following years, later renovations are not included (BFE/SFOE 2008a).

Plant	Construction cost (Mio CHF)	Replacement parts (Mio CHF)	Interest (Mio CHF)	Plant Cost (Mio CHF)	Average Capital Cost (CHF/ kW)	Ave. Cap. Cost (2016 CHF/kW)
Beznau I	433	6	28	467	1283	3891
NANO 1	257	5	36	298	2102	4821
Beznau 2	433	6	28	467	1283	3525
NANO 2	257	5	36	298	2102	4485
Mühleberg	577	12	49	638	1899	4892
SUSAN	132	3	11	146	2333	5453
Gösgen	2185	44	845	3074	3169	5944
Leibstadt	4243	85	1612	5940	5940	8976

Table 14.12: Discounted generation costs (Price basis 01.10.1985). Source: (BFE/SFOE 2008a).

Plant	Date	Average Generation Cost (Rp./kWh)			
		Capital Cost	Operation and Maintenance	Fuel	Total
Beznau 1	01.01.1970	1.081	1.837	1.98	4.898
NANO 1	1993	0.980			0.980
Beznau 2	01.02.1972	1.081	1.837	1.98	4.898
NANO 2	1992	0.878			0.878
Mühleberg	01.08.1972	1.479	1.996	1.98	5.455
SUSAN	1990	0.381			0.381
Gösgen	01.01.1979	2.707	1.992	1.98	6.679
Leibstadt	01.06.1985	5.108	1.946	1.98	9.034

As can be seen, the Beznau and Mühleberg retrofits increase the average generation costs for these smaller, older plants to approximately equal with the newer, larger Gösgen plant in this older, historic data. However the average cost of about 9 Rp/kWhe for Leibstadt is significantly higher than the cost shown in Figure 1.9 above, which reflects the capital depreciation that is included in the annual reports. Given this capital cost depreciation since the 2008 SFOE report, and the fact that the O&M, fuel, decommissioning and fuel disposal costs are quite similar, it is quite reasonable to to assume that current KKB and KKM operating costs are approximately equal to those for KKG and KKL.

The major problem for the Swiss nuclear utilities is that the average cost of nuclear generation is higher than the average revenue they receive per kilowatt hour. Figure 14.12 shows the price duration curves for the Swiss electricity spot market from 2007 through 2015, which give the number of hours at or above a certain price level. The general drop in the price duration curve over time is not only due to the drop in European electricity market prices, but also significantly due to the increasing strength of the Swiss franc over this period.

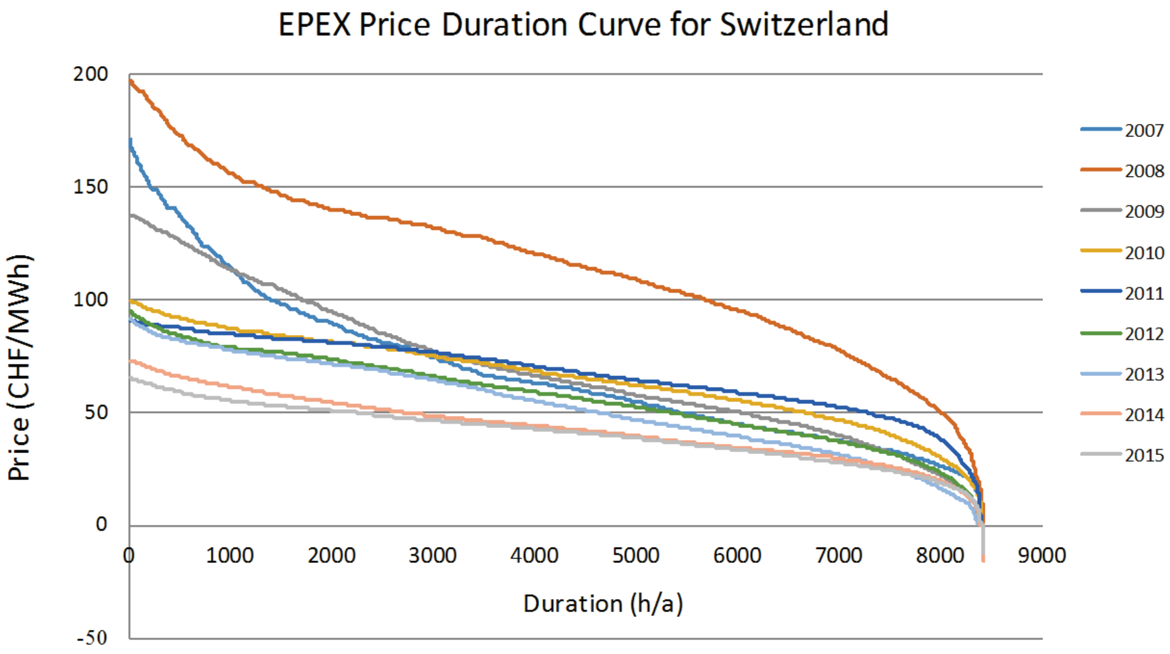

Figure 14.12: European Power Exchange (EPEX) energy spot prices for Switzerland.[362]

As can be seen, especially for the later years, there are large portions of each year where the spot market price is below the average plant generating cost of 5 to 6 Rp./kWh. The situation is further exacerbated by the facts that nuclear plants generally sell their power on lower priced, long term contracts rather than by the spot price, and also the ramp-up and ramp-down times for a nuclear plant are so long that the plant operators cannot simply turn the plants off when they would like. (Indeed, if the spot price goes negative, the nuclear plants can be forced to pay to keep generating, since they cannot be turned off quickly). This situation also exacerbates the issue of CO_2 emissions in the European market, as the need for swing generation capacity has increased generation from coal (including dirtier lignite).

All of this difficulty reflects the fact that nuclear power is very capital intensive and has a very low marginal cost (fuel, plus a low variable operation and maintenance cost). The Swiss power market price depends at the margin on the renewable generation in the larger European market (renewables are also capital intensive and have effectively a zero marginal cost). Combining these two facts means that the nuclear plants must choose to operate whenever the market price exceeds the plant’s marginal cost simply to minimize its losses, even though the market price is below the plant’s average cost.

14.6.2 Global historical perspective

It is useful to place the historic costs of the Swiss nuclear plants within the context of the global nuclear fleet. This has been done by a succession of review papers over the past several decades. The most influential early review (Komanoff 1981) compared the cost overruns for coal plants adding new pollution controls and the cost overruns of nuclear plants in the US. His conclusion was that nuclear plants would continue to experience cost overruns (more so than coal), which was proven to be the case historically.

[362] ftp.epexspot.com

The focus continued for many years to be on cost overruns within the US context, basically because the most comprehensive data was available there, and because the cost overruns were very significant, eventually leading to a practical cessation of new plant construction. In general, delays in plant construction caused by increased safety requirements, public opposition and occasionally costly mistakes, led to increased interest costs, and often to increased capital costs if plant rework was required or design changes were made. These cost overruns led to an increase in perceived economic risk and higher interest rates, creating a feedback loop that ultimately led to utilities ceasing orders for new plants.

It was not until 2010 that Grubler at IIASA obtained cost data for the French fleet of plants and did a comparative analysis of the two countries (Grubler 2010, Grubler 2012). His basic conclusion for France was that plant complexity had outstripped industry learning, in spite of a single builder/customer and much more design standardization, and that this caused 'negative learning.'

Finally in 2016, Lovering, Yip et al. (2016) gathered and published a more comprehensive global data set for nuclear plant construction costs covering 7 countries and approximately 60% of the global plant fleet, with the notable exception of Russian and Chinese plant costs. The results of this work are shown in Figure 14.13 below.

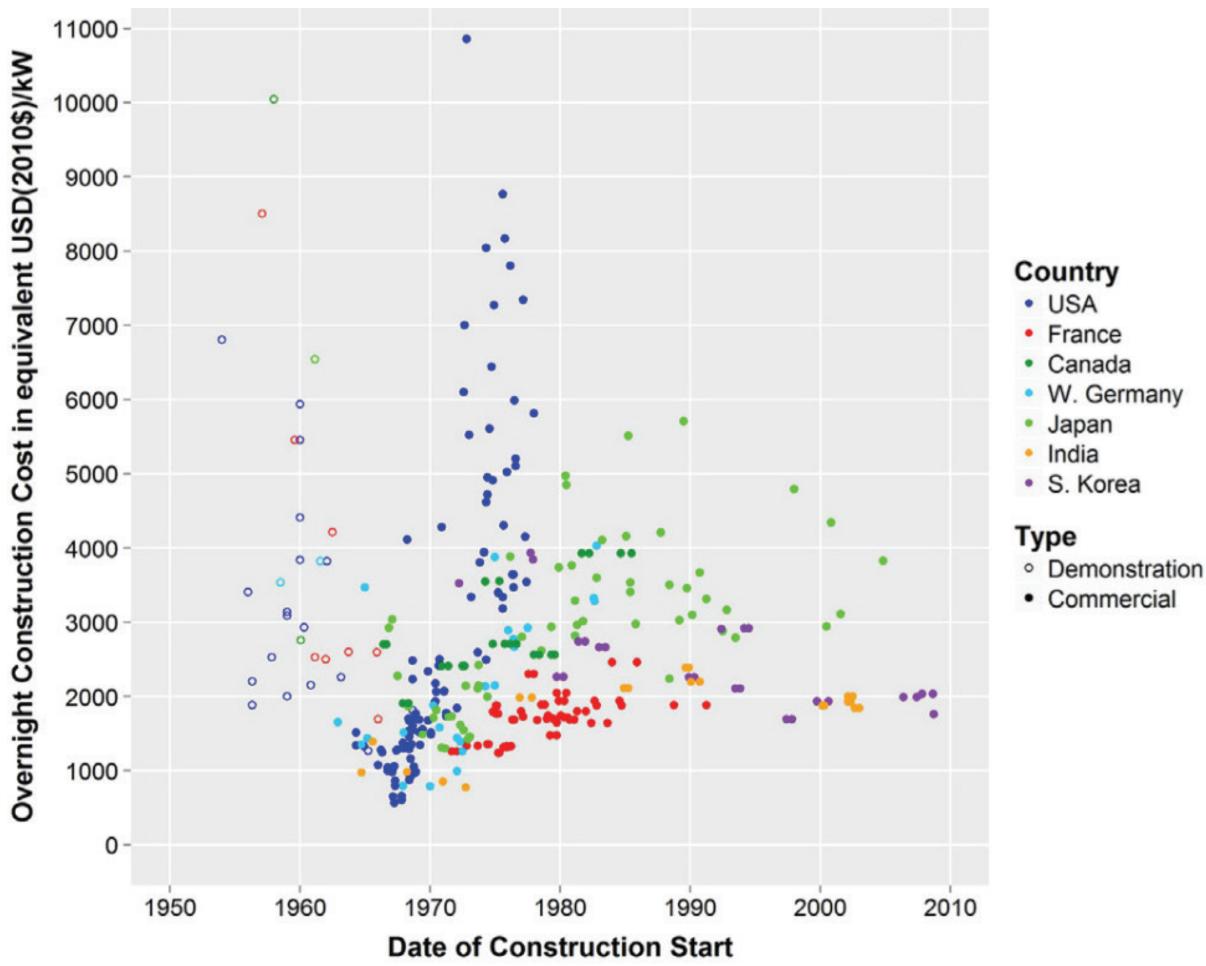

Figure 14.13: Construction costs vs date of construction start of nuclear power plant projects in different countries. Source: (Lovering, Yip et al. 2016).

This graph reiterates the growth of costs in the US and the practical halt of new construction by 1980, as well as the lower growth of costs in France. However what is also clear is that cost growth depends upon many factors that vary globally. The experience in India has been much more constant in terms of cost (although many plants are of the CANDU design, and less relevant to other countries). South Korea has had the most positive experience, with plant costs decreasing slightly over time to about 2000 $kW (2010 USD).

These results are not uncontested. The chief criticisms by e.g. (Gilbert, Sovacool et al. 2016, Koomey, Hultman et al. 2016) are that Lovering, Yip et al. (2016) concentrate on overnight costs that do not include interest costs, and do not address original cost estimates or schedules, the effects of overruns in both, and the overrun risks relative to other generation infrastructure. Other lesser criticisms have to do with lack of more cross-country comparisons, currency conversion and comparison issues and specific data questions.

It is the position of this report that the overnight capital cost is an appropriate measure for concentrating on the cost of the nuclear technology itself, and how it has generally grown over time due to issues of size, system complexity and safety systems. However, cost overruns and risks are also real, and using a net present value or levelized cost cost measure to include interest costs is a more realistic overall measure for society in comparing the overall cost of nuclear power versus other forms of power generation.

14.6.3 Costs of current nuclear plant designs

As shown by the historical costs above of nuclear plants up to the quite recent past, present estimates for the near future construction of current nuclear plant designs can vary widely, both across and within different global regions. It is instructive to see the international range of estimated overnight capital costs for nuclear plants that are currently planned or were recently under construction, including current Gen II+ to Gen III and III+ designs. Figure 14.14 below shows a graph of these costs between 2008 and 2015, subdivided by the North American, European and Asian and Middle East regions (Barkatullah 2016). It should be noted that these overnight costs not only exclude interest, but are also given in dollars per kilowatt of capacity (2014 USD/kWe) and *not* in total millions of dollars (MUSD) to allow for the comparison of different sized plants. It is obvious that that the region with the overall lowest and least variable cost plants is Asia. The variability of the costs for each region is also linked to the number of plants (and the range of ages) within the sample. While the average costs for North America and Europe are near to their midrange values, the relatively lower value for Asia reflects lower cost South Korean plants being added to more expensive and more variable Japanese plants (see also Figure 14.13 above), and the mid-range of costs for the Middle East have also shifted down, compared to previous data from the same author, due to more recent contracts to awarded to Asian builders.

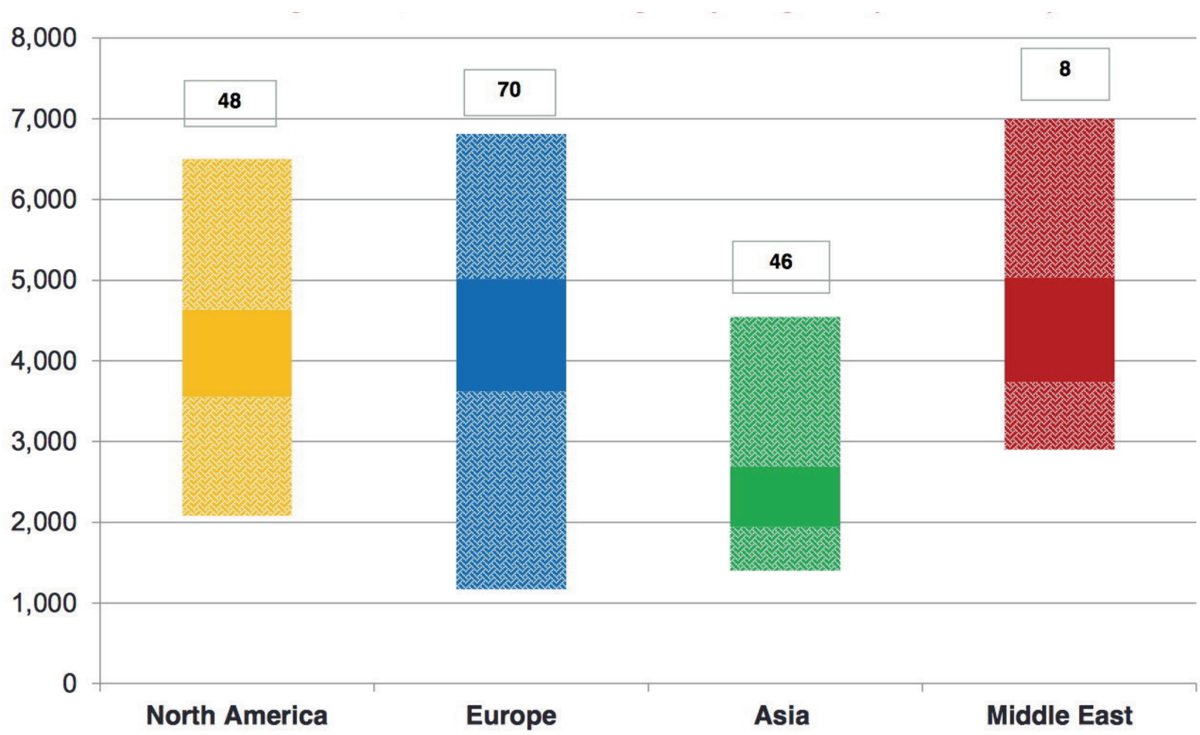

Figure 14.14: NPP Overnight Capital Cost Ranges by Region (2014 USD/ kW) (Barkatullah 2016).

PSI has used the EPR as its reference Generation III design in past research projects that have included multi-national and industry participation, not only for cost purposes but also for environmental and risk estimation. The currently ongoing EPR projects in Olkiluoto (Finland) and Flamanville (France) have experienced very significant cost and schedule overruns. Specifically, the Olkiluoto plant that started construction in 2005 has run over schedule from an initially online date of 2009 to an expected online date (announced in September 2014) of December 2018. Likewise the cost has escalated from an initial expected cost of 3 billion Euro (overnight capital cost) to an expected cost of 8.5 billion Euro (as announced in 2012). AREVA originally agreed to a fixed price contract for Olkiluoto, but both AREVA and the Finnish utility TVO are currently suing each other for the delays and lost generation.

The Flamanville EPR started construction in 2007 with an expected cost of 3.3 billion Euro, and as of September 2015 was expected to come online in December 2018 with an expected cost of 10.5 billion Euro. The EPR cost overruns in Finland and France are due to a number of factors, including being the first plants of a new design, and the loss of regional industry experience and capacity in key manufacturing areas. Figure 14.15 shows the recent cost overruns for some specific plants that include the two European EPRs, but gives the costs in USD/kW (Barkatullah 2016).

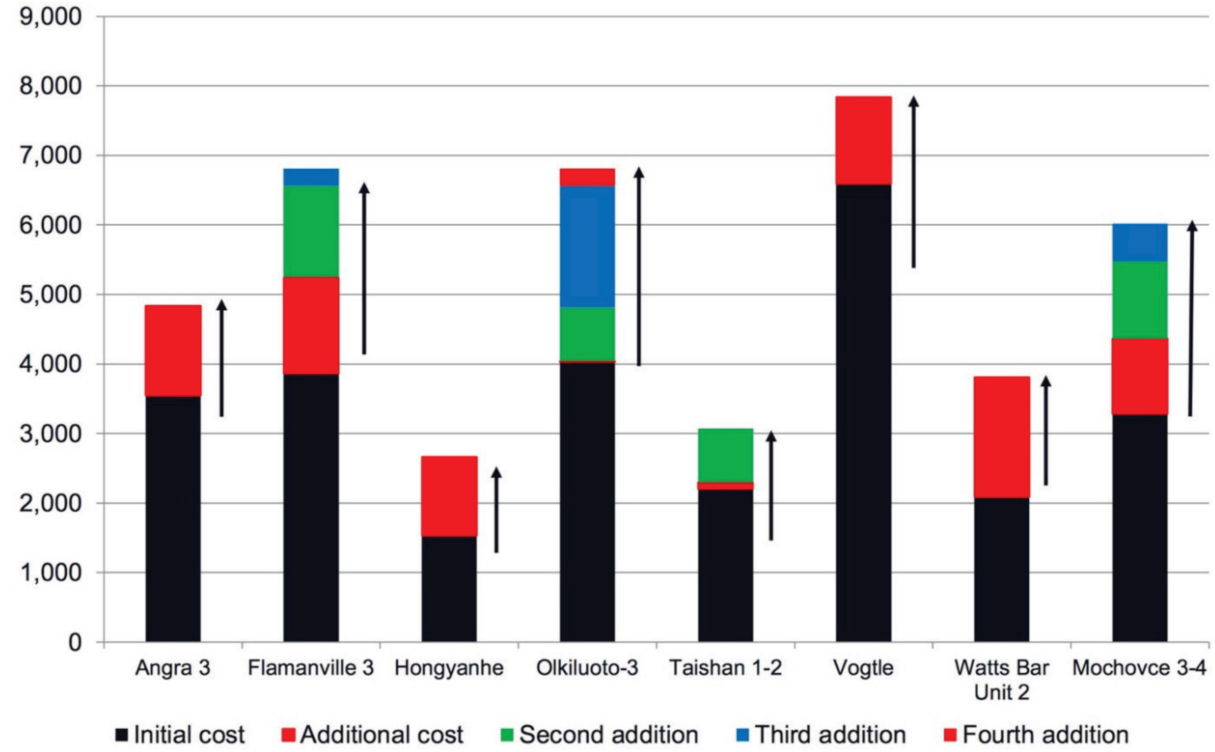

Figure 14.15: Overnight Capital Cost Overruns for Specific Plants (2013 USD/kW) (Barkatullah 2016).

It should be noted that Figure 14.15 (like the previous figure from the same author) gives the overnight capital cost in constant 2013 US dollars per kW. It shows that the European EPR's at Flamanville and Olkiluoto have increased in cost by about 75%, as opposed to the increase of about 200% in cost (i.e. about triple the original) as reported in the press. There several reasons for this apparent discrepancy. First, overnight capital cost does not include interest charges, which have naturally risen with the significant delays in completing construction. Second, the overnight costs are in constant dollars, whereas the press reports are in Euros (assumed nominal or current, but whether constant or nominal EUR is generally unstated). So a direct comparison is difficult, and depends in part on the date of currency conversion(s), the exchange rates, and the inflation rates for both currencies. Nevertheless both measures reflect the same reality, which has been a very significant increase in overnight and total costs.

The Taishan 1&2 EPRs being built in China began construction in November 2009 and April 2010 respectively. They have exceeded their originally planned construction period of 46 months, and as of February 2017 are expected to begin operation in the second half of 2017 (Taishan 1) and the first half of 2018 (Taishan 2). Although these delays must increase the cost, the publically stated cost has not varied from their originally expected cost of 4 billion Euro each. Asian nuclear construction has generally benefitted from more plants, shorter construction periods, and increasing nuclear industry capacity and experience. The World Nuclear Association shows a cost increase of approximately 25% in Figure 13.15 above, that is not specifically sourced and not reported in some other sources, which may reflect either non-public data sources or some confusion over increased interest costs that should not be included in overnight capital costs.

It is within this context that the British government has signed a contract in September 2016 with for *two* new EPRs at the Hinkley Point site (the Hinkley C project) totaling 3200 MW.

The French utility company EDF, which purchased the British nuclear utility British Energy (now EDF Energy Nuclear Generation Ltd.) and the Chinese General Nuclear Power Corporation are responsible for financing and construction. The public estimated overnight cost is 18 billion GBP (5625 GBP/kW, or 7158 CHF/kW), which is up from the 16 billion GBP estimated in 2012 due to inflation. The cost including interest charges given in the press is 24.5 billion GBP, which for the projected 9 year construction period would imply an interest rate of almost 8% for the builders.

In return the builders receive a guaranteed price (the "strike price") of 92.5 GBP/MWh for the next 35 years. The British government has in this way avoided the risk of the tremendous cost overruns at the other two European EPRs, but at the same time it is incurring the risk of future electricity prices. Because the government has guaranteed the strike-price to the builders, it is obliged to pay the difference between the market price for electricity and the strike-price (the "top-up" amount). If the average market price of electricity is high (due to high fuel prices, high renewables prices, or carbon policies), then the government will pay little, or may even receive something back. But if fuel prices are low or the price of renewables declines strongly, then the top-up amount will be very large. One British report by the Comptroller and Auditor General (DECC 2016) says that the net present value of the top-up charge could range between 6.1 and 29.7 billion GBP (i.e. more than the purchase price with interest). The government uses a lower interest rate of 3.5%, which with the contractual 35 year strike-price period corresponds to average electricity prices of 80 and 34 GBP/MWh, respectively. It is very reasonable for the government to have wanted to avoid the risk of cost overruns, but it is questionable why they have traded it for such a large electricity market price risk. In general, the decision to go forward with Hinkley C was very controversial, but also set in the context of low British generation capacity reserve margins, and general concerns about service reliability. On the builders' side, it is also very interesting, not only that they have agreed to take the opposite of this risk, but that the Chinese participation required by EDF's finances also brings the possibility of importing the Chinese success with lower EPR building costs and construction schedules.

Based on review of costs and their driving factors, it was PSI's earlier judgment that the cost range for a new, series EPR built in Europe between 2020 and 2030 could be in the range of 3500-5000 CHF/kW, with a midrange value of 4250 CHF/kW. This gave estimated production costs in the range of 6.4 to 8.0 Rp./kWh. Based on the regional cost ranges reported for other LWRs (Figure 14.15 above), the EPR cost overrun experience, and an expected cost premium for construction in Switzerland, PSI has updated its estimated range for the capital cost to be from 4000-7000 CHF/kW, with a midrange value of 5500 CHF/kW (the broader range also reflects the increased cost uncertainty). The decommissioning cost was also increased to 825 CHF/kW (15%), based on the increase in estimated decommissioning costs for the existing Swiss reactors given in the 2016 STENFO cost study. However this has a quite small effect, since discounting over 60 years means one CHF of future decommissioning cost is only worth about 0.05 CHF today. Using our previous interest rate of 6%, these two changes would raise the average cost of generation for the base case to 8.5 Rp./kWh. However, the present Energieperspektiven follows a period of historically low interest rates, and the original desire was to compare all generation technologies on a level playing field, which meant that for the present work the interest rate for nuclear cost was lowered from 6% to 5%, resulting in a base reference case average generation cost of 7.5 Rp./kWh. It should be noted that all these results are for an EPR construction period of 6 years, which was kept from the previous analysis. However, cost and schedule overruns generally go together, and if the construction period was as long as the nine years predicted for Hinkley C, then the average generation cost would increase to 7.7 Rp./kWh (and nine years at 6% would give 8.8 Rp./kWh). This report provides future technology costs for 2020 and 2035. Although the EPR is regarded as a current design, and its cost is given in the fact sheet for the year 2020, it is clear that even if it was politically feasible to build an EPR in Switzerland, given the time needed for planning, regulatory approval and construction, it is unlikely that this could be done before 2030 to 2035.

In general, the cost overruns for the European EPRs have increased the price uncertainty, even compared to other reactor designs, and it is generally acknowledged that Swiss quality standards come at a price. This is also true in the electricity sector, even though the exact amount of this “Swiss premium” is uncertain. It is also true that even with these uncertainties it is hard to foresee that a Swiss plant (likely a proven design) would produce the same overruns seen at first-of-its-kind EPR constructions in Flamanville and Olkiluoto. Furthermore, if a Gen III plant was to be allowed for new construction in Switzerland it is an open issue which specific design would be chosen. However PSI has kept the choice of EPR for other analytic reasons, including comparability, risk analysis, and life cycle analysis.

Figure 14.16 below shows sensitivity curves for a Generation III EPR assumed to be built hypothetically today or in 2030 with this updated cost, but keeping the base value of the other sensitivity parameters constant. Each parameter is varied from 50% to 200% of the base value that is shown in the legend (the load factor cannot be increased above 100%). The base case result for this sensitivity analysis is an average generation cost of 7.5 Rp./kWh.

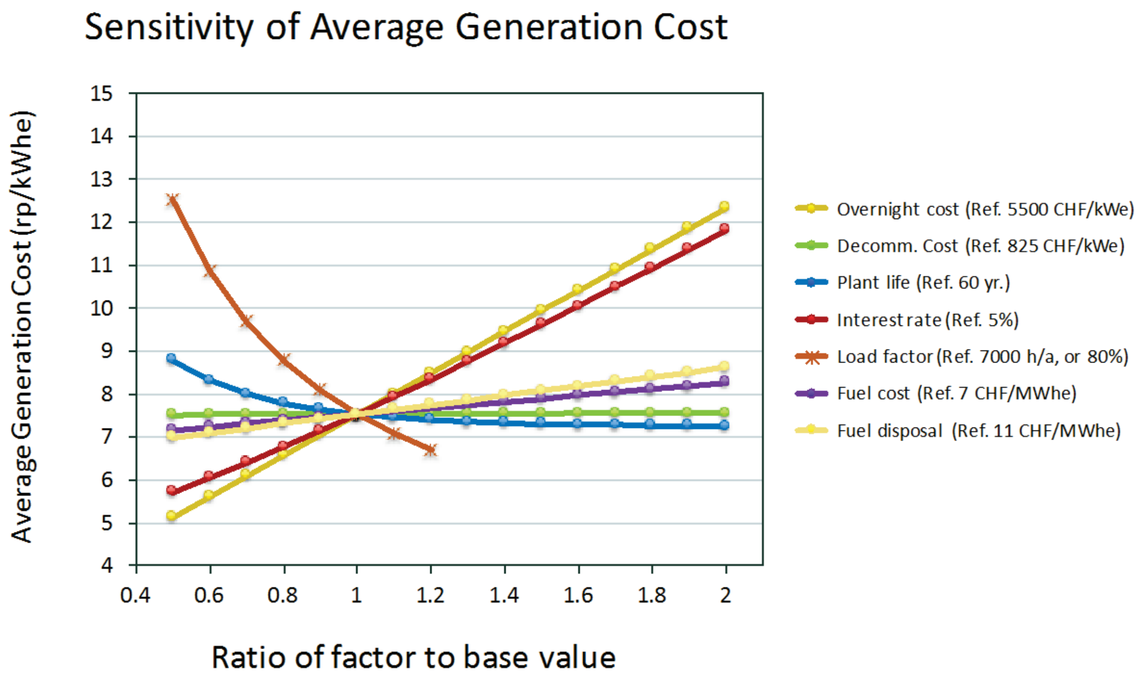

Figure 14.16: Cost Sensitivity Diagram (PSI).

Of these factors, the three most important driving the nuclear costs are: load factor, interest rate, and overnight capital cost (which produce a cost range of between 5 and 12.5 Rp./kWh). This is followed by the plant life whose sensitivity lies between 7.2 and 8.8 Rp./kWh, the fuel cost and fuel disposal and the decommissioning costs. In the worst case, when for example all parameters are 50% negative from the reference case, the generation costs could reach 27 Rp./kWh. Such a simultaneous variation in all the parameters would however be very unlikely. Based on the nuclear cost structure and historic trends, nuclear plants with low costs have the following general characteristics: turnkey contracts, not first-of-a-kind (FOAK), short construction periods, clear licensing processes without delays or changes, low interest rates and high load factors.

14.6.4 Future design costs

New construction of nuclear power plants in Switzerland has not been totally excluded, if the new technology can be shown to be sufficiently safe, politically acceptable and economically feasible. For this reason it is of significant interest for Switzerland to continue monitoring the development of economic trends and estimated costs for future reactor designs, including primarily the Gen IV design family and the many designs within the broad category of Small Modular Reactors.

14.6.4.1 Gen IV Reactors

The cost estimates for Gen IV are highly uncertain, although ambitious goals have been set up with cost competitiveness as a high priority. Most of the cost-related information published by the Gen IV alliance is more in the form of guidelines for cost analysis, including cost categorization and overall methodology. The original time horizon for most of the designs (except for the nearer-term High Temperature Pebble Bed Reactor) is that the first demonstration plants could be built between 2020 and 2030. The revised GIF-Roadmap (2014) indicates a general postponement between 5 years (for the SFR) and more than 7 Years (for the MSR) until the beginning of the demonstration phase. Commercial availability would come thereafter. Based on the updated GIF-Roadmap, this would mean availability after 2030 for all reactor systems. It is PSI's opinion that a Gen IV reactor, if of interest, will not be available for implementation by 2030 in Switzerland, and that 2040 is a more likely expectation, although this is uncertain. For the technology summary fact sheet the Gen IV reactors are therefore associated with the year 2050.

It is understandable that cost projections are still unclear, but nevertheless it is quite likely that the initial costs of Gen IV will be higher than for the current generation of plants. At present, PSI does not feel there is sufficient confidence to give a capital cost estimate for a Gen IV large reactor in general. Any eventual decisions by industry to build Gen IV power plants will not depend only on the original estimated capital costs, but also on the probability of cost overruns, the potential for cost reductions in following plants, and the amount of state subsidies for the first (demonstration) plant.

14.6.4.2 Small Modular Reactors

As described in section above, the SMR category (reactors with a generation capacity of 300 MW or less) covers a very wide array of reactor designs, including different coolants, different moderators, different fuels, and different neutron spectra (fast v. thermal). However this is a very active area of research and promotion. There is significant government support (in the US, China and Russia), much interest by major nuclear companies (e.g. B&W and Westinghouse), and in particular a level of entrepreneurial interest and design innovation that has not been present during the earlier period where the major reactor design families emerged. This level of activity is reflected in a wide range of publications, industry conferences, articles in the popular press, etc. A number of demonstration projects are underway, and time horizons for proposed plants are in general more near-term than for the bigger Gen IV designs. In particular, Terrestrial Inc. US [TEUSA], which is the US branch of Terrestrial Canada, has informed the US NRC in December of 2016 that is their intention to apply for licensing of its Integral Molten Salt Reactor (IMSR400) in the US towards the end of 2019. TEUSA plans to bring the IMSR400 to the market in the 2020's. Hence, it could well be that 2030 is a reasonable estimate for such a reactor in the US. The US regulators are preparing for MSR applications, including training for relevant parties and preparing a document on Advanced Non-LWR Design Criteria for public comment. In contrast, European regulators have not yet started to prepare for this advanced new technology, which is likely to delay implementation here. For the purposes of the nuclear technology fact sheet summary (chapter 1.5), the SMR has therefore been associated with the year 2035.

The most comprehensive overview of estimated SMR costs that was reviewed (OECD/NEA 2011) is now several years old. Table 14.13 and Table 14.14 below give these estimated costs for water-cooled reactors and reactors with other (gas and liquid metal) coolants, respectively. (Note that NEA uses the abbreviation LUEC for levelized unit electricity cost, which is more commonly called the levelized cost of electricity, or LCOE.)

Table 14.13: Cost data for water-cooled SMRs (2009 USD) (OECD/NEA 2011). Reactor abbreviations may be found in the original report[363] and the list of abbreviations at the end of this chapter.

SMR	Unit power MWe	Overnight capital cost USD per kWe	LUEC** USD per MWh	Levelised heat cost USD per GCal	Levelised desalinated water cost USD cent per m³
PWRs					
ABV [6.2]	8.5	9 100	≤120	≤45	≤160
CAREM-25 [6.8, 6.19]	27	3 600***	~42 at 8% discount rate	n/a	81 at 8% DR
KLT-40S [6.17]	35	3 700-4 200	49-53	21-23	85-95
NHR-200 [6.8]	200 MWth	809	n/a	-	66-86
SMART [6.8]	100	-	60	n/a	70
mPower [6.16]	125	-	47-95		
CAREM-125 [4.8]	125	1 900	-	n/a	n/a
CAREM-300 [6.8]	300	1 200	-	n/a	n/a
VBER-300 twin-unit [6.8]	325	2 800 barge 3 500 land	33 barge 35 land	18	n/a
QP300 two units average [6.18]	325	2 800 Pakistan	-	n/a	n/a
IRIS [6.8]	335	1 200-1 400 IC	34-45	n/a	n/a
BWRs					
VK-300 [6.8]	750	1 100	13	4	n/a
CCR	423	3 000-4 000	50	n/a	n/a
HWRs/AHWRs					
PHWR-220 [6.19]	220	1 400-1 600	39 50 at 7% discount rate	n/a	100-110 at 7% DR
AHWR [6.8]	300	1 300 F	25 single 24 four plants	-	n/a
CANDU-6 twin-unit [6.18]	715	3 600	35 Canada 32 China	n/a	n/a

363 https://www.oecd-nea.org/ndd/reports/2011/current-status-small-reactors.pdf

Table 14.14: Cost data for non water cooled SMRs (2009 USD) (OECD/NEA 2011). Reactor abbreviations may be found in the original report[364] and the list of abbreviations at the end of this chapter.

SMR	Unit power MW_{th}	Overnight capital cost, USD per kWe	O&M cost, USD per MWh	Fuel cost, USD per MWh	LUEC* USD per MWh	Levelised heat cost, USD per GCal	Levelised desalinated water cost, US cent/m^3	Levelised hydrogen cost, USD per kg
HTGRs								
HTR-PM [6.8]	250	<1 500	9	12	51	n/a	n/a	n/a
PBMR (previous design) [6.8]	400	<1 700	1.0 O&M+Fuel	1.0 O&M+Fuel	As large LWR	n/a	n/a	-
GT-MHR [6.8]	600	1 200	4	9	36	n/a	-	1.9
GTHTR300 [6.8]	600	<2 000	-	-	<40	-	-	-
Sodium cooled fast reactors								
4S [6.2]	30	-	-	-	130-290	n/a	-	-
Lead-bismuth cooled fast reactors								
PASCAR [6.20,6.21]	100	-	-	-	100	n/a	n/a	n/a
SVBR-100 [6.2]	280	1 200 prototype	-	-	19 for 1600 MWe plant; 42 for 400 MWe plant	-	88 for 400 MWe plant	n/a

The World Nuclear Association also tracks developments in the SMR field, including major publications, government support, design families, and individual reactor designs and projects. It is indicative that of approximately 75 different reactor designs, only 10 mention costs, and generally very briefly. These estimated costs are shown in Table 14.15 below.

Table 14.15: More recent SMR cost data for selected designs (OECD/NEA 2011). Reactor abbreviations may be found in the original report[365] and the list of abbreviations at the end of this chapter.

Reactor	Company	Country	Type	Year	Size MWe	OCC $/kW	LCOE $/MWh	Notes:
NuScale	NuScale Power Module	US	PWR	2010	50	4000		12 module plant
				2014		5078	100 FOAK, 90	
				2024		5000		Energy NW utility
mPower	BWXTechnologi es Inc.	US	PWR	2022	180	5000		B&W demo
Holtec SMR-160	Holtec Intl.	US	PWR		160	5000		800 M$ total, 24 m.
CAP-150	SNTPC	China	PWR	2013		5000	90	
HTR-200	Huaneng Group, CNEC, INET	China	HTGR pebble		210	2048		430 M$ total, pebble bed
						1500	50	later units
Xe-100	X-energy	US	HTR pebble		200	5000		1 B$/200 MWe 4-pack
4S 'nuclear		Japan	SFR			2500	50-70	Toshiba & CRIEPI
SVBR-100	AKME, Gidropress	Russia	SVBR			4000-5000	40-50	90% LF
AHTR/FHR	UCBerkeley, ORNL,	US	FHR molten		1500	< 1000		pebble bed, salt cooled
Transatomic TAP	Transatomic	US	MSR		550	3600		2 B$, NOAK, 3 yr build

364 https://www.oecd-nea.org/ndd/reports/2011/current-status-small-reactors.pdf
365 https://www.oecd-nea.org/ndd/reports/2011/current-status-small-reactors.pdf

As can be seen, the overnight capital cost in $/kW is the most common cost indicator given (or can be derived from the total cost and generation capacity). Most of the recent estimates are in the range of 5000 $/ kW (unstated, but assumed to be current, nominal USD), with some estimates ranging below to 3600 or 4000 $/kW. The lowest estimates were for units that were of a later generation (HTR-200, 1500 $/kW), or a significant technology variant (4S 'nuclear battery,' 2500 $/kW), or for large multi-module plants (AHTR/FHR plant of 1500 MW, < 1000 $/ kW). However, given the broad range of technologies and technical uncertainties, there is also a risk for significant cost overruns. Therefore for the year 2035, PSI estimates an overnight capital cost of 3000 to 9000 for the SMR. The mean of this cost range is the same as for the current one for EPR, but the wider range reflects the greater uncertainty. The mid-range value of 6000 CHF/kW that has been used to calculate the average cost of 7.4 Rp/kWh is higher than the 5500 CH/kW used for the EPR, but the shorter construction period (2 v. 6 years) reduces the average cost below the 7.5 Rp/kWh for the EPR. Varying individual cost factors from 50% to 200% of their base values gives a cost range for the SMR from 5.1 to 12.2 Rp/kWh. Given the relatively large uncertainty of the cost estimates for the broad SMR range of reactor technologies, the average cost estimate is effectively the same as for the EPR.

The Chinese HTR-200 (also referred to as the HTR-PM) reactor design deserves some particular comment. The gas-cooled, pebble bed high temperature reactor is currently one of the most advanced SMR designs, with a two reactor demonstration plant currently under construction in China. The second reactor vessel was installed in September 2016, pilot production of the pebble bed fuel elements started in March 2016, and start of operation is expected in late 2017. Chinese partners in this project have published estimates (Dong 2015, Zhang, Dong et al. 2016) that the cost for a 2 x 600 MWe multi-module HTR plant will be approximately 10-20% above the cost for a conventional 2 x 600 MWe PWR plant as built in China. The estimated costs of 2048, and eventually 1500 $/kW reported by WNA are consistent with this, for Chinese LWR cost levels, but would presumably be significantly higher for Western manufacture and siting. PSI has a current, on-going project with Chinese partners in this project (INET) and is currently in the process of making a confidentiality agreement that will allow access to component cost breakdowns that will enable analysis of how the Chinese design might be priced for Western markets.

Overall, current price estimates for SMR designs are still provisional and must be viewed with health skepticism. SMRs are touted to have many advantages, including mass factory production, small unit sizes relative to system needs, small financing risk (total cost), and suitability for niche markets. The latter advantages are basically uncontested, but giving up economies of scale for economies of factory production implies that sufficient orders are required in order to build the factory. Industry actors estimate that the minimum order size to justify factory construction would be on the order of 40 to 70 reactors. This leads to an obvious problem that the first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) prices are currently much different. Many customers may express interest to buy a SMR at the NOAK cost, if someone else will buy the FOAK unit. Thus, for a conventional LWR you get the economies of scale on the first plant, and the number of demonstration plant(s) that may need to be subsidized can be relatively small. For the SMR, you only get the economies of factory production once the factory is established, and you need to subsidize a greater number of demonstration plants, or the factory itself.

There are also (predictably) published sceptics pointing out the historic unsuccessful experience with the original small plants, the delays or step-backs by industry companies involved in the SMR efforts (B&W, etc.) based on hesitation in prompt market interest, and other barriers to SMR implementation. From this point of view, the recent, more conventional 'nuclear renaissance' which has sputtered in the US market is just being repeated or shifted to new reactor designs.

Healthy skepticism *is* called for, but the sheer range of SMR designs and their related advantages (and disadvantages) for different market needs and niches related not just to size, but also fuel choice, fuel cycle, fuel use, waste burnup, resource life, niche micro-demand markets, high temperature heat supply together make it seem very likely that one or more SMR designs will succeed.

14.7 Environmental aspects – normal operation

Based on various recent LCA literature (IPCC 2011, Bauer, Frischknecht et al. 2012, Simons and Bauer 2012, Warner and Heath 2012, Hertwich, Gibon et al. 2015, ecoinvent 2016, Volkart, Bauer et al. 2016)[366], normal operation of nuclear power plants with the associated fuel cycles leads to relatively low impacts on human health and ecosystems. Life-cycle greenhouse gas (GHG) emissions are discussed in detail in the following section; other burdens and potential impacts are provided in a less detailed way and in comparison to the burdens of the average Swiss electricity supply mix.

14.7.1 Life-cycle greenhouse gas (GHG) emissions of current and future nuclear power

Current Swiss nuclear power plants cause life-cycle GHG emissions in the range of 10-20 g CO_2eq/kWh[367] (Bauer, Frischknecht et al. 2012). Simons and Bauer (2012) showed that a potential future EPR (European Pressurized Reactor) would produce electricity with slightly reduced associated GHG emissions, if fuel supply chains remain as they were analyzed by Bauer, Frischknecht et al. (2012).[368] Warner and Heath (2012) reported a harmonized mean value of 12 g CO_2eq/kWh, with a range of 4-110 CO_2eq/kWh, from a review of international nuclear LCA studies. Their analysis can currently be considered as the most reliable, up-to-date and comprehensive review of LCA of nuclear power.

Life-cycle GHG emissions of nuclear power are most sensitive to the fuel supply chain, i.e. uranium mining and enrichment. Sensitivity analysis for current Swiss-specific conditions provides a potential range of 5-40 g CO_2eq/kWh (Bauer, Frischknecht et al. 2012).

14.7.2 Other environmental life-cycle indicators

Further environmental LCIA (Life Cycle Impact Assessment) indicators of current nuclear power in Switzerland in comparison with the current Swiss electricity consumption mix are provided based on (Hauschild, Goedkoop et al. 2013, ecoinvent 2016) and shown in Figure 14.17.

[366] PSI is currently carrying out a detailed update of the LCA of nuclear power generation in Switzerland. The report associated with this new analysis will be published in February 2017.
[367] Without considering emissions associated with electricity transmission and distribution to the consumer.
[368] Future Gen IV reactor technologies with reprocessing could lead to a more substantial reduction of GHG emissions and other burdens. However, solid LCA results of such technologies are not available.

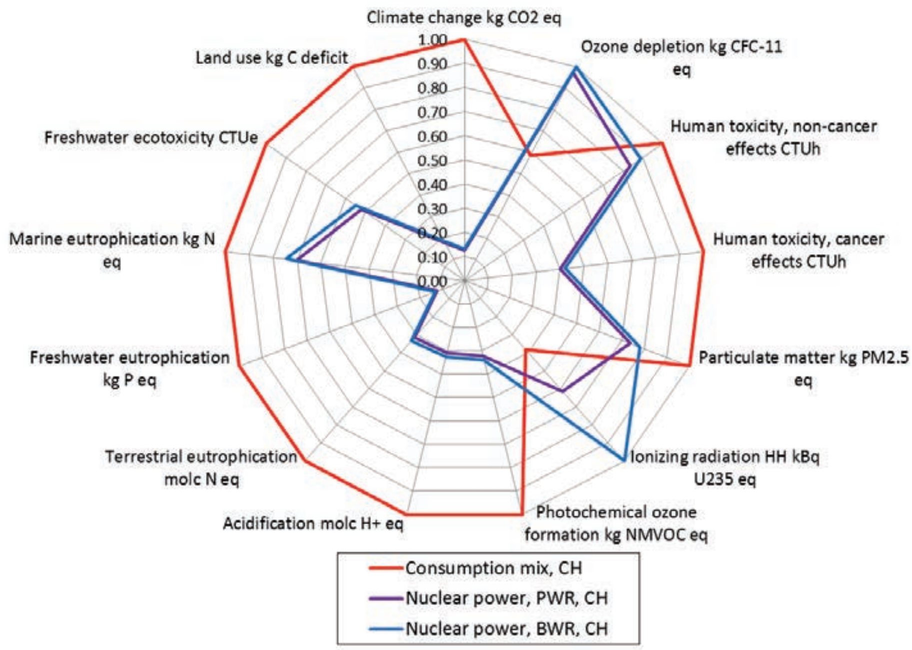

Figure 14.17: LCIA results of current Swiss nuclear power (ecoinvent 2016) using indicators recommended by Hauschild, Goedkoop et al. (2013) in comparison to the current Swiss high voltage consumption mix according to (ecoinvent 2016). Maximum for each indicator equal to 1.

Sensitivity analysis for Swiss nuclear power showed that radioactive emissions, particulate matter and GHG emissions are most sensitive to origin of uranium, mining method and enrichment technologies used in the fuel supply chain (Bauer, Frischknecht et al. 2012).[369]

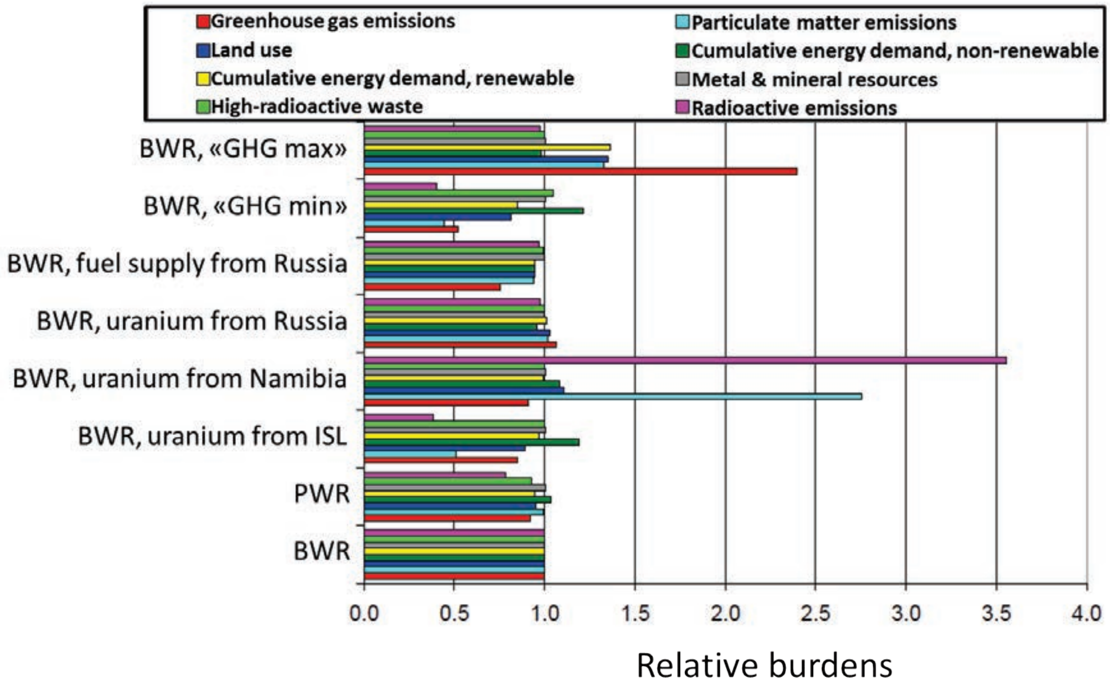

Figure 14.18: Sensitivity analysis of current Swiss nuclear power (Bauer, Frischknecht et al. 2012). BWR: boiling water reactor; PWR: pressurized water reactor; ISL: in-situ-leaching; "GHG min": fuel supply chain with minimum GHG emissions; "GHG max": fuel supply chain with maximum GHG emissions.

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[369] This analysis was partially based on different LCIA indicators than the ones used in Figure 14.17. However, qualitative conclusions should not be affected by this difference.

14.7.3 Radioactive waste

Radioactive wastes need to be stored for a very long time, which is a topic of concern to society. Table 14.16 below gives an overview of the radioactive waste volumes to be expected in Switzerland with an expected lifetime of the currently operating nuclear power plants of 60 years. Whereas low- and intermediate-level waste (L/ILW) is the dominating part in terms of volume, vitrified high-level waste from reprocessing (HLW) and spent fuel (SF) contributes most in terms of radioactivity.

Table 14.16: Volume of radioactive waste expected in Switzerland (NAGRA, 2014).

Predicted waste volumes (47/60 year NPP operation)[1]	L/ILW (m^3) conditioned	L/ILW (m^3) packaged	ATW (m^3) conditioned	ATW (m^3) packaged	HLW/SF (m^3) conditioned	HLW/SF (m^3) packaged
BA-KKW Operational waste from the NPPs (from cleaning systems and mixed waste), incl. post-operational phase before decommissioning	8 195	31 015				
RA-KKW NPP reactor waste (activated components)	475	1 810				
SA-KKW NPP decommissioning waste	22 440	30 760				
WA-KKW NPP reprocessing waste			100	635		
BA-ZWI Zwilag operational waste	270	290				
SA-ZWI Zwilag decommissioning waste	585	700	25	25		
BA-MIF MIR waste from FOPH, waste from PSI and CERN	7 750	12 210	185	670		
SA-MIF Decommissioning waste from PSI and CERN	13 260	13 565	30	115		
OFA Waste from the later surface facilities for the L/ILW & HLW repositories	645	2 290				
HLW Containers from reprocessing					115	380
BE Spent fuel assemblies					1 365	8 135
Total volumes (rounded)	**53 615**	**92 635**	**340**	**1 440**	**1 480**	**8 515**
Percentage (rounded)	96.7 %	90.3 %	0.6 %	1.4 %	2.7 %	8.3 %
Activity (Bq)[2]	$7.9 \cdot 10^{16}$		$2.2 \cdot 10^{16}$		$1.9 \cdot 10^{19}$	
Percentage	0.4 %		0.1 %		99.5 %	

[1] Basis: Model Inventory of Radioactive Materials (MIRAM 14)
Operating lifetime: Mühleberg 47 years (till 2019), other NPPs 60 years
Takes into account the planned revision of the Radiological Protection Ordinance and decay storage of materials with subsequent conventional disposal

[2] Activity inventory for reference year 2075

14.8 Safety and risks

The nuclear chain reaction, which is the source of the energy produced by a nuclear power plant, leads to accumulation of substantial amount of highly radioactive materials. Thus, the highest priority in the design of nuclear power plants is to prevent occurrence of accidental situations that could lead to unacceptable releases of radioactive emissions and to mitigate potential impacts on human beings and the environment. Examples of design features providing the necessary protection include defense-in- depth, redundancy, diversification and inherent safety features.

When the first commercial reactors were being developed it was already clear that a secure enclosure of the radioactive inventory was necessary. Reactors are equipped with multiple barriers against the release of radioactive materials, according the the principle of “defense in depth.” This means that there are a series of sequential, hermetic barriers surrounding the materials that have the highest concentration of radioactivity, which are the fuel elements. The concept rests on the assumption that it is very unlikely that all barriers will be damaged in an accident. Each barrier is able to prevent the release of radioactive materials into the environment.

In the case of light water reactors the main barriers are:

The fuel container, i.e. the sealed zirconium tube, that holds the fissile material as well as the radioactive fission products created.

The reactor vessel and other parts directly connected to the reactor like the primary circulation pipes and the heat exchanger tubes within the steam generator of a pressurized water reactor.

The reactor containment, which is a hermetically sealed building built around the reactor and the most important activated components.

While severe nuclear accidents have been historically rare events they may have disastrous consequences on health and environment. Technical safety upgrades particularly relevant for the older plants and severe accident management guidelines, if properly implemented, are of fundamental importance for the safe operation of existing nuclear power plants. Neglecting the state-of-art in the field of nuclear safety, combined with severe deficiencies in safety culture, has led to accidents in Chernobyl and Fukushima with large releases of radioactive materials. This has had a clearly negative impact on the acceptance of nuclear energy world-wide though the induced opposition has been subject to strong variety from country to country.

Accidents and incidents are rated according to the International Nuclear and Radiological Event Scale (INES) designed in 1990 by the International Atomic Energy Agency (IAEA) to classify events in nuclear power plants. In 2006, INES was adapted to also allow classification of other radiological events, e.g. in transport and storage. INES is a 7 step logarithmic scale, so that severity of an event increases ten-fold with each step in the scale. Events of severity 1-3 are called incidents, 4-7 classify accidents. The historical safety record of nuclear energy shows two cases at commercial nuclear power plants, classified as INES 7 (major release of radioactive material with widespread health and environmental effects requiring implementation of planned and extended countermeasures); these are Chernobyl in 1986 and Fukushima Daichi in 2011. In Switzerland there has not been any incident at commercial nuclear power plants above severity 2; however, a partial core melt (INES 5 accident) occurred at the Lucens test reactor in 1969.

The safety level of Gen II plants around the world is subject to extensive variation and changes in time. The older Swiss plants, i.e. KKB and KKM have been subjected to highly ambitious and efficient backfitting going much further than what has been representative for most nuclear programs abroad. As a result the core damage frequencies as estimated in

Probabilistic Safety Assessments (PSAs) for these plants were reduced by up to two orders of magnitude. The plants built later, i.e. KKG and KKL, were designed from the beginning in accordance with increased safety requirements manifested by higher levels of redundancy and separation, features of particular importance for efficient protection against area and external events. Nonetheless, the continuous developments of the state-of-art in nuclear safety were considered in the form of some substantial improvements also in these newer plants.

The Core Damage Frequencies (CDFs) and Large Early Release Frequencies (LERFs) for the Swiss plants are shown in the figures below, compared to the target values for existing and new plants, established by the IAEA in 1999. Internal events refer to transients and Loss of Coolant Accident (LOCA) initiators; Area events are such internal initiators as fires or flooding; external events are e.g. seismic events or external fires or flooding.

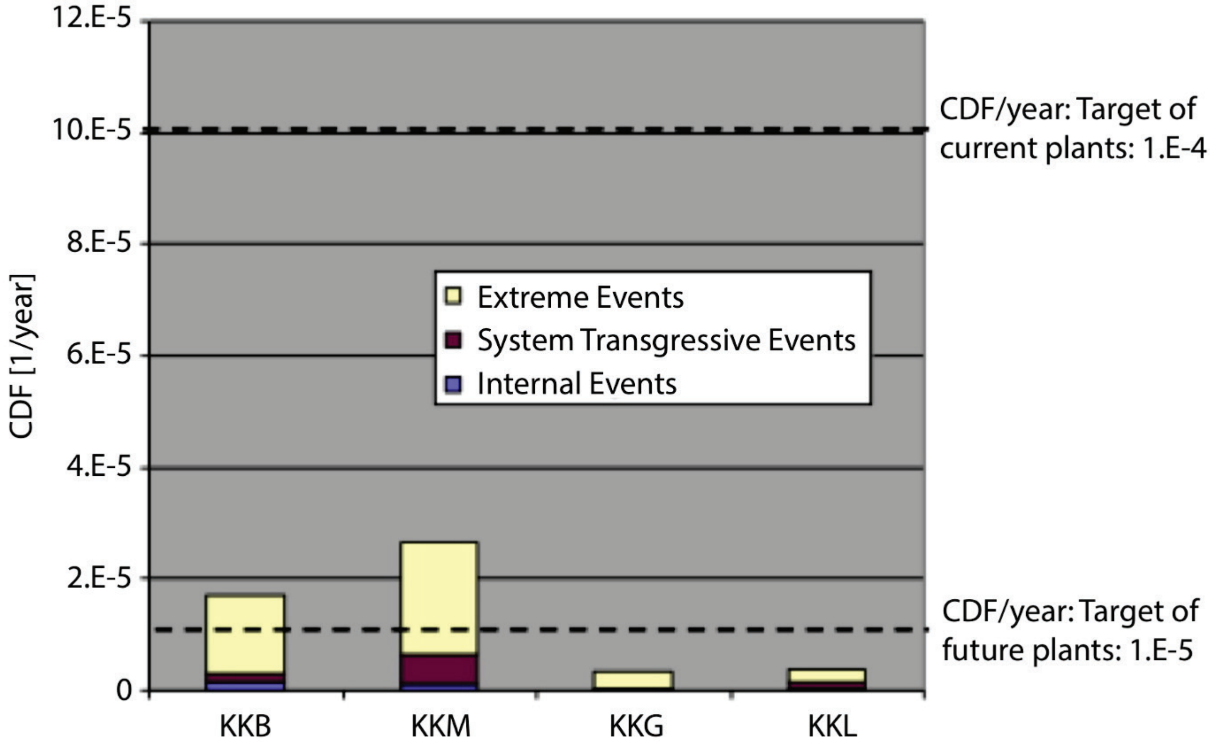

Figure 14.19: Core damage frequencies (CDF) for full load operation of the Swiss nuclear plants, based on newest estimates. The horizontal lines show the target values that have been established by the IAEA for current and future plants (International Nuclear Safety Advisory Group, 1999).

The CDFs and LERFs for all Swiss plants are clearly below the targets for the current plants and below or slightly to moderately above the target for the future plants. Further improvements, especially concerning external initiating events, are on the way in connection with the lessons learned in Fukushima and the corresponding activities of the regulator, e.g. the EU stress test and the implementation of the resulting recommendations of its results by the utilities.

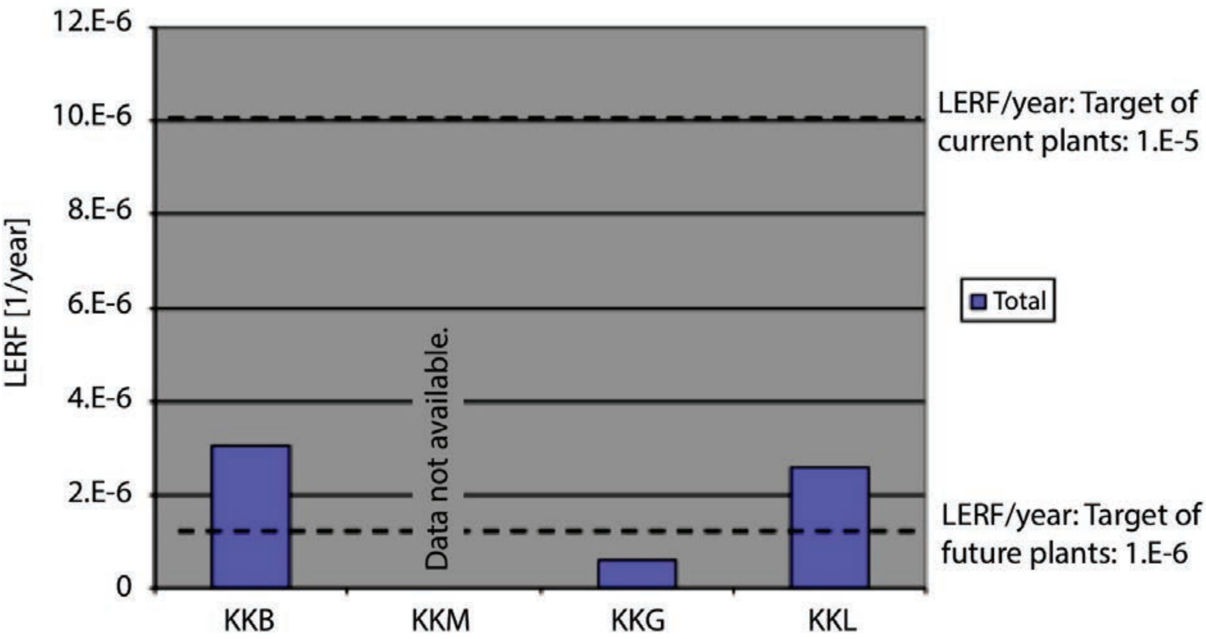

Figure 14.20: Large early release frequencies (LERFs) for full load operation of the Swiss nuclear plants, based on newest estimates. The horizontal lines show the target values that have been established by the IAEA for current and future plants (International Nuclear Safety Advisory Group, 1999).

Gen III and Gen III+ provide opportunities for further decisive safety improvements both with regard to prevention and mitigation of accidents. The original objective of this evolutionary development has been to exclude the necessity of offsite emergency response for credible accident scenarios. This goal has been pursued by enhancing existing active safety systems to prevent core damage, combined with the introduction of a core retention concept capable to prevent serious consequences of core damage beyond the plant. Gen III+ designs rely more extensively on passive safety features (which does not exclude the combination of active and passive systems in order to increase diversification).

The exclusion of the possibility of accident with public consequences (i.e. beyond the fence of the plant) is implicitly based on a probabilistic cut-off criterion, which is set very low. The "residual risk" in terms of extremely low probability accident scenarios leading to large consequences beyond the fence is not eliminated but is subject to large reductions. Thus, the expected frequency of such accident scenarios is typically a factor of 10-100 lower than for the currently operating Gen II plants.

Figure 14.21 shows a comparison between CDF on one side and LERF on the other side for the current Swiss nuclear power plants and the EPR (as an example of a Gen III/III+ design).

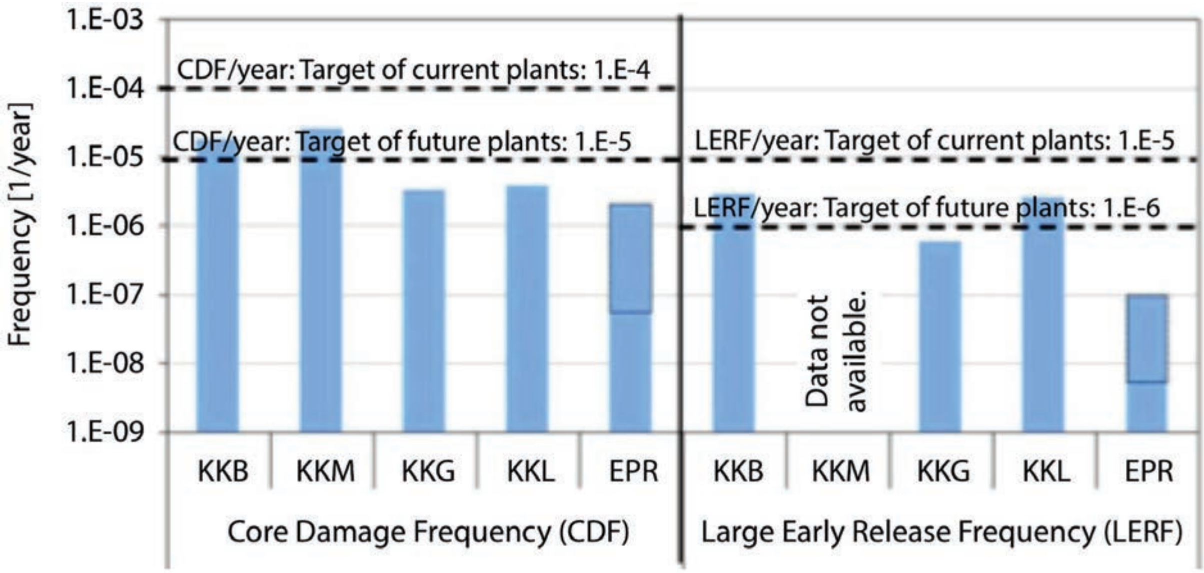

Figure 14.21: Risk indicators core damage frequency and probability of large early release for current Swiss nuclear power plants in comparison with IAEA targets for current and future nuclear power plants (International Nuclear Safety Advisory Group, 1999). For the EPR a value is given that mainly depends on the built-in safety measures again earthquake damage.

The prevailing perspective driving the development of Gen IV has been that the risk reduction achieved within Gen III is so extensive that other factors such as sustainability of resources, nuclear proliferation resistance, reduction of waste volumes and assurance of economic competitiveness should be focused on. The goals for safety should be comparable with Gen III/III+. Still, the six main reactor lines selected for the development of Gen IV offer interesting inherent safety features. On the other hand, there are also specific fundamental problems arising from the given combination of fuel, moderator and coolant, which are presently subject of intensive research. For some candidate Gen IV designs there are indications that maximum credible consequences of hypothetical accidents could be strongly reduced compared to Gen II and Gen III.

14.9 Comparison between nuclear technologies

Table 14.17 displays a comparison of the performance of Gen III and III+ relative to the performance of Gen II reactor systems. High safety standards are assumed for the Gen II, reference system, as can be found e.g. for the Swiss plants. Table 14.18 provides an incomplete comparison of the Gen IV reactor concepts.

The evaluation of the relative performance of Gen III und Gen III+ systems is subject to substantial uncertainties. Performance results are not publically available, and furthermore, consistent performance comparisons have not been performed to date. This particularly applies to the accident risk that may vary strongly between the documents of different organizations/authors. Yet, the strong risk reduction of the Gen III/III+ systems compared to the Gen II systems appears to be robust.

Table 14.17 Performance of Gen III and Gen III+ designs compared to Gen II designs.

Generation	Resource Usage	Waste	Accident prevention	Accident mitigation	Residual risk	Proliferation resistance	Cost and financial risk
Gen III	+	+	+ → ++	++	+ → ++	=	-
Gen III+	+	+	++	++	++	=	=

The following notation applies:

++ Decisive improvement
+ → ++ Non-decisive to decisive improvement
+ Non-decisive improvement
= Approximately unchanged performance
- Non-decisive deterioration
-- Decisive deterioration

The comparison among the GEN-IV systems is subject to high uncertainties given the current stage of development of the various concepts and very limited availability of comprehensive evaluations of their performance Furthermore, PSI has had only access to system information on GFR and as of now also on MSR. Generally the qualitative assessment of the systems is subject to judgment and in the case of systems for which performance-relevant information is very scarce itis merely an educated guess by the involved authors. For these reasons we use here a lower resolution in our judgmental scale compared to Table 14.17 (three levels vs. five levels).

Table 14.18 Relative performance of Gen IV concepts relative to each other.

Generation	**Resource Usage**	**Waste**	**Accident prevention**	**Accident mitigation**	**Residual risk**	**Proliferation resistance**	**Maturity**[370] expected end of viability phase (GIF, 2014)
SFR (Sodium cooled fast reactor)	+	+	=	=	=	=	2012
VHTR (Very high temperature reactor)	-	-	+	+	+	+	2010
LFR (Lead cooled fast reactor)	+	+	=	+	=	=	2013
SCWR (Supercritical water cooled reactor)	-	-	-	-	-	=	2015
GFR (Gas cooled fast reactor)	+	+	-	-	-	=	2022
MSR (Molten salt reactor)	+ (fast)	+	+	+	+	-	2025

The following notation applies:

= Reference performance in relation to which other concepts may perform better or worse
+ Better performance compared to reference level
- Worse performance compared to reference level

[370] During the viability phase, basic concepts, technologies and processes are tested under relevant conditions, with all potential technical show-stoppers identified and resolved. (GIF, 2014).

14.10 Abbreviations

4S	Japanese small modular sodium-cooled fast reactor
ABV	Russian barge-mounted small modular PWR
ABWR	Advanced Boiling Water Reactor
ACR	AECL CANDU PHWR
AES-92	An updated VVER 1000/320 that was planned in Bulgaria (a Soviet-type PWR known in Russia as the 3rd generation VVER 1000 reactor (alias VVER-1000/V392)
AHWR	Advanced Heavy Water Reactor
ALLEGRO	European Gen IV Gas-cooled Fast Reactor demonstration project
Am	Americium
AP1000	a PWR designed and sold by Westinghouse Electric Company
APR1400	Advanced Power Reactor (PWR) of 1400 MW designed by KEPCO
AREVA SA	multinational group specializing in nuclear power and renewable energy, majority owned by the French state.
ATMEA	a Gen III+ AREVA PWR design of 1100 MW
AVR	A German prototype pebble bed reactor (Arbeitsgemeinschaft Versuchsreaktor)
BDBA	Beyond Design Basis Accidents
BFE	Bundesamt für Energie (Swiss Federal Office of Energy)
BWR	Boiling Water Reactor
CANDU	CANadian Deuterium Uranium - a PHWR by Atomic Energy of Canada, Ltd.
CAP1000	Chinese reactor design of 1000 MW developed from AP1000
CAP1400	Chinese reactor design of 1400 MW developed from AP1000
CAREM	Argentinian small modular self-pressurized PWR
CCR	Toshiba small modular BWR
CDF	Core damage frequency
CHF	Swiss Franc
Cm	Cerium
CNNC-CGN	Partnership of China National Nuclear Corporation and China General Nuclear Corporation
CNRS	French National Center for Scientific Research (Centre national de la recherché scientifique)
DBA	Design Basis Accidents
EAF	Equivalent Availability Factor
EC6	Enhanced CANDU 6 reactor
ecoinvent	An independent organization that has established and provides a consistent and transparent life cycle inventory database of the same name
ENSI	Swiss Federal Nuclear Safety Inspectorate (Eidgenössiche Nuklearsicherheitsinspektorat)
EPEX	European Power Exchange
EPR	European Pressurized Reactor
ESBWR	Economic Simplified Boiling Water Reactor
EUR	Euro
EVOL	Gen IV molten salt fast reactor, Euratom project EVOL (Evaluation and Viability Of Liquid fuel fast reactor system) at French CNRS
FBR	Fast Breeder Reactor
FCVS	Filtered Containment Venting Systems
FHR	Fluoride salt-cooled High-temperature Reactor
FOAK	First-of-a-kind nuclear plant
g CO_2eq	grams CO_2 equivalent as a standard measure of GHG emissions
GBP	Great Britain Pound
GCR	Gas Cooled Reactor

Gen I	Generation I (first generation of prototype reactors
Gen II	Generation II (first generation of commercial reactors)
Gen III	Generation III (near future generation of improved reactors)
Gen III+	Generation III+ (near future generation of more improved reactors)
Gen IV	Generation IV (future generation of advanced reactors)
GFR	Gas-cooled Fast Reactor
GHG	GreenHouse Gas
GIF	Generation IV International Forum
GWe	Gigawatts of electric power (billions (10e9) of watts)
HEU	Highly enriched uranium
HLW	High Level Waste
HTPBR	High Temperature Pebble Bed Reactor
HTR	High Temperature Reactor
HTR-PM	High Temperature Reactor, Pebble-bed Module (SMR design)
HTR-TN	High Temperature Reactor Technology Network
HTTR	High Temperature Test Reactor
HWR	Heavy Water Reactor
IAEA	International Atomic Energy Agency
ICRP	International Commission on Radiological Protection
IEA	International Energy Agency
ILW	Intermediate Level Waste
IMR	Integral Modular Reactor (PWR)
INES	International Nuclear and Radiological Event Scale
IR	Inferred Resources
IRIS	Westinghouse (US) small modular PWR
ISL	In Situ Leaching
ITU	EC/JRC Institute for Transuranium Elements (Institut für Transurane) in Karlsruhe, Germany
KAERI	Korean Atomic Energy Research Institute
KEPCO	Korea Electric Power Corporation
KERENA	an AREVA Gen III+ BWR design
KHNP	Korea Hydro and Nuclear Power
KKB	Kernkraftwerk Beznau, or Beznau Nuclear Power Plant
KKG	Kernkraftwerk Gösgen, or Gösgen Nuclear Power Plant
KKL	Kernkraftwerk Leibstadt, or Leibstadt Nuclear Power Plant
KKM	Kernkraftwerk Mühleberg, or Mühleberg Nuclear Power Plant
KLT	Russian barge-mounted small modular PWR
kWh	kilowatthours of energy (implicitly electric energy)
LCA	Life Cycle Analysis
LCIA	Life Cycle Impact Analysis
LCOE	Levelized Cost of Electricity
LERF	Large Early Release Frequency
LEU	Low enrichment uranium
LFR	Lead-cooled Fast Reactor
LIS	Laser Isotope Separation
LLW	Low Level Waste
LMFBR	Liquid Metal Fast Breeder Reactor
LOCA	Loss of coolant accident
LUEC	Levelized Unit Electricity Cost (same as LCOE)
LWR	Light Water Reactor
MHI	Misubishi Heavy Industries, Ltd.

MJ	Megajoules of energy
MOX	Mixed oxide fuel (uranium/plutonium mixture)
MPa	Megapascals (an SI unit measure of pressure)
mPower	US small modular self-pressurized PWR
MSBR	Molten Salt Breeder Reactor
MSR	Molten Salt Reactor
MWe	Megawatts of electric power (millions (10e6) of watts)
MWh	Megawatthours of energy (implicitly electric energy)
MWth	Megawatts of thermal power (millions (10e6) of watts)
MWthd	Megawatt thermal day (unit of energy used to measure fuel burnup)
NANO	“Nachrüstung für den Notstand,” or Retrofit for Emergencies of Beznau plant
NEA	Nuclear Energy Agency
NHR	Chinese small modular, self-pressurized PWR for district heating
NNL	UK National Nuclear Laboratory
NOAK	Nth-of-a-kind nuclear plant (or Next-of-a-kind)
Np	Neptunium
NPP	Nuclear Power Plant
OECD	Organization for Economic Cooperation and Development
ORNL	Oak Ridge National Laboratory
Pa-233	Protactinium 233 (intermediate step from fertile thorium to bred uranium)
PASCAR	Korean small modular, lead-bismuth-cooled fast reactor
Pb-Bi	Lead-bismuth eutectic mixture used as a liquid metal coolant
PBR	Pebble Bed Reactor
PBMR	Pebble Bed Modular Reactor, helium-cooled
PHWR	Pressurized Heavy Water Reactor
PNNL	Pacific Northwest National Laboratory
ppb	parts per billion (measure of concentration)
PSA	Probabilistic Safety Assessment
Pu-239	Plutonium 239 (fissile isotope bred from U-238)
PUREX	Plutonium Uranium Redox EXtraction fuel reprocessing
PWR	Pressurized Water Reactor
PyC	Pyrolytic carbon (graphite?)
QP300	Chinese small modular PWR
RAR	Reasonably Assured Resources
RBMK	Russian Graphite Moderated Reactor (Reaktor Bolshoy Moshchnosti Kanalnyy = High Power Channel-type Reactor)
RIA	Radioactivity Induced Accidents
ROSATOM	Russian State Nuclear Energy Corporation
Rp	Rappen, Swiss Franc cent (0.01 CHF)
SAMG	Severe Accident Management Guidelines
SAMOFAR	Safety Assessment of the Molten Salt Fast Reactor – a major project in the Horizon 2020 Euratom research program.
SCWR	SuperCritical Water-cooled Reactor
SF	Spent Fuel
SFOE	Swiss Federal Office of Energy
SFP	Spent Fuel Pool
SFR	Sodium-cooled Fast Reactor
SiC	Silicon carbide
Silex	Separation of Isotopes by Laser EXcitation
SINAP	Shanghai INstitute of Applied Physics
SMART	Korean small modular integral PWR

SMR	Small Modular Reactor
SMRs	Small and Medium-sized Reactors
SNPTC	State Nuclear Power Technology Company, Chinese NPP developer/operator
SNR	Sodium-cooled Nuclear Reactor
SNR-300	A fast breeder SNR built in Germany (completed 1985, cancelled 1991).
SUSAN	"Spezialles unabhängiges System zur Abfuhr der Nachzerfallwärme," or Special Independent System for Disposal of Decay Heat at Mühleberg plant
SVBR	Russian small modular, lead-bismuth-cooled fast reactor
Th-232	Thorium 232 (99.98% of natural thorium)
THOREX	Thorium extraction fuel reprocessing
ton	short ton = 2000 lb = 909 kg
tonne	metric ton = 1000 kg
TRUW	TRansUranic Waste
tU	tonnes uranium
U-233	Uranium 233 (bred from thorium)
U-235	Uranium 235 (0.7% of natural uranium)
U-238	Uranium 238 (99.3% of natural uranium)
U3O8	Uranium oxide (yellowcake refined from ore)
UC	Uranium carbide
UF	Uranium fluoride salt
UF6	Uranium hexafluoride (gasifies at low temperature for enrichment)
UO2	Uranium oxide (as in fuel pellets)
USD	United States Dollar
USDOE	US Department of Energy
VBER	Russian small modular PWR, land-based or barge-mounted
VHTR	Very High Temperature Reactor
VK-300	Russian small modular BWR
VVER	from Russian WWER for Water-Water Energetic Reactor
WNA	World Nuclear Association

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15 Natural gas and coal power

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15.1 Introduction

Currently, most of the global technical energy consumption is still based on fossil energy resources. Figure 15.1 shows the global annual consumption of natural gas, coal and oil in comparison with other primary energy sources. For electricity generation, the major fossil resources are coal and natural gas. Fossil oil is mainly used for other purposes (in particular for transportation) and expected to play only a minor role for future electricity generation. Therefore, the focus here is on natural gas and coal.

The global technical primary energy consumption in 2014 (2015) was about 543 EJ/a (552 EJ/a), of which about 163 EJ/a (161 EJ/a) were coal and about 128.8 EJ/a (131.7 EJ/a) were natural gas (BP 2015, BP 2016). Thus, coal currently contributes about 29% and natural gas about 24% to the global technical primary energy consumption as of year 2015.

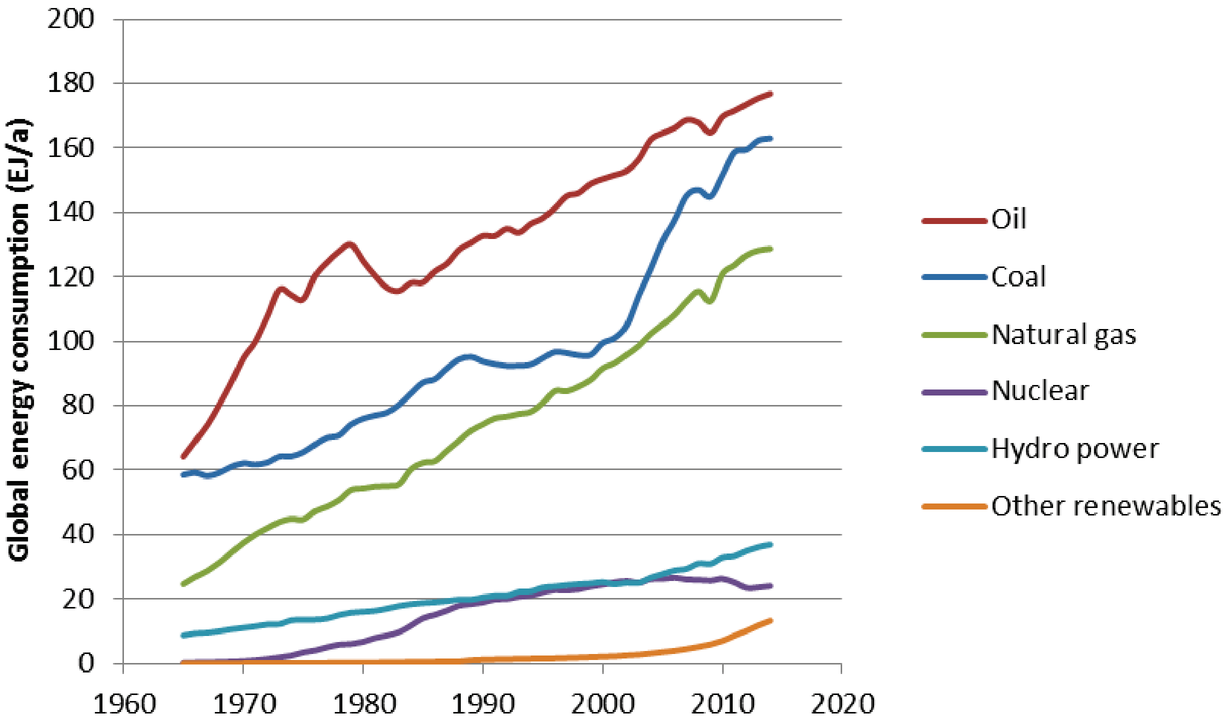

Figure 15.1: Global annual consumption of fossil (natural gas, coal, oil) and other primary energy (BP 2015).

In Switzerland, there are currently no large fossil-based power plants. Electricity generation from fossil energy within Switzerland is limited to a relatively small scale. Conventional non-renewable thermal power plants contributed to the Swiss inland electricity production only 1339 GWh/a (1.9%) in 2014 (BFE/SFOE 2015b) and 1545 GWh/a (2.3%) in 2015 (BFE/SFOE 2016f). This refers to small natural gas and diesel plants. In particular, there is no coal power plant in Switzerland.

Nevertheless, Switzerland is importing and exporting electricity from and to neighboring countries. Imports of electricity that include coal power or natural gas power affect also the actual electricity mix in Switzerland, i.e. there is also an indirect use of coal power plants in Switzerland via electricity imports.

Natural gas consists mainly of methane (CH_4). Currently, methane is taken mainly from fossil resources, but methane could be produced also from wood or other biomass, or from CO_2 together with other energy sources (e.g. currently investigated “power-to-gas” concepts or artificial photosynthesis concepts). The properties of synthetic natural gas (SNG) are comparable to the properties of fossil natural gas. Therefore, a lot of the technical and environmental aspects of natural gas discussed in the following are applicable also to synthetic natural gas (with the exception of the production and origin). Synthetic natural gas from biomass (“biomethane”) is described separately in chapter 10.6.

A key component for large combustion power plants with high electric efficiency is the gas turbine. Gas turbines can be used for fossil natural gas and synthetic natural gas in gas turbine power plants and in combination with steam turbines in CC (Combined Cycle) power plants. Gas turbines are also important for future coal power plants as components of IGCC (Integrated Gasification Combined Cycle) plants as well as for future biomass plants in BIGCC (Biomass Integrated Gasification Combined Cycle) plants.

Promising technologies for future large electricity generation systems for natural gas and synthetic natural gas are (SETIS 2014):

- Advanced Combined Cycle Plant
- Advanced Open Cycle Gas Turbine

Electricity from natural gas can also be produced in small power plants like micro gas turbines or small combined heat and power (CHP) plants. Nevertheless, current conventional small natural gas combustion plants (currently these are often piston engine CHP) have lower electric efficiencies than the best large combined cycle plants. Since the focus here is not on heat but on electricity production, the focus is on technologies with high electric efficiencies. For future small-scale or medium-scale electricity production from natural gas with high electric efficiencies, fuel cells are a promising technology. Fuel cells are discussed separately in chapter 16.

Promising technologies for future electricity generation systems for coal are (SETIS 2014):

- Integrated Gasification Combined Cycle plants
- Pulverized hard coal or lignite, supercritical
- Supercritical fluidized bed plants

General references for fossil fuels and technologies: (IEA 2007, IEA 2008a, IEA 2013b).

15.1.1 Carbon capture, utilization and storage (CCUS)

One of the major environmental issues of fossil fuel combustion is the long-term change of the global climate due to carbon dioxide emissions. Once emitted, carbon dioxide stays for a very long time in the atmosphere. The goal is the reduction of emissions of carbon dioxide and other greenhouse gases.

The basic techniques for CO_2 capture are post-combustion capture, pre-combustion capture and oxyfuel combustion. Post-combustion capture of CO_2 from the flue gas usually involves chemical solvents like monoethanolamine (MEA) or chilled ammonia. In pre-combustion capture, the fuel is converted into CO_2 and hydrogen-rich fuel; the hydrogen-rich fuel is then combusted. Oxyfuel combustion means an increase of CO_2 concentration in the flue gas by using concentrated oxygen (which is e.g. produced by cryogenic air separation) for combustion. CO_2 capture requires relatively large amounts of energy and therefore reduces the net efficiency of a power plant and thus increases the fuel consumption per kWh electricity output.

Currently, pre-combustion and post-combustion capture technologies have reached maturity close to application. Oxyfuel technology is expected to be relevant for future power plants (Soothill, Bialkowski et al. 2013).

After CO_2 capture, there are basically two ways to deal with the CO_2: On the one hand sequestration, i.e. geological storage ("Carbon capture and sequestration", or "Carbon capture and storage", CCS), on the other hand utilization ("Carbon capture and utilization", CCU). The methods or combinations of both are summarized as "Carbon capture, utilization and storage" (CCUS).

An often discussed option would be the sequestration of CO_2 in geological formations. Research on consequences of sequestration in ground is ongoing.

Another option would be the use of CO_2 for production of carbon based fuels or substitutes of other materials usually produced from fossil resources. The replacement of fossil products could possibly reduce overall CO_2 emissions, but the overall balance depends a lot on the details of the processes involved. (For power-to-gas see e.g. (Zhang, Bauer et al. 2017)).

If the product is used in a device which is also equipped with CO_2 capture technology, the CO_2 can be re-used again or the process can be combined with sequestration.

Examples for concepts for the utilization of CO_2:

- Power-to-gas or power-to-liquid: Electrolysis is used to produce hydrogen which is combined with CO_2 to yield hydrocarbons. The overall environmental balance mainly depends on the source of electricity used. Examples:
  - PSI ESI platform (power-to-gas in combination with biomass conversion)
  - E-diesel by Audi (power-to-liquid)
- CO_2 is combined with hydrogen from other sources like solar hydrogen to produce hydrocarbons.
- CO_2 is used to feed plants or microorganisms for production of biofuels or other biomaterials. Examples:
  - Biofuels from algae
  - Biofuels from cyanobacteria, e.g. ethanol from cyanobacteria by company Algenol, Florida, in closed, flexible plastic film photobioreactors into which the CO_2 is injected[371]
- Use in the chemical industry for production of materials (e.g. synthesis of polymers) or chemicals (e.g. urea).

Carbon dioxide is also used for enhanced oil recovery (EOR).

[371] www.algenol.com

The geological CO_2 sequestration potential in Switzerland has been estimated in the project CARMA (Carbon Management in Power Generation). According to the findings in the CARMA project, an area of about 5000 km^2 in Switzerland exhibits substantial CO_2 sequestration potential (Diamond, Leu et al. 2010). The area is located mainly in the sector Fribourg- Olten-Luzern. The theoretical storage capacity was estimated at about 2680 million tons of carbon dioxide (Diamond, Leu et al. 2010). This is an unproven capacity estimate based on nine qualitative and semi-quantitative attributes derived from analysis of deep drill-holes and geological and geophysical data (Diamond, Leu et al. 2010).

The carbon capture, utilization and storage concepts need further research and development in order to possibly be able to contribute significantly to a reduction of global overall CO_2 emissions in view of the large scale of the problem and in view of possible side-effects.

15.2 Technology description

The following section gives an overview on important current electricity generation technologies for natural gas and coal. Future developments of technologies until 2050 are discussed later.

15.2.1 Current technology

15.2.1.1 Current natural gas technology

15.2.1.1.1 Combined cycle (CC) plants

A combined cycle power plant includes a gas turbine cycle and a steam turbine cycle. The combusted gas drives the gas turbine at very high temperatures. The exhaust gas from the gas turbine is still hot enough to generate steam for the steam turbine. The combination of gas turbine and steam turbine yields high electric efficiencies. The basic principle of a combined cycle power plant is shown in Figure 15.2.

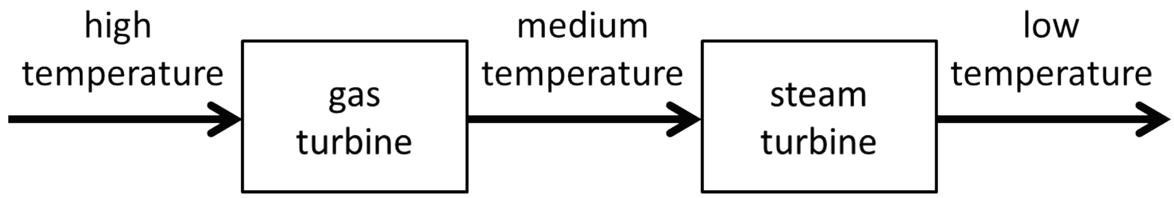

Figure 15.2 Basic principle of a combined cycle power plant.

Current new natural gas combined cycle (NGCC) power plants can reach already relatively high electric efficiencies of around 60%. Highly efficient combined cycle plants have typically a maximum electric output capacity on the order of 300 MW or more. The Siemens Mainz-Wiesbaden natural gas combined cycle plant reported a maximum efficiency of 58.4% already in 2001 (KMW 2002). A world record electric efficiency of 60.4% was claimed in year 2011 by the new natural gas combined cycle power plant in Irsching (E.ON 2011). The maximum temperature of the gas at the gas turbine is about 1500°C (E.ON 2011). An efficiency of more than 60% for a CC plant with large Siemens gas turbine was certified by an independent agency (Jansohn 2013). Comparable efficiencies are specified by all major manufacturers for their newest large gas turbines (Jansohn 2013).

The largest single gas turbines are reaching now electric outputs of almost 400 MW alone (Jansohn 2013). For a combined cycle plant this results in more than 500 MW for a single gas turbine and up to 1000 MW for a combination of two gas turbines with one steam turbine. (Jansohn 2013).

The construction time of NGCC plants is estimated at 22-24 months (Boyce 2006).

Table 15.1 gives an overview on net capacities and electric efficiencies of current natural gas combined cycle plants in different European countries according to (NEA/IEA/OECD 2015).

Table 15.1: Net capacities and electric efficiencies of current natural gas combined cycle plants in different European countries estimated for year 2015 (NEA/IEA/OECD 2015).

Country	Net capacity (MW_{el})	Electrical conversion efficiency (%)
Belgium	420	60
France	575	61
Germany	500	60
Netherlands	870	59
Portugal	445	60
United Kingdom	900	59

The combined cycle mode net efficiency of the GE 7F.05 gas turbine is 60.3 % (LHV) at 12 ppm NO_x emissions (15% O_2); the combined cycle net output is 376 MW (GEPower 2016).

The SGT5-8000H 400 MW gas turbine reaches a simple cycle gross efficiency 40% and a combined cycle net efficiency >60% with a net plant power output of 600 MW (with 1 gas turbine), 1200 MW (with 2 gas turbines) at 50Hz (Siemens 2016).

Table 15.2 summarizes technical data of a typical current natural gas combined cycle power plant.

Table 15.2: Technical data of the reference current natural gas combined cycle power plant investigated in NEEDS. Source: (Bauer, Heck et al. 2009).

Natural gas combined cycle		
Net Electric Power	[MW_e]	400
Technical Life Time	[a]	25
Load	[h/a]	7200
Net Electricity Generation (over the life time)	[TWh]	72.0
Net Electric Efficiency	[%]	57.5

15.2.1.1.2 Combined heat and power (CHP) plants

Currently, 954 small CHP (according to (Kaufmann and Gülden Sterzl 2015), this includes BHKW (“Blockheizkraftwerke”) <10MW_{el} or gas turbines <1MW_{el}) are installed in Switzerland as of 2014 with an electric capacity of 146.3 MW_{el} and an annual production of 577 GWh electricity or high-valued mechanical energy (Kaufmann and Gülden Sterzl 2015). This includes five natural gas turbines <1MW_{el}. The small CHP produced also 794 GWh heat of which 722 GWh was useful heat whereas 72 GWh (9%) heat was released with “Notkühler” to the environment (Kaufmann and Gülden Sterzl 2015).

527 of the small CHP are fossil fuel based with an electricity output of 267.5 GWh in 2014 (Kaufmann and Gülden Sterzl 2015). The natural gas consumption of the small fossil CHP was about 700 GWh, and the diesel consumption only about 50 GWh in 2014 (Kaufmann

and Gülden Sterzl 2015). Thus the current average electric efficiency of the small fossil CHP in Switzerland is about 35.7% as of year 2014.

There are 17 CHP >10 MW_{el} resulting in a total capacity of 191.3 MW_{el} and an electricity production of 449.8 GWh/a in Switzerland (Kaufmann and Gülden Sterzl 2015). Small CHP plants are often driven by heat demand. The electric efficiency of natural gas piston engine CHP plants depends on the size of plant as shown in Figure 15.3. The smallest natural gas CHP plants usually have electric efficiencies below 30%. The largest natural gas CHP in (ASUE 2014) is listed with an electric output of 18.3 MW, an electric efficiency of 48.6%, a thermal efficiency of 42.4%, a total efficiency of 91%, and is of type "Otto engine" (ASUE 2014). An industrial 55 MW_{el} combined cycle plant (348 GWh_{el}/year) operates as a combined heat and power plant in Monthey, Switzerland, since 2009 (VSE 2015, Kraftanlagen 2016).

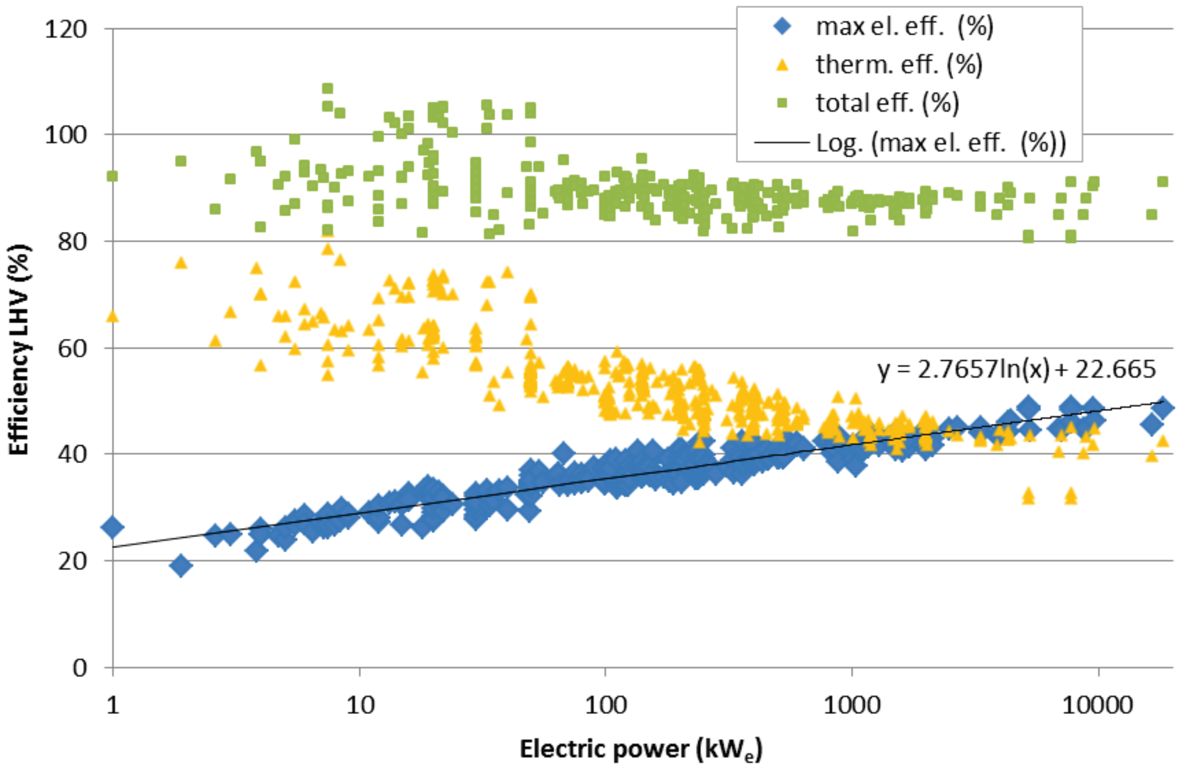

Figure 15.3: Electric, thermal, and total efficiency of natural gas piston engine combined heat and power (CHP) plants. Based on data from: (ASUE 2014).

The specific material requirement per kW for a CHP plant usually decreases with increasing capacity (Figure 15.4). On the one hand, this has an influence on the life cycle burdens. On the other hand, it influences the specific investment costs per kW, which decrease with increasing capacity (Figure 15.4). An approach to increase the electric efficiency of small or medium size CHP plants is the use of flue gas energy for additional electricity generation (Waste Heat to Power (WHP)). A combined heat and power plant (CHP) together with an ORC (Organic Rankine Cycle) has been installed by Stadtwerke Kempen (Stadtwerke-Kempen 2013). The CHP/ORC combination plant started operation in year 2012. The waste heat from 3 Jenbacher CHP units (Jenbacher 2006) is used for the ORC unit during periods of low heat demand. Data for the Kempen CHP/ORC plant are shown in Table 15.3. The electric efficiency is about 43.4% without ORC, and about 46.5% with ORC.

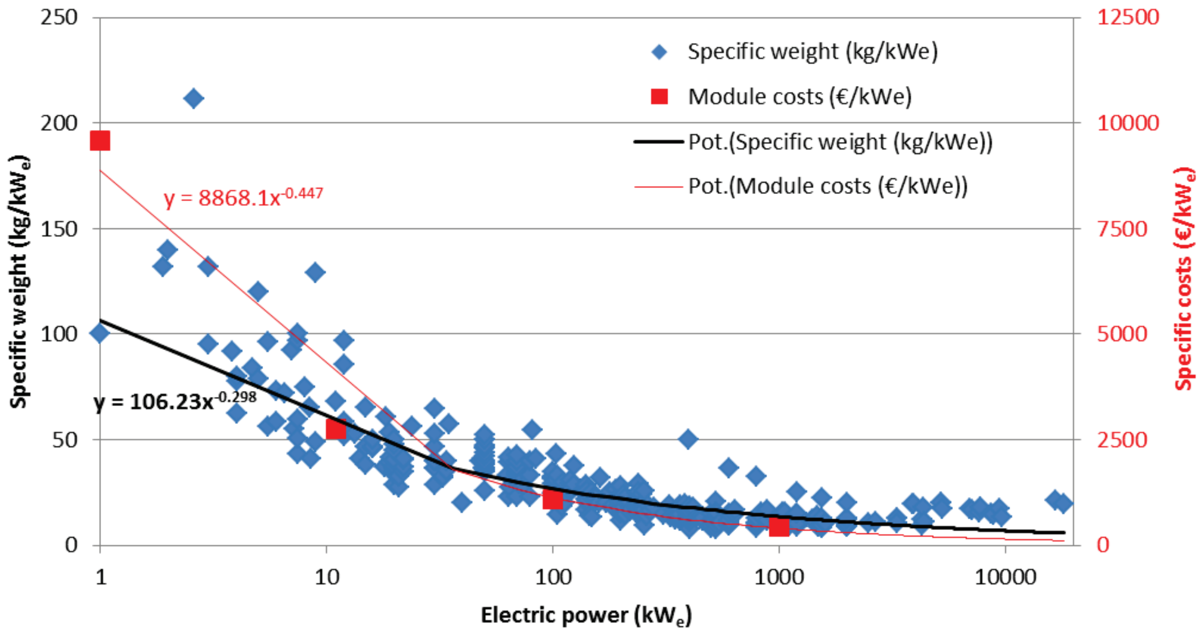

Figure 15.4: Specific weights and specific costs of natural gas piston engine combined heat and power (CHP) plants depending on the electric power. Module costs refer to the CHP plant without installation costs. Based on data from: (ASUE 2014, ASUE-BHKW-Infozentrum 2016).

Table 15.3: Data for the Kempen combined heat and power plant (CHP) with ORC (Organic Rankine Cycle).

		1 CHP	3 CHP + 1 ORC	Reference
CHP - Combined Heat and Power plant				
CHP units „Jenbacher JMS 616 GS“				(Stadtwerke-Kempen 2013)
Electrical output CHP	kW	2430	7290	(Jenbacher 2006)/ (Stadtwerke-Kempen 2013)
Recoverable thermal output CHP (120 °C)	kW	2399		(Jenbacher 2006)
Fuel energy input (natural gas)	kW	5606	16818	(Jenbacher 2006)
Fuel consumption based on LHV	Nm³/h	590		(Jenbacher 2006)
LHV	kWh/Nm³	9.6		(Jenbacher 2006)
Electrical efficiency, CHP only		43.4%		
Thermal efficiency, CHP only		42.8%		
Total efficiency, CHP only		86.2%		
Weight, empty, CHP module, without heat recovery module	kg	23800		(Jenbacher 2006)
Mass per kW input, CHP module, without heat recovery module	kg/kW	4.25		
ORC - Organic Rankine Cycle				
Heat from CHP used for ORC	kW	1244	3732	(Stadtwerke-Kempen 2013)
Flue gas temperature at CHP	°C	450	450	(Stadtwerke-Kempen 2013)
1 ORC unit „Turboden 6 HR“				(Stadtwerke-Kempen 2013)
Thermo-oil inlet temperature	°C		310	(Stadtwerke-Kempen 2013)
Thermo-oil outlet temperature	°C		142	(Stadtwerke-Kempen 2013)
Thermo-oil input power at vaporizer	kW		3000	(Stadtwerke-Kempen 2013)
Electrical output ORC, gross	kW		528	(Stadtwerke-Kempen 2013)
Heat from ORC delivered to district heating	kW		2452	(Stadtwerke-Kempen 2013)
Total electricity output CHP+ORC, gross	kW		7818	
Total fuel energy input	kW		16818	
Total electric efficiency in CHP+ORC mode, gross			46.5%	

15.2.1.2 Current coal technology

The most commonly used coal power plant technology today is pulverized coal (PC).

Supercritical pulverized coal (SCPC) and ultra-supercritical pulverized coal (USCPC) plants operate at higher temperatures and pressures than conventional pulverized coal plants and therefore achieve higher efficiencies.

Typical steam conditions for supercritical (SC) plants are characterized by a temperature of 565°C and pressure of 262 bar (Wheeldon and Phillips 2013). Ultra-supercritical (USC) plants operate at temperatures above 590°C, and advanced ultra-supercritical (A-UCS) plants at temperatures above 650°C (Wheeldon and Phillips 2013). Plants with 700°C and 350 bar are under development (Wheeldon and Phillips 2013).

In fluidized bed combustion (FBC), coal is burned in a bed of heated particles suspended in an upward gas flow. In an Integrated Gasification Combined Cycle (IGCC) plant, coal is converted into gas in a gasifier unit. The gas is then combusted in a combined-cycle unit.

Table 15.4 gives an overview on net capacities and electric efficiencies of current coal-fired power plants in different European countries according to (NEA/IEA/OECD 2015).

Table 15.4: Net capacities and electric efficiencies of current coal-fired power plants in different European countries estimated for year 2015 (NEA/IEA/OECD 2015).

Country	Technology	Net capacity (MWe)	Electrical conversion efficiency (%)
Belgium	Ultra-supercritical	750	46
Germany	Hard coal	700	46
	Lignite	900	43
Netherlands	Ultra-supercritical	777-1554	46
Portugal	Pulverized	605	46-51

Table 15.5 shows technical parameters for typical USC-PC (Ultra Super Critical Pulverized Coal) power plants.

Table 15.5: Technical data of the reference USC-PC power plants investigated in NEEDS (Bauer, Heck et al. 2009).

Gross Power	[MW_e]	378	642	848
Net Power	[MW_e]	350	600	800
Technical Life Time	[a]	35	35	35
Load	[h/a]	7600	7600	7600
Net Electricity Generation (over the life time)	[TWh]	93.1	159.6	212.8
Net Efficiency	[%]	45	45	46
Efficiency FGD	[%]	93	93	93
Efficiency de-NOx	[%]	70	70	70

Table 15.6 shows technical parameters for a typical lignite power plant.

Table 15.6: Technical data of the reference lignite power plant investigated in NEEDS (Bauer, Heck et al. 2009).

Gross Power	[MW_e]	1012
Net Power	[MW_e]	950
Technical Life Time	[a]	35
Load	[h/a]	7760
Net Electricity Generation (over the life time)	[TWh]	258
Gross Efficiency	[%]	46.0
Efficiency loss for auxiliary power	[%]	2.8
Net Efficiency	[%]	43.2

A new hard coal power plant in Mannheim/Germany started in 2015 (GKM 2015). The cost was 1.2 billion Euro for a gross electric power of 911 MW (GKM 2015). Thus, one can estimate the investment costs to be about 1300 Euro per kW. The maximum electric efficiency is announced at 46.4% (GKM 2015). In combined heat and power mode, total efficiency is estimated at 70%. The maximum heat output for district heating is 500 MW_{th}. Construction took six years and needed 60’000 tons of steel (Eberhardt 2015).

15.2.2 Future technology

15.2.2.1 Future gas turbine technology

The electric efficiencies of future highly efficient natural gas and coal power plants depend mainly on the maximum temperature that can be reached without damaging the gas turbine.

(The actual efficiency of a power plant with steam cycle at a specific location depends also on the cooling conditions.)

In future, super high-temperature gas turbines for temperatures up to 1700°C are expected to become available. Natural gas combined cycle plants equipped with such a 1700°C gas turbine are expected to reach electric efficiencies (LHV) in the range of 62-65% (IEA 2012, Isles 2012). Some references expect possible electric efficiencies of NGCC plants above 65% (Markewitz, Bongartz et al. 2015). Improvements of gas turbines are also important for future coal power plants. When the same super high-temperature gas turbine for 1700°C is used in an IGCC plant, the gross electric efficiency is estimated at about 55% and the net electric efficiency at about 50% (Isles 2012).

Size and capacity of gas turbines are limited by the rotational speed of the blades which should not exceed the speed of sound. The rotation of the gas turbine must be synchronized to the frequency of the electricity network. This puts a limit to the maximum gas flow. 50 Hz gas turbines are running usually at 3000 rpm, 60 Hz gas turbines at 3600 rpm (Jansohn 2013). Therefore, gas turbine or combined cycle power plants in Europe within the European 50 Hz electricity network reach higher electric power ratings than plants within a 60 Hz network (e.g. in USA) (Jansohn 2013).

15.2.2.2 Future Combined cycle (CC) plants

Table 15.7 shows estimates of electric efficiencies of large future NGCC power plants from different sources. In real operation, the maximum possible electric efficiency of a combined cycle power plant is not always reached. Therefore, it can be expected that the annual average efficiency in real operation is usually below the possible maximum electric efficiency.

Table 15.7: Estimates of electric efficiencies (LHV) of large future NGCC power plants from different sources. A: (NEA/IEA/OECD 2015). B: (Markewitz, Bongartz et al. 2015). C: (Isles 2012). D (IEA 2012). E: (SETIS 2014). F: (Bauer, Heck et al. 2009). G: (Statensnet 2004) data 2030 originally for 2020-2030. H: (Mom 2013). I: (E.ON 2011). J: (GEPower 2016). K: (Siemens 2016).

	2015	2020	2030	2035	2040	2050	Future, unspecified
A (Europe, different countries)	59-61%						
B						>65%	
C							62-65%
D							62-65%
E		60%	62%		62%	63%	
F	60%			63%			
G 100% load			59-64%				
G 75% load			57-62%				
G 50% load			53-57%				
H							65%
I	max 60.4%						
J	60.3%						
K	>60%						

15.2.2.2.1 Part load efficiency

Usually, one expects losses of 5-6%-points at 80% load compared to the efficiency at 100% load (Jansohn 2016). According to information from the Mainz-Wiesbaden combined cycle plant, the reduction of efficiency at 80% load for this plant is about 2%-points compared to 100% load (Faist Emmenegger, Heck et al. 2007). This corresponds approximately to the estimated efficiency loss at 75% load in Table 15.7 based on (Statensnet 2004) estimates for 2030. A loss of 2%-points at 80% load is considered a lower limit for current technology.

15.2.2.3 Power plants with CO_2 capture

For natural gas turbines and combined cycle plants, mainly post-combustion and pre-combustion carbon dioxide capture technologies are studied (Biliyok, Canepa et al. 2015, Carapellucci, Giordano et al. 2015, Cormos 2015, Jansen, Gazzani et al. 2015, Rezazadeh, Gale et al. 2015, Rubin, Davison et al. 2015, Luo and Wang 2016, Rubin 2016). Oxyfuel combustion for NGCC is also discussed sometimes in literature (Mletzko, Ehlers et al. 2016).

15.2.2.4 The future of combined heat and power generation

Existing gas boilers can often be replaced by CHP plants of the same heat capacity because the required space and gas infrastructure are similar. Therefore, there is a large potential for small gas CHP plants which can be installed directly at the central heating system of a building, as alternatives to gas boilers, without additional heat losses due to long-distance heat transport. Very large CHP plants (in the order of hundreds of Megawatts) would require a correspondingly high heat demand near the plant or a costly district heating system. Long-range transport of heat is associated with high losses. Therefore, it is difficult to transport heat over large distances. A detailed analysis of large scale heat distribution systems is beyond the scope of this study.

The performance of a combined heat and power plant depends mainly on the application and the use of the heat.

Figure 15.5 shows examples for a highly efficient CC plant and a small CHP plant in combination with heat pumps in different modes of operation, i.e. for different output and input temperatures. The size of the CHP is in the order of 10-20 kW_{el} so that losses due to heat transport can be neglected. The quality grade of the heat pump (ratio between real COP and ideal Carnot COP) was assumed to be 0.45 (Zogg 2009). If high temperatures are needed or the temperature of the environmental heat reservoir is very low, a combined heat and power plant can be favorable. For low temperature heating and small differences between temperatures, the combination of a power plant with very high electric efficiency (which is here a combined cycle plant, but which could be in future also a smaller fuel cell plant) and heat pumps has usually the better performance. The highest theoretical potential has the combination of highly efficient electricity generation with heat recovery at small temperature differences. (In the past, heat pumps have been optimized for temperature differences of 30-60°C. Current heat pumps for air to air heat transfer for heat recovery may have quality grades of 0.3 rather than 0.45 for small temperature differences. Nevertheless, advanced heat pumps for small temperature differences can reach quality grades of 0.5 or more (Wyssen, Gasser et al. 2013). They can be used e.g. with ground heat. The temperature of the ground in a depth of 15 m in Switzerland is at about 10°C (Wyssen, Gasser et al. 2013). The optimization of heat pumps for small temperature differences is subject of current research. Thus, high electric efficiencies are also desirable for advanced heating systems with heat pumps.

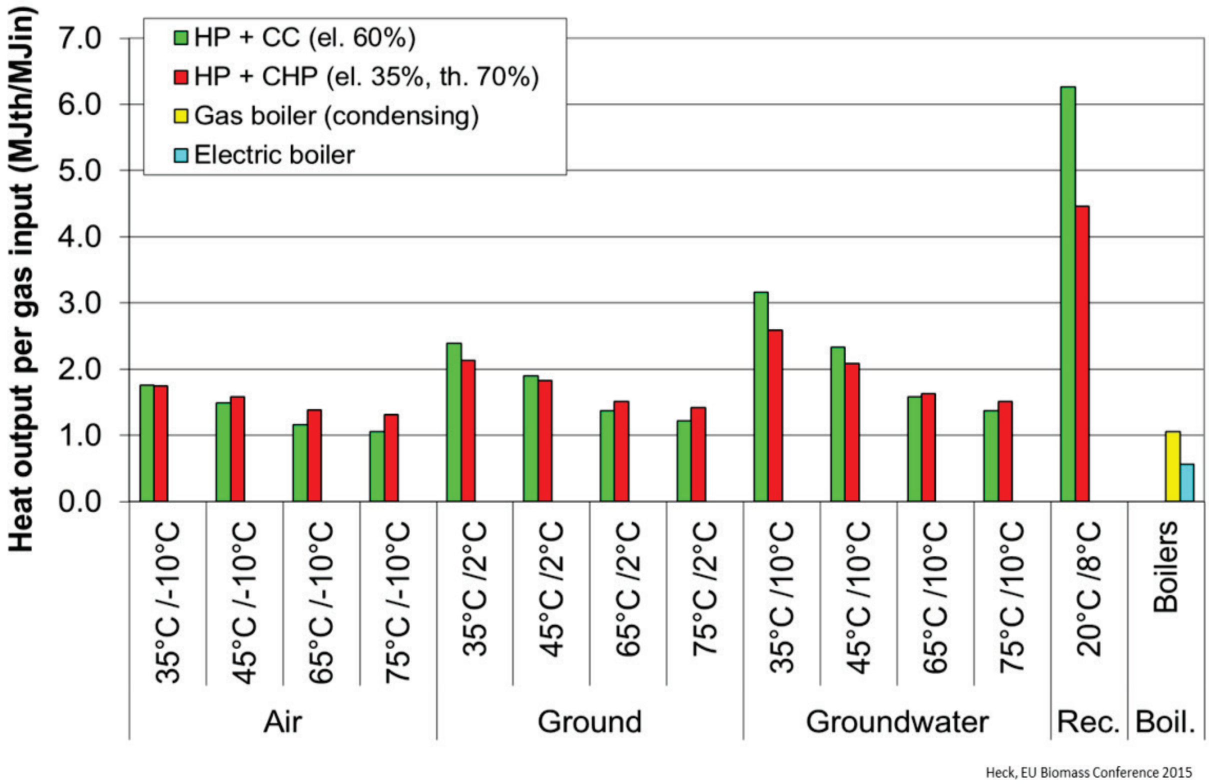

Figure 15.5: Different options of heat generation from (fossil or synthetic) natural gas in terms of total heat output relative to the lower heating value (LHV) of the gas. HP: heat pump, CC: combined cycle plant, CHP: combined heat and power plant, rec.: heat recovery. Source: (Heck 2015).

In order to estimate the development of electric efficiencies of CHP plants until 2050, the relative factors from the NEEDS (Bauer, Heck et al. 2009) project have been used, starting from the values for current systems in Table 15.13.

The assumed parameters for natural gas plants until 2050 are shown in Table 15.9.

15.2.2.5 Future coal technology

The goal of the development of advanced ultra-supercritical (A-USC) coal power plants is to increase the efficiency by increasing the temperature and pressure. Plants operating at 700°C and 350 bar are still being developed requiring new materials (Nicol 2013, Patel, Baker et al. 2013, Wheeldon and Phillips 2013, Zhong, Gu et al. 2013). The U.S. Program on Materials Technology for Ultra-supercritical Coal-Fired Boilers strives for A-USC with 760°C (Weitzel 2013).

IGCC (Integrated Gasification Combined Cycle) plants with higher efficiencies are expected in the future. Table 15.8 shows parameters for future hard coal IGCC plants until year 2050 assumed in (SETIS 2014). Current developments of IGCC plants with high efficiency and low emissions are discussed in (Giuffrida, Romano et al. 2013).

Table 15.8: Parameters of future hard coal IGCC (Integrated Gasification Combined Cycle) plants assumed in (SETIS 2014).

		2010	2020	2030	2040	2050
Net electrical power	MW	600	600	600	600	600
Gross electrical power	MW	700	700	700	700	700
Thermal power	MW	1330	1330	1330	1280	1200
Max. capacity factor	%	90	90	90	90	90
Avg. capacity factor	%	85	85	85	85	85
Technical lifetime	years	35	35	35	35	35
Net el. efficiency (LHV)	%	45%	46%	46%	47%	50%

Carbon dioxide capture, utilization and storage are particularly interesting for coal combustion technologies because of the high CO_2 emission factors per kWh electricity of conventional coal power plants i.e. plants without CO_2 capture (see chapter 15.6).

For coal power plants, post-combustion, pre-combustion, and oxyfuel combustion carbon dioxide capture technologies are currently investigated in several studies. Pulverized coal oxyfuel combustion is discussed in (Chen, Yong et al. 2012, SETIS 2014, Rubin, Davison et al. 2015).

Zhao, Minett et al. (2013) give a review of techno-economic models for the retrofitting of conventional pulverized-coal power plants for post-combustion carbon dioxide capture. Goto, Yogo et al. (2013) show a review of efficiency penalties in a coal-fired power plant with post-combustion carbon dioxide capture.

Studies on IGCC plants with carbon dioxide capture: IGCC pre-combustion (Moioli, Giuffrida et al. 2014, SETIS 2014, Urech, Tock et al. 2014, Jansen, Gazzani et al. 2015), IGCC post-combustion (Giuffrida, Bonalumi et al. 2013), IGCC with oxyfuel combustion (Oki, Hara et al. 2014), comparing post-combustion, pre-combustion, and oxyfuel combustion at IGCC (Kunze and Spliethoff 2012, Kawabata, Kurata et al. 2013), IGCC with CCS (Cormos 2012, Siefert and Litster 2013), H2-IGCC: (Majoumerd, Raas et al. 2014). Fluidized bed combustion with post-combustion capture is discussed in (SETIS 2014, Zhang, Liu et al. 2014), circulating fluidized bed combustion coal technology (CFBC) with post-combustion in (Dinca and Badea 2013).

Net efficiency reductions of about 8.5% points (resulting in 35.3%) compared to the reference case was estimated for the IGCC plant and approximately 10.5% points for the USC plant resulting in 34.2% was estimated for a CO_2 removal efficiency of 90% (Cau, Tola et al. 2014).

Carbon capture and storage for fossil power plants is generally discussed in several publications like e.g. (Kober 2014, Leung, Caramanna et al. 2014, Rubin, Davison et al. 2015, Rubin 2016), carbon capture, utilization and storage (CCUS) in general in (Markewitz, Kuckshinrichs et al. 2012).

A study found that more than 1000 patents worldwide have been published on sorbents, solvents, and membranes for CO_2 capture technologies (Li, Duan et al. 2013). Shakerian, Kim et al. (2015) review amines and ammonia as sorptive media for post-combustion CO_2 capture.

15.2.3 Overview of parameters for current and future natural gas and coal plants

Table 15.9 shows the technology data assumed in this study for current and future natural gas and coal plants with and without carbon dioxide capture. Costs are discussed in a separate section below.

Table 15.9: Assumed technology data for current and future natural gas and coal plants. Electric eff.: net electric efficiency, Thermal eff.: thermal efficiency (CHP), Load factor in hours per year, Technical lifetime, CO_2 capture eff.: CO_2 capture efficiency. Sources: (Rubin, Davison et al. 2015), (SETIS 2014), (Jansen, Gazzani et al. 2015), (NEA/IEA/OECD 2015), (Rubin, Azevedo et al. 2015), (Rubin 2016), (Bauer, Heck et al. 2009), (Volkart, Bauer et al. 2013), (Volkart, Bauer et al. 2016), (Cau, Tola et al. 2014), (ASUE 2014), (ASUE-BHKW-Infozentrum 2016).

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.lifetime a	CO_2 capture eff. %	Long name
Natural gas									
NGCC	Current	Base	500	58	0	7500	30	0	Natural gas combined cycle
		Low	500	57	0	6000	25	0	
		High	500	59	0	8000	35	0	
	2020	Base	500	60	0	7500	30	0	
		Low	500	59	0	6000	25	0	
		High	500	61	0	8000	35	0	
	2035	Base	500	62	0	7500	30	0	
		Low	500	61	0	6000	25	0	
		High	500	63	0	8000	35	0	
	2050	Base	500	63	0	7500	30	0	
		Low	500	62	0	6000	25	0	
		High	500	65	0	8000	35	0	
NGCC CO2 cap post	Current	Base	500	50	0	7500	30	88	Natural gas combined cycle, CO2 capture post-combustion
		Low	500	49	0	6000	25	86	
		High	500	51	0	8000	35	90	
	2020	Base	500	52	0	7500	30	88	
		Low	500	51	0	6000	25	86	
		High	500	53	0	8000	35	90	
	2035	Base	500	54	0	7500	30	89	
		Low	500	53	0	6000	25	86	
		High	500	55	0	8000	35	91	
	2050	Base	500	55	0	7500	30	90	

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.life time a	CO_2 capture eff. %	Long name
		Low	500	54	0	6000	25	86	
		High	500	56	0	8000	35	92	
NGCC CO2 cap pre	Current	Base	390	50	0	7500	25	90	Natural gas combined cycle, CO2 capture pre-combustion
		Low	390	48	0	6000	20	85	
		High	390	51	0	8000	30	93	
	2020	Base	390	53	0	7500	25	90	
		Low	390	52	0	6000	20	85	
		High	390	54	0	8000	30	93	
	2035	Base	390	54	0	7500	25	90	
		Low	390	53	0	6000	20	85	
		High	390	55	0	8000	30	93	
	2050	Base	390	55	0	7500	25	90	
		Low	390	54	0	6000	20	85	
		High	390	56	0	8000	30	93	
GT	Current	Base	250	40	0	2000	30	0	Natural gas turbine
		Low	250	39	0	1500	25	0	
		High	250	41	0	2500	35	0	
	2020	Base	250	40	0	2000	30	0	
		Low	250	39	0	1500	25	0	
		High	250	41	0	2500	35	0	
	2035	Base	250	44	0	2000	30	0	
		Low	250	43	0	1500	25	0	
		High	250	45	0	2500	35	0	
	2050	Base	250	45	0	2000	30	0	
		Low	250	44	0	1500	25	0	
		High	250	46	0	2500	35	0	
CHP 1kWe	Current	Base	0.001	26	66	2500	20	0	Natural gas piston engine combined heat and power plant 1 kWe
		Low	0.001	25	67	2000	15	0	
		High	0.001	27	65	3000	25	0	
	2020	Bas	0.001	27	65	2500	20	0	

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.life time a	CO_2 capture eff. %	Long name
		e							
		Low	0.001	26	66	2000	15	0	
		High	0.001	28	64	3000	25	0	
	2035	Base	0.001	28	64	2500	20	0	
		Low	0.001	27	65	2000	15	0	
		High	0.001	29	63	3000	25	0	
	2050	Base	0.001	29	63	2500	20	0	
		Low	0.001	28	64	2000	15	0	
		High	0.001	30	62	3000	25	0	
CHP 10kWe	Current	Base	0.01	28	64	2500	20	0	Natural gas piston engine combined heat and power plant 10 kWe
		Low	0.01	27	57	2000	15	0	
		High	0.01	30	76	3000	25	0	
	2020	Base	0.01	29	64	2500	20	0	
		Low	0.01	27	57	2000	15	0	
		High	0.01	31	73	3000	25	0	
	2035	Base	0.01	30	62	2500	20	0	
		Low	0.01	28	55	2000	15	0	
		High	0.01	32	72	3000	25	0	
	2050	Base	0.01	31	61	2500	20	0	
		Low	0.01	29	54	2000	15	0	
		High	0.01	33	71	3000	25	0	
CHP 100 kWe	Current	Base	0.1	37	50	3000	20	0	Natural gas piston engine combined heat and power plant 100 kWe
		Low	0.1	34	47	2500	15	0	
		High	0.1	39	57	3500	25	0	
	2020	Base	0.1	37	50	3000	20	0	
		Low	0.1	35	50	2500	15	0	
		High	0.1	40	52	3500	25	0	
	2035	Base	0.1	39	48	3000	20	0	
		Low	0.1	37	48	2500	15	0	
		High	0.1	42	50	3500	25	0	
	2050	Bas	0.1	40	47	3000	20	0	

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.life time a	CO_2 capture eff. %	Long name
		e							
		Low	0.1	38	47	2500	15	0	
		High	0.1	43	49	3500	25	0	
CHP 1000 kWe	Current	Base	1	40	46	4000	20	0	Natural gas piston engine combined heat and power plant 1000 kWe
		Low	1	38	43	3500	15	0	
		High	1	42	50	4500	25	0	
	2020	Base	1	40	45	4000	20	0	
		Low	1	39	43	3500	15	0	
		High	1	43	46	4500	25	0	
	2035	Base	1	43	43	4000	20	0	
		Low	1	41	41	3500	15	0	
		High	1	46	43	4500	25	0	
	2050	Base	1	44	42	4000	20	0	
		Low	1	42	40	3500	15	0	
		High	1	47	42	4500	25	0	
Hard coal									
IGCC	Current	Base	600	45	0	7500	35	0	Integrated Gasification Combined Cycle, hard coal
		Low	600	44	0	7000	30	0	
		High	600	46	0	8000	40	0	
	2020	Base	600	46	0	7500	35	0	
		Low	600	45	0	7000	30	0	
		High	600	47	0	8000	40	0	
	2035	Base	600	47	0	7500	35	0	
		Low	600	46	0	7000	30	0	
		High	600	48	0	8000	40	0	
	2050	Base	600	50	0	7500	35	0	
		Low	600	49	0	7000	30	0	
		High	600	51	0	8000	40	0	
IGCC CO2 cap pre	Current	Base	510	35	0	7500	35	90	IGCC, CO2 capture pre-combustion, hard coal
		Low	510	34	0	7000	30	86	
		High	510	36	0	8000	40	92	

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.life time a	CO_2 capture eff. %	Long name
	2020	Base	510	37	0	7500	35	90	
		Low	510	36	0	7000	30	86	
		High	510	38	0	8000	40	92	
	2035	Base	510	41	0	7500	35	90	
		Low	510	40	0	7000	30	86	
		High	510	42	0	8000	40	92	
	2050	Base	510	44	0	7500	35	90	
		Low	510	43	0	7000	30	86	
		High	510	45	0	8000	40	92	
SCPC	Current	Base	750	45	0	7500	40	0	Supercritical pulverized coal, hard coal
		Low	750	44	0	7000	35	0	
		High	750	46	0	8000	45	0	
	2020	Base	750	46	0	7500	40	0	
		Low	750	45	0	7000	35	0	
		High	750	47	0	8000	45	0	
	2035	Base	750	47	0	7500	40	0	
		Low	750	46	0	7000	35	0	
		High	750	48	0	8000	45	0	
	2050	Base	750	48	0	7500	40	0	
		Low	750	47	0	7000	35	0	
		High	750	49	0	8000	45	0	
SCPC CO2 cap post	Current	Base	630	34	0	7500	40	89	Supercritical pulverized coal, CO2 capture post-combustion, hard coal
		Low	630	33	0	7000	35	87	
		High	630	35	0	8000	45	90	
	2020	Base	630	35	0	7500	40	89	
		Low	630	34	0	7000	35	87	
		High	630	36	0	8000	45	90	
	2035	Base	630	37	0	7500	40	90	
		Low	630	36	0	7000	35	87	
		High	630	38	0	8000	45	92	
	2050	Bas	630	38	0	7500	40	90	

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.life time a	CO_2 capture eff. %	Long name
		e							
		Low	630	37	0	7000	35	87	
		High	630	39	0	8000	45	92	
SCPC CO2 cap oxy	Current	Base	580	36	0	7500	40	95	Supercritical pulverized coal, CO2 capture oxyfuel, hard coal
		Low	580	35	0	7000	35	90	
		High	580	37	0	8000	45	98	
	2020	Base	580	37	0	7500	40	95	
		Low	580	36	0	7000	35	90	
		High	580	38	0	8000	45	98	
	2035	Base	580	39	0	7500	40	95	
		Low	580	38	0	7000	35	90	
		High	580	40	0	8000	45	98	
	2050	Base	580	40	0	7500	40	95	
		Low	580	39	0	7000	35	90	
		High	580	41	0	8000	45	98	
Lignite									
IGCC	Current	Base	600	43	0	7500	35	0	Integrated Gasification Combined Cycle, lignite
		Low	600	42	0	7000	30	0	
		High	600	44	0	8000	40	0	
	2020	Base	600	45	0	7500	35	0	
		Low	600	44	0	7000	30	0	
		High	600	46	0	8000	40	0	
	2035	Base	600	47	0	7500	35	0	
		Low	600	46	0	7000	30	0	
		High	600	48	0	8000	40	0	
	2050	Base	600	47	0	7500	35	0	
		Low	600	46	0	7000	30	0	
		High	600	48	0	8000	40	0	
IGCC CO2 cap pre	Current	Base	510	35	0	7500	35	90	Integrated Gasification Combined Cycle, lignite, CO2 capture pre-combustion
		Low	510	34	0	7000	30	86	
		High	510	36	0	8000	40	92	
	2020	Bas	510	37	0	7500	35	90	

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.life time a	CO_2 capture eff. %	Long name
		e							
		Low	510	36	0	7000	30	86	
		High	510	38	0	8000	40	92	
	2035	Base	510	41	0	7500	35	90	
		Low	510	40	0	7000	30	86	
		High	510	42	0	8000	40	92	
	2050	Base	510	41	0	7500	35	90	
		Low	510	40	0	7000	30	86	
		High	510	42	0	8000	40	92	
SCPC	Current	Base	750	41	0	7500	40	0	Supercritical pulverized, lignite
		Low	750	39	0	7000	35	0	
		High	750	42	0	8000	45	0	
	2020	Base	750	43	0	7500	40	0	
		Low	750	40	0	7000	35	0	
		High	750	44	0	8000	45	0	
	2035	Base	750	47	0	7500	40	0	
		Low	750	45	0	7000	35	0	
		High	750	49	0	8000	45	0	
	2050	Base	750	49	0	7500	40	0	
		Low	750	47	0	7000	35	0	
		High	750	50	0	8000	45	0	
SCPC CO2 cap oxy	Current	Base	950	32	0	7500	35	95	Supercritical pulverized, lignite, CO2 capture oxyfuel
		Low	950	30	0	7000	30	90	
		High	950	34	0	8000	40	98	
	2020	Base	950	33	0	7500	35	95	
		Low	950	31	0	7000	30	90	
		High	950	36	0	8000	40	98	
	2035	Base	950	37	0	7500	35	95	
		Low	950	35	0	7000	30	90	
		High	950	41	0	8000	40	98	
	2050	Base	950	39	0	7500	35	95	
		Low	950	38	0	7000	30	90	

			Electric power MW	Electric eff. %	Thermal eff. %	Load h/a	Tech.life time a	CO_2 capture eff. %	Long name
		High	950	40	0	8000	40	98	
SCFBC	Current	Base	550	42	0	7500	40	0	Supercritical fluidized bed combustion, lignite
		Low	550	41	0	7000	35	0	
		High	550	43	0	8000	45	0	
	2020	Base	550	43	0	7500	40	0	
		Low	550	42	0	7000	35	0	
		High	550	44	0	8000	45	0	
	2035	Base	550	45	0	7500	40	0	
		Low	550	44	0	7000	35	0	
		High	550	46	0	8000	45	0	
	2050	Base	550	45	0	7500	40	0	
		Low	550	44	0	7000	35	0	
		High	550	46	0	8000	45	0	
FBC CO2 cap post	Current	Base	480	31	0	7500	40	90	Fluidized bed combustion, lignite, CO2 capture post-combustion
		Low	480	30	0	7000	35	87	
		High	480	32	0	8000	45	91	
	2020	Base	480	32	0	7500	40	90	
		Low	480	31	0	7000	35	87	
		High	480	33	0	8000	45	91	
	2035	Base	480	34	0	7500	40	90	
		Low	480	33	0	7000	35	87	
		High	480	35	0	8000	45	91	
	2050	Base	480	34	0	7500	40	90	
		Low	480	33	0	7000	35	87	
		High	480	35	0	8000	45	91	

15.3 Resources

Table 15.10 gives an overview on estimated global resources and reserves of natural gas and coal.

Table 15.10: Estimated global reserves and resources of fossil energy (EJ=ExaJoule). Source: (BGR 2015).

		Reserves	Resources
		EJ	EJ
Coal	Hard coal	17391	438729
	Lignite	3270	51987
	Coal, total	20661	490716
Natural gas	Conventional	7260	12162
	Unconventional	258	20441
	Natural gas, total	7518	32603
Oil	Conventional	7144	6815
	Unconventional	2005	11779
	Oil, total	9149	18594
Total fossil		37328	541913

Coal with a calorific value of more than 23.86 MJ/kg on a moisture- and ash-free basis is classified as hard coal, coal below 23.86 MJ/kg is classified as brown coal and lignite (Lett and Ruppel 2004). For life cycle assessment, a lower heating value (LHV) of 26-26.4 MJ/kg and a higher heating value (HHV) of 27.3-27.7 MJ/kg for hard coal, and LHV of 8.8 MJ/kg and HHV of 9.9 MJ/kg for lignite were assumed (Röder, Bauer et al. 2004, Bauer, Heck et al. 2009).

Table 15.11 shows more detailed the estimated conventional and unconventional reserves and resources of natural gas.

Table 15.11: Global conventional and unconventional reserves and resources of natural gas (tcm=trillion cubic meters, EJ=ExaJoule). Source: (BGR 2015).

	Reserves		Resources	
	tcm	EJ	tcm	EJ
Conventional:				
Conventional natural gas	191	7260	320	12162
Unconventional:				
shale gas	5	190	215	8189
tight gas			63	2385
coal gas	1.8	68	52	1963
gas in aquifers			24	912
gas hydrate			184	6992
Unconventional natural gas (sum)	6.8	258	538	20441
Total natural gas	197.8	7518	858	32603

The current global reserves of natural gas are estimated at 197.8 tcm according to (BGR 2015). Another reference estimated the global natural gas reserves for 2011 at 232 tcm (IEA 2013b).

The potential use of natural gas depends also on the gas transport technologies and gas storage possibilities. Both gas transport and gas storage are important issues not only for fossil natural gas but also for (future) synthetic natural gas. Traditionally, large amounts of natural gas are transported through gas pipelines. In the past few decades, gas transport in form of liquefied natural gas (LNG) has been developed. The global trade volume of LNG increased between 1990 and 2011, but leveled off in recent years between 2011 and 2014 (Figure 15.6).

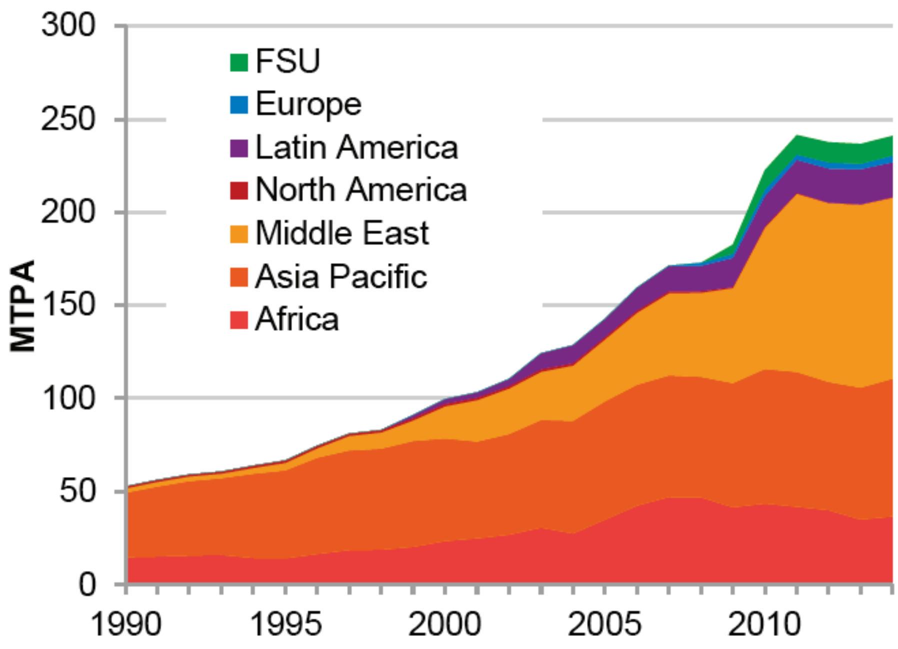

Figure 15.6: Global LNG exports by region 1990 to 2014. (MTPA = million tons per annum). Source: (IGU 2015).

15.4 Potential for domestic electricity generation and supply from imports

Although the technical potential based on global resource estimates looks very high, domestic fossil fuel based generation as well as electricity imports from natural gas and coal power plants will likely be limited by political, economic, environmental and social concerns.

15.4.1 Natural gas combined cycle power plants

Electricity production at NGCC plants in Switzerland has been considered an option in recent, official energy scenarios (Kirchner, Bredow et al. 2012). Whether such plants would be built depends on the boundary conditions.[372] One NGCC plant with an electric capacity of 400 MW operating 7'500 hours per year at full load would generate 3 TWh electricity per year.

15.4.2 Natural gas CHP plants

Kirchner, Bredow et al. (2012) estimated the technical potential for electricity from combined heat and power plants in Switzerland at about 45 TWh/a for 2010. The economically weighted potential for electricity from CHP was estimated at 16.53 TWh/a, of which 4.42 TWh/a are related to apartment buildings (Kirchner, Bredow et al. 2012).

15.4.3 Coal power plants

It seems unlikely that coal power plants will be built in Switzerland in the future. However, electricity from coal power plants is imported today as part of the generation mix in neighboring countries and this is likely to continue in the coming decades. Future amounts of imported coal power will depend on how much electricity will be imported as well as the composition of the generation mix in neighboring countries.

[372] Recent projects and plans, e.g. in Chavalon (www.chavalon.ch), have been abandoned.

15.5 Costs

In the following sections, costs of current electricity generation technologies are shown. Experience curves and learning rates are briefly discussed and estimates for costs of future technologies until 2050 are provided.

15.5.1 Costs of current technology

15.5.1.1 Costs of current natural gas technology

Table 15.12 shows recent cost data for natural gas combined cycle plants in different European countries.

Table 15.12: Costs of current NGCC plants in different countries of Europe (NEA/IEA/OECD 2015).

Country	Net capacity (MWe)	Electric efficiency (%)	Overnight cost (USD/kWe)	Refurbishment and decommissioning costs (USD/MWh)			Fuel cost (USD/MWh)	Carbon cost (USD/MWh)	O&M costs (USD/MWh)
				3%	7%	10%			
Belgium	420	60	1053	0.21	0.12	0.07	74.62	10.08	3.97
France	575	61	980	0.11	0.05	0.02	68.99	10.56	6.25
Germany	500	60	974	0.11	0.05	0.02	74.00	9.90	7.71
Netherlands	870	59	1134	0.13	0.05	0.03	75.25	9.90	3.53
Portugal	445	60	1067	0.16	0.08	0.04	74.00	9.90	6.24
United Kingdom	900	59	953	0	0	0	75.51	9.43	6.63

Cost data of natural gas piston engine CHP plants are shown in Table 15.13.

Table 15.13: Technical and cost data for current natural gas piston engine combined heat and power plant. Source: (ASUE 2014, ASUE-BHKW-Infozentrum 2016). (Assumed 1 Euro = 1.1 CHF).

Class		ca. 1 kWel	ca. 10 kWel	ca. 100 kWel	ca. 1000 kWel	Ref
Electric output	kW	ca. 1	10 (8 - 12)	100 (100 - 105)	1000 (1000 - 1040)	A
Thermal output	kW	ca.2.5	23 (18 - 28)	138 (128 - 166)	1171 (1106 - 1381)	A
Natural gas input (LHV)	kW	3.8	35 (29 - 44)	274 (267 - 290)	2528 (2442 - 2746)	A
Electric efficiency	%	ca. 26%	28% (27% - 30%)	37% (34% - 39%)	40% (38% - 42%)	A
Thermal efficiency	%	ca. 66%	64% (57% - 76%)	50% (47% - 57%)	46% (43% - 50%)	A
Total efficiency	%	ca. 92%	92% (84% - 104%)	87% (85% - 92%)	86% (82% - 88%)	A
Costs in Euro:						
Costs CHP unit	Euro/kWe	9585 (8600 - 10600)	2750 (2470 - 3030)	1090 (980 - 1200)	430 (380 - 480)	A
Installation costs	Euro/kWe	5700 (5100 - 6300)	1380 (1240 - 1520)	520 (460 - 580)	366 (320 - 410)	A
Total investment	Euro/kWe	15285 (13700-16900)	4130 (3710 - 4550)	1610 (1440 - 1780)	796 (700 - 890)	A
O & M	€Ct/kWhe	5.0 (4.5 - 5.5)	3.5 (2.0 - 6.0)	1.7 (1.2 - 2.2)	0.9 (0.6 - 1.4)	B
Costs in CHF:						
Costs CHP unit	CHF/kWe	10540 (9460 - 11660)	3030 (2720 - 3330)	1200 (1080 - 1320)	470 (420 - 530)	A
Installation costs	CHF/kWe	6270 (5610 - 6930)	1520 (1360 - 1670)	570 (510 - 640)	400 (350 - 450)	A
Total investment	CHF/kWe	16810 (15070-18590)	4550 (4080 - 5010)	1770 (1580 - 1960)	870 (770 - 980)	A
O & M	Rp/kWhe	5.5 (5.0 - 6.1)	3.9 (2.2 - 6.6)	1.9 (1.3 - 2.4)	1.0 (.7 - 1.5)	B

15.5.1.2 Costs of current coal technology

Table 15.14 shows recent cost data for coal power plants in different European countries.

Table 15.14: Costs of current coal power plants in different countries of Europe (NEA/IEA/OECD 2015).

Country	Technology	Net capacity (MWe)	Electric efficiency (%)	Overnight cost (USD/kWe)	Refurbishment and decommissioning costs (USD/MWh)			O&M costs (USD/MWh)	Fuel cost (USD/MWh)
					3%	7%	10%		
Belgium	Ultra-supercritical	750	46	2 307	0.21	0.07	0.03	8	26.67
Germany	Hard coal	700	46	1 643	0.1	0.03	0.01	9.14	26.38
Germany	Lignite	900	43	2 054	0.12	0.03	0.01	11.07	14.88
Netherlands	Ultra-supercritical	1070	46	1 620	0.12	0.04	0.01	8.88	31.49
Netherlands	Ultra-supercritical	777	46	2 746	0.2	0.06	0.02	8.88	31.49
Netherlands	Ultra-supercritical	1554	46	2 660	1.84	2.34	2.68	7.81	31.49
Portugal	Pulverized	605	51	3 067	0.29	0.12	0.06	6.16	31.47
Portugal	Pulverized	605	46	2 533	0.35	0.15	0.07	14.53	28.38

15.5.2 Experience curves and costs of future technologies

Experience curves (or learning curves) for costs are usually defined as

$$\frac{C_1}{C_0} = \left(\frac{P_1}{P_0}\right)^{-b}.$$

Here, C_0 denotes the cost and P_0 the cumulative production at a certain reference time. The cost C_1 at a later time is related to the cumulative production P_1 at this time. b is the learning index or learning elasticity. (Note that the lower limit of cost, the floor cost, is not reflected in the simple formula with constant learning index.)

The progress rate or progress ratio *pr* is defined by

$pr=2^{-b}$.

For example, a progress ratio *pr* of 0.9 or 90% means that a doubling of the cumulative production (or cumulative installed capacity) is associated with a reduction of the costs to 90% of the previous value. The learning rate is lr=1-pr.

An important component is the gas turbine. It is used in several applications and combinations. For natural gas electricity, gas turbines are operating in gas turbine power plants and in combination with steam turbines in combined cycle power plants. Gas turbines are also important for coal power plants as component of IGCC plants as well as for biomass plants in BIGCC plants or possibly for synthetic natural gas plants.

Figure 15.7 shows the cost experience curve of costs per kW for gas turbines and in comparison to other technologies. The progress ratio (PR) for gas turbines around 1980 was 90% which means a learning rate (LR) of 10% (LR=1-PR). More recent estimates of cost learning rates from the NEEDS project are 10% (5-15%) for advanced fossil gas technologies and 5% (3-7%) for advanced coal technologies (Neij, Borup et al. 2006) .

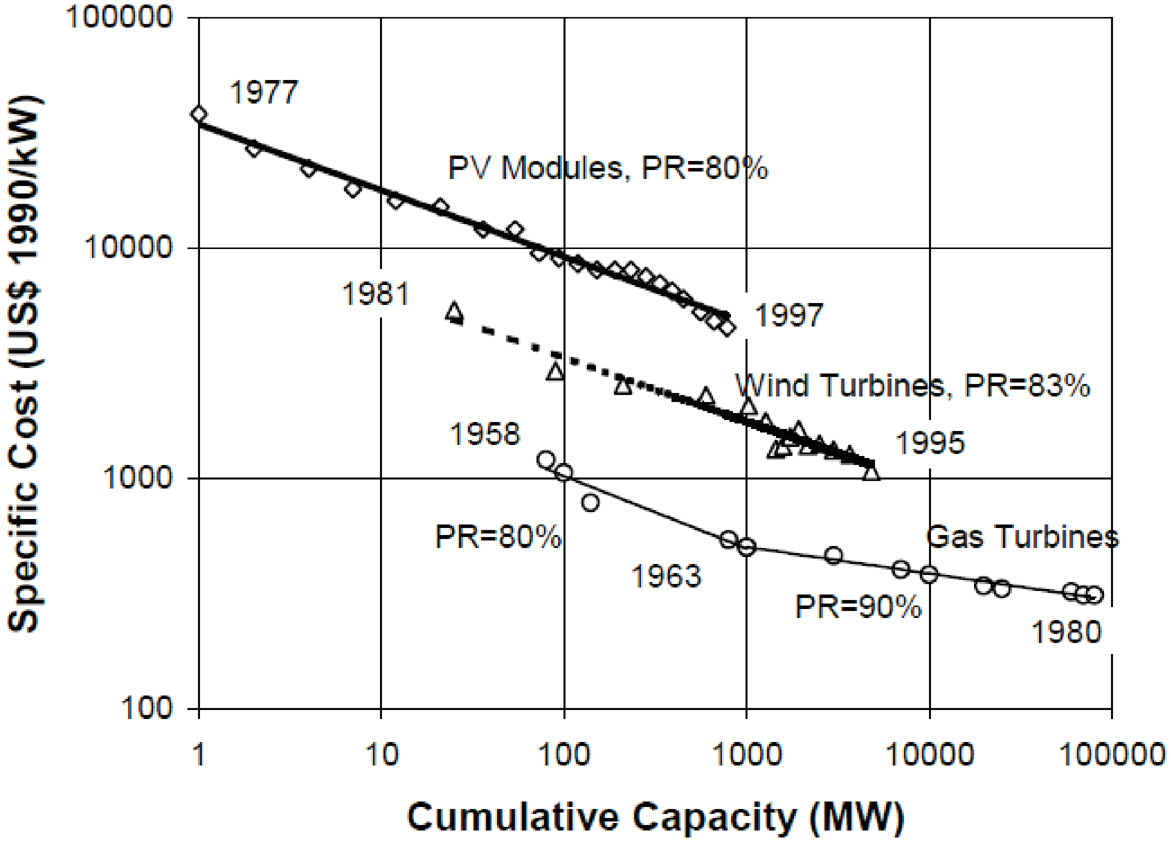

Figure 15.7: Cost learning curves for gas turbines and other energy technologies. Source: (Barreto 2001). (Note that these are historical curves. More recent numbers on costs can be found in the text and tables below for gas and coal technologies, and in the corresponding chapters for photovoltaics and wind.)

Learning rates for natural gas and coal technologies from a recent review (Rubin, Azevedo et al. 2015) are shown in Table 15.15.

Learning rates for natural gas combined cycle technology show a wide range from negative to positive values. This indicates that the margins for further significant cost reductions by experience might be limited.

For natural gas technologies, the studies reviewed in (Rubin, Azevedo et al. 2015) cover years until 1998 so that there seem to be no more recent updates of gas turbine or combined cycle cost learning curves based on actual cost and installation data. Estimates from projections are shown as well.

SETIS assumes a CAPEX (Capital Expenditure) learning rate of 5% for advanced combined cycle gas turbines for the years 2013 to 2040 (SETIS 2014).

Table 15.15: Cost learning rates for natural gas and coal technologies from a review of studies. Source: (Rubin, Azevedo et al. 2015). (Ranges without mean value are from projections.)

Fuel	Technology	Mean learning rate	Range of learning rates
Natural gas	Gas turbine	15%	10-22%
	Combined cycle	14%	-11 to 34%
	Combined cycle + CCS		2-7%
Coal	PC	8.3%	5.6–12%
	PC + CCS		1.1–9.9%
	IGCC		2.5–16%
	IGCC +CCS		2.5–20%

For coal power plants, learning rates in Table 15.15 are positive so that further reductions of investment costs in terms of present value are expected in particular for IGCC and CO_2 capture technology. IGCC capture costs learning curves are also discussed in (Knoope, Meerman et al. 2013).

A recent US study estimated increases in capital cost for CO_2 capture (without transport and storage) compared to the technology without capture at 76% (64-100) for post-combustion natural gas combined cycle, 63% (44-74) for oxy-combustion and post-combustion SCPC coal, and 37% (19-66) for pre-combustion coal IGCC plants (Rubin 2016).

For coal power in UK, Hammond and Spargo (2014) estimated an energy penalty of about 16% for a CO_2 capture rate of 90% and an increase of costs of electricity of about 140% compared with a PC (Pulverized Coal) reference plant.

Cost factors for natural gas CC pre-combustion CO_2 capture plants compared to non-CO_2 capture have been taken from (Jansen, Gazzani et al. 2015). Efficiency penalties for pre-combustion NG range from 7.6%-points to 16%-points (high value for one NGCC study) (Jansen, Gazzani et al. 2015). Investment costs for pre-combustion technologies to an IGCC range from 1656 to 3424 Euro/kW (Jansen, Gazzani et al. 2015).

For IGCC pre-combustion technology, CO_2 capture rates are in the range of 86-92% (Jansen, Gazzani et al. 2015).

For natural gas pre-combustion technology, CO_2 capture ranges are between 84.8% and 93.4%, and net electric efficiencies LHV range between 48.35% and 50.65% (Jansen, Gazzani et al. 2015).

Rubin, Davison et al. (2015) shows significantly higher costs for current pre-combustion capture at IGCC power plants using bituminous coals compared to adjusted values from IPCC Special Report on Carbon Dioxide Capture and Storage (IPCC 2005) and to (SETIS 2014).

Oxyfuel capture is a relatively new technology which has developed substantially during the past decade (Rubin, Davison et al. 2015), (studies on new oxyfuel refer mainly to sub-bituminous coal). There is a large variation of cost estimates in different studies.

Major references used for cost data for current and future large power plants have been (SETIS 2014), (Bauer, Heck et al. 2009), (Jansen, Gazzani et al. 2015), (NEA/IEA/OECD 2015), (Rubin, Davison et al. 2015), (Rubin 2016), as well as a number of technology-specific references mentioned in the text. Technology and cost data for carbon dioxide capture are based on different references: (Rubin, Davison et al. 2015), (Rubin, Azevedo et al. 2015), (Rubin 2016), (SETIS 2014), (Jansen, Gazzani et al. 2015), (Volkart, Bauer et al. 2013), (Volkart, Bauer et al. 2016), (Bauer, Heck et al. 2009), as well as a number of technology-specific references mentioned in the text.

In order to estimate the development of costs of CHP plants until 2050, the relative factors from the NEEDS (Bauer, Heck et al. 2009) project have been used, starting from the values for current systems in Table 15.13.

15.5.3 Overview: technology and cost data for natural gas and coal power plants

Estimates of the basic data of current and future costs for the different technologies are summarized in Table 15.16, together with technology data corresponding to Table 15.9. Note that the cost data have been converted from Euro or US-Dollars into Swiss CHF. Due to the exchange rates as of year 2015 Euro/CHF and USD/CHF close to parity and the generally high price level in Switzerland compared to Europe, it is likely that real costs would tend to be higher in case of plants located in Switzerland.

Table 15.16: Assumed technology and cost data for current and future natural gas and coal plants. El.pow: electric power, El.eff.: net electric efficiency, Th.eff.: thermal efficiency (CHP), Load factor in hours per year, Technical lifetime, CO_2 cap: CO_2 capture efficiency, cap post: post combustion CO_2 capture, pre: pre combustion CO_2 capture, oxy: oxyfuel combustion CO_2 capture, Inv: investment costs, Dism: dismantling cost, FOM: fixed operation and maintenance costs, VOM: variable operation and maintenance costs, O&M: total operation and maintenance costs (O&M=FOM+VOM, after conversion to the same unit. O&M doesn't include fuel costs. Note that sometimes O&M is given in the literature but the split into FOM and VOM is not available (n.a.)). Note that costs have been converted from Euro or USD to CHF. Due to the high price level in Switzerland it is likely that real costs would tend to be higher in case of plants located in Switzerland. Sources: (Rubin, Davison et al. 2015), (SETIS 2014), (Jansen, Gazzani et al. 2015), (NEA/IEA/OECD 2015), (Rubin, Azevedo et al. 2015), (Rubin 2016), (Bauer, Heck et al. 2009), (Volkart, Bauer et al. 2013), (Volkart, Bauer et al. 2016), (Cau, Tola et al. 2014), (ASUE 2014), (ASUE-BHKW-Infozentrum 2016).

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
Natural gas													
NGCC	Current	Base	500	58	0	7500	30	0	990	17	25	0.22	0.55
		Low	500	57	0	6000	25	0	770	17	19	0.22	0.46
		High	500	59	0	8000	35	0	1210	17	30	0.22	0.72
	2020	Base	500	60	0	7500	30	0	980	17	24	0.22	0.55
		Low	500	59	0	6000	25	0	770	17	19	0.22	0.46
		High	500	61	0	8000	35	0	1170	17	29	0.22	0.71
	2035	Base	500	62	0	7500	30	0	940	17	23	0.22	0.53
		Low	500	61	0	6000	25	0	770	17	19	0.22	0.46
		High	500	63	0	8000	35	0	1050	17	26	0.22	0.66
	2050	Base	500	63	0	7500	30	0	940	17	23	0.22	0.53
		Low	500	62	0	6000	25	0	770	17	19	0.22	0.46
		High	500	65	0	8000	35	0	1050	17	26	0.22	0.66
NGCC CO2	Current	Base	500	50	0	7500	30	88	1740	20	44	0.44	1.02

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
cap post													
		Low	500	49	0	6000	25	86	1200	20	30	0.44	0.82
		High	500	51	0	8000	35	90	2220	20	56	0.44	1.37
	2020	Base	500	52	0	7500	30	88	1720	20	43	0.44	1.01
		Low	500	51	0	6000	25	86	1200	20	30	0.44	0.82
		High	500	53	0	8000	35	90	2150	20	54	0.44	1.33
	2035	Base	500	54	0	7500	30	89	1650	20	41	0.44	0.99
		Low	500	53	0	6000	25	86	1200	20	30	0.44	0.82
		High	500	55	0	8000	35	91	1930	20	48	0.44	1.24
	2050	Base	500	55	0	7500	30	90	1650	20	41	0.44	0.99
		Low	500	54	0	6000	25	86	1200	20	30	0.44	0.82
		High	500	56	0	8000	35	92	1930	20	48	0.44	1.24
NGCC CO2 cap pre	Current	Base	390	50	0	7500	25	90	1620	20	43	0.48	1.06
		Low	390	48	0	6000	20	85	1360	20	34	0.41	0.83
		High	390	51	0	8000	30	93	1910	20	55	0.51	1.43
	2020	Base	390	53	0	7500	25	90	1530	20	43	0.48	1.06
		Low	390	52	0	6000	20	85	1290	20	34	0.41	0.83
		High	390	54	0	8000	30	93	1810	20	55	0.51	1.43
	2035	Base	390	54	0	7500	25	90	1270	20	43	0.48	1.06
		Low	390	53	0	6000	20	85	1060	20	34	0.41	0.83
		High	390	55	0	8000	30	93	1500	20	55	0.51	1.43
	2050	Base	390	55	0	7500	25	90	1210	20	43	0.48	1.06
		Low	390	54	0	6000	20	85	1020	20	34	0.41	0.83
		High	390	56	0	8000	30	93	1430	20	55	0.51	1.43
GT	Current	Base	250	40	0	2000	30	0	610	10	18	1.21	2.12
		Low	250	39	0	1500	25	0	440	10	13	1.21	1.74
		High	250	41	0	2500	35	0	720	10	21	1.21	2.64
	2020	Base	250	40	0	2000	30	0	610	10	18	1.21	2.12
		Low	250	39	0	1500	25	0	440	10	13	1.21	1.74
		High	250	41	0	2500	35	0	720	10	21	1.21	2.64
	2035	Base	250	44	0	2000	30	0	610	10	18	1.21	2.12

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
		Low	250	43	0	1500	25	0	440	10	13	1.21	1.74
		High	250	45	0	2500	35	0	720	10	21	1.21	2.64
	2050	Base	250	45	0	2000	30	0	610	10	18	1.21	2.12
		Low	250	44	0	1500	25	0	440	10	13	1.21	1.74
		High	250	46	0	2500	35	0	720	10	21	1.21	2.64
CHP 1kWe	Current	Base	0.001	26	66	2500	20	0	16810	n.a.	n.a.	n.a.	5.50
		Low	0.001	25	67	2000	15	0	15070	n.a.	n.a.	n.a.	4.95
		High	0.001	27	65	3000	25	0	18590	n.a.	n.a.	n.a.	6.05
	2020	Base	0.001	27	65	2500	20	0	16330	n.a.	n.a.	n.a.	5.38
		Low	0.001	26	66	2000	15	0	14640	n.a.	n.a.	n.a.	4.85
		High	0.001	28	64	3000	25	0	18060	n.a.	n.a.	n.a.	5.92
	2035	Base	0.001	28	64	2500	20	0	14890	n.a.	n.a.	n.a.	5.04
		Low	0.001	27	65	2000	15	0	13350	n.a.	n.a.	n.a.	4.53
		High	0.001	29	63	3000	25	0	16460	n.a.	n.a.	n.a.	5.54
	2050	Base	0.001	29	63	2500	20	0	14010	n.a.	n.a.	n.a.	5.04
		Low	0.001	28	64	2000	15	0	12560	n.a.	n.a.	n.a.	4.53
		High	0.001	30	62	3000	25	0	15490	n.a.	n.a.	n.a.	5.54
CHP 10kWe	Current	Base	0.01	28	64	2500	20	0	4540	n.a.	n.a.	n.a.	3.85
		Low	0.01	27	57	2000	15	0	4080	n.a.	n.a.	n.a.	2.20
		High	0.01	30	76	3000	25	0	5010	n.a.	n.a.	n.a.	6.60
	2020	Base	0.01	29	64	2500	20	0	4410	n.a.	n.a.	n.a.	3.77
		Low	0.01	27	57	2000	15	0	3960	n.a.	n.a.	n.a.	2.15
		High	0.01	31	73	3000	25	0	4860	n.a.	n.a.	n.a.	6.46
	2035	Base	0.01	30	62	2500	20	0	4020	n.a.	n.a.	n.a.	3.53
		Low	0.01	28	55	2000	15	0	3610	n.a.	n.a.	n.a.	2.02
		High	0.01	32	72	3000	25	0	4430	n.a.	n.a.	n.a.	6.05
	2050	Base	0.01	31	61	2500	20	0	3790	n.a.	n.a.	n.a.	3.53
		Low	0.01	29	54	2000	15	0	3400	n.a.	n.a.	n.a.	2.02
		High	0.01	33	71	3000	25	0	4170	n.a.	n.a.	n.a.	6.05
CHP 100 kWe	Current	Base	0.1	37	50	3000	20	0	1770	n.a.	n.a.	n.a.	1.87
		Low	0.1	34	47	2500	15	0	1580	n.a.	n.a.	n.a.	1.32

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
		High	0.1	39	57	3500	25	0	1960	n.a.	n.a.	n.a.	2.42
	2020	Base	0.1	37	50	3000	20	0	1720	n.a.	n.a.	n.a.	1.83
		Low	0.1	35	50	2500	15	0	1540	n.a.	n.a.	n.a.	1.29
		High	0.1	40	52	3500	25	0	1900	n.a.	n.a.	n.a.	2.37
	2035	Base	0.1	39	48	3000	20	0	1570	n.a.	n.a.	n.a.	1.71
		Low	0.1	37	48	2500	15	0	1400	n.a.	n.a.	n.a.	1.21
		High	0.1	42	50	3500	25	0	1730	n.a.	n.a.	n.a.	2.22
	2050	Base	0.1	40	47	3000	20	0	1480	n.a.	n.a.	n.a.	1.71
		Low	0.1	38	47	2500	15	0	1320	n.a.	n.a.	n.a.	1.21
		High	0.1	43	49	3500	25	0	1630	n.a.	n.a.	n.a.	2.22
CHP 1000 kWe	Current	Base	1	40	46	4000	20	0	880	n.a.	n.a.	n.a.	0.99
		Low	1	38	43	3500	15	0	770	n.a.	n.a.	n.a.	0.66
		High	1	42	50	4500	25	0	980	n.a.	n.a.	n.a.	1.54
	2020	Base	1	40	45	4000	20	0	850	n.a.	n.a.	n.a.	0.97
		Low	1	39	43	3500	15	0	750	n.a.	n.a.	n.a.	0.65
		High	1	43	46	4500	25	0	950	n.a.	n.a.	n.a.	1.51
	2035	Base	1	43	43	4000	20	0	780	n.a.	n.a.	n.a.	0.90
		Low	1	41	41	3500	15	0	680	n.a.	n.a.	n.a.	0.60
		High	1	46	43	4500	25	0	870	n.a.	n.a.	n.a.	1.41
	2050	Base	1	44	42	4000	20	0	730	n.a.	n.a.	n.a.	0.90
		Low	1	42	40	3500	15	0	640	n.a.	n.a.	n.a.	0.60
		High	1	47	42	4500	25	0	820	n.a.	n.a.	n.a.	1.41
Hard coal													
IGCC	Current	Base	600	45	0	7500	35	0	2920	55	73	0.55	1.52
		Low	600	44	0	7000	30	0	2700	55	67	0.55	1.39
		High	600	46	0	8000	40	0	3410	55	85	0.55	1.77
	2020	Base	600	46	0	7500	35	0	2820	55	70	0.55	1.49
		Low	600	45	0	7000	30	0	2610	55	65	0.55	1.37
		High	600	47	0	8000	40	0	3340	55	84	0.55	1.74
	2035	Base	600	47	0	7500	35	0	2530	55	63	0.55	1.39
		Low	600	46	0	7000	30	0	2370	55	59	0.55	1.29
		Hig	600	48	0	8000	40	0	3140	55	78	0.55	1.67

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
		h											
	2050	Base	600	50	0	7500	35	0	2420	55	61	0.55	1.36
		Low	600	49	0	7000	30	0	2370	55	59	0.55	1.29
		High	600	51	0	8000	40	0	3000	55	75	0.55	1.62
IGCC CO2 cap pre	Current	Base	510	35	0	7500	35	90	3850	61	116	0.66	2.20
		Low	510	34	0	7000	30	86	3300	61	99	0.66	1.90
		High	510	36	0	8000	40	92	4510	61	135	0.66	2.59
	2020	Base	510	37	0	7500	35	90	3660	61	110	0.66	2.13
		Low	510	36	0	7000	30	86	3180	61	95	0.66	1.85
		High	510	38	0	8000	40	92	4270	61	128	0.66	2.49
	2035	Base	510	41	0	7500	35	90	3110	61	93	0.66	1.90
		Low	510	40	0	7000	30	86	2810	61	84	0.66	1.71
		High	510	42	0	8000	40	92	3550	61	107	0.66	2.18
	2050	Base	510	44	0	7500	35	90	3080	61	92	0.66	1.89
		Low	510	43	0	7000	30	86	2750	61	83	0.66	1.69
		High	510	45	0	8000	40	92	3550	61	107	0.66	2.18
SCPC	Current	Base	750	45	0	7500	40	0	1760	36	44	0.40	0.98
		Low	750	44	0	7000	35	0	1710	36	43	0.40	0.93
		High	750	46	0	8000	45	0	1870	36	47	0.40	1.06
	2020	Base	750	46	0	7500	40	0	1760	36	44	0.40	0.98
		Low	750	45	0	7000	35	0	1710	36	43	0.40	0.93
		High	750	47	0	8000	45	0	1870	36	47	0.40	1.06
	2035	Base	750	47	0	7500	40	0	1760	36	44	0.40	0.98
		Low	750	46	0	7000	35	0	1710	36	43	0.40	0.93
		High	750	48	0	8000	45	0	1870	36	47	0.40	1.06
	2050	Base	750	48	0	7500	40	0	1760	36	44	0.40	0.98
		Low	750	47	0	7000	35	0	1710	36	43	0.40	0.93
		High	750	49	0	8000	45	0	1870	36	47	0.40	1.06
SCPC CO2 cap post	Current	Base	630	34	0	7500	40	89	3300	61	83	0.61	1.71
		Low	630	33	0	7000	35	87	2860	61	72	0.61	1.50
		High	630	35	0	8000	45	90	3690	61	92	0.61	1.92
	2020	Bas	630	35	0	7500	40	89	2970	61	74	0.61	1.60

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
		e											
		Low	630	34	0	7000	35	87	2570	61	64	0.61	1.41
		High	630	36	0	8000	45	90	3320	61	83	0.61	1.79
	2035	Base	630	37	0	7500	40	90	2810	61	70	0.61	1.54
		Low	630	36	0	7000	35	87	2430	61	61	0.61	1.36
		High	630	38	0	8000	45	92	3140	61	78	0.61	1.72
	2050	Base	630	38	0	7500	40	90	2810	61	70	0.61	1.54
		Low	630	37	0	7000	35	87	2430	61	61	0.61	1.36
		High	630	39	0	8000	45	92	3140	61	78	0.61	1.72
SCPC CO2 cap oxy	Current	Base	580	36	0	7500	40	95	3740	61	94	0.33	1.58
		Low	580	35	0	7000	35	90	2860	61	72	0.33	1.22
		High	580	37	0	8000	45	98	4550	61	114	0.33	1.95
	2020	Base	580	37	0	7500	40	95	3580	61	89	0.33	1.52
		Low	580	36	0	7000	35	90	2750	61	69	0.33	1.19
		High	580	38	0	8000	45	98	4350	61	109	0.33	1.88
	2035	Base	580	39	0	7500	40	95	3090	61	77	0.33	1.36
		Low	580	38	0	7000	35	90	2430	61	61	0.33	1.09
		High	580	40	0	8000	45	98	3750	61	94	0.33	1.67
	2050	Base	580	40	0	7500	40	95	2810	61	70	0.33	1.27
		Low	580	39	0	7000	35	90	2430	61	61	0.33	1.09
		High	580	41	0	8000	45	98	3410	61	85	0.33	1.55
Lignite													
IGCC	Current	Base	600	43	0	7500	35	0	3410	55	102	0.77	2.13
		Low	600	42	0	7000	30	0	2920	55	87	0.77	1.86
		High	600	44	0	8000	40	0	3690	55	111	0.77	2.35
	2020	Base	600	45	0	7500	35	0	3300	55	99	0.77	2.09
		Low	600	44	0	7000	30	0	2860	55	86	0.77	1.84
		High	600	46	0	8000	40	0	3580	55	107	0.77	2.30
	2035	Base	600	47	0	7500	35	0	3300	55	99	0.77	2.09
		Low	600	46	0	7000	30	0	2860	55	86	0.77	1.84
		High	600	48	0	8000	40	0	3580	55	107	0.77	2.30
	2050	Base	600	47	0	7500	35	0	3300	55	99	0.77	2.09
		Low	600	46	0	7000	30	0	2860	55	86	0.77	1.84

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
		High	600	48	0	8000	40	0	3580	55	107	0.77	2.30
IGCC CO2 cap pre	Current	Base	510	35	0	7500	35	90	4950	61	114	0.88	2.40
		Low	510	34	0	7000	30	86	4350	61	100	0.88	2.13
		High	510	36	0	8000	40	92	5500	61	127	0.88	2.69
	2020	Base	510	37	0	7500	35	90	4810	61	111	0.88	2.35
		Low	510	36	0	7000	30	86	4200	61	97	0.88	2.09
		High	510	38	0	8000	40	92	5340	61	123	0.88	2.63
	2035	Base	510	41	0	7500	35	90	4810	61	111	0.88	2.35
		Low	510	40	0	7000	30	86	4200	61	97	0.88	2.09
		High	510	42	0	8000	40	92	5340	61	123	0.88	2.63
	2050	Base	510	41	0	7500	35	90	4810	61	111	0.88	2.35
		Low	510	40	0	7000	30	86	4200	61	97	0.88	2.09
		High	510	42	0	8000	40	92	5340	61	123	0.88	2.63
SCPC	Current	Base	750	41	0	7500	40	0	2200	33	55	0.50	1.23
		Low	750	39	0	7000	35	0	1870	33	47	0.50	1.08
		High	750	42	0	8000	45	0	2640	33	66	0.50	1.44
	2020	Base	750	43	0	7500	40	0	2200	33	55	0.50	1.23
		Low	750	40	0	7000	35	0	1870	33	47	0.50	1.08
		High	750	44	0	8000	45	0	2640	33	66	0.50	1.44
	2035	Base	750	47	0	7500	40	0	2200	33	55	0.50	1.23
		Low	750	45	0	7000	35	0	1870	33	47	0.50	1.08
		High	750	49	0	8000	45	0	2640	33	66	0.50	1.44
	2050	Base	750	49	0	7500	40	0	2200	33	55	0.50	1.23
		Low	750	47	0	7000	35	0	1870	33	47	0.50	1.08
		High	750	50	0	8000	45	0	2640	33	66	0.50	1.44
SCPC CO2 cap oxy	Current	Base	950	32	0	7500	35	95	4180	61	146	1.32	3.27
		Low	950	30	0	7000	30	90	3620	61	109	1.32	3.27
		High	950	34	0	8000	40	98	4550	61	182	1.32	3.27
	2020	Base	950	33	0	7500	35	95	3850	61	135	1.32	3.12
		Low	950	31	0	7000	30	90	3360	61	101	1.32	3.12
		High	950	36	0	8000	40	98	4450	61	178	1.32	3.12
	2035	Bas	950	37	0	7500	35	95	2860	61	100	1.32	2.65

			El. pow MW	El. eff. %	Th. eff. %	Load h/a	Life time a	CO_2 cap %	Inv. cost CHF/ kWe	Dism cost CHF/ kWe	FOM CHF/ kWe*a	VOM Rp/ kWhe	O&M Rp/ kWhe
		e											
		Low	950	35	0	7000	30	90	2570	61	77	1.32	2.65
		High	950	41	0	8000	40	98	4230	61	169	1.32	2.65
	2050	Base	950	39	0	7500	35	95	2060	61	72	1.32	2.21
		Low	950	38	0	7000	30	90	1530	61	46	1.32	2.16
		High	950	40	0	8000	40	98	4150	61	166	1.32	2.27
SCFBC	Current	Base	550	42	0	7500	40	0	2090	40	42	0.66	1.22
		Low	550	41	0	7000	35	0	1780	40	36	0.66	1.10
		High	550	43	0	8000	45	0	2510	40	50	0.66	1.38
	2020	Base	550	43	0	7500	40	0	2090	40	42	0.66	1.22
		Low	550	42	0	7000	35	0	1780	40	36	0.66	1.10
		High	550	44	0	8000	45	0	2510	40	50	0.66	1.38
	2035	Base	550	45	0	7500	40	0	2090	40	42	0.66	1.22
		Low	550	44	0	7000	35	0	1780	40	36	0.66	1.10
		High	550	46	0	8000	45	0	2510	40	50	0.66	1.38
	2050	Base	550	45	0	7500	40	0	2090	40	42	0.66	1.22
		Low	550	44	0	7000	35	0	1780	40	36	0.66	1.10
		High	550	46	0	8000	45	0	2510	40	50	0.66	1.38
FBC CO2 cap post	Current	Base	480	31	0	7500	40	90	3850	40	96	1.10	2.38
		Low	480	30	0	7000	35	87	3270	40	82	1.10	2.12
		High	480	32	0	8000	45	91	4620	40	116	1.10	2.75
	2020	Base	480	32	0	7500	40	90	3850	40	96	1.10	2.38
		Low	480	31	0	7000	35	87	3270	40	82	1.10	2.12
		High	480	33	0	8000	45	91	4620	40	116	1.10	2.75
	2035	Base	480	34	0	7500	40	90	3770	40	94	1.10	2.36
		Low	480	33	0	7000	35	87	3110	40	78	1.10	2.07
		High	480	35	0	8000	45	91	4620	40	116	1.10	2.75
	2050	Base	480	34	0	7500	40	90	3700	40	92	1.10	2.33
		Low	480	33	0	7000	35	87	2950	40	74	1.10	2.02
		High	480	35	0	8000	45	91	4620	40	116	1.10	2.75

15.5.4 Electricity generation costs

Basic costs data (investment costs, dismantling cost, fixed operation and maintenance costs (FOM), variable operation and maintenance costs (VOM), and total operation and maintenance costs (O&M)) for current and future natural gas and coal technologies can be found in Table 15.16 together with technical parameters (electric power, net electric efficiency, thermal efficiency (CHP only), load, technical lifetime, and carbon dioxide capture rate in case).

The complete set of numerical results is provided in Table 15.18.

15.5.4.1 Electricity generation costs of current and future natural gas technology

The fuel price for natural gas power plants was assumed at 57 CHF per MWh gas in 2015 increasing to about 82 CHF/MWh until 2050 (see chapter 5.2.3). For the smallest (the 1 kW_{el} and 10 kW_{el}) CHP plants, a natural gas price for households of 85 CHF/MWh in 2015 and about 110 CHF/MWh in 2050 was assumed.

For CHP electricity, a heat credit of 70 CHF per MWh heat for 2015 was assumed. The heat credit was assumed to increase in relative terms like the gas price until 2050.

Figure 15.8 shows the electricity generation costs (LCOE, levelized costs of electricity) for large natural gas power plants with and without CO_2 capture. Costs for 2015 plants with CO_2 capture are based on estimates from literature for plants that could possibly be built currently. The LCOE shown here include the power generation and, where applicable, the CO_2 capture process. The costs for the subsequent treatment of the captured CO_2 are not included here. The captured CO_2 could go either to a utilization system (CCU) or to long-term storage (CCS) or a combination of both. Transport and geological storage of CO_2 are not included in the calculated LCOE. Estimates of a European study indicate that CO_2 transport and geological storage would further increase LCOE by about 4-13% for natural gas combined cycle plants depending on transport distance (assumed range 180-1500 km) and storage costs (ZEP 2011). These additional costs however represent only a rough estimate based on generic CO_2 transport and storage, not Swiss-specific boundary conditions.

Figure 15.9 shows the electricity generation costs for natural gas combined heat and power plants without and with heat credit.

Note that the total electricity generation costs (costs of electricity) for gas power plants depend strongly on the fuel price for natural gas. Fossil fuel prices varied strongly over time in the past and the future development of fossil fuel prices are hard to estimate. The fuel price volatility is not considered in the ranges shown in the figures. Note the vertical scale difference between Figure 15.8 and Figure 15.9.

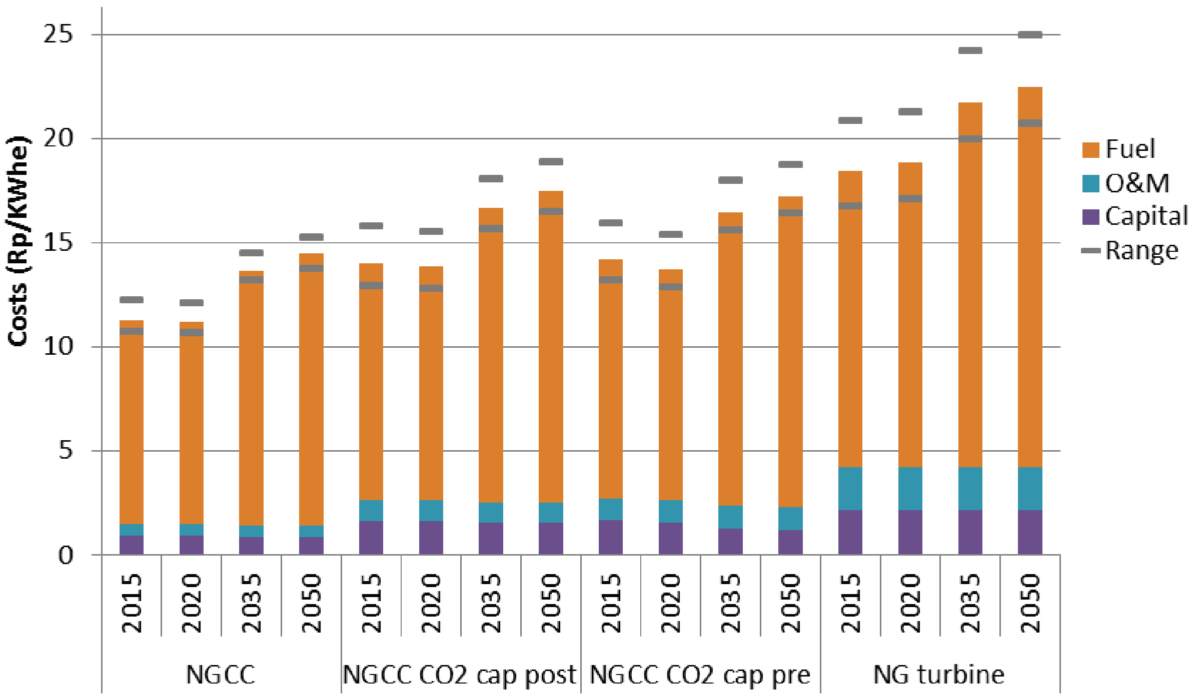

Figure 15.8: Estimated levelized costs of electricity (LCOE) for large natural gas power plants with and without CO_2 capture until year 2050. Costs for CO_2 transport and storage are not included. The ranges refer to the upper and lower estimates for technology parameters and technology costs but do not include fuel price volatility.

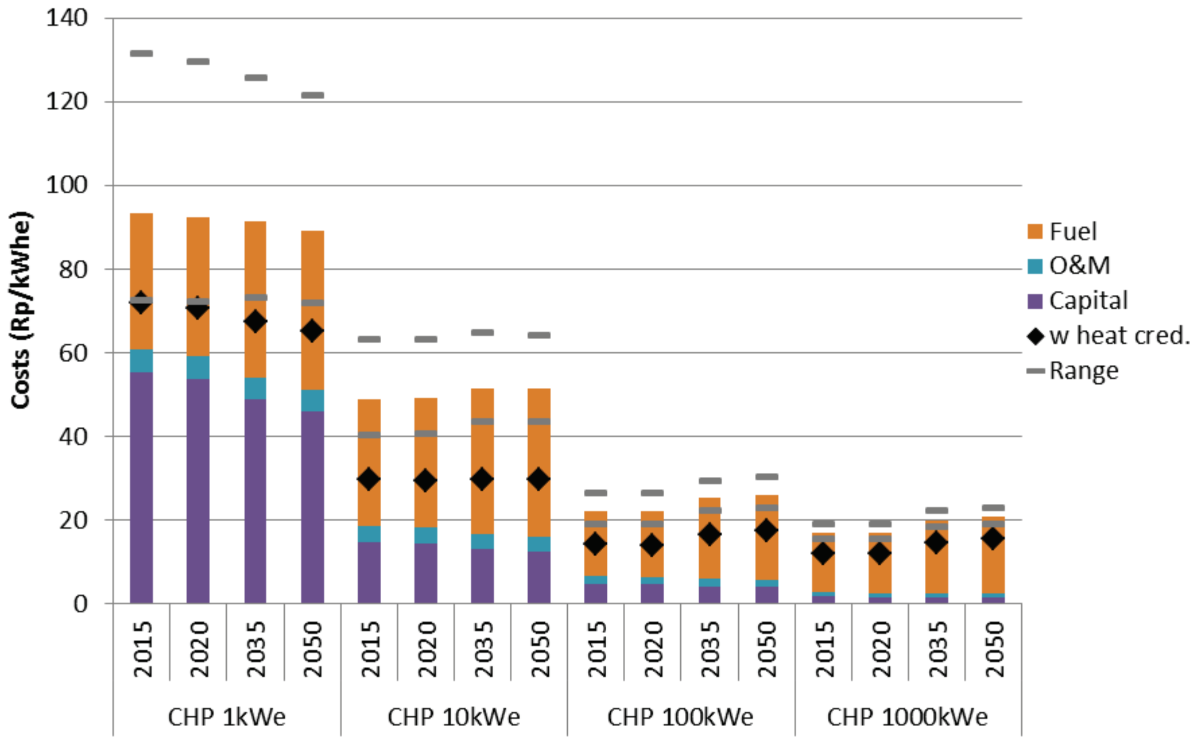

Figure 15.9: Estimated levelized costs of electricity (LCOE) for natural gas CHP plants until year 2050. The bars show costs without heat credit, diamonds show total electricity costs considering heat credit. The ranges refer to the upper and lower estimates for technology parameters and technology costs (without heat credit), but do not include fuel price volatility.

15.5.4.2 Electricity generation costs of current and future coal technology

The current fuel price for hard coal is assumed at about 13 CHF/MWh as of year 2015. The price is estimated to increase to about 22 CHF/MWh until 2050 (see chapter 5.2.3). The current lignite price of about 6 CHF/MWh was derived from (NEA/IEA/OECD 2015). It was assumed that relative changes of lignite prices until 2050 will be the same as for hard coal.

Figure 15.10 shows the electricity generation costs for coal power plants with and without CO_2 capture until year 2050. Costs for 2015 plants with CO_2 capture are based on estimates from literature for plants that could possibly be built currently. The LCOE shown here include the power generation and, where applicable, the CO_2 capture process. The costs for the subsequent treatment of the captured CO_2 are not included here. The captured CO_2 could go either to a utilization system (CCU) or to long-term storage (CCS) or a combination of both. Transport and geological storage of CO_2 are not included in the calculated LCOE. Estimates of a European study indicate that CO_2 transport and geological storage would further increase LCOE by about 5-45% for hard coal power plants depending on transport distance (assumed range 180-1500 km) and storage costs (ZEP 2011). These additional costs however represent only a rough estimate based on generic CO_2 transport and storage.

Note that the total electricity generation costs (costs of electricity) for coal power plants depend significantly on the fuel price for coal. Fossil fuel prices varied strongly over time in the past and the future development of fossil fuel prices are hard to estimate. The fuel price volatility is not considered in the ranges shown in the figures.

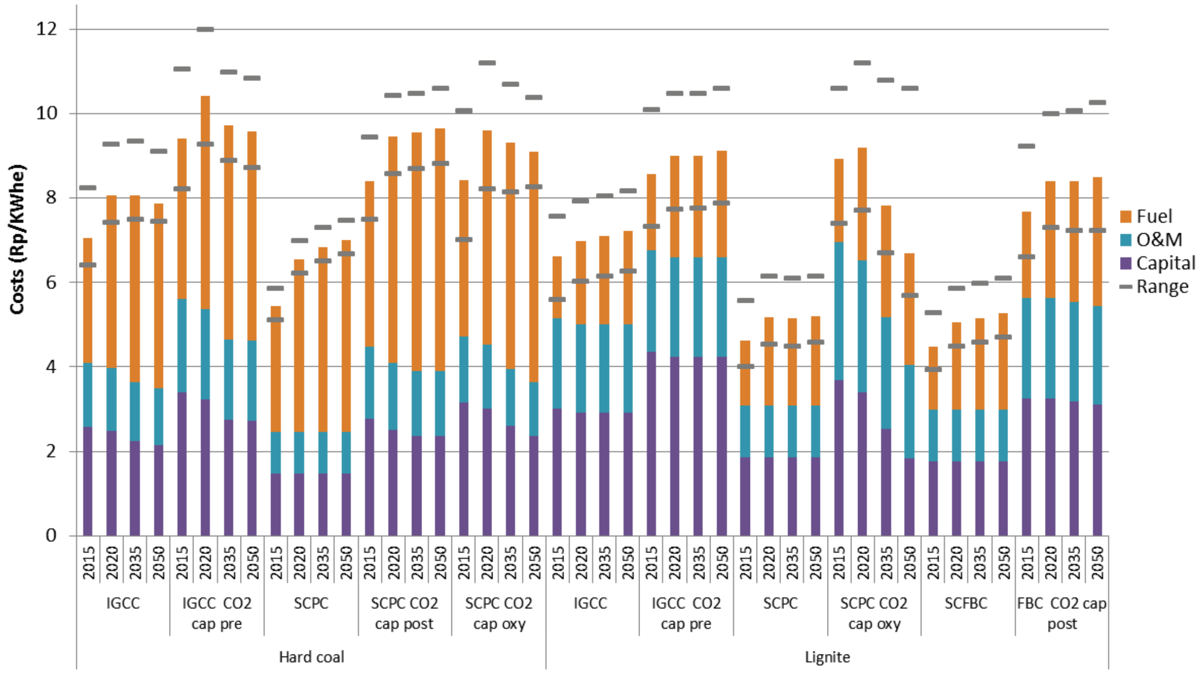

Figure 15.10: Estimated levelized costs of electricity (LCOE) for coal power plants with and without CO_2 capture until year 2050. Costs for CO_2 transport and storage are not included. The ranges refer to the upper and lower estimates for technology parameters and technology costs but do not include fuel price volatility.

15.5.4.3 Cost sensitivities

Figure 15.11 to Figure 15.18 show sensitivities of electricity generation costs for different power plant technologies concerning power plant load factor, lifetime, capital costs, interest rates and fuel costs. For NGCC, fuel costs are clearly the most sensitive factor. Fuel costs are also the most sensitive factor for hard coal power plants, while for lignite plants capital costs as well as interest rates are more sensitive.

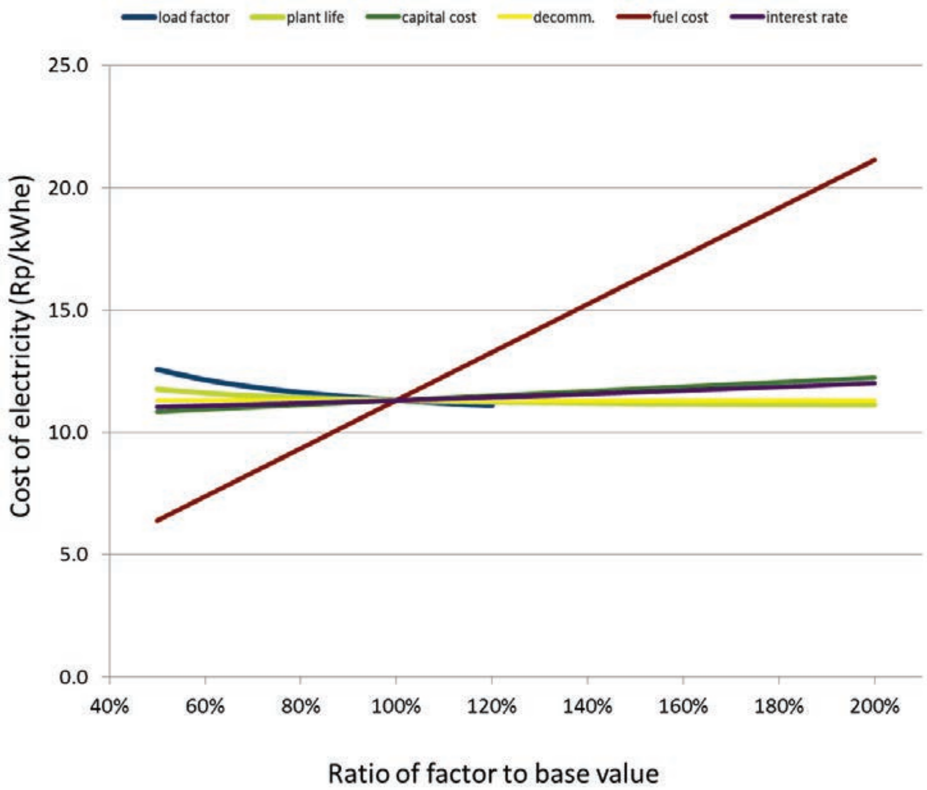

Figure 15.11: Sensitivity of cost of electricity for a natural gas combined cycle plant.

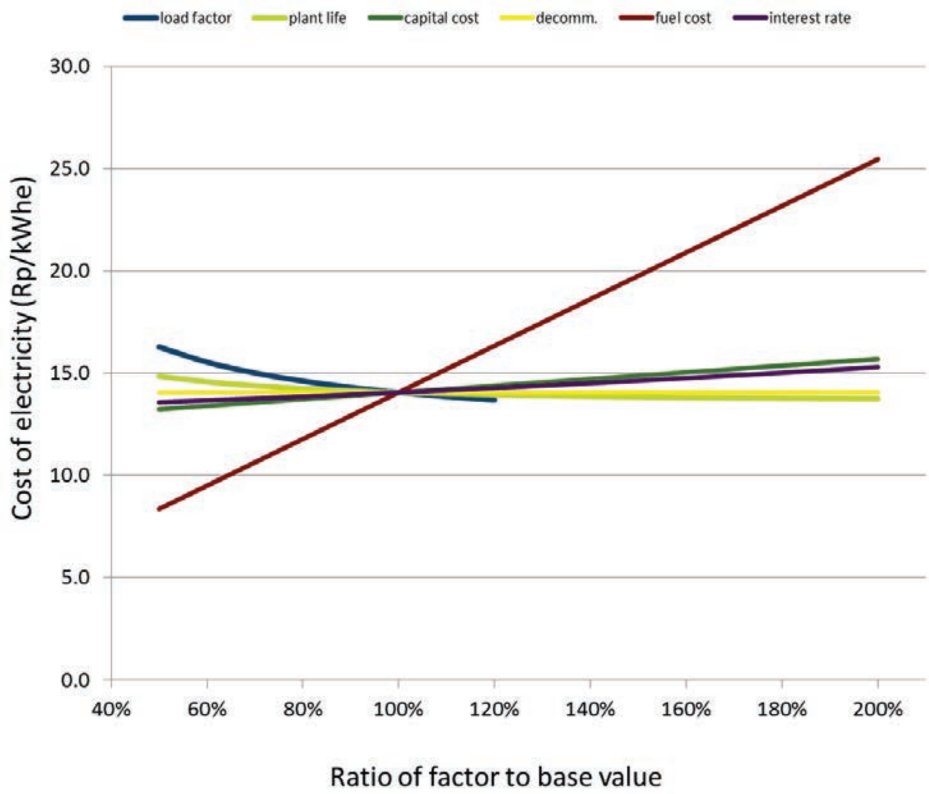

Figure 15.12: Sensitivity of cost of electricity for an NGCC plant with post-combustion CO_2 capture.

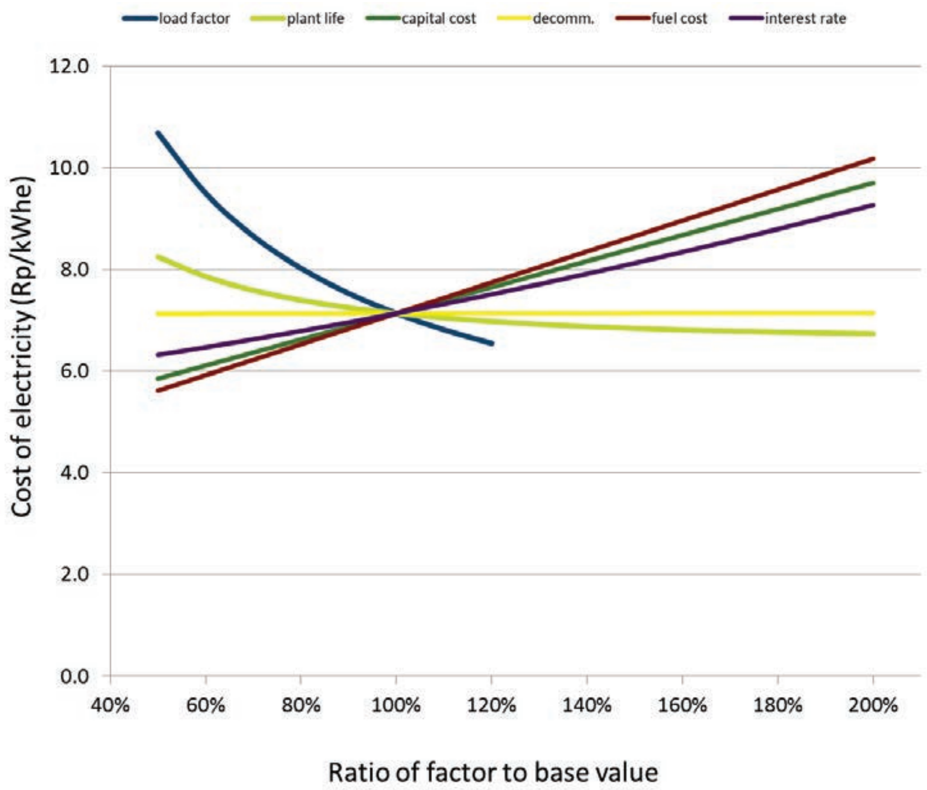

Figure 15.13: Sensitivity of cost of electricity for a hard coal IGCC.

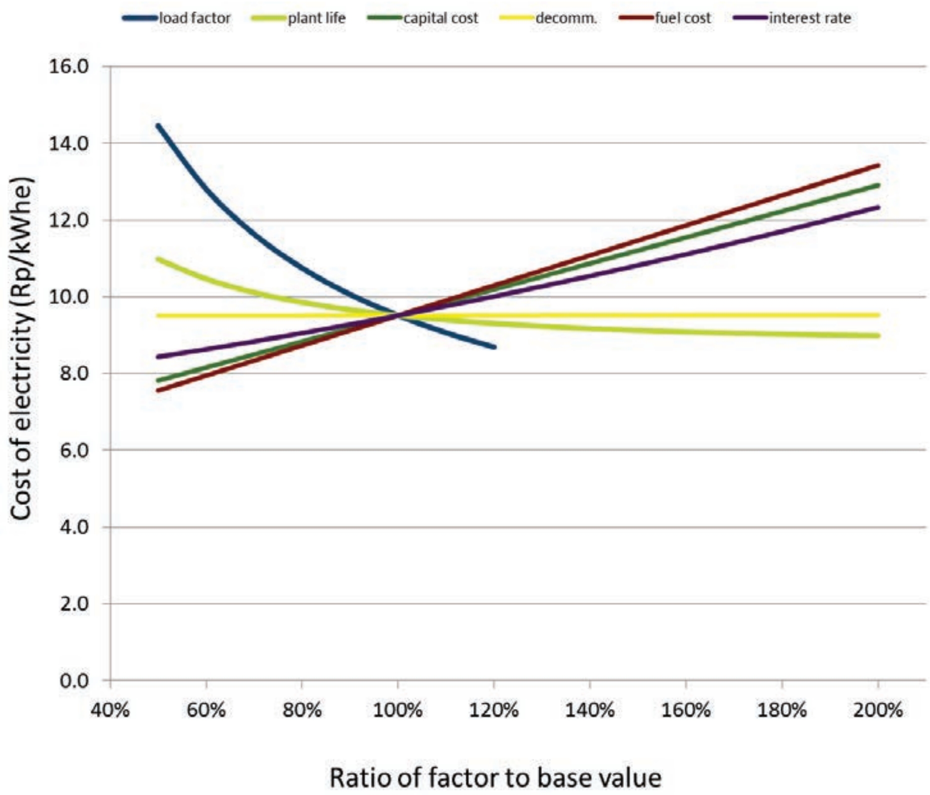

Figure 15.14: Sensitivity of cost of electricity for a hard coal IGCC with pre-combustion CO_2 capture.

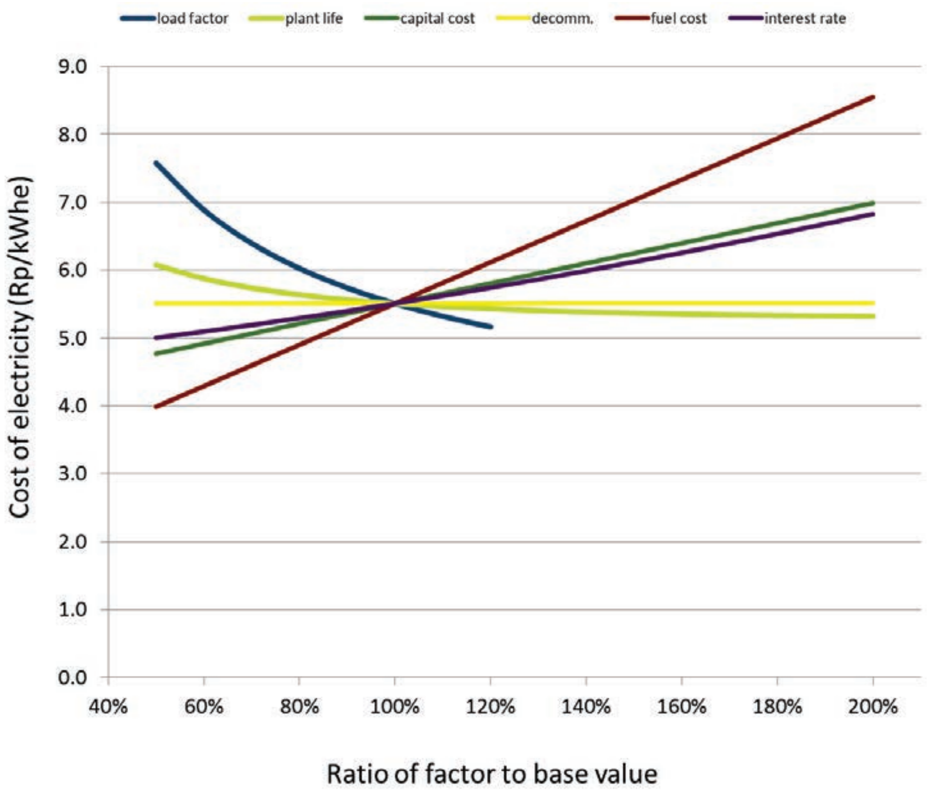

Figure 15.15: Sensitivity of cost of electricity for a hard coal SCPC.

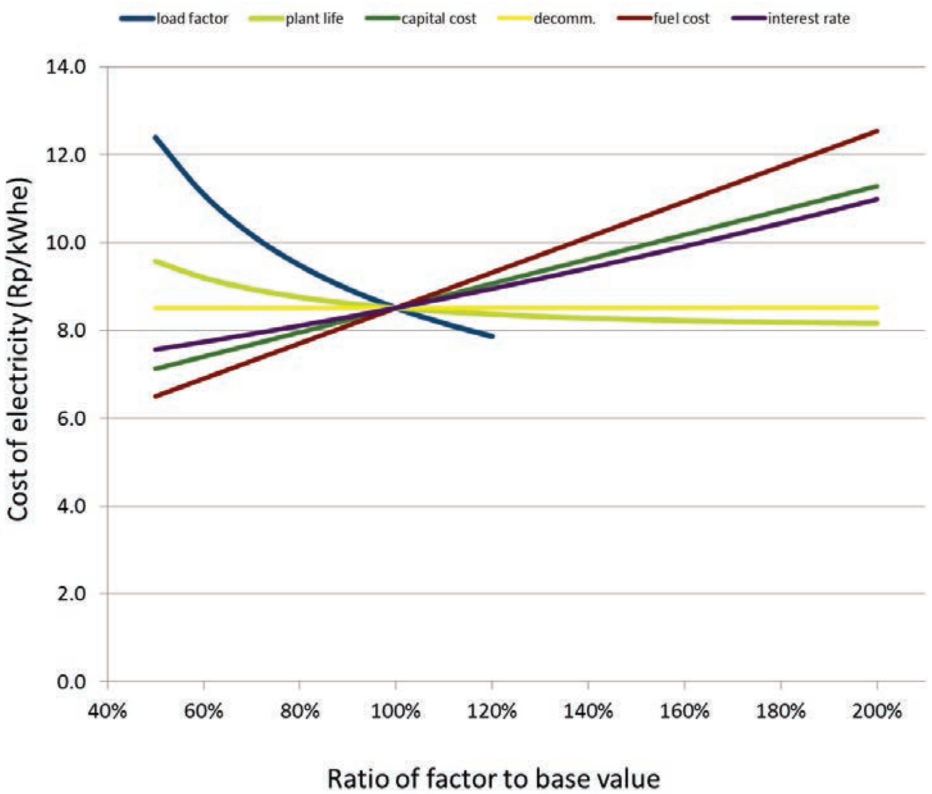

Figure 15.16: Sensitivity of cost of electricity for a hard coal SCPC with post-combustion CO_2 capture.

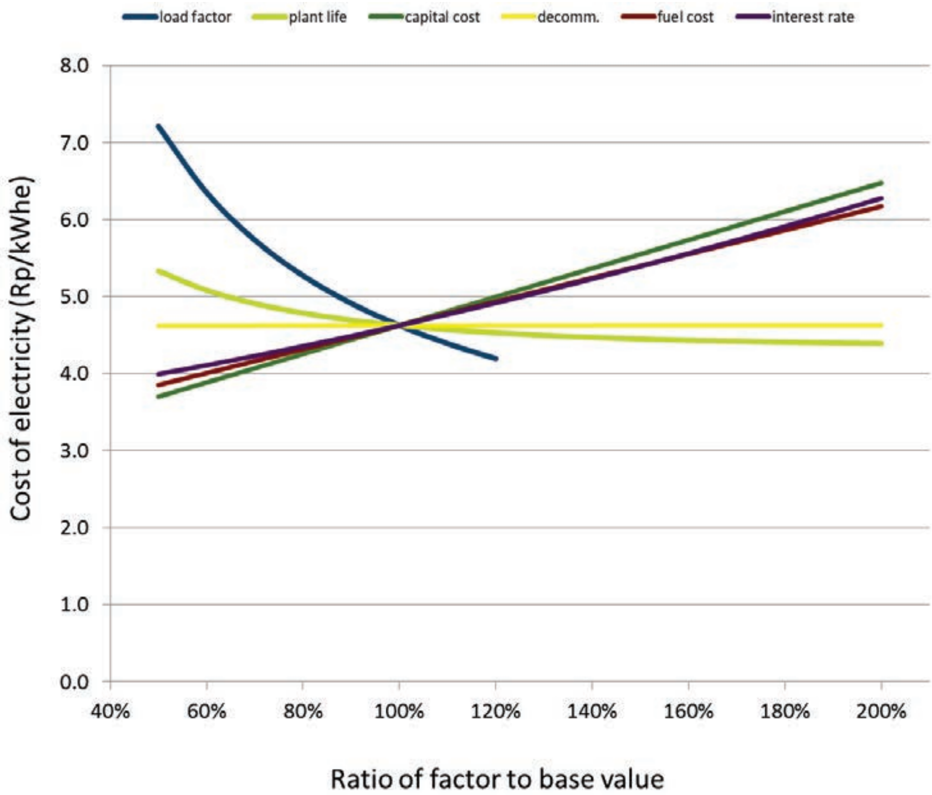

Figure 15.17: Sensitivity of cost of electricity for a SCPC lignite power plant.

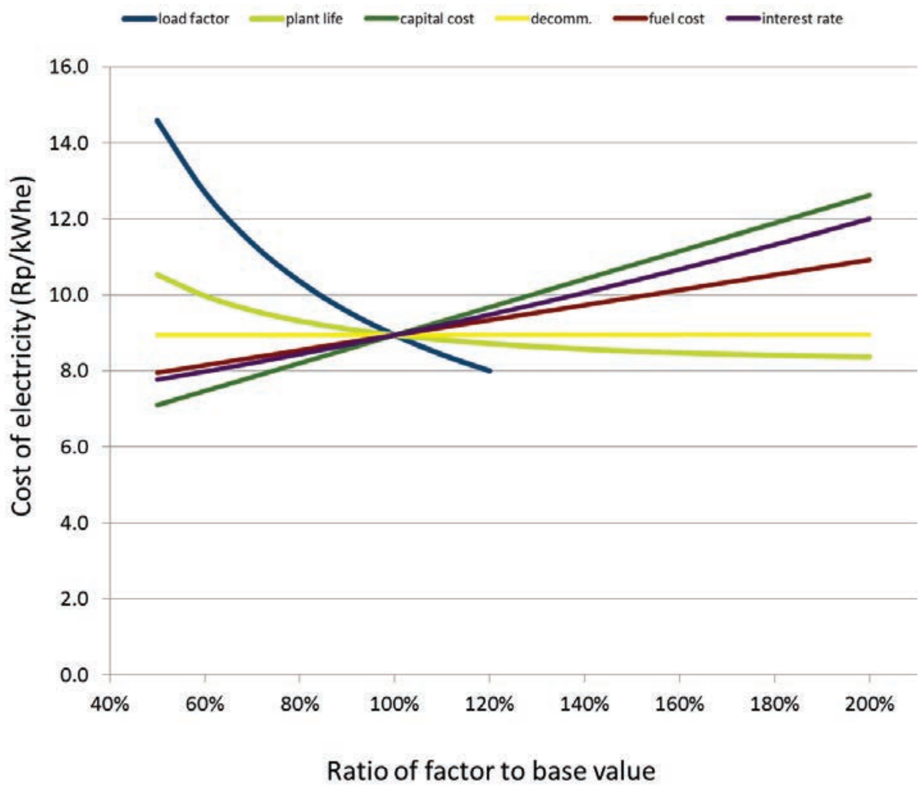

Figure 15.18: Sensitivity of cost of electricity for a lignite power plant with oxyfuel CO_2 capture.

15.6 Environmental aspects

The most important concern when it comes to environmental burdens of fossil electricity generation is the impact on climate change due to greenhouse gas (GHG) emissions. CO_2 emissions and emissions of other greenhouse gases are summarized as kg CO_2-eqivalents (weighted according to their global warming potentials). The time horizon for greenhouse gases considered in the following is 100 years.

Further environmental indicators are selectively discussed; main environmental issues in addition to GHG emissions are air pollutants such as particulate matter (PM), NO_x and SO_2 as well as releases of substances during coal mining activities.

All results shown here are based on Life Cycle Assessment (LCA), i.e. cover complete energy chains including mining, fuel production, transport and conversion (direct power plant emissions), and waste disposal with all associated environmental exchanges.

15.6.1 Greenhouse gas emissions

Greenhouse gas emissions include the direct emissions of CO_2 from the power plant and life cycle CO_2 emissions, but also other greenhouse gases, for example the leakages of methane during the gas transport (Faist Emmenegger, Heck et al. 2007).

The CO_2 emissions of the power plants result from the technology parameters in Table 15.9 and the carbon content of the fuel. Other life cycle data have been taken from the NEEDS project (Bauer, Heck et al. 2009).

Figure 15.19 shows greenhouse gas emissions of large natural gas power plants until 2050. These results do not represent the full CCS chain for NGCC power plants with CO_2 capture, i.e. emissions due to CO_2 transport and geological storage are not included. Considering also CO_2 transport and geological storage would increase life cycle emissions of electricity generation only marginally in the order of a few percent (Volkart, Bauer et al. 2013). However, due to lack of data, this estimated increase is based on generic assumptions, does not reflect Swiss-specific boundary conditions and is associated with comparatively high uncertainties.

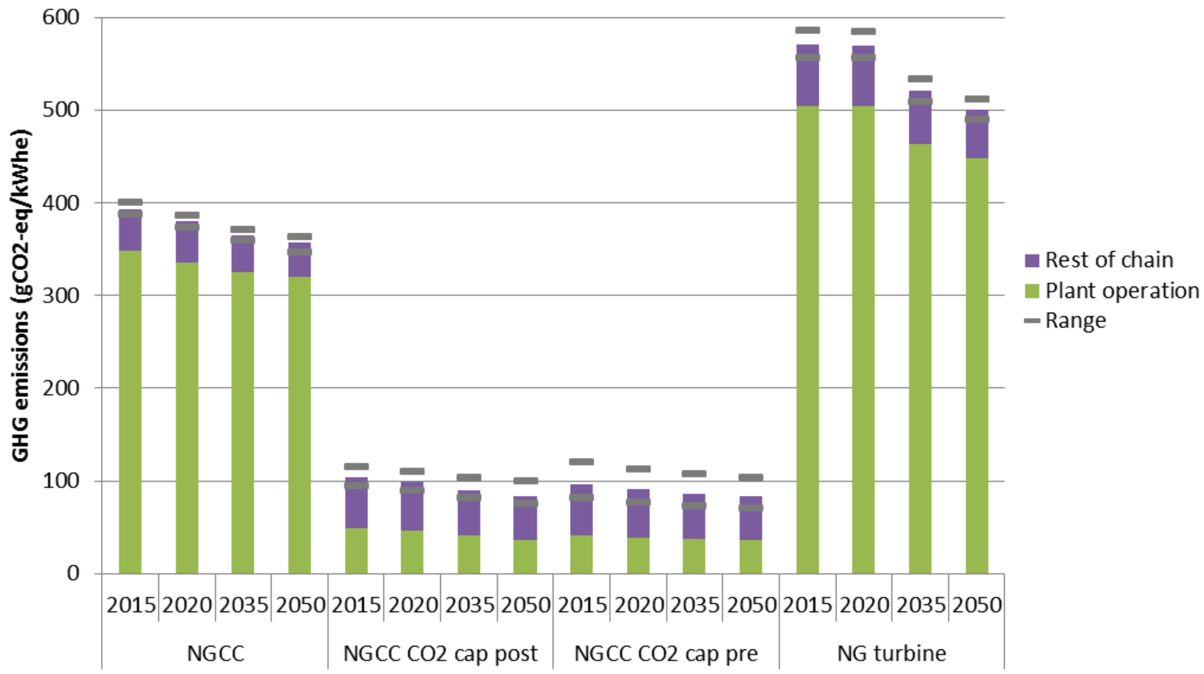

Figure 15.19: Estimated greenhouse gas emissions of large natural gas power plants until 2050. CO2 cap post/pre: power plants with post-/pre-combustion CO_2 capture.

Figure 15.20 shows greenhouse gas emissions of natural gas combined heat and power (CHP) power plants. For the CHP plants, exergy allocation has been applied for subdivision of environmental burdens to electricity and heat (Heck, Bollens et al. 2004).

Figure 15.20: Estimated greenhouse gas emissions of natural gas combined heat and power plants until 2050 (exergy allocation).

Figure 15.21 shows GHG emissions of hard coal and lignite power plants until 2050. (For lignite supercritical fluidized bed combustion (SCFBC) plants, life cycle data of the same level of detail was not available.) These results do not represent the full CCS chain for coal power plants with CO_2 capture, i.e. emissions due to CO_2 transport and geological storage are not included. Considering also CO_2 transport and geological storage would increase life cycle emissions of electricity generation only marginally in the order of a few percent (Volkart, Bauer et al. 2013). However, due to lack of data, this estimated increase is based on generic assumptions and is associated with comparatively high uncertainties.

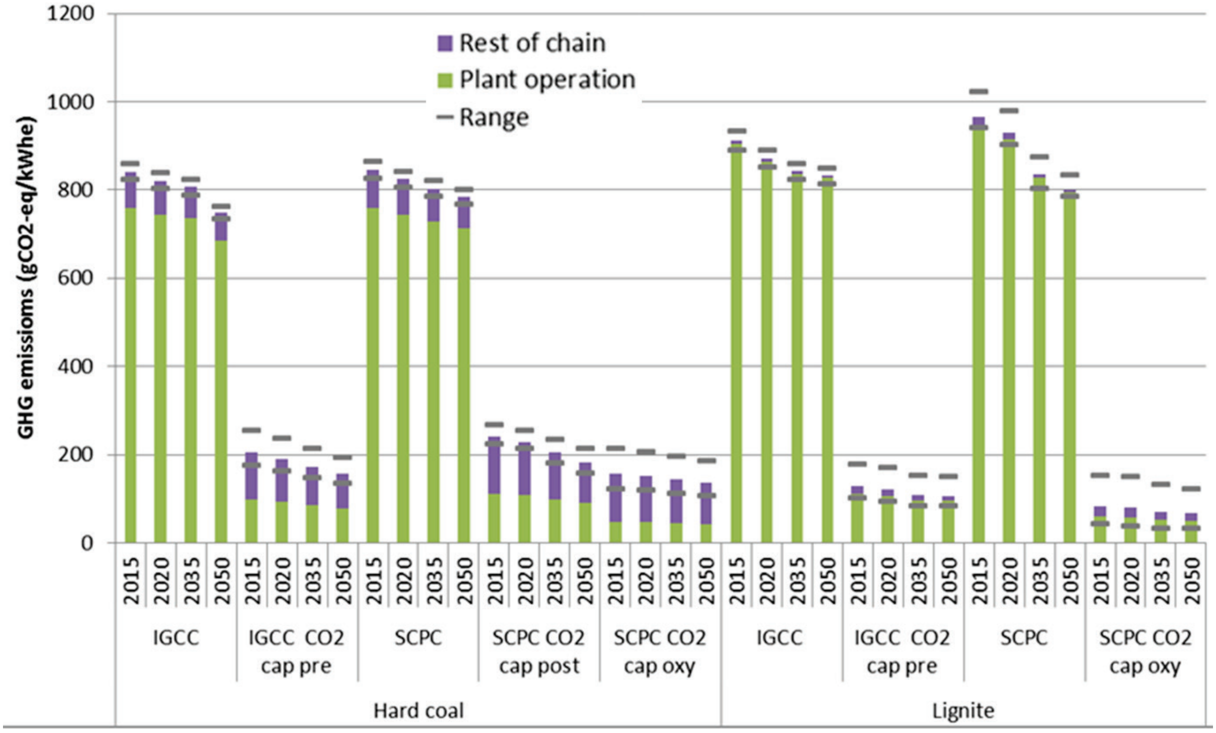

Figure 15.21: Estimated greenhouse gas emissions of coal power plants until 2050.

15.6.2 Other emissions and related impacts

The focus of the present study is on greenhouse gas emissions. Nevertheless, some other emissions and life cycle impact assessment results are briefly discussed.

The NO_x emissions of modern currently operating natural gas combined cycle plants were assumed in (Faist Emmenegger, Heck et al. 2007) at 29.7 mg/m^3 (15% O_2), i.e. about 15 ppm (15% O_2), or about 25.5 mg/MJ$_{\text{fuel input}}$ (relative to the input gas), according to information from the CC plant Mainz-Wiesbaden. Most advanced combined cycle plants can have lower NO_x emissions. NO_x emissions of 9 ppm using Dry Low NO_x technology are currently attainable (Mom 2013). Control and operation with low NO_x are still a challenge (Mom 2013). According to (Andrews 2013), emissions below 4 ppm in production engines are current technology for ultra-low NO_x gas turbines, 1 ppm is reachable (Andrews 2013).

Experience curves, or learning curves, are usually applied to economic cost data (see above). Nevertheless, for gas turbines, the experience curve approach has also been investigated for nitrogen oxide (NO_x) emissions (Heck, Bauer et al. 2009).

The environmental experience curve approach for emissions or other environmental burdens E of technical devices was defined in analogy to the cost experience curves as

$$\frac{E_1}{E_0} = \left(\frac{P_1}{P_0}\right)^{-b}.$$

Here P_0 is the cumulative production at a certain reference time and E_0 is the emission factor at the reference time. The emission factor E_1 at a later time is related to the cumulative production P_1 at this time. b is the learning index or learning elasticity specific for the considered technology and environmental burden. In general, the "*E*" can stand for "Emission" or "Environmental burden" or "External costs". Cost experience curves are reflecting the economic pressure to reduce costs; environmental experience curves are reflecting the political pressure to reduce environmental burdens. (Like in the case of costs, there is usually a lower limit for the environmental burden which is not represented in the simple formula with constant b, i.e. the formula cannot be extended arbitrarily in time with constant b.)

Figure 15.22 shows the estimated environmental experience curve in term of NO_x emissions for gas turbines and combined cycle plants. The extrapolation to 2030 was done using medium assumptions (realistic-optimistic scenario). The learning rate for NO_x emissions from gas turbines and combined cycle plants for the period from 1990 to 2030 has been estimated at about 22%, the corresponding progress ratio at about 78% (Heck, Bauer et al. 2009).

The historic emission data have been drawn from (Boyce 2006). The pessimistic scenario assumes that the NO_x emission factors remain almost constant because there might be no incentives to seriously reduce the NO_x emission below current values. The realistic-optimistic scenario is based on assumptions in literature about expected NO_x reductions (Boyce 2006). The very optimistic scenario assumes that NO_x emissions from gas turbines might be reduced to below 1 ppm in the far future (Brückner-Kalb 2008).

Historical data for the cumulative installed capacity for gas turbines and combined cycle plants have been extracted from the experience curves for costs in the literature (Barreto 2001, Colpier and Cornland 2002, Tester, Drake et al. 2005). For the extrapolation of the cumulative capacity to the future, the reference scenario for installed capacities in (IEA 2004) was used.

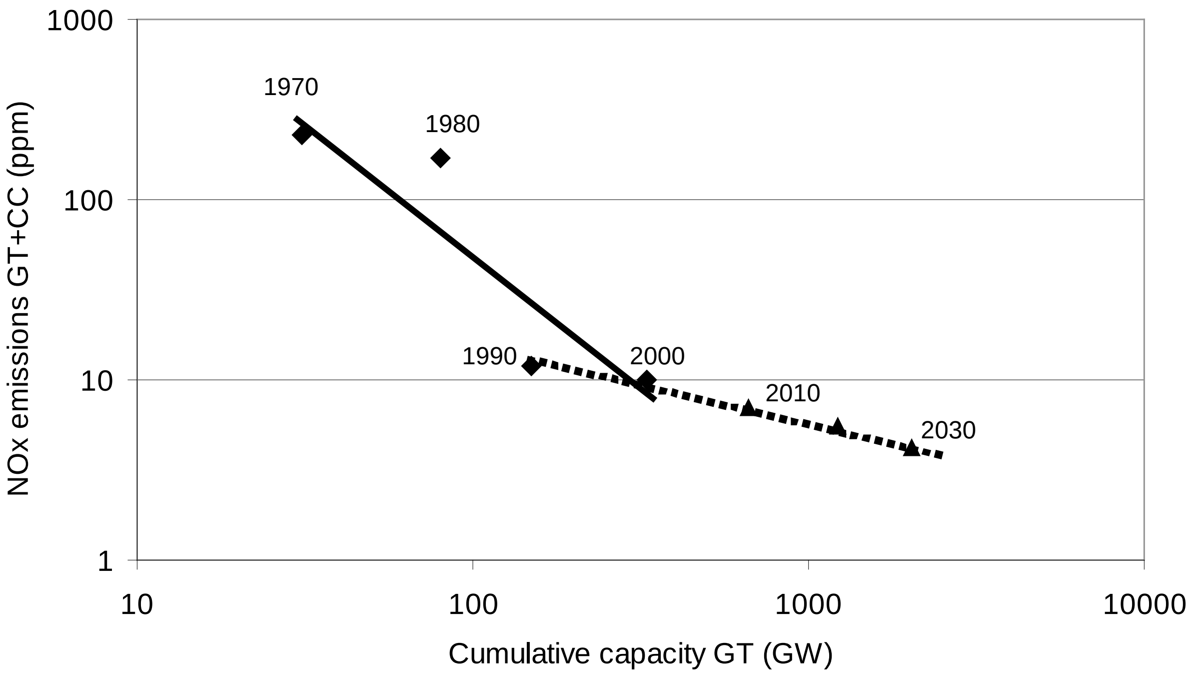

Figure 15.22: Experience curve of NO_x emissions (ppm at 15% O_2) from natural gas turbine (GT) power plants (including combined cycle (CC) plants) as function of the cumulative installed GT capacity. Note that there is a trade-off between the minimization of NO_x emissions and the optimization of efficiency and fuel consumption (see text). Source: (Heck, Bauer et al. 2009).

In December 2014, GE announced a gas turbine with NOx emissions below 5 ppm: "7F DLN 2.6+ technology also enables GE customers to reduce their NO_x emissions up to 40 percent and operate as low as sub 5 ppm NO_x" (GEPower 2014). Thus, as of year 2015, there is a large gas turbine with 5 ppm NO_x emission in the GE portfolio (GEPower 2016). This indicates that the political pressure to reduce NO_x emissions is still high.

Nevertheless, the optimization of gas turbines with respect to low NO_x emissions is in conflict with the goal of maximum electric efficiency.

For example, according to PE Power, the combined cycle mode net efficiency of the GE 7F.05 gas turbine is 60.3 % (LHV) at 12 ppm NO_x and CC net output of 376 MW (GEPower 2016). The turbine can reach 5 ppm NO_x (proven and demonstrated), but this reduces the efficiency of the gas turbine and the exhaust temperature available for the steam turbine. CC net efficiency for the 5 ppm NO_x mode is not given in the fact sheet. The single mode gas turbine net efficiency is 39.8% for 9 ppm NO_x and 39.6% for 5 ppm NO_x (GEPower 2016). Thus, a reduction of the NO_x emissions from 9 ppm to 5 ppm is associated with about 0.2 percent-points loss of the gas turbine net efficiency. The exhaust temperature of the gas turbine is 643°C for 12 ppm NO_x, 633°C for 9 ppm NO_x, and 605°C for 5 ppm NO_x (GEPower 2016). A lower exhaust temperature from the gas turbine leads also to a lower efficiency of the steam turbine process. Thus, the overall efficiency of the combined cycle process is lower for the turbine in low NO_x mode.

Primary particulate matter (PM) and SO_2 emissions and emission reduction technologies for PM and SO_2 are important issues for coal power plants. Primary PM and SO_2 emissions from natural gas combustion plants are very low.

Some selected life cycle impact assessment results summarizing important pollutant emissions (like SO_2, NO_x, and particulate matter (PM) are shown below.

A life cycle assessment of carbon capture and storage for European power generation and industry was recently performed at PSI by (Volkart, Bauer et al. 2013). Estimates for direct NO_x, SO_2, and particulate matter (PM) emissions of future coal power plants are shown in Table 15.17. A life cycle assessment was also made for mineral carbonation for carbon capture and storage by Giannoulakis, Volkart et al. (2014). Further overview and review LCA studies for fossil power plants with and without CCS have been performed by (Schreiber, Zapp et al. 2012, Whitaker, Heath et al. 2012, O'Donoughue, Heath et al. 2014).

Results of selected life cycle impact assessment indicators according to ILCD (Hauschild, Goedkoop et al. 2013) for future fossil power generation, quantified using the inventory data from (Volkart, Bauer et al. 2013) are shown in Figure 15.23. These results represent fossil power plants with implementation of the complete CCS chain, i.e. include CO_2 transport and geological storage (however, CO_2 transport and geological storage have not been analyzed for Swiss-specific boundary conditions).

Table 15.17: Emission factors for future hard coal and lignite power plants without and with CO_2 capture in kg/kWh. Source: (Volkart, Bauer et al. 2013).

		IGCC hard coal		Pulverized hard coal			IGCC lignite		Pulverized lignite		
		No cap	Pre	No cap	Post	Oxy	No cap	Pre	No cap	Post	Oxy
NOx, initial	2025	3.4E-03	4.1E-03	2.0E-03	2.5E-03	2.4E-03	1.2E-01	1.4E-01	2.3E-03	3.0E-03	2.9E-03
	2050	3.2E-03	3.6E-03	1.8E-03	2.1E-03	2.1E-03	1.0E-01	1.2E-01	2.0E-03	2.4E-03	2.4E-03
NOx, reduced	2025	1.3E-04	1.2E-04	1.2E-04	1.5E-04	7.5E-05	4.3E-04	3.9E-04	6.0E-04	7.6E-04	3.8E-04
	2050	1.2E-04	1.0E-04	1.1E-04	1.3E-04	6.5E-05	3.8E-04	3.2E-04	5.3E-04	6.1E-04	3.1E-04
SO2, initial	2025	1.2E-02	1.4E-02	4.9E-03	6.2E-03	6.1E-03	1.8E-01	2.2E-01	8.7E-03	1.1E-02	1.1E-02
	2050	1.1E-02	1.2E-02	4.5E-03	5.3E-03	5.2E-03	1.6E-01	1.8E-01	7.6E-03	9.1E-03	8.9E-03
SO2, reduced	2025	4.3E-05	4.6E-05	5.7E-05	3.6E-06	5.3E-05	6.5E-04	7.1E-04	4.4E-04	2.9E-05	4.2E-04
	2050	4.0E-05	4.0E-05	5.2E-05	3.1E-06	4.6E-05	5.8E-04	5.9E-04	3.9E-04	2.3E-05	3.4E-04
PM, initial	2025	0.0E+00	0.0E+00	8.3E-05	1.1E-04	1.0E-04	0.0E+00	0.0E+00	3.0E-02	3.9E-02	3.8E-02
	2050	0.0E+00	0.0E+00	7.6E-05	9.1E-05	8.9E-05	0.0E+00	0.0E+00	2.6E-02	3.1E-02	3.1E-02
PM, reduced	2025	0.0E+00	0.0E+00	4.1E-07	2.6E-07	2.6E-07	0.0E+00	0.0E+00	9.0E-05	5.8E-05	5.7E-05
	2050	0.0E+00	0.0E+00	3.8E-07	2.3E-07	2.2E-07	0.0E+00	0.0E+00	7.9E-05	4.7E-05	4.6E-05
PM2.5, reduced	2025	0.0E+00	0.0E+00	3.5E-07	2.3E-07	2.2E-07	0.0E+00	0.0E+00	7.6E-05	5.0E-05	4.8E-05
	2050	0.0E+00	0.0E+00	3.2E-07	1.9E-07	1.9E-07	0.0E+00	0.0E+00	6.7E-05	4.0E-05	3.9E-05
PM>10, reduced	2025	0.0E+00	0.0E+00	2.1E-08	1.3E-08	1.3E-08	0.0E+00	0.0E+00	4.5E-06	2.9E-06	2.8E-06
	2050	0.0E+00	0.0E+00	1.9E-08	1.1E-08	1.1E-08	0.0E+00	0.0E+00	3.9E-06	2.4E-06	2.3E-06
PM2.5-10, reduced	2025	0.0E+00	0.0E+00	4.1E-08	2.7E-08	2.6E-08	0.0E+00	0.0E+00	9.0E-06	5.8E-06	5.7E-06
	2050	0.0E+00	0.0E+00	3.8E-08	2.3E-08	2.2E-08	0.0E+00	0.0E+00	7.9E-06	4.7E-06	4.6E-06

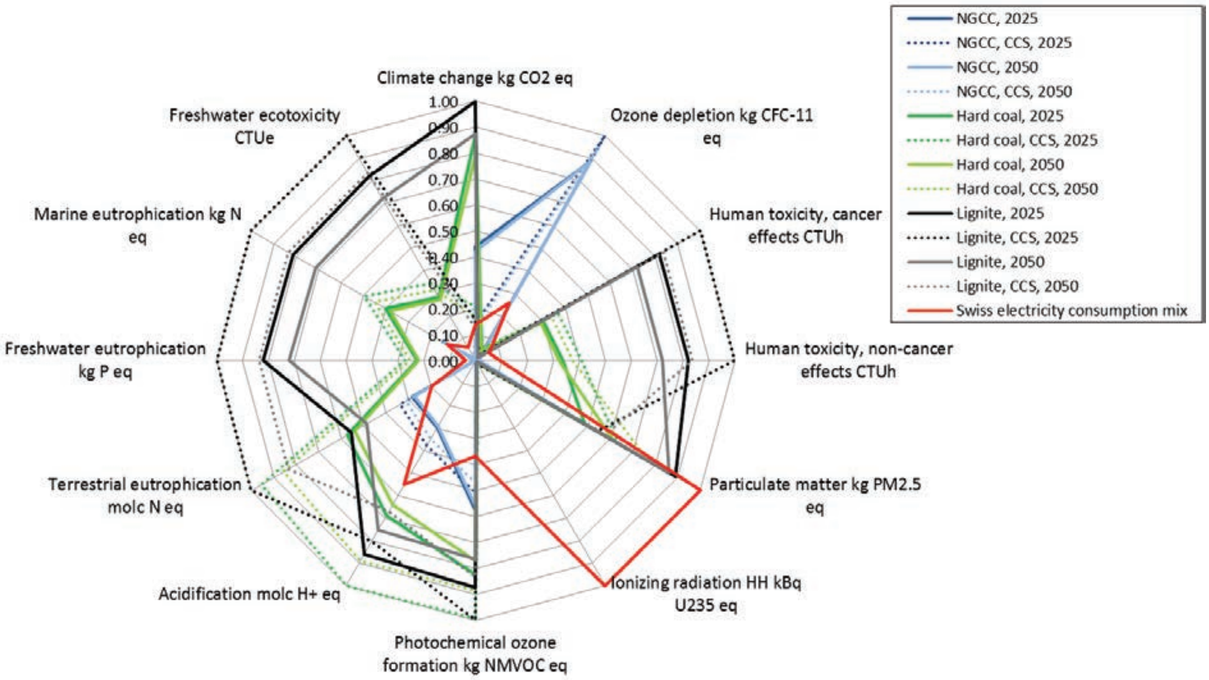

Figure 15.23: Relative LCIA results (ILCD midpoint indicators (Hauschild, Goedkoop et al. 2013)) for future power generation from natural gas, hard coal and lignite in comparison to the current Swiss consumption mix[373]. Maximum for each indicator (=worst result) equal to 1.

15.7 Development and market

Natural gas combined cycle plants are a mature technology. Net electric efficiencies have reached levels around 60%. In future, electric efficiencies around 65% are possible.

Steam coal power plants with improved efficiencies due to higher temperatures and pressures have been developed in the past decades. Advanced ultra-supercritical (A-USC) coal plants with temperatures around 700°C and pressures around 350 bar are currently under development. Materials for even higher temperatures around 760°C are investigated.

Alternatively, integrated gasification combined cycle (IGCC) coal power plants are under development. An IGCC plant includes a gasifier that converts coal into gas which is then burned in a gas turbine. The development of gas turbines is therefore also relevant for the optimization of IGCC plants.

Pre-combustion and post-combustion carbon dioxide capture technologies have reached an advanced level and are close to market application. Oxyfuel combustion for carbon dioxide capture is a relatively new technology under development.

15.8 Open questions and research activities

The optimization of the gas turbine combustion process is still a field of active research. The goal is a further increase of the combustion temperature and thus an increase of the efficiency while keeping the emissions of nitrogen oxides and other pollutants at a minimum.

[373] Swiss consumption mix including electricity imports according to the ecoinvent v2.2 database.

Carbon dioxide capture technologies are associated with significant losses of efficiency and an increase of fuel consumption. The optimization of carbon dioxide capture technologies is currently investigated in several projects for natural gas and coal power plants.

The overall environmental consequences of geological carbon dioxide storage are currently not fully understood. Further research on this subject is needed.

There are also open issues concerning the environmental risk of extraction of unconventional natural gas. For example, the Intergovernmental Panel on Climate Change (IPCC) wrote about the freshwater-related risk of extraction of unconventional natural gas: "Another emergent freshwater-related risk of climate mitigation is increased natural gas extraction from low-permeability rocks. The required hydraulic fracturing process ("fracking") uses large amounts of water (a total of about 9000-30'000 m^3 per well, mixed with a number of chemicals), of which a part returns to the surface (Rozell and Reaven, 2012). Fracking is suspected to lead to pollution of the overlying freshwater aquifer or surface waters, but appropriate observations and peer-reviewed studies are still lacking (Jackson et al., 2013)" (IPCC 2014b).

Substitutes for fossil natural gas as fuel for gas power plants show a possible way to avoid or at least reduce the combustion of fossil fuels. Synthetic natural gas from biomass or from power-to-gas technologies could be used in practically all types of natural gas power plants. Mixtures of hydrogen and methane (i.e. hydrogen and natural gas or synthetic natural gas) are a further interesting option for future energy systems. The combustion of pure hydrogen and oxygen in a gas turbine would imply combustion temperatures of about 3200°C (Siemens 2010) which is far too high for available gas turbines. Gas turbines for the combustion of gas with high hydrogen content are a field of research.

15.9 Summary of results: natural gas and coal power plants and natural gas CHP units

Table 15.18 shows an overview of the electricity generation costs, direct CO_2 emissions from the power plant, and life cycle GHG emissions for natural gas and coal power plants.[374]

Table 15.18: Summary: electricity generation cost, direct CO_2 emissions from the power plant, and life cycle greenhouse gas (GHG) emissions for natural gas and coal power plants. (The CO_2 and GHG emissions of CHP plants follow the exergy allocation scheme.) The ranges of costs refer to upper and lower estimates for technology parameters and technology costs but do not include fuel price volatility. Electricity generation costs and life cycle GHG emissions for power plants with CO_2 capture do not include CO_2 transport and geological CO_2 storage.

		Current	2020	2035	2050
Electricity generation costs (with heat credits for CHP) (Rp./kWhe)	NGCC	11.3 (10.8 - 12.3)	11.7 (11.1 - 12.6)	13.4 (12.9 - 14.2)	15.2 (14.5 - 16.0)
	NGCC post	14.1 (13.0 - 15.8)	14.4 (13.4 - 16.1)	16.3 (15.3 - 17.7)	18.4 (17.3 - 19.8)
	NGCC pre	14.2 (13.3 - 16.0)	14.3 (13.4 - 16.0)	16.1 (15.3 - 17.6)	18.1 (17.3 - 19.6)
	NG turbine	18.5 (16.8 - 20.9)	19.6 (17.9 - 22.0)	21.3 (19.6 - 23.8)	23.6 (21.8 - 26.1)
	CHP 1kW$_{el}$	71.8 (50.2 - 114.6)	70.6 (49.5 - 112.5)	67.0 (47.4 - 106.0)	65.6 (46.9 - 103.1)
	CHP 10kW$_{el}$	29.6 (22.2 - 45.3)	29.5 (22.2 - 45.6)	29.5 (22.5 - 44.8)	30.2 (23.4 - 45.3)
	CHP 100kW$_{el}$	14.3 (9.6 - 19.3)	14.9 (9.6 - 20.4)	16.5 (11.1 - 21.9)	18.3 (12.7 - 23.9)
	CHP 1000kW$_{el}$	12.1 (9.9 - 14.7)	12.7 (10.4 - 15.7)	14.5 (12.1 - 17.4)	16.6 (14.0 - 19.6)
	IGCC hard coal	7.1 (6.5 - 8.3)	7.2 (6.6 - 8.4)	7.5 (6.9 - 8.7)	7.7 (7.3 - 8.9)
	IGCC hard coal pre	9.5 (8.3 - 11.2)	9.3 (8.2 - 10.9)	9.0 (8.2 - 10.3)	9.4 (8.5 - 10.6)
	SCPC hard coal	5.5 (5.2 - 5.9)	5.7 (5.4 - 6.1)	6.3 (5.9 - 6.7)	6.8 (6.5 - 7.3)
	SCPC hard coal post	8.5 (7.6 - 9.6)	8.3 (7.5 - 9.3)	8.8 (8.0 - 9.7)	9.4 (8.6 - 10.3)
	SCPC hard coal oxy	8.5 (7.1 - 10.2)	8.5 (7.2 - 10.1)	8.6 (7.5 - 10.0)	8.9 (8.0 - 10.1)
	IGCC lignite	6.6 (5.6 - 7.6)	6.5 (5.6 - 7.5)	6.8 (5.8 - 7.7)	7.1 (6.1 - 8.0)
	IGCC lignite pre	8.6 (7.3 - 10.1)	8.4 (7.2 - 9.9)	8.6 (7.4 - 10.1)	9.0 (7.7 - 10.4)
	SCPC lignite	4.6 (4.0 - 5.6)	4.7 (4.1 - 5.6)	4.8 (4.2 - 5.8)	5.1 (4.4 - 6.0)
	SCPC lignite oxy	8.9 (7.4 - 10.6)	8.6 (7.1 - 10.5)	7.4 (6.3 - 10.4)	6.6 (5.5 - 10.4)
	SCFBC lignite	4.5 (3.9 - 5.3)	4.6 (4.0 - 5.4)	4.8 (4.3 - 5.6)	5.1 (4.6 - 5.9)
	FBC lignite post	7.7 (6.6 - 9.2)	7.8 (6.7 - 9.3)	8.0 (6.8 - 9.6)	8.3 (7.0 - 10.0)
Electricity generation costs (without heat credits) (Rp./kWh$_{el}$)	CHP 1kW$_{el}$	93.2 (72.7 - 131.5)	92.4 (72.4 - 129.6)	91.6 (73-1 - 125.8)	89.3 (71.9 - 121.6)
	CHP 10kW$_{el}$	48.8 (40.3 - 63.3)	49.1 (40.7 - 63.3)	51.5 (43.5 - 65.0)	51.3 (43.5 - 64.3)
	CHP 100kW$_{el}$	22.3 (19.2 - 26.2)	22.2 (19.2 - 26.5)	25.4 (22.3 - 29.6)	26.2 (23.2 - 30.3)
	CHP 1000kW$_{el}$	17.1 (15.5 - 19.3)	17.1 (15.5 - 19.2)	20.1 (18.4 - 22.2)	21.0 (19.3 - 23.1)
Direct CO_2 emissions from power plant (g/kWhe)	NGCC	348 (342 - 354)	336 (330 - 342)	325 (320 - 330)	320 (310 - 325)
	NGCC post	48 (40 - 58)	47 (38 - 55)	41 (33 - 53)	37 (29 - 52)
	NGCC pre	41 (26 - 63)	38 (25 - 59)	37 (24 - 57)	37 (24 - 56)
	NG turbine	504 (492 - 517)	504 (492 - 517)	463 (453 - 474)	448 (438 - 458)
	CHP 1kW$_{el}$	568 (540 - 599)	562 (535 - 592)	546 (520 - 573)	535 (511 - 561)
	CHP 10kW$_{el}$	540 (515 - 559)	534 (508 - 559)	518 (493 - 542)	508 (483 - 531)
	CHP 100kW$_{el}$	447 (420 - 467)	442 (410 - 469)	426 (396 - 452)	419 (390 - 445)
	CHP 1000kW$_{el}$	425 (406 - 442)	418 (397 - 440)	399 (379 - 420)	393 (374 - 414)
	IGCC hard coal	760 (743 - 777)	743 (728 - 760)	735 (720 - 752)	684 (671 - 698)
	IGCC hard coal pre	98 (76 - 141)	92 (72 - 133)	84 (66 - 121)	78 (61 - 111)
	SCPC hard coal	760 (743 - 777)	743 (728 - 760)	728 (713 - 743)	713 (698 - 728)
	SCPC hard coal post	111 (98 - 135)	107 (95 - 131)	98 (78 - 125)	90 (70 - 120)

[374] Electricity generation costs and life cycle GHG emissions for power plants with CO_2 capture do not include CO_2 transport and geological CO_2 storage. For further explanations see text.

		Current	2020	2035	2050
	SCPC hard coal oxy	48 (18 - 98)	46 (18 - 95)	44 (17 - 91)	43 (17 - 88)
	IGCC lignite	905 (884 - 926)	864 (846 - 884)	837 (819 - 855)	828 (810 - 846)
	IGCC lignite pre	111 (86 - 160)	105 (82 - 151)	96 (75 - 138)	95 (74 - 136)
	SCPC lignite	949 (926 - 1005)	915 (889 - 966)	828 (794 - 864)	794 (778 - 828)
	SCPC lignite oxy	61 (23 - 129)	58 (22 - 124)	53 (19 - 111)	50 (19 - 102)
	SCFBC lignite	926 (905 - 949)	905 (884 - 926)	864 (846 - 884)	864 (846 - 884)
	FBC lignite post	125 (109 - 169)	122 (106 - 163)	114 (100 - 153)	114 (100 - 153)
Life cycle GHG emissions (gCO2-eq/kWhe)	NGCC	393 (387 - 400)	380 (374 - 386)	365 (359 - 371)	357 (346 - 363)
	NGCC post	104 (94 - 114)	99 (90 - 109)	90 (81 - 103)	83 (75 - 100)
	NGCC pre	97 (81 - 120)	91 (76 - 112)	86 (72 - 107)	83 (70 - 103)
	NG turbine	570 (556 - 585)	570 (556 - 584)	520 (509 - 533)	500 (489 - 511)
	CHP 1kW$_{el}$	643 (611 - 677)	636 (605 - 670)	618 (589 - 648)	606 (578 - 635)
	CHP 10kW$_{el}$	611 (583 - 633)	605 (575 - 632)	586 (558 - 613)	575 (546 - 601)
	CHP 100kW$_{el}$	506 (476 - 529)	500 (464 - 530)	482 (448 - 511)	474 (441 - 503)
	CHP 1000kW$_{el}$	481 (459 - 500)	473 (450 - 498)	452 (429 - 476)	445 (423 - 468)
	IGCC hard coal	841 (823 - 860)	820 (803 - 838)	807 (790 - 824)	748 (734 - 764)
	IGCC hard coal pre	205 (177 - 255)	190 (164 - 237)	172 (148 - 213)	156 (135 - 194)
	SCPC hard coal	845 (827 - 864)	825 (807 - 843)	803 (786 - 820)	785 (768 - 801)
	SCPC hard coal post	240 (223 - 268)	229 (214 - 256)	204 (181 - 234)	181 (159 - 214)
	SCPC hard coal oxy	158 (123 - 215)	153 (119 - 208)	145 (113 - 197)	137 (106 - 187)
	IGCC lignite	912 (892 - 934)	871 (852 - 891)	842 (824 - 861)	832 (815 - 850)
	IGCC lignite pre	128 (103 - 178)	121 (94 - 170)	109 (85 - 154)	107 (83 - 151)
	SCPC lignite	965 (942 - 1022)	929 (902 - 980)	837 (803 - 874)	801 (785 - 835)
	SCPC lignite oxy	83 (43 - 152)	79 (38 - 149)	71 (33 - 133)	67 (34 - 122)

15.10 Abbreviations

A-UCS	Advanced ultra-supercritical
BFE	Bundesamt für Energie (SFOE, Swiss Federal Office of Energy)
BHKW	Blockheizkraftwerk
BIGCC	Biomass Integrated Gasification Combined Cycle
CAPEX	Capital Expenditure
CC	Combined Cycle
CCS	Carbon capture and sequestration, or Carbon capture and storage
CCUS	Carbon capture, utilization and storage
CHF	Swiss Franc
CHP	Combined heat and power
CO2-eq.	Carbon dioxide equivalent
COP	Coefficient of Performance
EJ	Exa-Joule
El. eff.	Electric efficiency
€Ct	Euro-Cent
FBC	Fluidized bed combustion
FOM	Fixed operation and maintenance costs
GHG	Greenhouse gas
GT	Gas turbine
H2-IGCC	Hydrogen Integrated Gasification Combined Cycle
HHV	Higher heating value
IGCC	Integrated Gasification Combined Cycle
LCA	Life cycle assessment
LCIA	Life cycle impact assessment
LCOE	Levelized cost of electricity
LHV	Lower heating value
LNG	Liquefied natural gas
LR	Learning rate
MEA	Monothanolamine
MTPA	Million tons per annum
MWel	Mega-Watt electric
NG	Natural gas
NGCC	Natural gas combined cycle
O&M	Operation and maintenance
ORC	Organic Rankine Cycle
PC	Pulverized coal
PM	Particulate matter
ppm	parts per million
PR	Progress ratio
Rp	Swiss Rappen
SC	Supercritical
SCFBC	Supercritical fluidized bed combustion
SCPC	Supercritical pulverized coal
SFOE	Swiss Federal Office of Energy (BFE, Bundesamt für Energie)
SNG	Synthetic natural gas

Tcm	Trillion cubic meters
Th. eff.	Thermal efficiency
USC	Ultra-supercritical
USCPC	Ultra-supercritical pulverized coal
USD	US Dollar
VOM	Variable operation and maintenance costs
WHP	Waste Heat to Power

Abbreviations for power plant types:

NGCC	Natural gas combined cycle
NGCC post	Natural gas combined cycle CO2 capture post-combustion
NGCC pre	Natural gas combined cycle CO2 capture pre-combustion
NG turbine	Natural gas turbine
CHP 1kWe	Natural gas piston engine combined heat and power plant 1kWe
CHP 10kWe	Natural gas piston engine combined heat and power plant 10kWe
CHP 100kWe	Natural gas piston engine combined heat and power plant 100kWe
CHP 1000kWe	Natural gas piston engine combined heat and power plant 1000kWe
IGCC hard coal	Integrated Gasification Combined Cycle, hard coal
IGCC hard coal pre	IGCC CO2 capture pre-combustion, hard coal
SCPC hard coal	Supercritical pulverized coal, hard coal
SCPC hard coal post	Supercritical pulverized coal CO2 capture post-combustion, hard coal
SCPC hard coal oxy	Supercritical pulverized coal CO2 capture oxyfuel, hard coal
IGCC lignite	Integrated Gasification Combined Cycle lignite
IGCC lignite pre	Integrated Gasification Combined Cycle lignite CO2 capture pre-combustion
SCPC lignite	Supercritical pulverized lignite
SCPC lignite oxy	Supercritical pulverized lignite CO2 capture oxyfuel
SCFBC lignite	Supercritical fluidized bed combustion lignite
FBC lignite post	Fluidized bed combustion lignite CO2 capture post-combustion

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16 Fuel Cells

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16.1 Introduction

16.1.1 Definition

Fuel cells are electrochemical devices that convert a fuel, such as hydrogen into electricity, heat and water, without relying on combusting the fuel. Because the process does not rely on the expansion of hot gases, but rather electrochemistry, fuel cells have the potential to operate with very high efficiencies. Although fuel cells are currently more expensive to install than conventional power plants, their very high working efficiency leads to comparatively low fuel costs making them more attractive. Furthermore, fuel cells are known for their low operational emissions. Because of the bypassed combustion process, fuel cell emissions of fine particulate matter and oxides of sulfur and nitrogen are practically zero (Dodds, Staffell et al. 2015). When hydrogen is used as a fuel source, the only emission is water; when natural gas is the fuel, the emissions are only water and CO_2.

There are two main uses for fuel cells in stationary electricity generation:

1. Providing combined heat and power (CHP)
2. Providing backup and off-grid power

Focus will be placed on CHP systems in this chapter as they are more applicable in the context of Swiss electricity supply. Fuel cells for backup and off-grid power are considered to be a niche market and are unlikely to contribute significantly to the Swiss electricity supply in the future. Furthermore, only natural gas and biomethane will be considered as a fuel source in this study, as this appears to be the market standard for CHP systems. Fuel cells that operate on hydrogen are assumed to be equipped with a fuel reformer to generate hydrogen on site as opposed to hydrogen being delivered from an external source.

Fuel cells, due to their high electrical efficiency and operational flexibility are well suited to household applications as well as commercial installations in larger buildings such as airports and hospitals. These systems are typically heat-led so that the heating and hot water demands of the house are always met, while the balance of electricity demand is met by the grid. Fuel cell CHP systems are extremely scalable and can be built small enough to meet the heating needs of a single family home, which is a market that other CHP systems, such as gas engines, cannot fill.

The two system sizes analyzed explicitly in this chapter are the single family home size, of 1 kW electrical capacity and the larger building size of 300 kW electrical capacity, though the systems can be scaled to all sizes in between and above this, even into the megawatt size scale.

Residential fuel cell systems, also known as micro CHP systems are predominantly powered by Polymer Electrolyte Fuel Cells (PEFC) and Solid Oxide Fuel Cells (SOFC). PEFCs operate at low temperatures (under 100°C) while SOFCs are much higher temperature, 600-100°C. However, because of the relatively low temperatures required for residential heating, both systems are sufficient. Due to their lower operating temperatures, PEFC have the highest operational flexibility of all fuel cell designs considered here.

Larger fuel cell systems are on the order of hundreds of kilowatts and are dominated by Molten Carbonate Fuel Cells (MCFC) and Phosphoric Acid Fuel Cells (PAFC) though SOFCs are gaining popularity. MCFCs operate between 600 and 700°C, while PAFCs operate between 150-200°C. Table 16.1 describes some general characteristics of each of these fuel cell types.

Table 16.1: General fuel cell characteristics

Fuel Cell Type	Temperature	Operating Flexibility	Fuel Reformer	Typical Size	Technology Maturity
PEFC	<100 °C	Excellent	External	<5 kW	Maturing
PAFC	150-220 °C	Poor	External	>100 kW	Mature
MCFC	600-700 °C	Poor	Internal	>300 kW	Mature
SOFC	600-1000 °C	Poor	Internal	<300 kW	Maturing

16.1.2 Global and European trends

Figure 16.1 shows the global annual newly installed fuel cell capacity according to application, region and type. As can be seen in this figure, the majority of new installations have been for stationary applications, though transport related installations increased significantly in 2015. Thus far, installations have occurred primarily in North America and Asia, though European installations are growing. The most common fuel cell types installed are PEFC, MCFC, SOFC and PAFC. Large stationary installations for the production of primary power have been installed in the United States and Korea, while Japan and Germany are the market leaders for the installation of micro CHP fuel cell systems (Carter and Wing 2013). The Japanese are have surpassed 120’000 residential units with electrical output between 0.3 and 1 kW in 2015, mostly due to the ene.farm initiative (Rose 2015).

The number of European micro CHP installations is expected to increase significantly in the coming years due to the support of the ene.field project, which is providing financial support via the European Union’s Seventh Framework Program for the Fuel Cells and Hydrogen Joint Technology Initiative and the German Callux project (Callux 2015). Up to 1000 micro CHP system projects based on PEFC and SOFC designs will be supported in 12 European countries, including Switzerland, from 2012-2017 in the European ene.field project (enefield.eu 2015). As of September 2015 over 250 units had been installed (enefield.eu 2015). The German Callux project finished in 2014, with a total of 500 units installed (Callux 2015).

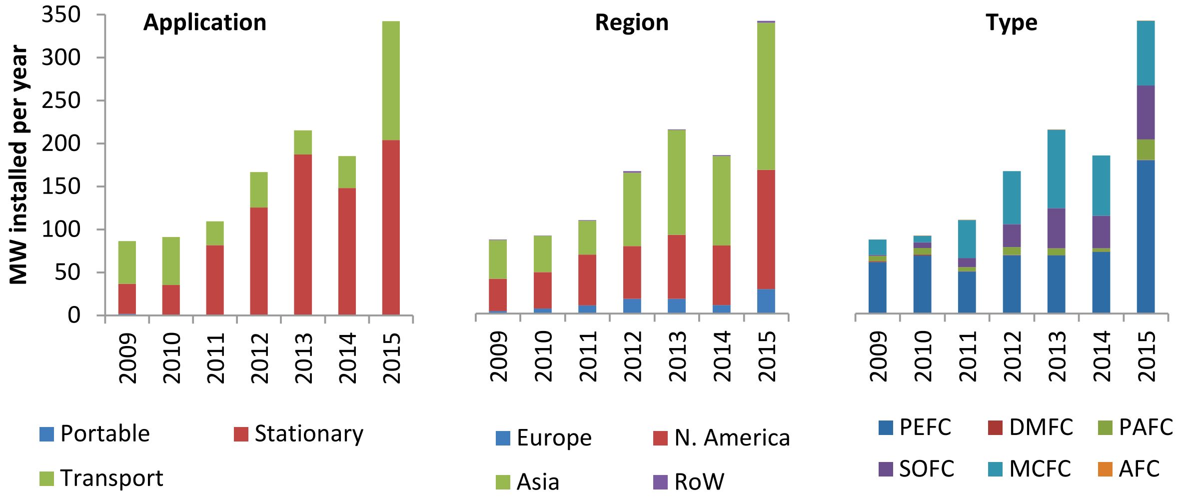

Figure 16.1: Global annual fuel cell new installations by fuel cell application, region and type. Source: Hart, Lehner et al. (2015). RoW: Rest of the world.

16.1.3 Swiss trends

There was already a 200 kW PAFC CHP system installed in Geneva in 1993, followed by another in Birsfelden, Basel Land in 2000 (Reese and Bode 2002). The systems had electrical efficiencies of nearly 40% and system efficiencies approaching 70%. Both systems were manufactured by UTC Fuel Cells, which is now Doosan Fuel Cell America[375]. A 230 kW MCFC system has been in operation in Grünau, Zürich since 2010. The system operates over 8000 hours per year with an average electrical efficiency of 42%. The 170 kW heat produced by the system is fed into the local district heating network. The overall system efficiency is approximately 80% (EWZ 2015).

Since 2012, project Pharos, funded by the Forschungs-, Entwicklungs- und Förderungsfonds der Schweizerischen Gasindustrie (FOGA), is supporting the installation of ten SOFC micro CHP systems in Switzerland (SVGW 2013). The installed systems are of the manufacturers Hexis and Ceramic Fuel cells (CFCL). Hexis, a Swiss company, based in Winterthur, has recently released its first commercial fuel cell system in 2013.[376] CFCL was an Australian company that produced a 1.5 kW electrical SOFC system, but now belongs to the Italian Solid Power.[377] The company Bruderus is currently testing their prototype SOFC, the FC10, in Zug (Bruderus 2015). Furthermore, several Swiss gas utilities are teaming up with fuel cell manufacturers to offer fuel cell CHP systems for residential heating. For example, GRAVAG Erdgas AG, a gas utility in north-eastern Switzerland will offer the Baxi Innotech GAMMA 1.0 starting in 2015 to its customers (GRAVAG 2015). The ene.field project website keeps an up-to-date list of the manufacturers that are currently offering micro-CHP fuel cell systems in western Europe (enefield.eu 2015). Vuille, Hart et al. (2014) provides a summary of fuel cell activities in Switzerland, including all relevant industrial and academic players. Figure 16.2 shows the location of known fuel cell installations in Switzerland as of 2014 (Nerlich and Seifert 2014).

[375] www.doosanfuelcell.com
[376] www.hexis.com
[377] www.solidpower.com

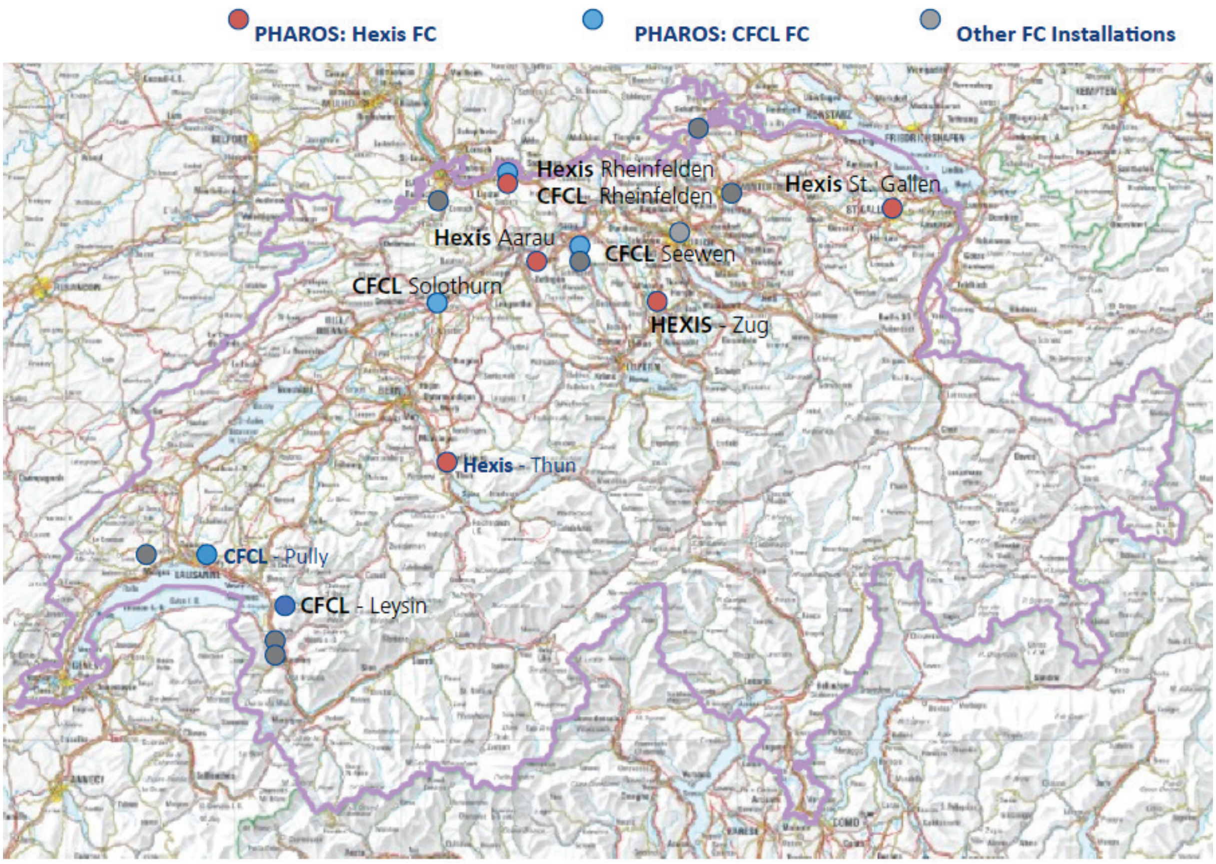

Figure 16.2: Known fuel cell installations in Switzerland in 2014. Source: (Nerlich and Seifert 2014)

16.2 Technology description

16.2.1 Literature review

The first task in this section was to compile current literature discussing the performance indicators, costs and environmental performance of fuel cells that are used in stationary electricity generation. Table 16.2 summarizes the literature reviewed and their main topics. Papers published in the past 15 years were considered, with special attention paid to review articles published in the past two years in order to ensure that the latest trends and developments are considered.

Table 16.2: Literature review summary

Study	Cost	Environment	Performance	Fuel Cell Type Analyzed					
				PEFC	MCFC	SOFC	PAFC	AFC	DAFC
Alkaner and Zhou (2006)		x			x				
Badwal, Giddey et al. (2015)				x		x		x	x
Baratto and Diwekar (2005)	x	x	x			x			
(Baratto, Diwekar et al. 2005)	x		x			x			
K.U. Birnbaum (2012)	x	x	x	x		x			
Cánovas, Zah et al. (2013)		x				x			
Chen, Chen et al. (2011)				x		x			x
Choudhury, Chandra et al. (2013)			x						
Cox and Treyer (2015)	x	x						x	
Dell, Moseley et al. (2014)			x	x	x	x	x	x	x
Dincer and Zamfirescu (2014)				x	x	x	x	x	x
Dodds, Staffell et al. (2015)	x		x						
Elmer, Worall et al. (2015a)	x		x			x			
Elmer, Worall et al. (2015b)	x		x	x		x			
Gerboni, Pehnt et al. (2008)	x	x		x	x	x			
Greene (2011)	x			x	x	x	x		x
Halliday, Ruddell et al. (2005)	x	x		x		x	x		
IEA (2015e)	x		x	x		x			
Kannan, Leong et al. (2007)	x	x		x					
Kanuri and Motupally (2011)			x				x		
Karakoussis, Leach et al. (2000)		x				x			
Karakoussis, Brandon et al. (2001)		x				x			
Kirubakaran, Jain et al. (2009)	x		x	x	x	x	x	x	x
Lee, Ahn et al. (2015)		x				x			
Lewis (2014)	x								
Lin, Babbitt et al. (2013)		X				x			
Lunghi (2004)		x			x				
Lunghi and Bove (2003)		x			x				
Mekhilef, Saidur et al. (2012)	x		x	x	x	x	x	x	x
Monaco and Di Matteo (2011)		x			x				
Mori, Jensterle et al. (2014)		x		x					
Nease and Adams (2015)		x				x			
Osman and Ries (2007)		x				x			
Pade and Schröder (2013)	x					x			
Pehnt (2000)		x				x			
Pehnt (2001)		x		x					
Primas (2008)	x	x	x	x		x			
Raugei, Bargigli et al. (2005)		x			x				
Rivera-Tinoco, Schoots et al. (2012)	x					x			
Roland Berger Strategy Consultants (2015)	x	x	x	x	x	x		x	
Schoots, Kramer et al. (2010)	x			x			x	x	
Sharaf and Orhan (2014)	x		x	x	x	x	x	x	x
Squadrito, Andaloro et al. (2014)	x		x	x	x	x	x	x	

				Fuel Cell Type Analyzed					
Study	**Cost**	**Environment**	**Performance**	**PEFC**	**MCFC**	**SOFC**	**PAFC**	**AFC**	**DAFC**
Staffell and Green (2009)	x			x					
Staffell and Green (2013)	x			x		x	x		
Staffell and Ingram (2010)		x						x	
Staffell, Ingram et al. (2012)		x				x			
Strazza, Del Borghi et al. (2010)		x				x			
Strazza, Del Borghi et al. (2015)	x	x				x			
van Rooijen (2006)		x					x		
Wilson, Lavery et al. (2013)		x						x	
Zucaro, Fiorentino et al. (2013)		x			x				

16.2.2 Fuel cell performance

The following section describes in more detail the performance assumptions used in this analysis. They were developed by comparing the most recent values published in the literature reviewed above. The main sources used to develop this table were (Birnbaum 2012, K.U. Birnbaum 2012, Mekhilef, Saidur et al. 2012, Staffell and Green 2013, Dell, Moseley et al. 2014, Lewis 2014, Dodds, Staffell et al. 2015, Elmer, Worall et al. 2015b, enefield.eu 2015, Roland Berger Strategy Consultants 2015). The future capital cost trends are taken from Staffell and Green (2013) and Roland Berger Strategy Consultants (2015). Due to the wide variety of values found in the literature, all values are reported as base case values along with a conservative (cons.) and optimistic (opt.) value. System capital costs include installation fees and have been adapted to estimate Swiss conditions.

Systems are assumed to operate 4000 hours per year. The system lifetime is assumed here to be equivalent to the stack lifetime, despite the fact that the stacks can be replaced during the lifetime. The reason for this is that the stack lifetime assumptions used here are high, allowing system lifetimes of at least 10 years in 2015 and increasing to 20 years or higher in the future for all systems. These system lifetimes are within the values quoted by manufacturers and literature.

Starting in 2035, SOFC and MCFC systems are assumed to be hybrid systems using the fuel cell off-gas to generate additional electricity in a heat engine (such as a gas or steam turbine) before utilizing the lower temperature exhaust for heating purposes. Thus, efficiencies are much higher.

Table 16.3: Fuel cell system performance indicators. Cost values are for European installations. Sources: (Staffell and Green 2009, Mekhilef, Saidur et al. 2012, Dell, Moseley et al. 2014, Lewis 2014, Dodds, Staffell et al. 2015, Elmer, Worall et al. 2015b, enefield.eu 2015).

				PEFC			SOFC			SOFC			MCFC			PAFC	
			Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.
Electrical Capacity	kW		1	1	1	1	1	1	300	300	300	300	300	300	300	300	300
Electrical Efficiency	LHV	2015	32%	35%	38%	35%	37%	40%	48%	51%	54%	39%	42%	45%	35%	38%	41%
		2020	35%	38%	41%	37%	40%	43%	52%	55%	58%	41%	44%	47%	37%	40%	43%
		2035	39%	42%	45%	42%	45%	48%	60%	63%	66%	52%	55%	58%	39%	42%	45%
		2050	42%	45%	50%	47%	50%	53%	62%	65%	68%	57%	60%	63%	42%	45%	48%
CHP Efficiency	LHV	2015	70%	80%	90%	70%	80%	90%	70%	80%	90%	70%	80%	90%	70%	80%	90%
		2020	75%	85%	92%	75%	85%	92%	75%	85%	92%	75%	85%	92%	75%	85%	92%
		2035	78%	88%	93%	78%	88%	93%	78%	88%	93%	78%	88%	93%	78%	88%	93%
		2050	80%	90%	95%	80%	90%	95%	80%	90%	95%	80%	90%	95%	80%	90%	95%
Heat Temperature	°C	2015	40	50	70	80	80	80	80	80	500	80	80	500	80	80	120
		2020	50	60	80	80	80	80	80	80	500	80	80	500	80	80	120
		2035	60	70	80	80	80	80	80	80	200	80	80	200	80	80	120
		2050	70	80	80	80	80	80	80	80	200	80	80	200	80	80	120
System Lifetime	years	2015	10	11	13	10	11	13	10	11	13	10	10	13	18	20	26
		2020	11	13	16	11	15	20	11	15	20	10	13	16	18	23	29
		2035	13	15	20	14	20	26	14	20	26	11	15	20	19	28	30
		2050	14	20	26	16	23	29	16	23	29	14	20	26	23	30	30
Stack Lifetime	thousand hours	2015	40	45	52	40	45	52	40	45	52	40	40	52	70	80	104
		2020	45	50	65	42	60	78	42	60	78	40	50	65	63	90	117
		2035	50	60	78	56	80	104	56	80	104	42	60	78	77	110	120
		2050	56	80	104	63	90	117	63	90	117	56	80	104	91	120	120
Capital Costs	CHF/kW	2015	30000	25000	18000	30000	25000	18000	18000	15000	12000	6000	4000	3200	9000	6000	4800
		2020	24000	16000	10000	24000	16000	10000	15000	10000	8000	5700	3800	3040	7500	5000	4000
		2035	15000	10000	4000	15000	10000	4000	10000	4000	3200	6000	4000	3200	4500	3000	2400
		2050	10000	4000	2000	10000	4000	2000	4500	3000	2400	4500	3000	2400	4000	2500	2000
O&M Costs	CHF/kW	2015	500	400	300	500	400	300	120	100	70	120	100	70	120	100	70
		2020	400	300	200	400	300	200	100	70	45	100	70	45	100	70	45
		2035	300	250	200	300	250	200	70	45	45	70	45	45	70	45	45
		2050	250	200	200	250	200	200	70	45	45	70	45	45	70	45	45

16.3 Technical potential for electricity generation

The technical potential for electricity generation from fuel cells is not a useful metric as it is, by definition, unlimited. The simplest method of estimating an upper limit of the potential for electricity generation with fuel cells in Switzerland would be to assume that all heating demand was met by fuel cell CHP. This is also not helpful, as the electricity supplied to meet the 2010 heat demand would still be over 100 TWh/a. As discussed in Appendix II-2 of the Swiss Energy perspectives until 2050 (Kirchner, Bredow et al. 2012), this potential can be limited to the economically weighted technical potential by taking into account considerations such as existing natural gas and district heating networks, the difference between baseload and peak heat demand, the controllability of CHP plants as well as investment, fuel and electricity costs. Even with these considerations in place, the 2010 economically weighted potential for electricity generation from CHP plants in Switzerland was calculated to be 16.5 TWh (Kirchner, Bredow et al. 2012). The Swiss Energy Perspectives also describe what is considered to be the realistic potentials of electricity generation from CHP plants until 2050, which are reproduced in Figure 16.3 below. These consider the potential replacement rates of conventional oil and natural gas heaters in addition to the above. This estimation of potential does not include any limitations on greenhouse gas emissions.

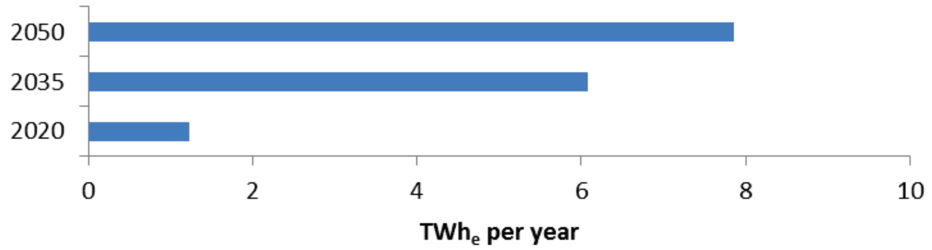

Figure 16.3: Economically realizable electricity generation potential from small combined heat and power plants.

16.4 Costs

16.4.1 Current and future technologies

This section shows results for current and future fuel cell levelised cost of electricity calculations. The fuel cell performance characteristics such as system efficiency, lifetime, capital costs and O&M costs are found in Table 16.3. The range of values shown in Table 16.3 is also included in the results figures as a simple estimate of the uncertainty in the results.

A discount rate of 5% was used to include the time value of money. The current (2015) natural gas price is assumed to be 0.084 CHF/kWh for households (1 kW$_{el}$ units) and 0.056 CHF/kWh for larger installations (300 kW$_{el}$ units). These prices are expected to slowly increase to 0.110 CHF/kWh and 0.082 CHF/kWh by 2050, respectively, as discussed in chapter 5.2.3. Biomethane prices were calculated with a 0.075 CHF/kWh surcharge based on the prices of Energie360, a gas provider in Zurich (Energie360 2016). As the heat is assumed to displace the use of a natural gas boiler, the heat produced by the fuel cells is credited with a value equal to the price of substituting natural gas or biomethane. The higher heating value was used for heat produced at temperatures below 100°C, while the lower heating value was used for all heat produced at temperatures above 100°C. End-of-life costs have been assumed to be equal to the scrap value of the system.

When examining the results, shown in Figure 16.4 and Figure 16.5, the significant decrease in capital costs for PEFC and SOFC in the coming decades is noticeable. This reduction is due to a combination of decreasing purchase costs and increasing lifetimes and is despite increasing gas prices. Current electricity prices from micro CHP systems range from 0.65-1.25 CHF/kWh, though these are expected to decrease rapidly in the future to a range of 0.25-0.47 CHF/kWh by 2050. It is noted that micro CHP systems are usually operated according to required heat demand, and thus the costs of electricity are higher than if their operation were optimized for electricity generation.

Electricity costs from larger fuel cell CHP systems currently range from 0.17-0.70 CHF/kWh, depending strongly on the maturity of the technology used. By 2050, these prices are expected to decrease to the range of 0.13-0.24 CHF/kWh. Price premiums for biomethane fuel cell systems are 0.08-0.14 CHF/kWh for all systems.

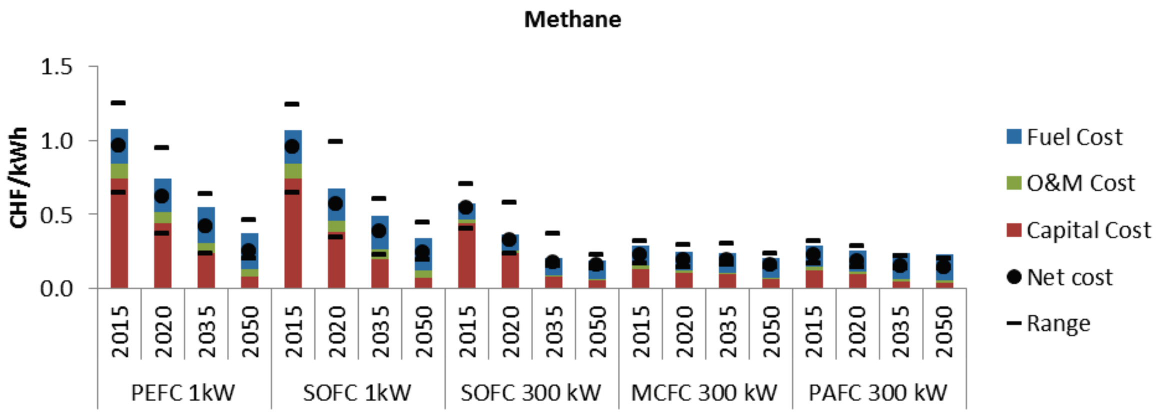

Figure 16.4: Electricity generation costs from combined heat and power fuel cell systems powered by natural gas in Switzerland until 2050.

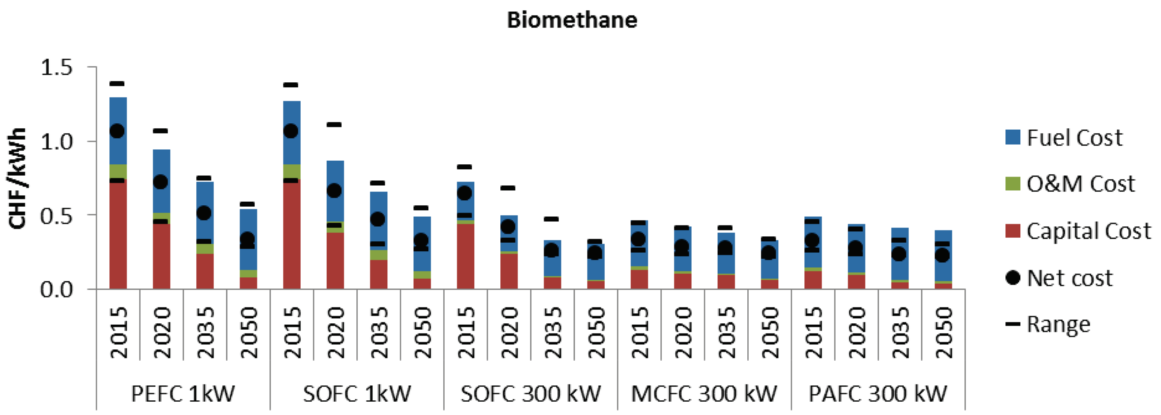

Figure 16.5: Electricity generation costs from combined heat and power fuel cell systems powered by biomethane in Switzerland until 2050.

16.4.2 Sensitivity Analysis

Sensitivity analysis was performed on the electricity generation cost results for the most important input parameters which were varied between the highest and lowest values listed in Table 16.3. As can be seen in Figure 16.6, the input parameters with the largest variability are system lifetime and capital cost. Results are most sensitive to system capital costs and fuel costs, though system lifetime also has significant impact on results. Interestingly, cost results are relatively insensitive to system efficiency and fuel price within the reasonable range of input parameters.

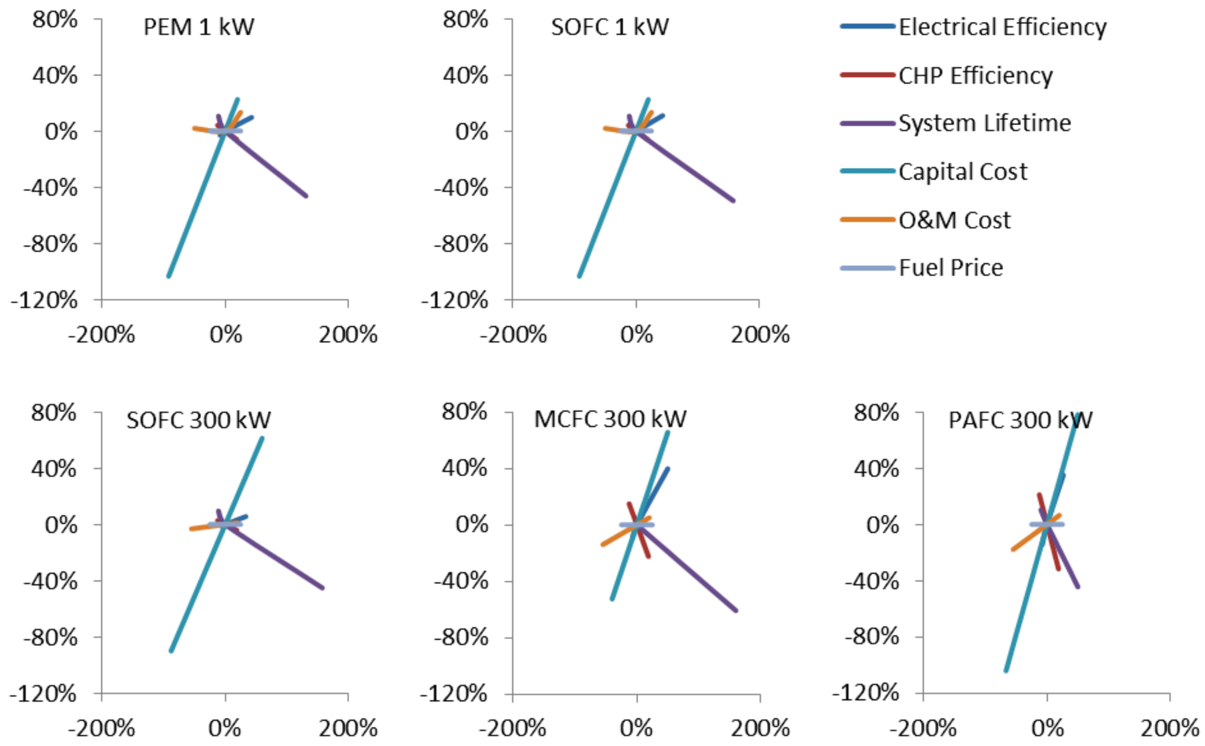

Figure 16.6: Cost sensitivity analysis results. The x axis shows the variation in input parameters, while the y axis shows the variation in results.

16.5 Environmental aspects

16.5.1 Climate change potential – greenhouse gas (GHG) emissions

Environmental burdens were calculated for life cycle climate change potential (in terms of emissions of CO_2eq.) according to the IPCC 2007 100 year methodology. Input parameters are described in Table 16.3, for the base case (Figure 16.7 and Figure 16.8), as well as conservative and optimistic scenarios, which are shown in Figure 16.9 and Figure 16.10.

Life cycle environmental impacts for fuel cell production are based on results from the NEEDS project (Gerboni, Pehnt et al. 2008), with consideration of the results from the other studies listed in Table 16.2. All other life cycle environmental impacts are directly from the ecoinvent database, version 3.1 (ecoinvent 2014a). The biomethane is assumed to be transported to the end user via the natural gas grid and is sourced from upgraded biogas from anaerobic digestion of manure and sewage sludge (ecoinvent 2014a).

Results for heat and electricity production are quantified per kilowatt-hour of electricity produced by the system in Figure 16.7 for methane and Figure 16.8 for biomethane fuel sources. In order to better compare fuel cell systems to other electricity production methods, the burdens need to be separated between heat and electricity production. There are two reasonable methods of performing this allocation. The first is allocation based on the exergy of the products which, due to the low temperature of the heat supplied, gives the majority of the impacts to electricity generation. The second allocation method is based on the concept of system expansion. In this allocation method the theoretical environmental burdens of heat production using a state of the art natural gas furnace with 100% conversion of the energy in natural gas to usable heat are subtracted from the total burdens of the fuel cell, with the result being the environmental burdens of producing electricity with the fuel cell system. This system allocates the burdens of heat and electricity production more equally. Allocated results are shown in Figure 16.9 and Figure 16.10 for both the base case as well as the range resulting from the conservative and optimistic scenarios. As can be seen from the results, the climate impacts of electricity production from fuel cells originate mostly from the fuel production and operation. The production and disposal of fuel cells was found to have comparatively little impact on results in the climate change impact category, indicating that fuel cell durability is a less important factor in terms of climate performance.

For fuel cells powered with methane, the burdens stem mostly from the operation phase where carbon dioxide is released into the atmosphere. For fuel cells powered with biomethane burdens originate in the fuel production phase, which has higher climate related emissions than for fossil methane. Despite these larger emissions from fuel production, the climate neutrality of the CO_2 released during the operation phase means that life cycle greenhouse gas emissions from biomethane powered fuel cells are only about two-thirds of those of fossil fueled fuel cells. Due to the expected efficiency improvements in the future, climate impacts from fuel cell electricity production are expected to decrease by roughly 25% by 2050.

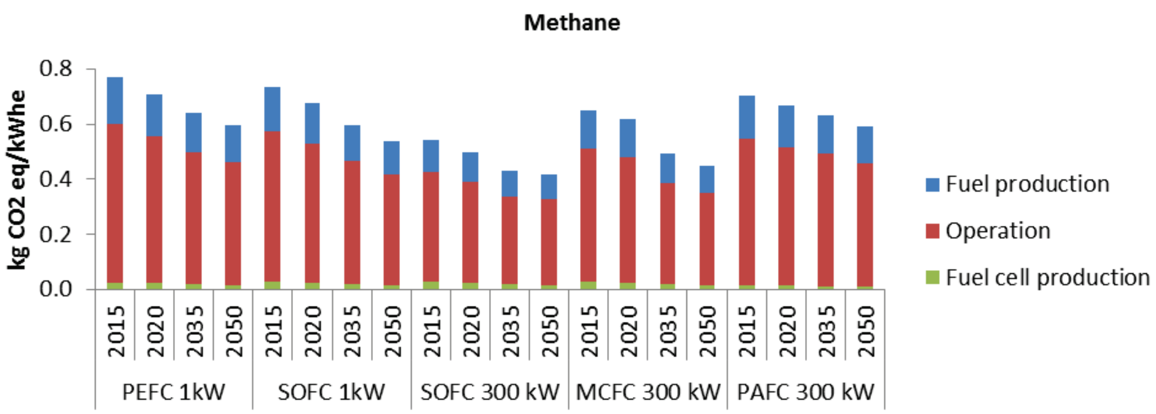

Figure 16.7: Lifecycle GHG emissions for current and future fuel cells powered by natural gas. Burdens for heat and electricity production are unallocated, though quantified per kilowatt-hour of electricity produced.

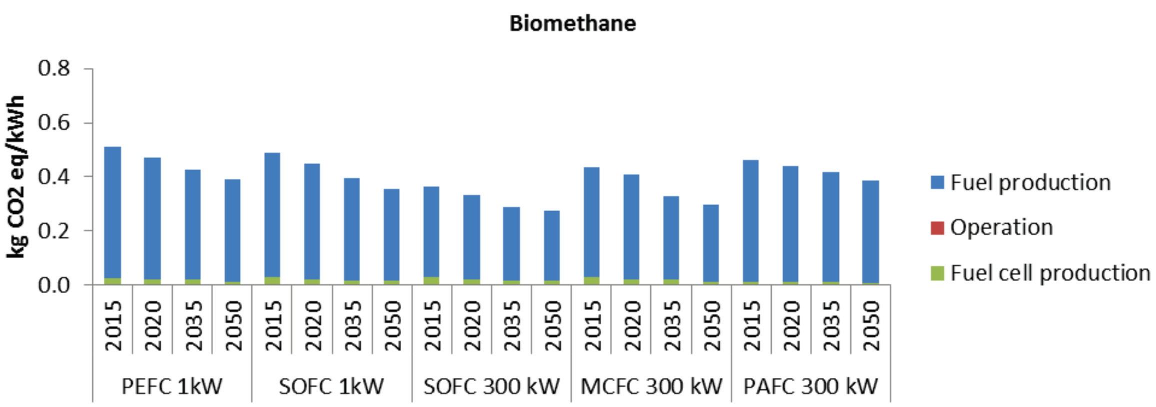

Figure 16.8: Lifecycle GHG emissions for current and future fuel cells powered by biomethane from sewage gas. Burdens for heat and electricity production are unallocated, though quantified per kilowatt-hour of electricity produced.

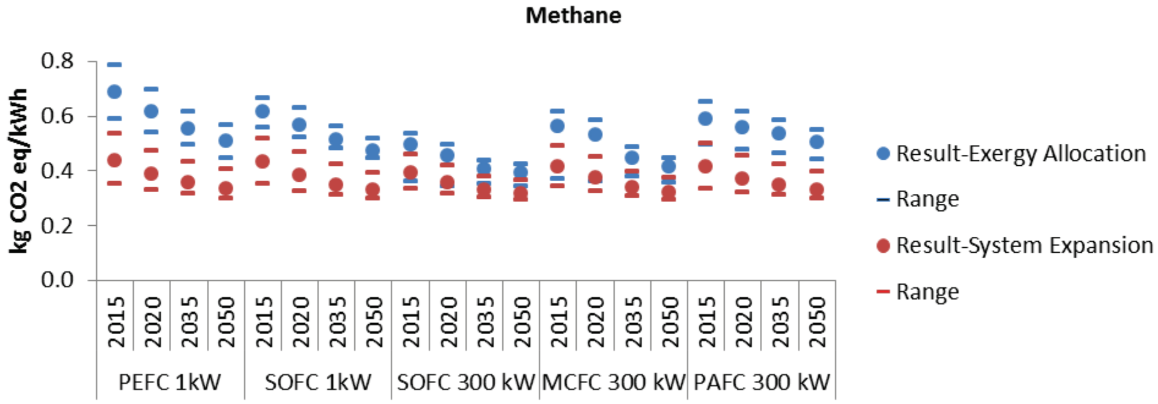

Figure 16.9: Lifecycle GHG emissions for current and future fuel cells powered by natural gas. Burdens for heat and electricity production are allocated by exergy allocation and system expansion, though quantified per kilowatt-hour of electricity produced.

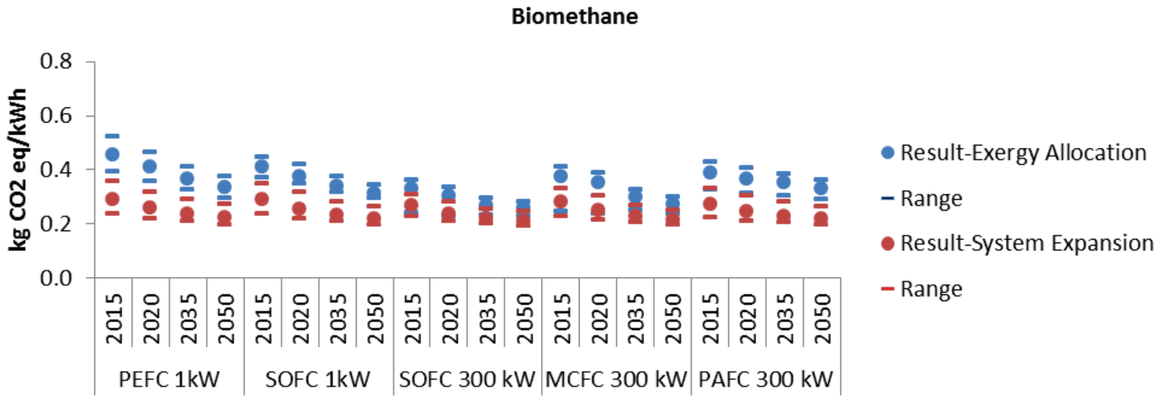

Figure 16.10: Lifecycle GHG emissions for current and future fuel cells powered by biomethane from sewage gas. Burdens for heat and electricity production are allocated by exergy allocation and system expansion, though quantified per kilowatt-hour of electricity produced.

16.5.1.1 Sensitivity Analysis

Sensitivity analysis was performed on the GHG results for the most important input parameters which were varied between the highest and lowest values listed in Table 16.3. The sensitivity was calculated for both exergy and system allocation methods, with differing results. For exergy allocation, the results were found to be most sensitive to system electrical efficiency. For system expansion allocation, the system total efficiency (CHP efficiency) is found to have the most impact on results, though electrical efficiency is also important.

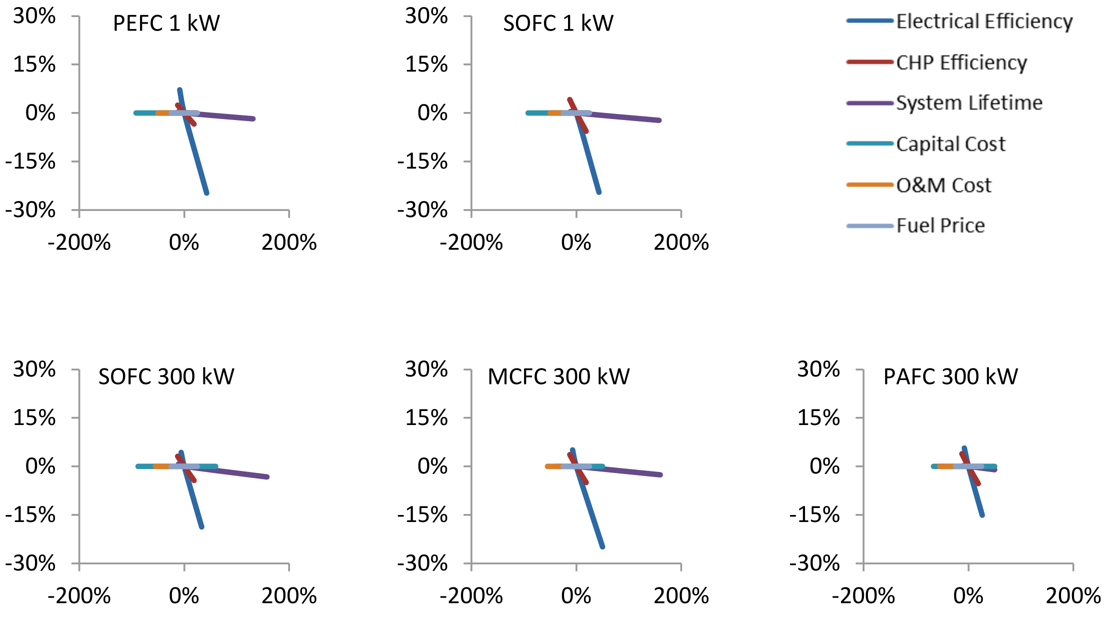

Figure 16.11: Greenhouse gas sensitivity analysis results calculated with exergy allocation. The x axis shows the variation in input parameters, while the y axis shows the variation in results.

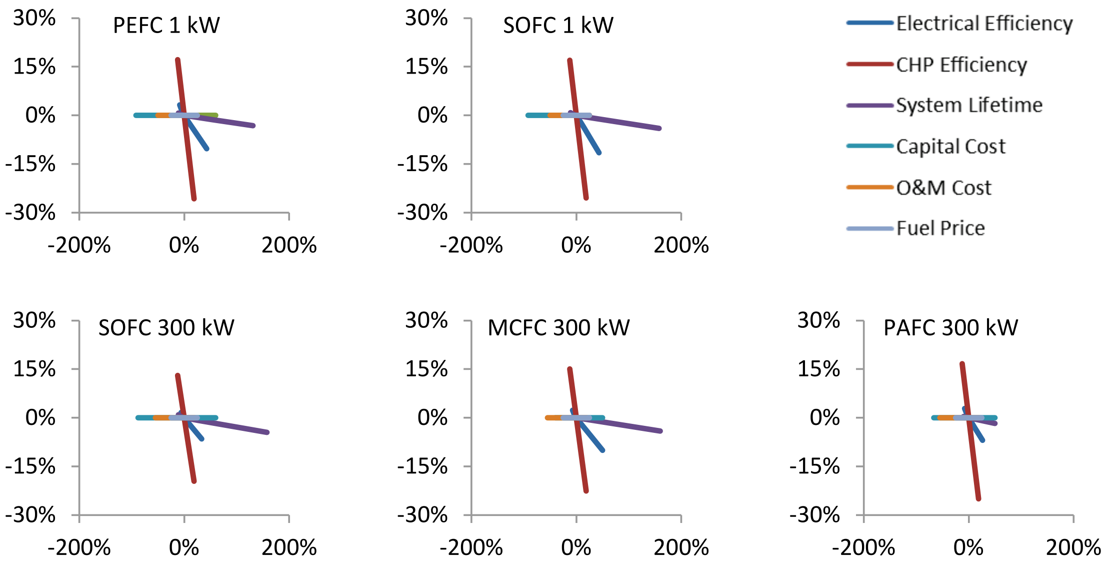

Figure 16.12: Greenhouse gas sensitivity analysis results calculated with system expansion allocation. The x axis shows the variation in input parameters, while the y axis shows the variation in results.

16.5.2 Other environmental impact categories

Although the scope of this analysis was limited to life cycle GHG emissions, other environmental impact categories should also be considered. In Figure 16.13 the values found in the literature (sources: Table 16.2, environment) for fuel cell global warming potential, terrestrial acidification potential, photochemical oxidant formation potential and particulate matter formation potential are summarized, showing both the mean and, where available, the range of values published. The mean global warming potential results are quite consistent with the exergy allocation results presented in Figure 16.9. The values found in the literature can vary quite substantially, depending on the level of detail in the study and the assumed performance characteristics.

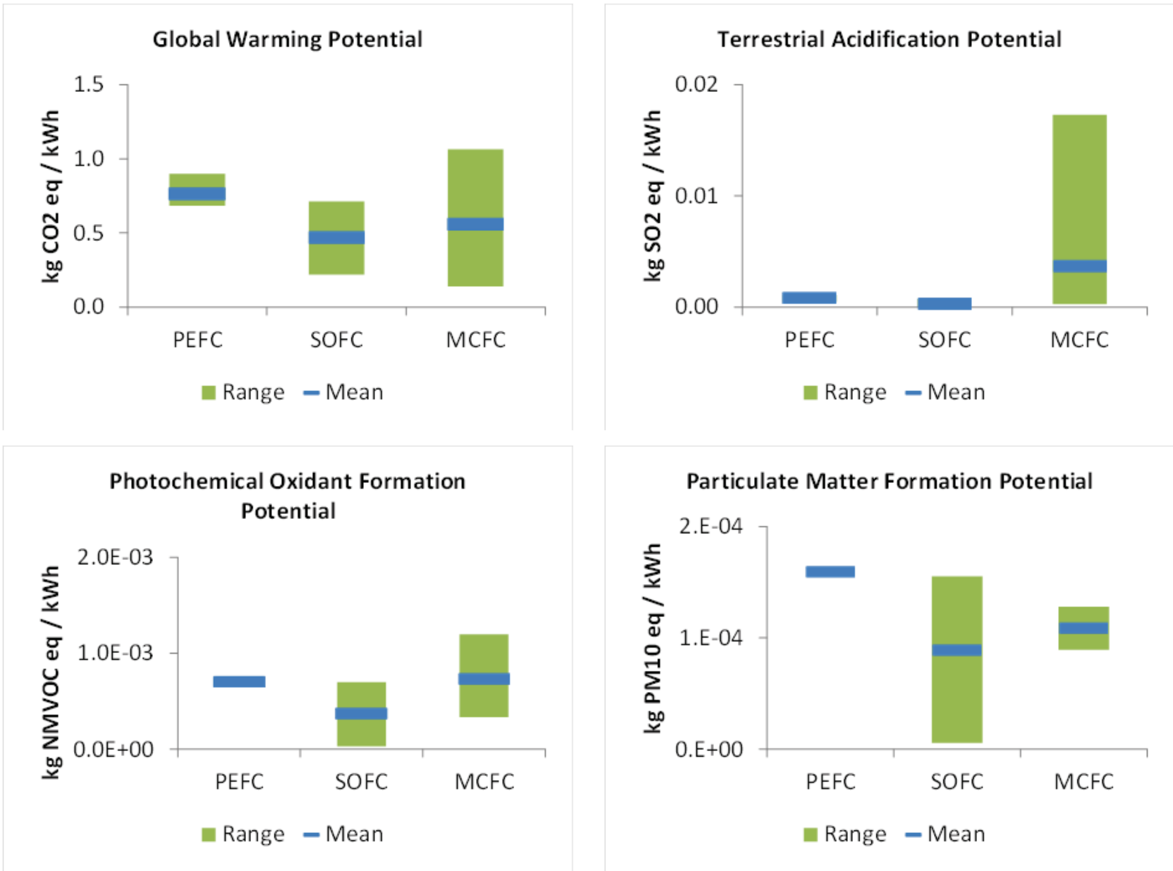

Figure 16.13: Literature review results for environmental burdens (sources: Table 16.2, environment). The blue line represents the mean of values found in the literature, while the green bar represents the range of values published. Where no green bar is present, this is because there was only one value found in the literature. No values were found for PAFC fuel cells.

16.6 Development and market

Fuel cell development relies heavily on reaching economies of scale so that production costs can decrease. Significant cost reductions are required before fuel cells can compete economically with other home heating systems. Demonstration projects such as the ene.farm, ene.field, and Callux provide subsidized fuel cell systems for consumers in order to increase consumer awareness of fuel cells while helping to achieve the production numbers that will drive down production costs. For example, experience from the ene.farm project has led to a per system cost decrease by over half since the project started in 2009, with plans to remove government subsidies altogether by 2017 as these systems are expected to be competitive with standard Japanese technology (Panasonic 2015, Rose 2015). As costs continue to decrease in the future, fuel cells will become even more competitive with other small CHP systems which should increase sales and further drive down costs.

16.7 Open questions and research activities

The main areas of improvement for fuel cell CHP systems are fuel cell lifetime, performance degradation and system capital costs. Especially system capital costs will strongly impact the future development of fuel cell micro CHP, as this is the main market entry barrier against which producers are currently struggling.

16.8 Abbreviations

a	year
AC	alternate current
BAFU	Bundesamt für Umwelt
BFE	Bundesamt für Energie
CAPEX	Capital expenses
CH	Switzerland
CHF	Swiss Francs
CHP	combined heat and power
CO_2eq	carbon dioxide equivalent
EU	European Union
DC	direct current
GHG	Greenhouse gas
HH	human health
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre
LCA	life cycle assessment
LCIA	life cycle impact assessment
LCOE	Levelised Cost of Electricity
LR	learning rate
max	maximum
MCFC	Molten Carbonate Fuel Cells
min	minimum
O&M	operation and maintenance
OPEX	Operating and maintenance expenses
PAFC	Phosphoric Acid Fuel Cells
PEFC	Polymer Electrolyte Fuel Cells
Rp.	Rappen (Swiss cents)
SOFC	Solid Oxide Fuel Cells
UK	United Kingdom
US	United States
USD	United States Dollar
WACC	weighted average cost of capital
yr	year

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17 Novel technologies

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17.1 Introduction

Technologies at an early stage of development and/or with very uncertain perspectives are discussed in this chapter. Due to their immature status, estimates for electricity generation potentials, costs and environmental impacts are either not possible, or associated with large uncertainties. Based on the currently available information, it cannot be judged whether these technologies will provide a contribution to Swiss electricity supply in the future.

17.2 Hydrothermal methanation of wet biomass – PSI's catalytic supercritical water process[378]

Frédéric Vogel (Bioenergy and Catalysis Laboratory, PSI)

This chapter covers PSI's catalytic supercritical water process for hydrothermal methanation of wet biomass. Other hydrothermal processes suited to convert wet biomass to a combustible gas and further to electricity are not discussed here, but can be found in (Vogel 2016b).

17.2.1 Introduction and overview

Biomass feedstock is prepared as a pumpable slurry, if needed by macerating and wet grinding. An organic dry matter content of at least 10 weight-% (wt%) should be targeted for an economical process. The slurry is pumped from the feed tank to the preheater by a high pressure slurry pump (Figure 17.1). The discharge pressure is typically in the range of 25-35 MPa. A tubular heat exchanger preheats the slurry to a temperature close to the critical one, ca. 350-360°C. During heating up, the solid biomass fraction is liquefied, while the salts present in the feedstock are kept dissolved. The heating rate in the preheater is chosen such as to minimize the formation of coke. The preheated and liquefied biomass stream then enters a separator vessel to precipitate and remove solid minerals and salts. This salt separator vessel is the key feature of PSI's process design. This vessel is heated to process temperature indirectly by hot fumes from a gas burner. The salt brine, along with some liquefied biomass, is removed continuously from the bottom of the separator. The remaining feed stream, cleaned from solid matter, enters the catalytic reactor, typically designed as a fixed-bed reactor, filled with a granular catalyst (ruthenium on a carbon support) and operated in an adiabatic mode. The reactor does not need to be heated nor cooled because the overall heat of reaction is close to zero. The catalytic reactions take place at 400-450°C and lead to a mixture of CH_4, CO_2, H_2, and some higher hydrocarbons such as ethane and propane. It is assumed that this gas mixture forms a homogeneous phase with the supercritical water inside the reactor.

[378] This chapter is based on (Vogel 2016a)

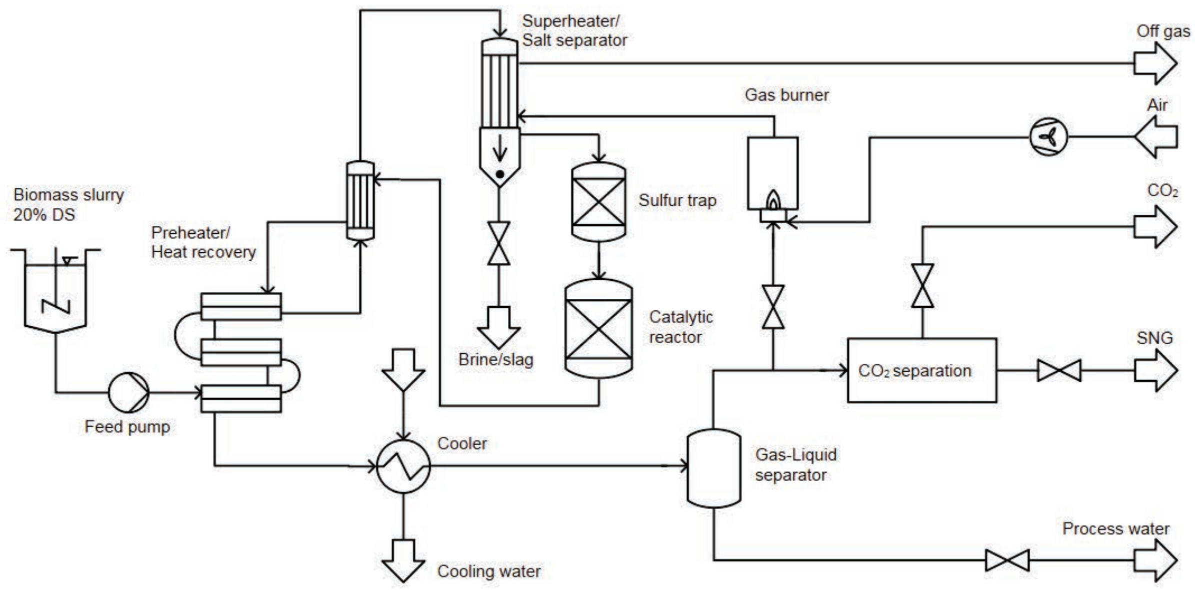

Figure 17.1: Simplified process flowsheet of PSI's catalytic hydrothermal SNG process. DS = dry solids. SNG = synthetic natural gas.

After leaving the reactor, the hot effluent is cooled in the preheater heat exchanger. The water-gas mixture becomes now a two-phase mixture. It is further cooled to below 100°C by an additional cooler. Here, care must be taken not to cool the mixture below ca. 20°C because at the high partial pressures of methane gas hydrates (or "clathrates") may form and cause a blockage of the cooler.

The two-phase mixture is then separated in a vessel under pressure. The gas and liquid phases are depressurized independently. One stream is the process water, containing most of the feedstock's nitrogen as ammonia, dissolved as ammonium carbonate. It will also contain some small amounts of residual salts not separated in the salt separator. Depending on the level of feedstock conversion the catalytic reactor is designed for, some small amount of residual organics are present in the process water. These organics are normally not causing a strong coloration or odor of the water.

A fraction of the gas phase from the gas-liquid separator is fed to a gas burner to provide the hot fumes needed to heat the salt separator to process temperature. These fumes leave the salt separator still at a high temperature (ca. 550°C) and, in a larger plant, may be used to co-produce additional electricity. The raw SNG contains about 45 vol% CH_4, 50 vol% CO_2, and 3-4 vol% H_2, as well as 1-2 vol% of higher hydrocarbons. If needed, the content of CO_2 can be reduced by scrubbing it with pressurized water, or with other available processes such as pressure swing adsorption.

The experimental proof of the design concept with the simultaneous gasification and salt separation, as well as autothermal operation of the catalytic reactor, was reported by Schubert, Müller et al. (2014).

17.2.2 Mass balance

The mass balance of a hypothetical plant processing 4.4 t of wet sewage sludge per hour with 22% dry solids was calculated using Aspen plus (Vogel 2012). The results are shown in Table 17.1.

Table 17.1: Calculated input and output mass flows for a hypothetical hydrothermal methanation plant processing 4.4 t/h of wet sewage sludge to SNG (Vogel 2012).

	Input (t/h)	Output (t/h)
Water (from sludge)	3.4	
Dry solids (from sludge)	1.0	
Air	2.2	
SNG		0.7
Process water		3.0
Flue gas		2.3
Brine – water		0.3
Brine – organics		0.07
Brine - inorganics		0.23
Total	**6.6**	**6.6**

The composition of the SNG after gas-liquid (G-L) phase separation was calculated to be: 46.2 vol% CH_4, 48.2 vol% CO_2, 4.4 vol% H_2, 1 vol% H_2O, and 0.2 vol% NH_3. The latter is an undesired component and its concentration in the SNG can be controlled by adjusting the pH in the G-L separator.

These data are based on idealized calculations assuming complete chemical equilibrium at the exit of the catalytic reactor and perfect salt separation. It should be used with caution, especially regarding the composition of the brine. One can see that the dry solids are mostly converted to SNG, together with a small fraction of the water. Considerable amounts of air are needed for the gas burner, resulting in a large amount of hot flue gas. In this simulation, the flue gas was used to preheat the combustion air. It may alternatively be used for generating electricity via a steam cycle, but this option would make sense only for larger plants.

The brine would typically contain most of the dissolved and suspended minerals from the feed. Although nitrogen will be mostly recovered in the process water as NH_4HCO_3, we found that some nitrogen may also be removed from the salt separator as solid magnesium ammonium phosphate (MAP or struvite; (Zöhrer, De Boni et al. 2014)). An important aspect of the hydrothermal methanation is that nitrogen in the feed is not lost to a flue gas but recovered as a nutrient salt. This applies of course also to most of the other nutrient elements such as K, P, Mg, Ca, etc. An element that has not been well studied at hydrothermal conditions is silicon. Its hydrothermal chemistry is complicated by the formation of oligomeric and polymeric species. Sewage sludge and other waste biomass are xenobiotic sources of organosilicon compounds, besides the natural sources from plants and aquatic biomass. These organic Si-compounds would most likely be converted to inorganic Si-compounds during high-temperature gasification (HTG).

17.2.3 Energy balance

The energy flow diagram for the same process simulation is shown in Figure 17.2. A considerable amount of energy is recirculated within the process itself in the feed heat exchanger. This part of the equipment is therefore key to a high thermal efficiency of the process. The high pressure slurry pump has only an insignificant power uptake because the feed is considered incompressible. Some losses occur with the hot brine and the heating value of the organics therein. For the well-insulated, adiabatic catalytic reactor, some heat loss to the surrounding air has been assumed. The process water contains most of the feed nitrogen in the form of NH_3 (or NH_4HCO_3). Since nitrogen is included in the calculation of the feed's heating value, it has to be accounted for as well in the energy balance, contributing ca. 10% of the feed's heating value.

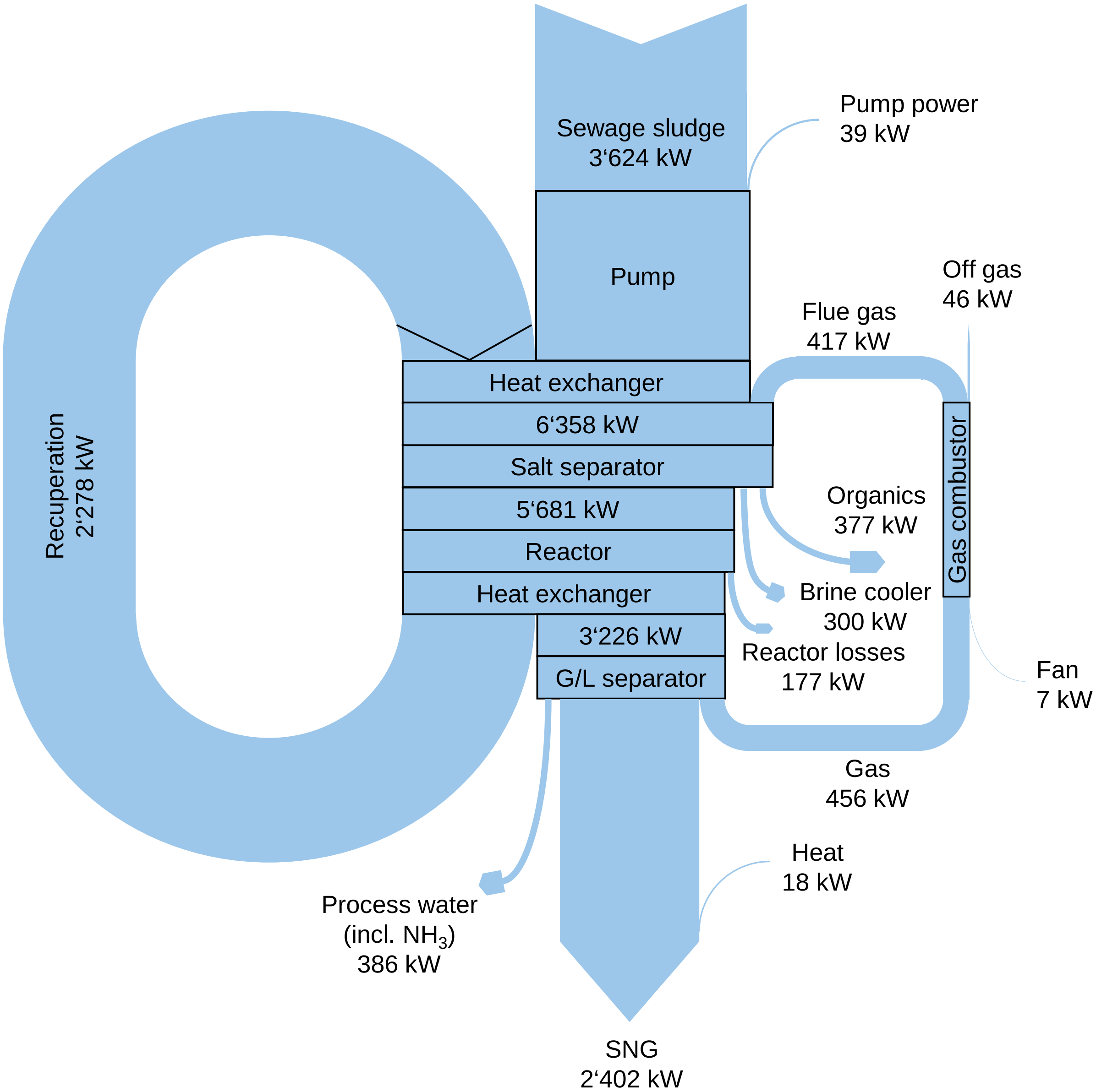

Figure 17.2: Energy flow diagram of PSI's catalytic hydrothermal SNG process for sewage sludge as feedstock. All enthalpies were calculated at 0.1 MPa and 25°C (Vogel 2012).

The thermal efficiency of this particular case is 66%, based on the lower heating value of the sewage sludge's dry solids and the one of the SNG produced. This is considered an upper limit for this process when using a feedstock with high content of minerals such as sewage sludge, animal manure, or algae. It may be increased by thermally integrating the hot brine stream and by minimizing reactor heat losses. Also, with feedstocks low in minerals, such as wood or spent coffee grounds, thermal process efficiencies higher than 70% may be achieved (compare Figure 17.4).

17.2.4 Status of developments and prospects for the future

17.2.4.1 Current status

PSI's hydrothermal SNG process has been demonstrated at the laboratory scale with a throughput of 1 kg/h using a number of model and real biomass feeds. As an important milestone, the simultaneous salt separation and methanation at autothermal conditions was successfully demonstrated by (Schubert 2010, Schubert, Müller et al. 2014). Operational difficulties for processing solids-containing streams owing to the small orifices in such a small-scale plant make it necessary to scale up the technology within reasonable limits. In 2010, the company Hydromethan AG has been founded to realize the scaling up and commercialization of the process. To this aim, a prototype salt separator vessel with an industrial design has been built and tested at a scale of 25 kg/h in KIT's pilot plant VERENA (Vogel 2015, Boukis, Herbig et al. 2016). Furthermore, an engineering study for a demonstration plant with a capacity of 1 t/h has been performed. The main conclusion was that such a technology can be realized at industrial scale in a safe and economically viable way.

In parallel, the mobile hydrothermal methanation plant KONTI-C with a capacity of 1 kg/h has been built at PSI to allow for longer term campaigns with a variety of real feeds, in particular algae (Figure 17.3). It has been operated successfully on an algae feedstock for about 100 hours of continuous operation in August 2014. Currently, a pilot plant with a capacity of ca. 100 kg/h is being erected at PSI within SCCER BIOSWEET[379]. It is planned to be operational in 2018.

Figure 17.3: PSI's mobile hydrothermal SNG plant KONTI-C.

A similar concept was realized at Pacific Northwest National Laboratory (USA) with a trailer-mounted reactor system for their subcritical catalytic gasification process with a capacity of 10 kg/h (Elliott, Neuenschwander et al. 2004).

[379] www.sccer-biosweet.ch

17.2.4.2 Comparison to other SNG processes

PSI's catalytic hydrothermal SNG process has a number of features such as:

- Efficient production of SNG from wet biomass streams (sludges) with a content in organic matter as low as ca. 10 wt%.
- No need for drying the feedstock, mechanical dewatering is sufficient.
- High thermal process efficiencies, biomass-to-SNG, of 60-70% (typical) and beyond 70% can be reached for polygeneration of SNG, electricity, and heat.
- Feedstock flexibility: The process can be designed to accommodate a relatively wide range of feedstock compositions regarding water content, mineral content, chemical composition, viscosity, and pH. The most severe limits concern the pumpability (feeding), the sulfur content (catalyst lifetime), and the chloride content and pH (corrosion).
- Reduced effort for SNG purification due to the absence of dust and tars, and only very low levels of HCl, NH_3, alkali, SO_2, H_2S, etc. because these compounds mostly remain dissolved in the process water or end up in the salt brine.
- The SNG produced can be made available at high pressure directly from the process, avoiding additional compression losses in downstream processing.
- Recovery of the nutrients, including N, P, K, with high efficiency, to be used as fertilizers.
- No formation of a solid byproduct, e.g. coke or char.
- A favorable environmental performance (see section 17.2.7).
- Small plant footprint.
- Scalable from a few MW to ca. 20 MW of thermal input.

As with any novel bioenergy process, hydrothermal production of SNG presents also some challenges:

- Increased risk of corrosion due to the aqueous electrolyte environment.
- Higher capital and maintenance cost due to the high pressure equipment and materials of construction[380].
- Potentially higher risk of societal acceptance due to high pressures and temperatures.
- Long-term performance at industrial scale not yet proven.
- Only very limited industrial experience available from only a few companies for the design, engineering, construction, and operation of such plants.
- The organic fraction in the salt brine must be separated from the salts before their use as fertilizer. If it cannot be recycled within the process, this organic fraction will have to be disposed of, creating additional costs.

[380] This is alleviated somewhat by the relatively simple process design with only few key process units. E.g. there is no need for an intermediate gas cleaning step.

- Heavy metals will end up in the salt brine, making its work-up to a fertilizer more costly.

17.2.4.3 Potential future development

As with any catalytic biomass process, it is a long way to a full-scale demonstration under “real life” conditions. Only limited research has been performed for catalysis at hydrothermal conditions and thus, most concepts known from gas-phase catalytic processes such as steam reforming, had to be adapted and restudied first under hydrothermal conditions (Vogel 2009). This process is not yet completed, and we keep discovering new aspects of this interesting topic in our daily work.

The aspect of the behavior of minerals at hydrothermal conditions bears many parallels to geochemical and geothermal situations. On the other hand, our findings related to SNG production may be of value to the geo-process field as well. The management of the hot brine from the geothermal production well in the surface power plant is a key topic in geothermal energy generation. Our findings and results on continuous salt separation from supercritical water may hopefully inspire our colleagues in the geothermal field. A closer cooperation could lead to fruitful discussions and novel ideas in both areas, hydrothermal processing of biomass and geothermal energy.

Several aspects of catalytic hydrothermal SNG production from biomass have not yet been studied in sufficient detail. Besides catalysis and minerals behavior, hydrodynamic flow simulations at supercritical water conditions relevant to SNG production have only been tackled by a few groups. The non-ideal phase behavior of supercritical fluids and mixtures and the steep gradients in physical properties near the critical point make these computations time-consuming. The limited accuracy of current equations of state, especially for mixtures, is a big obstacle in using such simulations as a predictive tool. Further phenomena that are not well described by physical models for practical application at hydrothermal conditions include salt nucleation and precipitation kinetics and reaction kinetics for mixed feeds. A promising approach may be the use of a Distributed Activation Energy Model (DAEM), based on carbon conversion. Although it was applied to supercritical water oxidation (Vogel, Smith et al. 2002), it has not yet been applied within the context of heterogeneous catalysis at these conditions. Other topics that need further investigation is the recovery of the nutrients from the salt brine as a marketable fertilizer, the detailed analysis of the trace compounds in the process water and the SNG, and the deep desulfurization of the feed to the catalytic reactor. The latter is a topic of current research in our group at PSI.

A feedstock meriting a deeper study for its suitability to hydrothermal methanation is black liquor, produced in large quantities from Kraft pulping of wood. This is a very challenging feedstock due to its high sulfur and minerals content, but its conversion to SNG may potentially replace the currently used black liquor boilers if the pulping chemicals can be recovered in a form suitable for recycling within the Kraft process.

From a process point of view, the coupling of hydrothermal gasification to a high temperature fuel cell (MCFC or SOFC) may result in a very efficient, small to medium-scale power generation process with estimated efficiencies, biomass to electricity, of up to 43% (Vogel 2009).

17.2.5 Estimated electricity generation potential in Switzerland until 2050

Two scenarios should be considered:

- producing SNG/electricity in Switzerland using indigenous biomass and wastes,
- producing the SNG from biomass abroad (including algae) and importing the SNG to Switzerland for centralized and/or decentralized electricity production

The first scenario has lower energetic potential. Based on the data from WSL, a sustainable primary energy potential of not yet energetically used wet biomass and wastes of roughly 28 PJ/a is available (chapter 10.2). In addition, some of the currently energetically used biomass (e.g. sewage sludge) could be used in a much better way with HTG (i.e. with higher biomass-to-electricity efficiency) and deliver more useful energy. This additional primary energy potentially to be redirected towards HTG is in the range of 13 PJ/a.

For the second scenario an additional primary energy potential of 33 PJ/a from algae has been estimated (Bagnoud-Velásquez, Refardt et al. 2015)[381].

The following conversion pathways from (wet) biomass to electricity via hydrothermal gasification (HTG) are realistic options:

1. S1: HTG – CHP
2. S2: HTG – Upgrading/Feed-In – Combined Cycle (CC)
3. S3: HTG – SOFC
4. S4: HTG – Upgrading/Feed-In – CHP

With the locally separated production of SNG and electricity (scenarios S2 and S4), no heat integration is possible. The maximum efficiencies from biomass to electricity are 40% for S2, 25% for S4-small[382] and 40% for S4-large[383] (see chapter 15.2 – efficiencies of future CHP units will be a few %-points higher). All these technologies can also be integrated into biomass-to-electricity power plants, in which the process heat of HTG is covered by waste heat from the electricity generation part. For such fully-integrated plants, the total efficiencies biomass-to-electricity would be 28-34% for CHP, 48% for CC, and 44% for SOFC.

Using 100% of the appropriate available biomass feedstock potential in Switzerland (~28 PJ/a) with overall process chain efficiencies of 25-48% results in a maximum technical generation potential of 1.9-3.7 TWh/a. Considering 33 PJ of imported SNG from algae per year results in a maximum technical potential of 2.2-4.4 TWh/a. Additionally considering the already energetically used primary energy potentially to be redirected towards HTG results in an electricity generation potential of roughly 0.5-1.5 TWh/a.

17.2.6 Cost estimates

Gassner, Vogel et al. (2011) have estimated the specific investment costs for a catalytic hydrothermal methanation plant of the 20 MW class for a number of different feedstocks. The general rule is that the lower the organic content of the feedstock, i.e. the higher the moisture and mineral contents, the lower the SNG efficiency (Figure 17.4). The specific investment costs depend on the desired SNG efficiency: up to a certain value, the specific investment costs remain quite insensitive to the efficiency. When a certain efficiency level is

[381] http://www.wsl.ch/fe/waldressourcen/projekte/fps_biosweet/index_EN (8.12.2016).
[382] Small CHP in the order of 1 kW_{el}.
[383] Large CHP in the order of 1 MW_{el}.

reached, a further increase of this level is very expensive. Thus, there is an optimum for every feedstock, and no general value can be given. For the seven feedstocks studied, the lowest specific investment costs were around 600 USD/kW. This would correspond to 12 million USD for a 20 MW plant (based on the thermal biomass input) and can be regarded as a lower bound for an "easy" feedstock such as spent coffee grounds. A study conducted for a plant with a capacity of 3.6 MW of sewage sludge, which is a more challenging feedstock than spent coffee grounds, estimated the investment costs to be ca. 22 million CHF (Vogel, Heusser et al. 2013).

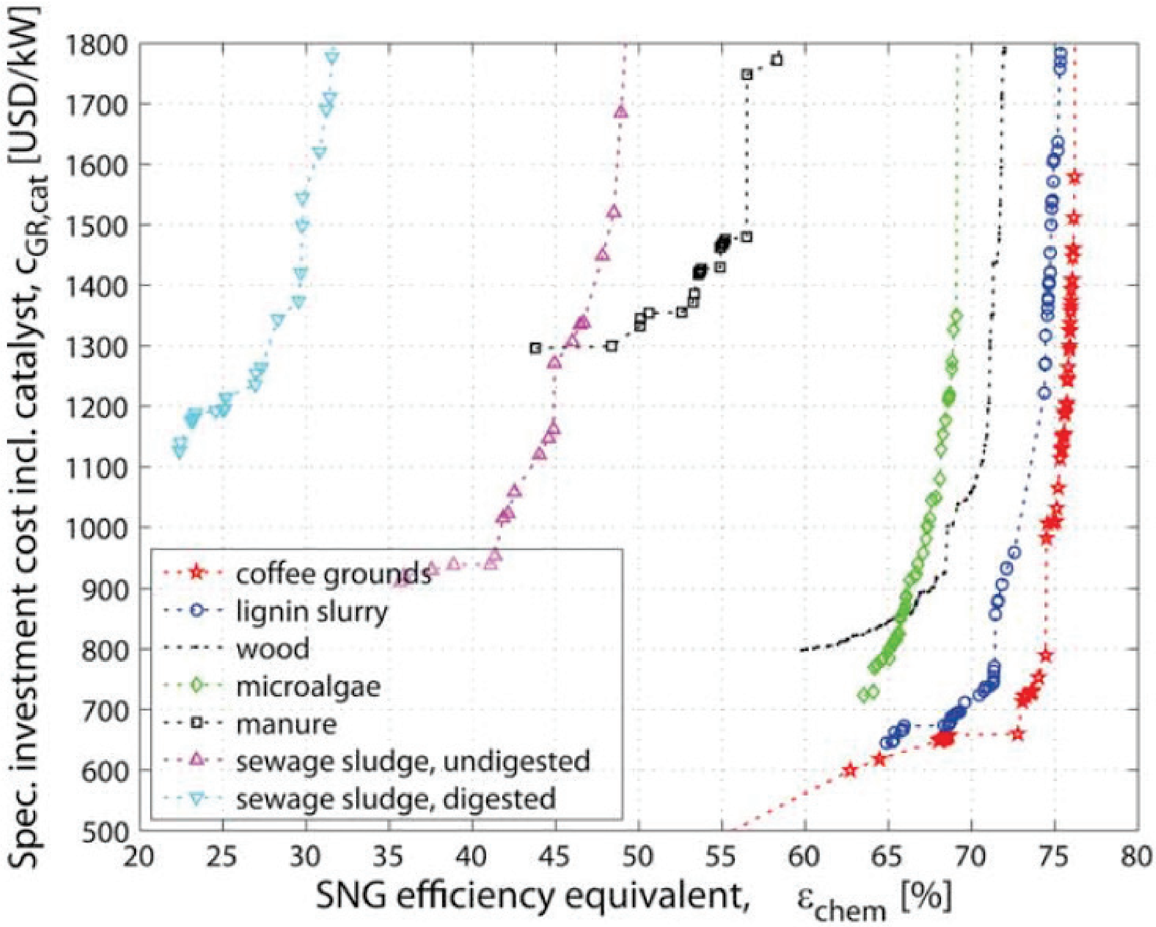

Figure 17.4: Specific investment cost and overall process efficiency without power recovery from the high pressure vapor phase for PSI's catalytic hydrothermal methanation process. Reproduced from (Gassner, Vogel et al. 2011) with permission.

17.2.7 Environmental aspects

A Life Cycle Assessment (LCA) performed by Luterbacher, Fröling et al. (2009) showed the hydrothermal methanation process to have a very low environmental impact. In fact, if manure is used as feedstock, a reduction of GHG emissions is achieved compared to fermenting the manure to biogas because the emission of N_2O and CH_4 from the fermentation residues spread on the field as fertilizer is avoided. Another study, based on the same LCI data, calculated the total environmental impacts and compared them to a number of other biofuel pathways for Switzerland. The use of biomethane from manure or wood chips via the hydrothermal methanation route as vehicle fuel ranked among the best options (Faist-Emmenegger, Gmünder et al. 2012). For SNG produced from algae biomass (SunCHem process), Brandenberger, Matzenberger et al. (2013) found the combination of raceway ponds and hydrothermal methanation to exhibit an energy return on energy invested (EROEI) of 1.8 to 5.8, depending on the assumptions regarding future developments in algae productivity.

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17.3 Novel geothermal technologies

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17.3.1 Introduction

Several novel, i.e., not hydrothermal, deep geothermal energy extraction and conversion technologies beyond so-called Enhanced (or Engineered) Geothermal Systems (EGS), discussed in chapter 11, are under various stages of development. This fact is often not considered as the MIT report entitled "The Future of Geothermal Energy ..." (Tester 2006) focuses (almost) exclusively on EGS (in Europe also often referred to as Petrothermal Systems), even though EGS has also not been demonstrated as a commercially viable option yet. Here, we briefly discuss some alternatives to EGS that may be of particular importance to Switzerland's geologic and societal conditions.

To use deep geothermal energy for power (or heat) production, three conditions have to be given:

1) sufficient subsurface **temperatures** (for economic electricity generation) at relatively shallow depths,

2) sufficient **permeability** (the ability of a porous and/or fractured medium to transmit any fluid, i.e., a fluid-independent parameter) for advective heat transport (i.e., fast heat transport due to fluid flow as opposed to slow heat conduction), and

3) presence and/or injection of a subsurface energy-extraction **working fluid** (typically water or brine but not necessarily so, as shown in Section below).

In this context, EGS is typically suggested when sufficient temperatures exist only at relatively deep depths (3-6 km) in then, due to high pressures at such depths, low-permeability formations (typically crystalline basement rocks). During EGS development, these low-permeability formations are hydraulically stimulated (via hydro-shearing of existing fractures and/or shear zones and/or hydro-fracturing of intact rock) to generate artificial permeability that enables the injection and circulation of a working fluid (typically water or brine) to advectively extract the heat. Thus, EGS addresses Condition (2) of the above three conditions. The EGS technology has yet to be proven to work in an economically viable fashion, but it is nonetheless one of the main, but not the only (as shown next), technologies that is hoped to enable economic geothermal power (i.e., electricity) production in Switzerland, despite the country's relatively low geothermal energy resources.

The two alternatives (to EGS) unconventional geothermal energy extraction and conversion technologies proposed here for Switzerland, that appear to deserve investigation in addition to EGS, address the issue of having to have 1) sufficient subsurface temperatures, 2) sufficient permeabilities, and 3) presence (or injection) of a subsurface working fluid to extract the heat and/or pressure energy (enthalpy), not from a permeability-enhancement point of view (i.e., not addressing Condition 2 above). Instead, the first one of these other two approaches addresses Condition (3) by exchanging water or brine with a different subsurface working fluid (carbon dioxide, CO_2, and/or nitrogen, N_2) which enables using both lower geothermal resource temperatures (i.e., softening Condition 1) and lower permeabilities (i.e., softening Condition 2), compared to water-based heat extraction. The second alternative approach employs auxiliary heating (with some secondary energy source) of geothermally preheated fluids (water/brine, CO_2, N_2, etc.) produced from the subsurface which makes use of very low-temperature geothermal resources for electricity production that would otherwise be uneconomical.

In the following sections, both of these novel technologies are described only briefly as they are even more unproven than EGS. However, they should be mentioned as potential "up-and-coming", game-changing technologies that may in fact be particularly suitable for Switzerland as neither of these two new technologies requires hydraulic stimulation, which is required by EGS and which is a topic that has been of significant concern in Switzerland, given the induced seismicity experiences in Basel (and to some degree St. Gallen, which, however, is not an EGS site) and, in fact, worldwide.

17.3.2 Option 1: Using a subsurface working fluid other than water/brine to extract geothermal energy for power production

As described in the introduction above, when sufficiently high geothermal temperatures are only present at considerable depths in crystalline basement rocks, typically an Enhanced Geothermal System (EGS), or Petrothermal, approach is suggested, although EGS has yet to be implemented in an economically viable fashion. During EGS development, hot-dry (where dry refers to naturally low-permeability) rock is hydraulically stimulated (hydro-sheared and/or hydro-fractured) to generate a relatively small-scale, fracture-based geothermal reservoir through which water (sometimes carbon dioxide, CO_2, as discussed below) can be circulated to extract heat energy. EGS is a promising technique which has, as all technologies, advantages and disadvantages that need to be weighed against each other to determine if, when, and where EGS could be an energy-supply solution that is acceptable to society. One major drawback to EGS is that, by its nature of hydraulically stimulation rock, it will induce at least some microseismicity. Thus, significant research worldwide addresses how to keep this seismicity small enough to avoid damages to surface structures. This research has also been conducted, and is ongoing, at various institutions in Switzerland such as ETH Zurich.

In this section we discuss an alternative novel technology to use relatively low-temperature (low-enthalpy) geothermal resources, which are the only ones potentially present in Switzerland, to generate electricity that is not EGS-based. While EGS addresses condition (2), i.e., increasing/enhancing permeability in otherwise low-permeability rock, which, again, is associated with at least microseismicity, the alternative method discussed here addresses condition (3), i.e., exchanging the subsurface working fluid with a different working fluid that then enables using much lower temperatures and permeabilities than when water is used as the subsurface working fluid. The main alternative subsurface working fluid proposed here is carbon dioxide, CO_2, the other, that may be used instead or as well is nitrogen, N_2. Both fluids are non-poisoness, in fact, humans breath in air that consists mainly (78%) of N_2 and exhale air enriched in CO_2. However, CO_2 enrichment in the Earth's atmosphere is the main driver of human-caused global warming, resulting in a global effort to reduce such emissions in order to restrict global warming to below 1.5/2^{o}C above pre-industrial levels (UN 2015). To reach this goal, it is almost inevitable (Pacala and Socolow 2004) that CO_2 will have to be permanently stored underground in various geologic formations such as deep saline (and thus otherwise unusable) aquifers with at least 10'000 ppm total dissolved solid (e.g., salt) content or other formations such as partially depleted oil or natural gas (e.g., methane) fields. In fact, the oil industry has injected CO_2 (and water) during so-called enhanced oil recovery (EOR) operations for many decades already. The practice of separating (capturing) CO_2 from industrial and power plant processes before it would be emitted to the atmosphere and permanently sequestering or storing it underground is referred to as carbon capture and storage (CCS). Earth's suitable subsurface storage capabilities, while difficult to determine in detail at a given site, are likely enormous, enabling storage of CO_2 from today's emitters for decades, possibly centuries. Thus, CCS will inevitably play a key role in reducing global warming as without CCS, it is very likely that all other measures combined to reduce global warming will be insufficient (Pacala and Socolow 2004).

Therefore, given that CO_2 injection into the subsurface due to CCS and EOR is occurring and will likely increase many-fold over the next several decades, the question is if there is anything useful that can be done with the injected and stored CO_2? The answer is "yes", at least in two ways. The first one is the above-mentioned EOR approach, which, however, at least partially brings the CO_2 back to the surface along with the oil and water and which releases more hydrocarbons that, when burned, will release more CO_2 to the atmosphere. The second option of using CO_2 underground is given with so-called CO_2-Plume Geothermal (CPG) system (Randolph and Saar 2011b). As both approaches make use of CO_2 underground, while also partially (in case of EOR) or fully (in case of CPG) storing the CO_2, they both fall within the category of what is called carbon capture utilization and storage (CCUS).

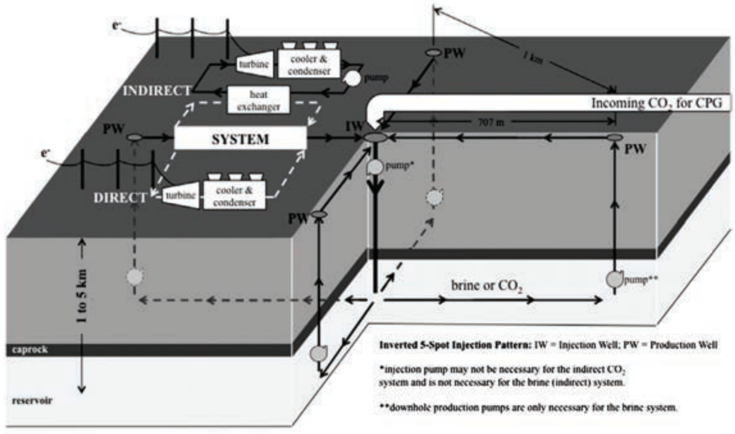

Figure 17.5: Schematic illustrating both a direct and an indirect CO_2-Plume Geothermal (CPG) system (Figure from (Adams, Kuehn et al. 2015)).

During CO_2-Plume Geothermal (CPG) operations, full (i.e., 100%) CO_2 storage and simultaneous geothermal energy extraction, using CO_2, are combined, resulting in a CO_2-sequestering geothermal power plant with a negative carbon footprint (when one excludes the CO_2 emitter from the carbon life cycle analysis – otherwise the technology is at least CO_2-neutral). During CPG, liquid CO_2 is injected into an underground formation (e.g., a deep saline, and thus unusable, aquifer) as during regular CCS. The liquid CO_2 experiences a phase transition to supercritical CO_2, $scCO_2$, with liquid-like density and gas-like viscosity, on its way to the reservoir at a depth of about 740 m (the critical point of CO_2 is at a pressure of 73.8 bar and a temperature of 31.1°C). In CCS, supercritical CO_2 conditions are desired to store the CO_2 as the increased density of $scCO_2$ allows more compact storage of the fluid. Once the $scCO_2$ is stored underground, it heats up due to the geothermal heat present in the reservoir. The deeper the reservoir is located, the hotter it is as the average continental geothermal gradient results in an approximate increase in temperature of 30°C per kilometer depth, so that, assuming a mean annual surface temperature of 10°C, a reservoir at a depth of 3 km, can expected to have a temperature of 100°C. With CCS, only an injection well for the CO_2 is needed (and perhaps some monitoring wells). A CPG operation adds a production well to the system, which is located some distance away from the injection well, but within the subsurface CO_2 plume that expands with time outwards from the injection well. At this production well, the geothermally heated CO_2 is brought back to the surface, where it is either directly expanded in a turbine (a direct CPG system) or sent through a heat exchanger to transfer the heat to a secondary or binary working fluid that is then expanded in a turbine (indirect CPG system), much as in an organic rankine cycle. Thereafter, the CO_2 is typically cooled in a cooling tower and then reinjected into the reservoir, along with the main CO_2 stream, coming from the CO_2 capture site (e.g., a coal-fired, methane, etc. power plant, a cement manufacturer, or a biofuel refinery). Thus, no CO_2 is released to the atmosphere and 100% of the injected CO_2 is stored permanently underground (while a small portion of CO_2 continuously circulates from the reservoir to the power plant and back to the reservoir). This basic CPG concept, illustrated in Figure 17.5, can be modified and optimized in many different ways, depending on reservoir depth (and associated temperature) and permeability, amount of CO_2 (to be) injected and several other parameters. Adams, Kuehn et al. (2015) investigated several CPG configurations and compared their net power output with traditional water/brine-based geothermal systems and power plants. They find that under a wide range of conditions, CPG systems are more efficient, i.e., produce more net power, than their water/brine-based counterparts, when the only difference in a given system is the exchange of water or brine with CO_2. The reason for this performance increase has several reasons, the main two being:

1) Under typical geothermal reservoir conditions (pressure and temperature), the kinematic viscosity of $scCO_2$ is much lower than that of water so that $scCO_2$ flows much more easily through the reservoir given a pressure drop from the injection well to the production well.
2) Upon (geothermal) heating, $scCO_2$ expands much more than water does (for the same amount of heating) so that the density decrease of $scCO_2$ upon heating is much more pronounced than that of water.

Together, the above two effects result in the formation of a significant CO_2 thermosiphon (Atrens, Gurgenci et al. 2009, Atrens, Gurgenci et al. 2010, Adams, Kuehn et al. 2014). As a result, the CO_2 in a CPG system almost never has to be pumped and when some pumping results in a slight increase in net power output (i.e., power output after subtraction of all parasitic power requirements from the gross power output), the required pump is small and is placed at the ground surface just before the injection well, i.e., the maintenance and power requirements of such a pump are negligible and not comparable to the powerful downhole production well pumps required in water-based geothermal systems which are prone to failure and expensive repair costs (see e.g. Unterhaching, Germany). All told, a CPG system is typically more efficient and robust than water-based geothermal systems and it permanently stores CO_2 underground. Not all is perfect with CPG systems, however, as all challenges (and benefits) of CCS apply to CPG as well.

Due to their heightened efficiency and due to supercritical CO_2's lower kinematic viscosity, CPG systems are expected to economically generate power using much lower geothermal resource temperatures and lower permeabilities than water-based systems. Since lower geothermal temperatures and permeabilities are found at a given depth in more regions, the geothermal energy resource base is expanded when employing CPG, compared to water-based geothermal systems, as shown in Figure 17.6 for the USA.

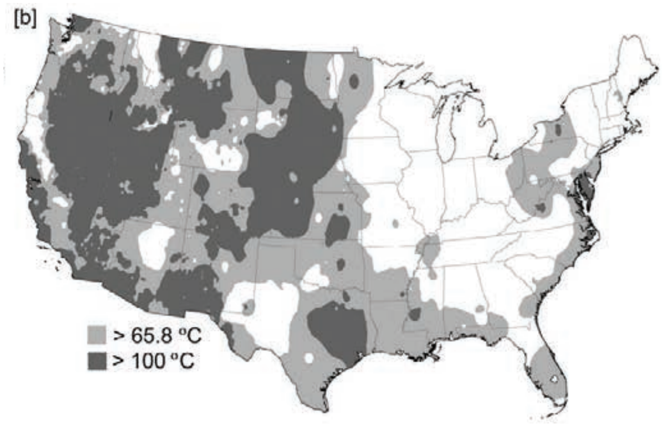

Figure 17.6: Assuming a minimum geothermal resource temperature of 100°C, required for water-based geothermal electricity generation corresponds to a resource temperature of only 65.8°C required to produce the same amount of electricity using CPG-based. The figure illustrates the geographic increase in the geothermal resource base when requiring only 65.8°C (light-gray and dark-gray areas) instead of 100°C (only dark-gray areas) at an example depth of 2.5 km (Figure from (Randolph and Saar 2011a)).

It should be noted here, that using CO_2 as the underground heat exchange fluid in a geothermal system was first proposed by Brown during the Stanford Geothermal Workshop (Brown 2000) and patented. However, what Brown suggested was to use CO_2 in EGS. Such use of CO_2 in EGS was later numerically simulated by Pruess (Pruess 2006, Pruess 2007) who, much like Brown, found that under some conditions, using CO_2 in EGS increases the efficiency of power production compared to water. In addition, both Brown and Pruess pointed out that some loss of CO_2 to the geologic formation during the CO_2-EGS operation constitutes auxiliary CO_2 sequestration. In 2009, Randolph and Saar, completely independent of Brown and Pruess, had the idea of using CO_2 not in EGS but to extract geothermal energy either during CCS, as described above, or during EOR. Encouraged by Pruess (personal communication), they started a major, still ongoing, research project, funded by the US Department of Energy and the US National Science Foundation) to investigate the performance of geothermally heated CO_2 in large-scale, naturally permeable formations (e.g., deep saline aquifers) targeted for CCS and to compare their results for what they called CO_2-Plume Geothermal (CPG) systems with both hydrothermal (i.e., non-EGS) systems and the CO_2-EGS of Brown and Pruess (Brown 2000, Pruess 2006, Pruess 2007), concerning both the amount of geothermal energy extracted and converted to power and the amount of CO_2 stored underground ((Randolph and Saar 2011b, Randolph and Saar 2011a)). They found that the amount of energy extracted and CO_2 stored is significantly larger for CPG systems than for both water-based geothermal systems and CO_2-EGS. Basically, the porous-medium-based, i.e., naturally high-permeability, large-scale CPG system enables much more thorough advective heat sweeping of the geothermal reservoir than in the (artificial and thus smaller-scale) fracture-based EGS, where, in the latter, heat has to conduct (a slow process compared to heat advection with the fluid flow) to the fractures before it can be advected within the fracture. Regarding CO_2 storage, as stated above, during CPG system operation, all of the injected CO_2 is eventually stored underground, much as in a standard CCS operation (during CPG operations, only a small portion of the CO_2 that is injected underground is circulated back to the surface but then reinjected underground along with the main CO_2 stream from the CO_2 capture site). In contrast, CO_2-EGS are expected to lose, i.e., geologically store, at most 10% of the CO_2 during CO_2 circulation. Consequently, CPG systems constitute full CCS systems with add-on geothermal power plants, whereas CO_2-EGS is mainly an EGS that may allow some minor underground CO_2 storage.

As CPG permanently stores all of the CO_2 injected underground, the question is, if it may be considered a CO_2-storing geothermal power plant with a negative carbon footprint. The answer depends on several factors as one has to consider the CO_2 generator from which the CO_2 is captured so that it is not emitted into the atmosphere. If the CO_2 generator is a fossil-fueled power plant, then the CPG system can, at best, be CO_2-neutral. If instead, the CO_2 generator is a biomass-combusting power plant, where the CO_2 has been “captured” from the atmosphere by the plants, then the CPG system would, indeed, constitute a geothermal power plant with a negative carbon footprint, although with the following caveat: If all of the generated power is needed to power the CO_2 injection pumps (even though the termosiphon discussed above will run the geothermal CO_2 cycle without the need of pumps, initial injection of the CO_2 does require pumps), then no net power is produced. In this case, one can think of CPG as a power- subsidized CCS system, where the power generated, using CO_2 as a high-efficiency geothermal heat extraction and conversion (to electricity) fluid, is used to power the CO_2 injection pumps needed for continuous CCS. However, the biomass power plant in this scenario would be generating CO_2-emission-negative power, where the parasitic power (and financial) requirements for CCS (for both capturing the CO_2 and running the CO_2 injection pumps) are partially or fully offset by the CPG system. And if the CPG system generates more power than what is needed for CO_2 capture and subsurface injection, then a geothermal power plant with a negative carbon footprint would result.

17.3.2.1 CO_2-Limited CPG Systems

When only limited amounts of CO_2 are available, a CO_2-limited CPG system may be installed (Garapati, Randolph et al. 2015), where, instead of continuous CO_2 injection from a CO_2 generator, a finite amount of CO_2 is brought to the site (e.g., by train or trucks) and injected.

17.3.2.2 Baseload Power and Water/Land Use

Geothermal energy in general, including CPG, is one of the few renewable energy resources that are baseload energy resources, i.e., that can be operated 24 hours a day, 7 days a week and thus do not require backup systems that many of the other renewable energy systems require such as wind and solar energy. In addition, CPG, which does not necessarily use water (water may be used in cooling towers when wet-bulb cooling towers are desired but this is typically not absolutely necessary), puts minimal strain on land and water use. Regarding land-use, new, CO_2-based power generating turbines and generators (of any sort, i.e., including also coal-fired, nuclear, etc. power plants in addition to CPG power plants) are much more compact than water-based ones.

17.3.2.3 Grid-Scale Energy Storage

CPG can also be used as a grid-scale energy storage system (Buscheck, Bielicki et al. 2014, Buscheck, Bielicki et al. 2016) and in this way support other renewable energy technologies that, in contrast to geothermal energy, including CPG, are not baseload energy sources that can provide power 24/7. Currently, providing expensive and often environmentally questionable battery systems to store power that can only be produced in an intermittent fashion, is a significant disadvantage of many renewable energy options such as wind and solar. Similarly, backup power systems, often natural gas, are installed at comparable capacities as the nameplate capacity of solar and wind power systems, resulting in true costs of wind and solar power that are much higher than those of just the wind or solar power systems, while rendering these systems as not truly being renewable anymore.

17.3.2.4 Costs of CO_2-Plume Geothermal (CPG) Systems

Several economic models have investigated the costs of CPG power (i.e., electricity) production which largely depend on whether the CPG power plant has to pay for the CO_2, receives funds for taking the CO_2, or neither makes money with, nor pays money for CO_2 supply. However, in many cases, CPG is envisioned to be added to existing CCS or EOR operations, where all these aspects, including costs of receiving, injecting, storing, monitoring, and ensuring CO_2 are taken into account already and only the costs of producing the geothermally heated CO_2 to the surface and converting it to power have to be added. Thus, one may conclude that when adding CPG to an existing CCS or EOR operation, that the costs (for the production wells and surface power plant system) are not higher than the costs for a standard geothermal system and, in fact, are likely lower as much of the geologic investigation and well drilling (injection and observation wells) has already happened. Thus, the expected levelized cost of electricity (LCOE) of CPG should, at most, be as high as that of standard, water-based geothermal (chapter 11).

Estimating the potential of CPG in Switzerland, its costs, and environmental impact is beyond the scope of this contribution and is, in fact, a multi-year/decade effort by the Geothermal Energy and Geofluids (GEG) Group at ETH Zurich. The previous discussion and the cited publications are meant to provide only a brief introduction of this technology and what has been found out thus far for the US market. The main conclusion that can be provided here is simply that CPG appears to be a potentially interesting option for Switzerland as an alternative to EGS, although both approaches should be continued to be investigated as it is not clear if either one or none will work in an economically fashion in general, and in Switzerland in particular. What CPG, if feasible, would offer, in contrast to EGS, is a technology that, if successful, would:

- make use of the low-temperature (i.e., low-enthalpy) geothermal resources that Switzerland has, in an economical fashion to provide baseload, renewable, "low-CO_2" (or even CO_2-negative) power.

- be much less likely to induce seismicity than EGS as it works without hydraulic stimulation.

- require much less deep drilling (only about 2.5-3.5 km compared to 4-6 km for EGS) which reduces costs substantially.

- combine CCS with geothermal energy extraction and utilization, thereby constituting a carbon capture <u>utilization</u> and storage (CCUS) system, unless a CO_2-limited CPG system is developed that only uses a finite amount of subsurface CO_2 to generate power as discussed briefly above.

- be usable as a high-efficiency, clean, grid-scale energy storage system that promotes implementation of other, only intermittently usable renewable energy resources such as wind and solar energy.

Some of the challenges of CPG include:

- all challenges of CCS apply, i.e. those related to storing CO_2 underground.

- negative public perception regarding CCS.

17.3.2.5 Multifluid, multi-ring geothermal systems for power production, grid-scale energy storage, heat production, water production, and/or integration with CCS

Based on CO_2-Plume Geothermal (CPG) energy utilization (discussed above), the concept has been extended to combine multiple subsurface working fluids to generate power (electricity), heat, and/or water/brine for consumption, industrial processes, and power plant cooling, where brine would have to be desalinated. The subsurface fluids considered here are water/brine, CO_2, and/or nitrogen, N_2, as described in (Buscheck, Bielicki et al. 2014, Buscheck, Bielicki et al. 2016). Buscheck, Bielicki et al. (2016) provide the most thorough and generally understandable explanations regarding such systems. The basic idea is to employ a set of concentric rings of horizontal subsurface wells that enables injection or production of various fluids (here shown brine and CO_2). This allows the formation of hydraulic troughs that better contain the cushion gas (CO_2). This approach has several other advantages, compared to traditional (hydrothermal) geothermal energy systems as well as to standard CPG (described above), while also facilitating CCS operations and providing water, often needed for CCS (and other uses). Furthermore, the approach may also be used as a grid-scale energy storage system. The following paragraphs reproduce parts of the conclusions of Buscheck, Bielicki et al. (2016):

"Addressing the challenge of reducing CO_2 emissions requires technology advances that enable viable, widespread deployment of geological CO_2 storage (GCS) and grid-scale energy storage that accommodates greatly increased use of variable renewable energy sources. We present a synergistic approach designed to address these challenges by enabling (1) geothermal energy production in widely distributed geologic settings (sedimentary basins) where conventional geothermal energy systems are not viable, and (2) grid- scale energy storage at a potentially greatly reduced cost, compared to existing technologies. Our approach is designed to address three key barriers to widespread deployment of GCS. By creating valuable uses for captured CO_2, our approach addresses an enormous deployment barrier, i.e., the cost of capturing CO_2. Our approach also addresses another major barrier for industrial-scale deployment of GCS, i.e., overpressure created by that storage. Because our approach provides a source of water, it also addresses the challenge of the water intensity of CO_2 capture."

Such a multi-fluid, multi-ring approach may be of particular interest for geothermal power generation in Switzerland, where standard geothermal (i.e., hydrothermal) systems are likely not economical possible and EGS may result in unacceptable levels of induced seismicity during hydraulic stimulation. In a way, the multifluid, multi-ring system discussed in this section is simply an extension of the CPG system discussed before. It is also a more practical approach that appears to provide several advantages (discussed previously) compared to the basic CPG idea. Nonetheless, since CPG and this multifluid, multiring version of CPG are in their infancies, despite several papers having been published on these topics (Randolph and Saar 2011b, Randolph and Saar 2011a, Adams, Kuehn et al. 2014, Buscheck, Bielicki et al. 2014, Adams, Kuehn et al. 2015, Garapati, Randolph et al. 2015, Buscheck, Bielicki et al. 2016), significant additional research at various scales (lab scale, pilot and demonstration scale, and actual field/reservoir scale), employing both numerical and experimental methods, still has to be conducted to move these technologies from an early technology readiness level to a one where industry can take over commercialization. Currently, CPG patents (Saar, Randolph et al. 2012-2015) are licensed to TerraCOH Inc. in the USA.

17.3.3 Option 2: Auxiliary heating of geothermally preheated fluids

In section 17.3.1, three necessary conditions are discussed, required for geothermal energy extraction and conversion to power (electricity). These are 1) sufficiently high subsurface temperatures, 2) sufficiently high subsurface permeabilities to allow advective heat transfer, and 3) presence (or injection) of an energy extraction fluid. So-called enhanced geothermal systems (EGS) address condition (2) by increasing (enhancing) permeability through hydraulic stimulation (which causes at least microseismicity), generating an artificial, and thus small-scale, geothermal reservoir through which a subsurface working fluid can then circulate to extract a fairly limited amount of geothermal heat. In contrast, section 17.3.2 describes an approach by which condition (3) is addressed by exchanging the typical subsurface working fluid (water or more commonly brine) with CO_2, or possibly N_2, so that lower temperatures (condition 1) and lower permeabilities (condition 2) can be used that are naturally present at large scales without needing to hydraulically stimulate hot, deep, and naturally low-permeability formations (typically crystalline basement rocks). The approach discussed briefly in this section addresses the three conditions from a different angle by, essentially not addressing them at all and instead use the moderate subsurface energy without enhancing permeability. The concept here is to use low geothermal temperatures and possibly low permeabilities as typically found at relatively shallow depths (1-4 km) without stimulation, using any convenient subsurface working fluid (e.g., water, brine, CO_2) and to then employ a secondary heat source to auxiliary heat the geothermally preheated fluid to temperatures required to achieve energy to power conversion efficiencies that are sufficiently high for economic power production.

Auxiliary heating of geothermally preheated fluids, while not constituting a pure geothermal power plant anymore, enables using low geothermal resource temperatures for electricity production, so that at least some portion of the power generated stems from geothermal energy. Ideally, the secondary energy resource, that is used to auxiliary heat the low-temperature geothermal fluid, is also a renewable energy resource that does not emit CO_2 to the atmosphere (e.g., solar-thermal which, however, is only an intermittent energy resource so that matching it with baseload geothermal energy can be problematic). However, the auxiliary heating technology may also make sense with biofuels or even fossil fuels, particularly when carbon capture and storage (CCS) is employed (Figure 17.7).

Therefore, from an environmental (i.e., global warming), an economic, and a power supply point of view, this approach of auxiliary heating geothermally preheated fluids is of interest when 1) low-temperature geothermal resources are unsuitable for economic power production and 2) at least a carbon-neutral (C-neutral), better a carbon-negative (C-negative) system results. Naturally, when employing auxiliary heating of geothermally preheated fluids with CCS, rather than shipping any captured CO_2 to some remote geologic CO_2 storage site, a CO_2-Plume Geothermal is used as in this case, the geologically stored CO_2 can be readily used as the geothermal energy extraction fluid underground. This approach constitutes a carbon capture utilization and storage (CCUS) geothermal power plant with auxiliary heating and a small or even negative carbon footprint.

Given the relatively low geothermal resource temperatures in Switzerland and the country's potential need to eventually generate some electricity with some fossil fuel, while desiring to simultaneously reduce CO_2 emissions to the atmosphere, this approach of combining CCS with geothermal energy extraction and with auxiliary heating of these relatively low-temperature geothermal fluids to increase the conversion efficiency above that of each energy resource's conversion efficiency alone, may be a good solution to achieve these goals. This way, the low to, at best, moderate geothermal resource temperatures in Switzerland would be utilized for power production, as desired, while reducing CO_2 emissions and, thus, contributing to reducing global warming.

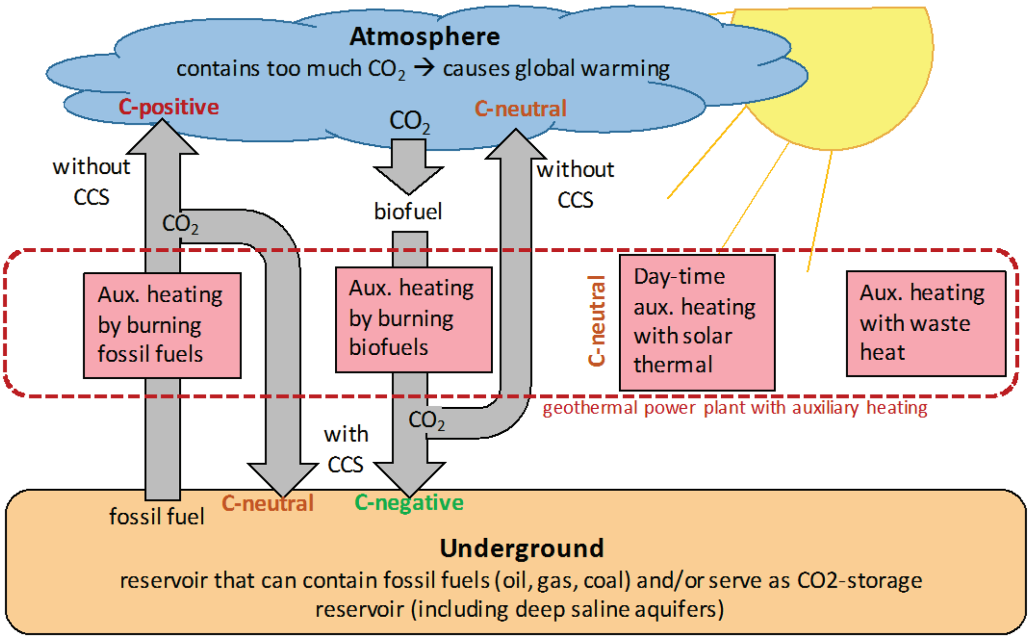

Figure 17.7: Auxiliary heating of geothermally preheated geofluids (water, brine, CO_2, etc.). Depending on the type of auxiliary, secondary heating source employed, the system may be carbon-positive, or carbon-negative.

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17.4 Nuclear fusion

Minh Quang Tran (School of Basic Sciences, Physics section, EPFL)

17.4.1 Introduction

The case for fusion energy is described in Chapter 1 of the recently published book and in a special issue of Nature Physics (IAEA 2012a). It introduces the different fusion reactions between light nuclei, the basis for a positive energy output (the Lawson criterion) and describes the different approaches towards an industrial realization of fusion. As a reminder, on Earth the fusion reactions under consideration are based on the fusion of the nuclei of Deuterium and Tritium according to the reaction:

$$D + T \rightarrow He\ (3.5\ MeV) + n\ (14.1\ MeV)$$

Other reactions exist but have smaller cross section and require higher temperature. The proton-proton fusion process occurring in the Sun does not work on Earth since its cross section is too small, due to the fact that it is a weak interaction process. In the rest of the text we shall limit the discussion to the D-T fusion process.

The fusion reaction between nuclei of deuterium (D) and tritium (T) has the highest cross-section (1 keV corresponds to about 10 millions of degrees). At temperatures above about 10^5 degrees, a gas becomes ionized: electrons are no longer bound to ions to form a neutral atom. The resulting state with free electrons and ions is called plasma, hence the importance of this field of physics for the realization of fusion.

The condition for a positive power balance is described by the so-called Lawson criterion, which can be written as:

$$n\ T\ \tau_E > 8.1 \times 10^{21}\ keV.\ S.\ m^{-3}\ (1)$$

The temperature T is expressed in keV, the number density n is in particles per cubic meter. The τ_E is the energy confinement time in the plasma expressed in s. For T = 15 keV, n= 10^{20} m^{-3}, τ_E is of the order of 5 s.

The key issue for the realization of fusion is to build a reactor in which the plasma parameter fulfils the condition (1). Two approaches are being presently considered:

a) Confinement of the plasmas by magnetic field (magnetic confinement)

b) Inertial confinement

17.4.1.1 Magnetic Confinement

In this approach, the plasma is confined by magnetic field in a closed toroidal configuration. Two configurations are being investigated:

1. The tokamak approach where the confining fields are created by external coils and by a magnetic field created by a current flowing in the plasma itself (Figure 17.8).
2. The stellarator approach were the confining magnetic field is created only by the external coils (Figure 17.9)

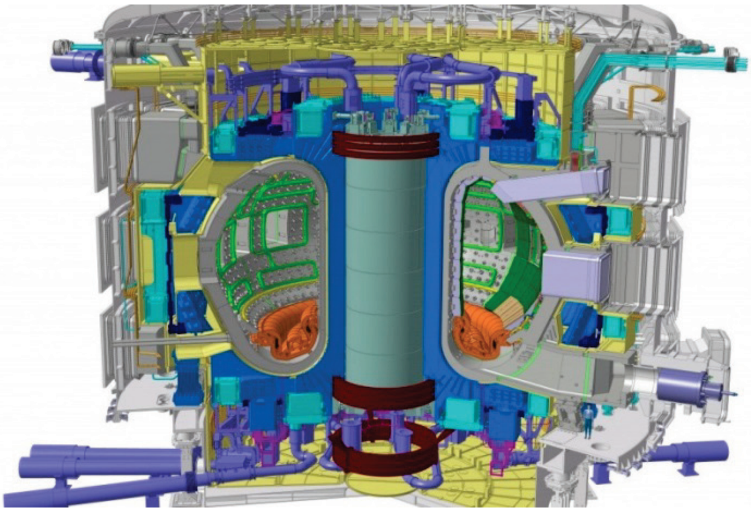

Figure 17.8: Schematic of a tokamak , ITER. The scale of a man is shown on the right. The plasma is a D shaped doughnut filling the central volume.[384]

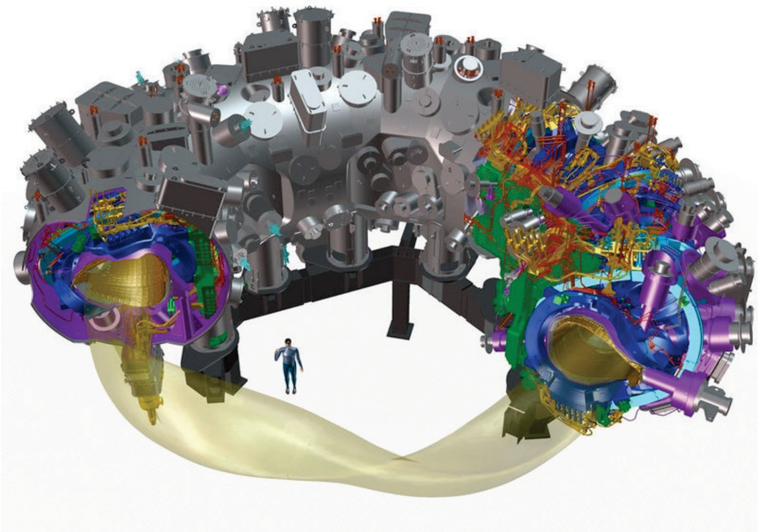

Figure 17.9: Schematic of a stellarator, the German Wendelstein 7-X, which was inaugurated in 2016. (Picture Courtesy IPP).

17.4.1.2 Inertial Confinement

Here the plasma is not confined and is left to expand at the natural sound speed (as a gas expanding into vacuum and is proportional to $(T/\rho)^{1/2}$, ρ being the mass density of the plasma). The fulfilment of Lawson criterion (Eq. 1) requires extremely high plasma density (a mass density of about 400 g/cm^3 compared to the fuel natural density of 0.2 g/cm^3 i.e. a density "compression factor of 2000"). The topic is described in Chapter 10 of (IAEA 2012a).

[384] Source: https://www.iter.org/img/crop-2000-90/all/content/com/img_galleries/in-cryostat%20overview%20110824.jpg

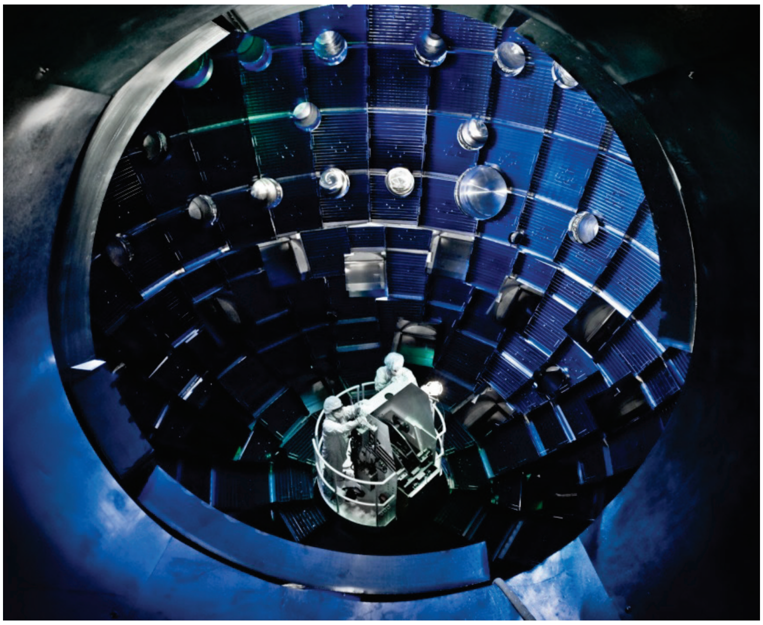

Figure 17.10: View inside the target area of NIF.[385]

This inertial confinement approach is mainly pursued for its application in nuclear weapons. In the USA it is pursued mainly at the National Ignition Facility (NIF) in Lawrence Livermore National Laboratory, in France at the Laser Mega Joule facility (LMF) near Bordeaux.

17.4.2 Current status

We shall limit the discussion to the case of magnetic confinement, inertial confinement being only explored in a few labs (the Euratom program has only a “keep in touch” activity), the major parts of them being partly classified.

17.4.2.1 Tokamak

Fusion reactions with D-T-fusion require a tokamak capable of handling T, a radioactive isotope. At present, only the European tokamak JE has this capability: JET has obtained a fusion power of 15 MW, corresponding to a fusion power gain of Q=Fusion power (power used to heat the plasma) equal to about 0.6.

Overall, the achievement, as far as the Lawson criterion (Equation 1) is concerned, is shown in Figure 17.11. It is important to highlight the steady progress perform throughout the year. The apparent “saturation in time” is just linked to the construction of ITER.

[385] Source: https://lasers.llnl.gov/content/assets/images/media/photo-gallery/large/nif-1209-18050.jpg

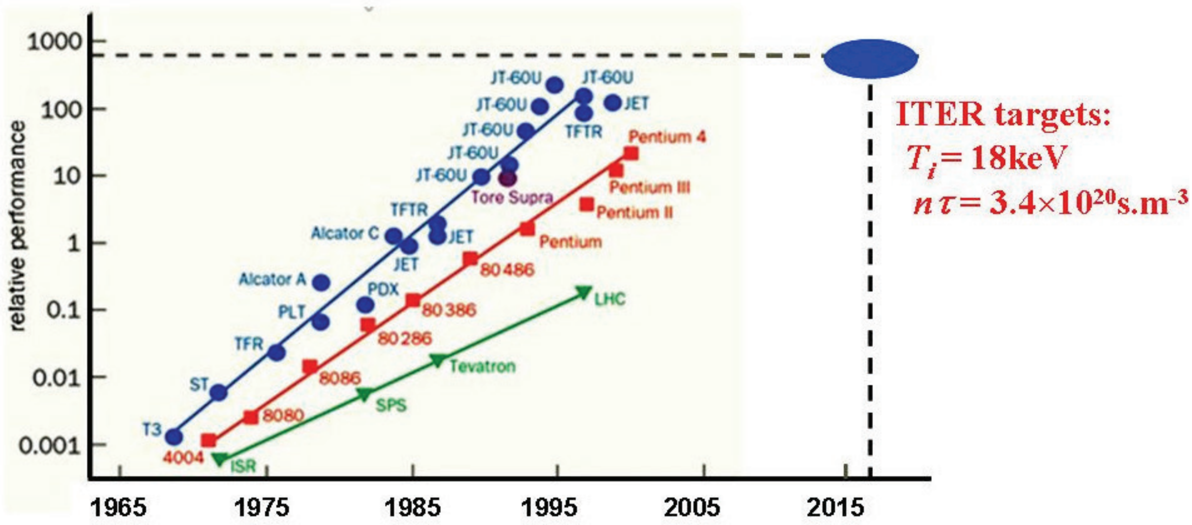

Figure 17.11: Moore's law type comparing fusion achievement (in blue), Moore's law for semi-conductor devices (in red) and Livingstone law for accelerator (in green) (IAEA 2012a).

The physics understanding and the progress in the technology have permitted the design and construction of ITER. ITER is an international endeavor with the partnerships of China, the European Union (with Switzerland as an Associated State[386]), India, Japan, Korea, Russia and the USA. ITER is designed to deliver 500 MW of fusion power (thermal) in pulses up to 3600s. The parameters of ITER are given in Table 17.2. The fusion power gain Q will be as high as 10. Being located in France, ITER is the first fusion nuclear reactor endorsed by the ITER Council to be licensed as "installation nucléaire de base" (i.e. as a nuclear plant) by the French government. The present planning of ITER foresees a first plasma by 2025 and D-T-fusion plasma by 2035.

Table 17.2: Parameters of ITER.

Plasma pulse duration	Up to 3600s
Major radius	6.2 m
Minor radius	2 m
Plasma current Toroidal magnetic field	15 MA 5.3 T
Fusion power	500 MW
External Heating power	50 MW

17.4.2.2 Stellarator

The stellarator concept is less advanced than the tokamak although it has some important advantages such as being intrinsically a steady state device (in a tokamak the plasma current, necessary for maintaining the plasma equilibrium, is generated inductively and must be "non inductively driven" in steady state of operation). In Europe, the superconducting stellarator Wendelstein 7-X (W7-X) was put in operation at the end of 2015 and inaugurated in 2016, joining the Large Helical Device (LHD) in Japan.

[386] Ukrain has joined recently as Associated State as well.

17.4.3 Prospects

In the medium term, ITER will be an important milestone for the industrial realization of fusion energy. If successful, it will show

- the physics phenomena occurring in a burning plasma, i.e. when the internal heating by the energetic He ions produced by the fusion reaction dominates the external heating;
- the safety aspects of a fusion reaction;
- the integration of the required technologies and the physics constants in a single device.

It is also important to highlight the next generation of physicists and engineers (the "ITER generation"). ITER construction is also stimulating industry in the innovative field of fusion technology. Both aspects are an asset for the next step, a DEMOnstration Power Plant (DEMO). In Europe, the Euratom Horizon 2020 is guided by the roadmaps called "Fusion electricity: a roadmap for the realization of fusion energy" (EFDA 2012). As stated in the roadmap, the goal is to have a demonstration power plant DEMO producing net electricity for the grid at the level of a few hundred Megawatts by the mid-2050s. The roadmap has led the European program to undertake during the period of Horizon 2020 (2014-2020) to a pre-conceptual study of a long pulsed duration DEMO version (called EU DEMO1 2015) with the parameters given in Table 17.3. For a description of the status of the work, please refer to (Federici, Kemp et al. 2014, Federici, Bachmann et al. 2016).

Table 17.3: EU DEMO 1 2015 Parameters.

Net electric power	500 MWe
Plasma pulse duration	2 hours[387]
Major radius	9.1 m
Plasma radius	2.9 m
Plasma current	19.6 MA
Toroidal magnetic field	5.6 T
Fusion power	2037 MW
Gross electric power	914 MW

The pre-conceptual study of DEMO performed during Horizon 2020 will be followed during the next Euratom framework program (2021-2027) by a conceptual study, which will allow determining the parameters of the pulsed DEMO. In parallel with the pulsed DEMO, a steady state version (DEMO2) is also considered, but it will have more demanding physics assumptions.

In parallel with pre-conceptual studies on DEMO itself, the roadmap includes another important component, a high flux and fluence 14 MeV (the energy of the fusion neutrons) neutron, which is needed to test the materials foreseen for DEMO (such as the already developed stainless steel EUROFER) under neutron fluence level relevant to the operation of DEMO.

The European fusion program is not the only one which has vision foreseeing the industry realization of fusion by the mid of this century. Plans from China with a device called CFETR (China Fusion Engineering Test Reactor) (Song, Wu et al. 2014, Yamada, Kasada et al. 2016), Korea with KDEMO (Kim, Im et al. 2015), India with the project SST-2 reactor (Srinivasan

[387] With a short dwell time. It is foreseen that DEMO will be connected to the grid.

2016), and in Japan with activities in DEMO (Yamada, Kasada et al. 2016) (called Fusion Nuclear Science Facility) have also been published by the US community (Garofalo, Abdou et al. 2014).

17.4.4 National and international programs including Swiss contribution

17.4.4.1 National programs

Research in fusion started in Lausanne in 1961 (Frei 2012) under the name of Laboratoire de Physique des Plasmas, as an Institute of the Swiss National Science Foundation. Its name was changed in 1968 to become the Centre de Recherches en Physique des Plasmas (CRPP) and then to Swiss Plasma Center (SPC) in 2015 to reflect its broad activities. The CRPP/SPC belongs to the Ecole Polytechnique Fédérale de Lausanne (EPFL) since 1973. It is the national Center of competence in fusion and plasma. In 1978, a Bilateral Agreement was signed between the Euratom and Switzerland in the field of fusion, and since then Switzerland is an Association State of all Euratom activities in the field of fusion (including the scientific exploitation of the JET, the ITER project and the "Broader Approach" with Japan). The SPC has two sites, the main one at the EPFL and the Superconductivity Group hosted by the Paul Scherrer Institute. Besides the SPC/EPFL, a group of the Nanolino Laboratory of the University of Basel is working on material problems.

The present Swiss program encompasses in the field of fusion:

- The development of the physics basis in view of the scientific exploitation of ITER and in support of DEMO design.
- The development of superconducting cable for ITER and DEMO.
- The development and test of heating by systems for ITER (electron cyclotron wave system ECWS) and for DEMO (ECWS and components for the Neutral Beam Injection).
- The training of young physicists and engineers ("the ITER and DEMO generation").

The program is fully in line with the European Fusion Roadmap (EFDA 2012). The EPFL is member of the European Consortium, EUROfusion, which is implementing the Roadmap. In Switzerland, besides SPC/EPFL other laboratories are also participating in Eurofusion R&D.

To perform this program, the SPC have a few unique installations:

- Its tokamak TCV (Figure 17.12) with a state of the art diagnostics system and heating system allowing to heat both the ions and the electrons. TCV is, besides JET, the only three medium size tokamaks, which are supported by the consortium EUROfusion during campaigns open to all of its partners and fully financed by EUROfusion during the campaigns. The tokamak TCV was granted recently funding to refurbish and upgrade its heating system;
- The SULTAN superconducting test facility, which is worldwide the only test facility capable to test superconducting cable for ITER and DEMO. During the present phase of ITER construction, the SULTAN facility was fully booked by the ITER Partners to perform test on the ITER SC conductors.
- Access to the Swiss National high Performances Computers (HPCs) at CSCS, as well as to HPC dedicated to fusion ("HELIOS" HPC for European and Japanese Fusion Program and the new Marconi HPC, which is replacing HELIOS).

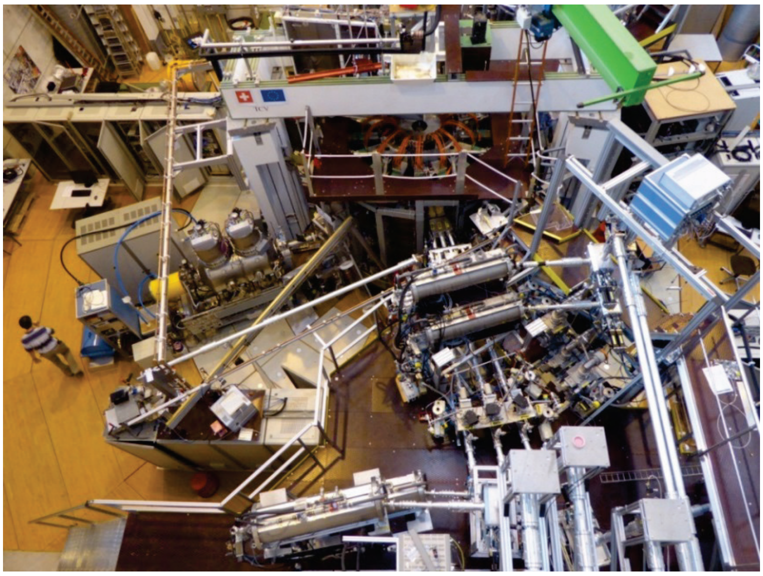

Figure 17.12: Picture of the tokamak TCV of SPC.

17.4.4.2 International program

The SPC is fully embedded in the Euratom fusion program as part of the EUROfusion consortium. The main key players in fusion are the ITER partners: China, India, Japan, Korea, Russia and the USA.

The SPC has collaborations with laboratories of all these countries and also with the fusion program of Brazil.

17.4.5 Safety and environmental aspects

17.4.5.1 Safety

Before discussing in detail the safety aspects of fusion reactors, let us remind the reader that ITER went through a full nuclear testing process (including the "Stress Test" imposed to all nuclear power plant after the Fukushima accident). The "Preliminary Safety Report" submitted to the French *Autorité de Sûreté Nucléaire (ASN*) is a 2'000 page document detailing all aspects of the plants. ITER is in the first fusion power plant to be licensed on November 20th 2012, date of the signature of authorization to construct ITER.

There exists a vast amount of safety analyses for fusion power plant (EFDA 2005). These safety studies includes items such dose rate to workers, to the release of T and other materials. In on-going DEMO study, safety is an important part of the analysis and concerns all other items.

A fusion reactor is characterized by the following features, which contribute to the safety aspects:

- The fusion reactions are not chain reactions: they are binary collisions between the nuclei of D and T;
- The fuel (a mixture of 50/50% D/T gas) inside the reactor volume is only sufficient for a few minutes, thus the energy available in case of loss of control is small;
- In case of the worst case accident, studies show that there will be no need for evacuation (EFDA 2005);

- With an adequate choice of material (known as Reduced Activation Material, RAM), the after heat (caused by the radioactive material transmuted by the 14 MeV neutrons flux) is low, avoiding the risk linked to loss of coolant accident when the reactor is not in operation. This point was assessed for ITER case (Figure 17.13) and for model power plant (Figure 17.14). In both case no excursion of temperature beyond melting point of stainless steel (the main structural material) is reached;
- Using RAMs, the issue of waste disposal was also examined during the study of the power plant concept. It was found that after a period of intermediate storage of about 100 years, there is no need of permanent waste disposal (Figure 17.15).

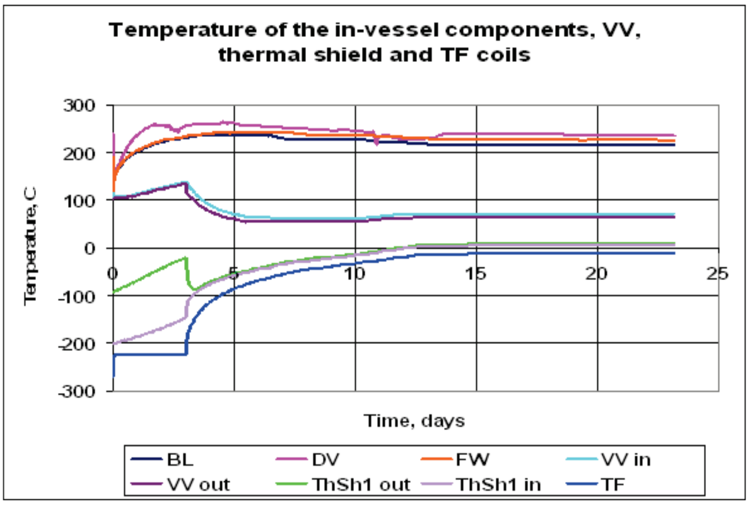

Figure 17.13: Temperature evolution in ITER in case of loss of coolant after a shut down.[388]

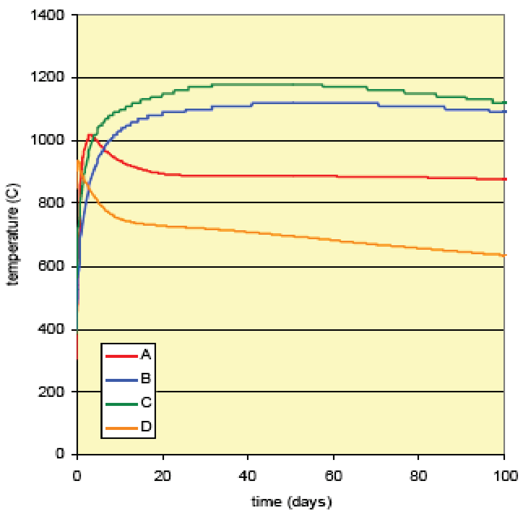

Figure 17.14: Temperature evolution in reactor after shut down in case of loss of coolant after a shutdown (EFDA 2005). The temperature does not exceed the melting temperature of structural materials.

[388] http://www.nuklearforum.ch/fr/forum-nucléaire-suisse/nos-manifestations/rencontre-du-forum-safety-characteristics-iter

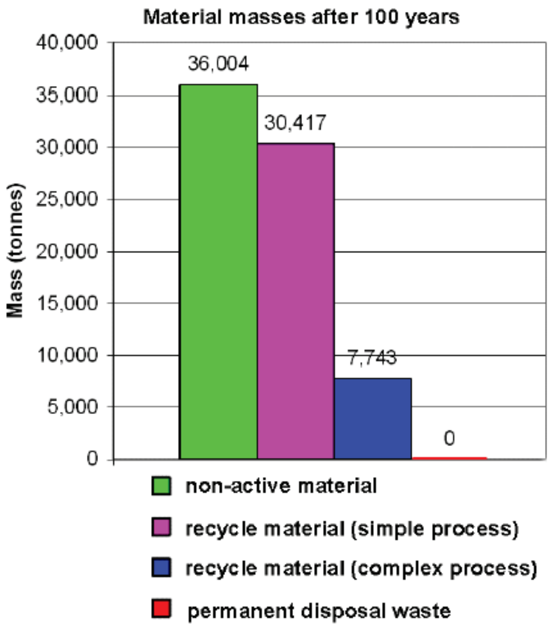

Figure 17.15: Classification of the waste of a fusion reactor after 100 years of intermediate storage. Please note the zero amount of waste, which requires permanent disposal (EFDA 2005).

17.4.5.2 Environmental aspects

The environmental impact in terms of CO_2 emissions per kWh was assessed for fusion power plants (Tokimatsu, Hondo et al. 2000). As stated by (Tokimatsu, Hondo et al. 2000), "the tokamak fusion reactors are excellent sources electricity with low CO_2 emission intensity" Figure 17.16. However, due to the current technology status of fusion, such an assessment is associated with large uncertainties.

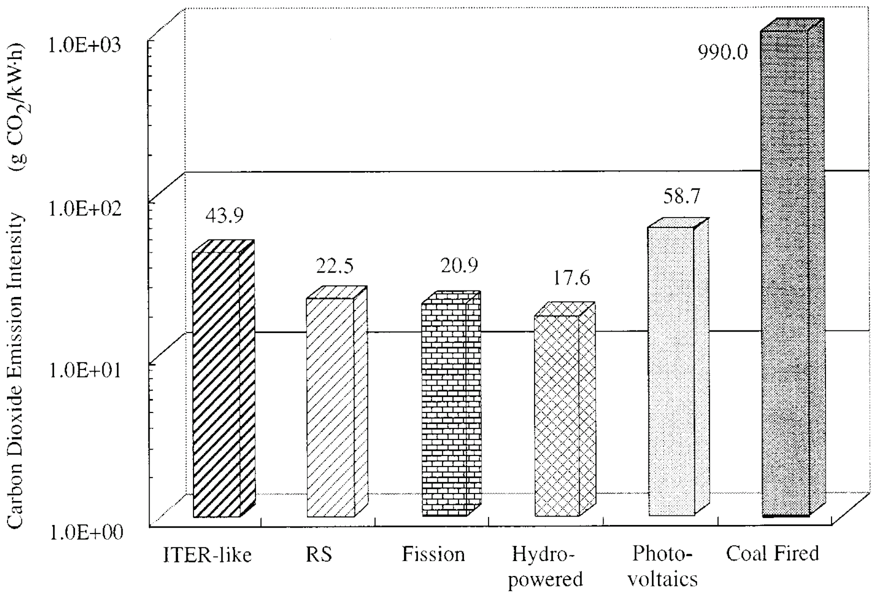

Figure 17.16: CO_2 emission of a fusion reactor of tokamak type (ITER - like or Reversed Shear RS) (Tokimatsu, Hondo et al. 2000).

Although not directly linked to environmental aspects, one can evoke here the issue of fuel sustainability. While Deuterium is abundant, Tritium does not exist naturally on Earth since it has a life-time of about 13 years. It is generated from fusion reaction using the neutrons which are produced in the reaction through the two reactions with Li:

$Li^6 + n \rightarrow T + He^4 + 4.8$ MeV   Exothermic reaction

$Li^7 + n \rightarrow T + He^4 + n - 2.5$ MeV   Endothermic reaction

The second reaction has therefore a threshold at 2.5 MeV and the breeding of the T will require an enrichment of the natural Li. The resources and reserves of Li are high in the Earth crust. Should it be necessary, Li can also be extracted from sea water. The resources of Li were discussed at the World Energy Conference 2013 in Daegu. We learnt from the panel that methods to extract Li from seawater exist and are being tested on pre industrial scale. The view of the Panel, the availability of Li will not be an issue for fusion.

17.4.6 Cost of electricity

The issue of evaluating cost of electricity (CoE) is a difficult issue, since:
- a first commercial fusion power plant might only be built in the second half of this century;
- the CoE depends on the “learning curves” of the reactor. The CoE from a first of a kind reactor will be more expensive than from a n^{th} of a kind one.
- the economic prevailing conditions in the different regions of the world cannot been foreseen at this stage;
- the environmental policy (greenhouse gas taxes, limit on the maximum CO_2 concentration in the atmosphere, subsidies).

In the past there were a few studies, which were performed in the field of CoE. We shall cite a few results, more as a comparative study with other ways of producing electricity. One should not use the value of the obtained CoE as absolute value.

(EFDA 2005) gives a range of CoE for fusion and the comparison with other ways to produce electricity; CoE for fusion are similar to wind power. Of interest is also the comparison of external cost of fusion and of different other electricity sources (Hamacher, Sáez et al. unknown). This study is based on the methodology established by the European ExternE project. The external costs for fusion are again similar to those of wind power.

As a summary, while it is nearly impossible to predict now the CoE for fusion, which might become commercial in the second half of the century, the study on CoE suggests that CoE would not be a show-stopper.

17.4.7 Conclusion

The deployment of fusion is expected for the second half of this century. Fusion offers features, which render it a sustainable and environmental friendly electricity source. With the construction of ITER and the design study of the step which will follow ITER, namely DEMO, the field is moving from only a science based field of study to a project oriented approach where technological constraints linked to industrial operation and grid connection will dominate.

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17.5 Thermoelectrics for stationary waste heat recovery

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To a large extent, this section is based on (Battaglia, Widmer et al. 2016). Further detailed information can be found in this recently published report. In addition, (BFE/SFOE 2016a) provides access to recently published research reports in the area of thermoelectric power generation. Further recently published, but not Swiss specific, literature is provided throughout this chapter.

17.5.1 Introduction

Thermoelectrics enables the direct conversion of heat flux into electrical energy. It can be regarded as alternative to conventional conversion of heat into electricity via water steam or organic rankine cycles and as additional process in order to use waste heat for additional electricity generation. Waste heat is defined as the part of heat that cannot be recovered with today's technologies and does not serve an intentional heating purpose. Main disadvantage of thermoelectric energy conversion is the comparatively low efficiency and therefore, under many circumstances, thermoelectrics is not competitive with water steam and organic rankine cycles. However, there are potential applications where thermoelectrics offer an advantage over competing technologies (Battaglia, Widmer et al. 2016).

17.5.2 Technology

Thermoelectric energy conversion is based on the thermoelectric effect, which is the direct conversion of temperature differences to electric voltage and vice versa. A thermoelectric generator, also called a Seebeck generator, is a solid state device that converts heat (temperature differences) directly into electrical energy through a phenomenon called the Seebeck effect (a form of thermoelectric effect).[389] Thermoelectric generators function like heat engines, but are less bulky and have no moving parts. However, TEGs are typically more expensive and less efficient (Adroja, Mehta et al. 2015).

Thermoelectric materials generating power directly from heat by converting temperature differences into electric voltage must have both high electrical conductivity and low thermal conductivity to be good thermoelectric materials. Having low thermal conductivity ensures that when one side is made hot, the other side stays cold, which helps to generate a large voltage while in a temperature gradient. For many years, the main three semiconductors known to have both low thermal conductivity and high power factor were bismuth telluride (Bi_2Te_3), lead telluride (PbTe), and silicon germanium (SiGe). These materials have very rare elements which make them very expensive compounds. Today, the thermal conductivity of semiconductors can be lowered without affecting their high electrical properties using nanotechnology. This can be achieved by creating nanoscale features such as particles, wires or interfaces in bulk semiconductor materials. However, the manufacturing of nano-materials is still challenging.

A comprehensive overview concerning the current status of thermoelectric materials research was recently provided by Battaglia, Widmer et al. (2016) and is also provided by (wikipedia 2017). Further basics and details can be found in e.g. (Riffat and Ma 2003, Snyder

[389] https://en.wikipedia.org/wiki/Thermoelectric_generator (4.1.2017).

and Ursell 2003, Wagner 2007, Bell 2008, Sundarraj, Maity et al. 2014, He, Zhang et al. 2015, Gao, Huang et al. 2016).

A thermoelectric module (Figure 17.17) is a circuit containing thermoelectric materials that generate electricity from heat directly. It consists of two dissimilar thermoelectric materials joining in their ends: an n-type (negatively charged); and a p-type (positively charged) semiconductors. A direct electric current will flow in the circuit when there is a temperature difference between the two materials. Generally, the current magnitude has a proportional relationship with the temperature difference.[390]

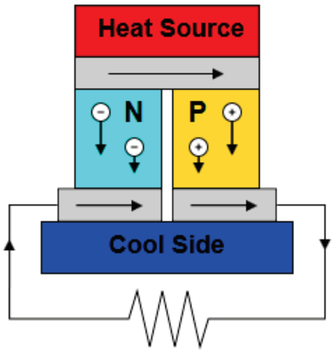

Figure 17.17: Scheme of a thermoelectric circuit composed of materials of different Seebeck coefficient (p-doped and n-doped semiconductors), configured as a thermoelectric generator.[391]

17.5.3 Potential for electricity generation

17.5.3.1 Industry

According to (Battaglia, Widmer et al. 2016), the chemistry/pharmaceutical industry, cement/concrete production and metal/steel production industries have the greatest waste heat potential, followed by food production. Battaglia, Widmer et al. (2016) conclude that the potential for industrial waste heat in the 250°C temperature range is very limited in Switzerland and focus their analysis on companies using waste heat in the 65°C temperature range. At temperatures above 65°C, thermoelectric heat to electricity conversion competes directly with heat transfer, remote heat utilization, or water steam and organic rankine cycles. Due to the relatively low conversion efficiency of thermoelectric generators (2.5%) their use is only in exceptional cases economically viable. However, opportunities for thermoelectric devices exist at temperatures below 65°C as the conversion efficiencies of cycle processes become low. In addition, cycle processes are relatively complex and not always compatible for refurbishing existing infrastructure and certainly not suitable for upgrading heat pumps in industrial manufacturing.

Unfortunately, Battaglia, Widmer et al. (2016) do not provide estimates for overall electricity generation potential with thermoelectric devices from industrial waste heat sources in Switzerland.

17.5.3.2 Buildings

Most natural applications of thermoelectric devices within Swiss buildings are cold storage warehouses, cooling of computer server rooms (Figure 17.18) and air conditioning in

[390] https://en.wikipedia.org/wiki/Thermoelectric_generator (4.1.2017).
[391] https://commons.wikimedia.org/wiki/File:Thermoelectric_Generator_Diagram.svg (4.1.2017).

summer (Battaglia, Widmer et al. 2016). For cold storage warehouses, Battaglia, Widmer et al. (2016) estimate a potential annual thermoelectric electricity generation of 875 MWh; further estimates are not provided.

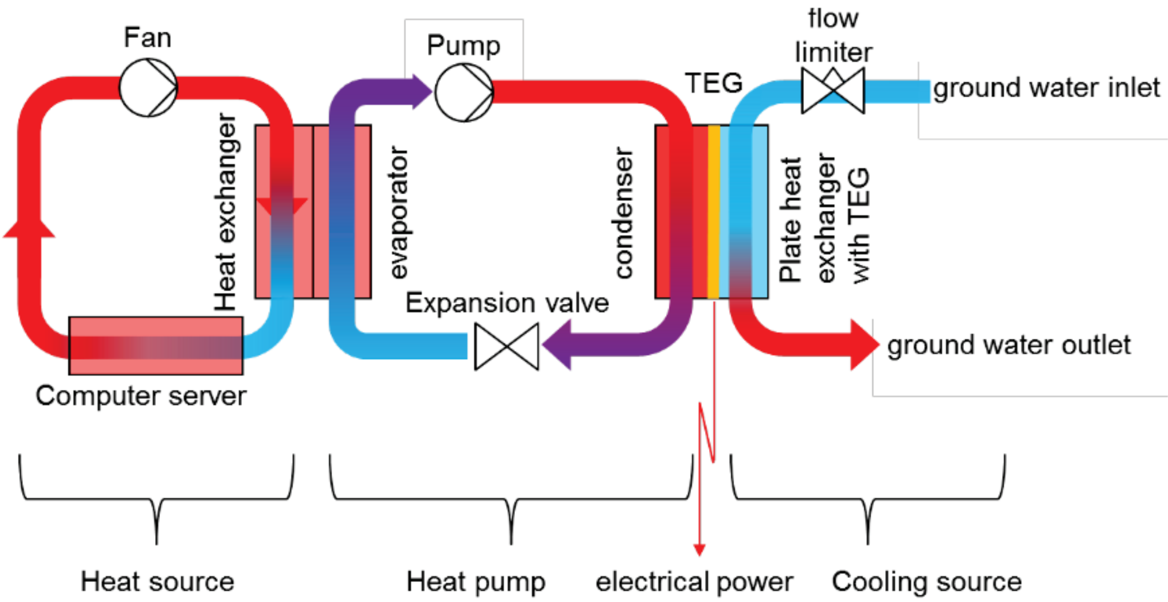

Figure 17.18: Scheme of a simplified cooling cycle for a heat source, e.g. a server room, with thermoelectric generators (Battaglia, Widmer et al. 2016).

17.5.4 Electricity generation costs

Currently, the economic feasibility for thermoelectric solutions is currently not given in the industrial waste heat recovery market – Battaglia, Widmer et al. (2016) estimate generation costs of 50 Rp./kWh for a Bi_2Te_3 based-thermoelectric unit and conclude that only off-grid applications might be economically attractive for thermoelectric generators.

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