4 Electricity Generation and Operational Planning

Electricity is a crucial resource for modern societies (see Sect. 2.2). The sustainable provision of electricity is at the same time at the core of the current debates about the energy system of the future. Key questions for designing future electricity systems are thereby:

- Which technologies may be used for electricity generation?
- What are physical and technical characteristics of these technologies?
- What are economic characteristics and potentials of these technologies?
- How may electricity demand be met using a mix of technologies, including notably also variable renewable generations?

These questions will be discussed subsequently, starting with available conventional electricity generation technologies in Sect. 4.1. Then renewable energy technologies are in the focus in Sect. 4.2. Key characteristics for both types of energy technologies are summarised in Sect. 4.3 and the problem of scheduling the different generation technologies to meet demand is discussed in Sect. 4.4, whereas the intermediaries of transport and storage are left for Chap. 5.

Key Learning Objectives
After having gone through this chapter, you will be able to

- Describe the basic principles and the key components of (conventional and renewable) electricity generation technologies.
- Describe the key techno-economic characteristics of power generation and state the magnitude of these characteristics for different generation technologies.
- Understand the scheduling of electricity generation.

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- Interpret the role of electricity generation technologies in day-ahead planning.
- Explain the merit-order approach and formulate the corresponding mathematical optimisation problem of plant scheduling.

4.1 Conventional Generation Technologies

One key advantage of electricity is that many technologies may be used for its production. There are technologies available to convert almost any primary energy source into electricity. In the following, first, an overview is given of the major technologies. Electricity generation technologies may be categorised according to different characteristics such as the underlying physical principles or the typical size of installations. We still follow the established distinction by primary energy sources, although electricity generation from biomass (see Sect. 4.2.4) mostly exploits similar technologies as fossil fuels.

4.1.1 Fossil-Fired Technologies

Fossil-based electricity generation systems consist of three main parts: (1) a combustion unit, where fossil energy carriers are burnt to convert the stored chemical energy into heat; (2) a thermal engine which converts the heat into mechanical energy and (3) the electricity generator itself converting the mechanical energy of a rotating shaft into electricity. For the thermal engine, three major types may be distinguished according to the basic thermodynamic processes used: steam turbines, gas turbines and motor engines. Before discussing these in some more detail, first, the combustion process is considered. Subsequently, we also discuss the electricity generator and fuel cells as conversion engines that are not based on combustion. Finally, the scaling up from physical principles to utility-scale units is briefly discussed.

4.1.1.1 Combustion Process

Fossil fuels are composed primarily of carbon and hydrogen (see Table 4.1).

Correspondingly, the main chemical reactions[1] in a combustion process may be described as:

$$C + O_2 \Rightarrow CO_2$$

[1] It should be noted that these are not chemical reactions in a narrow sense. Rather these equations abstract from the chemical equations and just summarize the essential main chemical components.

Table 4.1 Fossil fuels and their most essential components

Fuel	Components (**bold**: main components)
Coal	**Carbone** (**C**) plus varying proportions of water (H_2O), sulphur (S) and other substances (nitrogen (N), hydrogen (H_2), phosphorus (P), trace elements, ...)
Oil	(Various, mostly saturated) **Hydrocarbons** (**C_nH_{2n+2}** with n between 6 and 30) plus varying proportions of sulphur (S) and other substances (oxygen(O_2), hydrogen (H_2), metals, ...)
Natural Gas	**Methane** (**CH_4**) plus varying proportions of ethane (C_2H_6), propane (C_3H_8), etc., as well as nitrogen (N_2), hydrogenic sulphur (HS) and other substances (carbon (CO_2), water (H_2O), ...)

$$4\,H + O_2 \Rightarrow 2\,H_2O$$

Both reactions are exothermal; i.e. energy is released in the form of heat. Given the heterogeneous composition of most fossil fuels and the specifics of the combustion, further combustion reactions are occurring in parallel, notably the sulphur in the fuel is converted to sulphur dioxide SO_2 and sulphur trioxide SO_3, and part of the nitrogen in the combustion air forms nitrous oxides of the general formula NO_x (cf. Sect. 6.2).

4.1.1.2 Steam Cycle and Steam Turbines

The heat produced through the combustion process may be used in steam turbines. A **steam turbine** is part of a closed-cycle thermodynamic process, generally called the steam or water-steam cycle. The key elements of this cycle process are depicted in Fig. 4.1.

Energy enters the process through heat transfer in the boiler (c). In the case of fossil (or biomass) plants, the energy is obtained through the combustion of fuels – they may be solid (coal), liquid (oil) or gaseous (gas). The energy increases temperature and pressure of the fluid and eventually transforms the water into steam. In the so-called p–V diagram (see Fig. 4.2), the pressure–volume diagram, this heating and phase-shifting correspond to the movement from point I to point II. In the turbine, part of the enthalpy contained in the fluid is transferred to the rotating shaft of the turbine (e) – it is transformed into mechanical energy. This leads to a decrease in pressure and temperature with a simultaneous increase in volume (point II–III). The cool, low-pressure steam then enters the condenser (g), where it transfers the remaining energy to the cooling medium (in general water). In the p–V-diagram, this corresponds to the horizontal, i.e. isothermal and isobaric,[2] move from III to IV. The final step to complete the cycle is the pressure increasing pumping (h and b) of the water from the condenser to the boiler.

[2] An isothermal process is a type of thermodynamic process in which the temperature of the system remains constant. Analogical, an isobaric process, is a type of thermodynamic process in which the pressure of the system remains constant.

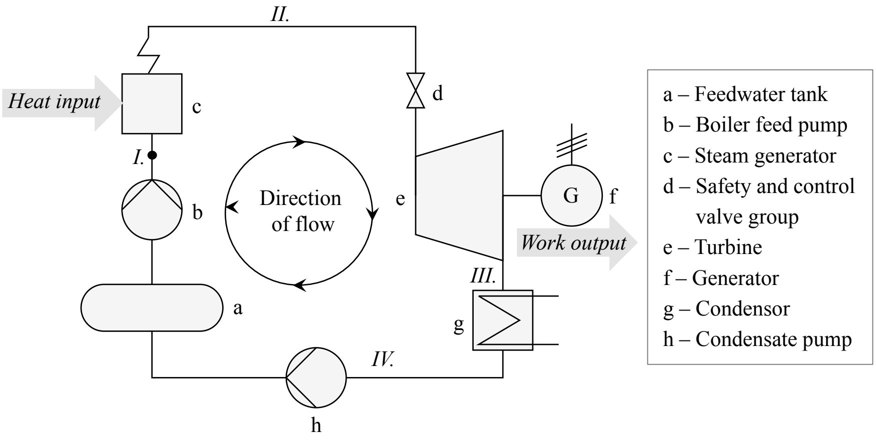

Fig. 4.1 Schematic representation of the steam cycle process of electricity generation

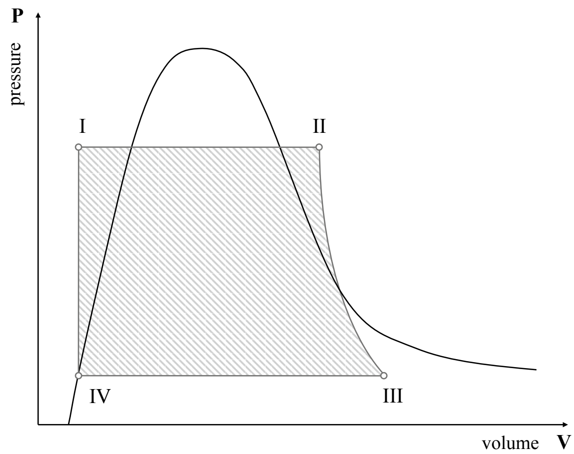

Fig. 4.2 p–V-diagram of the Rankine cycle (steam cycle process)

This description focuses on the key elements in terms of energy transformation. The thermodynamic, ideal reference process, which may be used to determine the achievable process parameters and efficiencies, is called the Rankine cycle or Clausius–Rankine cycle. Further process steps (partly indicated in Fig. 4.1) are needed for the technical operation or to improve overall efficiency.

The efficiency of the process cannot exceed the Carnot efficiency discussed in Sect. 2.1.2, which is the theoretical maximal efficiency of the process depending on the temperature difference. In practice, the Rankine cycle will be more efficient than a process using gas as a working fluid, notably because the mechanical energy needed for compression (IV–I) is small, given that water has a much higher density than steam. Instead of water also other working fluids like ammonia or organic substances may be used. The latter technical option is pursued in the so-called organic Rankine cycle (ORC), transforming lower-temperature heat (100–200 °C) into mechanical or electrical energy.

In large-scale fossil power plants, the Rankine cycle is operated with fresh steam temperatures of up to 600 °C and pressures of 280 bar. Separate steam turbines for high, medium and low pressure successively expand the steam. The combination of several turbines allows to increase the overall efficiency of the process as different temperature and pressure levels can transform heat energy into mechanical energy. The condenser is operated at about 25 °C and a pressure of 0.03 bar, i.e. below air pressure. Such a configuration allows achieving a net efficiency of up to 46% at modern steam power plants. Typical plant sizes range from 10 to 1000 MW_{el} (MW electrical output), with efficiency increasing with larger plant sizes due to lower losses.

To further improve the conversion efficiency and thus lower resource consumption and emissions, the following measures may be taken:

- Use of new materials and alloys to enable an increase of steam temperature and pressure: in fact, the steam parameters are not limited by the combustion process but by the materials' ability to sustain high temperature and pressure over long time periods. Further increases in temperature and pressure levels allow further net efficiency improvements.
- Intermediate reheating of steam and preheating of feeding water which allows to increase the efficiency by lower condenser temperatures respectively a higher average temperature of the energy transferred in the boiler.
- Heat use in combined heat and power (CHP) systems: this does not increase the efficiency of electricity generation but the overall efficiency (see Sect. 4.1.3).

  Besides improvements in energy efficiency, increases in operational flexibility are another primary goal of plant manufacturers' current research and development (R&D) activities. Traditionally, the flexibility of operation is limited by several factors:
- Thermal stress resulting from rapidly changing operation conditions. In operation, ramping rates are therefore limited, e.g. to 2% of the rated capacity per minute.
- Minimum operation times and minimum downtimes are also frequently defined to limit thermal stress.
- Start-up times as a consequence of defined start-up processes and the necessity to heat-up the equipment. For coal plants, these may be 4 h or even more and depend on the status of the plant (starting from cold or heated status).
- Stable operation requirements for grinding mills, pumps and combustion processes. This leads to a minimum stable generation level which for many plants used to be around 50% of the nameplate capacity.

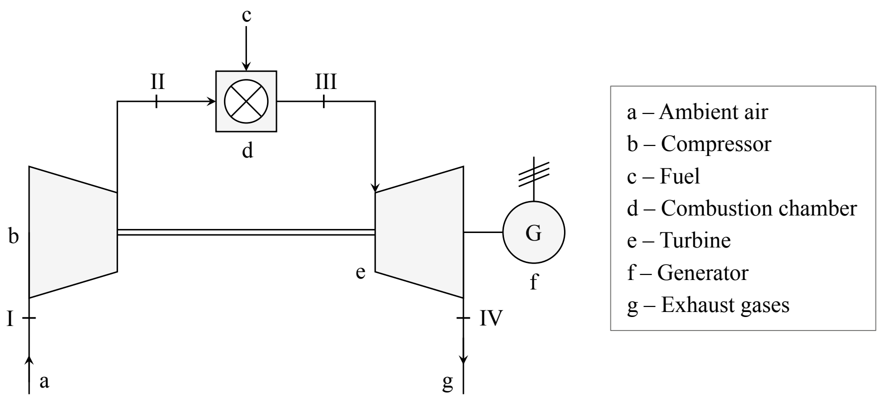

Fig. 4.3 Schematic representation of the gas turbine process for electricity generation

4.1.1.3 Joule Cycle and the Gas Turbine

A **gas turbine** is in its basic process details somewhat similar to a jet engine for aircrafts. The main components of the thermodynamic process are depicted in Fig. 4.3.

The process is "open" (in contrast to the above shown Rankine cycle) since ambient air enters the compressor and exhaust gases leave the process after the turbine through a chimney with possibly some intermediate cooling facilities. Therefore, this type of engine is also frequently called open-cycle gas turbine or **OCGT** for short. The term "gas turbine" refers to the fact that the working fluid is gaseous; it does not necessarily imply that the fuel is natural gas. Rather commercial gas turbines may also run on fuel oil or in the future on biogas (biomethane) or hydrogen. Even coal-fired plants may include a gas turbine: in that case the plant design consists of a gasification stage preliminary to the gas turbine. This concept, known as **IGCC** (**integrated gasification combined cycle**) has been realised in a limited number of industrial large-scale demonstration projects (e.g. in Puertollano, Spain and Priolo, Italy). This plant design is intended to make use of two processes, the conventional steam process (Rankine cycle) and the gas turbine process, to increase overall efficiency.

The thermodynamic reference process for the gas turbine is called the Brayton or the Joule cycle. The compression corresponds in the p–V diagram to an increase in pressure with a simultaneous decrease in volume (I–II), ideally at constant entropy (isentropic). The combustion is isobaric, i.e. occurs at constant pressure, with an increase in temperature and associated increase in gas volume (II–III). The conversion of this thermal energy into mechanical energy occurs in the gas turbine itself. It leads to a decrease in pressure and temperature but an increase in the volume of the combustion gas (III–IV). For the thermodynamic representation, the cycle is closed by the isobaric step from IV–I. The idealised cycle is depicted in Fig. 4.4.

Gas turbines are currently built with an output range of 5–300 MW. Microgas turbines with rated power starting at 5 kW have been intensively researched over the last decades, yet have hardly been a commercial success so far. Modern

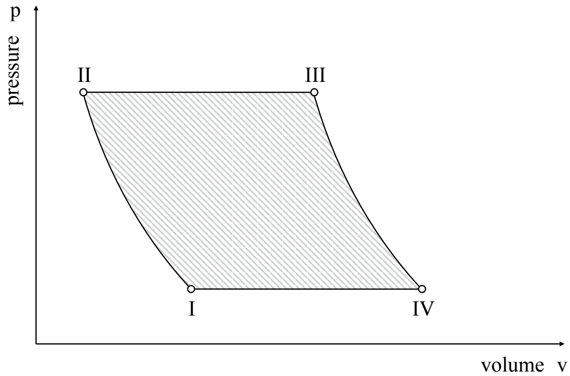

Fig. 4.4 p–V-diagram of the Brayton or Joule cycle (gas turbine process)

large-scale gas turbines achieve an efficiency of 38% (relative to the lower heating value, see definition Chap. 2). The efficiency is limited by the maximum inlet temperature of the gas turbine, which is currently around 1500 °C. For small-scale turbines, efficiency is substantially lower due to higher losses, notably related to a higher share of reverse flows in the compressor.

The maximum turbine inlet temperature effectively limits the attainable pressure ratio and thus the efficiency of the almost isentropic and isobaric processes of compression and combustion. As a consequence, the outlet temperature of the gas turbine is then also in the order of 500 °C. The hot outlet temperature implies a possibility for very substantial conversion efficiency increases: the use of the exhaust gases for heating the steam for a steam cycle process. This is the basic principle of the combined cycle gas turbine (CCGT) units described in the following section. Other possibilities for efficiency increases arise from higher inlet temperatures, possible with new materials such as ceramics.

Operation of gas turbines is much more flexible than operation of power plants with steam cycles. Pure open-cycle gas turbines may be started within less than a quarter-hour and may also ramp their entire operation range within the same time interval. However, a limitation in many designs is the low part-load efficiency, which makes operation at less than the rated output rather unattractive. Furthermore, flexibility improvements similar to those indicated for steam turbines in Sect. 4.1.1.2 are currently strived for.

4.1.1.4 Combined Cycle Gas Turbine

As indicated by the name, **gas combined cycle units** (short: CCGT) consist of a combination of one or several gas and steam turbines. As shown in Fig. 4.5, the fuel is burnt in the gas turbine process and the exhaust gases of the gas turbine are then used to heat the steam in a steam cycle. Whereas the efficiency of a gas turbine may reach up to 38%, the overall efficiency for **CCGT** plants may exceed 60%, based on the lower heating value.

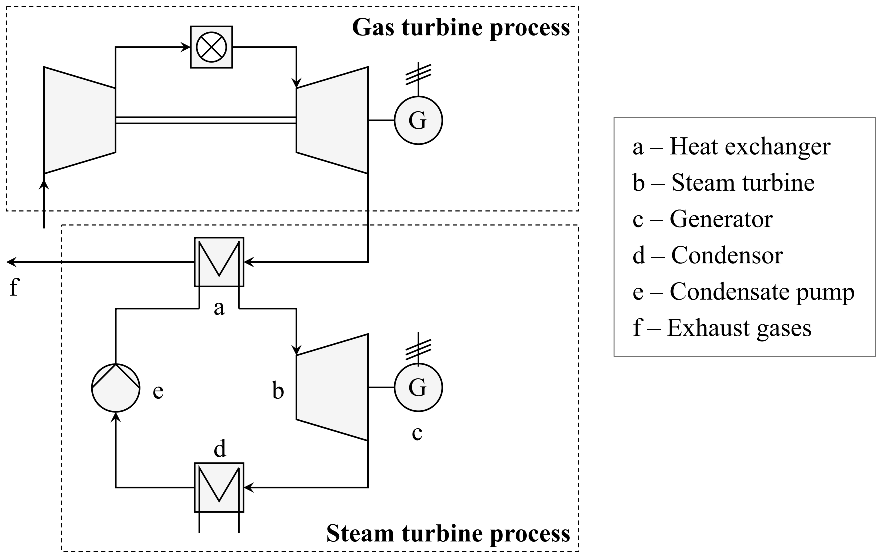

Fig. 4.5 Schematic representation of the combined cycle process for electricity generation

Commercial plants exist with nameplate capacities ranging from 20 to 800 MW and various turbine configurations. In terms of cost efficiency, the single shaft concept seems advantageous: gas turbine, steam turbine and generator are mounted on one single shaft, thus avoiding a separate generator unit for each turbine. Yet this implies that the gas and the steam turbine have to be continuously operated as a single unit. Moreover, a 2-1 configuration is preferable in terms of sizing: two gas turbines provide the heat input for one single steam turbine. Then gas turbines and steam turbines may be scaled to their economically efficient size, providing efficiency and cost advantages.

The operational flexibility of combined cycle units is strongly dependent on the actual plant design. Many of the CCGT units built in the 1990s and early 2000s in Europe were built as baseload units to run on cheap gas or in a carbon-constrained context. The plant layout was then optimised to maximise efficiency at full load. Newer designs and current development efforts aim to provide operational flexibility and high efficiency over a broader range of operation points, along the same lines as indicated for pure steam and pure gas turbines. Also, more frequent start-ups are a design feature important for new developments.

4.1.1.5 Motor Engine

Whereas gas and steam turbines dominate the large-scale electricity generation segment, **motor engines** are the preferred option for generation capacities in the range of 5 kW–2 MW. The newest generation even goes to a unit size of up to 10 MW with a nameplate electrical efficiency of 45%. The engines are similar to car motors, although they are rather designed for continuous operation than for frequent starts, accelerations or other regime shifts. For illustration: a typical car use of 1 h per day corresponds to less than 400 h of operation per year. By contrast, standard stationary motor engines are operating 4000–8000 h per years. Nevertheless, the basic processes are identical; i.e. Otto and Diesel cycles (cf. Granet and Bluestein 2014) are in use. The motor engines may be fuelled with liquid fuels like fuel oil or biogenic oils (e.g. palm oil or rapeseed oil), but in urban areas in Europe, they are more frequently run on natural gas, biogas or landfill gas.

Compared to gas and steam turbines, motor engines offer better possibilities for down-scaling while maintaining reasonable electrical efficiency. Well-established manufacturing concepts also make them cost-effective in terms of costs per capacity unit – at least at engine sizes above 100 kW. Operational flexibility is at least as high as for open-cycle gas turbines, although maintenance expenditures tend to be higher. Engines could also be used as CHP plants (see Sect. 4.1.3) when recovering the exhaust heat.

As with other combustion plants, research and development aim at increasing energy efficiency through higher combustion temperatures and pressures. For applications in residential housing, new designs for small-scale motor engines are looked for. One alternative that has received considerable attention is the so-called Stirling motor. It also has pistons and cylinders; yet combustion is done outside the cylinders. This provides, in principle, advantages in terms of fuel flexibility and, at the same time, allows small engine sizes. Yet still, it remains to be seen whether they may be produced at affordable costs when moving to larger scale production. So the main development focus is on cost reduction in parallel with further efficiency improvement.

4.1.1.6 Electricity Generators

Conversion of mechanical energy to electrical energy is done using the electrical induction principle discovered in the nineteenth century by Faraday and others. A **generator** consists of a rotating part, the rotor, and a stationary part, the stator. In general, two types of electromagnetic generators can be distinguished: dynamos induce pulsing direct current using a commutator, while alternators generate alternating current. With the rotation of the rotor, a time-varying magnetic field induces electrical currents in a conductor, and this effect is amplified if the conductor is wound up to form a coil.

Generators in large-scale power plants are in general so-called synchronous generators; i.e. their rotation speed is proportional to the frequency of the alternating current (AC) in the grid (see Sect. 5.1). The alternating current is induced in the coils of the outer, fixed part of the generator, the so-called stator (see Fig. 4.6). It results from the rotating magnetic field in the inner part, the rotor. For small-scale units, permanent magnets may be used for the rotor; yet in large-scale power plants, the magnetic field is generated by electromagnets, the so-called field coils. Synchronous generators primarily used in power plants can deliver pure active power or supply reactive power, which is required to compensate for inductive and capacitive loads. Thus, they can serve as active phase shifters in electrical power supply networks.

Apart from PV and fuel cells, generators are ubiquitous for electricity generation for most energy carriers, including fossil, nuclear and most renewables: wind, biomass, solar thermal, geothermal, hydro, tidal, wave, etc.

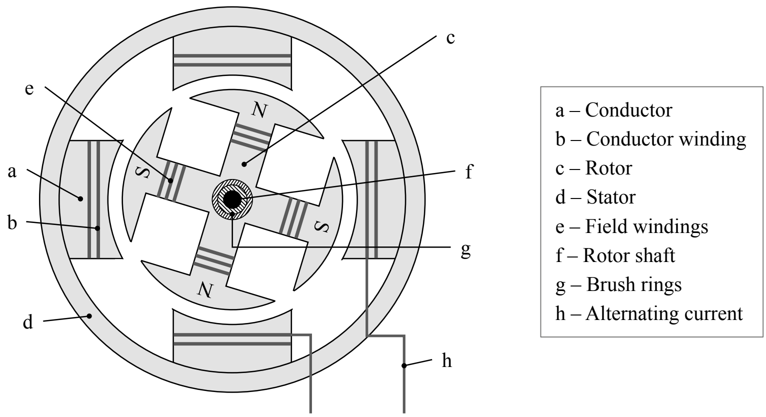

Fig. 4.6 Cross section of an electricity generator

4.1.1.7 Fuel Cells

As opposed to all the technologies discussed so far, fuel cells do not rely on combustion. Instead, they directly convert the chemical energy stored in the fuel to electricity in reversing the electrolysis process. The main components of a fuel cell are the two electrodes – cathode and anode, and an electrolyte (Fig. 4.7). The electrolyte selectively transports ions from one electrode to the other, e.g. protons from the anode, which is the negative pole of the fuel cell, to the cathode. There they recombine with oxygen, previously reduced by the electrons transported through the electrical system. Hence the basic reaction equations for a hydrogen fuel cell are:

$$\text{Anode}: \; H_2 \Rightarrow 2\,H^+ + 2\,e^-$$

$$\text{Cathode}: \; O_2 + 4\;e^- \Rightarrow 2\;O^{2-}$$

$$2H^+ + O^{2-} \Rightarrow H_2O$$

The electrolyte, e.g. a membrane, ensures that the fuel and the oxidant (oxygen or ambient air) do not recombine directly.

By avoiding the intermediate conversion of chemical energy into thermal energy, fuel cells have a higher efficiency than conventional power plants as they circumvent the limitations of the Carnot efficiency for the conversion of heat into power. Hence, in principle, very high electrical efficiencies may be obtained. Furthermore, the concept is scalable since a single cell typically delivers a voltage of 0.6–0.7 V. Thus, they have to be combined to form larger stacks. Yet, various practical issues make this appealing concept rather complicated for stationary and mobile applications.

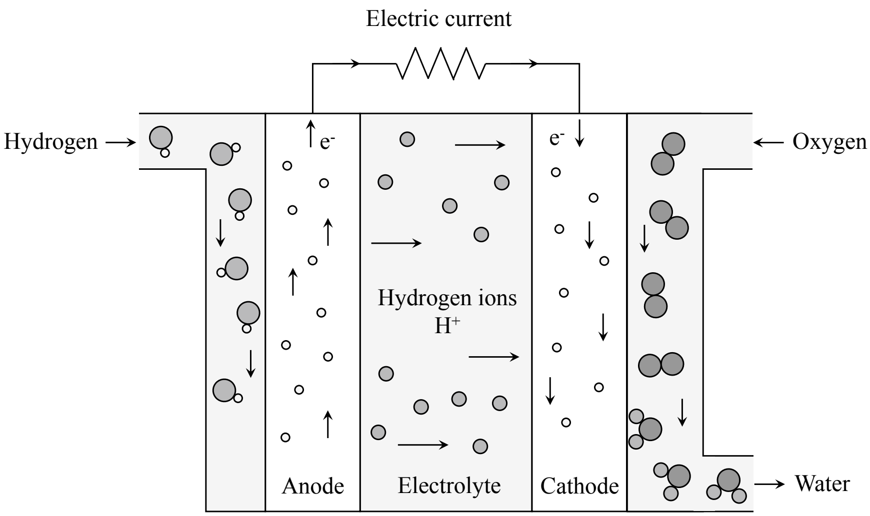

Fig. 4.7 Schematic representation of a fuel cell for electricity generation

Research, development and early commercialisation currently focus on four different types of fuel cells:

PEMFC – polymer fuel cells: these fuel cells are also called PEMFC—proton exchange membrane fuel cells, since they use a polymer membrane as electrolyte. They operate at low temperatures (40–80 °C) and are very flexible in operation. Yet, they require pure hydrogen as fuel. Unless this fuel is immediately available, the hydrogen conversion reduces the overall electrical efficiency so that at a plant level approximately 40–50% are achieved.

PAFC – phosphoric acid fuel cells: these fuel cells were among the first to be commercialised on a small scale. They use phosphor acid as an electrolyte which leads together with the operating temperature of 150°–200 °C to considerable corrosion problems. Commercialisation of these cells has been stopped in the early 2000s, as plant efficiency has been relatively low with 38%.

SOFC – solid oxide fuel cells: these are high-temperature fuel cells based on a ceramic as electrolyte. Here oxygen O^{2-}ions are transported through the electrolyte. The operating temperature is in the range of 800–1000 °C, which implies limited operational flexibility. Yet, on the other hand, this fuel cell type does not require pure hydrogen as fuel but may also run on methane, i.e. natural gas, which is then internally reformed. The electrical efficiency at the plant level is in the range of 55–60%.[3]

[3] The fuel cell efficiency maybe around 50%. However, because of a high temperature, a gas turbine could be connected to a SOFC, thus increasing the plant efficiency beyond 70%.

MCFC – molten carbonate fuel cells: also the MCFCs are high-temperature fuel cells based on carbonate ions CO_3^{2-}. Like SOFCs, the start-up is slow due to the necessary preheating (operating temperature around 700 °C). Plant-level efficiencies are in the range of 50%.

After high growth expectations around the turn of the millennium, prospects for fuel cells have been rather bleak for about a decade. Yet, in recent years, the commercialisation of fuel cells has expanded considerably, with first applications in vehicles and home-size CHP systems.

4.1.1.8 Large-Scale Fossil-Fired Power Plants

Power generation in practice requires industrial processes, which are considerably more elaborate than the basic physical processes sketched in the previous sections. Figure 4.8 summarises the key material flows in a large-scale **fossil-fired power plant**. The combustion process and the steam cycle are in the centre of the graph; yet here multiple steam turbines are included. Typically, large-scale power plants have two to three different steam turbines—from high pressure to low pressure. This design allows intermediate reheating, which generally improves efficiency. Moreover, some steam may also be diverted from the steam cycle between the high and medium pressure turbines to produce high-enthalpy steam and heat. This is notably important for combined heat and power generation (see Sect. 4.1.3). Besides these core elements, the cooling apparatus (in the bottom part of the figure) and the post-treatment of the combustion gases (upper part) have to be considered. When a cooling tower is present, this is typically the most prominent building on the plant site. Furthermore, the post-treatment of exhaust gases may occupy more than one-third of the entire area. The post-treatment in modern coal-fired power plants includes dust cleaning, desulfurisation and denitrification (see Sect. 6.2.2.3). The desulfurisation avoids emissions of SO_2 (and some SO_3) and leads to a solid by-product, plaster gypsum, which is partly used in the building sector. The remaining quantities and the fly dust from dedusting have to be deposited in landfills. By contrast, denitrification, mostly done via a selective catalytic reduction (SCR), has molecular nitrogen and water as final products. Especially when assessing the environmental impact of power generation, it is crucial to consider the multiple auxiliary units and processes making up a real-world power plant. This becomes evident when key material flows (as shown in Fig. 4.8) with their mass balances are considered.

4.1.2 Nuclear Energy

Like most electricity generation based on fossil fuels (see Sect. 4.1.1), nuclear power plants also consist of the three parts: (1) heat source (analogue to the combustion unit of a fossil-fuel based plant), (2) thermal engine and (3) electricity generator. But in contrast to steam power plants fired by fossil fuels like coal or gas, the needed heat in nuclear power plants comes from splitting heavy atoms (so-called fission). Nuclear power reactors in commercial operation are exclusively

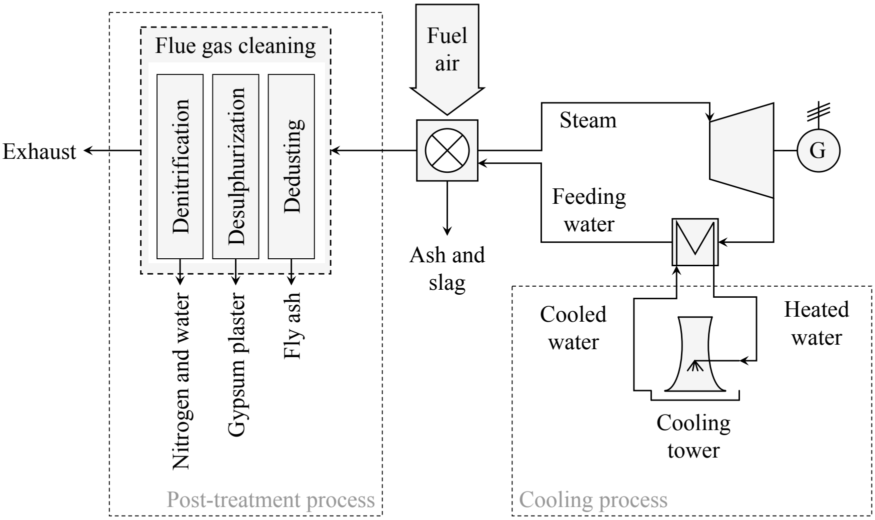

Fig. 4.8 Key material flows in a large-scale fossil power plant

nuclear fission reactors, while nuclear fusion reactors are still under research and development. In nuclear fission reactors, primarily the uranium isotope uranium-235 (^{235}U) is used as fuel input, as it can relatively easily be fissioned.

The **nuclear fuel cycle** (cf. e.g. Murray and Holbert 2020, p. 440) can be differentiated into the front end and the back end. The front end consists of mining and milling, conversion, enrichment and fabrication (cf. Larson 2019). The first step is mining and milling as uranium occurs on earth (e.g. in Canada and Australia) in the form of uranium ore, which first has to be extracted. Natural uranium is mainly composed of ^{238}U (about 99.3%[4]), ^{235}U only has a share of about 0.7%. The extracted uranium ore is then treated chemically, e.g. with acids. This treatment results in a mixture of different uranium oxides (so-called yellowcake), mainly triuranium octoxide, U_3O_8. The yellowcake is then transported to a conversion factory to produce UF_6 (uranium hexafluoride). UF_6 is then enriched in an enrichment plant to increase the concentration of ^{235}U to about 4%, which is necessary for the use in a light-water reactor. The final step in this supply side of the nuclear fuel cycle is the manufacturing of uranium dioxide (UO_2) filled in fuel rods used in nuclear power plants (cf. Zweifel et al. 2017, p. 251).

The principle of a nuclear fission reactor is to bombard ^{235}U with neutrons to split it into lighter atoms. By splitting such nuclei, the so-called mass defect can be used for energy generation (see Fig. 4.9). Due to the lower mass of the produced nuclei, energy will be delivered according to the formula[5] $E = mc^2$. The energy released is used to produce steam, and with this steam turbines are operated.

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[4] As the nucleon number already shows, ^{238}U has three neutrons more in the atomic nucleus than ^{235}U.

[5] Note that c here stands for the speed of light, whereas m is the mass and E is the energy.

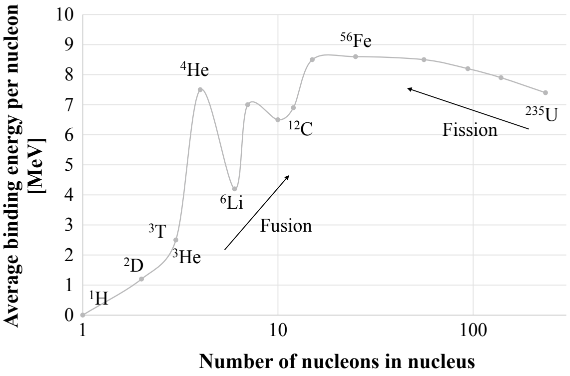

Fig. 4.9 Binding energy per nucleon. *Source* Own illustration based on Pistner (2012, p. 28)

Besides releasing kinetic energy (and radiation), free neutrons are unleashed by the fission process. These neutrons will then partly be absorbed by other atoms, resulting in new fission processes – the so-called nuclear chain reaction has started. The control of this chain reaction is realised with the help of so-called control rods by absorbing neutrons. The nuclear fuel is typically used for some years (about 3–5 years) in the reactor, and then the concentration of ^{235}U has become too low (below 1%). Hence, during the yearly fuel replacement, one-third to one-fifth of the used uranium is exchanged every year, typically during times with relatively low electricity demand (e-g. in summer months).

The spent nuclear fuel is highly radioactive and still producing heat; here, the back end of the nuclear fuel cycle starts. Due to its radioactivity, the spent nuclear fuel has to be stored safely for a long period. Nowadays, the disused fuel is first stored in (storage) pools close to the reactor and then (after some years) in dry casks [e.g. in casks for storage and transport of radioactive material (CASTOR)] in interim storage facilities directly located at the nuclear power stations. There is the possibility of realising a challenging reprocessing process to reuse parts of the nuclear waste (e.g. plutonium and ^{235}U) and produce mixed oxide (MOX) fuels. Without reprocessing, the spent nuclear fuel directly has to be transported to a final disposal facility, capable of storing this nuclear waste for thousands of years, e.g. somewhere in the underground. In this context, it has to be mentioned that up to now, no final storage facility for this kind of waste exists worldwide.

Besides splitting heavy atoms, the mass defect can also be used for energy generation by fusing light atomic nuclei like hydrogen (so-called **fusion**), which is the process with the help of which the sun generates energy for billions of years (see Sect. 4.2.3). To realise such a fusion process, the electrostatic force, which pushes the atomic nuclei apart, must be overcome. Therefore, extremely high temperatures and extremely high pressure are needed. Additionally, the so-called tunnel effect helps to increase the probability of the fusion of nuclei. There is still a lot of research to pursue to realise nuclear fusion on earth. Significant challenges are to reproduce conditions like inside the sun, e.g. to realise a stable plasma operation with a temperature of millions of degrees Celsius. Some prominent research institutions have succeeded in very short reactions at a small scale. Currently, an International Thermonuclear Experimental Reactor (ITER)[6] is under construction near to Cadarache, France, to demonstrate the scientific and technological feasibility of fusion energy. Since research, demonstration and implementation of nuclear fusion have been delayed several times, the promise that fusion is "always 50 years away" is valid for several decades.

4.1.2.1 Power Plant Technologies

Nuclear energy is used for electricity production commercially since the 1960s. Over the last sixty years, light-water reactors,[7] using enriched uranium as input, became the dominating technology to generate electricity by fission. Light-water reactors can be further subdivided into pressurized water reactors (PWR) and boiling water reactors (BWR).

The **pressurized water reactor** has a central characteristic: there are different circuits to prevent water from flowing through the reactor to reach the turbine (see Fig. 4.10). For cooling and as a moderator, which is needed to slow down the neutrons, ordinary water is used. In the core of the reactor, the water is heated up to temperatures of about 320 °C under a pressure of about 150 bar (Murray and Holbert 2020, p. 327). This heated water is used to produce steam with the help of steam generators. Due to the fact that there is no steam in the upper part of the reactor,[8] the control rods can be mounted at the top in PWRs, which comes along with the advantage that the rods may enter the core of the reactor by gravity if there is an interruption of power supply (cf. e.g. Murray and Holbert 2020, p. 331).

The second most common technology used for electricity production based on the fission process is the boiling water reactor. This kind of nuclear power plant has the characteristic that the water, which is again moderator and cooling medium, is also used as the steam source for the turbine, resulting in radioactivity reaching the turbine (see Fig. 4.11). Compared to pressurized water reactors, the temperature (about 290 °C) and pressure (about 70 bar) (Murray and Holbert 2020, p. 327) are lower; thus, the construction is easier and no steam generators are needed. Despite these differences the efficiency of both types – BWRs and PWRs – is rather similar and at about 33% (Lamarsh and Baratta 2001, pp. 140 and 147).

With a share of about 70% of the worldwide capacity of nuclear power plants, (light water) pressurized water reactors are the dominating plants (see Table 4.2). The typical capacity of such a nuclear power unit is approximately between 800 and 1200 MW, the capacity of one plant might even be higher as nuclear power plants

[6] https://www.iter.org/, accessed 13th May 2022.

[7] Light-water reactors use normal water, while heavy-water reactors use heavy water. Heavy water is water that contains essentially deuterium (^{2}H or D, also called heavy hydrogen). In contrast most of the hydrogen in normal water consists of the hydrogen-1 isotope (^{1}H or H, also called protium).

[8] The effect of inserting the rods in a steam area is lower compared to inserting them in a water area (Lamarsh and Baratta 2001, p. 147).

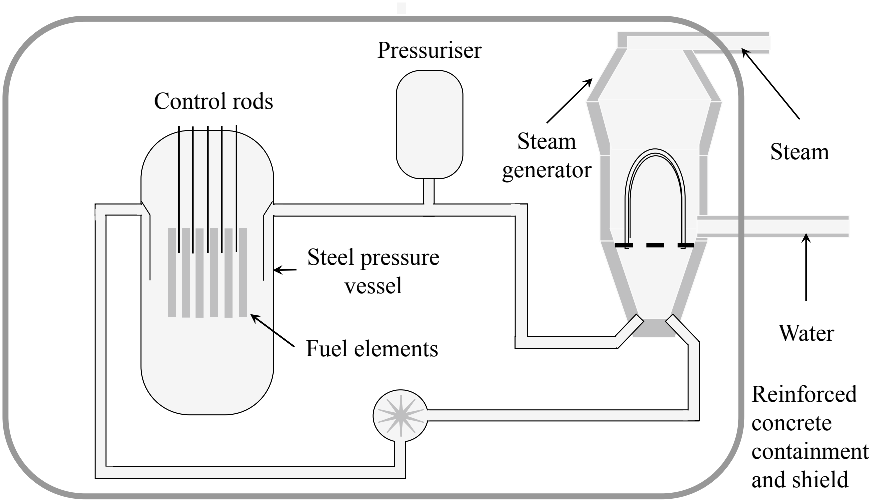

Fig. 4.10 Schematic representation of a typical pressurized water reactor. *Source* Own illustration based on World Nuclear Association (2018)

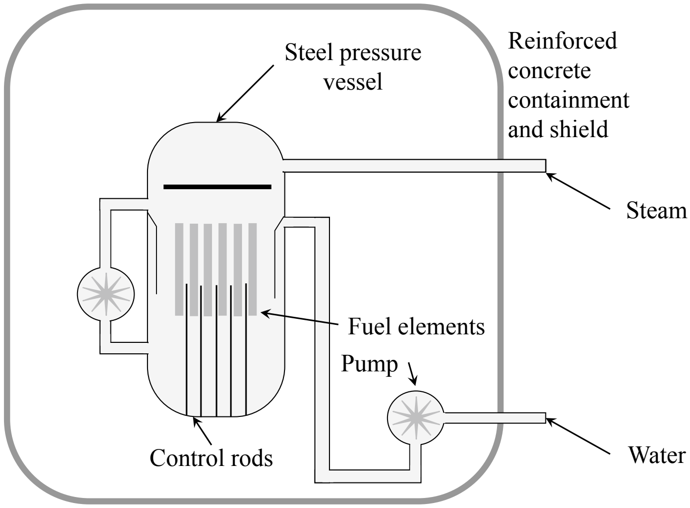

Fig. 4.11 Schematic representation of a typical boiling water reactor. *Source* Own illustration based on World Nuclear Association (2018)

often consist of two or even more units. Besides the dominating technologies (PWRs and BWRs) fast breeder reactors, where simultaneously to electricity production plutonium fuel is breeded, graphite-moderated reactors and pressurized heavy-water-moderated and cooled reactors, where natural uranium is used as fuel and heavy water as a moderator, can be found worldwide. According to Schneider et al. (2020, p. 21), nuclear energy had a share of about 10% of the world's gross

Table 4.2 Operational reactors by type

Reactor type	Reactor type descriptive name	Number of reactors	Total net electrical capacity (GW)	Relative share in capacity (%)
BWR	Boiling light-water cooled and moderated reactor	63	64	16.2
FBR	Fast breeder reactor	3	1.4	0.4
GCR	Gas-cooled, graphite-moderated reactor	14	7.7	2.0
LWGR	Light-water-cooled, graphite-moderated reactor	12	8.4	2.1
PHWR	Pressurized heavy-water moderated and cooled reactor	49	24.5	6.2
PWR	Pressurized light-water moderated and cooled reactor	303	288	73.1
Total		**444**	**394**	

Source IAEA PRIS (2021)

electricity production and of about 4% of the world's primary energy consumption in 2019.

Actual developments to improve nuclear power plants are focusing on improvements with regard to standardisation, efficiency and safety (so-called third-generation reactors) as well as on small modular reactors; long-term developments try to develop closed fuel cycles and to minimise nuclear waste (Generation IV) (cf. e.g. Murray and Holbert 2020, pp. 339–345).

4.1.2.2 Environmental Effects and Risks of Nuclear Technologies

From an environmental point of view, the main advantage of nuclear power plants is that there are no local air pollutions or CO_2 emissions as long as the plant is operated under normal operating conditions – disregarding the emissions arising during the construction of the plant. On the other hand, the operation of nuclear power plants leads to diverse forms of (radioactive) waste. Radioactive waste emits different types of radiation, representing a threat for human beings and the whole environment (for more details, cf. e.g. Krieger 2019).

Environmental effects can already be seen during the mining process, as in the mining areas, a lot of excavation material is produced. The uranium concentrations in the deposits worldwide tend to be relatively small. But also the other steps of the fuel cycle have significant environmental effects; e.g. the enrichment process leads to a lot of depleted uranium (so-called tails). The quantity of depleted uranium, for which also long-term storage is needed, is many times higher than the quantity of the enriched uranium – in two material balances for a nuclear reactor (cf. Murray and Holbert 2020, p. 443), the amount of depleted UF_6 is about 7–9 times higher than the quantity of enriched UF_6. Spent nuclear fuel is often referred to as the major source of environmental effects. According to the German Association of Energy and Water Industries, a German nuclear power plant produces an amount of

20–25 t of spent nuclear fuels per year, which corresponds to 0.0021–0.0027 g per kWh of electricity produced (cf. BDEW 2019, p. 37). But radioactive waste not only results from the used nuclear fuel but also from contaminated parts of the nuclear power plant – e.g. from components located within the primary circuits of the pressurized water reactors.

Radioactive waste can be classified into different types. The classification might vary from country to country, but often a differentiation, based on the radioactivity, into low-level waste (LLW), intermediate-level waste (ILW) and high-level waste (HLW) can be found. The waste submitted for final disposal (long-term storage) is differentiated into waste with negligible heat generation (LLW and partly ILW) and into heat-generating waste (partly ILW and HLW) (cf. Working Panel Waste Management 2012, p. 8).

To have sufficient financial resources to pay the nuclear liabilities caused by the deconstruction of nuclear power plants, the storage of components and the used fuel, energy companies have to set up accruals. Due to the many uncertainties coming along with this task (e.g. at what point in time will which amount of money be needed?) and due to the huge gap between the point in time, when setting up accruals, and that of the real cash flows, the calculation of accruals for nuclear liabilities is a challenging task.

Besides environmental effects that already take place under normal operating conditions, the use of nuclear energy is connected with different risks (Zweifel et al. 2017, pp. 256–258). First of all, there is the risk that a severe accident during the nuclear power plant operation leads to an uncontrolled release of radiation into the atmosphere. Nuclear accidents are measured with the help of the so-called International Nuclear and Radiological Event Scale (INES), which was developed by the International Atomic Energy Agency (IAEA), differentiating seven levels of severity. Up to now, two accidents at nuclear power stations have been classified at level 7 as "Major Accidents": the Chernobyl disaster in Ukraine in 1986 and the Fukushima Daiichi nuclear disaster in Japan in 2011 (Giraldo et al. 2012, p. 53). Besides, there is the risk that nuclear fuels are abused, e.g. by terrorists, or that nuclear power stations become the target of terrorist attacks. Furthermore, different risks come along with the final disposal of radioactive waste: there is a high uncertainty and related risk of how to ultimately dispose radioactive waste for thousands of years, resulting in the fact that so far, no repository for high-level waste is in operation worldwide. Nowadays, deep geological repositories seem to be the preferred solution for this problem. Most probably, a long-term disposal facility of this form will come into operation in the next years in Olkiluoto, Finland.

To calculate the expected monetary damage (e.g. per kilowatt-hour electricity produced), so-called probabilistic safety analyses of nuclear power plants are performed (cf. Zweifel et al. 2017, pp. 258–267). Thereby, for different scenarios, the probabilities of damage events are multiplied by the monetary damage. It has to be mentioned in this context that despite all efforts to improve the security of the plant operation, e.g. the provision of redundant safety systems (cf. e.g. Giraldo et al. 2012, pp. 58–61), the probability of occurrence is indeed very low, but will never become zero – risks are estimated between 1:33,000 and 1:10,000,000.

Furthermore, such calculations have to face the problem that for many damages (e.g. loss of life, environmental damage, etc.) an economic value is difficult to estimate.

4.1.3 Combined Heat and Power Generation (CHP)

The combined production of heat and electricity is frequently labelled by the abbreviation CHP or the term cogeneration. It is, in principle, a desirable means to enhance the overall efficiency of the energy conversion process. The Carnot efficiency limits the efficiency of electricity generation in thermal power plants (see Sect. 2.1). The usage of the waste heat is, on the other hand, only limited by the usefulness and usability of the heating energy which are dependent on the temperature level of the heat and the heat sinks in the vicinity of the power plant. Whereas heat demand, in general, is discussed in Sect. 3.2, the focus is here on the main technical characteristics of CHP generation systems, but also relevant heat demand patterns for CHP are addressed at the end of this subsection.

In principle, cogeneration may be applied to all thermal[9] power generation technologies and is even an option for fuel cells, given that their operating temperature is also considerably above the ambient temperature. Yet up-to-now, large-scale cogeneration has mostly been implemented with steam cycle-based power plants including CCGTs. By contrast, CHP solutions at intermediate and small scale are frequently based on motor engines or industry-scale gas turbines (size 5–100 MW). For the usage of the different options, it is furthermore essential to consider the application context of CHP solutions – i.e. the heat demand.

4.1.3.1 Large-Scale Cogeneration

Large-scale electricity generation is usually done based on the steam cycle (see Sect. 4.1.1). The simultaneous production of heat then implies that part of the energy contained in the steam is diverted for heat production. The heat collected in the condenser of conventional power plants does not have the temperature level necessary for almost any heat application. Moreover, its transport would require vast amounts of transportation fluid.

Two basic construction principles are possible for steam turbines with simultaneous heat and power production: **backpressure turbines** and **extraction-condensing turbines**.

Backpressure turbines: these turbines are similar to conventional steam turbines, only the pressure level at the rear end of the turbine is higher and correspondingly the temperature. Consequently, less heat energy is transformed into electricity and the remaining heat may be transferred through a heat exchanger to the district heating or process heating system (see Fig. 4.12, left part). The electricity produced is (at given steam parameters) almost proportional to the steam mass flow, as is the

[9] Be aware that CHP is not limited to conventional energy carriers as also renewable energy carriers, for example biomass, are converted to thermal energy.

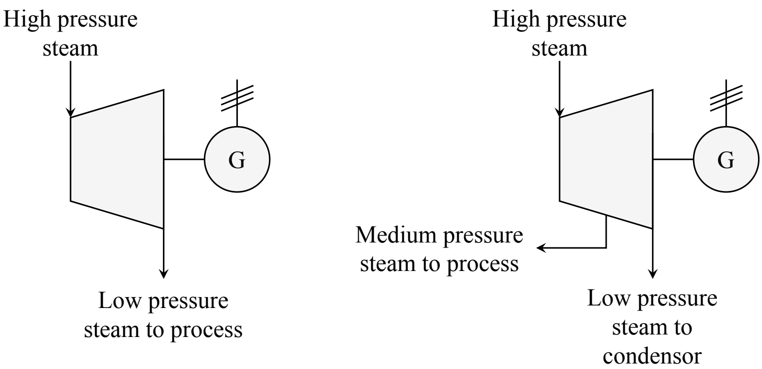

Fig. 4.12 Steam turbines for combined heat and power: backpressure turbine (left) and extraction-condensing turbine (right)

useful heat generated. Hence, in this case, there is an (almost) constant **ratio of heat-to-power**.[10]

Extraction-condensing turbines: in these turbines, part of the steam may be flexibly extracted, e.g. through openings in the casing at higher pressure levels (see Fig. 4.12, right part) or through extraction of part of the steam between the high pressure and the medium pressure turbine. The remainder of the steam is expanded as in conventional condensing turbines to below atmospheric pressure and corresponding low temperatures. Yet, the extracted steam may provide heat at useful temperatures via a heat exchanger to a district heating or process heating system. The advantage of this technology is its flexibility in the heat-to-power ratio.

The so-called **PQ chart** is used in thermal power plant engineering to characterise joint heat and power production possibilities and limits. P stands here for the electric power output and Q for the heat output of a plant. Given the fixed heat-to-power ratio, the permissible operation range for a backpressure turbine is depicted by a line segment in the PQ chart (see Fig. 4.13, left part). For an extraction-condensing turbine, the operation range has the form of a polygon (see Fig. 4.13, right part), the possible operation modes are limited by the maximum steam flow (line 1), the maximum generator output (line 2) and the maximum heat transfer capacity of the heat exchanger (line 3). Moreover, the lower limit of power generation – when all steam is extracted from the turbine – is given by line 4, the so-called backpressure line. Line 5 finally represents the minimum stable operation limit of the power plant (minimum steam flow).

4.1.3.2 Medium- and Small-Scale Cogeneration

In the case of medium-scale cogeneration (range of 2–100 MW), backpressure and extraction-condensing steam turbines may also be employed, notably in the context of **CCGT** units. But the smaller the demand, the more advantageous (notably in cost terms) is it to use only an open-cycle gas turbine together with a heat recovery

[10] Note that sometimes also the inverse ratio, the **power-to-heat ratio** is computed.

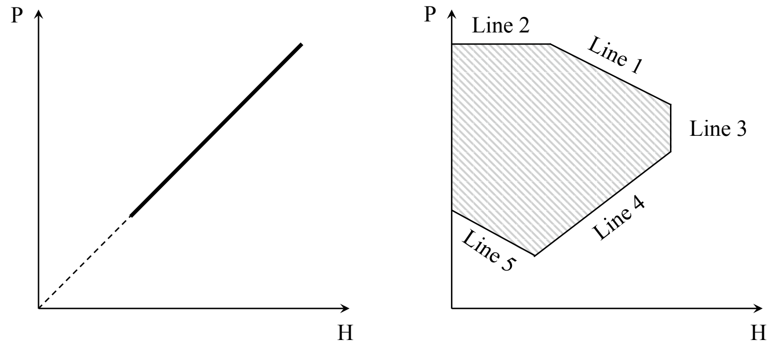

Fig. 4.13 PQ charts for combined heat and power: backpressure turbine (left) and extraction-condensing turbine (right)

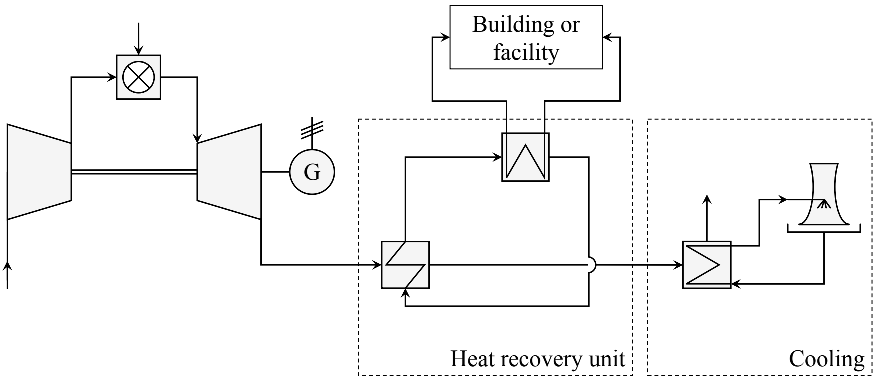

Fig. 4.14 Gas turbine with heat recovery boiler for combined heat and power

boiler, which allows capturing the heat contained in the flue gases of the turbine (see Fig. 4.14). Given the high exhaust temperatures of the gas turbine, such a solution also enables the provision of process heat at temperature levels up to several hundred degrees centigrade.

The flexibility of the combined heat and power production depends on the possibility to operate the gas turbine without the **heat recovery boiler**, i.e. whether sufficient cooling is available when the heat recovery boiler is bypassed. Without that flexibility, the heat-to-power ratio is fixed as for backpressure turbines (see Fig. 4.15 left); otherwise, flexible ratios may be possible. As opposed to steam turbines, increased heat use will then not induce any loss in power output.

4.1.3.3 CHP Based on Motor Engines and Further Technologies

For a long time, motor engine-based CHP has been an alternative for power ranges below the one of gas turbines. But in recent years, motor CHP engines have been scaled up and the largest reach 10 MW electric output (see Sect. 4.1.1.5). But they

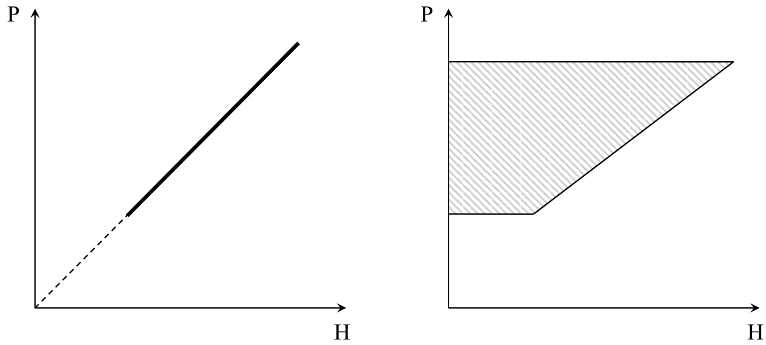

Fig. 4.15 PQ charts for combined heat and power with open-cycle gas turbine: without auxiliary cooling (left) and with auxiliary cooling (right)

may also be built in the size of (small) vehicle engines with an output of 5 kW_{el}. As with gas turbines, waste heat of the engine is used for heating purposes. The heat in the cooling water and the flue gases is typically used for heat sinks with temperatures up to 70–90 °C.

Besides the technologies above, also others may be used for CHP. In the last decade, fuel cells and Stirling engines have notably been developed and commercialised in small series. They have mainly been designed to provide combined electricity and heat at low nameplate capacities with a prime application field being small residential buildings, notably single-family dwellings. Such CHP units are technologically much more demanding than a conventional heating system, such as a condensing boiler, and correspondingly they are also much more expensive. At the same time, their electric capacity is very limited, notably in the case of Stirling engines, so that they are sometimes labelled “electricity-generating boilers”. The economic viability of such solutions strongly depends on the difference between wholesale and retail electricity prices.

There are various technologies and application areas for CHP, which vary according to the size and temperature of the heat demand, the economic sector and the generation technology. While several technologies are applicable over a broader range of sizes and applications, some such as Stirling engines are more suited to smaller-scale applications. An overview of the specifications of commonly employed generation technologies for small- and medium-sized systems is given in Table 4.3, from which it is clear that these technologies differ in their suitability for part-load operation as well as their stage of technological development. Some technologies, such as fuel cells, do not yet have high market penetration and suffer from high costs.

Table 4.3 Overview of typical generation technologies for medium- and small-scale cogeneration

	Gas/petrol combustion engine	Diesel engine	Stirling engine	Fuel cell	Gas turbine
Electrical power [kW]	1–5000	5–20,000	1–40	1–250	30–250,000
Overall efficiency [%]	up to 90	up to 90	up to 85	up to 90	up to 85
Electrical efficiency [%]	25–42	28–44	10–30	30–47	25–30
Part-load behaviour	Good	Good	Less good	Very good	Less good
State of the art	Proven	Proven	Small series	Pilot systems	Proven
Usual fuel	Gas, petrol	Diesel	Gas, wood	Gas	Gas, diesel

Source Pehnt and Schneider (2010, p. 124)

4.1.3.4 Heat Demand and Combined Heat and Power Plants

Different technologies can be used to satisfy the heat demand (see Chap. 3). Whereas central (e.g. biomass-fired district heating stations) and decentral (e.g. gas-fired calorific value boilers in households) heating (heat-only) installations are not part of this book, the combined production of heat and electricity (CHP or cogeneration) in large-scale, intermediate-scale and small-scale installations are. Yet it is primordial to match the cogeneration technology to the local heat demand. Therefore, some aspects are subsequently discussed which must be considered when planning the dimensioning and operation of a CHP installation.

CHP can be used to provide all three different kinds of heat: space heat, hot water and process heat. One of the most important contextual factors for applying CHP solutions is the distribution of heat demand in space and time. Weather conditions characterise the provision of space heat. Heat demand in systems with space heating has a clear seasonal pattern, although there are substantial stochastic variations like early snow in October. The sorted annual **duration curve** of heat demand provides a graphical means to describe and analyse the heat demand over time. Figure 4.16 gives an illustration for an exemplary municipal district heating grid.

The peak heat demand there exceeds the minimum demand by a factor of ten or more. The **capacity factor** of the heating installations (energy production during a period, e.g. one year, divided by the maximum possible energy production during that period, cf. Sect. 2.1.1) is frequently below 0.4, corresponding to only 3000–3500 **full-load hours** per year (capacity factor multiplied by the hours of the year). In single buildings or households, the heat provider has to cover peak demand, while in larger networks, peak load boilers are also used in addition to the CHP units.

When providing process heat by CHP the continuity of heat demand and the temperature level of the demand are decisive: some industrial processes, especially in the primary conversion sector, require constant heat supply, which might provide

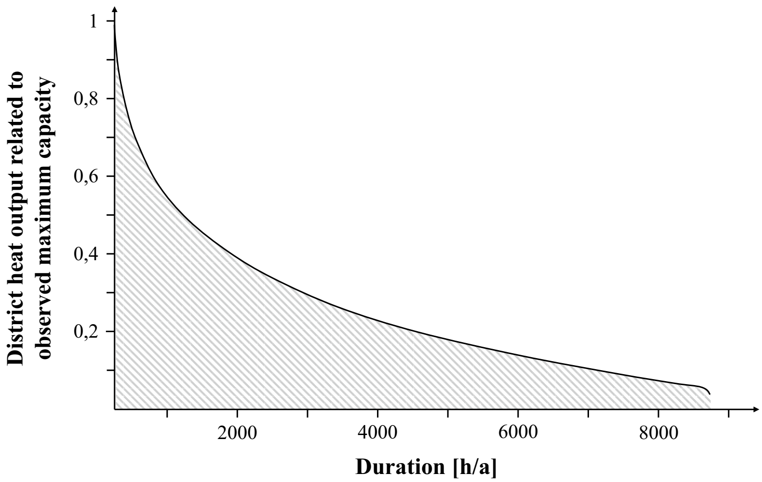

Fig. 4.16 Sorted annual duration curve of heat demand in an exemplary municipal district heating grid

opportunities for high capacity factors. Other processes are organised as batch processes. Here intermediate heat storage is necessary if CHP is to reach high capacity factors. Even more important is the temperature level for the heat provision from CHP. Process temperatures of 500 °C and more are hardly suitable for CHP applications. At best, the exhaust gases of open-cycle gas turbines may provide heat at temperatures of about 500 °C. Advantageous are process heat requirements at temperatures below 120 °C, since hot water may then be used as heat transfer medium. At temperature levels between 120 °C and 200 °C, CHP may offer potential, but then steam will usually be used for heat transfer.

Furthermore, the possibilities to market the produced electricity must be analysed to determine the optimal investment and production plan for a CHP installation. Here, the opportunity to feed in electricity into the electrical grid often provides a kind of backup solution if the customers' electrical and thermal demand profiles do not match adequately.

4.2 Renewable Generation Technologies

Electricity can be produced from various renewable sources, including wind, solar, hydro, tidal, geothermal and biomass. Biomass contributes most to the total renewable energy supply (see also Table 4.4), which is due to its high share in heat supply. Hydropower has a long tradition and is currently still the second-largest renewable power source in Europe. However, there has been no growth in hydropower electricity generation in the last years (as most potentials are already in

Table 4.4 Share of renewables in gross inland (primary) energy consumption, 2016 in %

	Renewable energies – total	Bioenergy[a]	Hydroenergy	Wind energy	Solar energy	Geothermal energy
EU-28	13.2	8.6	1.8	1.6	0.8	0.4
Belgium	6.8	5.4	0.1	0.8	0.5	0.0
Bulgaria	10.7	7.2	1.9	0.7	0.8	0.2
Czech Republic	10.3	9.3	0.4	0.1	0.5	0.0
Denmark	28.7	21.7	0.0	6.3	0.7	0.0
Germany	12.3	8.2	0.6	2.1	1.2	0.1
Estonia	15.5	14.7	0.0	0.8	0.0	0.0
Ireland	7.5	3.4	0.4	3.6	0.1	0.0
Greece	10.7	4.7	2.0	1.8	2.2	0.0
Spain	14.3	5.6	2.6	3.4	2.6	0.0
France	9.9	6.6	2.1	0.7	0.3	0.1
Croatia	23.3	15.2	6.9	1.0	0.1	0.1
Italy	16.8	8.5	2.4	1.0	1.4	3.6
Cyprus	5.9	1.7	0.0	0.8	3.3	0.1
Latvia	37.2	32.0	5.0	0.3	0.0	0.0
Lithuania	20.8	18.7	0.6	1.4	0.1	0.0
Luxembourg	5.3	4.6	0.2	0.2	0.3	0.0
Hungary	11.7	10.8	0.1	0.2	0.1	0.5
Malta	3.4	1.3	0.0	0.0	2.1	0.0
Netherlands	4.7	3.5	0.0	0.9	0.2	0.1
Austria	29.6	17.3	10.1	1.3	0.8	0.1
Poland	8.8	7.4	0.2	1.1	0.1	0.0
Portugal	24.1	12.3	5.8	4.6	0.7	0.7
Romania	19.1	12.0	4.8	1.7	0.5	0.1
Slovenia	16.5	9.7	5.7	0.0	0.5	0.7
Slovakia	9.6	6.9	2.3	0.0	0.3	0.1
Finland	30.7	26.0	3.9	0.8	0.0	0.0
Sweden	37.1	23.6	10.8	2.7	0.0	0.0
UK	8.1	5.7	0.2	1.7	0.5	0.0

[a] The category bioenergy includes wood and solid biofuels, liquid biofuels, biogas and renewable wastes
Source ec.europa.eu/eurostat.[11]

use). In contrast, solar energy, wind power as well as biomass have seen high growth rates. In the following sections, an overview of the different renewable energy sources focusing on electricity generation will be given.

[11] http://ec.europa.eu/eurostat/statistics-explained/images/d/dc/Renewable_energy_statistics-2018-v1.xlsx, accessed 13th May 2022.

4.2.1 Hydropower

The share of **hydropower** in power generation varies considerably in different European countries between 0% (e.g. Netherlands) and more than 90% (e.g. Norway) (see Table 4.4). These differences are mainly due to geographic conditions. The most extensive hydroresources in Europe and consequently the largest hydropower potential are in Scandinavia and the Alpine countries. No or only a slight increase in hydropower generation in the Alps can be expected as most of the economic potential in the Alpine region has already been developed.

In general, hydropower utilisation is characterised by

- very long technical and economical machine life (e.g. up to 80 years), especially when appropriate maintenance is carried out,
- the provision of electrical energy with terse lead times, making them interesting for peak load and reserve energy (see Sect. 10.3),
- the opportunity to provide black start[12] (see Sect. 10.4) as this type of power plant does not rely on the external electric power transmission network to recover from a total or partial shutdown,
- a very high efficiency of energy conversion (e.g. more than 90%), as well as
- quite a broad availability of hydropower worldwide (especially in nations with rapidly growing energy needs: China, India, South America).

Only water flows on the ground can be used for electricity generation, while the potential energy of all water raining down from the sky cannot be used yet (which would result in a much higher potential than only the share of water flows on the ground). Consequently, geographic conditions in combination with precipitations form water flows, which enable the exploitation of hydropower. Different geographic conditions and water flows result in various types of hydropower, which will be discussed in the following.

4.2.1.1 Types of Hydropower and Power Calculation

Hydropower plants convert water's potential and kinetic energy into electrical energy via mechanical energy, with potential energy making up the bulk of electricity generation. Hydropower plants can be differentiated according to various criteria, e.g. operation, head of water, type of turbine, capacity, annual output, etc. (see Table 4.5). In principle, three main types of hydropower can be distinguished:

Run-of-river power plants do not have a storage facility and process the inflows continuously. Run-of-river power plants, therefore, have only limited possibilities for changing the production volume. Storing water in the inflow is not or hardly achievable. If the incoming water volume exceeds the plant's capacity (e.g. in the case of a flood), the excess water remains unused and is bypassed in an overflow. Variations in production over a day are small, but output can vary

[12] A black start is the process of restoring an electric power station without relying on electricity from the power transmission network to recover from a total or partial shutdown.

Table 4.5 Characteristics of hydropower

<table>
<tr><th>Characteristic</th><th colspan="6">Attribute [a]</th></tr>
<tr><td>Operation</td><td colspan="2">Run-of-river power plant</td><td colspan="2">Reservoir power plant</td><td colspan="2">Pump storage power plant</td></tr>
<tr><td>Head of water</td><td colspan="2">Low pressure (1–20 m)</td><td colspan="2">Medium pressure (20–100 m)</td><td colspan="2">High pressure (>100 m)</td></tr>
<tr><td>Capacity</td><td colspan="2">Small power plants (<1 MW)</td><td colspan="2">Medium power plants (1–100 MW)</td><td colspan="2">Large power plants (>100 MW)</td></tr>
<tr><td>Type of head (depending on used turbine)</td><td colspan="3">Pressure head</td><td colspan="3">Velocity head</td></tr>
<tr><td>Type of turbine</td><td colspan="3">Reaction turbine</td><td colspan="3">Impulse turbine</td></tr>
<tr><td>Main turbine type</td><td colspan="2">Kaplan turbine</td><td colspan="2">Francis turbine</td><td colspan="2">Pelton wheel</td></tr>
</table>

[a] A specific hydroplant may be characterised by attributes from different columns

considerably between seasons. Hence, run-of-river power plants are mostly used to cover base load. A characteristic feature of run-of-river power plants is a large flow amount of water at relatively low heads, typically achieved in large rivers.

Reservoir power plants: the incoming water is stored as long as free storage volume is available. The stored water is used to provide electrical energy. In principle, differences can be made according to the storage volume in relation to the capacity. Depending on the duration required for emptying the reservoir at full load (using the full capacity of the plant), reservoir power plants can be classified in day storage plants (e.g. up to 6 h at full load), week storage power plants (between 6 and 25 h at full load), seasonal storage power plants (up to 500 h at full load), annual storage power plants (over 500 h at full load) or multi-year storage power plants. In addition to purely natural hydro inflows, the water can also be supplied to the reservoirs by so-called feeder pumps from side valleys. The basic rules for the utilisation of the stored water are subsequently discussed in Sect. 4.4.1.2.

Pump storage power plants (PSP) use only water to provide electrical energy which was previously pumped from a lower location into the upper storage basin.

Pumps and turbines are typically connected to the same lower and upper storage basin. The electrical energy required for pumping is usually consumed during off-peak hours (or rather at cheap electricity wholesale prices) and stored in the form of potential energy of water. In peak load periods (expensive electricity wholesale prices), the potential energy of the water is converted back into electrical energy. However, it should be noted that losses of approximately 10–35% (depending on the geographic situation, the efficiency of the plant, etc.) are associated with the conversion of electrical energy in pump storage plants from off-peak to peak load periods. The efficiency of storing electricity is called cycle- or round-trip efficiency and is accordingly between 65% and to a maximum of 90%.

Beyond this strict classification, combinations of run-of-river and reservoir power plants as well as reservoir and pump storage power plants may occur. If water in a river can be stored by (significantly) increasing the upper water level, this is a mixture between a run-of-river and a reservoir power plant. Furthermore, natural inflows can result in a combination of a pure pump storage and a reservoir power plant, sometimes also referred to as pump storage power plants with natural inflow. Hydropower plants, especially reservoir and pump storage plants, are generally characterised by very fast start-up times in the minute range and very high ramping rates compared to thermal power plants, which result in high flexibility, e.g. relevant for the provision of balancing energy as non-spinning reserve.

In areas with large river systems or lakes, the outflow of one plant may be the inflow of another. The lower basin of one hydroelectric power station becomes the upper basin of the next. Such linked formations are called hydropower cascades. Especially in the Alps, several hydropower cascades are made up by various reservoirs, pump storage and reservoir power plants. The interlinkages of hydro flows strongly impact power plant operation, necessitating the consideration of interlinkages in power plant dispatch planning.

Besides these main types of operation, hydropower plants can be distinguished according to the head of water from low heights and low pressure up to high heights and high pressure. Furthermore, the size of hydropower plants is strongly influenced by the geographic location, mainly by the amount of available water. Power plants with a capacity smaller than 1 MW are commonly labelled as small hydropower plants; sometimes, power plants with less than 100 kW are further distinguished as microhydropower, while capacities above 100 MW are classified as large power plants (see also Table 4.5).

The hydroturbine as core component of the hydropower plant converts water's potential and kinetic energy into mechanical energy, which is then converted with a generator in electrical energy. The power of a water turbine is derived from the physical equation of potential energy ($m \cdot g \cdot h$), by taking the time derivative. The electrical power output is calculated from the product of the water volume flow through the turbine ($\dot{V}$ in m^3/s) with the density of water (ρ in kg/m^3), the gravitational acceleration (g with 9.81 m/s^2), the head of water (h in m) and the total efficiency of the plant η_{total}, resulting in the following formula:

$$P_{el} = \dot{V} \cdot \rho \cdot g \cdot h \cdot \eta_{\text{total}}. \tag{4.1}$$

From this formula, it is obvious that a large head of water can compensate for low water flows and vice versa. A relatively small amount of water in a small mountain stream but with a high head of water of several hundred metres may generate more electricity than a large amount of water in a river that uses a shallow head of water in a weir. These different framework conditions necessitate different turbine types, which are explained in the next section.

4.2.1.2 Turbine Types

Several technical turbine concepts have been developed for different site conditions, enabling to exploit optimally the specific characteristics concerning water inflow and water height. Turbines can be differentiated according to various aspects: the application (part load or full load), the wheel shape (radial, diagonal, axial), the construction (vertical or horizontal shaft position) and the mode of action, which is probably most commonly considered distinguishing feature. Accordingly, there are **impulse turbines** and **reaction turbines**. Impulse turbines change the direction of flow of a high-velocity water flow. The corresponding impulse drives the turbine, and the water leaves the turbine with diminished **kinetic energy**. The pressure of the water does not change in the turbine blades; rather before and after the turbine, the same (standard) pressure applies. Consequently, no pressure casement around the rotor is required. The water jet's momentum is transferred to the turbine. In effect, "impulse" energy does work on the turbine. **Pelton turbines** and (historical) water wheels are impulse turbines. Pelton turbines are most efficient when the flow is low and the inlet pressure is high. These characteristics occur at small mountain streams with high water heads and are thus typical for power plants in mountain regions. Sometimes several Pelton wheels are mounted on one shaft. A giant Pelton wheel with 423 MW is in the power plant Bieudron within the reservoir plant complex Grande Dixence in Switzerland, with a head of 1883 m (world record), a total capacity of three turbines with each 423 MW and a maximum water flow of 75 m^3/s.[13]

In the Pelton turbine (see also Fig. 4.17), the water flow comes as a high-speed water jet from one or more nozzles tangentially to the wheel's blades. Each of the up to 40 blades is divided by a sharp edge, the so-called centre blade, into two approximately hemispherical half-blades, called buckets. In the middle of the cutting edge, the water jet from the nozzles hits tangentially. The buckets (or blades) redirect the water in the opposite direction so that the kinetic energy can be released to the impeller according to the principle of actio and reactio. The split into two water streams balances the side-load forces on the wheel. This enables an efficient transfer of the impulse from the water jet to the turbine wheel (cf. Giesecke et al. (2014)).

Besides Pelton turbines also cross-flow turbines, sometimes also called Ossberger turbines, are impulse water turbines as pressure remains constant at the

[13] http://www.grande-dixence.ch, accessed 13th May 2022.

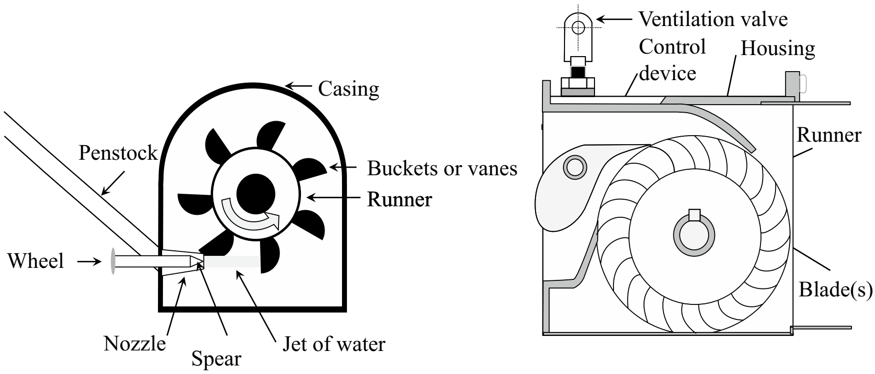

Fig. 4.17 Schematic illustration of a Pelton turbine (left) and an Ossberger turbine (right). *Source* Own illustration based on Giesecke et al. (2014, p. 532)

runner. Ossberger turbines (see also Fig. 4.17) consist of a cylindrical water wheel or runner with numerous blades. These are arranged radially and tangentially around a horizontal shaft. The water flows through the blade channels first from the outside to the inside and then back to the outside. Ossberger turbines typically have a nameplate capacity of less than 2000 kW. They are often used in mini- and microhydropower units with heads less than 200 m since they have a low price, an excellent behaviour under part load and are easy to operate, although the turbine's efficiency is somewhat lower than that of the other turbine types (cf. Giesecke et al. 2014, Chap. 14).

In contrast to impulse turbines, reaction turbines develop torque by reacting to the water pressure or mass. As the water passes through the turbine rotor blades, its pressure drops. Correspondingly, a pressure casement is needed to contain and direct the water. This serves also to maintain the suction imparted by the draft tube. **Francis turbines, Kaplan turbines** as well as Jonval turbines (as well as most steam turbines) make use of this concept.[14]

The Kaplan turbine (see Fig. 4.18 right side) is a propeller-type water turbine, combining features of radial and axial turbines. The waterflow is directed inwards and changes pressure as it moves through the turbine and gives up its energy. Thereby both the potential energy of the water head and the kinetic energy of the flowing water are converted in rotating energy. Kaplan turbine efficiencies are typically over 90% and they are broadly used worldwide for electricity generation, especially at sites with a low head of water combined with high water flows. Several variations of Kaplan turbines exist, such as, e.g. simpler propeller turbines, which have – in contrast to Kaplan turbines – non-adjustable propeller vanes.

[14] In contrast to water turbines, where only one turbine stage is needed as water is nearly incompressible, multiple turbine stages are usually used to harness the expanding gas efficiently for compressible working fluids, such as steam and gas.

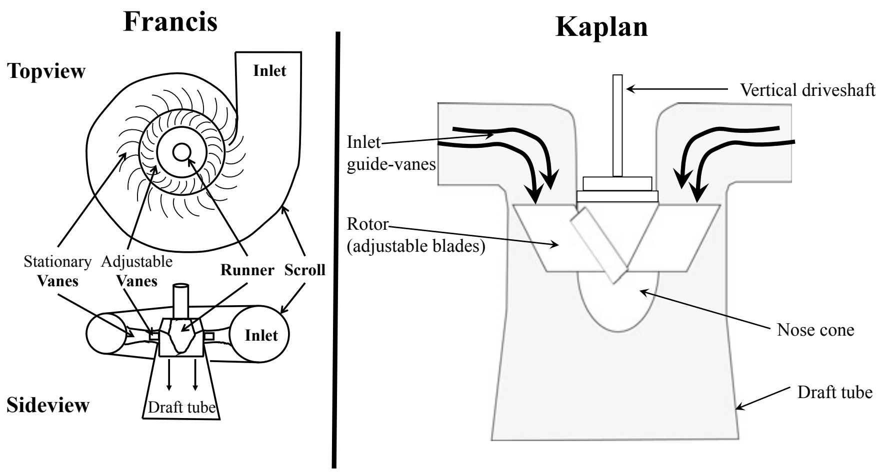

Fig. 4.18 Schematic illustration of a Francis turbine (left) and a Kaplan turbine (right). *Source* Own illustration based on Giesecke et al. (2014, p. 532)

Francis turbines (see Fig. 4.18, left side) are also reaction turbines and are the most common water turbines today. They operate at a water head from 40 to 600 m and have an electrical power output ranging from just a few kilowatts up to 800 MW. Francis turbines are also used for pumping water in pump storage plants. In the Francis turbine, the incoming water is directed by a volute housing, the so-called spiral, in an additional twist (thus sometimes also referred to as Francis spiral turbine). Then, the water is steered by a non-rotating, fixed stator blade ring with adjustable blades on the counter-curved blades of the impeller. The vanes at the inlet act as an actuator. With the setting of their angle, the speed and thus the turbine's power may be kept constant during load changes at changing water levels. The Francis turbine is a reaction turbine. At the impeller inlet, the pressure is higher than at the impeller outlet. Modern Francis turbines achieve efficiencies of over 90% (cf. Giesecke et al. 2014, Chap. 14).

As depicted in Fig. 4.19, the different turbine types are particularly suited for different water conditions. While Pelton turbines are designed for high water heads in combination with low flows, Kaplan turbines are used for low water heads combined with high flows. Francis turbines make use of medium water heads and flows.

As each hydropower plant is designed for individual site conditions (especially for larger plants), electricity generation costs strongly depend on the specific situation. The main cost drivers are the available water (flow), the head of water and the investment for installing a weir or reservoir. Thus, electricity costs vary broadly between 15 and 80 €/MWh (cf. Möst 2006). As the list of the top ten largest hydropower plants shows (see Table 4.6), the capacity of single power plants and their electricity production can be gigantic. The largest hydropower plant worldwide is the Three Gorges Dam in China at the river Yangtze with a capacity of 22.5 GW and an electricity production of almost 100 TWh. The 10th largest power plant Krasnoyarsk, located on the river Yenisei in Russia, still has a capacity of 6 GW and produces 15 TWh of electricity per year.

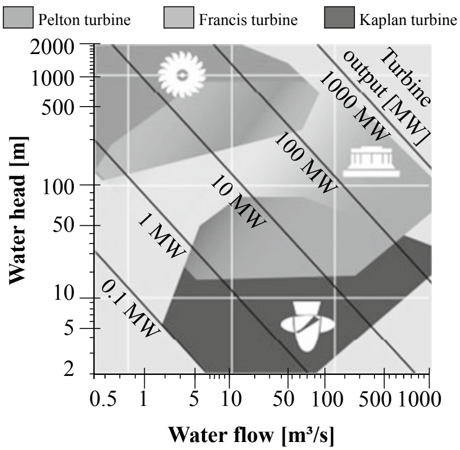

Fig. 4.19 Typical utilisation of turbine types dependent on head of water and hydro inflow. *Source* Own illustration based on Giesecke et al. (2014, p. 534)

Table 4.6 Top ten list of largest hydropower plants worldwide

Name	River and country	Years of completion (first and latest units)	Installed capacity (MW)	Yearly production (TWh)
Three Gorges Dam	Yangtze, China	2008/2012	22,500	98.8
Itaipu Dam	Paraná, Brazil/Paraguay	1984/1991, 2003	14,000	103.1
Xiluodu	Jinsha, China	2014	13,860	55.2
Guri	Caroní, Venezuela	1978, 1986	10,235	53.4
Tucuruí	Tocantins, Brazil	1984, 2007	8370	41.4
Grand Coulee	Columbia, USA	1942, 1950–1991; 1983 and 1984	6809	20.0
Xiangjiaba	Jinsha, China	2014	6448	30.0
Longtan Dam	Hongshui, China	2007/2009	6426	18.7
Sayano–Shushenskaya	Yenisei, Russia	1985/1989, 2010/2014[15]	6400	26.5
Krasnoyarsk	Yenisei, Russia	1967/1972	6000	15.0

Source https://www.power-technology.com/

4.2.1.3 Multipurpose Use of Hydropower

Many hydropower plants serve different infrastructural purposes and do not only generate electrical energy. If hydropower projects also provide other services, these are called multipurpose plants. Depending on the original requirements, the use of hydropower may be the primary objective (or secondary), while the other services are additional (or primary). Likewise, the available potential of the water can be used as a side benefit of another necessary measure. Multiple services represent an external benefit of hydropower and are often not directly compensated. However, not all multipurpose effects have to be external benefits; instead, they may be harmful. An example is the potential production of large quantities of methane from reservoirs due to decomposing organic matter under the water.

Positive multipurpose services of hydropower use are:

- flood control through the creation of artificial dams and thus the delayed release of strong water inflows after heavy or long-lasting precipitation events;
- irrigation by meeting high demands for agriculture when rainfall is low – reservoirs store runoff during times of high rainfall and low demand;
- provision of drinking and service water through dams;
- ensuring navigation through the regulation of running waters using cascaded storage reservoirs;
- regulation of groundwater levels by the attenuation of water-level fluctuations;
- delivery of minimum water to the lower reaches by the water retention during higher inflows, which is relevant to maintain the ecosystem functions – to mitigate negative impacts, adequate flows downstream of a barrier have to be maintained;
- the promotion of biodiversity by artificially damaging rivers and creating new water areas and riparian zones that allow the development of new biodiversity;
- creation of recreational space, suitable for boating, swimming and fishing, which are only secondary uses.

The fulfilment of these multipurpose services and the use of hydropower always raise economic, ecological and social issues in every hydropower project, which should be considered in a comprehensive assessment for each project.

4.2.2 Wind Power

Wind energy is a product of the sun, as the solar radiation leads to different temperatures of the (ground and the) air in different regions. This in turn induces areas of different air pressures. The differences in air pressure lead to wind formation; typically, the wind transports air to places with lower pressure (e.g. from the sea to the mainland during daytime). Near the earth surface, the wind speed is lower than at higher altitudes. This results from the fact that the wind is slowed down by surface friction. In this context, surface roughness plays an important role.

The wind speed v_i at an altitude h_i can be estimated, e.g. by the **Hellmann** approach (cf. Kaltschmitt et al. 2007, p. 55) from a given wind speed v_j at an altitude h_j and using approximate values for the exponent k:

$$v_i = v_j \cdot \left(\frac{h_i}{h_j}\right)^k. \quad (4.2)$$

Furthermore, wind speed is not only strongly varying with the altitude above ground but also over time. Distribution functions of measured wind speeds at a specific site and their mathematical approximations, e.g. in the form of Weibull distribution functions, are typically used to describe the frequency of different wind speeds – from hardly any wind (calm) to heavy storms with velocities of more than 25 m/s.

Wind power plants exploiting the aerodynamic principle transform parts of the **wind's kinetic energy** into mechanical energy and finally into electricity (cf. Kaltschmitt et al. 2007, pp. 295–348). In general, the kinetic energy of any body having the mass m and the velocity v can be calculated with the following formula:

$$E_{\text{kin}} = \frac{1}{2} \cdot m \cdot v^2. \tag{4.3}$$

Considering the mass with a given mass density ρ, that flows during a time period through an area A, (the so-called mass flow $\dot{m}$)

$$\dot{m} = A \cdot v \cdot \rho, \tag{4.4}$$

the power of the wind can be calculated using the following formula (for area A, see Fig. 4.20):

$$P = \frac{1}{2} \cdot A \cdot \rho \cdot v^3. \tag{4.5}$$

The wind speed is of highest importance for the power to be extracted from the wind: the available power is a cubic function of the wind velocity.

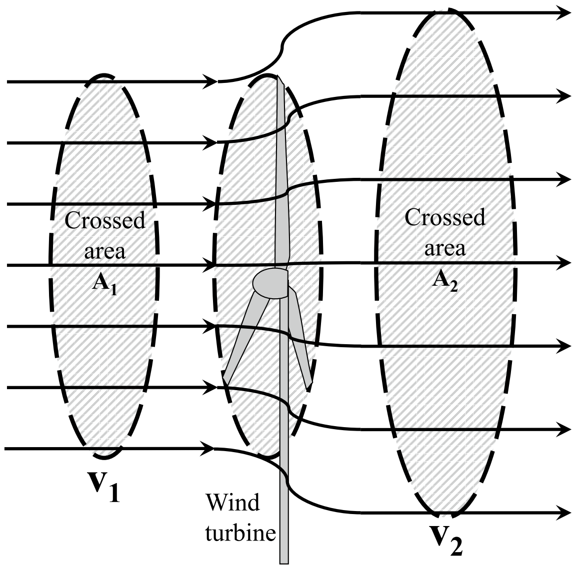

Fig. 4.20 Schematic illustration of wind speed and fluid flow before and after a wind turbine. *Source* Own illustration based on Kaltschmitt et al. (2007, p. 297)

Of course, not the wind power plants' whole kinetic energy can be used, as this would imply that the wind has a velocity of zero behind the wind power plant, leading to congestion hindering the further use of wind energy. The power to be utilised by the wind power plant is the difference between the power in front of the wind power plant (index$_1$) and behind it (lower velocity and larger area A_2, index $_2$) (see Fig. 4.20 and Kaltschmitt et al. 2007, p. 297):

$$P_{\mathrm{WPP}} = \frac{1}{2} \cdot A_1 \cdot \rho \cdot {v_1}^3 - \frac{1}{2} \cdot A_2 \cdot \rho \cdot {v_2}^3 = \frac{1}{2} \cdot \dot{m} \cdot \left(v_1^2 - v_2^2\right), \tag{4.6}$$

which can be reformulated using the average of the wind velocities before and behind the wind power plant as the velocity v of the wind in the wind power plant and the area of the rotor surface (A_{WPP}):

$$P_{\mathrm{WPP}} = \frac{1}{4} \cdot A_{\mathrm{WPP}} \cdot \rho \cdot {v_1}^3 \cdot \left(1 + \frac{v_2}{v_1}\right) \cdot \left(1 - \left(\frac{v_2}{v_1}\right)^2\right). \tag{4.7}$$

Dividing the power to be utilised by the wind turbine by the total power of the wind leads to the so-called power coefficient (maximal efficiency comparable to the Carnot efficiency in the case of thermal power plants, which takes its maximum at 16/27 = 0,593 (see Fig. 4.21), when a ratio of wind velocities v_2/v_1 of one-third is realised. This shows that at best about 60% of the wind power can be used, independently of the type of the wind power plant (so-called **Betz's law**).

Wind power plants use two different principles to harness wind energy: the lift principle or the drag principle or both (cf. Kaltschmitt et al. 2007, pp. 301–308). Different pressure levels below the blade (higher pressure on the underside of the blade) and above the blade are needed to use the **lift force**, which is similar to the use of the lift force in the case of aeroplanes. This is realised by the form of the blade

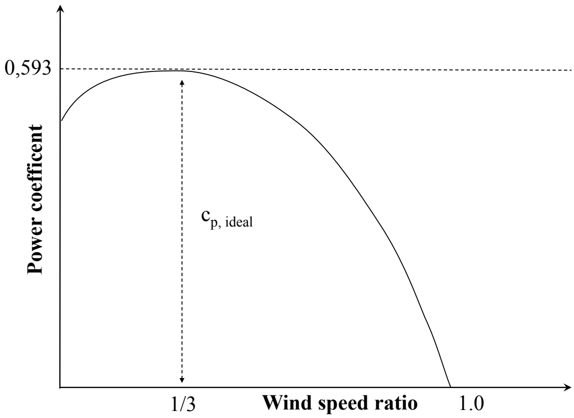

Fig. 4.21 Power coefficient curve for wind turbines exploiting the aerodynamic effect. *Source* Own illustration based on Kaltschmitt et al. (2007, p. 300)

(shape and concavity of the airfoil) and the angle of attack of the wind, which leads to longer distances to be covered by the air and a smaller current cross section at the upper side. The smaller current cross section results in a higher velocity at the top side and thereby lower pressure (Bernoulli's principle). The **drag force** is created by striking the air on a surface moved by this force. As the power coefficient achievable by the lift principle is considerably higher than the one realisable by the drag principle, modern wind power plants are designed to use the lift force primarily.

In general, wind power plants can be differentiated according to their axis into vertical axis wind turbines (VAWT, e.g. Savonius and Darrieus wind turbines) and horizontal axis wind turbines (HAWT) with one or more blades. HAWT have some advantages in comparison with VAWT, such as higher towers making use of higher wind speeds and by using cambered airfoils, which are more efficient due to a higher lift-to-drag ratio. Consequently, HAWT have a better cost-effectiveness and have thus obtained a much greater market penetration in today's wind power market. Wind power plants with a horizontal axis are provided with one to three blades, in most cases with three blades.

Wind power plants are typically equipped with a control mechanism to avoid overloads at high wind velocities and operate the turbine under optimal conditions. Different control mechanisms exist. A relatively simple control mechanism is the so-called stall control. Here the blades are fixed to the rotor hub without a possibility to twist the blades (therefore, this concept is also called passive pitch control). The power control is realised by the profile of the blade, which is constructed in such a way that in the case of strong winds the angle of attack, which is the angle between the chord line of the blade and the wind vector (see Fig. 4.22), is drastically increasing. This results in the so-called stall, meaning that the airflow separates from the contour of the blade. The control concept has been further developed to the so-called active stall control: here, the blades can be twisted slightly to initiate the stall. If the blades can be twisted more extensively, the mechanism is called pitch control. Pitch control enables an optimal angle of attack by automatically rotating each of the blades to maximise efficiency. In extremely high wind speed situations, the pitch control causes the blades to be totally turned out of the wind.

Wind power plants with a horizontal axis typically consist of the following components (cf. Kaltschmitt et al. (2007, pp. 308–322) and Fig. 4.23):

- Foundation: the design of the foundation of wind power plants depends mainly on the particular soil conditions. It is more expensive in the case of offshore wind power plants due to the more challenging framework conditions (e.g. water depth) compared to onshore sites, where typically a gravity foundation based on concrete and steel can be used. However, this may change if swimming foundations are used for offshore sites in the future.
- Tower: monopole towers of modern wind power plants are made of steel or concrete and reach heights of up to 200 m to be able to use higher wind speeds.
- Rotor: the rotor consists of a rotor hub and up to three rotor blades, typically made of fibreglass. Wind power plants can be equipped with rotors having up to 200 m rotor diameter.

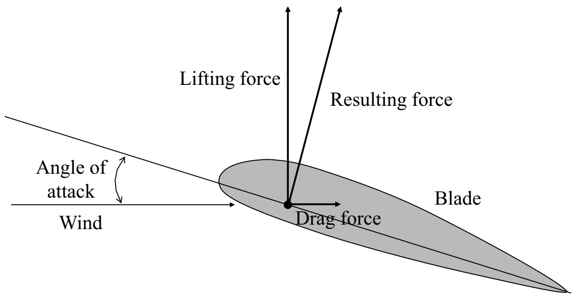

Fig. 4.22 Lift and drag forces at the blade. *Source* Own illustration based on Anderson (2011, p. 20)

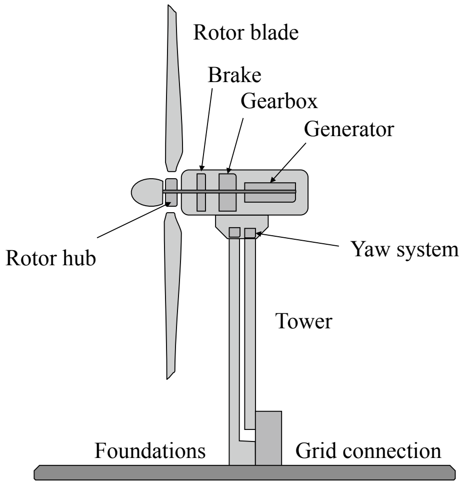

Fig. 4.23 Schematic representation of a modern wind power plant. *Source* Own illustration based on Kaltschmitt et al. (2007, p. 310) and Hau (2016, p. 73)

- Nacelle and its equipment: the nacelle of wind power plants might be equipped with a brake, a gearbox (not necessarily in the case of gearless turbines) to increase the rather low speed of the rotor revolution to higher speeds, and a generator to convert this mechanical energy into electricity, which is then transported through the tower to the grid.
- Yaw mechanism: the yaw system is needed to turn the whole nacelle into the wind and readjust its orientation according to the wind conditions.

Offshore wind turbines typically consist of larger towers and rotors than onshore wind turbines, which results in a greater electric capacity. In both cases the transportation, the foundation and the installation of the different components can be very demanding.

Wind power plants start converting the wind's kinetic energy into electricity as soon as the wind speed exceeds a minimal threshold (so-called cut-in speed, see

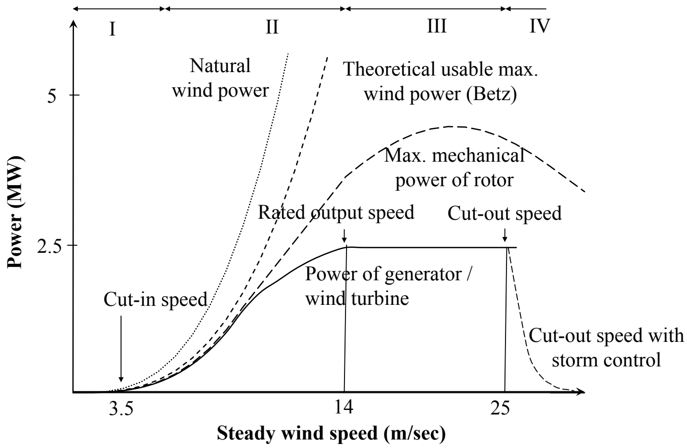

Fig. 4.24 Typical power curve of a wind power plant. *Source* Own illustration based on Wood et al. (2013, p. 23) and Kaltschmitt et al. (2007, p. 326)

phase I in Fig. 4.24), because a certain friction has to be overcome. Then the output of electrical power increases with the cube of the wind velocity until the rated output speed is reached; there, the wind power plant has reached its maximal capacity. To operate the wind turbine with increasing wind velocities at a constant output level requires an adequate control strategy (see above: stall or pitch control). If the wind speed outstrips the so-called cut-out speed, which is typically at about 25 m/s, the wind power plant is turned out of the wind and – with the help of the braking system – the blades are brought to a halt to avoid damages at the wind turbine (see phase IV in Fig. 4.24). As a sharp drop of power production at high wind speeds may be challenging for electricity grids, modern wind power plants have a so-called storm control, which slowly decreases the power with increasing wind speeds to avoid a sharp drop of power.

A wind power plant is rather seldom installed as a stand-alone unit. Typically many wind power plants are installed nearby, creating a so-called wind park. To reduce shadowing effects concerning the wind speeds available for the different wind power plants, certain design principles, e.g. the distance between the wind turbines of the park, have to be considered. Finally, it should be mentioned that also this way of using renewable energies leads to some environmental effects. In fact, there are no direct emissions like those of pollutants or greenhouse gases, but there are, e.g. noise emissions (audible and infrasonic sound), shadow impacts caused by the rotor blades and visual impacts (changes in the natural scenery) as well as the reduction of wind speed (which may result in local impact and which could be a non-negligible factor in the case of large-scale energy extraction).

4.2.3 Solar Energy

After a short introduction to the basics and characteristics of solar energy, subsequently, technologies will be in focus, which generate electricity from solar energy.

Solar energy is the energy of solar radiation from the sun. The sun has a mass of about 1.99×10^{30} kg (about 330,000 times the mass of the earth) and probably consists of about 91% hydrogen, 8.9% helium and 0.1% other elements. Temperatures of about 8 to 15 million Kelvin [K], as well as high pressure of more than 200 billion bar, prevail in the core of the sun. Under these conditions, nuclear fusion of hydrogen into helium takes place (see also Sect. 4.1.2). It amounts to about 4.3 million tonnes per second and thus corresponds to an average output of about 3.8×10^{26} J. This results in an average intensity of solar radiation at the boundary of the earth's atmosphere of about 1367 kW/m^2, which is also called solar constant. The solar constant is not a proper physical constant; it is just an average of a time-varying value.

Global radiation is the direct and diffuse radiation incident on a horizontal surface. Irradiance describes the power measured in W/m^2 and irradiation the energy measured in Wh/m^2. The global radiation at different locations and times depends on the angle of incidence (due to the earth's spherical shape), altitude and weather conditions. The mean annual value of the global irradiation is approximately 2200 kWh/m^2 at the equator and approximately 800 kWh/m^2 at the poles. The annual potential of solar energy, which is often derived as the energy from the sun at the total surface of the earth, is estimated to be between 1575 and 49,837 exajoules (EJ), which is several times larger than the total world energy consumption, being in the magnitude of approximately 570 exajoules (in 2015). Although this physical potential can only be used to a small share given technical and economic restrictions, it clearly shows that this energy source is abundant.

Solar energy, respectively, solar radiation, can be used technically in the form of electricity, heat or chemical energy. A range of technologies harnesses solar radiation, such as solar heating, photovoltaics, solar thermal energy, artificial photosynthesis, solar architecture (for light and heat usage), molten salt power plants, etc. Either passive or active solar usage can be distinguished:

- Active solar techniques transform the solar energy into other energy carriers by technical components (e.g. electricity or heat flows) and include photovoltaic systems, concentrated solar power and solar heating.
- Passive solar techniques include orienting a building to the sun and designing spaces and materials, making use of solar energy in the form of lighting and heating.
- Active solar techniques are required to transform solar energy into electricity, such as photovoltaic systems and concentrated solar thermal power plants, explained in the next sections.

4.2.3.1 Solar Thermal Power Plants

Solar thermal power plants make use of solar energy by converting it to heat. Thereby, concentrating collectors bundle the direct solar radiation and are thus called concentrated solar power plants (CSP). These power plants generate heat – solar thermal energy – by using mirrors or lenses to focus sunlight arriving on a large surface area onto a much smaller surface called the (energy) receiver. This concentration of sunlight enables a higher energy density at the receiver. Electricity is

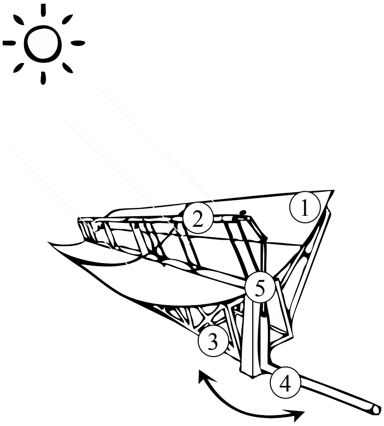

Fig. 4.25 Parabolic trough collector with sun tracking (1 reflector/mirror, 2 absorber tube, 3 frame, 4 solar field piping, 5 sun-tracking motor). *Source* Own illustration based on Kaltschmitt et al. (2013, p. 196)

generated using this concentrated solar thermal energy, respectively, heat, usually by a thermal engine (e.g. steam turbine as in a conventional power plant). Solar thermal power plants can either derive their primary energy exclusively from solar energy (solar only) and are then often equipped with solar thermal storage. Or they are equipped with fossil auxiliary firing (hybrid) to bridge (short) interruptions of solar radiation, but also a combination with conventional fossil power plants is possible. The advantage of systems with solar thermal storage is that besides a longer period of operation and thus a higher capacity factor, their use is dispatchable (at least in a short time horizon). Therefore, electricity generation is more independent from solar radiation, which is an advantage compared to weather-dependent technologies.

Different types of concentrating collectors exist for concentrating the solar radiation, such as parabolic trough collectors, Fresnel collectors or solar towers. Parabolic trough collectors and Fresnel collectors focus the solar radiation on a line, while solar radiation is concentrated on a point in solar towers. Parabolic trough collectors concentrate the solar radiation on an absorber tube (which serves as an energy receiver). Sun-tracking systems may be necessary and allow to adjust the mirror to the angle of incidence of the sun, as depicted in Fig. 4.25. Instead of using a curved reflector, Fresnel technology uses flat glass mirrors (instead of parabolic ones), making production and operation more straightforward and cheaper. In solar tower power plants, the solar light is concentrated at one point in the tower, resulting in extremely high temperatures at the receiver, which is a challenge for the material of the heat converter but results in higher temperatures for the steam process.

At the best sites (locations with very high solar radiation, such as in North Africa), the thermal efficiency of the solar field is on average about 50% and the total solar-electric efficiency of parabolic through power plants is up to 18%.[15] Concentrating solar power had a total installed global capacity of approximately 5 GW_{el} in 2016.

4.2.3.2 Photovoltaics

As opposed to solar thermal power plants, photovoltaic (PV) cells or systems convert light into electricity using semiconducting materials with the help of the photoelectric effect. The photoelectric effect describes a physical phenomenon of the interaction of photons with matter: an electron is dissolved from a bond – e.g. in an atom or the valence band – by absorbing a photon or, in other words, when light shines on a material. Electrons are only dislodged when photons reach or exceed a threshold energy (proportional to the frequency of the electromagnetic radiation). Below this material-dependent threshold, no electrons are ejected from a suitable material regardless of the light intensity or the length of exposure to the light. To explain that light can eject electrons even if its intensity is low, the concept of photons as a collection of discrete wave packets is necessary, which goes back to a proposal by Einstein. The electrons are lifted using the energy of the photons from the valence band into the energetically higher conduction band. The energy of each photon must correspond to at least the (photonic) bandgap of the irradiated semiconductor. The size of the bandgap depends on the used material. This explains the maximum wavelength for each material up to which the photoconductivity occurs (e.g. gallium arsenide: 0.85 µm, germanium: 1.8 µm, silicon: 1.1 µm). With the help of light, more precisely, the photons, voltage and electric current are created in the related materials (see Fig. 4.26).

For solar cells, the photovoltaic effect is used in combination with two differently doped materials, the so-called p- and n-layer. In the p-layer, trivalent-doped materials (doped with elements with three valence electrons) can take up an additional external electron and thus leave a hole in the valence band of the silicon atoms. This makes the electrons mobile in the valence band. In consequence, the "p" (positive) side contains an excess of holes. When photons hit the solar cell, they generate

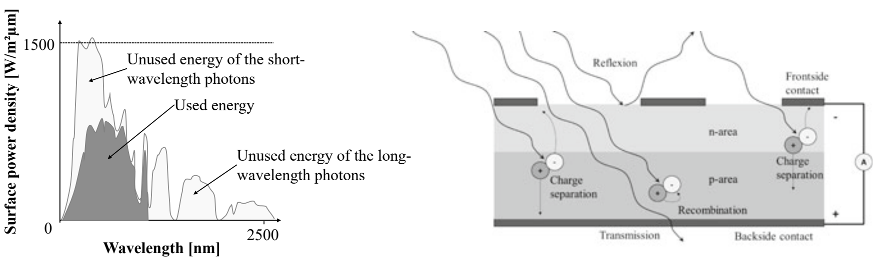

Fig. 4.26 Used energy by PV cells (left) and processes in PV cells (right). *Source* Own illustration based on Unger et al. (2020, p. 45) (left) and Quaschning (2004) (right)

[15] Efficiency is determined by the ratio of produced electricity and irradiated solar energy on the surface of the plant.

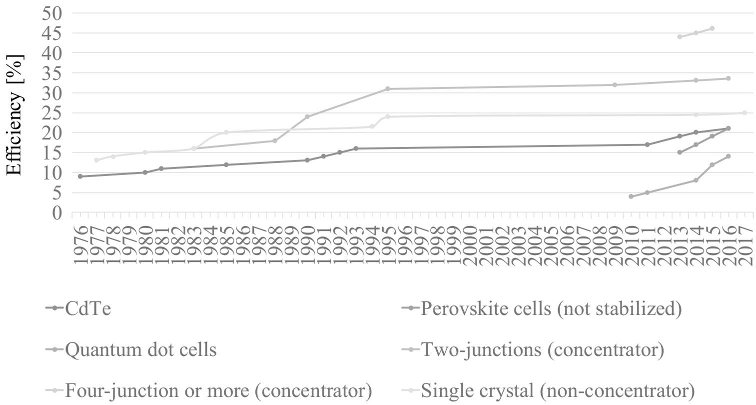

Fig. 4.27 Laboratory efficiencies of different types of solar cells. *Source* Own illustration based on NREL (2021)

so-called electron–hole pairs in the p-layer (positive). Electrons pass through the boundary layer in the n-region (negative), where they can move without problems. In contrast, the "n" (negative) side contains an excess of electrons in the outer shells as in the n-layer, 5-valent dopant (doped with elements with 5 valence electrons) has an outer electron. Due to the differently doped materials in the two layers, electrical current can only pass through the junction in one direction. The doping of the two layers is achieved by ion implantation or diffusion of dopants (e.g. n-doping with phosphorus and p-doping with boron). By separating the individual charges, a plus and a minus pole arise, and by the connection of the two poles with the interposition of a consumer, an electric current can flow (see Fig. 4.26).

In consequence, these solar cells can generate electrical power when light hits the cell. Several solar cells are combined into a solar panel. These solar panels may be ground-mounted, rooftop-mounted or wall-mounted. The solar panel can be mounted as a fixed installation or use a solar tracker to follow the sun across the sky (providing a higher solar yield but with a more expensive construction). The following advantages accompany solar PV: once installed, its operation generates no pollution and no greenhouse gas emissions. Solar PV is easy to scale regarding the provision of electrical energy but is strongly dependent on solar radiation.

Different types and materials of solar cells are used and are still in research. Solar cell (lab) efficiencies[16] vary from 6% for amorphous silicon-based solar cells to 44.0% with multiple-junction concentrated photovoltaics (see Fig. 4.27). Solar cell energy conversion efficiencies for commercially available photovoltaics are currently around 14–22%.

In 2020, approximately 140 GW of photovoltaic systems were installed, reaching a cumulative capacity of almost 800 GW worldwide (cf. IEA 2021). The growth rate of PV installations has been steadily above 30% in the last years: between 1998 and 2015, photovoltaic power grew on average by 38%. It is

[16] Solar cell efficiency is defined as quotient of solar power and solar irradiance.

expected (by several institutions, among others the International Energy Agency) that the installed capacity will increase to between 3000 and 10,000 GW by 2030. While different types of solar cells exist (see Fig. 4.27), the global market share of crystalline silicon cells was about 90% (in 2014). Silicon cells are expected to remain the dominant photovoltaic technology.

Photovoltaics has long been the most expensive form of electricity generation through renewable energy. However, substantial cost reductions of the system components have been realised, making solar power attractive for electricity generation (see Sect. 10.7.4). From 2011 to 2017, the cost of photovoltaic power generation decreased by almost 75%. With each doubling of the total installed capacity, the costs of photovoltaic modules have been decreasing by approximately 20%, often referred to as a learning rate (cf. Junginger et al. 2019). At locations with high solar irradiance, power generation costs are currently in the magnitude of 2–3 €ct/kWh or even less. In many locations, PV has reached grid parity, which is usually defined as PV electricity generation costs at or below retail electricity prices (cf. Sect. 10.7.4 for a detailed discussion). PV electricity generation costs are in the range of thermal power generation costs for coal or gas-fired plants or even significantly below (see the discussion of levelized cost of electricity, LCOE in Sect. 4.3.2). However, the weather-dependent feed-in requires complementary electricity storage. Batteries are becoming more and more attractive, also from an economic perspective, as they can store surplus energy of the day for demand at night. This energy management function strongly depends on the local regulations and the resulting incentive structure (cf. Sects. 6.1.4 and 10.7): if surplus energy at noon (high solar irradiance) cannot be injected into the grid (or only at low prices) and electricity purchase at high costs can be substituted in the night, batteries may be an economically attractive option for the PV owner. However, the gap between high summer solar irradiation (and a summer surplus) and a high winter demand necessitates shifting energy from summer to winter. This shifting of energy is still and will remain very costly, as infrastructure has to be installed for this one cycle per year and would necessitate enormous battery and PV capacities.

4.2.4 Bioenergy

Many different organic materials, including woody and agricultural residues, energy crops (like maize, miscanthus or jatropha) and various forms of waste, are subsumed under **biomass**, respectively **bioenergy** if these materials are used for energy provision. Biomass can be assigned to renewable sources of energy, if biomass is realised sustainably. The manifold forms of biomass can be classified in different ways, e.g. according to their aggregate state (e.g. solid, liquid and gaseous biomass), according to their origin (e.g. biomass from forests, agriculture, fishery and waste) or according to the type of feedstock (e.g. non-lignocellulosic biomass, lignocellulosic biomass). Fuels produced out of biomass, so-called biofuels, are typically differentiated according to their starting substances, e.g. into first-generation biofuels (produced from food biomass, e.g. sunflower oil), second-generation biofuels (produced from non-food biomass, e.g. straw) and third-generation biofuels (produced from algae).

Biomass-based energy carriers have their origin in the energy from the sun, as plants transform solar energy into chemical energy in the form of glucose via photosynthesis (cf. Kaltschmitt et al. 2007, pp. 81–88). Besides the sunlight, only water and carbon dioxide (from the air) are needed for this reaction, which is realised in the cells of plants – in the so-called chloroplasts containing chlorophyll – according to the following simplified overall reaction equation:

$$6\ H_2O + 6\ CO_2 \rightarrow C_6H_{12}O_6 + 6\ O_2.$$

The use of biomass for energy production is not only characterised by manifold forms of biomass, that can be employed, but also by different conversion pathways, that can be pursued (see Fig. 4.28 and Kaltschmitt et al. 2007, pp. 511–516). In contrast to the use of wind and PV for electricity production, the use of biomass has the advantage that energy production can be adjusted to the current energy demand. This holds even true for the biochemical conversion via anaerobic digestion used to produce so-called biogas. Indeed, the reactions of the biochemical conversion processes require a continuous production process, but there is the possibility to fulfil this requirement, without producing electricity, by storing the produced biogas. Furthermore, different products can be obtained from biomass that can meet various demands by displacing existing supply to different extents.

However, the energetic use of biomass is also connected with several challenges. Different biomass pathways potentially compete for the same resources with each other and other sectors like food and materials, which is crucial. Especially the use of first-generation biofuels produced from food biomass has led to discussions

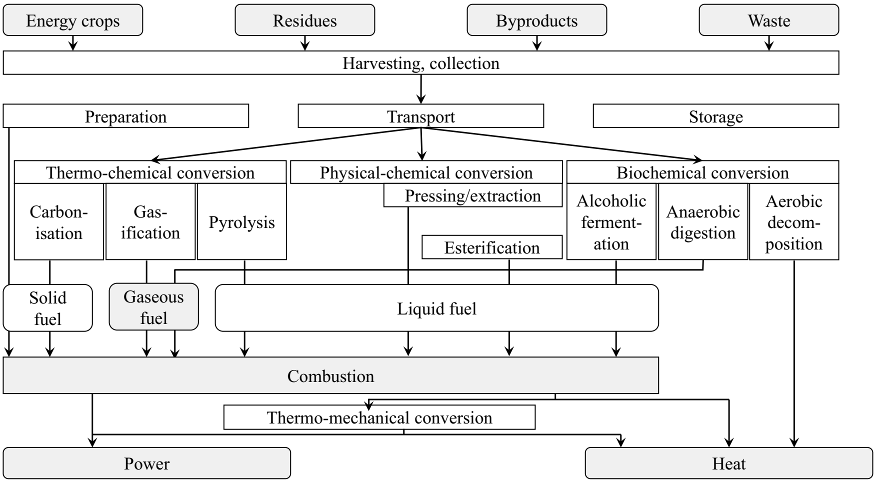

Fig. 4.28 Biomass conversion pathways. *Source* Own illustration based on Kaltschmitt et al. (2007, p. 512)

about whether the cultivation of biomass to produce energy should be realised, as long as we have problems feeding the world. In addition, depending on the form of the biomass used, the logistic steps necessary to provide the needed input can be rather complex and accordingly costly. Another disadvantage is that this form of renewable energy production leads to direct emissions, e.g. emissions of greenhouse gases (e.g. CO_2) and pollutants (e.g. heavy metals). It is argued that the absorption and the subsequent release result in a closed-loop of CO_2 as the used plants have absorbed the corresponding CO_2, which is needed for the photosynthesis relatively shortly before. Therefore, biomass can be seen as a CO_2-free energy carrier (so-called carbon neutrality). There is also a lot of discussion about creating negative emissions with the help of biomass combined with carbon capture and storage (CCS, see Sect. 6.2.2.3), especially in long-term scenarios of the Intergovernmental Panel on Climate Change (IPCC).

A widely used and relatively easy way to energetically use biomass, like wood (products) or straw, is to burn it to produce heat. The heat might then be used for heating purposes, e.g. via a district heating system, cooking, e.g. in developing countries, or producing electricity via the well-known steam cycle (see Sect. 4.1.1.2). This transformation pathway to produce electricity is based on the same components as other steam power plants. It is possible to switch partly – so-called **co-firing** – or totally from burning coal to burning solid biomass in existing steam power plants, e.g. hard coal power plants, when they are designed for switching these fuels. This strategy has the advantage that the power plant operator can – at least partly – use components of the existing power plant.

In addition to the combustion of biomass, which is provided in solid form by nature, the following pathways to provide solid, gaseous or liquid biomass can be differentiated:

- Thermo-chemical conversion (carbonisation, gasification, pyrolysis),
- biochemical conversion (alcoholic fermentation, anaerobic digestion, aerobic decomposition) and
- physical–chemical conversion.

Concerning thermo-chemical conversion, the gasification of the raw materials to produce a synthetic gas (syngas) is essential, not only because this gas can be used as the primary material for producing biofuels. Furthermore, anaerobic digestion, which belongs to the biochemical conversion possibilities, is found in many energy systems worldwide.

The example of biogas for electricity production shall be used for illustrating the biomass conversion pathway. The following four steps characterise this conversion pathway: (1) feedstock management, which comprises, e.g. harvesting, transport and pre-treatment of the biomass, (2) biogas production in biogas plants, (3) biogas treatment and use and (4) digestate treatment and use (cf. Balussou 2018, pp. 15–25).

The central element of the conversion via anaerobic digestion is the biogas plant (see Fig. 4.29), where the production of the biogas is realised in heated, oxygen-free tanks, the so-called fermenters. There are different ways of charging

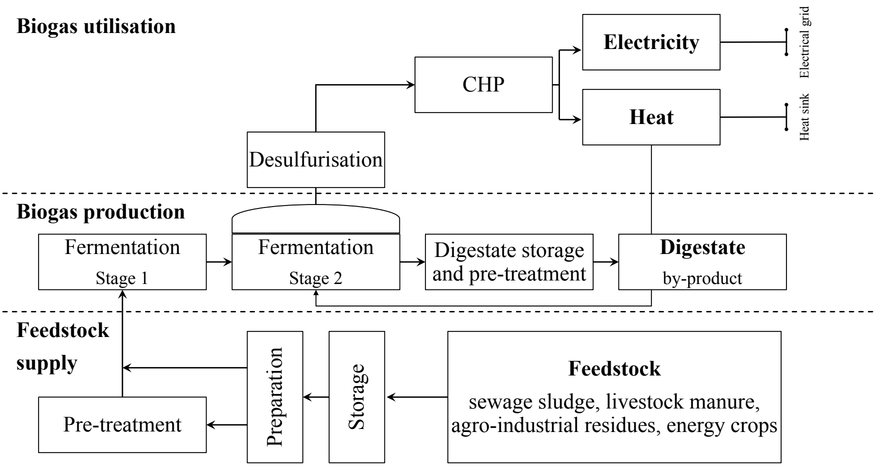

Fig. 4.29 Components of a biogas plant. *Source* Own illustration based on Bidart (2013, p. 81)

and discharging the fermenter (e.g. continuous mode or batch mode). The fermenters are equipped with stirring devices. As soon as the input materials, like energy crops and manure (wet fermentation), have been brought into the fermenter, bacteria begin to decompose the organic biomass. Two different products are obtained: biogas, which is a mixture of different gases, mainly methane and carbon dioxide, and a residue called digestate, which can later be used as a fertiliser. The produced biogas is often burned in small cogeneration units typically consisting of a motor engine installed at the site, e.g. the biogas-producing farm. The biogas is in general desulphurised and dried to reduce pollutant emissions and increase efficiency. The usage of produced heat increases the total efficiency of the small cogeneration unit, e.g. to serve local heat demand for houses and mews. In the absence of heat demand, biogas injection to a natural gas grid may be favourable. If the produced gas is injected into the natural gas grid, an even more sophisticated treatment process is necessary to comply with the quality requirements of the grid operators; one crucial part of this treatment is the removal of CO_2 from the biogas.

4.2.5 Other Renewable Energy Technologies

There are several other renewable energy technologies, such as geothermal energy, wave energy, tidal energy, seaflow energy, osmosis energy, ocean thermal energy conversion, etc. As geothermal energy and wave energy are also promising for electricity production, a short introduction will be given to these two technologies, while the other ones are not further detailed here.

4.2.5.1 Geothermal Energy

Geothermal energy corresponds to the energy stored in the form of heat below the earth's surface. Like solar and wind energy, hydropower and biomass, it is one of the regenerative forms of energy and has the unique advantage that it is continuously available. In general near-surface geothermal energy is differentiated from deep geothermal energy. The differentiation of both types is a consequence of legal aspects (e.g. mining law), but also refers to the used technologies. The focus is subsequently on technologies for power generation, which need higher temperature levels at the geothermal site. These higher temperature levels are available at either attractive geothermal areas[17] or by deep drilling (deep geothermal energy).

Geothermal energy in the earth's crust originates to approximately one-third from the original formation of the planet and to approximately two-thirds from radioactive decay of materials within the earth. It is estimated that 99% of the earth is warmer than 1000 °C. Temperatures at the core–mantle boundary may reach over 4000 °C. This results in a heat flux density of about 0.07 W/m^2 on average at the earth's surface (cf. Kaltschmitt et al. 2007, p. 94). This corresponds approximately to a total thermal power of 33 TW. Although geothermal energy is not infinitely available, it is considered renewable as the time dimension of earth cooling is "forever" compared to human life. As long as the geothermal resource is not locally overexploited, i.e. the inflowing heat flow from the earth is sufficient to serve the heat extraction, heat can be permanently extracted.

Geothermal energy in its simplest form is water from hot springs and has been used since Paleolithic times. In Roman times, geothermal energy was already used for space heating. Since the second half of the twentieth century, geothermal energy has also been used for electricity generation. Worldwide, a capacity of approximately 12 GW of geothermal power for electricity generation is currently installed (cf. Matek 2013). Historically, thermal energy usage has been limited to areas near tectonic plate boundaries as these result in higher temperature close to the surface (including hot springs, etc.). Also, geothermal electric plants have been first built in these regions, since the high-temperature geothermal resources enable higher conversion efficiencies (see Carnot efficiency, Sect. 2.1.3).

Global power generation from geothermal energy is mostly based on **high-enthalpy deposits** that provide heat at high temperatures. These are geological heat anomalies often associated with active magmatism. There are several hundred degrees hot fluids (water/steam) to be found at a depth of a few hundred metres. Their occurrence correlates strongly with active or formerly active volcanic regions, e.g. around the Pacific Ocean or in rift zones and hot spots. Depending on the pressure and temperature conditions, high-enthalpy deposits may be more vapour or water-dominated. Vapour-dominated sites offer temperatures from 240 to 300 °C that produce superheated steam. Liquid-dominated reservoirs are more common with temperatures higher than 200 °C, and they are also close to geological heat anomalies. The hot fluid or steam can be used to provide industrial steam, to feed local and district heating networks or to produce electricity. If electricity is produced, the closed circuit in the circulation system is under pressure so that boiling of the injected water is prevented and the steam is only generated at

[17] Geothermal attractive areas already provide the required heat temperatures near surface and thus allow for a cheaper power generation than in geothermal less attractive areas. Examples of countries with geothermal attractive conditions are New Zealand, Iceland and Italy.

the turbine (flash evaporation). At some sites, the steam was released into the air after use, which could lead to a significant smell of sulphur (e.g. as in Larderello, Italy), but nowadays, it is in general reinjected. As temperature levels of geothermal fluids are quite low (compared to temperatures in conventional steam power plants), the conversion efficiency of geothermal electric plants is also relatively low. The laws of thermodynamics (see Sect. 2.1) limit the efficiency of turbines or other heat engines in extracting useful energy, and thermal efficiency is in general between 10 and 23%. Essential is the selection of a proper working fluid, which is in general not water (as is the case for conventional steam power plants). The essential thermodynamic characteristic of a working medium is its saturation curve with the critical temperature and the critical pressure. Above the critical temperature, the medium can no longer be condensed, no matter how high the pressure is. These variables are essential parameters for selecting a working medium and the best possible adaptation to the temperature profile of the (low temperature) heat source. The potential environmental hazard resulting from the working fluid is, besides its thermodynamic characteristics, an important selection criterion. Examples of used working mediums in geothermal power plants are isopentane and the refrigerant R245fa (1,1,1,3,3 pentafluoropropane).

In non-volcanic areas, the temperatures in the ground can be very different. In general, however, deep drillings for power generation are neccessary as temperatures above 80 °C are required. For commercial use, the fluid temperatures should be above 100 °C. These areas are typically called **low-enthalpy deposits**. In the field of deep geothermal energy (more than 400 m), different types of heat extraction are generally distinguished (see also Fig. 4.30), which of the eligible processes is used depends on the respective geological conditions, the required amount of energy and the required temperature level of heat utilisation:

- **Petrothermal systems** are often referred to as HDR systems (hot dry rock) or enhanced geothermal systems. In case the rock or underground is less permeable, it is artificially cracked. This expands existing rock fissures and so enables the water to freely flow in and out (hydraulic stimulation or fracking). The technique has been adapted from oil and gas extraction techniques. As a result, flow paths are broken or existing ones widened, which increases the permeability of the rock. This procedure is necessary because otherwise, the heat transfer surface and the permeability would be too low. Subsequently, this system of natural and artificial cracks forms an underground geothermal heat exchanger. Consequently, two drillings are necessary, one bringing the carrier medium to the natural and artificial cracks, and through the second, the production well, the carrier medium is conveyed back to the surface.
- **Hydrothermal systems**: if an aquifer provides sufficient energy, thermal waters can be extracted (at one point), used and reinjected at another point (avoiding that the reinjected colder water flows back to the extraction point, resulting in a so-called heat short circuit). Hydrothermal energy can be used to generate heat or electricity, depending on the temperature.

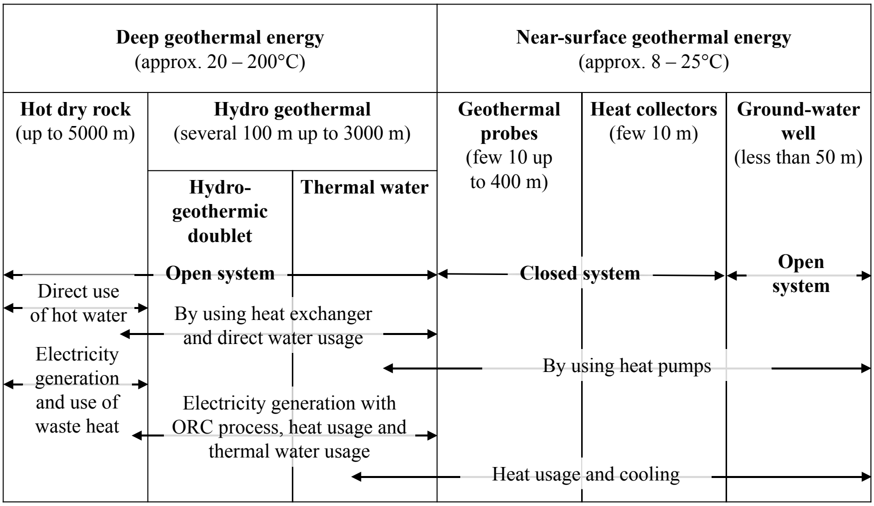

Fig. 4.30 Types of geothermal energy. *Source* Own illustration based on Bundesverband Geothermie (2021)

- A **deep geothermal probe** is a closed system for geothermal energy generation, in which – compared to "open" systems – comparatively little energy is extracted. Closed refers to the fact that the fluid used for heat transport is circulated in a closed system, while in an open system (e.g. hydrothermal system) the fluid is taken from and reinjected to the environment. The probes consist of a single borehole, sometimes drilled over 1000 m deep, in which a fluid is circulated, that is usually trapped in a coaxial tube. The cold heat transfer fluid flows down, is heated at depth in the probe and then rises again in the thinner inside riser. In such geothermal probes, there is no contact with the groundwater. Thus disadvantages of open systems are eliminated, and such systems are hence possible at any location with sufficient geothermal energy. Their withdrawal rate depends not only on technical parameters but also on the mountain temperatures and the conductivity of the rock. However, it will only be a few hundred kW and thus much smaller than a comparable open system. This is because the heat transfer surface is significantly smaller since it only corresponds to the lateral surface of the borehole. Geothermal probes are in general only used for heating and cooling and not for the production of electricity.
- Furthermore, **near-surface geothermal energy** is extracted with heat collectors at varying deeps or with groundwater wells. These are used for heating and cooling purposes, notably using heat pumps, and not for electricity generation.

Geothermal energy is used for electricity production only at a few sites, although it is available everywhere. Yet both the heat flow with only $\approx 0.07\ \mathrm{W/m^2}$ and the temperature increase with the depth of approximately 3 K/100 m make it challenging to access it economically, especially when conventional fuel prices are low.

With the recognition of CO_2 emissions as a problem, a more intensive geological exploration and technical development of geothermal energy started. However, drilling is expensive and several challenges arise, such as: can the rock be made permeable, is sufficient heat available, do seismic events (sometimes interpreted as positive signal for making the rock permeable) result in lacking acceptance and a stop of the projects[18] or are the water amounts in hydrothermal systems sufficient? In contrast, near-surface use of geothermal energy for heating (and cooling) of buildings using heat pumps is usually competitive and thus an interesting option for heating (and cooling).

4.2.5.2 Wave Energy

Waves are caused by the effect of wind forces on the water surface. Their structure depends mainly on the wind speed, the wind duration, the wavelength and the water depth. Wave energy converters attempt to use the energy of these waves for electricity generation or pumping water. Wave power is not to be confused with tidal power. Tidal power makes use of the energy of the falling and rising tide due to the gravitational pull of the sun and the moon. Furthermore waves and tides have to be distinguished from ocean currents which are caused by other forces, e.g. different water temperatures.

Up to now, wave power generation is not widely employed, notwithstanding that several wave power devices have been examined for power generation. Wave energy conversion units can be categorised by the methods used to harness the wave energy, by the location (e.g. shoreline, nearshore and offshore), and by how the power is drawn. Four main technological approaches are distinguished in the following enumeration (see also Fig. 4.31):

- **Point absorber buoys** generate electricity by the rise and fall of swells, e.g. by hydraulic pumps.
- **Surface attenuators** use multiple floating segments connected to one another. These units are oriented perpendicular to incoming waves. Again hydraulic pumps are used to generate electricity taking advantage of flexing motions caused by the swells. A well-known example of this form of using wave energy is the Pelamis Wave Energy Converter which was the first offshore wave conversion unit feeding electricity to the grid from 2004 onwards.
- **Oscillating water columns** consist of air chambers. In these chambers the swells press the air into a turbine with the help of which electricity is produced.
- **Overtopping devices** use the waves to fill an upper reservoir. As the water level is above the surrounding ocean, this potential energy can be transformed into electricity using low-head turbines (see Sect. 4.2.1.2).

[18] As it has been the case at a plant in Basel: the hot dry rock enhanced geothermal project induced seismicity in Basel and led to a suspension of the project. After the induced seismicity a seismic-hazard evaluation was conducted, resulting in the cancellation of the project in December 2009 (cf. Glanz 2009).

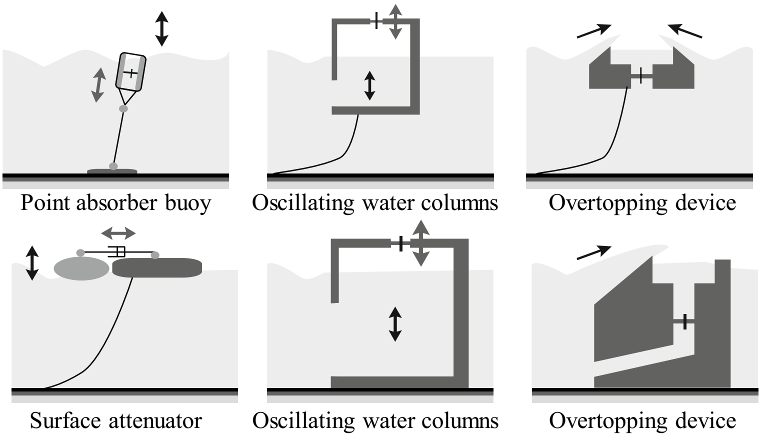

Fig. 4.31 Different technical implementations of wave power plants. *Source* Own illustration based on Graw (1995)

The worldwide resource of coastal wave energy has been calculated to be more than 2 TW (cf. Gunn and Stock-Williams 2012). However, only a few research and demonstration plants in the magnitude of several MW are installed worldwide, so the impact on electricity production has been very limited up to now.

4.3 Key Characteristics of Electricity Generation Technologies

In the following, key characteristics of electricity generation technologies are discussed. Thereby technical, environmental and economic elements are relevant. Also, the availability of the corresponding resources, i.e. primary energy carriers, is a prerequisite. Therefore, this section provides a first, concise overview of these aspects. However, they all deserve closer scrutiny when operating and designing electricity systems since they considerably vary over time and between locations.

4.3.1 Technical and Environmental Characteristics

From an engineering standpoint, the typical plant size and the conversion efficiency are certainly key characteristics of power plants. For future electricity systems, two further aspects are yet relevant: the controllability of the electricity output ("dispatchability") and the flexibility to adjust output to changing circumstances.

In ecological terms, multiple effluents and impacts on eco-systems may be considered. Yet the focal point subsequently is on air-borne emissions and mostly on CO_2 emissions given the primordial challenge of global warming. Other emissions, like e.g. SO_x, NO_x, heavy metals, particular matter, noise, etc., are usually regulated by emission limit values, which are reached with corresponding technical equipment.

Before providing overview tables including relevant information on all these aspects, it is worth reflecting briefly what these indicators measure and what has to be considered when interpreting them.

Typical plant size: these numbers refer to new state-of-the art generation units and are meant to illustrate differences in size between various generation technologies.

Conversion efficiency: this corresponds in general to the ratio of electricity (and heat) output to fuel or other primary energy input. The instantaneous efficiency – typically indicated at reference conditions such as output at nameplate capacity level – has to be distinguished from the annual efficiency, which considers all sorts of real-world losses, e.g. through start-up processes or part-load operation. Subsequently, we indicate the instantaneous efficiency at nameplate capacity since these numbers are better documented than annual efficiencies. The numbers refer to new state-of-the-art generation units.

Dispatchability: this binary indicator highlights when the electricity generation is not dependent on some highly variable input source such as wind or solar energy. Also, other generation units only deliver output if the logistics for the input energy carrier have been secured and if the power plant is available. Yet, these factors are primarily under human control as opposed to weather-dependent energy flows.

Operation lead time: this is one indicator of flexibility – indicating how long it takes to start a power plant from standstill – and hence the ability to adapt to changing demand and supply conditions in the system. Other flexibility indicators would be minimum operation and minimum downtimes, limiting the on-/off-switches of power plants, and the minimum stable operation limit, which informs about the possibilities to modulate output during operation. For the operation lead time, warm start-ups and cold start-ups are differentiated depending on the duration the power plant has been standing idle. Especially in the case of **CCGT** and coal-fired power plants cold start-up times (shown in Table 4.7) are considerably longer than hot start-up times (cf. Agora Energiewende 2017, pp. 44 and 48).

Ramping constraint: this indicator describes the short-term flexibility of a unit in operation, i.e. how fast it can change its output while running (Fig. 4.32).

Technical plant availability: The unavailability of power plants may be due to unplanned outages that typically arise due to some component failure. Or power plants may undergo planned maintenance or retrofit. For variable renewable sources like wind, solar and hydro, resource availability may also restrict power plant output. Yet, the indications given in Table 4.7 only refer to the (yearly average) technical availability, disregarding the possible unavailability of the natural resource.

Capacity and utilisation factor: in contrast to the plant availability, the **capacity factor** describes ex-post, the utilisation of a power plant. The **utilisation factor** (mostly synonymous to full-load hours) is just calculated by dividing the produced

Table 4.7 Key technical and emission indicators for electricity generation technologies

Key indicator	Dispatchability	Net capacity—typical plant K	Net electrical efficiency[a] η	Operation lead time t^{lead}	Ramping constraint $grad^{max}$	Technical plant availability	Operational CO_2 emission factor ε^{fuel} (fuel-specific)
Unit	[.]	[MW_{el}]	[–] (%)	[h;min]	[1/min] (%)	[–] (%)	[t CO_2/MWh_{th} and $*MWh_{el}$]
Natural gas—CCGT	*y*	480	60	1 h	5–12	~ 85	0.20 *0.33
Natural gas—OCGT	*y*	240	38	5 min	8–12	~ 90	0.20 *0.52
Coal	*y*	770	45	2 h	3–8	~ 85	0.34 *0.75
Nuclear	*y*	1300	36	120 h	3–10	~ 85	0.00
Solar PV—residential	*n*	0.005	100*	N.a	100[b]	~ 92	0.00
Solar PV—commercial	*n*	0.22	100*	N.a	100[b]	~ 95	0.00
Solar PV—large	*n*	2.5	100%*	N.a	100[b]	~ 99	0.00
Onshore wind	*n*	2.5	100*	N.a	100[b]	~ 98	0.00
Offshore wind	*n*	6	100*	N.a	100[b]	~ 95	0.00
Hydro—small	*n*	2	100*	< 1 min	100	~ 95	0.00
Hydro—large	*n*	50	100*	< 5 min	100	~ 95	0.00

[a] applying conventions from energy balances, see Sect. 2.3
[b] within the limits of the time variable natural energy supply
* electrical efficiency of renewable energy plants are set per definition at 100%
Source IEA and NEA (2015), VGB (2013), Dena (2014), own research

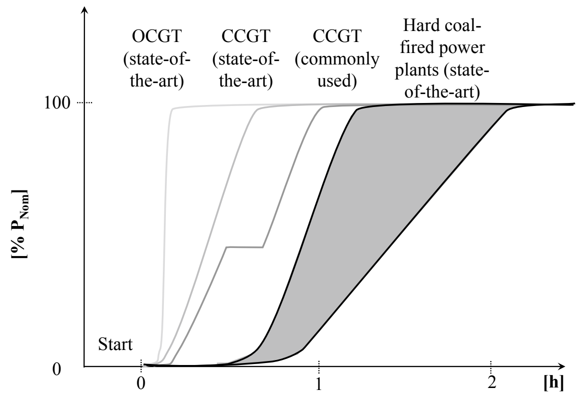

Fig. 4.32 Ramp rates and hot start-up times of selected power plants. *Source* Own illustration based on Agora Energiewende (2017, p. 47)

energy of a year by a plant's capacity. Accordingly, the utilisation factor is between 0 and 8760 h. While the utilisation factor is often used in Europe to describe production of power technologies, in USA typically the capacity factor is specified, which is the utilisation factor divided by 8760 h. In consequence, the capacity factor is between 0 and 1.

Emission factors: these may be given for various pollutants and varying operating conditions. **Emissions** from power generation systems include CO_2, NO_x, SO_x, heavy metals, particular matter, noise, etc. In the following, a focus is set on the CO_2 emission intensity since climate change remains the most challenging global environmental threat and CO_2 emissions from thermal power plants account here for roughly 40% of all emissions (see Sect. 2.3.2). However, other emissions are addressed in Chaps. 2 and 6. We provide emissions per energy unit of input fuel as these figures are only dependent on the fuel used—so they are also applicable for other power plants using the same fuel.

The data compiled in Table 4.8 reveal that conventional electricity generation is typically based on much larger units than renewable generation. Several wind turbines or solar panels may be grouped into utility-scale generation parks with nameplate capacities in the tens or hundreds of MW. Especially offshore wind farms reach connection capacities of more than 1000 MW (e.g. Hornsea, UK). Yet also more small-scale applications and hence more distributed systems exist.

Among the conventional units, the gas-fired **CCGT** plants reach the highest efficiency – and a fortiori the lowest CO_2 emissions per unit of electricity produced. At the same time, **open-cycle gas turbines** (**OCGT**) are the most flexible thermal generation units.

Dispatchability is an advantage of conventional generation units, although large-scale hydroreservoirs and biomass plants are also fully dispatchable (see Sect. 4.2.1 (hydropower) and 4.2.4 (biomass)). In terms of ramping, renewable-based generation is advantageous compared to thermal power plants, as it may usually downregulate (and upregulate, if the natural resource is available) within less than a minute.

Table 4.8 Key economic indicators for electricity generation technologies[19]

Key indicator	Investments c^{inv}	O&M expenditures $c^{O\&M}$	Fuel expenditures p^{fuel}	Technical lifetime T^{life}	Levelized cost of electricity c^{av} [a]
Unit	[€/kW$_{el}$]	[€/MWh$_{el}$]	[€/MWh$_{th}$]	[a]	[€/MWh]
Natural gas—CCGT	810	5	15–75[b]	35	50–150
Natural gas—OCGT	560	12	15–75[b]	25	70–230
Coal	1800	7	5–12	50	60–77
Nuclear	3900	11	1.5–4	50	70–77
Solar PV—residential	1400	24	0	25	108
Solar PV—commercial	1000	30	0	25	90
Solar PV—large	700	18	0	25	60
Onshore wind	1400	19	0	25	65
Offshore wind	3200	36	0	25	104
Hydro—small	4200	30	0	80	87
Hydro—large	2000	8	0	80	35

[a] Based on: interest rate in real terms i = 6%; CO_2 price p^{CO2} = 20 €/t; full-load hours H = 4500 for all conventional plants and according to Table 2.5 for renewables.
[b] In 2022, sudden reductions in Russian gas supplies (related to the war in Ukraine) have sent shock waves through the European gas markets. These have resulted in natural gas prices far above 100 €/MWh, which are much higher than the long-term range mentioned here.
Source IEA & NEA (2015), ISE (2018), own research and computations

In terms of technical availability, photovoltaic plants may reach almost 100%, although ageing may reduce the actual electricity generation, and wind attains approximately 95–98%. Yet, in terms of system **reliability** (cf. Sect. 5.1.4.1), the availability of the corresponding natural resource has also to be considered. For most thermal power stations, including coal, (combined cycle) gas and nuclear power plants, the availability factor ranges between 70 and 90%. Open-cycle gas turbines have even higher availability factors, ranging from 80 to 99%; yet this comes with a relatively rare dispatch (see Sect. 4.4).

4.3.2 Economic Characteristics

The economics of electricity generation technologies are driven by various cost categories that are briefly discussed subsequently. They may be aggregated into one

[19] Note that these values are changing over the years due to different factors, like volatile fuel prices, technological development, volatile material prices, etc. Especially in the last decades, investments and costs of some renewables significantly decreased due to technological learning and this development may continue.

single cost indicator, the so-called levelized cost of electricity generation (LCOE) as introduced below. Levelized cost of electricity can be seen as a benchmark, which allows comparing technologies over their lifetime. However, LCOEs may be less meaningful for weather-dependent renewables as they are not dispatchable. The calculation of LCOEs requires additional assumptions, and also given different application cases, a separate consideration of the cost components is useful.

Investments: investments are made in particular for building the infrastructure and can include expenses for land[20] acquisition, etc. Investments scale roughly proportional to the plant's nameplate capacity, although some economies of scale are observable. Therefore c^{inv} is typically indicated per unit of output capacity. As stated here, these are so-called overnight expenditures, i.e. the pure construction expenditures without financing expenditures during the construction period. These expenditures are often referred as capital expenditures (CAPEX). Capex are often colloquially referred to as "investment costs".

Operation and maintenance (O&M) expenditures: these include the plant's running expenditures, including standard maintenance works but excluding the fuel expenditures.

Fuel expenditures: those tend to fluctuate considerably over the years. Thus only rough indications may be provided. Note that fuel expenditures are typically given on the basis of the upper heating value. Fuel expenditures, in general, include also transport expenditures of the fuel. Consequently, fuel expenditures might be different depending on the location for technologies using the same fuel (e.g. power plant at the coast directly delivered with coal from ocean freighters versus delivery to a location within a country).

Expenditures for greenhouse gas emission allowances: besides fuel expenditures, expenses for greenhouse gas emission allowances might be considered, as it is for example the case for large power plants in Europe, which are under the regulation of the European emission trading scheme (see Sect. 6.2.4.1). Besides emission allowances, also other taxes and expenses might accrue.

Levelized cost of electricity (LCOE): they describe average cost per unit of electricity produced including all cost categories (see Sect. 4.3.3).

Technical lifetime and utilisation period: this parameter is needed to compute the LCOE, since investments must be repartitioned over the utilisation period. Whether the actual utilisation period corresponds to the technical lifetime depends on the economic context. If a continued operation is no longer profitable, decommissioning may occur prematurely. The technical lifetime is also neither strictly technical nor fully predetermined. Typically, the various components of a large plant have different lifetimes. For example, steam turbines in thermal power plants are replaced after around 20 years and gas turbines and motor engines even more

[20] In this context, it is worth noting that land is not depreciable.

frequently. The corresponding cost should be included in a detailed economic assessment or lumped into average operations and management (O&M) costs.

The data compiled in Table 4.8 reveal that the generation technologies not only differ in their technical characteristics but also in their cost components.

Notably, there are also considerable expenditure differences in investment expenditures respetively capital expenditures (CAPEX) and operational expenditures (OPEX). OCGT units are the cheapest in terms of investment expenditure; yet natural gas is considerably more expensive than hard coal or lignite – at least in Europe. Therefore a mix of various generation technologies may be economically most efficient to fulfill the energy demand at different loads. This will be discussed in Sect. 7.1.3 within a coherent theoretical framework.

The results given in Table 4.8 are dependent on the assumptions made. The chosen interest rate $i = 6\%$ in real terms reflects that generation investments are typically quite risky. Experience shows that the CO_2 price is highly uncertain. The CO_2 price p^{CO2} = 20 €/t is somewhat above average values in the European certificate trading system in the last decade, but significantly lower than today's prices. In contrast, for the fuel prices, the mid-point of the indicated range has been chosen. The full-load hours fh = 4500 for all conventional plants are those of a traditional mid-merit plant, whereas for renewables, they reflect average resource qualities across Europe.

Under these conditions, CCGT and coal-fired plants are the most cost-effective plants – which is in line with their traditional role as mid-merit plants in the European generation fleet (see Sect. 4.4.1.1 and Chap. 7). Wind onshore has LCOE in the same range, PV even lower at location with high sun availability. Yet, in economic terms, the wind (and PV) electricity is expected to be less valuable since it is not dispatchable instead of the electricity from thermal plants. On the other hand, the applied (low) CO_2 price certainly does not fully reflect the future damage cost of CO_2 emissions. For solar and offshore wind, the technology cost, on the other hand, may not reflect the latest progress in manufacturing cost – hence all these numbers should not be overinterpreted, but rather be considered first indications in economic terms.

4.3.3 Levelized Cost of Electricity

Levelized costs of electricity (LCOE)[21] are a simplifying indicator to compare the average costs of different generation technologies. They are defined as:

$$\mathrm{LCOE} = \frac{\sum_{t=0}^{\mathrm{T^{life}}} \left(C_t^{\mathrm{inv}} + C_t^{\mathrm{var}} + C_t^{\mathrm{decom}} \right) \cdot (1+r)^{-t}}{\sum_{t=0}^{T^{\mathrm{life}}} E_t \cdot (1+r)^{-t}} \tag{4.8}$$

[21] Levelized costs of electricity are in general calculated on the basis of expenditures. From a stringent terminological perspective, these should correctly be named as levelized expenditures of electricity. However, the term levelized costs of electricity is established in the energy industry, so that it is also used in this textbook.

Thereby C_t^{inv} stands for the investments and C_t^{var} for the variable expenditures. Additionally, the expenditures of decommissioning C_t^{decom} are included and all expenditure terms are discounted using the interest rate r and the lifetime T^{life} of the power plant.

In the denominator, the annual energy quantities E_t are also discounted to provide a constant payment per unit of energy produced, which would allow an investor to recover its entire expenditures over the lifetime of a generation facility.

The terms on the right-hand side may be computed in a simplified way as follows:

$$C_0^{\mathrm{inv}} = c^{\mathrm{inv}} \cdot K \tag{4.9}$$

Here only the upfront investment C_0^{inv} is considered, no reinvestments for replacing larger parts such as turbines nor financing cost during the construction period. For the variable expenditures, fuel and CO_2 certificate prices (as well as any further taxes and expenses) have to be considered together with operation and maintenance expenditures:

$$C_t^{\mathrm{var}} = \left(\frac{p_t^{\mathrm{fuel}} + \varepsilon^{\mathrm{fuel}} \cdot p_t^{\mathrm{CO2}}}{\eta} + c_t^{O\&M} \right) \cdot E_t \tag{4.10}$$

Finally, decommissioning expenditures should be included; yet discounted decommissioning expenditures are almost negligible except for nuclear plants.

The annual electricity production E_t may be written as a product of the installed capacity and the so-called full-load hours fh (see Sect. 2.1). Those may alternatively be expressed as a product of the capacity factor cf and the number of hours per year H:

$$E_t = fh \cdot K = cf \cdot H \cdot K. \tag{4.11}$$

But this requires an estimate of the capacity factor – for renewables like wind and solar, it will be mostly resource dependent (see below); yet for the dispatchable generation technologies, the capacity factor will depend on the system context (which other generation technologies are present) and on technology characteristics (what are the variable costs). Chapter 7 discusses how to determine equilibrium results regarding the generation fleet and its calculation.

The results given in Table 4.8 are obviously dependent on the assumptions made. The chosen interest rate i = 6% in real terms reflects that generation investments are typically quite risky. In periods with high (risk free) central bank rates and scarce project resources, the required return on investments may even raise much higher. Experience shows that the CO_2 price is highly uncertain. The CO_2 price $p^{\mathrm{CO2}} = 20$ €/t is somewhat above average values in the European certificate trading system in the last decade, but significantly lower than today's prices, whereas. In contrast, for the fuel prices, the mid-point of the indicated range has been chosen. The full-load hours fh = 4500 for all conventional plants are those of a traditional mid-merit plant, whereas for renewables they are reflective of, they reflect average resource qualities across Europe.

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4.4 Scheduling Electricity Generation—The Unit Commitment and Dispatch Problem

Traditionally, regional or national integrated utilities have run the electricity system. These had an assigned service area where they had to serve the demand. This traditional organisation model still prevails in many regions of the world, including parts of the USA. In such a setting, the utility has to serve all the demand arising in its service area – this demand being labelled frequently as "load" by engineers. We discuss different organisational structures of the electricity sector in Chap. 8, and demand is considered in detail in Chap. 3. But even under modified institutional settings and with flexible elements in electricity consumption, the challenge remains to match the time-varying demand for electricity with different generation units, some of which may also have time-varying output. This scheduling problem is frequently subdivided for conventional large power plants in the unit **commitment** and dispatch decisions. Unit commitment thereby describes the decision to turn units on and off, whereas the **dispatch** decisions consist in selecting the actual output level for the operating units.

The **scheduling** problem may be considered at different time scales, but one key operational planning approach is to schedule electricity generation on a day-to-day basis. In Sect. 4.4.1, we discuss this scheduling problem in detail to provide a flavour of the operational and mathematical challenges linked to the management of electricity systems worldwide. Section 4.4.2 then broadens the scope and discusses further issues and problems in operational planning in a less formal way.

4.4.1 Day-Ahead Operational Planning

The traditional operational planning (in a regulated market) is conceptually at first sight relatively simple: there is one entity, the (operational planning department of an) electric utility, aiming at making the best use of existing assets (generation units) to meet well-defined objectives. Its prime objective is (or at least should be) obviously to meet the demands from the customers. An additional objective from the perspective of the customers or society should be to do so at minimum cost. Further objectives may be relevant (e.g. meeting specific emission targets); yet we subsequently limit the analysis to the first two objectives in view of a concise treatment.

The first objective thereby sets a clear requirement or constraint to the operations, whereas the second objective is framed as reaching an optimum of a certain function, namely the cost of system operation. Hence we can formulate operational planning as a constrained optimisation problem (see Sect. 4.4.1.3). Alternatively, we may solve simplified versions of the problem graphically (see Sects. 4.4.1.1 and 4.4.1.2). In contrast to traditional operational planning in a regulated market, utilities in a liberalised market compete against each other and maximise their individual profit. At first glance, the traditional model appears to be no longer useful for this planning task. However, under the assumption of perfect competition and an inflexible (or nearly inflexible) demand, it can be shown that both planning problems result in an identical market equilibrium from a system perspective. Consequently, the described planning approach is also relevant (under some assumptions, see also Sec. 7.1.2) in a liberalised electricity market.

4.4.1.1 Simple Scheduling of Power Plants: Merit-Order Approach

Before providing a full mathematical description of the scheduling problem, one may consider a simplified version of the problem for thermal power plants. This so-called **merit-order approach** can be described and solved graphically and hence provides an easily accessible first-order approximation for the scheduling of thermal power plants.[22] The basic idea is that cheap generation units should be used first to meet the demand if costs are to be minimised. Since investments and other fixed costs are not influenced by operation decisions, only variable costs are considered – e.g. wind, solar and nuclear are used with highest priority, even if there has been important upfront investment. Additionally, none of the units may exceed its nameplate capacity and in the case of non-dispatchable renewables such as solar and wind, the output is also limited by the currently available input energy (e.g. no solar radiation at night).

We therefore order the available generation units by increasing variable cost and put their available capacities successively on the horizontal axis, while indicating their variable cost on the vertical axis. This is the merit order or supply stack as illustrated in Fig. 4.33.

Adding the demand level as a vertical line in the graph, we immediately obtain the units operating to meet demand (see Fig. 4.33). The same merit order may be used for each time period of the planning horizon – unless the availability of specific generation units varies over time (e.g. wind). In our simple example, the low load at night would require the operation of the wind (which is assumed to be available in this example), nuclear and coal units. During the daytime, utilisation of the coal unit would be increased and additionally, the CCGT is needed to meet demand.

[22] Note that a similar approach may also be used to analyse electricity market equilibria and therefore will be discussed in-depth in Chap. 7.

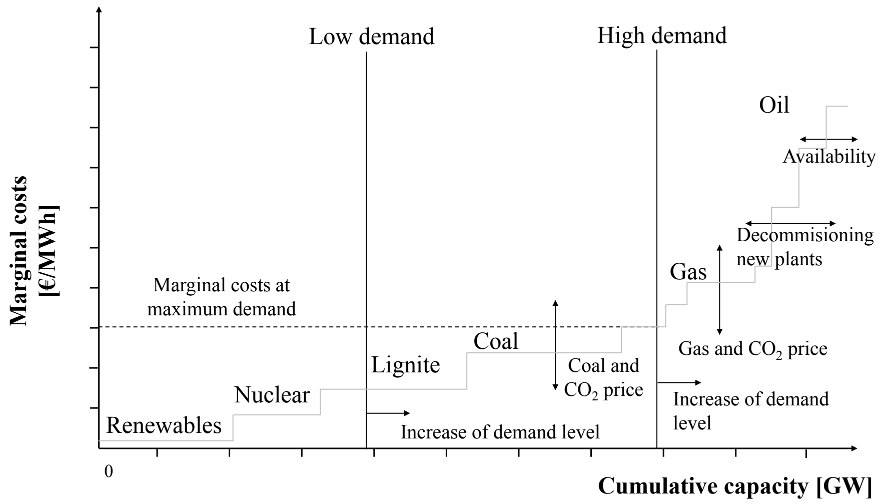

Fig. 4.33 Merit order for an exemplary power plant portfolio

This solution to the generation scheduling problem is straightforward. In general, it does not yet provide feasible operation schedules for the generation units. The reasons are operational constraints that prevent the flexible adjustment of power plant output to the requested levels. What the main restrictions are and how they may be handled is discussed in Sect. 4.4.1.3.

4.4.1.2 Simple Scheduling of Reservoir Power Plants

Hydroreservoir plants do not fit directly into the supply stack model discussed in the previous section. The reason is that their generation output does not come at any cost at first sight. This is true concerning so-called pagatory or cash-effective cost, i.e. cost corresponding to actual cash out. Yet, there is an indirect cost of producing electricity from a hydroreservoir: the opportunity cost of not being able to use the hydroenergy at some other point in time. Using water now means losing an opportunity to use the water later. The question then arises of how this opportunity cost may be determined.

This may be done by considering the profit maximisation problem for electricity production in reservoir power plants over time. To do so, the water inflow and the electricity prices for a given (future) period have to be estimated. When neglecting water inflow and reservoir restrictions, the optimal strategy is to use the available energy to produce electricity at the highest electricity prices. Three steps are necessary to identify these highest prices: (1) expected electricity prices are sorted in descending order (the so-called **price duration curve**, analogue to the sorted annual load curve, see Sect. 3.1.3). (2) Calculate the expected amount of water inflow (preferably converted in hours of full-load), (3) determine the intersection of the price duration curve and full-load hours (based on water inflow). The determined value describes the minimum expected electricity price at which the plant is

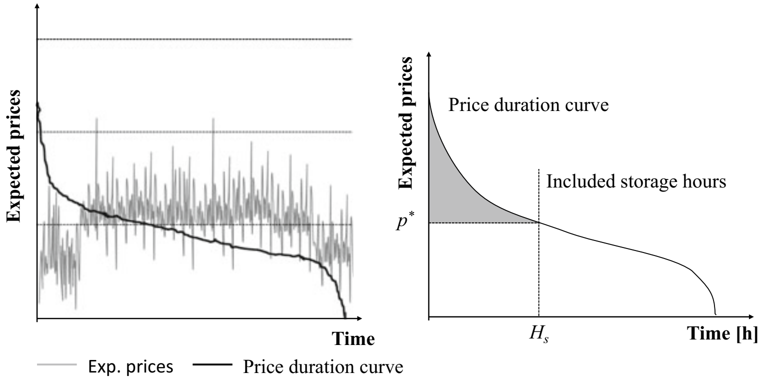

Fig. 4.34 Schematic illustration of the dispatch of a reservoir power plant in a given planning period

dispatched (see Fig. 4.34). This minimum price is also called "**water value**", reservation price or opportunity costs of water and is depicted as p^* in Fig. 4.34. In consequence, the water is used to produce at the highest prices in the given planning period. However, this procedure requires sound estimates of the water inflow as well as electricity prices.

The optimal use of pumping in **pump storage plants** (as well as the charging of other storage technologies, cf. Sect. 5.2) can be derived analogously. Therefore, the mirrored price duration curve has to be depicted starting from the y-axis, respectively, from the hydro inflow starting point H_a if hydro inflows occur (see Fig. 4.35). Additionally, the curve has to be stretched in the y-direction with 1/round-trip-efficiency (see Sect. 4.2.1) to account for efficiency losses and compressed in the x-direction with a term, which is calculated by multiplying the round-trip-efficiency by pump power and dividing this by turbine power, to account for the different capacity of the pumping process. In the case of a daily storage limit H_e, an upper price limit p_{t*} can be derived, at which water is used for electricity production (with the water turbine) as well as a lower price limit p_{p*}[23] at which water is pumped. In between the upper and the lower price level, the plant will not be operated. If the storage limit is not binding, the price for producing electricity corresponds to p_{s*}. The price for pumping has to be determined by retransforming p_{s*} by multiplying with the round-trip efficiency.

This schematic and simplified concept provides a rough understanding of the basic dispatch principles of storage. In reality, several restrictions have to be considered (and sometimes also hydrocascades), necessitating more complex dispatch models. A model which includes the most common restrictions, namely reservoir volume constraints, is discussed in the next section.

[23] As the pumping cost curve has been transformed with the round-trip-efficiency, a retransformation of this pumping price is necessary by multiplying the price with the round-trip-efficiency of the plant. In consequence, the price at which electricity is pumped is slightly less than p_{p*}.

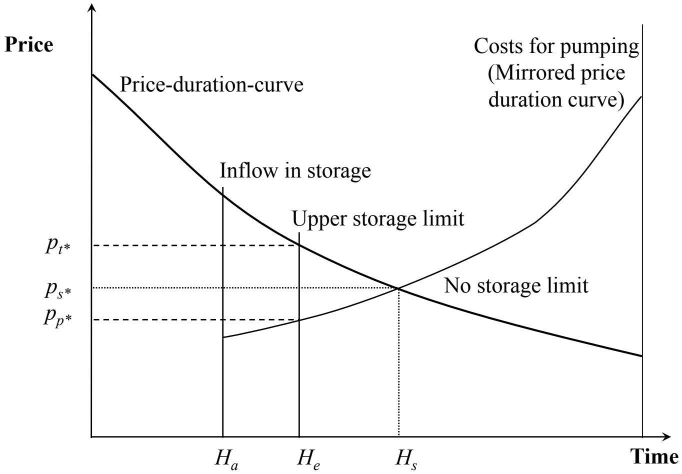

Fig. 4.35 Schematic illustration of the dispatch of a pumped hydropower plant in a given planning period

4.4.1.3 General Model of Short-Term Power Plant Scheduling

Production scheduling is a topic of relevance not only to the energy industry but also to almost any industrial production, be it for cars, washing machines or computers. Also, for services like airline travel, container shipping, or hotel stays, scheduling problems arise. Operations Research, as the branch of applied mathematics dealing with this kind of problems, has correspondingly developed multiple problem formulations and solution methods to support decision making in this field. The power plant scheduling problems have some specificities linked to the particularities of electricity, notably its limited storability and the characteristics of the generation units.

An immediate implication of the limited storability of electricity is that electricity has to be produced at precisely the point in time when it is needed. Correspondingly, production scheduling has to be done with a sufficient, at least hourly, time granularity.[24] The limited flexibility of many large-scale generation units (see Sect. 4.3.1) and the existence of limited storage capabilities (see Sects. 4.4.1.2 and 5.2) imply that the scheduling has to be done simultaneously for different time periods, including time-coupling constraints.

Consequently, the objective of the scheduling is to minimise the sum of operational costs C_{op} over all planning time steps $t \in \{1, \ldots, T\}$:

$$\min_{y_{ut}, s_{ut}, o_{ut}, L_{ut}, y_{ut}^{ch}} C_{\text{op}}$$

[24] The lack of storability and the limited predictability of demand also imply that some fast-reacting reserves have to be foreseen in system operation, so that the system may adjust to unforeseen disturbances in demand or supply. This issue is neglected here, but will be taken up again in Sect. 5.1.4.2 and in Sect. 10.3.

$$C_{op} = \sum_{t=1}^{T} \sum_{u} c_u^{var} \cdot y_{ut} \cdot \Delta t + \sum_{t=1}^{T} \sum_{u} \left(c_u^{\text{start}} \cdot s_{ut} \right) \tag{4.12}$$

Costs are thereby also summed over all units u, and they comprise not only the variable cost c_u^{var} related to the output y_{ut} of the units over the time step duration Δt, but also additional cost related to start-ups s_{ut}. Starting a large thermal power plant requires additional fuel (for heating up the components) and induces extra wear and tear related to thermal stress of the components. These costs are here collapsed into the cost term c_u^{start}, also neglecting that these costs may be dependent on the duration of the preceding shutdown period. Restarting a cold unit typically induces higher cost than restarts after short cool-down periods. Further variables of the optimisation problem are y_{ut}^{ch} describing the used electricity for pumping (storage charging), L_{ut} as storage level in period t of plant u, o_{ut} as binary variable of operation (on/off).

The cost minimisation is constrained by a number of restrictions which reflect system requirements and unit flexibility limitations. Note that all variables are restricted to positive values.

1. The main system requirement is the aforementioned demand–supply balance, which has to be fulfilled in each time segment with D_t as demand:

$$\sum_{u} y_{ut} \cdot \Delta t = D_t \cdot \Delta t \qquad \forall t. \tag{4.13}$$

The for-all operator $\forall$ thereby indicates that this constraint is not only to be applied for one particular t, but rather for all time segments of the planning horizon.

2. At the unit level, the limitation of the generation output to the installed capacity K_u is the fundamental requirement, which has to be fulfilled for each unit at each time step:

$$y_{ut} \leq K_u \cdot o_{ut} \qquad \forall u, t. \tag{4.14}$$

Yet this requirement is slightly modified here by introducing the binary on/off variable o_{ut}. If the unit is not operating, i.e. when $o_{ut} = 0$, the output level is also limited to zero.

3. The preceding upper bound to unit output is complemented by a lower bound, reflecting that there is usually a minimum output level required for stable operation. This is only relevant as long as the plant is turned on ($o_{ut} = 1$); otherwise, the minimum output drops to zero. Therefore the minimum operation restriction reads:

$$y_{ut} \geq P_u^{\min} \cdot o_{ut} \qquad \forall u, t. \tag{4.15}$$

4. The binary operation variables o_{ut} and the start-up variable s_{ut} are obviously linked. The simplest way to express the relation is by writing:

$$s_{ut} \geq o_{ut} - o_{u,t-1} \qquad \forall u, t. \tag{4.16}$$

This relationship, together with strictly positive start-up costs and the objective of cost minimisation, ensures that the start-up variable s_{ut} is zero throughout except when the on/off variables are $o_{ut} = 1$ and $o_{u,t-1} = 0$.

5. For variable renewable sources, generation is not only restricted by the installed generator capacity but also by the currently available supply, which may be described as a fraction w_{ut} of the installed capacity.[25]

$$y_{ut} \leq w_{ut} \cdot K_u \qquad \forall u, t. \tag{4.17}$$

This is notably relevant for photovoltaics, wind and run-of-river hydroplants.

6. For storage plants u' (notably hydroreservoirs), the storage fill level $L_{u't}$ is treated as an additional variable, which has to fulfil a dynamic energy balance equation:

$$L_{u't} \leq L_{u',t-1} + \left(i_{u't} + \eta_{u'}^{cyc} y_{u't}^{ch} - y_{u't}\right) \cdot \Delta t \qquad \forall u, t. \tag{4.18}$$

Thereby $i_{u't}$ describes natural inflow into the storage, which is only relevant for hydroreservoirs, whereas $y_{u't}^{ch}$ describes electricity used for filling the reservoir (e.g. through pumping in case of pumped hydrostorage). Note that for convenience, the filling level of the storage is directly expressed in energy units (e.g. MWh), whereas inflows and outflows $i_{u't}, y_{u't}^{ch}$ and $y_{t,u'}$ are described as power flows (with MW as unit or similar). Correspondingly the latter have to be multiplied by the length of the time segment Δt. Additionally, the charging power $y_{u't}^{ch}$ is multiplied by the round-trip or cycle efficiency $\eta_{u'}^{cyc}$, which considers losses both in the charging and in the discharging processes (e.g. pumps and turbines).

7. The storage filling level is not only non-negative like the other variables but also limited by the storage volume $V_{u'}$

$$L_{u't} \leq V_{u'} \qquad \forall t, u'. \tag{4.19}$$

8. For thermal power plants, starts and shutdowns put thermal stress on plant components. Therefore, their operation is usually further restricted by a minimum operation time T_u^{opmin} and a minimum shutdown time T_u^{sdmin}. There are

[25] Note that w_{ut} may also be viewed as a “momentaneous” **capacity factor** for unit u at time t.

several ways of implementing these restrictions; a rather compact one is[26]:

$$\sum_{\tau=t-T_u^{\text{opmin}}+1}^{t} s_{u\tau} \leq o_{ut} \qquad \forall u, t$$

$$\sum_{\tau=t-T_u^{\text{sdmin}}+1}^{t} s_{u\tau} \leq 1 - o_{u,t-T_u^{\text{sdmin}}} \qquad \forall u, t. \tag{4.20}$$

Further restrictions may complement these constraints to include, e.g. limited ramping for units during operation or specific constraints for CHP units. But the problem structure always remains similar: it is an optimisation problem with a linear objective function and linear constraints[27]; yet some of the variables only take discrete values, in occasion the unit commitment variables are binary variables.

Hence the problem at hand leads to a so-called mixed-integer programme, a programming class widely discussed and analysed in operations research over the last decades. These problems may be formulated in compact matrix notation as:

$$\min_{x} \quad \mathbf{c}^{\mathbf{T}} \cdot \mathbf{x}$$

$$s.t. \quad \mathbf{A} \cdot \mathbf{x} \geq \mathbf{b} \tag{4.21}$$

The vector of variables $\mathbf{x}$ thereby includes the generation quantities y_{ut} the operation and startup variables o_{ut} and s_{ut} and the storage filling level L_{ut} and charging y_{ut}^{ch}. The cost-vector $\mathbf{c}$ includes multiple instances of the coefficients c_u^{var} and c_u^i for the different time steps. Each line of the matrix $\mathbf{A}$ and the vector $\mathbf{b}$ corresponds to the coefficients of one particular restriction.

For the solution of pure linear programmes (LPs) without binary variables, computationally efficient standard methods are available, the best-known of which is the so-called simplex algorithm. By contrast, mixed-integer linear programmes (MILPs) require more advanced techniques, e.g. the so-called branch and bound algorithm, frequently complemented by heuristic strategies. The computation time rises rapidly with the number of integer variables considered. The MILP problems are even known to be NP-hard, i.e. that no algorithm guarantees in general that the solution time only increases polynomially (and not exponentially) with the number of binary variables. Nevertheless, day-ahead unit commitment and dispatch problems with dozens of units may nowadays be solved numerically within minutes.

[26] Cf. Rajan and Takriti (2005).

[27] Nonlinearities may be approximated through piecewise linear functions.

4.4.2 From Day-to-Day Planning to Portfolio Management

The scheduling problem described in the previous section has been and is at the heart of utility operations with regional monopolies (see Table 4.9, framed box). Notably in these cases, each electrical utility has an assigned service area, with an exogenously given "load" (demand). The scheduling of power plants then clearly aims to meet load with as low costs as possible.

Since the deregulation of the electricity industry (see Chap. 6), electrical utilities compete for customers. They, therefore, do not have a fixed load, but rather the demand they have to meet is a result of trading and sales activities. Hence the previously discussed day-ahead scheduling problem is particularly relevant after (day-ahead) spot market results have been published; i.e. prices as well as purchase and sales quantities are known (see last two lines of Table 4.9).

Before closure of spot trading, some planning activities are still necessary, even in deregulated markets, e.g. linked to the procurement of fuels or the scheduling of maintenance and hydroreservoirs. But then, the operation of the power plants is not to be considered as driven by a predetermined, fixed electrical load but rather by

Table 4.9 Scheduling problems at various time horizons and in different market types

Planning horizon	**Year ahead**	**Week ahead** month ahead	**Day ahead** **before spot market auction**	**Day ahead** **after spot market auction**	**Intraday** during intraday trading	**Real time** after intraday trading
Key decisions	Maintenance scheduling; Hydro reservoir planning; Fuel procurement	Unit commitment baseload units; Hydro reservoir planning	Bid submission to day-ahead-spot market	Unit commitment; Dispatch	Change in dispatch	System balancing
Integrated utility with regional monopoly						
Objective function	Min cost	Min cost		Min cost		Min cost
Load	Fixed	Fixed		Fixed		Fixed
Generation company in deregulated markets						
Objective function	Max op. profit	Max op. profit	Max op. profit	Min cost	Max op. profit	
Load	Variable	Variable	Variable	Fix	Fixed but adjustable	

(anticipated) market prices. The power plants will operate as long as they can earn money, or more precisely: as long as their operating margin is positive.

The previously defined scheduling model may be modified to account for the setting of a liberalised electricity market. The main change is thereby in the objective function, which now reflects the **maximisation of operation profits** (EBITDA), i.e. the difference of market-based revenues and the previously considered operational costs:

$$\max_{y_{t,u}, s_{t,u}, o_{t,u}, l_{t,u} y^{ch}_{t,u}} R - C_{op}$$

$$R = \sum_{t=1}^{T} \sum\nolimits_{u} p_{t,u} \cdot y_{t,u} \cdot \Delta t. \tag{4.22}$$

Pushing one step further, one may consider the price uncertainties on the procurement and sales markets and include different available products and contracts on the procurement and sales markets. Then methods of financial portfolio management may be applied to electricity generation and storage portfolios, albeit some characteristic differences have to be considered. Also, as a prerequisite, future prices have to be available with sufficient granularity. This generally requires building hourly price forward curves – a topic discussed in Sect. 11.2.

Overall, power plant scheduling is not limited to the day-ahead planning horizon. Rather, a broad range of scheduling problems arise in both types of markets (see Table 4.9) that are briefly explained subsequently, starting in the order of the table:

Long-term scheduling (year ahead): this is notably required for maintenance planning of thermal power plants, especially baseload power plants. Also, water management for seasonal (large) reservoir hydropower plants and the management of so-called take-or-pay contracts for fuels (especially natural gas) with a minimum annual purchase quantity require considering long planning horizons due to long-term quantity constraints.

Medium-term scheduling (week and month ahead): this is primarily done to manage (pumped-) storage hydropower plants. Also, unit commitment decisions for coal-fired power plants may be taken more on a week-ahead than day-ahead basis.

Short-term scheduling (day-ahead): this encompasses the unit commitment and dispatch planning for the following day after the publication of the day-ahead spot market results (generally after 12 p.m.). This is still the most important scheduling process in the current competitive market.

Very short-term scheduling (intraday): here, replanning of (unit commitment and) dispatch is done with a time horizon of less than one day. Portfolio managers reschedule especially to cope with unexpected events like power plant outages or renewables forecast errors or participate in intraday trading.

System balancing (real-time): this encompasses the real-time compensation of load and infeed variations and power plant outages. In deregulated electricity markets, this task is the responsibility of the grid operator. He thereby dispatches reserve power, which has been contracted from power plant operators beforehand.

The planning problems increase in size, computation time and uncertainty with longer planning horizons. Long-term planning is generally done with a lower degree of details in modelling to avoid intractable or computationally burdensome problem formulations, e.g. regarding approximation of nonlinearities or the modelling of small units.

4.5 Further Reading

Kaltschmitt, M., Streicher, W., & Wiese, A. (Eds.) (2007). Renewable Energy – Technology, Economics and Environment. Berlin, Heidelberg: Springer.

The book Renewable Energy presents the physical and technical principles of promising ways of utilising renewable energies. The book gives a detailed overview of the different renewable energy technologies for electricity production and heat provision.

Nag, P. K. (2014). Power Plant Engineering. 4th edition. New Dehli: McGraw Hill Education (India).
Hegde, R. K. (2015). Power Plant Engineering. Pearson India.

Both books provide an overview of power generation technologies and conceptual knowledge about power plants engineering.

Wood, A., Wollenberg, B., & Sheblé, G. (2013). Power Generation, Operation, and Control. 3rd edition. Hoboken, New Jersey: Wiley.

This book gives – among other things – a comprehensive introduction into the economic dispatch and unit commitment problems.

Strauss, K. (2016). Kraftwerkstechnik – zur Nutzung fossiler, nuklearer und regenerativer Energiequellen. 7th edition. Berlin, Heidelberg: Springer.

The book of Strauss provides an overview of power generation technologies and indicates future development opportunities. It gives an overview of available energy sources (fossil, regenerative, nuclear), the principles of converting the respective primary energy into electricity, environmental pollution resulting from the energy conversion, and statements about efficiency, system availability and costs.

4.6 Self-check of Knowledge and Exercises

Self-check of Knowledge

(1) Explain the steam cycle of a steam turbine and illustrate the cycle process in a p–V-diagram.
(2) Explain the Joule cycle of a gas turbine and illustrate the Joule cycle in a p–V diagram.
(3) Describe a gas combined cycle and give examples of technologies used for combined heat and power plants.
(4) Explain the mass defect and what it has do to with nuclear energy.
(5) Differentiate different types of hydropower and describe different turbine types as well as their general field of application concerning head height and water flow.
(6) Formulate the basic physical principle to calculate the power of wind and explain the typical power curve of a wind power plant.
(7) Compare solar thermal power plants and photovoltaic by showing the basic principle and their key characteristics.
(8) State a minimum of three different types of inputs in biomass plants, name the three principles types of conversion and arrange which input can be used in which conversion.
(9) Characterise a minimum of three technologies with their key techno-economic characteristics.
(10) Sketch an illustrative merit-order curve of the power plant portfolio in your country of residence.
(11) Illustrate the water value of a reservoir power plant with the help of a schematic illustration of the dispatch of a hydropower plant.
(12) Formulate the general mathematical model of short-term power plant scheduling.

Exercise 4.1: Hydropower Plant

You are the operator of a hydropower plant at the Ruhr built in 1957 and not modernised since. The river Ruhr has a barrage at the power plant with a height difference of 6.5 m between the upper and lower water. The Ruhr flows through the barrage in autumn with a constant flow of 1.7 million m^3 per day. However, 5% of the water flow has to be used for a fish ladder and is therefore not available for power generation by the turbine. In addition, the turbines can be switched off, whereby the water around the turbines is channelled through side channels so that the level in the upper water basin always remains constant.

Furthermore, the following assumptions are given:

- Electrical efficiency of the power plant: 87%.
- Density of water: 1000 kg/m^3.

- Gravitational acceleration (gravitational constant): 9.81 m/s^2.

(a) Which type of turbine would you choose? What are the advantages of this selection?
(b) What is the maximum electrical output that the power plant can provide under these conditions?

Exercise 4.2: Wind Power Plant
Calculate the theoretical annual energy yield (in kWh) of the following wind turbines with standard air density at 25 °C and a yearly availability of 95%:

You have the following information to complete the task:

$$P_{\mathrm{WEA}} = \frac{1}{2}\rho \cdot A \cdot v^3 \cdot c_p$$

ρ air density (1184 kg/m^3 at 25 °C).
A rotor area [m^2].
v wind speed [m/s].
c_p performance coefficient (system parameter).

(a) **At coastal area**: (constant) wind speed v = 8 m/s; (Performance coefficient of wind power plant at 8 m/s = 0.5)

Rotor diameter wind energy plant 1 = 71 m

Rotor diameter wind energy plant 2 = 90 m

(b) **inland**: (constant) wind speed v = 4 m/s, (Performance coefficient at 8 m/s of wind power plant = 0.4)

Rotor diameter wind energy plant 1 = 71 m
Rotor diameter wind energy plant 2 = 90 m

Calculate the full-load hours of the wind turbines mentioned (taking the produced energy at a constant wind speed), if all wind turbines are each equipped with a generator with a nominal electrical output of 2000 kW.

Exercise 4.3: Levelized Cost of Electricity

(a) Calculate the levelized costs of electricity of the following four technologies with the respective data given in the table.

The following data are given: i = 6%, CO_2 price of 15 €/t.

(b) What is the impact of an emission prices increase to 100 €/t on the LCOE?

Key indicator	Investment cost c^{inv}	O&M cost $c^{O\&M}$	Fuel cost p^{fuel}	Technical lifetime T^{life}	Full-load hours
Unit	[€/kW$_{el}$]	[€ / MWh$_{el}$]	[€ / MWh$_{th}$]	[a]	[€/MWh]
Natural gas—CCGT	810	5	15–45	35	5000
Coal	1800	7	5–12	50	7000
Solar PV—residential	1200	24	0	25	1300
Onshore wind	1500	19	0	25	2500

Exercise 4.4: Scheduling of Power Plants
You are responsible for the power plant scheduling of a utility. You have to prepare the power plant schedule for the next day based on forecasts for load and for wind generation as depicted in the following table:

Hours	Load (MWh$_{el}$/h)	Generation wind (MWh$_{el}$/h)	EEX prices (€/MWh$_{el}$)
1–8	1200	0	40
9–16	2300	250	35
17–24	1700	400	20

You are responsible for the scheduling of the three power plants in the portfolio with the following technical and economic data:

Power plants	Variable costs (€/MWh$_{el}$)	Maximum capacity (MW)	Minimum stable operation limit (i.e. minimum output in operation) (MW)
CCGT	38	180	80
Hard coal	30	750	150
Nuclear power	5	1200	320

(a) **Determine the cost minimising schedule of the portfolio**: Use the classical merit-order approach to determine the unit commitment and dispatch for the given time steps and indicate the generation output of each technology for each time step. Determine the total costs of generation.

(b) **Determine a profit maximising schedule of the portfolio**: Your boss asks you to analyse the possibility to sell and buy electricity at the EEX spot market. Expected prices are given in the above (first) table. Determine the optimal operation (i.e. the generation in each time step). Also, indicate in which hours you buy/sell which amount of electricity at the EEX spot market. Finally, compute the savings that can be achieved in comparison with a). What are the main differences between the two solutions and explain where they come from?

(c) **Determine the cost minimising schedule of the portfolio taking minimum stable operation limits into account**: You recognise that your solution in a) is insufficient since minimum operation limits of the power plants (see second table above) have not been considered so far.

   i. Determine first the time steps in which the solution violates the minimum stable operation limits.
   ii. Compute for these time steps the optimal unit commitment and dispatch with minimum operation limit. (*Hint: Compute* ***all*** *meaningful solutions and determine the optimal solution by comparing the respective changes in the objective function value.)*

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