

What is covered in this chapter?

Chapter 2 pointed out the fact that energy use is responsible for about two-thirds of greenhouse gas emissions, which is a good reason to explore in depth in this chapter what drives energy use, how it is supplied, why countries value energy security, where its main uses are, and what greenhouse gas emissions it produces. The chapter then focuses on electricity production. Improving the efficiency of power plants, shifting from coal to gas, nuclear power, renewable energy, and capture and storage of CO₂ from power plants can all help to reduce greenhouse gas emissions. The status of these technologies and their costs are discussed, as well as the competition between these technologies when reducing overall emissions from electricity supply. Economic, security, health, environment, and other considerations in choosing an optimal fuel mix for electricity generation are explored. Technology and economics present a fairly optimistic prospect for drastic emissions reductions. Implementing these opportunities however is hard. Selecting the right policies to provide incentives for implementation by business and individuals is crucial. On-the-ground experience is growing and lessons for effective policy choices can be drawn.

Energy and development

As outlined in Chapter 4, energy is an essential input for development. Historically there has been a very strong relation between income and energy use. Figure 2.10 shows that relationship for a number of countries for the period 1980–2004. Most countries show a steady increase in energy use per person when income per person goes up. Russia is an exception because of the economic recession after the collapse of the Soviet system. Canada and the USA show almost no increase in energy use per person over the period considered, despite an increase in incomes, because a kind of saturation has occurred. What is striking is the large difference in energy use per person between countries, for similar income levels. Some European countries and Japan use almost half the energy per person of that of the US and Canada. Differences in lifestyle, the structure of the economy

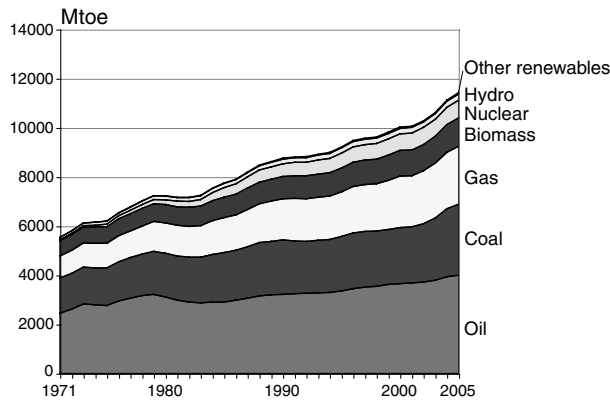


Figure 5.1 World primary energy supply, 1971–2005; for an explanation of ‘primary energy supply’ see Box 5.1. Source: IPCC Fourth Assessment Report, Working Group III, figure TS.13.

(the role of energy intensive industries in the economy), and efficiency of energy use are the major reasons behind this.

Rapidly developing countries like China and India are still at an early stage of income growth. It is of great importance to the world’s energy requirements how these countries develop. Will it be the American or the European/Japanese way? Or will they chart new territory by using less energy than other countries when going through a development transition?

It should be no surprise that overall energy demand has roughly doubled over the past 35 years and – since demand has to equal supply – so has energy supply. In 2005 fossil fuels (coal, oil, and gas) represented 80% of the total. Biomass, mostly traditional fuels like wood, agricultural waste, and cow dung, accounted for 10%. Nuclear energy was good for 6%, hydropower about 2%, and ‘new’ renewable energy (wind, solar, geothermal, modern biomass) less than 1% (see Figure 5.1).

Box 5.1

Units for energy

Amounts of energy are usually expressed in joule (J). Larger quantities can be expressed in kilojoule (kJ = 10^3 J), megajoule (MJ = 10^6 J), gigajoule (GJ = 10^9 J) or exajoule (EJ = 10^{12} J). Another unit for energy that is often used is Million tonnes oil equivalent (1Mtoe = 0.042EJ).

Capacity of power plants is expressed as the amount of energy that can be produced per second, or joule per second (J/s). 1J/s equals 1watt (W). Power plant capacities are therefore normally expressed in megawatt (1MW = 10^6 W) or gigawatt (1GW = 10^9 W).

Electricity produced is normally expressed in kilowatt hour (1kWh = 3.6MJ). Larger quantities as gigawatt hour (GWh = million kWh) or terawatt hour (1TWh = 10^9 kWh).

To convert power plant capacity into electricity produced you need to factor in the so-called capacity factor (the proportion of the time the plant is operational). For fossil fuel and nuclear power plants the capacity factor is usually something like 80–90%. For wind turbines and solar plants it is much lower.

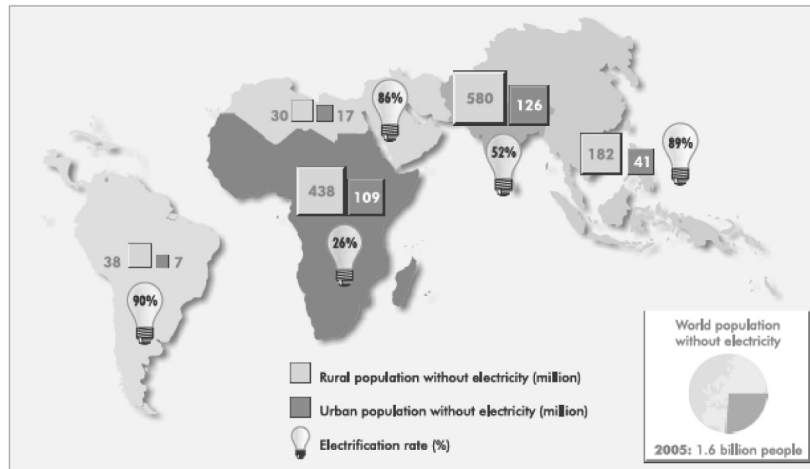


Figure 5.2

Population without access to electricity in 2005.

Source: IEA World Energy Outlook 2006.

Future energy demand

Access to modern energy, in particular electricity, is still a big issue for many developing countries¹. Currently about 1.6 billion people in developing countries have no access to electricity and about 2.4 billion rely on traditional fuels (wood, agricultural waste, cow dung) for their cooking and heating needs. Most of these people are located in Africa and South Asia. China on the contrary has reached a 99% access rate (Figure 5.2). Giving all the people in the world access will require a strong growth in modern energy supply, which would no doubt increase CO₂ emissions. If all households that still rely on traditional biomass fuels were provided with LPG for cooking, global greenhouse gas emissions could increase by 2%. However the reduced deforestation as a result of that could then be subtracted. An LPG programme in Senegal that led to a 33-fold increase in LPG use resulted for instance in a 15% lower charcoal consumption (see also chapter 4).

On top of that, the need for improvement of the well-being of people in developing countries, the expected economic growth in industrialized countries, and the expected population growth will likely lead to a 50% increase in world energy demand by 2030².

How will that energy be supplied in the absence of policies to curb climate change? Basically the dominance of fossil fuel will continue. All projections for the period until 2030 show a substantial increase of hydropower and other renewable energy sources, but they remain a small fraction of the total. Fossil fuel use remains at about 80%. Opinions about the role of nuclear power vary widely. Given the risks of nuclear power (reactor accidents, radioactive waste, and nuclear weapon proliferation) you find both optimistic and pessimistic projections for the role of nuclear power. Figure 5.3 shows some recent estimates for the energy supply situation in 2030. What stands out is the large differences in total energy demand and the contribution of various energy sources between the individual

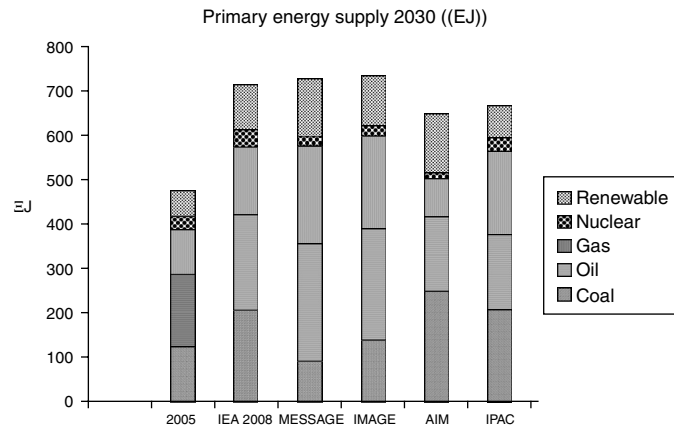


Figure 5.3 Energy supply projections for 2030 without climate policy (baseline). Results from different models.

Source: IPCC Fourth Assessment Report, Working Group III, chapter 3; IEA WEO 2008.

estimates. This is typical for projections over a 25 year period. It is more likely the energy demand will be on the high end of the range in light of the very strong growth in China and India over the past few years. As far as the projection for coal use is concerned, the IEA estimate is probably more in line with recent increases in coal use in China, India, and other parts of the world. This will make drastic reductions in CO₂ more difficult to achieve.

But fossil fuels are scarce, aren't they?

Contrary to the widespread belief that fossil fuels are scarce, there are in fact such big fossil fuel resources that there are no constraints to huge increases in the use of fossil fuels. To understand that it is important to make a distinction between 'reserves' and 'resources'. The fossil fuel industry defines 'reserves' as the quantities of oil, gas, or coal that have been proven to be available and economically attractive to extract. It is well known that other and larger quantities exist that are not economically attractive to exploit ('resources'). In other words, if the price of oil increases, the reserves of crude oil go up. Parts of the resources then become reserves.

There is another important distinction: between 'conventional' and 'unconventional' resources. For oil the unconventional resources are for example the so-called 'tar sands' and 'oil shales', basically oil containing soil or rock, from which oil can be released by heating it and extracting it from the raw material. This is a costly and energy intensive process, but at oil prices above US\$60 per barrel it is economically attractive in many places and therefore adds to the oil reserves, if oil prices stay above US\$60 per barrel. Another example is so-called 'natural gas hydrates' or 'clathrates', a kind of 'frozen' gas/water mixture that can be found in deep oceans. These hydrates are currently not economically attractive to use, but the quantities are so big (20 times all conventional gas

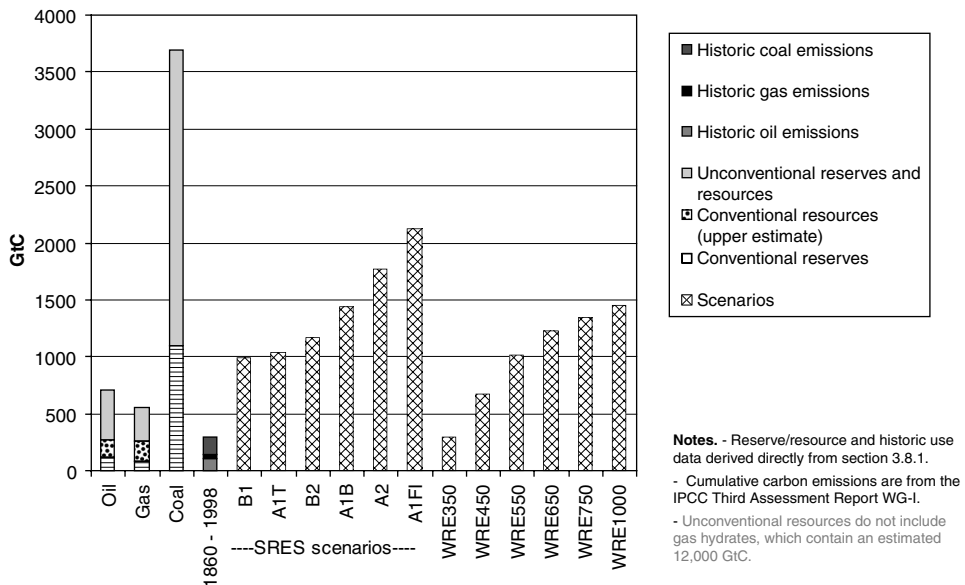


Figure 5.4 Fossil fuel reserves and resources, compared with fossil fuel use in various scenarios for future energy use and carbon released in the atmosphere for various atmospheric CO₂ concentration stabilization scenarios.

Source: IPCC, Third Assessment report, figure SPM.2.

resources) that they may well be exploited in the future. Conventional and unconventional fossil fuel resources together add up to enormous amounts.

Taking only the proven conventional reserves and resources, today's oil, gas, and coal use can be continued for about 60, 130, and 800 years, respectively³. Add to that the unconventional and 'yet-to-find' resources (note that nobody is really looking for coal these days), current use could be maintained for more than a thousand years. Or, to use a different perspective, the total amount of fossil fuel that would be needed during the 21st century if we assume strong economic growth and heavy fossil fuel use, is only a fraction of the fossil fuel resources. Figure 5.4 (left and middle part) shows how these quantities compare.

You might argue that the situation for oil is different. It is and it isn't. Oil resources are more limited and geopolitical tensions can easily lead to scarcity and price increases. There are also questions on how fast oil can be produced, even if there were large amounts available. This is the so-called 'peak-oil' issue. There are claims that geological formations would not allow production rates to be increased and that productions rates would start to fall in many oil producing regions. It is more likely however that the real reason for limits to production rates may be the national oil companies in the Middle East, China, Brazil, and elsewhere, the importance of which has grown enormously over the past 10 years. These national oil companies are behaving very differently from international oil companies, such as Shell, BP, Exxon, etc⁴. In any case, the technologies exist and are commercially viable to turn gas and coal into liquid transport fuels. This technology was used extensively in South

Africa when it was hit by an oil boycott during the apartheid regime. Today there are several such plants operating in the Middle East and China. Oil therefore is not the limiting factor for increased fossil fuel use.

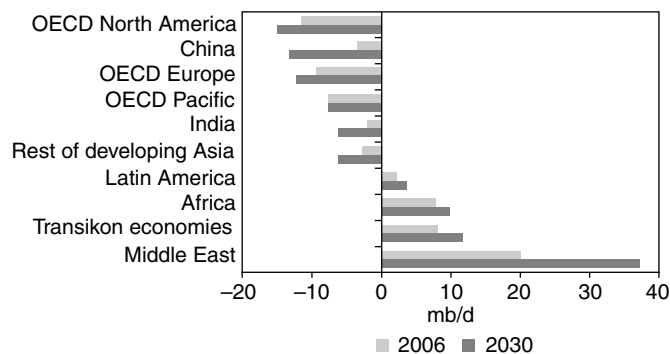
Figure 5.4 shows on the right hand side of the diagram how much carbon would be released into the atmosphere for various scenarios of stabilizing CO₂ concentrations in the atmosphere. Keeping CO₂ concentrations in the atmosphere below a level of 1000ppm (which is way above what most people would consider acceptable) would limit fossil fuel use even more than the high growth scenario described above. In other words, as the Stone Age did not end due to a lack of stone, so will the fossil fuel age end long before fossil fuels are exhausted.

Energy security

Since energy plays such a crucial role in development of countries, it matters politically how secure the supply of energy is. Is the country self-sufficient in energy or does it need to import? And if it imports, are the foreign suppliers reliable or is there a risk of political instability? Are the imports spread over many different suppliers or are there only a few? All those factors contribute to what is called energy security.

Oil, the fuel on which the world's transport runs, is well known to be a heavily traded energy source. There is a limited number of suppliers, particularly the Middle East, Russia, and some Latin American and African countries, who export large quantities. The main importers are North America, Europe, Japan, but also China and India and other developing countries (see Figure 5.5). This means there is a strong dependence on oil imports for many countries and this dependence tends to increase over time.

Energy security of course is not limited to oil. It equally applies to coal and gas. Coal resources are more widespread than oil. Some of the biggest energy using countries



Trade between WEO regions only: Negative figures indicate net imports.

Figure 5.5

Net oil trade (in million barrels/day (mb/d)) between regions for 2006 and projections for 2030. Transition economies are countries of Eastern Europe and the former Soviet Union.

Source: IEA, WEO, 2007.

Table 5.1. Proven coal reserves by country

Country	Per cent of world coal reserves
USA	27
Russia	17
China	13
India	10
Australia	9
South Africa	5
Ukraine	4
EU	4
Kazakhstan	3
Rest of world	8

Source: IEA WEO, 2006.

(USA, China, India, Russia, and Australia) have abundant coal reserves (see Table 5.1). Relying on a big domestic energy source is of course very good from an energy security point of view. The share of coal in the energy for electricity production in China and India for example is 89% and 82%, respectively. But many countries also import coal. The world average share of coal in electricity production is about 45%. By relying on a mixture of energy sources countries improve their energy security.

For natural gas there is a big mismatch between use and production. North America currently imports about 2% of its gas, but that is projected to increase to 16% by 2030. Most of this gas will be imported from Venezuela and the Middle East as LNG (liquefied natural gas). Europe already imports 40% (mostly from Russia and North Africa by pipelines), and this is expected to increase to almost 70% by 2030. For Japan the numbers are even more staggering: 97% is imported now, going up to 98%, most of it as LNG from Indonesia, the Middle East, and Australia. China and India are expected to import about 50% and 60%, respectively, of their gas by 2030⁵.

Where is energy used?

Energy is used in all sectors of the economy. About 45% goes into electricity generation and (to a small extent) centralized heat production for district heating purposes. Close to 20% each goes into transport (as fuel), industry (fuel and raw materials), and residential and commercial buildings (as heating and cooking fuel) and agriculture (see Figure 5.6).

In this chapter the supply of power and heat will be discussed. Energy used in the transportation, building, industry, and agriculture/forestry sectors (both the direct energy as well as the power and heat coming from the energy supply sector) is covered in Chapters 6, 7, 8, and 9.

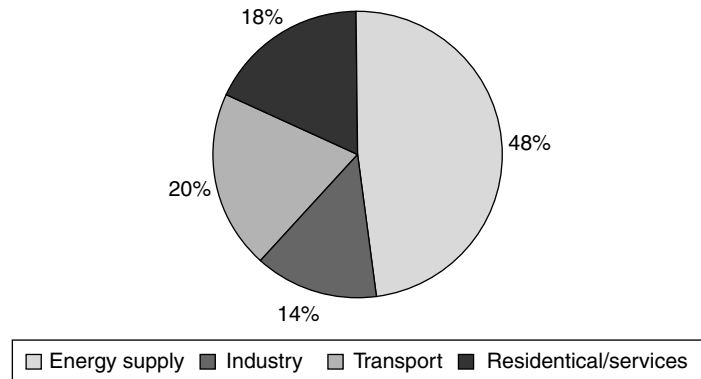


Figure 5.6

Share of energy going into the economic sectors.

Source: based on IEA, WEO 2008.

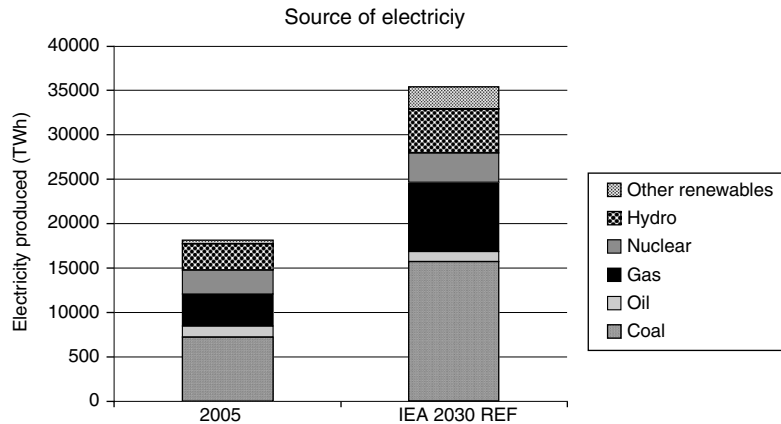


Figure 5.7

Energy sources used for electricity production now and for the 2030 baseline situation. TWh, terawatt-hour.

Source: IEA, WEO, 2007.

Electricity generation

Coal and gas are the dominant energy sources for power generation. Coal alone has a share of 40%. Together with a little bit of oil they cover about two-thirds of the energy sources. Nuclear and hydro both have about a 15% share. By 2030 the role of coal and gas is expected to be even stronger. Figure 5.7 shows the contribution from the various energy sources, based on the share of the electricity produced. It also shows electricity demand is expected to almost double by 2030.

You can also look at the generating capacity installed in the form of power plants, wind turbines, solar power, etc. Because wind and sun are not always available, wind

Table 5.2 Comparison of share in installed capacity and in electricity produced

Energy source	Installed capacity 2006 (GW)	Contribution in 2005 as % of installed electric power capacity	Electricity produced 2006 (TWh)	Contribution in 2005 as % of electricity produced
Coal	1382	32	7756	41
Oil	415	10	1096	6
Gas	1124	26	3807	20
Nuclear	368	8	2793	15
Hydro	919	21	3035	16
Other renewables	135	3	433	2

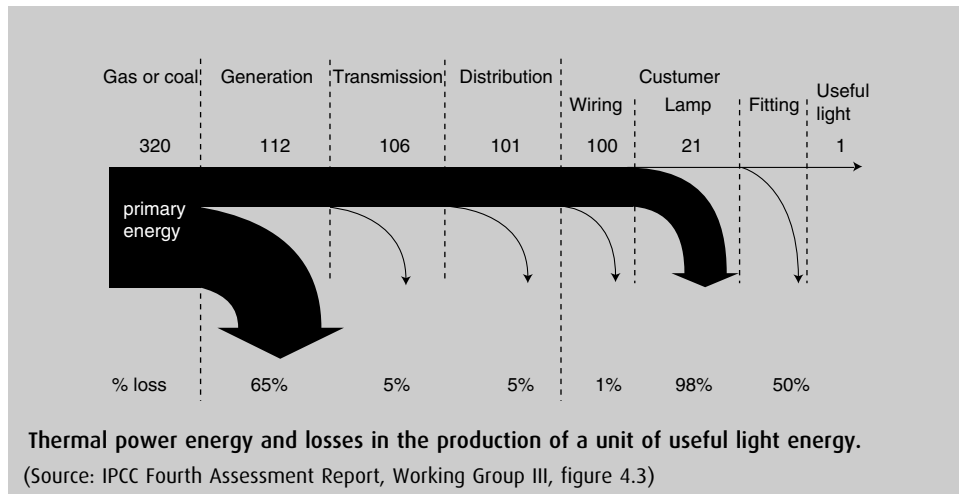
Coal fired and nuclear power plants are typically baseload installations, meaning they are operating almost continuously.
Source: IEA, WEO 2008.

turbines and solar power plants cannot operate continuously, unlike nuclear and fossil fuel plants, so for the same capacity their contribution to actual electricity production is less. Table 5.2 shows the difference in contribution when looking at the installed capacity of the various power sources. For an explanation of the units used see Box 5.1.

It is also useful to make a distinction between ‘primary energy’ (the raw energy sources) and ‘secondary’ or ‘final’ energy (the energy carriers that are actually used), because there is a significant energy loss when converting primary energy sources such as coal or biomass into energy carriers, such as electricity. Box 5.2 gives an explanation.

Box 5.2**Energy supply and energy end-use**

So-called ‘primary’ energy sources (coal, oil, gas, uranium, water (hydro), wind, solar radiation, geothermal energy, ocean energy) are converted to energy carriers (called ‘secondary energy’ or ‘final energy’) such as electricity, heat, or solid, liquid or gaseous fuels. During the conversion process, such as in electricity production, a significant part of the primary energy can be lost. The conversion efficiency (or, in the case of electricity, the efficiency of an electric power plant) is therefore a crucial element of the energy system. When energy carriers are used to deliver certain services (light, transport, heat), another conversion process happens, where energy losses are happening. For instance, the amount of energy obtained from a traditional light bulb in the form of light is only 2% of the electric energy used (and that electricity contained only 35% of the energy that was used to produce it; see figure). The overall efficiency of the energy system is therefore determined both by the supply side efficiency and the so-called end-use efficiency.



Greenhouse gas emissions

Energy supply and use in 2005 was responsible for about 64% of all greenhouse gas emissions. CO₂ alone accounted for about 60%, the rest came primarily from methane. The electricity supply sector is the biggest emitter, followed by industry, transport, and buildings (see Figure 5.8). Note that there is a small amount of emissions of CO₂ from cement manufacture (coming from the raw materials) and industrial nitrous oxide and fluorinated gases that are not energy related (shown separately).

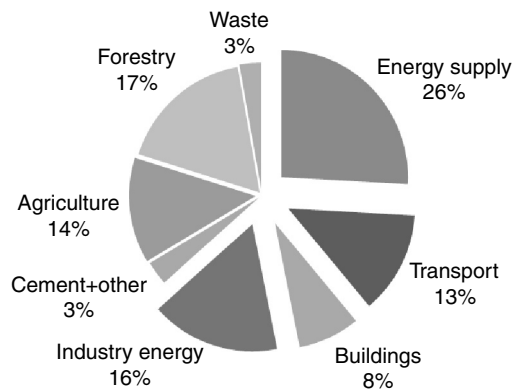


Figure 5.8

Greenhouse gas emissions from energy supply and use in 2004 as percentage of total emission. Only energy related emissions are covered in the energy supply, transport, buildings, and industry shares.

Source: IPCC Fourth Assessment Report, Working Group III, ch 1.

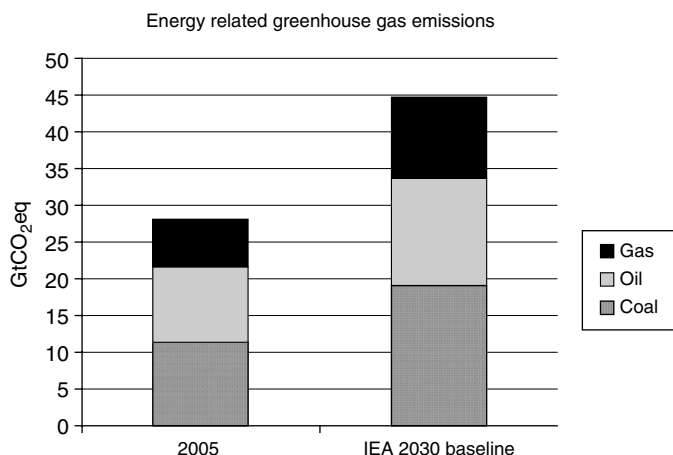


Figure 5.9

Increase in energy related greenhouse gas emissions 2005–2030.

Source: IEA, WEO 2007.

With the 50% increase of overall energy use expected by 2030, greenhouse gas emissions from energy supply and use will also rise strongly. The expected increase in emissions is about 45%, based on the latest International Energy Agency's scenarios⁶ (see Figure 5.9).

The electricity sector and the emissions reduction challenge

Greenhouse gas emissions from electricity generation are dominated by coal. Gas is responsible for about 30% and oil is becoming a negligible factor with something like 4% expected in 2030 (see Figure 5.10). Total emissions from the power supply sector are projected to grow by about 70% until 2030. So the challenge in reducing emissions from the power supply sector lies in finding alternatives to the use of coal and gas. In the next section these alternatives will be explored.

Emission reduction options in the electricity sector

Improving the efficiency of power plants, shifting from coal to gas, nuclear power, various renewable energy sources, and capture and storage of CO₂ from power plants can all help to reduce CO₂ emissions. They will be described briefly in terms of the status of their technology, their costs, and availability.

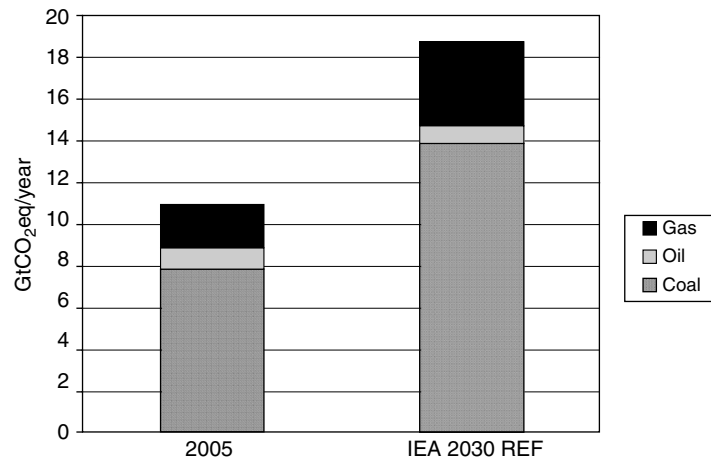


Figure 5.10

Greenhouse gas emissions from electricity generation without climate policy 2005–2030.

Source: IEA WEO 2007.

Often the discussions about the contribution of renewable energy are far too optimistic. Proponents tend to overestimate the speed at which renewables can penetrate the power supply market, costs tend to be too low, and problems in scaling up these technologies tend to be underestimated. This chapter wants to avoid those pitfalls and present a realistic picture.

On the other hand many discussions are too pessimistic about the potential of renewable energy by stressing the low share, the many obstacles to its introduction, and the resistance to promoting renewables. They forget that, even from a low starting point, annual growth rates of more than 10% can lead to enormous growth over a 20 year period. A 2% annual growth rate means a 50% overall increase over a 20 year period. A 20% annual growth rate means a 30-fold (!) increase over such a period. Several renewable energy systems have annual growth rates even beyond that. In addition, when investment in renewable energy systems really catches on, these barriers will be much less likely to play a serious role. This chapter aims to be realistic in this respect too.

Power plant efficiency and fuel switching

Electricity generation in thermal power plants is a wasteful operation. Most power plants operating today lose 50–70% of the energy that is put in (i.e. their efficiency is only 30–50%). Gas fired plants normally have a better efficiency than coal plants. Many coal fired plants operating today run at 30% efficiency. Newly built coal fired plants (so-called supercritical plants) reach an efficiency of about 42%, with some running at close to 50% efficiency. The most advanced coal fired plants, so-called ‘integrated gasification combined cycle plants (IGCCs)’, which first gasify the coal

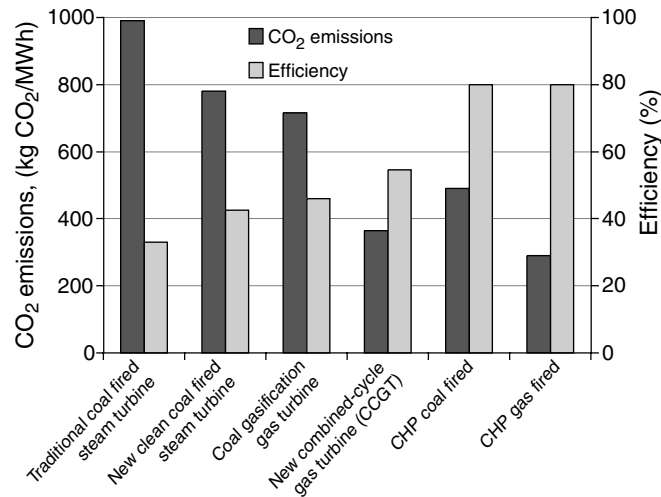


Figure 5.11 Efficiencies of different types of power plants and the CO₂ emissions per unit of electricity produced.

Source: IPCC Fourth Assessment report, Working Group III, figure 4.21.

before burning it, can reach comparable efficiencies, while at the same time allowing better cleaning of exhaust gases to minimize air pollution. Modern gas fired plants, so-called ‘combined cycle gas turbines (CCGTs)’, can reach 55% efficiency. These efficiencies are expected to increase due to further technological development (see Figure 5.11).

Because of the advantages of gas in terms of efficiency, the lower emission of CO₂ per unit of energy (see Box 2.2, Chapter 2), and also the much shorter construction time for gas fired plants, it is attractive to shift from coal to gas for electricity production. Recently, however, gas prices have gone up, mostly as a result of increasing oil prices, making this option less attractive.

A big step forward in terms of efficiency is the so-called Combined Heat and Power (CHP) plant. By using the heat that traditional power plants waste, CHP plants can get 80% useful energy from primary energy input (see Figure 5.11), so wherever heat is needed, CHP plants can make a strong contribution to reducing CO₂. CHP plants are used predominantly in industrial complexes that need a lot of process heat (with electricity partly exported to the grid) or in areas where district heating is used (providing heating to residential and commercial buildings through a network). The CHP principle can also be used at small scale (down to household size) and for a variety of fuels, such as biomass (see section on Bioenergy).

Power plant efficiency improvement happens autonomously when a new fossil fuel plant is built. Any new coal fired power plant basically has the best efficiency available. What is not happening autonomously is shifting to IGCC type plants, shifting to gas, or turning the power plant into a CHP plant. Those choices bring additional costs that will only be incurred if climate policy or other incentives make it attractive. The potential for emission reduction therefore is limited.

Table 5.3. Top 10 countries with nuclear power plants in operation.

Country	Number of nuclear power stations in operation by end 2006	Number of nuclear plants under construction by end 2006	Number of nuclear reactors planned	% of electricity from nuclear power (2006)
USA	103	0		19
France	59	1		78
Japan	55	1	13	30
Russia	31	5	50% increase	16
Korea	20	1	60% increase	39
UK	19	0		18
Germany ^a	17	0		31
India	16	7	16	3
Ukraine	15	2		48
China	10	4	28–40	2
Sweden ^a	10	0		48

Nuclear power plants under construction as well as percentage of electricity produced by nuclear power are shown.

^a Pledged nuclear phase-out.

Source: IAEA. Energy, Electricity and Nuclear Power Estimates for the Period up to 2030, 2007 edition.

Nuclear power

By the end of 2006, 442 nuclear reactors, with a total capacity of 370GW, were producing electricity, accounting for about 16% of world production. They are spread over 31 countries, with 10 countries responsible for 75% ⁷(see Table 5.3). Since the Chernobyl accident in Russia in 1987, no new nuclear plants have been built in North America and Europe and only about 50 plants have been built elsewhere.

The biggest reason for the stagnation of nuclear power is the discussion about its risks: (1) radioactive materials could escape from nuclear reactors or nuclear fuel processing and transport; (2) finding safe storage of radioactive waste with extremely long lifetimes from used nuclear reactor fuel is still problematic; and (3) possibly spreading the production of nuclear weapons by giving more countries access to nuclear technology. High investment costs, liability issues in case of accidents, and long regulatory procedures in light of the risks are an additional factor.

Safety of nuclear reactors has been an issue of concern, particularly after the Chernobyl accident in 1987. Reactor designs have been improved over time and development of safer designs is ongoing (see Box 5.3)⁸.

When uranium fuel from a nuclear reactor needs to be replaced, the material is highly radioactive. The biggest problem is the long-lived highly radioactive material that takes thousands of years to decompose. More than 95% of the total radioactivity of all waste generated from the nuclear fuel cycle (uranium processing, reactor waste, waste processing)

is in this high level waste, but this represents only 5% of the volume. One 1000 MW nuclear plant produces about 10m^3 of high level waste per year. If this waste is reprocessed, i.e. when usable uranium and plutonium and other highly radioactive materials are separated, this goes down to 2.5m^3 . Reprocessing facilities are operating in France, Russia, UK, and Japan, while the USA has so far refrained from building one to reduce the risk of diversion of plutonium for nuclear weapons production.

Deep geological storage of this waste material is generally seen as the safest way to deal with it. The radioactive waste is then embedded in glass and packed in containers to make leakage very difficult. There is widespread consensus amongst experts that this is a safe way to store the waste. However, all of the proposed storage projects are facing serious resistance from the general public or citizen groups. In Finland and the USA deep geological storage sites have been chosen, but controversy still remains, and

Box 5.3**Nuclear power reactors and safety**

Nuclear power reactors produce heat from the fission of uranium atoms as well as from plutonium formed during operation. They use uranium oxide in which the concentration of uranium-235 (the fissionable isotope) is increased from 0.7% to usually 4–5%. The core of the reactor (where the rods of uranium fuel are) is cooled with water or gas. The hot water or gas is then used to generate electricity via steam or gas turbines. About 80% of operating nuclear reactors use water (Boiling Water Reactors or Pressurized Water Reactors); most of the others use gas (helium or carbon dioxide).

Cooling of the reactor core is the most critical issue in terms of reactor safety. If cooling fails, the reactor core can melt and the molten reactor fuel can melt through the reactor vessel and get dispersed outside. Reactor safety is therefore strongly dependent on maintaining cooling at all times. Water based cooling systems have been improved over time by reducing the number of pumps and pipes (lowering the risk of leakage), adding several additional emergency cooling systems, and using gravity and natural circulation rather than electricity to operate the cooling system. The other safety element that has been strengthened in reactor design is the containment: modern reactors have double or triple containments, protecting against attacks from outside, and able to keep even a melted reactor core inside the building. These modern designs have considerably reduced the chances of releasing radioactive materials, but have not reduced that risk to zero.

Advanced high temperature gas cooled reactor designs use special fuel ‘balls’ that can resist very high temperatures (so-called ‘pebble bed’ reactors). No melting of reactor fuel would occur in these reactors, even when cooling completely fails. These reactors are under development in South Africa and China. A disadvantage of this design is that the capacity is 5 times as small as that of water cooled reactors, requiring multiple units that increase costs.

Most modern reactor types are able to use recycled uranium and plutonium (from used fuel rods) in so-called mixed-oxide (MOX) fuel. This reduces the need for new uranium, but of course requires the processing of the used fuel in special processing plants and therefore increases the risk of plutonium being diverted to nuclear weapons production. The gas cooled

'pebble bed' reactor fuel cannot be reprocessed, which would be an advantage from a proliferation point of view.

Special so-called 'breeder' reactors are designed to produce more nuclear fuel (in the form of plutonium) than is put in, thereby reducing the need for uranium imports. Such reactors are not yet commercially operating but the subject of active development in several countries, including China and India. India is putting a lot of effort in developing thorium based breeder reactors, because it has only small uranium reserves. The advantage of thorium is that it does not produce plutonium, which would reduce proliferation risks.

(Source: IPCC Fourth Assessment report, Working Group III, ch 4.3.2; Richter B. Nuclear Power: A Status Report, Stanford University Programme on Energy and Sustainable Development, Working Paper #58, September 2006)

detailed design studies are continuing. Actual operation is not expected to start before 2020. In Sweden, Germany, and France procedures for choosing sites are ongoing.

Nuclear weapons grade uranium can be obtained from extreme enrichment of uranium (much more than needed for a nuclear power reactor) and nuclear weapons grade plutonium from processing spent reactor fuel. Acquiring these technologies allows countries in principle to develop nuclear weapons⁹. In addition to the USA, UK, France, Russia and China, India, Pakistan and Israel now also possess nuclear weapons. The Treaty on Non-proliferation of Nuclear Weapons tries to limit that risk by a series of information and inspection obligations, overseen by the International Atomic Energy Agency (IAEA). Not all countries are a member of this treaty however. India, Pakistan, Israel, and North Korea have so far refused to sign. There have been several instances (Iraq, North Korea, Iran) where suspicions arose about possible intentions of countries to develop a nuclear weapon.

Uranium, the energy source for nuclear power reactors, is produced from uranium ore that is mined in a limited number of countries. Canada, Australia, Kazakhstan, and Russia account for almost 70%; Niger, Namibia, Uzbekistan, and the USA for another 25%. Reserves (identified amounts and those economical to produce) are good for 85 years at current consumption. Including all conventional resources brings this figure up to several hundreds of years¹⁰. When plutonium recycling from so-called 'breeder reactors' (see above) is included, resources would last several thousands of years. These kinds of reactors and the necessary fuel processing would however bring additional risks.

With climate change becoming an important political issue, nuclear power is seeing something of a revival in the USA and Europe. In the USA new legislation was passed in 2005 that simplifies licensing procedures, extends the limitation of liability of companies in case of accidents, and provides a subsidy (in the form of a tax deduction) of almost 2USc/kWh. In Finland and France a decision was made to build a new nuclear power plant.

So what are the prospects of nuclear power as a greenhouse gas emission reduction option? Projections for nuclear power in the future are very uncertain. On the one hand countries like Japan, China, Korea, and India are planning significant expansions of

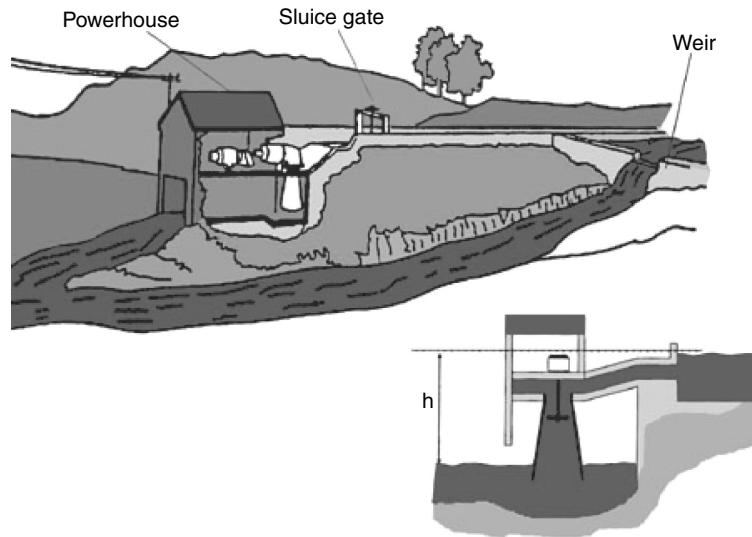
nuclear power. In many other countries plans for additional nuclear plants have been shelved and some countries have pledged a nuclear phase out. The International Atomic Energy Agency estimates for nuclear power capacity in 2030 therefore show a great uncertainty: between 280 and 740GW. The IEA projects 415MW nuclear capacity by 2030 without additional policy, but 30% more if climate policy is assumed¹¹. In terms of greenhouse gas emissions nuclear power is attractive, although it does not have zero emissions. Because of the energy needed for uranium mining, waste processing, and eventual decommissioning of nuclear reactors, emissions are estimated at about 40g CO₂/kWh of electricity produced. There are however some estimates that give much higher total emissions of 80–120g CO₂/kWh due to uranium ore processing, construction, and decommissioning (see also Table 5.5 below for a comparison with other supply options). The cost of nuclear power from existing plants is between 1 and 12ct/kWh, reflecting the different local circumstances. The low end of this range makes nuclear power competitive with coal. By 2030 the cost of electricity from newly built plants is estimated to be between 2.5 and 7USc/kWh.

The role that nuclear power will play in a world with limitations on CO₂ emissions will depend on two main issues. The first is how the risks of nuclear power are going to be perceived. A meaningful contribution of nuclear power to reduction of CO₂ emissions would require a substantial expansion of countries with access to nuclear technology. In a world where international terrorism is likely to remain a fact of life, it could be a matter of time before nuclear weapons are made by terrorist groups from diverted plutonium. While the safety and waste disposal risks may be technically manageable, this risk may not be. The second important factor is the costs and availability of other low carbon alternatives with which nuclear power would compete in a carbon constrained world. This issue will be revisited after other alternatives have been discussed (see below).

Hydropower

Hydropower is already supplying 16% of all electricity and more than 90% of all renewable energy^{12,13}. Most of this is coming from large scale hydropower stations with a capacity of more than 10MW to more than 10GW. The biggest hydropower project, the Three Gorges Dam in China, will have a capacity of more than 22GW when it is finally fully operational (that is 15% of the whole electric power capacity of India in 2005). Large scale hydro projects have become controversial because of the displacement of large numbers of people. A small percentage (0.1–9%, data are very uncertain) comes from mini (<10MW) and micro (<1MW) hydropower systems, mostly without reservoirs, but using river flows. These systems generally operate in rural areas (see Figures 5.12 and 5.13). The global installed hydropower capacity is about 850GW.

Hydropower installations normally have a capacity factor (the percentage of the time they are operational) of 80% or more, so they are usually operated to provide so-called base load power. Some hydropower installations however are operated for peak supply in

**Figure 5.12****Schematic diagram of micro hydropower installation.**

Source: Fraenkel P et al. Micro-hydro power: a guide for development workers, Practical Action, London, 1991.

**Figure 5.13****Picture of a floating turbine.**

Source: <http://www.hydro-turbines.com/id72.html>.

combination with pumped storage, meaning that at times of low demand water is being pumped up to a reservoir and at times of peak demand this water is flowing down again to generate electricity.

Hydropower is attractive as a low carbon energy source, although methane emissions from reservoirs due to rotting vegetation can be significant in some places. A study of Brazilian hydro reservoirs showed that some deep reservoirs emitted about as much per kWh

electricity as a modern gas fired power plant (i.e. about 400g CO₂-eq/kWh). On average hydropower emissions are estimated at 10–80g CO₂-eq/kWh of electricity produced.

The cost of hydropower is currently 2–10USc/kWh and is estimated to be 3–7USc/kWh by 2030. The increase of the low end of the cost range indicates that the best hydro power sites already have been occupied.

Technically and economically there is room for more than a threefold increase of hydro power capacity. Climate policy will provide strong incentives. The future contribution of hydropower will however depend on managing the social problems created by large new reservoirs. For small scale hydro these problems don't exist. This could add 50% to the current capacity (more than 400GW), which would create excellent opportunities for providing electricity to rural areas, where many people still lack access. Without climate policy a 40–60% increase of hydropower is expected by 2030. Ambitious climate policy scenarios assume this can go up to more than 100%, although the relative costs of other renewables may become so attractive that this figure could be much lower.

Wind

Wind power capacity increased from 2.3GW in 1991 to about 94GW at the end of 2007^{14,15}. Capacity has grown by about 25–30% per year since 2000. However, it only produced 0.5% of global electricity. More than 50 countries are using wind power as part of the commercial electricity supply. The biggest capacity can be found in Germany (22GW), USA (17GW), Spain (15GW), India (8GW), China (6GW), and Denmark (3GW). Italy, France, and the UK have a capacity of more than 2GW. New wind power development is aiming more and more at offshore locations, where higher wind speeds and absence of land use restrictions allow for significant expansion, albeit at higher costs. The average wind turbine sold in 2006 was about 2MW, but the largest that are commercially available now are 5MW. These windmills have a rotor diameter of about 120m and a height of more than 100m (see Box 5.4). Small wind turbines with capacities below 100kW are also widely used in many places.

Box 5.4

The influence of wind turbine scale

Wind turbines have been scaled up enormously since the 1980s. Currently about 5600 turbines deliver 20% of Danish electricity. In 1980 about 100 000 turbines would have been needed to produce 10% and by 2025 less than 2000 turbines could produce 50%.

Large windmills benefit from the fact that the wind speed increases with height, the power produced is proportional to the cube of the wind speed (a 2x higher wind speed gives a $2 \times 2 \times 2 = 8$ x higher power), and the power is proportional to the square of the rotor diameter (a 2x larger rotor gives a $2 \times 2 = 4$ x higher power).



Figure 5.14 Pictures of (a) large wind turbine and (b) small domestic wind turbine in rural New South Wales, Australia.

Source: (a) European Wind Energy Association (b) Shutterstock.com, © Phillip Minnis, image #31168516.

In some countries electricity from wind is reaching a significant percentage of total supply: in Denmark it is about 20%, in Northern Germany 35%, and Spain 8%. An important issue with wind power is the fact that the wind is not always blowing. In 2005 the average capacity factor (percentage of the time the turbines were delivering electricity) was 23%. That means supply needs to come from other sources at times and that backup capacity should be available. Managing the stability of supply requires good forecasting of wind speeds. When wind is integrated in networks that extend over large areas this becomes less of a problem, since ‘the wind will blow somewhere’ at any point in time.

Another issue with wind (and other dispersed and fluctuating renewable energy sources) is network access. Electricity grids are typically designed to take power from a limited number of big power plants. With an increasing number of small electricity suppliers, access to the network is becoming more difficult. In a number of cases it has already led to delay or cancellation of wind power projects.

The fluctuating character of wind adds to the cost of it, in as far as backup capacity needs to be built if wind power contributes a large percentage to total electricity production (typically at 20% or more). In the worst case scenario it would add something of the order of 1USc/kWh to the cost of wind power¹⁶ (wind power cost is currently

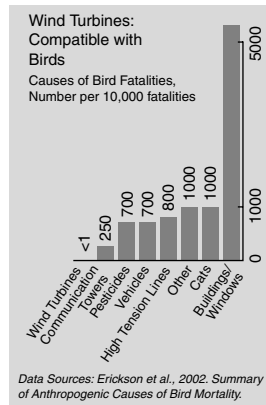


Figure 5.15

Causes of bird fatalities.

Source: American Wind Energy Association, Wind Energy Outlook 2007; Erickson et al. Summary of Anthropogenic Causes of Bird Mortality, 2002.

4–9USc/kWh), but very likely much less. Offshore costs are about 1USc/kWh higher than land-based wind power costs. Costs also go up when sites with lower wind speeds are used, but costs will come down as a result of further development and the influence of large scale production of wind turbines. Projections for 2030 on average indicate a cost of 3–8USc/kWh, which will be competitive with fossil fuel based electricity. The advantage of wind power is that it requires relatively low investment per unit of capacity and that it can be built relatively fast.

Prospects for the contribution of wind power to reduce CO₂ emissions are good. The technical potential, not influenced by costs or acceptability, is at least 500 times the current capacity. Taking into account limitations of acceptability and costs however would most likely keep capacity below a 25-fold increase by 2030 under a stringent climate policy scenario, i.e. a contribution of about 8% of total electricity supply. Even without climate policy a 10-fold increase is likely. Much of this new capacity would be offshore. To give an idea of the numbers of wind turbines needed, a 10-fold increase (with on average 2MW turbines) means about 200 000 new turbines. A 25-fold increase means 500 000 new turbines till 2030. The number of wind turbines produced in 2004 was about 6000. The wind turbine industry would have to expand considerably to meet those numbers, but given the historic growth rates that is certainly feasible.

Acceptability of wind turbines is an issue. Many people, even in a country like the Netherlands that has a long history with windmills, object to them because they spoil the landscape. In densely populated areas this limits the siting of new wind capacity seriously. This is an important factor in the move towards offshore locations. Mortality of birds, as a result of being hit by wind turbines, is also a much debated issue. Siting of wind parks away from bird migration routes can reduce those problems and the contribution of wind turbines to bird fatalities should not be overestimated as Figure 5.15 shows.

Bioenergy¹⁷

Biomass is a major source of food, animal feed, fibre for products like paper, cotton, etc., and last but not least of energy. About 2 billion people in developing countries still rely on traditional fuel such as wood, charcoal, or animal dung for their cooking and heating¹⁸. That is by far the biggest part of the energy use of biomass. There are many other forms of biomass used for energy: forestry and wood based industry residues, crop residues or whole crops, solid municipal and industrial waste and waste water. Outside the traditional biomass sector, these bioenergy products are usually transformed into different bioenergy carriers: modern solid biomass (as pellets, woodchips, etc.), liquid biofuels (alcohol, diesel fuel), or biogas. These carriers are used either directly as fuels or turned into electricity and heat. Figure 5.16 gives a schematic diagram of this bioenergy system.

In total, biomass supplies about 10% of current primary energy supply. Traditional biomass represents three-quarters of that; modern biomass one-quarter (i.e. 2.5% of total energy supply). About one-third of the modern biomass is used for electricity and heat production, industrial use also accounts for a third. Liquid biofuel only covers 10% of modern bioenergy.

Growth of biomass electricity and heat production is high (50–100% per year) in some OECD countries, like Germany, Hungary, the Netherlands, Poland, and Spain. Small projects in rural areas are also growing fast in some developing countries, such as

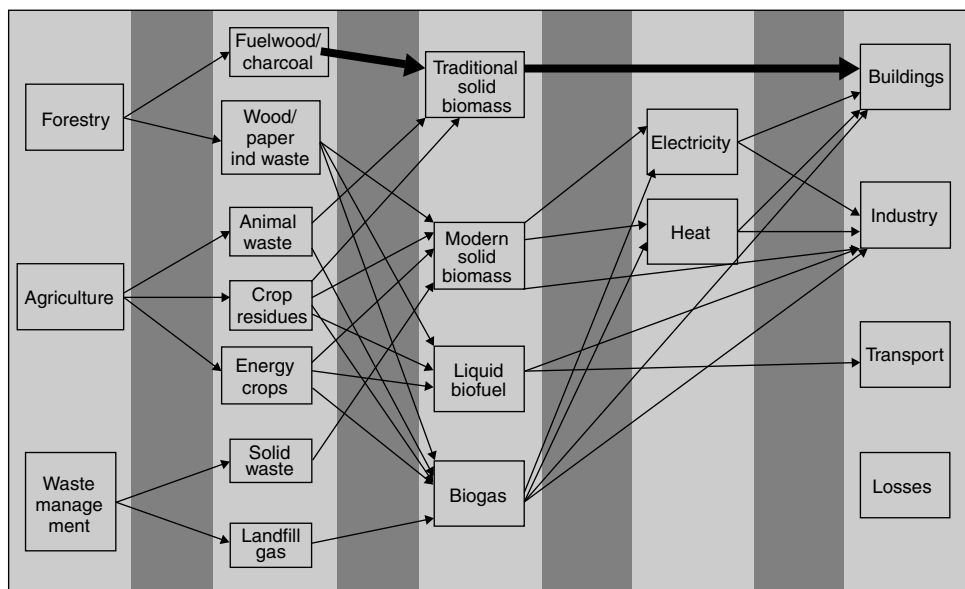


Figure 5.16

Schematic diagram of bioenergy sources, carriers, and end use sectors.

Source: based on IPCC Fourth Assessment report, Working Group III, figure 4.14.

Thailand. All growth however is from a very small base. Total installed capacity of biomass based power generation was about 45GW by the end of 2006¹⁹.

Technology

The dominant technology for modern solid biomass use in electricity and heat production is so-called co-generation (Combined Heat and Power (CHP); see section on Power plant efficiency and fuel switching) with direct firing of the biomass. Different technologies are being used, depending on the type of biomass available. These biomass systems are relatively small: they typically have a capacity of 50MW or less, compared to coal fired plants that have a range of 100–1000MW. Heat is normally used for district heating, industrial processes, or greenhouses²⁰.

Recently co-firing of biomass in coal fired power plants and co-firing biogas (from landfills and biogas plants) has gained interest. More than 150 coal fired power plants currently have operational experience with co-firing, using a large variety of biomass materials, including wood chips, wet and dry agricultural residues, and energy crops. It is a relatively simple and low cost method of using bioenergy. However, the supply of large quantities of biomass to big power plants may be a problem (see below). Municipal solid waste incineration, one of the widely used waste management technologies, is a form of co-firing: organic material combined with plastic and paper is used to generate heat and electricity.

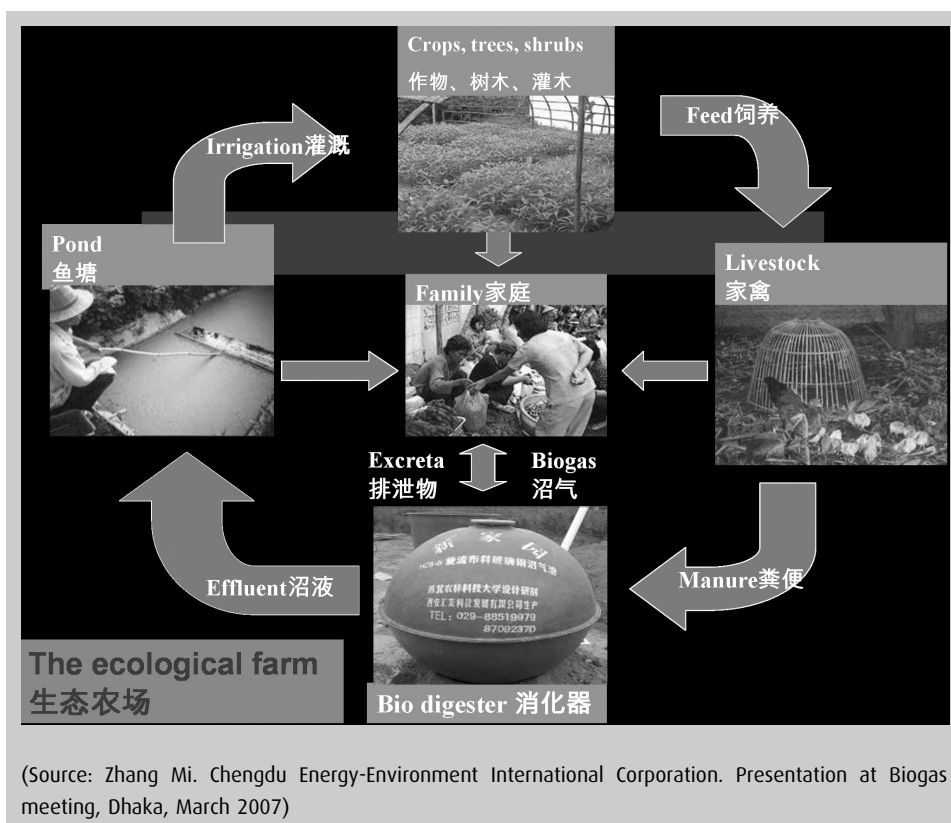
Biomass can also be gasified by heating it in an environment where the solid material breaks down to form flammable gas. After cleaning the gas can be burned in a gas turbine or more simple combustion engine. This technology is just beginning to become commercially available.

Gasification of biomass, in the form of animal waste and waste water, can also be done biologically in biological digesters in the absence of oxygen (called anaerobic digestion). This technology is being used in many places. In Europe alone, more than 4500 installations were operating in 2002. In several developing countries rural application of biogas has developed strongly (see Box 5.5 on biogas in China). Given the small scale of biogas digesters, the overall contribution is limited on a global scale, but can be significant in rural areas.

Box 5.5

Biogas digester programme in China

China has the biggest programme of installing biogas digesters in rural areas. By the end of 2005 about 18 million household digesters were installed and plans for reaching 84 million by 2020 are in place. It is now one of the priority areas in the central government's policy of improving the condition of people in rural areas. Subsidies are now available from the central and local governments for installing biogas units. Digesters are constructed from bricks and concrete and increasingly mass produced from fibreglass reinforced plastic. In recent times the emphasis is put on integrating the biogas plant in the farm: improving sanitation and crop productivity, and providing cooking gas.



Biomass sources

Figure 5.16 above already showed the various sources of biomass that are relevant to energy production. The bulk of the biomass becomes available in rural areas and a smaller fraction in urban areas (landfill and waste water treatment gas, municipal solid waste and industrial waste from processing of wood and agricultural products). One particular problem is that the energy density of biomass resources is low and it has to be collected from a wide area to supply the amounts needed at a CHP bioenergy plant. This explains the relatively small size of these units as outlined above.

Another issue is the sustainability of the biomass supply. For true waste materials, such as municipal solid waste, waste water and industrial waste materials, no problem exists. In many cases however there is competition. Crop residues for instance are often ploughed back into fields to keep up the organic content of the soils, animal manure is used as fertilizer, and land dedicated to energy crops would not longer be available for food or cash crop production. In rural areas there may also be competition for labour. Need for additional land for energy crops could lead to additional conversion of forests or

biologically rich natural vegetation into agricultural land and thereby destroy ecosystems and lead to loss of species and biodiversity. This displacement effect is often neglected when discussing bioenergy.

Impacts of energy crops on food production and on biological systems need to be carefully considered in decisions to develop bioenergy potential. There are indications that the currently used energy crops, such as maize, soybeans, sugar beet, and oilseeds, may have some negative impacts on food prices and biological systems, but the increased demand for food, animal feed, and industrial use is likely to be the real reason for price increases. This issue will be discussed in more detail in Chapter 9 on Agriculture and Forestry.

Costs

Costs of biomass based electricity vary between 5 and 12US\$/kWh. They can be lower if the biomass used has a negative value, i.e. in cases where waste otherwise would have to be disposed of. The relative small scale of biomass based CHP units and the relatively costly collection and preparation of the biomass explain this high cost. By 2030 further technological development and economies of scale should lead to lowering these costs to about 3–10US\$/kWh. In Sweden, where there is a long experience with biomass electricity, each doubling of the installed capacity of CHP plants led to a 7–10% reduction in costs per kWh²¹.

Reduction potential²²

The first issue, when discussing the CO₂ reduction potential from bioenergy, is the net gain in terms of CO₂ emissions. Bioenergy in principle has an advantage over fossil fuel in the sense that it captures CO₂ from the atmosphere when the biomass grows. However, it takes energy to grow and harvest the crops and to transport and process the biomass, and the efficiency of the electricity generation may be less than that for coal or natural gas. In case of liquid biofuel or biogas production there is also the energy to run the process and refine the product. There may also be a net loss of carbon, when forest or land with natural vegetation is converted to land for energy crops. Or, in the case of crop residues, carbon lost from the agricultural soil. The CO₂ generated from this additional energy use and land use change needs to be subtracted from the gains made by using bioenergy. Unfortunately there is still a large controversy about the right numbers.

The other issue is the demand for bioenergy. This demand depends on the relative costs of bioenergy in terms of CO₂ avoided, compared to other reduction options, the level of ambition of climate policy, and the question of whether there is enough supply of biomass available. As far as biomass for electricity and heat is concerned, supply is not the limiting factor. Without having to rely heavily on energy crops, ample amounts are available to supply the demand for electricity and heat in a number of scenarios until 2030. Modern biomass could increase its share from about 2% of total electricity generation in 2030

without climate policy to something like 6% under a moderate climate policy. This would mean electric power capacities of 200–400GW by 2030. For liquid biofuels the situation is less clear. This issue will be discussed in more detail in Chapter 6 on transportation.

Geothermal energy²³

Hot water and steam from deep underground in volcanic areas of the world are being used to generate electricity and to provide heat for warming buildings. In addition, heat from shallow soils and ambient air can be captured with heat pumps for warming of individual buildings, which will be discussed in Chapter 7. There are more than 20 countries where geothermal energy makes a significant contribution to electricity supply (see Table 5.4). Iceland, a country with high volcanic activity, gets more than 25% of its electricity and 87% of its home heating from geothermal energy. El Salvador (20% of electricity), Philippines (18%), Costa Rica, and Kenya (both 14%) are also forerunners. On a global scale geothermal electricity covers less than 0.3% of the electricity supply.

More than 40 countries use geothermal heat for purposes other than hot baths²⁴. About half is being supplied to industries, greenhouses, and buildings from centralized systems, the other half by individual heat pumps.

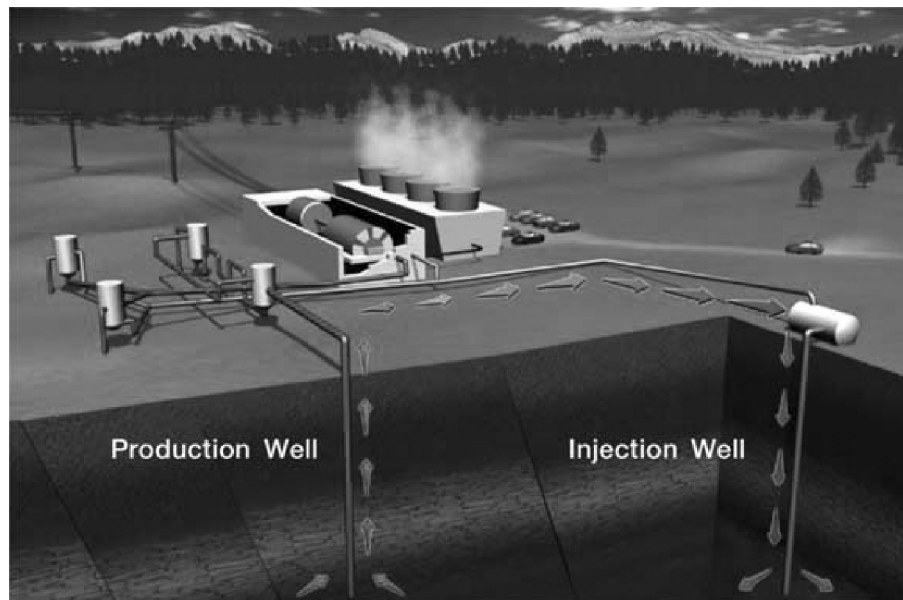


Figure 5.17

Schematic drawing of geothermal power plant.

Source: geothermal education office <http://geothermal.marin.org/GEOpresentation/sld002.htm>.

Table 5.4. Countries with highest geothermal electricity generating capacity by end 2005

Country	Geothermal electricity capacity (MW)
USA	2540
Philippines	1930
Mexico	950
Indonesia	800
Italy	790
Japan	535
New Zealand	435
Iceland	320

Source: International Geothermal Association.

Most geothermal power plants get a mixture of steam and water from drilled wells at depths of less than 2km, where temperatures are above 250°C (see Figure 5.17). In some cases water is pumped into hot dry rock formations. Water is often pumped back into the geological formations to keep pressure up and avoid water pollution from contamination. Some geothermal wells also produce CO₂ from volcanic origin, which comes up with the steam from deep wells and may annihilate the gains of geothermal energy in terms of CO₂ reduction.

Costs of geothermal electricity are currently 4–10USc/kWh, depending strongly on the local circumstances. This is well above the cost of coal fired power. Costs are projected to come down somewhat due to improvement of the technology by 2030 to 3–8USc/kWh. Emissions of CO₂ are often not equal to zero, because of volcanic CO₂ coming up with the water and steam. No reliable data are available however.

The technical potential of geothermal energy is very large, around 10 times current total primary energy use. Only a fraction of this can be tapped however by 2030, even with an ambitious climate policy in place. A share of about 1%²⁵ of total electricity supply by 2030 would probably be an upper limit, which is roughly equivalent to a fourfold increase of geothermal electricity and is consistent with the 7.5% per year growth that geothermal energy has shown over the last 35 years.

Solar

The solar radiation reaching the earth surface is more than 10000 times the current annual energy consumption. The intensity varies, with the best areas in the subtropics (see Figure 5.18). Solar radiation can however be captured anywhere in the world, albeit with lower efficiency. There are three ways of capturing this energy:



Figure 5.18

Areas with strong solar radiation (>400 GW/km²).

Source: Shine WB, Geyer M. Power from the sun, <http://www.powerfromthesun.net>.

- *Concentrating solar power*: concentrating the solar radiation with mirrors, heating a fluid, and using that heated fluid to generate electricity.
- *Solar photovoltaic*: generating electricity directly in a light sensitive device made out of silicon semiconductors (a photovoltaic (PV) cell)
- *Solar heating and cooling*: collecting direct heat of the sun in a system to heat water for domestic or other use or use solar radiation to drive a cooling system.

Concentrating solar power²⁶

Concentrating solar radiation can be done in several ways (see Figure 5.19).

The most mature form is a set of mirrors in the form of a ‘parabolic trough’ that concentrates solar radiation on a tube containing the working fluid from which electricity is produced. These systems have reached an overall efficiency of about 20% (i.e. 20% of the incoming radiation is converted to electricity). The biggest commercial plant is a 150MW facility in California (see Figure 5.20).

The other system operating at scale is a so-called ‘solar tower’: a set of flat mirrors that follow the sun (‘heliostats’) and concentrate radiation onto a tower where the working fluid is heated (see Figure 5.21). A few tower systems are operating in the USA and the EU (Spain) at a scale of about 10MW. The Spanish system is planned to be expanded to 300MW by 2013.

The total installed capacity of CSP is currently about 400MW, with most of it dating from the early 1990s, when tax credits in California led to construction of 350MW capacity plants. The recent addition of the Seville plant, as a result of a new feed-in tariff law in Spain, and plans for another 1400MW plant in 11 countries, indicate a more favourable situation. CSP systems are best placed in areas receiving high levels of solar radiation. They also have the advantage of a fairly high energy density, i.e. the land required for delivering significant amounts of energy from CSP installations is smaller

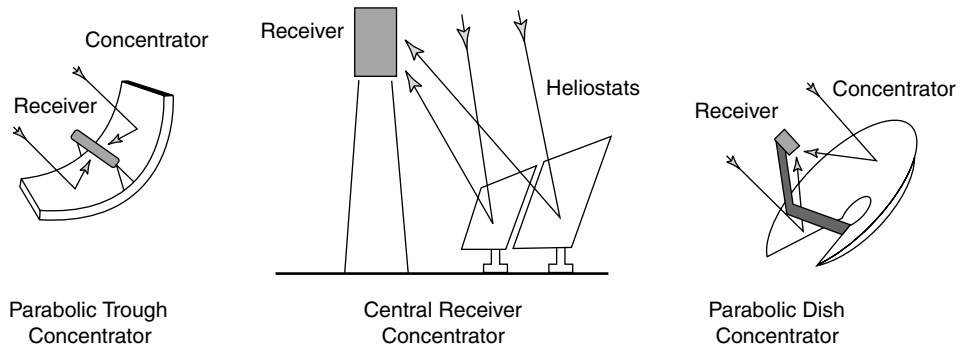


Figure 5.19 Different concentrating solar devices.

Source: Shine WB, Geyer M. Power from the sun, <http://www.powerfromthesun.net>.



Figure 5.20 Picture of the world's largest concentrating solar facility in California. It consists of a 150 megawatt concentrating solar power system that utilizes parabolic trough collectors.

Source: Desertec-UK, <http://www.trec-uk.org/images/>.

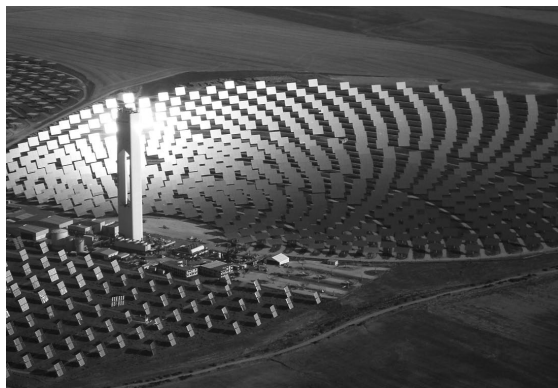


Figure 5.21 Picture of a 11MW concentrating tower system, Seville, Spain.

Source: Abengoa Solar, Spain.

than for most other renewables. Output is about 125 GWh/year for 1 square km (when a 10% conversion efficiency is assumed). That means only 1% of the world's deserts (240 000 km², half the area of France) would be sufficient to produce all the electricity needed in the world by 2030. Of course, this is only in theory, because so far no practical solutions are available to transport that power to where the users are. Research is ongoing on developing high voltage direct current grids to make that easier.

Costs of electricity from CSP systems are currently between 10 and 45 USc/kWh. Costs for new installations by 2030 are estimated to be much lower at 5–18 USc/kWh. The potential for contributing to CO₂ reductions will depend strongly on the cost reduction achieved over the next 20 years. For the time being costs of CSP are higher than many other low carbon options. Once the 5 USc/kWh level is reached, CSP would become competitive. For the price to come down that far many installations need to be built in order to gain experience. The current rate of cost reduction is about 8% for each doubling of capacity. Driving the cost down to the 5c/kWh level will require considerable subsidies.

Estimates of the contribution of CSP to low-carbon electricity are modest and very uncertain. For all solar power together no more than a 1.5% contribution to electricity supply is expected by 2030 under strong climate policy²⁷.

Solar photovoltaic²⁸

Silicon semiconductor based PV cells are currently the dominant technology. The cells come in different varieties: monocrystalline silicon with about 18% efficiency (33% of the market), cheaper polycrystalline cells with 15% efficiency (56% of the market), and even cheaper thin-film cells with 8% efficiency (9% of the market). There is a clear trade-off between costs and efficiency. They are applied on a wide variety of scales: from miniature cells powering a watch or a few PV panels on a roof, up to large arrays of PV panels generating more than 10 MW²⁹ of electricity. There are even serious plans to build a 100 MW PV plant in China³⁰.

About 70% of the total installed capacity by the end of 2007 was connected to the grid (about 8 GW). In the case of home systems that means electricity generated that is not needed for the building is delivered back to the grid (and the grid supplies when the PV cells do not generate enough electricity). This grid connection has for a long time been discouraged by electricity companies by offering very low pay-back rates. With feed-in tariffs becoming popular in many countries this is rapidly changing. A typical grid connected home system is shown in Figure 5.22.

In areas where no grid connection exists, particularly rural areas in developing countries, many individual solar home systems have been installed. This is part of the roughly 3 GW solar PV capacity that is not connected to the grid. These systems normally have a limited capacity, enough for a few light bulbs and a TV set. Increasingly there has been resistance by individual people to invest in these systems, because they fear that having a solar home system will make it unlikely that the government will invest in a grid system for their particular village. Mini-grid systems at village level may be the solution for this problem.

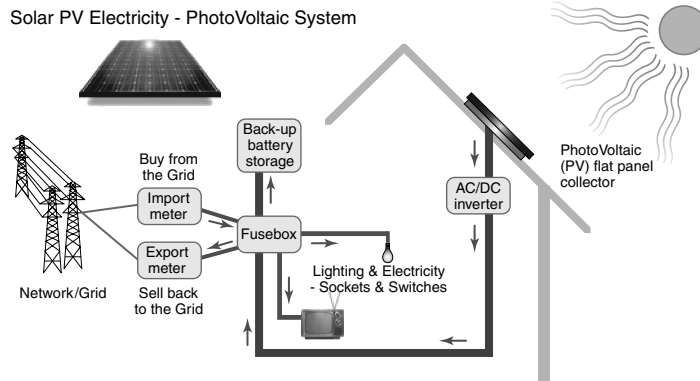


Figure 5.22

Grid connected solar home system.

Source: http://www.saveenergyuk.com/solar_lighting_electricity.htm.

The prospects for solar PV are very good. Growth rates of installed capacity of grid connected systems have been about 50–60% per year, albeit from a very small base (currently 0.004% of global electricity). Annual production of PV panels is now about 2GW. Costs of electricity from solar PV are however still high: from 25USc/kWh in very sunny areas to about 1.6\$/kWh in less attractive areas and somewhat older systems. Costs are coming down rapidly however (about 18% for every doubling of installed capacity) and by 2030 the cost could be 6–25USc/kWh, which would bring the cheapest systems into the range where solar PV can compete with other low carbon options. Much effort is currently put into developing PV integrated building materials, such as wall and roof panels (more about that in Chapter 7 on Buildings).

Estimates for the contribution that solar PV can make by 2030 towards CO₂ reductions vary widely, in light of the costs. As indicated above, total solar electricity by 2030 is likely to be less than 1.5% of total supply. In the longer term, beyond 2030, the potential for solar PV could become significant though, as costs continue to fall rapidly.

Solar heating and cooling³¹

Solar hot water heaters for domestic housing are the most common form of solar heating that is found today. Other applications are for space heating, swimming pool heating, and industrial processes. It is discussed in Chapter 7 for buildings and Chapter 8 for industrial processes.

Ocean energy³²

In principle a lot of energy could be obtained from waves, tidal flows, ocean currents, and from temperature differences between the ocean surface and the deep ocean.

The economically exploitable potential for the period until 2030 is however small. Currently there are only a few tidal flow installations with a capacity of not more than 260MW.

Wave energy contributes even less: there are only two commercial projects with a total capacity of 750kW. Most wave energy technologies operate at the surface, either through using the up or down movement of waves or the breaking waves at the shore, to operate a generator to produce electricity. There are many different types under development. One system, the Archimedes Wave Swing system³³, operates on the basis of a submerged buoy, 6m below the surface, filled with air and attached to the sea floor, that moves up and down with passing waves; the up and down movement is then converted into electricity.

Ocean thermal energy conversion (OTEC) systems, which aim to obtain electricity from temperature differences in the ocean, are currently only at the research and development stage, as are turbine systems positioned in areas of strong ocean currents and systems designed to obtain energy from salinity gradients.

It is very hard to predict when ocean energy systems could become commercially attractive, given the absence of large scale experience and realistic cost estimates. Theoretical calculations of the potential for wave power along the world's coasts show that 2% of the 800 000km of coast has a high enough wave energy density to make wave power systems attractive. Assuming a 40% efficiency in converting wave energy to electricity this would mean a 500GW electrical capacity. At this stage however these are purely theoretical calculations.

CO₂ capture and storage and hydrogen

The last option for reducing CO₂ emissions from the electricity sector is not to move away from fossil fuel, but to make fossil fuel use sustainable by capturing CO₂ before it is emitted, to transport it, and then either use it in some industrial process or to store it safely³⁴. This is called CO₂ Capture and Storage (CCS).

CO₂ capture

The technology of capturing CO₂ from gas streams has been applied at commercial scale for a long time in refineries and fertilizer manufacturing plants (to separate CO₂ from other gases) and natural gas cleaning operations (to get rid of high natural CO₂ levels in some gas fields). Application at large scale coal or gas fired power plants has not yet happened. There are three different systems for CO₂ capture at power plants³⁵:

- *Post combustion capture*: removing CO₂ from the flue gas that comes from the power plant, before it enters the smoke stack. The most common method for CO₂ removal is to let the flue gas bubble through a liquid that dissolves CO₂ and then to heat that fluid

again and drive the pure CO₂ out. This is in fact an add-on technology that could be used at any coal or gas fired power plant. The technology is basically the same as that used in natural gas treatment facilities, where CO₂ is removed from the gas stream before transporting it to users via pipelines.

- **Pre combustion capture:** in this system the fuel, mostly coal, but also applicable in principle to biomass, is gasified and converted in a chemical process (so-called Fischer Tropsch process) to hydrogen and CO₂. The CO₂ is then separated from the hydrogen with a liquid absorption as described above or a different process. The hydrogen is used in gas turbines to generate power. For coal fired plants this system is called Integrated Gasification Combined Cycle (IGCC). This technology is very similar to the one used in hydrogen production in refineries and in fertilizer manufacture.
- **Oxyfuel combustion and capture:** CO₂ in flue gases from a traditional coal or gas fired power plant is mixed with a lot of nitrogen and oxygen from the air that was used in the combustion. CO₂ in an IGCC is mixed with hydrogen. That means large quantities of gas have to be pumped through a CO₂ separation unit, which is costly. Therefore a third system was developed in which coal or gas is not burned with air, but with pure oxygen. This produces a flue gas stream with high CO₂ content, making the CO₂ removal simpler and cheaper. This technology has so far only been demonstrated at relatively small scale.

Figure 5.23 gives a schematic diagram of these three systems and also shows for comparison the systems used in natural gas treatment and industrial processes. Only about

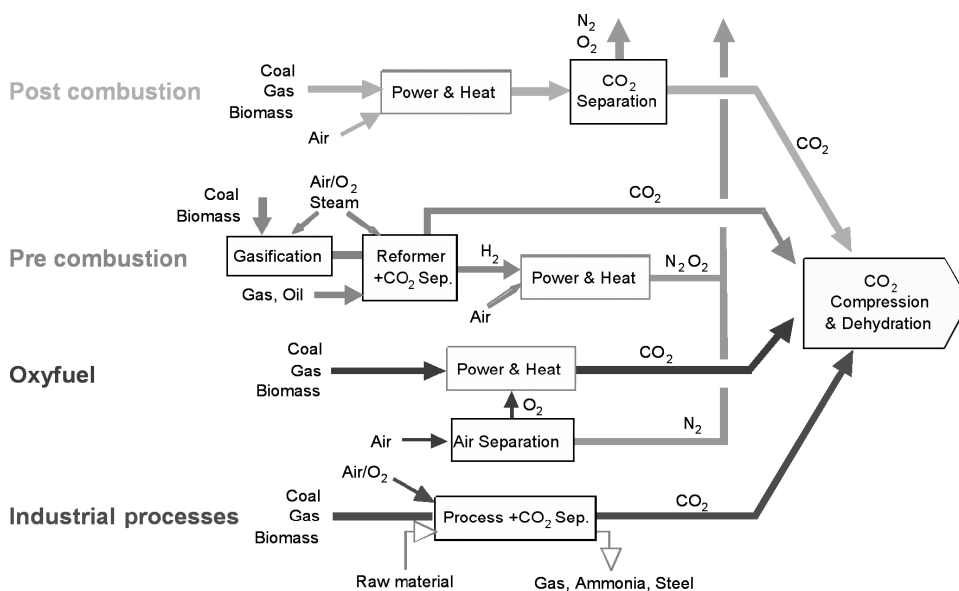


Figure 5.23

Different systems for CO₂ removal.

Source: IPCC Special Report on CO₂ Capture and Storage.

90% of CO₂ is captured, because going to higher percentages would require very costly installations. The capture process requires large amounts of energy, which means that the electricity output of a power plant goes down significantly when CO₂ capture is added. The amount of energy used for capture is 10–40% of the total. In other words, the net efficiency of the plant with CCS is reduced compared to the same plant without CCS. Technological development is aiming therefore at reducing this energy requirement by using more effective fluids or membrane systems. Expectations are that the energy loss can be reduced by 20–30% over the next 10 years.

Storage or usage of CO₂

There are some industrial processes that use CO₂, such as production of urea fertilizer, carbonated drinks, refrigeration, and food packaging. There is also some usage of CO₂ (normally through burning of gas) in agricultural greenhouses to enhance plant growth. Captured CO₂ can be used in such cases, but quantities are very small compared to the amounts power plants produce³⁶. Processes to convert CO₂ in chemicals or biological material such as algae are under development, but it remains to be seen if they can reach a positive energy balance. So far these processes require more energy than they produce.

So the only meaningful way is to store CO₂. Geological formations (depleted oil and gas fields, unusable coal seams, and water bearing formations that have no use for drinking or industrial water supply) are the preferred storage medium. Storage of CO₂ by dissolving it into oceans is still very much at the research stage (see below). In principle there is yet another storage method: letting CO₂ react with minerals to form a solid carbonate and to dispose of this solid waste. Costs and waste management problems are such however that there are very poor prospects for this method.

‘Depleted oil and gas fields’ (these fields still contain sizeable amounts of oil or gas, but are no longer economical) are prime candidates for CO₂ storage because their geology is well known and they have often contained gas for millions of years. That is very important because a good CO₂ storage site would have to retain CO₂ for a very long time (thousands of years). In addition, a well known technique for enhanced oil recovery (getting more oil out of a field than through traditional pumping) is to pump CO₂ into a ‘depleted’ oil field to ‘sweep’ additional oil out. Thus CO₂ storage in oil fields can be combined with getting additional oil out, provided that it is ensured that the CO₂ does not escape, which occurs in traditional CO₂ enhanced oil production. This approach is currently being used at large scale at the Wayburn oil field in Canada. The same principle can be applied to depleted gas fields. BP’s natural gas cleaning plant in In-Salah, Algeria, where about 1 million tonne per year of CO₂ is captured and stored, uses this approach.

There are large water bearing geological formations, so-called aquifers, that are not used for other purposes. If these aquifers had a structure that would prevent CO₂ from escaping to the surface, then they could be used for CO₂ storage. The Sleipner CO₂ capture plant in Norway (removing CO₂ from natural gas) pumps about 1 million tonnes of CO₂ annually into a nearby aquifer (see Figure 5.24).

**Figure 5.24**

Picture of Statoil's Sleipner CO₂ separation and injection platform.

Source: StatoilHydro, Image courtesy of Marcel Fox, image at <http://www.mfox.nl/experiences4.html>.

There are many coal seams that are uneconomical to exploit. These coal seams can in principle be used to store CO₂. When pumping CO₂ into the coal, it is adsorbed and so-called coal-bed methane is driven out, producing a useful gas stream. This technology is still in the development stage and so far there are still problems with getting the CO₂ to penetrate the coal seam in an even manner. Figure 5.25 shows schematically the different geological storage methods.

Hydrogen

CCS is the key to hydrogen as a future clean energy carrier. As outlined above, coal gasification combined with a Fischer Tropsch chemical conversion and CO₂ capture produces hydrogen. Natural gas can be converted in a similar way to hydrogen. Currently this is the cheapest way to do it, and its use is widespread in refineries, chemical plants, and fertilizer manufacture. When the CO₂ produced during hydrogen manufacture is properly stored, the hydrogen then is a low carbon fuel.

Hydrogen can in principle be produced by electrical decomposition of water. Low carbon electricity (nuclear, renewable) could therefore also produce a low carbon hydrogen. Costs are however much higher.

Hydrogen is a very clean fuel for heat and electricity production; it only produces water as a combustion product. Hydrogen also has the potential to be a clean transportation fuel, if hydrogen fuel cells are used in vehicles (more about that in Chapter 6 on transportation). For it to become a significant energy carrier, a hydrogen infrastructure needs to be developed in the form of a pipeline network. Currently there are only a few regional hydrogen pipelines in heavily industrialized areas like North-Western Europe. With a hydrogen pipeline network low carbon electricity and heat could be produced in multiple locations. Use of stationary fuel cells, having a higher electrical efficiency than gas or steam turbines, would then be possible.

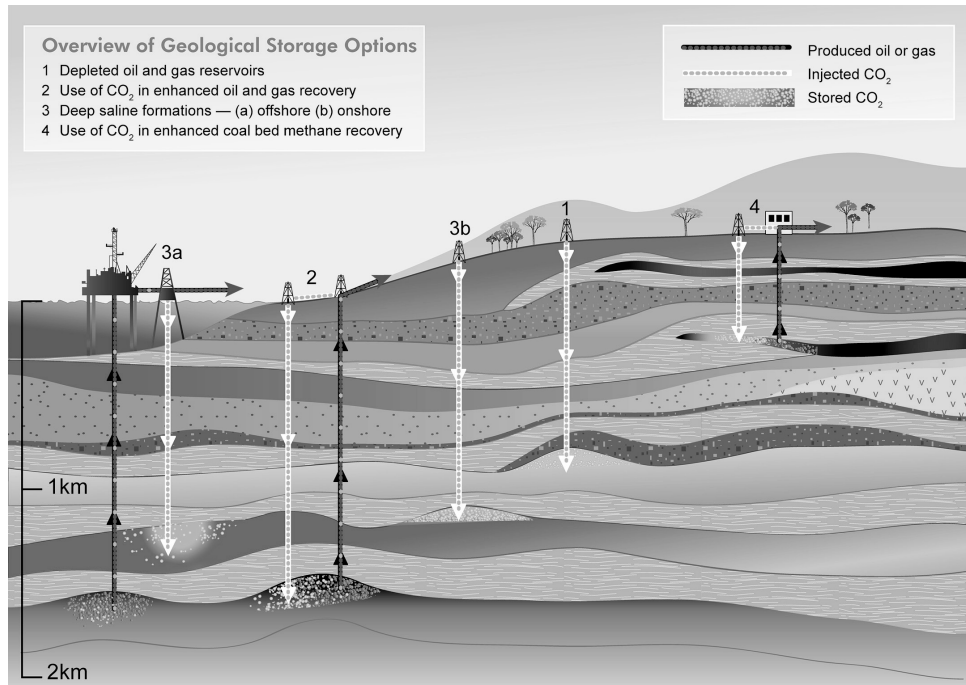


Figure 5.25 Methods for storing CO₂ in deep underground geological formations. Two methods may be combined with the recovery of hydrocarbons: EOR (2) and ECBM (4).

Source: IPCC Special Report on CO₂ Capture and Storage, figure TS.7. See Plate 10 for colour version.

Transport of CO₂

CO₂ needs to be transported from the place where it is captured to a storage site. The preferred method is by pipeline, after compressing the CO₂ to become a fluid-like substance. Since costs of pipeline transport are basically proportional to the length of the pipe, distances for this type of transport need to be limited to about 1000–1500 km. Beyond that, in cases where that would be economical, transport by ships, comparable to current LNG tankers, is better. Pipeline transport of CO₂ is a known technology. In the USA alone there is more than 2500 km of CO₂ pipeline. CO₂ shipping is not practiced yet.

Safety

There are risks involved in CO₂ capture, transport, and storage. Concentrated CO₂ is dangerous because it is colourless and odourless and at levels of more than 7–10% in air, it can kill after exposure of less than 1 hour. Handling concentrated CO₂ therefore requires stringent safety measures, comparable to those for handling toxic and flammable products from the oil and chemical industry. Pipelines need to be constructed from special corrosion resistant materials.

For storage similar considerations apply, since leaking of CO₂ to the surface from a geological storage site could concentrate CO₂ in the basements of houses. It can also cause harm to animals and plants. In addition, the biggest concern is that CO₂ could leak back to the atmosphere, which would make the whole operation of capture and storage a pointless exercise. Geological formations for storage therefore need to be carefully characterized in terms of their ability to retain gas. Monitoring of the distribution of the CO₂ underground needs to be performed and emergency measures to close a possible leak need to be prepared. If properly handled in that way, it is unlikely that CO₂ storage sites would leak more than 1% in 1000 years.

Costs

CCS is not cheap and that explains why it has only been applied in two large scale installations in the gas treatment industry (Sleipner and In-Salah). For use at power plants the costs of adding CCS are currently 1–3 US\$/kWh for gas plants and 2–5 US\$/kWh for coal fired plants. Or, expressed in \$/tCO₂ avoided: 20–70 US\$/t. This is higher than many other reduction measures available today. The potential for cost reduction is however significant, so that by 2030 costs could go down significantly.

Potential for CO₂ reduction

The reduction potential of CCS is very large. The total storage space available is more than 2000GtCO₂³⁷, which would be sufficient to store 80 times total current global CO₂ emissions and about double the amount that would be required this century, even under very ambitious climate policy assumptions. So it is basically competition with other reduction options that will determine the role of CCS in the period till 2030. Depending on climate policy, expectations are that CCS could become commercially applicable around 2020 and by 2030 could be applied at about 10% of all coal fired power plants in the world.

The prospects for hydrogen produced from natural gas or coal with CCS is very uncertain, because it depends on a hydrogen infrastructure. That infrastructure would probably only make sense if there were a significant demand from transportation. And as hydrogen fuel cell vehicles are not expected to become commercially available in significant numbers before 2030, these prospects are very uncertain at this moment.

Comparing CO₂ emissions

Table 5.5 gives an overview of the CO₂ emissions per kWh of the various power supply options that were discussed above, as well as the contribution these options can make to electricity supply.

Table 5.5. CO₂ emissions per kWh for different electricity supply options

Option	CO ₂ emissions (gCO ₂ -eq/kWh)	2006 electricity supply (TWh) ^a	2030 BAU electricity supply (TWh)	2030 ambitious climate policy (TWh) ^b
Coal	680–1350	7760	14600	4230
Gas	350–520	3810	6720	4190
Coal CCS	65–150	0	0	1740
Gas CCS	40–70	0	0	670
Nuclear	40–120	2790	3460	5430
Hydro	10–80	3040	4810	6640
Modern biomass	20–80	240	860	1730
Wind	0–30	130	1490	2750
Geothermal	n/a	60	180	220
Solar	10–100	4	350	720
Ocean	n/a	1	14	50

^a From IEA WEO 2008 reference scenario.

^b From IEA WEO 2008 450ppm CO₂-eq stabilization scenario; new renewable shares estimated based on relative share in 550ppm scenario.

Source: IPCC Fourth Assessment Report, Working Group III, fig 4.19, IPCC Special Report on CCS, fig TS.3 and IEA WEO 2008.

Comparing costs

Figure 5.26 summarizes the cost per unit of electricity for the various options. Low carbon options become competitive with coal and gas fired power plants, as costs for fossil fuel go up and costs of low carbon options come down. When climate policy leads to a price on carbon, more low carbon options become attractive. For instance, if it became a requirement that coal and gas fired plants were equipped with CO₂ capture and storage (CCS), many low carbon electricity generation options would become competitive by 2030, including the lowest cost solar power (CSP and PV).

These expected cost developments explain why the contribution of low carbon electricity is growing even without policy intervention. Policy intervention will further enhance these contributions.

Does that also work for climate policy?

For climate policy the cost of electricity is not the primary issue to look at. The main concern is to reduce emissions and therefore it makes sense to look at the cost per tonne of CO₂-eq avoided and then to take the cheaper measures first. These avoidance costs can only be calculated when two alternatives are compared. For example,

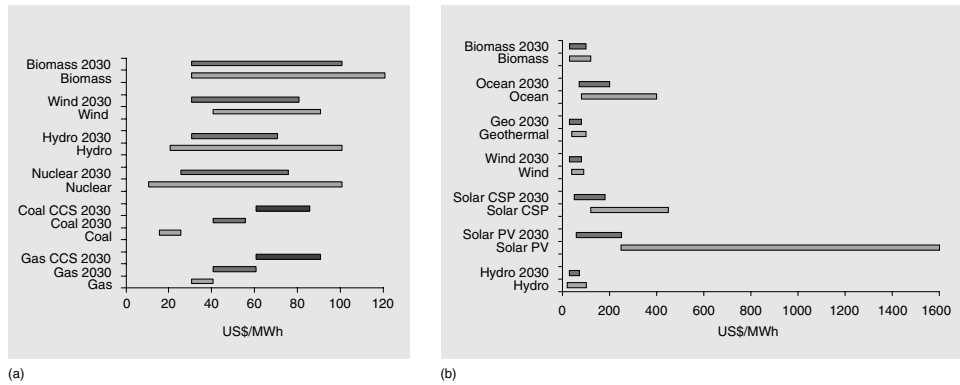


Figure 5.26

(a) Cost of different electricity supply options, current and for 2030; for coal and gas the 2030 cost including CCS is also given. (b) The same for renewable electricity options, indicating the strong expected cost reduction between now and 2030.

Source: IPCC Fourth Assessment Report, Working group III, table 4.7.

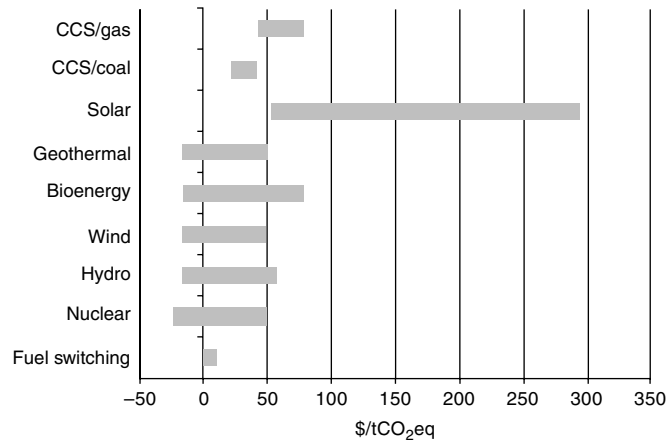


Figure 5.27

Relative cost in US\$/tonne CO₂-eq avoided for different electricity supply options, compared with a coal fired power plant.

Source: IPCC Fourth Assessment Report, Working Group III, ch 4.4.3.

the avoided CO₂ from wind power, compared with coal fired power, can be calculated, as well as the additional costs of using wind instead of coal. That would give a cost per tonne of CO₂ avoided. Comparing wind with gas fired power gives a different answer. Figure 5.27 summarizes the cost per tonne of CO₂-eq avoided for the various low carbon options, compared with coal fired power. It shows that many renewable energy options and nuclear power have a low-end cost per tonne of CO₂-eq avoided that is negative.

So how can climate policy transform the electricity supply system?

The first issue to consider is the reduction of energy demand. Climate policy will not only affect power plant efficiency and fuel choice in the power sector, but also end use efficiency. Electricity demand will be lower in a climate policy situation compared with a no policy situation, because energy efficiency improvement and energy conservation are generally cheap. Reduced demand will influence the need for additional power plant capacity and that will influence the share of low carbon options in the electricity mix.

The second issue concerns the choice of low carbon options. An economically rational approach for climate policy would pick the cheapest options first. That means options with the lowest costs per tonne of CO₂-eq avoided will be prioritized. In practice this ideal is not met. There are preferences and interests that will lead to less than optimal cost outcomes. In some countries nuclear power is not considered, in others there may be resistance against the building of many windmills, while in yet others considerations of energy security point in the direction of maintaining coal use. Such less than optimum choices can still deliver a low carbon electricity system, but at higher cost.

The third issue is the choice of policy instruments. When policy intervention is done in the form of a so-called renewable portfolio standard (requiring a minimum share of renewable energy), this normally does not lead to the least cost outcome for the electricity system as a whole. The same happens with feed-in tariffs (guaranteed prices paid for renewable electricity by the electricity distributors) or subsidies that are used to stimulate the penetration of renewable energy in many countries, because the specific tariffs may not be set in an optimal fashion.

Last but not least the stringency of the policy will of course have a dominant influence.

Figure 5.28 shows the share of the various electricity options for a number of policy scenarios for replacement of coal and gas. The scenarios have a different ambition level:

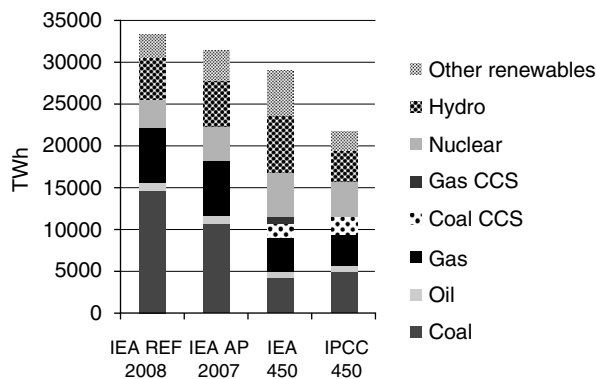


Figure 5.28 Share of low carbon options in the electricity sector in 2030 for a reference and two policy scenarios. CCS is not included in the IEA AP 2007 policy scenario, but it is in the IEA and IPCC 450 scenarios.

Source: IEA WEO 2007 and 2008.

the IEA 2007 Alternative Policy scenario roughly corresponds to a 550ppm CO₂ equivalent stabilization and the IEA 2008 450 and IPCC 450 scenarios³⁸ correspond to stabilization at 450ppm CO₂ equivalent. Only the IEA 450 scenario assumes early retirement of existing fossil fuel plants (i.e. before they are 50 years old). The scenarios generally use an approach in which the costs of the options are used to allocate the shares to the new plants to be built, but with restrictions on nuclear power in light of its acceptance problems.

Total electricity consumption for the policy scenarios varies significantly as a result of energy efficiency improvement assumptions in the end use sectors (transportation, buildings, industry). These will be discussed in more detail in Chapters 6, 7, and 8. Also the assumptions about the share of nuclear power vary between the scenarios. All this is well within the technical potential for the various low carbon options.

What does this tell us about what needs to be done?

Ambitious climate policy, aiming at stabilization at 450ppm CO₂-eq, corresponds to carbon prices of about \$100/tCO₂-eq avoided or more. It requires massive changes in the electricity sector. There is enough economic potential in the various low carbon options to make that happen. However this means a drastic change from business as usual. In the first place, it means building very few new gas or coal fired power plants without CCS worldwide after 2012. In some scenarios it is even necessary to close some of the older coal fired plants prematurely. It also means building more than 400 coal or gas fuelled plants with CCS, investing in 200–500 nuclear power stations, increasing hydropower capacity by up to 50%, doubling or tripling the number of biomass fired CHP plants, increasing the number of wind turbines from 50 000 to more than 500 000 by 2030, and a 100-fold increase in the capacity of solar CSP and PV.

Is that possible? It is good to keep in mind that wind power has seen a growth of 25–30% per year. Maintaining 25% growth means a 70-fold increase over 20 years. Solar PV capacity grew by 50–60% per year. Maintaining a 30% growth per year means a 140-fold increase over 20 years, and producing more than 400 coal and gas fired power plants with CCS in 20 years is a modest figure compared with the 100 coal fired power plants that China built in 2006 alone.

Investments also change drastically. In the first place it means that investments will shift: more will be invested in low carbon electricity supply and more in demand reduction and less in fossil fuel plants without CCS. The US\$22 trillion that will be needed for expanding and upgrading the world energy system between now and 2030 will thus be spent in a different way to that under a business as usual scenario. The 450ppm CO₂-eq scenario will also require additional investments. Newly built plants will on average have about double the investment costs per unit of capacity. The much better efficiency of energy use lowers the need for supply capacity and thus lowers the investment needs. For the ambitious policy cases considered however this does not compensate the higher power generation investments. The highest estimates of additional investment needs are about US\$9 trillion (partly as a result of early closing of coal

plants)³⁹. Reduced expenditure on fuels will however save about US\$6 trillion. Still, these large investment flows are less than 1% of global GDP.

What policy intervention is needed?⁴⁰

Low carbon power supply options are going to be used to some extent without climate policy, because they are cheaper than fossil fuels and energy security and air pollution considerations make them attractive. But they are not going to be implemented at the scale needed for drastic greenhouse gas emission reductions without additional policy intervention. However, in most countries governments no longer have direct control over electricity generation. In the past power supply was in the hands of government owned monopolies, but the sector has been thoroughly liberalized in many countries. So what are the policies that governments have available and what are the policies that would work?

A price for CO₂

The most important policy intervention is to create a price for CO₂, i.e. charging a fee when CO₂ is emitted. Traditionally, CO₂ emissions were free, which means that the actual costs of CO₂ emissions in terms of damaging the environment are not included in the price of the energy used. This is surprising, because charging a fee for emission of air pollutants or requiring abatement of such emissions at some cost is quite common practice.

How do you give CO₂ a price? The simplest way is to put a tax or a fee on every tonne of CO₂ (or other greenhouse gas) when emitted. Norway, Sweden, Denmark, and the UK have introduced such a direct tax for large companies. Many other countries have indirect energy and carbon taxes, levied on energy use of smaller consumers. Taxes are not very popular however. Attempts to introduce an energy/carbon tax in the EU for power companies and large energy using industries failed because of massive resistance. This eventually led to the introduction of the EU Emissions Trading System (see Box 11.5, Chapter 11). In the Netherlands the carbon tax and its exemption for renewable energy resulted in a booming market for 'green electricity' in households. Because prices of green electricity were the same as for regular electricity, about 20% of households shifted to green electricity.

Cap and trade⁴¹

Another way to create a price for CO₂ is to limit the amount of CO₂ that can be emitted by a company and allow trading in these allowances, a so-called 'cap and trade system'. Companies that want to emit more than their allowances permit can buy additional

emission allowances from others. Companies that find ways of reducing emissions can sell spare allowances. Just as in any other market a price for CO₂ emerges. If there are few allowances available for sale and demand for additional allowances is large, the price is high. Conversely, if there is not much demand for additional allowances (for instance because the companies were given ample allowances to begin with), the price will be low. The amount of allowances given out to companies therefore determines the price. Cap and trade systems have been used for other air pollutants in the past and have been used in very different sectors, such as the milk quota in the EU to control surplus milk production by farmers. In 2005 the EU introduced the European Emission Trading Scheme for CO₂. It applies to large electricity producers and large energy users. It covers about 40% of all CO₂ emissions emitted across the EU. Since the electricity sector is not very sensitive to international trade, the cap and trade systems are quite effective in this sector.

Subsidies

A more indirect way of establishing a price for CO₂ is to change the relative cost of low carbon versus fossil based electricity. There are still subsidies on fossil fuel electricity production, in the form of subsidized fuel (e.g. on domestically produced coal) or subsidized electricity. In total about US\$250–300 billion are spent annually on such fossil fuel subsidies. Doing away with those subsidies (which is good for the economy, but politically difficult to achieve) would narrow the gap between low carbon and fossil fuel based electricity.

Changing the relative cost can also be done by giving a subsidy on low-carbon electricity. This is done in many countries, but in different forms. The most successful method is the so-called ‘feed-in tariff’ system. Suppliers are given a guaranteed price for renewable electricity and electricity distribution companies are required to buy the renewable electricity at that price. The additional costs are then shared between all consumers. These feed-in tariffs can be adjusted over time, to reflect decreasing costs of low carbon electricity. More than 35 countries have introduced such a system.

The third method is to give direct subsidies to producers of low carbon electricity. Again, this can take several forms. Competitive bidding is used in several countries. In this system a low carbon power supplier can offer a certain amount for a specific price. The lowest bidders get the contract and the government pays the difference with the regular wholesale price. In the UK this system was abandoned in 2002 because it attracted only limited interest. It was replaced by a system of renewable portfolio standards (see below).

Another form is a subsidy on the initial investment, either as a rebate or a tax reduction. The idea behind that is to overcome the resistance against the high initial investment required for putting up solar PV panels, solar water heaters, windmills, or biomass fired CHP plants. China has been using this system in providing more than 700 rural villages with combined PV, wind, and hydropower systems. Japan managed to become the world leader in solar PV systems by providing for a long time a 50% subsidy on the initial

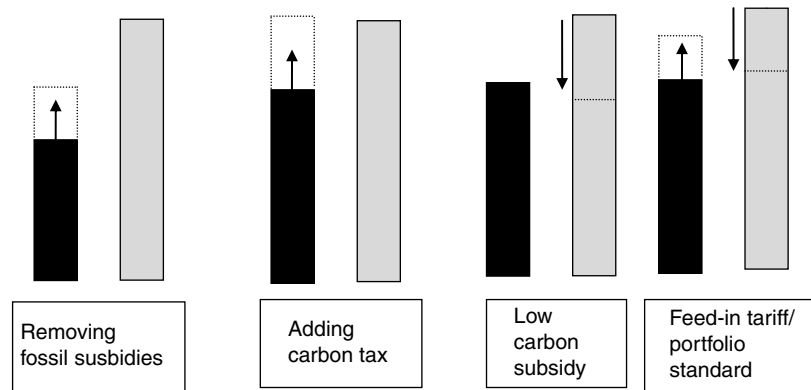


Figure 5.29 Schematic drawing of various subsidy schemes for making renewables penetrate the market. Dark bars represents fossil fuels, light grey bars renewable energy products.

investment of homeowners and project developers. After reducing the subsidy in 2002 from 50% to 12%, investments declined strongly.

Figure 5.29 gives a comparison of these various subsidy schemes.

Regulation

A regulatory system that is used widely, is the so-called ‘renewable portfolio standard’ approach. Electricity suppliers are required to have a certain minimum percentage of the electricity they sell from renewable energy sources. This percentage can be increased over time. Suppliers absorb the additional costs into their general prices. More than seven countries and many US States are using such a system. Since this system does not directly stimulate generators of low carbon electricity, effectiveness depends on the way the obligation is enforced.

New Zealand recently used legislation to put a 10 year moratorium on the building of new coal fired power plants in order to avoid lock-in while climate policy was put in place⁴².

Risk reduction

The policy instruments described above are particularly relevant for promotion of renewable energy by narrowing the cost difference for fossil fuel based electricity and heat. For nuclear power however cost is not the most important barrier. As mentioned above, new legislation in the USA has simplified licensing procedures and has extended limitations of liability in addition to providing a 2\$/kWh subsidy in the form of tax reductions. International efforts to control the risk of proliferation of nuclear weapons also forms part of the policy package to stimulate nuclear power.

Technology policy

For CO₂ capture and storage yet another issue is the main problem: making the technology commercially viable. Particularly for power plants, CCS has not been applied yet at large scale. The current carbon price is too low to make investment in a large CCS facility attractive. For that reason technology stimulation policies are applied. Apart from creating information exchange mechanisms between researchers and commercial companies (the EU CCS platform, the international Carbon Sequestration Leadership Forum, the IEA Implementing Agreement on greenhouse gas R&D), government financed demonstration programmes will be established. The EU decided to create 10–12 large scale demonstration plants, subsidized by member state governments. These plants should be operational by 2015. With the experience gathered, CCS costs coming down, and carbon prices going up, it is expected that by 2020 CCS in coal and gas fired power plants will become commercially attractive.

So what does this mean?

Technical possibilities for large reductions of greenhouse gas emissions from the energy supply sector are available. By 2030 many of these options will be cost competitive with fossil fuel based power, particularly when fossil fuel based plants have to be equipped with CCS. But the only way to get there is by strong policy action to make it attractive to invest in low carbon technologies and to avoid building many more fossil fuel based power plants that would lock-in the electricity infrastructure further into a fossil fuel future.

Notes

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2. IEA, World Energy Outlook 2008.
3. IPCC Fourth Assessment Report, Working Group III, table 4.2.
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14. REN21. 2008. "Renewables 2007 Global Status Report" (Paris: REN21 Secretariat and Washington, DC:Worldwatch Institute)."
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16. If a coal fired power plant were needed as a full back-up for wind (which is a worst case assumption), the costs of coal fired power minus the fuel costs, i.e. 70% of about 2\$/kWh, would be the additional cost.
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27. IEA, WEO 2007, 450ppm stabilization case.
28. IPCC Fourth Assessment Report, Working Group III, ch 4.3.3.6.
29. Largest PV plants are operating in Germany (10MW), Portugal, and Spain; source <http://www.pvresources.com/en/top50pv.php#top50table>; and REN21. 2006. Renewables Global Status Report 2006 Update (Paris: REN21 Secretariat and Washington, DC:Worldwatch Institute, 2006).
30. <http://www.redherring.com/Home/19866>.
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32. IPCC Fourth Assessment Report, Working Group III, ch 4.3.3.8.
33. The Engineer, 29 October–11 November 2007.
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35. IPCC Special Report on CO₂ Capture and Storage, 2005, ch 3.
36. IPCC Special Report on CO₂ Capture and Storage, 2005, ch 7.
37. IPCC Special Report on CO₂ Capture and Storage, 2005, ch 5 and IPCC Fourth Assessment Report, ch 4.
38. IPCC Fourth Assessment Report, Working Group III, ch 11, appendix.
39. See note 2.
40. IPCC Fourth Assessment Report, Working Group III, ch 4.5.
41. See also Chapter 11.
42. http://www.treehugger.com/files/2007/10/new_zealand_dec.php.