

## Chapter 2

# Fossil Energy Systems

**Abstract** This chapter gives an overview of the fossil energy sources, which undoubtedly still are dominating the supply of energy. We introduce here how coal, oil and gas are explored, recovered and used for energy production. The most conventional resources and production methods are described, and at the end of the chapter we introduce some of the unconventional fossil energy sources which have a promising resource potential. Fossil fuels are non-renewable resources and therefore represent a limited source of energy. The global reserves will be assessed and the cost of continued production of energy based on these diminishing resources will be evaluated. But first, we start with a historical review of mankind's involvement with fossil deposits and use as an energy source.

**Keywords** Coal · Oil and gas · Peak oil · Non-conventional fossil resources

### 2.1 Historical Development

We need energy because of the work it can do for us, and so we have developed elaborated supply chains to obtain fuel cheaply and reliably. Our world is not only served by those supply chains, but also shaped by them. Every time we have switched to a new primary fuel, society has undergone some fundamental reorganization as a result.

For 40,000 years, or more, controlled fire was our primary source of energy. We gathered sticks and twigs and stockpiled *firewood*, and then burned it to convert the energy stored in the wood into heat and light. Then, around 4,000 BC, we discovered how to harness the power of animals, for plowing or driving water pumps. This resulted in a great leap forward, into the agrarian age, and allowed us to convert the chemical energy in *hay*, the food eaten by the ox, into mechanical energy.

Records suggest that *coal* was first introduced as fuel in Scotland in the 9th century by monks to heat their abbeys. Over the next centuries, coal power became adopted

by brewers and smiths. Demand soon grew to such an extent that by the 14th century, a coal trade and a new energy supply chain had developed in England. However, an environmental conflict well known to our generation, soon arose. On the one hand, the government encouraged use of coal in breweries and smithies in order to conserve the rapidly diminishing forests needed for ship building. On the other hand, the pollution from coal burning soon became so extensive that the government also put restrictions on this energy source.

By the mid 16th century, the burgeoning iron trade in England increased the demand for coal and soon depleted the easily accessible coal layers near the surface of the ground. So coal miners had to do what oil drillers centuries later would do, go to ever deeper pits. A new challenge then arose, these deep pits needed to be drained of water on a nearly constant basis. Although crude pumps based on horsepower were available, the increasing demand for coal could hardly be met by the advent of the industrial age in the eighteenth century. But a radical new technology emerged that saved the day when the *steam engine* was invented. The steam being produced by burning coal, the steam engine was of course not a new energy source, but rather an energy conversion device. It was soon applied to a wide variety of innovations, and the world switched definitely from wood to coal, its first major fuel substitution, and nothing was ever to be the same again.

*Oil* has been an important commodity for mankind for thousands of years, but for most of this time oil has been of animal origin. Its most widespread use was in lamps and not as an energy source. Up until 150 years ago, whale oil was the world's primary illuminating fuel. But quality oil extracted from whale blubber was getting extremely expensive in the 1850s as the whales themselves were becoming more and more scarce. Fortunately, the new energy source, fossil oil, was discovered when the demand for lamp oil was at its peak and the supply rapidly falling. At first the new petroleum based oil was distilled from bitumen, a sticky, black and highly viscous liquid derived from tar sands found in Pennsylvania, USA and Ontario, Canada. The new fuel was called kerosene and was cheap enough that nearly everyone could afford it. But as an energy source substantial enough for heating and to run engines, the bitumen distillation was clearly too complicated and limited.

Soon, entrepreneurs and industrialists turned their minds to how they could get out oil from the ground in greater quantities to meet the world's demand. The first, but not very successful well was drilled in Hamilton, Ontario in 1858. It didn't go deep enough to yield much oil. In Titusville, Pennsylvania, prolific flows of subsurface oil was observed at the same time. It was therefore decided to drill into the formation using a derrick originally constructed to bore for salt and using a steam engine to power the drill bit. In 1859 the first underground oil well was a success as it struck oil about 70 feet or so beneath the surface.

Since then millions of oil and gas wells have been drilled globally, most of them now abandoned. But new wells are drilled all the time, and the amount yet to be recovered no one knows. However, the fossil energy resources must be limited, and it is a curious irony that the petroleum reserves which have taken the planet several hundred million years to produce, may be exploited in a couple of centuries, leaving nothing to future generations.

## 2.2 Coal

Globally, fossil fuels are providing about 80 % of our energy needs: 32 % from oil, 27 % from coal and 21 % from natural gas (in 2010). Coal has for centuries been used for domestic heating, but today, most of the coal is used for fueling electric power plants. In fact 41 % or 8,700 TWh of the electric energy produced globally in 2010 came from coal-fueled plants. Coal is one of the most abundant fossil fuels on Earth, and usually easier and cheaper to explore and produce than other fossil fuels such as oil and natural gas.

Coal formation began during the Carboniferous Period which spanned 360 to 300 million years ago. The build-up of silt and other sediments, together with movements in the Earth's crust—known as tectonic movements—buried wetland forests, swamps and peat bogs, often to great depths. With burial, the plant material was subjected to high temperatures and pressures. The plant matter was protected from biodegradation and oxidation, usually by mud or acidic water. This caused physical and chemical changes in the plant material, transforming it into peat and then into coal in a process called carbonization.

Several types of coal exist. According to their rank or grade:

- *Peat*, considered to be a precursor of coal, has industrial importance as a fuel in some regions.
- *Lignite* or brown coal, is the lowest rank of coal and used almost exclusively as fuel for electric power generation.
- *Sub-bituminous coal*, whose properties range from those of lignite to those of bituminous coal, is used primarily as fuel for steam-electric power generation.
- *Bituminous coal* is a dense sedimentary rock, usually *black*, is used primarily as fuel in steam-electric power generation. It may also be transformed into *coke*.
- “*Steam coal*” is a grade between bituminous coal and anthracite, once widely used as a fuel for steam locomotives.
- *Anthracite*, the highest rank of coal, is a harder, glossy black coal used primarily for residential and commercial space heating.

Coal is composed primarily of carbon along with variable quantities of other elements, chiefly hydrogen, oxygen, nitrogen and small amounts of sulfur. The composition depends on the rank and where it has been mined (see Table 2.1). The *calorific value*  $Q$  or energy content of coal is the heat liberated by its complete combustion with oxygen.  $Q$  is a complex function of the elemental composition of the coal.  $Q$  can be determined experimentally using calorimeters, and is of the order of 30 MJ/kg. Dulong has suggested following empirical formula to determine the energy content of coal:

$$Q(\text{MJ/kg}) = 337C + 1442(\text{H} - \text{O}/8) + 93S \quad (2.1)$$

where C is the mass percent of carbon, H is the mass percent of hydrogen, O is the mass percent of oxygen, and S is the mass percent of sulfur in the coal.

**Table 2.1** Characteristics of different types of coal (Lindner 2007)

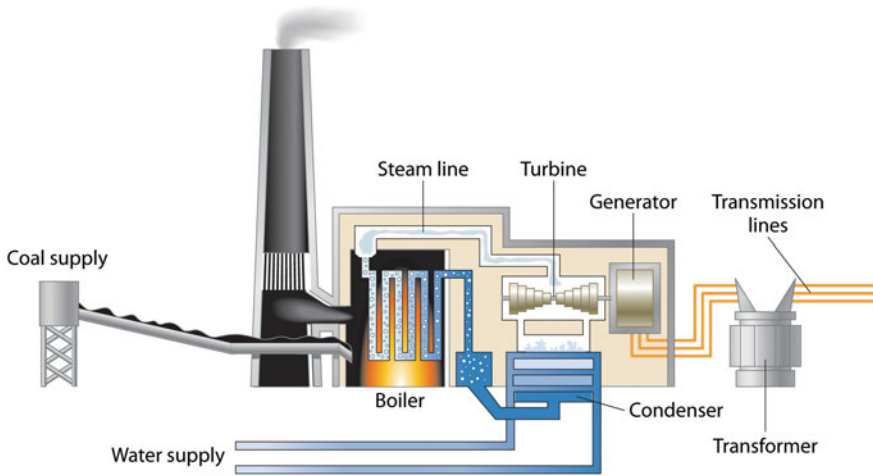
Type	Carbon MJ/kg	Hydrogen MJ/kg	Oxygen MJ/kg	Heat content MJ/kg
Lignite	60–75	6.0–5.8	34–17	<28.5
Flame coal	40–45	6.0–5.8	>9.8	<32.9
Gas flame coal	82–85	5.8–5.6	9.8–7.3	<33.9
Gas coal	85–87.5	5.6–5.0	7.3–4.5	<35.0
Fat coal	87.5–89.5	5.0–4.5	4.5–3.2	<35.4
Forge coal	89.5–90.5	4.5–4.0	3.2–2.8	<35.4
Nonbaking coal	90.5–91.5	4.0–3.75	2.8–3.5	35.4
Anthracite	>91.5	<3.75	<2.5	<35.3

**Fig. 2.1** Industrial complex with coal-fired power plant in Ontario, Canada

### 2.2.1 Coal Plants

In a fossil-fueled power plant, the chemical energy stored in fossil fuels such as coal and oxygen of the air is converted successively into thermal energy, mechanical energy and, finally, electrical energy for continuous use and distribution across a wide geographic area. The electrical power output from a fossil-fueled power plant typical ranges from 500–1,000 MW by burning 250–500 tonnes of fuel per hour under full load.

The second law of thermodynamics states that any closed-loop cycle can only convert a fraction of the heat produced during combustion into mechanical work. The rest of the heat, called waste heat, must be released into a cooler environment during the return portion of the cycle, (see Fig. 1.1). Coal-fueled power plants therefore have



**Fig. 2.2** Electricity from coal—flowsheet

two waste problems: the emission of greenhouse gases and waste heat. However, some of the latter may be used for heating homes or for industrial purposes etc.

The total energy production cycle in a coal-fueled power plant is complex and takes place in several stages. The major factory components are:

- Fuel transport, storage and preparation
- Burner
- Boiler
- Steam turbine
- Gas turbine
- Condenser
- Cooling tower
- Generator
- Emission control

Figure 2.2 displays the main components of a typical steam-cycle a coal power plant. Below we will give a short outline of each of the components.

### 2.2.1.1 Fuel Transport, Storage and Preparation

Coal is delivered from coal mines to power plants by rail, trucks or slurry pipe lines. For coastal or riverine plants it may also be delivered by ship or barge. Some plants may be built near coal mines so that the coal can be delivered by conveyor belts. When coal arrives by train, it is usually carried by a “unit train” with a total length of nearly 2 km, containing one hundred wagons, each wagon carrying 100 (metric) tonnes. The wagons or trucks are emptied by a rotary dump to conveyer belts transporting

the coal to a stockpile or delivering it directly to the power plant. Colliers which are cargo ships carrying coal, can hold  $4 \times 10^4$  tonnes of coal and may take several days to unload. Most plants store fuel for at least 30 days, which may amount to as much as  $10^6$  tonnes of coal.

The coal lumps delivered from a mine are usually from a few cm to ten cm of size and must be pulverized down to particles less than 1 mm before it is fed to the burner. This is done in a pulverizing mill with a rotating ring or a rotating hammer. The pulverized coal is temporarily stored in silos from which it is blown pneumatically into the burner.

In many countries the coal is washed at the mine, removing its mineral content, thus reducing its ash and sulphur content and improving its heating value per unit mass. In preparation for the washing process, the coal lumps may be crushed to less than 1 cm size already at the mine mouth.

### 2.2.1.2 Burner

The burner mixes air and the coal powder, and ignites the mixture by a spark-ignited oil jet until the flame is self-sustaining. The ashes produced consist of mineral matter, 90 % is *fly ash* which is drawn out of the burner by natural draft and is later captured in particle collectors. About 10 % of the mineral matter falls to the bottom of the boiler as *bottom ash*. When mixed with water, this forms a wet sludge which is carried away.

Some coal power plants use a cyclone furnace, a kind of combustor that can also effectively burn larger pieces of coal. It is formed as a barrel with water-cooled walls. The advantage of this burner is that the majority of the mineral matter forms a molten ash, called *slag*, which is drained into the bottom of the boiler and removed there, while only a small portion exits the boiler as fly ash. The heat is carried away with the hot combustion gases to the main boiler. The disadvantage of the cyclone burner is the high temperature of the furnace which produces large quantities of nitrogen oxides ( $\text{NO}_x$ ).

### 2.2.1.3 Boiler

While the burner is specific for the fossil fuel used, the boiler and the other major components in a thermal power station is similar for coal-, oil- or natural gas-fueled plants. The boiler is a central component in all kinds of fossil-fueled power plants which produce steam to run turbines. In a coal-fueled plant, the burner and the boiler is often integrated as shown in Fig. 2.3.

Heat is transferred by thermal radiation from the pulverized coal burner to the boiler *water wall* where riser tubes are circulating water which is vaporized into steam in a *steam drum* sitting on top of the water wall. The steam temperature in the steam drum is typically  $370^\circ\text{C}$  and the size of the steam drum is 30 m in length and 5 m in diameter. The saturated steam is heated further in a *superheater* to  $565^\circ\text{C}$  and

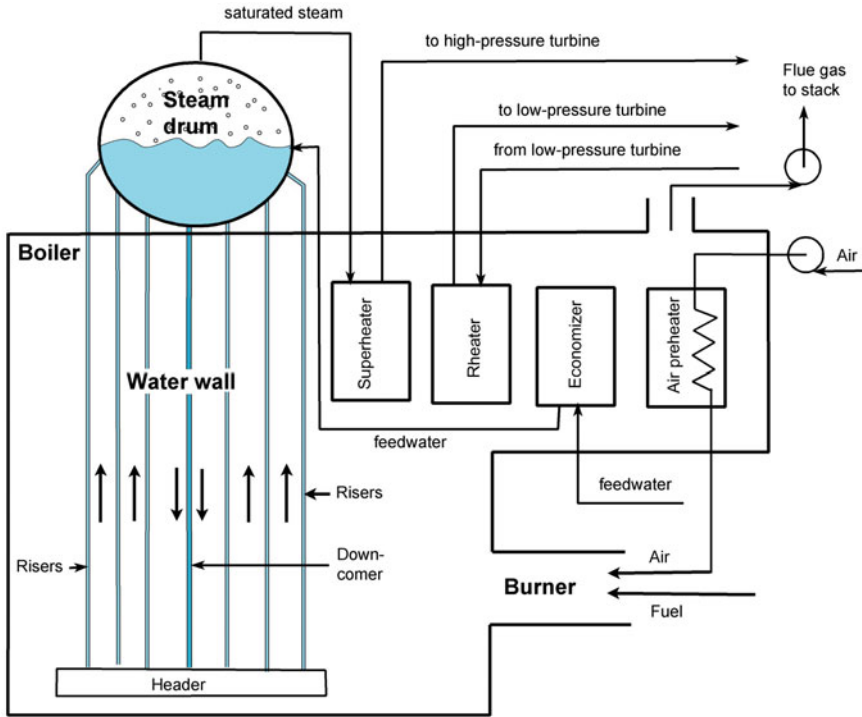


Fig. 2.3 The principle of a combined coal burner and boiler

a pressure of 24 MPa, which is above the critical temperature and pressure for water ( $T_c = 374\text{ }^\circ\text{C}$  and  $p_c = 22\text{ MPa}$ ). This high pressure steam is then passed on to high-pressure *steam turbines* and the exhaust steam from the turbine is condensed to water in the *condenser* and then passed back to the boiler. The water flow through the boiler is typically 400 l/s for a 500 MW plant at full load. It should also be mentioned that the burner/boiler contains some auxiliary components (air preheater, economizer, reheater) in order to improve the efficiency of the steam generating process.

### 2.2.1.4 Turbines

A photo of a steam turbine is shown in Fig. 2.4. The purpose of the turbine is to convert the *heat energy to mechanical energy* which can run the *electric power generator* (see Sect. 2.2.1.7).

The steam turbine is the most complex piece of machinery in the power plant. Just as water is pushing the blades of a water wheel in a hydroelectric power plant, a steam jet is pushing the blades of the steam turbine. Considering that the rotating blades of the turbine are subject to very high pressure and temperature, making a

**Fig. 2.4** Inspection of a steam turbine



leak proof construction is very demanding, and only a score of manufactures in the world can produce steam (and gas) turbines.

The turbine generator usually consists of a series of steam turbines interconnected to each other and the electric power generator on a common shaft which is subject to enormous centrifugal stress. There is a high pressure turbine at one end, followed by an intermediate pressure turbine and usually two low pressure turbines, utilizing the large pressure drop from the superheater of the boiler to the exit steam exhaust from the total turbine generator. The entire rotating mass may be over 200 tonnes and 30 m long.

There are two different types of steam turbines: the *impulse turbine* and the *reaction turbine*. They differ in the geometry and the angle at which the steam impinges on the blades of the turbine. Both systems have a set of rotors and stators. A schematic drawing of the two turbines is shown in Fig. 2.5. The steam jet is accelerated through a nozzle to a supersonic velocity of about 1,650 m/s and rotates the first rotor. The purpose of the stator is to lead steam on to the next rotor. Each set of rotor and stator is called a stage. When the pressure drop available is large, it cannot all be used in one turbine stage. A single stage utilizing a large pressure drop will have an impractically high peripheral speed of its rotor. This would lead to either a larger diameter or a very high rotational speed. Therefore, machines with large pressure drops employ more than one stage. As steam moves through the system and loses pressure and thermal energy, it expands in volume, requiring increasing diameter and longer blades at each succeeding stage to extract the remaining energy. Turbines can have several dozens stages.

In a *gas turbine plant* where oil or natural gas is used as fuel, the hot combustion gases are directly used to drive a gas turbine, rather than transferring heat to steam and driving a steam turbine. This requires a different turbine, appropriate for the much higher temperatures, 1,100–1,200 °C for the combustion gases, which is the maximum tolerable temperature for the steel alloys used in the turbine blades. The working fluid, composed of nitrogen oxides, water vapor, excess oxygen and carbon



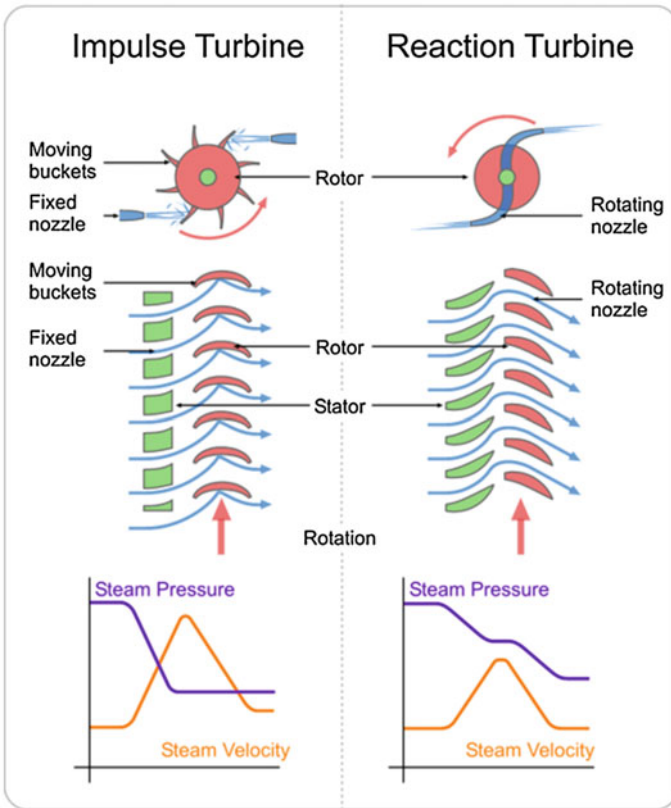


Fig. 2.5 The principle of an impulse turbine to the left; reaction turbine to the right

dioxides is not returned to the combustion chamber as is the steam in steam turbines, but instead vented into the atmosphere.

**2.2.1.5 Condenser**

According to the second law of thermodynamics no heat engine cycle can transfer heat from a hot reservoir and transfer it entirely into mechanical work without at the same time delivering heat to a colder reservoir. For a steam turbine, heat is rejected into the environment either in a steam condenser and/or vented into the atmosphere as hot flue gas in the smoke stack. For both cases, the receiving body (the cold reservoir) has a typical temperature of  $T_C = 25\text{ }^\circ\text{C} = 298\text{ K}$ . The hot reservoir which is delivering heat is the superheater of the boiler operating at  $T_H = 565\text{ }^\circ\text{C} = 838\text{ K}$ . The maximum theoretical efficiency of a heat engine operating between these two temperatures is given by the *Carnot cycle* which has an efficiency  $\eta = (T_H - T_C)/T_H = 64\%$ .

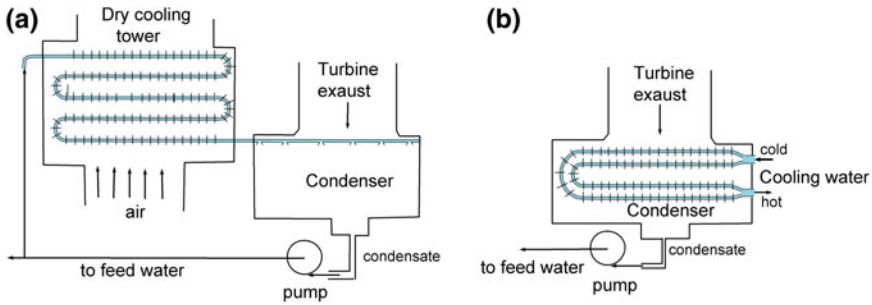


Fig. 2.6 a Direct contact condenser. b Surface condenser (schematic)

However, the typical efficiency of a steam power plant is in the 33–40 % range. This efficiency is the ratio between the mechanical energy delivered by the turbine to the electrical generator and the chemical energy of the coal fuel fed into the burner. The reason for the lower efficiency than the maximum Carnot efficiency is due to heat being lost through walls and pipes, frictional losses and heat escaping to the atmosphere with the flue gases at temperatures between  $T_H$  and  $T_C$ .

It is important that the temperature of the water leaving the condenser is as low as possible before it is returned to the steam cycle. We see from the efficiency of the Carnot cycle that the efficiency increases when  $T_C$  decreases. When the steam condenses to water, the pressure is also considerably reduced creating a near vacuum that helps the circulation. The cooling agent in the condenser is usually water from a nearby lake, river or ocean.

There are two types of condenser: *direct contact* and *surface contact* condensers. A direct contact condenser is depicted in Fig. 2.6a. The turbine exhaust passes an array of spray nozzles through which cooling water is sprayed, condensing the steam by direct contact. The warm condensate is pumped into a *cooling tower* where updrafting air cools the condensate that flows in the tubes. The cooled condensate is recycled into the spray nozzles. Because the cooling water is in direct contact with the feed water that goes back to the boiler, its purity must be maintained, just like that of the feed water. This purification may be expensive and the majority of power plants therefore use a surface contact condenser as shown in Fig. 2.6b. This is a shell type condenser where the turbine exhaust passes an array of tubes in which the cooling water flows. Very large volumes of steam need to be condensed and the contact surface area may be as large as 50,000 m<sup>2</sup> and the flow rate of the cooling fluid 15 m<sup>3</sup>/s for a 500 MW plant at full load.

### 2.2.1.6 Cooling Tower

Cooling towers are heat removing devices used to transfer rejected heat to the atmosphere. Heat removal by condensers described above where the excess heat is transferred to the surface in rivers or lakes represents a *thermal pollution* of the environment and possible harm to aquatic organisms. Many countries therefore man-

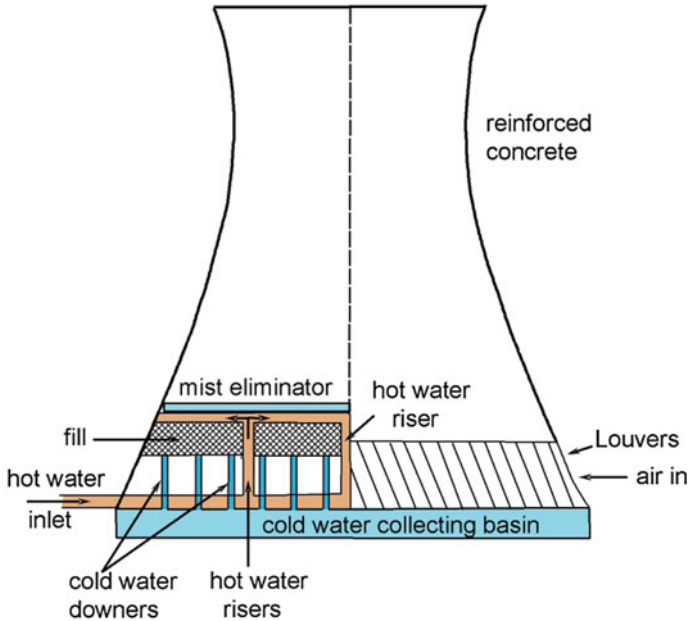


Fig. 2.7 Wet cooling tower, schematic

date that heat rejection occur into the atmosphere via cooling towers. These towers represent a visible landmark of thermal power plants. They have a spool-like structure with hyperbolic vertical cross section which is favorable from a structural standpoint and makes the sometimes 100 m high construction more resistant to strong winds.

There are two types of cooling towers: *wet* and *dry*. A schematic drawing of the wet cooling tower is shown in Fig. 2.7.

Hot water from the condenser is sprayed over a lattice work of closely spaced slats or bars, called *fill* or *packing*. Outside air is drawn by natural draft through louvers surrounding the bottom of the tower. Heat is transferred into the air directly or by evaporating some of the circulating water there by taking the latent heat from the steam flow. This results in a mist plume which is often mistaken as pollution, but it only consists of water droplets or ice crystals in the winter. The amount of water evaporated from a wet cooling tower in a 500 MW plant in a warm climate is of the order  $10^7$  m<sup>3</sup>/year. This must be replaced by surface water from a nearby river or lake, or by municipal water.

In a dry cooling tower, the recirculating water flow through finned tubes over which cold air is drawn and all the heat rejection goes into the air without any evaporation of the circulating water. The dry tower is less expensive to maintain, but the back pressure and the temperature of the returned water may be higher, thereby reducing the efficiency of the plant. In arid areas with little cooling water available, the dry cooling tower must be employed.

### 2.2.1.7 Generator

The generator is the heart of any power plant. This is where the mechanical energy of the rotating turbine shaft is transferred to electrical energy. The construction of the generator is very much the same in all fossil-fueled power plants as well as in hydroelectric power plants. It occupies only a small area compared to other components (burners, turbines, condenser, pumps, cooling tower etc.) in the plant, and its noise level is also negligible compared to these components.

The principle for all generators is a rotating shaft with conducting coils which rotates within a static magnetic field. This induces an electric current within the coils. The electric power output of the generator equals the mechanical power input of the shaft minus minor resistive losses in the coils and frictional losses. In order to prevent overheating of the generator induced by these losses, generators are cooled by high thermal conducting gasses, such as hydrogen or helium.

The generator produces an alternating current with a frequency determined by the rotational frequency of the turbine shaft. This is 50 Hz in most countries, but 60 Hz in North-America and a few other countries. The voltage produced by the generator is stepped up by transformers and transmitted to the grid. As explained on page 9 in Sect. 1.2.1 utility companies prefer to transport electric energy at high voltage in order to use thinner cables and thereby save on metal and reduce cable weight. Long-distance electrical transfer lines may have a voltage of 400 kV or more. At the user side of the line, the voltage is reduced again by transformers in several steps to 110 or 220 V.

### 2.2.1.8 Emission Control

The burning of coal in a power plant results in a considerable amount of pollutants that have to be controlled to protect human health and the environment. The emissions, as well as the overall efficiency of the plant, depends on which temperature the boiler/turbine is operated. In a *super critical power plant* this temperature is around 580 °C, compared to 450 °C for a *subcritical plant*. A supercritical plant is much more efficient than a subcritical plant, producing more power from the less coal and with lower emissions.

Most countries have environmental regulations requiring the operator of the power plant to install emission control devices for a number of pollutants escaping the burner to the smoke stack. The most important are:

- Products of incomplete combustion (PIC)
- Carbon monoxide (CO)
- Particulate matter (PM)
- Sulfur (SO<sub>2</sub>)
- Nitrogen oxide (NO<sub>x</sub>)

The control of PIC and CO is relatively easy to accomplish. If the fuel and air is well mixed, and the fuel is burnt in excess air, the flue gas will contain very little, if any, PIC and CO. It is also in the interest of the power plant to reduce

these emissions because a complete burn-out increase the thermal efficiency of the plant. Occasionally, especially during start-ups and component breakdowns, when the flame temperature and the fuel-air mixture is not optimal, PIC emanates through the smoke stack as black visible smoke.

Particles, also called *particulate matter* (PM), would be the most predominant pollutant emanating from the power plant if not controlled at the source. This stems from the fact that coal, and also oil, contains a significant fraction of incombustible *mineral matter*. Depending on the quality of the coal, the mineral matter may amount to typically 10 % by weight. This results in particles in the fly ash, including a host of toxic metals, such as arsenic, selenium, cadmium, manganese, chromium, lead and mercury. In addition there is nonvolatile organic matter (soot), including polycyclic aromatic hydrocarbons. For that reason, most countries have instituted strict regulations on particle emission from power plants. In older plants and plants with cyclone burners, the mineral accumulates at the bottom of the boiler as bottom ash and is discarded as solid waste and sluiced away.

The modern burners using pulverized coal produce as much as 90 % fly ash and these use two kinds of particle collectors. The *Electrostatic Precipitator* works on the principle of charging the particles in a corona discharge and then attracting the charged particles to a grounded plate where the charge is neutralized. The neutral particles are periodically shaken off the plates and collected as solid waste. An alternative particle collector, especially effective for collecting small particles, less than 2.5  $\mu\text{m}$  in diameter, is the *Fabric Filter* or *Baghouse*. It works on the principle of a domestic vacuum cleaner. Long cylindrical tubes (bags) of a special heat resistant fabric are hung up-side down. Each bag has 12–35 cm diameter and 4 m height. The baghouse may contain several thousands tubes. The fly ash is sucked through the tubes, and the particles in the fly ash are stopped by the fabric of the tube walls. The collected particles can be removed by mechanical shaking of the ram which holds the bags.

The coal usually contain 0.7–3 % sulphur by weight. The sulphur stems from cellular sulphur in plants and organisms and is carried on to the fossilized coal deposits. Without sulphur emission control, the sulphur which is oxidized to  $\text{SO}_2$  in the burner, will be emitted through the smoke stack into the environment. Emission of  $\text{SO}_2$ , minor quantities of  $\text{SO}_3$  and sulfuric acid  $\text{H}_2\text{SO}_4$  from fossil power plants are major contributors to acid precipitation. There are basically three approaches to reducing the sulphur emission: before, during or after combustion of the fossil fuel. Washing the coal at the mine mouth is used in many cases to reduce the mineral matter, including various metal sulfides. However, coal washing introduces a pollution problem of the environment. Removing sulfur oxides after combustion is often done in a so called *Scrubber* in which the flue gas is treated with a sorbent,<sup>1</sup> usually sintered limestone ( $\text{CaCO}_3$ ) in an aqueous slurry. The reactions taking place between the  $\text{SO}_2$  and the  $\text{CaCO}_3$  is:

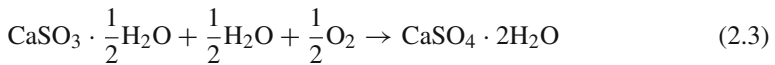
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<sup>1</sup> A sorbent is a material used to absorb liquids or gases.

**Table 2.2** Air pollution from fossil combustion plants in EU 2008: Mass (g) per energy unit (GJ)

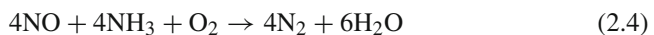
Pollutant	Hard coal	Brown coal	Fuel oil	Gas
CO <sub>2</sub> (g/GJ)	94,600	101,000	77,400	56,100
SO <sub>2</sub> (g/GJ)	765	1,361	1,350	0.68
NO <sub>x</sub> (g/GJ)	292	183	195	93.3
CO (g/GJ)	89.1	89.1	15.7	14.5
Organic compounds (g/GJ)*	4.92	7.78	3.70	1.58
Particulate matter (g/GJ)	1,203	3,254	16	0.1
Flue gas volume total (m <sup>3</sup> /GJ)	360	444	279	272

\*Non-methane



The sulphur has thus been transferred from a gas (SO<sub>2</sub>) to solid calcium sulfite and sulfate which falls to the bottom of the wet scrubber. The hydrated sulfate is gypsum which can be used as by-product of the power plant.

The other major category of gaseous pollutants which emanates from fossil fuel combustion is nitrogen oxides called NO<sub>x</sub>. These are pernicious pollutants because they are respiratory tract irritants, and they also contribute to acid precipitation. The NO<sub>x</sub> is produced because coal (and oil) contain organic nitrogen in their molecular structure. When burnt, these fuels produce so-called *fuel* NO<sub>x</sub>. In addition, all fossil fuel combustion produce *thermal* NO<sub>x</sub>. This is a recombination of atmospheric nitrogen and oxygen under conditions of high temperature. The NO<sub>x</sub> may be removed after combustion by *selective catalytic reduction* by injecting ammonia (NH<sub>3</sub>) into a catalytic reactor. The following reaction takes place:

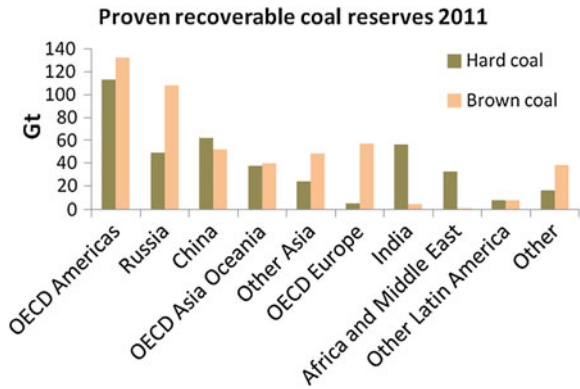


Thus NO is reduced to elemental nitrogen which is a natural constituent of the atmosphere. Similar reductions take place for other nitrogen oxides. The catalysts used are a mixture titanium and vanadium oxides.

The major effluent from the coal-fueled power plant is of course carbon dioxide (CO<sub>2</sub>) which is the product of burning carbon (coal) in an oxygen rich environment. However, CO<sub>2</sub> is not considered a pollutant. On the other hand carbon dioxide is a “green-house gas” which contributes to global warming, see Sect. 1.5.3. Therefore large projects are underway for capturing and storing carbon dioxide from fossil-fueled power plants (CCS), see Sect. 2.5.

Table 2.2 shows the average relative air pollution from 450 electricity-generating large combustion plants within the European Union.

**Fig. 2.8** Proven recoverable coal reserves at the end of 2011 (WEC 2013)



### 2.2.2 Present Use, Resource Considerations and Forecast

As indicated in Sect. 2.1, coal is a major source of energy. At present, almost the totality of the coal used serves as a fuel for electricity and/or heat generation. In few countries, South Africa being one such example, coal is also transformed into a liquid that is further refined into gasoline or diesel fuel.

Coal reserves are large compared to the reserves of other traditional fossil fuels. Figure 2.8 illustrates the state of the proven recoverable coal reserves around the planet, which are considered likely to be recovered under the current market conditions, taking into account the current mining technologies and their economics. Compared to other fossil fuels, coal is more evenly distributed around the globe and each major region has access to some quantities of coal. Yet, most reserves are located in the OECD countries, Russia, China and India.

At the current rate of extraction, hard coal<sup>2</sup> reserves will last for another 130 years and brown coal<sup>3</sup> reserves for another 270 years. Total coal reserves (including reserves that are not considered economically recoverable at present) are sufficient to last for many more decades.

Overall, the global production and consumption of coal have increased over time (see Fig. 2.9). Paradoxically, the growth rate of coal production exploded since the Kyoto protocol<sup>4</sup> was agreed upon. Almost all of the additional production took place within non-OECD countries, parallel to the growth of their energy needs (these countries did not ratify the Kyoto protocol). The share of the production taking place in OECD countries fell from 56 % in 1971 to 26 % in 2012. More precisely, over two thirds of the growth took place in China as this country has rapidly expanded its

<sup>2</sup> Bituminous, anthracite.

<sup>3</sup> Sub-bituminous, lignite.

<sup>4</sup> This is a global treaty under which many developed countries have accepted to reduce their carbon emissions.

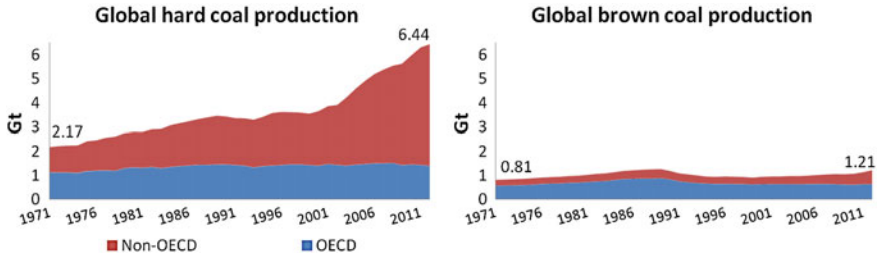


Fig. 2.9 Global production of hard coal and brown coal between 1971 and 2012 (IEA 2012)

Table 2.3 World total hard coal traded in 2010 in Mtonnes (IEA 2011a)

From/to	Japan	Other Asia	OECD Europe	N. America	L. America	Other
Australia	118.6	148.2	18.2	2.8	6.0	2.2
Canada	8.9	13.5	3.6	1.9	2.0	0
Poland	0	0	10.8	0	0	0.1
United States	3	13.4	27.5	9.0	8.7	6.6
PR China	7.0	12.3	0.1	0.1	0	0
Russia	12.1	31.0	46.0	0	0.4	15.9
Indonesia	34.5	291.1	9.1	1.7	0.8	0.9
South Africa	0.3	43.1	17.4	1.3	2.2	3.4
Other	2.2	60.2	49.1	17.1	1.1	15.1

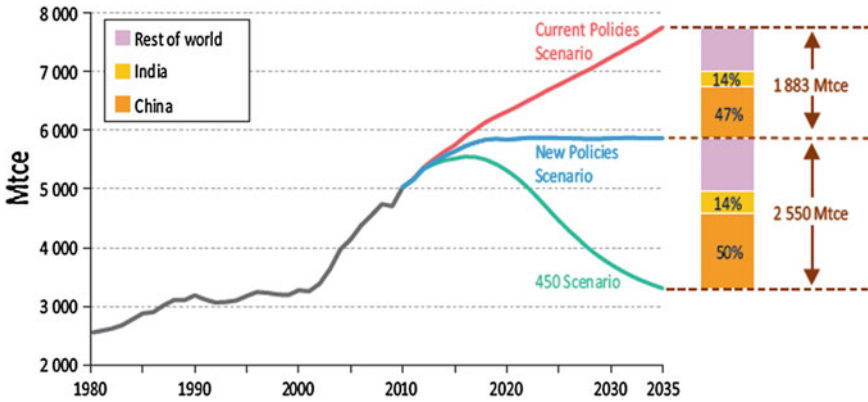
coal industry in the last decades. In 1971, China’s share of the world production of coal reached 13 % before steadily climbing to 27 % in 1999 and 42 % in 2010!

The quasi-totality of the extra coal produced or extracted is hard coal. Two reasons can explain that hard coal has expanded more rapidly than brown coal. First, the calorific value of hard coal is higher than the calorific value of brown coal, which generally leads to better economics. Second, the countries contributing most to the growth in coal production have access to large economically recoverable reserves of hard coal.

China is the biggest hard coal producer with 51 % of the global production in 2010. The United States (15 %), India (9 %), Australia (6 %), South Africa (4 %) and Russia (4 %) complete the top six. Germany leads in terms of brown coal production (16 %), followed by Indonesia (16 %) and Russia (7 %) (IEA 2011a).

Consumption generally goes along with production. The countries that have access to large economically recoverable coal reserves are usually the countries that consume most of the coal production. China is the biggest consumer of coal (48 %) followed by the United States (14 %), India (8 %), Russia (3 %) and Japan (3 %) which, together, consume over three quarters of the world coal production (IEA 2012). Large quantities of coal are nonetheless being traded and Table 2.3 illustrates the quantities of hard coal that have been traded between the major actors in 2010.





**Fig. 2.10** World primary coal demand by region and scenario. *World Energy Outlook 2011*, © OECD/IEA, 2011, Fig. 10.2, p. 358

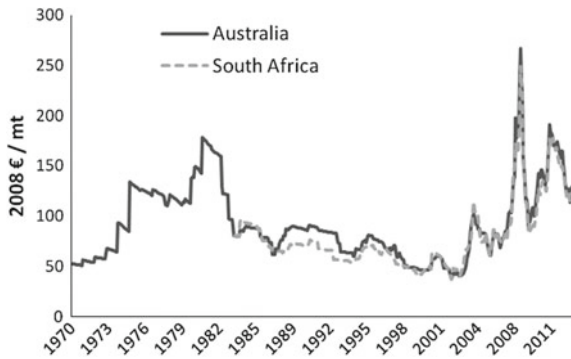
Over the past decades, environmental pressures have forced the coal power plants to become more efficient in terms of emissions and the average efficiency of new coal based power plant is steadily increasing around the planet. Yet, as these power plants have a long economic life (over 40 years), the average efficiency is only slowly improving.

The future development of coal is highly uncertain. Mostly due to increasing energy needs in developing countries, it is likely that coal will remain a major source of energy in the years to come and that the total installed capacity will expand. The magnitude of development of that energy source will however depend on the scale of future actions implemented to reduce greenhouse gas emissions, because as the ‘dirtiest’ fuel in terms of emissions, coal is likely to suffer most from climate regulations. Further development of carbon capture and storage technologies at a competitive rate will also influence the use of coal in the future. Figure 2.10 taken from a report by the International Energy Agency perfectly illustrates the uncertainty underlying the use of coal in the future.

The *Current Policies Scenario* assumes that the world follows a path leading to a maximum temperature increase of 2°C, which would require a steep decrease in the use of coal in the next decades. Implementing policies currently in discussion (the *New Policies Scenario*) will lead to a stabilisation in the consumption of coal, whereas a business-as-usual case (the *Current Policies Scenario*) implies that the use of coal will increase significantly in the future.

### 2.2.3 Cost

The costs presented in this section are based on the data available for black-coal fueled power plants and the emphasis is put on supercritical coal-fueled power plants. This



**Fig. 2.11** Coal prices in Australia and South Africa in <sup>2008</sup>Euro, 1970—July 13 (World Bank 2013)

type of power plants operates at higher temperatures and pressures than subcritical power plants, resulting in efficiency improvements and reduced carbon dioxide emissions per tonne of coal used compared to other types of coal-based power plants. Subcritical plants operate at efficiency levels of 39–46 %, which is to be compared to the 30–38 % achieved by subcritical power plants (OECD/Nuclear Energy Agency 2010). With increasing fuel prices and environmental pressures, it is likely that the popularity of the supercritical coal power plants will grow in the future.

### 2.2.3.1 Resource Cost of Coal

35–70 % of the LCOE for coal-fueled power plants is related to the cost of fuel. The prices of Australian and South African (two major exporters) coal in real terms over the period 1970–2013 are reproduced in Fig. 2.11. It is apparent that the price of coal can change drastically as a response to global events. For instance, the impact of the first oil crisis (1973) can clearly be seen on the graph as the price of coal nearly doubled as a result of a new political will to shift to coal in order to reduce countries' dependency on oil. The expected scarcity of supply meant that prices automatically increased until the supply side could adjust to this increasing demand. The second oil crisis (1979) also led to a surge in coal prices worldwide. More recently, fluctuations in coal prices are due to several distinctive events. First of all, the 2008 energy commodity price surge was also valid for coal. Coal prices later dropped in parallel to the prices of other commodities due to the financial crisis. Second, China started to import large quantities of coal since 2009. Added to an ever increasing coal demand from India since 1990, this increasing demand pressured prices upward. Thirdly, heavy rains and the flooding of some important areas in 2010 have disrupted the coal supply in some parts of Australia, as railway links and open pit coal mines were submerged (Blas 2011), leading to a decrease in the quantities of coal available for export and consequently, to an increase in the price of coal worldwide.

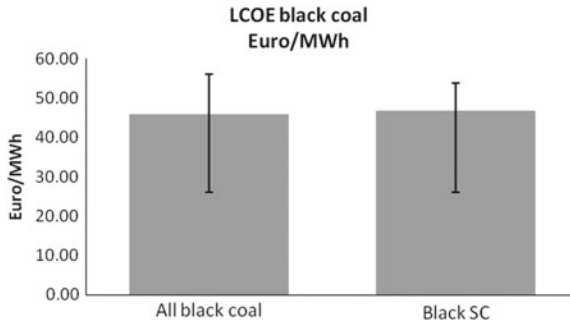
The two time series shown in Fig. 2.11 are highly correlated, showing that disruption in a particular coal market will impact other coal markets as well. In addition, the correlation between coal prices and oil prices is particularly high as well (around 0.76 for the period 1970–2013), indicating that a shock in oil prices will be reflected in the price of coal.

The importance of fuel for a coal-fueled power plant's LCOE combined to large fluctuations in coal prices illustrate one of the risks taken by investors when they invest in such plants. Coal-fueled power plants have an economic plant life of at least 40 years and predictions on future coal prices over the next few decades are needed in order to judge whether an investment is expected to generate positive returns or not. Such predictions are challenging (if not impossible) to make with a decent level of accuracy as many different factors impact the price of coal. For instance, some investors may claim that coal prices will increase in the future as a result of increased demand in China and India. This assumption will be challenged by others which predict that the emergence of unconventional fossil fuels (notably shale gas) will push some countries, e.g. the US, to shift from coal to natural gas, thus reducing global demand for coal and consequently lead to a decrease in the long-term coal prices.

At the moment, coal is one of the cheapest electricity generating technologies and even a moderate increase in the price of coal should not impact this statement. Nevertheless, a last factor, which is also the factor which embodies most uncertainty, is the possible emergence of stringent environmental regulations. Such regulations have the potential to make coal-fueled power plants economically unattractive, because carbon emissions related to coal are particularly abundant (twice those of natural gas for the same quantity of power generated). No one knows today if a global or regional climate agreement will be ratified, and especially its scale, and this uncertainty is perhaps the single most important source of uncertainty for investors. To date, this uncertainty has effectively discouraged many to invest in coal-fueled power plants in areas of the world (e.g. Europe, US) where such regulations may be implemented in the next decade or so.

### 2.2.3.2 Basic Cost of Coal Power Plants

Capital costs of coal-fueled power plants are low compared to the capital costs of other technologies, which partly explains why coal power is so popular in developing countries. The capital costs of a black-coal fueled power plant ranges between 400–1,800 Euro/kW of installed capacity. Compared to other technologies, the construction time of a coal power plant is relatively long as it takes nearly 4 years to build such a plant (OECD/Nuclear Energy Agency 2010).



**Fig. 2.12** Median levelized cost of electricity for black coal-fired power plants and supercritical coal-fired power plants. The ‘error bars’ indicate the range of cost

**Table 2.4** Levelized cost of electricity for black coal-fueled power plants

	All black coal	Black coal SC*
LCOE (Euro/MWh)	24–53	24–51
Overnight cost (%)	23–53	23–46
O&M costs (%)	4–18	4–16
Fuel costs (%)	34–72	39–72

\*Supercritical

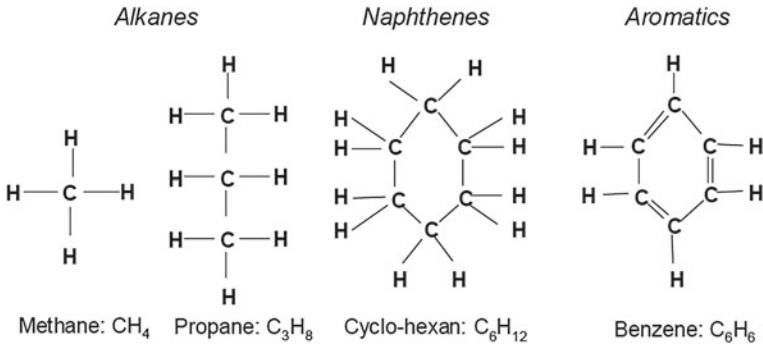
### 2.2.3.3 Electricity Generation Cost of Coal Power Plants

Power from coal is one of the cheapest, if not the cheapest, source of energy in most parts of the world. Low learning rates<sup>5</sup> do not let assume that the levelized costs of coal power will decrease significantly in the future. As long as no price is put on CO<sub>2</sub> emissions,<sup>6</sup> coal will remain highly competitive in the foreseeable future. As mentioned earlier, the big share of the levelized cost is due to the cost of fuel since they account for between 34 and 72 % of the levelized costs of electricity from coal. Capital costs account for a third to about half of the levelized costs of coal power, whereas O&M costs are less important and sum up to less than 10 % of the LCOE. These numbers are summarized in Table 2.4 and Fig. 2.12.

Finally, increasing efficiency can lead to better economics. One such option is to combine electricity and heat (Combined Heat and Power, or CHP) in order to reduce the energy loss in the process of producing electricity.

<sup>5</sup> See Sect. 5.1.4 for a description of learning rate.

<sup>6</sup> See Sect. 5.2.4 for a description of the impact of a carbon price on the cost of coal.



**Fig. 2.13** Examples of hydrocarbons in petroleum. Methane and propane are gases under normal conditions (atmospheric conditions). Cyclo-hexan and benzene are liquids

## 2.3 Oil and Gas

### 2.3.1 Basic Properties

In this chapter we will generally treat oil and gas together because they have many overlapping properties, and because the exploration for oil and gas usually is one and the same venture.

Most substances normally exist in three *phases*: the solid phase, the liquid phase and the gas phase. Temperature and pressure will decide in which phase a substance exists. Solids have a tendency to keep their shape and volume when subject to moderate external forces. Liquids on the other hand, will change their shape but retain their volume, and gas will change both shape and volume. Nevertheless, there is no clear separation between the three phases, especially not between liquid and gas, which is often denoted by the common name: *fluids*. Both oil and gas are therefore fluids. At the same time they belong to a chemical group called *hydrocarbons* because their molecules mostly consist of hydrogen and carbon atoms, but may also include sulphur, nitrogen, oxygen and metallic compounds. We use the term *petroleum* about the mixture of hydrocarbons that we want to recover from a petroleum reservoir. Depending on temperature and pressure, it may be a liquid, a gas or even a solid phase.

The hydrocarbons found in a petroleum reservoir vary from the simple molecule *methane* (CH<sub>4</sub>) with a molecule weight of 16, to naphthenes and polycyclic molecules with a molecule weight of more than a thousand. All molecules have been created through thermal or bacterial decomposition of organic matter subject to high pressure and temperature during millions of years. Figure 2.13 displays examples of molecules which may be found among the hydrocarbons in a petroleum reservoir.

It is often more practical to refer to a special hydrocarbon by the number of carbon atoms in the molecule instead of the exact chemical formula. Methane is then denoted C<sub>1</sub>, propane C<sub>3</sub> etc. The components which are liquids under atmospheric or *standard*

**Table 2.5** Crude oil classification based on its density

	$^{\circ}API$	$\rho_0$ (g/cm <sup>3</sup> )
Light oil	>31.1	<0.870
Medium oil	31.1–22.3	0.870–0.920
Heavy oil	22.3–10	0.920–1.000

*conditions* (1 atm =  $1.013 \times 10^5$  Pa and  $T = 15$  °C) are described as *crude oil* in commercial contexts. Crude oil may consist of thousands of different molecule types and can vary from a light-brown liquid to a very high viscosity tar-like fluid. Crude oils are often broadly categorized by using properties which are easy to measure in the field, such as the gravity of the oil. For historical reasons the gravity is measured in *degrees API* (American Petroleum Institute) which is defined:

$$^{\circ}API = \frac{141.15}{\rho_0} - 131.5$$

where  $\rho_0$  is the density in g/cm<sup>3</sup>. Crude oil is then classified according to its density as in Table 2.5.

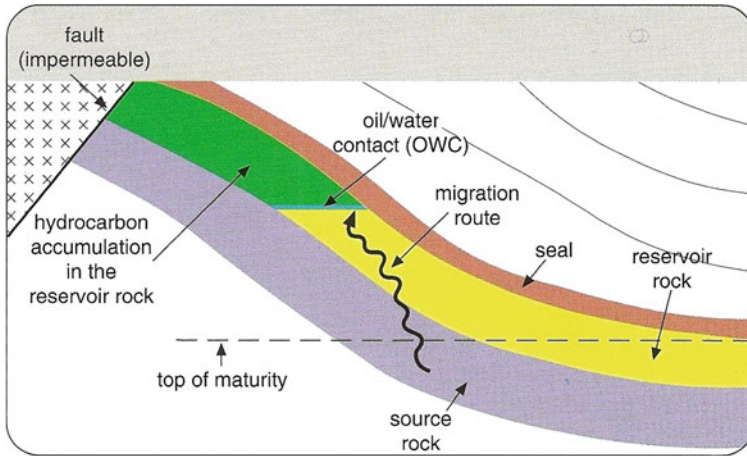
Because of the high temperature and pressure in a petroleum reservoir, the oil usually contains dissolved gas. When the oil is brought to the surface some of the gas will be released, which results in a shrinkage of the oil volume. The gas/oil ratio (GOR) is a dimensionless number equal to the ratio of the released gas volume to the oil volume at the surface (at standard conditions). The GOR and the API is a first indication of the quality of the oil.

### 2.3.2 Hydrocarbon Accumulations

Several conditions must be satisfied for a hydrocarbon accumulation to be established as a petroleum reservoir. The first is a *sedimentary basin* where a suitable sequence of rocks has accumulated over geological time. Within this sequence there must be a high content of organic matter, *the source rock*. The source rock reaches *maturation* through elevated pressure and temperature, a condition at which hydrocarbons are expelled through a process called *migration* and transferred into a porous type of sediment, the *reservoir rock*. Only if the reservoir is deformed in a favorable shape or if it is laterally grading into an impermeable formation, does a *trap* for the migrating hydrocarbons exist. These conditions are illustrated in Fig. 2.14 and we will describe them in more detail below.

#### 2.3.2.1 Source Rock

In petroleum geology, source rock refers to a rock where hydrocarbons are being generated from organic matter. About 90 % of all organic matter found in sediments is contained in *shale*, which is a fine-grained clastic sedimentary rock composed



**Fig. 2.14** Generation of hydrocarbons in a source rock, migration and trapping in the reservoir rock

of mud that is a mix of flakes of clay minerals. Continuous sedimentation over a long period of time causes burial of organic matter. These organic deposits can be divided into three groups depending on its origin and the type of hydrocarbon it produces. It may originate from *algal remains* deposited under anoxic (lack of oxygen) conditions in deep lakes or ocean. They tend to generate waxy crude oils when submitted to thermal stress during deep burial. An other source rock may be formed from *marine planktonic* and bacterial remains preserved under anoxic conditions in marine environments. Source rocks which are formed from terrestrial *plant material* that has been decomposed by bacteria and fungi under oxic or sub-oxic conditions. They tend to generate mostly gas and light oils when thermally cracked during deep burials. Most coals and coaly shales are this kind of source rock.

### 2.3.2.2 Maturation

The solid, insoluble organic matter that occurs in source rocks is called *kerogen*. Typical organic constituents of kerogen are algae and woody plant material, as described in the previous subsection. With increasing burial and pressure from later sediments, and increase in temperature, the kerogen within the source rock begins to break down. This thermal degradation or cracking releases shorter chain hydrocarbons from the original large and complex molecules found in kerogen. As a result lighter hydrocarbon molecules are formed. This conversion of sedimentary organic matter in the source rock into petroleum is termed *maturation*, and the important factor in this process is heat. Depending on the temperature in the source rock, the crude oil itself will begin to crack and gas will start to be produced. Initially the composition of the gas will show high content of C<sub>4</sub>–C<sub>10</sub> components (wet gas or condensate), but with further increase in temperature the mixture will tend towards the light hydrocarbons C<sub>1</sub>–C<sub>3</sub> (dry gas).

### 2.3.2.3 Migration

As we can see from Fig. 2.14, the hydrocarbons do not accumulate in the source rock, but following the maturation, they migrate into a reservoir rock where from we may produce oil and gas to the surface by drilling. During the *primary migration* hydrocarbons move from the deeper, hotter parts of the sedimentary basin into suitable structures. Hydrocarbons are lighter than water and will therefore tend to move upwards through permeable strata originally filled with water.

In the second stage of migration the generated fluids move more freely along bedding planes and faults into a suitable reservoir structure. This *secondary migration* process can occur over considerable lateral distances of several tens of kilometers.

### 2.3.2.4 Reservoir Rock

Reservoir rocks are either of *clastic* or *carbonate* composition. Both are sedimentary rocks. The former are composed of silicates, usually sandstone, the latter of biogenetically derived detritus, such as coral or shell fragments. There are some important differences between the two rock types which affect the quality of the reservoir and its interaction with fluids which flow through them.

The main components of sandstone reservoirs (siliciclastic reservoirs) is quartz ( $\text{SiO}_2$ ). Chemically it is a fairly stable mineral which is not easily altered by changes in pressure, temperature or acidity of pore fluids. Sandstone reservoirs form after the sand grains have been transported over long distances e.g. by rivers or wind, and have been deposited in particular environments of deposition, such as river deltas, shallow marine sand banks or sheet-like sand bodies from storms or transgression (a rising of the sea level relative to the land).

Carbonate reservoir rock is usually found at the place of formation (in situ). Carbonate rocks are susceptible to alteration by the process of *diagenesis* which are a chemical and physical processes affecting a sediment after deposition.

The pores between the rock components, for example the sand grains in a sandstone reservoir, will initially be filled by *pore water*. The migrating hydrocarbons will displace the water and thus gradually fill the reservoir. For a reservoir to be effective, the pores need to be in communication to allow secondary migration, and also need to allow flow towards the borehole once a well is drilled into the structure. The pore space is referred to as *porosity* in oil field terms. *Permeability* measures the ability of a rock to allow fluid flow through its pore system. Porosity is an important parameter for determining the amount of hydrocarbons stored in a reservoir, and the permeability indicates how easy these hydrocarbons are to produce. A reservoir which has a good porosity but low permeability is termed “tight”.

## 2.3.3 Exploration

Finding a petroleum reservoir may at first seem to be like finding a needle in a haystack. Given the cost of exploration ventures, it is clear that much effort will be



expended to avoid failures. A variety of disciplines are involved, such as geology, geophysics, mathematics, geochemistry, to analyze a prospective area. However, on average, even in very mature areas where exploration has been ongoing for years, only every third exploration well will encounter substantial amounts of hydrocarbons. In basins that have not been drilled before the rate of success may be as low as every tenth well. The first indication that an area is a potential candidate for closer geophysical exploration, is the general knowledge the geologists have of the area. Mapping of gravity anomalies and magnetic anomalies may be the first indications of a sedimentary basin. Next, *seismic surveying* is carried out, starting with a coarse two-dimensional (2D) seismic grid, covering a wide area. This is performed to find structures that may be candidates for potential hydrocarbon accumulations. These seismic surveying methods, which are described in more detail below, are based on sending *acoustic pulses* into the strata and recording the reflections. Recently, also *electromagnetic techniques* using electromagnetic pulses have been used.

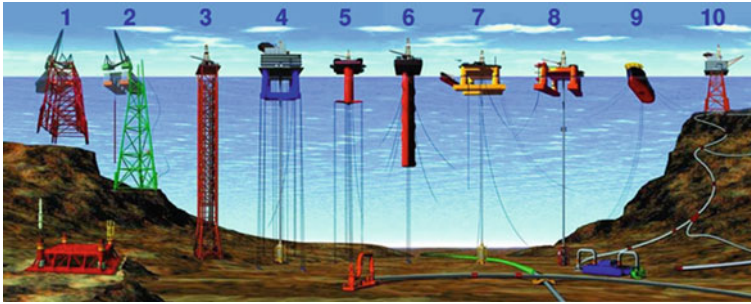
Acoustic seismic surveys involve generating *sound waves* which propagate through the Earth's rock down to reservoir targets. For land surveys this may be truck-mounted *vibrating sources* or small *dynamite charges* detonated in a shallow hole. The most common marine sources are pneumatic air guns or water guns that expel air or water into the surrounding water column to create an acoustic pulse. The waves are reflected from different strata in the underground and registered on the surface in receivers called *hydrophones*. The reflection data is recorded and stored for processing. The result is an acoustic image of the subsurface which is interpreted by geophysicists and geologists. It is quite clear that this involves a complicated analysis that need highly trained and experienced specialists. Their work is decisive for where the first wells will be drilled.

Seismic surveying has progressed to become one of the most effective methods for optimizing field production.

It is used in:

- *exploration* for delineating structural and stratigraphic traps
- deciding where the first wells will be drilled
- *field appraisal* and *development* for estimating reserves, and drawing up field development plans
- *production* for reservoir surveillance such as observing the movement of reservoir fluids in response to production

Seismic acquisition techniques vary depending on the environment (onshore or offshore) and the purpose of the survey. In an exploration phase a seismic survey consist of a loose grid of 2D lines. In contrast, in an underground appraisal, a 3D seismic survey will be shot. The 3D grid is more closely spaced than the 2D and have both vertical and horizontal positions. In some mature fields a permanent 3D acquisition network might be installed on the seabed for regular (6–12 months) surveillance of the reservoir's response to production. A collection of three-dimensional (3D) seismic data acquired at different times over the same area is called a four-dimensional (4D) seismic acquisition.



**Fig. 2.15** Offshore installations: 1, 2 Conventional fixed platforms; 3 Compliant tower; 4, 5 Vertically moored tension leg and mini-tension leg platform; 6 Spar; 7, 8 Semi-submersibles ; 9 Floating production, storage, and offloading facility; 10 Sub-sea completion and tie-back to host facility (NOAA)

### 2.3.4 Drilling

The oil rig is what most people first of all associates with the oil and gas industry. The rigs come in many sizes and constructions depending on where the reservoir is located:

- onshore (Saudi Arabia, Texas, Canada)
- shallow water (parts of the North Sea, Gulf of Mexico, Nigeria, Venezuela)
- deep offshore waters (Brazil, the Norwegian Sea, the Barent Sea, Gulf of Mexico) with 500–3,000 m water depths

An artistic review of different offshore installations, both for drilling and production is shown in Fig. 2.15. For offshore drilling rigs, we distinguish between two types: moveable and permanent rigs. The drilling of a well involves a substantial investment from a few million Euro for an onshore well to 100 million Euro plus for a deepwater offshore well. The purpose of the drilling is to collect information about geological formations, find and produce hydrocarbons or to inject water or gas to into the reservoir in order to maintain or increase the reservoir pressure. We may therefore divide the wells into three major classes:

- Exploration wells
- Production wells
- Injection wells

#### 2.3.4.1 The Main Components of the Drill Rig

The principle and the main components of an onshore rig is shown in Fig. 2.16. The basic drilling system is the same for both onshore and offshore rigs and the central unit is the drill tower, called a *derrick*, with a rotary system which rotates the *drill*

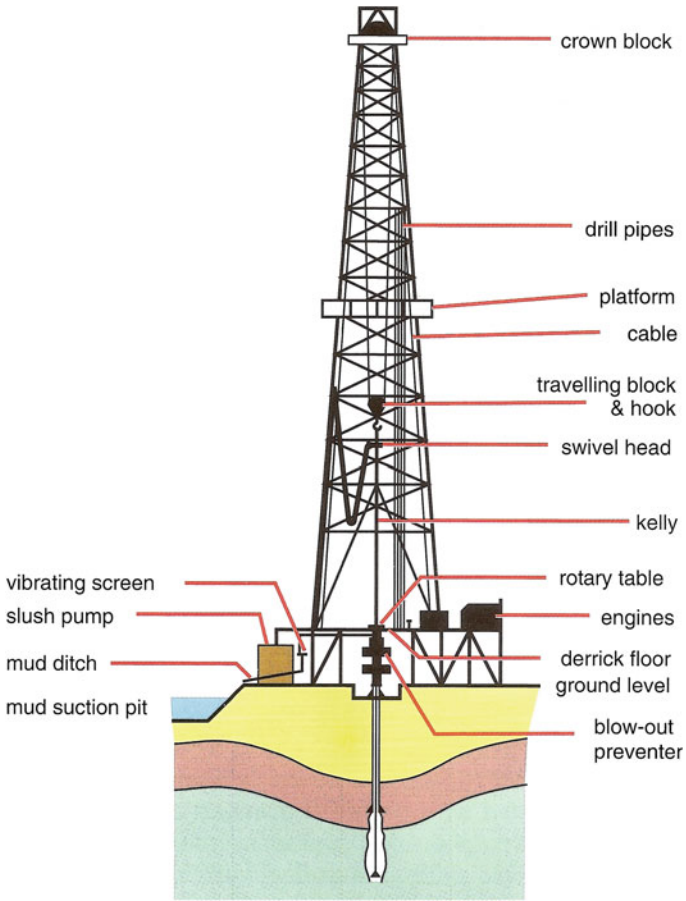


Fig. 2.16 Main components of an oil rig

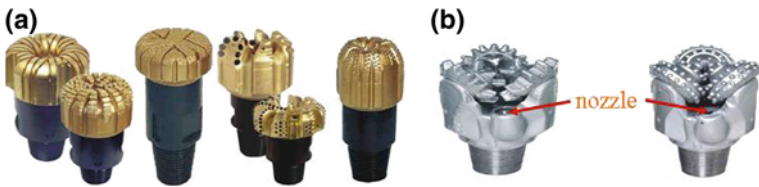


Fig. 2.17 a PDC-bits and b roller cone bits

*string* with the *drill bit* at the bottom of the well. The rotation is either provided by a *rotary table* at the derrick floor or for newer and more advanced rigs, by a *top drive* system which is coupled to the top of the drill string and guided by rails so it can move up and down inside the derrick.

After the drilling has progressed for some time a new piece of drill pipe will have to be added to the drill string. Each pipe section is usually 9 m (30 feet) long and the drill string is raised so that the drill bit no longer touches the bottom of the well. In this position the drill string is decoupled from the top drive and a new pipe section is added. Sometimes, for various reasons, such as to change the bit or drilling assembly, the whole drill string has to be brought to the surface. Normally 27 m sections, called a *stand*, and rack them in the mast rather than disconnecting all the 9 m sections. The procedure of pulling the whole string out and running it in again is called a *round trip* and takes the order of 24 h to complete.

There are two main groups of drill bits, see Fig. 2.17:

- PDC (Polycrystalline Diamond Cutter) bits
- Roller cone bits

The *PDS-bit* is lined with industrial diamond cutters and is cutting the rock at the bottom of the bore hole with a scratching movement. It has a high rate of penetration, a long life time and is suitable for drilling with high revolution frequency. The teeth on the three cones on the *roller cone bit* break and crush the rock. The cutting action is supported by powerful jets of drilling fluid which are discharged under high pressure through nozzles located on the side of the bit. The fluid or *drilling mud* is prepared at the platform and pumped down to the drill bit through the drill string and is circulated back up through the annulus which is the volume between the drill pipe and the wall of the bore hole. The mud has three important functions:

- cool the drill bit
- lift the cuttings created by the bit action out of the well
- provide a back-pressure against the reservoir pressure

Two main groups of mud are available; *water-based mud* (WBM) and *oil-based mud* (OMB). The WBM is the most common, and more environmentally acceptable than OMB, which is based on diesel or mineral oil. The correct gravity of the mud is achieved by adding a heavy mineral e.g. baryte ( $\text{BaSO}_4$ ). During drilling operations large quantities of mud is used. It is expensive and for environmental reasons it can not be dumped at sea. Therefore, the mud is filtered and cleaned at the surface and kept in large storage tanks before it is pumped back into the well through the drill string. Samples of the cuttings brought up by the mud is kept for analysis and give information about lithography (rock types) of the formations penetrated in the drilling process.

#### 2.3.4.2 Casing and Well Completion

To prevent the bore hole from collapsing the wellbore is lined with *casings* between the drill string and the borehole wall. The casing design resembles a periscope with the largest diameter at the top, and a decreasing diameter downwards towards the top of the reservoir, and cemented to the borehole wall. *Well completion* is the procedure

for preparing the well for production. The last section of the casing is the *liner* which perforated so that the reservoir fluids can enter into the production line inside the casings.

A *blowout preventer* (BOP) is sitting between the well head and the platform. The BOP is a series of powerful sealing elements designed to close off the annular space between the pipe and the hole through which the mud normally returns to the surface. As mentioned above one of the purposes of the drilling mud is to provide a hydrostatic head of fluid to counterbalance the pore pressure of the fluids in the reservoir. However, for a variety of reasons the well may “kick”, that is formation fluids may enter the wellbore, upsetting the balance of the system, pushing mud out of the hole, and exposing the upper part of the well and the equipment to the higher pressure from the deep subsurface. If left uncontrolled, this can lead to a blowout, a situation where formation fluids flow to the surface in an uncontrolled manner.

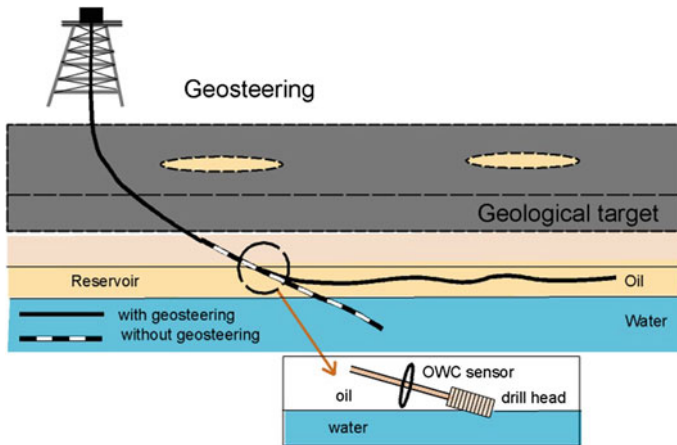
### 2.3.4.3 Directional Drilling and Geosteering

Almost no wells are vertical. Advanced *directional drilling* techniques using rotary steerable systems have been developed. Instead of rotating the whole drill string, mud motors sitting just behind the bit, facilitates the rotation. The motor is run by the circulating mud so that the rotation of the drill string is restricted to the motor section and the drill bit while the rest of the drill string moves with a sliding motion or only rotates with a much lower speed. The state of the art today is that by directional drilling to almost any target in the subsurface, in fact it is also possible to drill upwards. In this way even small pockets of hydrocarbons can be reached.

Directional drilling, often called horizontal drilling, with *geosteering* is probably the one factor that has contributed most to the increased recovery factor over the last two decades. It is based on downhole geological logging, called *measurement while drilling* (MWD). A sonde is placed on the drill string close to the bit. It contains logging tools which measures petrophysical data (porosity, density, resistivity etc.) while drilling. The resistivity measurements enable the driller to steer the bit above the oil water contact (OWC), a technique which is important for producing thin oil zones, see Fig. 2.18. Horizontal drilling and geosteering have today been refined to a technique where it is possible to steer the bit to a target 10 km from the platform with an accuracy of 1 m.

### 2.3.5 Production

Seismic data acquisition and geological models give important information about the size and the commercial capacity of a reservoir. However, it does not inform us about the flow properties of the reservoir fluids and their interaction with the rock. These fluids (water, oil, gas) are contained under high pressure in a porous network



**Fig. 2.18** The principle of geosteering. The drill path can be adjusted by the MWD sonde to stay on *top* of the pay zone

with pore sizes ranging from a few  $\mu\text{m}$  ( $10^{-6}$  m) to several hundred  $\mu\text{m}$ . Once the reservoir is opened to the surface through a production well, the high pressure in the reservoir will drive the hydrocarbon towards the well and produce it to the surface. Utilizing the natural pressure of the reservoir called *pressure depletion*, is the simplest of all production mechanisms. The following expansion of the reservoir fluids act as a source of drive energy which support the *primary production* from the reservoir. Primary production means using the natural energy stored in the reservoir as a drive mechanism for production. *Secondary production* implies adding energy to the reservoir by injecting fluids to help supporting the reservoir pressure as production takes place. One also speaks of *tertiary recovery* or *enhanced oil recovery* (EOR) which implies adding energy through thermal methods, chemical flooding or injection of gas, for example  $\text{CO}_2$  or nitrogen. We will discuss drive mechanisms in primary recovery in somewhat more detail in the next section, and return to secondary recovery (water flooding) later and to tertiary recovery (EOR) in Sect. 2.4.

### 2.3.5.1 Driving Mechanisms and the Material Balance Principle

A *drive mechanism* can be defined as the energy already present in the reservoir, or which is injected into the reservoir, so that hydrocarbons are produced to the surface. It may be the original reservoir pressure, an expanding gas cap, *natural water drive* when water from an underlying *aquifer* is able to flow into the reservoir, or energy added through injection of water or gas from the surface (secondary recovery). The drive mechanisms may vary from field to field and several drive mechanism may act simultaneously. The *material balance principle* (MBE) states the logical principle that:

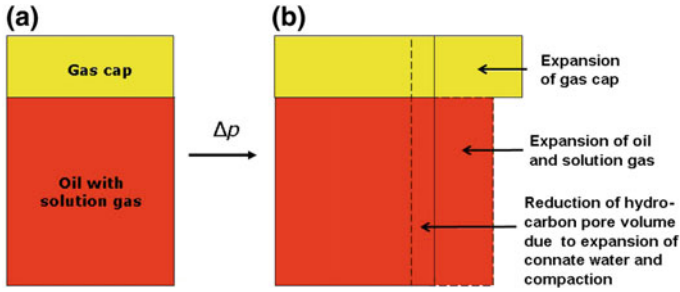


Fig. 2.19 a Oil and gas volumes before a production. b The volumes after a production which results in a pressure drop

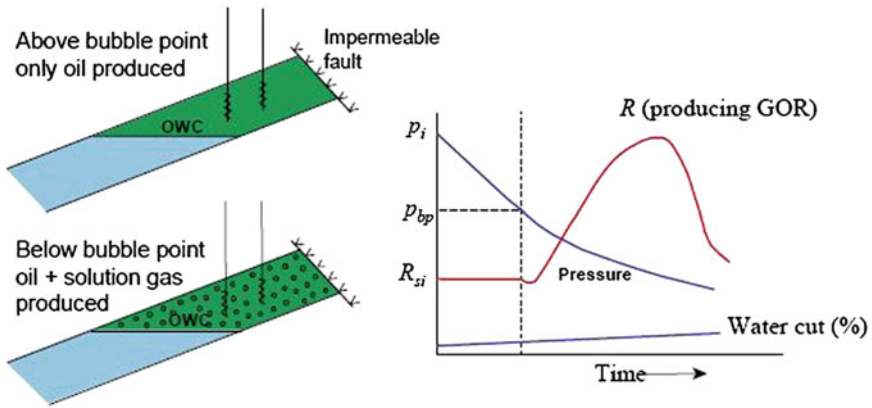


Fig. 2.20 Production profile for solution gas drive reservoir

The mass  $M_i$  of the hydrocarbons originally present in the reservoir is equal to the sum of the mass  $\Delta M$  produced and the mass  $M$  remaining in the reservoir.

The MBE-principle may be stated mathematically, which will not be done here, but the equation does not imply any detailed information about the processes going on in the reservoir or any geological models. However, this simple principle has proved to be valuable for:

- forward extrapolation of production curves for oil, gas and water
- identification of drive mechanisms
- history match

Figure 2.19 illustrates a production without any injection from the surface or inflow from an aquifer.

The reservoir contains oil with dissolved gas and a gas cap above the oil, Fig. 2.19a. Oil is produced from the oil zone and there is a pressure drop  $\Delta p$  in the reservoir. As a result of the reduced pressure, the gas cap will expand and so will the oil. If the pressure drops below the bubble point of the oil, some of the solution gas may

be liberated and enter the gas cap. An effect in the opposite direction as a result of a reduced reservoir pressure, is an expansion of the formation water and a decrease of the pore volume. The latter is due to increased compaction (the pressure from the overlaying formations). Both these effects reduce the volume available for the hydrocarbons, as indicated in Fig. 2.19b. The net result of all the effects is that oil is pushed out of the reservoir. The material balance is traditionally expressed in terms of volumes and for primary recovery we then have in reservoir volume units:

$$\begin{aligned} \text{Produced oil (Rm}^3\text{)} &= \text{Expansion of oil + solution gas (Rm}^3\text{)} & (2.5) \\ &+ \text{Expansion of gas cap (Rm}^3\text{)} \\ &- \text{Reduction of hydrocarbon pore volume (Rm}^3\text{)} \end{aligned}$$

The primary production from a reservoir when the driving force is the expansion of oil plus the solution gas, will depend on the pressure being above or below the bubble point  $p_b$ . A schematic production curve is shown in Fig. 2.20. As long as the reservoir pressure is above the bubble point, only oil is produced and the solution factor  $R_s$  of gas in the produced oil remains constant. When the pressure falls below the bubble point, the liberated gas may be produced into the wells together with the oil, and the produced gas to oil ratio (GOR) starts to increase. After some time the driving force is exhausted and the production curve starts to fall. At the same time, water production (water cut) may start, which is unfavorable. The total recovery for such reservoirs is small (5–25 %). Preferentially, the gas should have remained in the reservoir to maintain the driving force. This can to some extent be achieved by a well strategy which allows the liberated gas to migrate away from the production wells to the top of the reservoir.

### 2.3.5.2 Waterflood

*Waterflood* or water displacement is the secondary recovery method in which water is injected into the reservoir formation to displace oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells, see figure 2.21. Zone I is the swept region of the reservoir leaving only unproduceable residual oil, zone II is the water front where both water and oil is flowing, and zone III is the yet unproduced reservoir where the oil saturation is  $S_o = 1 - S_c$ , where  $S_c$  (connate water) is the original water saturation before production starts.

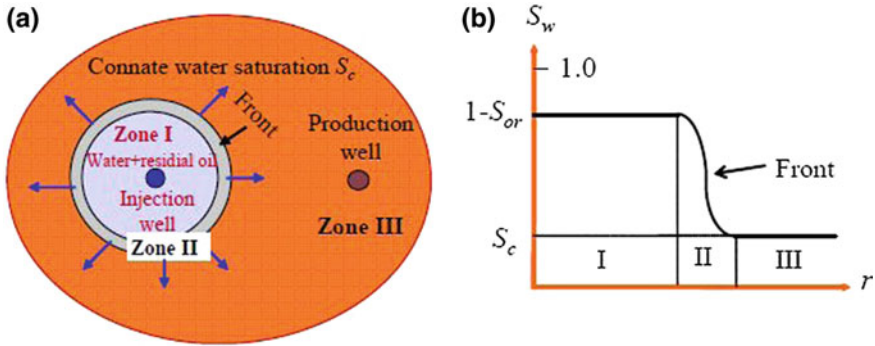
The *recovery factor*  $E_R$  is the ratio between the oil produced and the oil originally in place (STOOIP<sup>7</sup>). It depends on three factors:

$$E_R = E_D \times E_A \times E_V \quad (2.6)$$

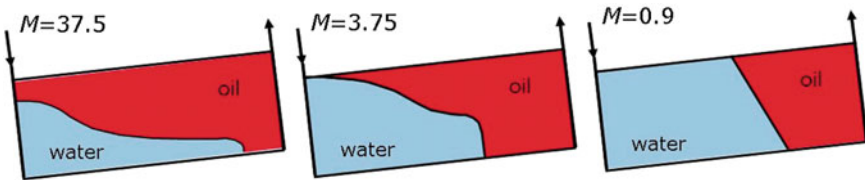
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<sup>7</sup> Stock Tank Oil Original In Place is a term which normalises volumes of oil contained under high pressure and temperature under ground to surface conditions, 1 bar and 15 °C





**Fig. 2.21** a A simple model of production by a waterflood. Water is injected in an injection well and oil produced in the production well. b The saturation front shows how the oil is displaced towards the production well



**Fig. 2.22** Watersweep with three different mobility ratios

$E_A$  is the *areal sweep efficiency* which reflects how well the reservoir is swept by the waterflood. It depends on the well pattern, the properties of the reservoir fluids (viscosity), the characteristics of the reservoir rocks (permeability), and the rate at which the displacement takes place.  $E_V$  is the *vertical displacement efficiency* which depends on the same properties, but in the vertical flow direction. The *microscopic displacement efficiency*  $E_D$  is the recovery rate at *pore level*. It can never be 100 % due to capillary forces which results in a residual oil saturation  $S_{or}$ . Oil saturation  $S_o$  is defined as the percentage of the reservoir pore volume which is filled by oil.

The volumetric sweep efficiency  $E_A \times E_V$  is the fraction of the total reservoir volume contacted by the injected water during the recovery. If the oil is very viscous, its mobility may be low compared to the mobility of the water in which case the water may move around the oil. This results in an unfavorable production situation with a poor sweep efficiency and an early water breakthrough in the production wells, leaving much of the oil behind. Figure 2.22 illustrates this for three different mobility ratios  $M$  between water and oil in a slightly inclined reservoir. The highest mobility ratio represents the most viscous oil. On the other hand, a piston shaped displacement with a high volumetric sweep efficiency is the result of a mobility ratio close to unity.

Recovery factors after secondary recovery (e.g. waterflood) range from 20 to 70 %, depending on well strategy. It has been considerably improved during the last decades by effective horizontal drilling and improved sweep efficiency. Table 2.6 ranks the 10

**Table 2.6** 10 largest oil fields on the Norwegian continental shelf by reserves originally in place (NPD 2013)

Field	STOOIP (mill Sm <sup>3</sup> )	Recovery (%)	Main drive mechanism
EKOFISK	1,099	49	Water injection, earlier pressure depletion and compaction drive
STATFJORD	860	66	Pressure depletion in the late phase, earlier water, water alternating gas
TROLL	642	39	Pressure depletion with natural water and gas drive
GULLFAKS	642	61	Water injection. Some gas, and water alternating gas injection
OSEBERG	592	64	Gas injection. Some water alternating gas injection
SNORRE	515	47	Water, gas and water alternating gas injection
ELDFISK	463	29	Water injection, earlier pressure depletion and compaction drive
VALHALL	435	33	Water injection, earlier pressure depletion and compaction drive
HEIDRUN	432	39	Water injection. Some gas injection and pressure depletion
GRANE	229	53	Gas injection, from 2011 water injection and gas reinjection

largest oil fields on the Norwegian continental shelf by reserves originally in place (STOOIP).

## 2.4 Enhanced Oil Recovery

Enhanced oil recovery (EOR), sometimes called improved oil recovery, is a term used for tertiary recovery methods in which energy is supplied by injecting substances which are not normally present in the reservoir. The purpose is to increase the recovery factor beyond what can be achieved by primary production methods (pressure depletion) or secondary production (water or natural gas injection), which on the average is of the order of 35 %. Most EOR methods are expensive and on the global scale there has been a clear connection between the oil price and the willingness of the oil companies to start up such measures. Internationally the EOR methods have so far almost exclusively been used on onshore fields, and have created significant values for the owners. Offshore application is still in its infancy, but studies predict that a combination of methods technically has the potential for an increase of 15–25 %.

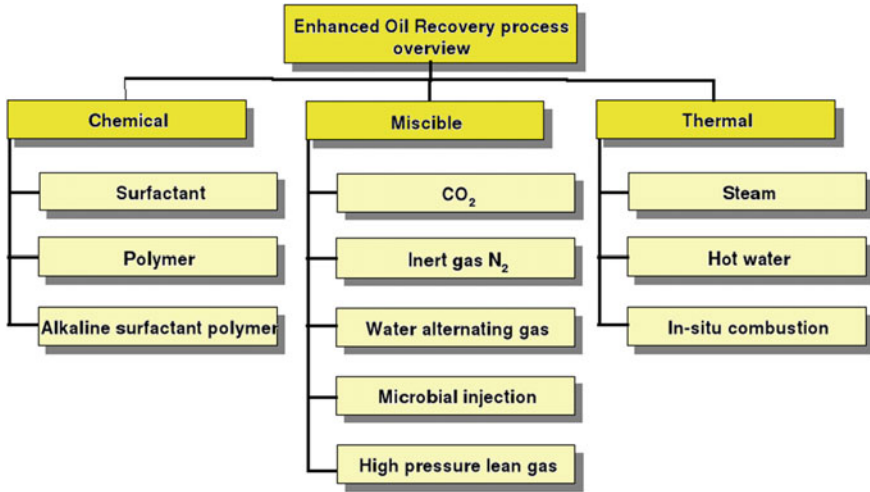


Fig. 2.23 Overview of the most important EOR techniques

Three main categories of EOR exist

- thermal techniques
- chemical techniques
- miscible techniques

The most common EOR techniques are summarized in Fig. 2.23 and described briefly below.

*Thermal EOR techniques* are used to reduce the viscosity of the oil, thereby improving its mobility, and allowing the oil to be more efficiently displaced to the producing wells. This is the most common EOR technique used on onshore reservoirs with oil gravity less than 20° API. Steam or hot water is injected into the reservoir. This can be done in dedicated injectors (steam or hot water drives) and producing oil from other wells much the same way as with water drives. Alternatively, the steam stimulation and production can be carried out in the same well in a cyclic process called “huff’n puff” in which the steam first soaks the reservoir before it is withdrawn allowing the oil production to take place. A more spectacular method is *in-situ combustion* or fire flooding where heat is generated by igniting a mixture of hydrocarbon gas and oxygen directly in the reservoir. As the fire moves, the burning front pushes ahead a mixture of hot combustion gases, steam and hot water, which in turn reduces oil viscosity and displaces oil toward production wells.

*Chemical EOR techniques* includes the injection of *polymers* which are long-chained organic molecules with high molecular weight, often one thousand or more. Both biopolymers (e.g. xanthan) or synthetic polymers are used. When injected in water with special chemicals added, the polymer form a *gel* which resembles a thick soup. This increases the viscosity of the displacing fluid, thereby reducing the mobility ratio *M* between water and oil to a more favorable value, see Fig. 2.22.

Hence, a more efficient volumetric sweep efficiency is achieved and an early water breakthrough can be avoided. The gel formed by polymers can also be used as a blocking agent, sealing off cracks and channels where the displacing fluids may take shortcuts to the producing wells, leaving much oil behind. Use of *surfactants* is an other chemical technique. A surfactant acts much the same way as a dish washing detergent which dissolves fat in the washing water. It is a chemical that preferentially adsorbs at an interface, lowering the surface tension or interfacial tension between fluids or between a fluid and a solid. Simply stated, one may say that the water and oil mix and form microemulsions which are more eligible for flow through the pore system of the reservoir rock. The residual oil saturation  $S_{or}$  is then reduced, and the microscopic displacement factor  $E_D$  improved, see Eq. 2.6. The overall result is a better recovery factor  $E_R$ .

A relatively new chemical EOR technique known as *alkaline surfactant polymer* (ASP) which is a mixture of polymer and surfactant, has successfully been conducted worldwide in recent years. Some ASP floods has been achieving 20 % incremental oil recovery (Zerpa et al. 2005).

*Miscible EOR techniques* implies the injection of miscible gases into the reservoir. A miscible displacement process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and water is reduced. Miscible displacement is a major branch of enhanced oil recovery processes. Injected gases include liquefied petroleum gas (LPG), such as propane, methane under high pressure, methane enriched with light hydrocarbons, nitrogen under high pressure, and carbon dioxide ( $\text{CO}_2$ ) under suitable reservoir conditions of temperature and pressure. The fluid most commonly used for miscible displacement is carbon dioxide because it reduces the oil viscosity and is less expensive than liquefied petroleum gas. A special and effective miscible method is called Water-Alternating-Gas (WAG) which has also been applied to offshore fields in the North Sea (NPD 2009). This is a process used mostly in  $\text{CO}_2$  floods, whereby water injection and gas injection are carried out alternately for periods of time to provide better sweep efficiency and reduce gas channeling from injector to producer.

EOR techniques require use of large amounts of chemicals and therefore represent a substantial *environmental hazard*. Offshore application creates extraordinary challenges related to the handling of back produced EOR chemicals and discharge to sea. These risks need to be assessed, and handling requirements before discharge must be established. It is necessary not only to use those chemicals which are technically most effective, but at the same time select those which have the lowest risk of environmental damage. The economic impact of implementation of EOR techniques can therefore be tremendous both for the operator and the society.

### ***2.4.1 Oil: Present Use, Resource Considerations and Forecast***

Oil is a remarkably valuable resource. Although most of the oil is consumed as a source of energy, refined oil products are key components of many finite products,

including plastic, some types of make-up, candles and synthetic fibers used in clothing.

In this book, we focus on oil as a source of energy. Keeping this scope in mind, oil has particular properties that makes it suitable to most applications requiring energy. As of today, oil still contributes to a third of the world primary energy (IEA 2011c). The word “still” in the preceding sentence matters, since most countries have tried to diversify their energy mix in order to smoothen the impact of oil shocks on their economy. As a consequence of this political will and to the emergence of cheaper substitutes for some applications, the share of oil has decreased in the past three decades. The net consumption of oil is however, increasing.

Once the crude oil has been produced, several steps are required before the crude oil can be delivered to the customer in the desired form. Crude oil will first have to be transported from the production site to the refinery. If the production site is located offshore, crude oil is generally transported in tankers or barges. If the production site is located onshore, trucks, trains and pipelines will be used, the choice of which depends on the distance and infrastructure available. Pipelines are economically preferred over short distances. In addition, pipelines will further be used to transport the various oil products from the refinery to the local distribution facilities. Finally, the various oil products, including gasoline, diesel and kerosene are distributed to the customers.

Oil can easily be brought to the point of consumption, stored until use and the energy embedded in oil can be produced at will. These qualities makes oil a fuel of choice in the transportation sector. Consequently, the big chunk of crude oil, or more precisely almost all of the gasoline and diesel obtained from crude oil, is used in the transportation sector.

Oil-derived products are also used to provide heat and some countries (albeit fewer over time because of the emergence of cheap substitutes) burn crude oil directly in order to generate electricity (e.g.: Japan, Moldova, Russia).

The oil consumed globally has increased over time, see Fig. 2.24. In the OECD countries, the demand for oil increased by 10 % between 1980 and 2012 to reach 46.2 million barrel/day<sup>8</sup> in 2012, whereas the demand for oil in non-OECD countries has more than doubled over the same time period (+110 % reaching 44.7 mb/day). Most of the growth in oil consumption over the past three decades is consequently mainly the result of the increasing oil demand in non-OECD countries.

Figure 2.25 shows how the proven reserves of crude oil is distributed over the continents. The total reserves at the end of 2012 were estimated to 1,669 billion barrels (BP 2013), which would suffice to cover our needs for another 50 years at the current rate of extraction. The latter number is however highly uncertain. First, the estimates of crude oil reserves are largely unprecise as they rely on somewhat subjective judgements on the estimated size of the total resource in the ground and on to what fraction of it is economically recoverable (Cassedy and Grossman 1998). Second, proven recoverable reserves have **increased** over the past decades due to the finding of new reserves (mostly in Southern and Central America) and to increasing crude oil prices (recall that proven reserves depend on economical factors too). In

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<sup>8</sup> 1 barrel = 0.159 m<sup>3</sup>

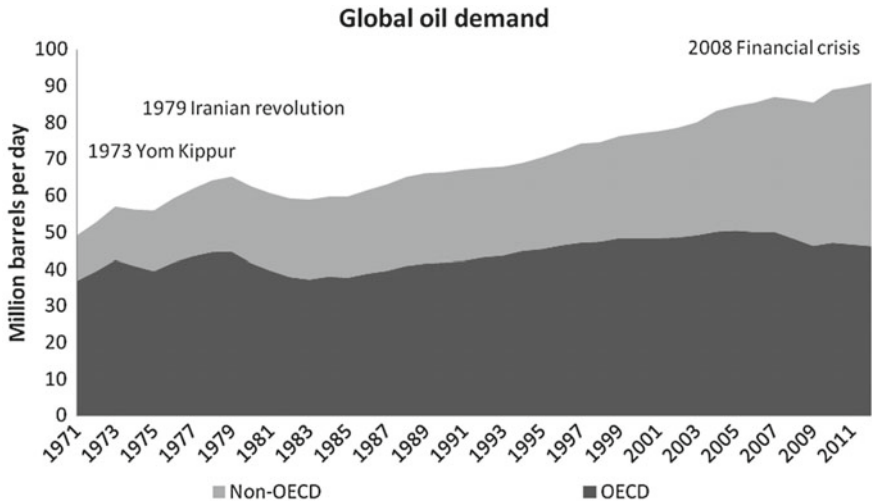


Fig. 2.24 Global oil demand (million barrels per day) (IEA 2013)

facts, global crude oil proven reserves have increased by almost 60 % since 1992 (BP 2013), see Fig. 2.26.

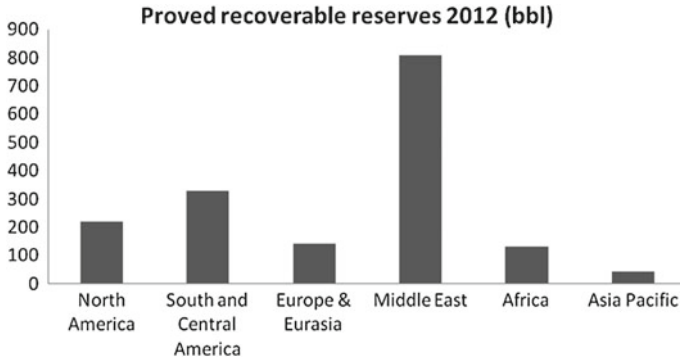
Compared to coal, oil reserves are very unequally spread around the world, with three quarters of the proven reserves located in the OPEC countries.<sup>9</sup> The following four countries: Venezuela (18 %), Saudi Arabia (16 %), Iran (9 %) and Iraq (9 %) together own over half of the world's proven reserves. Other parts of the world are much poorer in terms of how much reserves they own. Such concentrated reserves is considered as a threat by several countries as, in theory at least, some countries have the potential to influence the global oil market.

Countries extracting coal are generally those consuming most of it. This relationship is clearly not true for oil. In fact, there is a clear mismatch between production and consumption of oil. For example, the US consumed twice what they produced in 2012 and China consumed 2.5 times what it produced.

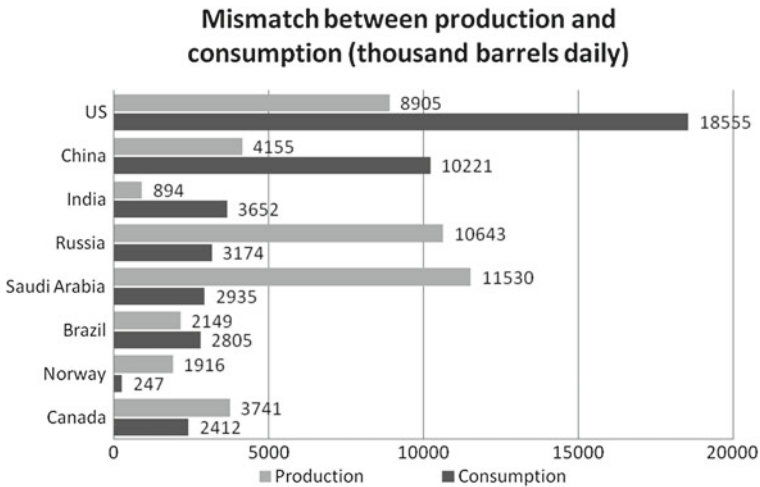
In order to balance supply and demand, some countries must logically produce more than they consume, which is the case of Saudi Arabia, Russia, Canada, Venezuela, Norway and a few others. Such as to balance the system, vast quantities of oil are being traded globally. The main trades are illustrated in Fig. 2.27. It is clear from the that figure that large quantities of oil are exported to the United States, Europe, Japan, China and India.

The future regional demands for oil are uncertain, although the global demand for oil is more than likely to increase. In parallel to the example of Germany, demand for oil in OECD countries is expected to slowly decrease overtime (IEA 2011c) due to increased efficiency, government policies implemented to reduce oil consumption (e.g.: fuel efficiency standards) and to the slow emergence of substitutes to oil (natural

<sup>9</sup> OPEC stands for Organization of the Petroleum Exporting Countries, organization aiming at coordinating the petroleum policies of its Member Countries.



**Fig. 2.25** Crude oil proven reserves at the end of 2012 (billion barrels) (BP 2013)

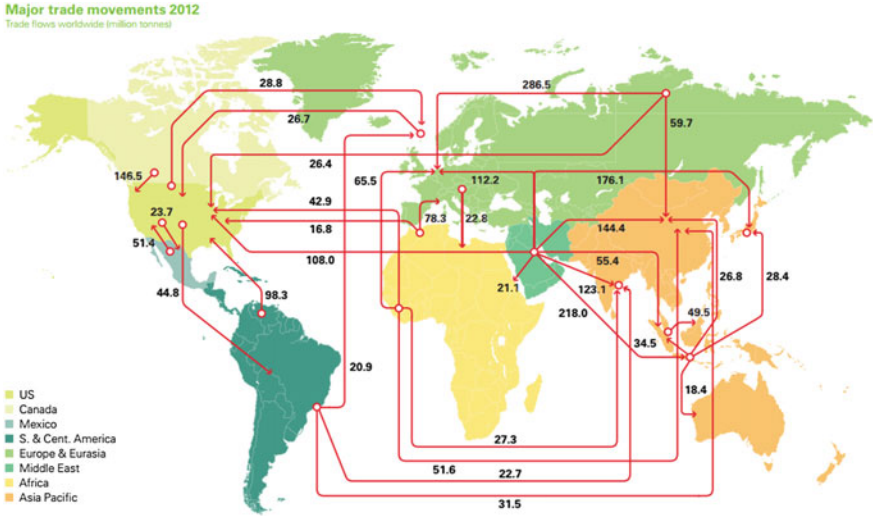


**Fig. 2.26** Production versus consumption in 2012 (thousands barrels daily) (BP 2013)

gas, biofuels, hydrogen and electricity). The demand in non-OECD countries is however expected to rise significantly due to an increase in population and to rising standards of living.

**Oil Refinery**

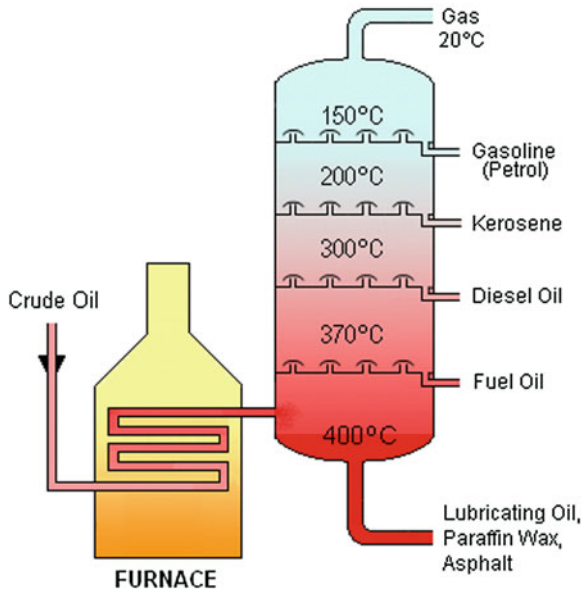
The crude oil which is recovered from an oil reservoir has a very complicated molecular structure, see Sect. 2.3.1. It ranges from the simplest hydrocarbon molecule which is methane (CH<sub>4</sub>) with a molecular weight of 16 to complicated



**Fig. 2.27** Major oil trade movements worldwide (million tonnes). Reproduced from the BP Statistical Review of World Energy, June 2013. Courtesy of BP p.l.c.

chains of hydrogen and carbon atoms with molecular weight of more than a thousand. In order to obtain the products which a modern society needs, such as gasoline, diesel, fuel oil, asphalt and many more, the crude oil has to be distilled. This is done in an oil refinery, which you may have seen from a distance as tall, slender towers that jut up above the horizon. It is an essential part of the *down stream* handling of petroleum. In the refinery, the crude oil is first heated to about 400 °C before the vaporized oil rises up the fractioning tower through trays with holes in them. As the gas cools, its components condense back into several distinct liquids. Lighter liquids like kerosene and naphtha, a product used in chemicals processing, collect near the top of the tower, while heavier ones like lubricants and waxes fall through weirs to trays at the bottom. This is illustrated by the distillation column in Fig. 2.28. The oil refinery is a complex chemical plant and the products from the primary distillation are processed further in other refinery processing units. Demand for gasoline is high, therefore some of the heavier components from the fractioning tower is turned into gasoline by processes called reforming, alkylation and cracking which breaks large hydrocarbon molecules down into smaller ones, making the end product more volatile. Oil refineries are large scale plants, processing about a hundred thousand to several hundred thousand barrels of crude oil a day.





**Fig. 2.28** Crude oil is separated into fractions by fractional distillation. The fractions at the *top* of the fractionating column have lower boiling points than the fractions at the *bottom*

### 2.4.2 Some Remarks on the Economic Characteristics of Oil

Oil is such a key element in today's economy that it is worth spending a few paragraphs emphasizing the particular economic aspects of oil.

Starting with the supply side of oil, it is characterized by a high capital intensity and a high risk (Clo 2000). Once a resource is found and the decision to extract it has been taken, a heavy extraction infrastructure needs to be put in place. Therefore, a large amount of capital will be needed before any oil can be sold. In that sense, extracting oil is a capital intensive enterprise. Even though the technology used to find oil resources has improved significantly in the past, the presence of oil and insights about its economic recoverability will only be known via the act of boring a well. This uncertainty is what makes this industry risky. In addition, high economies of scale and low short term price elasticity are also characteristics of the supply side. The low short term elasticity is due to the rigidity in the petroleum production sector.

On the demand side, economic conditions include very low short term price elasticity, a high income elasticity and cross elasticity. The low short term price elasticity is due to the fact that consumers will often not be able to opt for substitutes if oil prices suddenly increase and the consumers will therefore often be obliged to roughly buy the same quantities of oil even though prices have changed.

### **The Nigerian example**

On January 1st, 2012, the Federal Nigerian Government decided to remove the fuel subsidies which immediately resulted in the doubling of the fuel prices at the pump. Mass protests followed this decision, which created social unrest. Part of the issue is due to the short term elasticities described above. Nigerians did not have the possibility to substitute oil by other sources of energy and therefore the population could not soften the shock.

In the long-term, the demand for oil is more elastic as a sustained price increase might lead, for example, the consumers to switch transportation mode, opt for a different fuel or even relocate in order to reduce the quantity of oil needed to commute between work and home.

Income elasticity is a very important characteristic of oil. As purchasing power increases, the demand for oil increases (true at least until a certain level of purchasing power). This concept is simple to grasp if we consider a person which experiences a big increase in her income. Initially, this person commutes with her bike. As her income increases, she is likely to purchase a car to benefit from better comfort (she is now protected from the cold in winter) and save time. This effect does not only happen at the scale of the individual but also at a country scale. As developing countries get richer, their oil consumption increases which results in an increase in the global demand for oil products. Understanding these basic economic concepts is fundamental in order to understand the evolution of the fossil fuel prices, including oil prices.

### ***2.4.3 Natural Gas: Present Use, Resource Considerations and Forecast***

In the case of natural gas, almost all of what is currently extracted is eventually transformed into electricity by power plants, utilized by buildings for heating and cooking purposes or used by industries. Natural gas is also increasingly being used as a fuel by combined heat and power plants (CHP) and a very small share (0.15 % in 2007) of the gas extracted is used for transportation. The capital costs necessary to build a gas-fired power plant are low and the construction times short compared to other fossil fuel-based technologies. In addition, natural gas power plants combine a very high operational flexibility, high efficiency levels and a comparatively low carbon emission compared to other fossil fuel energies such as coal. These characteristics naturally makes natural gas attractive to the eyes of many plant operators, investors and governments. Based on these qualities, most of the incremental electricity generating capacity in IEA countries<sup>10</sup> is due to the installation of gas-fired power plants

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<sup>10</sup> OECD countries minus Chile, Estonia, Iceland, Israel, Mexico and Slovenia.

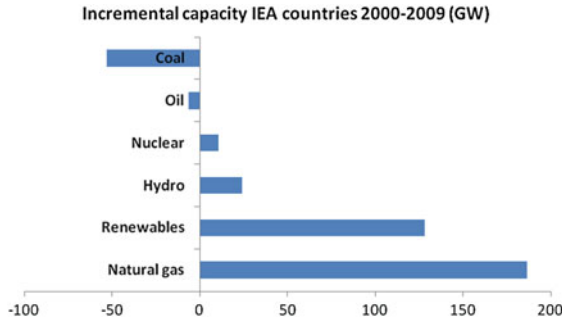


Fig. 2.29 IEA incremental electricity generating capacity in GW, 2000–2009 (IEA 2011b)

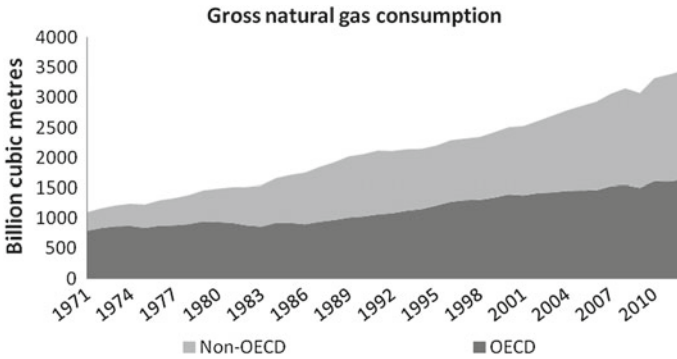


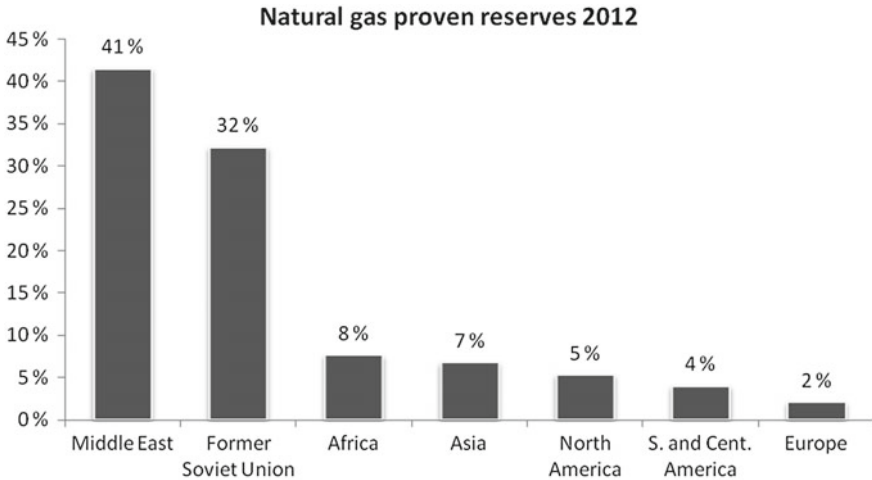
Fig. 2.30 Gross natural gas consumption 1971–2012 (IEA)

as indicated in Fig. 2.29. In the rest of the world, however, coal-fired power plants prevail in accounting for the increase in incremental electricity generating capacity.

Historically, the transformation of natural gas into electricity has been gaining in importance and the natural gas consumption has risen steadily over the past decades. Yet, non-negligible quantities of that precious resource are being flared (burned in the open air) by oil extracting companies focusing solely on crude oil due to cost reasons.

Similar to the case of crude oil, consumers of natural gas are not necessarily the countries extracting it. In 2012, the main natural gas producers were the United States (19.8 % of the world production), the Russian Federation (19.1 %), Qatar, Iran and Canada (each with 4.6 %). That year, the main consumers were the US (20.9 %), the Russian Federation (13.7 %), Iran (4.5 %), Japan (3.8 %) and Canada (2.9 %) (OECD 2011). Figure 2.30 shows the evolution of the natural gas consumption and production for OECD and non-OECD countries since 1971. The 2008 financial crisis is clearly visible as it negatively affected the global natural gas consumption, although the effect of this crisis were short-lived.

Natural gas reserves are not evenly spread around the planet and some countries control a big share of these reserves, see Fig. 2.31. Such an example is Qatar, which



**Fig. 2.31** Proven natural gas reserves at the end of 2012 (OECD 2013)

accounts for less than 0.02 % of the world's population but own approximately 13 % of the world's natural gas reserves. Other big resource owners are the former Soviet Union countries with over 30 % of the global natural gas resources located in their soil, 17 % in Iran and 4 % in the United States. At the end of 2012, it was estimated that the proven recoverable natural gas reserves amounted to roughly 192 trillion cubic meters (OECD 2013), which will be sufficient to cover the demand for the next 60 years at the 2012 rate of extraction. However, due to its flexibility, cost and environmental benefit, it is expected that the demand for natural gas will increase significantly in the near future.

Natural gas is not available everywhere and this commodity thus needs to be transported to where it is needed, the cost of which varies with respect to the distance, the scale and the transportation mode chosen. Liquefied natural gas (LNG), offshore and onshore pipeline are the existing technologies used to transport natural gas. Figure 2.32 illustrates the economics of these technologies.

LNG requires that the natural gas is first liquefied before transportation and regasified before use, which comes at a cost. Yet, this incremental cost rises slower than the incremental cost of building longer onshore and especially offshore pipelines (Jensen 2007), therefore LNG transportation will be privileged over long distances.

Europe gets its natural gas mainly via the use of pipelines from the North Sea, Algeria and from Russia. Supply and demand being inflexible in the short term (recall the concepts of elasticities discussed previously), disruption of natural gas from any of these places can quickly threaten the continuous natural gas supply to central European countries. For example, the January 2009 natural gas supply disruption of the gas transiting through Ukraine for political reasons affected 18 European countries.

The IEA expects the demand for natural gas to increase by 30–65 % by 2035 (IEA 2011c), mostly because of increasing natural gas demand from non-OECD countries and to the substitution of fossil-fuels by natural gas in the OECD countries. An

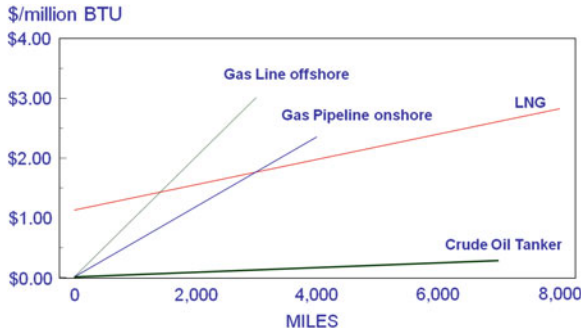


Fig. 2.32 Gas transportation costs in 2002 in USD/MMBTU (Jensen 2007)

increase of that magnitude means that in the absence of new natural gas field discoveries, the proven reserves will not last until the end of the century. However, the development of unconventional gas resources and shale gas principally, can mean that natural gas reserves will be sufficient for a much longer period (more about this in Sect. 2.7).

### 2.4.4 Cost

#### 2.4.4.1 Resource Cost of Oil and Natural Gas

The oil markets are integrated to such a point that major events impacting oil producing countries affect the crude oil prices worldwide. As Fig. 2.33 shows, oil prices have been relatively stable in real terms between 1986 and 2003 as growth in consumption was matched by growth in production and technological improvement. Shocks on prices disappeared with either the cause of the shock or because other oil producers managed to increase their production. Between 2003 and 2013, oil prices have fluctuated more violently. First, the addition of the Iraq war with growth in crude oil demand from rapidly developing countries and the failure to increase production at the same rate as the demand, generated an energy crisis where the theme of peak oil became popular. The 2008 financial crisis resulted in a violent market correction which was short lived as global economy started its recovery. The Arab Spring pressured oil prices upward since crude oil production was largely disrupted in that country and because of the importance of Libya in the oil production market. The strength of the shock is, once again, due mostly to the very low price elasticity of the oil commodity and to the quasi-absence of substitutes.

Figure 2.34 illustrates the monthly natural gas prices in real terms for the United States and Europe between 1970 and 2013. Comparing Figs. 2.33 and 2.34 shows that both resources have prices that tend to be highly correlated: as the oil price goes up or down, the price of natural gas follows the same trend.

Formally, natural gas prices are subjects to four main characteristics. First, supply and demand levels naturally play an important role in defining natural gas prices. The



Fig. 2.33 Crude oil prices in 2008 Euro (World Bank 2013)

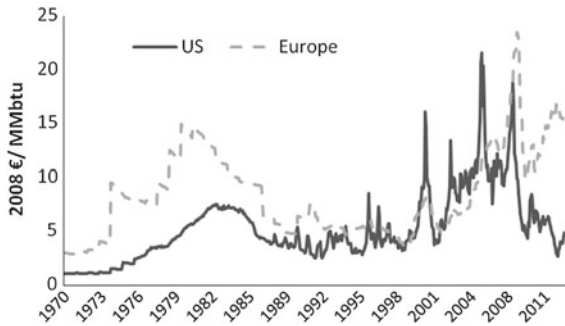


Fig. 2.34 Natural gas prices in Euro<sup>2008</sup>/MMBtu (World Bank 2013)

role played by major events on demand and supply should be clear after what has been written previously on coal and oil. For example, at least part of the drop in prices in the second part of 2008 can be attributed to decreasing industrial pressures on demand from the industry due to the financial crisis. Second, regional natural gas markets are increasingly interlinked. The various regional markets used to be more independent from each other, however, with the creation of numerous new LNG routes due to the emergence of that technology, regional markets are better interlinked (IEA 2009). Note however the divergence in prices between US and European gas prices since 2009. The diverging trends between the US and European natural gas prices is mainly due to the production of unconventional gas resources in the US, e.g.: shale gas, while this exploitation is often limited in Europe because of environmental concerns (e.g. France). The diverging trend is an indicator that the export capacity is insufficient (for now) in the US for the market prices to converge totally. In fact, before the emergence of the shale gas industry in the US, many LNG import stations have been

built in prediction of a large shortfall in the natural gas production in the US. These stations cannot be used for export unless extensive transformation is taking place, which means that divergence in natural gas prices between the US and Europe will be possible until appropriate trade facilities are put in place. Nonetheless, regional natural gas price patterns are likely to converge even more in the future and that regional shocks will be short-lived as natural gas can be supplied from or to another region.

Thirdly, long-term natural gas delivery contracts are often linked to the evolution of oil prices (IEA 2009) explaining the close link between the prices of the two resources. Lastly, the availability of substitutes to natural gas in the end-market impacts the natural gas price evolution, limiting the amplitude of shocks on natural gas prices.

More than oil, natural gas is used to generate electricity and the cost of fuel accounts for the big part of its levelized cost of electricity (over 60 %). Due to this high share, gas-fired power plants are the most sensitive to fuel price variation, even more so than coal. Therefore, it is especially important for the investor to properly estimate the cost of natural gas over the lifetime of the power plant in order to get proper estimates for the cost per kWh. The variations in natural gas prices make such estimates impossible. Instead, investors use a steady fuel cost increasing rate based on what the theory predicts.

#### **2.4.4.2 Basic Cost of Natural Gas Power Plants**

The numbers provided in this section are based on gas-fired combined cycle turbine (CCGT) power plants as this type of plant is particularly popular today.

The capital costs of a CCGT power plant cover basic elements such as those related to the turbine, the cooling systems for the steam condenser, water treatment and maintenance facilities (Council 2002) and the construction costs including materials, engineering and construction management. The capital cost of a CCGT power plant will depend on the location with regard to the electrical grid and the natural gas network. In addition, the location will influence the technology chosen as the absence of a large and stable source of water to cool the steam will force the developer to use a closed-loop system, which results in lower efficiency levels and also in higher capital costs. Regulations can impact the capital costs as more stringent pollution control requirements will eventually result in higher capital costs. Two years are usually sufficient to commission a CCGT power plant.

The capital costs of CCGT power plants reach Euro 350–1000 Euro/kW of installed capacity. Assuming a plant economic life of 30 years, these capital costs account for a small share (15–30 %) of the levelized costs of electricity compared to other technologies.

#### **2.4.4.3 Electricity Generation Cost of Natural Gas Power**

Natural gas is ‘cheap’ compared to other energy technologies. Capital costs are low, construction times short and efficiency levels high. Operation and maintenance work

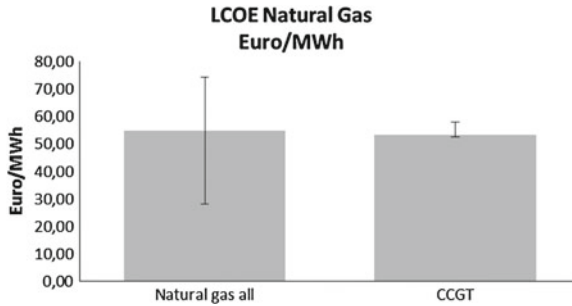


Fig. 2.35 Levelized cost of electricity: natural gas

Table 2.7 Levelized cost of electricity for natural-gas-fueled power plants

	All natural gas	CCGT
LCOE (Euro/MWh)	28–74	52–58
Overnight cost (%)	7–31	14–31
O&M costs (%)	2–11	2–11
Fuel costs (%)	61–87	61–80

is as necessary for natural gas power plants as for any other technology. However, these costs are particularly low for natural gas (Eurocents 0.1–0.5 Eurocents/kWh).

Summing up the levelized capital costs, O&M costs and fuel costs result in a LCOE of Eurocents 2.8–7.4 Eurocents/kW of electricity generated from natural gas for the minimum and maximum cases respectively. The maximum case is based on a plant in Japan, where the cost of fuel (LNG) is particularly high since it has to be imported. Because fuel costs account for the big share of the LCOE, the smallest price variation will be felt by the plant owner. Therefore, the exact LCOE of natural gas cannot be precisely known in advance as it relies heavily on hypotheses on future natural gas prices.

## 2.5 Carbon Capture and Storage

Three different classes of proposals to mitigate global warming resulting from increased concentration of atmospheric CO<sub>2</sub> due to fossil fuel have been raised:

1. Replace fossil fuels by energy sources which do not release any significant amount of CO<sub>2</sub> (e.g.: nuclear or renewables).
2. Continue using fossil fuels and at the same time, capture and store significant amounts of CO<sub>2</sub> and consequently reduce the total emissions into the atmosphere.
3. Apply various types of *geoengineering*, i.e. to introduce enterprises on ground, in the atmosphere or in space with the aim of counteracting the effect of increased CO<sub>2</sub> levels.



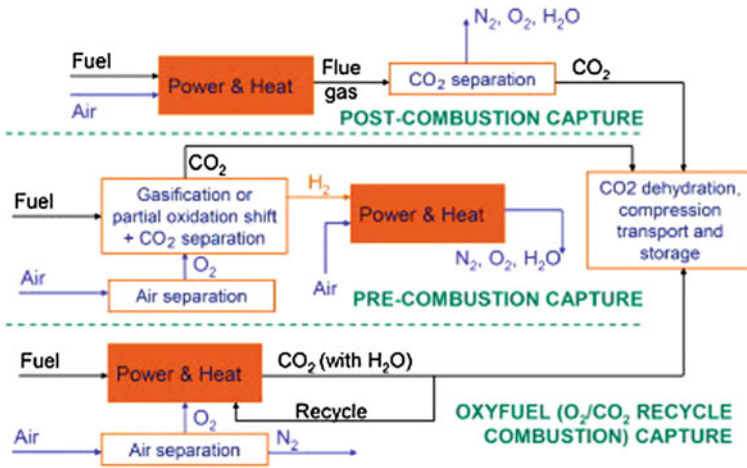


Fig. 2.36 Overview of the main CO<sub>2</sub> capture technologies (Gibbins and Chalmers 2008)

A range of suggestions exist under item 3, from placing mirrors outside the atmosphere to reflect sunlight to painting buildings and large areas on the ground in white such as to increase the albedo. We will not describe these issues any further, as they are considered outside the scope of this book. The alternative energy sources to fossil fuels will be described in the following chapters. In this section, we describe the carbon capture and storage (CCS) option.

The vision behind CCS is to allow for continued use of fossil fuels without contributing to global warming. One way of achieving this vision would be to collect the CO<sub>2</sub> and pump it back into the oil and gas reservoirs. This process has been carried out at a small scale with an industrial motivation for many years. Already in the 1970', the injection of CO<sub>2</sub> into oil fields in order to increase oil recovery was initiated and the idea of using depleted oil reservoirs as a store for human CO<sub>2</sub> production possibly has its origin in these projects.

It is important to realise that we have no realistic solutions for CCS in the transportation sector. CCS is therefore only a valid solution to CO<sub>2</sub> emission from power plants, in practice from coal-fueled and natural gas-fired power plants.

A range of technologies can capture the CO<sub>2</sub> before it is released. These are summarised in Fig. 2.36.

The figure shows the different technologies possible for CO<sub>2</sub> capture. Very briefly, there are two alternatives: Either the fuel is transformed in such a way that CO<sub>2</sub> can be extracted before (pre-combustion) or after (post-combustion) the combustion process. Pre-combustion implies that coal is gasified and turned into several new components such as CO<sub>2</sub>, CO and H<sub>2</sub>. The H<sub>2</sub> gas can be separated and used for energy production while the CO<sub>2</sub> is captured. In post-combustion processes the coal or hydrocarbons are first burned resulting in CO<sub>2</sub> as end products together with

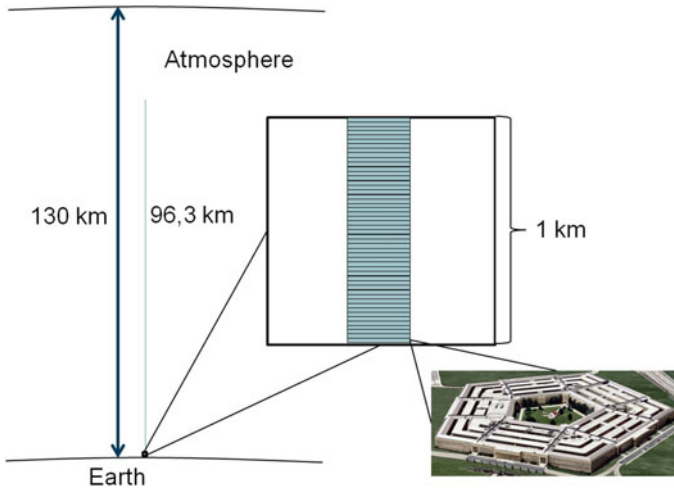
**Table 2.8** Thermal efficiency, capital costs and costs to remove CO<sub>2</sub> for various coal and gas at various technologies (Gibbins and Chalmers 2008)

Technology	Thermal efficiency (% LHV)	Capital cost (Euro/kW)	Cost of CO <sub>2</sub> avoided (Euro/tCO <sub>2</sub> )
<i>Gas-fired plants</i>			
No capture	55.6	340	
Post-combustion capture	47.4	590	40
Pre-combustion capture	41.5	800	76
Oxy-combustion	44.7	1,038	70
<i>Coal-fired plants</i>			
No capture	44.0	957	
Post-combustion capture	34.8	1,344	23
Pre-combustion capture	31.5	1,235	16
Oxy-combustion	35.4	1,500	24

water H<sub>2</sub>O and other gases. CO<sub>2</sub> may then be extracted by sending the end products through a fluid which binds CO<sub>2</sub>. Figure 2.36 also shows a combined version of these two techniques, the so-called oxyfuel process: Here natural air is replaced with pure oxygen in the combustion process which results in a much cleaner exhaust containing only CO<sub>2</sub> and H<sub>2</sub>O. The water may now easily be condensed allowing for a cheaper collection of CO<sub>2</sub>. However, the drawback with this method is the extra expense to replace air with clean O<sub>2</sub> before combustion.

It is clear that the process of removing CO<sub>2</sub> requires energy. It is easy to realise that carbon capture reduces the efficiency of the power plant, since this energy is naturally provided by the plant itself. We see in Table 2.8 that post-combustion is the best option in this case, and imply a reduction factor of about 20 %. In addition we see that capital costs also increase since the capture technology has to be installed as well. The LCOE in total can reasonably be expected to increase with about 20 % for the best capture technology. This adds up to a total cost per captured tonne CO<sub>2</sub> in the range from Euro 20 (coal) to 40–70 (gas). A massive program to install such technologies will likely slightly reduce costs on the capital side. Energy penalties and reduced efficiency are determined by laws of nature and cannot significantly reduced.

The storage problem is in practice more challenging than capture, and will also require a considerable amount of energy. In order to contribute significantly to climate change mitigation, the amount of CO<sub>2</sub> to be stored is of the order a few to ten Gt (Gigatonnes) per year since the present annual emissions are about 30 Gt per year. We have no experience in building such programs and, for comparison, the total amount of CO<sub>2</sub> captured so far during the last 30 years since the idea was conceived amounts to some 10 Mt, i.e. one thousandth of what we need to capture annually! When 10 Gt atmospheric CO<sub>2</sub> is compressed and cooled into a liquid, it would be take as much space as piling up 4,815 Pentagon, the famous headquarters of the US Department of Defense:



**Fig. 2.37** 10 Gt of liquid CO<sub>2</sub> is in order of magnitude similar to piling up nearly 5,000 Pentagon (each side of the Pentagon is approximately 280 m, and the height of the building is roughly 20 m)

The following storage possibilities are known:

- Ocean storage. The ocean is a gigantic CO<sub>2</sub> storage and contains, as seen from Chap. 1, more than 1,000 times the amount of annual anthropogenic CO<sub>2</sub> emission. By releasing CO<sub>2</sub> at about 1 km depth, it is therefore in principle possible not to change the CO<sub>2</sub> significantly on a grand scale. The storage capacity of the oceans are then in principle sufficient, but the price factor of pumping CO<sub>2</sub> down to 1 km which require a compression of liquid CO<sub>2</sub> about a 100 times represents the main barrier. Releasing CO<sub>2</sub> at shallow water would on the other hand be cheap, but in that case it would mix with the oceans biosphere and potentially damage it.
- Geological storage. Depleted oil and gas reservoirs are ideal for “returning” CO<sub>2</sub>. Extraction wells can be changed into injection wells. That world storage capacity is estimated to be in the order of 100–1,000 GtC. This amount is increased at least by a factor of two by adding deep saline aquifers and coal seams. Realistically this option then allow for a annual uptake of 5 GtC for more than 50 years which is considered a sufficient time window for continued use of fossil fuels without global heating allowing for new energy sources to be implemented. However, storing liquid CO<sub>2</sub> in depleted reservoirs or other underground voids also requires energy because they are usually filled with water which has to be displaced.
- Biological storage such as reforestation would also contribute to an uptake of CO<sub>2</sub>. Large areas of countrysize dimension needs to be planted on land. Other techniques based on plancton, algae etc in the sea have also been suggested. The total capacity is estimated to be an order of magnitude smaller than for geological storage sites.

As a summary we see that sufficient storage capacity exists in principle. The cost of any of these storage technologies is uncertain, and varies from as little as from

1 Euro per tonne to 70 Euro per tonne. The cost of storing the carbon dioxide is simply anything from a small fraction off the cost of capturing it to twice nearly twice that cost. Setting the physical price of storage<sup>11</sup> to the same level as the price of capturing CO<sub>2</sub> implies an efficiency reduction of thermal coal plants of about 40 %. Thus, it should be clear that the costs of CCS are such that it is unrealistic to foresee a global implementation unless international laws can be established which prohibits CO<sub>2</sub> emission or enforce a more significant carbon tax on emissions. With an unbalanced energy supply situation in the world, no such measure can be foreseen to become realistic in the near future. The situation may however rapidly change if global warming manifests itself in catastrophies or global food crises.

Some dangers are typically associated with the use of CCS. These are the risk of leakage and risk of creating earthquakes. In the event of a massive carbon leakage, people in contact with the gas before it dissipates are likely to die. The risk of deadly leakage can be lowered by carefully selecting the sites for CO<sub>2</sub> storage and suppressed by storing the gas off the coast. The risk of earthquakes caused by storing carbon dioxide underground results from a change in pressures in the ground, in the same way that extracting oil and gas can create an earthquake. The magnitude of potential earthquakes is expected to be tiny. However, it is generally not a good idea to cause them at the first place because it can leads to fractures in the sealing layer that prevents the carbon dioxide from escaping. The creation of earthquakes depend on a variety of parameters, with the type of sealing layer and the state of stress of the material being amongst them. Carefully selecting and monitoring the storage sites can lower this risk.

#### **Application: Technology Centres Mongstad, Norway**

The Technology Centre Mongstad located in Norway is one of the major research centre for carbon capture and storage. A variety of post combustion CO<sub>2</sub> capture technologies are being tested and improved exploiting the exhaust gases from a natural gas-fired power plant built at this centre.

About 800 million Euros had already been poored into the project by mid-2012 and the plant managed to capture 22,000 tonnes of CO<sub>2</sub> that year. The captured CO<sub>2</sub> was eventually released back into the atmosphere in the absence of a storage facility. Once fully operational, the plant should have been able to capture a Mt CO<sub>2</sub> annually. In the fall of 2013 the new Norwegian government decided to severely reduced its support to the centre for economical reasons.

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<sup>11</sup> The physcial price is the loss in efficiency here.



Fig. 2.38 Technology Centre Mongstad, Norway (courtesy TCM ©)

## 2.6 Peak Oil

How long can the oil supply satisfy the oil demand? This question depends on at least three factors. The first factor concerns the total amount of the resource which is found and can be extracted. Apart from the obvious fact that the quantity has to be finite, there is no exact public knowledge of how large our remaining petroleum resources exactly are. In addition, the constant ongoing search for oil results in an almost continuous discovery of new oil fields. The present discovery rate is about 10 Gb (Gigabarrels or  $10^9$  oil barrels) per year, which is significantly lower than the annual consumption of about 30 Gb.

A common term in the industry is to consider “2P” reserves as the best estimate for the remaining commercial resource base for conventional oil. 2P means the already proven reserves and the unproven reserves which are “likely” to be found with a probability larger than 50 %. The global world estimate of the 2P reserve has been evaluated to be about 1,000 Gb. The uncertainty is about  $\pm 300$  Gb. Up till now (2013), humans have already used about 1,100 Gb (Alekklett et al. 2012) which shows that as compared to a bottle of Coke, we have now most likely emptied more than half of it. Also, compared to the present annual consumption of oil we see that the resource is emptied in about 30 years from now if the production is kept constant.

In addition to the uncertainty in the resource base there are other factors which affect our estimate. The first is increased demand, through population growth and increased industrialization of large countries like India and China. A second problem is related to what today is known as the Hubbert “Peak Oil Theory” (Hubbert 1956). It says that the production from a finite resource can only increase for a limited time until a maximum production is achieved. This time is called “Peak oil”,  $t_{peak}$ . After “Peak Oil” the production will decline no matter how much the demand would be—unless revolutionary new production technologies are discovered. The only way to meet an increased demand after peak oil for a given resource is to find additional resources. Regarding conventional oil this is at present more unlikely than likely: Almost half of the oil resources exist in so-called giant oil fields which were discovered more than 50 years ago. Continuous search in increasingly more harsh environments (arctics, deep oceans) have so far not changed the almost constant and slowly decaying curve of new discoveries. In 2011 three new Norwegian oil fields were found in the North Sea and in the Barents Sea which were reported as significant and large. However, the estimated total amount of oil within these fields will only be able to cover the present global oil consumption for about a month!

The Hubbert curve can be derived from relatively simple physical models of production from a reservoir of finite size (Helseth 2012). We will consider the total accumulated produced volume  $V(t)$  of recoverable oil from a reservoir. The produced volume per time,  $dV/dt$  will be given by the product of the total area of producing units  $A(t)$  and the relative volume fraction of remaining producible oil  $S(t)$  and the flow velocity,  $u(t)$  of the oil through the producing area (a number of production pipelines with total cross sectional area  $A(t)$ ),

$$\frac{dV}{dt} = S(t)A(t)u(t) \quad (2.7)$$

By injecting fluids through some injection wells it is possible to keep the pressure within the reservoir almost constant. Then the velocity,  $u(t)$ , through the pipelines is almost constant. The flow area is determined by the number of production wells. Such are expensive to drill in general and a first order approximation is that the number of production wells at any time is proportional to the total volume of produced oil,  $N(t) = N_{max}V(t)/V_{tot}$ . Here  $N_{max}$  is the maximum number of wells bored when  $V(t) = V_{tot}$ , which is the total amount of oil originally in the reservoir, often called STOOIP (Stock Tank OIL Originally In Place). This implies that  $A(t) \propto V(t)$ . The relative fraction of remaining oil in the reservoir will also be proportional to  $V(t)$  through  $S(t) = S_0[1 - V(t)/V_{max}]$ , where  $S_0$  is the initial fraction of oil in the reservoir. Putting all this together we obtain the following equation for the production speed,

$$\frac{dV}{dt} = K_p V(t) \left( 1 - \frac{V(t)}{V_{tot}} \right) = K_p \left( V(t) - \frac{V^2(t)}{V_{tot}} \right), \quad (2.8)$$

where all the constants have been collected in a factor  $K_p$  which has the unit inverse time. The condition for the production peak velocity is  $d/dt(dV/dt)|_{t_{peak}} = 0$  which gives  $V_{peak} = V_{tot}/2$  and therefore

$$dV/dt|_{t_{peak}} = K_p \frac{V_{tot}}{4}, \quad (2.9)$$

This expresses a linear relationship between the total oil produced  $V_{tot}$  and the maximum production speed. The solution of the differential Eq. (2.8) is satisfied by the following function  $V(t)$  for the accumulated production,

$$V(t) = \frac{V_{tot}}{1 + e^{-K_p(t-t_{peak})}}. \quad (2.10)$$

This relationship can be differentiated to give the instant production speed,

$$\frac{dV}{dt} = \frac{K_p V_{tot} e^{-K_p(t-t_{peak})}}{(1 + e^{-K_p(t-t_{peak})})^2} \quad (2.11)$$

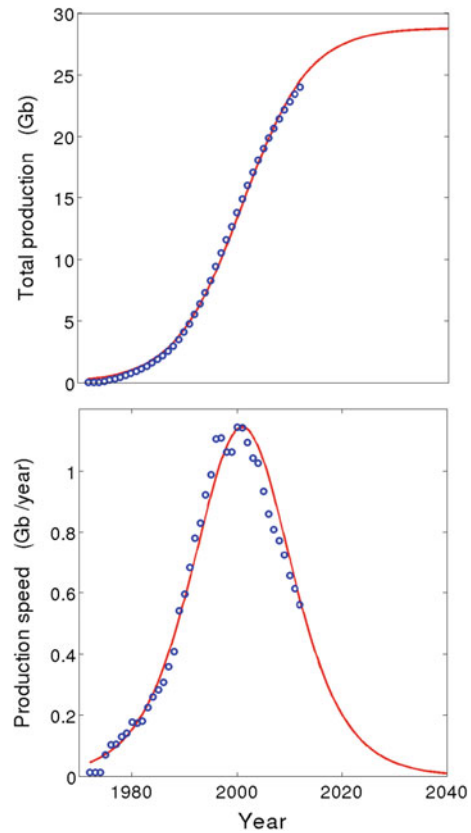
This curve has its production maximum at  $t_{peak}$  and falls towards zero (no production) when  $t \gg t_{peak}$ .<sup>12</sup> The curve can be fitted pretty well to the world total oil production (Alekklett et al. 2012) as well as to individual reservoirs. For example, by fitting the parameters  $V_{tot}$  and  $t_{peak}$  to official figures of Norwegian oil production we can plot the Hubbert curve [using Eq. (2.11)] in the figure below. The data are taken from the resource report of The Norwegian Petroleum Directorate (NPD 2013).

The accumulated oil production by the end of 2012 from existing producing Norwegian fields is about 26 Gb. Figure 2.39 shows the accumulated production (top) and the annual equation using Eq. (2.11) and with using  $t_{peak}$  and  $V_{tot}$  from the production data (NPD 2013) and using  $K_p$  as a fitting parameter. A pretty good agreement is noted, and we see that Norwegian oil production peaked around year 2000 and is now on a rapid decline.

Resources is a collective term for recoverable petroleum volumes (oil, gas and condensates). The resources are classified into the following categories: decided by the licensees or approved by the authorities for development (reserves), volumes dependent on clarification and decisions (contingent resources) and volumes expected to be discovered in the future (undiscovered resources). The main categories are thus reserves, contingent resources and undiscovered resources. The Norwegian petroleum resources are approximately 85 Gb o.e. (oil equivalents). Of this, a total of 37.7 Gb o.e. have been sold and delivered (oil, gas and condensates), which corresponds to 44 % of the total resources. The total remaining recoverable resources amount to 48 Gb o.e. Of this, 31 Gb o.e. have been discovered, while the estimate for undiscovered resources is approximately 17 Gb o.e., which is of course very

<sup>12</sup> There is an unimportant inconsistency at  $t = 0$  with (Eq. 2.10) since  $V(0) \neq 0$ . It can be removed by subtracting the constant  $V(0)$  from  $V(t)$ , i.e..  $V(t) \rightarrow V(t) - V(0)$ .

**Fig. 2.39** Norwegian oil production (NPD 2013) in giga barrels since 1970 shown as circles compared to the Hubbert curve, Eqs. (2.10) (top), (2.11) (below)



uncertain. The contingent and undiscovered oil resources are naturally not included in the Hubbert analysis presented in Fig. 2.39. When or if they are opened for new production they will have their own production history and Hubbert curve which must be added to the existing one. Only a giant discovery of the magnitude of, or larger than, the initial size of the resources can maintain and increase the production. It is more likely that new discoveries as well as improved recovery technologies only will add up to an extra shoulder of the production history, and expand the Norwegian oil production era for another 10–20 years.

According to the works of Aleklett et al. (2012), the world production as a hole may already have passed peak oil. Others estimate that it may not occur in another 10–20 years which in any case is very soon. The implications will become dramatic: It means that the oil production, very soon cannot meet the increasing demand. This may again lead to extreme oil prices, global political instability, economic depressions and even war. On the other hand it paves the way for commercial utilization of new energy sources, which may be unconventional fossil fuels in combination with increased use of coal and/or new and increased nuclear energy production and/or renewables.



What is meant by unconventional fossil fuel is treated in the following section, while nuclear energy and renewables follows in the forthcoming chapters.

## 2.7 Non Conventional Fossil Energy Sources

### 2.7.1 Basic Definition

Conventional oil and gas are produced by drilling into reservoirs, onshore or offshore, where the fluids have accumulated in traps formed by impermeable rock stratas, see Fig. 2.14. This technology has been around and refined over the last 100 years or more. It has been described to some detail in the previous sections of this book. Since the production from these conventional fossil fuel resources inevitably has to decline in the near future, oil industries and governments across the globe are investing unconventional oil and gas resources. The most important of these are

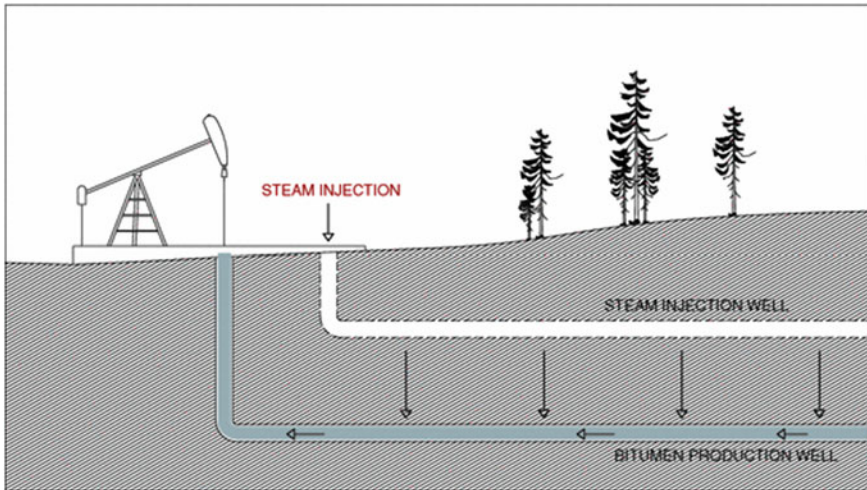
- tar sands or extra heavy oils
- shale gas
- shale oil
- coal conversion
- methane hydrates

They represent enormous energy resources but also involve huge technical and environmental problems.

### 2.7.2 Tar Sands or Extra Heavy Oils

Heavy oil are highly viscous, “cold syrup” like hydrocarbons which are formed much the same way as the conventional low viscous oil. The oil sands or tar sands are loose sand or partially consolidated sandstone containing naturally occurring mixtures of sand, clay, and water, saturated with a dense and extremely viscous form of petroleum technically referred to as *bitumen*. In the Athabasca sands in Alberta, Canada (see Fig. 2.41) there are very large amounts of bitumen covered by little overburden, making surface mining the most efficient method of extracting it. The overburden consists of water-laden muskeg (peat bog) over top of clay and barren sand. The oil sands themselves are typically 40–60 m deep, sitting on top of flat limestone rock.

Due to the high viscosity, heavy oil is more expensive to extract than conventional oil. The bitumen in tar sands cannot be pumped from the ground in its natural state. Therefore *surface mining*, requiring large areas, has been the preferred extraction technique. After excavation, hot water and caustic soda (NaOH) is added to the sand, and the resulting slurry is piped to the extraction plant where it is agitated and the oil skimmed from the top. Provided that the water chemistry is appropriate to allow bitumen to separate from sand and clay, the combination of hot water and agitation



**Fig. 2.40** Steam Assisted Gravity Drainage

releases bitumen from the oil sand, and allows small air bubbles to attach to the bitumen droplets. The bitumen froth floats to the top of separation vessels, and is further treated to remove residual water and fine solids. About two tonnes of oil sands are required to produce one barrel (ca. 1/8 of a tonne) of oil. Originally, roughly 75 % of the bitumen was recovered from the sand but today extraction plants recover well over 90 % of the bitumen in the sand.

Several techniques which restrain from occupying large surface land areas have also been employed, e.g. *Cyclic Steam Stimulation (CSS)*. In this method, the well is put through cycles of steam injection, soak, and oil production. First, steam is injected into a well at a temperature of 300–340 °C for a period of weeks to months. Then, the well is allowed to sit for days to weeks to allow heat to soak into the formation. Later, the hot oil is pumped out of the well for a period of weeks or months.

In the *Steam assisted gravity drainage (SAGD)* process, two parallel horizontal oil wells are drilled into the formation, one about 4–6 m above the other (Deutsch and McLennan 2005). The upper well injects steam, and the lower one collects the heated crude oil or bitumen that flows out of the formation, along with water from the condensation of injected steam (see Fig. 2.40). The basis of the process are that the injected steam forms a “steam chamber” that grows vertically and horizontally in the formation. The heat from the steam reduces the viscosity of the heavy crude oil or bitumen which allows it to flow down into the lower wellbore. SAGD has proved to be a major breakthrough in production technology since it is cheaper than CSS, allows very high oil production rates, and recovers up to 60 % of the oil in place.

Several more exotic techniques have also been tried at the tar sand fields. For example using solvent instead of steam to separate the bitumen from the sand, or an in-situ combustion process which ignites oil in the reservoir and creates a vertical wall of fire moving from the “toe” of the horizontal well toward the “heel”, which



Fig. 2.41 The Athabasca tar sands in Alberta, Canada

burns the heavier oil components and upgrades some of the heavy bitumen into lighter oil right in the formation.

The cost of producing one barrel of tar sands or extra heavy oil amounts to between 30 and 60 Euro<sup>2008</sup>/bl of oil equivalent, to which transport costs must be added. With current oil prices (70 Euro<sup>2008</sup>/bl in September 2013), it makes economic sense to extract this resource. It has been estimated (perhaps conservatively) that, given the existing technology and current oil prices, 1–1.5 trillion barrels of tar sands and extra heavy oil can be recovered economically (IEA 2013b), most of them being located in Canada and Venezuela.

All production methods of oil from tar sand requires large amounts of energy, chemicals and water. It also releases considerable amounts of CO<sub>2</sub> into the atmosphere. An upheaval of large land areas and substantial pollution is often the result. Needless to say there are strong environmental concerns regarding extraction of energy from these resources. However, with increasing oil prices, tar sands and extra heavy oil are considered important from an industrial perspective, especially since the resource base is significant.

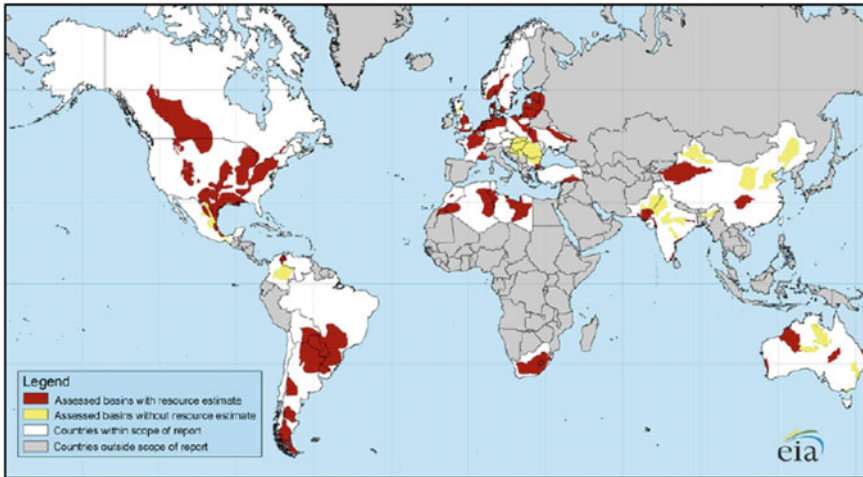
#### **Application: Canadian oil sands.**

From an economical perspective, the cost of extracting tar sand depends on the quality of the reservoir, the location of the project, the production method and the size of the project (IEA 2010). The following table indicates the typical costs of new Canadian oil sands projects in 2010. Most oil-sand projects become economically interesting with oil prices at around 40–50 Euro/bbl. *In-situ* relates to deeper deposits (75 m and below) and *SAGD* is the acronym for Steam Assisted Gravity Drainage, which uses steam to facilitate the extraction of oil.

	Capital cost Euro/bl/d capacity	Operating cost Euro/bl	Economic price Euro/bl
Mining	32,000–46,000	16–23	33–52
In-situ primary	6,600	3–7	16–33
In-situ SAGD	20,000–26,000	13–20	30–53

From an environmental perspective, oil-sand production releases higher carbon dioxide emissions compared to conventional oil production due mostly to the large amount of energy needed during the production process. In numbers, between 175 and 300 kg of CO<sub>2</sub> is released per barrel of crude oil and between three and four barrel of water is needed to produce one barrel of crude oil, of which 95 % can be reused (IEA 2013b). In terms of land area,

140,000 km<sup>2</sup> of northern and eastern Alberta were exploited in 2010 to extract oil from oil-sands, which is larger than the combined area of Switzerland and Austria together.



**Fig. 2.42** World shale gas resources (from US Energy Information Administration)

### 2.7.3 Shale Gas

Shale gas is natural gas trapped in shale formations of very low permeability. Therefore, it can not be produced by the same technology as conventional gas, e.g. from gas caps. However, shale gas is very abundant on most continents, see Fig. 2.42, and has become an increasingly important source of natural gas especially in the United States where around 30 % of the producible gas is assumed to be shale gas. Shale gas exploration and production is today one of the fastest growing trends within the petroleum industry worldwide, and shale gas has been found in regions with no previous hydrocarbon production.

Shale gas is a so called dry gas which consists primarily of methane, with small amounts of higher hydrocarbon gas components plus nitrogen and hydrogen sulfide. Shale is a fine-grained, clastic sedimentary rock formed from mud that is a mix of flakes of clay minerals and tiny fragments (silt-sized particles) of other minerals, especially quartz and calcite. Shale gas is the result of organic deposits being present during compaction. The shale rock acts both as source rock and reservoir rock, contrary to conventional gas reservoirs where a migration of the hydrocarbons from the source rock to a reservoir rock takes place. A schematic illustration of both processes is shown in Fig. 2.43.

Production of shale gas started in the 1920s in Ohio, USA using vertical drilled wells. Shale has low matrix permeability, so gas production in commercial quantities

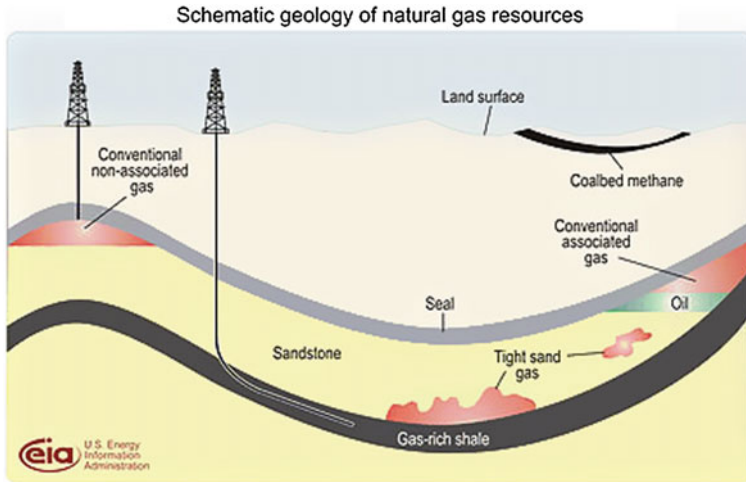
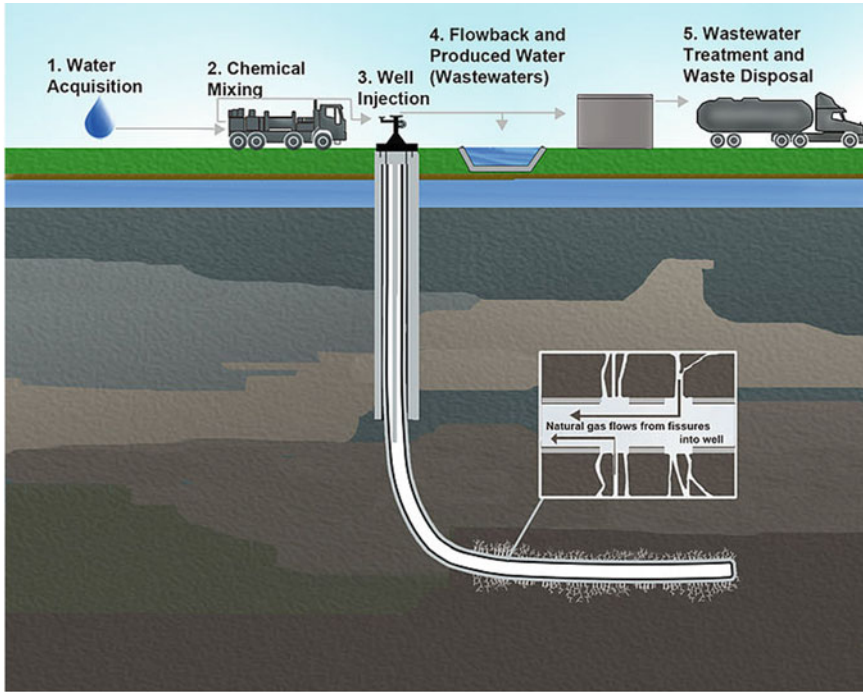


Fig. 2.43 Schematic geology of natural gas deposits (from US Energy Information Administration)

requires fractures to provide permeability. The natural fractures are predominantly vertical, so a large number of wells had to be drilled to drain a reservoir. For many years gas production from shales were considered unprofitable. But in the 1980s two new technologies emerged which revolutionized shale gas production—*horizontal drilling* and *hydraulic fracturing*. Horizontal wells reaching as far as 3,000 m create a maximum borehole surface area in contact with the shale. This makes it possible to produce below cultivated land and even underneath cities. A few vertical wells may be the starting point for a large number of horizontal production wells.

Hydraulic fracturing (fracking) is the main difference when producing gas from shale and from a conventional gas reservoir. A liquid at high hydraulic pressure is pumped into the formation which results in fracturing of rock, usually in the direction normal to the least stress in the formation. At large depth, the cracks have a tendency to become vertical and the influence of the hydraulic cracking may propagate several hundred meters, see Fig. 2.44. The fracturing strategy can be tailored for each specific shale formation by numerical simulations based on the special geometry and lithology of the petroleum bearing strata. This opens for large volumes of shale gas to flow to the wellbore and to be produced to the surface.

In an *unconstrained* world, the economics of shale gas is attractive. It currently costs between 2 to 6 Euro to produce one MMBtu of shale gas. This compares well to the production cost of one MMBtu of traditional gas, which amounts to between 0.1 and 6 Euro (IEA 2013b). The word *unconstrained* in the sentence above is important as most of the shale gas is so far produced in the United States and in Canada. With attractive economics, shale gas has been developed rapidly, especially in the US and the supply in natural gas increased drastically. In 2013, the US do not have the possibility to export its natural gas and prices have started to diverge from the price



**Fig. 2.44** Schematic depiction of hydraulic fracturing for shale gas; from U.S. Environmental Protection Agency (EPA)

of natural gas in other markets (see Fig. 2.34), limiting the margins of shale gas producers in the US.

Shale gas reserves are large, at least 210 trillion cubic meters, or enough to satisfy the world current demand for natural gas for another 60 years.

Hydraulic fracturing has raised environmental concerns about ground water contamination, risks to air quality, migration of gases and hydraulic fracturing chemicals leaking to the surface, mishandling of waste, and the health effects of all these, as well as its contribution to raised atmospheric CO<sub>2</sub> levels by enabling the extraction of previously sequestered hydrocarbons. In a recent report (posted to the web in November 2010) by the U. S. Environmental Protection Agency (EPA) on emission factors for greenhouse gas emissions by the oil and gas industry, EPA concluded that shale gas emits larger amounts of methane, a potent greenhouse gas, than does conventional gas, but still far less than coal.

### 2.7.4 Shale Oil

Oil shale is an organic-rich fine-grained sedimentary rock containing significant amounts of *kerogen* (a solid mixture of organic chemical compounds) from which technology can extract liquid hydrocarbons (shale oil) and combustible oil shale gas.

Oil shale deposits are found in all world oil provinces, although most of them are too deep to be exploited economically. The kerogen in oil shale can be converted to shale oil through the chemical processes of pyrolysis (decomposition by heating), hydrogenation, or thermal dissolution. The temperature when perceptible decomposition of oil shale occurs depends on the time-scale of the pyrolysis; in the above ground retorting process the perceptible decomposition occurs at 300° C, but proceeds more rapidly and completely at higher temperatures. The ratio of shale gas to shale oil depends on the retorting temperature and as a rule increases with the rise in temperature. Modern in-situ process, which involves heating the oil shale underground, may take several months of heating, decomposition may be conducted as low as 250 °C. Such technologies can potentially extract more oil from a given area of land than ex-situ processes, since they can access the material at greater depths than surface mines can. Oil shale has also been burnt directly as a low-grade fuel.

Depending on the exact properties of oil shale and the exact processing technology, the retorting process may be water and energy extensive. A critical measure of the viability of extraction of shale oil lies in the ratio of the energy produced by the oil shale to the energy used in its mining and processing, a ratio known as “Energy Returned on Energy Invested” (EROEI). A 1984 study estimated the EROEI of the various known oil-shale deposits as varying between 0.7–13.3. Global technically recoverable oil shale reserves are substantial with the largest reserves in the United States, Russia and Brazil. However, the production of shale oil is very limited compared to conventional oil production from sandstone and chalk reservoirs. The most important producers are Estonia, Brazil, China, and to some extent Germany and Russia. Oil shale gains attention as a potential abundant source of oil whenever the price of crude oil rises. At the same time, oil-shale mining and processing raise a number of environmental concerns, such as land use, waste disposal, water use, waste-water management, greenhouse-gas emissions and air pollution. The reserves of oil shale are large, estimated to about 4.8 trillion barrels. The economics of extracting this resource strongly limit its attractiveness for the time being.

### ***2.7.5 Coal Conversion***

*Coal liquefaction* is a general term referring to a family of processes for producing liquid fuels from coal. Specific liquefaction technologies generally fall into two categories: direct (DCL) and indirect liquefaction (ICL) processes. Indirect liquefaction processes generally involve gasification of coal to a mixture of carbon monoxide and hydrogen (syngas) and then using the so-called Fischer-Tropsch process to convert the syngas mixture into liquid hydrocarbons. By contrast, direct liquefaction processes convert coal into liquids directly, without the intermediate step of gasification, by breaking down its organic structure with application of solvents or catalysts in a high pressure and temperature environment. Since liquid hydrocarbons generally have a higher hydrogen-carbon molar ratio than coals, either hydrogenation or carbon-rejection processes must be employed in both ICL and DCL technologies.



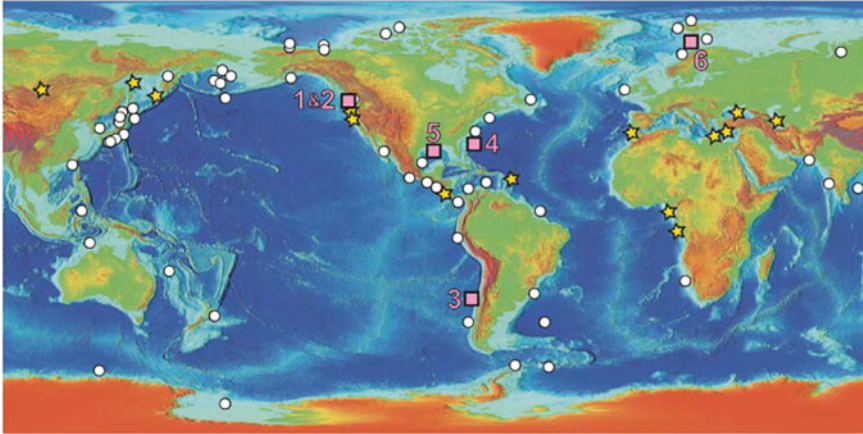
As coal liquefaction generally is a high-temperature/high-pressure process, it requires a significant energy consumption and large capital investments. Thus, coal liquefaction is only economically viable at historically high oil prices, and therefore presents a high investment risk.

Most coal liquefaction processes are associated with significant CO<sub>2</sub> emissions, resulting either from the gasification process or from generation of heat and electricity that serve as energy inputs to the reactors. High water consumption in water-gas shift or methane steam reforming reactions is another adverse environmental effect. On the other hand, synthetic fuels produced by coal liquefaction processes tend to be 'cleaner' than naturally occurring crudes, as e.g. sulfur compounds are not synthesized or are excluded from the final product.

### 2.7.6 Methane Hydrates

Methane is a natural gas (CH<sub>4</sub>) which exists in solid form together with frozen water, a so-called *methane hydrate*. The water molecules form, under certain conditions, cages which contain methane molecules. This results in large caps of methane hydrates which are deposited and stable on the sea floor at sufficient depths and in the ground. The map in Fig. 2.45 shows known locations of methane caps on the sea floor. The locations are closely correlated with the border zones of the continental plates. Natural deposits of methane hydrates also exist on Earth in colder regions, such as permafrost areas. There has been a long-term commercial production of natural gas from methane hydrates in Siberia.

The first enterprise to excavate methane hydrate from the seabed was started up in March 2013 about 70 km off the Atsumi Peninsula, in central Japan. A drill ship from Japan Oil, Gas, and Metals National Corporation (JOGMEC) will drill 1,000 m into a 300 m thick layer of methane hydrates. The next step will involve inserting a large pipe down into the well in order to separate methane hydrate into methane gas and water. This is not straight forward, but theoretical analysis as well as laboratory experiments, has shown that CO<sub>2</sub> is able to stabilize the hydrate better than methane does, Graue et al. (2006) and Ersland and Graue (2010). Thus, if CO<sub>2</sub> is pumped into the hydrate deposits, methane will be released and CO<sub>2</sub> may be captured. This is of course a very interesting process since it has the potential of solving two problems: hopefully a commercial production of methane and storage of CO<sub>2</sub> in safe formations. To test this out US Department of Energy (DOE) in 2012, in conjunction with the oil company ConocoPhillips and JOGMEC will pump CO<sub>2</sub> down a well in Prudhoe Bay, Alaska, into a hydrate deposit. If all goes as planned, the CO<sub>2</sub> molecules will exchange with the methane in the hydrates, leaving the water crystals intact and freeing the methane to flow up the well. Conventional wells in the Prudhoe Bay gas fields contain a very high concentration of carbon dioxide, about 12 % of the gas, some of it is being pumped back into the conventional wells as a drive gas to maintain pressure.



**Fig. 2.45** Global distribution of known offshore gas hydrate reservoirs (Pohlman et al. 2009)

Conservative estimates imply that the energy potential of methane hydrates is huge—at least twice as much as the existing amounts of conventional oil. But commercialization is still a long way off. The United States has no urgent need to mine methane hydrates because of the increasing success of shale gas production. Japan, on the other hand, has few other fossil-fuel resources and plan to start longer tests of methane production from the Nankai Trough in 2015.

Fascinating as it is, mining methane is a risky business. Many geologists suspect that gas hydrates play an important role in stabilizing the seafloor. Drilling in these oceanic deposits could destabilize the seabed, causing vast swaths of sediment to slide down the continental slope. Hydrates also tend to form along the lower margins of continental slopes, where the seabed falls away from the relatively shallow shelf toward the abyss. The roughly sloping seafloor makes it difficult to run pipeline. But perhaps the biggest concern is how methane hydrate mining could affect global warming. Hydrate deposits naturally release small amounts of methane. Once methane is in the atmosphere, it becomes a greenhouse gas 20 times more efficient than carbon dioxide at trapping solar radiation. Some experts fear that when drilling in hydrate deposits it will be problematic to keep the released methane under control. The gas works itself skyward, either bubbling up through permafrost or ocean water, until it is released into the atmosphere. This could cause catastrophic releases of methane that would greatly accelerate global warming. There may also be a dangerous feedback effect. As the global temperature increases, more methane will be released from the arctic tundra, which raises the temperature further.

With these very large reservoirs of unconventional fossil energy in the ground, it is far from certain that the “oil age” will end with the depletion of conventional oil resources. It is quite certain that the resource base is large enough to extend the “oil age” for up to another 100 years. As for development of other energy sources, the use of these non conventional energy sources will become a matter of price vs.

environmental impact. At the time we reach the world peak of conventional oil, it seems likely that the unconventional reserves will be one option which will be considered against nuclear and or renewable alternatives. In the following chapters, we will describe these alternatives.

## 2.8 Exercises

### 1. Coal fired power plant

A coal fired power plant has 1 GW electricity production when working at full capacity at a thermal efficiency of 35 %. The coal has a heating value of 30 MJ per kg and a sulfur (S) content of 2 % (by weight), a nitrogen (N) content of 1 % by weight and a mineral content (ash) of 10 %. Assume the coal consists of carbon with atomic mass 12 u, sulphur has mass 32.066 u, nitrogen 14.006 u, oxygen (O) has weight 15.994 u. Note: 1 u is equal to  $1.66 \times 10^{-27}$  kg.

- How much electricity can the plant produce per year?
- How much coal does the power plant consume each year?
- How much  $\text{CO}_2$ ,  $\text{SO}_2$  and  $\text{NO}_2$  does the plant emit per year?
- Chose a realistic electricity price (in Norway, eg. NOK 0.5 per kWh) and calculate the value of 1 year output with full production.

Assume in a “zero interest rate country“ that a device to capture and store  $\text{CO}_2$  (CCS) from the plant will cost GNOK 5 (= 5 billion kr) in capital costs to install. This device requires 25 % of the total energy produced for operation. Assume further that operation of the plant (with or without) CCS costs 10 % of the value of the electricity production (in average) and that the initial cost of the plant is 10 % of the price of the electricity produced in a 20 year period.

- What is the total cost of the plant in a 20 year perspective with and without CCS?
- Discuss necessary conditions for plant owners to install the CCS technology? Write down “pros and cons”.

### 2. Developing an oil reservoir

A small land based and essential horizontal oil reservoir has an area of approximately  $A = 0.76 \text{ km}^2$ , according to a geological model. The average thickness of the oil bearing zone is  $h = 35 \text{ m}$ . Retrieving sandstone core plugs by test drilling shows that the porosity is  $\phi = 23 \%$  and further core analysis indicate that the oil saturation is  $S_o = 0.72$ . There is no indication of a gas cap on top of the oil, but gas may be dissolved in the oil. When brought to the surface under standard conditions, dissolved gas will be released resulting in a shrinkage of the oil volume compared to the oil volume in the pressurized and temperature elevated reservoir. The *oil formation factor*  $B_o$  is the ratio between the oil volume in the reservoir

and the oil volume and the stock tank oil volume at the surface. For this particular reservoir  $B_o = 1.09 \text{ Rm}^3/\text{Sm}^3$ .

- (a) Calculate the Stock Tank Oil Originally In Place (STOOIP) for this reservoir in  $\text{Sm}^3$  (Standard cubic meters).
- (b) Assuming an oil price of 92 USD/bl, what is the gross value of the oil in the reservoir? (1 barrel = 159 l)  
The production strategy is to produce the oil by a simple water drive, i.e. pumping water into the reservoir through 4 injection wells and producing the oil in a production well centred between the injection wells.
- (c) Will it be possible to produce all the oil in the reservoir by this method? Which physical factors are limiting the recovery?  
The investment costs for drilling and well completion will be  $7 \times 10^5$  USD and the operational and maintenance costs are assumed to be 7.5 USD/bl. The reservoir engineers expect the recovery rate without any extra well stimulation to be 35 % and the production is started at a rate of 70 bl/day.
- (d) The oil company is uncertain about the future oil price. Make a plot of the annual profit from this field as a function of time based on an oil price of 85 USD/bl. Assume the capital costs to be paid back in 5 years at an interest rate of 7 %.  
After two years of production the investors decide that the return on their investment is unsatisfactory and ask the oil company to consider enhanced oil recovery (EOR) by injecting surfactants in the water drive.
- (e) Discuss how this can improve the oil recovery.
- (f) The cost of the surfactant is 20 USD/kg and its concentration in the injected water is planned to be 0.5 %. The oil production can then be increased to 100 bl/day without water breakthrough in the production well. What must the oil price be to make this programme profitable?

### 3. Fuel cost natural gas

Assume a natural gas price of 2.7 Euro/mmBtu.

- (a) Calculate the expected fuel cost per MWh of electricity produced for that plant, assuming a thermal efficiency of 55 %, a discount rate of 5 %, an escalation rate of 1 % and plant life  $T = 30$  years.
- (b) Now, building a 250 MW plant would require an investment of Euro 125 millions. Assuming an economic plant life of 30 years, a capacity factor of 85 % and a discount rate of 5 %, calculate the LCOE of that plant. Operation and maintenance costs would amount to Euro 56 millions for the first year of operation, increasing at a 1 % rate annually.
- (c) Taking the LCOE of question (b) as the expected electricity price you will receive over the next 30 years, you fear that the introduction of intermittent renewable energy generating capacity will harm the profitability of your plant. Such technologies have a marginal cost close to 0 Euro/MWh, which means that in hours with strong wind and sun, your plant will not be compet-

itive (electricity price  $<$  fuel + variable operation and maintenance costs of your natural gas-fired power plant). Taking this into account, you estimate that your capacity factor will decrease to 60 %. What is the LCOE of that plant with this new capacity factor.

- (d) Using your answer in (c) can you tell why gas-fired plant owner see the deployment of wind and solar as a threat?

#### 4. Fuel cost coal

Assume a coal import price of 70 Euro/metric ton, which is the same regardless of which coal type you import. Expecting that coal prices will be stable over the next 40 years, calculate the fuel cost per MWh of electricity produced for a plant with a thermal efficiency of 37 % if:

- (a) the coal used is lignite (use Table 2.1 to make an assumption on the heat content of lignite).  
 (b) the coal used in anthracite (use Table 2.1 to make an assumption on the heat content of anthracite).  
 (c) if using a fuel with higher heat content leads to better economics, can you think of an element which would push coal-fueled power plants to use fuel with lower heat contents?

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