1 Energy Markets

Despite a global sustainability trend including climate protection and more efficient use of energy, worldwide energy consumption will continue to grow over the coming decades (see Figure 1.1). Besides future economic growth, an important driver of global energy demand is policy commitments, such as renewable energy or energy efficiency targets. Depending on scenario assumptions, the average annual growth rate in energy consumption is estimated to be between 0.5% and 1.5% (International Energy Agency, 2012) until 2035, with significant regional differences. Most of the energy demand growth is expected to come from non-OECD countries, with China and India being the largest single contributors.

The main primary energy source worldwide is oil, covering 32% of worldwide energy consumption (see Figure 1.2). Second are coal and natural gas, with a share of 27% (respectively 22%). Nuclear energy (6%) and renewables (13%) have a much smaller share. To meet the growing worldwide demand for energy, there will need to be an increase in energy supply from all primary energy sources. However, depending on the scenario, the share of oil and coal will diminish in favour of gas and renewable energy sources (Figure 1.2).

Not all of the primary sources of energy are used directly for consumption; they may first be transformed into secondary forms of energy, such as electricity or heat. Since part of the primary energy is used for the transformation process, the final consumption is below the primary energy demand. A breakdown of the final consumption into different sectors is given in Figure 1.3.

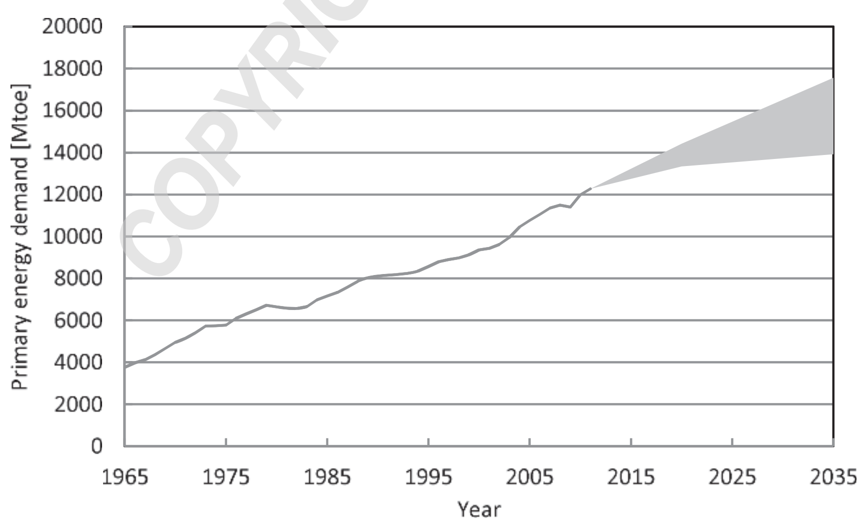

Figure 1.1 World energy demand. *Source*: International Energy Agency (2012).

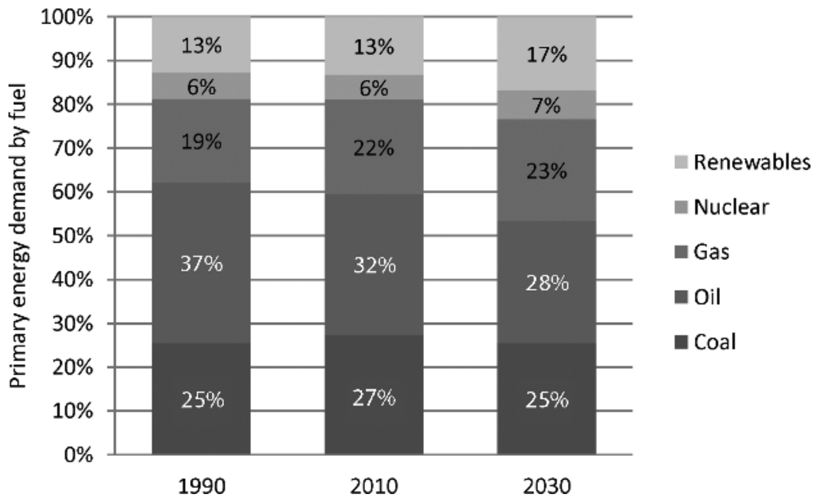

Figure 1.2 World primary energy sources. *Source*: International Energy Agency (2012).

The current trends by sector are as follows (International Energy Agency, 2012):

- *Industry:* The industrial sector accounts for 28% of the total energy consumption and has the highest growth rate among the sectors. The main energy sources are coal (28%), electricity (26%), gas (19%) and oil (13%). It is expected that electricity and gas will gain importance at the expense of coal and oil.
- *Transport:* The transport sector, which makes up 27% of the energy demand, is strongly dominated by oil (93%). On a worldwide scale, biofuels (2%) and electricity (1%) still play a minor role, but are expected to increase their share to 2% (respectively 6%) in the reference scenario. The actual development will be strongly influenced by future governmental policies.

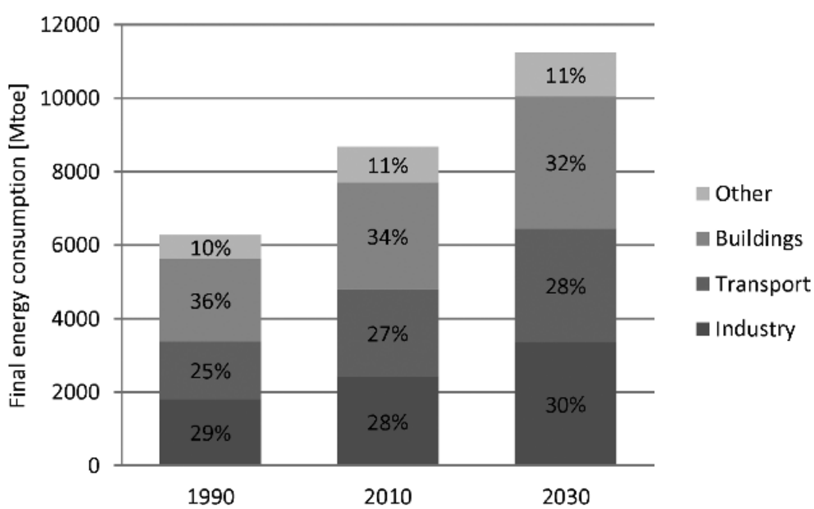

Figure 1.3 World final energy consumption. *Source*: International Energy Agency (2012).

- *Buildings:* This sector includes heating, air conditioning, cooking and lighting. It accounts for 34% of the total energy consumption. The energy is delivered mainly in the form of electricity (29%), bioenergy (29%), gas (21%) and oil (11%). There is a clear trend towards a higher share of electricity and gas at the expense of bioenergy and oil.

1.1 ENERGY TRADING

With the development of a global oil market in the 1980s, energy has become a tradable commodity. In the early 1990s, deregulation of the natural gas market in the United States led to a liquid and competitive gas market. In Europe, liberalisation of gas and electricity markets started in the UK in the late 1980s. In the late 1990s, the EU Commission adopted first directives making energy market liberalisation a mandatory target for EU member states along different steps of implementation. Whereas a wholesale market for electricity developed successfully in the early 2000s in some countries (e.g., Germany), a liquid gas wholesale market only existed in the UK. Gas markets in Continental Europe still remained fragmented and dominated by oil-indexed supply contracts. Further consolidation of market areas, easier market access and declining gas demand following the financial crisis in 2008 increased competition and finally led to growing market liquidity for gas markets in Continental Europe and a decoupling of gas and oil prices in the early 2010s.

Besides the commodities coal, oil, gas and electricity, which carry energy directly, the EU introduced carbon emission certificates (*European Emission Allowance* or *EUA*) in the year 2005 as part of the EU climate policy. The certificates were designed as tradable instruments for which a liquid market quickly developed. Since carbon certificates are closely related to energy commodities and electricity generation, they will be treated here along with the other energy commodities. Before describing the specific markets for each commodity, the general structure and basic products of commodity markets in general will be introduced. A more detailed description of commodity derivatives products will be given in Chapter 5.

We generally distinguish between *over-the-counter (OTC)* and exchange-traded markets. The OTC market consists of bilateral agreements, which are concluded over the phone or through Internet-based broker platforms. Such transactions are most flexible since the parties are free to agree individual contract terms. As a main disadvantage, OTC transactions may contain credit risk, meaning that one of the counterparties may not deliver on his contract (e.g., in case of insolvency). As a mitigation, collaterals may be defined to protect the counterparties from losses in such a case. Exchanges provide organised markets for commodities in the form of standardised contracts. In particular, they became popular for derivatives products (futures, options), where the exchange also eliminates credit risk for the market participants.

1.1.1 Spot Market

The *spot market* is the market for immediate (or nearby) delivery of the respective commodity in exchange for cash. The exact definition depends on the commodity. As an example, the spot market for electricity often refers to delivery on the next day or on the next working day. For coal markets, contracts delivering within the next several weeks ahead are typically still considered as spot transactions. Spot markets can either be bilateral OTC transactions or organised by exchanges. For electricity, gas and EUAs, energy exchanges typically offer spot market products.

A particular form of spot market is the *auction market*, where buyers submit their bids and sellers their offers at the same time. In most cases a uniform price, the *market clearing price*, is determined, which balances supply and demand. Such a uniform price auction is popular for electricity spot markets; traded products are typically single-hour (or even half-hour) deliveries.

Spot prices represent the final price of the "physical commodity" in the prevailing situation of supply and demand, and are therefore the *underlying* of the derivatives market, which is largely driven by expectations regarding the future situation on spot markets. There are various published spot price indices available for the different commodities that provide transparency for market participants and also serve as official references for the financial settlement of futures contracts.

1.1.2 Forwards and Futures

Forward and futures contracts are contractual agreements to purchase or sell a certain amount of commodity on a fixed future date (delivery date) at a predetermined contract price. The contract needs to be fulfilled regardless of the commodity price development between conclusion of the contract and delivery date. In case the spot price has increased, the seller needs to sell below the prevailing spot price at delivery and therefore incurs an opportunity loss, whereas the buyer makes an (opportunity) profit. In case prices decline, the situation is reversed. The buyer of a forward or future is said to hold a *long position* in the commodity (he profits from a price increase until delivery), the seller is said to hold a *short position* (he takes a loss from a price increase).

The final profit or loss for the buyer of a forward contract (long position) at delivery date T is the value of the commodity at delivery $S(T)$ minus the contract price K (i.e., $S(T) - K$), see Figure 1.4. Similarly, the profit or loss for the seller (short position) is $K - S(T)$.

Forward contracts are the most basic *hedging* instruments. If a producer of a commodity enters into a forward contract as a seller, he fixes his revenues and is indemnified from further

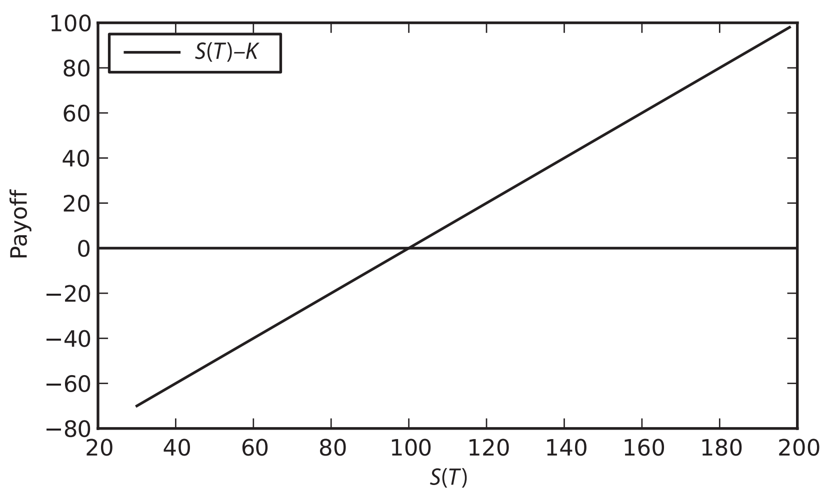

Figure 1.4 Profit or loss of a commodity forward contract.

price changes. On the contrary, a market participant who is dependent on the commodity for consumption may enter into a forward contract as a buyer to fix his purchasing costs for the commodity in advance.

The term "futures contract" is used for a standardised forward contract which is traded via an exchange. Often, futures contracts are financially settled, which means that only the value of the commodity at the delivery date is paid instead of a true physical delivery. Futures contracts open up the commodity market for participants who do not want to get involved in the physical handling of the commodity. Since the exchange serves as a *central counterparty* for futures contracts, market participants do not have to deal with multiple individual counterparties and their associated credit risk. This also makes it easier to unwind a position entered into previously.

The market size and liquidity of the futures market is often much higher than the actual physical (spot) market. A list of exchanges with global significance offering energy-related commodity derivatives products is given below.

- *CME Group (Chicago Mercantile Exchange):* The CME Group is the world's largest commodity futures exchange. The wide array of products offered by the CME Group includes futures and options contracts for energy (electricity, oil products, coal, natural gas), but also metals, agriculture, foreign exchange, equities and interest rates. The CME Group originated from a merger between the Chicago Mercantile Exchange (CME) and the Chicago Board of Trade (CBOT) in 2007. In 2008, the CME Group acquired the *New York Mercantile Exchange (NYMEX)*. The NYMEX light sweet crude oil futures contract introduced in 1983 and the NYMEX Henry Hub natural gas futures contract introduced in 1990 are the most popular energy benchmarks in the United States.
- *IntercontinentalExchange (ICE):* The ICE was founded in May 2000 with the objective of providing an electronic trading platform for OTC energy commodity trading. ICE expanded its business into futures trading by acquiring the International Petroleum Exchange (IPE) in 2001. ICE's products include derivative contracts based on the key energy commodities of crude oil, refined oil products, natural gas and electricity. The ICE Brent futures contract serves as an important international benchmark for pricing oil cargos (see Section 1.2) in Europe. In 2010, ICE acquired the European Climate Exchange (ECX), which is the leading exchange for emission certificates under the European Trading Scheme.
- *NASDAQ OMX Commodities Europe:* NASDAQ OMX Commodities Europe is part of the NASDAQ OMX Group and originates from the acquisition of the financial trading part of the Nord Pool exchange in 2008. Nord Pool was founded in 1993 in Norway and became the leading electricity market place for the Nordic and Baltic countries. Meanwhile, NASDAQ OMX Commodities Europe also offers electricity products for Continental European countries, electricity and gas contracts for the UK and emission certificates.
- *European Energy Exchange (EEX):* The EEX was founded at the beginning of the 2000s with origins in the German electricity market and has become one of the leading European energy exchanges with a focus on electricity, gas and emissions. EEX and the French energy exchange *Powernext* both hold a 50% share of the *EPEX Spot* exchange, which operates power spot markets for Germany, France, Austria and Switzerland.

There are several other energy exchanges with a focus on specific local markets for electricity or natural gas. Descriptions of these exchanges are included in the subsequent sections.

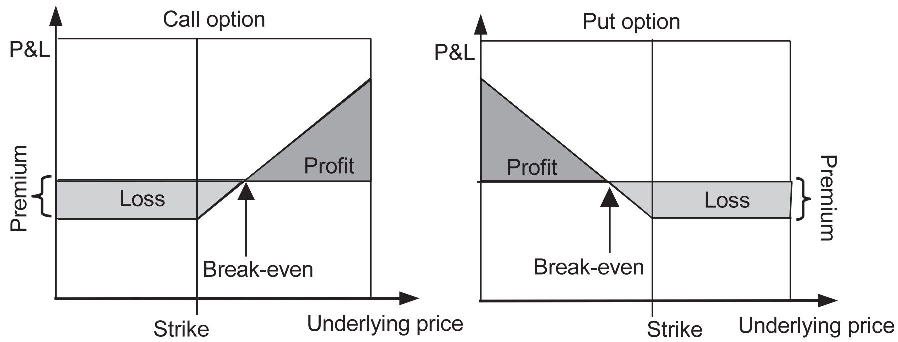

Figure 1.5 Profit or loss at maturity for an option holder.

1.1.3 Commodity Swaps

A *commodity swap* exchanges a fixed cashflow specified by a fixed commodity price against a varying cashflow calculated from a published commodity price index at the respective fixing dates. The risk profile of a commodity swap is similar to that of a financially settled forward (i.e., a forward paying the commodity price index instead of a physical delivery). Often, commodity swaps cover multiple payment periods, so that the swap is equivalent to a series of financially settled forward contracts with different delivery dates $T_1, \dots, T_n$. On each payment date T_i, one counterparty (the holder of the long position) receives the *floating* price index $S(T_i)$ and pays the fixed price K whereas the other counterparty (the holder of the short position) pays the price index and receives the fixed price. The net amount the holder of the long position receives on the payment date T_i is therefore $S(T_i) - K$. For more details and examples, see Section 5.1.3.

1.1.4 Options

An *option* holder has the right but not the obligation to purchase (*call option*) or sell (*put option*) a certain commodity at a predetermined *strike price* from the option seller. See Figure 1.5. In exchange, the option holder pays an option premium to the seller of the option.

A call option will only be exercised at the option's *maturity date* T if the spot price at time T is above the strike price, as otherwise purchasing from the market is cheaper. If the option premium is P, then the profit or loss for the holder of a call option is $\max(S(T) - K, 0) - P$.

A put option will only be exercised if the spot price at time T is below the strike price, as otherwise selling in the market generates higher value. If the option premium is P, then the profit or loss for the holder of a put option is $\max(K - S(T), 0) - P$.

For more details and examples, see Section 5.3.

1.1.5 Delivery Terms

Unlike in financial markets, the point of delivery plays an important role in commodity trading, since transportation can be costly (coal, oil) or dependent on access to a grid (power, gas). Therefore, commodity prices are usually quoted with reference to the delivery point. Typical delivery points depend on the type of commodity, for example Richards Bay in South

Africa for coal or Amsterdam–Rotterdam–Antwerp (ARA) for oil or coal. Another important specification for physical commodity trades are the *Incoterms* (international commerce terms) dealing with the clearance responsibilities and transaction costs. The most important Incoterms for energy markets are as follows.

- *Free-On-Board (FOB):* The seller pays for transportation of the goods to the port of shipment and for loading costs. The buyer pays for freight, insurance, unloading costs and further transportation to the destination. The transfer of risk is at the ship's rail.
- *Cost, Insurance and Freight (CIF):* The selling price includes the cost of the goods, the freight or transport costs and also the cost of marine insurance. However, the transfer of risk takes place at the ship's rail.
- *Delivered-At-Place (DAP):* The seller pays for transport similar to CIF, but also assumes all risks up to the point that the vessel has arrived at the port and the goods are ready for unloading.
- *Delivered-ex-Ship (DES):* Similar to DAP (eliminated from Incoterms 2010).

1.2 THE OIL MARKET

The oil market is certainly the most prominent among the energy markets. *Crude oil* (or *petroleum*) is found in reserves spread across particular regions of the Earth, where it can be accessed from the surface. Even though petroleum has been known and used for thousands of years, it became increasingly important during the second half of the 19th century as a primary energy source and as a raw material for chemical products. The main advantages of oil as an energy carrier compared with other primary energy sources is its high energy density and the ease of handling for storage and transport. Today, crude oil is still the predominant source of energy in the transportation sector and is often taken as a benchmark for the price of energy in general. Chemically, crude oil is a mixture of *hydrocarbons* with different molecular weights. For actual usage, crude oil is transformed via a refinery process into different petroleum products, such as fuel oil or gasoline.

Because of oil's great economic importance historically, oil markets have always been subject to political regulations and interventions. Figure 1.6 shows the historical spot prices for Brent crude oil. Clearly, the oil price is influenced by political or military events (especially in oil-exporting countries), which explains, for example, the price spike during the First Gulf War of 1990/91. In addition, there are economic developments, such as the increase of energy demand in Asia or the financial crisis following the bankruptcy of Lehman Brothers in 2008, which have an impact on the oil price.

1.2.1 Consumption, Production and Reserves

Oil consumption and oil production are unevenly distributed accross the world. The majority of the world's oil consumption is located in North America, Europe & Eurasia and Asia & Pacific (see Figure 1.7), whereas the majority of the reserves are located in the Middle East and South & Central America (see Figure 1.8).

Historically, the OECD countries clearly dominated oil demand, but over the last decades the share of non-OECD countries increased to nearly 50% (see Figure 1.9), largely driven by

Figure 1.6 Brent historical spot prices. *Source*: Energy Information Administration.

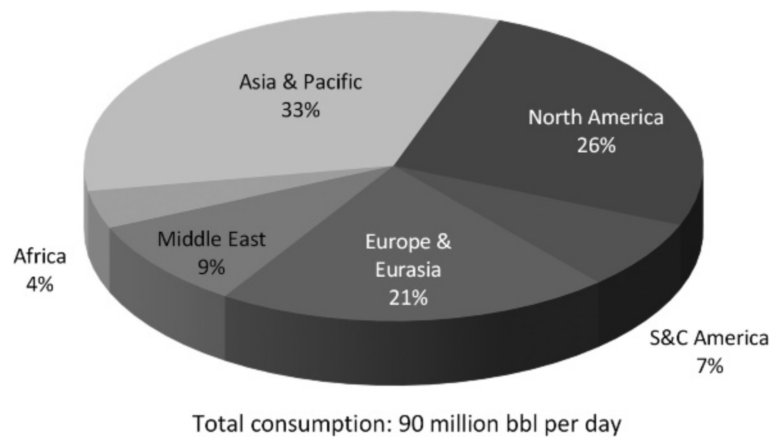

Figure 1.7 World oil consumption 2012 by region. *Source*: BP (2013).

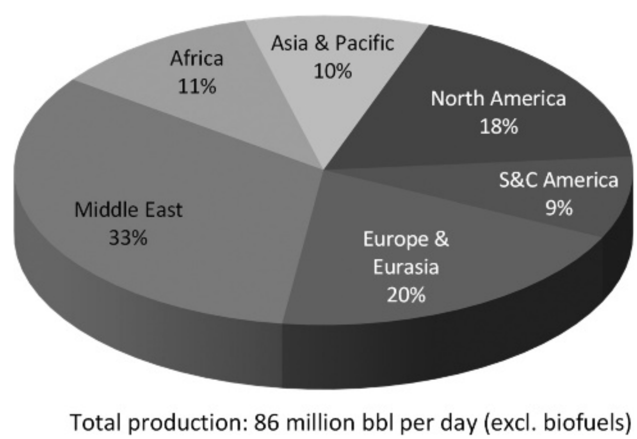

Figure 1.8 World oil production 2012 by region. *Source*: BP (2013).

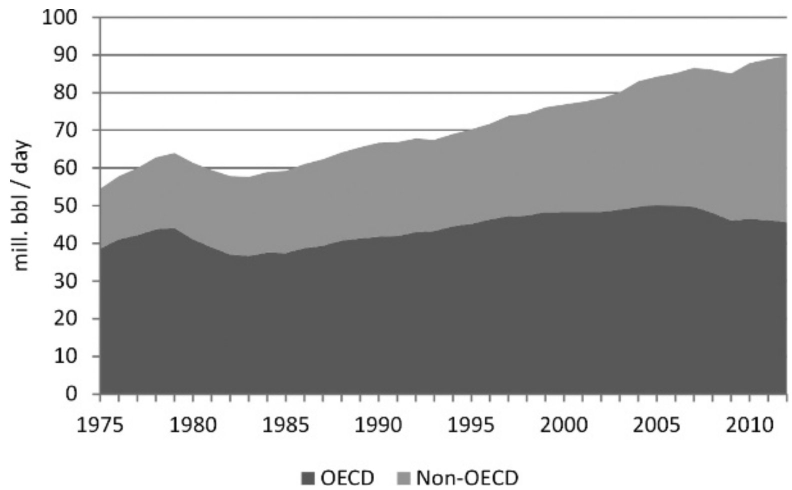

Figure 1.9 Historical oil demand. *Source*: BP (2013).

increased demand from China and India. The main driver for oil demand is the transport sector, accounting for more than 50% of the overall oil demand. Other drivers for oil demand include the buildings, industry and power generation sectors. Forecasts for oil demand over the next decades depend strongly on assumptions for the world's economic growth and government policies to curb oil demand. Different scenarios (see International Energy Agency, 2012) lead to an average annual growth rate between −0.5% and 1.80% in the period 2011 to 2035.

On the supply side, the OPEC member countries[1] control over 40% of the world's oil production and over 70% of all known conventional oil reserves (see Figure 1.10). An indication of the future production potential can be given by the *reserves-to-production ratio* describing the number of years that known reserves are estimated to last at the current rate of production. The worldwide reserves-to-production ratio as for 2012 was approximately 53 years, with great differences among the regions. For OPEC members the reserves-to-production ratio was 89 years, whereas for non-OPEC countries the ratio was only 26 years (see BP, 2013). However, this indication may be misleading due to changes in production, revised estimates for existing reserves and discoveries of new reserves. A major unknown is the future role of *unconventional oil*, which comprises extra heavy oils, oil sands, *kerogen oil* and *light tight oil*. Producing or extracting unconventional oil requires techniques that are usually more costly than conventional oil production and become profitable only if oil prices are sufficiently high. On the contrary, there may still be substantial "learning curve" effects leading to more efficient production processes. An example is the production of light tight oil, which only recently emerged with substantial production volumes using the same technology as for shale gas production (see Section 1.3).

Depending on its origin, oil can be of different quality. The main characteristics are viscosity and sulphur content. Fluid crude oils with low viscosity have a lower specific weight and are called *light* crudes. With increasing viscosity and specific weight the crudes are called *intermediate* and then *heavy*. Lighter crude oils are more valuable, since they yield more

[1] Iran, Iraq, Kuwait, Qatar, Saudi Arabia, United Arab Emirates, Algeria, Libya, Angola, Nigeria, Ecuador, Venezuela.

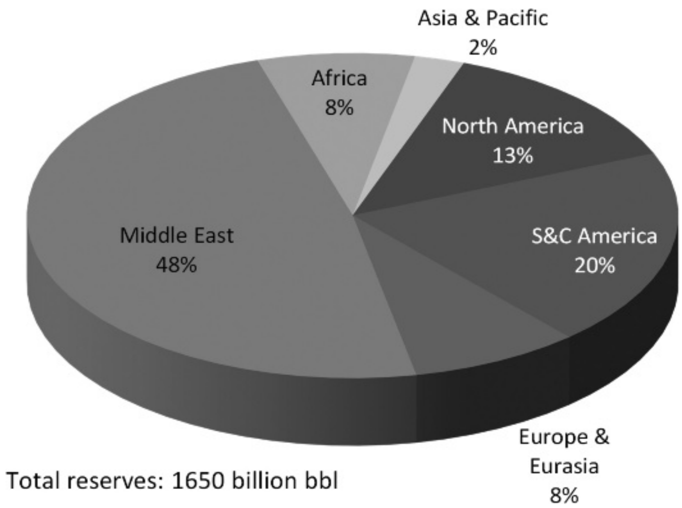

Figure 1.10 World oil reserves 2012 by region. *Source*: BP (2013).

marketable products. Crude oils with low sulphur content are called *sweet*, otherwise they are called *sour*. Since a high sulphur content causes additional costs in the refinery process, sweet crude oils are priced at a premium.

1.2.2 Crude Oil Trading

The physical crude oil market has to deal with a large variety of different oil qualities (viscosity, sulphur content) and with different means of transportation (pipeline, shipping). All of these characteristics influence the oil price. Nevertheless, a liquid oil market has developed, using reference oil qualities as benchmarks for pricing individual oil qualities. Depending on the quality, a certain price differential will be added to the benchmark price. Long-term supply contracts typically use such price formulas to price their individual cargos. The most popular benchmark oils are as follows.

- *West Texas Intermediate (WTI):* Quality sweet and light, main reference for the US market (delivery in Cushing/Oklahoma).
- *Brent:* Quality also sweet and light (slightly less than WTI), main reference for North Sea oil.
- *Dubai:* Reference for the Middle East and Far East with higher sulphur content ("sour").
- *ASCI:* Argus Sour Crude Index representing the price of medium sour crude oil of the US Gulf coast.

The benchmark price used in contracts is typically a spot price index for physical delivery published by an oil pricing reporting agency, such as Platts or Argus. Price assessments are carried out on the basis of information on concluded transactions or bids and offers in the market. The exact methodology varies between different reporting agencies. Also the benchmark itself may evolve over time, for example as the original Brent crude stream has declined over recent decades, the Brent benchmark now includes the North Sea streams Forties, Oseberg and Ekofisk (BFOE). The benchmark prices above also serve as an underlying for the oil derivatives market, such as futures and swaps.

The structure of the physical market for BFOE crude oil is connected to its nomination procedure. In case of a 25-day[2] forward contract, the sellers are obliged to tell their counterparties 25 days in advance the first day of the three-day loading window when the cargo will actually be loaded. The final loading schedule is then published by the terminal operator. A contract with already nominated loading window less than 25 days ahead is called *Dated Brent*. The *25-day forward market* trades contracts for delivery up to multiple months ahead. A typical crude oil cargo has a size of about 600 000 bbl.

The need for producers and consumers to financially hedge oil price risks and the growing importance of oil derivatives for asset managers and speculators gave rise to a very large market of financial instruments related to oil. The most important commodity exchanges offering oil futures and options are the CME Group (formerly NYMEX) for WTI contracts and the ICE for Brent contracts. Both the WTI and the Brent contracts are monthly futures contracts quoted in USD per barrel with a contract size of 1000 bbl. The *Light Sweet Crude Oil (WTI) Futures* contract was introduced by NYMEX 1983 and soon became a global reference for the price of crude oil. The ICE Brent Crude Futures Contract was launched in 1988 by the former IPE (International Petroleum Exchange) and also reached global importance next to WTI as pricing reference.

	WTI Future	Brent Future
Exchange	CME Group	ICE
Contracts	monthly	monthly
Contract size	1000 bbl	1000 bbl
Price quotation	USD/bbl	USD/bbl
Expiration date	3rd business day prior to the 25th calendar day of the month preceding the delivery month	15th day before the first day of the delivery month
Settlement	physical	physical or financial

In addition to the futures contracts described above there is a wide range of related products for specific purposes, such as different option products, contracts-for-differences (CFDs) to manage the price differential between Dated Brent and forward contracts or spreads between different oil benchmarks (e.g., WTI vs. Brent).

The long-term forward market for crude oil (up to 10 years) is dominated by Brent and WTI swaps exchanging a fixed monthly payment against a floating payment, which is the monthly average of the front month futures price. Such swaps are typically traded OTC, but exchanges (e.g., CME Group and ICE) meanwhile offer a clearing service for swaps that is increasingly used by market participants.

1.2.3 Refined Oil Products

As mentioned earlier, crude oil can be of various qualities concerning its density and sulphur content. To become marketable to consumers, *refineries* convert crude oil into various products.

[2] Before 2012, a 21-day nomination period was typically used.

The refining process in its basic form is a distillation process, where crude oil is heated in a distillation column. The lightest components can now be extracted at the top of the column whereas the heaviest components come out of the bottom. To increase the yield of the more valuable lighter products, a *cracking* process is used to break up the longer hydrocarbon molecules. Other processes are needed to remove the sulphur content. Ordered by increasing density, the most important oil products are

- *Light distillates:* Liquefied petroleum gases (LPG), naphtha, gasoline.
- *Middle distillates:* Kerosine, gasoil or heating oil and diesel.
- *Fuel oil.*
- *Others*: For example, lubricating oils, paraffin wax, petroleum coke, bitumen.

LPG (propane or butane) are hydrocarbon gases that are liquid under pressure or low temperature. They are used mainly for heating appliances or vehicles. Naphtha is used mainly in the chemical industry. Middle distillates are the largest group of oil products, accounting for around 50% of refinery output. Besides its use for domestic heating, middle distillates (diesel) is used for transportation. Improvements in diesel engine technology and tax incentives have led to a strong growth of diesel consumption in Europe. Being more polluting and more difficult to process, fuel oil is less valuable and used mainly as bunker fuel in ships and to a limited extent for power generation (e.g., as a backup for gas).

Worldwide there are approximately 700 refineries to match the demand for the different oil distillates. Since building new refineries is a complex project involving very large investments, refining capacities react slowly to changes in demand. Owing to the combined production process, the prices of different oil products are usually tightly related to each other and can be expressed in terms of price spreads against crude oil. The lighter and more valuable products have higher spreads against crude oil than the heavier products. In special circumstances, such as a military crisis, prices for certain products (e.g., jet fuel) can spike upwards in relation to crude oil because of the limited refining capacities and the limited flexibility of refineries to change the production ratios among the different products.

The European market for refined oil products is divided into ARA and Mediterranean (Genova). Typical lot sizes for these contracts are barges that correspond to 1000 to 5000 (metric) tonnes.

Typical financial instruments for European gasoil are

1. *Gasoil swaps:* Gasoil swaps are traded OTC and typically refer to the monthly average gasoil price (ARA or Mediterranean) as published by Platts for setting the floating payments.
2. *ICE gasoil futures:* The ICE offers monthly gasoil futures contracts FOB Rotterdam.

In addition, there are local oil price indices available. In Germany, typical reference prices for HEL (gasoil) and HSL (fuel oil) are published monthly by the "Statistisches Bundesamt". They include certain taxes and transportation costs within Germany.

1.3 THE NATURAL GAS MARKET

Next to oil and coal, natural gas is one of the most important primary energy sources, covering about 22% of worldwide energy consumption. It is used primarily as a fuel for electricity generation, transportation and domestic heating. Natural gas consists mainly of methane (CH_4), which is the shortest and lightest in the family of hydrocarbon molecules. Other components are heavier hydrocarbons such as ethane, propane and butane and contaminants such as sulphur. Natural gas volume is usually measured in cubic metres or cubic feet (1 m^3 = 35.3 ft^3). For larger quantities of natural gas the units bcm (billion cubic metres) or bcf (billion cubic feet) are used. The combustion heat stored in one cubic metre of natural gas at normal atmospheric pressure is about 10.8 kWh (0.0368 mmBtu), but can vary depending on the specific quality. This section gives a general overview of the natural gas market. For economic modelling approaches, see Section 7.6.

1.3.1 Consumption, Production and Reserves

Among the fossil fuels there is a global trend in favour of natural gas. On the one hand, natural gas is the fossil fuel with lowest carbon intensity, therefore it is considered to contribute least to the greenhouse effect. On the other hand, due to the "shale gas boom" in the USA and an expanding infrastructure for *liquefied natural gas (LNG)*, there is a stable outlook for gas supply.

Natural gas and oil are often found in the same deposits. Depending on which of the two dominates, it is called either a natural gas or oil field. Unlike oil, because of its low density, gas is difficult to store and transport. In the past, gas found as a by-product in oil fields was therefore simply burned without any economic use. With growing demand for primary energy sources, gas prices have risen and large investments have been made to build up an infrastructure for gas transportation, either in the form of pipelines or in the form of LNG terminals (see Section 1.3.3). Because of the required transportation infrastructure, which historically was mainly pipelines, the regional distribution of natural gas consumption and production is more balanced between continents than the regional distribution for oil (see Figures 1.11 and 1.12). The countries with the highest gas production are the United States and Russia (between 600 and 650 bcm/a), followed by Canada, Iran and Qatar with around 150 bcm/a and Norway, Saudi Arabia and China with around 100 bcm/a.

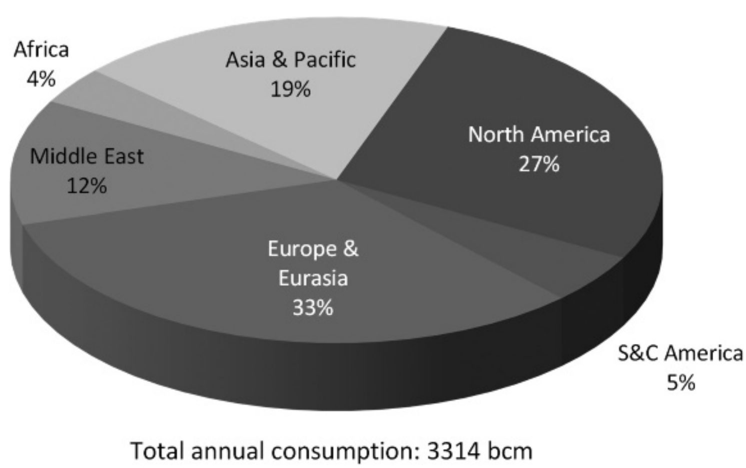

Figure 1.11 World gas consumption 2012 by regions. *Source*: BP (2013).

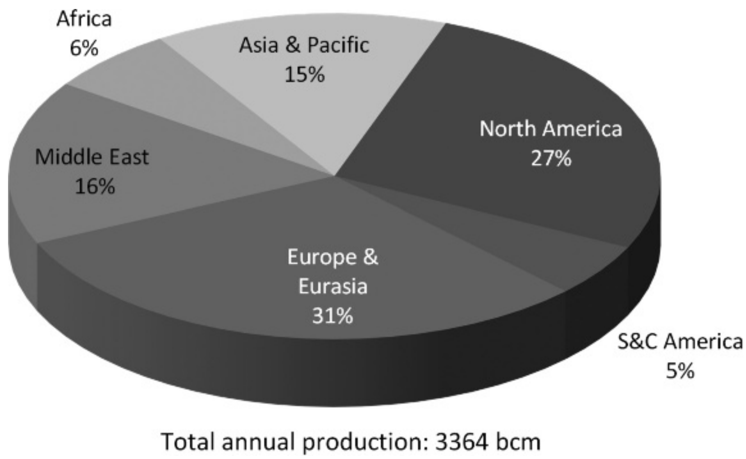

Figure 1.12 World gas production 2012 by regions. *Source*: BP (2013).

The distribution of natural gas reserves is less balanced, since gas production in many OECD countries (e.g., Europe) is in decline. Russia has a long history as a natural gas supplier to Western Europe and the reserves are well connected via pipelines. The large reserves in the Middle East (see Figure 1.13), however, could not be utilised fully in the past since efficient transportation to consumers was not available. Over the last decade a growing infrastructure for LNG has been established, allowing us to transport increasing volumes of natural gas between continents, leading to increased export volumes from the Middle East (e.g., Qatar). As of 2012, 90% of natural gas reserves are in non-OECD countries, mainly Russia and the Middle East.

At the current production rate, the proved natural gas reserves as of 2012 are estimated to last for 56 years (= reserves-to-production ratio). For OECD members, the reserves-to-production

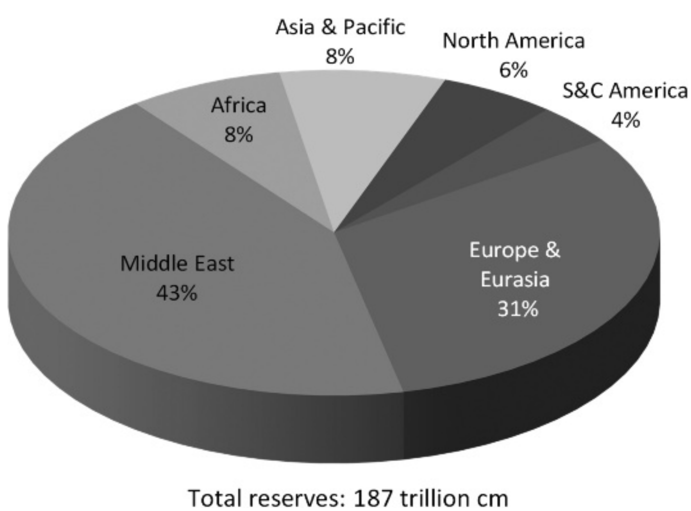

Figure 1.13 World gas reserves 2012 by regions. *Source*: BP (2013).

ratio is only 15 years as of 2012, whereas for non-OECD countries the ratio is 78 years (see BP, 2013). As for oil, the future development of the reserves-to-production ratio will depend heavily on production growth and revised estimates for gas reserves.

A major role for the future of gas supply will be played by *unconventional gas*, which comprises *tight gas*, *shale gas* and *coalbed methane*. Extracting tight gas and shale gas requires *hydraulic fracturing*. Coalbed methane is gas extracted from coal beds, with significant reserves being in the USA, Canada and Australia. Tight gas and coalbed methane have been produced for many decades; the extraction of shale gas is technologically more intricate and began to become profitable only at the beginning of the 21st century. Since then a "shale gas boom" has emerged in the USA, able to overcompensate declining conventional gas production and leading to decreased gas prices in the USA (see Section 1.3.2). The global potential of shale gas is still disputed, since outside the USA there is uncertainty around resources and there are also environmental concerns in many countries regarding the hydraulic fracturing process, for example with respect to potential contamination of groundwater.

1.3.2 Natural Gas Trading

Compared with oil, the natural gas market is more regional due to the higher costs of gas transportation. The following main gas markets can be distinguished:

- North America
- Europe
- Asia-Pacific

Historically, those regional markets have had little interaction, since LNG played a significant role only for the Asian market. Owing to a growing LNG infrastructure, market interaction has increased significantly during recent years. However, due to the shale gas boom in the USA and increasing demand in Asia, the price differentials between gas prices in North America, Europe and Asia-Pacific have first of all increased substantially (see Figure 1.14). These price differentials may attract additional investments in LNG infrastructure, which could lead again to convergence of prices to some extent in the future.

The North American Market

The United States is an importer of natural gas, with the main imports via pipeline from Canada. Before the shale gas boom in the mid-2000s there was the expectation that substantial LNG imports would be required to replace declining conventional domestic gas production and therefore infrastructure for importing LNG was built. The additional shale gas supply has reversed this picture and the United States may even become an exporter of natural gas around 2020 (see Figure 1.15). The extent of exports will depend on infrastructure investments and also regulatory approval for export licences.

The US wholesale market for natural gas is liberalised and competitive. The highest liquidity is found at Henry Hub (Louisiana) in the Gulf of Mexico. Besides a liquid spot market there is also a very liquid futures market introduced by NYMEX (now the CME Group) in 1990. The range of products offered by NYMEX includes options on gas futures and spreads between Henry Hub and other US gas hubs. As can be seen from Figure 1.16, wholesale prices in the USA deteriorated after 2008 along with the financial crisis and increasing shale gas supply. A

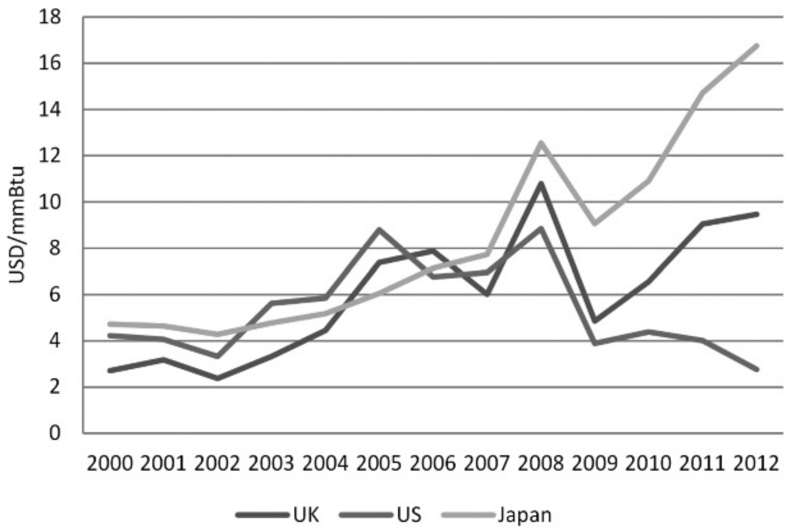

Figure 1.14 Global natural gas prices. *Source*: BP (2013).

recovery of prices will, among other factors, depend on future export volumes to higher-priced markets.

The monthly CME Natural Gas Futures contract has the following specification.

- *Trading unit:* 10 000 million British thermal units (mmBtu).
- *Price quotation:* USD and cents per mmBtu.
- *Trading months:* The current year and the following 12 years (Globex: 8 years).
- *Last trading day:* Three business days prior to the first calendar day of the delivery month.
- *Settlement type:* Physical delivery at Henry Hub.

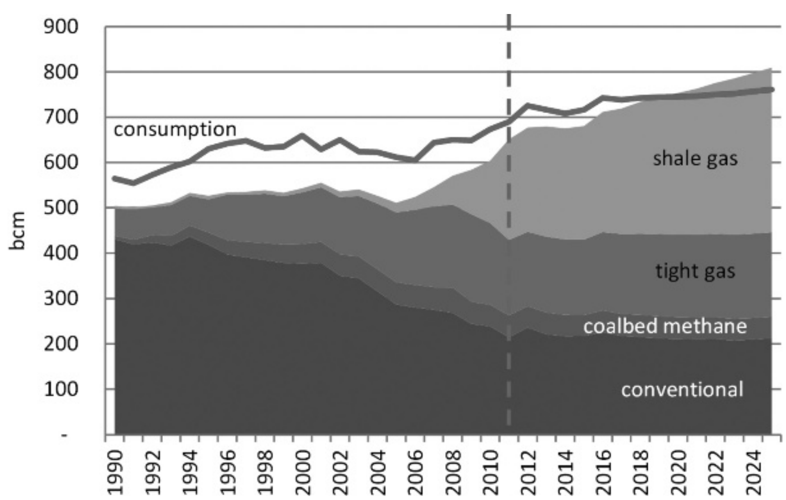

Figure 1.15 Projected US natural gas production and consumption. *Source*: EIA (2013).

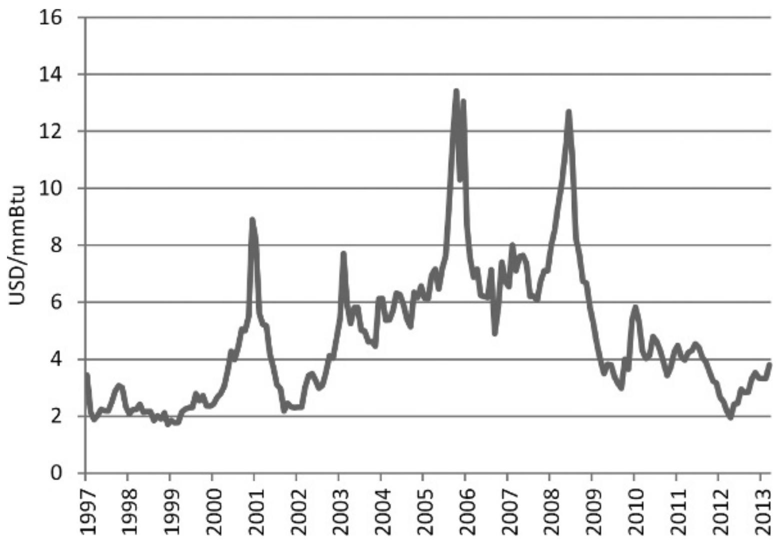

Figure 1.16 Natural gas US wholesale prices (Henry Hub, front-month contract). *Source*: EIA.

The European Market

As domestic gas production in Western Europe has been in decline for many years, an extensive infrastructure for gas imports was established. The main exporters to serve the Western European demand are Russia, Norway, the Netherlands, Algeria via pipelines and Qatar via LNG. The UK gas market was liberalised in 1996. The *National Balancing Point (NBP)* soon gained acceptance as a universal delivery point and "trading hub" in the UK. In 1997 the IPE (now ICE) launched a futures market for UK natural gas, which became the first liquid gas futures market in Europe. The natural gas market in Continental Europe was for a long time still dominated by long-term supply contracts indexed to oil prices. Fragmented market zones did not attract sufficient liquidity for a competitive wholesale gas market independent of oil-indexed supply contracts. This situation changed towards the end of the 2000s due to different developments:

- Downturn in gas demand caused by the global recession after 2008.
- Growth in global LNG supply.
- Consolidation of market zones, simplification of market access (e.g., in Germany).

Meanwhile, the liquidity of gas trading hubs has increased also in Continental Europe and corresponding futures markets were established. The most important natural gas hubs for trading in Europe are:

- National Balancing Point (NBP) in the UK;
- Title Transfer Facility (TTF) in the Netherlands;
- Zeebrugge Hub (ZEE) in Belgium;
- NetConnect Germany (NCG);
- Gaspool Hub (GPL) in Germany.

The Continental European market and the UK market are linked by the *Interconnector* pipeline that began operation in 1998. The Interconnector has a length of 235 km and connects Bacton, UK with Zeebrugge, Belgium. The pipline has a capacity of 20 billion cubic metres of gas per year to transport gas from Bacton to Zeebrugge (forward flow) and a capacity of 25.5 billion cubic metres in the reverse direction (reverse flow). Since the Interconnector enables arbitrage trading between the UK and Continental Europe (within the technical restrictions of the Interconnector), the gas spot prices at NBP and TTF are closely connected. However, the spread may become significant when the Interconnector is shut down due to maintenance work. The hubs in Continental Europe (TTF, ZEE, GPL, NCG) are well connected by pipelines, therefore prices are closely coupled.

The most liquid futures exchange for natural gas in Europe is the ICE. The ICE UK Natural Gas Futures have the following specifications.

- *Trading period:* 78–83 consecutive months, 11–12 quarters, 13–14 seasons and 6 years (however not all products are liquid).
- *Units of trading:* 1000 therms of natural gas per day.
- *Price quotation:* GB pence per therm.
- *Last trading day:* Two business days prior to the first calendar day of the delivery month, quarter, season or calendar year.
- *Settlement type:* Physical delivery at NBP, equal delivery during each day throughout the delivery period.

Further, there is a futures market for TTF natural gas at the ICE ENDEX and for NCG and GPL at the EEX. Liquidity on these exchanges has increased significantly since 2010.

Prior to hub-based pricing, long-term gas supply contracts were usually negotiated based on an oil price index formula. Since large investments were needed to build up a gas infrastructure, long-term contracts linked to oil prices guaranteed security of supply and a competitive pricing compared with oil. Contracts often contained a *take-or-pay* volume (i.e., a minimum off take) and flexibility components. Standard contract terms are as follows.

- *Take-or-pay volume:* Minimum annual off-take volume to be paid (even if not physically taken).
- *Maximum ACQ (annual contract quantity):* The maximum annual off-take.
- *Maximum and minimum DCQ (daily contract quantity):* The maximum and minimum daily gas off-take.
- *Make up:* Gas volumes below the take-or-pay volume that have been paid for, but can be taken in subsequent years.
- *Carry forward:* Gas volumes above the take-or-pay volume that can offset take-or-pay obligations in subsequent years.

A typical pricing formula for natural gas in Continental Europe is of the form

$$P = P_0 + A(X - X_0) + B(Y - Y_0), \tag{1.1}$$

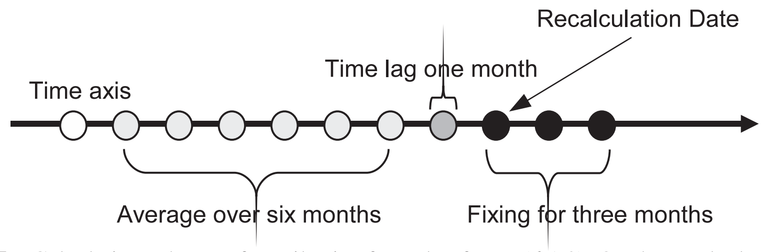

Figure 1.17 Calculation scheme of an oil price formula of type (6,1,3). On the recalculation date, the oil price is averaged over a period of six months ending one month prior to the recalculation date.

where A and B are constants and X and Y are monthly oil quotations such as gasoil or fuel oil. Typically, such formulas are characterised by a triple (n, l, m):

- n is the averaging period, e.g. 6 months ($n = 6$).
- l is the time lag of the price fixing, e.g. $l = 1$ means that to set a price for October the averaging period ends with August.
- m is the recalculation frequency, e.g. $m = 3$ means that the oil price formula is applied every 3 months to set a new price for the following quarter.

An example for a scheme of type (6,1,3) is shown in Figure 1.17. The new gas price is calculated on the recalculation date and is valid for a three-month period.

Long-term supply contracts typically contain price revision clauses, so that pricing parameters can be adjusted under certain conditions, for example if the market has changed structurally. At certain dates stipulated in the contract, either party can trigger such a price-revision procedure. In case the parties cannot agree on adjusted terms, an arbitration or court proceeding may follow. Such price revisions became an important topic when the end of the 2000s gas spot and futures prices fell substantially below oil-indexed prices.

The Asian Market

Japan and South Korea cover most of the gas demand through LNG, mainly from Indonesia, Malaysia, Australia and the Middle East. This market is dominated by long-term contracts linked to crude oil prices. A typical formula, used in Japan, is $P = A + B \times JCC$, where A and B are constants and JCC is the *Japan Customs-cleared Crude* (also known as *Japan Crude Cocktail*), a particular basket of crude oils. Instead of a linear dependence on the oil price, price formulas may be S-shaped, so that the slope is lower for very low or very high oil prices.

1.3.3 Liquefied Natural Gas

To transport natural gas over long distances where pipelines are not available, LNG can be used. LNG is natural gas condensed into a liquid at less than −160°C. The density is thereby increased by a factor of about 600 to approximately 0.46 kg/l. One (metric) tonne of LNG has a volume of 2.19 m^3, representing 1336 m^3 of natural gas with a heating value of 14.4 MWh. With a higher heating value of about 24 MJ/l, the energy density of LNG is around 70% of the energy density of crude oil (35 MJ/l). The LNG value chain is shown in Figure 1.18. In the *LNG plant*, which consists of one or more liquefaction units (*LNG trains*), the natural

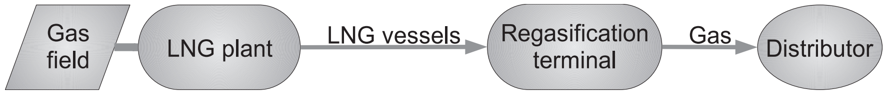

Figure 1.18 LNG value chain.

gas is cooled down until it becomes liquid. Liquefaction gives rise to the largest costs in the LNG value chain. A modern LNG train has a capacity of up to 8 million t of LNG per year. After the liquefication process, the LNG can be loaded onto special insulated *LNG carriers*. Conventional LNG carriers have a capacity between 125 000 and 149 000 m^3. The capacity of more recent carriers is between 150 000 and 177 000 m^3. The largest LNG carriers (type Q-Flex or Q-Max as used by Qatar) have capacities up to 266 000 m^3. The next step in the value chain is the *regasification terminal*, where the LNG is unloaded, regasified and injected into pipelines. Besides land-based terminals, regasification units can be built on board an LNG carrier (*storage and regasification vessel*).

The main exporters for LNG are shown in Figure 1.19. The total LNG exports in 2012 amounted to 330 billion cubic metres.

The infrastructure needed for production, transport and regasification is capital intensive and the value chain is costly. Consequently, LNG has traditionally played a major role only in countries where pipelines are not available, such as Japan, South Korea or Taiwan. Most current LNG contracts are long-term contracts with prices linked to pipeline gas prices or oil prices. Take-or-pay clauses typically reduce the volume risk for the seller. However, an increasing number of short-term (spot) transactions could be observed over recent years. Directing spot LNG purchases to the market with highest gas prices can exploit arbitrage opportunities between regional markets.

In the future, more and more LNG will be needed to serve the growing worldwide gas demand and to replace the decreasing regional gas production in Western Europe. Therefore, the LNG trade is expected to grow substantially over the coming years.

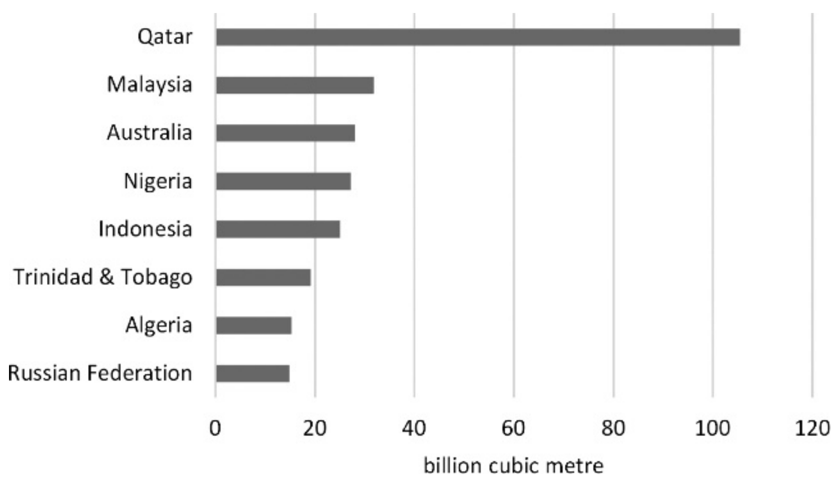

Figure 1.19 Largest LNG-exporting countries 2012. *Source*: BP (2013).

1.4 THE COAL MARKET

Coal is a fossil fuel, usually with the physical appearance of a black or brown rock, consisting of carbonised vegetal matter. It is formed from plant remains over geologic timescales under heat and pressure. Coal is a main source of fuel for the generation of electricity worldwide and for steel production. There exist a variety of different coal types which are distinguished by their physical and chemical characteristics. The characteristics defining coal quality are, for example, carbon, energy, sulphur, and ash content. The higher the carbon content of a coal, the higher its rank or quality. These characteristics determine the coal's price and suitability for various uses.

The three main categories of coal are (corresponding to their transformation process) *lignite*, *sub-bituminous coal* and *hard coal*. Lignite and sub-bituminous coal are also called *brown coal*. Hard coal has a high gross calorific value (GCV) greater than 23.9 MJ/kg (5700 kcal/kg). Lignite refers to coal with a GCV less than 17.4 MJ/kg (4165 kcal/kg), sub-bituminous coal includes coal with a GCV between those of hard coal and lignite. Depending on its usage, hard coal and sub-bituminous coal can be categorised as follows:

- *Coking coal* is a premium-grade hard coal used to manufacture coke for the steelmaking process.
- *Steam coal* is coal used for steam-raising and space-heating purposes. It includes all hard coals and sub-bituminous coals not classified as coking coal. As primary fuel for hard coal-fired power plants, steam coal with low moisture, ash and sulphur (less than 1%) is used.

Shipping of lower-quality coals is uneconomical, implying that they are not internationally traded. These low-rank coals are therefore not considered in more detail in this book. Since the energy content of coal determines the value to a large extent, coal volumes are often converted to energy units depending on their calorific value. Typical units are million tonnes of oil equivalents (Mtoe) or million tonnes of coal equivalents (Mtce), where 1 Mtce = 0.697 Mtoe. Measured in energy units, steam coal has a share of around 80% of overall coal production, coking coal a share of 15% and lignite a share of 5%.

1.4.1 Consumption, Production and Reserves

In 2010 coal accounted for 27% of total world energy consumption. In their International Energy Outlook 2012 (see International Energy Agency, 2012), the IEA forecasts a decreasing share of coal in total world energy consumption to slightly less than 25% by 2035. However, the future development of coal demand depends even more than that of other fossil fuels on environmental policies, since coal has a comparably high carbon intensity. Another driver is the competition with gas for electricity generation.

Total reserves of coal around the world are estimated at 861 billion tonnes according to BP (2013), half of which are hard coal and the other half lignite and sub-bituminous coal (see Figure 1.20). At the current consumption level those coal reserves should last approximately 109 years. There are, however, significant (unproven) resources, which may be developed. Even though many countries have access to coal reserves, the majority of reserves are located in the United States (28%), Russia (18%), China (13%) and India (7%). Other assessments

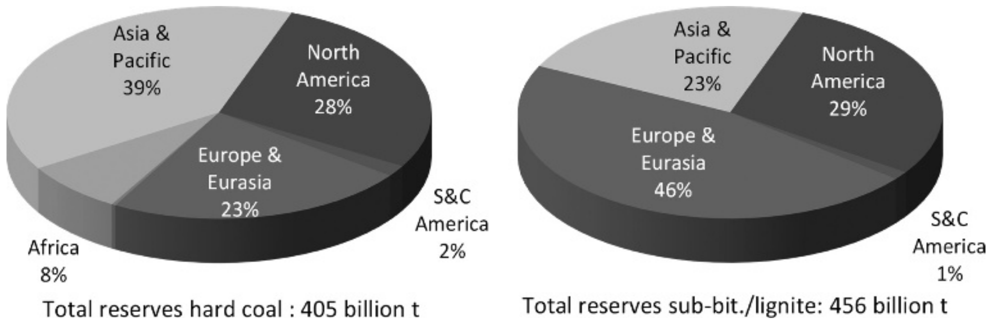

Figure 1.20 Total world coal reserves 2012 by regions. *Source*: BP (2013).

result in higher reserve estimates for coal, especially in China. In BGR (2011), coal reserves are estimated as 1038 billion tonnes corresponding to a reserves-to-production ratio of more than 130 years. There are also significant reserves in Australia, South Africa, Ukraine and Kazakhstan.

Coal production is highest in China, with 1825 Mtoe in 2012, which is nearly 50% of worldwide coal production. Production and demand in China more than doubled in the period 2002 to 2012, contributing around 80% to the worldwide growth in coal demand and production during that period. The second largest coal producer is the United States with 516 Mtoe in 2012, followed by Australia, Indonesia, India, Russia and South Africa. Figure 1.21 shows coal production in 2012 by region in million tonnes oil equivalent.

As a general pattern, countries with high coal production also have high coal consumption. Consumption in 2012 in China was 1873 Mtoe and in the United States 438 Mtoe, followed by India with 298 Mtoe. The coal consumption in 2012 by region is illustrated in Figure 1.22. Of the coal consumption, around 65% is used for generating electricity and 27% for industry (mainly steel production). Other usages, such as buildings or coal liquefaction, play a minor role. Increasing electricity demand in non-OECD countries is the main driver for the current

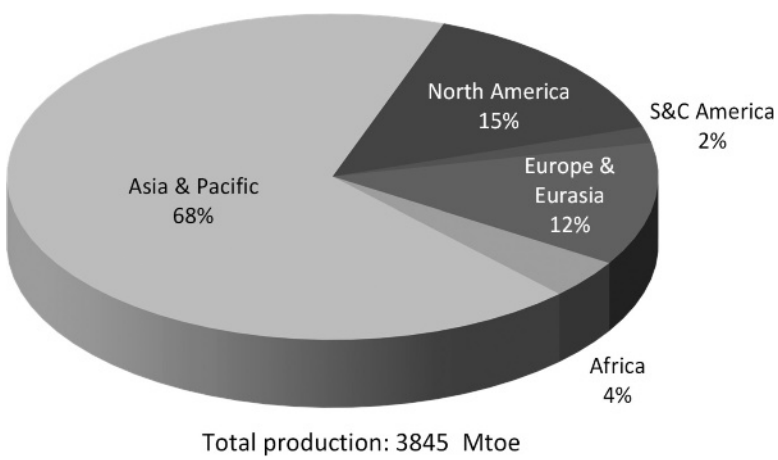

Figure 1.21 Total world coal production 2012 by regions. *Source*: BP (2013).

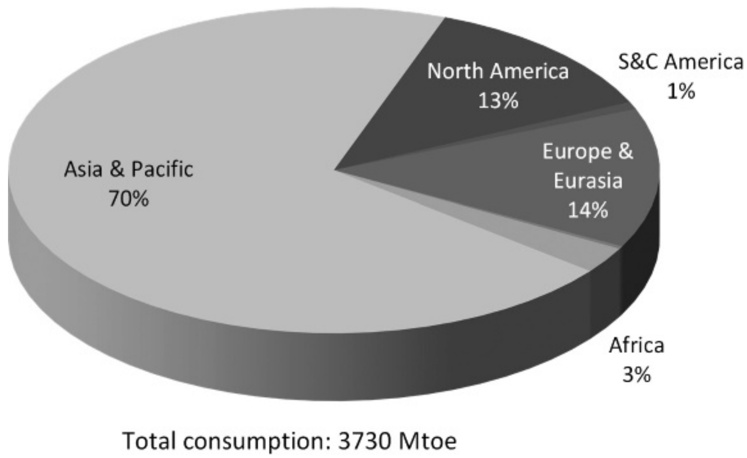

Figure 1.22 Total world coal consumption 2012 by regions. *Source*: BP (2013).

worldwide increase of coal demand. This is also the reason why the future growth of coal demand depends strongly on potential governmental interventions in the electricity generation sector to curb carbon emissions.

1.4.2 Coal Trading

Hard coal is traded worldwide as a commodity with increasing trade volumes over recent decades. Transport of lignite and other coal types with low energy density is uneconomic over large distances, therefore these coal types are mostly consumed near their production sites.

The volume of international physical coal exports in 2011 was 1080 million tonnes (source: BGR, 2011). Figure 1.23 shows the largest hard coal exporters. The largest coal importers were China, Japan, South Korea and India.

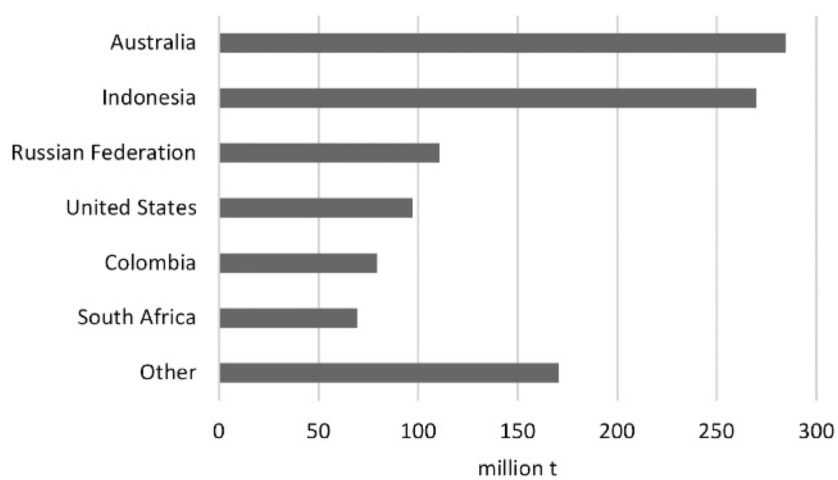

Figure 1.23 Largest hard coal exporters 2011. *Source*: BGR (2011).

Table 1.1 Largest coal producers 2011

Company	million t
Peabody Energy	268
Arch Coal	157
BHP Billiton	104
Anglo American	103
Xstrata/Glencore	85
Rio Tinto	49

Source: Verein der Kohlenimporteure (2012).

Most of the hard coal trade volumes are seaborne. The coking coal market (around 25% of trade volumes) is a premium-quality market with few suppliers, therefore a uniform worldwide market has been established. The steam coal market comprises the Atlantic and the Pacific region with different supply structures. South Africa, Columbia, Russia, and the United States are the main coal suppliers for the Atlantic region whereas Indonesia, Australia, South Africa, and Russia are the main suppliers for the Pacific region. There is also of course some exchange between the two regions, since especially Russia, South Africa, Indonesia and Australia supply both regions (see Verein der Kohlenimporteure, 2012).

Producers

Among the largest coal producers, several are state owned, for example, Coal India, Shenhua (China), China Coal and SUEK (Russia). The largest privately owned global coal producers are shown in Table 1.1.

Physical Coal Trading

Since coal transportation costs can be significant, coal prices depend on the point of delivery. Standard delivery points in international coal trading are, for example, Richards Bay in South Africa, Newcastle in Australia, ARA for Central Europe or the Central Appalachian in the United States. Both Richards Bay and the Central Appalachian are producing areas, so the price is usually quoted FOB. ARA is a consumer area and the price is often quoted as a CIF price. The FOB ARA price for further shipment is slightly higher.

The characteristics defining the quality of coal also determine its price. Energy content is the most price-relevant characteristic, and quoted prices per tonne (or per *short ton* in the USA, which equals around 907 kg) always refer to a specified quality and in particular to a specified energy content. Figure 1.24 shows coal prices for the years 2000–2012 for delivery points in NW Europe, the United States and Asia. Price differentials are naturally related to costs of freight. Large price differentials occur in cases where freight capacity is scarce.

Physical coal trading can be bilateral between producers and consumers or through trading companies or brokers. There are also online broker platforms available, for example *globalCOAL*. To standardise trading, globalCOAL has introduced a special master agreement, the Standard Coal Trading Agreement (SCoTA).

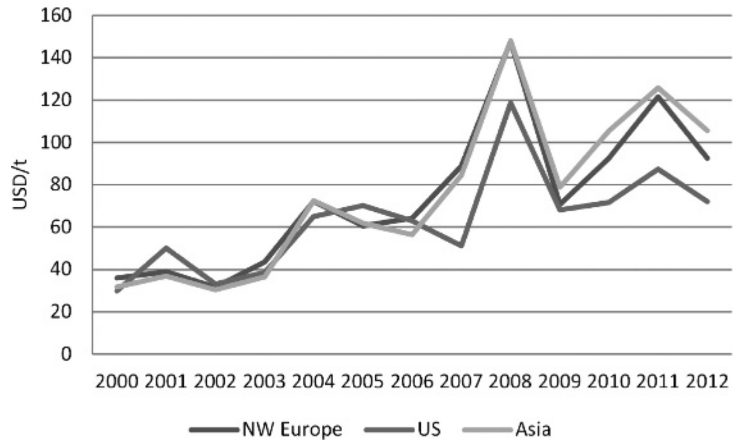

Figure 1.24 Coal prices for different NW Europe, United States and Asia delivery points. *Source*: BP (2013).

Price Indices

Price information for hard coal can be obtained either from exchanges, from brokers or from independent information service providers. These include Argus Media Ltd offering price information, market data and business intelligence for the global petroleum, natural gas, electricity and coal industries, and IHS McCloskey offering data, news and analysis focused on the coal industry. Price information published by information services is typically generated via telephone or e-mail survey covering sellers of physical coal, utility buyers, trading companies and broking companies. Market analysts then assess the price of the standard specified coal that conforms to the required specification. The mechanism of price assessment must eliminate the opportunity for gaming the mechanics of the index. In contrast to an exchange, an information service has no comprehensive secured information about the concluded trades.

The primary coal indices used as underlying for derivative contracts (e.g., swaps) are the API ("All Publication Index") indices published by the joint Argus/McCloskey Coal Price Index Service. The indices are calculated as averages of respective spot (i.e., delivery within the next 90 days) price assessments by Argus and McCloskey. There follows a list of API indices (see Section 1.1.5 for an explanation of the delivery Incoterms):

- API 2 is the index for the ARA region quoted as CIF ARA and is an important benchmark for NW Europe. It is calculated as an average of the Argus CIF ARA assessment and the McCloskey NW European steam coal marker. The energy content is specified at 6000 kcal/kg and the sulphur content must be less than 1%.
- API 4 is the index for the FOB Richards Bay, South Africa physical market. It is calculated as an average of the Argus FOB Richards Bay assessment and the McCloskey FOB Richards Bay marker. The energy content is specified at 6000 kcal/kg and the sulphur content must be less than 1%.
- API 5 is the index for the FOB Newcastle physical market in Australia, which is setting prices for delivery to China and South Korea. It is calculated from the Argus and McCloskey price assessments. The energy content is specified at 5500 kcal/kg and the sulphur content must be less than 1%.

Financial Derivatives for Coal

Financial swaps are the most common product for risk management for both coal producers and consumers. The swap market is particularly interesting for financial institutions, which are active market players. Financial swaps are traded usually up to three years in the future, while the time period for physical coal trading is usually shorter. Most swaps settle on the API indices described above. Coal swaps can be concluded OTC with banks or other traders or, for example, via the globalCOAL platform.

Exchanges also offer coal futures as trading product and offer clearing services for OTC trades. Both the CME Group and ICE have introduced coal futures for the main API coal indices.

1.4.3 Freight

The delivery price of coal is determined in part by ocean freight rates. They are an important factor for the price of coal in different regions and the competitiveness of coal against other fuels. The main factor that will affect the future movement of freight rates is the overall development of dry bulk trade.

Mainly Cape and Panamax-sized vessels are employed in international coal trading. Cape-sized vessels, used for example for the Richards Bay to ARA route, are also employed in the iron ore trade. As the shipping capacity is limited, the activity of the world's steel industry has an impact on coal freight rates. The other trade that can have an impact on coal freight rates is grain shipment, which is carried out predominantly in Panamax vessels. For both the export of grain and the import of iron ore, China's economy is an important factor.

A popular indicator for freight rates is the *Baltic Dry Index (BDI)* published by the Baltic Exchange. The BDI is an average of sub-indices for Cape, Panamax, Supramax and Handy-sized freight rates and considers different transportation routes. It is based on time-charter hire rates in USD per day. Figure 1.25 shows the considerable volatility of freight rates over recent years.

Figure 1.25 Historical development of the Baltic Dry Index.

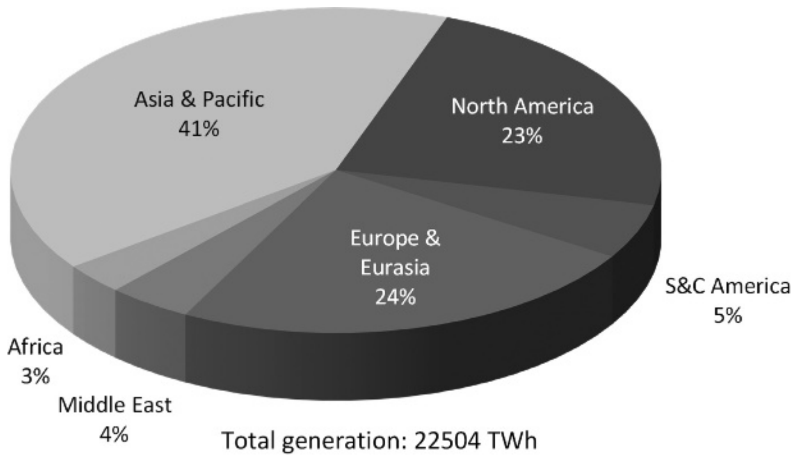

Figure 1.26 World electricity generation by country. *Source*: BP (2013).

1.5 THE ELECTRICITY MARKET

Electricity is a form of energy used for a very wide range of applications. It is easy to control, non-polluting at the location of its usage and convenient, used in the applications of heat, light and power. As a secondary energy source it is generated from the conversion of other energy sources, like coal, natural gas, oil, nuclear power, hydropower and other renewable sources. This implies that electricity markets and electricity prices are fundamentally linked to markets for primary fuels and environmental conditions. To understand electricity markets and price mechanisms, it is essential to consider the electricity generation process as well as the fuel markets. This section gives an introduction to the main marketplaces and wholesale products for electricity. Technical background information as well as energy economic modelling approaches can be found in Chapter 7.

1.5.1 Consumption and Production

Electricity is a growing market, even in proportion to the world energy market. The average growth rate of electricity consumption between 2002 and 2012 was 3.35%, whereas the average growth for primary energy demand was only 2.66%. This trend is likely to continue in the future, and most market projections assume higher growth rates for electricity compared with other forms of energy. In the year 2012, world electricity generation was 22 504 TWh.[3] According to the base scenario "New Policies" of the IEA (see International Energy Agency, 2012), electricity generation will grow to around 36 600 TWh by 2035. As for primary energy, the bulk of this growth is driven by increasing demand in non-OECD countries, with around 50% of worldwide growth originating from China and India. Figure 1.26 shows worldwide electricity generation by country. Between 1990 and 2012 the share of Asia & Pacific has grown from 20% to around 40%. China alone accounts for already 20% of worldwide electricity generation in 2012.

[3] 1 terawatt hour (TWh) = 1 billion kilowatt hour (kWh).

Electricity generation is highest in China with 4938 TWh, followed by the United States with 4256 TWh in 2012. Per capita consumption in the OECD countries was 7800 kWh compared with only 1600 kWh in non-OECD countries in 2010. However, per capita consumption in non-OECD countries is expected to grow much more strongly within the coming decades.

Since electricity requires a grid infrastructure, electricity markets are more regional than other commodity markets. However, efforts have been made over the past decades to integrate neighbouring market zones (e.g., in Europe) with the aim to foster competition and optimise usage of grid and generation infrastructure.

Traditionally, the electricity market in many countries was dominated by vertically integrated "incumbent" utility companies that owned generation assets, grid infrastructure and the retail business. Especially grid ownership has put those incumbents in a natural monopoly situation with high entry barriers for potential competitors. Often, incumbent utilities were state owned or at least regulated. Since the 1990s many countries have liberalised electricity markets to some degree. The details of market design and remaining regulation differ substantially between countries, but the main elements are common:

- Distinguish between natural monopoly areas (e.g., grid operation) and areas where competition shall be established. Monopoly areas need to be clearly separated ("unbundling") from competition areas, such that access to grid and other infrastructure is non-discriminatory for all market participants.
- Design wholesale markets to incentivise optimal economic usage of infrastructure, such as power plants and interconnections between market areas. Further, set sufficient incentives to build new generation capacity if required.
- Establish regulation to ensure security of supply and prevent market abuse.
- Incorporate mechanisms for environmental protection (e.g., carbon emissions).

European Union

Electricity market liberalisation started in the UK at the beginning of the 1990s, soon followed by Scandinavia. In 1996 and 2003 the European Commission issued Electricity Market Directives that defined steps for deregulated electricity markets on an EU-wide scale, which subsequently had to be implemented by the EU member states. Besides fostering competition in the generation and retail market, integration of the national electricity wholesale markets is seen as another important objective.

With the introduction of the European Trading System (EU ETS) for carbon emissions in 2005, the European electricity markets are closely connected to European environmental policy, since emission certificates (EUAs) have become an important driver for wholesale electricity prices. Another important driver is the increasing solar and wind generation fostered by national subsidy schemes, with ambitious growth targets (e.g., in Germany).

Electricity generation volumes for single European countries are shown in Figure 1.27. The generation structure differs substantially by country (see Figure 1.28). In most European countries electricity generation is dominated by conventional coal and natural gas plants. Exceptions are France with a 75% share of nuclear generation and Norway/Sweden with a high share (97%, respectively 48%) of hydro generation. In the EU-27 countries, nuclear, coal and natural gas each have a share of roughly 25% and renewables a share of slightly above 20%. Besides increasing renewable generation, there is generally a long-term trend

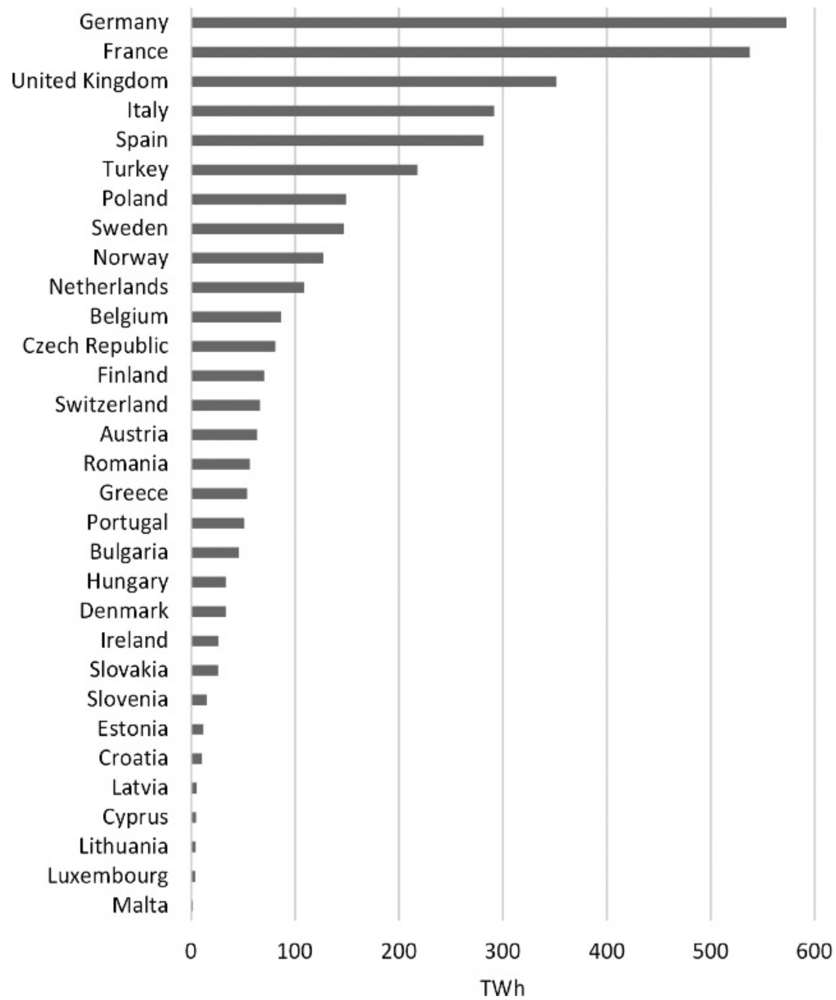

Figure 1.27 Electricity generation 2012 in European countries. *Source*: Eurostat.

towards a higher share of natural gas. However, due to low coal and carbon prices, this trend was at least temporarily broken from 2011 onwards, as generation volumes shifted from gas to coal.

Figure 1.29 shows historic wholesale spot prices (baseload) in Germany. In the period until 2008 frequent price spikes can be observed, which were caused by a tight supply situation. After 2008, prices generally dropped and even became negative on particular days. This change was caused on the one hand by increasing wind and solar generation volumes and decreasing power demand and decreasing EUA prices following the financial crisis on the other hand.

In several EU countries there is growing concern that lower wholesale electricity prices and the absence of price spikes do not sufficiently attract investments into conventional (non-intermittent) generation capacity to ensure security of supply. The background is that with

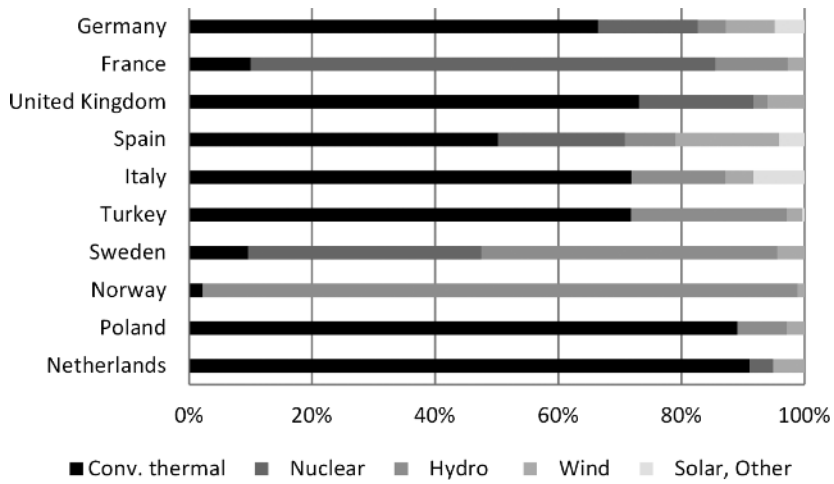

Figure 1.28 Generation structure 2012 in European countries. *Source*: Eurostat.

a growing share of intermittent renewable capacity, a larger part of conventional generation capacity is only required sporadically, when weather conditions lead to low renewable generation. In an "energy-only" market, investments in new conventional generation capacity would only be profitable in case of high price spikes on those selected days. However, such high price spikes may not be politically acceptable and would provide high volatility of earnings for investors. An alternative to the "energy-only" market is to introduce a *capacity market* that aims to provide a more stable revenue stream for conventional generation capacity – independent of actually generated electricity volumes. To some extent this can be seen as a premium to ensure security of supply at times of low renewable generation. Some countries have already introduced some form of capacity remuneration or are planning to do so. However, so far no unified mechanism across the European Union has emerged.

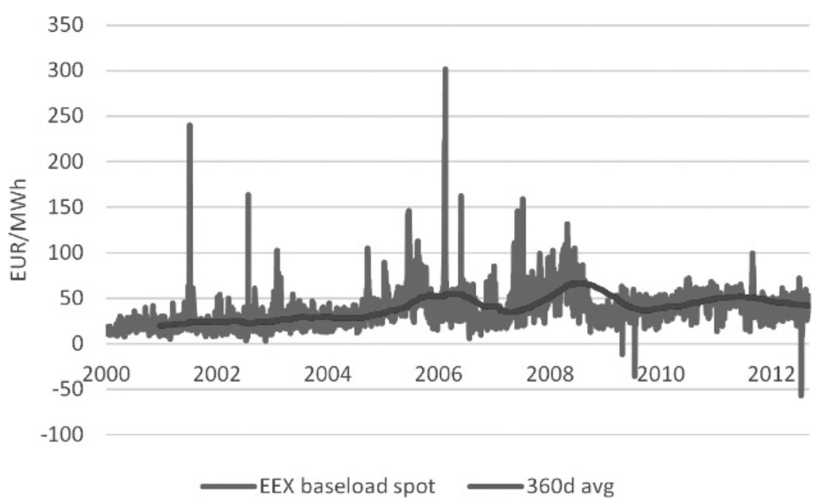

Figure 1.29 Historical EEX spot prices (baseload day-ahead Germany).

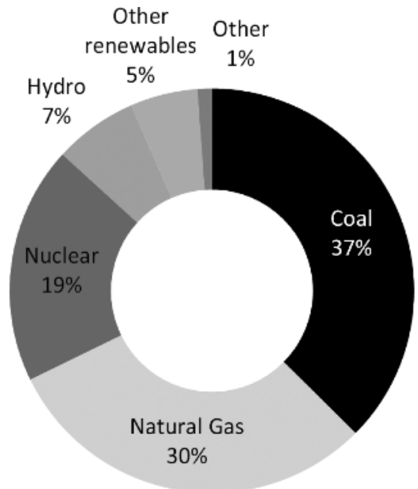

Figure 1.30 Electricity generation 2012 in the United States. *Source*: EIA.

United States

With overall electricity generation of around 4256 TWh in 2012, the United States is the second largest electricity producer behind China. Up to the beginning of the 2000s, generation was traditionally dominated by coal, followed by nuclear and gas. Driven by the shale gas boom, gas-fired generation has grown rapidly, reaching a higher share than nuclear generation. Coal-fired generation has decreased correspondingly, but still has the highest absolute share among the generation technologies. There is a trend towards increasing renewable generation, but further development will depend mainly on government regulation. The generation mix in 2012 is shown in Figure 1.30.

Deregulation of the United States electricity sector started with the Energy Policy Act of 1992 and developed unevenly amoung the states. A setback was caused by the California electricity crisis in 2000, where market manipulations caused shortages of supply. As a result, the market design had to be reviewed. Today, the US electricity market consists of a number of regional markets with different states of deregulation. In the deregulated regions, an independent system operator (ISO) or regional transmission organisation (RTO) operates the transmission system with non-discriminatory access for generators and suppliers. An example is PJM Interconnection covering all or parts of 13 states and the District of Columbia.

Also in the United States, wholesale electricity prices have decreased substantially in the years after 2008 following the financial crisis (see Figure 1.31). Low gas prices related to the shale gas boom contributed to this development.

1.5.2 Electricity Trading

For many commodities there is an intuitive answer to the question “What is the actual trading product?”, but for electricity the answer to this question requires some more understanding of the technical background. Among all commodities electricity has the unique feature that it is hardly storable. An exception are hydro pumped storage power plants, but in most countries their capacity is small compared with total consumption. The second main feature is the necessity for a transmission network, which prevents a global market. These characteristics of

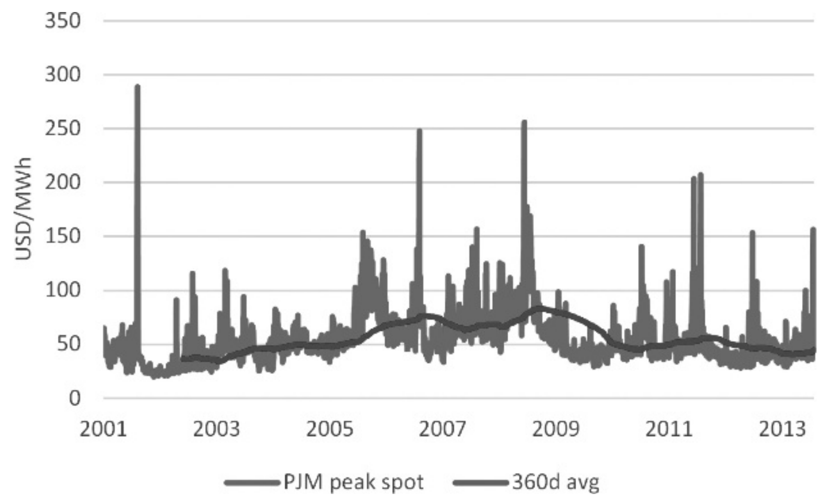

Figure 1.31 Historical US electricity spot peak prices (PJM Western Hub).

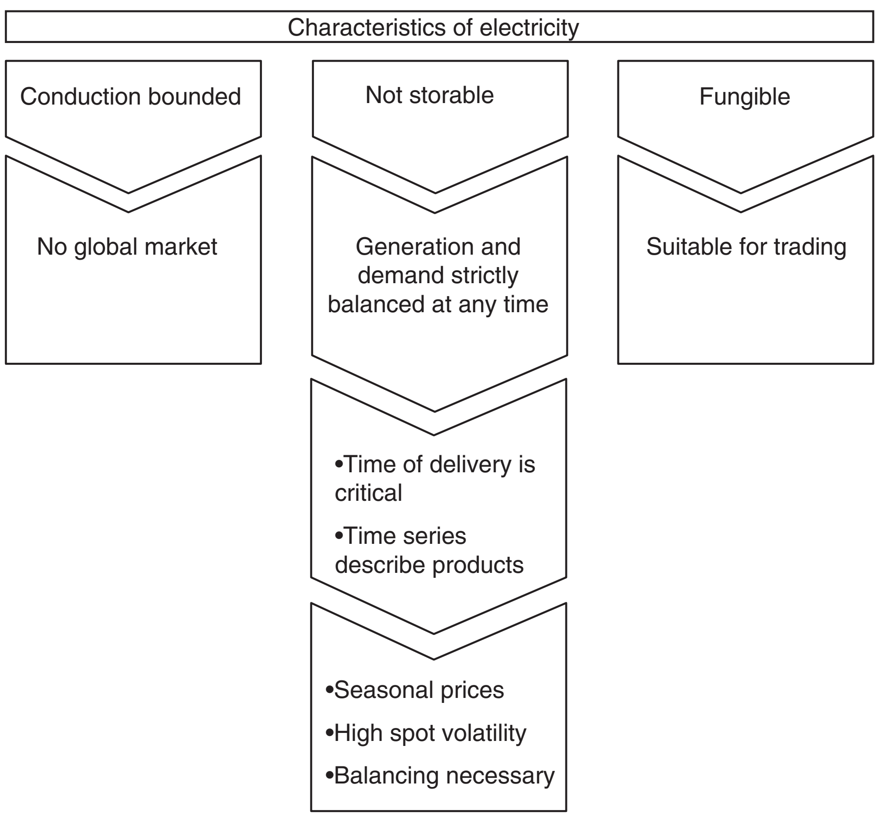

Figure 1.32 Characteristics of electricity.

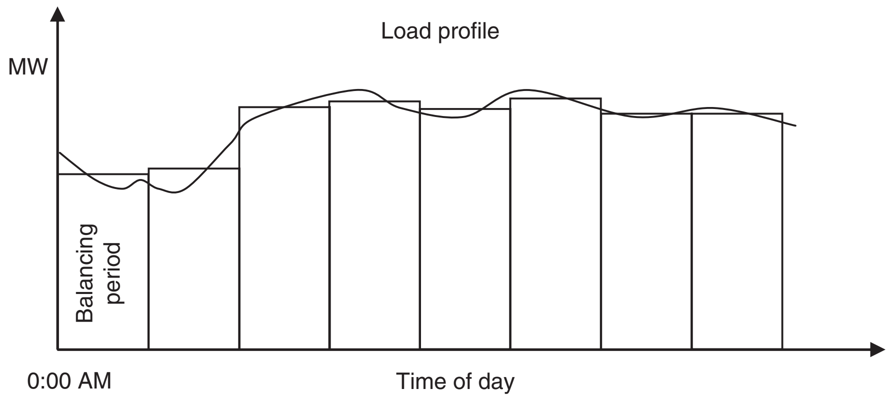

Figure 1.33 Balancing period.

electricity, shown in Figure 1.32, have strong implications for the trading products and their prices. An often discussed characteristic resulting from non-storability is the high volatility of power prices in the spot market in case of a tight or excessive supply situation. In the forward market the price movements are much smaller, because the availability of power plants and the weather-dependent demand are still unknown.

The lack of storability requires an exact matching of supply and demand at all times. Because a merchant cannot forecast the demand of his customers exactly, there must be someone responsible for balancing the system. This is the task of the transmission system operator (TSO), who charges the merchant directly or the retail customers via transmission fees for this service. The TSO defines a balancing period (e.g., 30 minutes in the UK, 15 minutes in Germany), which is the granularity of the measured electric energy supply. The continuously varying power requirements of retail customers are integrated over the balancing period and the average power is the size that is forecast and should be delivered by the supplying merchant. As a result, the merchant delivers energy as a discrete time series with time steps according to the balancing period and constant power during these time periods. Figure 1.33 illustrates the continuously varying power requirement (load profile) and the piecewise constant delivery of power during the balancing period.

The principal products in the electricity markets are delivery schedules in a granularity not finer than the balancing period. The usual granularity is one hour and this granularity is assumed in this book if not stated otherwise. The power balancing during the balancing period itself is the task of the TSO. Since the TSO usually has no own-generation capacities, it has to purchase products which allow the increase or decrease of production (including import and export) in its transmission system at short notice. In the following, the main features of products in the electricity market are described. As there is no global market for electricity, the products in regional markets may differ.

The electricity market can be divided into the following categories.

- *Forward and futures market:* The forward and futures market is the relevant market for risk management and serves the participants to hedge their positions. It is also the relevant market for traders who actively take positions and thereby also provide liquidity for hedgers. The agreed delivery period of these products may refer to specific weeks, calendar months or calendar years.

- *Day-ahead market:* In the day-ahead market products are traded which are delivered on the next day. If the next day is not a trading day, the day-ahead market also includes products delivered between the next day and the next trading day. Day-ahead products are common spot products and can be traded either on a power exchange or as bilateral agreement.
- *Intra-day market:* The intra-day market is for products with a delivery on the same day. This market allows the producers a short-term load-dependent optimisation of their generation and is typically not a market for pure trading purposes. Intra-day products are traded either on a power exchange or bilaterally.
- *Balancing and reserve market:* There are different definitions of the terms "balancing market" and "reserve market", because these markets depend on the regulator and are country specific. In the context of this book, the *reserve market* is the market allowing the TSO to purchase the products needed for compensating imbalances between supply and demand in the electricity system at short notice. The *balancing market* (also referred to as the real-time market) denotes the market where a merchant purchases or sells the additional energy for balancing his accounting grid. Since the balancing service is provided by the TSO, the TSO usually charges or reimburses the merchant for additional energy and only in some national markets does the merchant have the possibility to buy or sell this balancing energy from or to someone else. Therefore, the balancing market can be regarded as a market only in a broad sense. The different market categories and their time flow are described in Figure 1.34.

Outside the balancing and reserve market, products in the electricity market can be described by time series defining the delivery schedule. Usually the granularity of the time series is one hour and then each number of the time series specifies the constant power delivered in the corresponding hour. If the delivered power is constant over the delivery period $[T_1, T_2]$, the contract is called a *baseload contract*. If the delivered power is constant in those predefined hours of the delivery period when consumption is usually high, the contract is called a *peakload contract*. Peakload hours depend on the particular market. In Central Europe common peakload hours are the hours 8:00 AM to 8:00 PM on peakload days. Peakload days are usually Monday–Friday, including public holidays.

Forward Market

Forwards can be divided into standard forwards and individual power schedules. Standard contracts are baseload or peakload contracts whose delivery period is a day, week, month, quarter or year. Individual schedules are delivery schedules, whose power can vary every hour or even every balancing period (e.g., every 30 minutes in the UK). Figure 1.35 shows a baseload contract, a peakload contract, and an individual schedule, where the delivery period is one week.

Futures Market

Like other futures contracts, electricity futures are subject to daily margining (see Section 5.1.2). As electricity futures contracts do not have a single delivery date but a delivery period, the variation margin must also be calculated during the delivery period. Often, contracts with a long delivery period (e.g., a year or a quarter) are split into futures contracts with a shorter delivery period (e.g., a quarter or a month). This procedure is called cascading and is

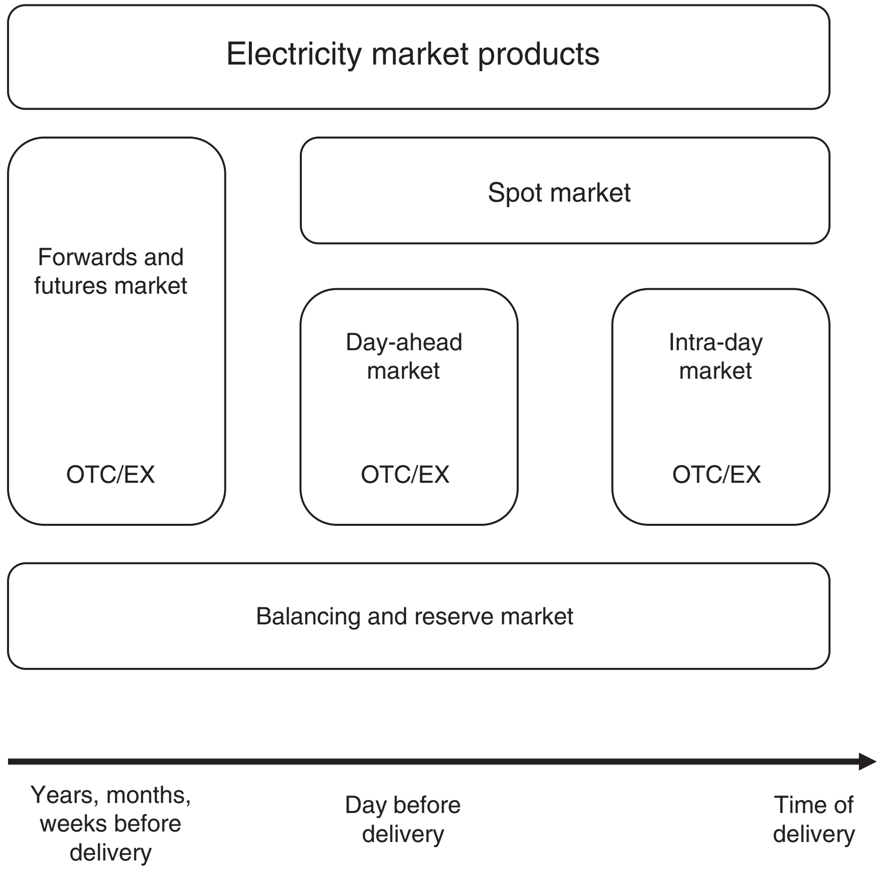

Figure 1.34 Categories of the electricity market.

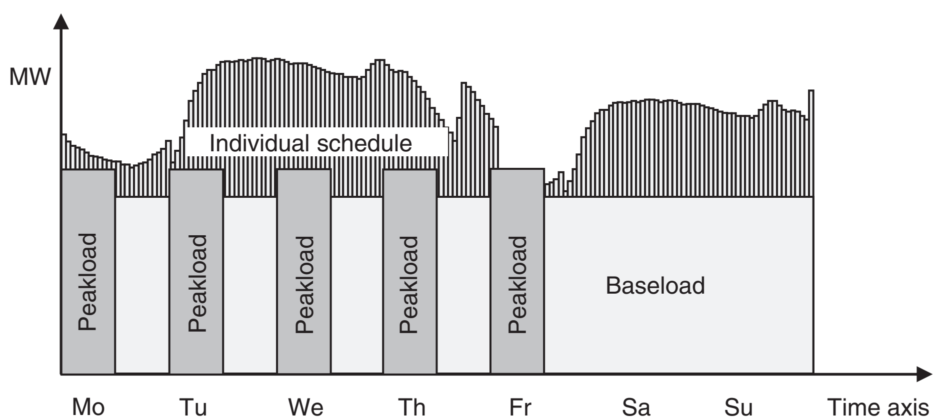

Figure 1.35 Delivery hours of a baseload, a peakload and an individual schedule contract with a delivery period of one week.

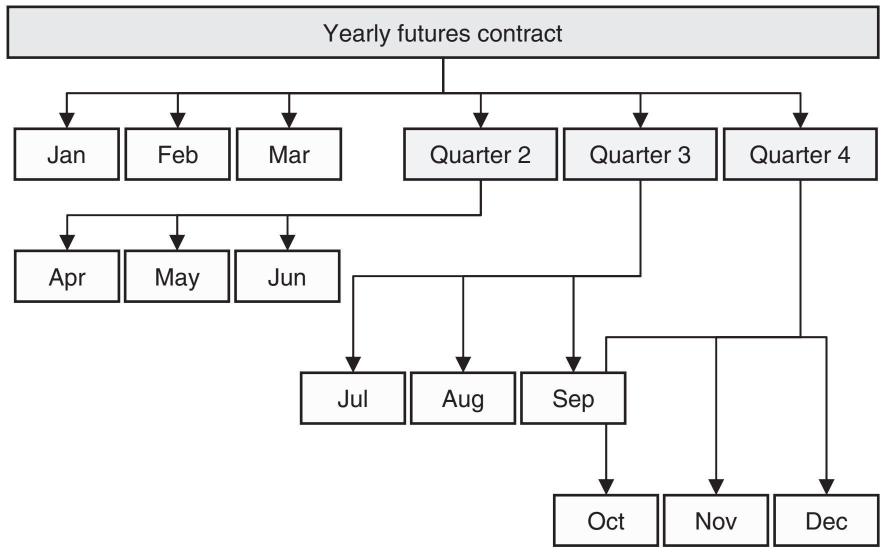

Figure 1.36 Cascading of a yearly futures contract.

shown in Figure 1.36. In this example the yearly futures contract cascades into three monthly futures contracts and into the three remaining quarterly futures contracts. Later, the quarterly contracts cascade into monthly contracts. The final settlement price of a monthly future is then established from the average of the associated spot market prices.

Spot Market (Day-Ahead and Intra-Day Market)

Spot products are traded OTC as well as on power exchanges. Standard products are baseload and peakload contracts with a delivery period of one day. In addition, there are usually hourly contracts and block contracts available. Contracts with a finer granularity (e.g., 30 or 15 minutes) can also be found in some markets. Hourly products are traded on the spot market only and are the basis for the pricing of many other products. In the case of block contracts, the delivery of electricity with a constant power over several delivery hours is traded. The spot market also serves as underlying for the forward and futures market.

Balancing and Reserve Market

While forwards and futures markets have a comparable structure in different regions, the balancing and reserve markets are affected more by national regulation, which defines the role of the TSO. In the United States, the system operators are regulated by the individual states and FERC.[4] There are also international associations which secure the interconnected power systems. In Europe, the *European Network of Transmission System Operators for Electricity (ENTSO-E)* is an association of 41 TSOs from 34 countries to coordinate overarching grid

[4] Federal Energy Regulatory Commission.

topics. It was established in 2008 as the successor of the European Transmission System Operators (ETSO).

One main task of a TSO is to ensure a constant power frequency in the transmission system. A change in frequency indicates to the TSO a shortage or a surplus of energy in the system. Physically, this means that there is a deceleration or acceleration of turbines because their kinetic energy balances consumption and generation. For such a case, there need to be rules and measures in place to stabilise the system.

For example, the ENTSO-E specifies control actions in its *Operation Handbook*. The frequency control actions are performed in different successive steps, each with different characteristics and qualities, and all depending on each other.

- *Primary reserve:* After a disturbance, the primary reserve (also called the primary control) starts within seconds as a joint action of all TSOs in the synchronised transmission system.
- *Secondary reserve:* The secondary reserve (also called the secondary control) replaces the primary reserve after a few minutes and is put into action by the responsible TSOs only.
- *Tertiary reserve:* The tertiary reserve (also called the tertiary control or minute reserve) frees secondary reserve by rescheduling generation and is put into action by the responsible TSOs.

The sequence of different control actions is displayed in Figure 1.37.

The products in the reserve market are derived from these control actions. The TSO tenders the required products to fulfil these functions. In contrast to forwards, futures or spot products, the reserve market products are more technical and refer to specified plants. These plants must be able to reduce or increase production at short notice. While for most other electricity products only energy delivered is paid for, reserve energy products often involve an additional payment for the availability of the reserved capacity.

The prices for balancing power are usually prices for the delivered energy only. For the merchant these are often additional costs, which are analysed in Section 4.6.3. Prices for balancing power differ widely and are only sometimes related to spot or futures market prices.

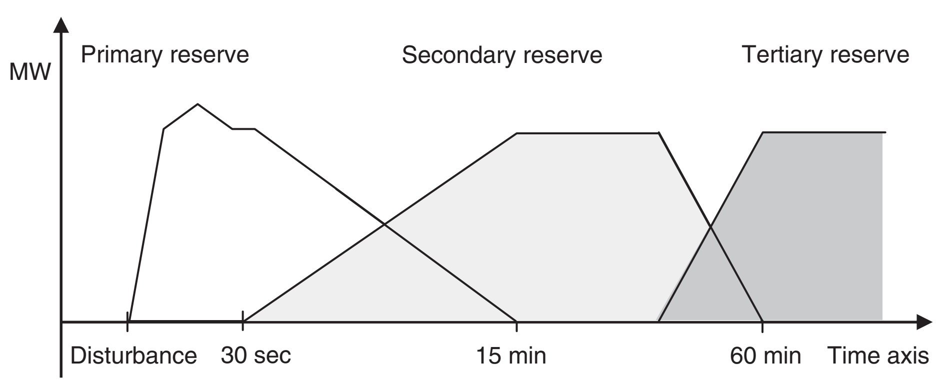

Figure 1.37 Control actions in the ENTSO-E system.

Market Coupling

In many cases, neighbouring local electricity markets are not completely disconnected but coupled via transmission capacities owned by the TSOs. An economically optimal usage of transmission capacities implies that in case of price differentials between two local markets, electricity would be transmitted from the higher-priced market A to the lower-priced market B. This would lower generation demand in B and increase generation demand in A, which in turn would push prices towards an equilibrium. Hence, a price differential between connected markets should only occur in case of congestions in transmission capacities.

One way of facilitating optimal usage of transmission capacities is to create an own-market for such capacities, for example via auctioning. The other way is to integrate allocation of transmission capacities in the price-finding algorithm of two or more collaborating spot exchanges via an *implicit auctioning*. This is generally considered more efficient because optimal allocation can be ensured by the exchanges and a separate auctioning of transmission capacities is no longer required. The result will be a single price in all participating markets unless there is a congestion of capacities.

In Europe, Nord Pool introduced a market coupling scheme in 1996 between Norway and Sweden, which later was expanded to other Nordic and Baltic countries. In 2006, Belgium, France and the Netherlands replaced explicit auctions of transmission capacities by implicit auctioning. This trilateral market coupling was expanded in 2010 by the Central Western Europe (CWE) initiative coupling Belgium, France, the Netherlands, Germany and Luxemburg. Further, the Interim Tight Volume Coupling (ITVC) provided an interim solution to include the connection between Germany and Denmark. The next step is the full integration of CWE with UK and the Nordic region (NWE) in 2014. Further integration is facilitated by the Price Coupling of Regions (PCR) initiative supported by different European power exchanges.

1.5.3 Electricity Exchanges

Energy exchanges are major marketplaces for electricity. In recent years more and more countries have founded exchanges for electricity. Some of them are only a marketplace for spot products, but the major exchanges are characterised by the existence of a derivatives market with a high trading volume. Most electricity exchanges are located in Europe and North America. Especially in Europe, the landscape of power exchanges has been changing rapidly over recent years. On the one hand, this is driven by a consolidation of derivatives trading platforms and related clearing services. On the other hand, further integration of electricity markets across Europe requires local power exchanges to cooperate more closely. Because of the large number of electricity exchanges, only a selection will be described further in this section.

Nord Pool Spot

Nord Pool Spot is a multinational exchange for trading electricity in Northern Europe. Its predecessor, Nord Pool ASA (then Statnett Marked AS), was founded in 1993 initially as a Norwegian market for physical contracts as a result of the deregulation of the Norwegian electricity market in 1991. In 1996 the joint Norwegian–Swedish power exchange commenced, the world's first multinational exchange for trade in power contracts. Subsequently, Finland and Denmark joined Nord Pool. In 2002, Nord Pool Spot was established as a separate company for short-term electricity trading. The derivatives trading business was sold in 2008 to *NASDAQ OMX Commodities*. In 2010, Nord Pool Spot and NASDAQ OMX Commodities jointly launched *N2EX*, which is a market for UK energy contracts. Overall, 432 TWh of electricity was traded through the Nord Pool Spot exchange in 2012.

Nord Pool Spot meanwhile comprises the Nordic countries of Denmark, Finland, Norway and Sweden and the Baltic countries of Estonia, Latvia and Lithuania. It operates a day-ahead market *Elspot* and an intra-day market *Elbas*.

The Elspot day-ahead market is based on an auction trade system. Bids for purchase and sale of power contracts of one-hour duration cover all 24 hours of the next day. As soon as the noon deadline for participants to submit bids has passed, all buy and sell orders are gathered into two curves for each power-delivery hour: an aggregate demand curve and an aggregate supply curve. The spot price for each hour is determined by the intersection of the aggregate supply and demand curves. This spot price is also called the *system price*. Since Nord Pool is a multinational exchange, possible grid congestions require a partition into separate bidding areas. Separate price areas occur if the contractual flow between bidding areas exceeds the capacity allocated by TSOs for spot contracts. If there are no such capacity constraints, the system price equals the spot price throughout the different bidding areas. The trading volume in the Elspot market was 334 TWh in 2012.

After publication of the Elspot results, trading continues in the physical intra-day market Elbas. The Elbas market is based on hourly contracts and provides continuous power trading 24 hours a day, up to one hour prior to delivery. Trading volume in the Elbas market was 3.2 TWh in 2012.

NASDAQ OMX Commodities Europe

The history of the NASDAQ OMX Commodities Europe financial market goes back to 1993, when the former Nord Pool AS began to establish a forward market in Norway with physical delivery. In 2008, Nord Pool's financial market business was acquired by NASDAQ OMX Commodities Europe. The market consists of futures, forwards, options and *contracts for differences (CfDs)*.

Futures contracts consist of standardised day and week contracts. Weeks are listed in a continuous rolling cycle of 6 weeks. The settlement of futures contracts involves a daily mark-to-market settlement and a final spot (system price) reference cash settlement after the contract reaches its due date.

Forward contracts are offered for the delivery periods of month, quarter and year. Months are listed in a continuous rolling cycle of 6 months. Years cascade into quarters, and quarters cascade into months. The term *forward contract* is used here also for an exchange-traded product. In the context of this book and consistent with the definition in many publications, the term "forward" is normally used for OTC trades, which implies that there is no mark-to-market settlement. The forward products offered by NASDAQ OMX Commodities Europe also have no mark-to-market settlement in the trading period prior to the due date. The mark-to-market value is accumulated as daily loss or profit but not realised throughout the trading period. During the delivery period the difference between the price when the contract was entered into and the spot reference price will be cleared.

Market participants who use financial market derivatives to hedge spot market prices remain exposed to the risk that the system price will differ from the actual area price of their spot purchases or sales. To overcome this potential price differential risk, NASDAQ OMX

Commodities Europe offers CfDs that settle on the difference between the system price and the area price. Thus, a perfect hedge can be obtained by a combination of a forward contract and a CfD.

Options contracts use standard forwards as the underlying contract. The option contracts are European-style, that is they can only be exercised at the exercise date. Options with new strike prices are automatically generated to reflect price movements of the underlying forward instrument.

In addition to products for the Nordic market, NASDAQ OMX Commodities Europe offers products for the German and Dutch market including CfDs to neighbouring countries. Further, futures for UK power are offered which are settled against the N2EX day-ahead index.

The NASDAQ OMX Commodities Clearinghouse provides a clearing service for contracts traded through the NASDAQ OMX Commodities Europe exchange as well as those traded OTC and registered for clearing. To be accepted for clearing, a bilateral market electricity contract must conform to the standardised products traded at the exchange. This clearinghouse guarantees the settlement of all cleared financial and physical derivative contracts.

N2EX

N2EX was established in 2010 jointly by Nord Pool Spot and NASDAQ OMX Commodities Europe. N2EX offers a day-ahead auction market for the UK and a continuously traded spot and *prompt* market. The prompt market covers the period 48 hours out up to 7 days out, afterwards the products are transferred to the spot market. The day-ahead prices are used as underlying for UK futures contracts offered by NASDAQ OMX Commodities Europe.

European Energy Exchange

The EEX is located in Leipzig, Germany and is one of the leading exchanges for electricity and gas in Central Europe. It was established in 2002 as a merger of the Leipzig Power Exchange founded in 2000 and the former European Energy Exchange founded in 2001. In 2008, the spot market operated by EEX was transferred into EPEX, a joint venture with the French exchange Powernext. In 2012 the total traded volume in the power derivatives market was 931 TWh.

The EEX Power Derivatives GmbH, which is owned 80% by EEX and 20% by Powernext, offers futures contracts for German and French power with delivery periods weekly, monthly, quarterly and yearly. For Germany, additional products for single days and weekends are available. The underlying of the financially settled futures contracts is the day-ahead auction results from the EPEX spot market. The settlement of futures contracts involves a daily mark-to-market settlement. Yearly and quarterly futures are fulfilled by cascading, and this process is displayed in Figure 1.36. At the end of a month the last payment for monthly futures is established on the basis of the difference between the final settlement price and the settlement price of the previous exchange trading day. The final settlement price is established from the average of the associated EPEX spot market prices.

In addition to futures, EEX offers European-style options for German electricity, that is the options can only be exercised on the last day of trading. The underlyings are the financially settled futures.

Through its subsidiary *European Commodity Clearing AG (ECC)*, EEX offers a well-accepted *clearing service* for OTC trades. OTC transactions corresponding to available products at the EEX or other partner exchanges can be registered by means of a so-called EFP trade (exchange futures for physical) for OTC clearing.

EPEX

In 2008, EEX together with the French energy exchange Powernext founded the electricity spot exchange EPEX based in Paris to jointly operate the electricity spot market for Germany, Austria, France and Switzerland. In 2012 the total traded volume was 339 TWh.

EPEX offers an auction day-ahead and a continuous intra-day market. Products are individual hours, baseload, peakload and other blocks of contiguous hours. The auction day-ahead market also contains *market coupling contracts* for deliveries between two market areas. The intra-day market is open 24 hours a day, 7 days a week and products can be traded until 45 minutes before delivery. For Germany, 15-minute periods can be traded in addition to hourly periods. Since 2010, EPEX has published the European Electricity Index ELIX, which represents a price level that would result in a physically unconstrained market environment.

APX

APX was founded in 1999 as Amsterdam Power Exchange. In the following years, APX expanded into the UK market under the name APX-UK (now APX Power UK). In 2008, APX acquired the exchange ENDEX, which was founded in 2002 and had a strong position in the derivatives market for Dutch and Belgian power and gas. The joint company, renamed APX-ENDEX, was again split in 2013 into a power spot exchange APX covering the Netherlands, Belgium and the UK and a derivatives exchange ICE ENDEX covering gas spot and power/gas derivatives. The traded volume of APX spot markets was 86 TWh in 2012.

The segments of APX are as follows.

- *APX Power NL:* Day-ahead auction and continuous intra-day market for Dutch electricity.
- *APX Power UK:* Day-ahead market (hourly), continuous spot market (half-hourly) and prompt market (block products up to 4 weeks out).
- *Belpex:* Day-ahead auction market and continuous intraday market for hourly periods.

ICE ENDEX

ICE ENDEX was split from APX-ENDEX in 2013 and provides gas spot products in the Netherlands, Belgium and the UK and power/gas derivatives in the Netherlands and Belgium. The majority shareholder of ICE ENDEX is the ICE, with a share of about 80%. The traded volume for the ENDEX futures market in the Netherlands and Belgium was 58 TWh in 2012. The ICE ENDEX electricity products comprise baseload and peakload futures in the Netherlands for weeks, months, quarters and calender years. For Belgium, only baseload futures for months, quarters and calender years are provided.

Intercontinental Exchange

UK electricity futures traded through ICE comprise products for weeks, months and seasons. A peculiarity of the UK power market was the use of the *EFA calendar* instead of the usual

Gregorian calendar as a convention for electricity futures. According to the EFA calendar, months by definition have either 4 or 5 weeks. However, a transition to the standard calendar is taking place in 2014.

For the United States the ICE offers financially settled monthly peak and off-peak futures and options for various delivery locations, for example PJM Western Hub. The underlying of these monthly futures is the arithmetic average of the PJM Western Hub real-time locational marginal price (LMP) for the peak hours, respectively off-peak hours, of each day provided by PJM Interconnection LLC. Alternative products are based on day-ahead prices instead of real-time prices.

CME Group

NYMEX, which was later acquired by the CME Group, launched the first electricity futures contracts in 1996. After a setback following the California electricity crisis in 2000/2001, NYMEX successfully launched financially settled electricity futures with settlement on PJM real-time Western Hub prices. The CME Group now provides financially settled monthly peak and off-peak futures and options for various delivery locations in the United States based on real-time prices and day-ahead prices.

1.6 THE EMISSIONS MARKET

Global warming caused by the greenhouse effect is one of the key environmental challenges of the 21st century. The greenhouse effect itself is caused by the property of certain gases in the atmosphere to absorb and reflect thermal radiation of the Earth's surface back to the Earth. The natural greenhouse effect is caused mainly by water vapour (H_2O), carbon dioxide (CO_2) ozone (O_3), nitrous oxide (N_2O) and methane (CH_4). Without the natural greenhouse effect, the average surface air temperature would be $-20°$C instead of $+15°$C.

Increased concentrations of greenhouse gases in the atmosphere caused by human activities are responsible for the anthropogenic greenhouse effect. Since the beginning of the 20th century the average air surface temperature has increased by 0.6°C and the UN Intergovernmental Panel on Climate Change (IPCC) has projected a further increase by 1.4°C to 5.8°C by 2100. Climate change will have a severe impact on the environment, including rising sea levels, which will threaten coastal communities. The frequency of extreme weather events, storms, droughts and floods is expected to increase, thus causing the extinction of endangered species (European Commission, 2013).

1.6.1 Kyoto Protocol

Since the 1970s, climate change has been on the political agenda. The first World Climate Conference with scientific focus was organised in 1979 in Geneva. It issued a declaration calling on the world's governments "to foresee and prevent potential man-made changes in climate that might be adverse to the well-being of humanity". The declaration also identified increased atmospheric concentrations of carbon dioxide resulting from utilisation of fossil fuels, deforestation and changes in land use as a main cause of global warming. The conference led to the establishment of the World Climate Programme, a series of intergovernmental climate conferences and in 1988 to the establishment of the IPCC by the United Nations Environment

Programme (UNEP) and the World Meteorological Organization (WMO). Organised in three working groups, the IPCC prepares assessment reports on available scientific information on climate change, environmental and socio-economic impact of climate change and formulation of response strategies. Based on the first IPCC reports published in 1990, the United Nations General Assembly (UNGA) decided to initiate negotiations on an effective convention on climate change. The United Nations Framework Convention on Climate Change (UNFCCC) was opened for signature at the United Nations Conference on Environment and Development (UNCED) in Rio de Janeiro in 1992 and entered into force in 1994.[5] Signatories of the UNFCCC have different responsibilities.

- *Annex I countries:* Industrialised countries that have agreed to reduce their greenhouse gas emissions.
- *Annex II countries:* Developed countries that are responsible for bearing the costs of climate change mitigation in developing countries. The Annex II countries are a subset of the Annex I countries.
- *Developing countries:* These countries have no immediate responsibilities.

The UNFCCC sets a framework for climate change mitigation but does not contain greenhouse gas emission limits for individual countries. Since the UNFCCC entered into force, the parties meet annually in Conferences of the Parties (COP) to assess the progress in climate change mitigation and to negotiate legally binding targets.

The Kyoto Protocol to the UNFCCC was adopted at the 1997 COP 3 in Kyoto, Japan and entered into force in 2005. The Kyoto Protocol commits Annex I Parties to individual, legally binding targets to limit or reduce their greenhouse gas emissions. Only Parties to the Convention that have ratified the Kyoto Protocol will be bound by the Protocol's commitments; 191 countries and the EU had ratified the Protocol by the end of March 2013. Of these, 37 industrialised countries and the EU committed to reduce greenhouse gas emissions during 2008–2012 to individually designated levels (Annex B countries, which are almost identical with the Annex I countries of the UNFCCC). The Kyoto Protocol was not ratified by the USA. Canada withdrew from the Kyoto Protocol in December 2012. In total, the Annex B countries have committed to reduce their emissions by at least 5% from 1990 levels.

The global warming potential of different greenhouse gases is expressed in CO_2 equivalents. Annex A specifies which greenhouse gas emissions are subject to the Kyoto Protocol.

- Carbon dioxide (CO_2).
- Methane (CH_4), CO_2 equivalents: 23.
- Nitrous oxide (N_2O), CO_2 equivalents: 310.
- Hydrofluorocarbons (HFCs), CO_2 equivalents: 140–11 700.
- Perfluorocarbons (PFCs), CO_2 equivalents: 6500–9200.
- Sulphur hexafluoride (SF_6), CO_2 equivalents: 23 900.

The CO_2 equivalent figures above refer to the 100-year time horizon (International Panel on Climate Change, 2005). Furthermore, Annex A specifies sector and source categories for

[5] By 2013, the UNFCCC was ratified by 194 countries and the European Union.

emission covered by the Kyoto Protocol. The main categories are: energy, industrial processes, solvents and other product uses, agriculture and waste.

Quantified emission limits for the first commitment period, from 2008 to 2012, were specified in Annex B of the Kyoto Protocol. The base year was the year 1990. Instead of 1990, Parties may use 1995 as base year for HFCs, PFCs and SF_6. In addition to total emissions, the impact of Land-Use, Land-Use Change and Forestry (LULUCF) is considered. In 2012, the Doha Amendment to the Kyoto Protocol, was adopted. It includes new commitments of Annex I Parties to the Kyoto Protocol who agreed to take on commitments in a second period from 2013 to 2020. The scope of this extension is limited to only 15% of the global greenhouse gas emissions, due to lack of participation by major emitters, including Brazil, Canada, China (the world's largest emitter), India, the United States and Russia. Therefore, it is uncertain if and when a new international agreement with significant impact on the world's greenhouse gas emissions will be achieved.

Emission limits for the first and second commitment period under the Kyoto Protocol and changes in emissions between 1990 and 2010 are listed in Table 1.2. While the 8% EU target for the first commitment period was broken down to the EU Member States, so far no breakdown for the second period exists. The total greenhouse gas emissions from Annex I Parties declined by 8.9% between 1990 and 2010. In spite of significantly increasing emissions since 2009, the 5% reduction target for the Kyoto period 2008 to 2012 has most likely been achieved.

Table 1.2 Committed emission limits under the Kyoto Protocol

Emission reduction targets for 1st and 2nd period (% of base year) and changes in emissions without LULUCF between 1990 and 2010 (%)							
Country	1st P	2nd P	Change	Country	1st P	2nd P	Change
Australia	+8	−0.5	+30.0	Liechtenstein	−8	−16	+1.1
Austria	−13	*EU*	+8.2	Lithuania	−8	*EU*	−56.9
Belarus	–	–	−35.7	Luxembourg	−28	*EU*	−5.9
Belgium	−7.5	*EU*	−7.6	Malta	–	*EU*	+49.1
Bulgaria	−8	*EU*	−52.0	Monaco	−8	−22	−18.7
Canada	−6	–	+17.4	Netherlands	−6	*EU*	−0.9
Croatia	−5	*EU*	−9.1	New Zealand	0	–	+19.8
Czech Rep.	−8	*EU*	−28.9	Norway	+1	−16	+8.2
Denmark	−21	*EU*	−10.5	Poland	−6	*EU*	−28.9
Estonia	−8	*EU*	−49.6	Portugal	+27	*EU*	+17.5
EU	−8	−20	−15.4	Romania	−8	*EU*	−57.6
Finland	0	*EU*	+6.0	Russian Federat.	0	–	−34.1
France	0	*EU*	−6.0	Slovakia	−8	*EU*	−35.9
Germany	−21	*EU*	−24.8	Slovenia	−8	*EU*	−3.5
Greece	+25	*EU*	+12.6	Spain	+15	*EU*	+25.8
Hungary	−6	*EU*	−40.9	Sweden	+4	*EU*	−9.0
Iceland	+10	−20	+29.7	Switzerland	−8	−15.8	+2.2
Ireland	+13	*EU*	+11.2	Turkey	–	–	+114.9
Italy	−6.5	*EU*	−3.5	Ukraine	0	−24	−58.8
Japan	−6	–	−0.7	UK	−12.5	*EU*	−22.6
Kazakhstan	–	−5		United States	−7	–	+10.4
Latvia	−8	*EU*	−54.5				

Source: Kyoto Protocol, Doha Amendment and UNFCCC (2012).

The decrease in emissions is mainly caused by the economic decline in Eastern European Countries and the global recession of 2009.

The Kyoto Protocol defines three types of “flexible mechanisms” to lower the overall costs of achieving its emissions targets: Joint Implementation (JI – Article 6), Clean Development Mechanism (CDM – Article 12) and International Emissions Trading (IET – Article 17). These mechanisms enable the Parties to access cost-effective opportunities to reduce emissions or to remove CO_2 from the atmosphere (e.g., by afforestation) in other countries. The establishment of these flexible mechanisms acknowledges that marginal emission reduction costs can vary considerably from region to region while the benefits for the atmosphere are the same, wherever the action is taken. Flexible mechanisms are explained in more detail in Section 1.6.3.

At annual climate conferences (COPs) following Kyoto, implementation rules for the Kyoto Protocol were negotiated.[6]

1.6.2 EU Emissions Trading Scheme

The member states of the European Union (EU-15) agreed in 1998 on a Burden Sharing Agreement. It redistributes among them the overall 8% reduction target under the Kyoto Protocol. The individual quantified emission limitation or reduction commitments for the Kyoto period 2008–2012 are listed in Table 1.2. Based on the latest available emission data for 2010, many, but not all, of the European countries will have achieved the emission targets for the Kyoto period.

At the end of the 1990s, only a few EU Member States were on good track to achieve their targets, while other countries were expected to have emissions that significantly exceeded these targets. Overall, it was realised by the European Commission that the EU commitment under the Kyoto Protocol would not be achieved without additional measures.

The European Commission considered the introduction of an emissions trading scheme on a company level as an appropriate measure for achieving the Kyoto target. In 2003, the European Council formally adopted the Emissions Trading Directive (Directive 2003/87/EC). The directive describes the framework for the EU ETS. The scheme limits the overall amount of CO_2 emissions of the participating sectors, introduces allowances for emissions and uses market mechanisms for the final allocation of these limited allowances to individual installations emitting CO_2. The EU ETS covers the electricity and heat sector as well as energy-intensive industrial sectors. All installations above certain size limits, for example rated thermal input exceeding 20 MW for combustion installations, have to participate. The EU ETS covers approximately 40% of all emissions under the Kyoto Protocol in the EU. So far, there are three trading periods under the EU ETS:

- 2005–2007: first trading period.
- 2008–2012: second trading period.
- 2013–2020: third trading period.

In the first two trading periods, only CO_2 emissions are covered by the EU ETS. In the third trading period, N_2O and PFC emissions formed by certain chemical processes are covered as well. While in the first trading period the EU ETS covered all 25 member countries of the

[6] Detailed information on the UNFCCC, the Kyoto Protocol and the COPs can be found on the UNFCCC Secretariat’s homepage http://unfccc.int.

EU, it has been extended in the meantime to 27 member countries plus Liechtenstein, Iceland, Norway and Croatia. In total, more than 12 000 installations are covered.

All participating countries were responsible for the allocation of free emission allowances by means of national allocation plans (NAPs) for the first and second trading period. The NAPs had to be approved by the EU. Free EUAs were distributed to participating installations. The unit of the EUAs is 1 t CO_2 equivalent. For the first trading period, at least 95% of the EUAs have been allocated at no cost and for the second period, at least 90% of them. In the third trading period the allocation of EUAs was determined in accordance with EU community-wide harmonised rules based on national implementation measures (NIMs) submitted by each EU Member State. The NIMs contain lists setting out the proposed levels of free allocation in accordance with Article 11 of the revised ETS Directive (2009/29/EC). The overall emission limit for the EU ETS decreases by 1.75% per year during the third trading period. The free allocation decreases annually from 80% in 2013 to 30% in 2020. The remaining certificates are distributed to market participants through auctions. These auctions are executed by the Member States. For new installations or significant capacity increases of existing installations, EUAs have been set aside in new entrants reserves (NER).

All operators of installations participating in the EU ETS are required to compile annual emission reports to be verified by an independent auditor in accordance with EU regulation. Based on these emission reports, the operators must submit EUAs for their emissions to national emissions registries. EUAs can be traded freely. Therefore, installations with emissions above their allocation can buy EUAs to meet their demand and installations with emissions below their allocation can sell them. Transfer of certificates from one year to the next (banking) and for one year to the previous year (borrowing) is possible within a trading period. Banking or borrowing was not possible between the first and second trading periods, but banking was possible from the second to third trading period and will be possible for all subsequent trading periods. If the operator of an installation fails to deliver sufficient EUAs, a penalty of 40 EUR/t CO_2 for the first period as well as 100 EUR/t CO_2 for the second and third periods apply.

Each Member State has its own national registry containing accounts which hold the EUAs. These registries interlink with the European Union Transaction Log (EUTL) and the Community Independent Transaction Log (CITL), both operated by the Commission. These registries record and check every transaction. Apart from allocated EUAs for each installation, the EUTL and CITL also contain information on verified historic emissions for previous years for each installation. Figure 1.38 shows the distribution of historic emissions for the second trading period 2008–2012 by country. Four countries – Germany, the UK, Poland and Italy – are already responsible for more than 50% of all emissions covered by the EU ETS and half of the countries are responsible for approximately 90%.

CITL emission data allow the classification of emissions by activity. The most important category is combustion installations (72%), followed by mineral oil refineries (8%).

Unfortunately, the categories are not used in a consistent way for all countries. Therefore, for a detailed analysis it is necessary to consider the data on installation level.

1.6.3 Flexible Mechanisms

Under the Kyoto Protocol, countries may meet their emission targets through a combination of domestic activities and the use of flexible mechanisms. Besides allowing countries to meet their targets in a cost-effective way, flexible mechanisms aim to assist developing

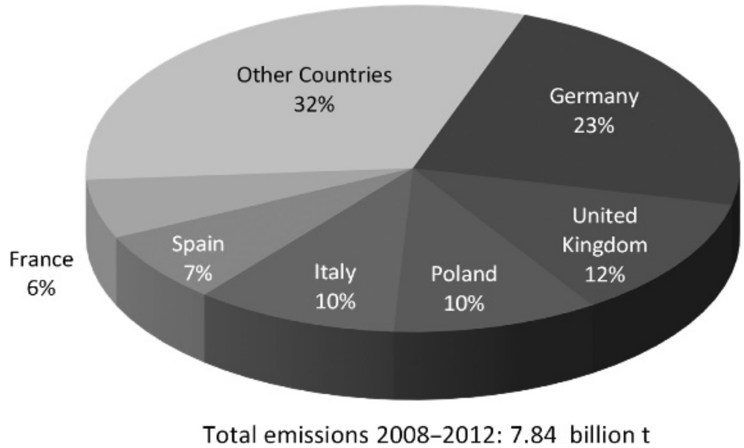

Figure 1.38 CO_2 emissions 2008–2012 in the EU ETS by country. *Source*: CITL, June 2013.

countries in achieving sustainable development. The Kyoto Protocol includes three flexible mechanisms:

- Joint Implementation (JI)
- Clean Development Mechanism (CDM)
- International Emissions Trading (IET).

JI and CDM are project-based mechanisms. They involve developing and implementing measures that reduce greenhouse gas emissions in another country to generate emission credits. JI projects are carried out in industrialised countries with existing emission targets (Annex B countries under the Kyoto Protocol). CDM projects are carried out in developing countries without targets. JI projects generate Emission Reduction Units (ERUs) and CDM projects generate Certified Emission Reductions (CERs). Not only CO_2, but all greenhouse gases under the Kyoto Protocol are considered for JI and CDM projects. The unit of ERUs and CERs is t CO_2 equivalents. Sometimes these credits are also called Kyoto offsets.

JI projects have to be approved by the country in which they are implemented. One criterion is additionality; that is, the project would not have been implemented without the incentives created by JI. Therefore, measures covered by a company emissions trading scheme like the EU ETS are not eligible as JI projects. Until August 2013, almost 650 JI projects had been developed in 17 countries and submitted for approval to the UNFCCC.[7] With the expiration of the first Kyoto commitment period at the end of 2012, the future of JI is uncertain.

Under the CDM, investors from Annex I countries receive CERs for the actual amount of greenhouse gas emission reductions achieved. The issuing of CERs is subject to host and investor country agreement, third-party assessment and registration by the UNFCCC Clean Development Mechanism Executive Board (CDM EB). A key requirement for CDM projects is additionality: emissions reductions will only be recognised if the reduction of greenhouse gas emissions is in addition to any reduction that would have occured without the certified

[7] The UNFCCC Secretariat publishes detailed information on JI and on all submitted projects on the Internet under http://ji.unfccc.int.

project activity. Additional restrictions for projects apply, for example nuclear power projects are excluded. Until August 2013, more than 7100 CDM projects were registered by the CDM EB and more than 1.3 billion CERs had been issued. The majority of annually generated CERs are expected from projects in China (62%), India (10%) and Brazil (5%). The main areas of the CDM project activities are energy industries (75%), waste handling and disposal (11%) and manufacturing industries (4%).[8]

International Emissions Trading (IET) of Assigned Amount Units (AAUs) allow industrialised countries with emission targets (Annex B countries) to exchange emission allowances to meet their national Kyoto targets. Unlike CDM and JI, IET is not project based. Emissions in some countries, especially in Russia and Ukraine, were significantly below their Kyoto targets for the commitment period 2008–2012 (see Table 1.2) and more than sufficient AAUs have been available. As the use of this “hot air” is not really politically acceptable for meeting Kyoto targets, IET played only a minor role in the commitment period 2008–2012.

Besides AAUs, Annex B countries can also use CERs and ERUs for meeting their Kyoto targets. For instance, the Netherlands is aiming to do so through a state purchasing programme.

The Linking Directive (Directive 2009/27/EC), adopted by the EU Parliament in 2009, allows emission reduction units generated by project-based flexible mechanisms (JI and CDM) to be utilised for compliance by companies under the EU ETS. The rationale behind this linkage is to create additional potential for cost-effective measures and to reduce the overall costs for emission compliance for the participating companies. The Kyoto Protocol states that a significant portion of reductions should be achieved by domestic actions. Therefore, flexible mechanisms are considered supplementary to domestic measures and most NAPs have implemented limits for the use of JI and CDM. These limits are applied for each installation separately and not on a nationwide level. These limits are cumulative for all years of the second and third trading periods (e.g., 2008–2020). The Linking Directive allows the use of all ERUs or CERs that comply with the requirements established under the UNFCCC and which fulfil additional criteria set by the European Union. Only CERs and ERUs of projects registered before 2013 by the UNFCCC are eligible under the EU ETS, unless projects are located in Least Developed Countries (LDCs). The use of CERs and ERUs from projects involving the destruction of trifluoromethane (HFC-23) and N_2O from adipic acid production has been prohibited since 2013. Hydropower projects greater than 20 MW are required to be in line with criteria from the World Commission on Dams.

In addition to the EU ETS, the emission trading schemes in Australia and New Zealand allow the use of CERs and ERUs with certain restrictions. Furthermore, CERs are also used as voluntary emission offsets. But until August 2013 only 0.2 million CERs had been used for this purpose.

1.6.4 Products and Marketplaces

The main products on the market are EUAs and CERs eligible under the EU ETS. Common are spot, forward and futures trading of EUAs and CERs. In the case of spot trading, the certificates are transferred from the seller’s account at a national registry to the buyer’s account directly after the contract is concluded. Forward and futures trades generally settle in December of the specified year. Physical settlement by transferring certificates is common, but futures with

[8] The UNFCCC Secretariat publishes detailed CDM statistics on the Internet under http://cdm.unfccc.int/Statistics.

Table 1.3 Trading volumes of CO_2 emissions allowances

	Volume (million t CO_2 equivalent)			Value (million EUR)		
Certificate type	2010	2011	2012	2010	2011	2012
EUA	5172	6057	7478	71939	76162	54616
CER	1508	2012	2408	17993	17736	6120
ERU	59	101	574	507	713	906
AAU	63	69	119	460	404	151
North America	189	100	130	365	220	576
NZU	8	10	8	90	105	30
ACCU	–	–	0.3	–	–	6
Other	35	25	–	206	116	–
Total	7035	8373	10717	91559	95459	62404

Source: Talberg and Swoboda (2013).

financial settlement can be found as well. Standardised option contracts for EUAs and CERs also exist.

EUA and CER spot and forward contracts as well as options are traded bilaterally, either OTC or via brokers. Spot and futures trading of EUAs and CERs is possible at several exchanges. Futures contracts with settlement in December have the highest liquidity. Options are traded at exchanges as well, but the liquidity is very low. The main exchanges are:

- IntercontinentalExchange (ICE)[9]
- European Energy Exchange (EEX)
- NASDAQ OMX
- New York Mercantile Exchange (NYMEX)
- Commodity Exchange Bratislava (CEB).

As in other markets, the attractiveness of exchanges changes over time. One example in the emissions market is the BlueNext, which opened in 2007 and closed in 2012. It was considered the largest spot market for emissions certificates.

CERs are often bought in the form of bilateral Emission Reduction Purchase Agreements (ERPAs). Risks can be distributed differently between buyer and seller. In most cases, the seller commits to delivering all CERs generated from a specific project to the buyer, but the amount of CERs is not set. The buyer commits to buying all CERs delivered by the seller at a fixed price. In addition to participants in the EU ETS, also Annex B countries buy CERs in order to achieve their Kyoto targets.

In Table 1.3, trading volumes for EUAs, CERs and other types of CO_2 certificates are shown for the years 2010 to 2012. EUAs and CERs are the most important certificates in the emissions markets by far.

Figure 1.39 shows the development of CO_2 emission allowance prices in the EU ETS during the first trading period 2005–2007. The development is characterised by high volatility. While futures for the first period (settlement in December 2007) and for the second period (settlement

[9] The ICE acquired the ECX in 2010.

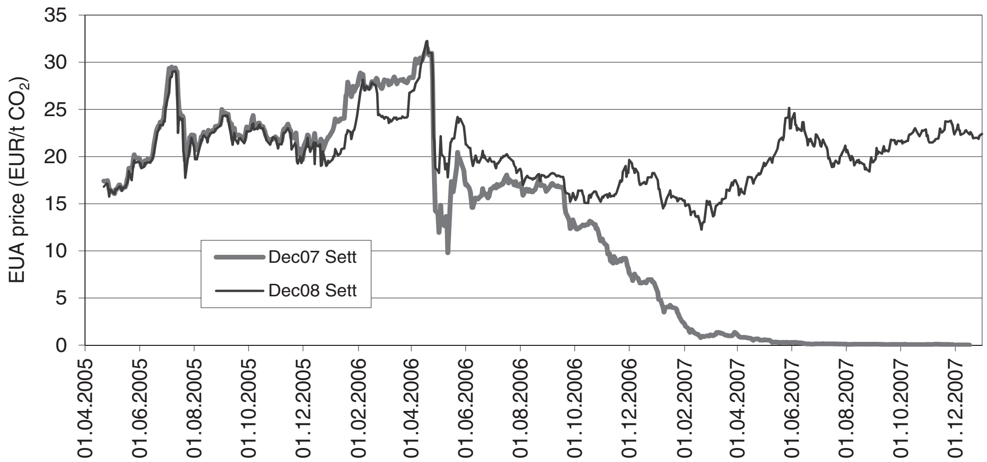

Figure 1.39 CO_2 emissions prices, EU ETS, first trading period. *Source*: ECX.

in December 2008) were priced more or less identically in the beginning, their prices became decoupled. The strong decline in prices for the 2007 futures can be explained by the excess of EUAs allocated by the NAPs for the first period. The futures for the second period (settlement in December 2008) remained at a level of 15 to 25 EUR/EUA, as no oversupply for the second trading period could be foreseen.

Fundamentally, the high volatility of CO_2 prices during the first trading period of the EU ETS can be explained by the price-inelastic supply of EUAs in the NAPs, and the low-demand elasticity in the short term. Most of the short-term demand elasticity exists in the electricity sector, where switching from coal-fired generation to gas-fired generation (fuel switching) is possible. Many other measures for emission reduction require investments with lead times too long to be effective within the first trading period. Furthermore, the demand is uncertain and depends on exogenous influences like wind and hydrological conditions that impact the demand for electricity generation from fossil fuels. Owing to the very small elasticity of the demand and the inherent demand uncertainty, fundamental prices are very uncertain and can decrease to zero.

One additional effect is the free allocation of EUAs via the NAPs. This resulted in most countries having an undersupply in the electricity sector and an oversupply in all other sectors. Electricity companies were the main actors in the first years. They intended to cover their short position (allocation below expected demand), but only a few other actors with a long position (allocation above expected demand) were willing to sell. Furthermore, no consistent and verified historical emission figures for participating installations were available for the years before 2005. Based on estimated historical emission figures, a significant shortage in the EU ETS was expected in a business-as-usual scenario. This led to high CO_2 prices until April 2006, with peak prices above 30 EUR/t CO_2. At the end of April 2006, certified emission figures for 2005 were published for several countries. They were significantly lower than expected. This led to a price collapse of more than 50% within one week.

The European Commission tried to improve the EU ETS by lengthening trading periods, allowing the possibility of banking EUAs from one period to the next, and by uniform allocation methods for all participating countries.

Figure 1.40 CO_2 emissions prices, EU ETS, second and third trading period. *Source*: ECX/ICE.

Figure 1.40 shows the price development of EUAs and CERs for the second and third trading periods. As the most liquid contracts are futures with settlement in December of the current or following year, these contracts have been selected for the figure. Until December 2008, the futures contract with settlement in 2008 is depicted as contracts with earlier settlement fell into the first trading period.

During the second trading period, the high price volatility continued. The sharp decline in prices between June 2008 and February 2009 can be explained by declining prices for oil, gas and coal, and by the economic recession in the European Union which led to a reduction in demand for allowances. After two years of relative stability, prices dropped further. The main reason was that it became apparent that there would be an oversupply of certificates during the third trading period 2008–2020. The European Commission considered several methods for reducing the amount of EUAs in the market, hence increasing the price, but nothing was implemented by the end of 2013. CERs were always traded with a discount to EUAs, as the quantity of CERs which can be used in the EU ETS is limited. Prices declined below 1 EUR per CER in 2013 due to the expectation that the number of CERs generated by 2020 would exceed the quantity restrictions for CERs in the EU ETS by far and the expectation that no new international agreement which could create additional demand for CERs would be in place until 2020. Prices for ERUs developed in a similar way to those of CERs.

1.6.5 Other Emissions Trading Schemes

As part of the Acid Rain Program, trading was introduced in the United States in the 1990s for sulfor dioxide (SO_2) emissions from fossil fuel power plants. This was the first emissions trading scheme. The so-called “cap-and-trade” method constrains overall emissions and allows certificate trading between participating generation units. In Phase I from 1995 to 1999, almost 500 generation units participated. In Phase II, which started in the year 2000, the number of participating units exceeded 2000. The Acid Rain Program is regarded as a success, as SO_2 emissions were reduced faster than anticipated. Figure 1.41 shows the development of the average prices for spot SO_2 emissions allowances at the annual Environmental Protection Agency

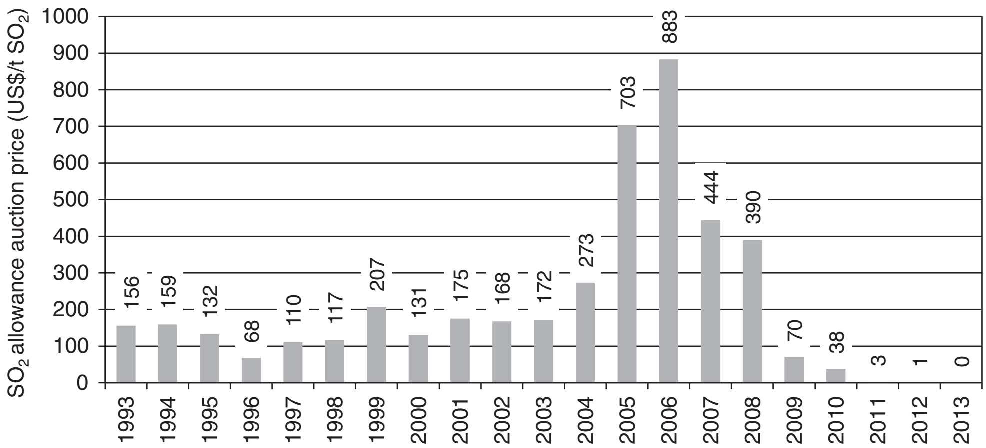

Figure 1.41 SO_2 emissions allowances auction prices. *Source*: EPA.

(EPA) auctions.[10] Similar to the EU ETS, this oldest emissions market is also characterised by high price volatility. While prices reached almost US$ 900 per tonne of SO_2 emissions in 2006, they dropped below US$ 1 in 2012 due to low demand caused by a shift from coal to natural gas as the main fuel in the electricity generation sector.

Regarding greenhouse gas emissions, there are several other smaller cap-and-trade systems implemented besides the EU ETS. Table 1.3 earlier gives an overview on traded volumes for different types of CO_2 emissions allowances and markets. The most important system is the EU ETS, in which EUAs, CERs and ERUs are traded.

The New Zealand Emissions Trading Scheme (NZ ETS) began in 2008 as a scheme covering only forestry activities. Land owners can generate certificates called New Zealand Units (NZUs) by afforestation and have to surrender NZUs for deforestation under certain conditions. In 2010, the NZ ETS was amended and expanded to cover also stationary energy, fishing, industrial processes and the liquid fossil fuels sectors. CERs and ERUs are accepted in the NZ ETS with some quality but without quantity restrictions. Therefore, with the decline in CER prices, the price for NZUs has fallen below NZ$ 2 in 2013. Plans for the New Zealand government to expand its emissions trading scheme to all sectors of the economy including agriculture, New Zealand's largest source of emissions, have been postponed. Therefore, it is unlikely that the NZ ETS will have a significant impact on greenhouse gas emissions in New Zealand in the near future.

Australia has introduced an emissions trading scheme called Carbon Price Mechanism (CPM). It is a mandatory scheme which covers all installations with annual emissions above 25 000 tonnes of CO_2 equivalents. In 2012, approximately 400 installations were covered. The emission certificates in the CPM are called Australian Carbon Credit Units (ACCUs). One ACCU is equivalent to one tonne of CO_2 emissions. The CPM is established in two phases. In the first phase from 2012 to 2014, a fixed price of A$ 23 applies. In the second phase from 2015 onward, a floating market price will be established under a cap-and-trade system. At this point there will be a unilateral link to the EU ETS. EUAs are accepted in the Australian

[10] Detailed information on the Acid Rain Program can be found on the US EPA's Acid Rain Program homepage http://www.epa.gov/airmarkets/progsregs/arp/.

system. And from 2018 onwards, a bilateral link is expected which will allow ACCUs to be used by European installations as well. As offset mechanisms, the CPM accepts CERs from the Clean Development Program under the Kyoto Protocol, with qualitative and quantitative restrictions, as well as offsets from national emission reduction measures from agriculture and landfill activities via the Carbon Farming Initiative (CFI).

Switzerland has introduced a carbon tax of CHF 36 per tonne of CO_2 in 2008. As Switzerland had not met its Kyoto targets, the tax was increased to CHF 60 per tonne of CO_2 in 2013. Large emitters were exempted from the carbon tax if they had participated in the Swiss Emissions Trading Scheme (Swiss ETS). Since 2013, participation in the Swiss ETS is compulsory for installations with an installed capacity above 20 MW, and voluntary for installations with an installed capacity between 10 MW and 20 MW in exchange for an exemption from the carbon tax. Approximately 400 installations participate in the Swiss ETS. Emission allowances are allocated for free based on benchmarks, and the remaining allowances are sold by auction. CERs and ERUs are accepted within the Swiss ETS with qualitative and quantitative restrictions. Switzerland plans to link its ETS to the EU ETS.

The Republic of Kazakhstan began a mandatory national emissions trading scheme in 2013. This scheme covers installations in the manufacturing, energy, mining, metallurgy, chemicals, agriculture and transport industries with emissions above 20 000 tonnes of CO_2 per year. It includes approximately 200 installations.

In North America several regional emissions trading schemes have been established. The oldest one is the Regional Greenhouse Gas Initiative (RGGI). It was established in 2009 and brings together nine states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont). It is a mandatory scheme for fossil fuel power stations with an installed capacity above 25 MW, including approximately 200 installations. Certificates are sold by auction. The number of certificates available depends on certain price thresholds. RGGI accepts credits from five different types of offset projects in the participating states subject to quantitative and qualitative limits.

The Western Climate Initiative (WCI) started in 2007 with several states in the USA and provinces in Canada. But by 2013, only two trading schemes at state or provincial level have been implemented out of this initiative, the California Cap-and-Trade Program and the Quebec Cap-and-Trade System.

Since 2013, the Californian scheme is mandatory for installations with emissions above 25 000 tonnes of CO_2 equivalents per year. The number of participating installations is approximately 600. Initially, 90% of the permits have been allocated for free, the rest are sold by auction by the California Air Resources Board (CARB). For auctions, a floor price of US$ 10 per certificate applies. And if market prices exceed certain thresholds, the quantity of certificates can be increased. Participants can use offset credits to cover up to 8% of their total obligation.

The Quebec Cap-and-Trade System is very similar to the California Cap-and-Trade Program. It has also been in operation since 2013 and includes approximately 100 installations. Plans exist to link these two programmes.

The Canadian province of Alberta introduced a Greenhouse Gas Reduction Program in 2007 which requires installations with emissions above 100 000 tonnes of CO_2 equivalents per year to reduce their emission intensity by 12%. Participating companies can meet this obligation by the following means: making improvements to their operations, purchasing Alberta-based offset credits, purchasing tradable Emission Performance Credits (EPCs) which are generated by reducing the emission intensity below the target, or paying a penalty of C$ 15 per tonne to the Climate Change and Emissions Management Fund. Targets and the penalty for not meeting the targets are revised from time to time.

Two Japanese regions have operational mandatory emissions trading schemes in place: Tokyo and Saitama. The Tokyo metropolitan mandatory cap-and-trade scheme was launched in 2010. It covers approximately 1500 buildings and installations with a fuel, heat and electricity consumption above 1500 kilolitres of crude oil equivalent per year. Until 2014 the scheme only covered CO_2 emissions, but from 2015 all six Kyoto Protocol gases will be included. The region of Saitama launched a similar scheme in 2011 with approximately 600 participating installations. Both schemes are linked.

In addition, a national emissions trading scheme was in the implementation phase in South Korea in 2013. And in China, regional schemes were in the implementation phase in Beijing, Tianjin, Shanghai, Chongqing, Shenzhen, Hubei and Guangdong. Several other countries or regions worldwide are considering the implementation of a mandatory emissions trading scheme.[11]

In the long run, convergence of CO_2 prices in all trading schemes can be expected – either through a direct linkage of the schemes, or through an indirect linkage via CERs, ERUs or other certificates from offset projects which are accepted by more than one scheme.

[11] The homepage http://www.icapcarbonaction.com of the International Carbon Action Partnership (ICAP) gives a good overview on the development of regional and national emissions trading systems.