Chapter 1
Energy Markets

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Abstract Most of the risks in energy production and trading are related to market prices. As a consequence, this first chapter provides a short introduction to energy markets. Products (or more precisely contracts) which are traded in energy markets can concern either the physical delivery of energy (physical settlement) or only the payment of the financial value of such a delivery (financial settlement). In the case of a physical settlement, the traded quantities directly influence the whole system; if the settlement is financial, trades are basically bets on prices. Motivated by this distinction, we separate this chapter into two major parts: The first part considers the physical side of markets, focusing on the physical spot markets for natural gas and electric power. The second part serves as an introduction to the financial aspects of the markets, describing derivatives on physical spot contracts.
In both sections our geographical focus will be on European markets. Due to the inhomogeneities of market designs, we will focus on stylized market characteristics rather than details. We mainly consider natural gas and electricity due to their distinctively different behavior to financial markets.

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1.1 Effects of Market Liberalization

Energy plays a central role in modern economies and the everyday life of people in industrialized countries. Consequently, it is no surprise that huge amounts of oil and coal, just as other storable and thus easily transportable commodities, have been traded around the globe in the twentieth century.

A somewhat more recent phenomenon is the emergence of markets for electricity and natural gas, which rely on a complex and expensive distribution network. Due to the huge initial investments in the infrastructure necessary for distribution and because of significant effects of scale in their production, for a long time, state-owned monopolists were the most efficient providers. In fact, electricity and natural gas were seen as typical cases of natural monopolies. This is still the state of affairs in many countries with not fully liberalized energy markets.

From the last decade of the twentieth century onwards, competitive markets for grid-based energy have been established all over the world with the hope of economic benefits from cheaper energy supply. Competition was usually established by unbundling the roles of network operation, production, and retailing. By opening access to the distribution infrastructure, market entry barriers were drastically reduced and opportunities for sourcing and trading were generated for various market participants, such as financial investors or large energy consumers.[1]

One particularity of the energy industry is the major role of uncertainty: Demand for natural gas, for example, is usually driven by several factors like temperature or even macroeconomic factors, which are hard to predict. As another example, the level of electricity supply depends not only on availability of transmission networks and power plants but also on wind, sunshine, and rainfall due to the importance of renewable energy production. To absorb variations in supply or demand it is vital for energy companies to secure access to short-term supply of energy.

As a consequence of matching short-term supply and demand, ideal[2] spot markets also create a source of flexibility[3] (i.e., short-term supply of energy) and establish the related prices. Instead of holding flexible generation assets or supply contracts like an insurance to cover the own worst-case needs, market participants are essentially enabled to use available flexibility to gain short-term profit in the spot market. Essentially, this amounts to projecting the risks of energy companies onto the spot markets, making it possible to quantify and trade them.

A side effect of the increase in market activities is an increase of exposure to (market price) risks for both suppliers and producers of energy. Therefore energy derivatives can be used to shape the risk profiles of energy portfolios.

Thus, with the emergence of liquid markets for energy, quantification and trading of risks become a crucial part of daily business for the energy industry, triggering the development of techniques tailored to energy risk management.

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[1] For details on the rationale behind energy market liberalization we refer to [22].

[2] That is mature, liquid markets, allowing to execute trades of arbitrary size at quoted prices (cf. p. 18).

[3] cf. [8].

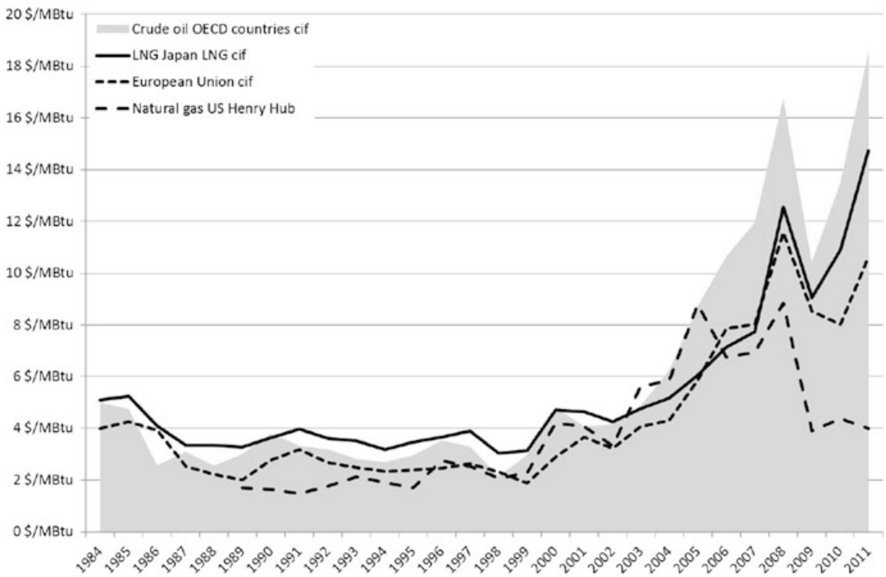

Fig. 1.1 Price levels of natural gas in different regions [source: [3], cif = cost + insurance + freight (average prices)]

1.2 The Physical Side of Markets

The main purpose of physical spot markets is the matching of supply and demand. Accordingly, markets for natural gas and electricity are principally based on physical spot products, which also serve as the main building blocks of most energy derivatives. We define spot prices as the prices for physical delivery of energy at a certain location the following day. The exact delivery period varies between products and markets. Usually electricity can be purchased for each single hour of a day or as a combination of several hours (peak/off-peak/base products) whereas natural gas spot is (mostly) delivered at a constant load during the whole following day. However, since the underlying concepts are quite similar, we will not distinguish between them.

For grid-based energies, particularly for electricity, balancing of delivery systems is crucial. Consequently, for each power market, there also exist balancing markets, where short-term generation capacities of power plants can be acquired by the system operator. We devote only a small part of our attention to balancing.

1.2.1 Natural Gas Markets

1.2.1.1 The Natural Gas Value Chain

As with oil, production of natural gas is not evenly spread over the globe. In 2011, natural gas production was dominated by the USA (20%) and the Russian Federation (18.5%), followed by Canada (4.9%), Iran (4.6%), Qatar (4.5%), and Norway (3.1%). Major exporters of natural gas are the Russian Federation, Canada, Qatar, and Norway. Similar to oil, at the moment, increasing production appears to be met with increases in confirmed reserves. According to [3] global proved gas reserves at the end of 2011 were sufficient to meet 63.6 years of production.

Before further transportation, natural gas has to be processed to remove contamination and to generate standardized products, which are tradable and fit the consumer's needs. The major share of long-range transportation is done by pipelines, which leads to a separation of the world into several markets for natural gas. Figure 1.1 illustrates the different price levels of natural gas in different regions, relying on different sources for natural gas supply.

Complementary to transport by pipeline, already in the late 1950 liquified natural gas (LNG) was used for transportation to Great Britain [8]. For this way of transport, natural gas is cooled down until it reaches a liquid state, which reduces its volume to a fraction of its original state. As a result, LNG is suitable for storage and transportation per ship. LNG plays an increasing role in connecting the different market areas for natural gas. However, the construction of the related infrastructure is expensive and time demanding and liquification as well as regasification are energy intensive. Especially due to the last point, LNG can hardly be used for arbitrage between continents, but price levels are coupled more indirectly due to the fact that LNG deliveries can be (re)directed to the market with the highest price.[4]

At a regional level, natural gas is distributed by retailers to their customers via distribution networks which are organized on a local level. Natural gas can be stored by several means, differing in size of storage and speed of input and output. In general, depleted gas fields are used for absorbing long-term fluctuations such as seasonal demand patterns, whereas salt caverns are used to flatten short-term fluctuations and to increase network stability (balancing energy).

1.2.1.2 The Development of Natural Gas Markets

In the sense of decoupling of production, transportation, and retailing, the first liberalized natural gas market appeared in the USA in the 1980s, followed by the UK in the late 1990s [11]. In pursuit of a common market for energy, several members of the European Union started implementing natural gas spot markets in the early 2000s.

Historically, natural gas markets developed very differently in various countries. Europe was reliant on the supply of a few big (stateowned) companies. This resulted in a specific European supply structure based on long-term agreements: To secure the massive investments in exploitation and transportation, producers and retailers typically negotiated long-term bilateral delivery contracts (often exceeding a time

[4] For example, the emergence of cheap USA shale gas around 2010 did not lead to significant exports of natural gas to other continents. However, market prices outside the US still dropped, to some extent caused by LNG transports stopping to deliver to the USA and serving the rest of the global market instead [1].

span of 20 years). Usually, such contracts link the price of natural gas to the price of fuels that are competitors to natural gas in the respective market region (fuel oil[5] for residential heating) or industry (oil or coal for power generation). In addition, often volume constraints are included in the contracts. These so-called take-or-pay (ToP) clauses constrain the cumulative amount to be delivered over certain time periods from below and above. This structure serves two main goals: connecting the gas price to the price of a related fuel ensures competitiveness of the price for the redistributor, while the ToP clause mitigates volume risk from the producer to the importer (see, e.g., [8, 11]). The long-term nature of the contracts amounts in a sense to vertical integration, guaranteeing a stable relation between producer and gas retailer, which simplifies long-term planning and infrastructure investments such as pipelines.

1.2.1.3 The Organization of Natural Gas Markets

As a general prerequisite, markets for trading natural gas rely on (physical) access to gas sources and potential trading partners.

The first market places for natural gas emerged at the so-called (physical) hubs, i.e., the intersections of long-distance pipelines, where gas from and to various locations could be traded between shippers. The administrator of the hub arranges the actual physical transaction and the resulting administrative actions such as transport nomination and confirmation procedures. In addition, sometimes storage (or "parking") of natural gas is offered at hubs.

This generic method of trading natural gas is based on the exact location of delivery which has one central drawback: contracts refer to more than one point of a distribution network. This may split the whole market into smaller parts with reduced liquidity. One way to bundle and increase liquidity is the introduction of virtual hubs: a virtual hub[6] is a fictive point through which *legally* all gas in a region flows. Therefore, trading for the whole region is focused at the unique virtual point. The suppression of the physical system in the market prices can lead to problems for the network operator in the case of congestion.

The actions of market participants, such as trading, delivery to customers etc. result in physical inflows and outflows at a hub. To absorb eventual imbalances in the system from imperfect matching of inflows and outflows, the transport system operator takes balancing actions by adding or extracting gas to or from the system. Usually system management relies on storage, short-term market purchase, or special flexible contracts for this task and is financially compensated by the market participants.

[5] One of the major drivers behind the large-scale usage of natural gas was to diversify energy consumption from oil in the oil crises in the 1970s, see [8].

[6] For example, NBP in Great Britain or the NCG and GP in Germany.

1.2.1.4 Stylized Facts on Natural Gas Prices

For a long time there have been strong links between natural gas prices and oil prices (cf. [19] for a model based on this). One reason is certainly the link to oil as a substitute. Another reason is the oil indexation of long-term supply contracts (discussed above). However, recently some markets experienced a decoupling of oil and gas prices (Fig. 1.1). This may be a consequence of increasing market liquidity, notably in the USA. In Europe, at the moment, it seems that the oil indexation of gas prices is losing importance along with the growing development of natural gas markets, which—provided liquidity—allows flexible sourcing at a more competitive price level but also entails more risk.

The demand for natural gas arises from electric power generation, use in energy-intensive industries (such as paper mills, cement, chemical industry), residential usage for heating and cooking and to a minor extent for transportation.

Especially large-scale usage for heating typically leads to a distinctive seasonal pattern in consumption. In addition to high price levels in winter, in some markets, high prices may occur when natural gas is used for generation at electricity peaks—for example, due to high demand in summer. This relation between natural gas demand and seasonal temperatures is reflected in the price forward curve (which is closely related to expected spot prices) (Fig. 1.2).

Many industrial users are able to switch from gas to oil. Together with the possibility of storage, this increases the elasticity of demand. As a consequence, natural gas prices in general exhibit a lower volatility and fewer spikes than electricity prices. Still, compared to stock prices, natural gas prices are quite volatile, in particular in periods of scarcity (cf. [20]). Their reliance on infrastructure is a big constraint on locational arbitrage and can result in abrupt scarcity due to physical disruptions.[7] The effects of storage are dampened by the high investment and operational cost.

In (continental) Europe, a large portion of supply still relies on long-term delivery contracts as introduced above.

1.2.1.5 Transmission Capacity Allocation in Europe

Transmission of natural gas in Europe is based on zones (largely based on member states or market areas). Transport costs between markets arise from the number of zones, which have to be crossed, and from the interzonal capacities, which have to be booked in advance. Capacities are usually classified as firm or interruptible.

In April 2013, a pan-European platform[8] was established to centralize the acquisition of capacities from transport system operators and to offer a secondary market for capacity trading between shippers. For details see http://www.prisma-capacity.eu/.

[7] For example, outages of the interconnector between GB and continental Europe or hurricanes blocking the natural gas infrastructure in the gulf of Mexico.

[8] At the moment consisting of Germany, France, the Netherlands, Belgium, Italy, Austria, and Denmark.

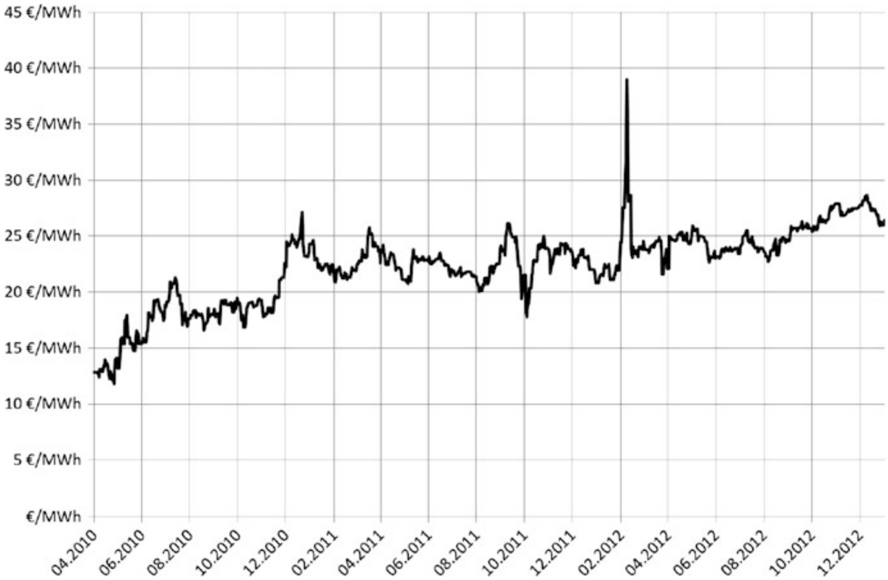

Fig. 1.2 Spot price at Zeebrugge natural gas hub (data source: `http://www.net-connect-germany.de`)

1.2.2 *Electricity Markets*

1.2.2.1 The Power Value Chain

The main market players at electricity markets are generators, distributors, and network operators. Generators convert different sources of energy into electrical energy and feed it into high-voltage networks. Distributors transform electricity from high-voltage networks into electricity with lower voltage and resell it to final consumers. Finally, network operators (independent system operators) maintain the physical network.

The main sources of power are thermal power plants (largely fossil-fueled power plants), where heat is transformed into electrical energy. The transformation can basically be achieved in two ways: The first is to generate steam which drives steam turbines. This transformation process is applicable for all fossil fuels as well as nuclear energy, waste, and some types of solar thermal plants. The second method is to directly drive turbines (basically enhanced jet engines or diesel motors) by oil or natural gas, where switching between fuels is often possible (Fig. 1.3).

The conversion factor of fuel input to electricity output is usually defined as the heat rate, which is in general a nonlinear (concave) function of the output level, i.e., electricity generation is most efficient when neither at minimal nor maximal possible output level. Often, the efficiency of thermal power plants is increased by reusing residual heat from the transformation process (cogeneration plants or combined cycle gas turbines).

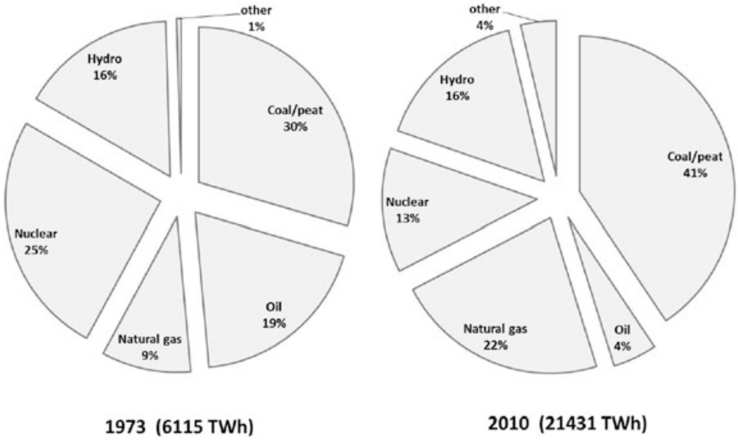

Fig. 1.3 Fuel shares in global electric power generation: 1973 (*left*) and 2010 (*right*) show an increase in relative generation by the fossil fuels natural gas and coal (data source: [15])

Depending on the layout, the electricity production of power plants is restricted by several operational characteristics (cf. [24] or [18]). The most obvious restriction on power production is the minimum and maximum production capacity of a plant, which is induced by its layout. To decrease the risk of component failures, in particular for coal and nuclear plants, it can be infeasible to turn a power plant off or on unless it has already been online or offline for a certain time period. Ramp rates specify the possible increments in power output for an online plant (due to system "inertia" or again reliability considerations). Finally, to guarantee reliability of a power plant, maintenance is necessary on a regular basis, which leads to scheduled shutdowns for all plants.

As a rule of thumb, there exists a trade-off between power production cost and system inertia, i.e., power production of plants using lignite is in general much more inflexible than of those with gas turbines. This leads to a certain degree of specialization among power plants: base load plants generate a constant power output at a low price and are sometimes turned off for maintenance only, whereas peak power plants are used to absorb high demand at high prices which compensate for their more expensive production.

Nonthermal power plants consist mainly of hydro generation, wind generation, and photovoltaic generation. In the case of hydro generation, different layouts provide very different operational characteristics. Run-of-river plants provide a constant output and are mainly used for base load generation; pondage power plants use the water from a reservoir, which provides them with a certain degree of flexibility, whereas pump storage plants can be used to store electric energy.

The special characteristic of wind and photovoltaic generation is that they are very difficult to predict due to the dependence on weather conditions (i.e., wind and sunshine) (Fig. 1.4).

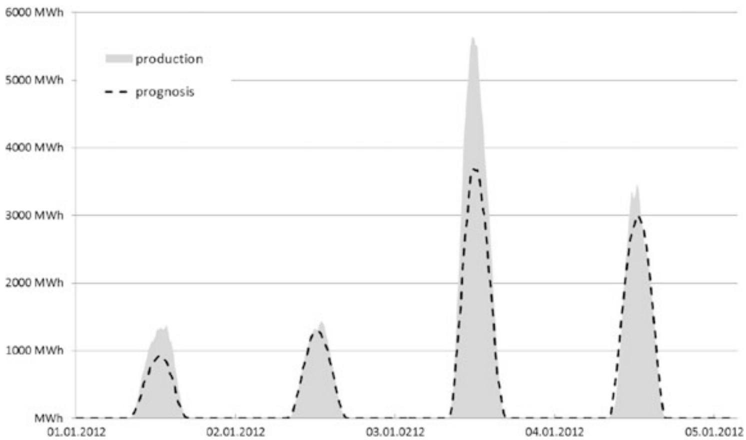

Fig. 1.4 Day-ahead forecast (*dashed*) and actual (*shaded*) production of solar power in Germany (data source: EEX)

Spot and Adjustment Markets

Short-term electricity markets typically contain a multitude of submarkets with different time horizons for delivery, reaching from day-ahead spot markets—trading power related to individual hours of the following day—to real-time markets where prices may change within minutes. In addition, power systems need reserve-capacity generators that can produce additional power within short time. Clearly, both location and time of delivery are defining elements of power products due to nonstorability and complexity of transportation.

The central goal of a spot market is the meeting of total generation and demand. Details of market design differ significantly between various market places. Following [11] (compare also [22]), we distinguish between two typical forms of power spot markets: power pools and power exchanges (bilateral markets).

- **Power pools** (single-buyer market): The distinguishing feature of this system is the central role of a system operator, who formally buys the whole generation from producers at one price.
  This can be done by collecting bids from suppliers (i.e., price for a certain generation capacity) and aggregating them from cheapest to most expensive. The result is the so-called bid stack (or merit order curve), describing the power price as a function of the demand. Intersection with the (usually inelastic) demand curve—which can be estimated or also generated by bids from buyers—gives the market price.
  In some cases,[9] the system operator collects bids from producers, containing also operational characteristics of generation units. Based on this, the system operator computes the optimal production schedule, satisfying the demand. This system

[9] Such as in the PJM market area at the east coast of the USA.

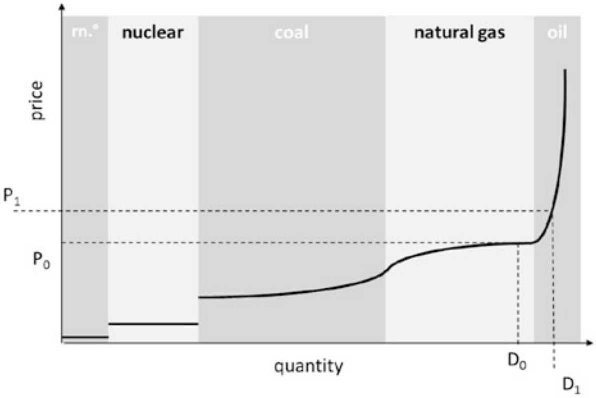

Fig. 1.5 Bid stack (schematic, rn.° = renewables). For satisfying a demand D_0 (D_1), an equilibrium price P_0 (P_1) emerges, which (simplified) corresponds to the marginal production cost of the most expensive plant producing

leads to prices which are close to the actual economic cost of production, in particular when used in connection with locational marginal pricing (as discussed below).

Figure 1.5 shows a schematic bid stack and the derivation of equilibrium prices by matching of supply and demand.

- **Power exchanges** (bilateral markets): All transactions are bilateral without connection to other trades on the markets. Since bids do not have to be publicly announced, a market clearing price (actually an exchange index) is computed based on trades (or bids/offers) and published by the exchange.

Adjustment markets work in a different way: To avoid system instability, the system operator has to maintain the target frequency in the network. Changing the real-time price of power can be used as an incentive for producers to increase or decrease their power production immediately. Reserve contingents differ with respect to the speed and likelihood of their availability: The spinning reserve encompasses units with additional capacities that are already producing, while the scheduled reserve contains units that are offline but can be brought up quickly. Generally speaking, operating reserve aims at correcting short-term disturbances and planning reserves should meet annual demand peaks. As a rule of thumb, the whole reserve capacity is held at approximately 10% of load at any time.

Besides the complex temporal distinction of different products, the location of electricity delivery has to be considered. The root of the difficulty of this issue lies at the differing cost of supply at different points in a network, which can emerge due to congestion.

To reflect the true cost of supply in market prices, the principle of locational marginal prices[10] has been introduced. For this approach, power is priced at the

[10] For details we refer to the webpage of the PJM system operator: www.pjm.com.

incremental cost of generation given the current state of the system. The benefit of being economically sensible comes at the cost of potentially unintuitive prices as well as lower liquidity due to segmentation of a market into several markets for different delivery points.

In the alternative concept of zonal prices, electricity delivery points are aggregated to zones. Transmission is only an issue between whole zones and is managed by contractual transmission rights. This approach promises higher liquidity at the cost of an imprecise transfer of actual cost (i.e., physical difficulties) of delivery.

1.2.2.2 Stylized Facts on Electricity Prices

One of the principal drivers of electricity prices are the marginal production costs, which consist largely of fuel prices and operational costs.

Some aspects of the complex interplay of electricity price, fuel prices, and demand level can be analyzed by bid stacks, as in Fig. 1.5. Since the electricity price is given by the intersection of bid stack and demand, power prices can be traced back to movements of the demand curve and movements of the bid stack.[11] If producers bid at their marginal production cost,[12] every segment of the bid stack corresponds to a power plant (with given production efficiency) and its respective production cost, which is basically driven by the fuel prices for power generation. In particular, market clearing power prices are connected to the price of the fuel which drives the generation stack at its intersection with the demand curve, the so-called marginal fuel. As a consequence, there can exist a strong dependency between electricity spot prices and the spot price of the marginal fuel. This connection can also hold for futures prices of electricity and marginal fuel.

Demand for electricity is largely inelastic due to price insensitivity of many final customers. As the demand curve can be shifted by external factors like temperature or business activity, electricity spot prices show pronounced intraday, weekly, and seasonal patterns. Note that in some markets, complex bidding behavior of producers may lead to seemingly elastic demand, for example, due to the so-called make or buy bidding: at low price levels, producers may satisfy delivery obligations by spot purchases instead of own production, leading to a price sensitive demand on the market (Fig. 1.6).

The bid stack also illustrates potential causes for price spikes and high volatility: high demand can shift the equilibrium price to regions where the offer curve is steep (due to dependency on expensive production units), leading to high, volatile prices. Finally, negative prices may be induced by a coincidence of peaking renewable production (at low price) and low demand, for example, due to holidays. This may result in a situation where base load plants face the decision of shutting down (connected to high operational costs) or paying negative prices to get rid of their production.

[11] This relation is the fundament of the so-called hybrid or structural price models which merge equilibrium and econometric models. Cf. [7] for a detailed discussion.

[12] The validity of this assumption is debatable, for example, due to strategic bidding by the producers.

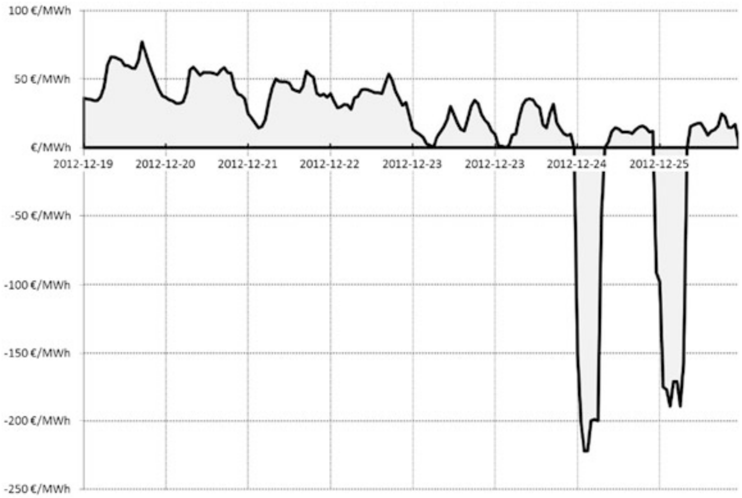

Fig. 1.6 PHELIX power spot Dec 2012 (data source: EEX)

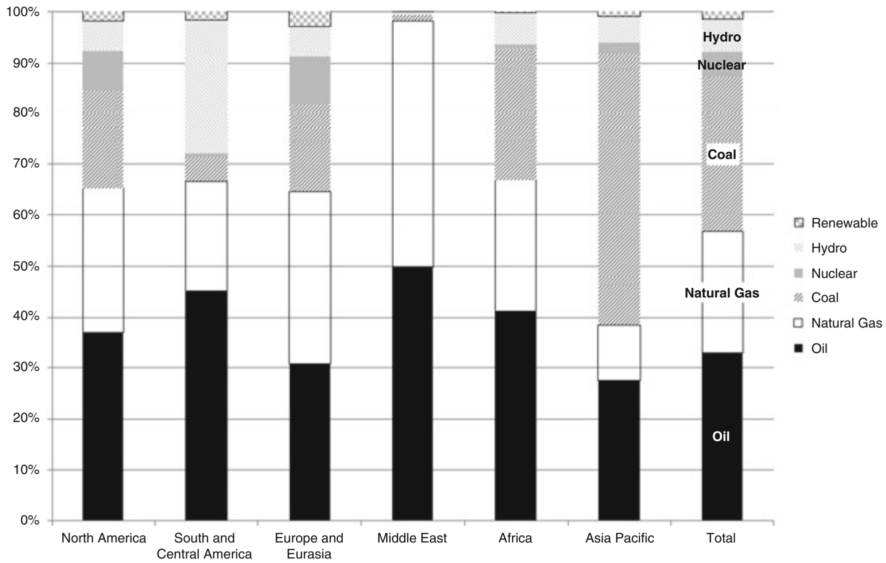

Fig. 1.7 Global consumption of primary energies (data source [3])

1.2.3 Oil and Coal Markets

Oil is a crucial commodity used for transportation, as primary energy, and in the chemical industry. As of 2011, oil had the greatest share (33.1%) in global consumption of primary energy, followed by coal with 30.3%. Whereas this marks the lowest percentage for oil in history, it is the highest share in coal since 1969 [3].

In contrast to electricity and natural gas, both oil and coal are not bound to a fixed transportation grid (although oil can be transported by pipelines as well). As a consequence there exist global markets for both commodities (Fig. 1.7).

Apparently, even the historically maximal oil consumption in recent years has been matched by updates in proved reserves. BP [3] states that world proved oil reserves at the end of 2011 were sufficient to meet 54.2 years of global production. Although the increase in proved reserves in coal does not match its production according to [3], coal has the largest reserves to production ratio of all fossil fuels.

The same ton of oil can be traded twice: once as crude oil, i.e., unrefined, and then again after refinement. The properties of crude oil vary strongly between different production locations. To achieve the grade of standardization necessary for a market, only a small number of reference qualities of oil are liquidly traded, their quotes providing a basis for trading other products. Since global transportation of oil is largely achieved by ship, delivery is usually specified at port locations. Freight rates as well as refinement capacities can have a strong influence on the prices of oil and of some refined oil products. Similar to oil, long-distance transportation of coal is usually seaborne, which makes freight rates a very important component of coal prices.[13]

In general, the oil price has the property of leading the primary energy price, i.e., the price levels of other primary energies are strongly coupled to the oil price. This is due to the frequent coupling of energy delivery contracts to oil indices as well as oil being a major competitor to other primary energies, especially for heating and power production.

In contrast to the liquid markets for some oil products, most coal trading is done via bilateral OTC contracts, due to the difficulty of standardizing the quality of coal [4].

For more detailed accounts of the oil and coal markets we refer to [4, 11].

1.3 The Financial Side of Markets: Derivatives

A derivative is a contract which can be defined as "an instrument whose price depends on, or is derived from, the price of another asset" (cf. [14]).

Although actual physical demand and physical supply meet at spot markets, huge volumes of energy are traded as derivatives on physical spot products. The main reasons for the high amount of "paper energy" in circulation are hedging and speculation.

Hedging can be defined as the execution of trades to reduce exposure to price risks. Risk reduction can require both sales and purchases of derivatives: Whereas power producers may sell parts of their production in advance, large consumers may buy parts of their demand also in advance—both to reduce their exposure to future price variability.

[13] According to [4], freight rates sometimes amount to 70% of the coal price.

Speculation is exactly the reverse of hedging: it consists of the execution of trades to deliberately gain exposure to price risks.

Without knowing the actual portfolios of market participants, it is impossible to distinguish between hedging and speculation. However, the increasing liquidity in energy markets results at least partly from increased activity of financial institutions. This development is sometimes referred to as the "financialization of commodity markets."

In the following section, we will first discuss futures contracts as the most liquid derivatives and *en passant* notice the features of exchange-traded contracts. Later we investigate the link between spot and futures prices and give a short overview of bilateral trading and nonstandard contracts.

1.3.1 Futures and Exchange Trading

Futures contracts are exchange-traded standardized contracts which specify the price of a sequence of spot deliveries, usually stretching over weeks, months, quarters, or years. For electricity there is usually a distinction between peak and off-peak (or base) futures, specifying delivery over hours of high and low demand.

The settlement of a contract specifies the mode of delivery, which can be physical (i.e., actual delivery) or financial (i.e., payment of the difference of the futures price and the spot price).

Benth et al. [2] observe that, from a financial engineering point of view, energy futures are actually swaps where a fixed payment (futures price) is swapped for a floating payment (spot price). Note that the futures price denotes the agreed delivery price per unit, but the actual volume of the contract is given by the product definition.[14]

Since futures are traded on exchanges, the exchange serves as counterparty for both buyer and seller for every trade. Since neither buyer nor seller know who is standing at the other side of the trade, exchange prices have the benefit of being nondiscriminating.

As a consequence of the intermediary position of the exchange, bankruptcy of a contract party only affects the exchange but not the participants in the trade. To avoid the risk emanating from nonpayment of a contract party (counterparty risk), the exchange imposes a margining system. This means that at every trading day, the value changes of all positions ("open interest") are financially netted among contract holders, and the contracts are replaced by current contracts with the actual market value. An initial deposit[15] from every market participant is used to cover the variation during a single day in case of insolvency of a contract holder. As a consequence of the margining systems, exchange-traded contracts are practically free of counterparty risk.

[14] Usually the contract size times length of the delivery period.

[15] Initial margin.

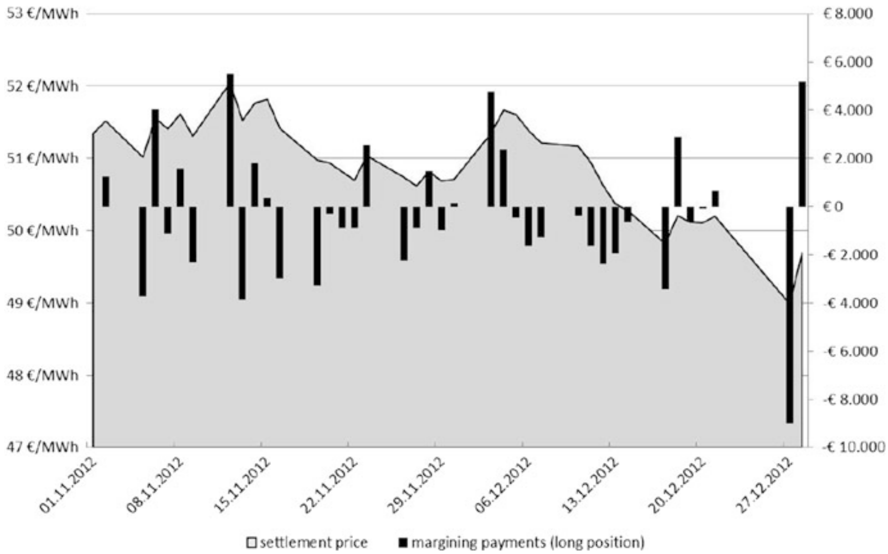

Fig. 1.8 Margining Phelix base futures Feb 13 contract (source: EEX)

The following example illustrates the procedure:

Example 1. [16] On November 1, 2012, a market participant decides to buy a constant load of 10 MW of power, deliverable in the month of January 2013. The corresponding futures contract $F(1,T)$ is bought at the exchange for the current price of 50.85 EUR/MWh. On November 2, the market price of power futures contracts with delivery period January 2013 rises, $F(2,T)$ being now 51.02 EUR/MWh. At the end of the day, the contract $F(1,T)$ held by the market participant is replaced by the new contract $F(2,T)$ (specified at a delivery price of 51.02 EUR/MWh corresponding to the current market view), and the value change is compensated by a financial payment of 1264.8 EUR,[17] which amounts to the difference in value of the two contracts. Figure 1.8 shows the whole sequence of margining payments, from November 1 until delivery at January 1.

One consequence of margining is that the values of all open positions have to be determined—even if there happened to be no active trades. Thus, a central role of an exchange is the determination of settlement prices, i.e., the prices at which open positions are valued at the end of a trading day. Weighted means of trades are often used for determining settlement prices; in the case of too few trades, the prices are to be estimated.

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[16] We assume no interest rate and ignore initial margin for the sake of simplicity.

[17] $= 10\,\mathrm{MW} \times (24 \times 31)\mathrm{h} \times 0.17$ d’/MWh.

1.3.1.1 Usage of Futures

Futures are to a large extent used for hedging purposes. Examples include the fixing of profit of a fossil-fueled power plant by buying fuel futures and selling power futures for the same delivery period to lock in the margin (cf. [9]). See [23] for a detailed account on hedging a natural gas portfolio with futures products. Note that even perfect hedging of risks (i.e., the exact offsetting of risky positions) can lead to losses due to margining payments.

Besides actual trading, futures provide information about the market assessment of future prices. This information can be of tremendous value and is widely used as "objective" evaluation of contracts and whole portfolios, a practice known as mark to market. Essentially this is done by valuing future obligations or deliveries by the quotes of the corresponding futures products on the market. This makes it possible to "value any contract without need to rely on the view of a trader" [11]. In practice, some effort is put into the transformation of market quotes into forward looking prices with daily or even hourly time resolution. These so-called price forward curves are often used for the valuation of daily or hourly load patterns (cf. [10, 21]).

It is especially the transparency and nondiscriminativity of futures prices—and the absence of counterparty risk premia—that recommend them as benchmarks. Note however that the concept of mark to market is theoretic to some extent: it implicitly is assumed that a whole portfolio can be sold at market prices—no matter what the size. This assumption may turn out not to be valid when a portfolio actually has to be liquidated.[18]

Several properties of a market which are prerequisites for using market prices as reference for valuation and risk management are subsummized in the term of market liquidity.

1.3.1.2 Market Liquidity

Generally spoken, market liquidity describes the possibility to trade arbitrary volumes in a market at quoted prices. Following [8], liquidity can be defined more precisely by splitting it into four distinct properties:

- *Depth*: large volumes can be bought or sold without moving the price excessively.
- *Breadth*: large number of different bids and offers are present in the market.
- *Immediacy*: the possibility to trade large volumes in a short period of time.
- *Resilience*: the ability of the market to recover towards its natural supply/demand equilibrium after having been exposed to a shock.

Note that liquidity is rather a property of single products than of markets: in many markets, (monthly) futures close to their maturity are more liquid than futures maturing far in the future.

[18] A famous example is the case of the hedge fund Amaranth Advisors L.L.C., which collapsed, unable to liquidate its huge portfolio of natural gas futures (cf. [5]).

One means by which exchanges try to establish liquidity is to establish market makers. Market makers provide liquidity by buying or respectively selling a certain quantity of energy if it is quoted outside a prespecified price range, which reduces the risk of finding no counterparty.

1.3.2 Pricing of Futures

Arbitrage-free pricing methods for futures contracts exist, both for financial and commodity markets, and are widely used. They are based on the idea of constructing a portfolio that replicates the cash flows of a derivative by borrowing money now and buying the security or commodity under consideration in order to meet the final demand ("cash and carry strategy"; cf. [14]). The proper strategy may involve rebalancing the amount of commodity held over time and is subject to interest payments, e.g., transport costs and storage costs.

Denote the forward price at delivery time T, agreed at time 0—that is today—by F_T and the current spot price with S_0. Subsuming all related costs under the terminus *cost of carry*, absence of arbitrage leads to the following relation:

$$F_T \leq S_0 + cost\ of\ carry \tag{1.1}$$

Assume inequality (1.1) is strictly satisfied. Then, in classical finance, the "reverse cash and carry" strategy could be applied by short selling spot and closing the position at time T via the futures contract. However, for commodities, this arbitrage strategy may not be viable: In the first place, short selling is not possible without having physical energy in stock. But besides this, the holder of the commodity may not even be willing to reduce the storage level for fear of not being able to satisfy the own demand. This line of thought is the idea behind the concept of convenience yield (introduced by [16, 25]). This quantity is interpreted as the financial value of having a commodity in stock and can be formally defined as the slack variable for inequality (1.1):

$$F_T = S_0 + cost\ of\ carry - convenience\ yield. \tag{1.2}$$

In situations of extreme scarcity, the convenience yield outweighs the cost of carry, thus forcing the spot above futures prices, whereas in periods of abundance cost of carry dominates the relation.

This approach suggests that the key drivers of the forward prices of storable commodities are the spot price and scarcity (given for example by inventory, demand, or production level).

Using stochastic convenience yield, Eq. (1.2) has been used as starting point for the (widely used) two-factor spot price models [13]. Empirical results in [20] also suggest connections between scarcity and volatility.

The derivation of the convenience yield relied on storage, which may be questionable for natural gas since storages have limited capacity and turnover rates.

Unfortunately, given the nonstorability of electric energy, the usual no-arbitrage arguments fully break down for power markets. A direct relation between the actual spot price and forward price is not observable for electricity. This means that forward prices contain additional information about the future and are related to expected prospective spot prices. Stoft [22] proposes to use the simple relation

$$F_T = \mathbb{E}[S_T]\,. \tag{1.3}$$

While admitting that this relation is not exact, Stoft consists other effects as " too subtle and too unpredictable to be of interest." Others have made the effort to extend relation (1.3), which leads to

$$F_T = \mathbb{E}[S_T] + Risk\,premium(T). \tag{1.4}$$

The size (and sign) of the risk premium can be explained by the hedging pressure on producers of consumers: a positive (negative) risk premium is read as insurance premium paid by consumers (producers) to avoid price risk. Based on real data [11] shows that for some electricity markets the risk premium is positive if T is small, particularly if it corresponds to a winter or summer month, and may be negative if T is large, i.e., several years. Similar results are discussed in [12].

Equation (1.4) is the starting point for introducing risk neutral probabilities[19] Q (or equivalent martingale measures), loosely speaking by incorporating the risk premium into the probability distribution:

$$F_T = \mathbb{E}_Q[S_T]$$

Note that in the context of Eq. (1.2), choosing Q corresponds to specifying the convenience yield [2].

Other models for the spot price and/or the forward price structure—in fact the whole arsenals of econometrics and finance—have been used as well. Because of long-term equilibria of demand and supply of energy, models with mean reversion are usually preferred. See [9] for a broad overview and [2] for a rigorous modeling approach.

Summarizing, we can state that short- and long-term prices are almost entirely disconnected as soon as storability is not granted. In particular, information about future events such as planned outages of power plants or a change in the market structure affect only the prices of futures with suitable delivery period (cf. [17] for an empirical study of the effect of information on risk premia for electricity futures).

[19] Not necessarily unique; see discussion at the end of Sect. 1.3.3.

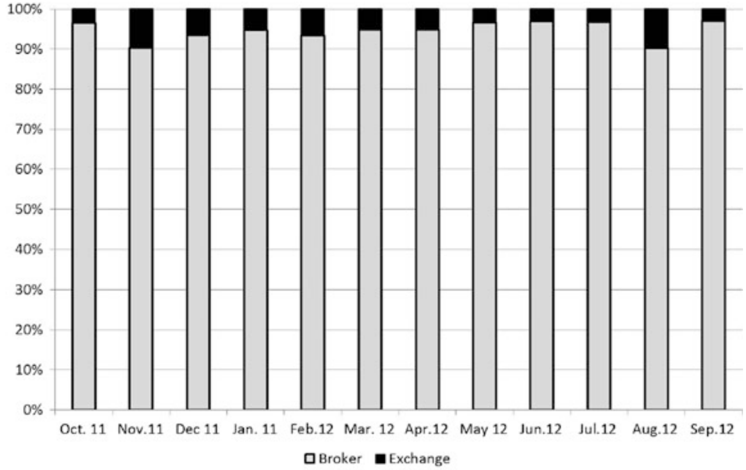

Fig. 1.9 Relative volumes traded at the German virtual natural gas hub NCG (data source: http://www.net-connect-germany.de)

1.3.3 Bilateral Trading in Energy Markets

As an alternative to trading at an exchange (mediated), there is the possibility to trade directly (bilaterally) with counterparties, the latter being called OTC (over-the-counter) trading. Compared to mediated markets bilateral markets are much more flexible with respect to the exact formulation of contracts. This is probably the reason why the major portion of energy trading still occurs bilaterally, an extreme example being the German NCG market for natural gas (see Fig. 1.9). However, writing those contracts is more involved. The main complexity arises from the tailored contractual trading agreements, which have to be negotiated. Usually bilateral trading occurs between parties who have already established contractual frameworks for trading, which are extended by standardized annexes[20] for specific trades.

In general, bilateral trades can be organized in two ways: by broker platforms (such as ICE or Spectron) that "match" the bids of participants or by direct communication between companies. As a result, counterparty risk exists but depends on the specific contractual details.

Bilateral trading occurs—at least theoretically—at individual prices, which are not published and are not necessarily connected to any other market prices. However, the data published by broker platforms show a close connection between OTC prices and exchange prices.

[20] For details see European Federation of Energy Traders, http://www.efet.org/ or International Swaps and Derivatives Association, http://www2.isda.org/.

Table 1.1 Organization forms of energy trading (see [8])

	Bilateral with broker	**Exchange**	**Bilateral without broker**
Contracts	Agreement between companies	Agreement with exchange	Agreement between companies
Trading method	Through broker	Electronic platform	Personal contact
Counterparty	Other company	Exchange	Other company
Transaction costs	Medium	High	Low
Transparency	Good, publications on end of day prices	High, information given by exchange	None
Anonymity	Identity revealed after deal	Anonymous	Identity revealed before deal
Main usage	All products	Most liquid products	Illiquid products / large volumes
Type of agreement	Framework contract	Agreement with exchange	Bilateral contract

1.3.3.1 A Survey of Bilateral Contracts

The flexibility of bilateral contracts allows potentially arbitrary conditions. However, some contract specifications proved to be especially suitable to mitigate risks in the energy industry, leading to some level of standardization even for OTC products (Table 1.1).

Probably the most common OTC products are *forward contracts* which are in fact identical to futures contracts but are traded bilaterally. The difference to futures contracts of equivalent delivery period results from the absence of margining and the presence of counterparty risk. For deterministic interest rates and absence of counterparty risk, forward and futures prices with the same maturity are equal ([11], p. 44). Consequently, futures and forwards are often used synonymously in literature. Note however the different behavior of forwards and futures in hedging.

As in financial markets, *European call* and *put options* are traded OTC, mostly on futures. European options are also traded at some exchanges, such as NYMEX, EEX, and Nordpool.

As a particularity of energy markets, *swing options* (also often called ToP contracts for natural gas) are used by market participants to hedge price risks and volume risks. Swing options have a long history as hedging instruments against those risks. At every day t of the runtime $[0,T]$ of the swing option, the holder is entitled to obtain an amount y_t of energy for a strike price K, which has been specified in advance. Usually, constraints are put on the consumption of the holder q_t, such as

$$\begin{aligned} \underline{e}_t \leq & \quad y_t & \leq \bar{e}_t \\ \underline{E} \leq & \sum_{t=0}^{T} y_t & \leq \bar{E}, \end{aligned}$$

bounding the single-period consumption by $\underline{e}_t$ and $\bar{e}_t$ and cumulative consumption by $\underline{E}$ and $\bar{E}$.
The strike price K can be dependent on price indices (such as oil prices for natural gas delivery contracts) but usually is independent of the current spot price of the underlying good.
Note that as a consequence of the constraints on cumulative consumption, the exercise strategy of a holder at time t depends on the whole history $y_0, \ldots, y_{t-1}$ of previous decisions since they determine the remaining quantity to be taken from the contract in the future. This makes the valuation of swing options much more complicated than the valuation of European options.

Finally, in the context of commodity markets, a *spread* refers to the difference between the prices of two products. The difference can be expressed either in terms of physical, temporal, or spatial properties. One example is the so-called *spark spread*, denoting the difference between the price of electricity and the price of the quantity of fuel required for generation. The spark spread or options on it can be used to hedge fossil-fueled power plants.

For further details on energy derivatives we refer to [4, 6, 9, 11].

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