9 Markets for Gaseous Fuels

This chapter discusses markets for natural gas, biogas, and hydrogen. While the markets for biogas and hydrogen are still in their infancy, natural gas ranks third globally among primary energy sources (after crude oil and hard coal). One of its advantages are technologies with high fuel efficiencies which release relatively little carbon dioxide (CO_2). Another advantage is the fact that existing infrastructure can be used for distributing gas from new, unconventional reserves. On the other hand, its transportation calls for a capital-intensive and geographically inflexible network of pipelines which cannot be used for other purposes and is therefore factor-specific. This raises several questions concerning the properties of natural gas markets:

– Are pipeline investments economically viable without long-term contracts?
– Can market liquidity for gas be achieved without abolishing long-term contracts?
– How can supply be secured in the absence of long-term contracts?
– Is vertical integration along the value chain economically beneficial or not?
– Can liquid natural gas (LNG) play the role of a game changer, making consuming countries less dependent on suppliers with monopoly power and political clout?

In many regions of the world, the highly seasonal demand for space heating determines the sales of natural gas. As gas customers usually lack storage capacities, deliveries by suppliers must track demand closely. This raises further questions that will be discussed in this chapter:

– How can volatile demand be met?
– What role could gas storage capacities play?
– Regarding the potential for substitution between natural gas and heating oil, what are the implications for retail gas pricing?

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The variables used in this chapter are:

a	Maximum willingness to pay
c	Average cost
Cap	Capacity
c_{prod}	Unit cost of extraction
$c_{transit}$	Unit cost of transit
d	Pipeline diameter
FLD	Full load days per year
FLH	Full load hours per year
ic	Capital user cost
K	Capital stock
LNG	Liquefied natural gas
l	Length of pipeline between two compressor stations
P	Pressure
Π	Profit of the importer (Π_{imp}) and the producer (Π_{prod})
p_{gas}	Wholesale price (based on the upper heating value)
p_{imp}	Average import price at the border
p_{hel}	Price of heating oil extra light (based on the lower heating value)
p_{retail}	Retail price paid by end users
Q	Quantity (in energy units)
$Temp$	Temperature
tr	Transit fee

9.1 Gaseous Fuels and Gas Infrastructures

Gaseous energy sources consist mostly of oxidizable substances, in particular methane (CH_4) and hydrogen (H_2). The energy content of a cubic meter depends not only on the chemical composition of the gas but also on pressure and temperature. This follows from the formula for an ideal gas,

$$\frac{P\,V}{\vartheta} = \text{constant} \tag{2.7}$$

with P symbolizing pressure, V volume, and ϑ temperature measured in degrees Kelvin (see Sect. 2.2.2).

For the purpose of standardization, the lower and upper heating values of a normal cubic meter Nm^3 of gases are measured at a pressure of 1.013 bar and a temperature of 0 °C, alternatively 15 °C. Whatever its chemical composition, 1 Nm^3 of gas always contains 44,614 gas molecules. International gas statistics use a variety of units. Therefore the conversion factors shown in Table 9.1 can be helpful. They are based on natural gas with a lower heating value of 10.4 kWh/Nm^3.

Table 9.1 Conversion factors for natural gas (at upper heating value H_s)

	Nm^3 natural gas	scf[a] of natural gas	kg LNG	MJ	mn BTU	Therm	kWh
Nm^3 natural gas	1	35.3	0.73	37.5	0.035	0.355	10.4
scf[a] natural gas	0.0283	1	0.0207	1.06	0.001	0.01	0.294
kg LNG	1.37	48.36	1	51.3	0.049	0.486	14.2
MJ	0.027	0.94	0.019	1	0.001	0.0095	0.2778
mn BTU	28.2	996	20.6	1055	1	10	293
Therm	2.82	99.6	2.06	105.5	0.1	1	29.3
kWh	0.096	3.40	0.07	3.6	0.0034	0.0341	1

[a]*scf* Standard cubic feet, measured at a pressure of 1.013 bar and a temperature of 60 F; one scf is equal to 0.0283 Nm^3 (normal cubic meter)

9.1.1 Properties of Gaseous Fuels

Table 9.2 presents an overview of the most important chemical components of gaseous energy sources, including inert gases devoid of a thermal contribution, such as oxygen and nitrogen.[1] Evidently, types of natural gas differ widely both in terms of density and heating values. Those containing a great deal of propane and butane are particularly valuable *ceteris paribus* because these components combine high density and high heating values, which serve to keep the cost of transportation, distribution, and storage low.

The following commercial products can be distinguished.

– Natural gas: This type of gas has a high share of low-density methane. In Northwestern Europe, one distinguishes between low-energy natural gas (L gas, with an upper heating value between 8.4 and 11.6 kWh/m^3, or 30.2 and 41.8 MJ/m^3, respectively) and high-energy natural gas (H gas, with an upper heating value between 10.2 and 13.1 kWh/m^3, or 36.7 and 47.2 MJ/m^3, respectively). Some types contain amounts of hydrogen sulfide (so-called sour gas) which may cause damage to the infrastructure. Since gas is invisible and odorless by nature, it is mixed with tetrahydrothiophene before distribution for detecting leakages, giving it an unpleasant odor.
– Liquid gas (also known as refinery gas): This type consists mainly of propane and butane, which are byproducts of oil refinery processes (see Sect. 8.1.5). Contrary to other components, propane and butane are heavier than air, which is an advantage for some uses. While gaseous at normal temperature and pressure, they can be liquefied using moderate pressure and sold in pressure bottles.

[1]The combustion properties of gases are reflected by their Wobbe number. Gases with the same Wobbe numbers are considered substitutable. Low-energy (L) gas has a Wobbe number of 12.4, high-energy (H) gas, of 15.0.

Table 9.2 Properties of gaseous fuels

		Density (kg/m^3)[a]	Upper heating value H_s (MJ/m^3)	Lower heating value H_i (MJ/m^3)
Methane	CH_4	0.7175	39.819	35.883
Ethane	C_2H_6	1.3550	70.293	64.345
Propane	C_3H_8	2.0110	101.242	93.215
Butane	C_4H_{10}	2.7080	134.061	123.810
Hydrogen	H_2	0.08988	12.745	10.783
Carbon monoxide	CO	1.25050	12.633	12.633
Nitrogen	N_2	1.2504		
Oxygen	O_2	1.4290		
Carbon dioxide	CO_2	1.9770		
Air		1.2930		
Natural gas H		0.79	~41	~37
Natural gas L		0.83	~35	~32
Biogas		1.12	~27	~24

[a]At a temperature of 0 °C and a pressure of 1.013 bar

– Town gas (also called cooking gas) is a byproduct of coke plants. It consists mostly of hydrogen (H_2) and carbon monoxide (CO). This gas is lighter than air and toxic due to its CO content.

Conditioning plants are used to modify gases by adding inert or liquid gas in order to attain certain quality standards. This can also be necessary for ensuring interoperability of different pipeline systems, a precondition for physical gas trade.

Compared to other hydrocarbons, storage of gaseous energy fuels is costly due to their comparatively low energy density (see Table 9.3). Even at a pressure of 200 bar, the volumetric energy content of natural gas is only 156 kg/m^3, i.e. some 20% of gasoline (see compressed natural gas CNG). Higher storage densities are achieved if the natural gas is cooled down to become liquid (LNG). However, hydrogen is even worse: At a pressure of 700 bar, a hydrogen tank contains 56 kg/m^3, i.e. only 7% of the energy contained by a gasoline tank of comparable size.

9.1.2 Reserves and Extraction of Natural Gas

According to Table 9.4, the static range of conventional natural gas reserves amounts to 67 (=185.7/2.763) years worldwide. While this value exceeds that of crude oil, this is an advantage that will be offset by expected growth of gas demand. Like conventional crude oil, conventional gas reserves are concentrated in the 'energy ellipse' extending from Siberia to the Middle East.

Table 9.3 Storage properties of hydrocarbons

	Temperature (°C)	Pressure (bar)	Density (kg/m^3)	Lower heating value (kWh/l)
Gasoline	20	1	750	9.0
Diesel	20	1	840	9.9
Methanol	20	1	794	4.4
Ethanol	20	1	793	5.9
Natural gas	20	1	0.80	–
Compressed natural gas (CNG)	20	200	156	1.9
Liquid natural gas (LNG)	−162	1	473	6.2
Hydrogen (H_2)	20	1	0.91	0.003
Compressed hydrogen (CH_2)	20	200	16	0.55
Compressed hydrogen (CH_2)	20	700	56	1.85
Liquid hydrogen (LH_2)	−252	1	71	2.4

Table 9.4 Reserves and extraction of conventional natural gas

	Natural gas reserves 2013		Natural gas extraction 2013	
	(tn m^3)	Share (%)	(bn m^3)	Share (%)
Iran	33.8	18.2	167	4.9
Russia	31.3	16.8	605	17.9
Qatar	24.7	13.3	158	4.7
Energy ellipse	132.5	71.4	1325	39.3
United States	9.3	5.0	688	20.6
Norway	2.0	1.1	109	3.2
The Netherlands	0.9	0.5	69	2.0
Great Britain	0.2	0.1	37	1.1
World	185.7	100.0	2763	100.0

Data source: BP (2014)

In addition to conventional reserves, several unconventional sources of natural gas exist, among them shale gas, coal bed methane, and methane hydrates. Currently, the most relevant unconventional gas resource is shale gas. Shale is a fine-grained sedimentary rock that can readily be split into thin pieces along its laminations. Methane trapped in shale formations is recovered using advanced extraction technologies known as fracking. According to 2014 estimates of the German Federal Office of Geo Science and Resources (BGR 2014), global shale gas resources amount to 210 tn m^3 of methane. Coal bed methane is extracted by drilling wells into the coal seam and pumping water from the well. The concomitant decrease in pressure allows methane to escape from the coal and to flow up the well to the surface. Finally, methane hydrates are a solid energy source found in ocean depths of more than 500 m, assumed to originate from the decomposition of microorganisms. At atmospheric pressure, methane hydrates melt, releasing up to 160 m^3 methane gas per m^3 hydrate.

Table 9.4 also reports rates of extraction of usable natural gas[2] according to geographical region. At present, the United States account for more than 20% of global gas extraction, making it the largest gas producer worldwide, whereas its estimated share of conventional reserves amounts to a mere 5%. Conversely, the countries of the 'energy ellipse' have a market share of less than 40% but control more than 71% of reserves. However, shares in extraction have changed substantially since 2000. From that year, the U.S. share grew by 40% while that of the European Union fell by 37%, a consequence of its resistance to fracking. Since natural gas might be associated with crude oil deposits and be exploited together with them, some oil majors are also trading on gas markets. However, due to missing pipeline infrastructures, not all of this so-called associated gas can be used commercially at present.

Similar to crude oil extraction, state concessions are needed in most countries (except in the United States) to exploit gas fields. In market-oriented economies, these concessions are allocated mainly to private companies through auctions. In most 'energy ellipse' countries, companies cannot purchase concessions unless majority-controlled by the government of the state where the deposit is located. This is an obstacle for companies who seek to vertically integrate the upstream parts of the value chain (so-called backward integration; see Sect. 9.2).

9.1.3 Biogas and Renewable Natural Gas

Biogas derives from the fermentation of biomass, whose output is a vapor-saturated mix of methane (40–75%) and carbon dioxide (25–50%) with some ammonia and hydrogen sulfide. Due to its high CO_2 share, it has a lower energy content than natural gas (see Table 9.2). Biogas escapes continually and unchecked from landfills, sewage plants, and liquid manure. If captured and used in combustion, it serves to mitigate the greenhouse gas problem since unburned methane has a greenhouse effect which exceeds that of CO_2 by a factor of about 21.

However, the typical sources of biogas are limited. Thus, renewable raw materials from agriculture, in particular maize, are used in combination with liquid manure and food waste as feedstock.[3] One hectare of farmland can provide 4.5 tons of maize per year. With an output of 180 m^3 gas per ton of maize and a methane content of 55%, the biogas return per hectare (ha) is about 450 m^3. McKendry (2002) estimates the energy harvest at 2 GJ, or a mere 554 kWh per ha and year, respectively. Evidently, producing energy from agricultural products claims a great deal of agricultural land that could be used for food production. In regions with

[2]The data exclude natural gas which is flared or reinjected into gas deposits.

[3]Nearly all biomass can be fermented, with the exception of lignin.

excess supply of food like the European Union, this is no cause for concern at present. Indeed, the European Union is about to cut back its set-aside program in agriculture, which creates scope for subsidizing this type of fuel (currently at the rate of 45 EUR per ha and year). However, producing biogas from renewable biomass is quite costly. While it can be obtained from landfills, sewage plants, and liquid manure at a cost of 0.03–0.05 EUR/kWh, it costs between 0.06 and 0.08 EUR/kWh if obtained from maize (at a price of 30 EUR/tons). The latter range is beyond that of natural gas, which is between 0.03 and 0.05 EUR/kWh.

This comparison still neglects the fact that biogas production units are located in rural areas close to maize fields since transporting maize more than 20 km is usually uneconomic. This means that input quantities are limited, resulting in plant output capacities below 250 m^3/h, too small for economies of scale. In the absence of a gas transport infrastructure, biogas must be burned on the production site, notably as a fuel for combined heat and power stations. Yet the electrical efficiency of these stations is usually below 40%. Moreover, the energy needed for fertilizing and harvesting the maize fields has to be taken into account.

Alternatively, biogas may be upgraded to attain the chemical and physical properties of natural gas, enabling it to be fed into local distribution grids (at a pressure of 5–8 bar) or into long-distance gas pipelines. This makes biogas a (mostly) renewable substitute of natural gas which can be sold on all types of gas markets in principle. To distinguish it from natural gas, it is labeled ‘bio methane’ or ‘bio natural gas’, respectively. Of course, quality upgrading, compression, and gas grid access result in additional costs. Currently bio methane exceeds the European natural gas wholesale price by a factor of three to four. A discrepancy of this amount is unlikely to vanish anytime soon because there is no prospect of a higher price of natural gas or a lower unit cost of biogas, respectively.

Yet for farmers, biogas or bio methane constitutes an attractive option if amply subsidized. One the one hand, they can generate additional revenue from selling the fuel or from renting the farm land to biogas producers. On the other hand, they can count on higher sales prices for food, which becomes scarcer. In fact, farmers have the option of offering their production on both the market for food and energy markets, wherever the profit margin is higher. To the extent that the cost of production is similar, they will supply the market that offers the higher price. The economic conclusion is that with an important biogas production, food prices will follow the price of natural gas or the biogas price guaranteed by the government through its subsidy, respectively. This causes the two prices to become cointegrated (see Sect. 8.3.2).

9.1.4 Hydrogen

In terms of energy systems, hydrogen (H_2) is a secondary fuel that does not exist on the globe as an accessible energy source, despite the fact that it is assumed to be the most common element in the universe. This is the consequence of its low density (see Table 9.2) and extreme dissipation. Most of the hydrogen on Earth exists as a chemically fixed component of molecules, for example water (H_2O) or methane (CH_4).

Hydrogen can be produced from practically any primary energy source. At present, hydrogen is mostly produced using natural gas through a two-step process with an overall fuel efficiency between 65 and 75%,

$$\text{Steam reforming } CH_4 + H_2O \rightarrow CO + 3\,H_2 \text{ (endothermic process)}$$
$$\text{Shift reaction } CO + H_2O \rightarrow CO_2 + H_2 \text{ (exothermic process)}$$

Another relevant technology is the electrolytic separation of water (H_2O) to become hydrogen (H_2) and oxygen (O). This process requires electricity as an energy input and attains energy efficiencies between 70 and 80%. However, since electricity is much more expensive than natural gas, electrolysis is usually too costly for applications at market scale. To the extent that it can accommodate the intermittent nature of wind and photovoltaic energy, it does offer a way to render renewable electricity storable. Thus, so-called 'renewable hydrogen' is widely seen as a key element of future carbon-free energy systems. It could be used in transportation (through fuel cells) or to produce electricity (through fuel cells or gas turbines), on demand. Yet these options will only become economically viable if inexpensive renewable electricity is available. Failing this, engagement by the private sector continues to be limited, with investment projects predominantly financed by government research and development programs.

At present, the global hydrogen production amounts to 500 to 600 bn m^3 or 120 mn tons per year, respectively. It is used in the following ways,

– Ammoniac synthesis (60–70% share);
– Refineries (hydro cracking, 15–25% share);
– Methanol synthesis (8% share).

Hydrogen is mostly used by chemical companies, who also produce it. Therefore, there is no liquid market providing reliable price information. Wholesale prices of around 10 EUR per kg of compressed hydrogen (at 350 bar), are reported in the literature, which represents an energy content of about 120 MJ or 33 kWh, respectively (see Table 9.2).

9.2 Natural Gas Economy

Historically, the natural gas industry is older than the oil industry because the first natural gas deposit was used as early as 1825 in the New York City area. However, until the 1950s exploration efforts were limited since natural gas was found alongside crude oil (so-called associated natural gas). Another source was town gas, a byproduct of coke plants which triggered investment in urban gas grids. These local grids created the opportunity for the building of long-distance pipelines connecting them to large-scale natural gas deposits.

In Europe, this process began later than in the United States, around 1970. The starting shot was the development of the huge Groningen gas field in the Netherlands, located quite closely to already existent local gas markets. Within a short period of time, additional high-pressure pipeline connections to gas fields in Western Siberia (Russia), the North Sea (Norway and the United Kingdom), and North Africa (Algeria, Tunisia) were built, along with LNG terminals on the shores of the Mediterranean Sea and the Atlantic Ocean. As a result, within 30 years quite a comprehensive infrastructure was established as the physical backbone of European gas markets.

9.2.1 Transport by Pipeline

High-pressure pipelines are used to transport natural gas over long distances. At a pressure of up to 80 bar, and with a diameter of 1200 mm, they cover up to 6000 km. Investment outlay varies between 0.5 and 1.5 mn EUR/km, depending on local conditions.

A single 80 bar pipeline is able to transport up to 3 mn m^3/h (or 26 bn m^3/a, respectively) of natural gas at a speed of up to 40 km/h. As an approximation, the throughput rate Q depends on pressures P_1 at the beginning of a pipeline section and P_2 at the end of it. With length of section l and pipeline diameter d, throughput is proportional to

$$Q \sim \sqrt{\frac{P_1^2 - P_2^2}{l/d^2}}. \tag{9.1}$$

Therefore, given a required pressure P_2 at the point of delivery, throughput is the greater the higher initial pressure P_1, the shorter the distance to be covered l, and the bigger the diameter of the pipeline d. Compressor stations designed to compensate pressure losses (0.1 bar per 10 km) and to keep the gas flowing are placed at intervals ranging between 80 and 400 km.[4] They contain turbines that usually take their energy from the pipeline, consuming about 10% of the gas over a distance of 5000 km. This requirement declines with the diameter and the quality of the tube.

At least during the early stages of gas infrastructure development, the transport capacity of a high-pressure pipeline tends to exceed both the market potential and the financial capacity of a single gas company. However, pipelines exhibit economies of scale (see Knieps 2002): When capacity is doubled, cost of construction increases by two-third only.

The solution could be for several companies to build and operate a pipeline in co-ownership despite the fact that they are competitors in the markets where the pipeline originates and/or where it ends (so-called pipe-in-pipe competition). Yet

[4]The pressure in a pipeline declines primarily due to frictional losses. In addition, it needs to be managed if elevation changes.

companies may sooner or later extend their cooperation beyond the operation of the pipeline to form a cartel fixing prices in the purchasing and/or sales markets. This risk can be avoided through ownership unbundling, requiring the owners of the pipeline to be independent of other companies along the value chain. However, experience shows that companies that are prevented from freely using an asset costing several bn of EUR are unwilling to make the investment.

Once a long-distance pipeline has been built, the capital expenditure is mostly sunk, i.e. it is lost unless the pipeline can be put to profitable use. A pipeline thus constitutes a factor-specific asset in that it can only be used for long-distance gas transport between the beginning and the end of the line and nothing else. Therefore, its owner must make sure there are customers at both ends who are willing to pay for transporting the gas.

In general terms, investors are in a strong strategic position *vis-à-vis* customers and governments before the start of the project but in a weak one after its completion because they cannot easily defeat opportunistic behavior on the part of their contractual partners. This situation is known in the economic literature as the 'holdup problem'. It can be solved by vertical integration, which however is in conflict with the requirement of unbundling cited above.

Absent vertical integration, investment and pricing behavior of two market participants with monopoly power in the pertinent market along the gas value chain needs to be analyzed. The usual approach is to formulate a two-stage game theoretical model. In its first stage, a monopolistic producer of natural gas decides about the optimal capital stock K reflecting the capacity of a planned pipeline. In the second stage, the producer and a gas importer, who has a monopoly over distribution to final customers, have to agree on the import price $p_{imp}(K)$ which is the producer's sales price. The outcome of this negotiation depends on pipeline capacity, which is also denoted by K for simplicity.

Since the producer rationally anticipates the import price when deciding about investment resulting in capital stock K, the model is solved in reverse order (so-called backward induction). Therefore, the outcome of the negotiation concerning the import price is determined first, assuming that both players seek to maximize profit independently of each other, resulting in a so-called Nash equilibrium (an equilibrium pertaining to a non-cooperative game).

On the part of the importer, it has to take into account that a higher retail price p_{retail} reduces the volume Q of gas sales. For simplicity, a linear demand function is posited,

$$Q = a - p_{retail}. \tag{9.2}$$

Here, a denotes marginal willingness to pay for the first unit of natural gas, which is the maximum price consumers are willing to pay (to see this, set $Q = 0$ and solve for p_{retail}).

Neglecting other costs the importer may incur (for distribution in particular), its profit Π_{imp} is related to the sales price p_{retail} and the import price p_{imp} paid as follows,

$$\Pi_{imp}(p_{retail}) = \left(p_{retail} - p_{imp}\right) \cdot Q = \left(p_{retail} - p_{imp}\right) \cdot (a - p_{retail}). \tag{9.3}$$

Since p_{retail} is the variable controlled by the importer, the profit function (9.3) needs to be differentiated with respect to p_{retail} for obtaining the first-order optimality condition. Also, given the optimal sales price, the optimal quantity sold and imported $Q = Q_{imp}$ is determined as well. Setting the derivative of (9.3) with respect to p_{retail} equal to zero, one has (* indicating optimal value for the importer),

$$p^*_{retail} = \frac{a + p_{imp}}{2}, \quad Q^*_{imp}\left(p_{imp}\right) = \frac{a - p_{imp}}{2}. \tag{9.4}$$

This equation points to an interesting fact. The importing company cannot pass on an eventual increase in the import price fully to its customers. In the case of a linear demand function, the degree of pass-through is 50%. The reason is that a higher degree of pass-through would cause sales to fall to an extent that results in a reduced profit. From Eq. (9.4), one can calculate the importer's maximum profit, which depends on the import price to be paid,

$$\Pi^*_{imp} = \left(\frac{a + p_{imp}}{2} - p_{imp}\right) \cdot Q^*_{imp} = \left(\frac{a - p_{imp}}{2}\right)^2. \tag{9.5}$$

Turning to the producer of the natural gas, assume that it seeks to maximize its profit, too, knowing the importer's demand function and hence optimal $Q^*{}_{imp}$. With $c(K)$ symbolizing unit cost of extracting and transporting gas (which depends on capacity) and in view of Eq. (9.4), the profit function is given by

$$\Pi_{prod} = \left(p_{imp} - c(K)\right) \cdot Q^*_{imp} = \left(p_{imp} - c(K)\right) \cdot \frac{a - p_{imp}}{2}. \tag{9.6}$$

Since the quantity ${}_{delivered}Q^*{}_{imp}$ is controlled by the importer, the decision variable left to the producer is the sales price p_{imp}. If $c(K)$ is independent of the produced quantity $Q = Q^*{}_{imp}$ and thus from price p_{imp}, the first-order optimality condition of the profit function calls for setting the derivative of (9.6) with respect to p_{imp} to zero. Doing this yields the optimal import price $p^*{}_{imp}$ (* indicating now optimal value for the producer), and using this in Eq. (9.6), the optimal export quantity as well,

$$p^*_{imp} = \frac{a + c(K)}{2} > c(K), \quad Q^* = \frac{a - p^*_{imp}}{2} = \frac{a - c(K)}{4}. \tag{9.7}$$

The '>' sign is ${}_{justified}$ by the fact that gas production and gas trade is economically viable only if maximal willingness to pay a exceeds unit cost $c(K)$ such that $a \geq c(K)$. Neglecting the costs of capital, transport and distribution, maximum profit of producer and importer can be derived by inserting (9.7) into Eqs. (9.6) and (9.5), respectively,

$$\Pi^*_{prod} = \frac{1}{2} \cdot \left(\frac{a - c(K)}{2} \right)^2, \quad \Pi^*_{imp} = \frac{1}{4} \cdot \left(\frac{a - p_{imp}}{2} \right)^2. \tag{9.8}$$

Equations (9.4), (9.7), and (9.8) characterize a Nash equilibrium, defined as a situation where neither of the parties has an incentive to deviate from it (after all, both are optimizing on the premise that the other is optimizing as well, see Tirole 1988, Chap. 11).

An interesting conclusion can be drawn if the pipeline operator and the gas distributor are assumed to cooperate. This means that they maximize their joint profit, given by

$$\Pi_{coop} = (p_{retail} - c(K)) \cdot (a - p_{retail}). \tag{9.9}$$

In this case, the optimal retail price p_{retail} would be

$$p^{**}_{retail} = \frac{a + c(K)}{2} < \frac{a + p^*_{imp}(K)}{2} = p^*_{retail} \tag{9.10}$$

in view of Eq. (9.4) and the inequality in (9.7). Therefore, the retail price given cooperation is below the one in the non-cooperative situation. This means that a welfare loss results if two monopolistic companies along a value chain do not cooperate. The reason is so-called double marginalization: The monopolistic producer opts for a quantity of output where marginal revenue equals marginal cost rather than where sales price equals marginal cost. This leads to a sales price above marginal cost [see Eqs. (1.3) and (1.4) in Sect. 1.2.2]. However, this sales price constitutes the marginal cost of the monopolistic importer, who again imposes equality of marginal revenue and marginal cost. This accumulation of surcharges over marginal cost is called double marginalization. It can be avoided by cooperation (or vertical integration, see below) because now the two parties share an interest in keeping marginal cost as low as possible in order to maximize their joint profit. Therefore, retail price p_{retail} and hence market volume Q are higher given cooperation than given non-cooperation, benefitting consumers.

At the same time, joint profit given cooperation exceeds the sum of profits of two monopolists who fail to cooperate. Recalling Eq. (9.9) and using Eq. (9.10), one obtains

$$\Pi^*_{coop} = \left(\frac{a - c(K)}{2} \right)^2. \tag{9.11}$$

From Eqs. (9.8) and (9.7), one has by way of contrast

$$\Pi^*_{imp} + \Pi^*_{prod} = \frac{3}{4} \left(\frac{a - c(K)}{2} \right)^2. \tag{9.12}$$

Thus, the amazing conclusion is that both customers and companies benefit from cooperation since avoiding double marginalization is to the advantage of both. Note that the ultimate form of cooperation is vertical integration, i.e. a merger of the two companies, who become one. From the welfare point of view, this would be superior to a non-cooperative industry structure, *ceteris paribus*. However, one downside is so-called foreclosure, meaning that a newcomer in the distribution market (say) cannot compete against the incumbent monopolist because there is no natural gas available outside the vertically integrated value chain.

Now that the second stage has a solution, the first stage can be solved. Here, the pipeline operator decides the optimal capital stock K in view of the optimal quantities determined in the second stage of the game. The Nash equilibrium implies that the two companies agree on the optimal import price p^*_{imp} according to Eq. (9.7) once the pipeline is finished. Assume that the unit cost $c(K)$ of natural gas production and transportation (in the exporting country) declines with the amount invested, but at a decreasing rate,[5]

$$\frac{\partial c}{\partial K} < 0, \qquad \frac{\partial^2 c}{\partial K^2} \geq 0. \tag{9.13}$$

Also, let ic denote capital user cost per unit, which itself may be a function of K [see Sect. 3.1, Eq. (3.7)]. Then, by Eq. (9.8) the owner of the pipeline determines optimal capital stock K by solving the following problem,

$$\max_{K \geq 0} \left(\frac{1}{2} \left(\frac{a - c(K)}{2} \right)^2 - K \cdot ic(K) \right). \tag{9.14}$$

However, the social optimum would call for the maximization of consumer surplus, given by the triangular area below the demand function (9.2) net of marginal cost $c(K)$. Also, fixed cost must be covered because otherwise the pipeline does not come into existence, resulting in the problem,

$$\max_{K \geq 0} \left(\left(\frac{a - c(K)}{2} \right)^2 - K \cdot ic(K) \right). \tag{9.15}$$

Obviously the two optimization problems have different solutions: Under the non-cooperative Nash equilibrium, the pipeline operator earns only 50% of the contribution margin that would be socially optimal. This weakened incentive translates into an investment in capacity that is too small. One could say that in the light of the two-stage theoretical model, failure to cooperate reduces the security of gas supply in the importing country (which among other things depends on the capacity of the transportation network).

[5]While implying that returns to scale are exhausted sooner or later, this assumption guarantees the existence of a single equilibrium.

Note that there are other approaches than vertical integration to solve the holdup problem. One alternative is for the gas producer and the distributor to establish a joint subsidiary that is responsible for investment in and operation of the pipeline. This subsidiary could even be open to competitors on both sides, although presumably on terms defined by its owners. Therefore, foreclosure would be mitigated but not eliminated. Other options are long-term contracts struck between the two companies in which a price prior to the undertaking of the investment in the pipeline is fixed (see Sect. 9.3.1).

A variant of the holdup problem is linked with gas pipelines that transit a third country. Once built, they cannot be rerouted. This lack of flexibility gives governments of transit countries scope for opportunistically appropriating part of the exporter's profit. This problem can also be formulated in terms of non-cooperative game theory (see Hirschhausen et al. 2005). The model considers an exporting and a (government-owned) transit company, who are both monopolists in their respective markets. The exporting company maximizes the product of quantity Q times the contribution margin per unit,

$$\max_{Q \geq 0} \left(p_{imp} - tr(Q) - c_{prod}\right) \cdot Q \tag{9.16}$$

where the contribution margin is equal to the sales price at the border of the importing country p_{imp} net of transit fee tr and unit production cost c_{prod} (assumed constant). Setting the derivative with respect to Q to zero yields the following first-order optimality condition,

$$p^*_{imp} = c_{prod} + tr - Q \cdot \left(\frac{\partial p_{imp}}{\partial Q} - \frac{\partial tr}{\partial Q}\right). \tag{9.17}$$

The transit company solves an analogous optimization problem,

$$\max_{tr \geq 0} (tr - c_{transit}) \cdot Q, \tag{9.18}$$

with $c_{transit}$ denoting constant unit transit cost. If the exporting company has no alternative than pumping the gas through this particular pipeline, the transit company could raise its fee to $tr \leq p_{imp} - c_{prod}$, leaving just a minimum profit to the exporter [see Eq. (9.16)]. Conversely, $tr \geq c_{transit}$ constitutes a lower bound, in which case the exporting company would reap maximum profit. Realistically, the transit tariff lies between these two extremes,

$$c_{transit} \leq tr \leq p_{imp} - c_{prod}. \tag{9.19}$$

The final result depends on the relative bargaining power of the exporter compared to the transit company. Let the exporter's bargaining power be formalized by a function $Q(tr)$, with $\partial Q/\partial tr = \kappa < 0$. Then, the first-order optimality condition for the transit company is given by

$$Q + (tr - c_{transit}) \cdot \kappa = 0 \quad \text{or} \quad tr = c_{transit} - \frac{Q}{\kappa} > c_{transit} \tag{9.20}$$

where the bounds specified in (9.19) must be satisfied. Because of $\kappa < 0$, the optimal transit tariff increases with gas sales Q and declines with the bargaining power of the export company.

This model was complemented by Zweifel et al. (2009/10) in several ways. With the breakdown of the former Soviet Union in 1990, two transit countries, Ukraine and Belarus, became independent. The loss of control over the (now Ukrainian and Belarussian) pipelines caused the bargaining position of the Russian exporting monopolist Gazprom to be weakened. This means that cooperative game theory needs to be used for predicting whether Russia (who is part of all possible coalitions) teams up with Belarus, Ukraine, or both of them. Moreover, their relative bargaining power can be determined by calculating the so-called Shapley and Banshaf values (which reflect a player's contribution to the coalitions' total profit in slightly different ways). As could be expected, in 2004 Russia had the highest bargaining power, followed by Ukraine due to its relatively high transit capacity, and Belarus. With the opening of the North Transit pipeline (and even more so if the planned Yamal pipelines were to be built), the dominance of Russia is predicted to become even more marked in future, mainly to the detriment of Ukraine.

The conditional payoffs determined in the non-cooperative module lead to the prediction that the all-inclusive coalition will form because it generates maximum profit, while the cooperative module predicts that the lion's share of profit goes to Russia (who can use part of it to buy the participation of Belarus and Ukraine). However, all of these results are conditioned on an aggregate demand function characterizing Western Europe. With the advent of fracking and the possibility of liquefied natural gas being imported from the United States, this demand function may soon shift inward as far as Russian gas is concerned.

9.2.2 LNG Transport and Trade

An alternative to long-distance transport by pipeline is seaborne liquefied natural gas (LNG) trade. The LNG technology was developed for Japanese gas imports as this country cannot be supplied through pipelines still today. It has also been used for European gas imports from North Africa and the Middle East. The technology is complex and usually expensive compared to pipelines. A standard LNG chain has a capacity of 3.5 to 4.8 bn tons/a (4.8 · 6.6 bn m^3/a, respectively) and consists of the following elements (Cayrade 2004).

– Liquefaction plant in the export harbor: When cooled to ·163 °C, gas turns liquid, causing its volume to be reduced by a factor of 580. Investment outlay on a plant amounts to about 900 mn EUR. At 0.04 EUR per m^3 of natural gas, operating expenses need to be accounted for as well.

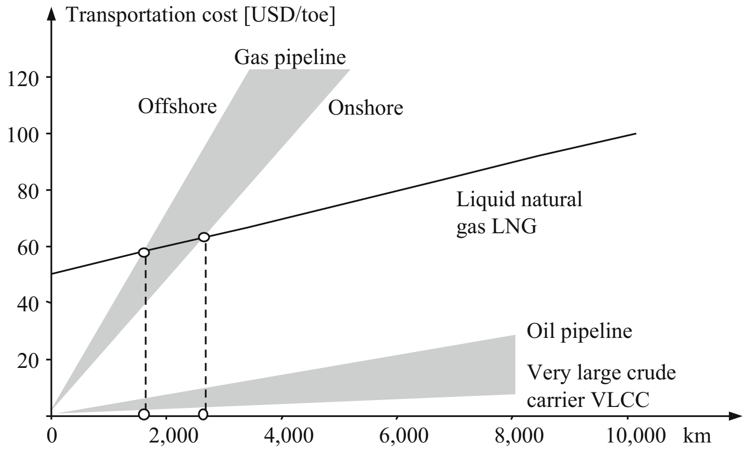

Fig. 9.1 Long-distance transportation costs of oil and gas. Source: Erdmann and Zweifel (2008, p. 233)

– Fleet of LNG vessels: Being special purpose, these vessels constitute factor-specific capital (see Sect. 9.1.2 for the consequences). LNG transport from Port Said in Egypt to Cartagena in Spain over a distance of 2700 km may serve as an example. It is performed by two vessels with a capacity of 135,000 tons each, requiring an investment of about 360 mn EUR. One trip takes 10.5 days, at a cost of about 0.014 EUR per m^3 of natural gas.
– Regasification plant including LNG storage: In Cartagena, three storage tanks with a capacity of 80,000 m^3 each are available. The investment outlay amounted to 320 mn EUR. The LNG is transformed into gas again at a cost of about 0.015 EUR per m^3 of natural gas.

An additional cost component of LNG derives from the fact that operation of the LNG chain requires about one-third of the energy contained in the gas that is delivered to the pipeline of the importing country. At a total unit cost of some 0.06 USD per m^3 of natural gas, LNG cannot compete with pipeline gas in many locations, depending on the length of the haul. According to Fig. 9.1, transporting natural gas through a pipeline is much more costly than transporting crude oil to begin with, especially when using a very large crude carrier. Moving gas from an offshore deposit in particular is so expensive that the LNG alternative becomes competitive beyond a distance of less than 2000 km; if the deposit is onshore, the critical distance increases to almost 3000 km.[6] However, this may change in future

[6]This comparison is flawed, however, as LNG vessels may have to travel longer distances around continents while pipelines can use the direct path. This difference does not obtain if deep oceans have to be crossed. Yet pipelines have not been competing against the LNG chain across deep oceans up to present.

because the unit cost of LNG is likely to fall thanks to improvement in the design of liquefaction and regasification plants.

In 2013, about 30% of natural gas was traded internationally. While this share has been increasing over many years, the share of international LNG trade has been growing even faster, from 27% in 2003 to more than 30% by 2013. The growing importance of LNG on global gas markets has several reasons:

– The LNG chain allows developing remote natural gas fields that cannot be connected by pipelines for geographical, geological, political, or economic reasons.
– Since gas fields close to consumers have the highest scarcity rents, they are developed prior to more remote gas fields (see Sect. 6.2.3).Yet when they are exhausted, more remote fields need to be developed for meeting demand, and according to Fig. 9.1 this improves the relative competitiveness of LNG.
– Compared to pipeline projects, the LNG chain is more flexible. While a pipeline is operational no sooner than the entire project is finished, capacities along the LNG chain can be used even if the chain is not yet complete. This serves to reduce the economic impact of project delays and operational disruptions compared to pipelines. This advantage becomes more important as the number of LNG installations is increasing globally, reflecting a so-called positive network externality.
– For both gas producers and consumers, LNG offers a chance for diversification, which mitigates the holdup problem associated with pipeline projects.

With international LNG trade, regional gas markets become more integrated. In its absence, gas prices on both sides of the Atlantic would develop quite independently from each other because there is no scope for arbitrage. While LNG export and import capacities cause natural gas prices to converge, convergence is not perfect due to the substantial cost of operating the LNG chain.

9.3 Gas Markets and Gas Price Formation

As in the case of the oil industry, wholesale gas markets are characterized by two types of companies:

– Gas producers such as state-owned Gazprom, Sonatrach, and Statoil as well as private companies such as BP, ChevronTexaco, ExxonMobil, Shell, and Total usually have supplies in excess of demand at the prevailing market price—they are long in gas.
– Gas importers and distribution companies such as E.ON, GdF, Wingas, ENI, and Tokyo Gas seek to meet a demand in excess of their own production at the prevailing market price—they are short in gas.

As long as the two types of companies are not vertically integrated, they need to trade gas in order to close their long and short positions, respectively. As shown below, there is a choice of design options for this wholesale trade.

9.3.1 Long-Term Take-or-Pay Contracts

Until recently, long-term take-or-pay contracts (ToP contracts) between producers and domestic importers of natural gas have dominated gas wholesale markets, particularly in Europe. These contracts used to have durations of 15 to 30 years. They make the importing company pay at least some 90% of the contracted gas even if its imports fall short of it because of reduced demand, e.g. due to a mild winter or an economic recession. The contracted price derives from a sliding-price formula that usually is based on the price of heating oil.[7] A typical long-term contract may use the so-called '6/3/3 rule', according to which the gas price depends on the six month average of the heating oil price, calculated with a lag of three months and applicable to deliveries over the following three months.

For a long time, the German Federal Office of Foreign Trade (*Bundesamt für Wirtschaft und Ausfuhrkontrolle* BAFA) has been publishing monthly gas border prices (solid line in Fig. 9.2). A simple ordinary least-squares (OLS) estimation explains the gas border price using a single independent variable, the monthly heating oil price along the Rhine river (in EUR/100 l; data source: German Federal Statistical Office),

$$p_t = \underset{(-14)}{-3.44} + \underset{(90)}{0.504 \cdot \sum_{k=3}^{9} \frac{p_{HEL,t-3-k}}{6}} \tag{9.21}$$

(t statistics in parentheses). The variable $p_{HEL,t\text{-}3\text{-}k}$ symbolizes the price of heating oil extra light, averaged over six months and lagged by three months, thus reflecting the popular sliding-price formula. For the 132 monthly observations from 2000 to 2010, this regression explains more than 98% of the variance of the gas border price (see the dotted line in Fig. 9.2).[8] However, an extrapolation of Eq. (9.21) beyond 2010 does not perform as well (see the light dotted line of Fig. 9.2). Simulated prices exceed actual ones by up to 10 EUR/MWh, indicating that the era of stable long-term ToP contracts has come to an end, at least in Continental Europe.

From an economic point of view, long-term contracts are an imperfect substitute of vertical integration; they are typically signed if vertical integration is prohibited.

[7]Some long-term contracts use other pricing factors, e.g., the wholesale prices of heavy oil or coal. Such arrangements are designed to keep gas competitive in power generation.

[8]As both time series are cointegrated of degree one, a cointegration equation should be estimated. The pertinent methodology is explained in Sect. 9.3.2: however, it does not affect estimation results in the present case.

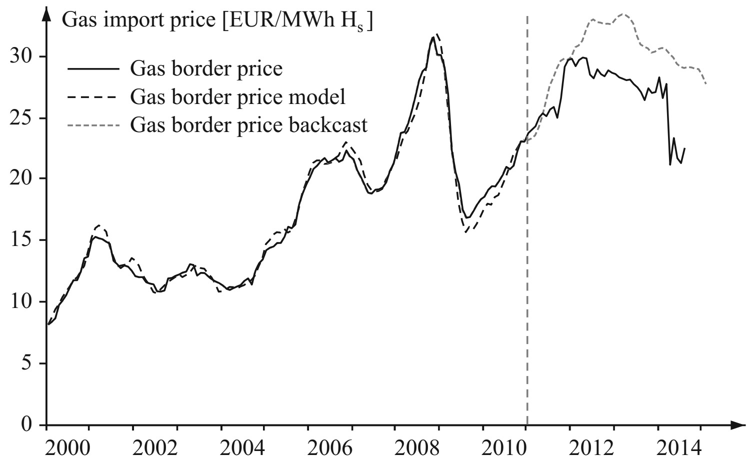

Fig. 9.2 German natural gas border prices (data source: BAFA (2014))

Note that they allocate risk in a particular way: The exporter bears the price risk, while the importer bears the quantity risk. Economic theory predicts that risk is allocated to the party who is better able to bear it. This gives rise to the question of why the exporter can manage the price risk better than the importer, while the importer can manage the volume risk better than the exporter.

– As to the importers, they usually make distributors accept a sliding-price formula as well. This is possible because gas distributors are mainly active in the market for space heating, where they compete with heating oil. A substantial markup on the price of heating oil would lead to a loss of sales.[9] In addition, many gas consumers are risk averse, causing them to value the assurance that the retail price of gas will always track that of heating oil, albeit with a lag according to Eq. (9.21) that may provoke public anger. Finally, gas importers can deal with the quantity risk by investing in gas storage facilities, which are necessary at any rate to balance seasonal fluctuations in demand.
– As to the gas exporters, they would run into problems if they had to bear both the price and the quantity risk because this would undermine the willingness of banks and financial institutions to provide the necessary loans for financing pipeline projects. Elimination of the quantity risk can be seen as contributing towards a minimum return on investment.

[9]Distributors charge a so-called gas netback price which contains a markup on their purchase price. This markup is stable as long as the prices of gas and heating oil move in parallel. Due to the advantages of natural gas in terms of cleanliness and comfort, a certain markup over heating oil can be enforced in retail markets.

Despite of their economic advantages, long-term contracts are viable only if both parties credibly commit to their obligations over an extended period of time. Concerning the export company, credibility importantly hinges on sufficient gas reserves. Concerning the import company, the determinants of its long-term credibility are less obvious, in particular if they lose their political protection and become exposed to competition. It is not surprising that the duration of long-term contracts has significantly shortened since 1997, when the liberalized European single gas market was created (see Neumann and Hirschhausen 2004).

The binding force of long-term contracts has been a topic in economics for some time. According to Crocker and Masten (1985, 1991), it should be effective to the extent that neither party has an interest in a premature termination of the contract unless this would be socially efficient. Thus, contractual penalties (inherent in ToP clauses) should be designed in a way that no party has an incentive to breach the contract if this would be socially inefficient.

Long-term contracts are viewed more critically by competition theory. The basic argument is that they lack transparency, reduce the liquidity of spot markets, and constitute a barrier to entry for new competitors. In addition, the price formula applied may not be flexible enough to accommodate new developments, e.g. the use of natural gas in combined cycle gas turbines (CCGT) for power generation in the present context. Finally, linking the price of gas to the one of heating oil not only creates an avoidable cluster risk but also prevents gas from becoming an instrument of risk diversification. These considerations have led the Commission of the European Union to adopt a negative attitude towards long-term contracts, even while recognizing their contribution to the security of energy supply (EU Directive 2003/55/EC).

9.3.2 Natural Gas Spot Trade

Another and more advanced market design is physical gas trade on spot and futures markets, first introduced in the United States (since 1978) and in Great Britain (since 1993). Liquid markets have evolved, generating transparent price signals. Finally, liberalization of European electricity markets around the year 2000 (see Sect. 12.2.2) created impetus to the development of liquid gas markets in Continental Europe as well.

However, physical gas trade is impossible unless traders can access the gas infrastructure (pipelines, LNG terminals), which is typically controlled by monopolistic companies. Third parties need to obtain access to this infrastructure for a market place to exist where gas can be exchanged between traders. Two types of gas exchanges have developed so far.

– Physical gas hubs: These are locations where pipelines, storage facilities, and liquefaction terminals meet like the spokes of a wheel, enabling the exchange of gas delivered though different pipelines. Pipelines that can be operated in both directions are particularly advantageous. An independent hub operator is called for who provides non-discriminating access and processing of transactions, evens out short-term physical imbalances, and publishes market prices in timely manner. The first physical gas hub worldwide was the Henry Hub, located close to the gas fields of Louisiana and Texas in the southern United Sates. It is the most important to this day. Its liquidity derives from 14 gas pipelines which come together there, connecting large parts of the country. The Henry Hub gas price (quoted in USD per mn BTU) has become the benchmark for the entire U.S. wholesale gas market. It also provides the reference price for gas futures traded on the New York Mercantile Exchange NYMEX. In Continental Europe, the number one physical gas hub is located in Belgium, near Zeebrugge.

– Virtual gas hubs: Since there are few places in the world with a concentration of pipelines qualifying them for serving as a physical gas hub, parts of a high-pressure pipeline grid may constitute an alternative. The market place is defined by a number of entry and exit points, where traders can feed in and take out gas, to be delivered to final consumers. Since the pipelines may be owned by different companies, an independent hub operator is again necessary who coordinates entry and exit rights, processes transactions, and charges entry and exit fees which are used to finance the infrastructure. Trades must be executed in a timely manner as traders do not have the right to use the grid for storing their gas. The first virtual gas hubs were established in Great Britain (National Balancing Point NBP) and in the Netherlands (Title Transfer Facility TTF). In the meantime, there are also virtual gas hubs in Belgium (ZEE), France (Points d'Echange de Gaz, comprising Peg North, Peg South, and Peg TIGF), Germany (NetConnect Germany, Gaspool), and Italy (Punto di Scambio Virtuale).

The spot market price of an active and liquid gas hub[10] can become the reference price for gas contracts, serving to sever the link between long-term gas contracts and the heating oil price. This happened in Continental Europe around the year 2011 (see Fig. 9.2). However, the two prices are unlikely to diverge a great deal because heating oil and natural gas are close substitutes in the market for space heating. Moreover, fuel switching is facilitated by bivalent burners which can use either fuel. In fact a strong correlation between the two prices is observed on the U.S. gas market where price formulas based on heating oil are absent from long-term gas contracts. Yet divergences over extended periods of time do occur, which are due to the following factors:

– Gas prices are usually based on the upper heating value H_s rather than on the lower heating value H_i which is common on other energy markets. A cubic meter of natural gas with an upper heating value of 11.5 kWh/m^3 contains the same

[10] Liquidity can be measured using the so-called churn rate, defined as the ratio of traded volume to physically delivered volume.

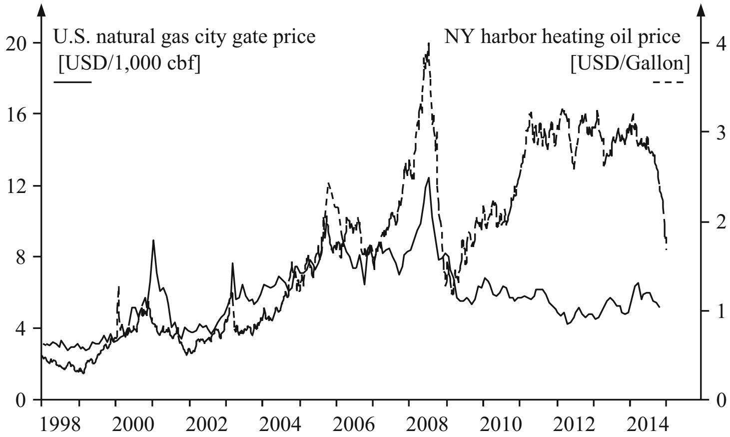

Fig. 9.3 Gas and heating oil prices on the U.S. spot market. Monthly price averages; data source: Energy Information Administration EIA

energy content as 1.05 kg (or 1.15 l, respectively) of heating oil.[11] However, even when this difference in measurement is accounted for, wholesale gas prices still differ from the energy-equivalent prices of heating oil due to a difference in the user value of the two fuels.

– Gas prices exhibit very strong seasonality, traditionally even more so than heating oil prices. In addition, they spike during extremely cold winter and hot summer days (see Fig. 9.3). The reason is the comparatively high storage cost of gas, which prevents the holding of stocks that buffer surges in demand.
– Volumes of storage that are high or low for the season as well as disruptions in the gas infrastructure (e.g. due to hurricanes) can also impact the spot price of natural gas.
– Finally, gas transportation cost may cause gas prices to differ between regional markets.

While the prices of wholesale gas and heating oil are expected to be related, these considerations serve to qualify this relationship. Indeed, until 2006 it used to be quite close in the United States but has fundamentally changed after 2009 at the latest (see Fig. 9.3). While the gas price still followed the 2008 hike in the price of heating oil, the two prices have become uncorrelated since 2009. Accordingly, a stable price relation is predicted until the end of 2006 or perhaps 2008 only.

In estimating this relationship, one is confronted with the following methodological problem. As is the case with most financial time series, the two fuel price series are not stationary, i.e. their means and variances are time-dependent.

[11]In U.S. units, one thousand cubic feet (cbf) of natural gas contain an energy equivalent of eight gallons of heating oil. Therefore, one would expect eight gallons of heating oil to fetch the same price as 1000 cbf of natural gas (which is not true, see Fig. 9.2.)

Table 9.5 Indicators for natural gas and heating oil spot market prices

	Natural gas price (p_{gas}) (U.S. city gate) (USD/1000 cbf)		Heating oil price p_{hel} (New York Harbor) (USD/Gallon)	
	$\ln(p_t)$	$\ln(p_t)–\ln(p_{t-1})$	$\ln(p_t)$	$\ln(p_t)–\ln(p_{t-1})$
Mean	1.724	0.002	0.327	0.008
Standard deviation	0.341	0.090	0.674	0.085
Skewness	−0.121	0.073	−0.435	0.041
Kurtosis	2.571	4.665	2.013	5.056
ADF test	−2.3	−13.5[a]	−1.8	−11.5[a]
PP test	−2.3	−13.5[a]	−1.7	−11.5[a]

202 monthly observations between 1998 and 2014

[a] Test statistics indicate stationarity at a significance level of 1%

Table 9.5 contains first indications suggesting that the (logarithm of) the two prices may not be stationary. In particular, the negative skewness points to an asymmetry in the distribution that may be due to a shifting mean or variance σ^2. Contrary to the normal distribution (whose skewness is zero because of symmetry), a log-normal distribution has positive skewness which depends on its variance. It is given by $(e^{\sigma 2}+2)(e^{\sigma 2}–1)^{1/2}$. With the values in Table 9.5, skewness given log-normality would amount to $(e^{0.3412}+2)(e^{0.3412}–1)^{1/2} = 1.096$ for the gas price and $(e^{0.6742}+2)(e^{0.6742}–1)^{1/2} = 2.711$ for the heating oil price. The observed values −0.121 and −0.435 are far away from these benchmarks, indicating that the logarithms of the two prices are not normally distributed, possibly due to a stochastic trend, i.e. non-stationarity.

First differences $\Delta \ln p_t = \ln p_t – \ln p_{t-1}$ usually do not contain a trend anymore. Also, amounting to percentage changes, they have a natural interpretation (see Sect. 5.1). Statistical tests for non-stationarity such as the Augmented Dickey-Fuller test (ADF test) or the Phillips-Perron test (PP test) are described e.g. in Engle and Granger (1987). According to the two bottom lines of Table 9.5, the hypothesis of non-stationarity can be rejected at a high level of significance for the percentage changes in both the U.S. city gate gas price and the New York harbor heating oil price. The two modified price series are therefore called integrated of order zero, while the original ones, integrated of order one.

If two time series are integrated of order one or higher, OLS regression is inappropriate as it may estimate a relationship where there is nothing but a common stochastic trend. While an OLS regression relating the percentage changes may solve this problem, its estimated parameters show only the short-term relation between the two prices but not a possible long-term relation. If such a long-term relation exists, the two time series are called cointegrated. This means that they tend to return to their long-term relation after some time; in the short term, however, they may develop independently of each other. The formal representation of this long-term relationship is the so-called cointegration equation, to be interpreted as the equilibrium relation between the two time series.

The error correction approach developed in the context of nonstationary time series analysis (see Engle and Granger 1987) has become the standard method to identify a possible cointegration equation. The first step is to find out whether two time series are cointegrated or not. Here the Johansen test can be used (Johansen 1991). Applied to the U.S. monthly fuel prices shown in Fig. 9.3, this test confirms cointegration for the period up to 2008 but not after, as revealed by Fig. 9.3. Next, the Johansen test also suggests the following cointegration equation for the common stochastic trend of the gas price p_{gas} and the heating oil price p_{hel}, estimated from 72 monthly data between 2001 and 2006 (t statistics in parentheses),

$$\ln\left(p_{gas,t}\right) = \underset{(83.0)}{-1.87} + \underset{(14.1)}{0.77} \cdot \ln\left(p_{hel,t}\right). \tag{9.22}$$

Thus, even in the absence of a contractual pricing formula, U.S. gas and heating oil prices are found to move together. Third, an error correction model is specified. It describes how prices return to the estimated equilibrium relation if disturbed by exogenous shocks (72 observations between 2001 and 2006; adjusted $R^2 = 0.59$),

$$\begin{aligned} \Delta\ln\left(p_{gas,t}\right) = & \underset{(-6.9)}{-0.409} \cdot \left(\ln\left(p_{gas,t}\right) + 1.87 - 0.77 \cdot \ln\left(p_{hel,t}\right)\right) \\ & \underset{(1.4)}{+0.110} \cdot \Delta\ln\left(p_{gas,t-1}\right) \underset{(1.5)}{+0.156} \cdot \Delta\ln\left(p_{hel,t-1}\right) \\ & \underset{(-5.4)}{-0.0025} \cdot \text{GASST-RESID}_t \underset{(-.34)}{+0.00027} \cdot \text{TEMP-RESID}_t \underset{(-6.7)}{-0.281} \cdot DMY. \end{aligned} \tag{9.23}$$

Equation (9.23) can be interpreted as follows. Its first row explains what happens if the cointegration equation (9.22) is not satisfied at time t, resulting in a difference between the observed (logarithm of the) gas price and its value predicted by the regression using the heating oil price. The parameter −0.409 indicates the extent to which such a difference decreases per unit during period t. Accordingly, it takes on average 1/0.409 = 2.44 months for a disequilibrium to be eliminated. For a comparison with European long-term gas import contracts with their price formula, one may interpret equation (9.21) as pertaining to a cointegration equation, neglecting the fact that it is in arithmetic rather than logarithmic values. However, any shock in month t would affect the moving average only with one-sixth of its value, and the moving average itself is lagged by three months. Therefore the estimated coefficient 0.504 shrinks to 0.084, indicating an adjustment period of 12 (= 1/0.084) months, to which three months have to be added. This exceeds the 2.44 months estimated above by far, indicating that adjustments to shocks are much more sluggish in European than U.S. imports of natural gas.

The second row of Eq. (9.23) shows the short-term relationship between relative changes in the gas price and the heating oil price. It is lagged by one month to render it predetermined in period t, thus making it unlikely that causality runs from the dependent variable $\Delta\ln(p_{Gas,t})$ to the explanatory variable rather than the other way round. According to the positive (but insignificant) sign of 0.110, the coefficient pertaining to $\Delta\ln(p_{Gas,t-1})$, gas price fluctuations may be somewhat self-reinforcing, implying high price volatility. This would motivate gas traders to hedge the price risk by signing long-term gas contracts, forwards, and futures.

The third row of Eq. (9.23) shows the impact of some shocks, represented by three exogenous variables.

– *GASST-RESID*: unusually high stocks of gas (in percent of the seasonal mean);
– *TEMP-RESID*: unusual temperatures during the heating season;
– *DMY*: dummy variable reflecting unusual events (hurricanes, spillovers from turbulences on financial markets).

As expected, unusually high stocks have a recognizable dampening effect on surges of the gas price. According to Table 9.5, the average value of $\Delta\ln(p_{Gas,t})$ is 0.008 or 0.8% per month. Compared to it, the coefficient of –0.0025 pertaining to *GASST-RESID* is anything but small, indicating that an extra percentage point in excess of the usual magnitude of gas stocks serves to slow the average price increase from 0.8 to 0.55 (= 0.8 – 0.25) percent per month ceteris paribus. Somewhat surprisingly, *TEMP-RESID* is statistically insignificant, while the occurrence of an unusual event swamps everything else by turning the 0.8% increase into a 27.3 (= 28.1 – 0.8) percent decrease in price.

In sum, the model (9.23) provides an interesting explanation of the U.S. wholesale gas market before the shale gas revolution. However, the new fracking technology led to a basic change, breaking up the stable relation between gas and heating oil prices. Between 2010 and 2014 wholesale gas prices are less than half the level predicted under the old regime. In addition, they were not affected by the collapse of heating oil prices at the end of 2014, suggesting that U.S. gas markets have become fully independent of the heating oil market despite the fact that the two fuels continue to be close substitutes. The likely reason is that at relatively low prices, gas has conquered new markets (in particular for power generation), where the relevant substitutive fuel is not heating oil but coal.

9.4 Third Party Access to the Gas Infrastructure

Third party access (TPA) describes a situation in which agents other than the owner of an asset are allowed to use the asset. In the case of natural gas, traders other than the owners of the gas infrastructure (in particular the grid) can use it for transport. Without TPA, the set of trading partners is limited to those companies who have their own transport capacities for their service area. Therefore a liquid natural gas market is possible only if the operators of the grid offer other parties effective, nondiscriminatory, and transparent TPA.

This access can be granted on a negotiated or a regulatory basis. In the first case, traders and grid operators need to sign contracts allowing the use of the grid and specifying the terms of its use. If more than a handful grid contracts are to be negotiated, they are quite unlikely to be nondiscriminatory in the sense that all traders benefit from the same access conditions. In the second case, contracts are still necessary but their rates and conditions are set by a public regulator, who denies the grid operator the right to reject third parties seeking to sign a contract. Conditions importantly specify the beginning and end of a gas transfer as well the quantity per time unit to be transported.

Regulated TPA comprises two very different variants.

- Contract path (also known as point-to-point system): Gas traders choose the entry and the exit points as well as the pipelines between the two points they want to use. The grid operator allocates this transport capacity provided it is available and charges the transportation fee, which may be a function of distance or a flat rate, depending on the type of regulation.
- Entry-exit system: Here, entry and exit capacities are booked and charged separately. This permits a trader who has booked entry capacities to sell gas during the reservation period to any party disposing of exit capacities for the same period. Conversely, traders who have booked exit capacities can contract with others who have entry capacities during the same period. The grid operator charges entry fees and exit fees but no distance-related transportation fees.

Entry-exit systems amount to virtual hubs or market areas, respectively. There must be an agent who controls the relevant part of the pipeline grid, maintains its pressure, registers applications for capacity by traders, and coordinates the gas flows through the grid. The condition is that these flows can be executed during each time interval given the capacities of the pipelines. The agent also identifies gas traders who have excess capacity and excess transportation demand relative to capacity and provides the necessary positive or negative balancing energy. While imbalances can often be offset at the aggregate level in this way, this is not always possible, exposing traders to the risk of failure to fulfil their contracts. Of course, traders are charged for their imbalances and may even be fined for them if they are sizable.

On the other hand, the separate booking of entry and exit capacities enhances trading opportunities: Traders who hold exit capacities but no entry capacities can purchase gas from traders who have entry capacities for the same time interval. Situations where the physical flow between an entry and an exit point turns out to exceed the capacity of the pipeline system can be avoided by limiting admissible gas flows at all entry and exit points to values that are compatible with capacity. This calls for specifying hydraulic load flow models and solving them for short (typically hourly) intervals. The objective is for the grid operator to offer firm rather than interruptible entry and exit capacities to the greatest extent possible.

Still, the risk of failure to fulfil contracts may persist. There are two ways to further lower it:

- The size of the market area may be reduced. This leads to fewer restrictions on the allocation of firm entry and exit capacities. On the other hand, smaller market areas diminish market liquidity, the number of market participants, and hence trade benefits. Also, traders may enjoy more market power since they are less exposed to the pressure of competition from other market areas due to the transportation cost of border-crossing gas.

– Firm and interruptible capacities are offered alongside each other. This more common alternative enables the grid operator to avoid bottlenecks by blocking traders with (lower-priced) interruptible capacities from access at critical entry and exit points.

Bookings of entry and exit capacities may be honored on a first-come-first-served basis. This rule not only favors incumbents to the detriment of newcomers but also creates scope for traders to manipulate the wholesale gas market. An obvious strategy is the purchase of entry capacities designed to prevent competitors from delivering gas to the market area, resulting in so-called foreclosure. It is attractive if the achievable price markup exceeds the unit cost of these extra capacities. The regulator can counteract this strategy by imposing the 'use it or lose it' principle: Wholesale traders who hold firm entry or exit bookings but fail to order commensurate transportation services (before a defined closing date) lose their capacities to other customers. A more market-oriented approach is for the grid operator to create a secondary market for entry and exit rights that allows traders to buy and sell unused capacity rights. As always, abuse of market power may have to be reined in by public authorities.

Many grid-related aspects of the wholesale gas market are quite similar to those of the market for electricity, which are discussed in Chap. 13. However, European gas markets continue to be characterized by a few particularities. The gas year starts on October 1 at 6.00 a.m. and ends in the following year on October 1 at 5.59 a.m. Due to the importance of gas in the space heating market, the calendar year is not appropriate as it cuts into the heating season. Next, the smallest trading unit is a block of 1 MWh, i.e. 1 MW to be delivered during one hour. Day-ahead contracts with delivery within 24 h are typical of spot markets, while block contracts for months, quarters, and years are traded on futures markets.

Turning to the final users of natural gas, their demand exhibits a strong seasonal pattern because it importantly derives from their demand for space heating. However, gas consumers with other uses have a more balanced demand profile. Commonly used indicators are full load hours *FLH* or full load days *FLD*, respectively. For instance, annual gas sales can be expressed as the product of capacity (called maximum load) and degree of utilization (measured in hours per year). Division by the maximum load yields *FLH* (*FLD*, respectively if utilization is measured in days per year),

$$FLH = \frac{\text{Gas sales } [\text{m}^3/\text{a}]}{\text{max.load } [\text{m}^3] \text{ per h}} \quad \text{and} \quad FLD = \frac{\text{Gas sales } [\text{m}^3/\text{a}]}{\text{max.load } [\text{m}^3] \text{ per day}}. \tag{9.24}$$

As shown in Table 9.6, average capacity utilization of the gas infrastructure is low, amounting to 3600 of 8760 h and 150 of 365 days (or 41%) per year, respectively. Moreover, there are substantial differences between consumer groups.

Table 9.6 Capacity utilization by final users of natural gas

	Full load hours (FLH) (h/a)	Full load days (FLD) (d/a)	Capacity utilization (%)
Private households	1500–2000	60–95	16–26
Real estate companies	1800–2700	75–110	20–30
Industrial customers	2500–5000	100–210	27–58
Market average	3600	150	41
Structured natural gas contracts with nearby wells	3000–4000	125–167	34–46
Block delivery	8000–8760	340–365	>93

Source: Erdmann and Zweifel (2008, p. 243)

While most of the demand by private households occurs during relatively few hours and days, resulting in a capacity utilization of no more than 26%, demand by industrial consumers is more regular, resulting in a capacity utilization of up to 58%.

In view of this high degree of volatility, predicting demand is important. One of the common explanatory variables is the heating degree day $HDD_t := \max(0, 15–Temp_t)$, where $Temp_t$ is the average outside temperature of day t measured in degree Celsius (°C). It is positive on days with an average outside temperature below 15 °C and zero otherwise. Daily fluctuations in the demand for gas can be well explained by models using this variable. Yet even with reasonably accurate predictions, costly gas storage facilities are needed to optimize capacity utilization of the pipeline infrastructure.

An alternative is to provide financial incentives for using the gas infrastructure in a more regular way. For instance, costumers with a so-called structured gas contract reach a capacity utilization of up to 46% (see Table 9.6 again). These customers can be gas distributors or large-scale industrial users who agree to shift part of their demand out of peak periods if necessary. For a maximum relief effect, they should be located near a gas well, permitting them to obtain their regular supply without greatly burdening the transport infrastructure.

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