Market fundamentals, competition and natural-gas prices

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HIGHLIGHTS

- We analyse the development of the day-ahead spot price at TTF over 2011–2014.
- The oil price had a small impact on the gas price, while the coal price had no effect.
- Changes in the concentration on the supply side did not affect the gas prices.
- The gas prices are predominantly determined by weather and storage availability.
- Policies to integrate gas markets foster gas-to-gas competition.

ARTICLE INFO

ABSTRACT

After the liberalisation of the gas industry, trading hubs have emerged in Europe. Although these hubs appear to be liquid market places fostering gas-to-gas competition, the efficiency of the gas market remains a topic of interest as a fair share of gas is still traded through long-term contracts with prices linked to the oil price while the number of gas suppliers to the European market is limited. In order to assess the efficiency of the gas market, we analyse the day-ahead spot price at the Dutch gas hub over the period 2011–2014. We find that the oil price had a small positive impact on the gas price. Changes in the concentration on the supply side did not affect the movement in gas prices. The availability of gas in storages and the outside temperature negatively influenced the gas price. We also find that the gas price was related to the production of wind electricity. Overall, we conclude that the day-ahead gas prices are predominantly determined by gas-market fundamentals. Policies to further integrate gas markets within Europe may extend this gas-to-gas competition to a larger region.

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1. Introduction

The institutions of the European gas market have changed considerably in the last decade. Trading at gas hubs such as the National Balancing Point (NBP) in the United Kingdom and the Title Transfer Facility (TTF) in The Netherlands have gained rapid importance (Heather, 2012). Parallel to this development, the convention of explicitly linking the gas price to the oil price has lost importance. Because oil and gas were substitutes in many processes, oil indexation became the leading pricing mechanism for gas in the 20th and early 21st century in Europe. Since the gas market has changed significantly in recent years, however, gas-to-gas competition seems to have become the dominant price mechanism (IGU, 2014). Moreover, recent evidence shows that

national gas markets in North-west Europe are increasingly integrated with each other, resulting in a North-west European market covering countries as the UK, France, The Netherlands, Belgium, Germany, Denmark, Italy and Austria (Growitsch et al., 2012; Kuper and Mulder, 2014; Neumann and Cullmann, 2012; Petrovich, 2013; Timera Energy, 2013).

Nevertheless, there are still concerns regarding the intensity of competition within the European gas market as the dispersion of reserves is concentrated while the number of suppliers is limited. If firms are able to exert market power, above-competitive gas prices may result which reduces consumer welfare. Furthermore, the gas market faces periodical shocks in both supply and demand, which distort the gas prices. For example, the extremely cold weather throughout Europe in February 2012 led to a (perceived) tightness of the market supply. In addition, the Fukushima disaster and the consequent nuclear shutdown in Japan led to a substantial increase in Asian demand for LNG.

A number of different approaches to understand the factors behind gas prices have been used in the recent literature. Several

authors have established long run co-integrating relationships between gas and oil prices (e.g. Asche et al., 2006; Regnard and Zakoïan, 2011, for the European gas market and Erdős, 2012; Villar and Joutz, 2006, for the US gas market). Some papers have emphasised the role of other supply and demand fundamentals, in particular for the short-run price development because energy commodities differ in fuel density and accordingly in production, transportation and environmental cost (Smith, 2004; Mu, 2007; Brown and Yücel, 2008). Ramberg and Parsons (2012) show that the vector error-correction models typically applied in the co-integration framework do not perform very well in explaining short run gas price development. In another fashion, Nick and Thoenes (2014) investigated the effect of market shocks in a structural vector autoregressive (SVAR) model and found that temperature, storage and supply shocks lead to relatively short lasting effects on the gas price whereas oil and coal price shocks result in more persistent effects on the gas price.

With the strongly reduced share of explicit oil indexation and the reduced options for short run gas–oil substitution in Northwest Europe (Stern, 2007, 2009), the supply and demand fundamentals might have become more important for the development of the gas price at liberalised hubs. This is the reason that we estimate a reduced form model of the gas price which enables us to assess the impact of the key fundamental factors on the short term movements of the gas price.

The main question addressed in this paper is: what drives natural gas prices at liberalised European gas markets? More specific, to what extent is the gas price tied to oil and/or coal and what is the effect of other supply and demand fundamentals? This paper contributes to the literature by providing a comprehensive empirical analysis, facilitated by the collection of data for a broad set of gas-market variables. Moreover, while other papers have largely focussed on a single national market, we include a number of variables related to the North-west European market for natural gas. We define the North-west European gas market as the markets in Austria, Belgium, Denmark, France, Germany, Italy, the Netherlands and the UK. The gas networks in these countries are closely connected. In addition, gas is being exported from the Netherlands to each of these markets, which fosters the integration of the markets. As a result, changes in fundamental factors affecting supply or demand in these countries may also affect the gas price at the TTF.

This paper analyses the development of spot market gas prices at the TTF hub over the period 2011–2014 by assessing the contribution of a number of supply and demand fundamentals. We focus at the TTF since it is viewed as a suitable reference hub which is the most liquid and mature trading hub in continental Europe (Heather, 2012). The annual volume delivered at TTF is about 40 bcm while the total gas consumption in the Netherlands is about 45 bcm, which indicates that the TTF is important for the Dutch gas market (GTS, 2012). Moreover, the TTF appears to be strongly integrated with gas hubs in neighbouring markets such as the NCG in Germany (ACM, 2014; Kuper and Mulder, 2014). As a result, the prices on TTF and the other hubs show almost the identical pattern. The day-ahead price is appropriate because it refers to one of the most liquid traded products, which makes that the price of this product is strongly related to the underlying factors (Heather, 2010). The liquidity of the day-ahead products follows from the depth of this market, which is significantly higher than for the other products (ACM, 2014).[1] Hence, in the short run, fundamental supply and demand factors are especially important for the development of the day-ahead price. The fundamentals

include the outside temperature, the macroeconomic development, the price of substitute fuels, the concentration in physical terms on the supply side to the European market, the expected level in global gas reserves and the development in renewable energy. While assessing the impact of these factors, we control for a number of incidental events such as the inability of Gazprom to meet unexpected demand and the Fukushima disaster.

We find no evidence of a strong tie between the spot prices of natural gas, crude oil and coal over 2011–2014. The development of the gas price is mainly determined by own fundamentals. Though, a short-run link between the three energy commodities is present via arbitraging between oil indexed gas and hub gas as well as via fuel competition in the power market. Despite being a fairly concentrated market, the changes in the daily gas price do not depend on the changes in the structure on the supply side. Overall, we conclude that the day-ahead gas prices are predominantly determined by gas-market fundamentals.

The remaining of this paper is organised as follows. Section 2 describes the method of research which includes a description of the variables which are used to measure the fundamentals behind the gas price. This section also presents the data which is used to estimate the model. Section 3 presents and discusses the results. The conclusions and policy recommendations are given in Section 4.

2. Method and data

We estimate a reduced-form model of the gas price. This model is based on the idea that the gas price is a function of shifts in the demand and the supply curves. To determine the effect of supply and demand factors on the gas price the equation $P^{TTF} = \phi(X, Y)$ is estimated, where X and Y contain the demand and supply variables and P^{TTF} reflects equilibrium gas prices on both the supply and demand schedules, i.e. the points of intersection of both curves. In this section we elaborate on the key factors affecting the demand and supply curves behind the TTF price. The dataset for the quantitative analysis comprises data from 4/1/2011–30/12/2014. It consists of daily observations except for the macroeconomic indicator which is available on a monthly frequency. The dataset does not include prices for weekends limiting the analysis to weekdays only. Table 1 gives an overview of all variables, how they are measured and the data sources. See Fig. 1 for the day-ahead gas price

2.1. Price of oil

A factor which may affect both the demand and the supply of gas is the price of oil. The price of oil is relevant because of substitution properties of gas and oil (Villar and Joutz, 2006). Substitution is primarily relevant in the electricity generation and the heavy industry. If the price of oil rises, burning gas becomes relatively cheaper, increasing the demand for gas which results in an upward pressure on the gas price. However, Stern (2007, 2009) argues that short-run fuel switching is hardly relevant anymore in West Europe because oil has virtually disappeared in most stationary energy sectors, maintenance of dual-fuel burners is expensive, tight environmental standards as well as the inefficiency of using oil in new gas burning technologies.

In addition to the apparent lack of short-run substitutability there are several other reasons why oil and gas should have distinct price dynamics (Smith, 2004). The transportation costs differ and there are differences in the costs of production, processing, storage and environment. Moreover, the differences in characteristics have led gas and oil prices to be determined in different geographical market places, as noted by Ramberg and Parsons

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[1] The depth of a market is measured by the number of additional lots of 30 MW traders could sell or buy without influencing the price (ACM, 2014).

Table 1
Variable definitions.

	Description	Source	Frequency (unit)
Heating degree days	West European gas consumption weighted average number of heating degree days	European Climate Assessment and Dataset (ECA&D)	Daily (degree celcius)
TTF gas price	Title Transfer Facility day-ahead natural gas price	ICIS Heren	Daily (€/MWh)
Brent oil price	European Brent crude oil spot price	ICIS Heren	Daily (€/Barrel)
NW European coal price	Northwest European coal price	Bloomberg	Daily (€/Tonne)
CO2 price	Price of European carbon credits	Bloomberg	Daily (€/Tonne)
Gas storage	Deviation in the daily filling degree of West European gas storage facilities from the daily average filling degree of the past 3 years	Gas Infrastructure Europe (GIE), Cedigaz Underground Gas Storage Database (CUGS) and Gasunie Transport Services (GTS)	Daily (Percentage points)
Herfindahl-Hirschman index (HHI)	Aggregated squared market shares of suppliers	Eclipse-Own calculations	Daily (index [0,10000])
Macroeconomic indicator	Monthly gas consumption weighted average production volume index of the manufacturing sector in West Europe	Eurostat	Monthly (indice)
Wind electricity Germany	Day-ahead prediction of electricity generation from German wind power	50 Hertz, Amperion, TenneT, TransnetBW	Daily (MWh)
Global discoveries	Dummy indicating announcement and period after large global gas discoveries	WoodMackenzie	–
Fukushima nuclear disaster	Dummy separating the period before and after the Fukushima nuclear disaster on the 11th of March 2011	–	–
Cold spell in Europe 2012	Dummy indicating the period of extremely cold weather throughout Europe in February 2012	–	–
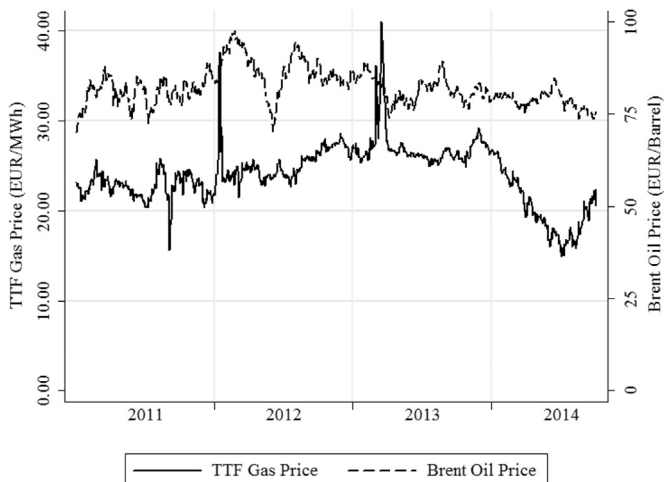
Fig. 1. TTF gas price and Brent crude oil price per week day, 2011–2014 (Source: ICIS Heren).

(2012). Although regional differences between types of crude oil exist, such as Brent and West Texas Intermediate, their prices are usually correlated. Natural-gas prices at the hubs, however, are much more subject to regional supply and demand conditions. The regional gas markets are not independent from each other, and perhaps are becoming increasingly tied (Stern and Rogers, 2014), but regional prices can move in very different directions as can be seen from the recent divergence in European and North-American gas prices (Mulder, 2013).

Even if the supply and demand dynamics of gas and oil differ and there is a lack of short run substitution, the price of oil influences the price of gas if the gas price is explicitly linked to the oil price in contracts, as was a common practice in Europe since the 1960s. The key question is how important this price mechanism still is for the West European market. The answer is somewhat difficult to obtain because most information sits in the private domain. The IGU (2014) nevertheless estimates that the share of oil indexation in North-west Europe decreased from 72% in 2005 to 20% in 2013.

Because of the remaining oil-indexation contracts, traders try to arbitrage between spot and contract gas insofar this is possible given the minimum take obligations in these contracts (Stern and Rogers, 2014). If the gas spot price is below the oil-indexed contract price, the demand at hubs for spot priced gas will increase whereas demand for oil indexed gas decreases. This will increase the price of spot gas. Consequently, buyers with long term contracts try to decrease their nominations up to the minimum take obligation resulting in lower upstream production and total market supply. The opposite mechanism holds if the gas spot price is above the oil-indexed contract price.

Because of these remaining arbitrage possibilities, we include the price of oil as an independent variable. The spot price of Brent oil is the most relevant crude oil price for the West European market. Prices are specified in US Dollar per barrel. In order to account for exchange rate fluctuations the US Dollar per barrel, the price is divided by the day-ahead US Dollar/Euro exchange rate to obtain a day-ahead Euro per barrel price.

The other relevant variables for inter-fuel competition that are included are the price of North-west European coal and the price of CO2 in the European Union Emissions Trading Scheme, both in Euro per tonne as reported by Bloomberg (Fig. 2).

2.2. Market structure

Although a large numbers of traders are active on the gas hubs like TTF, the supply to the gas market is concentrated because of the limited number of producers. The main sources of supply to the North-west European market are 'indigenous' production in The Netherlands and UK as well as imports from Russia, Norway, Algeria and LNG, primarily coming from Qatar. This supply can be distinguished in inflexible and flexible supply (Timera Energy, 2013). Inflexible supply of gas include pipeline-contract gas up until take-or-pay volumes, destination-inflexible LNG cargoes (mainly into Southern Europe) and indigenous production which do not seem to respond to hub price signals in practice. While these tranches may have some flexibility (e.g. to allow for seasonality), they generally flow irrespective of the absolute level of hub prices and have therefore no primary impact. The flexible supply of gas consists of pipeline-contract gas between the take-or-pay and maximum annual contracted volume, un-contracted pipeline import flexibility from mainly Norway and Russia and flexible LNG supply.

The limited number of producers of gas to the European market raises some concerns on the degree of competitiveness of the gas
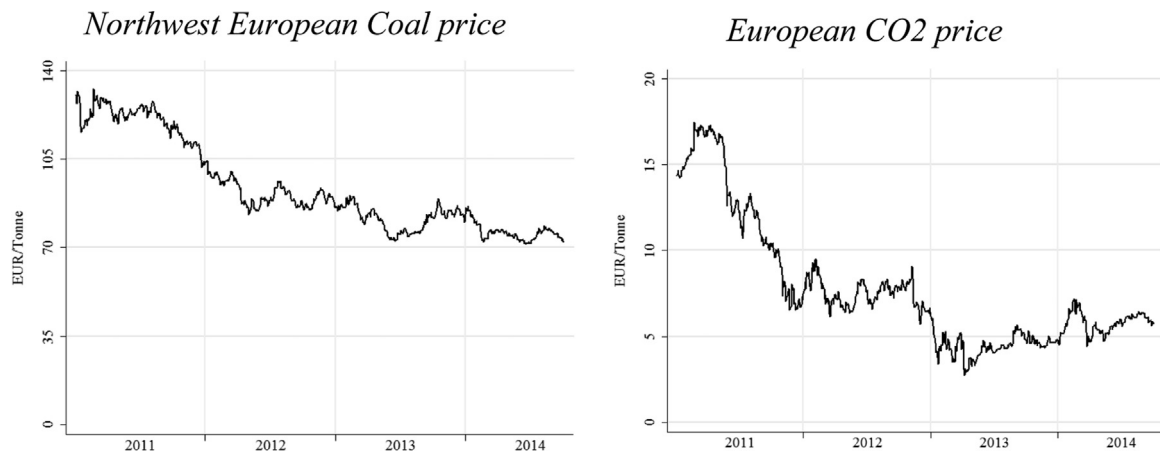
Northwest European Coal price

European CO2 price

Fig. 2. Coal price and CO2 price, per day, 2011–2014 (Source: Bloomberg). (a) Northwest European Coal price (b)European CO2 price.

market. Typically, the production and export in one country is dominated by large state-controlled companies. This gives rise to concerns regarding oligopolistic market behaviour and profound effects following supply disruptions. If firms hold a strategic position, they are able to execute market power resulting in prices above the competitive level. It should be noted that other parts of the gas market than production affect the degree of competition as well. Gas producers are often not responsible for transportation and each part of the value chain has its own dynamics. However, production is essential to understand competition in the market for gas as it are producers who determine the gas volumes the other value chains work with (Brakman et al., 2009).

In terms of industry structure the gas market is commonly described by a Cournot configuration as the market trades in the homogenous good gas,[2] prices observed are above marginal costs, quantity is the strategic variable and a limited number of firms supply the market. To assert the degree of competition in a market the Herfindahl-Hirschman index (HHI) is widely used. The HHI is an indicator for market concentration, defined as: $HHI = \sum_{i=1}^{n} S_i^2$ where S_i is the market share of firm i and n the number of firms; i.e. the aggregate of the supplier's squared market shares. As such it is an indicator for the structure of a market and signals the potential for the exertion of market power by firms. We, therefore, include the HHI in our model which is based on the supply coming from different players to the North-west European market.

The supply data includes supply from Russia, Norway, Algeria, LNG, The Netherlands and UK.[3] The daily supply is based on the supply entering the system via pipelines from Norway, The Netherlands, UK, Russia and Algeria and total LNG supply (Fig. 3 and Table 2).[4] The data does not allow us to determine the source of LNG entering the system and therefore LNG is treated as a single market supplier.

Daily production data for The Netherlands and UK is readily available, but the relevant export of other suppliers to North-west Europe is not. To determine imports via the pipeline system from the most important 'foreign' suppliers, Russia, Norway and Algeria, all those gas transmission points at the 'border' of the market via
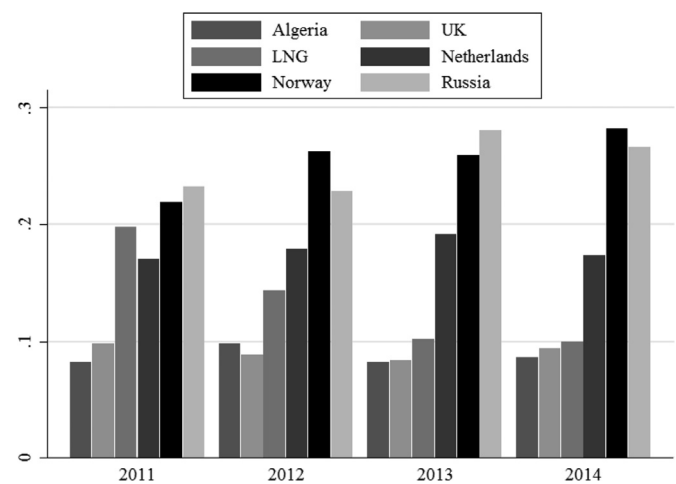

Fig. 3. Daily average market share per country per year, 2011–2014 (source: own calculations based on data from Eclipse).

Table 2
Daily average gas supply per country/source (GWh).*Source*: Eclipse.

	2011	**2012**	**2013**	**2014**
LNG	2367	1674	1183	1055
Russia	2821	2675	3257	2829
Norway	2643	3095	3045	3019
The Netherlands	2098	2151	2261	1875
UK	1181	1032	981	1001
Algeria	994	1164	970	909
Total	12,104	11,791	11,697	10,688

which production of the respective suppliers can enter the pipeline system in Central and West Europe are identified.[5] Generally, there exists more than one receiving Transmission System Operator (TSO) at a gas transmission border point. The physical flow in MWh reported by each TSO at border points is extracted from Eclipse. For Norway 16 relevant border points are identified, arriving in The UK, France, Belgium, The Netherlands and Germany (see appendix A for a list of all the identified entry points for each non-indigenous supply source). For Russia, 4 relevant border points in 3 countries are identified: one for gas entering via Ukraine and Slovenia, two for the direct connection between Germany and Russia via the Nordstream pipeline and one for gas

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[2] Quality differences in terms of energetic content exist, however, trade and prices are based on energy content rather than physical volume.

[3] It should be noted that because production in other European countries (e.g. Germany, Denmark and Italy) is excluded, total supply is somewhat underestimated and the market shares and HHI are somewhat overestimated. The joint production in the omitted countries is, however, small.

[4] It is not possible to distinguish the type of supply by flexibility. The vast majority of the production from Norway, Algeria and Russia enters the European system via pipelines, however, these countries also ship some LNG to North-west Europe.

[5] Gas from Russia to North-west Europe is measured at the border points Polen–Belarus and Slowakije–Ukraine.

Fig. 4. Herfindahl-Hirschman Index (HHI) from 2011–2014 (daily data). Source: own calculations based on data from Eclipse.

entering Europe via Belarus and Poland. Algerian production enters the pipeline system at 4 border points in Spain and Italy. Regarding LNG, 18 relevant terminals in 7 countries are identified. The production data limits us to study the period after 1/1/2011 as data is largely unavailable prior to this date.

The total market supply is estimated as the aggregate of supply from each source and consequently the HHI is constructed by summing over all the squared market shares of the 6 supply sources. The HHI has increased from approximately 1900–2100 from 2011–2014 (see Fig. 4).[6] Table 2 shows that LNG supply to Europe has more than halved in that period, which is an important contribution to the increase in the HHI. The decrease in European LNG supply occurs simultaneously with the surge in Asian LNG demand after 2011. The increases in supply of the two largest suppliers, Russia and Norway, have contributed to the increase in the HHI (Fig. 3).

2.3. Storage

Storage of gas plays an important role for hub prices as storages can be used for inter-temporal arbitrage. The theory of gas storage states that the level of inventories affects the difference between spot and futures gas prices (Kaldor, 1939; Brennan, 1958; Fama and French, 1987). Brown and Yücel (2008) find that natural gas storage has an effect on the price of gas. Due to the fact that the consumption of gas is seasonal while the production has generally more limitations to adapt its levels accordingly, storages can be used.[7] These inventories are filled in the summer for use in the winter. In addition, above normal heating and cooling-degree days put upward pressure on the gas price. Inventories above the seasonal norm depress prices while inventories below the seasonal norm have a positive effect on prices. Disruptions in production might also have a positive effect on prices. The above authors calculate a storage differential as the difference between storage in a given week and the average for that week over the past five years. These authors find that when the filling degree of a natural gas storage facility is above the seasonal norm, it depresses natural gas prices.

Traditionally, storage capacity in Europe is mainly used to smooth out the seasonal demand shape. The storage facilities

demand gas in the warm period of the year when gas is injected and they become suppliers in the colder periods as gas is withdrawn. Technical restrictions on injection and withdrawal result in some inflexibility of storage facilities to respond to price signals in the short term. However, many storages currently under construction are being built for short-run arbitrage opportunities between spot and contract gas (Stern and Rogers, 2014). Considering that most storage facilities largely operate on a yearly planned cycle, Cartea and Williams (2008) argue that deviations from the expected storage cycle are most relevant for spot price development. If inventory levels are lower than expected, storage operators demand a higher price and vice versa for storage levels above expectations.

Following the approach taken by Cartea and Williams (2008) and Brown and Yücel (2008), we calculate a storage differential. This storage differential is calculated as the difference between the storage on a given day and the average for that day over the past n years. This can be represented as follows:

$$\varnothing_t = S_t - \left(\frac{1}{n} * S_{t-365} + \ldots + \frac{1}{n} * S_{t-n*365} \right) \tag{1}$$

where S_t is the weighted percentage of total capacity filled on a given day and $\varnothing_t$ is the actual deviation from the average filling grade of the past n years, measured in percentages. In their paper, Brown and Yücel use a period of $n = 5$ years for their analysis. In this paper, we will use a period of 3 years as reliable data concerning the filling grade of storages in the respective countries is available as from the end of 2007.

In order to capture the impact of storage, a variable is constructed which measures the deviation in the utilisation level (i.e. filling degree) from the average North-west European storage utilisation level. The countries that possibly influence the TTF price through their storage facilities are: Austria, Denmark, France, The United Kingdom, Germany, The Netherlands, Belgium, and Italy.[8] Data for the storage variable are available on a weekly basis from October 2007 onwards. From the 1st of January 2010, data are available on a daily basis.

Fig. 5 clearly shows two peaks in the beginning of the time period of analysis. The first two peaks are the winters of 2011 and 2012 respectively, which were relatively mild, while the winter of 2013 was colder than average. The winter of 2014 was a very mild winter, even more than the winters of 2011 and 2012. Storages were 13% more filled compared to the 3-year average.

2.4. Resource rents

A factor which is specifically relevant for a market of natural resources is the resource rent. According to the resource-depletion theory of Hotelling (1931), the price of a resource is based on the actual costs of production and the resource rent. This rent is the value of having a stock of assets now which can be used in the future. The conclusion of this theory is that the net price of a natural resource grows with the rate of interest. This is, however, not generally observed in reality which can be explained by the presence of other factors affecting the price, in particular related to extraction costs, market structure and uncertainty (Gaudet, 2007). Extraction costs are decreasing over time, due to technological

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[6] The HHI is constructed by summing over all the squared market shares of the 6 supply sources.

[7] Note that the Groningen gas field in the Netherlands is a prominent exception on this rule. This field acts as a swing supplier to the North-west European market offering seasonal as well as short-term flexibility.

[8] For Austria and Denmark, no data on storages are available unfortunately. The other six countries mainly use 3 types of gas storage facilities, namely depleted gas fields, aquifers and salt caverns. Data for the storage facility utilisation for the UK, Belgium, Germany, France and Italy are extracted from Gas Infrastructure Europe (GIE). GTS provided the data for The Netherlands. Although the database distinguishes between the several types of storages, data concerning the actual filling grade does not make this distinction. It is therefore impossible to make an analysis with regard to specific storage types.

Fig. 5. Difference between current filling grade and the average seasonal filling grade of the past 3 years for the countries Belgium, France, Germany, Italy, the Netherlands and the United Kingdom. Source: *gas storage*: GIE, CUGS and GTS; *HDD*: ECA&D; own calculations.

Table 3
Major global gas discoveries between 2011 and 2014.Source: WoodMackenzie. Discoveries in Bold are included in the analysis.

Announcement date	Location	Field name	Estimated volume (bcm)
8-8-2011	Iran	Madar	347
20-10-2011	**Mozambique**	**Mamba South**	**425**
28-12-2011	Cyprus	Aphrodite	198
15-5-2012	**Mozambique**	**Gulfinho**	**524**
16-5-2012	Mozambique	Coral	227
18-4-2013	Mozambique	Espadarte	204
27-9-2014	**Russia**	**Pobeda**	**498**

progress, which depress prices. The market structure has a strong influence on price as in the case of imperfect competition a tendency exists to keep production below the optimum rate which has an upward effect on prices. Finally, uncertainty about the total size of the natural resource stock is clearly a factor that influences the price.

Nevertheless, the relationship between the market price of a resource and the marginal natural resource rent is expected to be positive (Faber and Proops, 1993). The higher the resource rents, the higher the market price of the natural resource. These authors find a number of factors that influence the level of resource rents, such as the availability of the natural resource, the technical progress in natural resource extraction as well as the time preference and the length of time horizon of decision makers. In order to capture some of these factors we include a variable related to the expected future availability of resources. Based on the resource-depletion theory, we assume that if the expected size of available resources increases, the current gas price will be lower.

The effect of large discoveries on the gas price is estimated in the regression model by including dummy variables for the 3 largest discoveries, with reserves over 400 bcm each, which were announced during the sample period. The data is extracted from WoodMackenzie. Table 3 lists all announced discoveries in the period 2011–2014 with estimated reserves of 195 bcm and over. The Russian Pobeda discovery in September 2014 was the only giant European discovery in this period. One may expect that this discovery is most relevant for the European market due to its relative proximity to the European market and the existing infrastructure between Russia and the Europe.

Table 4
Selected weather stations for construction of West European heating degree days measure.Source: European Climate Assessment & Data (ECA&D).

Country	Weather station	Correlation coefficient between temperature and monthly gas consumption
Austria	Innsbruck	− 0.8827
Belgium	Uccle	− 0.5724
Denmark	Hammer Odde Fyr	− 0.7499
France	Nancy	− 0.8534
Germany	Frankfurt am Main	− 0.8244
Italy	Verona	− 0.8519
The Netherlands	Schiphol	− 0.8242
United Kingdom	CET	− 0.8359

2.5. Demand factors

Natural gas is the primary source of heating in North-west Europe and as such, demand from residential and commercial users mainly depends on the temperature. Gas consumption is higher in the cold fall and winter periods and lower in the warmer spring and summer months. This gives rise to a profound seasonal pattern in the gas price in North-west Europe. As alternative fuels for heating are typically limitedly available, gas demand related to heating is inelastic. In the long run, however, people are able to switch from heating source and, consequently, the long run demand depends on relative fuel costs.

To control for the influence of the temperature, a Heating Degree Days measure for North-west Europe is estimated. Daily average temperatures measured at several (geographically dispersed) weather stations are extracted from the European Climate Assessment and Data (ECA&D) for Austria, Denmark, Germany, The Netherlands, UK, France and Italy. For Belgium, only daily average minimum and maximum temperatures measured at one weather station (Uccle) are available. In this case the daily average between these two is taken. Any gaps in the data are interpolated by taking the average of the next and previous available observation. Following Mu (2007), we calculate the correlation coefficients between the temperatures reported at a weather station and the domestic monthly gas consumption as reported by Eurostat. Consequently, the weather station that yields the highest correlation coefficient is selected for construction of the North-west European HDD estimate. Weather stations with a large amount of missing values are excluded. Table 4 lists the selected weather station for each country and corresponding correlation coefficients. On the basis of these temperature series, a gas consumption weighted average daily temperature for North-west Europe is estimated which is used to construct the number of Heating Degree Days with base temperature 18 °C (Fig. 6). The weights are based on monthly natural gas consumption. The derivation of this variable can be presented as follows:

$$HDD_t = \sum_{i=1}^{8} \delta_{i,m} HDD_{i,t}$$
(2)

where the subscript i denotes the respective country, m the month of the year and t the respective day of the year. $\delta_{i,m}$ denotes the share of gas consumption in country i in total gas consumption of the selected countries in month m, i.e. $\delta_{i,m} = \frac{q_{i,m}}{Q_m}$, where Q_m is total monthly gas consumption in the selected countries.

Several industrial sectors use gas as primary input into their production processes. Accordingly, their gas demand depends primarily on the level of economic activity in the short run. In the long run, industrial end-users have more options to switch from a
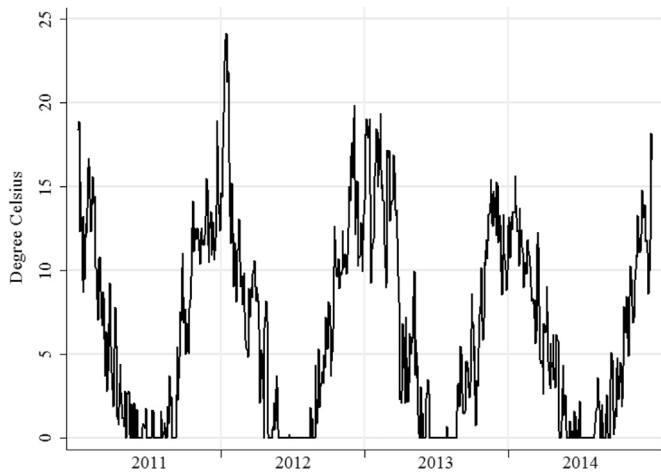
Fig. 6. Heating Degree Days in Western Europe, per day in 2011–2014 (own calculations based on ECA&D).
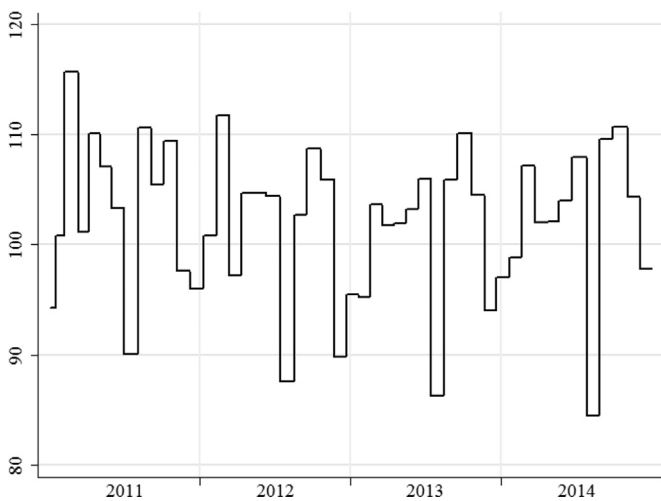

Fig. 7. Industry index (2010=100), per day in 2011–2014 (own calculations, based on Eurostat).

gas-fired production plant to other fuels. The economic activity is captured by including a monthly volume index (2010=100) of gross production of the manufacturing sectors ($ln\,IND$) in Austria, Denmark, Germany, The Netherlands, UK, Italy, France and Belgium, extracted from Eurostat. The values for the separate countries are weighed by using data on the monthly gas consumption per country (Fig. 7). The following equation presents the calculation of this variable:

$$IND_m = \sum_{i=1}^{8} \delta_{i,m} IND_{i,m} \tag{3}$$

where the subscript i denotes the respective country and m the month and $\delta_{i,m}$ is the same gas consumption based weighting factor as in Eq. (2). Note the monthly value of IND is used for all days in a month.

Moreover, a considerable part of electricity in North-west Europe is generated using natural gas as input. The demand for gas by gas-fired electricity generators depends primarily on the price of gas relative to other fuels used for electricity generation, in particular coal. In addition, the price of CO_2 emission, resulting from the European Emissions Trading Scheme, affects the relative cost of gas fired generators to coal fire generators as the latter emits significantly more CO_2 in the production of electricity. If the

price for carbon credits increases, gas-fired generators move down in the power generation merit order, likely at the expense of coal fired plants, thereby increasing the demand for gas from the power generation sector. Hence, we include the price of coal and the price of CO_2 to capture these two effects.

The importance of gas in electricity generation varies per country. In The Netherlands natural gas accounts for the largest share in power generation, while in France it has a negligible share due to the intensive use of nuclear energy. Mainly driven by EU and national policies, there has been a vast increase in the share of renewables in electricity generation. This holds in particular for Germany, where the 'Energiewende' has resulted in a dramatic change in the energy mix. Renewables typically have very low marginal costs and have a lower position in the merit order than gas fired power plants. Demand for gas from the power sector is therefore reduced by the rise in renewable capacity in electricity generation. In order to capture this effect, we include a variable measuring the production of wind energy. As high-frequency data on wind energy is available for Germany and this country is centrally located in the North-west European region, we take these data as proxy for the production of wind energy in this region.[9] The day-ahead prediction of electricity generation from wind power in Germany is extracted from the 4 German TSOs 50 Hertz, Amperion, TenneT and TransnetBW. The sum of predicted electricity generation between super peak hours (10:00–19:00) is taken as it is during these hours when gas fired generators are most likely to run (Fig. 8).

2.6. Incidental shocks

In addition to the above fundamental factors, we have to control for a number of incidental shocks to the market. Supply disruptions can have a profound impact on hub prices. Because production is concentrated within a limited number of producers, disruptions in the supply of one company can lead to increased supply from more expensive sources or a decrease in total market supply. Given that demand is relatively inelastic in the short run and the flexibility of the remaining sources of supply is somewhat limited this can lead to sharp increases in spot prices at hubs following supply shocks.

In particular we include a dummy for the extremely cold temperatures throughout North-west and East Europe from the 31st of January until the 19th of February 2012. Gazprom was unable to meet the dramatic rise in demand for gas leading to shortages in a number of countries. Moreover, Russia alleged Ukraine of gas theft (Henderson and Heather, 2012). In addition, we include dummies for the Fukushima disaster and the consequent nuclear shutdown in Japan which have led to a substantial increase in Asian demand for LNG.

2.7. Empirical model

We estimate a linear regression model to investigate how the above mentioned supply and demand variables contribute to the short run development of the gas price (P_t^{TTF}). This allows us to identify the existence and strength of a relationship between the gas price and the selected market fundamentals. The explanatory variables are the Brent oil price (P_t^{Brent}), the price of coal (P_t^{coal}), the price of CO_2 permits (P_t^{CO2}), the Heating Degree Days (HDD_t) as measure for outside temperature, the HHI (HHI_t) as measure for market concentration, an index for industrial activity (IND_t), the

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[9] As high-frequency data on generation by solar cells are not available for the period of analysis, we can only measure the impact of RES through the generation by wind turbines.
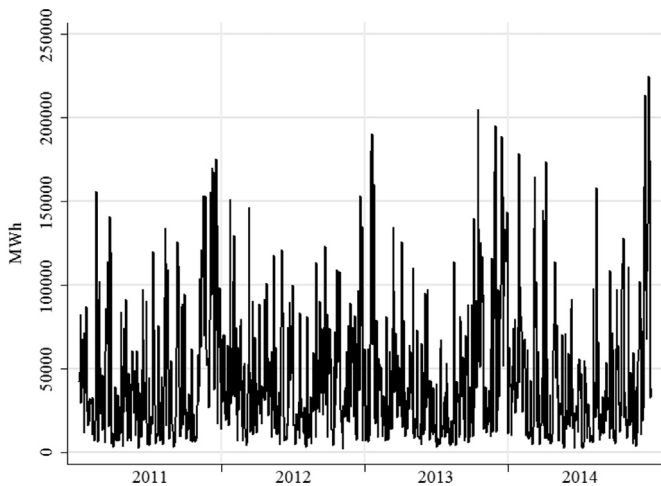
Fig. 8. Generation by wind parks in Germany during peak hours (10:00–19:00), per day in 2011–2014 (Source: own calculations based on 50 Hertz, Amperion, TenneT, TransnetBW).

filling degree of storages ($Stor_t$), a measure for the production of wind electricity in Germany ($ln\ Wind_t$), two dummies to capture exogenous shocks to the gas market (D_t^{shocks}), three dummies to capture the discovery of new major gas resources ($D_{p,t}^{DISC}$) and finally, dummies to control for the day-of-the-week effect (D_q^d, $q=1,2,..,5$). Hence, the following model is estimated:

$$ln\ P_t^{TTF}=\alpha+\beta\left(ln\ P_t^{Brent}\right)+\mu\left(d.\ ln\ P_t^{coal}\right)+\pi\left(d.\ ln\ P_t^{CO2}\right)+\gamma\left(HDD_t\right)$$
$$+\delta\left(ln\ HHI_t\right)+\zeta\left(ln\ IND_t\right)+\omega\left(Stor_t\right)+\rho\left(ln\ Wind_t\right)+\eta(D_t^F)$$
$$+\sum_{s=1}^{2}\varphi_s\left(D_t^{shocks}\right)+\sum_{p=1}^{3}\upsilon_p\left(D_{p,t}^{DISC}\right)+\sum_{o=2}^{5}\xi_o(D_{o,t}^d)+\varepsilon_t \tag{4}$$

The subscript t indicates time and $d.$ refers to the first differences of the variables P^{coal} and P^{CO2} which are I(1).

2.8. Statistical tests

The logarithms of all variables that only take up non-zero values are taken to allow for any nonlinear relationships and to facilitate interpretation. This concerns all prices, the industry index, market supply and HHI. Table B.1 in appendix B lists the correlation coefficients between the variables and variation inflation factor (VIF) for all dependent variables, defined as $1/(1 - R^2)$ where R^2 corresponds to the auxiliary regression of each regressor on the other set of independent variables. The descriptive statistics are listed in Table B.2 in appendix B. From Table B.1 we conclude that if we include the full set of independent variables the estimation may suffer from severe multicollinearity since several VIF estimates are undesirably high. This seems to be caused by the high correlation between the coal price, CO_2 price and discovery dummies. If the CO_2 price and discovery dummies are omitted from the model, the VIF estimates are in an acceptable range. We estimate versions of the model both including and excluding these four variables. The sign of the coefficients and significance levels are unaffected. The White test indicates that the null hypothesis of homoskedastic errors is rejected and therefore the equations are estimated with White robust standard errors. In order to control for serial correlation in the dependent variable, we include the lag of this variable as additional explanatory variable.

Augmented Dickey–Fuller (ADF) unit root tests are used to test for the presence of unit roots in the variables. Table 5 reports the test results for the full sample period and a subsample period excluding the last quarter of 2014. For the reported results, the lag length selection is based on the Bayesian information criterion.

Table 5
ADF unit root test results.

	04/01/2011–31/12/2014		04/01/2011–30/09/2014	
	Levels	First differences	Levels	First differences
ln(TTF gas price)	−3.056**		−3.063**	
ln(Brent oil price)	1.318	−30.355***	−3.763***	
ln(Coal price) [/]	−2.620	−25.225***	−2.479	−24.486***
ln(CO2 price) [/]	−1.444	−29.062***	−1.811	−28.015***
Gas storage	−1.736	−32.324***	−1.658	−31.267***
HDD	−3.288**		−3.260**	
ln(HHI)	−3.737***		−3.552***	
ln(Industry index)	−5.229***		−5.066***	
ln(Wind electricity)	15.611***		−15.302***	

Note: ***, **, * refer to 1%, 5% and 10% significance level. [/] trend included in levels test equation. The null hypothesis of the ADF test is the existence of a unit root.

For the full sample period, the gas price, industry index, gas supply, HDD, HHI and wind electricity variables are stationary in levels. The CO_2 and the coal price are non-stationary in levels but stationary in their first differences which are, therefore, included in the linear regression. Although the test indicates that the storage differential is non-stationary, we are sceptical regarding this result. There is no theoretical ground for non-stationarity in this case due to the fixed limits of the variable and seasonal utilisation of storage capacity. The storage differential, therefore, is treated as I(0).

Moreover, the ADF test suggests that the oil price is non-stationary in levels. However, a visual inspection (see Fig. 1) of the oil price does not object to stationarity. Rather, there seems to be a structural break at the last quarter of the sample period, when the oil price almost halved in three months subsequent to a sharp decrease on the 1st of October 2014. A Chow test confirms the existence of a structural break on this date (F(13, 712)-test statistic is 1.87). The ADF test results for the subsample excluding the last quarter of the sample are materially the same for all variables, except for the oil price which is now stationary in levels. To derive a consistent estimator for the effect of the oil price, we therefore proceed with the subsample excluding the last quarter of 2014.[10]

Some of the independent variables may suffer from an endogeneity bias due to reverse causality. The storage differential and oil price are possibly a function of the gas price themselves because oil and gas are competing fuels while the storage facilities may react to gas price fluctuations. One could argue, along the lines of the Lucas critique, that oil prices and storage behaviour are influenced by expected future gas prices, which would invalidate the exogeneity of the instruments. Other credible alternative exogenous instruments are, however, difficult to find. Hausman endogeneity tests are used to assess whether gas storage and the oil price are exogenously determined. The results are reported in Table 6. The instruments used are the first order lags of the respective variable. The results imply that the gas storage differential is exogenously determined whereas the oil price is not. To obtain consistent estimates we use instrumental variable (IV) regression using the first order lag of the oil price as instrument for the current oil price.

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[10] In order to further test the stationarity, we applied the Dickey–Fuller test on the residuals of the regression model. Referring to Hamilton (1994), we must reject the null hypothesis of a unit root. Hence, we conclude that the model can be viewed as stationary.

Table 6

Hausman *F*-test statistics for exogeneity using the first order lag as instrument (*p*-value in parentheses) and *F*-test statistic for instrument relevance.

Hausman	
ln(Brent oil price)	4.80 (0.028)**
Gas storage	0.28 (0.597)
Instrument relevance	
l.ln(Brent oil price)	9906
l.Gas storage	68,037

Note: ** Statistically significant at 5%.

3. Results and discussion

The results of the regression analysis are presented in Table 7. To take into account that the estimation may suffer from multicollinearity two versions of (4) are estimated. The complete model in Table 7 includes all dependent variables whereas in the other model the CO_2 price and discovery dummy variables are excluded. Exclusion does not materially change the results for the other variables.

The regression estimations confirm that supply and demand fundamentals are important for short-run price determination and that prices are to a large extent determined by gas-to-gas competition. The first order lag of the gas price is highly important for the current gas price. The coefficient of approximately 0.92 suggests a high degree of inertia within the system. The estimates imply that the Brent oil price positively affects the day-ahead TTF gas price, but the effect is small. The elasticity in the complete model is 0.054 and 0.042 in the parsimonious model i.e. an increase in the price of oil by 10% increases the gas price by 0.42–0.54%. Changes in the price of coal have a positive but insignificant effect on the spot price of gas. This positive relationship is in line with the direct fuel competition between coal and gas in the power sector. The price of CO_2 does not seem to have influenced the spot price of gas during the sample period. Our estimates for the macroeconomic indicator are positive but insignificant. Deviations from the average level of storage capacity utilisation help explain daily fluctuations in the gas price, as the coefficients are

significantly negative. When the filling degree of storage facilities is below expected levels, the spot price of gas is higher. The estimated effect is small as the point estimate implies that a 1 percentage point increase in the deviation from average utilisation is associated with a decrease in the gas price of approximately 0.0007–0.0008%.

As expected the coefficients for heating degree days are positive and significant at 1%, implying that the outside temperature is important for the short run development of the gas price.

There appears to be no effect of a change in the HHI on the spot price of gas. This effect is negative but statistically not significant. While the daily average HHI increased from 1905 in 2011 to 2098 in 2014, the degree of competition as measured by the HHI did not affect spot price development. Suppliers of gas to the European market do not seem to be able to exert market power and profitably raise prices. Therefore, pricing of natural gas at European hubs appears to be competitive and not affected by the degree of competition

In contrast with our a priori expectation, the sign of expected German wind generation is positive and significant at 1%. The estimated effect is small: a 0.032% increase in the day-ahead TTF price for a 1% increase in expected generation of wind. Further investigation into the Dutch–German cross-border electricity connection, however, reveals that when expected wind generation in Germany is high, the Dutch TSO operating the cross-border connection, TenneT, reduces the available cross-border electricity connection capacity significantly in order to deal with loop flows (TenneT, 2014). Consequently, domestic electricity production in The Netherlands needs to be increased to meet demand which raises the demand for gas from the Dutch power sector causing a minor upward pressure on the gas price. Hence, this result regarding the effect of renewable electricity on the gas price is related to the fact that renewable electricity may create bottlenecks in the electricity grid through loop flows. Loop flows are unscheduled flows stemming from scheduled flows within a neighbouring bidding market. Unscheduled flows are implicitly prioritised in the current market, which means that the size of the cross-border capacity which is available for trade is calculated after controlling for (expected) loop flows (Thema Consulting Group, 2013). The existence of this problem is related to the distinction between the definitions of regional markets and the

Table 7

Results of IV regressions analysis over 2011–2014.

	Complete model		**Excluding discovery dummies and CO2 price**	
ln(TTF gas price)	Coefficient	Standard error	Coefficient	Standard error
constant	−0.0804615	0.1276223	−0.0302767	0.1168564
l.ln(TTF gas price)	0.9210672***	0.0141282	0.9250257***	0.0136737
ln(Brent oil price)	0.0536673**	0.0232900	0.0424412**	0.021053
d.ln(Coal price)	0.1067752	0.1034514	0.1184197	0.1035376
ln(Industry index)	0.0176299	0.0193639	0.0122521	0.019169
d.ln(CO2 price)	0.0378437	0.0262201		
Gas storage	−0.0007680***	0.0001867	−0.0007494***	0.0001837
HDD	0.0008540***	0.0002735	0.0006889***	0.0002445
ln(HHI)	−0.0030387	0.0243245	−0.0079741	0.0199788
ln(wind electricity Germany)	0.0031654***	0.0011417	0.0031312***	0.0011424
Dummy Fukushima	0.0050091	0.0051273	0.0010574	0.0041612
Dummy Russia 2012	0.0000160	0.0085338	0.001855	0.0086916
Dummy DISC_1	−0.0062035	0.0048638		
Dummy DISC_2	0.0026992	0.0039164		
Dummy DISC_3	−0.0226407	0.0217259		
Dummy day_2	−0.0059824*	0.0032626	−0.0057887*	0.0032657
Dummy day_3	−0.0100036***	0.0032646	−0.0096806***	0.0032667
Dummy day_4	−0.0119538***	0.0032388	−0.0115321***	0.0032364
Dummy day_5	−0.0051642	0.0032500	−0.0049093	0.0032558
R^2	0.95		0.95	
N	901		901	

Note: ***, ** and * refer to 1%, 5% and 10% significance levels, respectively. We us the first order lag of the Brent oil price as instrument for the Brent oil price.

Table B.1
Correlation coefficients and Variance Inflation Factor (VIF)[a]

	ln(Brent oil price)	ln(Coal price)	ln(CO2 price)	HDD	Gas storage	ln(HHI)	ln(industry index)	ln(wind electricity)	DummyRussia 2012	Dummy Fukushima	DDISC_1	DDISC_2	VIF	VIF excl. CO2 price and discoveries
ln(Brent oil price)													1.02	1.11
ln(Coal price)	0.0969												12.82	2.30
ln(CO2 price)	0.0444	0.8491											8.67	
HDD	0.1878	0.1120	−0.0625										1.75	1.27
Gas storage	0.0712	0.2178	0.4640	0.0648									2.06	1.14
ln(HHI)	−0.1855	−0.6861	−0.6182	−0.1903	−0.3262								2.23	2.12
ln(industry index)	−0.0466	0.0750	0.1768	−0.1298	0.0791	−0.0688							1.10	1.04
ln(wind electricity)	0.0180	0.0275	−0.0530	0.2340	0.0111	−0.0637	−0.0560						1.08	1.07
Dummy Russia 2012	0.1761	0.0527	0.0567	0.2900	0.1157	−0.1188	−0.0498	0.0252					1.22	1.13
Dummy Fukushima	0.0994	−0.4858	−0.5619	−0.1595	−0.1365	0.2870	−0.0920	0.0101	0.0371				1.95	1.42
DDISC_1	0.1976	−0.8003	−0.8086	0.1616	−0.1836	0.4378	−0.1196	0.0683	0.0638	0.5820			5.69	
DDISC_2	−0.1588	−0.8731	−0.7632	−0.1283	−0.3724	0.6675	−0.1244	−0.0260	−0.1775	0.3898	0.6698		5.65	
DDISC	−0.0691	−0.0612	−0.0213	−0.0485	0.0215	0.0886	0.0657	−0.0529	−0.0061	0.0135	0.0231	0.0345	1.02	

[a] VIF is defined as $1/(1 - R^2)$ where R^2 is the square of the correlation coefficient of an auxiliary regression with the respective column variable as dependent variable and all other variables as regressors.

physical realities of the electricity networks. An policy option to solve this problem is to introduce dynamic prices for using the grid, resulting in electricity prices which are not only related to the demand and supply of electricity but also to the existence of network constraints. If these problems regarding international trade in electricity markets would be solved, an increase in the supply of renewable electricity may be expected to have a negative effect on the demand for gas and, hence, the price of gas, as gas-fired power plants may be switched off to keep the power system in balance.

The Fukushima nuclear disaster did not lead to higher spot gas prices at the TTF. In addition, we do not find evidence that the extremely cold weather in February 2012 throughout Europe had a significant effect on the TTF gas price. Regarding the giant discoveries, none of the giant discoveries had a significant effect on the spot price. Perhaps the typically high degree of uncertainty associated with new discoveries, for example regarding the true size of the recoverable reserves, is a reason for the lack of a reaction in gas spot prices. Another suggestion is that the lag between discovery and extraction is too long to have an effect on the current price.

The high degree of persistence in the gas price may to some extent reflect the high degree of persistence in the underlying fundamental variables. Temperature tends to develop relatively smoothly while gas storage and supply are also fairly inflexible in the short term as a result of technical restrictions and planned cycles. Disentangling flexible and inflexible supply sources and storage facilities should provide more clear evidence on these mechanisms although data limitations currently complicate such an analysis

4. Conclusions and policy implications

We have found that the gas prices at hubs can be viewed as prices resulting from gas-to-gas competition. Fundamental factors affecting demand or supply in the gas market have significant effects on the movements in the day-ahead gas price. Although the price of gas is still related to the price of oil, this linkage is not strong anymore. Moreover, the high degree of concentration on the supply side of the gas market does not affect the gas price, suggesting that the market prices are not distorted by a lack of competition.

Our findings indicate that the policy measures implemented in the North-west European countries to introduce competition in wholesale gas markets and to integrate these markets by reducing cross-border barriers appear to have been successful in realising an efficiently working gas market. These effective policy measures are related to the capacity-allocation mechanisms and congestion management as well as investments in cross-border capacity. Policies to further integrate national gas markets within Europe may extend this gas-to-gas competition to a larger region. These policies may contribute to realise a fully integrated European energy market as it is pursued by the European Commission (EC, 2015).

Acknowledgements

Appendix A. Market entry points in the pipeline infrastructure via which non-indigenous gas supply enters the North-west European system.

The relevant border points are listed per supply source below. The TSO at the arriving end of the border point is noted between brackets.

Norway
1. Zeebrugge Pipeline Terminal (Fluxys)
2. Emden EPT (Gasunie Deutschland)
3. Emden NPT (Gasunie Deutschland)
4. Dunkerque (GRT gaz de France)
5. Emden EPT (GTS)
6. Emden NPT (GTS)
7. Easington (National Grid)
8. St. Fergus Shell (National Grid)
9. St. Fergus Total (National Grid)
10. Dornum (Open Grid Europe)
11. Emden EPT (Open Grid Europe)
12. Emden NPT (Open Grid Europe)
13. Teesside (National Grid)
14. Emden EPT (Thyssengas)
15. Dornum (Gasunie Deutschland)
16. Dornum (Jordgas)

Russia
1. Velke Kapusany (Eustream)
2. Greifswald (OPAL)
3. Greifswald (NEL)
4. Kondratki (GAZ-SYSTEM)

Algeria
1. Tarifa (Enagas)
2. Almeria (Enagas)
3. Gela (Snam)
4. Mazara (Snam)

LNG
1. Montoir (GRT gaz de France Nord)
2. Fos (GRT gaz de France Sud)
3. Isle of Grain (National Grid)
4. Teesside (National Grid)
5. Zeebrugge LNG (Fluxys)
6. Southook (National Grid)
7. Dragon (National Grid)
8. Barcelona (Enagas)
9. Bilbao (Enagas)
10. Cartagena (Enagas)
11. Huelva (Enagas)
12. Mugardos (Enagas)
13. Sagunto (Enagas)
14. Panigaglia (Snam)
15. Rovigo (Snam)
16. Sines (REN)
17. Gate LNG (GTS)
18. Livorno (Snam)

Appendix B. Correlation coefficients and descriptive statistics

See Table B.1 and Table B.2

Table B.2

Descriptive statistics (all daily averages)*Sources*: *TTF gas price, Brent oil price*: ICIS Heren; *Coal price, CO2 price*: Bloomberg; *HDD*: ECA&D; *Gas storage*: GIE/GTS; *Supply*: Eclipse; *HHI*: own calculations; *Industry index*: Eurostat; *Wind electricity*: 50Hertz, Amperion, TenneT, TransnetBW.

		2011	2012	2013	2014
TTF gas price (€/MWh)					
	Min	15.6	20.78	24.85	14.88
	Max	25.85	37.63	41	26.85
	Average	22.71	25.00	27.03	20.41
	Std. Deviation	1.36	2.04	2.2	3.24
Brent oil price (€/Barrel)					
	Min	69.97	70.29	73.80	73.64
	Max	87.75	97.60	89.73	84.64
	Average	80.52	86.88	81.84	78.57
	Std. Deviation	3.33	5.17	3.22	2.25
North-west European coal price (€/Tonne)					
	Min	109.5	83	72.6	71.4
	Max	133.00	110.95	90.5	86.4
	Average	121.55	92.45	81.62	76.13
	Std. Deviation	5.47	5.95	4.68	3.22
CO2 price (€/Tonne)					
	Min	6.57	5.73	2.75	4.44
	Max	17.46	9.52	6.66	7.19
	Average	13.00	7.49	4.52	5.80
	Std. Deviation	3.12	0.73	0.67	0.60
HDD (Degree Celcius)					
	Min	0	0	0	0
	Max	18.9	24.17	19.37	15.67
	Average	5.83	7.03	7.28	4.82
	Std. Deviation	5.38	6.20	6.15	4.74
Deviation from average gas storage filling degree (percentage point)					
	Min	− 7.33	− 4.18	− 37.72	− 2.05
	Max	10.58	14.2	2.82	15.2
	Average	3.65	2.24	− 11.37	9.42
	Std. Deviation	3.43	5.69	7.51	4.51
HHI					
	Min	1780	1820	1931	1876
	Max	2118	2150	2403	2242
	Average	1905	1944	2107	2083
	Std. Deviation	75	67	101	58
Supply (GWh)					
	Min	8524	8278	9238	8484
	Max	16,128	15,566	13,655	12,830
	Average	12,103	11,791	11,697	10,569
	Std. Deviation	1934	1840	1080	1129
Industry index					
	Min	90.09	87.57	86.29	84.45
	Max	115.73	111.75	110.18	109.57
	Average	104.47	101.41	100.86	101.69
	Std. Deviation	7.27	7.04	6.51	7.20
Production of wind electricity in Germany (GWh) 10:00–19:00					
	Min	2.97	2.52	3.38	3.00
	Max	155.98	175.47	204.82	178.30
	Average	43.48	45.54	45.33	43.15
	Std. Deviation	37.00	35.27	40.61	38.14

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