Energy Policy 49 (2012) 707–718

Contents lists available at SciVerse ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Have oil and gas prices got separated?

Péter Erdős *

Swiss Institute of Banking and Finance, University of St. Gallen, Rosenbergstrasse 52, 9000 St. Gallen, Switzerland

HIGHLIGHTS

- VEC models are applied to investigate the relationship between oil and natural gas prices.
- While natural gas prices in Europe and Asia react to oil price, US gas price decoupled from oil in 2009.
- Since 2009, the US gas price has decoupled from the European and Asian gas prices.

ARTICLE INFO

Article history:
Received 2 April 2012
Accepted 11 July 2012
Available online 5 August 2012

Keywords:
Gas prices
Oil prices
Atlantic arbitrage

ABSTRACT

This paper applies vector error correction models that show that oil and natural gas prices decoupled around 2009. Before 2009, US and UK gas prices had a long-term equilibrium with crude prices to which gas prices always reverted after exogenous shocks. Both US and UK gas prices adjusted to the crude oil price individually, and departure from the equilibrium gas price on one continent resulted in a similar departure on the other. After an exogenous shock, the adjustment between US and UK gas prices took approximately 20 weeks on average, and the convergence was mediated mainly by crude oil with a necessary condition that arbitrage across the Atlantic was possible. After 2009, however, the UK gas price has remained integrated with oil price, but the US gas price decoupled from crude oil price and the European gas price, as the Atlantic arbitrage has halted. The oversupply from shale gas production has not been mitigated by North American export, as there has been no liquefying and export capacity.

1. Introduction

On empirical and theoretical grounds, oil and gas prices exhibit a strong relationship. Oil and gas are close substitutes in the long run, thus these fuel prices should form a long-term equilibrium level around which they swing in the short run. The equilibrium level should be close to thermal parity, i.e., the price level at which one million British thermal units (Btu) of oil is sold for the same price as one million Btu of natural gas.[1] Brown and Yücel (2008) find clear evidence that oil prices drive US gas prices, controlling for exogenous gas industry-related variables. More recently, in an extension of their previous model, Brown and Yücel (2009) conclude that the co-movement of European and North American natural gas prices is driven by crude oil prices rather than gas-to-gas arbitrage across the Atlantic. Despite the ample empirical evidence, US oil and gas prices have decoupled since January 2009. This paper applies a similar model as Brown and Yücel (2009) and shows that, based on vector error correction models, oil and natural gas prices decoupled around the end of 2008. Before 2009, US and UK gas prices had a long-term equilibrium with crude prices to which gas prices always reverted after exogenous shocks. Both US and UK gas prices adjusted to the crude oil price individually, and departure from the equilibrium gas price on one continent resulted in a similar departure on the other. After an exogenous shock, the adjustment between US and UK gas prices took approximately 20 weeks on average, and crude oil mainly mediated the convergence with a necessary condition that arbitrage across the Atlantic was possible. After 2009, however, the UK gas price has remained integrated with the oil price, but the US gas price has decoupled from crude oil, as the Atlantic arbitrage has halted. The oversupply from shale gas production has not been mitigated by North American export, as there has been no liquefying and export capacity.

The question is whether the divorce between US oil and natural gas prices is permanent. If oil-linkage persists in Europe and Asia, we might eventually see US gas and oil prices coupling and US and European or Asian gas prices balancing in the long run. However, US oil and gas price equilibrium cannot rise overnight, as it requires that either North American gas consumption substantially increases or North American liquefying and export capacities are developed that can cope with the

* Tel.: +41 71 224 7037.
E-mail address: peter.erdos@unisg.ch

[1] Brown and Yücel (2007) indicate that it is more realistic if thermal parity at the burner tip is considered, accounting for different shipping costs of competing fuels.

0301-4215/$ - see front matter © 2012 Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.enpol.2012.07.022

oversupply. The third less likely option is to reduce production considerably, which is less feasible because adapting producers to the elevated supply is sluggish, as a lease contract is for a limited period of time, typically ten years (43 CFR Chapter II, Subchapter C—Minerals Management (3000)). Even if it were economical to halt production when there is oversupply and wait until prices recover, the limited nature of lease contracts might not allow production suspension in the short run.

The remainder of the paper is organised as follows. Section 2 reviews the three main gas-consuming regions and related literature. Section 3 presents the theoretical model concerning what drives gas prices and Section 4 introduces the data. Section 5 provides the statistical models and empirical results, and Section 6 presents the conclusions.

2. Review of gas-consuming regions and related literature

Differing from the oil market, which is a globally connected market, natural gas markets are segmented. On the one hand, oil is relatively cheap and easy to ship; if there is a significant price differential between continents, arbitrage positions thus enforce price balancing.[2] On the other hand, the energy density of natural gas is only a thousandth the size of that of crude oil, which makes transporting natural gas far more complex and expensive. Gas pipelines are shown to be over seven times more expensive than oil pipelines (Geman, 2005, p. 248). LNG (liquefied natural gas) shipping vessels are also over six times more expensive than oil tankers. Freight rates show similar differences, making LNG shipments approximately six times more expensive than oil shipments (Lloyd's Shipping Economist, 2011; UNCTAD, 2011, p. 66). Long-distance natural gas shipping (more than 2500 miles) is cheaper in its liquefied form (Geman, 2005), and there is no pipeline across the Atlantic or Pacific Basin.

The excessive natural gas shipping costs mean that gas-to-gas competition is limited and might result in substantial short-term price differentials between regionally segmented markets. Three major regional markets exist, all of which exhibit different properties. Currently, the largest market is Europe, followed by North America and Pacific Asia. The European market is characterised mainly by importing natural gas from Russia, Norway and Algeria; there are also two major domestic sources: UK offshore gas fields under the North Sea and one giant onshore field in Groningen (The Netherlands).

Natural gas is a homogenous product; quality differences cannot account for substantial price differentials.[3] The only major quality difference is between conventional gas and its liquefied form. The LNG is of better quality, as its methane content is higher and its combustion emits less carbon dioxide. Although LNG is more expensive than conventional gas due to higher production costs, it can be shipped in a way similar to crude oil and used as auto fuel.

In continental Europe, gas is sold mainly based on long-term contracts that consider the 'replacement value' of natural gas, i.e., pricing reflects competing fuel prices (e.g., heavy and light fuel oil, crude oil, coal and electricity) in the buyer's country (Davoust, 2008). Continental gas prices follow developments in the oil market with a time lag of four to nine months (Asche et al., 2002; Siliverstovs et al., 2005; Davoust, 2008). Furthermore, Russian, Norwegian and Dutch natural gas prices are indexed at over 80% compared to fuel oil products, while crude oil has a 70% weight in the Algerian gas price. Davoust (2008) argues that fuel oil products have an importance of 80% in Western European gas prices but 95% in Eastern European gas prices. Similar pricing schemes in Europe result in integrated markets; Asche et al. (2001, 2002), Siliverstovs et al. (2005), and Harmsen and Jepma (2011) show that European prices are integrated. Somewhat conversely, Robinson (2007) finds mixed evidence on the convergence of European gas prices. Furthermore, Neumann et al. (2006) show that the German Bunde and Belgian Zeebrugge gas prices have not converged.

The opening of the Interconnector between Bacton and Zeebrugge in 1998 has contributed to integrating the UK market into the continental European markets (Neumann et al., 2006). The pipeline under the English Channel can flow in both directions: it flows from the UK to Europe when prices are higher on the Continent, and natural gas flows from the Continent to the UK when prices are higher in the UK. Asche et al. (2006) and Panagiotidis and Rutledge (2007) conclude that the UK gas and Brent prices were cointegrated before and after the opening of the Interconnector. In a more recent paper, Harmsen and Jepma (2011) also confirm that the UK market is integrated with the continental European market.

A few major players buy natural gas in Europe, predominantly from national gas companies, based on long-term contracts that link gas prices to oil prices. Long-term agreements usually include a so-called TOP (take-or-pay) clause, where the buyer is obliged to buy at least a certain part of the contracted volume or must pay a penalty. Because of the seasonal nature of gas demand, TOP clauses can lead to supply (including inventory levels) exceeding demand. However, large imbalances in the European markets are not likely because trading hubs provide an efficient way to dissolve disequilibrium between national markets. The gas-to-gas competition that characterises Europe thus fosters close-to-equal prices through national markets.

The Pacific–Asia region is not connected to producing areas via pipelines; nevertheless, natural gas is important to the region's energy mix. Japan, South Korea and China are the largest LNG importers. They mainly import from Indonesia, Malaysia, Australia and the Middle East, based on long-term contracts. The Japanese Custom Cleared crude oils, nicknamed the Japanese Crude Cocktail (JCC), are used as an indexation benchmark. Siliverstovs et al. (2005) show that Japanese LNG prices are integrated with European gas and Brent crude oil prices but not with US gas prices.

In the third major consuming region, North America, there is no explicit link between oil and natural gas prices. However, North American gas markets exhibited strong convergence after opening network access in 1985, in accordance with FERC (Federal Energy Regulatory Commission) order 436 (Serletis, 1994; Walls, 1994; De Vany and Walls, 1995; King and Cuc, 1996; Cuddington and Wang, 2006). There is also evidence of inter-fuel competition: Villar and Joutz (2006) find a rather stable relationship between West Texas Intermediate (WTI) oil and Henry Hub (HH) natural gas prices, even if there are periods when they may have appeared to decouple in the short run. Similarly, Serletis and Herbert (1999) conclude that US natural gas prices are cointegrated with US fuel oil prices. Barcella (1999) finds that crude oil or refined products and gas prices show high correlation and are cointegrated because of significant inter-fuel competition in the US electric power sector. Bachmeier and

[2] This view is challenged by the recent price differential between Brent and WTI. The Brent premium over the WTI reached an all-time high of approximately \$27 per barrel in September 2011. Although the premium dropped to approximately \$10 per barrel by the end of 2011, it is still extraordinary; between 1994 and 2011, the market priced the average premium at 4.18% for the WTI or slightly less than \$2 per barrel on average. This has a similar magnitude to the shipping cost of one barrel of crude oil from Europe to the US (Lloyd's Shipping Economist, 2011). The all-time high inventory level in Cushing (Oklahoma, the delivery point of the WTI crude oil), observed closely by oil traders, caused the recent Brent premium. However, inventories in Cushing might not reflect global oil demand; tightening of the Brent–WTI spread is thus expected.

[3] US and Russian gas have energy densities of 1281 and 1275 million Btu per cubic feet, respectively.

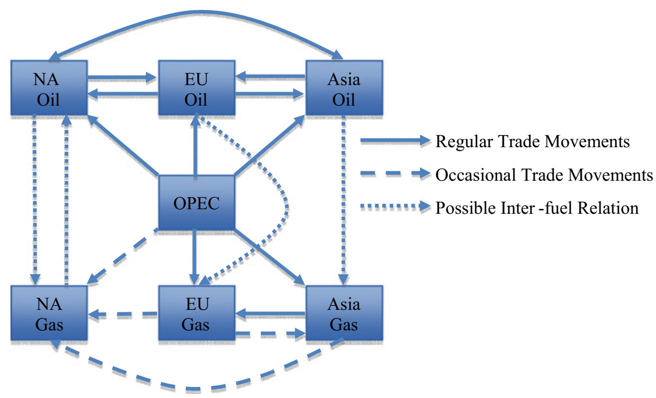

Fig. 1. This figure schematically describes the natural gas and oil trade movements and possible inter-fuel relations regionally and intercontinentally.

Griffin (2006) document strong integration between the US oil and gas markets. However, Siliverstovs et al. (2005) find that US gas prices are not integrated with Brent crude oil prices.

3. Theoretical gas market model

Brown and Yücel (2008), applying a VEC model that controls for exogenous variables related to the gas industry, show that oil price movements can explain natural gas prices between June 1997 and July 2006. Although they extend the analysis with an intercontinental outlook in their more recent paper (Brown and Yücel, 2009), their data exclude the post-2008 period when US oil and gas prices decoupled. They thus conclude that the co-movement of European and US gas prices reflects inter-fuel competition on both continents and, to a lesser degree, LNG trade movements across the Atlantic. Conversely, Neumann (2009) argues that European and US gas prices exhibit convergence because of increasing spot LNG trading. On both theoretical and empirical bases and being aware of the post-2008 period, this study shows that intercontinental arbitrage is a necessary condition of the long-term US gas and oil price integration. In the past decade, there was little room for inter-fuel competition in the US, as the importance of crude oil in electricity generation was marginal: even if natural gas was cheaper than oil, dual-fired power plants could not switch from oil to natural gas, as most already ran on natural gas.[4] Inter-fuel replacement is possible through other channels, but these channels, e.g., natural gas as auto fuel or GTL (gas-to-liquid) projects, are in their infancy.

Insufficient inter-fuel replacement, however, does not necessarily mean that US oil and gas prices tend to decouple. Fig. 1 shows a schematic overview of the intercontinental trade movements and possible inter-fuel replacement channels in oil and natural gas markets: NA refers to North America, here the US plus Canada; the EU refers to Europe (excluding Russia); and Asia refers to Pacific–Asia plus Russia. All three consuming regions import oil and natural gas from OPEC. Europe also imports oil and natural gas from Russia as well as former Soviet states and imports oil from the US. North America imports oil from Europe, Russia and OPEC, and it imports LNG from OPEC, Norway and Pacific Asia, occasionally on a netback basis. LNG exports from the US are not substantial; only the intra-continental US pipeline gas export to Canada and Mexico is noteworthy. Pacific Asia (excluding producing nations such as Indonesia, Malaysia, Brunei and Australia) imports oil from Europe and North America as well as OPEC countries. Europe does not export natural gas to Pacific Asia; however, if there were a significant price difference between the two continents, arbitrage would be possible on a netback basis.

Intercontinental gas-to-gas competition can trigger a long-term oil–gas relationship in the US even if the inter-fuel replacement is marginal. However, this is only possible if gas prices are higher in the US than in Europe or Asia. Higher US prices attract LNG shipments on a netback basis that lowers the US gas price to a level that equals the European or Asian price plus freight to the US. Importing cheaper oil-indexed European or Asian gas would imply coupling oil and gas prices in North America. Conversely, if the US price level is lower than the European and Asian prices, assuming limited inter-fuel competition, natural gas prices decouple from oil prices. Currently, there are administrative obstacles that are against natural gas exports from the US, but the US does not have sufficient LNG export capacity to allow natural gas outflow in large quantities even without these restrictions. The exporting obstacles in the US along with the oversupply cause US oil and gas prices to decouple.

4. Data

Following Brown and Yücel (2008, 2009), weekly spot West Texas Intermediate (WTI) prices and Henry Hub (HH) prices represent the US oil and natural gas markets, respectively. The WTI price is considered a proxy for the global crude price.[5] As the intercontinental gas-to-gas competition depends on the premium of the US gas price over oil-linked gas prices, a suitable European or Asian benchmark is needed. The most liquid and longest-standing available oil-related gas price is the National Balancing Point (NBP). As shown in Section 2, UK gas prices are explicitly not linked to oil prices but are fully integrated with the oil-driven continental European gas prices. Furthermore, Siliverstovs et al. (2005) show that the Japanese LNG price, which is the leading benchmark for the Asian LNG market, is integrated with European gas prices. This is not striking, as both European and Asian gas prices are anchored to crude prices. For simplicity, European and Asian prices are thus represented with one single series. The spot NBP prices hereafter capture the oil-integrated gas markets. Brown and Yücel (2009) and Neumann (2009) also use the NBP price as a proxy for European gas prices.

The spot HH, NBP and WTI price series were downloaded from Datastream for the period from January 1994 to December 2011. The NBP price, which is available only from February 1997, is quoted originally in the UK pence per therm; this is converted to US dollars per million Btu. The British pound is changed to the US dollar at the daily official exchange rate of the Bank of England.

5. Statistical models and results

Engle and Granger (1987) suggest that linear combinations of non-stationary time series integrated at the same order can produce stationary time series. They call the linear combination of such series the cointegrating vector. The cointegrating vector constituents have the same stochastic component: in their linear combination, the stochastic trend is cancelled out, and the series head to their equilibrium levels in the long run. The econometric analysis in this study applies vector error correction (VEC) models that account for the possible cointegrating relationship between

[4] As of 2010, fuel oil use in power generation was only 1.2% in 2010 (EIA, 2012).

[5] Brown and Yücel (2009) also apply the Brent crude oil in their analysis, but it became insignificant after involving the WTI.

fuel prices and relate to the period 1997–2011. The VEC analysis might capture the assumed long-term relationship between natural gas and oil prices. Such an analysis hypothesises that if fuel prices can depart from the equilibrium level in the short-term due to exogenous shocks, there is always the tendency that competing fuel prices revert to the long-term equilibrium level modelled by the cointegrating vector.

5.1. Time series properties of gas and oil prices

To check whether fuel prices are integrated at the same order, unit root and stationarity tests are performed on the level and first differences of HH, NBP and WTI prices: Table 1 reports the results. Three test statistics were calculated: the Augmented Dickey and Fuller, 1979 and Phillips and Perron (1988) tests with a null hypothesis of unit root and the Kwiatkowski et al., (1992) test with a null of stationarity. Brown and Yücel (2008) argue that, considering the energy content of both fuels, one million Btu of natural gas should be priced approximately 0.1511 times the price of one barrel of WTI less the approximately half dollar shipping cost to the burner tip; this is the so-called 'burner tip parity'. One can thus expect that the HH to WTI price ratio should converge to this value in the long run. From January 1994 to December 2008, this was the case; though the US natural gas was underpriced for burner tip parity on average, the HH to WTI price ratio always returned to this value. Conversely, the ratio has not drifted back to the burner tip parity level since January 2009. The tests are performed for three periods: the longest period data available (January 1994 to December 2011); the period when the price ratio drifted back to burner tip parity (January 1994 to December 2008, although the NBP price is only available from February 1997); and the period when the burner tip parity was not fulfilled (January 2009 to December 2011). The dataset is small for the tests using 2009–2011 data, and these may be exposed to dimensionality problems. For the period when oil and US gas prices did not diverge (January 1994 to December 2008), the price series showed random walk, i.e., the unit root hypothesis cannot be rejected, but stationarity can be rejected. Since January 2009, WTI and NBP prices, which are assumed to be closely related even in this period, have not shown evidence against unit roots, and the HH price that decoupled from oil appears to be stationary; random walk can be ruled out but not stationarity.

The WTI and NBP prices are integrated at order one, i.e., price levels include a random walk component, while the first differences are stationary. On the contrary, the HH price in the period January 2009–December 2011 exhibited clear signs of stationarity. As mentioned above, first difference stationary series can demonstrate cointegrating long-term relationships, which should be considered in modelling to avoid misleading inferences. To test for cointegration, pairwise Johansen (1991) tests are performed (Table 2). In the testing vector autoregression (VAR), lag selection is based on the Akaike criterion, and only the cointegrating equation includes a constant. For the full sample period, the cointegrating relationship between HH and WTI can be rejected, which is likely due to the change in price formation in the three years after 2009. Before 2009, there is a long-term relationship between HH and WTI. There is a long-term equilibrium between NBP and WTI; however, the relationship is weaker after 2009 than before. After 2009, only the maximum eigenvalue statistic indicates a long-term relationship at the 95% level for the period 2009–2011. The relationship between HH and NBP shows a similar picture: cointegration cannot be questioned before 2009, but it can be rejected at any usual significance level after 2009. Cointegration test results clearly indicate that the relationship between the US gas and oil markets has changed since January 2009. The model in Fig. 1 suggests that such a breakpoint could evolve, as the natural gas price became lower in the US than in Europe and the US natural gas price thus decoupled from the oil price. Conversely, if the US gas price was higher than the European price before 2009, trade movements tended to balance prices across the Atlantic.

5.2. Gas price models

In this paper, the most general VEC model applied to fuel prices allows for causality links between oil and natural gas prices and controls for exogenous shocks in the natural gas industry. The VEC thus includes heating and cooling degree days and their deviations from seasonal norms, Gulf of Mexico natural gas production shut-ins and natural gas storage deviations from the five-year average as exogenous variables. The Climate Prediction Center of the National Center for Environmental Prediction collects the weekly weather-related variables. Degree days are available only from June 1997, which limits the time span of the analysis. The shut-in statistic is obtained from the Bureau of Ocean Energy Management and based on storm reports. Cumulative weekly shut-in is calculated from individual reports in billion cubic feet. The US Energy Information Administration publishes weekly gas inventory levels and five-year averages for that week in billion cubic feet. Moreover, to account for gas-to-gas adjustments over the Atlantic, the NBP price is added as a third endogenous variable to the HH natural gas and WTI oil prices.

Table 1
This table shows the test statistics of the Augmented Dickey and Fuller (1979), Phillips and Perron (1988) unit root and Kwiatkowski et al. (1992) stationarity tests and associated *p*-values. These tests are applied using weekly data that include the spot Henry Hub (HH) natural gas price, the National Balancing Point (NBP) gas price and the West Texas Intermediate (WTI) oil price. A constant is included in both the level and first difference test equations. The Schwarz criterion is used for ADF lag selection, and the Newey–West automatic bandwidth selection is used for the PP and KPSS tests.

		Augmented Dickey and Fuller (1979)				Phillips and Perron (1988)				Kwiatkowski et al. (1992)			
		Level		First Difference		Level		First Difference		Level		First Difference	
		t-stat	*p*-value	*t*-stat	*p*-value	*t*-stat	*p*-value	*t*-stat	*p*-value	LM-stat	*p*-value	LM-stat	*p*-value
HH	Jan 1994–Dec 2008	−2.851	0.052	−27.489	0.000	−2.615	0.090	−27.969	0.000	2.639	0.000	0.029	0.916
NBP	Feb 1997–Dec 2008	−2.278	0.180	−8.136	0.000	−2.197	0.208	−28.507	0.000	2.123	0.000	0.024	0.971
WTI	Jan 1994–Dec 2008	−2.270	0.182	−6.383	0.000	−1.842	0.360	−29.633	0.000	2.496	0.000	0.071	0.471
HH	Jan 2009–Dec 2011	−2.982	0.039	−8.915	0.000	−3.513	0.009	−14.485	0.000	0.115	0.302	0.060	0.572
NBP	Jan 2009–Dec 2011	−1.325	0.617	−11.955	0.000	−1.431	0.566	−11.973	0.000	1.193	0.000	0.236	0.156
WTI	Jan 2009–Dec 2011	−2.261	0.186	−10.829	0.000	−2.176	0.216	−13.578	0.000	1.255	0.000	0.154	0.237
HH	Jan 1994–Dec 2011	−3.225	0.019	−30.563	0.000	−2.952	0.040	−31.139	0.000	1.839	0.000	0.054	0.592
NBP	Feb 1997–Dec 2011	−2.392	0.144	−11.606	0.000	−2.451	0.128	−31.348	0.000	2.226	0.000	0.022	0.989
WTI	Jan 1994–Dec 2011	−0.988	0.759	−31.163	0.000	−1.188	0.682	−31.301	0.000	3.158	0.000	0.045	0.472

Table 2
This table shows the pairwise Johansen (1991) cointegration tests applied for weekly time series: these include the spot West Texas Intermediate (WTI) oil price, the Henry Hub (HH) natural gas price and the National Balancing Point (NBP) gas price. Lag selection is based on the Akaike information criterion.

		No. of cointegrating relation	Trace statistic	*p*-value	Max-Eigenvalue statistic	*p*-value
HH–WTI	Jan 1994–Dec 2008	None	24.675	0.012	20.021	0.011
		At most 1	4.654	0.323	4.654	0.323
HH–WTI	Jan 2009–Dec 2011	None	19.925	0.056	12.141	0.178
		At most 1	7.784	0.091	7.784	0.091
HH–WTI	Jan 1994–Dec 2011	None	10.002	0.640	6.541	0.725
		At most 1	3.461	0.498	3.461	0.498
NBP–WTI	Febr 1997–Dec 2008	None	40.196	0.000	35.698	0.000
		At most 1	4.498	0.343	4.498	0.343
NBP–WTI	Jan 2009–Dec 2011	None	19.065	0.072	17.003	0.033
		At most 1	2.062	0.765	2.062	0.765
NBP–WTI	Febr 1997vDec 2011	None	41.858	0.000	38.689	0.000
		At most 1	3.168	0.550	3.168	0.550
NBP–HH	Febr 1997–Dec 2008	None	28.236	0.003	23.545	0.003
		At most 1	4.691	0.319	4.691	0.319
NBP–HH	Jan 2009–Dec 2011	None	12.610	0.396	11.344	0.227
		At most 1	1.266	0.913	1.266	0.913
NBP–HH	Febr 1997–Dec 2011	None	21.178	0.037	14.733	0.075
		At most 1	6.445	0.159	6.445	0.159

The model is estimated thus:

$$\begin{aligned}
\Delta(P_{\mathrm{HH}})_t &= \hat{\gamma}_{\mathrm{HH}}(\mathrm{CI}_{1,t-1}) + \hat{\delta}_{\mathrm{HH}}(\mathrm{CI}_{2,t-1}) + \sum_{i=1}^{n} \hat{b}_{\mathrm{HH},i}\Delta(P_{\mathrm{HH}})_{t-i} \\
&\quad + \sum_{i=1}^{n} \hat{c}_{\mathrm{HH},i}\Delta(P_{\mathrm{NBP}})_{t-i} + \sum_{i=1}^{n} \hat{d}_{\mathrm{HH},i}\Delta(P_{\mathrm{WTI}})_{t-i} \\
&\quad + \sum_{j=1}^{k} \hat{x}_{\mathrm{HH},j}X_j + \hat{\varepsilon}_{\mathrm{HH},t} \\
\Delta(P_{\mathrm{NBP}})_t &= \hat{\gamma}_{\mathrm{NBP}}(\mathrm{CI}_{1,t-1}) + \hat{\delta}_{\mathrm{NBP}}(\mathrm{CI}_{2,t-1}) + \sum_{i=1}^{n} \hat{b}_{\mathrm{NBP},i}\Delta(P_{\mathrm{HH}})_{t-i} \\
&\quad + \sum_{i=1}^{n} \hat{c}_{\mathrm{NBP},i}\Delta(P_{\mathrm{NBP}})_{t-i} + \sum_{i=1}^{n} \hat{d}_{\mathrm{NBP},i}\Delta(P_{\mathrm{WTI}})_{t-i} + \sum_{j=1}^{k} \hat{x}_{\mathrm{NBP},j}X_j \\
&\quad + \hat{\varepsilon}_{\mathrm{NBP},t} \\
\Delta(P_{\mathrm{WTI}})_t &= \hat{\gamma}_{\mathrm{WTI}}(\mathrm{CI}_{1,t-1}) + \hat{\delta}_{\mathrm{WTI}}(\mathrm{CI}_{2,t-1}) + \sum_{i=1}^{n} \hat{b}_{\mathrm{WTI},i}\Delta(P_{\mathrm{HH}})_{t-i} \\
&\quad + \sum_{i=1}^{n} \hat{c}_{\mathrm{WTI},i}\Delta(P_{\mathrm{NBP}})_{t-i} + \sum_{i=1}^{n} \hat{d}_{\mathrm{WTI},i}\Delta(P_{\mathrm{WTI}})_{t-i} \\
&\quad + \sum_{j=1}^{k} \hat{x}_{\mathrm{WTI},j}X_j + \hat{\varepsilon}_{\mathrm{WTI},t} \qquad (1)
\end{aligned}$$

where P_y, $y=$HH, NBP, and WTI is the log price and CI_1 and CI_2 are equilibrium error terms of cointegrating equations; i.e.,

$$CI_{1,t} = P_{\mathrm{HH},t} - \hat{\alpha}_1 - \hat{\beta}_1 P_{\mathrm{WTI},t}; \quad CI_{2,t} = P_{\mathrm{NBP},t} - \hat{\alpha}_2 - \hat{\beta}_2 P_{\mathrm{WTI},t},$$

where $\hat{\alpha}_w$, $\hat{\beta}_w$, $w=1,2$ are coefficients to be estimated simultaneously with the parameters in Eq. (1) and X_j is the vector of exogenous variables. Table 3, Model 1 reports the results. The estimated cointegrating vectors capture the possible long-term equilibriums between oil and gas prices. Long-term price adjustments between oil and gas are expected because of fossil fuel substitutability. Furthermore, ample empirical evidence documented in the literature also suggests integrated fuel markets. Specifying Eq. (1) allows departing from the long-term equilibrium through shocks captured by the exogenous variables, but these swings from the parity level revert to the equilibrium in the long run. The lag selection is based on the Akaike information criterion, and lags that result in insignificant coefficients in the three equations that constitute the system are omitted[6] . Some exogenous variables, including cooling degree days, production shut-ins and storage deviation from the five-year average that are identified as key to explaining natural gas prices in Brown and Yücel (2008) and are not significant. In applying the same unit root and stationarity tests on the exogenous variables as on oil and gas prices in Table 1, only storage differential appears non-stationary because the PP test rejects the unit root and the KPSS test rejects stationarity. Although taking the first difference of the storage differential induces a significant positive parameter estimate, economically important industry variables remain insignificant. Moreover, the parameter estimate of the cooling degree days variable is controversially negative. The first differences of all exogenous variables are thus taken, and the model is re-estimated in Model 2 and presented in Table 3. The first differences of the cooling and heating degree days are removed from the model: they have become redundant, as the first differences of heating and cooling degree day deviations from the seasonal average can also capture temperature change and seasonality. Model 2 shows that WTI does not take part in the long-term adjustment to equilibrium fuel prices. The WTI price is not affected if the HH or NBP price swings away from the equilibrium. Though HH tends to close the gap if it drifts away from WTI, it remains stable if the spread between NBP and WTI widens. The NBP price seems to be the most flexible from the long-term adjustment perspective. If HH is overpriced in its long-term equilibrium with WTI, NBP gets more expensive to tighten the spread between HH and NBP. Furthermore, NBP adjusts to reach the long-term equilibrium with WTI more than four times faster than HH. The most interesting result is that NBP gets more expensive if HH is relatively overpriced with respect to the long-term HH–WTI equilibrium. This result can confirm the theory outlined above. UK gas, whose price follows developments in the crude oil market in the long run, can be exported to North America when HH is relatively overpriced to WTI. This trade flow induces higher prices in Europe but helps realign the equilibrium in the US. The contrary is not true: HH does not adapt when NBP is too expensive or too cheap and is thus in disequilibrium with WTI. This is clear evidence that the Atlantic arbitrage can flow just from Europe to North America. High gas prices in North America caused by exogenous shocks can be eased by import from Europe, though the contrary is not true: high (low) and above (below)-equilibrium European gas prices have no significant effect on US gas prices.

In Model 2, all parameter estimates for exogenous variables are significant and have the expected sign in the HH regression. Colder or hotter weather than the seasonal average leads to higher heating and cooling demand, which boosts US natural gas prices. Natural gas production shut-ins through lower supply contribute

[6] The most parsimonious model that exhibits no autocorrelation in the residuals can thus be estimated.

Table 3
This table shows the parameter estimates of vector error correction (VEC) models for the period from June 1997 to December 2011. Models 1 and 2 include the spot Henry Hub (HH) US natural gas price, the National Balancing Point (NBP) UK gas price, and the West Texas Intermediate (WTI) oil price as endogenous variables. CI stands for the cointegrating vector. Models 3–5 assume only two endogenous variables, the HH and the NBP log returns, and they treat WTI as an exogenous variable. The VECs include gas industry-related exogenous variables: the deviations of cooling (CDD) and heating degree days (HDD) from the seasonal norm, the natural gas shut-ins in the Gulf of Mexico and the Storage Difference, which is the deviation of the US natural gas inventory from its five-year average (Model 1 also includes the CDD and HDD variables). The lag selection is based on the Akaike information criterion. The parameter estimates for the lagged values are not reported but are available upon request.

	Δ(log(HH))(t)		Δ(log(NBP))(t)		Δ(log(WTI))(t)	
	Coefficient	p-value	Coefficient	p-value	Coefficient	p-value
Model 1						
CI[HH,WTI]($t-1$)	−0.0238	0.0008	0.0047	0.4563	−0.0023	0.5866
CI[NBP,WTI]($t-1$)	−0.0104	0.3128	−0.0608	0.0000	0.0055	0.3726
CDD(t)	−0.0003	0.1940	−0.0008	0.0000	0.0001	0.4031
CDD deviation(t)	0.0027	0.0000	0.0014	0.0113	0.0005	0.1954
HDD(t)	0.0002	0.0018	−0.0003	0.0000	4.96E−05	0.1320
HDD deviation(t)	0.0008	0.0000	0.0004	0.0320	−0.0001	0.3992
Shut-in(t)	4.79E−07	0.4133	1.35E−06	0.0099	−7.80E−07	0.0249
Storage difference(t)	4.03E−07	0.9734	−4.58E−06	0.6719	8.54E−06	0.2338
Adj. R^2	0.1167		0.0927		0.0466	
Model 2						
CI[HH,WTI]($t-1$)	−0.0178	0.0082	0.0195	0.0013	−0.0059	0.1478
CI[NBP,WTI]($t-1$)	0.0142	0.2878	−0.0769	0.0000	0.0025	0.7537
Δ(CDD deviation)(t)	0.0017	0.0004	0.0002	0.6402	0.0003	0.2634
Δ(HDD deviation)(t)	0.0008	0.0000	0.0001	0.6828	−0.0001	0.3528
Δ(Shut-in)(t)	1.99E−06	0.0573	1.53E−06	0.1060	1.30E−07	0.8370
Δ(Storage difference)(t)	−0.0003	0.0003	4.87E−05	0.5494	−0.0001	0.3460
Adj. R^2	0.1352		0.0710		0.0361	
Model 3						
CI[HH,WTI]($t-1$)	−0.0187	0.0700	0.0206	0.0267		
CI[NBP, WTI]($t-1$)	0.0114	0.3471	−0.0751	0.0000		
Δ(CDD deviation)(t)	0.0016	0.0010	0.0001	0.8033		
Δ(HDD deviation)(t)	0.0008	0.0000	3.04E−05	0.8404		
Δ(Shut-in)(t)	2.03E−06	0.0494	1.51E−06	0.1064		
Δ(Storage difference)(t)	−0.0003	0.0007	3.78E−05	0.6384		
Δ(WTI)(t)	0.2820	0.0000	0.0954	0.0797		
Adj. R^2	0.1504		0.0883			
Model 4						
CI[HH,WTI]($t-1$)*D($t\leq 2008$)	−0.0264	0.0367	0.0229	0.0433		
CI[HH,WTI]($t-1$)*D($t\geq 2009$)	−0.0081	0.6379	0.0101	0.5155		
CI[NBP,WTI]($t-1$)*D($t\leq 2008$)	0.0188	0.1597	−0.0831	0.0000		
CI[NBP,WTI]($t-1$)*D($t\geq 2009$)	−0.0025	0.9269	−0.0573	0.0170		
Δ(CDD deviation)(t)	0.0016	0.0009	0.0002	0.6412		
Δ(HDD deviation)(t)	0.0009	0.0000	4.01E−05	0.7866		
Δ(Shut-in)(t)	2.02E−06	0.0502	1.59E−06	0.0856		
Δ(Storage difference)(t)	−0.0003	0.0006	0.0001	0.3879		
Δlog(WTI)(t)*D($t\leq 2008$)	0.3047	0.0000	0.1254	0.0397		
Δlog(WTI)(t)*D($t\geq 2009$)	0.2092	0.1141	−0.0149	0.8999		
Adj. R^2	0.1474		0.0955			
Model 5						
CI[NBP,HH]($t-1$)*D($t\leq 2008$)	0.0184	0.0704	−0.0453	0.0000		
CI[NBP,HH]($t-1$)*D($t\geq 2009$)	0.0008	0.9466	−0.0060	0.5777		
Δ(CDD deviation)(t)	0.0016	0.0009	0.0002	0.6122		
Δ(HDD deviation)(t)	0.0009	0.0000	2.82E−05	0.8515		
Δ(Shut-in)(t)	2.11E−06	0.0416	1.93E−06	0.0400		
Δ(Storage difference)(t)	−0.0003	0.0006	3.11E−05	0.6958		
Δlog(WTI)(t)*D($t\leq 2008$)	0.3071	0.0000	0.1196	0.0547		
Δlog(WTI)(t)*D($t\geq 2009$)	0.2202	0.0969	−0.0144	0.9053		
Adj. R^2	0.1413		0.0607			

to higher US natural gas prices, while inventory level growth undermines gas prices. The exogenous variables are not significant in the NBP or WTI regressions, except for the natural gas production shut-ins in the NBP regression, which is significant at the 89% level. The positive impact of production shut-ins on the NBP price is also a sign that imports to the US can trigger equal gas prices across the Atlantic. Production shut-ins might result in natural gas shortages that boost US gas prices above UK prices. Such a price shock can be overridden by higher LNG exports to the US. On a netback basis, some LNG cargoes are expected to be shipped to the US instead of Europe; this lower European supply leads to higher prices in Europe. That not even weather variables influence oil prices is a manifestation of the marginalised role of refined petroleum products in heating or in electricity generation.[7]

In Model 2, WTI shows no long-term correction and is not influenced by the lagged price differentials of HH or NBP; WTI is thus not affected by HH and NBP in the Granger sense. However, the WTI price drives natural gas prices in the US and Europe; WTI can thus be treated as an exogenous variable. Asche et al. (2006)

[7] In the Residential Energy Consumption Survey (EIA, 2009), of 113.6 million US households, 55.6 million use natural gas, while only 6.9 million use fuel oil as a primary energy source of heating. Furthermore, 58.4 million households use natural gas and only 3.6 million use fuel oil for water heating.

and Brown and Yücel (2009) also find the WTI price weakly exogenous. The VEC is restructured in Model 3, assuming two endogenous variables and two cointegrating relationships; one between HH and WTI and another between NBP and WTI and the WTI is treated as an exogenous variable. The VEC has the following form:

$$\begin{aligned}
\Delta(P_{\mathrm{HH}})_t = {} & \hat{\gamma}_{\mathrm{HH}}(\mathrm{CI}_{1,t-1}) + \hat{\delta}_{\mathrm{HH}}(\mathrm{CI}_{2,t-1}) + \sum_{i=1}^{n} \hat{b}_{\mathrm{HH},i}\Delta(P_{\mathrm{HH}})_{t-i} \\
& + \sum_{i=1}^{n} \hat{c}_{\mathrm{HH},i}\Delta(P_{\mathrm{NBP}})_{t-i} + \sum_{i=1}^{n} \hat{d}_{\mathrm{HH},i}\Delta(P_{\mathrm{WTI}})_{t-i} + \sum_{j=1}^{k} \hat{x}_{\mathrm{HH},j}X_j \\
& + \hat{\varepsilon}_{\mathrm{HH},t} \\
\Delta(P_{\mathrm{NBP}})_t = {} & \hat{\gamma}_{\mathrm{NBP}}(\mathrm{CI}_{1,t-1}) + \hat{\delta}_{\mathrm{NBP}}(\mathrm{CI}_{2,t-1}) + \sum_{i=1}^{n} \hat{b}_{\mathrm{NBP},i}\Delta(P_{\mathrm{HH}})_{t-i} \\
& + \sum_{i=1}^{n} \hat{c}_{\mathrm{NBP},i}\Delta(P_{\mathrm{NBP}})_{t-i} + \sum_{i=1}^{n} \hat{d}_{\mathrm{NBP},i}\Delta(P_{\mathrm{WTI}})_{t-i} + \sum_{j=1}^{k} \hat{x}_{\mathrm{NBP},j}X_j \\
& + \hat{\varepsilon}_{\mathrm{NBP},t}
\end{aligned} \tag{2}$$

Eq. (2) differs from Eq. (1) only in that the third equation for WTI is omitted; the two cointegrating vectors between oil and gas prices identified in Eq. (1) and at least for the pre-2009 period in the Johansen tests in Table 2 are included. The first difference of the log WTI price is included in the matrix of exogenous variables (X_j). This VEC specification allows long-term gas price adjustments across the Atlantic in either direction, but the pairwise adjustments between gas benchmarks and the oil price are unidirectional: WTI can influence gas prices, but feedback from gas to oil prices is not possible. Table 3 presents the estimated parameters for Model 3. The estimates in the HH and NBP regressions are not significantly different from those obtained in Model 2, which indicates that WTI can be treated as an exogenous variable.

The results for the full sample show that HH is unresponsive to disequilibrium between gas and oil prices in Europe. Conversely, the intercontinental arbitrage has a significant role in creating equilibrium gas prices across the Atlantic when HH is in disequilibrium with WTI, as NBP reacts suitably if HH swings from the equilibrium with WTI. US oil and gas prices visibly separated at the end of 2008, and the long-term adjustment might have also changed. The cointegration tests have confirmed the hypothesis that the US oil and gas prices have separated. To test for a breakpoint in the long-term adjustment at the end of 2008, the following VEC is estimated:

$$\begin{aligned}
\Delta(P_{\mathrm{HH}})_t = {} & \mathrm{CI}_{1,t-1}\left(\hat{\gamma}_{\mathrm{HH}}^{2008} D(t \le 2008) + \hat{\gamma}_{\mathrm{HH}}^{2009} D(t \ge 2009)\right) \\
& + \mathrm{CI}_{1,t-1}\left(\hat{\delta}_{\mathrm{HH}}^{2008} D(t \le 2008) + \hat{\delta}_{v}^{2009} D(t \ge 2009)\right) \\
& + \sum_{i=1}^{n} \hat{b}_{\mathrm{HH},i}\Delta(P_{\mathrm{HH}})_{t-i} + \sum_{i=1}^{n} \hat{c}_{\mathrm{HH},i}\Delta(P_{\mathrm{NBP}})_{t-i} \\
& + \sum_{i=1}^{n} \hat{d}_{\mathrm{HH},i}\Delta(P_{\mathrm{WTI}})_{t-i} + \sum_{j=1}^{k} \hat{x}_{\mathrm{HH},j}X_j + \hat{\varepsilon}_{\mathrm{HH},t} \\
\Delta(P_{\mathrm{NBP}})_t = {} & \mathrm{CI}_{1,t-1}\left(\hat{\gamma}_{\mathrm{NBP}}^{2008} D(t \le 2008) + \hat{\gamma}_{\mathrm{NBP}}^{2009} D(t \ge 2009)\right) \\
& + \mathrm{CI}_{1,t-1}\left(\hat{\delta}_{\mathrm{NBP}}^{2008} D(t \le 2008) + \hat{\delta}_{\mathrm{NBP}}^{2009} D(t \ge 2009)\right) + \\
& + \sum_{i=1}^{n} \hat{b}_{\mathrm{NBP},i}\Delta(P_{\mathrm{HH}})_{t-i} + \sum_{i=1}^{n} \hat{c}_{\mathrm{NBP},i}\Delta(P_{\mathrm{NBP}})_{t-i} \\
& + \sum_{i=1}^{n} \hat{d}_{\mathrm{NBP},i}\Delta(P_{\mathrm{WTI}})_{t-i} + \sum_{j=1}^{k} \hat{x}_{\mathrm{NBP},j}X_j + \hat{\varepsilon}_{\mathrm{NBP},t}
\end{aligned} \tag{3}$$

where $D(t \le 2008)$ and $D(t \ge 2009)$ are dummy variables that take the value one if the condition in parentheses is fulfilled and zero otherwise; Table 3, Model 4 reports the results. The CI_1 and CI_2 cointegrating vectors are the same as in Eq. (2), i.e., they are estimated for the full sample size and only the loadings, $\hat{\gamma}_x^T, \hat{\delta}_x^T$; $x = HH, NBP$; $T = 2008, 2009$, on the cointegrating vectors can time-vary. As for the adjustment coefficients, two parameters have been estimated for the crude oil log returns, for the pre- and post-2009 periods. The HH–WTI adjustment coefficients estimated for the pre-2009 period in both the HH and NBP regressions are not significantly different from the adjustment coefficients estimated in Model 3. These coefficients have higher absolute values, indicating faster adjustment in the pre-2009 period than the average correction speed estimated for the full sample period in Model 3. Before 2009 the US gas price tended to correct to the HH–WTI equilibrium faster, and the UK price also reacted faster in response to disequilibrium in the HH–WTI relation. However, the absence of adjustment between HH and WTI after 2009 is more eye-catching. US gas prices do not head to the long-term equilibrium with WTI, and adjustment thus does not occur between US gas and oil prices after 2009. Furthermore, the HH–WTI disequilibrium leaves the NBP price unaffected. Conversely, the UK gas price adjusts when it is in disequilibrium with WTI before and after 2009, though the adjustment speed is significantly slower after 2009 than before 2009. In the pre-2009 period, HH adjusts by a 2.64% weekly rate to WTI, and NBP gets 2.29% more expensive per week in response to HH being overpriced relative to the HH–WTI equilibrium level. An exogenous shock that diverts US gas prices from the equilibrium with oil prices also dissolves the equilibrium between oil and gas prices in Europe to narrow the spread between the two gas benchmarks. The price differential between HH and NBP is expected to disappear within 21 weeks on average.

NBP corrects to WTI 8.31% a week. Though the disequilibrium between NBP and WTI does not affect US gas prices significantly, HH gets more expensive at a similar rate (1.88% weekly) to NBP when HH is in disequilibrium with WTI. Before 2009, both gas benchmarks adjust to WTI in the long run, and the disequilibrium with WTI on either continent influences gas prices on the other. When NBP is overpriced/underpriced relative to the equilibrium level before 2009, US gas prices tend to be higher/lower. A relatively expensive/cheap NBP means higher/lower US import prices and therefore higher/lower gas prices in the US. There is no correction between HH and WTI after 2009, and disequilibrium on either continent has no impact on gas prices on the other. In Europe, gas prices remain connected to the oil price in the long run, but there is no tendency in the US for gas prices to revert to the equilibrium level after an exogenous shock. This result shows that US gas prices could be separated from oil prices around 2009 and the long-term link between US and UK gas prices could thus also be at stake. Interestingly, the immediate effect of the oil price on gas prices also changes around 2009. Before 2009, the oil price has an immediate positive effect on gas prices on both continents; however, this link has disappeared in the post-2009 period, not just for HH but also for NBP. This result, along with the measured slower speed of adjustment for NBP after 2009, might be the result of larger LNG spot trading market shares. Those producers who sell LNG in the US and price LNG based on the HH price might be willing to sell liquefied gas in Europe for a higher price than the HH but lower than the oil-indexed price. European gas could thus become cheaper with respect to oil-indexed gas price; however, this correction towards equal prices across the Atlantic has not been sufficient to pursue gas-to-gas equilibrium.

To analyse the US–UK gas-to-gas competition in detail requires estimating a VEC in the form:

$$\begin{aligned}
\Delta(P_{\mathrm{HH}})_t = {} & \mathrm{CI}_{t-1}\left(\hat{\gamma}_{\mathrm{HH}}^{2008} D(t \le 2008) + \hat{\gamma}_{\mathrm{HH}}^{2009} D(t \ge 2009)\right) \\
& + \sum_{i=1}^{n} \hat{b}_{\mathrm{HH},i}\Delta(P_{\mathrm{HH}})_{t-i} + \sum_{i=1}^{n} \hat{c}_{\mathrm{HH},i}\Delta(P_{\mathrm{NBP}})_{t-i}
\end{aligned}$$

$$+\sum_{i=1}^{n}\hat{d}_{\mathrm{HH},i}\Delta(P_{\mathrm{WTI}})_{t-i}+\sum_{j=1}^{k}\hat{x}_{\mathrm{HH},j}X_j+\hat{\varepsilon}_{\mathrm{HH},t}$$

$$\Delta(P_{\mathrm{NBP}})_t=\mathrm{CI}_{t-1}\left(\hat{\gamma}_{\mathrm{NBP}}^{2008}D(t\leq 2008)+\hat{\gamma}_{\mathrm{NBP}}^{2009}D(t\geq 2009)\right)$$
$$+\sum_{i=1}^{n}\hat{b}_{\mathrm{NBP},i}\Delta(P_{\mathrm{HH}})_{t-i}+\sum_{i=1}^{n}\hat{c}_{\mathrm{NBP},i}\Delta(P_{\mathrm{NBP}})_{t-i}$$
$$+\sum_{i=1}^{n}\hat{d}_{\mathrm{NBP},i}\Delta(P_{\mathrm{WTI}})_{t-i}+\sum_{j=1}^{k}\hat{x}_{\mathrm{NBP},j}X_j+\hat{\varepsilon}_{\mathrm{NBP},t} \quad (4)$$

where CI is the cointegrating vector between NBP and HH that includes a constant; Table 3, Model 5 presents the results. The cointegrating vector is estimated for the full sample size; only the adjustment coefficients are allowed to vary over the two considered periods. The estimated cointegrating vector shows that HH and NBP are strikingly close to thermal parity in the period between 1997 and 2011, as the elements of the cointegrating vector are $(P_{NBP},P_{\mathrm{HH}},C)=(1,-1,0.036)$, where C is a constant. Between 1997 and 2008, both gas prices tend to recover from shocks that diverted them away from each other. The HH price corrects to NBP by 2.64% a week, while the NBP price heads towards HH at a rate of 2.29% a week. Long-term adjustment is fast before 2009, taking an average of only 20 weeks, which almost matches the 21 weeks estimated in Model 4. The similar results of Models 4 and 5 show the robustness of the estimations. The same inference can be drawn from the estimates of Model 5 for the post-2009 period as from the estimates of Model 4: no adjustment occurs across the Atlantic after 2009. This is largely because arbitrage takes place across the Atlantic before but not after 2009. The estimates from Model 4 show that most adjustment between the two gas benchmarks occurs with the mediation of crude oil; however, the direct gas-to-gas arbitrage is also significant. Moreover, Model 5 indicates that when there is no arbitrage across the Atlantic, there is no long-term equilibrium between the two gas benchmarks. Oil is thus an important factor that influences gas prices on both continents in the long run, but the segmented inter-fuel competition on each continent alone does not result in equal gas prices across the Atlantic. If an exogenous shock offsets the balance between oil and gas prices on either continent, the long-term equilibrium gas prices across the Atlantic are restored only if transatlantic arbitrage functions. Before 2009, LNG sold based on long-term contracts, and with prices integrated with oil prices, it could be shipped to the US, thus inducing equal prices across the Atlantic, as gas prices in Europe were also anchored to crude prices. Not ignoring that the inter-fuel competition also plays a significant role, the gas-to-gas arbitrage across the Atlantic triggered oil-linkage in US gas prices. Since 2009, NBP has yet to be in equilibrium with WTI in the long run, and no gas arbitrage has occurred across the Atlantic; hence the oil-linkage in Europe cannot enforce oil-linkage in US gas prices, and US oil and gas prices became separated as a result of ample US inventory levels. These results confirm those of Brown and Yücel (2009) in that the crude oil price does indeed coordinate natural gas prices in the long run; however, the mediation after an exogenous shock such as the advance in shale production technology is viable only if arbitrage across the Atlantic is possible.

Throughout Models 2–5, the parameter estimates for the gas industry-related exogenous variables in the HH regression do not differ in sign and magnitude. Heating and cooling degree days and shut-ins boost prices, while higher storage results in weaker prices. In Models 4 and 5, the coefficients estimated for WTI log returns are significant only for the pre-2009 period; higher oil prices lift natural gas prices on both continents. The coefficient for WTI log returns for the post-2009 period is not significant, indicating that HH and WTI prices are also separated in the short run.

According to the theoretical model presented, adjustments towards thermal parity between competing fuels and equal gas prices across the Atlantic occur only if HH is more expensive than NBP; the analysis is thus limited to this case. A VEC is applied that estimates the long-term adjustment between the two gas benchmarks, provided HH is more expensive than NBP (Model 6, Table 4):

$$\Delta(P_{\mathrm{HH}})_t=\mathrm{CI}_{t-1}\hat{\gamma}_{\mathrm{HH}}D(P_{\mathrm{HH}}\geq P_{\mathrm{NBP}})+\sum_{i=1}^{n}\hat{b}_{\mathrm{HH},i}\Delta(P_{\mathrm{HH}})_{t-i}$$
$$+\sum_{i=1}^{n}\hat{c}_{\mathrm{HH},i}\Delta(P_{\mathrm{NBP}})_{t-i}+\sum_{i=1}^{n}\hat{d}_{\mathrm{HH},i}\Delta(P_{\mathrm{WTI}})_{t-i}+\sum_{j=1}^{k}\hat{x}_{\mathrm{HH},j}X_j+\hat{\varepsilon}_{\mathrm{HH},t}$$
$$\Delta(P_{\mathrm{NBP}})_t=\mathrm{CI}_{t-1}\hat{\gamma}_{\mathrm{NBP}}D(P_{\mathrm{HH}}\geq P_{\mathrm{NBP}})+\sum_{i=1}^{n}\hat{b}_{\mathrm{NBP},i}\Delta(P_{\mathrm{HH}})_{t-i}$$
$$+\sum_{i=1}^{n}\hat{c}_{\mathrm{NBP},i}\Delta(P_{\mathrm{NBP}})_{t-i}+\sum_{i=1}^{n}\hat{d}_{\mathrm{NBP},i}\Delta(P_{\mathrm{WTI}})_{t-i}+\sum_{j=1}^{k}\hat{x}_{\mathrm{NBP},j}X_j+\hat{\varepsilon}_{\mathrm{NBP},t} \quad (5)$$

where CI_{t-1} is the equilibrium error term and $D(P_{\mathrm{HH}}\geq P_{NBP})$ is a dummy variable, which equals one if HH is more expensive than NBP and zero otherwise.

HH does not adjust significantly to the long-term equilibrium, but NBP heads towards the equilibrium at a weekly rate of 3.44%. Eq. (5) has also been estimated for cases when HH is more expensive than NBP by 10, 20, 30, 40 and 50% (Models 7–11, respectively). The results do not change significantly with the extent of the spread between HH and NBP. The adjustment coefficient in the HH regression varies between 3.38% and 3.70% a week. The coefficients for the exogenous variables do not significantly differ among Models 7–11. Only WTI in the pre-2009 period and shut-ins significantly influence both gas prices. The WTI becomes insignificant after 2009 in both the HH and NBP regressions, matching the results in Models 4–5.

Eq. (5) is re-estimated to investigate the long-term adjustment process when NBP is at a premium with respect to HH. The dummy variable has been changed accordingly: $D(P_{\mathrm{HH}}\leq P_{NBP})$ is one if NBP is equal to or more expensive than HH and zero otherwise; Table 5, Model 12 reports the results. The estimated coefficients for exogenous variables do not significantly differ from the coefficients estimated in Models 6–11, but the adjustment coefficient in the NBP regression has become substantially lower than in Models 6–11. The estimated adjustment speed does not alter with the size of the NBP's premium over HH when NBP is more expensive by at least 10, 20 or 30% (Models 13–15, Table 5). However, when NBP is at least 40% more expensive than HH, the adjustment coefficient in the NBP regression becomes insignificant (Model 16, Table 5); when NBP is at least at a premium of 50%, the coefficient of the cointegrating vector is virtually zero (Model 17, Table 5). When NBP is severely overpriced with respect to HH, there is no correction across the Atlantic. The dataset contains 105 weeks when NBP was more expensive by at least 40% than HH, and 78 of these observations fall between 2009 and 2011. The distribution of those observations when NBP was at a premium of at least 40% confirms again that the Atlantic arbitrage has not been working since 2009 and that the two gas benchmarks on the two coasts of the Atlantic have not drifted back to their long-term equilibrium level after an exogenous shock. Though NBP has yet to be integrated with WTI since 2009, the long-term equilibrium between the HH and WTI prices has disappeared (Model 4, Table 3), as the potential Atlantic arbitrage cannot be exploited due to the lack of US export capacity. Model 4 shows that crude oil price is the main factor that mediates the

Table 4
This table shows the estimates of vector error correction (VEC) models for the period June 1997 to December 2011. The VECs include the spot Henry Hub (HH) US natural gas price and the National Balancing Point (NBP) UK gas price as endogenous variables. CI[NBP,HH]($t-1$) is the cointegrating vector, estimated when HH is equal to or more expensive than NBP in Model 6 and when HH is more expensive by at least 10, 20, 30, 40 and 50% in Models 7–11, respectively. The VECs include five exogenous variables: the deviations of cooling (CDD) and heating degree days (HDD) from the seasonal norm, the natural gas shut-ins in the Gulf of Mexico, the Storage Difference, which is the deviation of the US natural gas inventory from its five-year average, and the spot West Texas Intermediate (WTI) oil price. Two parameters have been estimated for the pre- and post-2009 periods. The lag selection is based on the Akaike criterion. The parameter estimates for the lagged values are not reported but are available upon request.

	Δ(log(HH))(t)		Δ(log(NBP))(t)	
	Coefficient	p-value	Coefficient	p-value
Model 6				
CI[NBP,HH]($t-1$)*D(NBP $\le$ HH)	−0.00205	0.85967	−0.03435	0.00123
Δ(CDD deviation)(t)	0.00158	0.00084	0.00015	0.72236
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.70870
Δ(Shut-in)(t)	1.90E−06	0.06796	1.80E−06	0.05940
Δ(Storage difference)(t)	−0.00030	0.00073	0.00001	0.91598
Δlog(WTI)(t)*D($t \le 2008$)	0.28520	0.00003	0.14004	0.02502
Δlog(WTI)(t)*D($t \ge 2009$)	0.18094	0.17044	−0.02522	0.83514
Adj. R^2	0.14035		0.04396	
Model 7				
CI[NBP,HH]($t-1$)*D(1.1NBP $\le$ HH)	−0.00186	0.87243	−0.03421	0.00129
Δ(CDD deviation)(t)	0.00158	0.00084	0.00015	0.72262
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.71128
Δ(Shut-in)(t)	1.90E−06	0.06788	1.80E−06	0.05941
Δ(Storage difference)(t)	−0.00030	0.00073	0.00001	0.91922
Δlog(WTI)(t)*D($t \le 2008$)	0.28524	0.00003	0.14011	0.02495
Δlog(WTI)(t)*D($t \ge 2009$)	0.18096	0.17040	−0.02507	0.83608
Adj. R^2	0.14035		0.04383	
Model 8				
CI[NBP,HH]($t-1$)*D(1.2NBP $\le$ HH)	−0.00325	0.77950	−0.03380	0.00154
Δ(CDD deviation)(t)	0.00158	0.00084	0.00015	0.72579
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.71089
Δ(Shut-in)(t)	1.89E−06	0.06861	1.80E−06	0.05963
Δ(Storage difference)(t)	−0.00030	0.00072	0.00001	0.91588
Δlog(WTI)(t)*D($t \le 2008$)	0.28506	0.00003	0.14114	0.02391
Δlog(WTI)(t)*D($t \ge 2009$)	0.18086	0.17063	−0.02525	0.83496
Adj. R^2	0.14041		0.04341	
Model 9				
CI[NBP,HH]($t-1$)*D(1.3NBP $\le$ HH)	−0.00078	0.94732	−0.03621	0.00079
Δ(CDD deviation)(t)	0.00158	0.00083	0.00015	0.72335
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.71649
Δ(Shut-in)(t)	1.90E−06	0.06741	1.78E−06	0.06156
Δ(Storage difference)(t)	−0.00030	0.00075	0.00001	0.93685
Δlog(WTI)(t)*D($t \le 2008$)	0.28546	0.00003	0.13987	0.02511
Δlog(WTI)(t)*D($t \ge 2009$)	0.18102	0.17027	−0.02544	0.83359
Adj. R^2	0.14032		0.04503	
Model 10				
CI[NBP,HH]($t-1$)*D(1.4NBP $\le$ HH)	−0.00038	0.97512	−0.03698	0.00082
Δ(CDD deviation)(t)	0.00158	0.00083	0.00016	0.71050
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.70426
Δ(Shut-in)(t)	1.90E−06	0.06723	1.77E−06	0.06266
Δ(Storage difference)(t)	−0.00030	0.00075	0.00001	0.94434
Δlog(WTI)(t)*D($t \le 2008$)	0.28553	0.00003	0.13881	0.02626
Δlog(WTI)(t)*D($t \ge 2009$)	0.18105	0.17020	−0.02547	0.83343
Adj. R^2	0.14032		0.04495	
Model 11				
CI[NBP,HH](t-1)*D(1.5NBP $\le$ HH)	0.00185	0.88470	−0.03439	0.00336
Δ(CDD deviation)(t)	0.00158	0.00083	0.00017	0.69351
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.68493
Δ(Shut-in)(t)	1.91E−06	0.06601	1.77E−06	0.06404
Δ(Storage difference)(t)	−0.00030	0.00079	0.00001	0.94927
Δlog(WTI)(t)*D($t \le 2008$)	0.28579	0.00003	0.14364	0.02163
Δlog(WTI)(t)*D($t \ge 2009$)	0.18119	0.16987	−0.02521	0.83542
Adj. R^2	0.14034		0.04152	

gas-to-gas equilibrium across the Atlantic before 2009, but a functioning Atlantic arbitrage is a necessary condition for trans-atlantic long-term equilibrium. If the Atlantic arbitrage does not work, the estimated adjustment coefficients for the post-2009 period show that at least in the past three years, US gas prices decoupled from oil prices (Model 4, Table 3) and US gas prices decoupled from European gas prices (Models 5, 16 and 17).

6. Discussion and conclusion

Vector error correction estimates show that US natural gas prices have decoupled from European gas and crude oil prices since 2009. In the preceding period between 1997 and 2008, US gas and oil prices co-moved in the short-term and were integrated in the long-term. Moreover, the US and European gas

Table 5
This table shows the estimates of vector error correction (VEC) models for the period June 1997 to December 2011. The VECs include the spot Henry Hub (HH) US natural gas price and the National Balancing Point (NBP) UK gas price as endogenous variables. CI[NBP,HH]($t-1$) is the cointegrating vector, estimated when NBP is equal to or more expensive than HH in Model 12 and when NBP is more expensive by at least 10, 20, 30, 40 and 50% in Models 7–11, respectively. The VECs include five exogenous variables: the deviations of cooling (CDD) and heating degree days (HDD) from the seasonal norm, the natural gas shut-ins in the Gulf of Mexico, the Storage Difference, which is the deviation of the US natural gas inventory from its five-year average, and the spot West Texas Intermediate (WTI) oil price. Two parameters have been estimated for the WTI for the pre- and post-2009 periods. Lag selection is based on the Akaike criterion. The parameter estimates for the lagged values are not reported but are available upon request.

	Δ(log(HH))(t)		Δ(log(NBP))(t)	
	Coefficient	p-value	Coefficient	p-value
Model 12				
CI[NBP,HH]($t-1$)*D(NBP ≥ HH)	0.01076	0.29231	−0.01861	0.04834
Δ(CDD deviation)(t)	0.00159	0.00078	0.00016	0.72172
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.69719
Δ(Shut-in)(t)	1.90E−06	0.06661	1.92E−06	0.04531
Δ(Storage difference)(t)	−0.00030	0.00066	0.00003	0.74127
Δlog(WTI)(t)*D(t ≤ 2008)	0.28866	0.00002	0.14163	0.02409
Δlog(WTI)(t)*D(t ≥ 2009)	0.17163	0.19421	−0.00670	0.95619
Adj. R^2	0.14165		0.03526	
Model 13				
CI[NBP,HH](t-1)*D(NBP ≥ 1.1HH)	0.01169	0.25454	−0.01916	0.04303
Δ(CDD deviation)(t)	0.00159	0.00077	0.00015	0.72395
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.70274
Δ(Shut-in)(t)	1.90E−06	0.06623	1.91E−06	0.04574
Δ(Storage difference)(t)	−0.00030	0.00065	0.00003	0.74348
Δlog(WTI)(t)*D(t ≤ 2008)	0.28931	0.00002	0.14085	0.02490
Δlog(WTI)(t)*D(t ≥ 2009)	0.17123	0.19512	−0.00691	0.95482
Adj. R^2	0.14187		0.03552	
Model 14				
CI[NBP,HH](t-1)*D(NBP ≥ 1.2HH)	0.01256	0.22940	−0.01864	0.05336
Δ(CDD deviation)(t)	0.00159	0.00076	0.00015	0.72971
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.69391
Δ(Shut-in)(t)	1.90E−06	0.06650	1.91E−06	0.04541
Δ(Storage difference)(t)	−0.00030	0.00066	0.00003	0.75317
Δlog(WTI)(t)*D(t ≤ 2008)	0.28997	0.00002	0.14044	0.02540
Δlog(WTI)(t)*D(t ≥ 2009)	0.17181	0.19337	−0.00930	0.93924
Adj. R^2	0.14205		0.03504	
Model 15				
CI[NBP,HH](t-1)*D(NBP ≥ 1.3HH)	0.01004	0.35513	−0.01960	0.05035
Δ(CDD deviation)(t)	0.00159	0.00079	0.00016	0.71905
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.70140
Δ(Shut-in)(t)	1.89E−06	0.06879	1.94E−06	0.04226
Δ(Storage difference)(t)	−0.00030	0.00071	0.00002	0.76960
Δlog(WTI)(t)*D(t ≤ 2008)	0.28870	0.00002	0.14089	0.02490
Δlog(WTI)(t)*D(t ≥ 2009)	0.17469	0.18603	−0.01058	0.93082
Adj. R^2	0.14134		0.03517	
Model 16				
CI[NBP,HH](t-1)*D(NBP ≥ 1.4HH)	0.01589	0.16255	−0.01623	0.12272
Δ(CDD deviation)(t)	0.00160	0.00073	0.00015	0.72728
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.70900
Δ(Shut-in)(t)	1.87E−06	0.07141	1.95E−06	0.04193
Δ(Storage difference)(t)	−0.00031	0.00060	0.00003	0.73939
Δlog(WTI)(t)*D(t ≤ 2008)	0.28938	0.00002	0.14307	0.02282
Δlog(WTI)(t)*D(t ≥ 2009)	0.17104	0.19512	−0.01279	0.91655
Adj. R^2	0.14265		0.03322	
Model 17				
CI[NBP,HH]($t-1$)*D(NBP ≥ 1.5HH)	0.01806	0.15510	−0.00440	0.70826
Δ(CDD deviation)(t)	0.00159	0.00076	0.00017	0.70556
Δ(HDD deviation)(t)	0.00084	0.00000	0.00006	0.69053
Δ(Shut-in)(t)	1.89E−06	0.06776	1.92E−06	0.04570
Δ(Storage difference)(t)	−0.00031	0.00055	0.00002	0.77190
Δlog(WTI)(t)*D(t ≤ 2008)	0.28649	0.00002	0.14670	0.01969
Δlog(WTI)(t)*D(t ≥ 2009)	0.17132	0.19429	−0.02066	0.86573
Adj. R^2	0.14274		0.03020	

prices exhibited long-term equilibrium levels. Crude oil primarily mediated the Atlantic gas price convergence with the necessary condition that arbitrage position across the Atlantic could occur.

Between 1997 and 2008, the US gas price tended to be higher than the oil-integrated UK gas price. Higher US prices attracted LNG exports to the US on a netback basis that lowered the potential supply in Europe. The higher supply in the US and lower supply in Europe contributed to price adjustments across the Atlantic. Furthermore, the Atlantic gas market integration had two side effects. First, the Atlantic arbitrage triggered integration between US oil and gas prices. Second, it likely induced long-term adjustments across the Pacific, as Asian gas prices are indexed to crude prices.

The Atlantic arbitrage should flow from the US to Europe since 2009, as oversupply from shale gas production has led to systematically lower gas prices in the US than in Europe. The Atlantic arbitrage has not worked due to the lack of liquefying and export capacities in the US. In such circumstances, the North American gas prices decouple from oil prices and drift away from oil-integrated gas prices, i.e., European and Asian.

One question remains: Is it likely that natural gas prices will separate from crude prices permanently? The US gas price may be at a substantial discount to crude oil in years to come, as policies that can enforce inter-fuel or gas-to-gas competition can take years to implement. Even if the US eventually exports LNG, the first substantial project, Sabine, with an export capacity of two billion cubic feet per day, will not be launched before 2015. However, opponents to exporting natural gas argue that doing so would result in higher consumer prices and could derail the US from tackling climate change, as coal's role in power generation is expected to drop if natural gas prices remain low (Plumer, 2012). Furthermore, if using natural gas is promoted as an auto fuel, energy dependence in the US can be reduced. If the governmental proposal for a credit worth 50% of the extra cost of purchasing a natural gas-powered truck over one that runs on diesel or gasoline comes into effect, this might induce inter-fuel competition, especially if it is also extended to cars (Goldman and Snyder, 2012). Moreover, advances in gas-to-liquid projects (GTL) that produce refined oil products from natural gas could revive inter-fuel competition and could thus restore thermal parity.[8]

Besides the policies that promote natural gas consumption or exportation, production costs could also support natural gas prices. This support does not grant integration between fuel prices automatically, but it prevents further departure from the equilibrium. As Barton and Vermeire (1999) argue, gas prices are bounded: inter-fuel competition can serve as an upper limit and marginal production costs as a lower limit, to which the current natural gas price level is close. The IEA (2011) estimates that the lower limit of the US production cost is at $3 per million Btu, while the Henry Hub natural gas stands at $2.98 per million Btu as of 31 December, 2011.

From an international perspective, the oil linkage of European and Asian natural gas prices has also been challenged. Natural gas prices are traditionally linked to crude oil because oil prices are considered more stable than natural gas prices. When the long-term contracts currently in effect were made, both sides were interested in oil linkage; however, this has changed due to elevated crude prices. If netback-based LNG trading triggers gas-to-gas competition, gas producers who previously sold gas indexed on crude prices might have to relinquish oil indexation. The European Union imported a combined 9241 billion cubic feet of gas from Russia, Norway and Algeria in 2010 (BP Statistical Energy Review, 2011). Approximately three-quarters of this imported gas was oil-indexed (IEA, 2011, p. 74); however, Norwegian producers had to offer greater price flexibility, while Gazprom, the Russian gas monopoly, also had to grant some concessions in 2010 under pressure from cheaper spot LNG imports (IEA, 2011, p. 74). Conversely, the pricing scheme has remained untouched in Asia due to rising demand, fed by the switch from coal to gas throughout Asia in a bid to create a greener power generation and by the decreased nuclear power usage in Japan after the Fukushima disaster. It is not expected that oil linkage will be dismissed entirely in the near future; these achievements in relaxing oil price linkage might contribute to an oil-independent gas market in the long-term.

[8] The share of natural gas in total world road-fuel consumption is currently around 1%; however, in a non-optimistic scenario, it is forecast to reach 1.7% by 2035 (IEA, 2011, p. 116). The IEA suggests that, with policy changes, natural gas could gain a much larger share of auto fuel consumption. By 2015, GTL production might remain below 1% of the world market gas volume, but substantial oil–natural gas price differentials could create opportunities for additional plants and technological advances (IEA, 2011, p. 70).

Acknowledgements

I am grateful to Stephen Brown from the University of Nevada and Mine Yücel and Jackson Thies from the Federal Reserve Bank of Dallas for providing me with data and their helpful comments. I wish to thank my colleagues Mihály Ormos and Gábor Bóta from the Budapest University of Technology and Economics and Paul Söderlind, Stephan Süss and Nikola Nikodijevic Mirkov from the Swiss Institute of Banking and Finance, who have helped me improve the quality of the paper. I wish to express my special thanks to Ferenc Hosszú from the OTP Fund Management, who has provided advice from a practitioner's perspective. I thank to the two anonymous reviewers for their valuable comments and suggestions. This work is connected to the Sciex Programme (Project code: 11.029).

References

Asche, F., Osmundsen, P., Tveterås, R., 2001. Market integration for natural gas in Europe. International Journal of Global Energy 16, 300–312.
Asche, F., Osmundsen, P., Tveterås, R., 2002. European market integration for gas? Volume flexibility and political risk. Energy Economics 24, 249–265.
Asche, F., Osmundsen, P., Sandsmark, M., 2006. The UK market for natural gas, oil and electricity: are the prices decoupled? Energy Journal 27, 27–40.
Bachmeier, L.J., Griffin, J.M., 2006. Testing for market integration: crude oil, coal, and natural gas. Energy Journal 27, 55–71.
Barcella, M.L., May 1999. The pricing of gas. Oxford Energy Forum. Oxford Institute for Energy Studies, Oxford.
Barton, A.P., Vermeire, T.A.L., September 1999. Gas price determination in liberalising markets: lessons from the US and UK experience. Conference Papers. British Institute of Energy Economics Conference, St. John's College, Oxford.
BP Statistical Energy Review, 2011.
Brown, S.P.A., Yücel, M.K., 2008. What drives natural gas prices? Energy Journal 29, 43–58.
Brown, S.P.A., Yücel, M.K., 2009. Market arbitrage: European and North American natural gas prices. Energy Journal 30, 167–186.
Cuddington, J.T., Wang, Z., 2006. Assessing the integration of US natural gas spot markets: evidence from daily price data. Journal of Regulatory Economics 29, 195–210.
Davoust, R., 2008. Gas Price Formation, Structure and Dynamics. Institut Français des Relations Internationales. Working paper.
De Vany, A.S., Walls, W.D., 1995. The Emerging New Order in Natural Gas—Market Versus Regulation. Quorum Books, Westport, CT.
Dickey, D.A., Fuller, W.A., 1979. Distribution of the estimators for autoregressive time series with a unit root. Journal of the American Statistical Association 74, 427–431.
EIA, 2009. Residential Energy Consumption Survey.
EIA, 2012. Net Generation by Energy Source. Electric Power Monthly. (release date: January 30, 2012).
Engle, R.F., Granger, C.W.J., 1987. Co-integration and error correction: representation. Estimation, and Testing Econometrica 55, 251–276.
Geman, H., 2005. Commodities and Commodity Derivatives. Modeling and Pricing for Agriculturals, Metals and Energy. John Wiley & Sons Ltd., West Sussex.
Goldman, J., Snyder, J., 26 January 2012. Obama Seeks Tax Break for Natural-Gas Trucks, Oil Lease Sale. Bloomberg.
Harmsen, R., Jepma, C., 27 January 2011. North West European gas market: integrated already. European Energy Review.
IEA, 2011. Are we entering a golden age of gas? Special report. IEA World Energy Outlook.
Johansen, S., 1991. Estimation and hypothesis testing of cointegration vectors in gaussian vector autoregressive models. Econometrica 59, 1551–1580.
King, M., Cuc, M., 1996. Price convergence in North American natural gas spot markets. Energy Journal 17, 47–62.
Kwiatkowski, D., Phillips, P.C.B., Schmidt, P., Shin, Y., 1992. Testing the null hypothesis of stationary against the alternative of a unit root. Journal of Econometrics 54, 159–178.
Lloyd's Shipping Economist. December 2011.

Neumann, A., Siliverstovs, B., von Hirschhause, C., 2006. Convergence of European spot market prices for natural gas? A real-time analysis of market integration using the Kalman filter. Applied Economics Letters 13, 727–732.
Neumann, A., 2009. Linking natural gas markets–Is LNG doing its job? Energy Journal 30, 187–200.
Panagiotidis, T., Rutledge, E., 2007. Oil and gas markets in the UK: evidence from a cointegrating approach. Energy Economics 29, 329–347.
Phillips, P.C.B., Perron, P., 1988. Testing for a unit root in time series regression. Biometrika 75, 335–346.
Plumer, B., 4 January 2012. Should the US export its natural gas? A debate flares. Washington Post.
Robinson, T., 2007. Have European gas prices converged? Energy Policy 35, 2347–2351.
Serletis, A., 1994. A cointegration analysis of petroleum futures prices. Energy Economics 16, 93–97.
Serletis, A., Herbert, J., 1999. The message in North American energy prices. Energy Economics 21, 471–483.
Siliverstovs, B., L'Hégaret, G., Neumann, A., von Hirschhausen, C., 2005. International market integration for natural gas? A cointegration analysis of prices in Europe, North America and Japan. Energy Economics 27, 603–615.
UNCTAD, 2011. Review of Maritime Transport.
Villar, J.A., Joutz, F.L., 2006. The relationship between crude oil and natural gas prices. Energy Information Agency, Office of Oil and Gas.
Walls, W.D., 1994. Price Convergence across Natural Gas Fields and City Markets. Energy Journal 15, 37–48.