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JEL Classification Q41, Q47, G10

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Abstract

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1 Introduction

The North West (NW) European natural gas markets are deeply divided into two competing pricing mechanisms. In Continental Europe, gas supplies are predominantly governed by long-term supply contracts, indexed to the price of oil products. In contrast, the UK market underwent liberalization in 1995 and by now is characterized by full gas-on-gas competition and single hub pricing. That is, UK long-term supply contracts, in contrary to the European Continent, use spot gas prices as a benchmark for indexation and not oil product prices. Following Melling (2010), the difference between the two pricing systems has become increasingly pronounced since 2006 when a large share of UK long-term contracts expired and were rolled over to contracts with spot gas price indexation. By 2010, spot gas price indexation accounted for approx. 90% of all gas sales in the UK, whereas only for 25% in Continental Europe. This growing divide between the two markets results in large tensions only if spot prices diverge significantly from oil-indexed prices. Two situations might arise. Spot prices might exceed oil-indexed prices for a considerable period, hence pricing a physical shortage in the market. In this case, gas consumers locked into long-term supply contracts might face upwards price revisions by their suppliers. In the reverse case, when spot gas trades at a significant discount to oil-indexed prices, pricing an oversupply of spot gas, Continental European gas consumers are locked into their long-term positions and cannot benefit from lower spot prices[1], a situation which has prevailed in the market since summer 2008. It becomes obvious that the stress between the two pricing systems is an increasing function of the price differential.

However, even in the absence of a contractual linkage between the UK hub prices and the price of crude oil (or oil products), the two are not independent. UK spot prices are influenced by storage arbitrage with the Continental European markets during the summer, and demand/supply imbalances during the winter, facilitated to a large extent by trade flows across the Interconnector (IUK) pipeline, linking the UK with Belgium and therefore the Continental European markets, Heather (2010). This arbitrage between the UK and Continental Europe has helped prevent a structural price divergence between the two markets, and hence kept the tension between them small.

Since 2005, the UK has expanded its import infrastructure for natural gas by adding two import pipelines as well as significant LNG regasification capacity. As a result, Heather (2010) maintains that the UK has become subject to global arbitrage for the marginal supply of natural gas[2]. That is, given demand and supply imbalances in the UK market, the marginal supply might not be priced against Continental European oil-indexed gas, but against global spot LNG prices. This has the potential to significantly change the long-term relationship between the UK and Continental European markets. This view is confirmed by Stern and Rogers (2011). They

[1] They can only benefit from spot price volatility to the degree of volume flexibility dictated by their long-term supply contract.

[2] The term *marginal* supply refers to the last unit which balances demand and supply in the market. The UK NBP price reflects the value of the marginal supply unit into the UK.

argue that even if market fundamentals ensure that the price differential between oil-indexed and hub priced gas is small, there is a threat of a widening differential in an increasingly uncertain LNG-connected global gas system. In particular, if the addition of UK LNG import capacity has weakened the long-term relationship between the UK spot price and the oil-indexed price on the Continent, by affecting the arbitrage dynamics across the IUK pipeline, then the price differential between UK hub and oil-indexed prices could widen. The resulting friction will then increase the tension between the two markets even further.

The empirical investigation of this potential weakening lies at the core of the present study. The following analysis determines the dynamic behaviour of the long-term relationship between UK NBP hub and NW European gas prices, predominantly oil-indexed, which is conventionally measured in a cointegration framework. Importantly, the possibility of a price decoupling is examined. Following the spirit of Ramberg and Parsons (2012), the present study aims to answers the question whether the extension of natural gas import infrastructure in the UK has lead to any of the three forms of price decoupling: (i) prices have *temporarily* deviated from their long-term relationship to which they will return later; (ii) prices have *permanently* deviated from the old relationship and moved into a new long-term relationship; or (iii) the two prices no longer maintain a long-term relationship with each other at all.

The contributions of this study are threefold: (i) to the best knowledge of the author, this is the first study to take into account important UK spot gas market drivers such as seasonality, temperature and gas storage injection/withdrawal behaviour when examining the structural relationship between UK and Continental European markets. (ii) The effect of import capacity extensions (pipeline/LNG) on the long-term relationship between UK spot and Continental European oil-indexed gas prices will be analyzed. In doing so, this study is the first to use a direct measure of oil-indexed gas prices in the NW European market, the Average German Import Price (AGIP), rather than price for crude oil. The second contribution is of particular importance for two reasons. First, it determines whether the opening of the UK to global LNG trade has permanently broken the long-term relationship between UK and NW European gas markets, or whether this relationships still exists, yet maybe in a changed form. This information about the dynamic properties of the price differential between spot and oil-indexed gas prices appears somewhat critical to large-scale consumers of natural gas, if positioned in long-term oil-indexed supply contracts. Further, it informs exporters of natural gas into the NW European market, as price decoupling increases the pressure to move away from oil-indexation. Second, it provides an improved understanding of how the UK domestic gas market is exposed to global (exogenous) oil price movements. (iii) The empirical analysis is based on a larger dataset compared to previous research, which covered data up until and including 2005. This will provide the basis for re-examining the long-term structural relationship between the UK and Continental European markets.

The rest of this study is organized as follows. Section 1.1 provides a brief overview of the UK natural gas market and its interconnection. Section 1.2 describes the rationale for a linkage of gas to oil product prices. It goes on to motivate in more detail the connection of UK spot prices to oil-indexed prices through arbitrage across the Interconnector. The potential influence of LNG on the arbitrage dynamics is analyzed in section 1.3 and a brief overview of the price data between 1999-2011 is given in section A.1. The relevant empirical literature in the field is presented in section 2. Details about the energy market data and its time series characteristics are discussed in section 3. Sections 4 and 5 respectively describe the econometric methodology applied in this study and present the estimation results. Section 6 concludes.

1.1 The UK gas market: liberalization and interconnection

In 1995 the UK market for natural gas was subject to a deep structural change, namely a transition from a vertically-integrated and publicly owned monopoly to a fully liberalized gas market[3]. In this liberalized market, natural gas prices are determined by the forces of demand and supply, reflecting local imbalances[4]. The price for natural gas in the UK is determined at a virtual hub, called the National Balancing Point (NBP). The UK NBP is generally regarded as a mature market with sufficient depth and liquidity. The average churn rate (the number of times gas contracts are traded before physical flows take place) is, at around 15 in 2010, significantly higher than in other NW European spot markets (between 2-3), Stern and Rogers (2011).

Along with deregulation came the development of gas trading on both a national and international level, facilitated by the opening of the Interconnector UK (IUK) pipeline between Bacton (UK) and Zeebrugge (Belgium) in 1998[5]. With an import (export) capacity of 25.5 bcma[6] (20.0 bcma), the pipeline established the first physical link of the newly liberalized UK market with the Continental European markets, therefore allowing to trade on arbitrage opportunities across the two markets[7].

Further physical linkages with Continental European gas markets followed in more recent years. In December 2006, the Balgzand (Netherlands) and Bacton interconnector, called the BBL pipeline, became operational and secured an import capacity from the Netherlands to the UK of 15 bcma. In October 2007, the Langeled pipeline between Nyhamma (Norway) and Easington (UK) opened fully, and with an import capacity of 25.5 bcma, is the longest underwater pipeline worldwide[8].

In addition to pipeline capacity, 2005 marked the introduction of liquefied natural gas (LNG) to the UK market with the opening of the Isle of Grain regasification terminals[9]. Since then,

[3] Newbery (1999) provides a thorough account of the restructuring process of the UK gas and electricity sectors.

[4] A detailed description of UK gas markets and key price drivers is given in Wright (2006).

[5] A comprehensive analysis of the functioning of UK gas trading can be found in Heather (2010).

[6] *bcma* billion cubic meters annually.

[7] The initial import capacity in 1998 was only 8 bcma. This was only later expanded in three phases to reach the current 25.5 bcma (as from October 2007). For a history of the IUK and a discussion of its economic impact, see Futyan (2006). For technical details visit `http://www.interconnector.com`.

[8] See Gassco (2010).

[9] *Regasification* refers to the transition of natural gas from the liquid to the gaseous state, i.e. controlled warming. LNG enters the importing country in a liquid state and is then regasified. In this study, regasification capacity is used interchangeably with LNG import capacity.

LNG imports have played a key role in UK gas supply and import capacity has continuously expanded. Table 1 provides an overview of the existing UK regasification capacity of about 51.5 bcma, which represents about 57 % of the UK's natural gas demand in 2009, of 90.8 bcm[10].

In addition to existing import capacity, there are potential extensions. Proposed is a capacity extension of the Isle of Grain site, owned by National Grid, with unknown commissioning date[11], as well as the investment into an offshore terminal, with a capacity of 3-6 bcma[12].

Table 1: UK LNG Regasification Capacity

Terminal Name	Operator/Developer	Commissioning Date	Landfall in the UK	Capacity in bcma
Isle of Grain 1/2	National Grid	2005	Isle of Grain	13.5
Gasport	Excelerate	2007	Teesside	≈ 4
Dragon	BG/Petronas	2009	Milford Haven	6
South Hook 1	QP/ExxonMobil	2009	Milford Haven	10.5
South Hook 2	QP/EcconMobil	2010	Milford Haven	10.5
Isle of Grain 3	National Grid	2010	Isle of Grain	7
			Total existing	≈ 51.5
Isle of Grain 4	National Grid	?	River Medway	?

Source: Heather (2010) and NationalGrid (2010). QP Qatar Petroleum. BG British Gas (Centrica).

1.2 Rationale for crude oil and natural gas price linkage

A dominant share of gas supplies into NW Europe is delivered and priced against long-term supply contracts indexed to the price of oil products. While contractual terms are confidential and subject to revisions, oil products used for indexation are predominantly light fuel oil (gasoil) and heavy fuel oil, Stern (2007). Long-term contract gas prices are then indexed to those prices with a lag of up to 9 months [13]. Further, long-term contracts provide consumption flexibility over the gas year[14]. This flexibility is expressed as a band of potential gas offtake around the Annual Contract Quantity (ACQ), usually between around 85% and 120%, Stern and Rogers (2011). The minimum consumption level, which has to be paid for irrespective of actual consumption, is called the take-or-pay level (TOP). Within these bounds, gas consumers are able to substitute contracted pipeline gas with other forms of supply, e.g. from European spot gas hubs such as the UK NBP, depending on relative price signals.

There are several factors which naturally link the prices of crude oil and natural gas. With a focus on the US, Villar and Joutz (2006) categorized these into demand and supply factors. On the demand side, price linkage occurs due to competition at the 'burner-tip'. Crude oil

[10]See IEA (2010).
[11]See NationalGrid (2010).
[12]See Reuters (2011a).
[13]Other indexing targets may include inflation or other commodity prices. For an extensive discussion of oil-indexation and its historical context, see Melling (2010).
[14]The gas-year starts on October 1st and ends on September 30th of the following calendar year.

and natural gas are competitive substitutes predominantly in the power generation sector. An increase in the price of crude oil will therefore induce some generators to switch to natural gas. All else being equal, this demand increase for natural gas will push up its price until it converges with the price of oil products and the motivation to switch input fuels is removed.

On the supply side, the linkage is less clear cut than on the demand side. First, an increase in the price of crude oil may stimulate oil drilling and hence the production of associated gas[15]. The increase in gas production will depress its market price. Second, natural gas and crude oil are competing for the same upstream drilling assets. An increase in the price of crude oil will stimulate oil drilling and hence increase the production costs of natural gas, which pushes up its price. Third, as many of the firms drilling for crude oil also drill for natural gas, increasing oil prices result in an increased cash-flow of drilling companies and hence free resources for natural gas drilling. Increased natural gas production again depresses its price[16].

However, in the European context, Finon (2008) claims that the original rationale for an oil-gas price linkage, competition at the burner-tip, has become increasingly dubious for two reasons. First, there has been a continuous reduction of dual-fired generation capacity in the EU power sector. Second, the dying out of oil-based generation. Similarly, Stern (2009) attributes the weakening rationale for a linkage of long-term contract gas prices to those of oil products in NW Europe to four key factors[17]: the virtual elimination of oil products from many stationary energy sectors in NW European energy markets, the high cost of maintaining oil-burning equipment and oil stocks, the improvement in gas-burning efficiencies and increasing environmental concerns, especially with regards to high carbon emission of oil-fired power generation. In summary, Stern (2009) argues that there is only very limited oil switching capacity remaining in those markets, weakening the rationale for contractual gas price indexation to those of oil products, in particular since the mid 2000s[18].

Despite the absence of a contractual link between the UK gas price to those of oil products, the UK NBP price might nevertheless reflect variations in crude oil prices and therefore oil product prices. This is due to limited gas storage capacity in the UK and arbitrage between the UK NBP and oil-indexed gas across the IUK pipeline. The historical flow pattern across the IUK for the year 2003-05 is depicted in figure 1, that is before the opening of UK LNG regasification capacity. The flow data highlights the strongly seasonal pattern of gas trades across the pipeline. The summer months are characterized by significant forward flow, exporting natural gas into the NW European market, where storage is refilled. As long as long-term contract gas is priced above UK NBP, and pipeline consumers are within the flexibility limits dictated by their supply contracts, that is they can substitute expensive pipeline gas for cheaper spot gas, there is an opportunity for arbitrage. The additional demand from NW European markets pulls the UK

[15] *Associated* gas is a by-product to crude oil production, as opposed to *dry* gas.

[16] Competition for upstream drilling assets as well as competition at the 'burner-tip' as a rationale for price linkage is also maintained by IEA (2009).

[17] For an earlier analysis of the price linkage of long-term gas contracts to those of oil products, see Stern (2007).

[18] In a recent publication, Stern and Rogers (2011) examine the progress of the transition from oil-indexed to hub-based pricing since 2009 and its likely evolution over the next few years.

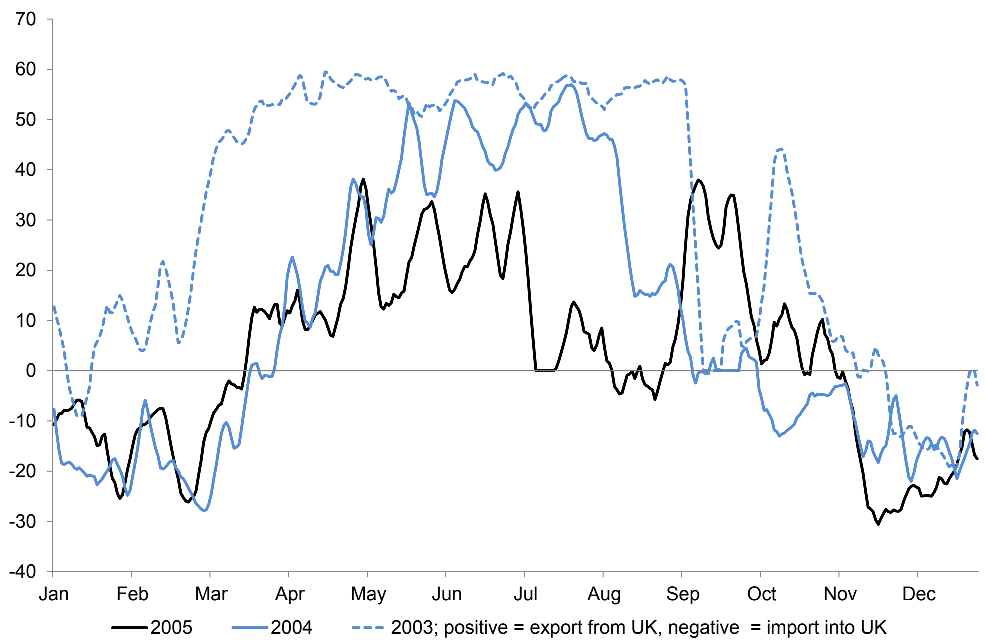


Figure 1: Interconnector Daily Pipeline Flows pre LNG (Weekly average in mcm/day) 2003-2005, Source: Interconnector

NBP price higher, potentially until it reaches the contract price and the initial motivation for arbitrage is removed, all else being equal. This process links the UK NBP price to those of oil products despite the absence of any contractual indexation. In the reverse case, UK NBP being priced above oil-indexed gas, long-term contract consumers on the continent can sell gas into the UK market and back-fill with cheaper pipeline gas. This then puts downwards pressure on the UK price, potentially until it converges with lower priced long-term contract gas.

During the winter months, the UK peak heating season, domestic demand for natural gas increases and limited storage capacity turns the UK into a net importer. The net trade flows across the IUK are reversed. That is, before the opening of additional pipeline capacity (BBL/Langeled) and LNG regasification capacity, the marginal supply balancing the UK market during peak consumption months came from the NW European market. In order to attract sufficient quantities, the UK NBP price must reflect the value of this marginal supply unit, which means rise to the price level of the long-term contract gas on the European continent. Again, this provides a rationale for the connection of UK NBP to oil-indexed gas prices and therefore to oil price movements.

1.3 The influence of LNG on UK NBP pricing

The important role global trade in LNG plays in re-balancing the international gas-system is well documented in Rogers (2010)[19]. In the UK, LNG has become increasingly important in

[19] Rogers (2010) provides a detailed study on LNG trade flows in the Atlantic basin. The author models the dynamics of pipeline gas-LNG arbitrage scenarios between Europe and North America, given various demand and

securing supply of natural gas, in particular in the light of declining domestic production. The continuous expansion of import capacity exposes the UK, and therefore the UK NBP price, to global arbitrage for the marginal supply of natural gas, Heather (2010). Appendix A.1 provides a brief discussion of relative global natural gas prices, in particular that of spot LNG relative to oil-indexed, for the period 1999-2011.

Total LNG import capacity in the UK has increased significantly with the completion of the South Hook 2 terminal in 2010 and lies now just over 50 bcma. Figure 2 illustrates the development of UK LNG imports and their seasonal behaviour. As opposed to import capacity, actual imports picked up at the end of 2008 and have continuously risen until the first half of 2011, after which they retreated markedly. Weekly averaged imports into the UK peaked in April 2011 with just over 100 mcm/day[20].

Trade in LNG changes the historical relationship between UK NBP and oil-indexed prices, as it introduces an additional source for the marginal unit of supply in the UK market. That is, whether the UK NBP will converge with the oil-indexed price on the continent is no longer determined by relative demand and supply imbalances in the UK alone. It is now also determined by global energy prices, in particular that of LNG relative to oil-indexed gas.

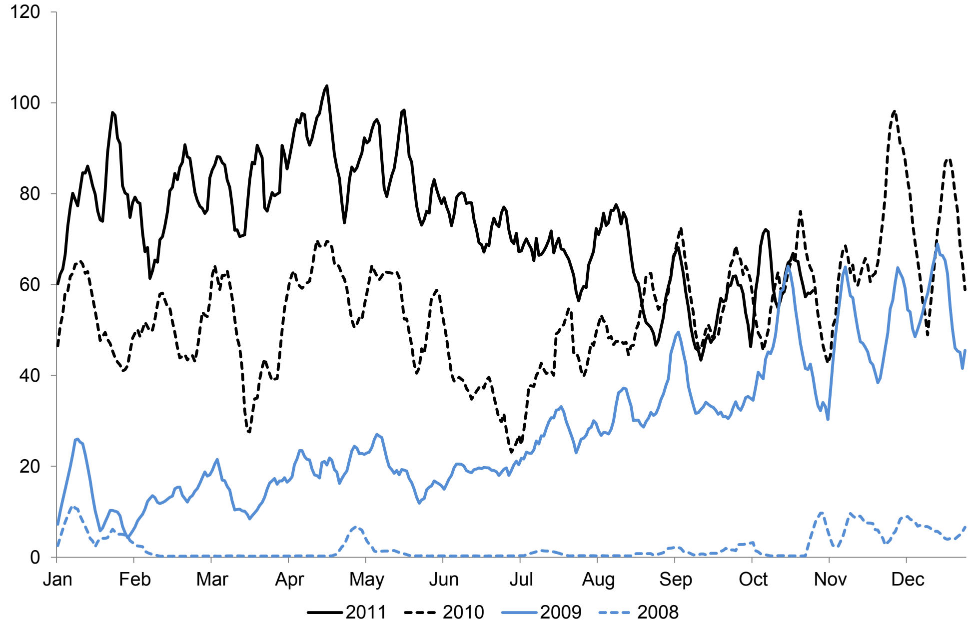


Figure 2: UK LNG imports (Weekly average in mcm/day) 2011-08, Source: Bloomberg/NationalGrid

During the winter months, the UK is a net importer of natural gas. If sufficient spot LNG can be delivered to balance the UK market, at a cost below that of oil-indexed pipeline gas,

supply uncertainties.

[20]This coincides with the ramp-up of the last Qatari LNG liquefaction train, shortly before in February 2011, Reuters (2011b).

the UK NBP price will increase to that of spot LNG but remain below that of oil-indexed supply[21]. Given the relative price of spot LNG to oil-indexed gas, seasonal price convergence between the UK NBP and oil-indexed gas is then no longer necessary. Whether convergence occurs during peak UK demand periods is determined by factors influencing global LNG spot prices. In particular, higher LNG demand from key importers, such as Japan, South Korea and Taiwan, will increase the pressure on global LNG spot markets. On the supply side, LNG liquefaction constraints in major producing countries, such as Qatar and Algeria, exert further pressure on spot prices. In general, tighter global LNG markets will feed into the UK market by increasing the upward pressure on the NBP price. It will have to increase in order to attract the marginal cargo during peak demand periods. Convergence of UK NBP to oil-indexed prices is still possible, but conditional on at least one of the following two conditions: (i) global spot LNG prices exceed those of oil-indexed gas in Continental Europe, and (ii) UK peak demand (winter) exceeds available spot LNG, such that the marginal supply unit balancing the market, will have to be attracted from the European continent.

The effect on UK NBP pricing during the summer months, when the UK is a net gas exporter, is less clear. If global LNG spot prices are below those of oil-indexed gas on the European continent, there is an arbitrage opportunity for NW European gas consumers positioned in long-term supply contracts, given they are confident about meeting their take-or-pay (TOP) obligations. LNG could then be imported into the UK and priced at the NBP, only for it to be re-exported through the IUK pipeline[22]. LNG essentially overflows into the NW European market, using the UK as an 'offshore unloading jetty', Rogers (2010). This additional pull on the UK market would result in upward pressure on the UK NBP price until it ultimately converges with that of oil-indexed gas, even during summer months. Whether TOP obligations pose a limit to this arbitrage process, and hence to price convergence, is determined by the level of demand for natural gas on the European continent.

Figure 3 illustrates the seasonal behaviour of the trade flows across the IUK pipeline for the years 2008-11. Compared to the period 2003-05, the volatility of export flows during the summer appears to have increased, whereas the general seasonal flow pattern has dampened, Rogers (2010). Net imports back into the UK during peak demand periods appear to start later in the year and stop earlier, whereas strong exports during the summer months persist. This lends intuitive support to the argument that additional supply from Norway and in the form of LNG has substituted oil-indexed pipeline gas from the NW European markets, which would have entered the UK through the IUK during winter months.

[21] This equally holds for marginal supply secured through the BBL and Langeled pipelines and priced at European (UK) hub spot prices.

[22] This assumes that LNG cannot enter Continental Europe directly, as constraints in regasification capacity are binding. However, the growth in Continental European regasification capacity over the recent years makes this scenario less likely, GIE (2011).

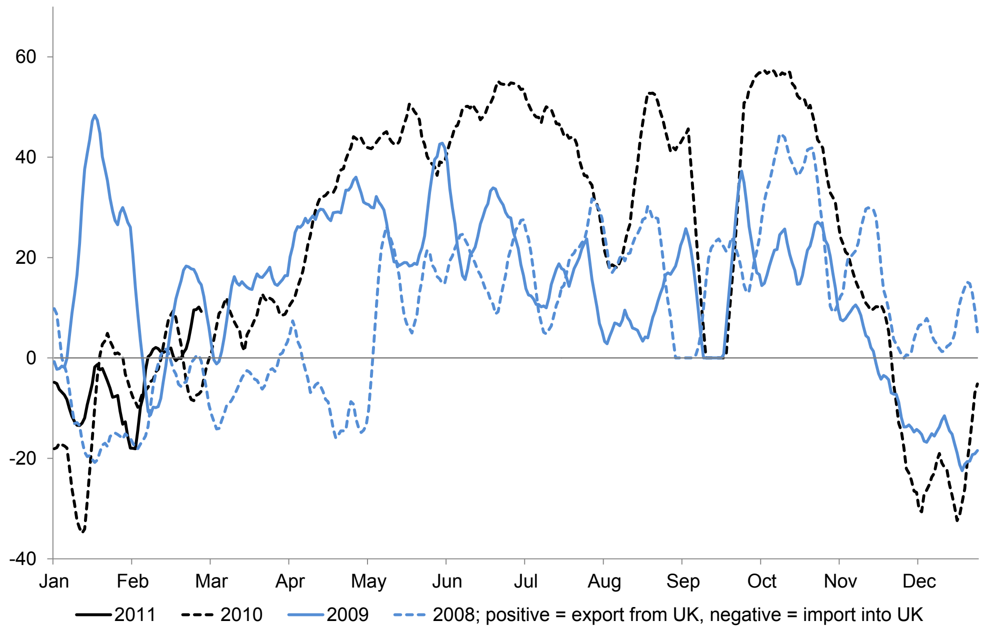


Figure 3: Interconnector Daily Pipeline Flows post LNG (Weekly average in mcm/day) 2008-2011, Source: Interconnector

2 Relevant literature

There is a growing body of literature analyzing the relationship between energy prices, some of which is directly relevant to the present study. Serletis and Herbert (1999) investigate the empirical relationship between natural gas, fuel oil and power prices in North America. Their results show evidence of a cointegrating relationship between natural gas and fuel oil prices, which is attributed to an effective arbitrage mechanism between the two fuels in industrial usage[23]. Power prices, however, show no structural relationship with the other fuels.

In a later study, Bachmeier and Griffin (2006) examine the long-run relationship between crude oil, natural gas and coal prices. Their findings suggest that the global market for crude oil is a single and highly integrated market. Further, while there exists a cointegrating relationship between different coal prices across the US, the degree of market integration is much weaker. Across primary energy markets, cointegration is only found to be very weak. In a similar study, Villar and Joutz (2006) investigate the relationship between the Henry Hub natural gas price in the United States and the West Texas Intermediate crude oil price. They find a stable cointegrating relationship between the two fuels for the period 1989-2005. Further, they argue that the natural gas price is growing at a slightly faster rate than the crude oil price, narrowing the gap between them over time[24].

Siliverstovs et al. (2005) investigate the integration of international natural gas markets in the

[23]Fuel oil and natural gas are competitive substitutes for the use in industrial boilers.

[24]For another study with a focus on the relationship between the US Henry Hub gas price and the crude oil price, see Hartley et al. (2008).

time period between the early 1990s and 2004. They find significant evidence for highly integrated markets within the North American and European continents. Integration across those markets, however, is rejected. This strong divide between the North American and European gas market during the sample period, so the authors, highlights the limited effect inter-continental gas trade has on price convergence, lending support to the market power of regional suppliers.

In a similar fashion, Neumann et al. (2006) analyze the integration of European gas markets. They use daily day-ahead prices between March 2000 to February 2005 in a Kalman filter framework in order to examine price convergence between major UK and Continental European gas trading hubs. Their findings suggest that there is almost perfect convergence between the NBP and Zeebrugge (Belgium) hubs. Within-continent convergence, however, is found to be only weak, which could be the result of only limited degrees of maturity of the other Continental European hubs[25].

At the core of this study lies the structural relationship between the UK NBP price and the price of oil-indexed gas in NW Europe. Previous work on the empirical connection of UK gas prices and the price of oil has produced mixed results. Following the liberalization of the UK gas market in 1995, Barton and Vermeire (1999) claim that gas-on-gas competition in the UK has weakened the oil and gas price link. They argue that gas prices can now move over the range determined by, on the lower end, the marginal cost of gas production and, on the higher end, the price at which consumers would switch to oil. In 1998 the IUK opened and connected the until then isolated UK gas market to the oil-indexed Continental European gas markets. Gas arbitrage across the North sea, between the NBP and oil-indexed pipeline gas on the Continent, and traded via the IUK, re-established the price link between natural gas and crude oil, ILEX (2001). Together, Barton and Vermeire (1999) and ILEX (2001) argue for a weak price link before and a strong price link after the opening of the interconnector.

However, Asche et al. (2006) present contradicting empirical evidence. They use a co-integration framework in order to detect a significant long-term relationship between the UK gas (NBP) and crude oil (Brent) prices. They focussed their attention on the period 1995-98. During those four years, the UK gas market was deregulated yet not physically connected to the continental gas markets. For the period of market isolation (1995-98), they find a significant co-integrating relationship between Brent and NBP. Co-integration is rejected for the period after the opening of the IUK, i.e. after 1998 until the end of their sample in 2002. These results appear counterintuitive, as it is should be the arbitrage across the IUK which is responsible for the co-integration between the two. In a later study, Panagiotidis and Rutledge (2007) re-examine the co-integration relationship, based on a sample of Brent spot prices and the Heren Monthly gas price index between 1996 and 2003. Their findings support the idea of a long-term relationship between UK gas and crude oil prices. Further, testing for time-variation in co-integration, their econometric specification accepts co-integration over the entire sample period, even pre-dating the opening of the IUK in 1998.

[25] See Stern and Rogers (2011) for a detailed discussion on the relative maturity of European gas trading hubs.

Over the second half of the past decade, the role of LNG in global gas trade has become of significant importance, as it allows arbitrage across previously segmented markets. Neumann (2009) picks up on the results of Siliverstovs et al. (2005) and investigates whether LNG has led to the integration of natural gas markets in North American, Europe and Asia. Their results identify LNG as the key driver of international transmission of regional price impacts, suggesting an increasing convergence of daily spot prices on either side of the Atlantic Basin.

Very close to the present analysis is a study by Ramberg and Parsons (2012). They investigate the relationship of WTI crude oil prices and Henry hub prices in the US, based on weekly price data over the period 1997 through 2009. Specifically, the authors assess whether prices have decoupled. The results of a conditional vector error correction model, controlling for seasonality, weather variables and hurricane related shut-ins, suggest the existence of a cointegrating relationship, in which changes in the price of crude oil appear to translate into changes in the price of natural gas. Further, movements of the natural gas price away from this long-run relationship tend to reverse, such that it will be re-established in equilibrium. Ramberg and Parsons (2012) argue, however, that the long-run relationship was likely subject to a gradual shift during the sample period. This, so the authors, is a form of decoupling in which the prices permanently moved from an old to a new long-run relationship, rather than the relationship being permanently severed.

In context of NW European natural gas markets, the literature in the field of price co-integration between UK NBP and Continental Europe does not deliver clear cut results and the question whether there is a stable long-run relationship between oil and natural gas is a difficult one to answer. The current consensus appears to be one of convergence between NBP and Continental European spot prices, facilitated by arbitrage across the IUK. However, the question of how LNG affects the structural relationship between UK NBP and oil-indexed gas on the European continent remains unanswered. This study is only aware of co-integration (convergence) studies using data up until and including 2005. Since then, however, the UK and NW European natural gas markets were subject to significant changes. First, there has been a large change in energy price volatility and risk perception. While the NBP spot market price fluctuated between 1.5 and 5 USD/mmbtu[26] between 1997 and the end of 2004, prices moved within a significantly higher band of around 4-14 USD/mmbtu between the beginning of 2005 and 2010[27]. By 2009, UK NBP price had declined to the lower end of this band as a result of lower global demand for energy following the 2008 financial crisis[28]. Second, the UK increased its pipeline interconnection with neighbouring NW European gas markets in addition to the opening of several LNG regasification terminals. The events are summarized in figure 4.

There is strong reason to believe that these events had a large impact on UK gas price

[26] *mmbtu* million British thermal units.

[27] See Rogers (2010).

[28] Heather (2010) further outlines the increasing risk aversion in global energy markets as a result of the crisis, shifting significant volumes of gas trading from the less regulated over-the-counter (OTC) market onto regulated exchanges with decreased counter-party risk.

dynamics and are the motivation for this study to revisit the issue of estimating the structural relationship between the UK NBP and oil-indexed gas prices on the European continent.

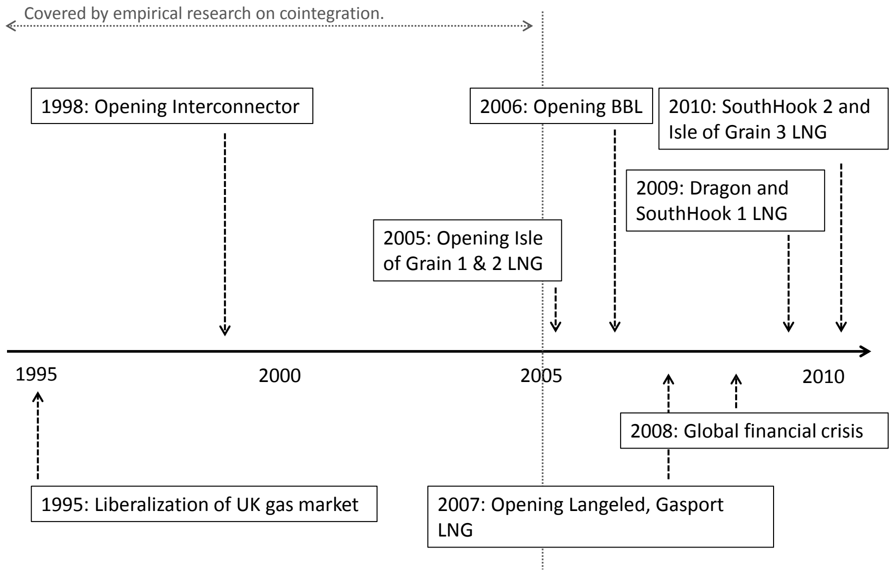


Figure 4: Major Events in the UK Gas Market, 1995-2010

3 Energy market data: sources and characteristics

Estimation is based on two sets of data. The first set are energy prices, whose sources and time series characteristics are discussed in the next section. The second set are control variables which are assumed to affect the price of natural gas, namely natural gas storage injections and temperature. They are discussed in section 3.2.

3.1 Natural gas prices

There is not just one wholesale price of natural gas in the UK[29]. Two price series are used to capture the dynamics of the UK NBP gas price. The first series is the Over-the-Counter (OTC) day-ahead or 'spot' market price. Trade on the OTC market is conducted bilaterally or through a broker and terms are therefore confidential. The OTC price used is provided by brokers, such as ICAP and Spectron, and obtained via Bloomberg. The second UK natural gas price series used is the Intercontinental Exchange (ICE) front-month (one-month ahead) futures contract. The futures market was established in January 1997 and serves to hedge the risk in the underlying spot market[30]. Both UK NBP prices are traded in GBpence/therm and are converted

[29] See extensive discussion in Wright (2006) for details on UK wholesale gas price formation.

[30] Compared to the rather opaque OTC price, the exchange traded futures price is completely transparent. While the futures price is recorded at a centralized exchange, the OTC price is *reported* to information agencies such as Platts or ICIS Heren. Reporters might have their own definition of 'price' and so discrepancies between the different information providers are not uncommon and can be large. See p. 18 in Energy Information Administration (2002).

into USD/mmbtu. The sample covers 12 years of monthly data, from September 1999 through September 2011. While the two wholesale gas prices are highly correlated, the front-month futures price exhibits slightly higher levels of volatility over the sample period[31].

In place of the Continental European gas price, the Average German Import Price (AGIP) is used, which is published each month by the German Office for Economics and Export Control and denominated in Euro per terajoule. The series is a volume weighted import price into the German market and is a common industry proxy for oil-indexed supply contract prices on the European continent, Stern (2009). The AGIP is converted into USD/mmbtu using the reference exchange rate of the European Central bank.

This study is concerned with the structural relationship between the oil-indexed price in the NW European market, for which the AGIP is a proxy, and the UK NBP price and, in particular, with the differential (y_t^m) between the two, which is given by

$$y_t^m = AGIP_t - NBP_t^m \tag{1}$$

where m = OTC or front-month (futures), depending on which UK NBP price is employed. Both prices and the differential are plotted in figure 5[32].

In contrast to the prices, the differential appears to be stationary, with a constant mean and variance over time[33]. Its autocorrelation function (ACF) and empirical distribution are plotted in figure 6. The empirical distribution shows a positive skew relative to a normal distribution, with clear signs of significant negative outliers. These outliers, consistent with figure 5, are identified as February 2005 and the period November 2005 to February 2006. During the later period, several events posed significant upward pressure on the UK NBP price. Rogers (2010) outlines three main contributors to the tight UK supply during the winter 2005-06. First, an early spell of cold weather increased UK demand for natural gas in November 2005, which was not met by sufficient supply from Continental European gas storage owners, over fears of not meeting their domestic demand during that winter. Second, Indonesian underperformance in supplying LNG to Asian markets pushed the price of spot LNG cargoes in excess of 15 USD/mmbtu. Third, UK supply was further tightened by problems with the UK's largest gas storage facility, the depleted Rough gas field[34]. To control for the effects of these events on the UK NBP price, the following dummy variable is defined and used in the estimation.

$$Winter_t^{05/06} = \begin{cases} 1 & \text{if } t = 2005(11) \text{ to } 2006(2) \\ 0 & \text{otherwise} \end{cases} \tag{2}$$

[31]Descriptive statistics and a table of pairwise correlations are provided in Appendix A.2, in tables 6 and 7 respectively.

[32]For a more complete discussion of the time series characteristics of the prices, see appendix A.

[33]For the results of a formal ADF/PP stationarity test, see Appendix A.3. The null-hypothesis of a unit root in the differential can safely be rejected at the 5% significance level, i.e. the differential is stationary.

[34]There was a fire on an offshore platform of the Rough gas storage facility on February 16th, 2006, which reduced effective supply into the UK transmission system, see Centrica (2006)

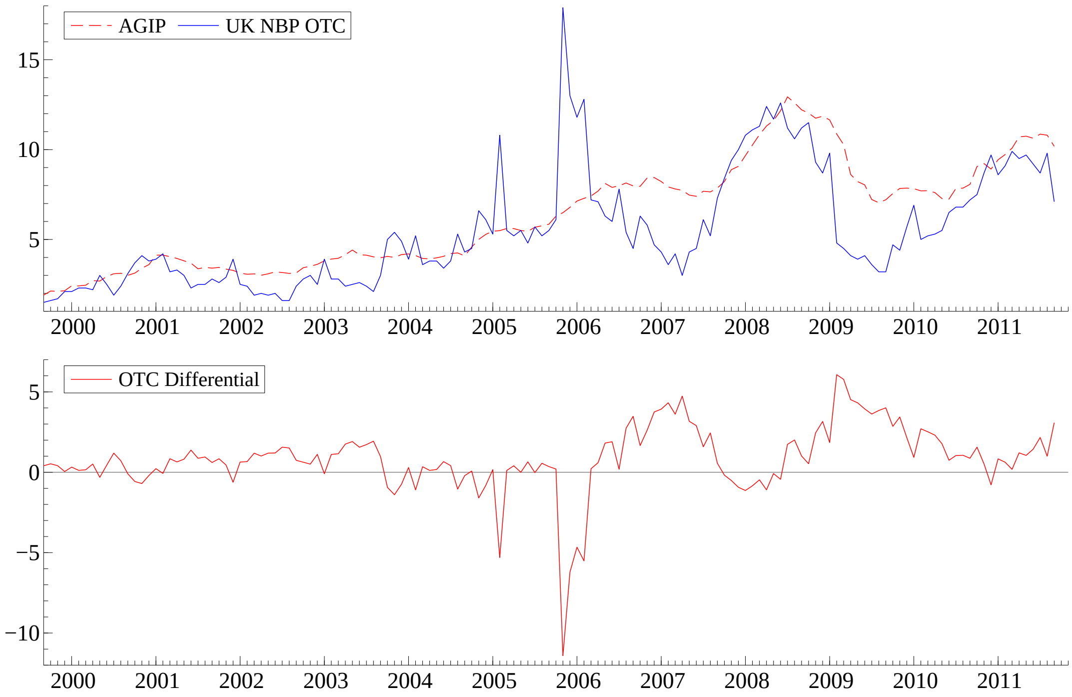


Figure 5: AGIP, NBP OTC and Differential (in USD/mmbtu): September 1999 to November 2011

Finally, UK gas demand is highly seasonal. Winter months are characterized by peak natural gas demand as a result of higher residential heating demand, pushing the UK NBP price upward to attract sufficient supply and balance the market. The AGIP does not exhibit such seasonal movements. It is to a large extent determined by lagged oil product prices, which determined on a global market, are not subject to seasonal swings. The constructed differential therefore exhibits a seasonal pattern, winter months being associated with a higher UK NBP price, hence a lower differential. This motivates the inclusion of a seasonal component in the estimation framework.

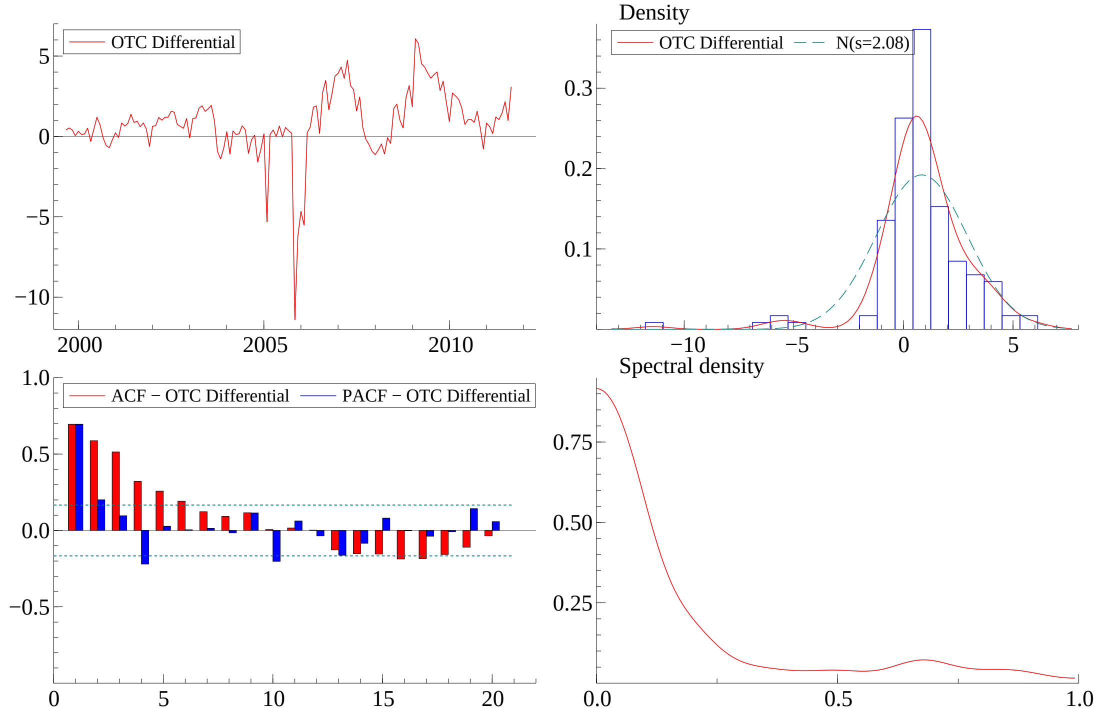


Figure 6: AGIP-NBP OTC differential, ACF (PACF), distribution and spectral density

3.2 Short-term market drivers

The UK market for natural gas is competitive and demand is highly variable. Temperature induced changes to residential heating demand account for the majority of the seasonal variation in total gas demand, Wright (2006). In the short-term, demand changes not necessarily in line with supply and gas storage becomes an important marginal unit of supply during peak demand periods. Given the close interconnection of temperature and storage behaviour and its effect on short-term demand and supply imbalances, it is reasonable to assume that these variables are key drivers of near-term natural gas prices[35]. In particular, it is assumed that deviations from normal (expected) temperature and storage injections and withdrawals drive variations in the spot, and to a lesser extent, front-month prices used.

3.2.1 Storage

For the period January 2000 until September 2004, storage injections/withdrawals are obtained from the UK gas balance. The balance is calculated based on UK domestic gas production and import data as well as domestic consumption and export demand. The data is provided by National Grid and DECC[36]. This study assumes that any demand and supply imbalances in a

[35] Mu (2007) examines the effect of weather and storage shocks to US natural gas futures prices. His empirical findings suggest a significant weather effect on both conditional mean and volatility of natural gas futures returns.
[36] *DECC* UK Department for Energy and Climate Change.

particular month are smoothed by a storage injection/withdrawal in that month. The balance is plotted in figure 16 in Appendix A.4. For the period October 2004 through to September 2011, explicit natural gas storage information for the UK is provided by National Grid. Given monthly storage level data, monthly injections/withdrawals are calculated. Let DS_t be the deviation of monthly storage injection/withdrawal from the normal (expected) level of injection/withdrawal for that month. It is defined by

$$DS_t = INJ_t - \overline{INJ^m} \tag{3}$$

where INJ_t is the injection/withdrawal at time t and $\overline{INJ^m}$ is the corresponding mth month average injection/withdrawal[37]. Figure 7 illustrates both the actual storage changes and monthly averages as well as the calculated deviations DS_t.

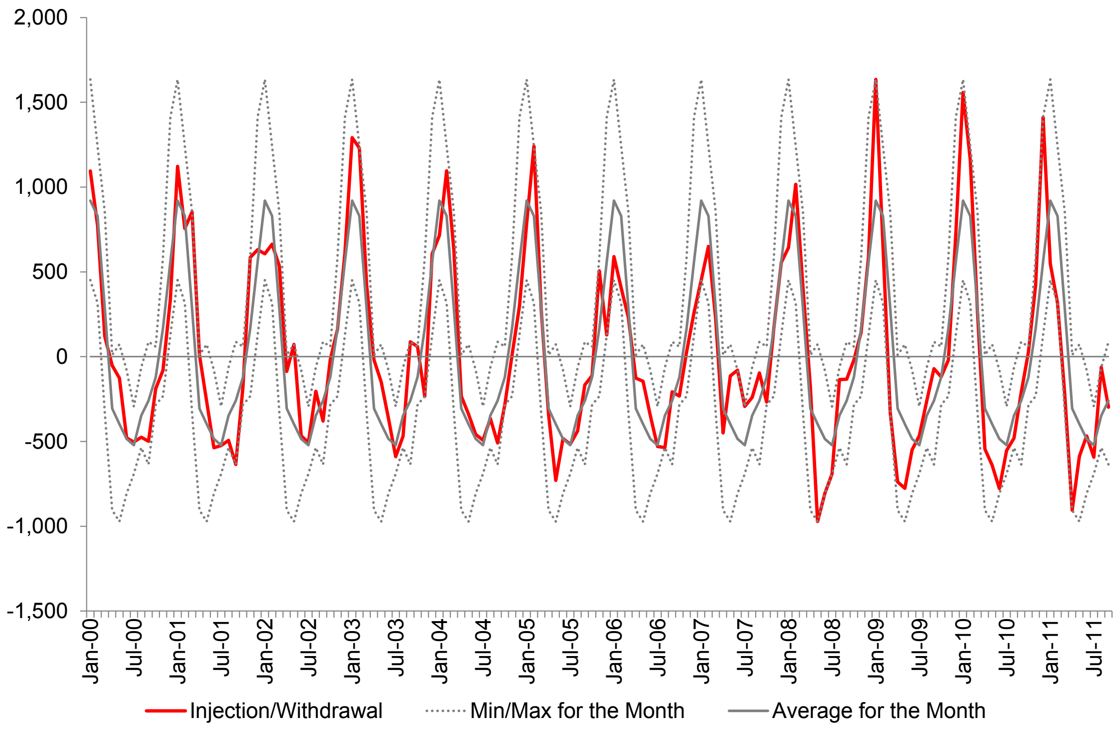
A positive value for DS_t means that this month was either characterized by higher (lower) than normal storage withdrawal (injection). A positive DS_t is therefore associated with upward pressure on the UK NBP price. A negative DS_t, means that the month is characterized by lower (higher) than normal storage withdrawal (injection), which puts downward pressure on the UK NBP price. These effects and their sample frequencies are summarized in table 2.

Table 2: UK Natural Gas Storage Injection/Withdrawal, deviations from normal

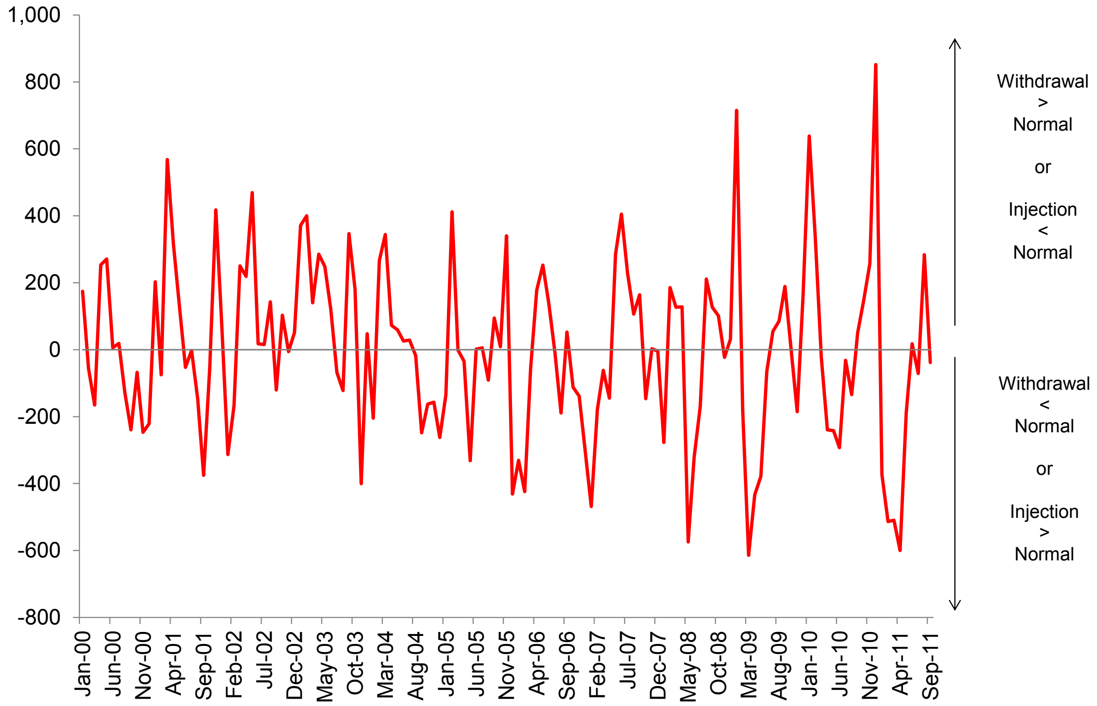
Deviation	Storage Injection	or	Storage Withdrawal	Count	Hypothesized Effect on UK NBP spot price
$DS_t > 0$:	$< Normal$	or	$> Normal$	71	*Upward pressure*
$DS_t < 0$:	$> Normal$	or	$< Normal$	70	*Downward pressure*

DS = *Actual* Injection (Withdrawal) - *Normal* Injection (Withdrawal)

[37]E.g. t = January 2005 and m = January, such that $\overline{INJ^m}$ is the average injection/withdrawal over all months January in the sample.



(a) Injections (-) and withdrawals (+)



(b) Deviations from Normal

Figure 7: UK natural gas storage injections (in mcm) - Source: National Grid, author's calculation.

3.2.2 Temperature

Temperature data is included in the form of Heating Degree Days (HDD). HDD measures the extent to which outside temperature T_t at date t is below a given base temperature B. While any base temperature could be used in theory, this study employs the conventional base temperatures of 15.5 and 18 degrees Celsius. Let HDD_t be defined by

$$HDD_t = \begin{cases} B - T_t & \text{if } B - T_t > 0 \\ 0 & \text{if } B - T_t <= 0 \end{cases} \tag{4}$$

where B is equal to 15.5 or 18. Equation (4) is calculated for each day in the sample period and summed up for each month, providing a measure of aggregate monthly heating demand. Daily temperature data for the UK (country average) is obtained from Bloomberg. Deviations from *normal* heating demand are calculated as

$$DHDD_t = HDD_t - \overline{HDD^m} \tag{5}$$

where $\overline{HDD^m}$ is the corresponding mth month average[38]. A positive value for $DHDD_t$ indicates that the month was colder than the normal month. This should provide upward pressure on residential heating demand in the UK and therefore upward pressure on the UK NBP price. A negative value for $DHDD_t$, in a similar fashion, should be associated with downward pressure on the UK NBP price. These effects and their sample frequencies are summarized in table 3.

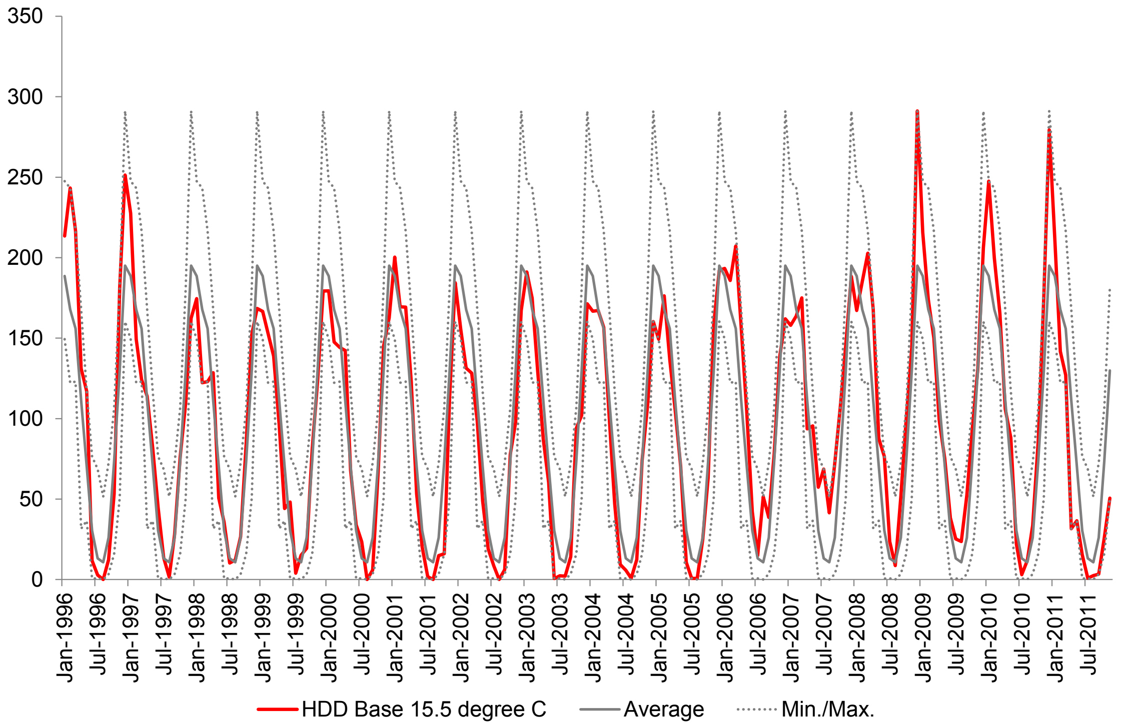
Table 3: UK Heating Degree Days (HDD), deviation from normal

HDD Deviation	Count Baseline 18C	Count Baseline 15.5C	Hypothesized Effect on UK NBP spot price
$DHDD_t > 0$:	67	65	*Upward pressure*
$DHDD_t < 0$:	74	76	*Downward pressure*

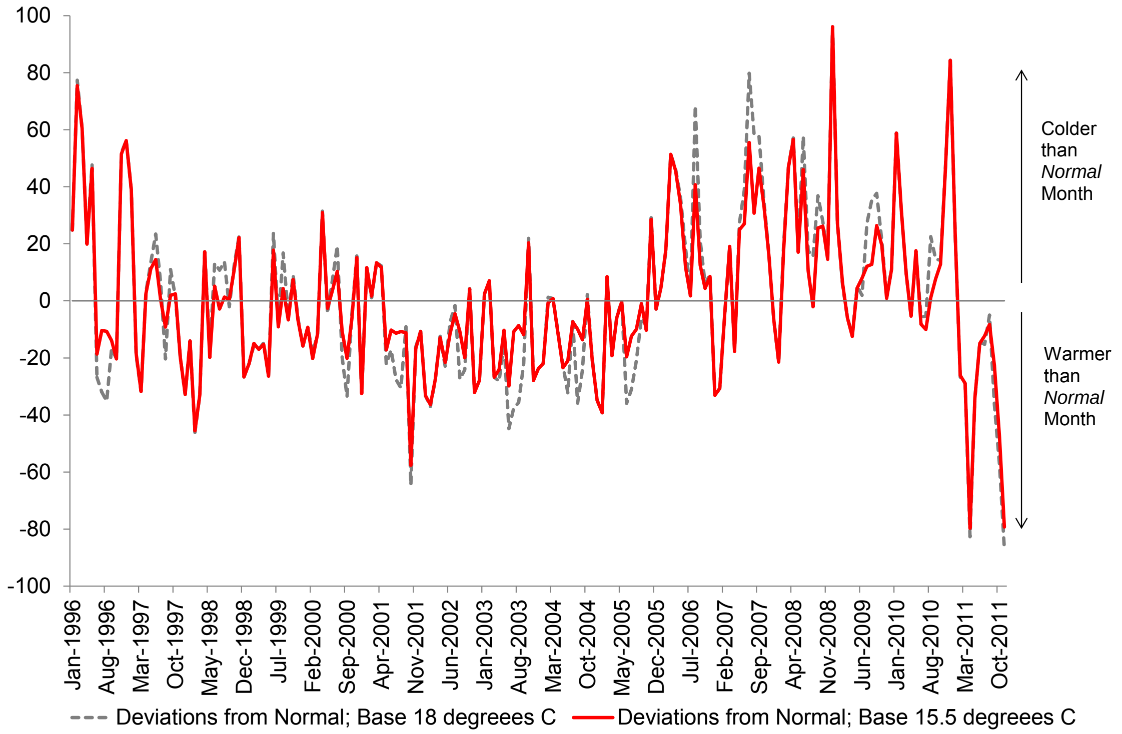
$DHDD = ActualHDD$ for the month - $Normal$ (Average) for the month.

Following Mu (2007), the effects of temperature on the NBP price are expected to be more pronounced in the case of spot prices than front-month futures price. Temperature induced demand variations trigger physical demand and supply rebalancing, which is achieved by spot price changes, rather than futures price changes. Figure 8 illustrates both HDD and its deviations from normal.

[38] E.g. t = January 2005 and m = January, such that $\overline{HDD^m}$ is the average HDD over all months January in the sample.



(a) HDD base temperature 15.5 degree C



(b) HDD deviation from normal

Figure 8: UK Heating Degree Days (HDD), monthly aggregates - Source: Bloomberg

4 Econometric methods

At the core of this study lies the testing for existence and stability of a long-run relationship, or 'coupling', between oil-indexed gas prices and the UK NBP price. The literature on energy price dependence has conventionally modelled price coupling in a cointegration framework. Only if prices are cointegrated, that is they share a common stochastic trend, are they coupled, and any deviation from the common trend path is temporary[39]. In particular, if there is a cointegrating relationship, this study aims to identify whether a break in the cointegrating relationship exists, which manifests itself in any of the three forms of price decoupling, as discussed by Ramberg and Parsons (2012):

(i) Prices have *temporarily* broken away from their long-term relationship, to which they will later return. Implies: no break in the cointegrating relationship.

(ii) Prices have *permanently* broken away from the old long-term relationship and have entered a new long-term relationship. Implies: a regime shift in the cointegrating relationship.

(iii) Prices broke away from the old relationship and no longer maintain a long-term relationship with each other at all. Implies: prices are no longer cointegrated.

To investigate the existence of any of these three mutually exclusive forms of price decoupling, the estimation will follow two parallel methodological approaches. First, section 4.1 discusses price (de)coupling in its conventional framework - cointegration. Here, a long-run model is estimated which connects the two natural gas prices in equilibrium. The existence and stability of any long-run relationship between the two prices is then based on the time series characteristics of the estimated residual from this long-run model. In this approach, the potential break dates are determined endogenously. In the second approach, the existence and stability of a long-run relationship between the two prices is based directly on the time series characteristics of their differential. Specifically, the AGIP-UK NBP price differential is modelled in an unobserved components model (UCM), which allows to test for the effect of break-dates whose timing is known a priori, while controlling for time-varying seasonality. This approach is discussed in section 4.2.

The reason for using two parallel approaches is that, in the context of the question at hand, both approaches have relative advantages as well as disadvantages. The first approach, conventional cointegration, tests for a single break in a cointegrating vector at an unknown date. While this approach does not require a priori knowledge of the timing of the break, it maintains the restrictive assumption that after the break-date both series are still cointegrated. The second

[39]It needs to be highlighted here, that the present study is purely interested in the existence and dynamics of the long-run equilibrium relationship between the two natural gas prices. That is, the short-run adjustment process to deviations from this long-run equilibrium, which is commonly modelled in an Error Correction Model (ECM), is not considered. The ECM includes (lagged) first-differences of the observations which would reduce the already limited effective sample size further. For this reason, only the long-run equilibrium model is estimated.

approach, the UCM, does not require this restriction. However, this approach tests for the significance of break-dates whose timing is known a priori. Both approaches assess the question of existence and stability of a long-run relationship from somewhat different perspectives, such that they are regarded as complements rather than complete substitutes.

4.1 Cointegration and stability

The existence of a cointegrating relationship between the two natural gas prices is determined by applying the usual cointegration tests[40], which assume the following underlying long-run model (LRM) relationship:

$$log(nbp_t^m) = \alpha + \beta log(agip_t) + \epsilon_t \tag{6}$$

where m = OTC or front-month (futures), depending on which UK NBP price is employed. α is a constant, which measures differences in the levels of the two prices, and β measures the relationship between the two prices[41]. In particular, if $\beta = 0$, prices maintain no long-term relationship, whereas $\beta = 1$ means they are proportional[42]. The LRM in equation (6) only forms a very basic specification and the model is therefore extended to include controls for the deviations of normal storage behaviour and temperature, as defined by equations (3) and (5) respectively, as well as for the outlier in the winter 2005/06, as given by equation (2). The extended LRM is given by:

$$log(nbp_t^m) = \alpha + \beta log(agip_t) + \phi_1 Winter_t^{05/06} + \phi_2 DS_t + \phi_3 DHDD_t + \epsilon_t \tag{7}$$

While estimation of this LRM determines the coupling of the two prices over the entire sample period, it provides no information about the stability of the parameters α and β over time, nor does it allow for cointegration to hold only over sub-samples. Both of these cases correspond to a break in the cointegrating relationship described in equation (7).

The first case, namely a change in the parameters α and β at an unknown break date, can be addressed in the conventional cointegration framework. The standard testing procedure is extended to allow for the possibility of a regime shift in the cointegrating relationship, as originally proposed by Gregory and Hansen (1996). They define structural change as a change

[40]Cointegration will be established based on three test procedures, namely the Johansen-test for system cointegration and the Engle-Granger and Phillip-Ouliaris single equation residual based tests. For a formal discussion of the concept of cointegration and the test procedures, see Greene (2008).

[41]If the residuals from the estimation of the LRM in equation (6) are stationary, then the two prices series are said to be cointegrated with cointegrating vector $(1, -\beta)$.

[42]Both prices are in logarithms, such that β gives the elasticity of the UK NBP prices to changes in the AGIP series.

of the constant and/or slope of the cointegrating regression, using the timing-dummy variable

$$\delta_{t\tau} = \begin{cases} 0 & \text{if } t \leqslant [T\tau] \\ 1 & \text{if } t > [T\tau] \end{cases}$$

where $\tau \in (0,1)$ denotes the (relative) timing of the break point[43], and $t = 1, ..., T$. Importantly, τ is not known a priori and is estimated to be the point where a break is most likely. The null-hypothesis of their test is that of no cointegration of the two prices. In the present study, two alternative hypotheses are of particular interest. The first alternative hypothesis is that cointegration holds with a single level shift at unknown time $T\tau$, that is

$$log(nbp_t^m) = \alpha_1 + \alpha_2\delta_{t\tau} + \beta log(agip_t) + \phi_1 Winter_t^{05/06} + \phi_2 DS_t + \phi_3 DHDD_t + \epsilon_t \tag{8}$$

where α_2 is the shift in the level from period $T\tau$ onwards. The second alternative hypothesis is that cointegration holds with a single level and slope (regime) shift at unknown time $T\tau$, that is

$$\begin{aligned} log(nbp_t^m) = \alpha_1 + \alpha_2\delta_{t\tau} + \beta_1 log(agip_t) + \beta_2 log(agip_t)\delta_{t\tau} + \phi_1 Winter_t^{05/06} \\ + \phi_2 DS_t + \phi_3 DHDD_t + \epsilon_t \end{aligned} \tag{9}$$

where α_2 and β_2 are the level and slope change respectively from period $T\tau$ onwards. Based on the estimated break-point τ, a cointegrating regression on each side of the break point provides insight into how constant and slope coefficients have changed.

The advantage of this approach is that it does not require a priori knowledge of the break-date in the sample, rather it produces an estimated date at which a break is most likely. That is, it helps identify the point in time at which prices have moved from an old to a new long-term relationship, as both alternative hypotheses state that cointegration holds on either side of the breakpoint. This corresponds to the second form (ii) of decoupling discussed by Ramberg and Parsons (2012). The estimated break-date can then be compared to potential break-date candidates, which are known a priori. To be precise, this study expects a downward shift in both constant and slope during the second half of 2006.

However, there are three disadvantages to using this approach. (a) There is no account for time-variant seasonality, which is a key concern in the present context. (b) The assumption that cointegration holds also after the break-date is too restrictive and excludes the possibility of a break-down of cointegration altogether. Finally, (c) it does not allow to test for the effect of break-dates which are known a priori. In the present context, these dates are the opening of the BBL/Langeled pipelines in 2006 and the pick-up of UK LNG imports in 2008. The next section introduces the second approach, namely the UCM of the AGIP-UK NBP price differential.

[43] For computational reasons, a break-point is only identified for the interval ([.15T],[.85T]). See Gregory and Hansen (1996).

4.2 Unobserved components model: the AGIP - UK NBP price differential

An alternative approach is to test for the existence and stability of a long-run relationship between the two natural gas prices directly on the time series characteristics of their differential. This approach proceeds in two steps. First, an UCM of the price differential is used to determined whether two exogenous market events had an effect on the stability of the relationship between the two prices, while controlling for time varying seasonality. Second, if any of the two dates is found to significantly influence stability, a conventional cointegration model is estimated on either side of the break-date and the cointegrating properties are assessed pre- and post-break separately. This then determines whether the relationship has moved from an old to a new stable long-run relationship, or whether no long-run relationship exists in the post-break period.

Following the methodology set out in Harvey (1989), the AGIP - UK NBP price differential y_t^m, defined in equation (1), is modelled as the sum of various unobserved components in a 'local-level' model[44]. Formally

$$y_t^m = \mu_t + \gamma_t + \sum_{i=1}^{k} \phi_{i,} x_{i,t} + \epsilon_t, \qquad \epsilon_t \sim NID(0, \sigma_\epsilon^2) \tag{10}$$

where μ_t is a stochastic trend, γ_t is a stochastic seasonal component, $x_{i,t}$ are a set of explanatory variables and ϵ_t is an irregular component. The stochastic trend and the stochastic trigonometric seasonal components are respectively given by

$$\mu_t = \mu_{t-1} + \eta_t, \qquad \eta_t \sim NID(0, \sigma_\eta^2) \tag{11a}$$

$$\gamma_t = \sum_{j=1}^{s/2} \gamma_{j,t} \tag{11b}$$

$$\begin{bmatrix} \gamma_{j,t} \\ \gamma_{j,t}^* \end{bmatrix} = \begin{bmatrix} cos\lambda_j & sin\lambda_j \\ -sin\lambda_j & cos\lambda_j \end{bmatrix} \begin{bmatrix} \gamma_{j,t-1} \\ \gamma_{j,t-1}^* \end{bmatrix} + \begin{bmatrix} \omega_{j,t} \\ \omega_{j,t}^* \end{bmatrix}, \qquad \begin{bmatrix} \omega_{j,t} \\ \omega_{j,t}^* \end{bmatrix} \sim NID(\mathbf{0}, \sigma_\omega^2 \mathbf{I_2}) \tag{11c}$$

for $j = 1, ..., [s/2]$ and $t = 1, ..., T$ where $\lambda_j = 2\pi j/s$ is the seasonal frequency, in radians, and ω_t and ω_t^* are two mutually uncorrelated NID seasonal disturbances with zero mean and common variance σ_ω^2. For s even, the component at $j = s/2$ collapses to

$$\gamma_{j,t} = \gamma_{j,t-1} cos\lambda_j + \omega_{j,t}$$

As opposed to fixed seasonality, the trigonometric specification allows for a change in the seasonal pattern across the sample[45]. This is of particular importance, as the seasonal pattern in y_t^m is assumed to diminish somewhat over the sample period. Seasonality in the differential is a result of winter month re-connection of UK NBP to AGIP, in order attract sufficient gas into the UK

[44] The estimation for this section is performed in STAMP, a module for OxMetrics, see Koopman S.J. and Shephard (2009).

[45] For more details on seasonal components, see Harvey and Scott (1994) and Proietti (2000).

market through the IUK pipeline. This driver of seasonality, however, is assumed to weaken as additional import capacity in the form of LNG comes online.

In order to control for the effects of the exceptional winter months of 2005-06, as well as the deviation of storage injections/withdrawals and temperature from their normal values, three explanatory variables are included. The third term in equation (10) becomes

$$\sum_{i=1}^{3} \phi_i, x_{i,t} = \phi_1 Winter_t^{05/06} + \phi_2 DS_t + \phi_3 DHDD_t \tag{12}$$

where $Winter_t^{05/06}$, DS_t and $DHDD_t$ are defined in equations (2), (3) and (5) respectively.

4.2.1 Testing for structural breaks

In order to test for the existence of structural breaks in the level of the differential, i.e. in the stochastic trend component, this study follows the intervention analysis methodology by Harvey (1989). The stochastic trend component is subjected to two interventions, which permanently shift the level of the trend component, upwards or downwards. More formally, equation (11a) is redefined as

$$\mu_t = \mu_{t-1} + \theta_{bbl} w_t^{bbl} + \theta_{lng} w_t^{lng} + \eta_t, \qquad \eta_t \sim NID(0, \sigma_\eta^2) \tag{13}$$

where w_t^{bbl} and w_t^{lng} are two dummy variables corresponding to the inauguration of the BBL pipeline (December 2006) and the pick-up of UK LNG imports (November 2008) respectively[46]. They are defined as

$$w_t^{bbl} = \begin{cases} 1 & \text{if } t = 2006(12) \\ 0 & \text{otherwise} \end{cases} \qquad \text{and} \qquad w_t^{lng} = \begin{cases} 1 & \text{if } t = 2008(11) \\ 0 & \text{otherwise} \end{cases}$$

Assuming that both price series are cointegrated, such that the differential is stationary, a statistically significant break in the stochastic trend component corresponds to a break of the cointegration relationship. To be more precise, if the stochastic trend component deviates significantly from zero at the break dates, the underlying cointegrating vector has changed or cointegration ceased to hold altogether. In the context of equation (13), this means that if we can reject the null-hypothesis $H_0 : \theta_{bbl} = 0$ in favour of the alternative ($H_1 : \theta_{bbl} \neq 0$), then there exists a statistically significant structural break in the stochastic trend component of the AGIP-UK NBP price differential, corresponding to a break in the cointegrating relationship between the two prices, from December 2006 onwards, the date at which the BBL pipeline became operational. Similarly, if we can reject the null-hypothesis $H_0 : \theta_{lng} = 0$ in favour of the alternative ($H_1 : \theta_{lng} \neq 0$), then there exists a statistically significant structural break in the stochastic trend component of the differential, and a break in the cointegrating relationship of the prices, from

[46] A complete derivation of the model in state space form (SSF) is given in Appendix B.

November 2008 onwards, the date at which the UK LNG imports started to pick up markedly. If the effect of any of the two break-dates is statistically significant, indicating a break in the cointegrating relationship, a cointegrating regression is estimated on each side of the break[47]. In contrast to the conventional Gregory and Hansen (1996) approach outlined in the previous section, there is no need for the assumption that the two natural gas prices are still cointegrated *after* the break-date. Cointegration after the break-date will be tested for explicitly. This then determines whether the prices have merely moved from an old to a new long-run relationship, or whether there is evidence of decoupling of the third form (iii), such that the prices no longer maintain a long-term relationship at all.

5 Results

This section discusses the empirical findings. Section 5.1 contains the results of the conventional cointegration analysis, while section 5.2 presents the results of the unobserved components model of the price differential.

5.1 Cointegration and stability

A necessary condition for cointegration is that both series, the UK NBP price and the AGIP, are integrated of the same order. Unit root test on both the levels and first differences of the log-prices have established this[48]. Both prices are integrated of order one, i.e. they are $I(1)$. The results of both the trace and maximum eigenvalue Johansen cointegration tests indicate the existence of a cointegrating relationship at the 1% significance level over the entire sample period, September 1999 through September 2011[49]. The corresponding cointegrating vector is given by $[log(nbp_t^{OTC})$, -.9719*$log(agip_t)]$[50]. Both the Engle-Granger and Phillip-Ouliaris residual based tests reject a unit root in the residual of the cointegrating regression at the 1% level, only if the UK NBP series is taken as the dependent variable. Therefore, future estimation will only consider single-equation cointegrating relationships, the UK NBP being the dependent variable and treating the AGIP as pre-determined, hence excluding feedback from the UK NBP to the AGIP[51].

[47] The sign of both θ_{bbl} and θ_{lng} is expected to be positive. That is, both the inauguration of the BBL pipeline and the picking-up of UK LNG imports provide additional marginal supply to the UK market, such that a structural deviation of the prices, even during UK peak demand periods, is feasible. Specifically, UK NBP then trades at a discount to AGIP, leading to a structural positive widening of the price differential.

[48] See appendix A.3.

[49] For detailed results, see table 9 in appendix A.3.

[50] The estimated β is not significantly different from 1, based on a Wald test on coefficient restrictions, the results of which are omitted. This is consistent with the result that the price differential y_t^m, corresponding to a cointegrating vector of $[log(nbp_t^m)$, -$log(agip_t)]$ is stationary over the entire sample period.

[51] The AGIP appears weakly exogenous, which is consistent with a very low adjustment coefficient in the Johansen test. Exogeneity of the AGIP is not surprising. It is a function of lagged oil product prices (and to a lesser extend lagged gas prices), which are determined on a *global* market and can be taken as exogenous for the sake of our analysis.

While the analysis over the entire sample confirms the existence of a long-run relationship with an elasticity of close to 1, verifying stability of this cointegrating vector requires further evaluation. The results of the Gregory and Hansen (1996) test for cointegration under the presence of an unknown structural break reject the null-hypothesis of no cointegration in favour of the alternative, cointegration allowing for a break in both constant and slope parameters, at the 5% significance level[52]. Although there is slight discrepancy regarding the determined break-date across the three test statistics, the results indicate that there is a break in both the constant and slope of the cointegrating relationship between the logarithms of the UK NBP OTC price and the AGIP during May 2006. For the relationship between the logarithms of the UK NBP front-month price and the AGIP, the break date is estimated to be August 2006. These endogenously determined break-points take place in an important year for the UK natural gas market and are very close to the first LNG shipment into the Isle of Grain LNG terminal (July 2006) and the opening of the first stage of the Langeled pipeline (September 2006), both sources of additional gas supply into the UK market.

To determine whether the constant and slope parameters have changed across the break-date, the cointegrating regression model is estimated three times. The first model, model 1, uses no break-dummy variable. It is equivalent to the LRM specification in equation (7). The second model, model 2, is based on the estimated break dummies obtained from the Gregory and Hansen (1996) method, and assumes a break in the level parameter only. The third model, model 3, then assumes a full regime shift of both level and slope parameters. It is equivalent to the model in equation (9)[53]. Table 4 displays the results for all three models for each of the two dependent variables. The estimated regression coefficients are meaningful as the null-hypothesis of no cointegration has been rejected at the 1% level, based on the Gregory and Hansen (1996) test statistics.

In all three models for both dependent variables, the constant term is negative[54]. This is as expected, as in the present sample the UK NBP prices is on average below the AGIP, even before the opening of the UK to additional import sources. Interestingly, the results of both break models, models 2 and 3, indicate that this level difference widens substantially, as the coefficient on the interaction term of break-dummy and level is also negative. Importantly, the coefficient on the AGIP is much higher in model 2, assuming a break in the constant only, compared to model 1, which assumes no break in the constant. A 1% increase in the AGIP results in a 1.6% increase in the UK NBP OTC price, compared to .96% in the model without a break. A similar

[52] For full details about the test results, see table 10 in appendix A.3.

[53] The break-dummy variable δ_τ equals one from 2006(5) or 2006(8) onwards, and zero otherwise, for estimation of the NBP OTC or front-month series respectively.

[54] It is noted that Gregory and Hansen (1996) highlight that inference based on the statistical significance of the OLS estimates of the break dummy terms is highly flawed for various reasons. The robustness of the results are checked by estimating a split cointegrating regression on both sides of the break dates suggested by the Gregory and Hansen (1996) method. The qualitative results do not change. The constant decreases in the post-break sample, whereas the slope parameter increases. The results are presented in table 11 in appendix C. Cointegration test results for the post-break sample yield conflicting results, which are attributed to the low post-break sample size.

difference holds for the front-month model. Moving to the results of the models for both level and slope breaks, model 3, the elasticity of the UK NBP price to changes in the AGIP does not markedly vary across the break-date, whereas it was expected that the sensitivity decreases.

Taken together, the effect of allowing for a one-time structural break in the cointegrating vector, that is in the level parameters or in both the level and slope, results in a significant downward shift of the cointegrating relationship in the post-break period. Models accounting for a structural break in the cointegrating vector also provide a better fit to the data, explaining between 8-10% more of NBP price volatility.

The coefficient on the temperature variable is positive and statistically significant at the 5% level. That is, hotter than normal months significantly increase the NBP OTC price , all else being equal. While still positive, the temperature effect is not significant in the front-month model. This is somewhat intuitive, as current temperature is expected to affect forward prices to a lesser extent than current prices. Counter to expectations, the effect of storage is negative, yet only weakly statistically significant in the front-month model. One possible explanation for the lack of explanatory power of the storage variable is the absence of a seasonal control in the LRM. Including a large set of monthly dummy variables, however, given the low number of observations in the post-break sample is problematic.

Table 4: Cointegration Regressions and Endogenous Breaks

	Dependent: $log(nbp^{otc})$			Dependent: $log(nbp^{front})$		
	$m = otc$			$m = front$		
Break†	No	$\tau = 2006(5)$	$\tau = 2006(5)$	No	$\tau = 2006(8)$	$\tau = 2006(8)$
Model	1	2	3	1	2	3
$log(agip)$	0.9584***	1.5587***	1.5293***	0.9828***	1.4912***	1.4443***
	(0.1040)	(0.1336)	(0.1473)	(0.1053)	(0.1367)	(0.1487)
$log(agip)*\delta_\tau^m$	-	-	0.1283	-	-	0.2208
			(0.2775)			(0.3053)
Dev. Storage	-0.0001	-0.0001	-0.0002	-0.0002	-0.0002	-0.0002*
	(0.0002)	(0.0001)	(0.0001)	(0.0002)	(0.0001)	(0.0001)
Dev. HDD(b=15.5)	0.0011	0.0027*	0.0029**	0.0004	0.0011	0.0014
	(0.0020)	(0.0015)	(0.0014)	(0.0020)	(0.0016)	(0.0015)
Constant	-0.1684	-0.9029***	-0.8338***	-0.1361	-0.7703***	-0.6768***
	(0.1874)	(0.1950)	(0.2135)	(0.1896)	(0.2040)	(0.2203)
Constant*δ_τ^m	-	-0.6711***	-0.9661*	-	-0.5743***	-1.0607*
		(0.1189)	(0.5627)		(0.1214)	(0.6311)
R^2	0.6575	0.7611	0.7657	0.6556	0.7332	0.7389
adj.-R^2	0.6499	0.7541	0.7569	0.6480	0.7253	0.7291
N	140	140	140	140	140	140

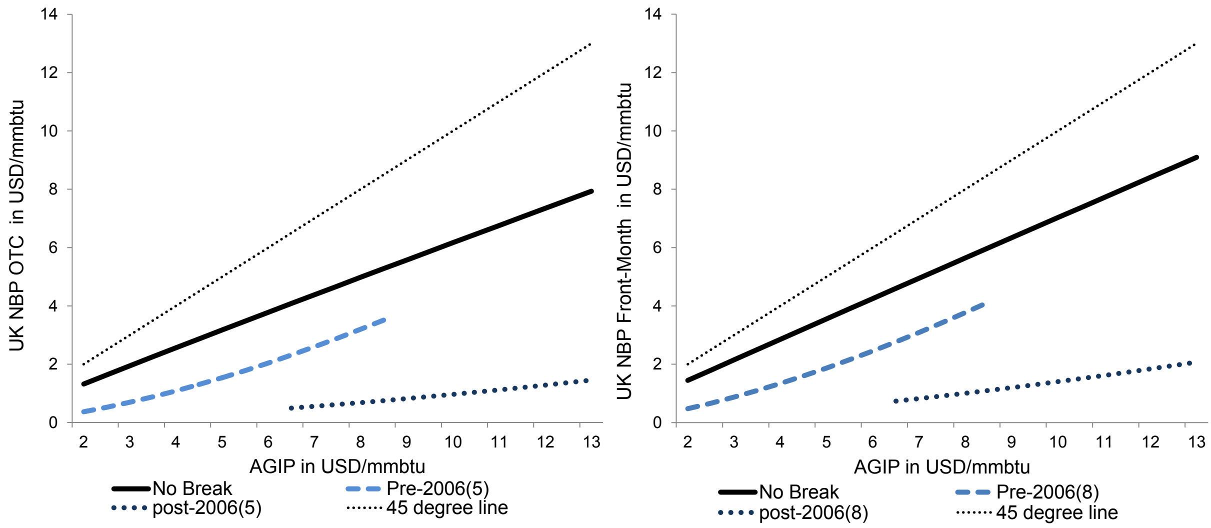
* = significant at the 10% level, ** = significant at the 5% level,*** = significant at the 1% level.

(...) Standard errors in parentheses. † break dates estimated using Gregory and Hansen (1996).

Model: 1 no break, 2 break only in level, 3 break in both level and slope parameter.

As discussed in Ramberg and Parsons (2012), the cointegrating relationship is linear in log-prices and therefore becomes non-linear once converted back into USD/mmbtu. Figure 9 plots the cointegrating relationship for the model without a break (model 1) as well as the two pre- and post-break cointegrating relationships for the model with a level break (model 2). All cointegrating relationships are plotted for the AGIP price range prevailing over the respective time periods[55]. The figure illustrates the drastic change in the implied long-term relationship from before to after the break date, which is the result of the significant downward change in the log-level[56]. The new relationship suggests that after the break in 2006, the range of UK NBP prices which correspond to a given range of the AGIP is much narrower in equilibrium.

In summary, there is evidence of a clear shift in the cointegrating relationship and a price decoupling of the second form (ii), in which prices move from an old to a new, much weaker, long-term relationship. Low post-break sample size, however, makes precise estimation of break dummy coefficients on the slope difficult and they need to be interpreted with caution. In order to introduce a seasonal control variable, and examine the effect of two break dates whose timing is known a priori, the next section will present the results of the alternative modelling approach, namely the unobserved components model of the price differential.



(a) UK NBP OTC

(b) UK NBP Front-month

Figure 9: UK NBP and AGIP Cointegrating Relationships

[55]E.g. the observed AGIP price range over the entire sample period is approx. 2-14 USD/mmbtu, whereas the observed AGIP price range over the pre-2006(5) break period is approx. 2-9 USD/mmbtu.

[56]Converting the estimated $log(nbp^m)$ back into USD/mmbtu by simply exponentiating will underestimate the UK NBP price due to Jensen's inequality for convex functions, since $exp(E(log(nbp^m))) \leq E(exp(log(nbp^m)))$. Correcting for the introduced bias involves multiplying the exponentiated estimates by a function of the estimated residual variance of the LRM. However, all series plotted in figure 9 are from the same estimation, thus correcting for the bias would shift all curves upwards by an identical amount. The results regarding the relative behaviour of the cointegrating relationship before and after the break dates therefore remain intact, even without a correction.

5.2 Unobserved components model: the price differential

This section will present the results of an alternative modelling approach. In a first step, an unobserved components model is estimated, which is used purely to determine whether two exogenously given break-dates affect the stability of the relationship between the UK NBP price and the AGIP. This approach allows to control for time-varying seasonality. In a second step, conditional on finding a significant break, a conventional cointegration model is estimated on each side of the break-date. The second step is necessary to determine exactly *how* the parameters have changed in the long-run model across pre- and post-break samples and critically whether the new post-break model can be considered a *stable* long run relationship or not. The last step therefore tests for what was maintained implicitly as a restrictive assumption in the previous approach, namely that both prices are still cointegrated after the break-date.

The conventional cointegration analysis in the previous section has found that a cointegrating relationship exists when estimated over the entire sample and under the assumption of no structural breaks. This is consistent with the result that over the entire sample, the price differential y_t^m is stationary[57]. To exploit the advantages of the unobserved components modelling approach, a local level model, with a stochastic seasonal component and exogenous control variables is fitted to the price differential. The basic intuition is that, should the cointegrating relationship be stable over time, the stationary price differential should have a rather flat trend component, which is not significantly different from zero. To be more precise, large deviations from zero in the stochastic trend are an indication of a break in the cointegrating relationship, which can then be interpreted as either a change in the cointegrating vector or a break-down of cointegration altogether. Both cases are considered a price decoupling. The results of this estimation are presented in appendix C, in tables 12 and 13 for the NBP OTC and front-month differentials respectively. This section will only discuss the results for the NBP OTC price differential, as the results for the front-month series are somewhat similar.

Before introducing structural break dummies into the trend component, a benchmark model is determined which best characterizes the dynamic properties of the price differential. Model fit is evaluated by minimizing the BIC information criterium. A number of specifications are tested with regard to fixed versus stochastic seasonality, as well as the inclusion of relevant control variables. They are referred to as models 1-5 in table 12. Best fit is achieved in model 5, only after controlling for the winter events of 2005/06 as well as temperature deviations from normal. The temperature control has the expected sign, as an increase in the control, corresponding to colder than normal months and therefore higher than normal heating demand, is associated with a higher UK NBP price and hence a lower price differential. While the coefficient of the storage control has the correct sign, it is not statistically significant in benchmark model 5[58].

[57] This corresponds to the cointegrating vector [$log(nbp_t^m)$, -$log(agip_t)$].

[58] It is noted that the results for the front-month estimation are different with respect to the importance of storage behaviour and temperature deviations. The front-month price differentials is significantly influenced by storage, with correct sign, whereas temperature appears to have no significant effect. This is expected, as current temperature is thought to affect current forward prices to a lesser extent than current spot prices. Mu (2007)

After estimating the parameters of the model, the Kalman filter algorithm produces smoothed estimates of the unobserved elements, which in the present case are stochastic trend and seasonal components. They are plotted in figure 10. The seasonal component exhibits a gradual decline over the sample period. This is as expected, as the opening of the UK market to additional import infrastructure over the second half of the sample has the potential to diminish the effect of seasonal arbitrage on the UK NBP price. It is interesting to observe that the decline in seasonality appears to be mostly driven by lower peaks during the summer months, as opposed to higher values during the winter months. Given the definition of the price differential, this suggests that UK NBP prices detach less from the AGIP during the summer, purely based on seasonal considerations[59]. It was expected that additional import sources reduce the need to close the gap between UK NBP and AGIP during the winter peak demand periods.

Importantly, the estimated stochastic trend component shows the expected behaviour. It remains rather flat and not significantly different from zero up until the beginning of 2006, and after the first LNG shipment into the UK market. From the middle of 2006, however, the trend component significantly deviates from zero, indicating that the *imposed* cointegrating vector no longer ensures stationarity of the relationship[60].

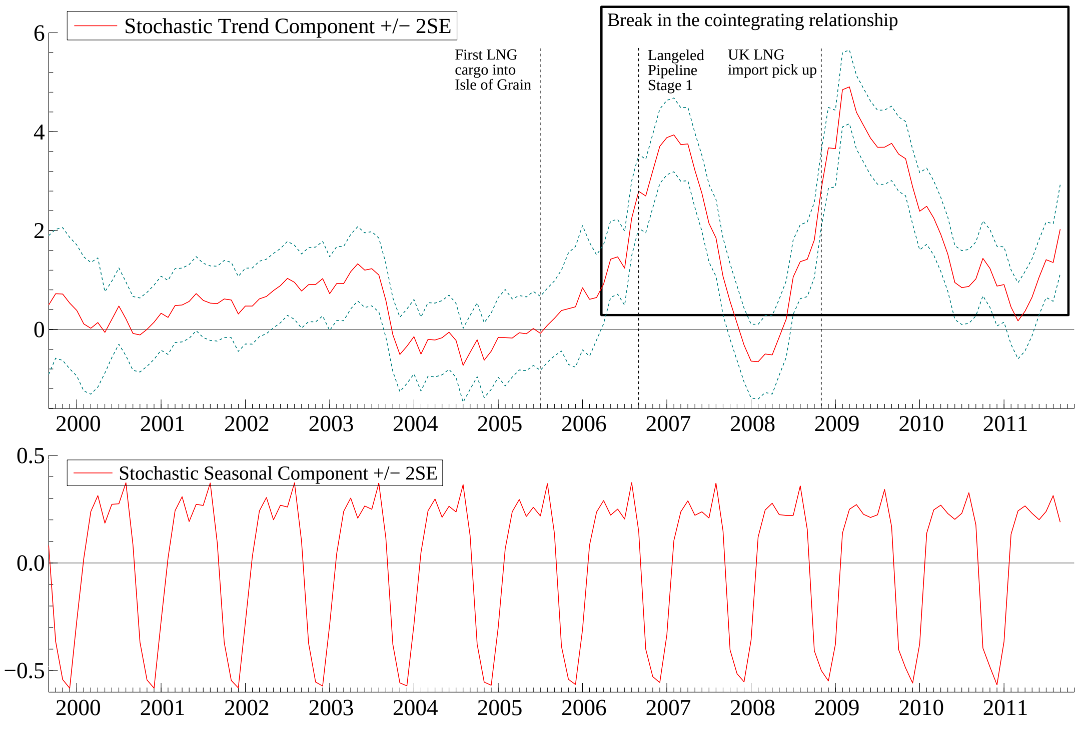


Figure 10: UC Model 5 (OTC): stochastic trend and break in co-integrating vector

argues that while it seems obvious that the arrival of weather and inventory information will establish a new price equilibrium in the spot market, the rationale for weather shocks to influence futures prices is more complicated.

[59]One possible explanation for this could be the additional demand pull on the UK NBP price during the summer, as imported LNG overflows into the NW European market.

[60]The imposed cointegrating vector corresponds to the vector [$log(nbp_t^m)$, -$log(agip_t)$].

In the following, the effect of two exogenous break-dates on the stochastic trend component is examined in models 6 and 7. The dates correspond to the opening of the BBL pipeline in December 2006, shortly after the completion of the first stage of the Langeled import pipeline, and the pick-up in UK LNG imports in November 2008. Introducing these intervention dummies significantly improves the model specification in terms of normality and serial correlation of the estimated residuals[61]. However, a statistically significant effect on the stochastic trend component is only detected for the LNG dummy variable and so the final model (model 7) only contains this break-date dummy[62]. Figure 11 compares the actual OTC differential with the fitted differential of the final specification (model 7)[63].

Since the pick-up of LNG imports in the UK in November 2008, the AGIP-NBP OTC differential has on average increased by 2.63 USD/mmbtu. This effect is significant at the 1% level, controls for seasonality as well as deviations from normal temperature and is robust to the presence of the BBL break dummy. Figure 12 illustrates the effect of the LNG break control on the stochastic trend component. Since November 2008, there is a significant upward shift in the trend, away from zero, which result in non-stationarity of the price differential. This means that from this date onwards, there is a significant change in the cointegrating relationship, such that prices are cointegrated in a different way, or cointegration breaks down altogether, in which case prices no longer maintain a long-term relationship at all.

[61]Diagnostic plots of the estimated residuals are displayed in appendix C in figure 19. They show a very low degree of remaining serial correlation as well as near normality. This section further contains a plot of one-step predictions of the final model, indicating suitable model specification. The predictive failure $\chi^2(24)$ test is 26.9598 [0.3063], that is we fail to reject the null hypothesis of correct model predictions at conventional significance levels.

[62]In contrast to the OTC differential, the front-month differential also contains a highly statistically significant structural break from December 2006 (BBL pipeline) onwards.

[63]Appendix C provides additional model components of the final specification, OTC model 7. In particular, the smoothed estimate of the stochastic trend component, the regression effects as well as the effect of outliers and the LNG level intervention are illustrated.

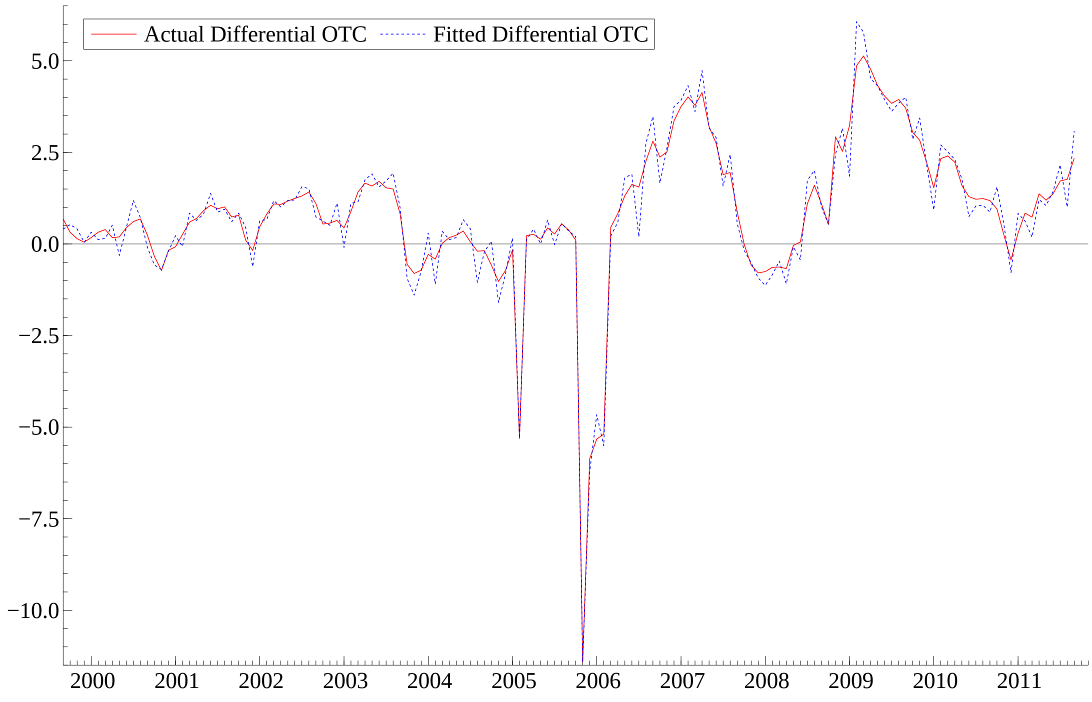


Figure 11: UC Model 7 (OTC): actual and fitted differential

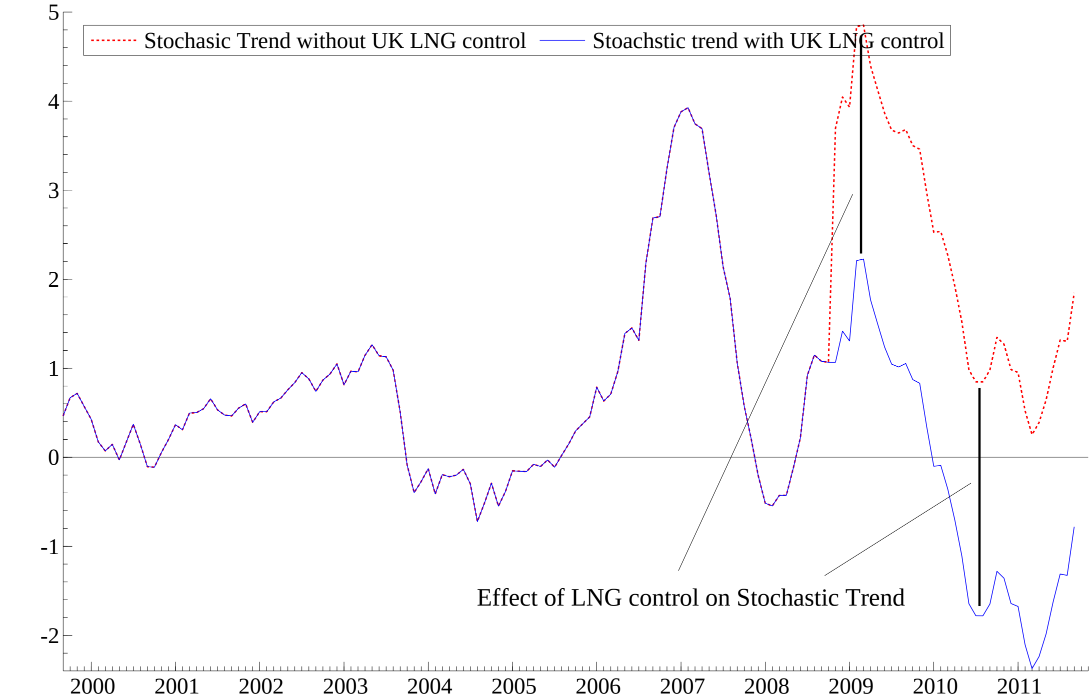


Figure 12: UC Model 7 (OTC): the effect of LNG on the stochastic trend

The unobserved components model confirms the significance of the November 2008 break date, however it does not provide information as to which of the two forms of price decoupling has taken place. To see which of the two possibilities is more likely, the sample is split according to the relevant break dates and a cointegrating model is estimated for either side of the break separately[64]. Importantly, the Engle-Granger, Phillips-Ouliaris and Hansen cointegration tests are used to test for stability of the relationships in the split samples. Table 5 presents the results for the split cointegrating regression.

Consistent with the results of the Gregory and Hansen (1996) methodology in the previous section, the results indicate a significant decrease in the constant of the cointegrating relationship. As before, the elasticity of the UK NBP price to changes in the AGIP is higher in the post-break sample. These results hold for both the OTC and front-month relationships. While the higher slope parameter in the post-sample period indicates a stronger sensitivity, the much lower constant results in an overall weaker relationship between the two prices, similar to the one illustrated in figure 9. The focus of this analysis, however, lies on the results of the cointegration tests performed on the sub-samples. Both the Engle-Granger and Phillips-Ouliaris tests reject the null-hypothesis of 'no cointegration' in all full-sample and pre-break sample models. This is confirmed by the Hansen cointegration test, which fails to reject the null-hypothesis of cointegration.

Moving to the post-break samples, the result are less consistent. Both the Engle-Granger and Phillips-Ouliaris tests fail to reject the null-hypothesis of no cointegration, which indicates that no long-term relationship exists post-break. However, the outcomes of the Hansen test statistic fail to reject cointegration in the post 2006(12) samples. The low number of observations in the post-break sample can reduce the power of these tests and therefore lead to this apparent inconsistency. Importantly, the results are in contrast to those of the conventional Gregory and Hansen (1996) approach. Their test rejects the null-hypothesis of no cointegration in favour of cointegration with a structural break. In particular, prices are assumed to still be cointegrated after the estimated break date. However, based on the results of the split regression with a break at 2006(12), cointegration can neither be accepted nor rejected in the post-break sample.

For the 2008(11) LNG break, the Hansen p-value in the post-break sample of the OTC model is much lower (p=.13), which makes a rejection of cointegration more likely. In case of the front-month model, the p-value of the Hansen test is very low and cointegration can safely be rejected. That is, despite the even lower sample size in this model, the Hansen test confirms the results of the other two tests that from 2008(11), the UK NBP front-month and AGIP no longer maintain a stable long-term relationship.

Together with the result of the previous section, there is considerable evidence for a significant change in the cointegrating relationship between the UK NBP price and the AGIP in the latter half of the sample period. The results suggest that the break dates in 2006, whether endogenously estimated using the Gregory and Hansen (1996) test or exogenous, are associated with a price

[64]Note that given the reduced sample size in the split cointegrating regressions, it is preferred to estimate the models without control variables.

decoupling from an old to a new, much weaker, cointegrating relationship. No clear evidence against cointegration can be found from this date onwards, as the test results fail to unanimously reject it. For the LNG related break in 2008, however, a break-up of cointegration appears much more likely, and can be confirmed for the UK NBP front-month and AGIP relationship. The results need to be interpreted with caution, as the low post-break sample size makes inference difficult.

Table 5: Split Cointegration Regressions UK NBP and AGIP

Dependent Variable: $log(NBP-OTC)$

Full sample	N	Constant	$log(AGIP)$	R^2	Engle-Granger τ	Phillips-Ouliaris τ	Hansen‡
1999M10:2011M09	144	-0.2747*	1.0174***	0.6793	-4.6463	-4.65315	
		(0.1489)	(0.0825)		[0.0011]	[0.0011]	[> 0.2]
Break 2006(12)	N	Constant	$log(AGIP)$	R^2	Engle-Granger τ	Phillips-Ouliaris τ	Hansen‡
1999M10:2006M11	86	-0.4961**	1.2335***	0.6655	-4.4270	-4.4915	
		(0.2006)	(0.1368)		[0.0030]	[0.0025]	[> 0.2]
2006M12:2011M09	58	-1.7975***	1.6743***	0.5890	-2.6023	-2.5196	
		(0.4169)	(0.1883)		[0.2505]	[0.2838]	[0.1707]
Break 2008(11)	N	Constant	$log(AGIP)$	R^2	Engle-Granger τ	Phillips-Ouliaris τ	Hansen‡
1999M10:2008M10	109	-0.3108*	1.0680***	0.7058	-4.4115	-4.4578	
		0.175077	(0.1054)		[0.0028]	[0.0024]	[> 0.2]
2008M11:2011M09	35	-1.5206**	1.5541***	0.4738	-1.9869	-1.8954	
		(0.6063)	(0.2767)		[0.5418]	[0.5873]	[0.1343]

Dependent Variable: $log(NBP-Front)$

Full sample	N	Constant	$log(AGIP)$	R^2	Engle-Granger τ	Phillips-Ouliaris τ	Hansen‡
1999M10:2011M09	144	-0.2312	1.0364***	0.6798	-4.3488	-3.9463	
		(0.1563)	(0.0866)		[0.0031]	[0.0109]	[0.1379]
Break 2006(12)	N	Constant	$log(AGIP)$	R^2	Engle-Granger τ	Phillips-Ouliaris τ	Hansen‡
1999M10:2006M11	86	-0.6111***	1.3796***	0.7349	-4.4787	-3.8342	
		(0.1953)	(0.1332)		[0.0026]	[0.0171]	[> 0.2]
2006M12:2011M09	58	-1.8862***	1.7390***	0.5975	-2.5399	-2.6611	
		(0.4079)	(0.1842)		[0.2754]	[0.2285]	[> 0.2]
Break 2008(11)	N	Constant	$log(AGIP)$	R^2	Engle-Granger τ	Phillips-Ouliaris τ	Hansen‡
1999M10:2008M10	109	-0.3239*	1.1352***	0.7310	-4.3516	-3.7310	
		(0.1797)	(0.1081)		[0.0034]	[0.0212]	[> 0.2]
2008M11:2011M09	35	-1.3049***	1.4708***	0.4664	-1.9270	-1.8517	
		(0.4646)	(0.2120)		[0.5716]	[0.6087]	[< 0.01]

(...) Standard errors in parentheses. [...] MacKinnon (1996) p-values in parentheses.

‡ Hansen (1992) p-values in parentheses.

* = significant at the 10% level, ** = significant at the 5% level, *** = significant at the 1% level.

The null-hypothesis of both Engle-Granger and Phillips-Ouliaris tests is: *no cointegration.*

The null-hypothesis of the Hansen test is: *cointegration.*

6 Conclusion

The paper empirically investigated the long-term structural relationship between the UK NBP price for natural gas and the AGIP, a proxy for oil-indexed gas in the NW European market. In particular, the focus was on the potential of an increase in UK import capacity, both in terms of import pipelines and LNG regasification capacity, to structurally weaken this long-term relationship, hence lead to a form of price decoupling. Special attention was given to UK spot market drivers such as seasonality, deviations from normal temperature and storage injection/withdrawal behaviour. Considered over the entire sample period, from September 1999 through September 2011, both prices were found to be cointegrated and the associated cointegrating vector suggests a close to unit elasticity between them.

Two approaches were taken to determine the stability of this relationship over time. First, an endogenous break-date estimation was performed in the Gregory and Hansen (1996) framework. Hereby, the cointegrating relationship between the two markets was estimated controlling for the effect of temperature and storage as well as allowing for the presence of a break in both constant and slope parameters. The test results confirmed cointegration of both prices and suggested a break date in the middle of 2006. Allowing both the slope and constant parameters in the cointegrating regression to vary around this break-date improved the model fit considerably, explaining between 8-10% more of UK NBP price volatility. The results show a significant weakening of the long-run relationship from 2006 onwards, mainly driven by a substantial decrease in the constant term in the post-break sample. The new relationship suggests that after the break in 2006, the range of UK NBP prices which correspond to a given range of the AGIP is much narrower in equilibrium.

Second, the price differential was analyzed in an unobserved components framework to account not only for the effects of temperature and storage but also for time-variant seasonality. As expected, the stochastic trend component exhibits a significant departure from zero starting in the middle of 2006. This suggsts a break of the previously stable cointegrating relationship in the year in which additional UK import pipelines came online. The seasonal pattern was found to decline slightly over time, indicating a reduced effect of seasonal arbitrage on the price differential. In addition to a break in 2006, this methodology also confirmed a significant change in the cointegrating relationship from November 2008, the point in time in which UK LNG imports picked up. Estimating the model on each side of those breaks separately suggests that from 2006 onwards prices moved from an old to a new, much weaker, long-term relationship. From November 2008 onwards, it appears that the long-term relationship has broken down altogether. Importantly, this suggest that the pressure on exporters of natural gas into the NW European market, to move away from oil-indexation and toward gas-indexation of long-term supply contracts, is mounting and was substantial elevated by the opening of the UK to global LNG trade. It is important to outline that from November 2008 onwards, Asian LNG markets were tight, and the average Japanese LNG import price continuously exceeded the AGIP. Given these relative prices, the break-up of the long-term relationship between UK NBP and AGIP is even more remarkable.

The results need to be interpreted with caution, as the low post-break sample size makes inference more difficult. However, it appears that a longer post-break sample would allow one to either (i) find consistent evidence against cointegration or (ii) find consistent evidence supporting the new, much weaker, cointegrating relationship. In either case, the tie between the UK NBP price and the AGIP appears to be significantly severed, the timing of which coincides with the opening of the UK natural gas market to global arbitrage.

Going forward, the analysis should be repeated as more data becomes available to help determine the cointegrating properties of the post-break model. In addition, including an LNG spot price marker into the analysis would help determine whether the global price of spot LNG cargoes has taken over from the AGIP in setting the UK NBP price during periods of peak UK natural gas demand.

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Appendix A Data analysis

A.1 Anecdotal evidence: 1999-2011

The empirical relationship between the UK and Continental European gas markets, as well as the average Japanese LNG import price and the price for Brent oil are illustrated in figure 13. During the period 1999-2005, the UK gas market was both liberalized and interconnected with NW European markets, yet no additional import capacity in the form of pipelines or LNG terminals was in place. Over this period, the structural connection (or 'coupling') of UK NBP to the oil-indexed contract gas price, here approximated by the Average German Import Price (AGIP), becomes apparent[65]. Up until 2005, the data suggests that there is empirical evidence for a seasonal reconnection of UK gas prices to oil-indexed contract prices (AGIP) during the winter months[66]. From 2005 onwards, however, there appears to be a structural change to this relationship, which coincides with the coming online of additional pipeline and LNG import capacity.

There are several interesting price points during 2005-11. The winter 2005/06 was characterized by a severe upward price spike in the UK NBP. For a brief period, the UK NBP spot price exceeded that of oil-indexed gas by more than 10 USD/mmbtu. Initially, the spike was due to

[65]The AGIP is a monthly volume weighted import price published by the German Federal Office for Economics and Export Control (BAFA).

[66]The fact that UK NBP prices for the summer months are determined by storage arbitrage, whereas the prices for the winter months by demand and supply imbalances is also maintained by Heather (2010).

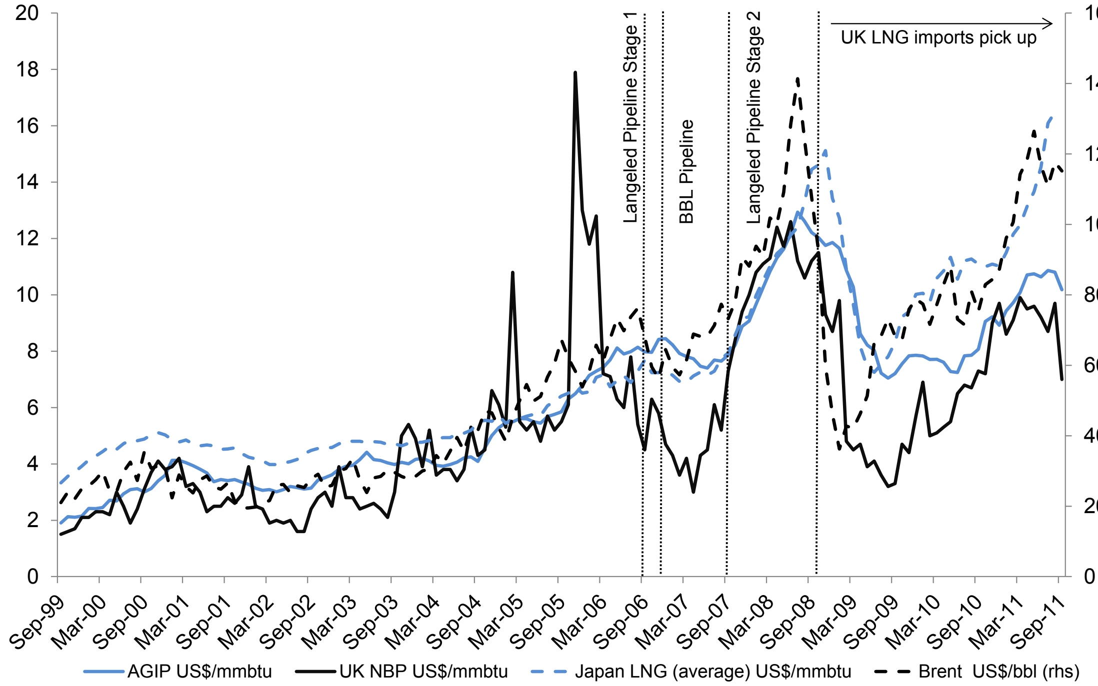

Figure 13: UK NBP day-ahead, AGIP and Japan LNG import price in USD/mmbtu (lhs), Brent crude oil in USD/bbl (rhs) September 1999-2011, Source: Bloomberg, BAFA

an unexpected cold spell of weather in both the UK and NW Europe, which pushed up demand for natural gas in both markets. Supported by tight spot LNG markets in Asia and a fire at the Rough gas storage facility close to Easington (UK), UK NBP prices remained well in excess of oil-indexed prices until March 2006[67]. The UK and oil-indexed markets diverged again during the summer of 2006. Both the first leg of the Langeled pipeline and the BBL pipeline, became operational in September and December 2006 respectively, supplying additional gas into the UK market. This lead to an obvious divergence of UK from oil-indexed markets during the winter, which lasted until October 2007 when UK NBP converged again with oil-indexed prices, due to the continuing decline in UK domestic production, Rogers (2010).

Actual LNG imports started to pick up by the end of October 2008, which coincides with a significant divergence of UK NBP from oil-indexed prices. The financial crisis in 2008 depressed the global demand for energy and global spot LNG prices dropped. Spot LNG cargoes therefore provided a cheaper source for the marginal supply into the UK market during the winter 2008/09, which caused the NBP to remain significantly below oil-indexed prices. Importantly, there was no convergence of UK and oil-indexed prices even during the peak demand winter months of 2009/10. This could partially be attributed to lower than normal economic activity during the weak recovery from the 2008 financial crisis, and resulting lower industrial demand for natural

[67]Note that the LNG price in figure 13 is an *average* price. Some spot LNG prices into Japan were in excess of 15 USD/mmbtu, Rogers (2010).

gas[68]. However, counteracting this downward pressure on prices was the particularly cold winter in the UK, resulting in higher than normal residential heating demand[69]. The global economy underwent a weak recovery from Q3 2009 onwards, increasing the demand for primary energy. This, combined with sustained high energy demand from growth markets such as India and China, has lead to tightening crude oil markets, followed by higher average LNG import prices for Japan and oil-indexed gas prices in NW Europe. Record low temperatures in the UK during the winter 2010/11 lead to a convergence of UK NBP with oil-indexed gas prices, as residential heating demand for natural gas peaked. This convergence of UK and oil-indexed markets is in line with expectations, as global spot LNG markets were relatively tight and the UK NBP had to increase to oil-indexed prices in order to attract the marginal supply[70].

During Q1 2011, global energy markets started to tighten further for two reasons. First, February 2011 marked the beginning of the revolutionary uprising in Libya, which resulted in a significant shortfall in Libyan oil output, increasing global prices for light sweet crude oil. This provided upward pressure on oil-indexed gas prices, albeit with a lag of 6-9 months. Secondly, the earthquake and tsunami in Japan in March 2011 and the resulting nuclear incident in Fukushima, brought a significant share of Japanese nuclear capacity offline. This loss in power generation capacity was compensated, where possible, by a ramp-up in gas-fired generation, pushing up Japanese demand for natural gas (LNG) imports.

In summary, the persisting discount at which the UK NBP traded to oil-indexed gas between Q2 2008 - Q4 2010, in particular the failure to converge during peak winter demand periods, is a reflection of the availability of additional supply sources to balance the UK market, primarily spot LNG.

A.2 Descriptive statistics

Visual inspection of the data in figure 5 suggests that the log-prices are non-stationary. Both prices appear to have a trend, with non-constant mean over time. Further, there appears to be significant serial correlation in the data, with successive upwards movements followed by an extended period of successive downward movements. The autocorrelation functions (ACFs) of both log-prices are plotted in figure 14. They show very high (hence highly significant) autocorrelations, close to unity, which are decaying only very slowly. This is especially true for the log AGIP. Further examination of the histogram and implied empirical distributions in figure 14 suggests that both prices are clearly non-normally distributed. The probability distribution of the log AGIP appears bimodal. These findings are consistent with the presence of a unit root in both series.

[68]NBER (2011) dates the recession from Q4 2007 to Q2 2009, from peak to trough respectively, regarding Q3 2009 onwards as a weak, yet expansionary phase of economic recovery.

[69]The mean UK temperatures for December 2009 and January 2010 were significantly below their respective long-run averages, see MetOffice (2011).

[70]For the period December 2009 - July 2011, average LNG import prices for Japan continuously exceeded those of oil-indexed gas in NW Europe by between 2-5 USD/mmbtu.

If there is a unit root present, taking the fist-differences (one-month difference) of the log prices generates a stationary series. The ACFs and distributions of both one-month log differences are plotted in figure 15. Most autocorrelations appear to be insignificant and the implied empirical distributions of the one-month differences is closer to a normal distribution. This suggest that the differenced series are stationary, and the log-prices are integrated of order one, i.e. $I(1)$. For a formal test of the presence of a unit root in the log prices, see section A.3.

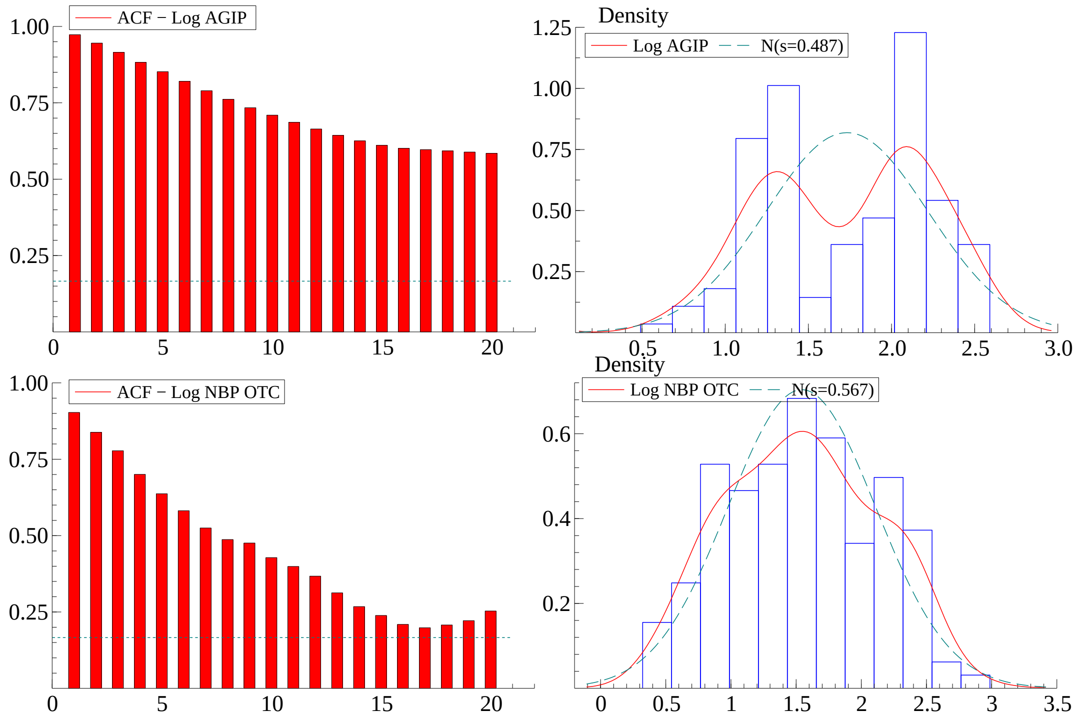

Figure 14: Distribution and ACF: Log Prices

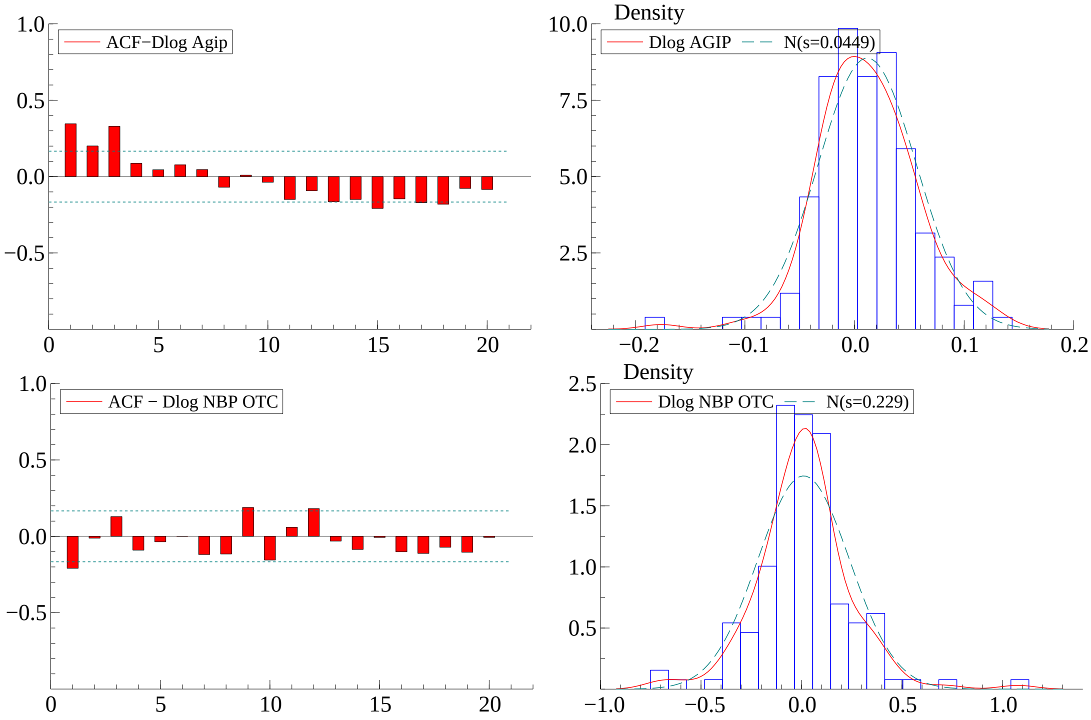

Figure 15: Distribution and ACF: 1-month difference - Log Prices

Table 6: Descriptive Statistics

	AGIP	UK NBP Front	UK NBP OTC	Log Differential OTC	Log Differential Front	Dev. Storage	Dev. HDD *base*=15.5	Dev. HDD *base*=18
Observations	141	141	141	141	141	141	141	141
Mean	6.4501	6.0416	5.5943	0.1885	0.1136	-0.9854	0.6733	0.6491
Median	6.4910	5.2880	4.8000	0.1450	0.1028	1.5406	-2.8933	-4.3750
Maximum	12.9362	18.6203	17.9000	0.9471	0.8154	852.0697	96.1067	96.1067
Minimum	2.4154	1.7814	1.6000	-1.0144	-1.0538	-614.3223	-79.7375	-82.7062
Std. Dev.	2.8585	3.3898	3.1503	0.3160	0.3189	260.8423	25.8353	29.9141
Skewness	0.4013	1.0001	1.0546	-0.3037	-0.2354	0.2011	0.6392	0.5510
Kurtosis	2.0250	3.6163	3.7256	4.2352	3.6911	3.4694	4.4921	3.5140
JB (p-value)	0.0092	0.0000	0.0000	0.0038	0.1283	0.3256	0.0000	0.0130

JB is the Jarque-Bera test for normality (null hypothesis: normally distributed). The sample covers September 1999 - September 2011.

$Log\ Differential\ OTC = \ln(AGIP) - \ln(NBP\ OTC)$; $Log\ Differential\ Front = \ln(AGIP) - \ln(NBP\ Front)$

Table 7: Data Cross-Correlations

	Log AGIP	Log NBP Front	Log NBP OTC	Log Differential Front	Log Differential OTC	Dev. Storage	Dev. HDD *base*= 15.5	Dev. HDD *base*=18
Log AGIP	1.0000	0.8197	0.8189	0.0272	0.0460	-0.1505	0.4118	0.4454
Log NBP Front	0.8197	1.0000	0.9388	-0.5503	-0.4279	-0.1695	0.3514	0.3714
Log NBP OTC	0.8189	0.9388	1.0000	-0.4447	-0.5357	-0.1235	0.3857	0.4032
Log Differential Front	0.0272	-0.5503	-0.4447	1.0000	0.8139	0.0763	-0.0130	0.0011
Log Differential OTC	0.0460	-0.4279	-0.5357	0.8139	1.0000	-0.0065	-0.0655	-0.0465
Dev. Storage	-0.1505	-0.1695	-0.1235	0.0763	-0.0065	1.0000	0.3919	0.3597
Dev. HDD *base*=15.5	0.4118	0.3514	0.3857	-0.0130	-0.0655	0.3919	1.0000	0.9655
Dev. HDD *base*=18	0.4454	0.3714	0.4032	0.0011	-0.0465	0.3597	0.9655	1.0000

A.3 Unit root, cointegration and stability tests

To formally test for the presence of a unit root in the log price series, the augmented Dickey-Fuller (ADF) and the Phillips-Perron (PP) tests are employed[71], the results are provided in table 8. The null-hypothesis of a unit root present in the log-levels of all three price series cannot be rejected at the 5% significant level. However, applying the tests to the first-differences of log prices leads to a rejection of the null hypothesis of a unit root in favour of the alternative, a stationary first-difference. It can therefore be formally concluded that all log-prices are integrated of order one.

Table 8: Unit Root Tests

		Levels		First Differences	
		t-Statistic	Prob.*	t-Statistic	Prob.*
Log AGIP	ADF	-1.5847	0.4878	-8.3079	0.0000
	PP	-1.8995	0.3318	-8.6210	0.0000
Log NBP OTC	ADF	-2.8369	0.0557	-14.6156	0.0000
	PP	-2.6473	0.0860	-14.6339	0.0000
Log NBP Front	ADF	-2.5214	0.1125	-9.3982	0.0000
	PP	-1.9917	0.2903	-9.3026	0.0000
Log Differential OTC	ADF	-4.6208	0.0002	-	-
	PP	-4.6237	0.0002	-	-
Log Differential Front	ADF	-4.3322	0.0006	-	-
	PP	-3.9740	0.0021	-	-
Differential OTC	ADF	-3.7060	0.0049	-	-
	PP	-4.9030	0.0001	-	-
Differential Front	ADF	-4.4254	0.0004	-	-
	PP	-4.1584	0.0011	-	-

*MacKinnon (1996) one-sided p-values, including constant. Lag-length selection based on Schwartz information criterion (min-lag=0, max-lag=13)
Null-hypothesis: the series is integrated of order one, $I(1)$.
ADF= Augmented Dickey-Fuller; PP = Phillips-Perron

[71] For details on the specification of both test statistics, see Hamilton (1994).

Table 9: Cointegration Tests

Johansen System Cointegration Test

Series: $log(agip)$, $log(nbp^{OTC})$

Sample (adjusted): 2000M02 2011M09

Unrestricted Cointegration Rank Test (Trace)

Hypothesized No. of CE(s)	Eigenvalue	Trace Statistic	0.05 Critical Value	Prob.**
None *	0.1336	22.2187	15.4947	[0.0042]
At most 1	0.0152	2.1398	3.8415	[0.1435]

Unrestricted Cointegration Rank Test (Maximum Eigenvalue)

Hypothesized No. of CE(s)	Eigenvalue	Max-Eigen Statistic	0.05 Critical Value	Prob.**
None *	0.1336	20.0789	14.2646	[0.0054]
At most 1	0.0152	2.1398	3.8415	[0.1435]
1 Cointegrating Equation:		Log likelihood		288.93

Normalized cointegrating coefficients	$log(nbp^{OTC})$	$log(agip)$
	1.0000	-0.9719
		(-0.1008)

Adjustment coefficients	$Dlog(nbp^{OTC})$	$Dlog(agip)$
	-0.3306	0.0219
	(-0.0882)	(-0.0156)

(...) Standard errors in parentheses. Both Trace and Max-Eigen tests indicate
1 cointegrating equation at the 0.05 level. * denotes rejection of the hypothesis at the 0.05 level.
**MacKinnon-Haug-Michelis (1999) p-values

Single-Equation Cointegration Tests

Series: $log(AGIP)$, $log(NBP-OTC)$

Sample: 1999M09 2011M09

Engle-Granger†

Dependent	τ-statistic	Prob.*	z-statistic	Prob.*
$log(UKNBPOTC)$	-4.6463	0.0011	-37.8681	0.0006
$log(AGIP)$	-2.9623	0.1260	-17.9166	0.0746

Phillips-Ouliaris

Dependent	τ-statistic	Prob.*	z-statistic	Prob.*
$log(NBP-OTC)$	-4.6531	0.0011	-37.9991	0.0006
$log(AGIP)$	-3.6469	0.0252	-24.0454	0.0189

Null-hypothesis: Series are not cointegrated. † automatic lags specification
based on Schwarz criterion (maxlag=13). *MacKinnon (1996) p-values.

Table 10: Gregory and Hansen (1996) Cointegration with structural break test

Dependent: UK NBP OTC	Test stat.	Breakpoint τ	Breakpoint
ADF†			
C	-5.8542***	(0.54)	2006M02
C/S	-5.8626***	(0.54)	2006M02
Z_t			
C	-5.6700***	(0.56)	2006M05
C/S	-5.7069***	(0.56)	2006M05
Z_α			
C	-51.9027***	(0.56)	2006M05
C/S	-52.6916**	(0.56)	2006M05
Dependent: UK NBP Front	Test stat.	Breakpoint τ	Breakpoint
ADF†			
C	-5.4669***	(0.58)	2006M08
C/S	-5.5412***	(0.58)	2006M08
Z_t			
C	-4.9809**	(0.57)	2006M06
C/S	-5.0039**	(0.58)	2006M08
Z_α			
C	-45.3522**	(0.57)	2006M06
C/S	-45.8005*	(0.57)	2006M06

* = significant at the 10% level, ** = significant at the 5% level, *** = significant at the 1% level. † automatic lags specification based on BIC (maxlag=10). Null-hypothesis: series are not cointegrated. Alternative-hypothesis: series are cointegrated with shift only in constant (C) or in constant and slope (C/S).

Approximate asymptotic critical values for single explanatory variable, Gregory and Hansen (1996)

Level	0.01	0.025	0.05	0.1
ADF and Z_t				
C	-5.13	-4.83	-4.61	-4.34
C/S	-5.47	-5.19	-4.95	-4.68
Z_α				
C	-50.07	-45.01	-40.48	-36.19
C/S	-57.17	-51.32	-47.04	-41.85

A.4 UK gas balance: 2000-2011.

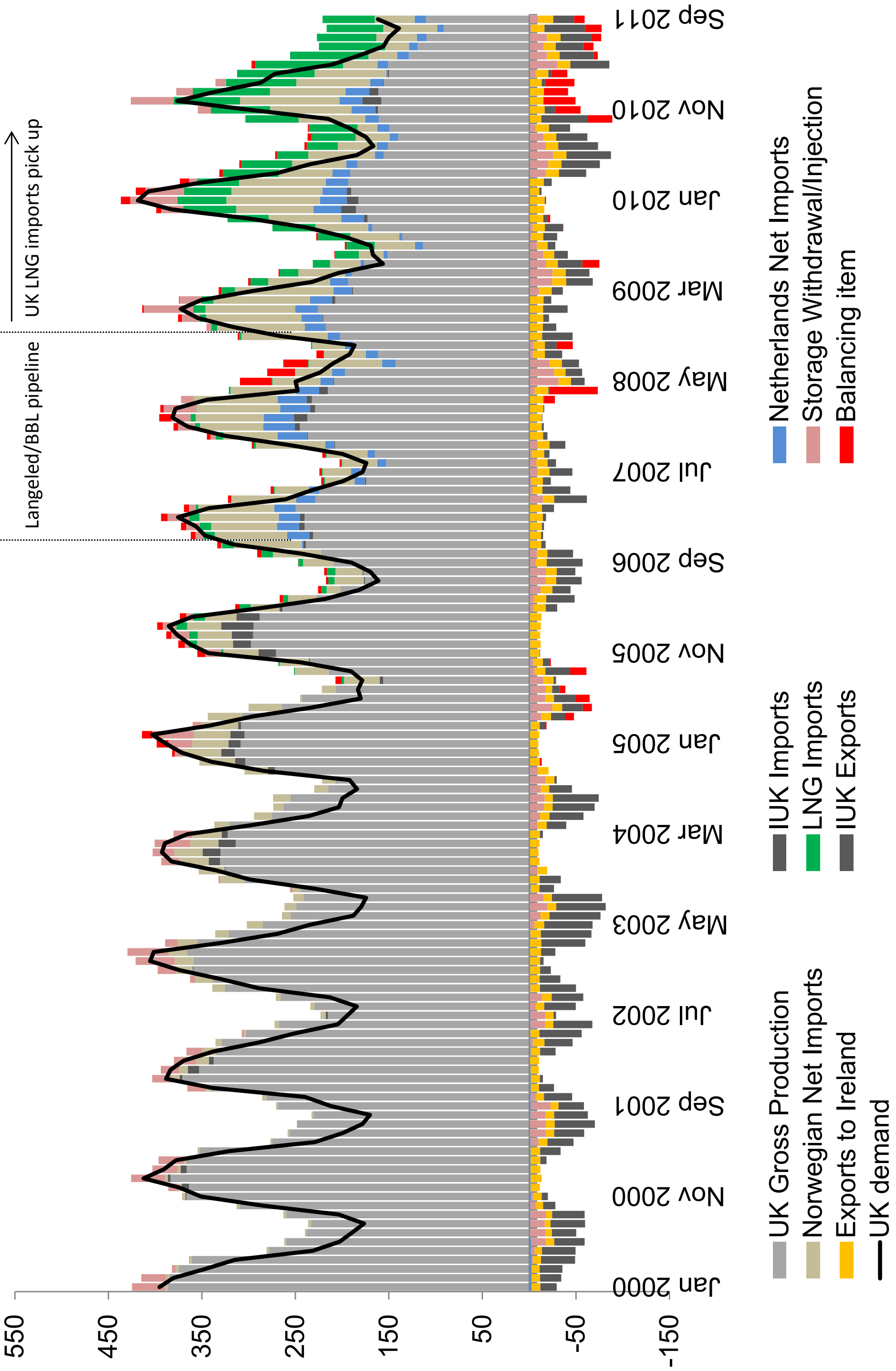

Figure 16: UK Natural Gas Balance (mcm/day) Jan 2000 - Sept 2011, Source: DECC, National Grid, author's calculation

Appendix B State space form and the Kalman filter.

Following Harvey (1989), the model outlined in section 4.2 is equivalent to

$$y_t^m = \mu_t + \gamma_t + \sum_{i=1}^{k} \phi_i, x_{i,t} + \theta_{bbl} w_t^{bbl} + \theta_{lng} w_t^{lng} + \epsilon_t, \qquad \epsilon_t \sim NID(0, \sigma_\epsilon^2)$$

where the intevention dummies are now defined as a *step* impulse, given by

$$w_t^{bbl} = \begin{cases} 1 & \text{if } t >= 2006(12) \\ 0 & \text{otherwise} \end{cases} \qquad \text{and} \qquad w_t^{lng} = \begin{cases} 1 & \text{if } t >= 2008(11) \\ 0 & \text{otherwise} \end{cases}$$

and all remaining elements are as introduced in section 4.2. The model can be formulated as a linear state space model specified by the equations

$$y_t = Z\boldsymbol{\alpha_t} + D\mathbf{x_t} + \epsilon_t, \qquad \epsilon_t \sim NID(0, \sigma_\epsilon^2) \tag{14}$$

$$\boldsymbol{\alpha_t} = T\boldsymbol{\alpha_{t-1}} + \boldsymbol{\xi_t}, \qquad \boldsymbol{\xi_t} \sim NID(\mathbf{0}, H) \tag{15}$$

where (14) is the measurement equation, relating the observed y_t to the unobserved state vector $\boldsymbol{\alpha_t}$. The state vector is modelled as a VAR(1) and contains the stochastic trend as well as the stochastic seasonal component. It is given by

$$\boldsymbol{\alpha_t} = (\mu_t \quad \gamma_{1,t} \quad \gamma_{1,t}^* \quad \gamma_{2,t} \quad \gamma_{2,t}^* \quad \cdots \quad \gamma_{[\frac{s-2}{2}],t} \quad \gamma_{[\frac{s-2}{2}],t}^* \quad \gamma_{[s/2],t})' \tag{16}$$

where the first element corresponds to the stochastic trend and the remaining $(s-1)$ terms to the trigonometric seasonal. The associated error vector $\boldsymbol{\xi_t}$ is given by

$$\boldsymbol{\xi_t} = (\eta_t \quad \omega_{1,t} \quad \omega_{1,t}^* \quad \omega_{2,t} \quad \omega_{2,t}^* \quad \cdots \quad \omega_{[\frac{s-2}{2}],t} \quad \omega_{[\frac{s-2}{2}],t}^* \quad \omega_{[s/2],t})'$$

The vector $\mathbf{x_t}$ contains the explanatory variables, described in section 3, and redefined structural break dummies:

$$\mathbf{x_t} = (Winter_t^{05/06} \quad DS_t \quad DHDD_t \quad w_t^{bbl} \quad w_t^{lng})'$$

The system variables Z, D, T, σ_ϵ^2 and H depend on unknown parameters, which are estimated by maximizing the Gaussian log-likelihood function of the model. They are given by

$$Z = (1 \quad 1 \quad 0 \quad 1 \quad 0 \quad \ldots \quad 1 \quad 0 \quad 1)$$

$$D = (\phi_1 \quad \phi_2 \quad \phi_3 \quad \theta_{bbl} \quad \theta_{lng})$$

$$T = \begin{bmatrix} 1 & 0 & 0 & 0 & 0 & 0 & \cdots & \cdots & 0 \\ 0 & cos\lambda_1 & sin\lambda_1 & 0 & 0 & 0 & \cdots & \cdots & 0 \\ 0 & -sin\lambda_1 & cos\lambda_1 & 0 & 0 & 0 & \cdots & \cdots & 0 \\ 0 & 0 & 0 & cos\lambda_2 & sin\lambda_2 & 0 & \cdots & \cdots & 0 \\ 0 & 0 & 0 & -sin\lambda_2 & cos\lambda_2 & 0 & \cdots & \cdots & 0 \\ 0 & 0 & 0 & 0 & 0 & \ddots & \cdots & \cdots & 0 \\ \vdots & \vdots & \vdots & \vdots & \vdots & \vdots & cos\lambda_{\frac{s-2}{2}} & sin\lambda_{\frac{s-2}{2}} & 0 \\ \vdots & \vdots & \vdots & \vdots & \vdots & \vdots & -sin\lambda_{\frac{s-2}{2}} & cos\lambda_{\frac{s-2}{2}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & cos\lambda_{[s/2]} \end{bmatrix}$$

$$H = \begin{bmatrix} \sigma^2_\eta & \mathbf{0} \\ \mathbf{0} & \sigma^2_\omega I_{s-1} \end{bmatrix}$$

Once the unknown parameters in the system variables are estimated via maximum likelihood, the unobserved components can be recovered using the Kalman filtering and smoothing equations. Harvey (1989) and Durbin and Koopman (2001) provide a complete derivation of the Kalman filter algorithm and associated likelihood functions.

Appendix C Additional model output

Table 11: Split Cointegration Regressions UK NBP and AGIP - Endogenous Breaks

Cointegration Regression						
	Dependent: $log(nbp^{otc})$			Dependent: $log(nbp^{front})$		
Sample	Full	1999M09: 2006M04	2006M05: 2011M09	Full	1999M09: 2006M07	2006M08: 2011M09
$log(agip)$	0.9584***	1.4070***	1.6964***	0.9828***	1.3505***	1.6321***
	(0.1040)	(0.1668)	(0.1837)	(0.1053)	(0.1626)	(0.2263)
Dev. Storage	-0.0001	-0.0005**	0.0002	-0.000209	-0.0007***	0.0001
	(0.0002)	(0.0002)	(0.0001)	(0.0002)	(0.0002)	(0.0002)
Dev. HDD(b=15.5)	0.0011	0.0039	0.0004	0.000393	0.000614	0.0005
	(0.0020)	(0.0025)	(0.0014)	(0.0020)	(0.0026)	(0.0017)
Constant	-0.1684	-0.6486**	-1.8448***	-0.136062	-0.5475**	-1.6263***
	(0.1874)	(0.2466)	(0.4034)	(0.1896)	(0.2461)	(0.4984)
R^2	0.6575	0.7122	0.6026	0.6556	0.7130	0.5319
N	140	75	65	140	78	62

Single-equation cointegration tests						
	Dependent: $log(nbp^{otc})$			Dependent: $log(nbp^{front})$		
Sample	Full	1999M09: 2006M04	2006M05: 2011M09	Full	1999M09: 2006M07	2006M08: 2011M09
Engle-Granger						
τ -statistic	-4.5798	-5.1637	-2.7318	-4.214026	-3.885802	-2.4720
	[0.0175]	[0.0046]	[0.5684]	[0.0457]	[0.1067]	[0.6948]
z-statistic	-36.7555	-40.6047	-13.6811	-36.12684	-26.43683	-10.9636
	[0.0136]	[0.0027]	[0.5500]	[0.0155]	[0.0783]	[0.7128]
Phillips-Ouliaris						
τ -statistic	-4.5756	-5.2046	-2.6904	-3.953663	-4.071479	-2.7557
	[0.0177]	[0.0041]	[0.5892]	[0.0836]	[0.0728]	[0.5570]
z-statistic	-36.6749	-41.5643	-13.2196	-29.40926	-29.49681	-14.0209
	[0.0138]	[0.0021]	[0.5781]	[0.0583]	[0.0419]	[0.5263]
Hansen ‡	[> 0.2]	[> 0.2]	[> 0.2]	[0.0491]	[> 0.2]	[> 0.2]

(...) Standard errors in parentheses. [...] MacKinnon (1996) p-values in parentheses.

‡ Hansen (1992) p-values in parentheses.

* = significant at the 10% level, ** = significant at the 5% level, *** = significant at the 1% level.

The null-hypothesis of both Engle-Granger and Phillips-Ouliaris tests is: *no cointegration*.

The null-hypothesis of the Hansen test is: *cointegration*.

Table 12: UC Estimation Output - Dependent variable: Differential OTC

Model	1	2	3	4	5	6	7
Final State							
Level	1.8898	2.2061	2.2508	2.1121	2.0282	-2.1644	-0.7802
(p-value)	(0.0151)	(0.0000)	(0.0000)	(0.0000)	(0.0000)	(0.0700)	(0.3912)
Seasonality	*Fixed*	*Fixed*	*Stochastic*	*Stochastic*	*Stochastic*	*Stochastic*	*Stochastic*
Controls							
Outlier 2005(2)	-	-5.4397***	-5.0587***	-4.9687***	-5.1346***	-5.0903***	-5.0826***
		[0.7613]	[0.7579]	[0.7550]	[0.7494]	[0.7333]	[0.7349]
Outlier 2005(11)	-	-5.6266***	-4.9945***	-4.9311***	-5.2699***	-5.3041***	-5.1776***
		[0.8377]	[0.8527]	[0.8481]	[0.8263]	[0.8095]	[0.8085]
Winter 05/06	-	-5.6565***	-5.9881***	-5.9742***	-5.7795***	-5.6249***	-5.6895***
		[0.6633]	[0.6734]	[0.6679]	[0.6486]	[0.6057]	[0.6125]
Dev. Storage	-	-	-0.0007**	-0.0005	-	-	-
			[0.0003]	[0.0003]			
Dev. HDD(b=15.5)	-	-	-	-0.0058	-0.0084**	-0.0083***	-0.0091***
				[0.0037]	[0.0032]	[0.0031]	[0.0031]
Structural Breaks							
BBL/Langeled	-	-	-	-	-	**1.31318**	-
(December 2006)						[0.7627]	
LNG	-	-	-	-	-	**2.6647*** **	**2.6280*** **
(November 2008)						[0.7570]	[0.7689]
Diagnostics							
Doornik-Hansen	76.924	12.286	7.892	6.998	9.269	7.267	6.059
Box-Jung Q-statistic	(0.0553)	(0.0001)	(0.0003)	(0.0003)	(0.0002)	(0.0164)	(0.0172)
(p-value)							
PEV	1.9915	0.6866	0.7058	0.7083	0.6989	0.6298†	0.6454
Rs^2	0.2251	0.7389	0.7384	0.7416	0.7363	0.7660	0.7583
Log-L	-77.2817	-8.99255	-17.5269	-21.2719	-11.9751	-6.72134	-7.40349
BIC	1.1351	0.1731	0.2350	0.2729	0.2252	0.1898	0.1800†
AIC	0.86822	-0.1554	-0.1140	-0.0967	-0.1238	-0.2003†	-0.1896

[..] Standard errors in parentheses. Doornik-Hansen test for normality, distributed $\chi^2(2)$ under the null hypothesis of normality. The 5% critical value of $\chi^2(2)$ is 5.99. BIC = Bayesian Schwartz Criterion; AIC = Akaike Information Criterion; PEV = prediction error variance. Log-L = Log Likelihood. The sample period for the model analysis is January 2000 through Septemer 2011. † *break* model that minimizes the respective (information) criterion.
* = significant at the 10% level, ** = significant at the 5% level, *** = significant at the 1% level

Table 13: UC Estimation Output - Dependent variable: Differential Front

Model	1	2	3	4	5
Final State					
Level	0.9160	1.0348	1.0073	-5.9681	-4.5338
(p-value)	(0.0473)	(0.0073)	(0.0038)	(0.0000)	(0.0013)
Seasonality	*Fixed*	*Stochastic*	*Stochastic*	*Fixed*	*Stochastic*
Controls					
Outlier 2005(11)	-	-4.7233***	-3.9156***	-4.7983***	-4.4283***
		[0.8400]	[0.8492]	[0.8634]	[0.8424]
Outlier 2006(2)	-	3.0367***	2.8976***	3.1720***	2.9215***
		[0.8400]	[0.8165]	[0.8283]	[0.8073]
Winter 05/06	-	-3.6697***	-3.9341***	-3.8325***	-3.7126***
		[0.9039]	[0.9258]	[0.7630]	[0.8609]
Dev. Storage	-	-	-0.0006**	-0.0003	-0.0006**
			[0.0003]	[0.0003]	[0.0003]
Dev. HDD(b=15.5)	-	-	-0.00417	-0.0033	-
			[0.0036]	[0.0036]	
Structural Breaks					
BBL/Langeled	-	-	-	**3.1660*** **	**2.8381*** **
(December 2006)				[0.8411]	0.90554
LNG	-	-	-	**3.4558*** **	**2.5803*** **
(November 2008)				[0.8324]	[0.9063]
Diagnostics					
Doornik-Hansen	122.050	14.203	11.484	14.798	13.215
Box-Jung Q-statistic	(0.0645)	(0.0003)	(0.0019)	(0.1323)	(0.0677)
(p-value)					
PEV	1.3667	0.8233	0.7937	0.6222†	0.7503
Rs^2	0.0886	0.4634	0.5013	0.6154	0.5286
Log-L	-52.6300	-15.7145	-27.9571	-19.2932	-20.1215
BIC	0.7586	0.3548	0.3867	0.2119†	0.3648
AIC	0.49172	0.0263	0.0172	-0.1987†	-0.0253

[..] Standard errors in parentheses. Doornik-Hansen test for normality, distributed $\chi^2(2)$ under the null hypothesis of normality. The 5% critical value of $\chi^2(2)$ is 5.99. BIC = Bayesian Schwartz Criterion; AIC = Akaike Information Criterion; PEV = prediction error variance; Log-L = Log Likelihood. The sample period for the model analysis is January 2000 through Septemer 2011. † model that minimizes the respective (information) criterion. * = significant at the 10% level, ** = significant at the 5% level, *** = significant at the 1% level.

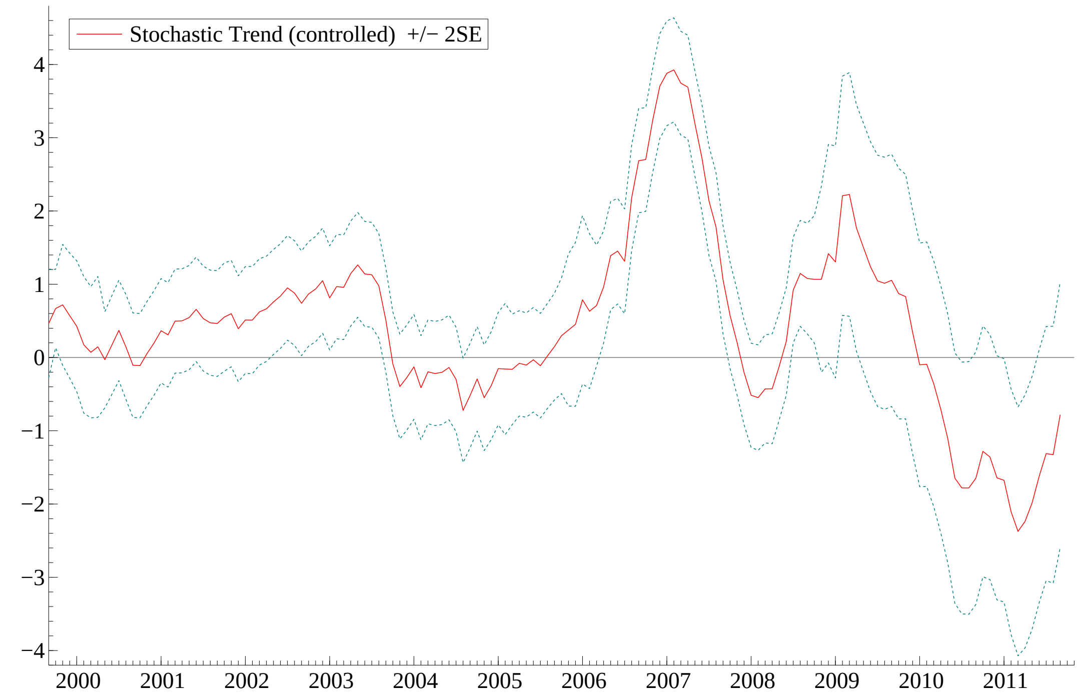

Figure 17: UC Model 7 (OTC): stochastic trend component

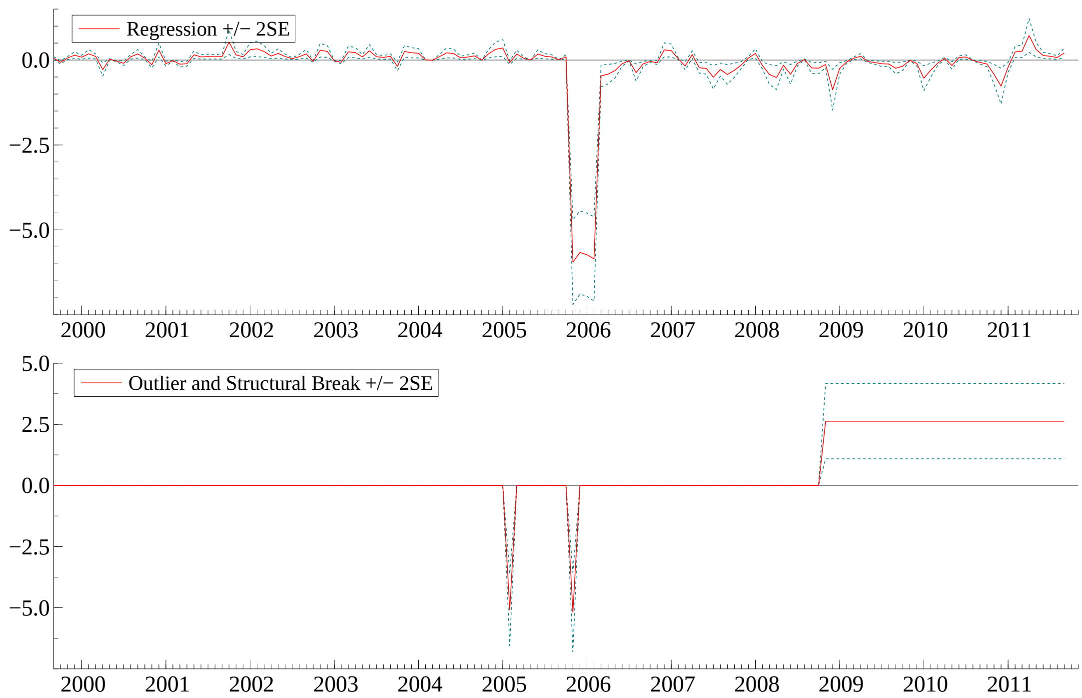

Figure 18: UC Model 7 (OTC): regression components and structural breaks

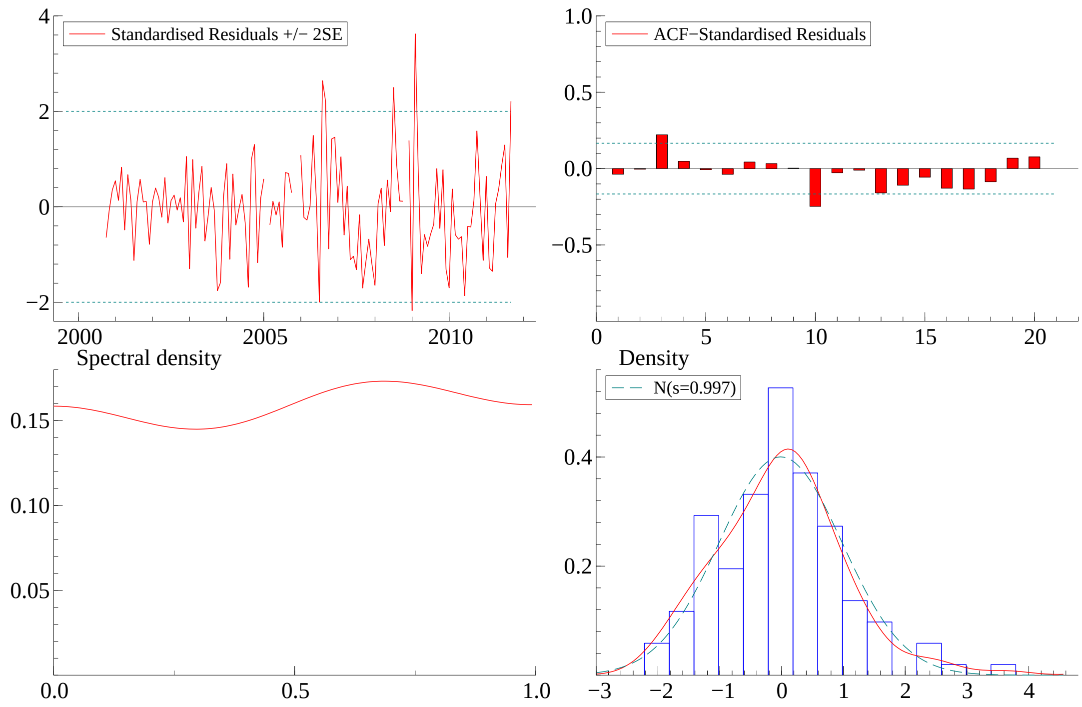

Figure 19: UC Model 7 (OTC): residual diagnostics

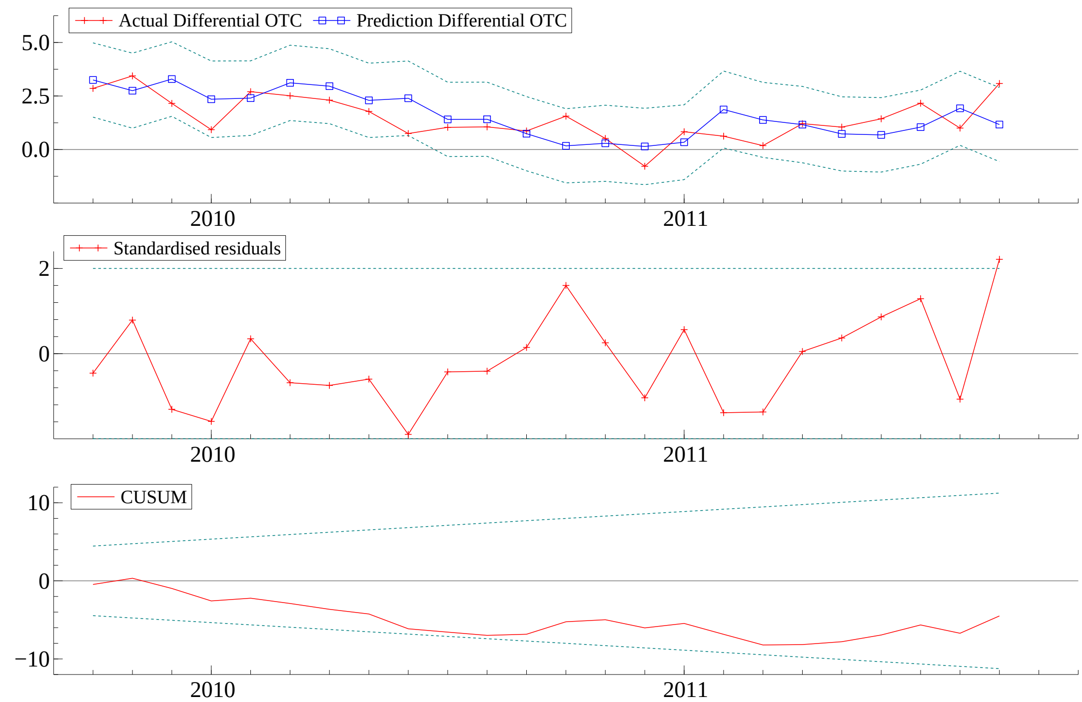

Figure 20: UC Model 7 (OTC): in-sample predictions