# WHOLESALE GAS MARKET

## Working Group report to the All Party Parliamentary Group on Energy Costs

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A full list of participants in the Working Group can be found in Appendix 6.

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# Contents

# EXECUTIVE SUMMARY

This Report was prepared by a Working Group of the All-Party Parliamentary Group on Energy Costs. A full list of the members of the Working Group is provided at Appendix 6.

This Report seeks to describe the structure and regulation of the Great Britain (GB) wholesale gas market and the level of competition in the market, and compare the GB market with similar wholesale markets in the European Union. A report of this nature was deemed timely given the Competition and Markets Authority investigation into energy retail markets and the electricity wholesale market.

## Key Findings

This report has considered the evolution of the GB wholesale gas market and the current state of competition in this market. It has highlighted important measures that provide confidence to consumers, regulators, government and industry participants. In particular, it has highlighted the importance of liquidity, transparency, and access to the markets as key for a well-functioning wholesale market.

- Ease of entry and exit: the GB market operates a licensing regime for the majority of market activities. These licences are inexpensive and there are relatively few barriers to securing the appropriate licences, provided that the applicant is a reasonable and prudent operator.
- Liquidity: the GB market benefits from a healthy degree of liquidity as judged against the Agency for the Cooperation of Energy Regulators (ACER) Gas Target Model. It is the only European market to meet all of the criteria defined under the Gas Target Model as a fully functioning gas market.
- Transparency: the GB gas market benefits from a high degree of data and information transparency. The infrastructure operators publish high levels of data and information, some near real-time or within day, and the remainder at the end of the day. This information is freely and widely available to any interested party. There also exists a vibrant and competitive market in market reporting and market analysis.
- Number of participants: with more than 200 licensees active in the physical over the-counter (OTC) market and over 100 participants registered on the InterContinental Exchange (ICE), the GB market has demonstrated that it is an attractive trading venue for a wide spectrum of counterparties. This includes small local cooperatives, through to large international oil and gas producers and utilities.

## How the Market Works and is Regulated

The wholesale natural gas market in GB operates under a liberalised, regulated model. Its structure is different to other liberalised natural gas markets, including those in continental Europe, which, nevertheless, were heavily influenced by the development and success of the traded market in GB.

The passing of the Gas Act in 1995 and development of the Network Code in 1996 (replaced by the Uniform Network Code in 2005) were key enablers behind the development of the GB market. The Network Code was the rulebook for transporting gas through the pipeline network. Central to this was daily balancing and a virtual delivery point, the National Balancing Point (NBP), which created the need and mechanism for a short term traded market.

Shippers are incentivised to balance - the physical and contractual inputs to the network equal the amount of gas that they used or sold - on each day. All of this must be done at the NBP. Any imbalance is settled financially with the System Operator.

National Grid Gas is the Transmission System Operator (TSO) and runs a regulated near-monopoly of the British high pressure transmission pipeline network. The Uniform Network Code is the regulated contract that controls how users of the network behave.

As the GB market is already highly evolved, EU regulation has had only a modest impact on the GB market to date and the process of liberalisation in the EU has moved slowly towards a single gas market largely based on the British design. More recently, as part of the EU's Third Energy Package, additional European-wide oversight of the energy markets has been established. Ofgem, along with all national energy regulatory authorities, now works in coordination with ACER, its EU umbrella organisation.

As part of the Third Energy Package some changes are planned in GB charging and balancing regimes for gas wholesale markets.

On top of the regulations and codes which operate the structure of the gas market, there is also specific EU and UK legislation concerning the outright trade of energy commodities. Fundamental to this is the EU's Regulation on Energy Market Integrity and Transparency (REMIT). This regulation, which came into force in December 2011, has extensive provisions to protect against abuses within the wholesale energy markets, including criminal sanctions. From October 2015, Market Participants will be required to report details of all market activity to regulators.

In addition to its ability to regulate the market through codes and enforcement actions, Ofgem also has the ability to refer sections of the energy markets to the Competition and Markets Authority (CMA). It has recently exercised these powers with regards to the electricity wholesale market and energy retail markets.

Going forward, an increasing proportion of new regulation is expected to originate in the EU, albeit with some member state control over the method of implementation.

## Number and Type of Participants

Any company in Britain that physically operates or utilises any gas infrastructure must have a specific licence awarded by the regulator Ofgem. Ofgem's most recent licence list contains around 400 distinct licences, almost twice that of any other European market. Of the 400 or so companies listed, around 250 are distinct separate entities. The list includes 227 trading participants known as shippers from 176 distinct companies. In addition, it is possible to become a non-physical trader without holding any form of Ofgem-issued licence. A wide range of companies operate on the NBP, although the majority fall into at least one of five broad categories: suppliers; producers; financial institutions; trading houses; and power generators. These categories include companies in a range of sizes from small suppliers to international oil companies, and some companies will be in more than one of these categories.

## Information and Transparency

A key factor for the continued success of NBP trading is the availability of information pertinent to supply and demand in close to real-time. Public domain gas flow information at transmission system entry points is updated every two minutes. This means that in a very short space of time, market participants are able to react to any change in market conditions.

The British wholesale gas market is highly transparent, with detailed wholesale price information available from the three main price reporting agencies (PRAs), the ICE exchange and several commodity brokers. In addition, National Grid's On-the-day Commodity Market (OCM), which is the commercial mechanism by which the gas grid is physically balanced in real time, produces a daily System Average Price (SAP).

There is high confidence in the information in the market as much of the information used by the market is independent in nature, coming from either National Grid or from the three main PRAs, which are all independent of any entity with a trading interest in those markets.

In addition, regulations addressing market abuse have been progressively tightened since 2008[1]. In particular, REMIT introduces significant sanctions against market participants that attempt to bias markets. In the UK, Ofgem is charged with enforcing the terms of REMIT. The regulator is able to impose financial and criminal penalties on transgressors.

## Contractual structures

The delivery times of trade of gas at the NBP can range from the same day to several years in the future. Much of this trading is undertaken using standard contract forms and is for physical gas.

Broadly speaking there are two main avenues through which trades are conducted: bilateral trades where a buyer and seller trade with each other (known as over-the-counter or OTC); and through an exchange (cleared). The share of the overall NBP traded market is roughly equally divided between OTC and exchange.

To aid trading, an inter-dealer broker usually matches would-be buyers and sellers, although this is not always the case.

## Sources of Supply

The GB gas market, so long a self-sufficient gas island, is today import-dependent and an integral part of the wider European market, which stretches from Norway to Algeria and from Russia to Portugal. Liquefied Natural Gas (LNG) imports ensure that the GB gas market is increasingly influenced by wider global market developments. On any day gas in the market can come from GB production, storage or imports, either through pipelines or as LNG. The volume of each of these sources will vary according to market prices.

Currently, GB production still accounts for around half of gas used, although Norway has emerged as a major supplier in recent years. Despite public perceptions to the contrary little or no gas is currently piped directly from Russia. A significant proportion of GB produced gas is Associated Gas,

[1] The European Union (EU) has recently introduced changes to financial services regulations which have some limited impact on parties that trade in commodities markets. Most recently the EU has proposed the introduction of benchmark regulation which is likely to apply to commodities markets, including energy.

which is a by-product of oil production. This supply source is expected to decline in line with oil production in the North Sea.

GB enjoys a very significant surplus of physical import infrastructure. In the GB market this surplus of infrastructure provides security of supply without the need for large amounts of storage. In 2013, import capacity utilisation was thus less than 30%, although utilisation is higher in winter.

## Trends in Supply and Demand

The main observed trends are a 67% decline in annual UKCS gas production since 2000 and a 22% fall in gas demand since 2008. The fall in demand reflects a range of factors such as a sharp decline in gas use in electricity production, where cheaper coal and renewables have taken a larger share, improved energy efficiency and conservation measures taken by consumers, and demand destruction in the industrial sector.

## Security of Supply

The rise and fall in prompt prices and along the curve provides a signal about the expected demand and supply balance. Rising prices will incentivise the increase in supply (or reduction in demand) while falling prices will do the opposite. The most significant drivers of the NBP price are supply and demand fundamentals.

Because of the transparency of information concerning supply and demand and the large number of participants trading the commodity, the liquid NBP price reacts exceptionally quickly to changes in either supply or demand and ensures a balance between the two is always met, without the need for significant intervention from a system operator. The security of supply in Britain is therefore underpinned by the activity at the NBP.

The activities of the market are backed up by emergency regulations mandated by government. The regulations were built into the original design of the industry, and they allow the Secretary of State to direct all licence holders (transporters, shippers and suppliers) in an emergency. This includes requiring UKCS producers, LNG terminal operators and storage operators to comply with instructions regarding their system flows. Equally, there are emergency procedures that require consumers to reduce demand. To date, these reserve powers have not needed to be put into effect.

## Liquidity and Forward Pricing

The churn ratio is the measure of the average number of times that a unit of the relevant commodity is traded on the market before it is actually delivered to a final buyer.

A churn ratio of 10 is generally considered to be a minimum value for wholesale gas markets to be considered liquid, although ACER has set a churn ratio of 8 as one of the threshold criteria of a functioning wholesale gas market under its EU 'Gas Target Model'. The gross churn rate at the NBP was above 20 during 2014 and has consistently ranged between 15 and 25 every month between January 2011 and December 2014. The churn rate in 2014 was almost seven times that of the German NCG hub, Europe's third largest, and excluding the Dutch TTF was more than double that of other European trading hubs combined. The British and Dutch wholesale gas markets are the only two European trading venues to pass ACER's churn ratio target of 8.

Bid-offer spreads in the OTC market in Britain are lower than in comparable continental European wholesale gas markets, and also compared to the UK electricity market.

# MAIN REPORT

## 1. Regulatory Background

### 1.1 History and Evolution

The wholesale natural gas market in Great Britain (GB) operates under a liberalised, regulated model. Its structure is different to other liberalised natural gas markets in the world, including those of the United States, which liberalised before GB, or continental Europe, although the latter nevertheless were heavily influenced by the development and success of the traded market in GB.

The process of gas market liberalisation in GB began with the privatisation and restructuring of the gas industry in the 1980s and took approximately 11 years from the removal of British Gas Corporation's monopoly in 1982 to the start of over-the-counter and on-the-exchange trading at a hub.

A full history of the development of the GB wholesale gas market is detailed in Appendix 1.

The first reported trade on record was in late 1992 between PowerGen, acting as seller of equity gas from the North Sea Pickerill field, to a marketing joint venture between Southern Electric and Phillips Petroleum[2]. Others followed in sporadic fashion. From early 1994, regular spot price assessments began to be published, although the pace of competition was slow and most of the 25-30 companies that were in a position to trade short term gas would only do so for operational reasons.

The passing of the Gas Act in 1995 and development of the Network Code in 1996 were key enablers behind the further development of the wholesale gas market. Essentially the Network Code was the rulebook for transporting gas through the Transco[3] network. It came into effect in March 1996 and set out the penalties imposed on gas shippers for being out of balance. Central to this was the system of daily balancing, which facilitated the need for a short term traded market. The Uniform Network Code (UNC) replaced the Network Code in 2005 and included a number of amendments and updates to reflect the experience gained from the first ten years of the liberalised market.

The other key provision of the Network Code was the creation of the National Balancing Point (NBP), a virtual delivery point which rapidly became the focus of trading and pricing. Previously, gas trading had been located at physical delivery points. [4] The NBP is a "super-firm" delivery point. A company that buys gas at the NBP by definition receives it; the company that sells it by definition has the gas to sell. Any imbalance of a market participant with respect to their net contracted position with all

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[2] See *World Gas Intelligence*, October 1992, page 20.

[3] Now National Grid Gas

[4] Physical delivery takes place at beach terminals along the coast where gas is piped ashore from the fields and processed before entering the National Transmission System. The major terminals are Bacton in Norfolk and St Fergus in northeast Scotland. Bacton, the entry point for large volumes of highly flexible gas from the Southern North Sea, was the benchmark pricing point, and NBP prices, when they appeared, were essentially the same as Bacton.

counterparties is settled financially with the system operator, rather than between individual contract counterparties.

It is difficult to overstate the importance of the NBP in the development of the British wholesale gas market. It was created as the balancing mechanism of the Network Code, but quickly evolved into a trading hub. Many (though not all) import contracts are contractually delivered at the NBP rather than at the physical entry point (the notable exception being LNG contracts, which are often delivered at the import/regasification terminal). Broadly speaking the NBP's design has been replicated by other European countries when their governments have sought to create liberalised gas markets. EU law – most notably under a raft of legislation known as the Third Energy Package – calls on all member and candidate states to now establish competitive, yet regulated, wholesale gas markets that resemble the NBP.

## 1.2 Regulatory Trends

EU regulation has had little direct impact on the GB market to date, although the sluggish pace of market liberalisation in the EU has frustrated GB market participants from time to time. There has been resistance to gas market liberalisation in some EU member states and the process of liberalisation has moved slowly towards a single gas market largely based on the British design. In June 1998 Directive 98/30/EC (the First Gas Directive) established common rules for the transmission, distribution, supply and storage of natural gas. The First Gas Directive, amongst other things, required Member States to ensure Third Party Access (TPA) to transmission and distribution networks, and gas and LNG storage facilities. It gave Member States the option to meet these requirements through implementing either a negotiated or a regulated TPA regime.

More recently, as part of the EU's Third Energy Package, additional European-wide oversight of the energy markets has been established. Ofgem, along with all national energy regulatory authorities, now works in coordination with its EU umbrella organisation, the Agency for the Cooperation of Energy Regulators (ACER).

As part of the Third Energy Package there will be EU mandated codes governing the operation of both the gas and electricity markets. Bringing these codes into effect will require some changes in GB charging and balancing regimes for gas. For example, there is a requirement to move the start of the downstream Gas Day from 06:00 to 05:00. Other areas that may have significant effects on the operation of the GB market include rules for determining flows across interconnectors (Market Coupling) and changes to gas quality requirements. Gas trading is now also subject to EU financial regulations governing commodity trading with more types of trade subject to financial rather than gas-specific regulation and many market participants being regulated as Investment Firms. Going forward, most new regulation is expected to originate in the EU, albeit with some member state control over the method of implementation.

On 25 February 2015, the European Commission published its Energy Union Package, a framework strategy highlighting the requirement to accelerate the process towards greater market integration and greater energy security at the EU-level.[5] Among the policy objectives outlined in the package is a proposal for the European Commission to take a more active role at the negotiation stage when EU

[5] http://ec.europa.eu/priorities/energy-union/docs/energyunion_en.pdf

companies try and secure long-term supply agreements with non-EU countries. This could include the establishment of standard contract clauses to ensure that EU law is observed before supply agreements are finalised.[6] An enhanced role for ACER is also proposed.

# 2 Number and Type of Market Participants

## 2.1 Number of Participants

Any company in Britain that physically operates or utilises any gas infrastructure must have a specific licence awarded to them by the regulator Ofgem.

As outlined in section 1, the initial pace of competition in the years between the removal of British Gas Corporation's monopoly in 1982 and the passing of the 1995 Gas Act and establishing the Network Code and the virtual NBP in 1996 was gradual. By 1994 there were around 15-20 companies using a very simple standard contract to trade over-the-counter (OTC). These were primarily the marketing arms of upstream producers along with some independent suppliers.

The number of market participants rose to around 50-60 companies within two years following the 1995 Gas Act, as a rapid growth in indigenous gas production put downward pressure on spot prices, allowing new aggressive entrants to undercut established suppliers' long-term contract prices.

As liquidity built on the NBP more participants joined. The commissioning of a pipeline to Belgium in 1998 established a physical connection with continental Europe which was the catalyst for new European participants to start to trade on the NBP.

Ofgem's most recent licence list, updated 12 February 2015[7], contains around 400 distinct licences. As there are different types of licence and one company may have various entities operating separately through the supply chain, a single organisation can often hold multiple licences. Because of historical mergers and contract requirements some of the licensees retain their original names rather than adopting a brand-affiliated name.

Of the 400 or so companies listed by Ofgem, around 250 are distinct separate entities.

The different key licences include: interconnector operator; shipper; supplier; private network operator; transporter; system operator; and site specific operator. The latest list includes 227 registered trading participants known as shippers, collectively accounting for 176 distinct companies.[8]

In addition, it is possible for an entity to become a non-physical trader without holding any form of Ofgem-issued licence.

Counterparties that wish to trade on an exchange must become a member. Of the hundreds of members of ICE Futures Europe, the largest GB gas exchange, just over 100 are listed as being active in the gas market. It is difficult to ascertain what proportion concentrate on the NBP as the exchange

[6] ibid

[7] https://www.ofgem.gov.uk/ofgem-publications/91596/externalgaslist190115.pdf

[8] https://www.ofgem.gov.uk/publications-and-updates/list-all-gas-licensees-registered-or-service-addresses

also offers futures contracts for other global gas markets. However, broadly half those on the members list are located in Europe, which goes some way to indicate the number of ICE members at the NBP, rather than in the US.

As with the Ofgem list of licensees, some companies are listed a number of times on ICE, with different divisions of an organisation operating separately.

More participants are registered and actively trading on the NBP than in any other European market, underlining the NBP'`S position as the largest traded market in Europe, if volumes traded on OTC and exchange are taken into account.

The gas market in the Netherlands is the second largest European gas market in terms of total traded volumes, and the largest OTC market, although fewer participants are registered and actively trading on its virtual hub, the Title Transfer Facility (TTF). There were 117 companies holding a TTF shippers licence at the beginning of 2015, according to Dutch network operator Gasunie Transport Services. [9]

In contrast to the OTC market, the ICE NBP market is over five times the size of the ICE's TTF market, which is in an earlier stage of growth, having only been set up in 2010. 45 companies were registered to trade the Dutch TTF hub on the ICE Endex exchange at the beginning of 2015. [10]

The British and Dutch gas markets are significantly more liquid than other European gas hubs and in turn have more participants who are both registered and regularly trading at the NBP and TTF. There are, for example, 64 registered companies licensed to trade at Austria's Virtual Trading Point (VTP)[11], while the physical trading point at Zeebrugge in Belgium has 82 registered traded companies including 72 separate entities, many of which are also active on the NBP, reflecting the physical connection between the two markets. [12]

## 2.2 Type of Participants

A wide range of companies operate on the NBP, although the majority fall into at least one of five broad categories. These are: suppliers, producers, financial institutions; trading houses and power generators. Depending on how a company is organised, it can of course be a producer, a supplier and generator, as is the case with some of the vertically-integrated utilities.

Indeed, utilities are a fundamental trading component of any gas market. In Britain, the so-called Big Six hold a large proportion of the retail market, and these are: Centrica (British Gas); EDF (EDF Energy); E.ON; Iberdrola (Scottish Power); SSE and RWE (Npower). As well as selling households duel fuel they all hold stakes in power production – albeit not necessarily in gas-fired generation – with some also active in gas production and storage too.

There are also a number of smaller suppliers, including those to the non-domestic sector. As well as some independent organisations, a number are backed – or have trading partnerships – with either a financial institution or trading house. Key examples include First Utility, which is associated with

[9] http://www.gasunietransportservices.nl/uploads/download/4c3cee3a-e4b5-4a63-b615-d89c6baf80e6
[10] http://www.iceendex.com/members/spot-markets/trading-members/
[11] http://www.cegh.at/members
[12] http://www.huberator.com/en/membership/hub_members

Shell; Corona Energy, owned by Macquarie; and Vayu which is partnered to Switzerland-headquartered commodities trader Glencore.

A number of larger international oil and gas companies have a well-established presence as independent suppliers. These include France-headquartered oil and gas major Total, Gazprom Marketing & Trading, Denmark's DONG, Italy's Eni, Norwegian Statoil and Franco-Belgian energy group GDF SUEZ.

According to Cornwall Energy, at 31 October 2014 independent suppliers accounted for around 9% the residential energy market account numbers. Independent suppliers accounted for 39% of sales to small and medium sized businesses and 88% of all sales to larger industrial and commercial customers. [13] The significant volumes traded by these independent suppliers ensure a more varied wholesale marketplace.

With the pivotal role of the suppliers to the market, many of these participants generally will be present on both short- and long-term futures and forward contracts, looking to secure their needed supply efficiently. Given the volumes required by these participants, even those with their own production will need to procure and hedge additional gas and this process can occur over a number of years.

Major utilities whose core markets are on the European mainland will also tend to hold some position on the NBP. As the most active trading hub in the continent, European utilities will often look at the GB market as an attractive trading venue and many have established affiliates or subsidiaries in Britain. These utilities include Sweden-headquartered utility Vattenfall, Denmark's DONG and Switzerland-based commodity traders Axpo and Alpiq.

At the other end of the supply chain, many of the international oil companies are active in the British market. ConocoPhillips, ExxonMobil, BP, BG Group, Statoil, Total, GDF SUEZ and Shell all have stakes in gas-producing fields in the North Sea, as do a number of independents such as Anglo-French producer Perenco, US-headquartered Hess Corporation and Canada's Nexen (owned by Chinese state producer CNOOC).

These companies operate on both the UK Continental Shelf (UKCS) and the adjoining Norwegian Continental Shelf, with the newly formed Oil and Gas Authority, the Department of Energy and Climate Change (DECC) and its Norwegian equivalent providing regulatory oversight.

Capacity holders at Britain's three liquefied natural gas (LNG) import terminals include BG Group, Malaysia's PETRONAS, Qatar Petroleum, ExxonMobil, BP, Total, E.ON, Algeria's state producer Sonatrach, Centrica, and Iberdrola. Spare capacity at these terminals is also regularly offered to interested parties when unused space becomes available.

Given the liquidity of the NBP, key commodity global trading houses are active at the British hub. These include Geneva-headquartered Vitol, Gunvor, Koch, Mercuria and Noble Group. Smaller trading businesses are also common. Commodity trading houses will often seek to trade short-term cross-border price differences, shipping volume from one European market to another, which helps

[13] http://www.energy-uk.org.uk/publication.html?task=file.download&id=5017

flatten price differences across borders, fulfilling a central objective of EU single-market energy policy.

Financial institutions have reduced commodity trading in the period since the 2008, in response to the increased regulatory capital requirements under EU legislation that makes it more expensive to hold a position for long periods. This has affected liquidity in the British gas market. However, as well as the banks already mentioned above, US-headquartered Goldman Sachs remains, as does Citi, as key providers of liquidity to longer dated contracts at the NBP. These institutions play a key role in the gas market, allowing utilities to offload some of the potential risk in undertaking long-term deals.

As banks have rolled-back their exposure to commodities, specialist hedge funds have been increasingly active in gas trading. These counterparties will typically operate only via the exchange, and therefore be more focused away from the volatile dynamics of prompt trade. Any position they do take will be closed out before it reaches expiry, so these companies never take physical delivery of any gas.

# 3 How the Market Works

## 3.1 Regulation and Industry Codes

National Grid Gas is the Transmission System Operator (TSO) and runs a natural near-monopoly of the British high pressure transmission pipeline network. It plays no part in the trade of gas, other than for its own operational purposes to maintain the integrity of the system, and the cost of this operational trading provides the basis of the System Average Price. It is a regulated business. A monopoly in this instance creates an efficient, level playing field upon which a competitive market in the trade of gas can exist. This is because National Grid manages and allocates all the transmission pipeline capacity within the system on a full third party access (TPA) regime, so all those wishing to utilise some of that capacity have an equal and fair chance of obtaining it.

Any company wanting to trade, and use the transmission system, must become a signatory to a set of pipeline management rules known as the Uniform Network Code (UNC). The UNC is therefore, in essence, the foundation of the whole British gas market structure, as it is the commercial regime that underpins the British gas market. Since all users of the network need to adhere to the UNC, the whole market is covered by regulation.

To manage the entire pipeline network, all shippers need to regularly inform National Grid what they expect to supply or consume on a given Gas Day, in a processes known as nominating. Currently, a Gas Day is a 24 hour period from 06:00. In this way, the TSO is able to forecast whether supply will cover demand and whether further action needs to be taken. By providing this nomination data to the entire market (in anonymous form) and by National Grid publishing its own demand forecasts, all those trading at the NBP have the tools necessary for the maintenance of Britain’s security of supply.

The majority of changes made to the UNC need the approval of the British energy market regulator, Ofgem. Furthermore, all participants physically active in the gas market are licensed by the regulator, with Ofgem holding the power to revoked as well as issue these licences.

According to Ofgem[14]: "The UNC is the hub around which the competitive gas industry revolves, comprising a legal and contractual framework to supply and transport gas." "It has a common set of rules which ensure that competition can be facilitated on level terms. It governs processes, such as the balancing of the gas system, network planning, and the allocation of network capacity."

Signatories of the code are permitted to seek amendments to UNC. The proposed changes undergo heavy scrutiny from all parties involved through a highly transparent regulatory amendment process. These code modifications are administered by the Joint Office of Gas Transporters, with all proposals and iterations retained on their public website[15]. Ofgem has the final say on most proposed modifications.

Although the NBP has no specific physical location, it is confined to gas bought and sold within the transmission pipelines as managed by the TSO. It is often referred to as a virtual hub or virtual trading point. When the title of gas is transferred within Britain the delivery of the commodity almost always occurs at the NBP; in other words the ownership of the gas changes hands within the infrastructure operated by the TSO.

Although the NBP has been something of a blueprint for gas market design in Europe, new EU codes that were outlined within the Third Energy Package are now being included within the UNC. These EU codes are developed by a TSO umbrella organisation called the European Network of Transmission System Operators for Gas (ENTSOG), with the guidance of ACER. These network codes cover areas such as balancing, congestion management and capacity allocation procedures. A further code on gas transmission charging is currently under development.

On top of the regulations and codes which operate the structure of the gas market, there is also legislation concerning the outright trade of the commodity of gas. Fundamental to this is the EU's Regulation on Energy Market Integrity and Transparency (REMIT), where all wholesale gas trades are reported to Ofgem and ACER. This regulation also has extensive provisions to protect against abuses within the wholesale energy markets, including criminal sanctions. This regulation has been in force since 28 December 2011, and it:

- defines market abuse (market manipulation, attempted market manipulation or insider trading);
- explicitly prohibits market abuse;
- requires effective and timely public disclosure of inside information by market participants; and
- obliges firms to report suspicious transactions.

In addition to its ability to regulate the market through codes and enforcement actions, Ofgem also has the ability to refer sections of the energy markets to the Competition and Markets Authority

[14] https://www.ofgem.gov.uk/licences-codes-and-standards/codes/gas-codes/uniform-network-code
[15] http://www.gasgovernance.co.uk/

(CMA). It has recently exercised these powers with regards to the electricity wholesale market and energy retail markets.

## 3.2 Information and Transparency

The key to success for NBP trading is the availability of information pertinent to supply and demand in close to real-time. As already mentioned, National Grid publishes its own forecasts of whether the network will have sufficient supply to meet demand, based on all the nomination data it receives from shippers. This is updated hourly within any given gas day.

The TSO also publishes data on the rate at which entry pipelines are flowing into the network, every two minutes. This means that in a very short space of time, market participants are able to react to any sharp change in deliveries that may be caused by the start-up or failure of any given asset that is producing or importing gas into Britain.

As well as mandating the reporting of trades, REMIT rules also require that any owner of an asset that is material to the supply or demand of gas in Britain must immediately give notice if that asset is malfunctioning. This, coupled with the wealth of information published by National Grid, allows all present to see where a physical problem has occurred and to measure the impact it is having on the market. As all the information is freely available on the internet, all in the market have equal knowledge of state of the NBP.

This is crucial for price formation of any given contract, as it allows all those present to make the same informed decision about its value based on supply and demand.

## 3.3 Contractual structures

The trade of gas at the NBP bought on any given day can range from immediate delivery, to the delivery over any period of time in the future. The most typically traded contracts are for next-day or next-month delivery. When gas is dealt for a period longer than a 24-hour period, the contract terms typically require the seller to deliver an equal amount of gas each day for the duration of the contract. These so-called forward and futures contracts lock-in the price of the gas, regardless of whether later the price changes. This allows both buyers and sellers to manage the fluctuating price risk.

Prices for short-term delivery – usually up until the end of the month – are referred to as prompt contracts. Contracts beyond the end of the month often are called curve contracts. The curve itself is then sub-divided into near- and far-curve.

### 3.3.1 Trading products

Besides many supply-side factors, the cost of gas bought for future delivery is heavily influenced by the expected consumption during the period in which it will be supplied. During the summer-months demand is lower and there are limits to the flexibility of gas production, so prices are also expected to be lower, with the reverse occurring during the winter period. There is no fixed differential between winter and summer prices, with the spread tending to be larger when winter demand is expected to be high, and the cost of storage provides an effective floor.

At the NBP, forward and future contracts are therefore typically broken down along two so-called seasons that cover the full 12 months of a year. A winter product runs from 1 October until 31

March, with the summer covering the other six months. Periods are then broken down further to a more granular level, with Q2 and Q3 equally dividing a summer, and Q4 and Q1 encompassing the winter. Each quarterly product is made up of three months, which follow a standard calendar.

At any given moment, the average cost of three component months should be equal to their respective quarter, and similarly two quarters within a season should be priced in line with the six-month long contract. Any differences will quickly be traded away in a process known as arbitrage.

As these products approach their delivery time, known as their expiration date or expiry, weather forecasting information becomes more accurate. Traders will seek at this point to buy or sell more, depending on their own expected demand. They will often switch from trading a season to instead concentrate on its two constituent quarterly parts, or replace their interest in the quarter with the three individual months.

When delivery of the gas is required within the next month, trade switches again to a suite of different prompt delivery products. The front and back half of a month is tradable, but most common is the five-day periods of a given working week, as well as two-day periods for weekends.

The best weather forecasts refer to the next day, and for this reason gas delivered the following day is ultimately the most actively traded product. This is the so-called Day-ahead contract.

Operational breakdowns and changes in weather-related demand mean that the gas market needs to respond quickly to deviations in expected supply and demand on any given day. A Within-day contract can also be traded and helps the GB gas market to manage its daily balancing obligations in real time. The delivery of the Within-day gas must occur within the current Gas Day.

### 3.3.2 OTC and Exchange

Broadly speaking there are two typical avenues through which counterparty can conduct most of their trade at the NBP: over-the-counter (OTC) and through an exchange (cleared). The share of the overall NBP traded market is roughly equally divided between OTC and exchange, although – as opposed to continental Europe - the share of the exchange has increased compared to the OTC share in recent years.

OTC trades are physical deals based on a standardised contract known as the “Short Term Flat NBP Trading Terms & Conditions” – or the NBP ’97. This very simple contract has proved to be robust since its introduction in 1997, and gives traders a known and secure basis for trading. The OTC market has also evolved in a standardised way in which trades are conducted in ‘clips’ or multiples of 25,000 therms per day in one of several clearly defined time periods. This allows for ease of trading, greater transparency and inevitably greater liquidity.

To aid trading, an inter-dealer broker usually matches would-be buyers and sellers, although this is not always the case. More often than not, traders place electronic bids (when buying) and offers (when selling) onto a web-based trading screen belonging to an inter-dealer broker, along with a stated volume. Deals are then completed when another trader, known as an aggressor, selects the bid (a process known as being given), or the offer (known as being lifted), depending on the second counterparty’s own trading requirements. Deals can also occur over the telephone and even through internet-based instant messaging services.

The inter-dealer brokers of the NBP include: GFI, ICAP, Marex Spectron, Tradition, Tullett Prebon and Griffin Markets.

Most traders will utilise the electronic matching services of more than one inter-dealer broker. With the advent of increased electronic trading, software which aggregates the highest bids and lowest offers from across these different screens is increasingly used. The most used software of this type is provided by Trayport.

Along with all the typical length contracts mentioned above, it is possible to procure OTC gas for irregular lengths of time, in irregular volume. These so-called non-standard contracts give gas shippers increased versatility, which can be particularly important should an asset malfunction, or have to be shut for maintenance.

OTC trades are still bilateral contracts and still hold counterparty credit and performance risk. Therefore, it is frequently a requirement that collateral is posted, with the level being adjusted to reflect movements on market prices.

Shippers are aware of who they are trading with when conducting an OTC deal, and will have previously had their legal departments sign master agreements on the terms and conditions of all subsequent transactions. Documents developed by the European Federation of Energy Traders (EFET) industry association are typically utilised in this process.

The delivery of an OTC trade is not automatically protected should either a buyer or seller be forced to forfeit the agreement between the contract being struck and delivery taking place. Should either side seek this protection, the trade must go through a process known as clearing.

The alternative to trading OTC involves futures and cleared trades. These are regulated markets governed by the Financial Conduct Authority. One exchange dominates the British market, which is operated by the InterContinental Exchange's European division, ICE Futures Europe (ICE); the clearing is provided by another subsidiary, ICE Clear Europe. This market is also highly competitive with other exchanges offering competing products. For example, one of the world's largest commodity exchange groups, CME, has recently launched competing NBP products.

The process of shippers placing their chosen bids and offers on screen works in a very similar manner to the OTC market. As with the screens run by the inter-dealer brokers, the electronic system run by the exchange ranks the highest bids next to the lowest offers for a specific delivery period, allowing all with access to see the tightest bid-offer range.

Unlike OTC trade, the exchange acts a central counterparty in any given deal, in essence buying from one trader and then almost instantaneously selling onward to the second. As a result, all deals are centrally cleared, and trade occurs anonymously. Tradable products on an exchange are typically uniform in their delivery-length with little opportunity to trade in irregular volume.

Whether trading OTC or through an exchange, there is a cost associated with using these services.

OTC deals are referred to as forwards, with exchange trades called futures. Brokered OTC and exchange trading are only possible during the working week and during typical working hours.

### 3.3.3 Balancing and Cash-out

To maintain the structural integrity of the gas network and the efficiency of the NBP as a whole, shippers that flow gas into the network and those that off-take from it are incentivised to ensure that they are in balance on any given day. This is to say, they have supplied and/or consumed the volume of gas they had previously nominated.

The most typical reasons for a shipper not being in balance derive from demand being different than forecast (e.g. if there are large temperature changes that result in end consumers changing their behaviour), or from problems with supply (e.g. caused by an unplanned asset outage). Whether a shipper is balanced or not becomes increasingly clear as the Gas Day progresses.

To keep in balance, a shipper – in normal circumstances – would seek to either buy or sell the required volume, or to utilise a flexible, responsive asset at their disposal (see *Swing and Storage below*). However, should this not be possible for any reason – for example because it is the middle of the night – then the shipper will be forced to trade on a specific balancing market. In essence this is the third avenue through which to procure or sell gas on the NBP.

The balancing market, which is called the On-the-day Commodity Market (OCM), is operated by the ICE Endex exchange on behalf of National Grid.  This part of the ICE's activities is distinctly separate from its other commercial operations. Here, only Day-ahead and Within-day trades occur anonymously, with the aggregate price traded for a specific delivery-day being used to formulate a system average price. The OCM is open until 03:35 for any Gas Day, leaving just over two hours of any given day where no trade can occur.

If after trading through the OCM a shipper still is not in balance, it will be balanced by National Grid. Here a so-called cash-out price will be charged for the gas. If the TSO has to buy gas from the shipper in question, the cash-out value will be marginally lower than the OCM's system average price, while if National Grid has to sell to the counterparty the gas will be marginally more expensive.

These incentive prices are designed specifically to discourage shippers from letting their positions be balanced by the system operator on a regular basis.

### 3.3.4 Swing

Conventional gas production can either occur at the same time as oil extraction or alone, with no other major hydrocarbons. Gas output from the former is known as associated or wet gas, while the latter is called dry gas. While associated gas will often be pumped irrespective of the gas price – because it is instead driven by the oil price – the same cannot be said of dry gas.

Production of gas fields that feed into Britain is, therefore, responsive to the price at the NBP. Because many are able to vary their production rates, they have been referred to a swing fields. These fields will often be called upon to make up any shortfall in supply on any given day.

The volatility of a price at the NBP therefore drives the use of these fields. Key swing fields in Britain have historically included Centrica's North and South Morecambe. However, Britain's changing supply mix means that these fields may no longer need to operate in this way.

In many ways these fields operate in a similar manner to storage (see below) with the caveat that they are only able to add gas to the network, and are not able to be refilled.

In addition, large long-term contracts will often have flexibility built into them that allow the buyer or (less often) the seller to apply a degree of flexibility in the volume of gas provided.

### 3.3.5 Storage

In order to manage the fluctuations in demand which occur between the seasons or within a given traded day, and also to hedge price risk, shippers hold gas in reserve at a number of underground storage facilities around Britain. The geology of the storage units is typically in depleted oil and gas fields, or within salt cavities.

Shippers can book capacity at specific storage sites for varying periods of time, allowing them to inject gas into these facilities in periods of low demand or low price, and then withdraw it during times of high consumption or high price. Typically capacity is booked for a full 12 months starting from 1 April, allowing a shipper to inject during the summer and to then empty their quota during the winter, or react to shorter term price or demand trends.

Forward prices will indicate to traders whether or not there is an incentive to inject or withdraw at any given time. For example, if it is April and the cost of the coming winter forward contract is more expensive than the May contract – plus the cost of storage capacity – then it makes sense to buy May gas for the purposes of injecting into storage with the assumption it will be used, or sold back to the market, over the winter. Alternatively, if a Day-ahead contract rallies to be the most expensive price over the next 12 months, then there is a clear incentive to withdraw from storage the following day. A trader may also at the same time choose to buy an equal volume for another (but later) prompt contract, which will then be used to replenish the capacity that will be partially emptied by the Day-ahead withdrawal.

Physically there are four types of storage facility in the UK:

1. Depleted gas field: The Rough field off the coast of Humberside, is the largest single gas storage facility. This 'long-range storage' site can technically hold enough gas to cover around 4-5% of GB annual demand. [16] With a maximum technical withdrawal rate of around 41 million cubic metres (mcm)/day[17], Rough can meet approximately 10% of GB winter peak day demand.[18] Designed originally as seasonal storage, to be filled gradually during the summer and drawn down steadily during the winter, Rough has over time been developed into a more flexible instrument. Given its size and importance, Centrica, the parent company of its owner, is limited by regulation to booking no more than a maximum of 25% of its primary capacity.
2. Salt caverns: These are designed to respond rapidly to market signals, and offer users rapid cycling (allowing for instance gas to be injected during the night and withdrawn during the day). There are four in operation, the largest being Hornsea in East Yorkshire, that can provide roughly 4% of GB winter peak-day demand.

[16] The technical and operational capabilities of Centrica's Rough site can be found here: http://www.centrica-sl.co.uk/files/operational_guide.pdf
[17] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337633/dukes4_4.xls
[18] http://www.centrica.com/?pageid=122

3. LNG import terminals: Although their principal role is to import LNG, of necessity they are also storage units for the liquefied gas before it is vapourised and injected into the grid. South Hook, for instance, has five storage tanks each of 155,000 cubic metres liquid capacity: together these represent over 1 billion cubic metres (bcm) of gas.
4. LNG Peak Shaving: National Grid operates one LNG peak shaving unit at Avonmouth, near Bristol. This is now used primarily to supply customers who require LNG by road tanker. There were originally five such LNG units dotted around the extremities of the National Transmission System used for peak demand. However these plants became redundant as baseload LNG import plants were built and the topography of the NTS changed. National Grid proposes to close the Avonmouth plant in 2016.

Figure 3.1 below shows British storage sites, their outright owner(s), capacity and the maximum amount of gas that can be put (injected) into storage and taken out (withdrawn). Given the cost of constructing a storage unit many of the medium-range sites were granted Third Party Access (TPA) exemptions by Ofgem, meaning the asset owner is not obliged to allow other network users to book capacity at their sites. Details of LNG import terminals are detailed in section 3.3.6.

Figure 3.1 (source: National Grid)[19]

| Storage site | Owner | Location | Approximate Withdrawal Capacity (mcm/day) | Approximate Storage Capacity (bcm) | Type | Status |
|---|---|---|---|---|---|---|
| Rough | Centrica Storage Ltd | Southern North Sea | 41 | 3.30 | Depleted field | Long |
| Aldbrough | Scottish and Southern Energy & Statoil | East Yorkshire | 40 | 0.30 | Salt cavern | Medium |
| Holford | E.ON | Cheshire | 22 | 0.20 | Salt cavern | Medium |
| Hornsea | Scottish and Southern Energy | East Yorkshire | 18 | 0.30 | Salt cavern | Medium |
| Holehouse Farm | EDF Trading | Cheshire | 11 | 0.05 | Salt cavern | Medium |
| Humbly Grove | Humbly Grove Energy | Hampshire | 7 | 0.30 | Depleted field | Medium |
| Hatfield Moor | Scottish Power | South Yorkshire | 2 | 0.07 | Depleted field | Medium |
| Stublach[20] | Storenergy (GDF SUEZ) | Cheshire | <3 | 0.04 | Salt Cavern | Medium |

[19] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337633/dukes4_4.xls

[20] Storenergy commissioned the initial two salt caverns at Stublach in September 2014. A total of 20 caverns are scheduled to be developed by 2020 bringing total storage capacity to 400 million cubic metres with a withdrawal capacity up to 33 million cubic metres per day. See https://www.storengy.com/countries/unitedkingdom/en/oursites.html

| | | | | | | |
|---|---|---|---|---|---|---|
| Avonmouth | National Grid LNGS | Avon and Somerset | 13 | 0.08 | LNG Peak Shaving | Short |

### 3.3.6 Interconnectors and LNG

GB enjoys a very significant surplus of physical import infrastructure. In the GB market this surplus of infrastructure provides security of supply, and helps to manage significant variations in the mix of gas import sources, without the need for large amounts of storage.

In 2013, the country consumed 73.1bcm, produced 36.5bcm from domestic resources and imported around 37bcm. Pipeline import capacity was 78.8bcm, and LNG import capacity 48.3bcm, making a total technical capacity of 127.1bcm. Import capacity utilisation was thus less than 30%. However this does not tell the whole story: gas is a seasonal fuel, and imports rise steeply in the winter, when pipeline utilisation rises.

Two pipelines connect GB to the main continental markets. Four pipelines bring in Norwegian gas[21]. Two further pipelines export to Northern Ireland and the Republic of Ireland respectively.

The pipeline owned and operated by Interconnector (UK) Ltd (IUK) connects the Bacton terminal in Norfolk with Zeebrugge in Belgium. Zeebrugge is a major European gas hub closely connected to the Belgian, French, Dutch, German and more distant markets. IUK's technical import capacity will be expanded to 25.5bcm/year from 2018, while export capacity is 20bcm/year. IUK is used as a balancing mechanism between the Belgian and British markets, with gas being delivered to either terminal as prices dictate. The direction of flow can and often does change within a single day. In the winter, when demand is high, it operates primarily in import mode.

The BBL (Balgzand-Bacton Line) runs from Balgzand on the Dutch coast to Bacton. It operates primarily as a GB import line, with a capacity of around 16bcm/year. BBL also offers virtual reverse flow[22], under which gas can be netted off at Bacton in order to allow a UK shipper to deliver at Balgzand.

These pipelines facilitate trading with the key European hubs Zeebrugge, Title Transfer Facility and NetConnect Germany.[23]

The two largest pipeline systems provide a total of around 38bcm/pa GB import capacity. Langeled, with 25.5bcm/pa capacity, runs 1,166 kilometres (725 mi) through the North Sea from Nyhmana on the west coast of Norway via the Sleipner Riser platform to the Easington terminal in East Yorkshire. Vesterled has a capacity of 12.3bcm/pa and delivers gas from the northern North Sea to the St Fergus terminal north of Aberdeen.

GB supplies Ireland north and south with gas via an exit point from the NTS at Moffatt in south eastern Scotland. This feeds one line to Northern Ireland and two lines to the Republic. Moffatt exit capacity is 11bcm/pa, but actual flows are less than half of this. There is at present no provision for

[21] Two Norwegian pipelines connect to the UK using the FLAGS infrastructure at St Fergus. Two have their own dedicated landfall points.

[22] A contractual structure whereby someone that needs gas in Country A can buy gas in country B without having secured physical pipeline capacity. For example, if company 1 wants to export 100, company 2 wants to export 200 and company 3 wants to import 150, then the physical export flow is (200+100)-150 = 150

[23] See Appendix 4

reverse flow, although there have been some discussions. The Republic of Ireland has so far failed to develop a large gas field, Corrib, on the Atlantic coast; when and if Corrib does begin to flow gas into the Irish grid, some may be exported to the GB market.

There are four liquefied natural gas (LNG) reception terminals in Britain. Grain LNG in the Thames Estuary is owned and operated by National Grid, and has an import capacity of 20.5bcm/pa. Two further terminals are located in Milford Haven, in southwest Wales: South Hook LNG, a joint venture between Qatar Petroleum, ExxonMobil and Total, with a capacity of 22bcm/pa; and Dragon LNG, jointly owned by BG plc and PETRONAS of Malaysia, with a capacity of 7.6bcm/pa. Teesside GasPort, jointly owned by Excelerate Energy, is the world's first dockside floating regasification facility, with a capacity of 4.2bcm/pa. Thus the GB market has combined LNG import capacity of 48.3bcm/pa

Figure 3.2 below shows British LNG import facilities and import and export pipelines, their outright owners, annual capacities and maximum flow rates.

| **Facility** | **Owner** | **Between/Location** | **Annual Capacity (Billion Cubic Metres)** | **Maximum Flow Rate (Million Cubic Metres/day)** |
|---|---|---|---|---|
| | | **Operational Pipelines** | | |
| Bacton-Zeebrugge Interconnector | Interconnector (UK) Limited | Zeebrugge and Bacton | 25.5 | 74 |
| Langeled Pipeline | Gassco | Nyhamna and Easington | 25.5 | 72 |
| BBL Pipeline | BBL Company | Balgzand and Bacton | 16 | 48 |
| Vesterled Pipeline | Gassco | Heimdal Riser Platform | 12.3 | 39 |
| Tampen Link | Gassco | Links Statfjord to FLAGS (terminating at St Fergus) | 9.1 | 27 |
| Gjøa Pipeline | Gassco | Links Gjøa/Vega to FLAGS and St Fergus (terminating at St Fergus) | 6.2 | 17 |
| | | **LNG Import Terminals** | | |
| South Hook | Qatar Petroleum and ExxonMobil | Milford Haven, Pembrokeshire | 21.2 | 58 |
| Isle of Grain | National Grid Grain LNG | Isle of Grain, Kent | 20.5 | 56 |
| Dragon | BG Group and Petronas | Milford Haven, Pembrokeshire | 7.6 | 24 |
| Teesside GasPort | Excelerate | Teesside | 4.2 | 11 |
| | | **Export Pipelines** | | |
| Bacton-Zeebrugge Interconnector | Interconnector (UK) Limited | Bacton and Zeebrugge | 20 | 58 |
| UK- Irish Gas Interconnector (IC1/IC2) | Bord Gais | Moffat and Ireland | 8.4 | 31 |
| Source: National Grid[24] | | | | |

### 3.3.7 Security of Supply

The rise and fall in prompt prices and along the curve provides a signal to those active in the market as to the state of supply and demand within the network. Rising prices will incentivise the increase in supply (or reduction in demand) while falling prices will do the opposite. The security of supply in Britain is therefore underpinned by the activity of the NBP.

As noted above, the GB market enjoys a large surplus of import infrastructure, much of which has been built in recent years in response to declining indigenous production. With this surplus there is much less need for storage capacity and the amounts of storage available are much lower than is

[24] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/337633/dukes4_4.xls

common in other European countries. The risk of a stored gas being depleted before the winter has ended must be acknowledged but, barring very abnormal weather or supply conditions is small.

The activities of the market are backed up by Emergency Regulations mandated by government. The regulations were built into the original design of the industry, and they allow the Secretary of State to direct all licence holders (transporters, shippers and suppliers) in an emergency. This includes requiring UKCS producers, LNG terminal operators and storage operators to comply with instructions regarding system flows. Equally, there are emergency procedures that require consumers to reduce demand. To date these reserve powers have not been put into effect.

# 4 Interaction of supply with the wholesale market

The GB gas market, so long a self-sufficient gas island, is today import-dependent and an integral part of the wider European market, which stretches from Norway to Algeria and Russia to Portugal.

Pipelines connect the GB market to northern Europe and Norway, while LNG terminals link it to the wider gas world.

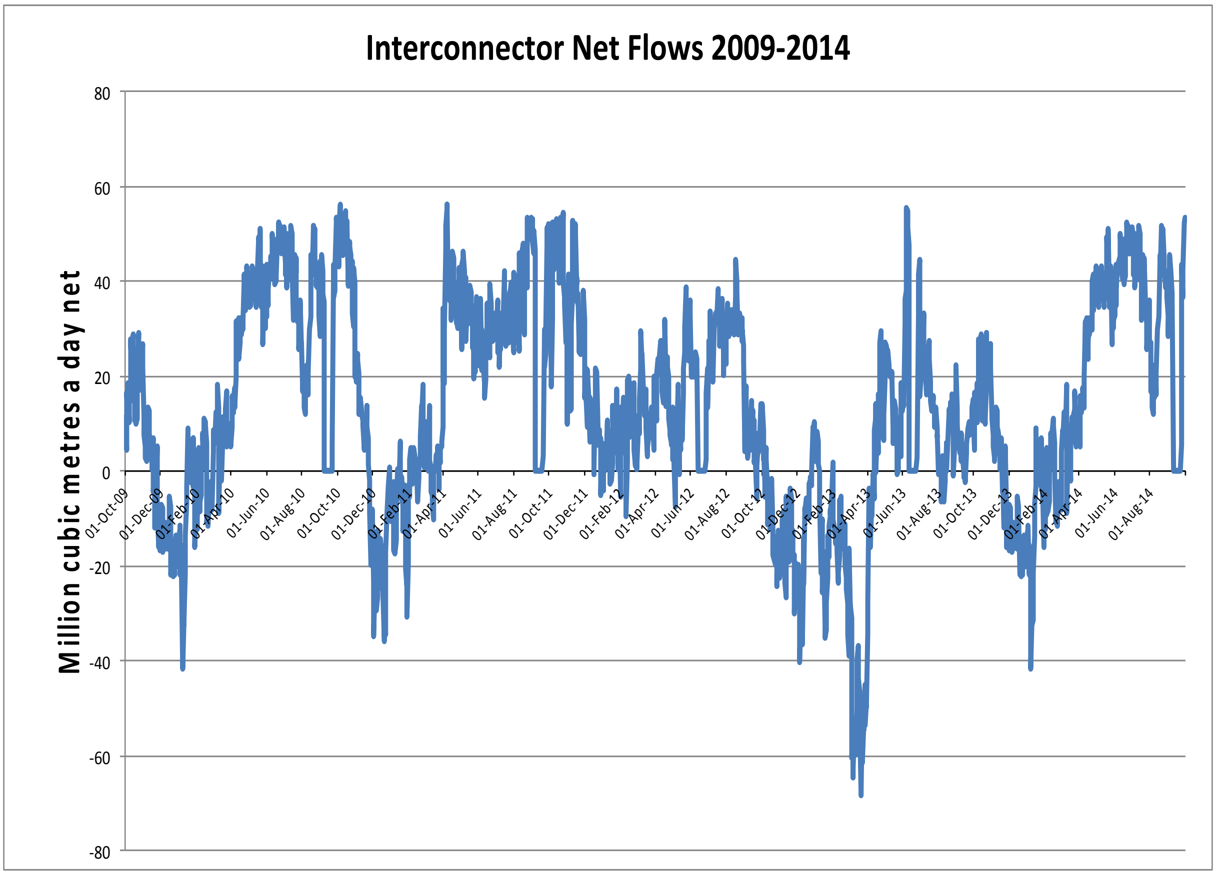
## 4.1 Interconnectors and major import pipelines

Primarily sources of imported gas, the pipelines, at times, also export gas in a price-responsive manner.

Interconnector (UK) was designed primarily to import GB gas from the continent, but developed into a bi-directional balancing tool. When demand was higher at Zeebrugge, gas flowed from Bacton, and vice versa. In a balanced market, net flows can be very low. In general, NBP and Zeebrugge prices are closely aligned.

According to Interconnector (UK), the highest recorded daily forward flow (export mode to continental Europe) was 644 GWh (equivalent to 20.4 bcm/pa) on 8 April 2011, while the highest recorded daily reverse flow (import mode to UK) was 787 GWh (equivalent to 25.5 bcm/pa) on 21 March 2013. Figure 4.1 below shows net daily flows between Bacton and Zeebrugge. Negative numbers (below the centre line) represent GB imports.

**Figure 4.1 Interconnector Net Flows 2009-2014 (source: Interconnector UK)**




The BBL pipeline is designed to export Dutch gas to the UK and was originally underpinned by an 8 bcm/pa supply contract, delivered at the NBP, between Gasterra, the largest Dutch supply company, and Centrica. For the first few years of the pipeline's operation flow was entirely physical from Balgzand to Bacton. However a virtual reverse flow facility has been introduced in order to allow shippers to net off flows into the NBP at the Dutch TTF.

Norway has emerged in the past decade as the UK's largest foreign supplier and delivers supplies via two main pipelines, Langeled and Vesterled.

The Langeled pipeline was brought online in 2006 in order to transport gas from the Norwegian Ormen Lange field into the Easington terminal. The pipeline consists of two sections, one running from Ormen Lange into the Nyhamna processing plant then onto the Sleipner East hub. From there gas travels into the southern section of the pipeline into the Easington terminal in the North East of England.  It has a maximum technical capacity of 75 million cubic meters (mcm)/day.

Due to Langeled's connection with the Sleipner East hub, which allows gas to be diverted to the continent, and a seasonal Norwegian production schedule, it tends to operate within a wide range. During 2014 the pipeline delivered to GB between 7 and 73 million cubic metres per day. The pipeline provided an average of 18% of Britain's daily supply in 2014, compared with an average of 10% in the preceding year.

The smaller Vesterled pipeline was constructed in 2001 as an addition to the Frigg Norwegian Pipeline that had been in operation since 1978. The pipeline transmits gas from the Heimdal Riser platform into the British system at the St Fergus Total entry point. It has a maximum capacity of 39 million cubic metres and it accepts gas from a number of different fields connected to the Heimdal platform.

Gas arrives into the St Fergus Total terminal combined with supplies from UKCS fields. This entry point delivered between a range of 1 and 28 million cubic metres per day in 2014.

## 4.2 LNG

Most LNG import capacity is used only when prices at the NBP are more attractive than other markets. In recent years, LNG prices in Asia and South America have been significantly higher than at the NBP and GB imports have been low, although weaker Asian demand and increased global LNG production during 2014 saw more LNG flow back to the GB market in the second half of the year. In 2013 GB imported 9.53bcm of LNG, mostly from Qatar: total LNG capacity utilization was only 19.3%. By contrast, LNG imports in 2014 rose by 21% to 11.51bcm, according to Department of Energy and Climate Change provisional data. [25] Qatar again was the major supplier accounting for 92% of all LNG supplies. In 2014 LNG imports were sourced from four countries compared to a peak of eight in 2011.[26]

## 4.3 Long Term Contracts and Indexation

Despite the growth of short term trading in the past two decades, long term gas supply agreements (LTGSA) remain fundamental to British energy security. Broadly they fall into three categories:

- Older legacy contracts, now few in number, between producers on the UKCS and large gas merchants or power generators. A few date back to the days of the British Gas monopoly. In most cases the original price and delivery terms of these contracts have been altered to reflect open market conditions.
- LTGSAs signed since 2000 for pipeline gas from Norway, the Netherlands and the UKCS. Typically these are delivered and priced at the NBP, with a degree of optionality that allows counterparties to arbitrage across British and European markets.
- LNG contracts, which allow the seller maximum flexibility in order to arbitrage global markets. The prime example is the contract between Qatargas-2 and ExxonMobil Gas Marketing, which allows the seller to deliver any volume from nothing up to the full output of the LNG facility.

## 4.4 Associated Gas

Associated gas is primarily a co-product of crude oil and tends to be "wet", meaning that it contains significant quantities of natural gas liquids such as ethane, butane and condensate, and requires processing before being injected into the transmission system. Dry gas is predominantly methane.

[25] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/406749/et4_4.xls
[26] Other LNG exporters to the GB market in 2014 were Algeria (approx. 536 million cubic metres of regasified LNG); Trinidad & Tobago (331 million cubic metres) and Nigeria (50 million cubic metres).

On the UK Continental Shelf, dry gas has been concentrated in the Southern Basin of the North Sea, off Norfolk and Lincolnshire. Associated gas is mostly produced further north and deeper offshore, where the bulk of UKCS crude oil is found. The volume of associated gas produced depends on the volume of oil, and the proportion actually delivered into the onshore GB market depends on other factors, such as the use of associated gas as an offshore fuel. Unlike dry gas, which lends itself to flexible production, associated gas tends to be produced at a steady rate.

17.96bcm of associated gas was delivered to shore in 2013, down from the peak of 58.81bcm in 2002. Associated gas accounts for more than half of marketed indigenous production, which suggests it may be vulnerable to accelerated field closures due to a prolonged period of low oil prices.

### 4.5 Shale Gas

To date, no shale gas has been produced in GB. Exploratory drilling has barely begun in the most prospective areas, such as the Fylde coast of Lancashire. Nevertheless the resource appears substantial. The British Geological Survey takes a cautious view, although it notes the high potential of the source rocks. Commercial explorers are more optimistic. Cuadrilla plc, for instance, estimates that there are 200 trillion cubic feet (5.7 trillion cubic metres) of gas in place in its licence area in Lancashire. 5.7tcm is more than double the total amount of gas ever produced from the UKCS, but only a small part of this is likely to be technically producible. It has been suggested that a10% ultimate recovery rate may be a reasonable assumption in light of US experience. While the geology and economics have yet to be proven, in principle the GB shale resource could provide a significant addition to national reserves and important source of domestic production, improving security of supply.

## 5 Supply Costs

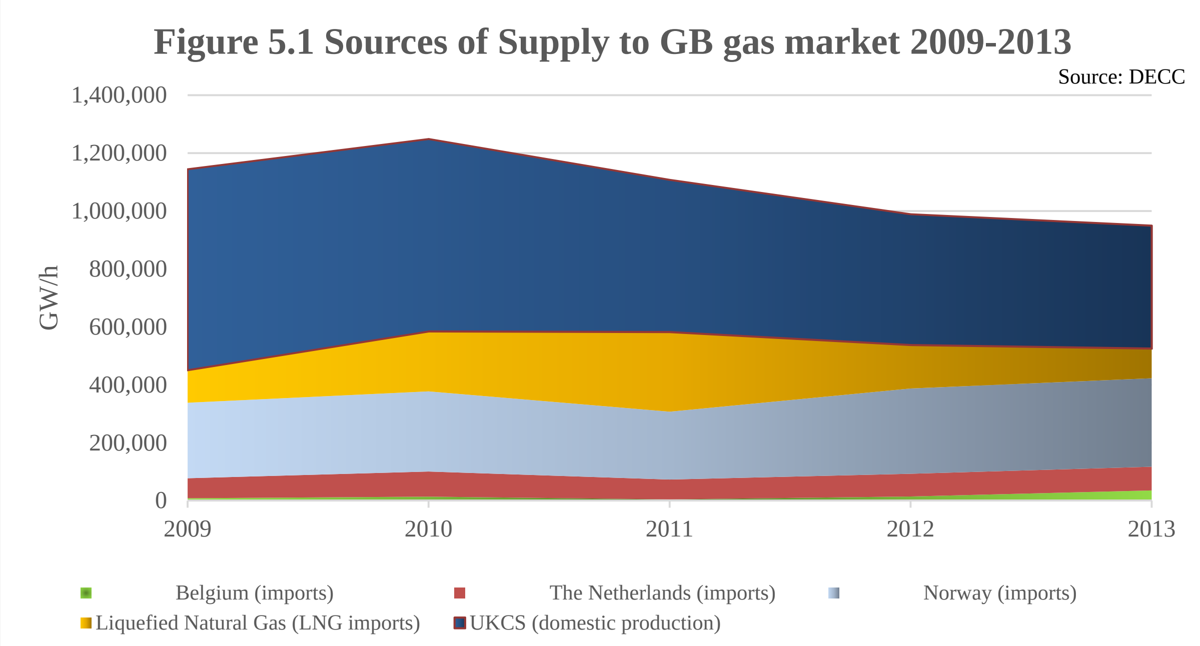
The benchmark cost of gas supply on the GB wholesale market is represented by the prompt NBP gas price, typically the forward month (M+1) index. However, the costs incurred by the suppliers may have been built up over months and even years by a supplier's hedging strategy (see section 9).

On average, about half the gas delivered at the NBP is produced from British fields and half is imported. In periods of peak demand in the winter, domestic gas is usually produced at or close to capacity, which makes the country particularly reliant on other sources. In general British consumers can have a high degree of confidence that market mechanisms will deliver required supply at prices in line with those in Europe and beyond. However some sources may be vulnerable to technical or even political factors.

The five main supply components consist of:

- UK Continental Supplies (UKCS)
- Norwegian imports
- LNG imports
- Continental imports
- Storage

Figure 5.1 below shows the main supply sources to the GB market between 2009 and 2013.




A full description of the costs of the each of the main supply components is provided in Appendix 2

## 6 Trends in Supply

The downward trends in GB gas supply and demand are partly structural and partly governed by markets and prices. The structural trends are:

a) The 67% decline in annual UKCS gas production since 2000.

b) The 22% fall in gas demand since 2008; this is due in part to improved energy efficiency and conservation measures taken by consumers and also to demand destruction in the industrial sector, but it has been made worse by market factors, with cheap coal displacing gas in power generation.

c) The increase in renewable energy which has restricted the scope for gas (and other fuels) in power generation.

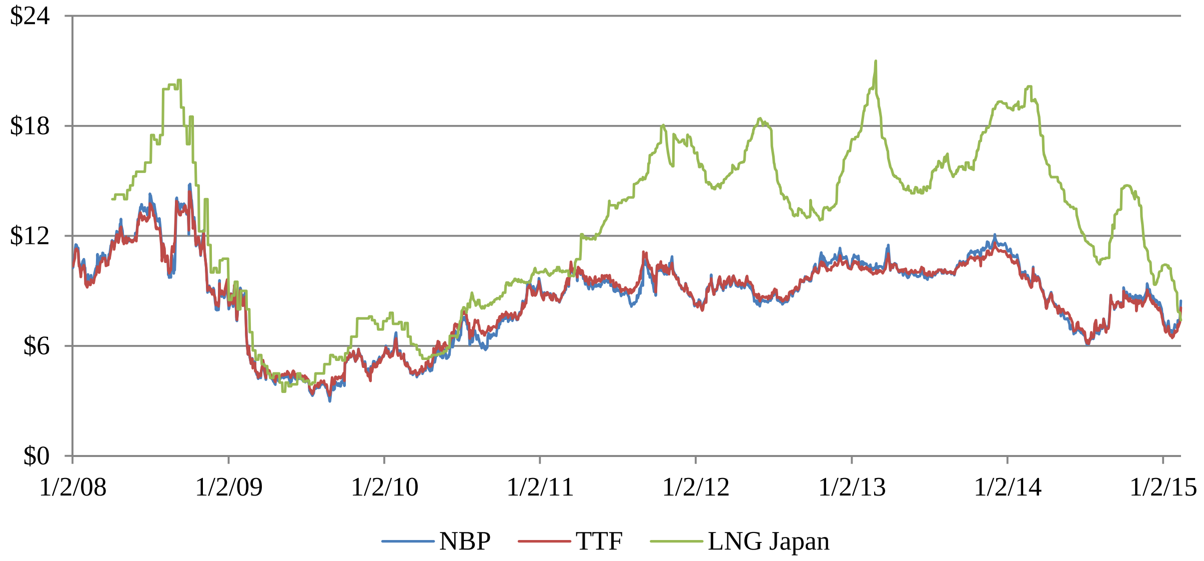
Principal market trends are:

a) The increasing liberalisation of interconnected EU markets, which has improved mutual cross-border trade.

b) The globalisation of LNG trade, with GB imports governed to a large degree by price signals from Asian and American markets.

c) The rise of US shale gas production has left more LNG available in the market and has also resulted in lower global coal prices.

**Figure 6.1 Selected global market prices 2008-2015** (source: ICIS)




Gas demand has fallen by more than a fifth since the start of the economic recession in 2008, with some energy intensive users closing their GB sites altogether and others severely cutting operations. In addition, consumers have intensified efforts to conserve energy, notably through more efficient domestic insulation.

Since 2008, gas use has declined sharply in electricity generation, giving way to coal and, to a smaller extent, wind and other renewable technologies. The shift is due primarily to the availability of cheap coal from the United States, where low cost shale gas forced coal out of power generation and on to the world market. The trend was exacerbated by the low cost of EU carbon trading certificates.

Gas production recovered fractionally in 2014, due to the start-up of two new North Sea fields, but remains little more than a third of its 108.4bcm peak in 2000. The fall in global oil prices during the second of 2014 and in early 2015 has added pressure on UKCS producers to cut costs or defer investment. This may exacerbate already falling UKCS North Sea gas production and increase the requirement to import.

In 2014 net imports were down by 11.4%. Pipeline imports fell by 19.2%, while LNG imports rose 21%, with Qatar accounting for 92% of LNG imports.

Norwegian and Dutch pipeline gas provides the bedrock of GB gas imports. Gas supplied from Belgium via Interconnector (UK) does not have a specific origin but can be regarded as West European market gas. LNG supply is price-elastic, as was seen with the diversion of LNG cargoes away from GB (and other western markets) to meet Japanese demand.

A less noticed feature of the supply picture has been the resilience of UKCS flexible gas production, which means that a higher proportion of peak demand – up to 45% - continues to be supplied by offshore fields than would be indicated by the annual statistics. In addition, GB storage facilities operate at high level of economic efficiency.

# 7 Response of Price to Demand and Supply Balance

The most significant drivers of the NBP price are supply and demand fundamentals. The actual or perceived availability of gas and, inversely, the real or forecast consumption of the commodity, drive prices higher or lower from minute-to-minute within a trading day. The ability of the market price at the NBP to react exceptionally quickly to sharp changes in either supply or demand ensures that gas will always flow to consumers.

Because of the transparency of information concerning supply and demand in Britain and the large number of participants trading the commodity, the liquid NBP price ensures a balance between the two is always met, without the need for significant physical intervention from an operator. This market homeostasis, or equilibrium to supply-security, is driven by the moving price.

The volatility in the price of a given delivery-contract, because of demand and supply, can be subtle and short-lived in some instances, but can also be significant and long-term. Particular developments regarding supply and demand may also have differing results on various contracts, depending on their delivery in the future. Some changes to supply and demand will impact a limited number of market participants, while other developments may impact all counterparties. Typically there is a proportional link between how great a price move can be, to the number of shippers affected by a change in supply and demand.

Given the nature of British demand – which is intrinsically linked to temperature and therefore highly seasonal – historical or statistically normal consumption patterns are the cornerstone of a price of a NBP contract, regardless of whether it is a product for next-day delivery, or for four years in the future. This is because in the last three full gas years, heating in the commercial and residential sectors (as measured by local distribution zone demand) has constituted on average 44% of all gas consumed in Britain during the six summer months, and on average 67% during the six winter months.

Supply on the other-hand – and the need for it to always meet demand – is more prone to external developments. The ability to supply gas to Britain is chiefly based on the operation of infrastructure. But developments further afield, be they political or forces of nature, can similarly impact the availability of gas to the NBP.

The greatest and sharpest price movements are caused by short-term shocks to the British market, which require almost-immediate reaction by participants. The most pronounced spike in recent years, in March 2013, came as factors impacting both supply and demand hit the market in tandem. A market participant's willingness to contract at any particular price will depend in large part on the expectation of the costs of being out of balance under the Uniform Network Code.

A full description of response of price to demand-side and supply-side drivers and linepack balance can be found in Appendix 5.

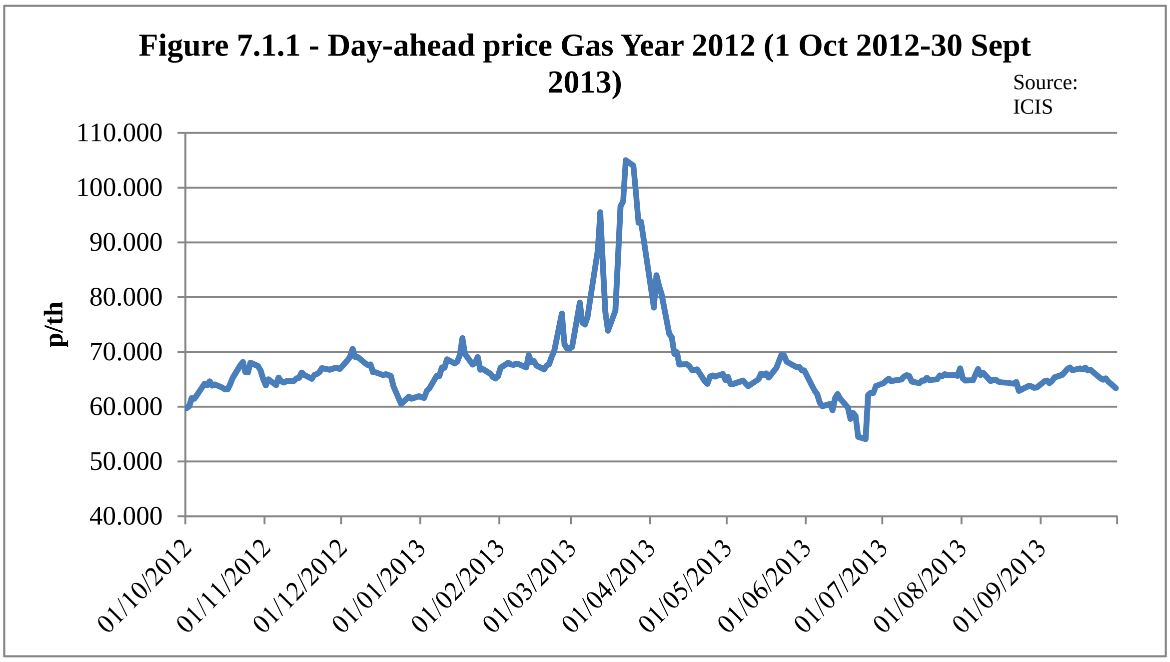
## 7.1 The responsiveness of the NBP to rising demand and reduced supply

The long-term NBP price has demonstrated resilience to individual supply or demand events. However, those individual supply or demand events can have a greater impact on short-term NBP prices.

This is logical given the GB market's ability to attract gas from other sources, particularly LNG. However, this can take some time as LNG vessels may have to divert from other global markets at short-notice.

Pipeline gas can be diverted at short notice from connected European markets. However, in order to do so, the GB market must pay a premium to cover transportation costs and an incentive for European utilities to release volume.

March 2013 demonstrates the responsiveness of price to extreme demand and supply conditions. The particularly cold winter of 2012/13 had already depleted storage stocks to very low levels. A cold snap then coincided with an unplanned outage on the Interconnector (UK) pipeline, linking Britain to Belgium.




With prompt prices high in the run-up to the event, the Interconnector had already been delivering gas above its nameplate capacity, supplying 21% of Britain's daily demand with flows from the European mainland. In addition most GB producers were running at close to maximum capacity. The failure of the pipe meant a combination of additional supplies and reduced demand had to be incentivised to bring the system into balance.

The outage occurred at 07:00. During the morning the Within-day contract had traded up to a high of 150p/th, with the Day-ahead contract rising to 124p/th. By the end of the day the Day-ahead contract had fallen back to 105p/th; 7.525p/th higher than the previous close.

Although the market was already spiking in response to low storage levels, the further price rise in reaction to the Interconnector (UK) outage clearly demonstrated the further response of price bringing forward increased supply and reduced demand to achieve a supply balance. This is an efficient market response. In some other European markets that have little liquidity, the required response would have been to utilise strategic stocks and to cut supplies to some industrial users. The costs of developing and maintaining strategic storage are considerable, and these have been unnecessary in GB due to an effective market-based response mechanism.

# 8 Liquidity and Forward Pricing

This section will examine the various methods of measuring liquidity and compare liquidity in the British wholesale market with other European and international wholesale gas markets.

## 8.1 Historic Trends

The Competition and Markets Authority defines a product as liquid "if it is possible to buy it without causing a significant change in price".[27] This definition leaves open the question of how much one should be able to buy without having a significant impact on price for the product to be considered to be liquid? This shows that there is no standard method to measure liquidity across financial and commodity markets. The most commonly used liquidity measures in wholesale gas markets are the churn ratio and the bid-offer spread, supported by other indicators such as traded volumes, the range of traded products, the extent of forward trading and the number of market participants.

The churn ratio is the measure of the average number of times that a unit of the relevant commodity is traded on the market before it is actually delivered to a final buyer. With respect to wholesale natural gas markets, the most common measurement is the gross churn rate, which is the ratio of traded gas volumes in the relevant market to physical gas deliveries.[28]

Usually in liquid markets, the traded volumes are several times the physical consumption of the traded commodity. This reflects the fact that the ownership of the gas in the wholesale market is passing from counterparty to counterparty as it moves down the supply chain. With no trading and optimising of positions we would expect title to transfer just a few times (e.g. producer to shipper to end user). However, we expect shippers in the GB gas market to trade gas to balance the inputs and outputs of the GB gas network. This trading is helpful in ensuring that the GB gas network remains well supplied.

A churn rate of 10 is generally considered to be the minimum value at which wholesale gas markets may be considered liquid[29], although national energy regulators across the European Union, working under the Agency for the Cooperation of Energy Regulators (ACER) umbrella, have set a churn ratio of 8 as one of the threshold criteria of a functioning wholesale gas market under its 'Gas Target Model'. [30]

The most commonly used indicator of the transaction costs associated with trading is the bid-offer spread (i.e. the difference between the price a seller can expect to receive and the price a buyer

[27] Competition and Markets Authority: Paragraph 88 Energy Market Investigation Updated Issues Statement 18th February 2015
[28] The gross churn rate in a GB context includes all OTC and exchange trades, but does not include volumes delivered under long-term contract.
[29] See Jonathan Stern and Howard Rogers, 'The Transition to Hub-Based Pricing in Continental Europe', Oxford Institute for Energy Studies (2011).
[30] The Gas Target Model is a structural framework that sets out how a functioning and integrated European gas market could emerge. Details of the model and the criteria can be found on the website of the Agency for the Cooperation of Energy Regulators: http://www.acer.europa.eu/Gas/Gas-Target-Model/Pages/default.aspx

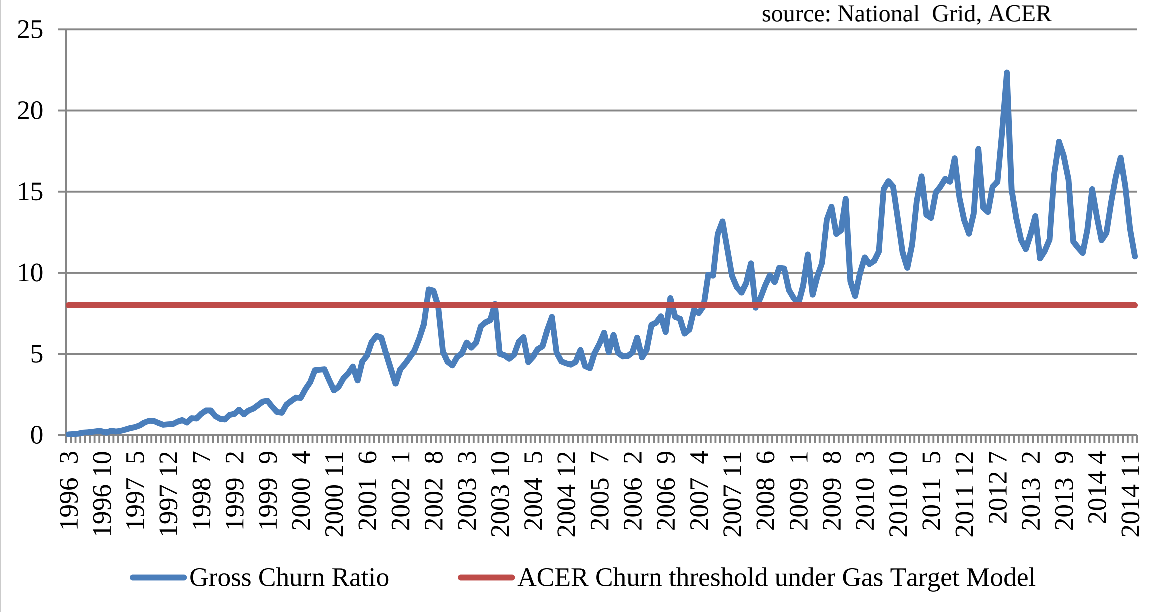
must expect to pay), which provides an estimate of the implicit trading cost sustained by market participants.

The number of products available for forward trading, and the depth of trading on those products are also important liquidity indicators. The number of participants is another useful measure and is discussed in section 2.

Historically, trading activity in the British wholesale gas market rose steadily following the introduction of the Network Code and creation of the virtual NBP hub in the mid-1990s. The major production expansion in the Central North Sea caused a sharp drop in spot gas prices for third-party customers, and this, allied to the regulatory certainty provided by the Network Code, encouraged more participants to trade at the NBP.

The aggressive market making activity of US-based trading houses such as Enron, who took large short positions in the expectation of falling prices, was a key factor in enabling liquidity to build, with the churn ratio rising from below 1 to around 7-8 over a four year period from mid-1998 to mid-2002 (see Figure 8.1 below).

**Figure 8.1 NBP OTC Gross Churn Ratio 1996-2014**




Market liquidity was impacted by the collapse of Enron in 2001 and energy group TXU Europe (which also operated one of the seven main UK electricity generators) in October 2002. The withdrawal of two major trading entities from the wholesale market and the stricter trading guidelines imposed by other market participants ensured that there was no risk of contagion as other US trading companies exited GB and European gas and power markets, but it temporarily constrained the growth in liquidity that the NBP had experienced over the previous four years.

Between late 2002 and 2005 trading volumes were range-bound, as market participants largely confined their activities to trading on the prompt and near curve products, and limited their financial exposure to longer-dated contracts.

From 2006-2007, market liquidity began to recover and traded volumes grew significantly as European utilities, seeking to diversify their portfolios, purchased UK gas and power assets and began to increase their trading activities in the wholesale gas market. Large financial institutions, such as Goldman Sachs, JP Morgan, Barclays Capital and Bank of America Merrill Lynch, also stepped up their OTC trading activities, often acting as counterparties to large utilities and industrial consumers looking to hedge long-term deals, and therefore providing confidence and liquidity to the far curve.

OTC traded volumes and churn rates quickly surpassed the levels seen in mid-2002 and by the end of 2008 the churn ratio was consistently above 10. The 2008-09 recession itself had little impact on overall trading volumes, although subsequent regulatory changes – such as the introduction of Regulation on Energy Market Integrity and Transparency (REMIT) in October 2011 – and the withdrawal of a number of investment banks from European wholesale gas and power markets, has led to a shift in trading activity, with regulated futures trading on the exchange increasing its share of overall trade at the NBP.

While existing liquidity levels in Europe continue to rise, concerns have been raised by market participants that tightening financial legislation risks reducing liquidity and may discourage participation in the market.

## 8.2 Expected Liquidity in Competitive Markets

Governments and regulators worldwide recognise the importance of liquidity in wholesale markets underpinning truly competitive retail markets. The European Union has placed well-functioning wholesale markets at the heart of its energy strategy. It has provided resources to the Agency for the Cooperation of Energy Regulators (ACER) to create a model of a well-functioning gas market against which to compare the national and local trading venues.

The European Gas Target Model (GTM) was first developed in 2011 for this purpose and was updated in January 2015. It seeks to facilitate the emergence of a pan-European integrated, transparent and liquid wholesale market. ACER has recognised that liquidity is vital for the cost effective management of market risk.

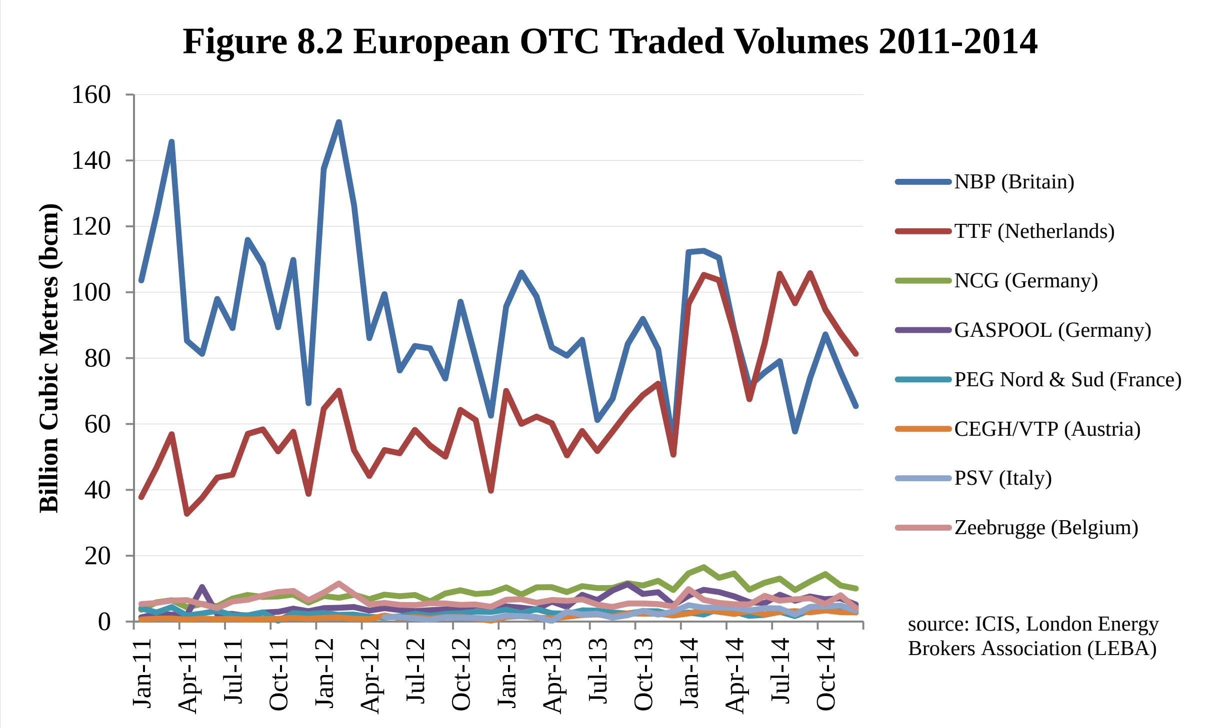
## 8.3 Traded Volumes and Churn Ratio

Volumes traded in the British wholesale gas market remain significantly higher than in other European energy markets, and the British and Dutch wholesale gas markets are the only two European trading venues to pass ACER's churn ratio target of 8 as part of its Gas Target Model.[31]

Figure 8.2 below shows the clear divide in liquidity between the British NBP and Dutch Title Transfer Facility (TTF) hubs and other European gas markets. Traded OTC volumes at the NBP stood at just over 1,000bcm in 2014, corresponding to a gross churn rate above 10. This was almost seven times

[31] The British wholesale gas market is the only European market to meet all five of the 'Gas Target Model 1'. criteria set by ACER. The other criteria includes: a market zone with a gas consumption above 20 billion cubic metres per annum; the ability to source gas supplies from three or more countries; a measure of market concentration of less than 2,000 based on the Herfindahl Hirschman Index; and a Residual Supply Index (Share of consumption which can be met without largest supplier) above 100%. Full details of the criteria can be found here: http://www.acer.europa.eu/Media/Events/3rd-Gas-Target-Model-Stakeholders-Workshop/Documents/03.%20Boltz%20objective%20and%20criteria.pdf

that of the German NCG hub, Europe's third largest, and excluding the Dutch TTF was more than double that of other European trading hubs combined.[32]




One of the trends over the past five years has been the rapid rise in liquidity of the Dutch TTF hub, which in 2013 overtook the NBP for the first time in terms of total OTC volume traded, although the British wholesale gas market remains significantly larger if exchange volumes are included.

OTC traded volumes at the NBP have been waning since the peak in 2011, as the focus of trading activity has shifted  to continental European hubs and to regulated futures trading on the exchange. The NBP became the most important hub largely because the British gas market liberalised first, but also because it had the greatest transparency on fundamental data in Europe, with universal access to information on storage, flows, and outages. The transparency requirements of REMIT, which have now been implemented at the European level, provide greater confidence in other markets. As Germany and the Netherlands are now trading actively, and market liberalisation and wholesale trade spreads across the continent, the importance of Euro denomination rather than sterling has also, to a degree, eroded the influence of the NBP OTC market.

The British NBP, however, remains Europe's largest wholesale gas market by some distance, with futures trading on the exchange growing strongly since 2010. Futures trading on the exchange (not

[32] Total OTC traded volumes in 2014 was approximately 436 bcm on a range of European gas hubs (Zeebrugge, NCG, GASPOOL, PEG Nord & Sud, VTP and PSV), whilst the figure was 1,010bcm for the NBP (source: London Energy Broker Association, ICIS).

including OTC trades being cleared through the exchange) accounted for nearly half of total traded volumes.

The increase in traders opting for exchange trading has formed a virtuous circle, whereby more liquidity tightens bid and offer spreads and thereby encourages more trading. The increasing use of aggregator broker screens is also a factor with many brokers now offering bids and offers from exchange venues.

Exchange trading is historically more expensive, and the difference between exchange fees and the cost of trading OTC has traditionally left the latter the venue of choice for near term trading. In recent years, this difference has reduced due to three factors.

Firstly, an increased regulatory burden – including uncertainty over how the agreement to exempt physical power and gas forwards from the updated Markets in Financial Instruments Directive (MiFID II) will be implemented at a technical level in 2017 - has made OTC trading more expensive and the economics of exchange trading more favourable.

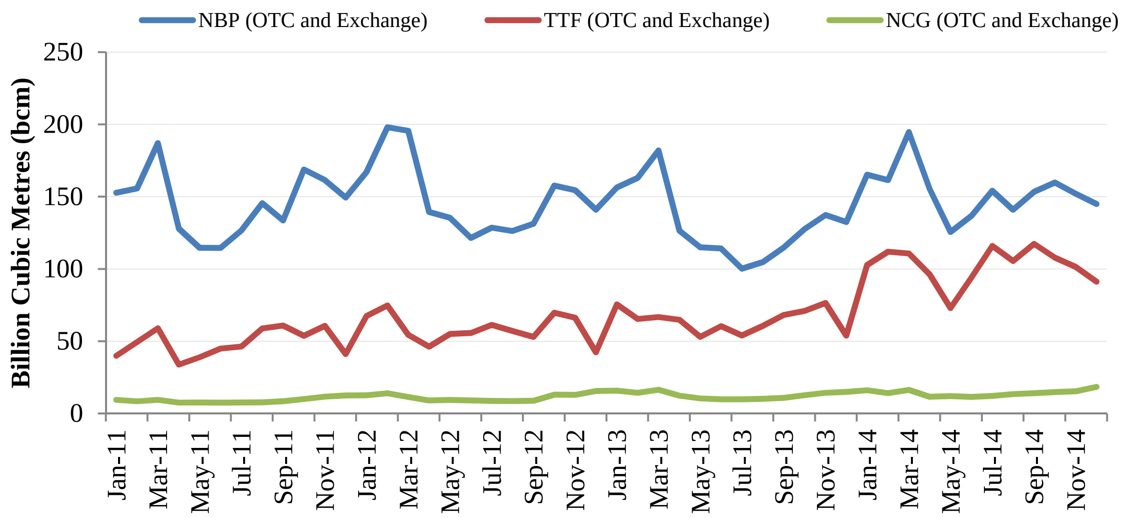
Secondly, competition between exchanges has increased, which gives participants the option to trade at lower transaction costs. And thirdly, exchange fees typically drop as more volume is traded through the venue, thus as participants trade on exchanges more their transaction costs are lowered.

Despite the three factors above, the status of the near term OTC market remains largely unaffected. Equally, the further ends of the trading curve remain largely dominated by exchange trade.

The makeup of the market has also been a factor in the growth of exchange trade as financial institutions have either scaled back from trading large trading positions or withdrawn completely from commodities trading. They have been largely, although not totally, replaced by private hedge funds who have moved to increase their activity on longer dated products. Private funds often prefer the anonymity that exchange trading provides. This has seen utilities who want to hedge their risk heading to exchanges in order to trade with the private entities.

Figure 8.3 shows the total combined OTC and futures trading on the exchange for the NBP, TTF and Germany’s NCG hubs since 2011. Traded volumes at the NBP stood above 1,800bcm in 2014, putting total volumes 36% higher than the Dutch TTF hub. The corresponding gross churn rate at the NBP was above 20 during 2014 and has consistently ranged between 15 and 25 every month between January 2011 and December 2014.

**Figure 8.3 Total Traded Volumes (OTC and futures combined) 2011-2014**




source: London Energy Brokers Association, ICIS, Intercontinental Exchange, European Energy Exchange, PEGAS

## 8.4 Bid-Offer Spread

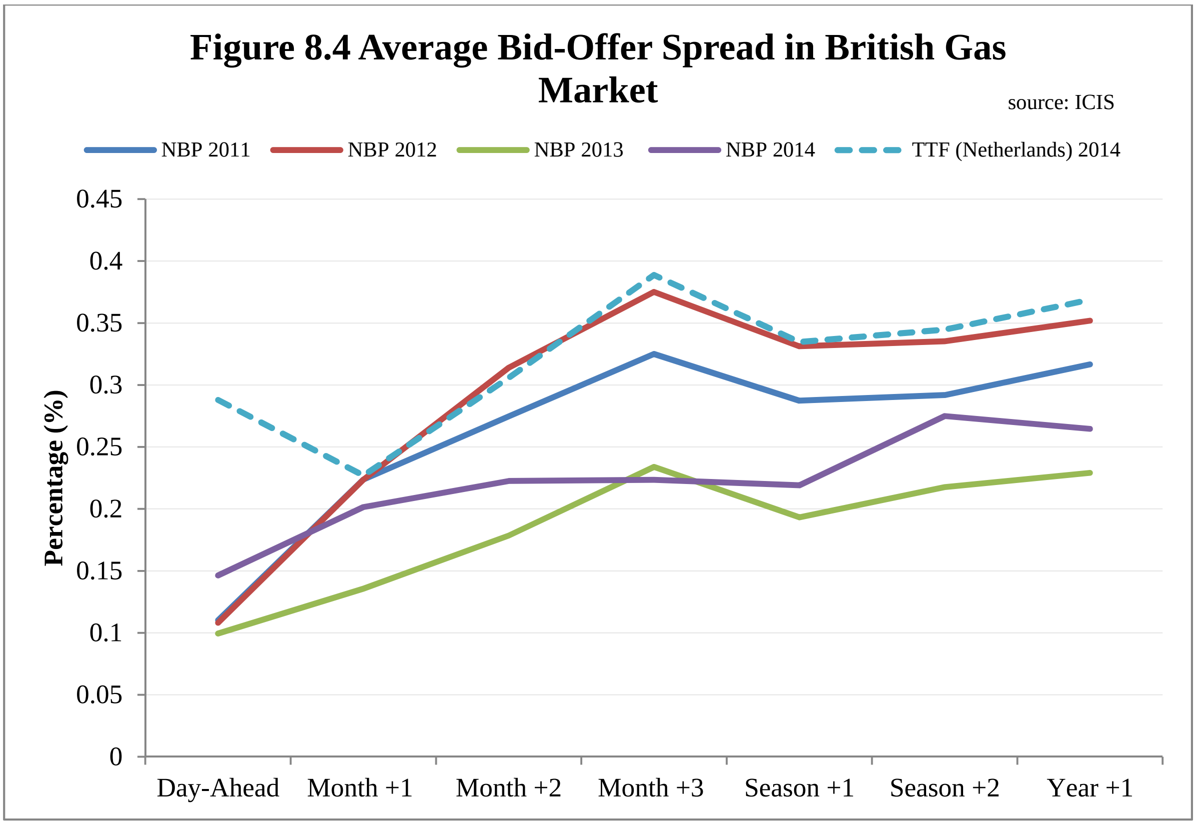
The bid-offer spread is another indicator of market liquidity. The bid represents the best (i.e. highest) price a buyer has publicly stated it is willing to pay. Conversely, the offer represents the best (i.e. lowest) price a seller has publicly stated it is willing to sell.

A tight bid-offer spread is likely to indicate active trading in a product, as well as signalling increased market confidence that participants will be able to take or exit a position with relative ease and at a low cost.

Bid-offer spreads in the OTC market in Britain are lower than in comparable continental European wholesale gas markets, and also compared to the UK electricity market. Figure 8.4 details the average bid-offer spread percentage based on ICIS Heren's closing price assessments between 2011 and 2014. Spreads range between 0.1% and 0.15% for the Day-ahead contract, rising to 0.14-0.30% for the front month and front season product, and to 0.22-0.35% for the front year.

These are higher than comparable spreads in some of the most liquid global commodity markets such as oil, but they are lower than all other European gas markets, including the Dutch TTF hub.

GB gas spreads are also considerably lower than the UK electricity market. The average bid-offer spread for the UK electricity front season during 2014 was 0.33%, which was an improvement on the 2013 average of 0.40%. However, some of this improvement in electricity spreads may have reflected the mandatory market-making obligation imposed on the largest market participants, which from April 2014 requires each to post bid-offer spreads of no more than 0.5% during two hour-long windows.




## 8.5 Forward Trading

Market participants can usually obtain bids and offers for up to six years ahead on the InterContinental Exchange (ICE) platform and around two or three years ahead on the OTC market, although liquidity is significantly lower further along the curve.

The ICE offers NBP futures contracts for 83 consecutive months, 11-13 consecutive quarters, 13-14 consecutive seasons and six calendar years.[33]

Detailed price information on the OTC market is available from a variety of sources, including the three main price reporting agencies (see Section 10); and several commodity brokers. In addition to NBP prompt contracts, PRA assessments generally extend to 5-6 months ahead, 11-20 quarters ahead, 10-11 seasons ahead and 2-3 gas years (1 October-31 September) or calendar years ahead, according to the different degree of liquidity in these contracts.[34]

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[33] The InterContinental Exchange's NBP product specification can be found on its website: https://www.theice.com/api/productguide/spec/910/pdf

[34]ICIS European Spot Gas Market methodology can be downloaded here: http://www.icis.com/globalassets/Global/ICIS/pdfs/Methodology/GasSpot.pdf
Argus European Natural Gas methodology is available here: http://www.argusmedia.com/~/media/Files/PDFs/Meth/argus_euro_naturalgas.pdf?la=en
Platts European Natural Gas methodology is available to download here: http://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/eurogasmetho.pdf

This compares favourably to other European markets assessed by PRAs, with only the Dutch TTF and, to a lesser degree the German NCG hub, having assessments that extend beyond one calendar year ahead, although coverage varies between PRAs. Spot and prompt (anything up to the end of the month) contracts are almost exclusively focused on the physical OTC market. Within this, the NBP Day-ahead contract remains the most influential OTC gas product in Europe, reacting to market fundamentals and influencing prompt pricing at other major hubs. Day-ahead OTC has tended to be immune from reductions in liquidity in recent years and often records year on year increases in activity for specific sessions or months.

Spot and prompt traded volumes have varied between 12% and 20% of the OTC market between 2011 and 2014, and around 8-13% of combined OTC and exchange traded volumes.[35]

## 8.6 Comparisons with other markets

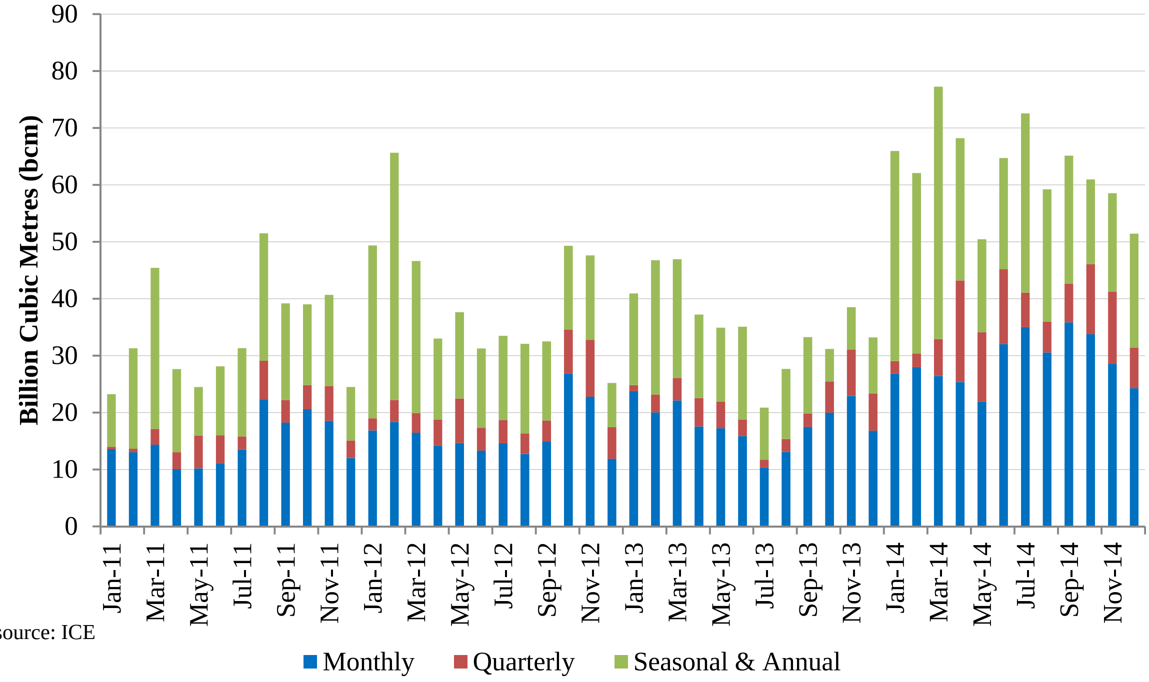
In terms of how far forward products are traded, the British gas market compares favourably with a number of commodity markets such as oil, where the vast majority of Brent oil trading is for contacts with expiry of less than 12 months.

It also compares well with other European gas markets. Around 45% of total OTC trade during 2014, for example, were settled on seasonal or annual contracts, compared to around 40% on the InterContinental Exchange (see Figure 8.6 below).

Figure 8.6 shows the exchange based trading on the InterContinental Exchange has grown by over 50% overall between 2011 and 2014, with seasonal and annual volumes growing more slowly, but still 25% higher over the four year period.

[35] Volumes based on ICIS and InterContinental Exchange data.

**Figure 8.6 Traded NBP Volumes by product on the InterContinental Exhange 2011-2014**




source: ICE

## 9 Role of Hedging

Hedging is usually defined as reducing risk by making an investment or trade with the intent of offsetting or limiting potential losses or gains from another investment. This definition would encompass insurance, but insurance is typically regarded as a separate form of risk mitigation and in this section is excluded from consideration.

Hedging will rarely eliminate all risk, but the action of the market should leave the minimum level of risk with the parties most able to manage it. For example, a gas producer may sell gas forward at the same time that it invests in a new production well (e.g. drilling new wells and investing in new rig equipment). As a result, the producer has hedged the price of its future output. However, the gas producer has created production risk, and in the event of an issue it may now have unfulfilled contracts if it is unable to produce.

The producer has also foregone the benefits in any increase in the price. Equally, it has protected itself against any fall in the price.

In the example above, the gas bought may have been purchased to hedge the risk of a large energy buyer such as a steel works, chemicals plant or public sector contract. The ability of these purchasers to fix their price ahead provides budgetary certainty and can underpin investments and commercial decisions. For example, at the same time that it fixes its energy prices, the steel works may be providing a customer with a fixed price over the same period. This kind of hedging is essential to the functioning of the UK economy and we note that government, via the Crown Commercial Service, chooses to procure the bulk of its energy need in exactly this way.

Financial derivatives are occasionally used as an additional method of reducing risk. In the GB gas market derivatives are not as commonly traded as in many financial markets or the Brent crude market. Most financial gas trading occurs on exchange platforms and is in gas futures, which may be physically delivered under specified terms. The term financial derivatives, therefore, is usually reserved for swaps (i.e. Contract for Difference[36]) and options.

Swaps, or a Contract for Difference (CFD) is a contract where one counterparty agrees to a fixed price and the other agrees to a market index price. The contract is entirely financial, and the price paid will depend on the difference between the two prices. It allows a party to swap a fixed price for a market price or a market indexed price for a fixed price. Therefore, a producer can fix the price of its output by entering into a swap/CFD.

Options are financial instruments that are used at the discretion of the party buying the option. There are two main types; a put option and a call option.

A put option allows the buyer of the option to sell an amount of gas at the agreed price at a particular time. If the market price is below the agreed price at the particular time the option will be exercised. This would allow a producer of gas to achieve a minimum price. The cost to the producer of this optionality is the option fee. This is very similar to taking insurance that the price will not fall below a minimum value.

A call option allows the buyer of the option to buy an amount of gas at an agreed price at a particular time. Similarly, if the market price is above the agreed price at the particular time, the option will be exercised. This allows a buyer of gas to limit the maximum price paid.

An efficient derivatives market performs a similar function to physical sales in reducing the risk faced by individual participants. It does this by netting off individual risks, leaving only the level of risk inherent in the market.

The buyer of physical gas or a derivative might be a Supplier of gas to retail customers. The extent to which buying gas forward is a hedge for a Supplier depends upon its customer base. Some customers may choose a fixed price contract and their Suppliers will therefore look to secure this volume in the wholesale market. Other customers may prefer to have their prices vary as the wholesale market moves. A third category may wish to have a proportion of their volume fixed and a proportion at the floating wholesale price.

In some markets, retail customers accept prices moving rapidly to reflect wholesale prices (such as petrol). However, it is generally accepted in utilities markets that customers would not want tariffs that changed every day with the wholesale market price[37]. Thus, it is part of the service offered by the Supplier to smooth those price fluctuations.

When responding to price fluctuations, different energy companies will have a multitude of approaches to hedging dependent upon their willingness to be exposed to risk and their commercial

[36] The term swap is widely used in Europe whereas the term Contract for Difference is an American term for the same instrument.
[37] Some energy suppliers offered tracker gas contracts to domestic customers in the period 2006-7, but there was little appetite for them and they were withdrawn.

strategy. Some may wish to be completely insulated whilst others will be happy to only buy on the short term market and be exposed to price fluctuations. In reality, energy companies will be somewhere along that spectrum depending on strategy and also their financial ability to buy contracts ahead of time. The suppliers' hedging strategy will alter the amount that their customers' bills are subject to near-term market price fluctuations and the time frame over which any long term price movements will be reflected in their bill.

# 10 . Independence and Accuracy of Price Reporting

## 10.1 How Reported Prices are Determined

The British wholesale gas market is highly transparent, with detailed price information available from the three main price reporting agencies (PRAs), which gather and publish anonymised and summarised price data, the ICE exchange and several commodity brokers. In addition, National Grid's On-the-day Commodity Market (OCM), which is the commercial mechanism by which the gas grid is physically balanced in real time, produces a daily System Average Price (SAP).

For commercial and contractual purposes, the dominant sources of transparency are the PRAs, which focus on the physical OTC markets, rather than the futures markets. The main PRAs are Argus Media, ICIS, a division of Reed Elsevier and Platts, a division of McGraw Hill Financial.

Although each has its own methodology, Argus, ICIS and Platts have similar approaches which are essentially journalistic. All three companies comply with the Principles for Oil Price Reporting Agencies laid out by the International Organisation of Securities Commissions (IOSCO)[38].

Each company publishes:

1. A **bid-offer price range** for delivery periods ranging from the day ahead to two or even three years forward. A bid-offer range is defined as the highest confirmed price a buyer is prepared to pay at a given time (the bid) against the lowest confirmed price a seller is prepared to sell the same commodity (the offer). The time (16:30 GMT) at which the bid-offer range is assessed is towards the close of the trading day, when market participants are finalising their daily positions.

   This method of assessing value in commodity markets uses sources of trading information gathered by telephone, instant messenger, electronic trade feeds and e-mail, which are processed and standardised.

   Reporters investigate the reasons for market price movements and cross-check information received against other data including market fundamentals. Some of which are provided by National Grid and other transmission operators such as Interconnector UK, and are updated throughout the day.

2. A **price index**, or series of indices, which are derived from transaction prices. Typically these indices are volume-weighted averages of confirmed transaction prices across the period before the Index delivery period. The most common indices are: a monthly index, which

[38] http://www.iosco.org/library/pubdocs/pdf/IOSCOPD448.pdf

includes all relevant transactions during the month preceding the delivery month; a daily index, which includes all transactions during the day before the delivery day.

Both bid-offer assessments and transaction-based indices are used throughout the industry as price benchmarks. The choice of bid-offer range or transaction-based index often reflects the particular needs of a market participant. The two methods give broadly similar but not identical results.

Indices have wide appeal because they are founded on completed market trades. The bid-offer assessment is made at a designated point in time. This 'point in time' assessment is particularly useful when comparing prices from one location to another (e.g. NBP prices to Belgian Zeebrugge prices, a key determinant of the direction and flow level of the bi-directional Interconnector pipeline), one time period to another (the spread between summer and winter prices often used for natural gas storage pricing), or to value a trader's financial position at a point in time.

## 10.2 Independence of Providers

The three PRAs active in providing transparency to the British wholesale gas market are all independent of any entity with a trading interest in those markets. They provide a service to the markets which requires them to be independent and impartial, with an overriding commitment to accuracy. PRAs have no vested interest in the level of any price that they publish, as their revenues come from subscriptions to their publications. Failure on any of these points would be fatal to their business prospects. All three companies are largely focused on price discovery across a range of markets around the globe, and have been so for many years.

## 10.3 Safeguards, Manipulation and Accuracy

The three main PRAs covering the GB and European gas markets have all accepted the IOSCO Principles for Oil Price Reporting Agencies, and all have been certified compliant with those principles.[39]

The IOSCO principles, agreed in 2012, initially addressed concerns about the integrity of oil price reporting and benchmarking. However, once accepted by the PRAs, they were extended to all the physical commodity markets which the PRAs covered, including the GB wholesale gas market.

These principles, which define best market practice, together with the economic incentive on PRAs to maintain user confidence, are key safeguards to maintaining integrity and accuracy. They guarantee the independence of the price reporter and ensure the PRAs have published methodologies for all published market prices.

PRAs do not have a formal market monitoring role. However, they have an important role in adding transparency to the markets and informing market participants. PRAs draw on information from a wide range of participants and apply robust control frameworks to safeguard the integrity of the information they publish.

[39] See Appendix 3

In addition, EU regulations have been progressively tightened since 2008. In particular, REMIT introduces significant sanctions against market participants that attempt to bias markets, including by providing false or misleading information to a PRA. In the UK, Ofgem is charged with enforcing the terms of REMIT. The regulator is able to impose financial and criminal penalties on transgressors[40].

Allegations of price manipulation are taken extremely seriously by Ofgem, the Financial Conduct Authority, the PRAs and the gas market as a whole. Price manipulation is illegal. If an important benchmark were to be manipulated, the wrongful economic effect would potentially be multiplied through the large number of supply contracts whose prices are indexed to that benchmark.

In November 2012, allegations, that on 28 September 2012 the closing NBP Day-head bid-offer range in ICIS's ESGM report had been distorted by suspicious trading around the market close at 16:30,[41] appeared in the *Guardian* newspaper and were subsequently repeated in other media, notably the BBC. It was stated that several trades had been recorded at 58 pence per therm (p/th), when the observable bid-offer level was at least 0.5p/th higher: the imputation being that these trades had been arranged in order to lower the price. Further allegations were made that this sort of illegal activity routinely inflated household energy bills, despite the trades in question being allegedly below prevailing market prices at the time.

The allegations received immediate and widespread attention in the media and at Westminster. The Secretary of State for Energy & Climate Change, the Rt Hon Ed Davey MP, made a statement to the House of Commons on the day the allegations were published[42]. The matter had already been referred to the Financial Conduct Authority and Ofgem by ICIS itself.

ICIS pointed out that it had clearly identified the issue to its readers on the day, flagging the trades as unusual and pointing out that they were below the prevailing market trend.  It explained that weeks earlier it had taken the unusual step of highlighting the issue to the regulator, as it had been 'unable to establish the cause of the trading pattern'[43].

Following a lengthy investigation by Ofgem and the FCA, the allegations published by the *Guardian* were judged to be without foundation. Ofgem, the lead agency, said in a statement that:

"It has been concluded that no evidence of the alleged market manipulation could be found and therefore that the interests of consumers have not been harmed." The two regulators took what they described as the unusual step of publicly commenting on their work because of the concern expressed by consumers[44].

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[40] https://www.ofgem.gov.uk/gas/wholesale-market/european-market/remit
[41] http://www.theguardian.com/business/2012/nov/12/gas-price-manipulation-how-it-works
[42] http://www.publications.parliament.uk/pa/cm201213/cmhansrd/cm121113/debtext/121113-0001.htm#12111384000004
[43] http://www.icis.com/press-releases/statement-on-uk-gas-market-reporting/
[44] https://www.ofgem.gov.uk/press-releases/ofgem-statement-allegations-gas-market-manipulation

Ed Davey accepted the inquiry's findings but added that the government proposed to create criminal sanctions for any person found guilty of rigging the energy markets[45].

More recently the Competition and Markets Authority concluded that "market prices are transparent".[46]

## 11 State of Competition

This report has considered the evolution of the GB wholesale gas market, and the current state of competition in this market. It has highlighted important areas for providing confidence to consumers, regulators, governments and industry participants. In particular, we have highlighted the importance of liquidity, transparency, and access to the markets as key for a well-functioning wholesale market.

- Barriers to entry and exit: The GB market operates a licencing regime for the majority of activities (see Section 3). These licences are inexpensive and there are relatively few barriers to securing the appropriate licences provided that the applicant is a reasonable and prudent operator.
- Liquidity: As outlined in Section 8, the GB market benefits from a healthy degree of liquidity as judged against the ACER Gas Target Model. It is the only European member market to currently meet all of the criteria defined under the Gas Target Model as a fully functioning gas market.
- Access to information/data transparency: The GB gas market benefits from a high degree of data and information transparency (see Sections 3.2, 7 and 10.2). The infrastructure operators publish high levels of data and information, some near-real time, some within day, and after the gas day. This information is freely and widely available to any interested party. There also exists a vibrant and competitive market in market reporting and market analysis.
- Number of participants in market: With over 200 registered market participants active in the physical over the-counter (OTC) market and over 100 participants registered on the InterContinental Exchange (ICE), the GB market has demonstrated that it is an attractive trading venue for a wide spectrum of counterparties. This includes small local cooperatives, through to large international oil and gas producers and utilities.

### Queries and questions.

For further information please contact the Chair of the working Group on david.lewis.lws@ntlworld.com

[45] https://www.gov.uk/government/news/edward-daveys-response-to-conclusion-of-investigation-in-to-alleged-uk-gas-market-manipulation

[46] Competition and Markets Authority: Paragraph 78 Energy Market Investigation Updated Issues Statement 18th February 2015

# APPENDIX 1 – Historical development of the GB wholesale gas market

## History and Evolution

The wholesale natural gas market in Great Britain (GB) operates under a liberalised, regulated model. Its structure is different to other liberalised natural gas markets in the world, including those of the United States, which liberalised before GB, or continental Europe, although the latter were nevertheless were heavily influenced by the development and success of the traded market in GB.

The process of gas market liberalisation in GB began with the privatisation and restructuring of the gas industry in the 1980s and took approximately 11 years from the removal of British Gas Corporation's monopoly in 1982 to the start of over the counter and on the exchange trading at a hub.

Figure A1.1 sets out the liberalisation process, illustrating the key milestones and regulatory decisions leading to market opening. The fundamental tenet of the process was, and remains, the separation of gas transport from gas trading, with the transport function operating on a non-discriminatory basis available to all gas traders.

Fig A1.1 Key regulatory decisions leading to market opening [47]

| | |
|---|---|
| 1982 - Oil & Gas (Enterprise) Act | • Removes British Gas Corporation's statutory first right of refusal on gas purchases from onshore and offshore fields and removes its monopoly to supply gas to large customers (defined as entities consuming more than 25,000 therms pa).<br>• Has no impact in practice, but does in theory give third parties access to the market. |
| 1986 - Gas Act | • Sanctions the privatisation of British Gas Corporation; Establishes the first regulator, the Office of Gas Supply (OFGAS). |
| 1988 - Monopolies and Mergers Commission (MMC)<br><br>1991 - Office of Fair Trading Review | • MMC recommends that British Gas Plc (BG) should be allowed to contract no more than 90% of any incremental gas brought to market and that the company should publish tariffs for commercial and industrial market. A subsequent MMC review recommends BG should be forced to unbundle into its three main divisions.<br>• OFT review finds that there was insufficient competition in the market and suggests that it was unlikely to change unless market structure changed. In 1994 , BG creates five separate units, including Transco as a ring-fenced transmission, distribution and storage operator. |

[47] The full 1982 Oil & Gas (Enterprise) Act can be accessed here http://www.legislation.gov.uk/ukpga/1982/23
1986 Gas Act: http://www.legislation.gov.uk/ukpga/1986/44

**1995 Gas Act**

- Establishes a timeline for the development of full competition in British gas market.
- Creates licencing regime which defines Gas Transporters/pipeline operators; Gas Shippers/wholesalers and Gas Suppliers/retailers.

**1996 Network code**

- Establishes procedures and rules for third party access to British network and introduces daily balancing regime
- The virtual National Balancing Point (NBP) hub is established in March 1996 and trade quickly migrates from the beach and starts to build on the hub

Following the Gas Act 1986, the Electricity Act 1989[48] (Electricity Act) privatised the formerly state-owned electricity supply industry and introduced a competitive framework for the electricity market. The Electricity Act created five major generators which owned and operated the generating stock formerly held by the Central Electricity Generating Board (CEGB), the two Scottish electricity boards and the Atomic Energy Authority[49].

The Area Boards in England and Wales were also privatised, effectively as local distribution and supply monopolies (Regional Electricity Companies or RECs), although these supply monopolies were eroded over time as retail competition strengthened later in the decade.

The generators would be free to market their electricity as they saw fit, while the RECs were also free to invest in generation.

The high voltage transmission system in England and Wales was placed in a new company called National Grid, with a remit to transport electricity for all of the new market participants, from generation or import point to the customer, either directly to large customers, or to the entry point into the local distribution network. National Grid would not be allowed to own or operate generation, but later would become the owner and operator of the gas transmission system by the acquisition of Transco (see below).

Crucially, the Electricity Act also permitted the creation of independent power plants (IPPs) as competitors to the five legacy generation companies. Seventeen IPPs were eventually built, and with one exception, they were all gas-fired. This was the genesis of the "Dash for Gas", which for the first time inextricably linked the GB gas and power markets.

Most of the IPPs turned to the North Sea for their supplies, although some signed Long Term Interruptible contracts with British Gas Corporation (BGC). Those who looked offshore met willing producers obliged, under the terms of the 1988 Monopolies & Mergers Inquiry, to sell no more than 90% of any new fields they developed to the former monopoly BGC.

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1995 Gas Act http://www.legislation.gov.uk/ukpga/1995/45/contents
[48] http://www.legislation.gov.uk/ukpga/1989/29/contents
[49] The five were: National Power, PowerGen, Scottish Power, Scottish Hydro and Nuclear Electric.

The result was a rapid increase in market prices for long term supplies from the North Sea, and a regulatory imbroglio which led to the effective withdrawal of BGC from the power station market.

Initially, the new gas buyers adopted the same approach to contract pricing as BGC had always done. For a long term contract from a particular field, they would negotiate a starting price, with annual escalation indexed to inflation, or in some cases, oil and electricity prices. There was at this stage no gas market and therefore no gas market price index. BGC had been relatively inactive in the North Sea in the preceding few years; its existing portfolio of contracts, some of them dating back to the late 1960s, being adequate to its needs. The most recent initial price for a BGC North Sea purchase contract was roughly 13p/th[50], and this provided the starting point for the new negotiations. Unsurprisingly, given the number of projects vying for gas supply, prices rose rapidly from 1990 onwards, with long term gas sales agreements being agreed from 16p/th to 24p/th.

In parallel with the emerging IPP market, the Industrial & Commercial gas market opened to competition[51]. Gas producers, sometimes in partnership with RECs, signed rudimentary transportation contracts with BGC's transportation division, soon to be rebranded as Transco, and began to take market-share from BGC's marketing arm. The regulator, Ofgas, required BGC to publish scheduled prices, which made it easy for competitors to build market share. By late 1993, BGC had ceded 28% of the contestable gas market to new entrants[52].

### The birth of spot gas trading

The first gas-fired IPPs began to come on line in 1993. The previous year, early spot gas transactions were reported. The first on record was between PowerGen, acting as seller of equity gas from the North Sea Pickerill field, to a marketing joint venture between Southern Electric and Phillips Petroleum[53]. Others followed in sporadic fashion. From early 1994, regular spot price assessments began to be published, which showed that gas was being traded at around 22p/th, higher than BGC's weighted average cost of gas (wacog) of around 19p/th[54].

Most of the 25-30 companies that were in a position to trade short term gas would only do so for operational reasons. The balancing requirements at this stage were extremely light: a shipper was supposed to balance its account with Transco every month: in practice they did so after each month's end, sometimes by trading or swapping gas with other shippers. In reality, BGC's trading arm balanced the entire market.

A few companies were interested in trading, either for its own sake or as a way of encouraging the development of more competition. The most important were the American energy merchant Enron, which operated the 1875 MW Teesside Power CCGT, the investment bank Morgan Stanley, and,

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[50] The Bruce and Beryl field contracts. See *World Gas Intelligence*, February 1990, page 2.
[51] The market for customers taking more than 2,500 therms per year was legally open to competition from 1986, although it took four years and significant regulatory action until any competitors actually appeared. BGC retained its monopoly below 2,500 th/yr (the household, or tariff, sector) until 1996
[52] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/235685/0203.pdf; see page 14.
[53] See *World Gas Intelligence*, October 1992, page 20.
[54] These assessments appeared from January 1994 in *European Gas Markets*, published by Heren Energy (now ICIS Heren), and by licence in a number of financial wire services.

ironically, Accord Energy, a trading unit established in the summer of 1994 as a joint venture between BGC and the US Natural Gas Clearinghouse.

Accord was led by experienced American gas traders. From the outset it was prepared to make a market, i.e. to offer a fair price for any proposition. In addition, Accord's 50% shareholder, BGC, provided it with extensive gas supplies from the Morecambe Bay high swing field, initially at BGC's wacog, then at cheaper fixed prices and finally on a netback basis. In other words, Accord was guaranteed a margin whatever price it sold on the open market.

The inevitable result of this BGC policy was to drive down the price of gas. During the winter of 1994/5, the price hovered just below BGC's wacog of 19p/th. In March 1995, with seasonal demand falling, the spot price began to slide. The first Heren Index published at the end of March 1995 was 14.1p/th. By the summer the price was 9p/th, and the pace of competition increased as new entrants were able to source gas on the open market at half of the incumbent BGC's wacog.

The low level of spot prices – which persisted until the end of the decade – caused structural difficulties for BGC and, to a lesser extent, for the IPPs which had entered the market in the early 90's with gas portfolios sourced under traditional long-term contract terms (see above). BGC eventually paid several billion pounds to a number of North Sea gas producers to alter the pricing terms of legacy long term contracts. Most IPPs were able to manage with supply portfolios significantly out of the market because prices in the Electricity Pool into which they sold their power output were kept relatively high by coal-fired generation, and most had long term power purchase agreements with the RECs, which were able to pass any excess costs on to their captive domestic customers until 1999.[55]

Enron however found themselves in serious difficulties with the high-priced J-Block contract (some 3.3 billion cubic metres a year) priced at around 19p/th[56]. They took legal redress, but after a lengthy struggle were forced to pay $440 million to change the pricing terms to market index.

These contractual struggles were important as they encapsulated the difficulties of moving from a once monopolistic market to competition. Their resolution also gave further impetus to the development of the competitive market.

The pace of competition prior to the 1995 Gas Act and 1996 Network Code was gradual, with the initial impetus provided by new entrants attracted to the end-user market. This included the marketing affiliates of producers such as BP/Statoil (Alliance), Amerada Hess, Shell/Esso (Quadrant), Mobil and Conoco/PowerGen (Kinetica), as well as independent suppliers such as AGAS and United Gas. The deals between these entities were bilateral and private, but by 1994 there were around 15-20 companies using a standard contract and an over-the-counter (OTC) market was in fact established, although it was still very illiquid and opaque. [57]

[55] The Electricity Pool operated from 1990 to 2001 and was priced by bids only from generators who set the price of wholesale electricity via the System Marginal Price.
[56] http://www.publications.parliament.uk/pa/ld200001/ldjudgmt/jd010404/amoco-1.htm
[57] Long, Moore, Wenban-Smith (eds), *Gas Trading Manual: A Comprehensive Guide to the Gas Markets,* London (2001).

After the chaotic early years, the development of the Network Code was the key enabler behind the further development of the wholesale gas market. Essentially the Network Code was the rulebook for transporting gas through the Transco[58] network. It came into effect in March 1996 and set out the penalties imposed on gas shippers for being out of balance. Central to this was the system of daily balancing, which facilitated the need for a short term traded market. The Uniform Network Code (UNC) replaced the Network Code in 2005 and included a number of amendments and updates to reflect the experience gained from the first ten years of the liberalised market.

The other key provision of the Network Code was the creation of the National Balancing Point (NBP), a virtual delivery point which rapidly became the focus of trading and pricing. Previously, gas trading had been located at physical delivery points. [59] The NBP is a "super-firm" delivery point. A company that buys gas at the NBP by definition receives it; the company that sells it by definition has the gas to sell. Any imbalance of a market participant with respect to their net contracted position with all counterparties is settled financially with the system operator, rather than between individual contract counterparties.

The certainty provided by the 1995 Gas Act, the introduction of the Network Code and the establishment of the virtual NBP hub, coupled with favourable market conditions, was the catalyst for more new participants to enter into market. By 1996/97, an estimated 50-60 companies were regularly trading on the NBP. These companies included Regional Electricity Companies, gas producers, merchant banks and trading houses, and, in particular, Enron and Accord, whose aggressive market making and price disclosure helped to build liquidity on the NBP.

A successful natural gas futures contract was launched on the International Petroleum Exchange[60] in 1997. In the physical market, commission brokers played an increasingly prominent role.

It is difficult to overstate the importance of the NBP in the development of the British wholesale gas market. It was created as the balancing mechanism of the Network Code, but quickly evolved into a trading hub. Many (though not all) import contracts are contractually delivered at the NBP rather than at the physical entry point. Broadly speaking the NBP's design has been replicated by other European countries when their governments have sought to create liberalised gas markets. EU law – most notably under a raft of legislation known as the Third Energy Package – calls on all member and candidate states to now establish competitive, yet regulated, wholesale gas markets that resemble the NBP.

The collapse of Enron in 2001 followed by the demise of TXU in 2002 temporarily reduced market liquidity, but the structure of the Network Code ensured that there was no loss of supply to customers and the credit controls ensured that there was no widespread contagion. Liquidity

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[58] Now National Grid Gas

[59] Physical delivery takes place at beach terminals along the coast where gas is piped ashore from the fields and processed before entering the National Transmission System. The major terminals are Bacton in Norfolk and St Fergus in northeast Scotland. Bacton, the entry point for large volumes of highly flexible gas from the Southern North Sea, was the benchmark pricing point, and NBP prices, when they appeared, were essentially the same as Bacton.

[60] In 2001 the IPE was taken over by the Intercontinental Exchange (ICE)

recovered quickly as more participants entered the British market, notably European energy companies seeking to diversify their corporate portfolios.

As of November 2014, there were 226 registered trading participants at the NBP, known as shippers, collectively accounting for 176 distinct companies[61]. These include the largest vertically-integrated utilities, independent suppliers, oil and gas producers, commodity merchants and financial institutions.

## Connection with Europe

The Interconnector pipeline between Bacton and Zeebrugge in Belgium was originally proposed by the British government as a means of securing future gas imports. By the time its construction was agreed by a consortium of major British and European gas companies, it was clear that it would be used to export surplus GB gas to the continent[62]. When Interconnector (UK) actually opened in December 1998 it rapidly began to be used as a balancing tool between the British and Belgian markets. It also played a key role in "exporting" competitive British gas market practice to the continent which in those days was still clinging to monopolistic forms of energy business.

[61] https://www.ofgem.gov.uk//publications-and-updates/list-all-gas-licensees-registered-or-service-addresses
[62] See "The Art of Speculative Engineering", *European Gas Markets*, December 1994, page 1.

# APPENDIX 2: SUPPLY COSTS

The five main supply components consist of UK Continental Supplies (UKCS), Norwegian imports, LNG imports, continental imports and storage.

## A2.1 UKCS

UKCS gas supply is flexible production that can be increased in line with demand. Therefore, even on peak days, UKCS contribution to supply tends to average 40-45% of the total. During the warmer months many of these fields operate at low levels or are shut in. Given the age of much of the UKCS infrastructure, production can be vulnerable to outages of varying lengths, especially during rough weather.

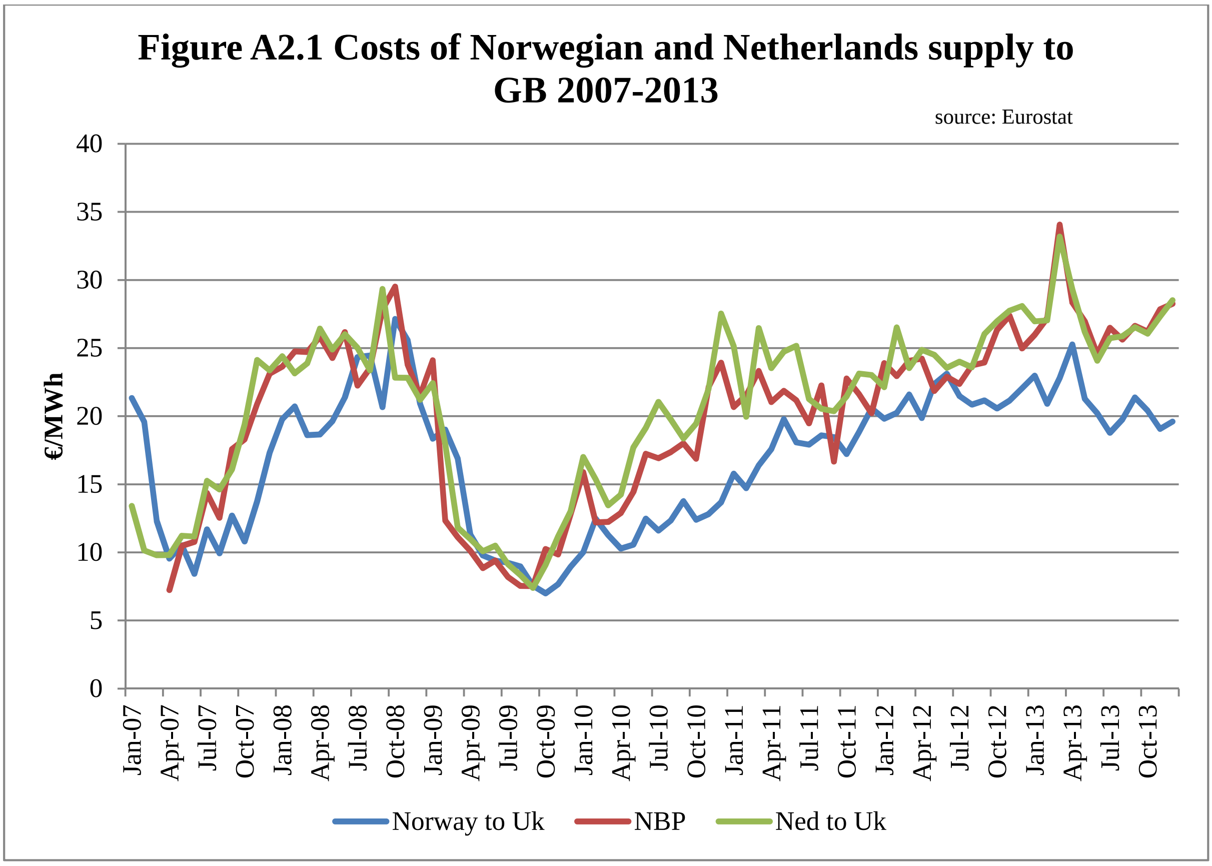
Gas delivered to shore is almost all priced on an NBP index, even that which is physically delivered to each terminal rather than virtually at the NBP. A tiny proportion of gas – probably no more than 1% - from older fields may still be priced on a legacy basis.

## A2.2 Norway

Norwegian gas accounted for 30% of GB gas supply in 2013. Norway is purely an exporter of gas, to the continent as well as to GB. Its export infrastructure is configured to give it a high degree of flexibility in its exports. Gas fields that one day are providing exports to GB may the next day be delivering to Germany, Belgium or France. Although Norwegian exports are dominated by one company, Statoil, the Norwegian gas industry is not a monolith[63]. Each producer is responsible for its own gas sales, and choices are made based on supply, demand and price across all connected markets.

Most Norwegian gas is sold at NBP prompt, either day-ahead or month ahead. However, tax and customs data suggests that some Norwegian gas sold in GB is discounted from the NBP price. This may relate to confidential terms in certain LTGSAs which were negotiated at a period when continental oil-indexed gas prices were significantly higher than UK (or continental) gas market indices. The chart below is derived from tax and trade data published in Eurostat and based in part on reporting by HM Revenue & Customs. It shows Norwegian gas sales realisations to the UK significantly falling below NBP prices as well as the realisations of Dutch exports to the UK.

[63] During the course of its investigation into wholesale electricity markets, the Competition & Markets Authority stated: "We found that Statoil is the one company that might have the ability to raise (gas) wholesale prices by withholding output in an exceptionally cold winter. However, Statoil is unlikely to have the incentive to sustain the output reductions required to raise prices. Our initial view is that the wholesale gas market is unlikely to be at risk of being subject to Unilateral Market Power. Competition and Markets Authority: Paragraph 76 Energy Market Investigation Updated Issues Statement 18th February 2015




## A2.3 LNG

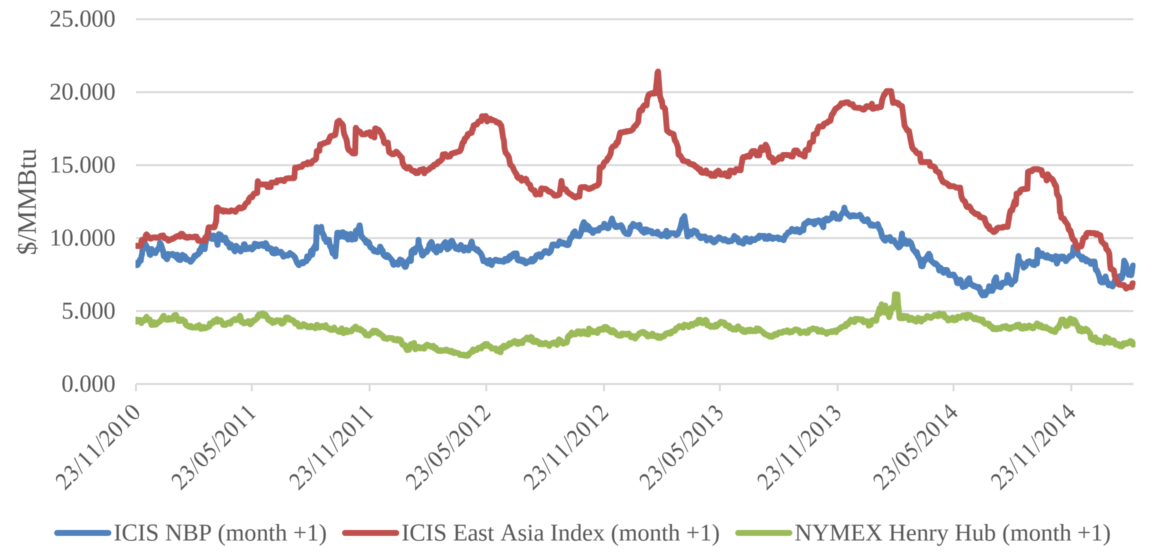
Imports of Liquefied Natural Gas (LNG) are an important but highly variable source of supply to the GB market. Cargoes of LNG are mainly delivered to UK terminals as and when the NBP price is attractive relative to other markets. Between 2011 until the second half of 2014, the volume of LNG delivered to GB declined drastically as Asian buyers ramped up their purchases and were willing to pay. The main cause of this shift was the Fukushima disaster in Japan, which caused that country's electricity utilities to shut down their nuclear fleet for prolonged inspection and maintenance, and to increase LNG imports to provide alternative generation fuel. Some South American countries, principally Brazil and Argentina, were also willing to pay a premium to the NBP price for flexible LNG cargoes to meet their demand requirements.

That trend began to reverse in 2014, and prices in the eastern and western hemispheres came back into balance. The result was that LNG imports rose by over 20% year on year in 2014 to 11.51bcm, according to Department of Energy and Climate Change provisional data, as Qatar began to ship increasing volumes of LNG to the British market, primarily via its South Hook terminal at Milford Haven.

This trend has continued through the 2014/2015 winter to the extent that Asian LNG spot prices fell below the British NBP front month in early February 2015 for the first time in almost five years, despite the corresponding NBP contract also standing at a five year seasonal low (see graph below).

Figure A2.3.1 US, GB and East Asian (spot LNG) prices Nov 2011-Feb 2015

source: ICIS, NYMEX




GB LNG Import Sources (bcm)

| | Americas | Europe | Qatar | ME/Africa | TOTAL |
|---|---|---|---|---|---|
| 2014 | 0.3 | | 7.2 | 0.22 | 7.7 |
| 2013 | 0.1 | 0.1 | 8.6 | 0.5 | 9.3 |
| 2012 | | 0.3 | 13.3 | 0.1 | 13.7 |
| 2011 | 0.7 | 4 | 21.9 | 1.6 | 28.2 |
| 2010 | 1.8 | 0.9 | 13.9 | 2.1 | 18.7 |

*Source: ICIS, BP*

Globally, the LNG market operates under two distinct but increasingly inter-related pricing systems:

1. The traditional method is oil price indexation, though in a variety of systems. In Asia, long term LNG import prices are indexed to crude oil. In parts of Europe, particularly the Mediterranean and southern France, they are still indexed to refined oil products such as fuel oil and heating oil.
2. An alternative method is to use a competitive gas market index such as the NBP or Henry Hub in the United States. However such contracts also have delivery flexibility built into them, so that, though they may be designed initially to cater to a particular market, cargoes can be diverted to other destinations when the price is right. Thus LNG cargoes from Qatargas 2, a project designed to supply the UK at the NBP price, have been diverted to Japan and other Asian markets in recent years.

The disparity in global gas pricing between premium markets in Asia and the US and Europe, coupled with LNG cargo diversion to oil-indexed markets in Asia has helped to challenge the dominance of the older pricing system. Long term oil-indexed contracts have been adapted to allow cargoes from these also to be diverted in certain circumstances.

## A2.4 Continental Imports

Pipeline imports from the continent started with the inauguration of the Anglo-Belgian Interconnector in 1998, but have become more important since the opening of BBL, the pipeline from the Netherlands in 2006. Since that date, continental markets have become more competitive, prices have aligned with the NBP, and the main European markets have become closely integrated.

Continental markets have not entirely transferred to hub pricing. Prices of perhaps half of the continent's gas imports – from Russia, Norway and Algeria – are still formally indexed to oil, despite numerous negotiations and legal arbitrations. The spread of competitive hub trading rapidly led to a situation where spot prices were significantly lower than oil indexed prices, causing commercial hardship to importers holding LTGSAs. Some – particularly Norwegian contracts - have been converted to gas index, but other suppliers, such as Gazprom, have tried to stick to oil indexation. To compensate they have paid importers large rebates and in some cases lowered the base prices used in contract formulae. More recently, the collapse in the oil price has meant that these traditional oil-indexed prices have become cheaper than price at the gas hub.

## A2.5 Storage

GB storage plays an important supply and balancing role in the NBP market. Although by European standards, British storage cover is smaller in absolute volume terms relative to consumption, the commercial structures around storage are highly developed, and storage services are tightly integrated into the workings of the gas market. Storage is a commercial product and the costs of storage are determined by the market. The availability of storage reduces the price differentials between high and low demand days.

## APPENDIX 3: IOSCO Principles for Price Reporting

The IOSCO PRA Principles are a detailed set of regulatory best practices with respect to price reporting covering governance, controls, integrity and transparency. Issued in October 2012, the IOSCO PRA Principles comprise 27 specific principles and a large number of further sub-principles across methodology, changes to a methodology, quality and integrity of price assessments, use of market data, integrity of price reporting process, assessors, supervision of assessors, audit trails, governance, complaints, cooperation with regulatory authorities and external auditing.

Principle 2.2(b) of the PRA Principles requires PRAs to:

> *"Utilize its market data, giving priority in the following order, where consistent with the PRA's approach to ensuring the quality and integrity of a price assessment:*
>
> *1. Concluded and reported transactions;*
>
> *2. Bids and offers;*
>
> *3. Other market information.*
>
> *Nothing in this provision is intended to restrict a PRA's flexibility in using market data consistent with its methodologies. However, if concluded transactions are not given priority, the reasons should be explained as called for in 2.3(b)*
>
> *c) Employ sufficient measures designed to use market data submitted and considered in a price assessment, which are bona fide, meaning that the parties submitting the market data have executed, or are prepared to execute, transactions generating such market data and the concluded transactions were executed at arms-length from each other. Particular attention should be made in this regard to inter-affiliate transactions;*
>
> *d) Establish and employ procedures to identify anomalous (i.e., in the context of a PRA's methodology) or suspicious transaction data and keep records of decisions to exclude transaction data from the PRA's price assessment process.*
>
> *e) Encourage parties that submit any market data ("submitters") to submit all of their market data that falls within the PRA's criteria for that assessment. PRAs should seek, so far as they are able and is reasonable, that data submitted are representative of the submitters' actual concluded transactions.*
>
> *f) Employ a system of appropriate measures so that, to the extent possible, submitters comply with the PRA's applicable quality and integrity standards for market data."*

## APPENDIX 4: Principal Northern European Hubs

The principal Northern European gas hubs are:

- **Zeebrugge** is best described as transit hub for gas en route either to the UK or to central and southern Europe. In addition to Interconnector UK (20 bcm/pa), it boasts Zeepipe (15 bcm/pa), a major Norwegian export line, and the Zeebrugge LNG terminal (9 bcm/pa). All are controlled by Fluxys, which also owns and operates the pipelines that transit gas to and from the Dutch, French and German borders[64]. Belgium itself is not a gas producer. The Zeebrugge Hub, a virtual trading facility, is closely aligned with the NBP, and facilitates trading into the UK and across Europe. It is operated by Huberator, a subsidiary of Fluxys[65].
- **TTF (Title Transfer Facility)** is the Dutch gas hub, established in 2002 and now rivalling the NBP as Europe's most liquid and influential trading point. The TTF is operated by the Dutch TSO Gasunie Transport Services, which is owned by the Dutch state. Trading on TTF services not only the Dutch domestic market (about half the size of GB's) but also Germany and other neighbours.
- **The Dutch industry** is based on the Groningen gas field, the largest ever discovered in Western Europe, which for fifty years has supported both the Dutch gas market and those of its Belgian, French and German neighbours. The monopolistic system originally designed to exploit this enormous resource has been progressively dismantled since the year 2000, though elements remain. Competition on the Dutch market is now strongly entrenched. Groningen's particular role has been as a swing producer, helping to meet peak demand, but in early 2015 a cap on production was introduced.[66] The balance of Dutch production comes from the so-called small fields offshore the Dutch coast.
- **NCG (NetConnect Germany):** Germany, though an active and competitive gas market, does not have a single national gas hub as do GB and the Netherlands. NCG is the larger of the two main German hubs, NCG[67] provides balancing and trading services across the networks of six gas companies, including the former Eon Ruhrgas network (Germany's largest) and two of the principal international transmission systems, Tenp (Netherlands-Italy) and Megal. Until recently the most liquid continental gas hub, NCG was surpassed by TTF in 2013.
- **Gaspool** is the second of Germany's two major gas hubs; Gaspool[68] represents six gas companies, including the networks of Wingas and VNG. Although closely aligned, Gaspool prices tend to be slightly below NCG.

[64] http://www.fluxys.com/belgium/en/About%20Fluxys/AboutFluxys
[65] http://www.huberator.com
[66] The production cap is designed to reduce the incidence of earth tremors around the Groningen field. Around 1,500 bcm has been produced since the early 1960's, and in places the ground level has sunk by three metres.
[67] https://www.net-connect-germany.de/en-gb/
[68] http://www.gaspool.de

# APPENDIX 5: Response of Price to Supply and Demand Balance

## A5.1 Linepack Balance

In the very short term, a key measure for all markets participants at the NBP as to whether supply will meet demand on any given is day is derived from forecast linepack information provided by National Grid. Strictly speaking linepack is the tolerance of the pipeline network to be literally packed with more gas, in essence acting as very short-term storage. However, market participants use this information – which is updated hourly – to judge whether supply and demand will be in balance.

National Grid calculates the linepack data by aggregating all demand-side nominations for a gas day against a collective supply-side nomination, both of which are then updated hourly. The difference between the two shows clearly if there is an expected undersupply or oversupply for that gas day.

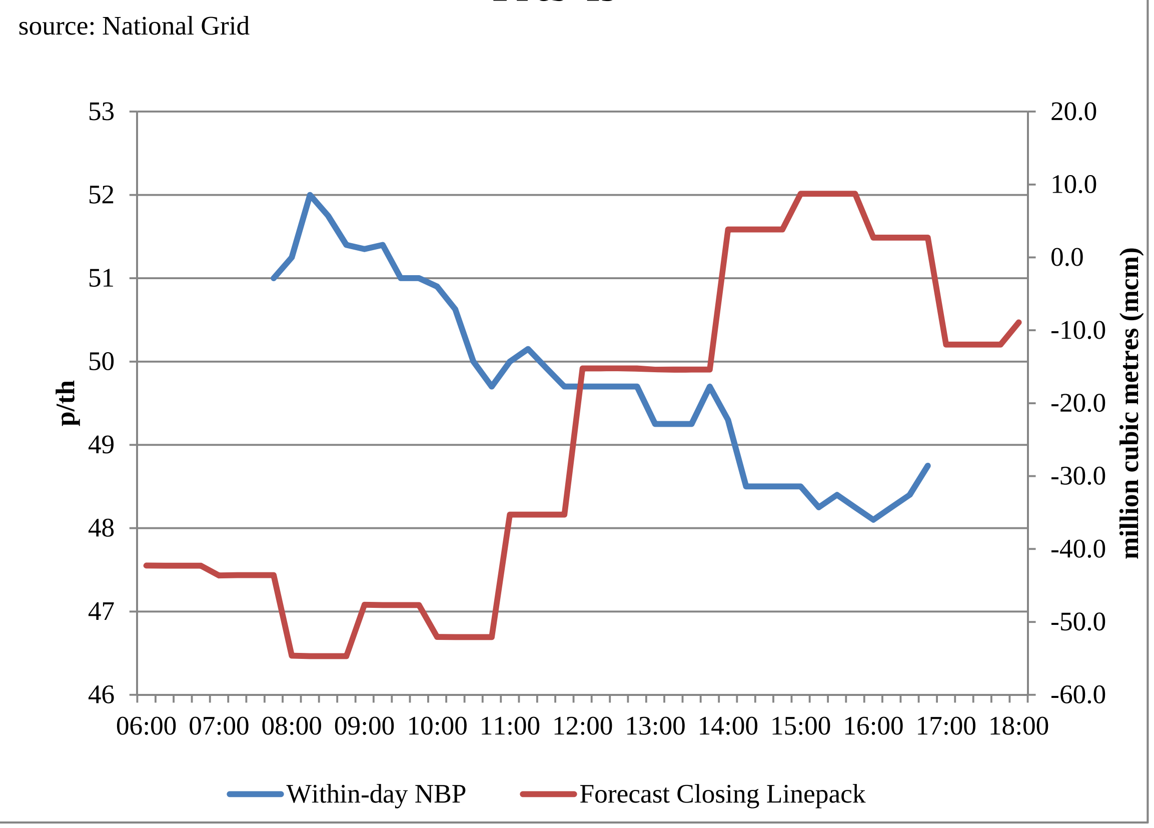
A prediction that linepack would be lower than target at the end of the day (Short predicted-closing linepack) would normally increase short-term prices, while  a prediction that linepack will be higher than target (long predicted-closing linepack) would tend to reduce prices. The Within-day contract will be the most responsive to the changes in linepack balance, although should the market consider that a causal factor for the imbalance could persist, then it is likely other prompt prices could react too.

In a situation where there is a predicted shortfall in supply, the rising Within-day price will lead counterparties with supply flexibility to sell their gas, which in turn will bring the expected outturn closer to balance. Inversely, with an oversupply scenario, those with flexible gas will reduce their throughput to the network.

Any imbalance might also be managed through altering demand, and not just supply. For example, changing the amount being injected into storage or varying the output of gas-fired power stations.

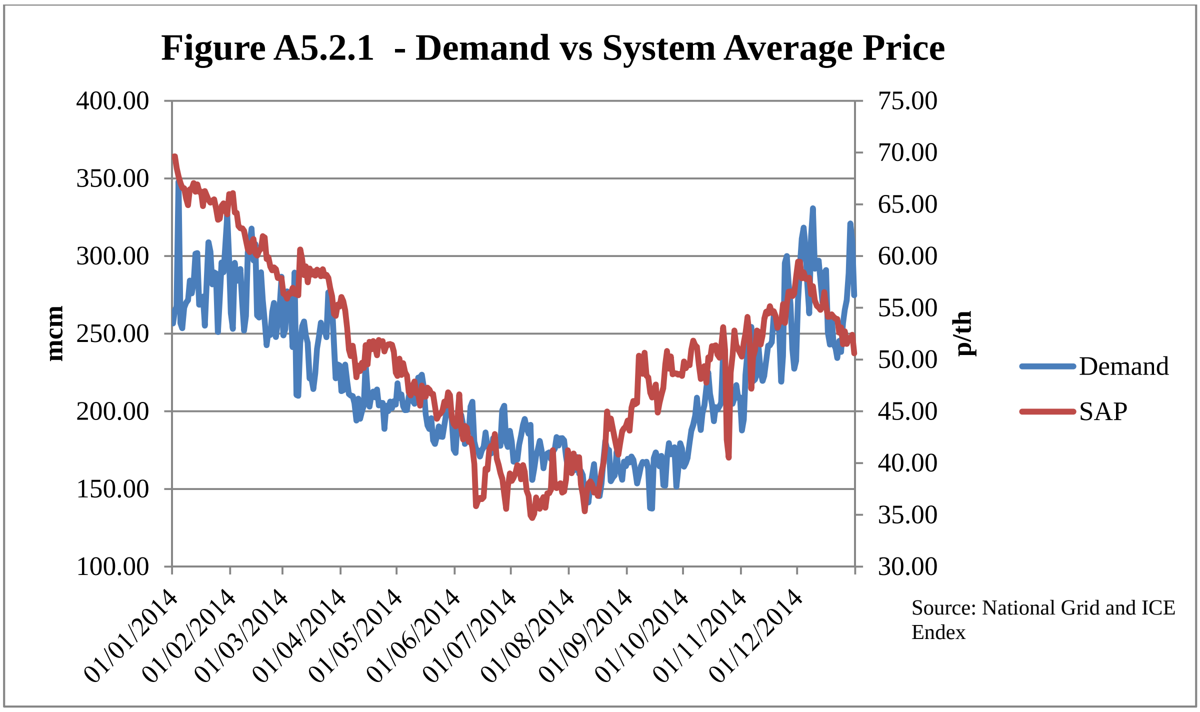
Figure A5.1.1 shows how prices react to short term supply imbalance. On 2 February 2015, forecast closing linepack (right hand axis) moved from an early shortfall of more than 50mcm, to a position of being slightly long, and then again to a slight undersupply. The Within-day NBP price (left hand axis) started high – driving the incentive for shippers to flow additional gas to the system – then fell as the predicated deficit diminished.

**Figure A5.1.1 Predicted closing linepack vs Within-day NBP price - 2 Feb '15**




## A5.2 Demand-side drivers

Weather-driven demand is the cornerstone of pricing at the NBP. Figure A5.2.1 shows the balancing market's system average price (SAP) over 2014 (right hand axis), against average British demand (left hand axis).

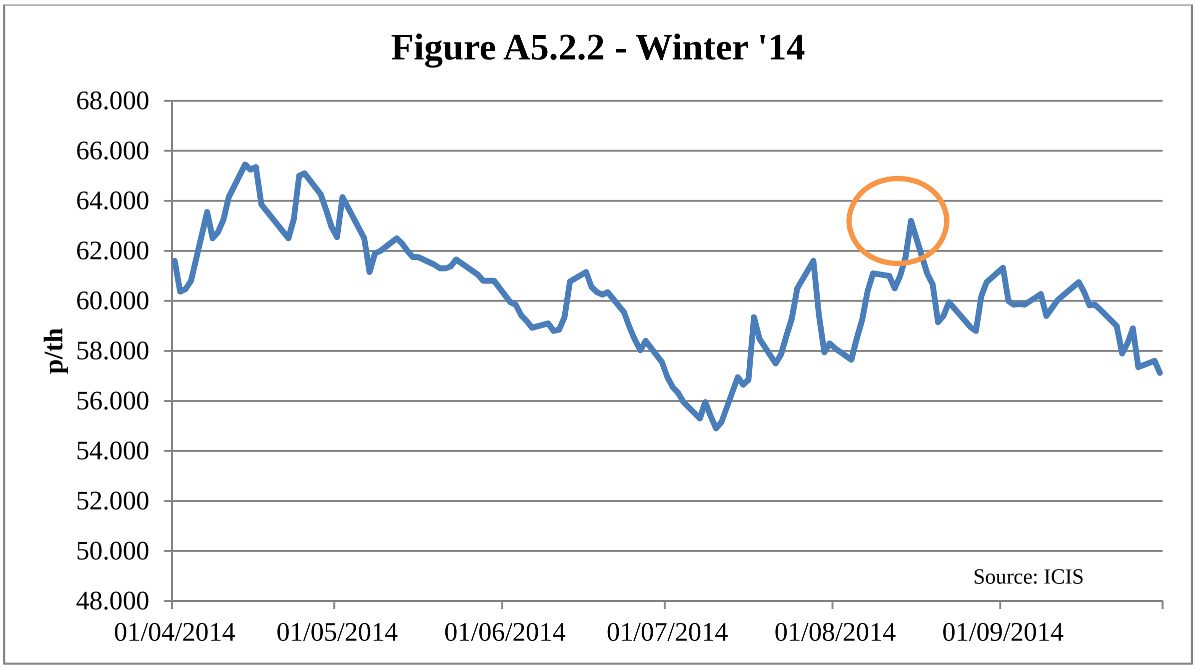



The pricing of forward or futures contracts also follows the same shape as demand, with February typically the most expensive of any single month, within a gas year.

It is important to note that during the summer, and as temperatures rise to the point of reducing almost all space heating requirements, the overall gas demand profile does not drop to close to zero. Gas demand remains for domestic cooking and water heating, from commerce and industry for both heating and as a feedstock, and from the power sector. Further, shippers expect to inject gas into storage. It is for this reason that prices are supported over the summer-months.

Gas demand from the power sector depends on a number of factors. Electricity demand tends to be higher in winter than in summer, because of lower temperatures and the need for additional lighting. However, the amount of electricity produced using gas will depend on the market prices for gas and other fuels, the cost of carbon and the availability of other forms of generation such as renewables and nuclear plant. Should the wind-forecast change dramatically over the days preceding delivery, it is likely that the price of the prompt contact will move in response. As well as variations in wind generation that can be forecast, there are potentially also very short term fluctuations. Gas-fired generation is more suited than coal-fired or nuclear for offsetting these short term fluctuations, which may affect within day prices.

A good example of forecast gas demand jumping came in mid-August 2014, when EDF Energy, in line with safety protocols, announced the closure of four of its nuclear reactors for safety inspections. The loss of these plants for an indeterminate period was not anticipated by the market. This, coupled with a number of other power plants being offline, meant that market participants expected and increase in gas demand over the winter. Figure A5.2.2 shows the winter '14 forward price, as assessed by ICIS, over the six months until its expiry. The spike in prices following the announcement from EDF Energy is clearly identifiable.




## A5.3 Supply-side drivers

As described in section 4, the GB market has a diverse array of supply sources. Some are flexible and therefore particularly price responsive, while others will typically flow regardless of price, for example associated gas.

Traders and analysts of the NBP will have a clear understanding of how these various sources of supply are priced into the market and this feeds into forward prices. When supply failures occur, or unexpected events develop, the price at the NBP will react to keep the hub in balance. The availability of transparent information allows the market to react to immediate problems with supply.

This responsiveness exemplifies the maturity and liquidity of the NBP in ensuring supply, which is not always present in smaller European markets.

Given the depth and maturity of the GB gas market, events which have a long-term effect on the supply balance of the market do not necessarily have a large long-term impact upon price. Rather the shock of the event is quickly absorbed, with the trading volumes rising around the event. Prices, however, can quickly return to levels similar to those seen before the driver being factored in. The lack of a significant increase in prices is a function of a well-connected and liquid market.

For example, in March 2012, the Elgin offshore platform, operated by French oil and gas major Total, suffered from a gas leak. Production at Elgin – and at the associated Franklin field – was stopped immediately, resulting in the loss of 15mcm/day. The outage lasted just under a year. As shown in Figure A5.3.1 the winter '12 price reacted immediately, although the support to the contract was relatively brief.

In fact the price of the winter contract hardly rose above levels seen earlier in the month. Again, the lack of a long-term reaction to a potentially long-term event is a function of the liquid market.

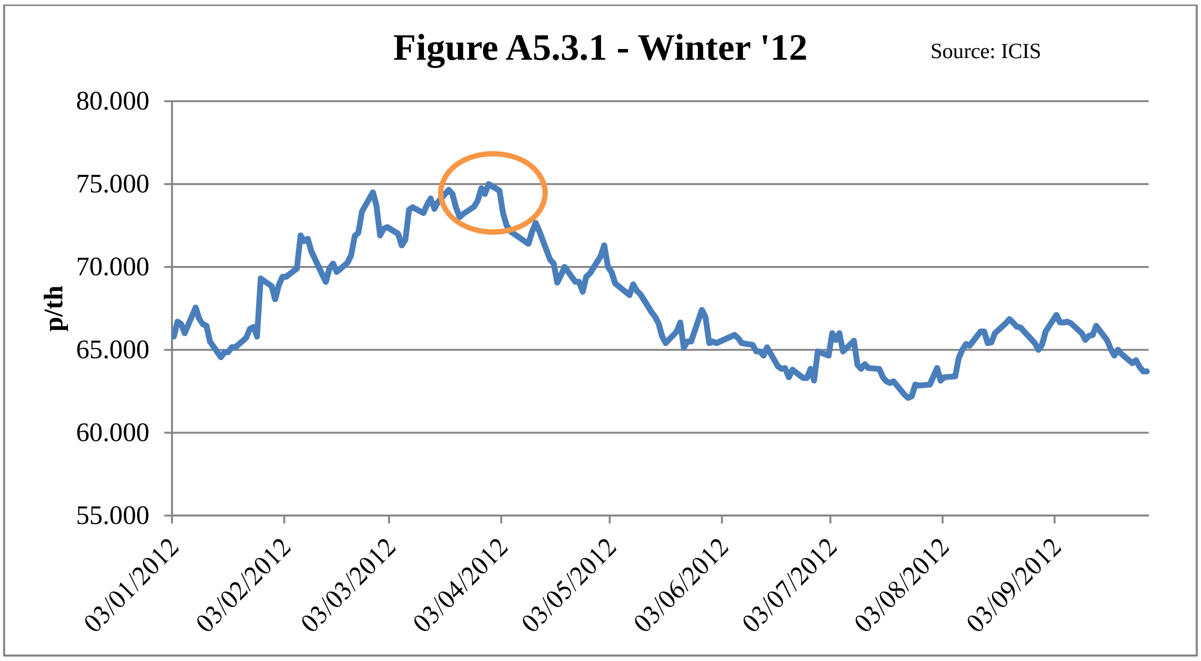


Figure A5.3.1 - Winter '12
Source: ICIS
p/th
80.000
75.000
70.000
65.000
60.000
55.000
03/01/2012
03/02/2012
03/03/2012
03/04/2012
03/05/2012
03/06/2012
03/07/2012
03/08/2012
03/09/2012

## Appendix 6: List of Working Group Participants

| | |
|---|---|
| David Lewis | Chair |
| Sarb Bajwa | IGEM |
| James Brabben | Cornwall Energy |
| Phil Broom | GDF SUEZ UK |
| Andrew Buckley | MEUC |
| John Costa | EDF Energy |
| David Cox | The Gas Forum |
| John Grant-Arrowsmith | EDF Energy |
| Nick Grealy | No Hot Air |
| Marshall Hall | Oil and Gas UK |
| Aviv Handler | ETR Advisory |
| Grant Harris | RES |
| Patrick Heren | Crown Commercial Service |
| Tomas Marzec-Manser | ICIS |
| John McPate | Hudson Energy |
| Matthew Monteverde | Argus Media |
| David Mooney | Scottish Power |
| David Moore | Gemserv |
| Charles Ruffell | RWE Supply and Trading |
| Lawrence Slade | Energy UK |
| Simon Smith | Argus Media |
| James Staff | SSE |
| Richard Street | ICIS |
| Mark Todd | Energy Helpline |
| Barbara Vest | Energy UK |
| Sam Hollister | Substitute Energy UK |
| Magnus Walker | CEL |
| Gay Wenban-Smith | Gas Strategies |
| Ben Wetherall | ICIS |
| Chris Wright | Centrica |
| Beverley Kotey | APPG Secretariat |
| Phil Royal | APPG Secretariat |

## Abbreviations

ACER: Agency for the Cooperation of Energy Regulators

BBL: Balgzand – Bacton Line

bcm: billion cubic metres

BGC: British Gas Corporation

CEGB: Central Electricity Generating Board

CFD: Contract for Difference

CMA: Competition and Markets Authority

DECC: Department of Energy and Climate Change

EFET: European Federation of Energy Traders

ENTSOG: European Network of Transmission System Operators for Gas

EU: European Union

FCA: Financial Conduct Authority

ICE: InterContinental Exchange

IUK: Interconnector UK – interconnector between Bacton and Zeebrugge in Belgium

LNG: Liquefied Natural Gas

LTGSA: Long Term Gas Supply Agreement

mcm: million cubic metres

NCG: NetConnect Germany – one of two German gas hubs

NBP: National Balancing Point

NBP97: Standard Contract for OTC trades at NBP

OCM: On-the-day Commodity Market

OFGAS: Office of Gas Supply

Ofgem:  Office of Gas and Electricity markets

OFT: Office of Fair Trading

OTC: Over the Counter

PRA: Price Reporting Agency

REMIT: Regulation on Energy Market Integrity and Transparency

SAP: System Average Price

TPA:  Third Party Access

TSO: Transmission System Operator

TTF: Title Transfer Facility – the Dutch Gas hub

UKCS: UK continental Shelf

UNC:  Uniform Network Code

VTP: Virtual Trading Point – Austrian gas hub

wacog: weighted average cost of gas

## Definitions

Associated Gas: Gas produced as a by-product of oil production. Usually “wet” including significant quantities of liquid hydrocarbons, e.g. propane and butane

CFD: Contract for Difference - an alternative name for a Swap

Cleared Trade: Anonymous trade undertaken on an exchange where the exchange acts as a counterparty

Clip: standard volume for trading gas equal to 25,000 therms

Day-ahead Contract: Contract for delivery on the next day

Exchange Traded: Cleared trade

Forward Contracts: Bi-lateral or Over-the-Counter trade

Futures: Standard contract exchange traded

Gas Day: normally 24 hours starting at 06:00 but adjusted twice yearly to accommodate clock change

Gas Shipper: Gas wholesaler

Gas Supplier: Gas retailer

Gas Transporter: Pipeline operator

Inter-dealer broker: Party that gathers information from traders and brings together buyers and sellers at a mutually acceptable price

National Balancing Point: Virtual trading point established by the Uniform Network Code

On-the-day Commodity Market: market operated on behalf of the GB gas system operator to allow shippers to balance their positions within day

Over the Counter: Bi-lateral contracts

Price Reporting Agency: A commercial organisation that gathers information about market prices and reports that information in a summarised and anonymised form, usually as either a bid-offer spread or a transactions-based price index

Prompt Contracts: Contracts for delivery within the current month

Swap: a derivative contract in which parties agree to swap an index price for a fixed price at a particular date

Third Energy Package: a package of Directives and other EU regulations governing the development of the single markets in gas and electricity

Third Party Access: Making a key asset available to all participants on non-discriminatory terms

Transmission System Operator: National Grid Gas

Uniform Network Code: Regulated contract that governs the transmission of gas through the GB high pressure transmission system