Designing and Structuring the Secondary Market, Short-term Markets and their Management Mechanisms

Task 2 & 3 Report

17TH FEBRUARY 2011

David Harbord, Marco Pagnozzi (*Market Analysis*)
Paul Carpenter, Dan Harris, David Robinson (*The Brattle Group*)

CONTENTS

1. INTRODUCTION

The *Comisión de Regulación de Energia y Gas* (CREG) has retained *Market Analysis* and *The Brattle Group* to advise on the design of secondary markets for the trading of gas and gas transport capacity in Colombia. This report describes the results of Tasks 2 and 3 of this project.

We have organised the report as follows. Section 2 discusses some key issues in the development and organization of natural gas markets from a broad analytical perspective. Section 3 provides a discussion and taxonomy of gas products typically traded and the institutional arrangements for trade, including a discussion of exchange based trading and over-the-counter trading. This section is intended to define a common language and understanding for terms that will be used throughout the project. Section 4 describes the important relationship between the definition of gas transport capacity rights, and the trading of the gas commodity. Section 5 describes the roles and responsibilities that typically occur in gas markets, and Section 6 then illustrates the previous points made by providing a detailed description of some of the most important gas markets which are functioning today, including the US and GB markets. Section 7 describes the current functioning of the Colombian gas market. Section 8 contains some preliminary conclusions on issues to be developed in the subsequent tasks.

2. ORGANIZATION OF NATURAL GAS MARKETS

"Market architecture" refers generally to the main structural features of a market and the set of institutions and rules governing trading processes. Among the key broad features or market design choices which Wilson (2002) identifies are:[1] (i) the degree of market centralization or decentralization; (ii) the specification of forward and spot markets and their price determination procedures; and (iii) the rules or regulations to mitigate or control the exercise of market power. Other "microstructure" choices determine or affect important market properties such as the speed and quality of price discovery, liquidity and the cost of trading. Such choices include, for example:[2]

- the degree of trading continuity, *e.g.* periodic auctions versus continuous exchange-based trading;
- the variety of contract forms and their timescales;
- dealer presence, *i.e.* whether trades are bilateral or intermediated by a counter party who takes the opposite side of every transaction;
- pre- and post-trade transparency, *i.e.* the quantity and quality of information provided to market participants during the trading process;

[1] Robert Wilson, "Architecture of Power Markets," Econometrica, Vol. 70, No. 4 (July 2002), 1299-1340.

[2] See Ananth Madhavan, "Market Microstructure – A Practitioner's Guide," Financial Analysts Journal, Vol. 58, No. 5, September/October 2002, for a discussion of some of these in the context of financial markets.

- information dissemination, *i.e.* the amount of information made available to traders or the public, and the speed of information dissemination (*e.g.* in real time or delayed); and
- off-market trading, *i.e.* whether all trade occurs in organized or centralized markets, or private bilateral/"after hours" trading is permitted.

As Wilson (2002) notes, in liberalized electricity wholesale markets many of these market design choices are constrained by the need to maintain continuous electrical equilibrium in the transmission network (implying a need for centralized system control), the fact that electricity cannot be stored, and stochastic retail demand which it is too costly to moderate via price signals. The solution initially adopted in most countries was to create centralized day-ahead spot or auction markets whose dual function is to set hourly or half-hourly market prices and to determine the despatch order of generating units. Most "physical" trade in electricity occurred via these markets, with longer-term contracts being almost purely financial. Increasingly more decentralized forms of trading have been introduced, such as the New Electricity Trading Arrangements in the UK and other market designs adopted in Belgium, Germany, Spain and the Netherlands, but without eliminating the need for centralized system control.

Natural gas markets share many of the features of electricity markets in the sense of using a transmission network through which all traded gas flows and which requires some degree of centralized oversight and management.[3] This means that, similar to electricity, no one literally "owns" the gas in the network *per se*; rather, market participants obtain rights to inject or withdraw gas from the transmission network at specific locations. These rights entail obligations to comply with technical rules and procedures for settling accounts based on metered injections and withdrawals. Thus, as Wilson puts it for the case of electricity markets, "*all rights are reciprocal and derived from contracts*".

The ability to store gas in the transmission network (and elsewhere), and the consequent ability to "balance" network flows (*i.e.* injections and withdrawals) over longer time periods than is possible in an electricity network, allows for greater flexibility in how gas is traded and this has led to different organizations of these markets.[4] For example, it is possible to allow traders to buy and sell gas, and alter their use of the transmission network, more or less continuously in real time within certain limits, subject only to requirements that their flows (injections and withdrawals) be balanced over some time horizon, as much for economic accounting purposes as for technical system requirements. Nevertheless, the requirement to maintain a balance of network flows and system pressure means that full decentralization is not possible, leading to a system of day-ahead "nominations" and involvement of the transmission system operator (TSO) in various forms of trading or other activities to maintain system stability. In many jurisdictions a single regulated entity manages the entire transmission network (*e.g.* in much of Europe and Victoria, Australia) while in others regional pipeline networks are owned by different companies

[3] Unlike in electricity markets where auction prices vary hourly or half-hourly depending on the costs or bids of the marginal generating unit required to meet varying demand, there is little reason for natural gas prices to vary significantly over the day, hence demand-side issues are less critical.

[4] Wilson (2002) describes gas transmission as a "displacement system" in which the gas in the pipe (linepack), is merely displaced by an injection at one point and withdrawal of an equal quantity at another point. Reserves can be obtained by varying the pressure in the pipe. Longer term reserves can be provided by underground storage.

who manage their own systems (*e.g.* in the US and Colombia) subject to various obligations and controls placed on them by regulatory authorities.

In common with electricity markets, the need to maintain gas network balance places constraints on trading activity and prevents full decentralization. Different countries have adopted different approaches to this issue, as we discuss in more detail below. In some countries (such as Colombia) traders (or "shippers") have "balancing agreements" and accounts with TSOs which specify time periods for correcting imbalances (up to five days in the case of Promigas) with charges/compensation applied for failure to balance within the specified time period. In Great Britain (GB) and Germany, shippers may correct imbalances by trading with one another until a few hours before the end of each "gas day", after which they are penalized for remaining imbalances by the TSO. In the Netherlands there is a separate "balancing market" in which the TSO is the counter party to all trades. In the United States each regional pipeline sets its own FERC-approved tariff for imbalances and different approaches to setting these prices have been adopted. The required time periods for balancing imposed on shippers also vary widely from hourly (in the Netherlands), to daily (in GB, Germany and Colombia), to monthly in some regions in the United States.[5] These choices affect not only the efficiency of trading, but also have consequences for other important features such as market liquidity.[6]

Apart from markets or institutions for resolving imbalances, which are features of both gas and electricity markets, the greater flexibility allowed by gas transmission networks has led to a greater variety of markets, trading institutions and contracts than are typically found in electricity markets. These are described and discussed in some detail below. Unlike in electricity markets, short-term trading tends be continuous rather than confined to hourly or half-hourly auctions, for example, and many different forms of trading institutions are used, from longer-term bilateral contracting to minute-by-minute exchange-based trading, with markets and exchanges often managed and operated by private companies. Economic theory does not constrain these choices, but the organization of the sequence of markets, as well as their transparency and liquidity, can have important consequences for trading efficiency and longer-term investment and contracting decisions. Even between gas networks, the specific features of the network – for example the volume of storage available and the location and flexibility of gas production – will affect the market arrangements.

A. TRANSPORT CAPACITY AND MARKET LIQUIDITY

A key challenge in the natural gas markets around the world (addressed most successfully in Europe and the United States) has been to achieve sufficient market liquidity. Thin markets make efficient trades more difficult to achieve and reduce the reliability of price signals. To

5 Although in Colombia balancing is evidently only literally required over a five-day period. To some extent at least, these choices depend on the properties of the network. US pipelines are large with a lot of linepack and storage (which is bundled in to the pipeline service), making much longer balancing periods possible.

6 Imposing costs or penalties on shippers for imbalances which impose no corresponding costs on the system as a whole, will potentially prevent efficient trades from being made. The choice between creating a separate balancing market, as in Netherlands, versus combining spot market and balancing trading in a single market (as in GB) obviously affects the liquidity of these markets.

participate in gas market trading, sellers need to acquire rights to transport gas to the point where it is sold, and buyers require transport capacity rights to take the gas away. Accordingly, there is a crucial link between the availability and management of gas transport capacity, and the liquidity of trading in both primary and secondary markets.

In the EU a system of entry-exit capacity rights has been adopted in most countries, and this is now required by law.[7] Under an entry-exit system, there is no concept of a "contractual path" for the gas: rather producers purchase rights to inject gas into the system at entry points, which can then be sold to buyers holding exit capacity rights. The TSO does not define the path the gas takes to get from entry points to the exit points, so sellers can sell to any party with exit capacity rights in the system.[8]

In contrast, in a distance-based, or point-to-point capacity contracts system, such as in Colombia and the United States, gas must be sold at a specific point in the network, and can only be sold to parties who have purchased capacity to transport the gas away from that point to the point of consumption. For this reason it is often argued that entry-exit capacity rights can improve market liquidity and efficiency, since the number of available counter parties is typically larger than in an point-to-point system The EU Regulation cited above makes an explicit link between market liquidity and entry-exit capacity rights, and the German regulator has cited the move away from point-to-point contracts to an entry-exit system as an important factor in increasing competition and liquid commodity trading in the German secondary gas market.[9]

Entry-exit capacity rights do not literally increase the number of available trading partners or counter parties, however. Rather they simplify trading by making it unnecessary for purchasers or shippers to simultaneously trade in transport capacity rights alongside each gas transaction. This consideration is particularly important in complex interconnected pipeline networks such as those found in most European countries.

In other systems, adopting entry-exit capacity tariffs seems to be less essential for market liquidity and successful secondary trading. The US has the most liquid gas market in the world without an entry-exit system. The Zeebrugge hub in Europe is also a reasonably liquid physical

7 Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005.

8 Note that in an entry-exit system the regulator first calculates the asset value or rate base that the pipeline system should be allowed to recover, and then sets charges at the entry and exit points so as to recover the allowed revenue (possibly allowing for under or over recovery depending upon utilization). Accordingly, any of the usual methods (price cap, revenue caps, rate of return etc.) can be used to determine allowed revenues and regulated tariffs. Equally, there are numerous ways in which the regulator can then set entry and exit charges – for example by setting all entry and exit charges equal, or setting entry charges to be higher at congested points in the network.

9 A potential disadvantage of entry-exit capacity rights is that TSOs have less precise information on gas flows in the transmission network at any one time, and hence the amount of firm capacity they are able to offer is less than in a point-to-point system, where contractual gas flows are well defined. In practice, however, TSOs have found that they can reliably estimate where gas will physically flow in an entry-exit system, and hence the amount of firm entry and exit capacity they are able to sell.

hub that does not rely on entry-exit capacity contracts. However, Henry Hub and other US gas markets are successful largely because a significant number of market participants hold point-to-point capacity rights to and from the hub. Similarly, Zeebrugge connects a large group of shippers who hold capacity rights to and from the hub. Unless the trading point or hub connects a sufficiently large group of potential traders, a liquid market is unlikely to develop. Simultaneous secondary trading of gas transport capacity may facilitate secondary gas trading in point-to-point systems, and help to deepen markets.[10]

B. Development of Trading Institutions

In both EU markets and the US, exchanges have developed after the growth in OTC/bilateral trading.[11] It is not necessary to have an exchange for price information to be available. In the EU and the US, most prices are reported based on assessments by trade journals of bilateral or OTC trades. Only a minority of prices in near-term contracts are based on the results of exchange trading.[12] This is mainly because in the EU at least, the majority of trading is still done OTC, and exchange trading remains quite thin. The main exception to this is the UK's short-term market, but this only provides day-ahead and on the day gas prices.

C. Roles and Responsibilities

Practically all natural gas markets allocate responsibilities in a similar way. The tasks of System Operator (SO) and Market Operator (MO) are usually carried out by different entities. A further division is sometimes made between the SO and the owner of the gas transmission assets – the Transmission Owner or TO. Where the entity both owns and operates the pipeline network, it is called a Transmission System Operator (TSO).[13] The TSO has responsibility for balancing the transmission network, keeping track of traders' imbalances, and organizing the financial arrangements to resolve them. The TSO also keeps track of who owns what gas at any point in time, and shippers are obligated to notify the TSO of any trades that have taken place close to the delivery date. They must also tell the TSO how they plan to use the system the next day via daily nominations. Where there is an exchange, the TSO will typically delegate this operation to a third party Market Operator.

---

[10] In the EU secondary transport capacity trading usually takes place via bulletin boards. However, as noted above, in an entry-exit system there is less need to trade capacity since once gas is injected into the system, it is available to all buyers and there is no need to buy capacity that will transport the gas to a specific place in the network. Generally shippers trade capacity if they want to be able to inject more or less gas at a particular point, or want to be able to withdraw more or less gas.

[11] OTC trading may be more suitable in the early stages of a secondary market. This is because it can be difficult to know which contracts are most suitable to offer on the exchange in the early stages of a market. In contrast OTC trading allows new types of contracts to evolve. As a consensus emerges on the most popular contract types, these contracts could migrate to an exchange.

[12] However, other longer-term contracts might be indexed to the results of the exchange trading, so that the prices can affect larger gas volumes than only those traded on the exchange.

[13] In this paper we use the term TSO to refer to both SOs and TSOs.

D. Market Power Issues

Market design or organization cannot in itself eliminate, or necessarily even mitigate, the exercise of market power by traders, although poor market designs can exacerbate market power problems and create opportunities for market manipulation which otherwise would not exist.[14] Open and transparent markets (for example, organized auctions or exchanges) provide more information, which at least makes it easier to identify firms with market power and to impose remedies where needed. They can also help to "level the playing field" for smaller traders and new entrants, by allowing them to trade with the "market" rather than having to negotiate with large incumbents, and by guaranteeing the ability to purchase or sell on the same terms as every other trader in the market. By making the same information equally available to all market participants, organized markets or exchanges also help smaller traders by relieving them of the burden of information acquisition, which will typically be less costly for larger firms.

Wilson (2002) notes a number of means which have been used in liberalized electricity markets to control or mitigate the exercise of market power by generating companies including;[15] (i) asset divestiture; (ii) imposition of long term contracts at fixed prices (essentially a form of price regulation); and (iii) forced sale of part of the dominant firms' capacity or output in auctions, such EDFs virtual power plant auctions. The last of these is obviously similar to "gas release" programs which have been implemented in many European countries, and recently proposed for Colombia by Harbord (2010) and Frontier Economics (2010).[16]

3. TAXONOMY OF GAS TRADING

Before discussing international experience of gas trading arrangements in more detail – both the gas commodity and gas transport capacity – we first discuss some of the main concepts and terms in this sections so that these terms are well defined and clear in the following discussions.[17]

A. Gas Products Typically Traded

Gas products are typically defined by the period in which gas delivery will take place. Typical gas products seen in EU markets are:

- Within day – delivery on the same day as the trade is done;

[14] A classic example of this is the manipulation of the capacity payment mechanism in the original English electricity auction.

[15] Transmission and distribution networks are considered to be natural monopolies and subject to direct price regulation everywhere.

[16] David Harbord "Upstream Issues in Colombian Gas Supply", April 2010; Frontier Economics, "Propuesta de soluciones a las fallas del mercado de gas de Colombia," Abril de 2010.

[17] We discuss gas trading in general – the gas could have originated from pipeline or LNG.

- Day-ahead;
- Weekend;
- Next working week (Monday to Friday delivery);
- Balance of the Month – for gas delivery for the remainder of the month;
- Front Month or Month Ahead – delivery for the next calendar month – for example a front month contract trading in November would involve delivery in December;
- Monthly contracts – most EU markets typically offer contracts for delivery in the next few months ahead. For example in January the GB gas market trades gas for delivery in February, March, April or May. However, in US gas markets such as the Henry Hub, monthly contracts extend several years into the future.
- Beyond the range of the monthly contracts, products are offered by Quarter or by Season (Summer and Winter), typically for 2-3 years ahead. Other products include gas for delivery over a year, either a calendar year or a 'gas year', which in Europe typically runs from 1 October to 30th September. However, these products are not common in the US, where instead monthly contracts extend further out.

People often divide up the range of contracts above into 'spot' and prompt contracts, and forward contracts, but there is no firm agreement on where the dividing line is. Some people take a view that spot gas is anything that will be delivered within 30 days, while others refer to the day-ahead market as the 'spot market'. In this report we will use the latter definition of spot gas. Most people would agree that prompt gas is anything with a delivery date before the end of the next month and that forward contracts involve delivery after the end of next month.

A further division is between financial and physical products, but again the difference between the two is not as clear as one might think. Put simply, a physical product is one in which the buyer takes physical delivery of the gas, and a financial product is one in which the transaction is settled in cash. For example, suppose that in January 2010 a trader bought a MWh of gas for delivery in December 2010 for a price of €20/MWh. In November 2010 the price for December 2010 gas is €25/MWh. The trader could settle the contract against the current price of €25/MWh, by receiving €5/MWh from the seller. In reality whether the product is physical or financial depends largely on the intention of the counter parties, since most products have the option for physical delivery, even if this is rarely used, and most 'financial' traders will hold the required licenses to enable them to take physical delivery of gas should they need to do so. For example many of the gas contracts traded on the New York Mercantile Exchange (NYMEX) are in theory involve physical delivery, but the majority of these contracts are settled financially before delivery occurs.

Finally, we should distinguish between forward and futures contracts. As described above, a forward contract is a contract for gas that will be delivered beyond the end of the next month. A futures contract is simply a standardised form of forward contract that can be easily traded on an exchange.

B. COMMODITY TRADING INSTITUTIONS AND ARRANGEMENTS

The most typical forms of gas trading arrangements are:

- **Bilateral trades**. These are individually negotiated contracts where all the key terms – gas delivery point, quantity, price, gas quality, terms and conditions – will be negotiated between the parties. High-volume, usually long-term (*e.g.* 20 year) bilateral trades between large sellers and buyers used to be the standard way of selling gas in pre-liberalised markets. In mature liberalised gas markets such as the GB and US markets, other ways of buying and selling gas have gained a larger share of the market. For example, in between 2007 and 2010 in the GB market about 50% of gas was sold via long-term bilateral contracts, while the remainder was traded under a shorter term deal.

- **Over-the-counter (OTC) trading**. OTC trades are still bilateral trades, but the key difference with a more 'tailor made' bilateral trade is that OTC contracts are to a large extent standardised. Almost all of the terms and conditions for the trade will be fixed, with only the price, delivery window and the quantity left open. With respect to quantity, OTC trades will typically take place in standardised amounts – for example bundles of 25,000 therms in the GB gas market. In the GB market, most of the gas that is not sold under long-term contract is traded OTC.

- **Exchange based trading**. The main EU and US gas exchanges – including the Austrian CEGH exchange, the German EEX, the Dutch APX, the Nordic Nord Pool gas exchange and the UK's Intercontinental Exchange (ICE) – all have very similar arrangements. The key difference between OTC trades and exchange trades is that, for the latter, the trading is 'cleared' by the exchange. This means that the exchange itself – or a clearing house – is the counter party to the trade and takes on the risk of default. For example, if a shipper has agreed to buy gas at a given price, but the seller goes into liquidation before the contract is cashed out, then the exchange will honour the contract on behalf of the seller. In contrast, with bilateral trades the counter parties must make their own agreements as regards creditworthiness and any collateral or financial guarantees that need to be in place, if any. The other key difference under exchange- based trading is that trading is anonymous – that is, the seller does not know who the buyer is and vice versa, because the counter party is the exchange. This latter point can be important if traders want to keep their positions secret. For example, a trader might not want others to know that it is buying heavily, or is short of gas in a particular period, because then others could take advantage of this information. Another difference between OTC and exchange based trading is that an exchange is a 'club', and participants must demonstrate certain minimum requirements to join an exchange. These might include general credit checks, assurance that appropriate managements systems are in place and the firm is a 'fit and proper' legal person. In contrast, anyone can trade OTC, providing they can find a willing counter party. In reality, the conditions laid down by exchanges for membership are not onerous and can be met by most firms, perhaps unsurprisingly as the exchanges would like to encourage as many people as possible to use them.

> Moreover, counter parties in the OTC market will be wary about who they trade with, since they bear the risk of default. Hence it is not the case that there is a large difference in the 'quality' of OTC and exchange participants.

In the US and the EU, the majority of OTC trading and exchange-based trading is done via electronic screens using proprietary trading systems. In the past more trading would have been done via telephone. Bilateral deals, which are heavily customised, would be negotiated over months or even years.

In almost all cases, gas trading on exchanges is continuous – that is, there is no set time at which trades will be matched. Traders simply make an offer or a bid at any time and wait for an acceptable counter-offer. This is a key difference between gas and electricity exchanges, with the latter involving set auctions typically for every hour or half hour of the following day. The reason for this difference is because balancing on an hourly basis in gas markets is less critical than balancing in electricity market, because the gas network can absorb some imbalances. Traders in gas markets prefer continuous trading because it does not artificially restrict trading to a specific time period. For example, in a recent document commenting on the development of an Italian gas market exchange, the European Federation of Energy Traders (EFET) notes that it "would prefer a market based on continuous trading, which enhances trading possibilities, delivers immediacy and increases the frequency of trading execution."[18] Despite this, the new Italian gas exchange does have some trading sessions that are conducted by auction, but it is the only example that we are aware of. The keenness for auctions in Italy could be because the operator of the Italian gas exchange also operates the electricity exchange, and so it is used to the idea of auctions rather than continuous trading.

It is also worth commenting on the role of the market maker. A market maker helps to ensure liquidity on the exchange, by making simultaneous offers to sell gas and bids to buy gas. So the market maker is always standing by ready to make a transaction, even if the price may not be that attractive. The market maker also provides a pricing reference point. For example, the market maker could offer to buy at €28/MWh, and sell at €32/MWh, implying a 'bid-offer' spread of €4/MWh. The market maker has an incentive to bracket the 'real' market price, other wise it could lose money. For example, if the price at which the market maker offered to sell was too low relative to the real, it would be inundated with buy requests from traders who realised that they could buy the gas and sell it on at a higher price. Similarly, if the market maker offered to buy gas at a price that was too high, others could produce or buy gas at a lower price and sell it to the market maker at a profit. If the market maker misjudges the market price or if the market price changes before the market maker can react and adjust its bid and offer prices, it may incur a loss. To deal with the issue, trading platforms typically include rules such as permission to widen the bid/offer spread or reduce volumes at times of price volatility.

The market maker role can be important in the early years of the markets development as a way of ensuring liquidity.[19] Some exchanges operate with officially designated market markers.

---

18 EFET recommendations for the development of the Italian gas exchange

19 Academic support for the market maker role can be found in, for example, 'Middle Men Versus Market Makers: A Theory of Competitive Exchange', John Rust and George Hall, Journal of Political Economy, 2003, vol. 111, issue 2, pages 353-403. The paper concludes that the market maker's entry induces other

Typically, the exchange will stipulate a cap on the bid/offer spread that the market maker is allowed to quote, and the exchanges may also require the market makers to commit to a minimum volume that they are prepared to buy/sell. While the market maker role is usually voluntary, there are precedents for regulators requiring a party to act as a market maker to address liquidity concerns, including low levels of market liquidity. For example in Denmark DONG Energy and Energi Danmark have committed to act as market makers in the electricity market, and there is a mandatory market maker role in the electricity market of New Zealand. The GB energy regulator, Ofgem, has also considered introducing a mandatory market maker role for the GB electricity market.[20]

C. Exchanges vs. OTC Trading

Typically, OTC trading develops first in a market, and is then followed by exchange based trading. As a recent report notes:

> "the ability to engage in OTC trading can be particularly important in the early years of a market. Because exchanges use multilateral trading platforms and central clearing, they generally rely on standardized contracts. The OTC market permits new transaction types to emerge, which, over time, may become sufficiently standardized and commonplace to sustain migration to an exchange platform."[21]

In practice, the distinction between exchange trading and OTC trading has become rather blurred. It is not unusual for OTC trades to be cleared via one of the exchanges or another clearing house, in which case there is little to distinguish such trades from an exchange based trade.

In most gas markets, there is a mix of trading among the different arrangements described above. These different trading institutions serve different needs, particularly with respect to clearing and collateral requirements, which can be significant. In general, traders on an exchange will be required to post some collateral – a letter of credit or some cash-equivalent asset – to cover some of the value of their trades. The traders will then face 'margin calls'; as the value of the reference price changes with respect to the deal originally struck. For example, consider again the example above where in January 2010 a trader bought one MWh of gas for delivery in December 2010 for a price of €20/MWh, and in November 2010 the 'settlement' price for December 2010 gas is €25/MWh. In this example the seller 'owes' the buyer €5/MWh, since this is the profit the buyer can make by buying gas at the contract price of €20/MWh and selling it again at €25/MWh. The exchange would require the seller to post collateral for this difference or margin, so that if the seller goes bankrupt the exchange can use the collateral to settle the deal. Note that in many cases parties will be sellers in some transactions and buyers in others with the same counter party. The clearing house will net out these positions, and only require that collateral be posted for the net positions. The settlement price for each contract is established

---

middlemen to reduce their bid-ask spreads, and as a result, all producers and consumers who choose to participate in the market enjoy a strict increase in their expected gains from trade.

20 Ofgem, Liquidity Proposals for the GB wholesale electricity market, February 2010.

21 Report on the Oversight of Existing and Prospective Carbon, Interagency Working Group for the Study on Oversight of Carbon Markets, January 18, 2011. pp.18-19. Available at www.cftc.gov.

toward the end of the trading day during a pre-defined time window. If there is insufficient trading to set a settlement price then exchanges and committees that will set an administered settlement price.

Collateral or margining requirements can become very significant for gas traders, tying up large amounts of capital. As a result, some market parties may prefer to do some or all of their trading using bilateral or OTC trades, where the collateral requirements can be mutually agreed between the counter parties, or dispensed with altogether if the counter parties are willing to bear the risk. OTC trading is also preferred for less liquid products. For example OTC trading will usually involve forward products with delivery dates further into the future than contracts traded on an exchange. This is because interest in such products is relatively limited, and so the liquidity is not sufficient for exchange-based trading. OTC trading may also be preferred to negotiate the sale of large volumes, the sale of which on an exchange would move the market. For the same reasons, in financial markets large blocks of shares are usually sold bilaterally via private placement, rather than simply being offered on the stock exchange.

Another key difference between exchange based trading and OTC trading is the level of oversight and supervision. This is a complex legal area, but broadly speaking exchange trading has a far greater degree of supervision and oversight by financial regulators than OTC trading. Exchanges must carry out detailed checks on the parties using the exchanges, who themselves must provide regular reports to the financial regulator regarding their trading activities and financial health. This increased oversight creates costs for both the exchange and its members, with the benefits of increased transparency and reduced risk of failure, fraud or bankruptcy by counterparties. In contrast OTC trading is relatively lightly regulated, and many parties trading OTC products are not supervised by financial regulators. Note that it is the nature of the party undertaking the trading and the underlying reasons for their trading which drives the degree of regulation, rather than the product being traded. For example, a financial institution trading OTC forward gas contracts would be subject to oversight by the financial regulator, whereas an energy producer trading the same products to hedge production price risk might not be. Note also that there is nothing intrinsic about an exchange that requires a greater degree of financial regulation – this is simply the way in which legislation has evolved.

In the EU, following the financial crisis there has been an extended debate over whether parties that traded energy derivatives – including forward contracts – should be forced to clear their trades. In September 2010 the European Commission proposed legislation that could have required energy companies trading more than a certain amount of derivatives – the amount was not defined – to ensure that these derivatives were cleared via a clearing house. The motivation is the concern over systematic risk, that with un-cleared OTC trading the failure of a large counterparty could cause other traders to fail in a 'domino reaction'. The presence of a clearing house should, in theory, provide a 'firewall' isolating the failure of a single trader. However, the proposals have met strong resistance from some large energy firms, who claim that the requirement to clear trades would cost them many billions of Euros every year in terms of increased capital requirements.[22] Others have claimed that forcing all trades through clearing

[22] For example, major EU utility RWE claimed that Proposed EU legislation to regulate the over-the-counter derivatives market could cost the energy sector "tens of billions". RWE estimates it could face costs of "between Eur1-4 billion ($1.3-5.4 billion) associated with additional collateral margins and the related

houses creates a new form of systematic risk – the clearing houses themselves – which must be underwritten by the government.

D. Gas Balancing and Balancing Markets

Gas systems require shippers – that is, users of the gas transmission system – to balance or match their inputs and outputs over a specified period (often 24 hours), at least to within a given tolerance. Imbalances are usually measured over a shipper's portfolio – that is, the sum of all their inputs and withdrawals to and from the system. Any shortfall or excess will usually be sold to the shipper or bought from the shipper by the TSO.

In the early days of gas market liberalisation in the EU, TSOs generally 'punished' imbalances with penal fees, and there was little or no opportunity to solve imbalance situations via trading. As EU gas markets have developed, some countries now have dedicated balancing markets where shippers can buy and sell gas so as to balance their portfolio over the required period, and balancing costs are more market based. An important driver for the improvement in balancing arrangements has been pressure from the EU. In 2009 the EU laid out specific requirements for the imbalance rules to avoid some of the problems seen in the past. The new rules specified that:[23]

1. Balancing rules should reflect genuine system needs taking into account the resources available to the transmission system operator. Balancing rules shall be market-based;

2. The transmission system operator shall provide sufficient, well-timed and reliable on-line based information on the balancing status of network users;

3. Imbalance charges shall be cost-reflective to the extent possible, whilst providing appropriate incentives on network users to balance their input and off-take of gas;

4. Any calculation methodology for imbalance charges as well as the final tariffs shall be made public.

Not all gas markets have a dedicated imbalance market – sometimes the imbalance market is combined with general commercial trading. We describe some of the arrangements in place in section 6.

Note that the imbalance market, or the mechanism for resolving imbalances, is not intended to ration gas or solve gas shortages. Rather, it is simply a mechanism for ensuring that the pressure in the gas pipeline system does not fall too low or become too high.

---

processing and documentation requirements". RWE said it believes that moves to introduce mandatory clearing could hamper liquidity in a sector which is still "relatively young" and could deter large financial institutions from trading, while small independents in the energy sector may be discouraged from hedging effectively. See *Platts European Gas Daily*, September 24 2010.

[23] These points are summarised from Article 21 of Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005.

Note that there is a difference between balancing charges and nomination or scheduling fees. The latter are to motivate shippers to give the TSO an accurate estimate of how they intend to use the system. A shipper can be perfectly in balance – that is, its inputs equal its outputs – but could attract a scheduling fee if the inputs and outputs differ from the nomination submitted.

E. Market Liquidity

At present, particularly in the EU, there are several distinct gas trading platforms and locations, and each is keen to increase the liquidity of trading. When gas or any other commodity is traded, liquidity is a measure of the ease of trading activity. A liquid market with active trading is better than one in which trading is infrequent. However, liquidity is not a concept which can be simply reduced to a single number: having more traders (potential counter-parties) is better than having fewer; more frequent trading is better than trading which happens sporadically; 'low' bid-offer spreads indicate a high level of liquidity; trading of a range of different products (for example, delivery dates) is better than trading only a few products. All of these factors are important. One frequently cited metric is the "churn rate", defined as the ratio between the volume traded and the volume actually consumed.

Truly liquid gas markets are currently rare outside the US, GB and Canada. A commonly accepted measure for a 'workable' level of liquidity is a churn rate of between 10-15 – it was at this level of trading activity that the prices generated by the GB gas market were regarded as reliable enough to base contracts on – that is, to sell gas priced using a price index generated by GB gas trading. At the time of writing only the GB, Canadian and US gas markets have achieved this level of liquidity. Note that the level of liquidity can also vary between products – for example spot and prompt trading in GB is liquid, but forward trading much less so. In the US trading is liquid also in contracts with delivery dates one to two years forward.

4. RELATIONSHIP BETWEEN GAS COMMODITY TRADING AND GAS TRANSPORT CAPACITY

The definition of gas transport capacity rights, trading of those rights and the trading of gas are all closely related. To execute a gas trade, the seller must have gas transport capacity rights to the point of sale, and the buyer must have gas transport capacity rights away from the point of sale. This is the key link between trading of the gas commodity and the definition and trade of gas transport capacity rights.

Around the world broadly speaking two systems of gas capacity rights have been defined:

- Point-to-point capacity rights. Under this system the Transmission System Operator (TSO), who manages the gas transport system under regulatory supervision, defines capacity rights from and to specific points in the network.

- An entry-exit system. Under an entry exit system, the TSO sells entry capacity – that is capacity to enter the gas transmission system – and exit capacity to leave the gas transmission system. Entry and exit capacity are sold independently from one another, so that there is no concept of a path of the gas flow. Some parties buy entry capacity, inject gas into the system, and sell to others who withdraw the gas. As a result the TSO does not always have an overview of the physical gas flows associated with contractual gas arrangements.

Hybrids and variations of the two systems above of course exist. For example in the US pipelines generally sell point to point capacity, but there is sometimes the possibility to deliver gas to a range of destinations within a given geographic area, or similarly to inject gas from a range of input points, and so the systems are not strictly point-to-point. But the two systems described above represent the main paradigms for gas capacity definition applied around the world.

In the EU, TSOs and regulators have gradually converged on an entry-exit system of gas capacity rights, with gas traded at Virtual Trading Points. There are several reasons for this, as we discuss below.

Gas pipeline network topology – in other words, the physical arrangement of the pipes – has a large influence in the way capacity rights can be defined, and so on the way gas is traded. Broadly speaking, networks in European countries are complex pipeline 'meshes'. There are usually several ways to get gas from point A in the network to point B. Moreover, the capacity available to transport gas from A to B depends on other gas flows, from A to C, C to D and so on. Accordingly, in European meshed networks it is difficult to define capacity rights on a point-to-point basis. Other systems, for example Australia, have simpler network topology, which involve point-to-point pipelines with relatively little inter-linkage. There is generally only one way to get from A to B, and consequently point-to-point capacity rights can be clearly defined.

In a meshed system, point-to-point capacity rights or distance based tariffs are not cost reflective, since the contractual path for the gas (the path from the seller to the buyer) usually does not represent the actual physical flow of the gas. In a complex meshed system, injecting an extra unit of gas at point A and withdrawing it at point B will change all the flows in this system, but in most cases it will not actually cause an extra unit of gas to physically flow from point A to point B. Moreover, regulators in the EU recognised that point-to-point charges disadvantage smaller new entrants disproportionately. This is because incumbent shippers have a large portfolio of gas and can perform internal 'swaps' of gas between point A and point B. In contrast new entrants usually have to transport all of their gas from point A to point B. One of the main aims of EU regulators during the liberalisation project was to have cost reflective tariffs that did not discriminate against new entrants, and in most EU networks point-to-point tariffs did not achieve this objective.

Regulators, including the European Commission, also recognised the trade off between market liquidity and the definition of capacity rights. In an entry exit system, a holder of entry capacity can inject gas into the system, and trade the gas with *any* party holding capacity at any exit point. The counter party does not have to buy any transport capacity.[24] For this reason, often entry-exit systems are called ‘virtual’ hubs, since the trading does not take place at any specific physical location on the system.

In contrast, under a point-to-point system, for a trade to take gas at point A in the system, the seller can only sell to counter parties that have transport capacity from point A. Other counterparties could also buy the gas at point A, but they would simultaneously need to acquire gas transport capacity rights from point A. The need to acquire transport capacity to be able to buy the gas can increase transaction costs. Accordingly, in some gas systems point-to-point capacity rights limit the pool of potential buyers and sellers, making the market less liquid. This may also increase the risk of the exercise of market power. As Newbery (2001) notes, “*the tension is between a single wide area pool and nodal pricing [the equivalent of point-to-point transmission rights]….the ideal is to have a deep liquid market, but the reality is that gas in different locations, like electricity, may not be easily substitutable at short notice*.”[25]

The 2009 European gas Regulation requires that all EU Member State TSOs must apply an entry exit system of tariffs, and is explicit that the reason for this is to encourage liquid trading:

> “To enhance competition through liquid wholesale markets for gas, it is vital that gas can be traded independently of its location in the system. The only way to do this is to give network users the freedom to book entry and exit capacity independently, thereby creating gas transport through zones instead of along contractual paths. The preference for entry-exit systems to facilitate the development of competition was already expressed by most stakeholders at the 6th Madrid Forum on 30 and 31 October 2002. Tariffs should not be dependent on the transport route. The tariff set for one or more entry points should therefore not be related to the tariff set for one or more exit points, and vice versa.”[26]

Under an entry exit system, the TSO does not know for sure where gas is flowing. The TSO must make its best guess regarding gas flows, and estimate the ability of the system to accommodate these flows. The TSOs prudently ensure that they can deliver the firm capacity promised, and leave a safety margin with respect to firm capacity available that will account for unexpected system flows. Therefore there will be less firm capacity in an entry exit system than when the TSO defines point-to-point capacity rights. Under the latter system, the TSO has a better idea of what gas flows in the system will be. Therefore the TSO can allocate more firm capacity with point-to-point capacity rights.

In the EU, regulators had started with a market dominated by national incumbent gas suppliers. Regulators were keen to promote competition, so that consumers could benefit from the market liberalisation. Moreover, in the EU at the beginning of the liberalisation project the gas networks had if anything been ‘over built’, since there was less regulatory scrutiny of investment decisions than would be the case today. Consequently most European gas networks

24 Parties only need to acquire more capacity if they want to inject more gas than they currently have a right to do, or withdraw more gas.

25 Newbery, David M., Privatisation, Restructuring and Regulation of Network Utilities, MIT Press, Third edition 2001, p.377.

26 Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005. Recital ¶19.

had little if any congestion. Accordingly, when faced with the trade off between increasing firm capacity rights on the one hand, and increasing market liquidity on the other, regulators in the EU chose the option of less firm capacity and more liquidity. In practice, this meant a preference for entry-exit systems and the creation of 'Virtual Trading Points' or VTPs. EU regulators have recently set out a vision for the EU gas market as a series of VTPs with TSOs selling 'virtual' capacity to facilitate inter-VTP trade.[27]

The above discussion does not mean that a system of entry-exit capacity rights is the only way to achieve a liquid market. The US has the most liquid gas market in the world without an entry-exit system. The Zeebrugge hub in Europe is also a reasonably liquid physical hub that does not rely on entry-exit capacity contracts. However, the conditions for a liquid physical hub are rather specialised, relative to the conditions for a liquid 'virtual' hub at an entry-exit system. The physical trading point or hub must connect a sufficiently large group of potential traders. Both the Henry Hub and Zeebrugge physical hubs connect a group of diverse pipelines and LNG terminals, so that at both physical locations there is a large group of market participants that can trade at that point without having to simultaneously trade gas transport capacity. However, there are not many physical locations which have such properties – hence the EU's preference for entry-exit systems to stimulate liquidity. As we will explain in the section of this report which discusses the US gas market, the liquid Henry Hub is also the basis for trading at many locations around the US – so in a sense Henry Hub liquidity lubricates the entire US gas market. But again this is possible because pipeline capacity from the Henry Hub to many locations is held by a large group of potential traders. In contrast the Zeebrugge hub in Belgium is not the basis for EU gas trading, mainly because capacity rights are not as diversely held as in the US.

In sum, while both entry-exit and point-to-point capacity rights can create liquid markets, to design a successful secondary market one must careful consider the relationship between the trading of gas, gas transport capacity rights, and trading of those rights.

5. MARKET ROLES AND RESPONSIBILITIES

This section introduces the typical roles and responsibilities of the main agents involved in the secondary trading of gas and transport capacity:

- The Transmission System Operator (TSO) is typically both the owner of the transmission network (the TO) and the system operator (the SO). We use the term TSO in this report to refer to both the TO and SO function. In most cases, these two functions – pipeline owner and system operator – are managed within the same organization, although there is often some degree of management or accounting separation between the functions.

- The TSO is responsible for balancing the system, including monitoring the balance position of each shipper, and invoicing the shippers for any imbalances. The TSO will also be responsible for taking any actions required to balance the system. This could

[27] See CEER vision for European gas target model 1st workshop, Vienna, 3 December 2010

include taking actions to resolve ‘geographical’ imbalances – that is, the system as a whole might be balanced, but there could be too much gas in the north and not enough in the south.

- As part of its balancing role, the TSO will also need to keep track of who owns how much gas at any point in time. For this reason, shippers or the exchange (see below) must report trades of gas to the TSO, so that the TSO can ensure that the gas is allocated to the correct shipper, when the TSO does its balance calculations.

- One could also distinguish a separate role of ‘physical hub operator’, although at present Huberator (the company operating the hub at Zeebrugge) is the only party undertaking this role in the EU. The role of the physical hub operator is to track trading activity and provide back-up services to make trading as firm as possible. In effect, the hub operator acts as the TSO of the hub.

- In its role as system operator, the TSO also sells primary gas transport capacity, and manages the transfer of capacity between shippers. The TSO needs to know in advance how shippers plan to use the system – typically the next ‘gas day’, and so shippers will submit nominations with their planned inputs and withdrawals for the following day. The TSO can then gauge which compressors to operate and make other operational decisions based on this data.

- In a market with more than one Transmission Owner (TO) it is more useful to distinguish between the SO and TO role. The most prominent example of this kind of system in the EU is in Germany, which we discuss from page 34. In Germany, up to ten TOs join in a common market area which is operated by a single SO. The SO organizes balancing and other market functions across the entire market area – so that rather than have to balance inputs and outputs across the assets of a single TO shippers can balance across the assets of several TOs. Imbalances between TOs are handled by the SO. The SO also manages transfers or swaps of gas between shippers with the market area. Having a single SO across multiple TOs encourages market liquidity and trade, and makes it easier for shippers to balance their portfolios. As we explain in the section on Germany, the consolidation of multiple TOs into larger market areas has been a key factor in the growing liquidity of the German market.

- Where there is an actual gas exchange for balancing purposes, the TSO will usually delegate the operation and management of this to a third-party Market Operator (MO). For example, the TSOs in GB, Italy and the Netherlands have all delegated the MO role. This is for two reasons. First, if the TSO is trading on the exchange to balance the system, then it could create a conflict if the TSO is also the operator of the exchange. Second, the jobs of managing an exchange and managing a gas transportation network are very different, so that it is efficient to appoint a more specialist MO. The exchange or market operator (MO) is then responsible for the management of the exchange including clearing of trades. It is usually the exchange that will notify the TSO of the net results of trades done on the exchange, and the exchange will notify the TSO so that the TSO can then keep track of individual shipper's inputs and withdrawals (including any exchange based transactions) for the purposes of balancing calculations. This is the main interface between the MO and the TSO. In contrast, shippers must notify the TSO of the results of any OTC trades.

- While the Operator of an exchange is subject to oversight by financial regulators, the MO will not be subject to price controls in the way that the TSO is. This is because the exchange is not a monopoly, but rather it is competing against OTC trading. The exchange must persuade market participants that the benefits of using the exchange – which are mainly reduced counterparty risk – justify the costs of using the exchange. To increases it business, the exchange has a natural incentive to reduce its costs and charges as far as possible. The regulator or TSO can also encourage the exchange to reduce its costs as far as possible by holding a competitive tender process for the right to manage the exchange, with costs being one of the elements on which the license is awarded.

- There is no explicit co-ordination between the gas and electricity markets in the EU, though gate closures are timed so that generators know if they are scheduled to generate before having to make final nominations to the gas TSO. But given that in the EU most power is sold bilaterally, there are no mandatory pools and there are opportunities for within day trading, market participants can adjust their positions in both the gas and electricity market close despatch.

A. Requirements for the MO and SO

Since the TSO/SO and MO are monopolies there may be concerns that affiliated shippers might receive preferential treatment. Such preferential treatment might be very difficult to detect: for example, non-affiliated shippers might be concerned that the TSO is more likely to curtail their flows than flows of affiliated shippers when there is congestion. Another concern is that the MO will have access to more information than is released to traders or the public. Shareholders of the TSO/SO/MO who are also traders could potentially acquire information that others do not have, securing an unfair advantage in the market place. The extent of the potential problem depends on decisions regarding transparency. The less information the TSO/MO divulges to the market, the greater the danger that shareholders could have an unfair advantage.

For this reason, it is usual for there to be restrictions on the relationship between the TSO/SO MO and shippers. One approach (taken in the UK) is to forbid the TSO/SO MO from having any affiliation with shippers. This is known as "ownership unbundling" which implies that formerly integrated operators have had to sell off any ownership interest in gas and transport capacity.

For example, the GB energy regulator's consultation document regarding the appointment of the GB System Operator (GBSO) stated that "[t]he party [the GBSO] should not have affiliates who will be undertaking the activity of generation, supply or energy trading other than for balancing services".[28] The document clarified that 'affiliated' meant within the same

[28] 'The process for identifying the GB system operator – Key conclusions and invitation for applications.' DTI/Ofgem Conclusions document August 2002, p.12.

corporate group, or within the same company. This means that a generation, supply or energy trading firm could not own any own shares in the GBSO.

The alternative to ownership unbundling is "management unbundling", whereby the management of the TSO/SO is separate from the management of any affiliated shipper. This is the approach taken in the US, for example. Management unbundling requires that employees of the TSO/SO with access to confidential information relating to shippers should not communicate with employees of the affiliated shipper. Unbundling rules could also require that the compensation of the TSO/SO employees be linked only to the financial performance of the TSO/SO, but not to the performance of the wider corporate group (including the affiliated shipper). Sometimes unbundling rules require that TSO/SO employees be located in physically separate offices.

We recommend that both the MO and the TSO/SO should be independent from shippers and traders as far as possible.

It is also instructive to consider the conditions from NGG's transporter license with regards to appointment of an MO. These license conditions state that the MO should have:

(a) financial resources;

(b) skilled and experienced personnel, and

(c) systems;

adequate to ensure that the market is conducted in an orderly and proper manner according to clear and fair rules. The license also calls for a clearing function that enables NGG and shippers to net out any sales, so that a sale to any one participant in the market can be netted against an equivalent purchase from that or any other participant in the market.

These conditions give some useful guidance as to the competencies that the MO should have.

6. INTERNATIONAL EXPERIENCE WITH GAS TRADING ARRANGEMENTS

In this section we describe the trading arrangements that have evolved in some of the key gas markets around the world, including

- Great Britain
- The Netherlands
- Germany
- Belgium

- The US
- Italy
- Victoria, Australia

We have selected these countries so as to give a good range of gas market maturities and of different approaches to gas trading arrangements. We spend more time discussing GB and the US, first because these are the most mature gas markets in the world and therefore we can benefit from many years of experience by examining their structure and institutions (and how they have developed), and second because they are good examples of the two paradigms we discussed in the previous section.

Our analysis begins with a more detailed look at the GB system because it is one of the most developed secondary gas and transport markets in the world. For that country, we describe:

- Gas transport capacity rights – that is, how are capacity rights defined, as point-to-point rights, an entry-exit system or something else.
- The imbalance market.
- The main gas trading institutions – gas exchanges or bilateral markets.
- Price and trading data availability – what information is available on prices, availability of pipeline capacity and the status of the gas pipeline system?
- Main participants in the market – roughly how many players are active in the market, if known, and the types of players (gas marketers, financial traders, banks etc.)
- Roles and Responsibilities – who does what, in particular with respect to information flows.
- Nominations – the procedure for telling the pipeline operator the planned gas flow;
- Trading of secondary transport capacity – how is pipeline capacity traded – what are the procedures and the mechanisms?

We describe most of these aspects for the other countries too. If details are omitted it can be assumed that they are similar to the GB market.

Note that, unless stated otherwise, in all the gas markets that we discuss there is no distinction between the trading of primary and secondary gas, in the sense that both types of trade take place using the same institutions. For example gas producers in the GB gas market might sell produced (primary) gas bilaterally using a long-term contract, on the within-day physical market or in the over-the-counter market. The general exception to this is where there might be a 'gas release' program, where a market participant is required to sell gas by auction. The only specific exception that we are aware of in the countries studied is Italy, where the Italian government's Royalty gas must be auctioned on the gas exchange.

By way of introduction, Table 6.1 provides an overview both of the relative importance of exchange vs. OTC trading in different markets, as well as the volumes traded. The table shows that the volumes traded in the UK market as far higher than any other European market at present, and that most trading is OTC. With the exception of the Netherlands, most trading is physical.

Table 6.1: Overview of Gas Trading

Country	Market/hub	Physical trading vol. bcm/year	Financial trading	Degree of forward trading	Amount traded OTC
UK	NBP	1,263	very little	25% is year ahead	almost all
The Netherlands	TTF	115	4x physical	25% is year ahead	almost all
Germany	Gaspool	59	very little	no data	almost all
Germany	NCG	79	very little	no data	almost all
Belgium	Zeebrugge	62	very little	no data	All
Italy	PSV	45	very little	no data	All
US	Henry Hub	approx 7,500	approx 30x physical	2% is year ahead	Both significant

In terms of information requirements, it is worth noting that EU law describes a very prescriptive set of information that TSOs must publish.[29] Specifically the EU Regulation states:

> "Information to be published at all relevant points and the time schedule according to which that information should be published
>
> 1. At all relevant points, transmission system operators shall publish the following information about the capacity situation down to daily periods on the Internet on a regular/rolling basis and in a user-friendly standardised manner:
>
> (a) the maximum technical capacity for flows in both directions;
>
> (b) the total contracted and interruptible capacity; and
>
> (c) the available capacity.
>
> 2. For all relevant points, transmission system operators shall publish available capacities for a period of at least 18 months ahead and shall update that information at least every month or more frequently, if new information becomes available.
>
> 3. Transmission system operators shall publish daily updates of availability of short-term services (day-ahead and week-ahead) based, inter alia, on nominations, prevailing contractual commitments and regular long-term forecasts of available capacities on an annual basis for up to ten years for all relevant points.

[29] *Op. Cit*. footnote 25 Annex I section 3.3.

> 4. Transmission system operators shall publish historical maximum and minimum monthly capacity utilisation rates and annual average flows at all relevant points for the past three years on a rolling basis.
>
> 5. Transmission system operators shall keep a daily log of actual aggregated flows for at least three months.
>
> 6. Transmission system operators shall keep effective records of all capacity contracts and all other relevant information in relation to calculating and providing access to available capacities, to which relevant national authorities shall have access to fulfil their duties."

In the US, interstate pipelines are required to maintain an "electronic bulletin board". This must show:

- Details of the capacity holdings of all shippers, including whether a particular contract was discounted or not.
- Where spare capacity is available.
- Where primary capacity holders have spare capacity that they would like to sell.
- Requests to trade out imbalance positions.

A. Great Britain (GB)

Gas transport capacity rights

The liberalization of the GB gas market[30] occurred with the passing of the Gas Act in 1996, which was followed by the creation of the Network Code in 1996. The Network Code laid out the rules for using the GB National [gas] Transmission System or NTS. The Network Code defined a system of entry-exit tariffs, as well as a Virtual Trading Point called the National Balancing Point or NBP. Once gas had been injected into the NTS at an entry point, the gas was 'in' the system and so could be traded with another party at the NBP, and then extracted from an exit point. Almost all GB gas trading takes place at the NBP. Note that prior to introduction of the Network Code and the NBP, trading took place at entry points – presumably because this was a common point where the production of many producers mingled. Because trading activity was split among several physical entry points, trading was much less liquid before the introduction of the NBP. The TSO, National Grid Gas (NGG) sells primary entry transport capacity by auction, and exit capacity is sold at regulated prices on a first-come-first served basis. Auctions for entry capacity were felt to be necessary to give clearer signals as to the need for further investment at different entry points. This in turn was motivated by relatively rapid changes in the locations where gas was injected into the NTS, as offshore fields declined and other sources of gas, such as LNG, became more important. In contrast, demand at exit points was more stable and so an auction was not felt to be required. Note that in the first years of market liberation, the incumbent

[30] Note that we refer here to the gas market of Great Britain (GB), as opposed to the United Kingdom (UK). The UK includes Northern Ireland, which has a different gas market and trading arrangements than GB. All the arrangements we discuss apply only to GB.

British Gas played a market maker role. However, there is no longer an official market maker in the GB gas market.

Imbalance market

The Network Code, which was established in 1996, reduced the balancing period for GB shippers from one month to one day – though the change was implemented gradually with increasingly penal charges for imbalances and decreasing tolerances. The full daily balancing regime only came into effect in October 2002. The responsibility for balancing the system on a daily basis was assigned to Transco (later renamed as National Grid Gas or NGG), which both owned and operated the NTS. Between 1996 and 1999 Transco balanced the system using its Flexibility Mechanism, which enabled shippers to buy gas from, or sell gas too, Transco at specific entry points on the NTS. However, the Flexibility Mechanism was perceived as being an inefficient and costly way to balance the NTS, mainly because it did not allow shippers to resolve imbalances between themselves.[31] Accordingly, the New Gas Trading Arrangements replaced the Flexibility Mechanism in 1999 with the creation of one of the key trading institutions in the GB market – the 'On-the-day Commodity Market' or OCM, which is an exchange used for short-term balancing of the NTS.

The key difference between the old Flexibility Mechanism and the OCM is that the latter system enabled shippers to resolve imbalances with one another, and to do so at the NBP rather that at specific physical entry points. This led to a much greater liquidity in trading. Transco also actively traded on the OCM, buying and selling gas in an effort to balance the system. The net cost of balancing the system is passed onto the shippers or users of the NTS. To ensure that NGG minimises these costs the regulator gives it a financial incentive to balance the system at a price of gas as close as possible to the average price of all trades on the OCM – the System Average Price or SAP. This avoids NGG trying to balance the system by trading heavily at the end of the day, which could drive price up (or down) and increase the cost of balancing the system.

There are actually three types of products traded on the OCM, which reflect its nature as a balancing market, which is ultimately needed to physically balance the system:

- NBP Title – this involves a transfer of title of gas at the NBP, and may or may not involve a physical change in the gas flow. For example a party could sell gas to NGG at the NBP, and might choose to produce the 'extra' unit of gas sold, or simply to make do with one less unit of gas than it would have had. Therefore NGG cannot be sure what effect NBP title trades will have on the physical balance of the system. However, in general, buying gas and increasing gas prices should elicit more production to resolve a system shortage. Conversely selling gas should help resolve a long system. Most trades on the OCM are NBP title trades.

[31] Professor Yarrow 'The Beesley Lectures: Lectures On Regulation Series X 2000', New Gas Trading Arrangements, 31 Oct 2000. For a more formal economic treatment of some of the problems with the Flexibility Mechanism and the old gas trading arrangements see: Mario Pagliero, Strategic interaction on the UK Gas Transportation System: the St. Fergus and Bacton constraints, *Energy Economics*, Volume 25, Issue 4, July 2003, Pages 345-358.

- NBP Physical – after the trade has taken place, the counter party will identify where in the system gas will be delivered, or where it will be removed from the system. NBP Physical trades result in a physical change in flows, and NGG knows where the change will take place.

- NBP Locational – gas is offered or bid for at a specific entry or exit point. NGG uses these kinds of trades if it needs to balance one specific part of the system. That is, the NTS as a whole may be in balance, but there could be too much gas in the north of the system (meaning excessive pressure) and too little in the south (meaning pressure is too low). NGG can resolve these issues by using locational trades. NBP Locational was in fact the only product available under the old Flexibility Mechanism.

NGG is always a counter party to the Physical and Locational trades, but NBP Title trades can, and usually do, occur between shippers without any involvement from NGG. Shippers can trade with each other to resolve imbalances from 12:00 on D-1 (that is one day before the start of the gas day), until 03:35 on the gas day itself – that is, with about 2.5 hours left of the gas day to run (in the GB market the gas day runs from 06:00 to 06:00). After that time no more trading can take place for that gas day. All OCM trades are physical, in the sense that the contracts specify the delivery of a certain volume of gas at a certain time. However, traders can and do close out their physical positions, for example by selling gas all the gas that they have bought leaving them with no net physical gas deliveries. Accordingly, the volume of gas traded is far higher than the volume that is actually delivered.

Traders that are short of gas after the conclusion of the gas day – so have taken out more gas than they put into the system – must pay NGG the System Marginal Price (SMP) for the gas shortage, which is the highest price of gas traded on the OCM that gas day. Shippers that are long on gas are paid the lowest price of gas traded on the OCM that gas day. The use of ‘marginal’ prices gives shippers the incentive to balance.

Trading on the OCM takes place in defined bundles or lots of gas of 1,000 therms or about 29 MWh – the minimum trade is for four lots or 117 MWh. The minimum amount that a bid or offer can be increased or decreased (the ‘tick size’) is 0.34 pence/MWh.

The current Market Operator (MO) of the OCM is APX-Endex, which bought the original MO EnMO. OCM trades are anonymous and cleared, with APX gas as the counter party, and trading is screen based using the APX’s trading system.

Main gas trading institutions

As well as the OCM discussed above, the APX also operates a gas trading exchange – the NBP Gas Prompt Market. This market is a cleared exchange with APX Gas acting as the counter party, where Day Ahead, Weekend, Balance-of-Week, Working-Days-Next-Week, Balance of Month and Front Month gas products are traded. However, APX informs us that the NBP Gas Prompt Market is relatively illiquid, and that most exchange-based trading is done on the OCM.

OTC trading at the NBP represents the most common form of gas trading in the GB gas market.[32] As described in section B, OTC trading is bilateral trading involving the use of standardised contracts, and is separate from trading on the OCM. In the case of the GB market traders use the so-called NBP '97 contract.

The InterContinental Exchange (ICE) provides exchange-based NBP futures contracts. Products include consecutive monthly contracts, which as of January 2011 extended to September 2017; Quarterly contracts up to Q1 2014; and Seasonal (Summer/Winter) contracts out to Summer 2017. All trades are cleared by the ICE, and are physical, although most contracts are settled before delivery.

One author estimates that about 70-80% of gas is traded as spot (including OCM trades), or prompt (or close to prompt), with the reminder traded as gas with delivery dates further into the future. Trading of forward gas is relatively illiquid in the GB gas market, although the author notes that since the financial crisis in 2008, the volume trading in ICE futures increased from about 10% of all trading to 30%. The increase is as a result of increased risk-aversion following the financial crisis – traders want both more hedging of gas prices and to do this hedging using cleared trades which remove counter-party risk.

Price and trading data availability

Price reporting in the GB gas market occurs in several ways. Trade journals, which can be accessed by subscription, provide assessments of NBP prices based on surveys of traders involved in OTC trades and are one of the main sources of price information. Platts, which is one of the most widely read trade journals, says that it conducts price assessments by canvassing brokers, traders, foreign and local producers, distributors and end-users. It contacts key market players by phone or email on a daily basis, and canvasses other smaller players on a less frequent but regular basis. In addition, some companies email Platts with trade and market information. For each market – including the GB market – Platts aims to speak to the participants that were most active in the market on a particular day, and Platts reporters aim to call 8-10 players per market each day.[33]

APX-Endex publish price data for both the OCM (System Average Price and System marginal Prices, both high and low) and the NBP Gas Prompt Market for any products traded. The price data is the result of actual trading activity on the exchange, rather than a survey of traders. The ICE publishes the latest prices of all its traded products as well as the open interest in those products on its website, free of charge. The ICE also publishes a gas price index, which it calculates at the close of trading on the calendar day that the front month contract expires (that is the last but one business day of each month). The index represents the un-weighted average of all settlement prices from the expiring front month contract. This index is used to settle financial and physical contracts.

---

[32] See 'The Evolution and Functioning of the Traded Gas Market in Britain' Patrick Heather, August 2010, *Oxford Institute for Energy Studies*, p.25.

[33] For more details see *Platts* Methodology and Specifications Guide European Natural Gas Assessments and Indices, April 2010.

NGG, its role as TSO, publishes a wealth of information on the NTS and related issues including:

- Aggregate flows into the NTS
- Forecast and outturn demand
- Interruptions
- Weather variables
- System balance history, including opening and closing linepack
- Data on gas storage levels
- Data on flows by terminal including from main interconnection points to other countries and from offshore production.
- System Average and Marginal Prices set by trading on the OCM;
- Amount of gas traded on the OCM, number and volumes of trades and number of unique parties trading.

All the data is available on NGG's website. Note that all price data is reported anonymously – details of individual transactions are not released.

Main participants in the market

There are currently about 30 firms that participate on a daily basis in the GB market, and a further 50 that are present but less active. A paper by Patrick Heather, a former trader in the GB market, organises the main participants into four groups as shown in Figure 6.1.

Figure 6.1: Main participants in the GB gas market[34]

Banks and funds	Producers
J.Aron(GoldmanSachs), Barcap, BNP, Calyon, Centaurus, Citadel, Citibank, Credit Suisse, Deutsche, Elliott Advisors, Macquarie, Merrill Lynch, JP Morgan, Morgan Stanley, Nomura, Tudor	BG Group, BP, Conoco, ENI, ExxonMobil, Gazprom(GM&T), Shell, Statoil, Total
End-users	**Proprietary Traders**
Accord(Centrica), EDF Energy, Eon, RWE, Scottish Power, Scottish & Southern, Smartest, Wingas (UK)	EDF Trading, Gunvor, Hetco, Koch, Mercuria, Noble, Vitol

Roles and Responsibilities

In the GB market, the NGG is the TSO, in that it owns the main pipeline network and is responsible for the day-to-day management of the NTS. In particular, NGG is responsible for measuring the imbalance position of shippers and administering imbalance charges. Shippers must make nominations to NGG for inputs and outputs to the system, for each entry and exit point. They can do this up to 30 days in advance of the gas day, and are able to re-nominate up to 04:00 on the gas day itself. However, nominations to input gas into the system do not have to be matched by output nominations, because the shipper may well be planning to trade the gas and but does not know who the counter-party is at the time it makes the input nomination.

Shippers must also inform NGG of trades at the NBP, so that NGG can make adjustments for the calculation of the shippers' imbalance charges. Nominations by the seller must match the nomination by the buyer in terms of quantity and timing of the trade, or else the nomination will be rejected and the parties risk being out of balance.

For trades on the OCM, MO (APX-Endex) will make nominations on behalf of shippers/traders to NGG. Trading on the OCM then eliminates the risk that trades will not be reported properly to NGG – that is that nominations by the seller and buyer fail to match, since APX-Endex assumes this risk. For NBP Gas Prompt Market trades, APX-Endex nominates the market parties net position to NGG – the market party is then responsible for making a matching nomination in the 'other' direction.

The Information technology system that shippers actually use for making nominations to NGG is run by a separate firm called xoserve. Xoserve also handles the administration of the metering, handles all of the data read by the meters and sends out invoices on behalf of NGG, as

[34] *Loc. cit.* footnote 31 Table 7.

well as managing the data base that enables customers to switch supplier, and managing all the information relating to the 22 million gas supply points in Britain. Xoserve is jointly owned by the five major gas distribution Network companies and NGG.

The Joint Office of gas transporters is responsible for maintaining the Uniform Network Code (UNC), which applies to the NTS and the lower pressure Local Distribution Zones or LDZs.

There is no formal communication of information from the gas network operators to the electricity network. All the required information, for example on planned electricity production etc. is supplied by generators and end users.

Nominations

To enable NGG to plans its system management, shippers must tell NGG how much gas they plan to inject or withdraw at each entry and exit point over the following gas day. The timetable for nominations varies slightly for customers that are metered on a daily basis, which we shall for convenience call larger customers, and for non-daily metered customers – 'households'. Shippers must nominate their planned offtakes for large customers at 13:00 on the day preceding the gas day, and the nomination deadline for inputs is 30 minutes after that. NGG itself makes the nominations for households and other small gas users at 14:00. Shippers do not need to submit matching nomination schedules, because trading at NBP will in any case introduce differences between a shipper's inputs and outputs.

After 15:00 on the day preceding the gas day, shippers can change their nominations – a process called re-nomination. This is possible until up to 04:00 on the gas day, so in other words with only 2 hours of the gas day left. So the purpose of nominations is not to constrain the shippers into a rigid schedule, but rather to ensure that NGG has sufficient warning of shippers' plans so that it can manage the system properly. Note that shippers nominate a volume over the gas day, which is assumed to be constant. In reality gas flows will vary over the gas day, but this can be handled by re-nominations. For example, a shipper wishing to increase its injection flow rate within the gas day will simply re-nominate a higher volume.

So that NGG can track shippers' imbalances, shippers must also tell NGG about trades they have made. Shippers make so-called Trade Nominations up to 30 days before the gas day or as late as 04:00 on the gas day. Both the buyer and seller must make nominations to NGG, and the volumes need to match.

Note that the MO, APX-Endex, will complete re-nominations for its members' Net Daily Positions for relevant NBP trades at 17:35hrs on the day preceding the gas day. The Member is then required to submit matching input or output re-nominations to NGG by 19:00hrs. For example, if the shipper has a net position which means that it has sold 10 MWh of gas, then the MO, acting as the counter-party to the trade, will tell NGG that it has sold 10 MWh of gas to the shipper, and the shipper must then confirm that it has bought 10 MWh of gas from the MO.

NGG applies a penalty or scheduling charge if shippers' nominations differ from their actual inputs or offtakes by more than a defined tolerance. NGG considers input nominations and offtakes and output nominations and offtakes separately. Specifically, it will compare the sum of a shipper's nominated inputs with its actual inputs, and the sum of a shipper's nominated outputs with its actual outputs.[35] NGG applies a two-step scheduling charge. Shippers are allowed to deviate from their nominations by up to 3% of the nominated quantities without charge. Where the difference between nominated and actual flows is greater than 3% but less than 5%, NGG will charge the shipper 2% of the System Average Price for the quantity that is beyond the 3% tolerance band. For example, suppose a shipper nominated an input of 100 MWh – they would have a tolerance of 3 MWh. If the actual input was 104 MWh, then NGG would charge the shipper for the scheduling imbalance quantity (4 MWh less the 3 MWh tolerance) multiplied by 2% of the System Average Price. If the difference is greater than 5% then NGG charges the shipper 5% of the SAP times the amount in excess of the 5% limit. So returning to the previous example, if the actual input was 107 MWh, then the shipper would pay 2% of the SAP times the first scheduling imbalance quantity (which would be 5 MWh less the 3 MWh tolerance) plus 5% of the SAP times 2 MWh (7 MWh less 5 MWh). A similar arrangement applies for outputs, but the tolerances are larger and depend on the type of output point, for example whether it is a daily-metered site or a large user.[36]

Trading of secondary transport capacity

In the GB system, shippers can trade capacity among themselves and the rules for trades and transfer of capacity is governed by section 5 of the Uniform Network Code.

The trading arrangements are different for entry capacity and exit capacity. Shippers are allowed to trade entry capacity within a defined Aggregate System Entry Point (ASEP), which are one or more system entry points that NGG considers as being substitutes for one another. For example, entry points physically close to one another would normally be in the same ASEP.

However, until 2007, it was not possible for shippers to trade capacity from one ASEP to another – presumably because NGG did not regard these products as substitutes. For example, shippers could not swap entry capacity at St. Fergus, in Scotland, with entry capacity at Bacton, in the east of England. Since 2007, NGG has applied so-called exchange rates for inter-ASEP capacity trades. So for example 1 unit of capacity at St. Fergus might be swapped for 0.5 units of capacity at Bacton. The exchange rate depends on a technical analysis of the system and predicated gas flows. However, capacity trades between ASEP's cannot be done bilaterally, but must be done via NGG who will determine the appropriate exchange rates to use.

Entry capacity can be traded and transferred for a day or a period of consecutive days for which the primary capacity holder owns the capacity. Both the buyer and seller of capacity must notify NGG of the capacity transfer, detailing the amount to be transferred, the relevant entry (or exit) point and the period of the transfer. Shippers can notify NGG of the transfer up to 04:00 on the gas day that the capacity is being used. Note that liability for all payments and obligations

[35] NGG actually looks at groups of entry and exit points, rather than the shipper's whole portfolio.

[36] See section F.3 of the Uniform Network Code for more details of scheduling charges.

remain with the primary capacity holder, and as a result NGG does not need to check the creditworthiness of the capacity buyer.

Shippers can advertise to buy or sell capacity on an electronic Bulletin Board, and inform NGG of the exchange of capacity using the ‘Gemini’ IT system. Note that the Bulletin Board is not an exchange, and any transfers of cash for capacity bought or sold takes place privately between shippers.

At present, shippers (including end users) cannot trade exit capacity either between exit points or to another user at the same exit point. If shippers want to increase or decrease their exit capacity they must buy capacity from or sell capacity to NGG. The exceptions to this are so-called Connected System Exit Points (CESPs), where users can trade capacity among themselves. CESPs are a small number of exit points usually connected to cross-border gas pipelines being used by multiple shippers.

However, under new rules that will come into effect from 1 October 2012, shippers will be able to trade exit capacity from one shipper to another at a given exit point – in other words, the trading arrangements that currently apply to CESPs will apply to all exit points. The other changes that will apply is that shippers taking gas on the lower pressure distribution networks will now no longer book their exit capacity from the NTS directly with NGG. Instead, shippers will book capacity with the Distribution Network Operator, who will make a single exit capacity booking with NGG on behalf of the users on its network.

B. THE NETHERLANDS

Gas transport capacity rights

As in the GB market, the Dutch gas transport system – which is managed by Gas Transport Services or GTS – is an entry-exit system. System users can buy entry and/or exit capacity independently from one another. Once gas has entered the GTS system, shippers can trade it at the Dutch virtual trading point known as the Title Transfer Facility or TTF.

Imbalance market

GTS is responsible for balancing the Dutch gas system. Unlike in the UK, shippers on the Dutch system must balance their inputs and outputs to within a defined tolerance on an hourly basis, as well as balancing on a daily basis to a smaller tolerance. The Dutch balancing regime has recently been modified, and here we describe the main elements of the new arrangements that will apply from April 1 2011, though we will refer to this as the ‘present’ regime for convenience.

In the Netherlands GTS uses the Balancing Price Ladder (BPL) to set imbalance prices and manage system imbalances. The BPL is a series of offers from shippers to either increase production or decrease production, depending on whether the system is short or long. Shippers wanting to make offers on the BPL must register their ‘flexibility instrument’ – in practice a gas storage facility, a producing gas field or some other mans of varying gas production – with GTS, and the instrument must meet certain minimum technical requirements in terms of the speed at which it can deliver or withdraw gas from the system. Approved bidders then make offers on the BPL on a daily basis, up to eight hours before the hour of delivery.

The BPL is a therefore a one-sided market, in which GTS is always the counter party, and in some ways is analogous to the GB Flexibility Mechanism. The main difference with the Flexibility Mechanism is that in the BPL system offers are made in advance, so the menu of bids and offers is known to GTS, whereas the Flexibility Mechanism involved calling for bids and offers as and when they were required. The BPL system appears to be very similar to that used in the Dutch electricity market to resolve imbalances, and this could be where the inspiration for the market design came from.

Shippers that contribute to system imbalance – for example shippers who are short when the system is short – will have to pay their share of the costs of balancing the system. For example suppose that the one group of shippers is 90 GWh long, and another is 200 GWh short, so that the entire system is 110 GWh short. The system can tolerate an imbalance of 100 GWh by using linepack (gas stored in the pipes) but GTS must bring the system back to being only 100 GWh short by calling from offers from the BPL. GTS buys 10 GWh from the BPL at the marginal BPL price – say 30 €/MWh. GTS also buys the 90 GWh of gas from the shippers that were long at this marginal price. The shippers who were collectively 200 GWh short must pay for the imbalance costs (equal to 100 GWh priced at 30 €/MWh). Note that settlement of imbalances only occurs when the system exceeds the tolerance level of imbalance and GTS needs to take a balancing action and buy gas from or sell gas to the BPL. If the system has not exceeded the tolerance level, then shippers can hold an imbalanced position indefinitely.

Reversing the example, one group of shippers is 90 GWh short, and another is 200 GWh long, so that the entire system is 110 GWh long. The system can tolerate an excess of 100 GWh of gas by using linepack (gas stored in the pipes) but GTS must bring the system back to being only 100 GWh long by calling from offers from the BPL to buy gas. GTS sells 10 GWh to the BPL at the marginal BPL price – say 15 €/MWh. GTS also sells 90 GWh of gas to the shippers that were short at this marginal price. In other words, these short shippers are forced to buy gas at 15 €/MWh. The shippers who were collectively 200 GWh long must sell their gas for the imbalance costs – giving a price of €7.5/MWh (equal to 100 GWh priced at 15 €/MWh, divided by 200 GWh).

Shippers can also trade between themselves to try and resolve imbalances, either bilaterally or on the within-day market (discussed below). Unlike in GB, the TSO does not trade with shippers in the within-day market, and the within-day market plays no role in setting imbalance prices. Both the BPL market and the within-day market will be trading simultaneously.

We note that the previous balancing regime involved a purely administered price for imbalances which GTS set. The new mechanism (BPL) is therefore a move toward more market-based balancing prices. However, we understand that the choice not to create a system similar to GB OCM market, which combined a balancing market with commercial on-the-day trading, has been controversial. Apparently GTS did not trust that the existing Dutch within day gas market was sufficiently liquid to give reliable balancing prices, and wanted to wait until there was sufficient liquidity. On the other hand, critics say that creating a separate balancing market in the form of the BPL will split liquidity, making it more difficult to attain the desired goal of a liquid within-day gas market in the Netherlands.

Main gas trading institutions

APX-Endex operates a within day and day-ahead gas market (APX Gas NL), where balance of day, day-ahead, working days next week balance of week and weekend gas products are traded. All trades are cleared by APX-ENDEX. Currently Vattenfall, a large utility, acts as a market maker on the day-ahead market.

APX-Endex also operates a futures market. Products traded are three consecutive monthly contracts, four consecutive quarterly contracts, six consecutive seasonal contracts and four consecutive annual contracts. APX-Endex also clears OTC forward trades for its members, and regards OTC forward contracts and futures contracts traded on the exchange as interchangeable for the purposes of netting. At expiry date, all net positions will be physically delivered. A counterparty that does not want to be involved in physical delivery can sign a close-out agreement with the clearing house. In this agreement, the counterparty assures that it will close all open positions before expiry date.

As in GB, most trading in the Netherlands is carried out by off-exchange OTC trading taking place at the TTF.

Price and trading data availability

As in the GB market, price data is available from trade journals such as Platts, who survey market participants on a daily basis to make price assessments. APX-Endex, the exchange, also publishes the price results of its exchange-based trading, and this price information can be bought by market participants. APX-Endex also publishes summaries of the volume of trading that took place each month, both in the spot and futures markets.

GTS, the TSO, also makes a wide range of data available, including the average day-ahead price from the exchange, which GTS used for settling imbalances under the ‘old’ balancing system (which will operate until April 2011). The TSO also publishes a wide range of information regarding the available transport capacity on the system including:

- Data on volumes traded at the TTF;
- Data on hourly domestic gas consumption, net exports and flows in and out of storages;
- Historical monthly data on demand, imports, exports, onshore and offshore production and physical imbalance;

- The available capacity of system entry points the current quarter and the following four quarters;

- The number of active shipper portfolios at each entry and exit points – this serves as a proxy for the number of active shippers at each point, although a shipper can in theory have more than one portfolio;

- Data on planned maintenance;

- The average flow per year at each border entry and exit point;

- An indication of available firm capacity on a yearly base for the following 10 years.

Main participants in the market

There are currently about 80 parties active on the TTF, either in OTC trading and/or exchange based trading. There are 26 registered members on the within day and day-ahead gas market, and 45 members on the gas futures market.

Roles and Responsibilities

The main agents in the Dutch system are the shippers that use the system, GTS who operates it, and APX-Endex which operates the gas exchanges. GTS is responsible for operating and balancing the system on an hourly basis. GTS also has a 'provider of last resort' role in the event of extremely cold temperatures (and therefore very high demand) and in the event of the bankruptcy of a supplier.

Shippers are responsible for making nominations on gas injections and withdrawals to GTS, as well as informing GTS of trades undertaken.

Nominations

A shipper will indicate to GTS how much gas he intends to transport at an entry point or exit point at any given hour of the gas day by submitting nominations. Nominations are required at entry and exit points wherever GTS needs nominations for technical transport reasons or for the purpose of calculation of the assignment of interruptible capacity. In practise we understand this means almost all entry and exit points.

Shippers must submit nominations to GTS on the gas day preceding the gas day on which the gas will flow. In principle re-nominations are allowed at the latest up to 2 hours before the hour to which the re-nomination refers.

As in GB and other gas markets, trades must also be notified to GTS via a nomination. Trade nominations on the TTF are governed by the "lesser rule" principle. This means that if there is a difference between the nominated volumes of the two shippers or traders who report a gas trade, the lesser volume will be confirmed to both parties by GTS. (Re)nominations at TTF points can be made at the latest up to 30 minutes before the hour to which the nomination refers.

Confirmation at TTF points will be given after matching the nominated volumes of the two parties transferring gas to one another, in accordance with the “lesser rule” principle. Both parties will receive a confirmation with the status ‘settled’ in case the nominations match. A (re) nomination by one of the parties will not lead to an adjustment of the confirmation with the status ‘settled’. Not until both parties send new matching nominations, will a new confirmation with the status ‘settled’ follow for the new matching volume.

Trading of secondary transport capacity

Shippers in the Netherlands can trade both entry and exit capacity, under rules governed by the Dutch Network Code (Transmission Service Conditions or TSC). GTS runs a Bulletin Board where shippers can advertise bids or offers for capacity and engage in bilateral exchanges, and as in the GB gas market all payments take place bilaterally between shippers. Actual transfers of capacity can be processed by GTS’s ‘GEA Click & Book’ system or by faxing or mailing an application form to GTS.

Unlike the GB system, shippers can only trade entry or exit capacity to another shipper at the same entry or exit point. In other words, a shipper can only sell entry capacity at entry point A to another shipper who would like capacity at entry point A. There is no equivalent of NGG’s exchange rate system.

Also unlike the GB system in the Netherlands all obligations are transferred with the capacity, and the original or primary capacity holder transfers any obligations associated with the capacity. Accordingly, capacity transfers are subject to a check by GTS on the creditworthiness of the buyer. GTS confirms the request for a transfer of capacity on the day the request is received electronically or within four days of receipt of the request if the request is faxed/mailed.

C. GERMANY

Germany is unusual within the EU, in that it has several large separate pipeline systems covering its territory, owned and operated by different TSOs. In this sense at least Germany is similar to Colombia which also has several different pipeline owners and operators on its territory. We understand that all of the TSOs have similar procedures, and so we have based the detailed descriptions of nominations etc. on the network of Open Grid Europe, which is one of the largest TSOs in Germany.

Gas transport capacity rights

All the German TSOs use a system of entry and exit capacity, which was defined by law in Germany in 2006. Prior to the introduction of the entry-exit system capacity rights were defined on a point-to-point basis. The switch to an entry-exit system was made explicitly to encourage the creation of market areas where gas products could be traded. Indeed, in a discussion with a senior member of staff at the German energy regulator (the Bundesnetzagentur or BNA) the BNA claimed that the single most important development in increasing competition in the German market was the move away from point-to-point capacity to entry-exit capacity. The regulator claimed that this change in the way transport rights were defined was critical to the development of trading and competition.

While Germany has entry-exit capacity rights, unlike in most EU markets there is not at present one single market area. Indeed, when the system of entry-exit was first introduced in Germany there were over 20 different market areas, divided by network ownership, transport constraints on the system and gas quality. This meant that trading was fragmented across many different market areas, and that transporting gas from one side of Germany to the other involved buying multiple entry and exit capacities, as shippers left one system and entered the adjacent system.

Eventually the so-called 'two-contract' model emerged, whereby the market areas expanded to include several networks with different owners. Within a market area, the shipper could hold one contract for entry capacity and another for exit capacity (hence 'two contracts'), even if the gas physically travelled across several different networks with different owners. This was in contrast to having to buy entry and exit capacity from each individual network, and sometimes within sub-systems owned by that network.

At the time of writing Germany has six market areas, although this should reduce further in future.

Imbalance market

Germany operates a system of daily balancing, meaning that shippers have to match inputs and outputs to each market area over the course of a gas day. If the shipper is long at the end of the gas day, it sells gas to the network operator and if the shipper is short it buys gas from the network operators. The price for selling gas to the network operator is 90% of the second lowest price of NBP (the GB gas market) TTF (Dutch market), Gaspool and NCG (these last two are the main German gas markets, discussed below). Similarly, the price for buying gas from the network operator is 110% of the second highest price of the same four markets. The methodology for determining the imbalance price was determined by the BNA, which chose these four markets because it judged them to be sufficiently liquid. Accordingly, trades on the NBP can determine the price of balancing gas in Germany, despite the large physical distance between the German and GB markets. The BNA determined a 'spread' around the reference gas prices of 90%/110%, the idea being to give shippers an incentive to balance over the gas day without facing excessively penal charges.

Shippers also have to stay within certain limits on an hourly basis, as in the Netherlands. The hourly balancing requirements vary according to the type of customer. Shippers must balance large (more than 300 MWh/h) metered customers on an hourly basis. For other daily-metered industrial, shippers must inject gas at a constant rate equal to the average daily consumption of the customer. If the shipper deviates from the required flat input, it will pay a scheduling fee, equal to 15% of the average of the prices for negative and positive daily balances.

Shippers can trade between themselves to manage both daily balance volumes and hourly balancing requirements, and they can also trade a within day gas product on the gas exchange (see below).

The responsibility for balancing the system throughout the gas days falls to the network operators, who use linepack and storage to meet the variability in gas demand throughout the day. Network operators have held tenders to procure balancing gas and day-ahead gas, in a system similar to the new Dutch balancing system (which uses a Balancing Price Ladder, formed by market offers).

The net costs of keeping the system in balance within the day are then allocated to shippers, in proportion to the volumes that they have delivered. Large customers are not allocated costs, because they (or their gas suppliers) are responsible for their own hourly balancing.

Main gas trading institutions

As we describe above, Germany is divided into six market areas, and OTC trading takes place in each market area. The initial market areas were defined by differences in gas quality and physical constraints on the system, but over time the market areas have merged and consolidated. The two largest market areas that have emerged as the focus of trading are the NetConnect Germany (NCG) market area and the Gaspool market area. Both market areas consist of the networks of several different transmission companies, and new networks are occasionally added and the areas expand.

A variety of OTC products are traded in both market areas – for example the trade press give price assessments for Gaspool for day-ahead and front month contracts and for NCG the same products as well as the following season and the following calendar year. Presumably the trade press assesses more products on the NCG market because it is more liquid.

The European Energy Exchange or EEX trades a variety of cleared gas products that are delivered at either NCG or Gaspool hubs. EEX clears within day and day-ahead products for both market areas, as well as front month, following quarter and the following calendar year. These are all physical products, and trading is continuous. EEX also holds a single daily auction, for smaller lots of gas (1 MW as opposed to the minimum 10 MW trance on the continuous trading platform).

EDF Trading Limited acts as the market maker for trading on the EEX, and submits quotes for the first two front months and front quarters in the NetConnect Germany (NCG) market areas.

Roles and Responsibilities

As described above, shippers are responsible for making nominations to the network operators regarding the volumes they plan to inject the following day. The shippers must make an estimate of the offtake of large daily-metered customers to be able to make their nomination. The network operators make estimates of the Standard Load Profile of non-daily metered customers – in other words their best estimate of the volumes of gas these customers will use over the course of the day. These profiles are communicated to the shippers, who must then inject these volumes into the network at a constant rate over the course of the gas day.

For OTC and bilateral trades, buyers and sellers must submit matching transfer nominations to the network operator. In the case of a mismatch between the volumes, the network operator will use the lower of the two volumes.

Trading of secondary transport capacity

Network users can buy or sell transport capacity on an internet-based trading system called 'trac-x'. Trac-x users (including registered visitors to the site) can check how much capacity is available at each point on the network and see all bids and offers for capacity. The term of capacity rights traded varies from daily capacity to 16 year capacity rights. In December 2010 an average of 8,548 GWh/h per day of capacity was traded, all of this for capacity from at least one month in duration. As in the GB system, once capacity is sold all rights and obligations also transfer to the new capacity holder.

However, in our conversation with the BNA they reported a number of problems with the system of secondary capacity trading. First, until recently each network had operated a separate trac-x system, which diluted liquidity in the market for secondary capacity. The BNA will introduce new rules for a single trac-x system, where all network capacity will be bought and sold.

Second, the BNA thought that there were insufficient incentives for incumbent players to sell unwanted secondary capacity, and that the use-it-or-lose-it rules were currently ineffective. Under the current system, a user can hold capacity, even if it uses it for only one hour a year. Under the new system, holders of capacity will be required to inform the relevant TSO of the capacity it wants to use before about 14:00 on D-1. The TSO will then offer any capacity that is not nominated on the trac-x system on a firm basis. The BNA will also limit the extent to which primary capacity holders can re-nominate transport capacity, to prevent then from trying to claim back un-nominated capacity at a later stage in the gas day.

D. Belgium

Gas transport capacity rights

Belgium has an entry exit system of capacity rights – however, the Belgian area is divided into four zones, and shippers must also book capacity between each zone. As a result there is no virtual trading point or VTP within the Belgian system.

Imbalance arrangements

The Fluxys network is divided into two balancing zones, and Fluxys calculates shippers' imbalances over each zone separately.[37] Balancing is done on an hourly, daily and cumulative basis. For cumulative balancing, an account is kept of the running total of the shipper's hourly imbalances across each day. The cumulative imbalance is then reset to zero at the beginning of the next day. The idea behind cumulative balancing is that it avoids shippers from being persistently short or persistently long throughout the day only to offset their imbalance in the final hour of the day to avoid a daily imbalance penalty.

Shippers are allocated a separate imbalance tolerance for each of hourly, daily and cumulative balancing. If shippers stay within these tolerances they face no tariff supplements. However, shippers who exceed the upper limit of the tolerance or are below the lower limit of the tolerance may have to pay one of Fluxys's tariff supplements for balancing obligations. These supplements are based on the market value of gas as set according to rules outlined by Fluxys.

Shippers are allocated imbalance tolerances when they purchase transportation capacity rights from Fluxys. Holders of both firm and interruptible capacity qualify for imbalance tolerances. The amount of tolerance given to a shipper depends on the amount of capacity purchased and type of supply point the shipper is using. For instance a user supplying gas to a customer without daily metering capabilities (usually a household customer) may be given a different tolerance to a user who has booked capacity at a storage injection site. Shippers can also purchase additional imbalance tolerance from Fluxys. This is then added to any imbalance tolerances they have from purchasing transportation capacity from Fluxys. Additional tolerances are only available for cumulative and daily balancing. Shippers can also trade their imbalance tolerances with one another in the secondary market.

The upper limit of the imbalance tolerance relates to shippers who have put more gas into the system than they take out (*i.e.* shippers who are long). The lower limit relates to users who have taken more gas from the system than is put into the system (*i.e.* shippers who are short). For hourly imbalances above the upper tolerance limit, Fluxys does not charge a tariff supplement. However, if the hourly imbalance is below the lower limit, the tariff supplement is equal to the imbalance overrun multiplied by the capacity component of the annual firm transportation tariff divided by 365.

[37] During the preparation of this report, Fluxys announced that it would be moving to a single balancing area. No further details were available at the time of writing.

Fluxys buys and sells gas to try and balance the system, but there is no dedicated balancing market or within-day market. Fluxys's trades are done bilaterally with shippers.

Fluxys's tariff supplements for daily and cumulative balancing are based on a "reference price". Because there is no Belgian balancing market equivalent to the GB within-day market, the reference price is either the day-ahead price at the Belgian physical hub (discussed below) for the day prior to the imbalance, the SMP-buy or SMP-sell price from the On-the-day Commodity Market in Great Britain for the day on which the imbalance occurred, or the price at which Fluxys bought or sold gas for balancing purposes. The exact value of the reference price depends on whether the user is short or long. If the user has exceeded the lower tolerance limit (*i.e.* is short), the reference price is the maximum of the Zeebrugge price, the SMP-buy price and the priced paid for gas by Fluxys for balancing purposes. If instead the user exceeded the upper limit (*i.e.* the shipper was long), the reference price is the minimum of the Zeebrugge price, the SMP-sell and the price at which Fluxys sold gas for balancing purposes.

The tariff supplements for daily balancing have two components: a commodity part and a penalty part. The commodity term is always the reference gas price for the part of the imbalance that is greater than the tolerance level. When the shipper exceeds the upper tolerance, Fluxys pays the shipper the commodity tariff and therefore returns part of the value of the gas to the shipper. The size of the penalty charge depends on the size of the imbalance. The penalty is:

- 40% of the reference price for the part of the imbalance that is above the tolerance but less than or equal to the allowed tolerance plus the daily imbalance tolerance.

- 60% of the reference price for the part of the imbalance that is more than the allowed tolerance plus the daily tolerance and less than or equal to the allowed tolerance plus twice the daily tolerance.

- 80% of the reference price for the part of the imbalance that is more than the allowed tolerance plus twice the daily tolerance and less than or equal to the allowed tolerance plus three times the daily tolerance.

For imbalances that exceed the cumulative tolerances, the user only pays the penalty which is calculated as set out above for daily balancing. To avoid paying the penalty twice, once through daily imbalance penalty and once through the cumulative imbalance penalty, only the higher of these two penalties is charged.

Main gas trading institutions

Belgium's division into four balancing zones means that there is little trading within the entry-exit system. Instead, trading in Belgium is dominated by the Zeebrugge hub, which is on Belgium's east coast. The Zeebrugge hub is one of the major physical trading hubs in Europe. This is in contrast to the 'virtual' trading hubs associated with entry exit systems. Entry-exit hubs are virtual in the sense that there is no tangible physical location for gas trades. Gas can be traded anywhere within the gas transport system. In contrast, trading at a physical hub involves exchanges at a specific physical location. Traders must be able to get their gas to this location to be able to sell, and take gas away from the location to buy. Like any trading hub, a successful physical hub should be liquid, with as many market participants as possible. Accordingly, physical hubs normally develop where there is a confluence of pipelines and/or sources of gas production. In the case of Zeebrugge, the physical hub is located at the junction of a major pipeline bringing gas from Norway, another large pipeline which connects Belgium to the UK, an LNG terminal and an onshore pipeline which connects Zeebrugge to the rest of the Belgian gas system and other European gas markets. In this sense Zeebrugge is similar to the US Henry Hub, which is also a physical hub situated at the junction of several large pipelines. However, trading at Zeebrugge is far less liquid than trading at Henry Hub.

The operator of the Zeebrugge hub is not the Belgian TSO (Fluxys) but a separate entity called Huberator (which is owned by Fluxys). Huberator manages the physical gas flows at the hub, chiefly ensuring that the traded volumes can actually be delivered. For example, in the event of an outage of a source of gas production, Huberator will attempt to make up the shortfall of gas using gas from storage. This ensures that trading at Zeebrugge is as firm as possible, which gives confidence in the market and promotes liquidity.

Huberator in effect acts as the TSO of the physical hub. Members register their trades with Huberator by means of nominations stating for each hour the volumes of gas transferred and the purchasing and selling counterparties. Huberator then checks if volumes and counterparties effectively match. If not, transactions are adjusted.

Most trading at Zeebrugge is OTC trading. However, APX-Endex operates an exchange for Zeebrugge day-ahead and within-day gas. As with the Dutch exchange, trades are anonymous and cleared by APX-ENDEX. However, we understand that exchange trading at Zeebrugge is relatively thin, and the vast majority of gas is traded OTC.

It is also worth noting that the Zeebrugge physical hub is outside of the Fluxys entry-exit system. Shippers trading at Zeebrugge who then wish to sell gas in Belgium must buy entry capacity upon leaving the hub, as well as exit capacity to deliver gas to the final customer. In this sense, the Zeebrugge hub is an 'island' on the edge of the Belgian system. Huberator note that this is advantageous, at least in the sense that trading fees and other arrangements are not subject to regulation by the Belgian energy regulator. The lack of regulatory interference is felt to be a benefit, in that trading arrangements are kept simple and stable over time.

Main participants in the market

There are about 80 registered traders at the Zeebrugge hub. The list includes a mix of gas producers and marketers/suppliers as well as banks and other financial institutions.

Daily nomination procedures[38]

In order to notify the Transporter of the quantity of Natural Gas that will flow at each Entry Point, Supply Point and Transfer Point (if applicable), the Grid User shall send

[38] *"Master Agreement for Transport and Related Services"*, Attachment C, p.13

Nominations and, if applicable, renominations to the Transporter, according to the following procedure:

The Grid User shall communicate to the Transporter the initial Nominations for each Entry Point, Supply Point and Transfer Point (if applicable), being the nomination received by the Transporter before 14:00 hours on Day d-1 and confirmed by the Transporter. If applicable, the Grid User shall communicate to the Transporter the last renominations for each Entry Point, the Supply Point and the Transfer Point (if applicable), being the last (re)nomination confirmed by the Transporter. If no renomination is received by the Transporter, the last Nomination is deemed equal to the confirmed value of the initial Nomination.

Scheduling Fees[39]

Entry Zone

For entry zones the scheduling fees are calculated on a daily basis, and each entry zone is calculated separately. There is no charge if the nominated daily flow is within 10% of the actual daily flow. Anything in excess of this is charged incurs a scheduling fee, which is calculated as 0.1% of the excess multiplied by the 'standard gas price' of 0.02 €/kWh. For instance:

- If there was an actual flow during the day of 10 kWh, the allowed tolerance would be 10% of 10 kWh, or ±1 kWh. If the nominated flow for the day was 9 kWh there would be no fee as it falls within the acceptable limits.

- If the nominated flow for the day was only 7 kWh then a fee would apply to the excess over the allowed tolerance, which in this case is 2 kWh. The fee would be identical if 13 kWh had been nominated rather than 7 kWh as the excess over the tolerance in both cases is 2 kWh.

Supply Point

Supply point scheduling fees are calculated on an hourly basis. For each Supply Point where the maximum transport service right (MTSR)[40] is higher than or equal to 30,000 $m^3(n)/h$ and the supply point is not an 'aggregated receiving station', the difference between the last nomination and the actual flow must not exceed 100,000 kWh at each hour.

For all other supply points the allowed tolerance is the higher of 30,000 KWh/h or 10% of the available maximum transport service right (AMTSR)[41] for the grid user.

For both cases, anything in excess of the tolerance incurs a scheduling fee which is calculated as 0.1% of the excess multiplied by the 'standard gas price' of 0.02 €/kWh.

---

39 "*Master Agreement for Transport and Related Services*", Attachment B, pp.42-43

40 The MTSR is the transport capacity, expressed in $m^3(n)/h$, to which the Grid User is entitled at the Entry Point, Transfer Point or Supply Point.

41 The AMTSR is the MTSR less any interrupted capacity of which the Grid User has been notified by the Transporter.

Trading of Transit Capacity: Capsquare

Primary and Secondary trading of transit capacity is carried out on a platform called Capsquare. This is a joint effort with GRTgaz, and allows trading of transit capacity between France and Belgium.

Capsquare is a web-based platform to buy or sell secondary market capacity in the Fluxys network (Belgium), and in the GRTgaz network (France). Capsquare also offers primary capacity for both networks at once through the Bundled Fluxys-GRTgaz product Zeebrugge Hub to PEG North.

- Sell - If you hold capacity you do not intend to use, you can realize the value at market price by selling it through the capsquare platform.

- Buy - If you are looking to buy capacity, capsquare provides an alternative source for the standard primary market: you can book single capacity on the secondary market and bundled capacity on the primary market.

A short to medium term trade on capsquare confers all rights and obligations to the buyer except the obligation to pay. Long-term trades are title transfers: all rights and obligations are conferred to the buyer.

E. ITALY

Gas transport capacity rights

In common with the other EU countries discussed here, the Italian TSO Snam Rete Gas (SRG) has defined a system of entry-exit capacity rights. Shippers can then trade gas at the entry points, at the 'city gate' exit points or at the *Punto di Scambio Virtuale* (Virtual Trading Point or PSV), which was established in October 2003. Exchanges at the PSV have increased since the trading point was first introduced, and PSV trades are particularly important for small and very small wholesalers. Particularly, wholesalers who sold less than 0.1Gm3 in 2009 purchased 35% of their gas on the PSV.[42]

Imbalance market

Currently SRG is responsible for the commercial and physical balancing of the Italian gas system and manages the physical daily imbalances of the system mostly through the use of gas storage. SRG verifies the commercial balance of the shippers on a daily basis. The Italian system differs from the others we have discussed, in that there is currently no balancing market, and SRG in effect forces shippers to balance through the use of gas storage, injecting gas into storage on shippers' behalf when they are long and withdrawing gas when they are short. Because shippers are always in balance, there are no imbalance 'cash out' prices. However, shippers must pay for the storage capacity SRG uses on their behalf. Shippers either buy storage directly, which

[42] AEEG 2010 Annual Report, p. 141.

SRG then operates for them to solve imbalances, or if they are unable to buy storage they pay progressive penalty fees to SRG, equal to €0.1/GJ for imbalances between 8% and 15% of the daily withdrawal amount, and €0.3/GJ for imbalances exceeding 15% of the daily withdrawal amount.[43] On a daily and monthly basis SRG informs the storage operators about the shippers' imbalances. Shippers can also trade on the PSV to try and reduce their imbalance position and hence storage costs. However, SRG does not trade in the market to manage system imbalances. Our understanding is that physical and commercial imbalances might not coincide. SRG uses the storage capacity to cover the *physical* imbalances, while users have to pay for their *commercial* imbalances even if sometimes they would offset in the system balance equation, and therefore would not represent actual usage of the storage capacity.

However, the current Italian balancing system is due to be reformed. In 2010 the Italian Energy Authority published three consultation documents which included a proposal to reform the balancing system, to create a balancing market based on economic criteria. The main changes discussed in the consultation documents regard the transition away from the treatment of users' imbalances as an automatic recourse to storage, to the treatment of imbalances as gas sold (or bought) from the operator of the balancing system to the shipper. Under the new system the imbalance penalties would be replaced by the payment of a market-based price for imbalances, in common with other more developed gas markets, and SRG would trade in the balancing market in a similar way to NGG in the GB gas market.

The consultation suggests maintaining the storage as the only balancing tool, at least during the balancing market's start-up. Therefore, the operator of the balancing market will purchase gas to balance the system from users with available storage capacity. These users will have the status of "essential" users of the balancing market. The consultation intends also to maintain the 24 hour gas-day as the relevant balancing period.

Main gas trading institutions

There are currently three main institutions in the Italian market: the PSV (Punto di Scambio Virtuale), the P-Gas, and the M-Gas.

PSV

The PSV was created in October 2003. It is a virtual hub managed by the TSO (SRG) for bilateral transactions. The PSV has initially been set up as a tool for the shippers to balance their position, as it facilitates bilateral transaction between users, enabling them to exchange and trade gas on a daily basis. The PSV has then evolved into the trading of contracts with longer delivery period further out into the future, (weekly, monthly, quarterly basis) which are not related to balancing. Since 2006 parties can trade even without being registered users of the gas transport system, and this has increased the pool of potential traders. That said, the PSV remains relatively illiquid compared to the Dutch and German trading hubs.

43 SRG, Network Code, Charter 9, p. 21.

As a complement of the PSV platform SRG manages a bulletin board where it is possible to advertise both gas commodity and transport capacity offers and requests. Transactions on the PSV bulletin board are not standardised and SRG is not responsible for their clearance.

Operators can still choose to trade gas from pipelines at the entry points, and not at the PSV, but gas delivered via one of the two LNG terminals must be delivered on the PSV. To increase the PSV liquidity, the legislation forces the operators of the two Italian LNG terminals to register all the LNG deliveries at the PSV (since November 2005 for Panigaglia and since October 2009 for Rovigo). There have been also other decisions that have increased the liquidity of the PSV, such as:

- The obligation for ENI to sell certain amounts of gas at the PSV. These "g*as releases*" were decided to fulfil competition requirements;

- The obligation to sell at the PSV a percentage of gas imported from countries outside of the EU;

- The obligation to sell at the PSV the royalties due to the government for the exploitation of national gas fields.

P-Gas platform

Created in May 2010, the P-Gas is a trading platform managed by the GME (Electricity exchange market operator). The P-Gas is a transitory step towards the creation of a 'full' gas exchange market, and will cease to operate once the exchange market is fully operative.

Users of the P-Gas must be registered on the PSV, and all the transaction on the P-Gas are then registered at the PSV. The P-Gas is only a platform and the GME is not a counterparty to the trades, nor are the trades cleared. GME simply passes information on the executed trades to SRG, which registers the position at the PSV. The P-Gas is divided into two trading platform: the Imports' Segment, to sell imported gas quotas of non-EU gas, and, since August 2010, the Royalties' Segment, for the payment of royalties for the exploitation of national gas fields.

In the Imports' Segment of the P-GAS, trading is continuous and contracts in respect of quantities with monthly and yearly delivery periods may be negotiated. In the Royalties' Segment of the P-GAS, trading takes place under the auction mechanism and contracts in respect of quantities with monthly delivery periods may be negotiated.

M-Gas exchange

The Gas Market (M-Gas) started in December 2010, as the second step – after the P-Gas –towards the creation of a gas exchange. At present, it is only a spot Exchange, with two products, day-ahead and intra-day gas. Unlike the P-Gas platform, the M-gas platform is a full exchange, with GME providing a clearing service and acting as counterparty to the trades. As with all exchanges, market participants need to provide adequate financial guarantees for the participation in the market. However, because of the very short-term nature of the products there are negligible collateral requirements.

The day-ahead market includes two sessions: a session that starts at 8am of day D-3, and ends at 10am of day D-1, where the trade is continuous; and a second session, that starts at 10am of day D-1 and lasts 1 hour, where trade takes place through auctions. In the infra-day market trading is also based on auctions.

The scheduled date for the launch of exchange-traded forward gas products is April 2011, but this date is subject to the creation of the balancing market discussed above, to allow the GME to register possibly imbalanced positions on the PSV and close-out the transactions using the balancing market.

Price and trading data availability

The GME publishes the list of operators allowed to trade on the P-Gas and M-Gas.

For the P-Gas and M-Gas, GME also publishes data on the average negotiated price for each day and each type of contract,[44] as well as the number of contracts and the volume of gas traded. However, the platform and the market have been created very recently, therefore there are not many data published yet.

The SRG website publishes the following summary information:

- Monthly data on the number and volume of PSV transactions;
- Every thermal year, a summary of capacities booked for a period of over a year, at each entry point;
- A monthly summary of available and booked capacities at each entry and exit point, for the residual months of the thermal year;
- Daily flows at each entry point – including entry points at the border, from storage and from national production – and segment of consumption (industrial, thermo electrical, distribution network).

Main participants in the market

In 2008 61 players registered transactions on the PSV, and in 2009 the number increased to 82. In 2009, 22 users were pure "traders" as they were not also users of the gas transport system.[45]

[44] In terms of delivery period. However, terms and conditions of contracts with the same delivery period might vary, as noted by GME on the data website.

[45] AEEG 2010 Annual Report, p. 143.

Trading of transport capacity

Transport capacity rights at entry or exit points can be transferred during the course of the thermal year, from one user to another, with the following restrictions, listed in SRG Network Code:[46]

- For Entry Points through pipeline at the border, it is possible to transfer entry capacity rights for any day of the thermal year and for a minimum duration of 1 day.

- For Entry points from national production, storage, exit points and re-delivery points, it is possible to transfer entry capacity rights starting from the first day of each month and for a minimum duration of a calendar month.

Different rules apply when a user demand the transfer of re-delivery capacity rights necessary to serve certain customers that have been acquired by the user. In this case the capacity is transferred for the entire residual duration of the thermal year.

Since July 2009 (thermal year 2009/10), SRG website hosts an electronic bulletin board to support the allocation of capacity at the beginning of the thermal year, as well as the allocation of capacity during the thermal year and the transfer of capacity rights.

F. THE UNITED STATES

The US gas market is regulated both at national (Federal) and local (state) levels. Local distribution networks which deliver gas to all but the largest end-users are regulated at state level and are not described in this report. High-pressure pipelines which move gas from producing to consuming regions and which deliver to the local distribution networks and the largest directly-connected loads, are regulated at Federal level if they cross a state border. Pipelines which are located wholly within a single state are typically state-regulated instead of federally-regulated (even if the gas they transport has crossed the state line).

There are many different companies active in the gas pipeline market in the US, some of them concentrating more or less exclusively on gas transportation, others also owning other businesses (which could include upstream production and processing, as well as downstream distribution and power generation). There is no restriction on gas pipelines transporting gas on behalf of affiliated entities, but there are requirements for operational independence and prohibitions on affiliate favouritism.

Although there is a degree of pipe-on-pipe competition, especially in certain regions of the US, federal authorization is required for the construction of new interstate gas pipelines and all interstate gas pipelines are required to post regulated rates, although negotiated rates are permitted as long as they are below the posted, regulated "recourse rate."

The regulatory arrangements we describe in this chapter are the federal rules which apply to all interstate gas pipelines. Much of the detail of, for example, balancing arrangements, is contained in each pipeline's tariff documentation and can therefore differ from pipe to pipe.

[46] SRG, Network Code, Charter 7, p. 7.

Where there are no generally-applicable rules, we describe examples of the rules in place at a specific but representative pipeline.

Gas transport capacity rights

Interstate pipelines in the US sell point-to-point capacity rights. That is, the shipper holds a contract to transport gas from point A to point B. However, many pipelines offer some flexibility as to where shippers can inject gas within a certain geographic area, and similarly where they can take out gas.[47] This gives the shippers some flexibility as to the exact injection and withdrawal points.

To understand why the US gas industry is organised as it is today, it is helpful to understand the recent history of the industry. Up to the early 1970s both wellhead prices and pipeline rates were regulated by the Federal Power Commission (FPC). Pipelines purchased gas from producers at the wellhead, typically under long-term contracts, and resold the gas to local distribution companies. The oil shocks of the 1970s – where oil-prices rose dramatically – increased demand for gas, but exploration was discouraged by regulation of wellhead prices. In 1978 the deregulation of wellhead prices was partially phased in for newly developed gas, encouraging exploration and development, and a subsequent surplus of uncontracted gas. This created pressure in the early 1980's for spot trading in the surplus gas. The subsequent recession of the early 1980s left pipelines paying high prices under long-term, take-or-pay contracts with lower price surplus gas available on the spot market. The availability of cheap spot gas created pressure for open access to the transmission pipelines, as buyers sought to access the cheap, uncontracted gas. A sequence of FERC orders from Order 436 in 1985 to Order 636 in 1992 encouraged and then mandated that pipelines switch to "contract-carrier" status. The later orders, accompanied by full wellhead price deregulation permitted the reforming pipelines to recover some of the costs associated with their stranded long-term gas contracts, and put in place rules to prevent pipelines from favouring affiliated shippers.

Order 636, among other things, required pipelines to:

- Exit the "merchant function" whereby they contracted for, and resold, gas supplies;
- Act in a non-discriminatory fashion, and ensure that the pipeline is operated independently from any affiliated shippers;
- Facilitate a secondary market in capacity rights, including through the operation "electronic bulletin boards" ("EBBs"); and
- Provide flexibility in terms of primary and secondary receipt and delivery points.

[47] For example, the Columbia Gas Transmission pipeline tariff allows shippers to change entry and exit points, provided that the pipeline "determines in its reasonable discretion" that sufficient firm capacity exists. In addition, the pipeline allows shippers to switch entry and exit points on an interruptible bases. (See Tariff, General Terms and Conditions, Sections 11.2 and 11.3.)

Balancing arrangements

The FERC has not made prescriptive rules about balancing mechanisms on interstate gas pipelines. Rather, the balancing rules for each pipeline are part of that pipeline's "tariff",[48] which must be approved by FERC before it comes into effect. Many pipelines have "monthly balancing": shippers are required to balance their inputs and off-takes over the course of each calendar month, and are usually able to trade imbalance positions with one another in order to do so. Typically the pipeline would post requests to trade imbalance positions on its EBB, and would allow shippers to transfer quantities between balancing accounts (relating to similar service types) at no charge. Shippers that are significantly out of balance at the end of the month would be charged a penalty.[49] Some pipelines set the imbalance penalty with reference to market prices. For example, SoCalGas (a state-regulated distribution company with significant transmission pipelines) has a similar 10% tolerance band on monthly balancing, within which there is no penalty. Outside this band, shippers are "cashed out" – long shippers are paid a price no higher than the lowest price paid by the utility for balancing gas during the month, and short shippers pay 150% of the highest daily market price during the month.[50]

The SoCalGas transmission system also has daily balancing during the winter period. When gas storage inventory is high, shippers are required to deliver at least 50% of offtake over rolling 5-day periods. As storage inventories fall, the requirement shifts to 70% (and then 90%) of daily offtake. Under-delivering shippers are charged a make-up price based on 150% of market prices.[51] Imbalance trading is not permitted for reducing daily imbalances.

In addition to penalizing out-of-balance shippers, pipelines may also have the right to "direct" shippers, through "operational flow orders", to adjust their nominations if the pipeline's operational integrity requires it.

Many US interstate pipelines offer "flexibility products" to shippers. For example, "parking" service"—whereby the shipper delivers gas to the pipeline at the delivery point and receives the gas at the delivery point in a later period—is effectively a storage product. Use of these products allows shippers to manage their delivery profiles to avoid imbalance penalties.

Main gas trading institutions

Much trading in the US gas market is referenced to the physical and highly liquid Henry Hub in Louisiana. While there are significant volumes of OTC trading, in contrast to the EU,

---

48 The "tariff" not only contains the transportation charges (rates), but also contains all the terms and conditions under which capacity is offered, including, for example, balancing arrangements. A typical tariff document might run to 500 pages.

49 For example, shippers on the Columbia Gas Transmission pipeline are charged a penalty of $0.25/Dth at the end of each month on any difference between cumulative receipts and cumulative deliveries in that month, except that differences of less than 10% of the shipper's subscribed capacity do not attract a penalty. (Tariff section VII.19.4)

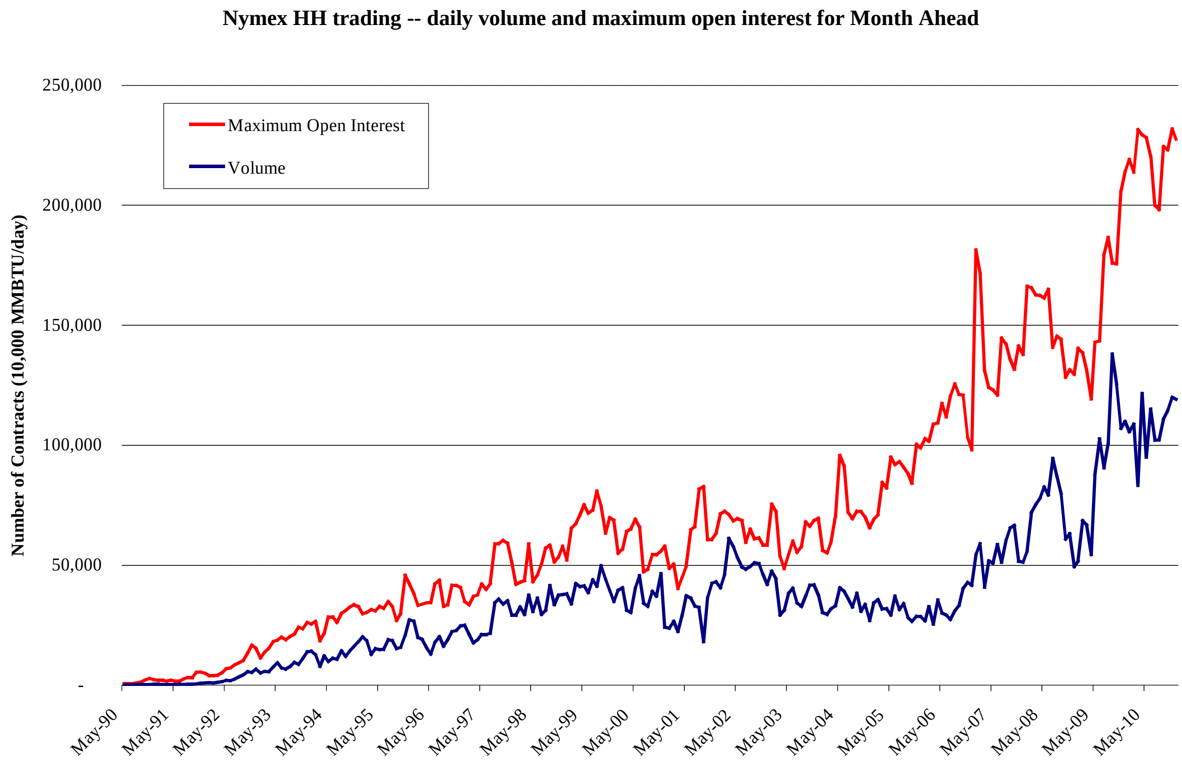
50 See SoCalGas Schedule No. G-IMB.

51 See SoCalGas Rule 30.

most volumes in the US are traded on exchanges. Trading in financial products – futures as well as other derivatives – is also highly liquid.

The New York Mercantile Exchange (NYMEX) introduced a Henry Hub futures product in April 1990. Trading volumes rapidly took off (see Figure 6.2). NYMEX contracts are physical, so that if they are held to maturity they result in physical delivery of gas at Henry Hub. But in practise the vast majority of contracts are closed out financially, so settled in cash.

Figure 6.2[52]



Source: Bloomberg.
Note: Days with no trading are omitted.

In addition to the Henry Hub contract on NYMEX, the ICE trades Henry Hub gas products and gas products at many other locations around the US. Typically, trading at locations other than Henry Hub operates through financial contracts for price differences relative to the Henry Hub price, called "basis" contracts. Exchange and OTC trading of basis contracts is possible at dozens of locations on pipelines across the US.

Trading is liquid in both spot and forward products. Prices are quoted four or more years out, and there are significant volumes of trading in at least the first 12 to 24 months. Liquidity is much higher than in any other gas market in the world (although it is not as high as in oil or financial markets).

Although exchange-based trading is possible at many locations in the US (and dominates OTC activity at some of them), OTC trading is also very important.

[52] Physical throughput at the Henry Hub is equivalent to around 180 contracts, and total US consumption is around 6,000.

Price and trading data availability

Price reporting is organized though trade publications. Although it is not compulsory to report the prices of OTC trades, any trader which does report must report the prices of all trades. Platts, for example, has close links with the back office function of traders that report to it. Despite this, and despite the liquidity of exchange based trading, there have been concerns that the liquidity of OTC trading is thin in some locations. FERC has recently reported that only around 20% of trades were fixed-price deals (that is, gas sold at a negotiated fixed price), with 70% being priced against a price index (itself based on the underlying 20% of fixed-price deals).

Operational data is published by pipelines, some being required by FERC rules (for example, the availability of capacity). Some data is only available to registered shippers through a secure website.

Main participants in the market

Typically there are many different shippers on each inter-state pipeline. Table 6.2 shows the number of shippers holding capacity on a selection of six important US interstate pipelines.

Table 6.2: No of shippers holding firm capacity in a sample of US pipelines

Pipeline	No. of shippers
Natural Gas Pipeline Company of America	123
Rockies Express Pipeline, L.L.C.	21
Midcontinent Express Pipeline, LLC	14
Kinder Morgan Interstate Gas Transmission LLC	53
Northern Border Pipeline Company	45
TransColorado Gas Transmission Company	13

Notes:
Based on the number of shippers recorded in each pipeline's customer list (FERC Form 549B) for Q1 2010.
We did not attempt to filter out related entities.

Nominations

Scheduling rules, as for balancing, are contained in individual pipeline tariffs, and thus may vary from pipeline to pipeline. For example, Columbia Gas Transmission requires shippers to match physical flows to nominations ("scheduled" flows) within 5%. Outside this limit the shipper is charged a fee equivalent to the cost of interruptible service. However, on "critical days" (declared by the pipeline on days when system integrity is at risk), shippers must flow within 3% of nominations, and anything outside this limit is penalised at three times the market gas price.[53]

[53] Columbia Gas Transmission tariff, section VII.19.5.

Trading of transport capacity

Trading of transport capacity is facilitated through Electronic Bulletin Boards (EBBs), which all interstate pipelines must offer. A shipper wishing to sell surplus capacity may either offer it directly to the highest bidder through the pipeline's EBB, or it may sell the capacity bilaterally. In the latter case the deal must be posted on the EBB, and third parties have the opportunity to beat the price offered.

Differences between the US and the EU gas systems

Several features of the US system stand out as different from arrangements in Europe. First, point-to-point capacity is sold, contrasting with the preferred entry/exit system in Europe. Second, there is typically no organised "balancing market", with the pipeline as counterparty. Despite these apparently less "organized" features, the US gas market is the most liquid in the world. We can suggest a number of factors which may contribute to the success of these arrangements:

There is typically some flexibility offered for shippers to transfer capacity between different entry and exit points and on a primary and secondary rights basis, so that the capacity rights are not strictly point-to-point.

There are typically many shippers. Thus, even if the point-to-point nature of capacity rights might tend to reduce the availability of counter-parties for trading of imbalance, there still a relatively large number of shippers to trade with at the key pipeline receipt and delivery points.

Balancing tends to be monthly rather than daily. This reduces the frequency with which shippers need to trade out imbalances, and allows "self-balancing" because what would otherwise be daily imbalances can net out over the course of the month. At the same time, the pipelines typically have access to a certain amount of storage (and/or linepack). In effect the standard transportation service includes a certain amount of bundled storage.

G. AUSTRALIA (VICTORIA)

The original model for the gas market in Victoria was a production monopoly which supplied an integrated transmission/distribution/retail monopoly under a long-term contract. The network was not interconnected with other regions. In the 1990s a restructuring was undertaken to foster competition both up- and down-stream: the downstream monopoly was de-integrated and split up, with an independent transmission network, three distribution networks and three competing retailers with overlapping service territories. A government agency bought gas upstream and resold it to the three retailers. Subsequently the Victorian system has become increasingly interconnected with other regional markets (New South Wales and South Australia), and new sources of upstream supply have been developed.

The Victoria network was primarily supplied from a single processing plant (at Longford), and is characterised by extremely seasonal demand (a significant fraction of demand being for space heating), and a relatively complicated network with bi-direction flows on some lines and relatively little linepack (embedded storage).

The current Victoria gas market design seems to have been heavily influenced by read-across from the electricity market. Competition and liquidity has developed, mainly due to a) the construction of new pipelines, especially those interconnecting with other markets, and b) the development of other upstream supply sources.

Gas transport capacity rights

The Victoria system was set up as a "market carriage" model: rather than selling capacity rights, the system operator was obliged to fulfil all transportation requests from shippers willing to pay the relevant transportation tariff. At the time of industry reforms in 1999, the transmission system had sufficient capacity to meet all likely demands from then-connected customers, except on extremely cold days. Existing users were "grandfathered" rights to a certain amount of "authorised" capacity free from curtailment and congestion charges. When there is congestion on the system, only withdrawals in excess of the "authorised" capacity would attract congestion uplift charges, and, in the case of severe congestion, "authorised" capacity would be curtailed last. Trading of authorised capacity is possible, as is the purchase of additional authorised capacity, either by contracting for pipeline expansion or by arranging for gas to be injected into the system downstream of the congestion.

Balancing arrangements

From 2009 to 2007 the Victoria market had daily balancing, with an "ex post" penalty based on spot market prices. (Note that in Victoria the "spot market" is a centrally-administered market in which the system operator is the only counter-party.) In addition to simple nominations to inject and/or withdraw gas, shippers can also submit a schedule of "inc" or "dec" offers, which are offers to increase injections and/or reduce withdrawals, at specified price points. The system operator forecasts a market price by finding the combination of inc and dec offers which will balance the system. After the gas day, the actual price required is used to cash out any out-of-balance shippers. The market price is calculated without taking into account constraints. When there are constraints, the system operator accepts additional inc and/or dec offers. The cost (*i.e.*, the difference between the market price and the inc/dec offer) is funded through uplift payments.

In 2007 the system moved to a four-hourly balancing period, based on forecast prices. Imbalances are cashed out at the forecast price. However, "deviations"—differences between nominated and actual flows—are cashed out at the forecast price for the *following* balancing period.[54]

[54] The logic being that deviations have an impact on linepack in the following period, whereas imbalance in the first instance affects linepack in the current period.

Main gas trading institutions

There is no formalized exchange-based trading in Victoria, only OTC financial contracts to manage spot market exposure. In 2009 the Australian Stock Exchange (ASX) launched a futures contract.

Price and trading data availability

Spot market prices are published by the system operator. Apart from the recently-launched ASX futures product, we are not aware of any other exchange-based or price-reporting price series.

7. THE COLOMBIAN GAS MARKET

A. OVERVIEW

Supply

All natural gas consumed in Colombia is domestically produced with roughly 90% coming from two main fields: Guajira on the Caribbean coast and the Cusiana fields in the interior. Several minor fields account for the remaining 10%.

Guajira has about one-half of Colombia's reserves (but this is declining over time), and currently provides 65% of production. The field is jointly operated by Ecopetrol, the state-owned oil company, and Chevron Texaco. In 2009, average production of the Guajira fields was approximately 695 GBTU per day. Gas from these fields is delivered to the entry point of Ballena, and is shipped to the inland part of the country, the Atlantic/Caribbean coast, and to Venezuela.

Cusiana has about 38% of total Colombian gas reserves and provides approximately 21.7% of current supply, producing approximately 226.4 GBTU per day. Until recently, the fields were operated jointly by Ecopetrol, BP, and Tepma/Total. In January 2011 Equion Energia Ltd, a joint venture between Ecopetrol and Talisman Energy, acquired all of BPs oil and gas production assets in Colombia. Ecopetrol owns 51% of the new company and Talisman the remaining 49%.

Other minor fields produce around 105.7 GBTU per day: La Creciente, 42.8 GBTU; Payoa, 19 GBTU; other, 43.8 GBTU. There is also a new field in Gibraltar, expected to produce 30 GBTU per day by the end of 2010.[55]

[55] In addition, a mining company that operates close to the Ballena -- Barrancabermeja pipeline has recently announced the existence of coal-bed methane reserves that could be developed in the near future. There is also offshore exploration activity in the Caribbean that appears to have significant potential for future gas production.

The upstream gas market in Colombia is highly concentrated. Table 7.1 shows average daily production by company in 2009 and 2010, and Table 7.2 shows average daily gas production by field and company. The 2009 Herfindahl-Hirschman Index (HHI) for gas supply was 4529, and the degree of concentration is increasing as Ecopetrol acquires further control of the Cusiana fields production.

Table 7.1 Gas supply by company in 2009-10

Company	**GBTUD**	**Share**	**GBTUD**	**Share**
	2009		**2010**[56]	
Ecopetrol	603	61%	624	61%
Chevron	228	23%	233	23%
BP[57]	59	6%	54	5%
Tepma/Total	34	4%	32	3%
Others	61	6%	76	8%
Total	985	100%	1018	100%

Table 7.2. Gas supply by company and field, 2009

Field	**Company**	**GBTUD**	**Share**
LA GUAJIRA	Ecopetrol	435	66%
	Chevron	228	34%
"CUSIANA"	Ecopetrol	136	60%
	BP[58]	59	26%
	Total/Tepma	34	15%
LA CRECIENTE	Pacific Rubiales	43	100%
SMALLER FIELDS	Ecopetrol	32	63%
	Others	18	36%

Demand

Demand for gas in Colombia falls into four main categories: residential and commercial (19%); industrial (45%); electricity generation (24%); and vehicles (11%), located on the

56 January-October 2010.

57 Now Ecopetrol/Talisman.

58 Now Ecopetrol/Talisman.

Atlantic/Caribbean coast (34%) and in the interior (52%). Exports to Venezuela currently account for 14% (approx. 150 GBTUDs) of demand.

Approximately 49% of demand on the north coast comes from thermal electricity generators. The interior also has significant gas-fired generation capacity, but these units generate little or no electricity in a typical year, since hydro resources are less expensive when there are sufficient water resources. Table 7.3 shows demand by region and sector for 2010 in both “normal” and “El Nino” conditions.

The main consumption points are located in the major urban centers (*e.g.* Bogotá, Cali, Barranquilla, and Medellín among others), and where gas-fired power plants and refineries are located. These plants are located in the southern part of the country, near to Barranquilla, and in the central interior region near to Barrancabermeja.

Table 7. 3. Demand by Region and Sector, 2009

Region		**Normal Conditions**		**El Nino Conditions**	
Atlantic Coast	LDCs	30.5	11%	30.5	6%
	Industry	119.2	42%	119.2	24%
	NGV	18.1	6%	18.1	4%
	Thermal plants[59]	115	41%	327.8	66%
	Total	**283**		**495**	
Interior	LDCs	118.6	27%	118.6	19%
	Industry	245.2	56%	245.2	39%
	NGV	64.8	15%	64.8	10%
	Thermal plants	8.9	2%	198.4	32%
	Total	**438**		**627**	
Exports		150		150	
TOTAL		**871**		**1272**	

The market is unconcentrated on the demand side with approximately 37 companies in the market (including exports). Table 7.4 below shows the annual average contract positions of the larger consumers and shippers from 2009 to 2010.[60]

The largest single purchaser of gas in 2010 was PDVSA (Petróleos de Venezuela) for export, followed by E2 (Energia Eficiente), a gas trader located on the Atlantic Coast, followed by the gas distribution companies Gas Natural (Bogota) and EPM (Empresas Publicas de Medellin).

[59] Data from September 2008 – May 2009.

[60] Colour coding indicates companies under common ownership.

Table 7.4 Contract positions of purchasers, 2009-2010 (MBTUDs)

	Demand 2009	Market share	Demand 2010	Market share
PDVSA	150,000	16.17%	150,000	16.60%
E2	140,000	15.09%	134,583	14.89%
GECELCA	100,700	10.86%	57,260	6.34%
GAS NATURAL	95,192	10.26%	96,715	10.70%
EPM	83,787	9.03%	84,553	9.36%
ISAGEN	59,000	6.36%	59,000	6.53%
ECOPETROL REFINERIA	55,377	5.97%	74,019	8.19%
TERMOFLORES I, II, III	52,021	5.61%	52,021	5.76%
EPSA	36,000	3.88%	36,000	3.98%
MERIELECTRICA	32,800	3.54%	32,800	3.63%
ABONOS COLOMBIANOS	20,500	2.21%	20,500	2.27%
CERROMATOSO	16,000	1.73%	16,000	1.77%
TERMOEMCALI	16,000	1.73%	16,000	1.77%
REFICAR	14,940	1.61%	14,940	1.65%
CHEC	9,624	1.04%	9,624	1.06%
ECOPETROL	9,102	0.98%	6,254	0.69%
DINAGAS	6,563	0.71%	7,768	0.86%
ALCANOS DE COLOMBIA	8,100	0.87%	13,696	1.52%
OTHERS	21,825	2.35%	22,016	2.44%
TOTALS	**927,530.67**	**100%**	**903,748.50**	**100%**

Table 7.5 shows the purchasers of gas contracts by field from 2008-2012. Twenty-seven (27) companies purchase gas from the Guajira field (15 independent buyers once common ownership is accounted for), twenty-seven (27) from the Cusiana fields (24 once common ownership is accounted for), and ten (10) from La Creciente. Companies shaded in green do not hold contracts currently but have either purchased gas contracts in the recent past or have particpated in recent auctions.

Table 7. 5 Gas purchasers by field

GUAJIRA	CUSIANA	LA CRECIENTE
TERMOFLORES II	GAS NATURAL	PROELECTRICA
TERMOFLORES III	EPM	GECELCA
EPM	E2	MANUFACTURAS SILICEAS
GECELCA	ISAGEN	FAVIDRIO
ISAGEN	TERMOEMCALI	PRODS FAMILIA SANCELA
CHEC	TERMOCOA	TOPTEX
EPSA	ECOPETROL	SIDENAL
MERIELECTRICA	PETROBRAS	GNV
CERROMATOSO	CEMEX	EPM
CEMENTOS ARGOS	MANSAROVAR	PETROMIL
ABONOS COLOMBIANOS	GASES DEL LLANO	
DRUMMOND	GASES DEL CUSIANA	
GASES DEL CARIBE	DINAGAS	
SURTIGAS	ENERCA	
GASES DE LA GUAJIRA	MADIGAS	
GAS NATURAL DEL CENTRO	ESTACIÓN BOMBEO	
EDALGAS	ALCANOS DE COLOMBIA	
GASES DE OCCIDENTE	COLINVERSIONES	
ALCANOS DE COLOMBIA	EFIGAS	
GAS NATURAL	GASES DE OCCIDENTE	
GAS DEL RISARALDA	GAZEL	
GASES DEL QUINDIO	PLEXA	
GAS NATURAL DEL CESAR	TERMOYOPAL	
E2	PERENCO	
PDVSA	GECELCA S.A. E.S.P.	
REFICAR	METROGAS S.A. E.S.P	
ECOPETROL REFINERIA	TRNS DE GAS INTERNACIONAL	

Transport

Colombia has two large Transportation System Operators (TSOs): Promigas on the Atlantic/Caribbean coast, and TGI in the inland part of the country. The Promigas system's Ballena -- Barranquilla -- Cartagena -- Jobo network is 590 kilometers long with a capacity of 545 Mmcfd (million cubic feet per day). The TGI has two interconnected pipelines systems: the Ballena -- Barrancabermeja pipeline which runs for 580 kilometers and has a capacity of 260 MMcfd, and the Cusiana -- Bogotá -- Vasconia -- Cali -- Neiva pipeline (1700 kilometers long) with a capacity of 392 MMcfd. Other minor TSOs deliver gas from the TGI system to local markets such as Medellín and Bucaramanga.[61]

The two large pipeline networks are not interconnected so it is currently not possible for shippers on the Atlantic/Caribbean coast to physically ship gas from the interior fields such as Cusiana.

The CREG has been responsible for regulating charges for the transport of gas since 1994. Resolution CREG 126 of 2010 defines the current methodology for calculating charges which consists of:

- a regulated charges scheme which sets average-cost based price caps for pipeline segments calculated from investment costs using 20 year demand forecasts;
- a method for shippers and transporter to define the split in the regulated charges between capacity-based and volume-based (commodity) charges; and
- a methodology for calculating the regulatory asset base (investment costs) and Administration, Operation and Maintenance (AOM) costs.

The regulated transport charges are set every five years, and consist of the following:

- average-cost based maximum charges for shipping gas in each pipeline segment for each TSO ("Cargos de Paso") to remunerate investments or recover fixed pipeline costs; and
- fixed charges to remunerate Administration, Operation and Maintenance (AOM) costs.

For each pipeline segment, the CREG defines an array of fixed (capacity) and variable (commodity) charges, in the form of a menu of two-part tariffs. So if, for example, the capacity charge remunerates 80% of investment costs, the variable commodity charge should remunerate the remaining 20% (an "80-20" charge). Two-part tariffs are defined for pairs from 0-100 to 100-0.

Shippers and transporters have to use an "ordinal approximation procedure", defined by the CREG, in order to establish the split between capacity and commodity charges for a pipeline segment. This procedure takes into account the historic average load factor of the shipper. Non-

61 The TGI purchased its pipeline network from the state-owned EcoGas in an auction in 2006 for a price of $1.4 billion (US). The other pipeline networks have been developed under private ownership.

regulated users and marketers selling gas in the non-regulated market are free to negotiate their own charges.

The regulated charges apply to contracts for firm capacity only. For a contract for X units of firm capacity, the shipper thus pays:

- the annual capacity charge times the contracted maximum capacity, X;
- the amount of the variable (commodity) charge multiplied by the volume transported; and
- the annual fixed charge remunerating AOM expenses, times X.

Under a firm capacity contract the shipper is entitled to use all the contracted capacity at all times, independently of the pair of capacity and commodity charges paid. The duration of firm capacity contracts is not regulated and must be agreed between TSOs and shippers. Contracts for interruptible capacity are unregulated, and sold both by TSOs and by shippers who have acquired firm capacity contracts.[62]

Since the regulated maximum charges are fixed for at least a five-year period, the risk that actual demand differs from expected demand is borne by TSOs. If actual demand exceeds expected, the TSO may recover more than its investment costs; if actual demand is less than expected the TSO may under-recover its costs. No adjustments are made ex post, or in subsequent regulated charges, to account for either over or under-recovery in previous price control periods.

CREG Resolution 057 of 1996 specified restrictions on the degree of vertical integration between gas transporters, producers and distributors. CREG Resolution 126 of 2010 modified the restrictions on vertical integration between distributors and transporters, allowing distributors to participate in a competitive bidding to build secondary pipelines[63]

B. Main Gas Trading Institutions

Primary Gas Market

The vast majority of gas in the primary market is sold by producers under either firm or interruptible contracts with durations varying from one year (approx. 40%) to nine years (for some gas-fired power plants). The majority are take-or-pay contracts the minimum percentage of "take" varying from 25% to 70% for the gas-fired power plants, and with 100% levels of “take” not being unusual.

There are essentially three types of **firm** gas supply contracts allowed by regulation the Colombian market: (i) traditional “take or pay” contracts; (ii) gas purchase option contract which specify a quantity and an exercise price; and (iii) “conditional firm” contracts under which the

[62] The CREG is currently revising the regulated charges.

[63] Secondary pipelines are those derived from main pipelines in order to carry gas to markets around the main pipeline.

seller offers firm gas with deliveries conditional on the electricity spot market price. **Interruptible** contracts are not subject to any form of regulation.

Gas supply contracts from the Guajira field are sold at a regulated price, currently \$4.25 per MBTU, using a value estimated in the 1970s and indexed twice a year with the New York fuel oil price. The prices of gas supplied from other fields are unregulated.

In December 2009, Ecopetrol held auctions for 32,821 MBTUDs in five-year, firm gas contracts with take-or-pay levels of 100% from the Cusiana field, resulting in a price of \$6.14/MBTU. BP/Tempa held auctions in 2010 for 40,600 MBTUDs in five-year firm gas contracts with 100% take-or-pay levels at a clearing price of \$4.73/MBTU.

Declarations and Auctions

The sale of gas from all companies are subject to regulation. Ministerial Decree 2687 (of July 2008) obliged the major gas producers to submit annual declarations to the Ministry of Mines and Energy specifying:

- the potential production available from each gas-producing field for a ten-year period
- the amount of committed (*i.e.* contracted) production for each company in each field for a ten-year period
- the amount of gas offered in interruptible gas contracts for the ten-year period
- the amount of gas offered as in firm gas contracts for the ten-year period

CREG Resolution 95 of 2008 set out the procedures for the sale of firm gas contracts declared under Ministerial Decree 2687. This requires that firm gas from unregulated fields be sold via an ascending, simultaneous auction within 45 days of the declaration, whenever purchase requests exceed the offered supply. Otherwise, the gas can be sold via bilateral negotiations. Firm gas from the price-regulated Guajira field must be sold at a regulated price according to allocation procedures specified in Article 8, Decree 2687and Article 7, Resolution 95 of the CREG. Gas supplies declared as "interruptible" are not subject to any regulations with respect to the means of sale.

Annex A of Harbord (2010)[64] provides details on the declarations made by producers from the three main gas fields in September 2008, February 2009 and October 2009. Despite some anomalies and inconsistencies in the declarations, a clear pattern emerged in the Guajira and Cusiana fields, *vis*. an unwillingness to offer significant quantities of firm gas contracts to the market, especially after 2012/13. In the three declarations since September 2008:

Guajira

- Chevron offered firm gas from 2009-13 in the first declaration

[64] David Harbord "Upstream Issues in Colombian Gas Supply", April 2010.

- No firm gas was offered from February 2009
- From 2012 large quantities of gas was offered as interruptible contracts

Cusiana

- No firm gas offered in first two declarations
- Large quantities of interruptible gas offered from 2012/2013
- Ecopetrol offered small quantities of firm gas in October 2009, and auctioned 32,821 MBTUDs in five-year contracts from August 2010

La Creciente:

- Pacific Rubilaes offered firm gas in first two declarations, but no auction was held due to lack of demand
- Subsequently offered mostly interruptible gas from 2012/13

Although Ministerial Decree 2687 and CREG Resolution 95 were designed to ensure that larger quantities of firm gas were offered by producers to the market, their effect appears to have been the opposite of what was intended. For a combination of reasons, producers have offered less and less firm gas in their declarations, exploiting the opportunity offered in the regulation to declare all, or most, future supplies as interruptible. A proposal for addressing this issue was presented in Harbord (2010).

Primary Transport Market

Firm transport contracts are sold at regulated prices, except for non-regulated users and marketers selling gas in the non-regulated market that have agreed on other prices with the transporter, as noted above. The form and duration of these contracts are freely negotiated between shippers and TSOs.

Imbalances

There is currently no "market" for imbalances in Colombia. Daily imbalances between gas delivered into a pipeline network and the amount taken out are resolved via bilateral agreements between the shipper and the TSO called "balance agreements". Under these agreements the shipper can either place more gas into the system within a specified time period , or make a cash settlement with the TSO.

In the TGI system, penalties for imbalances that are not resolved within a few days of being reported are applied when the imbalance is +/- 0.5% - 2% of the nominated amount. Shippers have the ability to take gas at different delivery in order to clear imbalances. Other transportation contracts, such as those issued by Promigas and Transoccidente, have an imbalance clause where there is no penalty until the difference is +/- 10%. If the variation is greater than 10%, there is a tiered penalty based on the amount of gas taken in excess of the contracted amount. In addition to the penalty, if the imbalance is negative (more gas was taken than agreed), the TSO will purchase gas from a supplier to make up the difference and the shipper is responsible for this cost, the transportation cost of this gas to the point of delivery, and an additional charge of 5%. If the imbalance is positive (less gas was taken than agreed), the TSO will request the producer to deliver less gas into the pipeline.

Nominations

Gas supply and transport nominations follow electricity market despatch which occurs from 6:15 AM to 3:15 PM daily. Supply nominations take place from 15:30 until 19:50, and transport nominations from 16:25 to 20:20.

Entry/Exit Variations: These occur when a shipper transports more gas through a pipeline network than it has nominated. They are resolved through either: (i) reducing the amount delivered or taken in order to preserve operational stability; (ii) contracting the additional capacity with the transporter; or (iii) compensating the transporter..

Diversions (Change of Entry/Exit Point): These are either accepted by the TSO or an additional distance-based charge is applied.

C. Secondary Trading

Gas

There are no organized markets for secondary gas transactions, nor any organized sources of information for secondary market transactions.[65]

Transport capacity

Transport capacity can be freely resold. There are no organized markets for secondary transport transactions, nor any organized sources of information on secondary market transactions.

Note: Each TSO maintains a BEO ("Boletín Electrónico de Operaciones" on the web, as required by Resolution CREG 071 of 1999. The TSO must publish the following information:

1. Transporter Manual

2. Nomination cycle

[65] Before Decree 2687/08 secondary market prices were freely negotiated between buyers and sellers. Since Decree 2687, gas from the Guajira fields must be sold at prices below the regulated price. Decree 1514/10 requires that gas from unregulated fields must be sold in the secondary market at a price equal to the one of the primary market prices plus a regulated margin, with the CREG in charge of setting this margin. This regulation has not yet been implemented by the CREG.

3. Daily transported volumes

4. Transport and supply gas releases, including entry and exit points

5. Available primary capacity, including entry and exit points

6. Service request, including volumes and entry and exit points

7. Contracted capacity

8. Balancing accounts

D. Short-Term and Secondary Gas and Transport Markets in Colombia

As noted above, there are no organized markets for secondary or short-term trading either in gas or transport capacity in Colombia, nor any organized method for collecting and disseminating information on such trading activities. There appears to be a clear demand for the creation of such markets or trading platforms from both producers and consumers of gas, however.

Chevron[66], for instance, points to a lack of information on market transactions and transport capacity availability, and to a lack of opportunities for supply-transportation coordination. It proposes the creation of an ISA & MO and strengthening of CNO gas. It also suggests that such markets should take advantage of existing Electronic Bulletins (Transporter's BEO's).

Isagen[67] "considera que en general un mercado secundario estructurado debería tener las siguientes características:

- la información se debe administrar de manera centralizada, debe ser pública y los agentes tener acceso a ella en tiempo real.

- debe ser un mercado en competencia: que no sea tomador de precio, en el que cada agente define el mecanismo más conveniente para optimizar la venta de su propio gas.

- debe estar debidamente reglamentada la participación de productores y transportadores de manera que no puedan revender lo comprometido en firme.

Tambien, Isagen considera que es necesaria la existencia de un mercado de corto plazo (spot), pero este será sólo uno de los canales que tendrían los agentes para vender su propio gas. Debe tener como referente el mercado eléctrico colombiano, en aspectos como: definir nodos, tipo de productos, forma de liquidación, garantías, etc."

66 Chevron Presentation, Bogotá, December 28th, 2010.

67 Presentation, December 2010. Left in Spanish to avoid misinterpretation.

Colinversiones[68] argues for:

- a secondary gas market which excludes participation by the upstream producers;
- a centrally-administered short-term market for gas;
- a deviations market: with demands and offers for flexibility, including quantities and prices, closing near to the beginning of the operation day; and
- a spot/balancing market with rules for gas renomination during the operational gas day

They also suggest the need for a short-term transport capacity market, centralized operation of the transport – supply system (independent exchange and system operator); transparency and public information concerning availability of secondary transport capacity; and a mechanism for planning, monitoring and auctioning, in a timely manner and open to private initiative, the gas transport infrastructure needed to supply the expected demand.

Various other proposals for the creation of shorter-term gas and transport markets have come from Frontier Economics (2010)[69] and Ministerial Decree 2730 of 2010.

8. PRELIMINARY CONCLUSIONS FROM TASKS 2 & 3

- Experience from the US and the EU indicates that for secondary trading to be successful, the market must be liquid. This means maximising the number of counter parties that can trade gas with one another without having to buy or sell transport capacity.
- A liquid market can be achieved in one of two main ways: by creating an entry-exit 'Virtual Trading Point'; or by the creation of a physical hub. Both systems can achieve a liquid market, and the solution largely depends on both the physical topology of the pipeline system and the history of the market. The EU has opted for entry-exit systems to encourage liquidity largely because EU pipelines systems are often highly meshed and there are few natural locations for physical trading at a hub. In contrast, the world's most liquid gas market at Henry Hub in the US is based on a physical hub.[70]

[68] "Visión de los cambios requeridos en el Sector de Gas Natural" December 2010.

[69] Frontier Economics, "Propuesta de soluciones a las fallas del mercado de gas de Colombia," Abril de 2010.

[70] In theory one could implement a system of entry-exit charges in Colombia by a) preserving the allowed asset base for each pipeline; and b) converting existing point-to-point charges into charges for entry and exit capacity. One could also preserve features of the existing system, for example making remuneration for pipelines dependent on the degree of capacity utilization. In the short term such a change would be impractical because a new five-year price control methodology was adopted in 2010 (CREG Resolution 126), and some existing contracts run for up 15 years.

- Colombia has a simple pipeline layout, and at least two major physical trading locations at Ballena and Cusiana. There are about 37 independent parties buying gas from upstream producers in Colombia – 15 buying gas from the Guajira field (with delivery at Ballena), 24 from the Cusiana fields and 10 from La Creciente. These numbers may be sufficient to start a functionally liquid market. The challenge in the next phases of the project will be to allow these parties to trade with one another in a manner which minimises transactions costs.

- There is already some secondary trading of gas from Ballena and Cusiana, and it could be relatively cheap to take measures to encourage further trading. For example, the creation of standardized contracts and more transparent provision of information. Probably the biggest barrier to trading is a lack of information, both on the bids and offers of parties willing to trade and on the volumes successfully traded and the prices at which these trades took place. Increasing the level of information available could be carried out at relatively low cost.

- In other gas markets, exchanges have typically developed after OTC trading has matured. An exchange is not required to promote liquidity, and OTC prices can be reported without the need for an exchange. Exchanges are more complex and costly to establish and require the counter parties to post collateral, which can be burdensome especially for smaller market players. On the other hand, if anonymity for traders is felt to be important, then an exchange could be beneficial.

- Our international survey shows that some countries do not have a balancing market, some have a dedicated imbalance market and others have a combined balancing/commercial trading market, the GB OCM market being the most important example. It seems that having a combined balancing and trading market like the OCM would maximise liquidity. The Dutch arrangements, which have a separate balancing market, would appear to split the market and reduce liquidity. The EU has concluded that balancing arrangements should be cost reflective and use market-based prices as far as possible. We think that these are sound principles to apply to the design of a Colombian balancing market.

- Our survey indicates that other gas markets do not create separate trading institutions for the sale of short-term secondary trades and long-term secondary trades. In other gas markets there are many different gas products involving delivery over different durations, but these are all traded using the same arrangements and platforms. While producers will often sell primary gas under bilaterally negotiated long-term contracts, they also sell primary gas using the same mechanisms and institutions as applied for secondary trading. The main exceptions are gas release programs, where to address competition concerns a dominant player auctions gas to third parties.

- International experience points to several ways that liquidity in a secondary market could be promoted. These include the creation of a market-maker position, and mandating the sale of specific volumes of gas *e.g.* ‘Royalty gas’ on an exchange or via OTC trading.

- The MO and TSO should be independent of shippers and traders. In a system like Colombia's with several asset owners (TGI, Promigas) etc.) it could be beneficial to have one System Operator as is the case in Germany. This could facilitate trading of gas between the different pipeline systems. Rather than calculating imbalance positions for each pipeline separately imbalances could be calculated over all pipelines.