Market design for natural gas: the Target Model for the Internal Market

A report for the Office of Gas and Electricity Markets

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Section 1

Executive Summary

1.1 In light of the important challenges facing the future development of European gas markets, and the concomitant need for rapid progress in building the internal gas market within the framework of the 'Third Package', the Council of European Energy Regulators ("CEER") and the European Regulators' Group for Electricity and Gas ("ERGEG") are in the process of developing a 'target model' for gas market design. Ofgem has commissioned LECG to produce this paper as input to the CEER/ERGEG process. The aim of the paper is to provide clearer conceptual foundations for the debate, lay out the main options, provide some preliminary assessment, and recommend further analyses.

1.2 At highest level, it is clear that the target model should be developed with the aim of promoting competition, security of supply, and the rapid and efficient completion of the internal gas market. At a more detailed level, we have identified five key criteria, derived from these high level goals, against which possible options for the gas target model should be assessed:

(1) The promotion of **efficient use of cross-border capacity**, in particular in light of ongoing problems with "contractual congestion" that contribute to the continued fragmentation of the internal market. The model should also aim to maximise available physical capacity, avoid tariff distortions caused by flows crossing many 'price zone' borders ("pancaking"), and provide appropriate incentives for Transmission System Operators ("TSOs") to invest in cross-border capacity;

(2) The impact on **long-term contracts and on investment incentives upstream**, in particular by avoiding changes that unnecessarily undermine existing long-term contracts, require costly renegotiations, and might contribute to a perception of regulatory instability, thereby damaging future investments and potentially harming security of supply;

(3) The promotion of **liquid trading and transparent spot prices**, so as to facilitate market participation by entrants, traders and consumers, and to enhance the potential for market-based risk management;

(4) The impact on the **role of TSOs**, inter alia in relation to ensuring that tariffs provide efficient, cost-reflective signals and that TSOs are fully able to exploit resources cross-border to maximise operational efficiency (e.g. in relation to cross-border balancing); and

(5) **Ease of implementation**, inter alia in relation to: the extent of harmonisation of national rules that is required as a pre-condition for implementation, and that may prove to take considerable time to achieve; changes in TSO roles and responsibilities, which may also prove time-consuming; overall cost and regulatory burden imposed on all parties.

1.3 We classify alternative market designs for wholesale natural gas markets along two key dimensions:

(1) **Size of price zone.** By "price zone" we refer to an area where a single wholesale gas price prevails. Under an entry/exit system this coincides with a single "entry/exit zone", as for example Great Britain ("GB"), which is a single entry/exit zone and has a single wholesale price (the NBP price), or the Netherlands (the TTF price). At present price zones are generally national or sub-national in scope (e.g. France has three price zones, Germany will have three as of April 2011). Some market designs would aim to merge existing price zones to create large areas with a single common price. This approach has already been taken at national level, in reducing the number of entry/exit zones in Member States such as France and Germany. Other market designs would maintain the existence of locational price differences, or even increase the geographical 'granularity' of pricing.

(2) **Allocation of cross-border capacity**. At present in European Union ("EU") gas markets, capacity is allocated via a primary distribution to shippers of explicit physical transmission rights, followed by secondary trading. An alternative approach is to allocate capacity 'implicitly' via some form of "market coupling"/"market splitting". Under this approach, buyers and sellers of gas make offers (through a specified platform, typically operated by a TSO or energy exchange) to buy or sell gas at specified times and locations, and at specified prices. The platform then produces a 'programme' for gas flows based on accepting bids so as to maximise surplus (the difference between the price buyers are willing to pay and the price sellers are willing to accept) while respecting system constraints. This procedure also produces "locational prices", i.e. a gas price in each zone. The price in two zones will be the same if there are no transmission constraints that limit flows between the two zones (and will differ if there are such constraints).

1.4 Different combinations along these two dimensions give rise to a number of potential target models, as shown in Figure 1-1 below.

Figure 1-1: possible options for the gas target model

		Size of price zone		
		Medium mostly national	Big often super-national	Sub-national (prices at points not zones)
Cross-border capacity allocation	Explicit trading of capacity	Explicit trading of capacity. Emerging as "standard approach" in European gas market e.g. NBP, TTF. **Framework Guidelines Driven**	Merge current balancing zones. Explicit trading of capacity remains at borders. **Merged Markets**	Point to point capacity. e.g. US gas market. Not possible under 3rd Package. **Point To Point**
	Implicit trading of capacity	Zones as now, or re-chosen on an objective basis. Implicit auctions for cross-border capacity, like CWE and Nordpool in the electricity market. **Coupled Markets**	Implicit trading but with larger pricing zones. **Hybrid**	Nodal pricing e.g. US electricity market. **Nodal Pricing**

1.5 We focus in particular on three of these six options, which we consider of most practical relevance to the current debate:

(1) explicit transmission capacity combined with national/sub-national price zones. We refer to this as **"Framework Guidelines Driven"**, because we view it as the likely outcome of the current Framework Guidelines development process, unless the choice of gas target model provides an alternative vision;

(2) explicit transmission capacity combined with larger, regional price zones (**"Merged Markets"**); and

(3) implicit transmission capacity combined with national/sub-national price zones (**"Coupled Markets"**). We assume that at least for the present market coupling would be used for the allocation of short-term rights, while TSOs would continue to provide long-term explicit rights.

1.6 We have assessed these options against the five criteria laid out below:

1) **Promotion of efficient use of cross-border capacity**.

   a. Experience to date shows that the Framework Guidelines Driven model encounters significant difficulties with **contractual congestion and 'capacity hoarding'**. Effective implementation of Use-It-Or-Lose-It ("UIOLI") and Use-It-Or-Sell-It ("UIOSI") mechanisms has proven difficult, and is still opposed by many market players. The alternative approach of 'over-selling' might prove more successful[1], but will also be difficult to implement and make effective. The Merged Markets approach would mitigate the problem, by removing explicit capacity rights on certain borders. Its effectiveness depends on the extent to which regions can be merged, which in turn depends on a number of factors discussed below. Coupled Markets automatically deals with problems of contractual congestion.

   b. Coupled Markets can also help to **increase the use of available capacity** compared to the current system, as has been shown by experience in power markets. The same holds for Merged Markets, but again its effectiveness depends on the extent to which regions can be merged.

   c. Coupled Markets can also help to prevent problems with **pancaking**, but the benefit would be quite limited if coupling is used only for shorter-term rights, while long-term explicit transmission rights remain. Merged Markets would also help prevent pancaking, including with regard to long-distance rights, but again its effectiveness depends on the extent to which regions can be merged.

[1] "Over-selling" refers to an approach where the TSO sells more transmission capacity than may be physically possible to provide, based on its estimate of what actual demand will be on the network. Such a system would mean that capacity hoarding by an incumbent was less effective as a means of foreclosing competition, because the TSO would react to routine hoarding of capacity by selling greater volumes. It is used in GB by National Grid (as well as being familiar from the aviation industry).

2) **Impact on long-term contracts**.

   a. New provisions in the Third Package create uncertainty for **existing long-term transit arrangements** that might potentially have to be amended to create a series of new entry/exit transmission contracts under the Framework Guidelines Driven model. This problem is partly mitigated under Merged Markets, because with fewer, larger entry/exit zones there would be fewer new entry/exit contracts to negotiate. Coupled Markets would not help unless it included long-term implicit allocation, in which case it could be solved if TSOs replace existing transit arrangements with "Financial Transmission Rights"[2]. However, that would likely occur some years into the future.

   b. A move towards Merged Markets could create problems if it means that the designated **delivery point in a long-term contract** is no longer a point at which the TSO will make deliveries. For example, merging two countries into a single entry/exit zone would mean that the TSO would no longer deliver at a border point between the two countries.

   c. If trading through the platform was made compulsory under Coupled Markets, then parties would still be able to maintain the same financial arrangements as under existing long-term gas sales contracts, but they would need to sign additional side contracts to do so (so-called 'contracts for difference').

3) **The promotion of liquid trading and transparent spot prices.**

   a. Under the Framework Guidelines Driven model, trading risks being fragmented by the existence of a large number of relatively illiquid 'hubs'. This would be improved by Merged Markets, and potentially even more so if Coupled Markets were implemented with a single regional platform (comparable to Nordpool in wholesale power, and usually referred to as "market splitting").

4) **The impact on the role of TSOs.**

   a. In relation to **tariffs**, a switch to Merged Markets would lead to higher tariffs because merging entry/exit zones means that the TSO has to incur greater congestion costs, since more congestion is internal to the merged entry/exist zone and must be dealt with via re-despatch. The tariffs would be less cost-reflective, because the increased use of re-despatch implies greater 'socialisation' of congestion costs, and therefore greater cross-subsidies.

[2] This concept is explained later in the report.

b. Regional explicit markets might undermine **investment incentives for TSOs**, in circumstances where investment by one TSO was needed, but additional revenues would flow to other TSOs within the region. Similar problems have been observed in the Nordic power market. They could be solved by the introduction of inter-TSO compensation ("ITC").

c. In relation to **balancing**, TSOs would take on a greater role under Coupled Markets, because they would be responsible for all balancing after 'gate closure'. Under Merged Markets they would also take on a greater role, because of the increased need for re-despatch as discussed above.

5) **Ease of implementation.**

a. The Framework Guidelines Driven model would require least **harmonisation of national rules**, and therefore would face lower implementation costs than the other options.

b. The Framework Guidelines Driven approach would also require the least **changes in TSO roles and responsibilities**, and therefore would face lower implementation costs than the other options. Merged Markets and Coupled Markets would both require much greater regional cooperation between TSOs. Merged Markets would probably require early implementation of an ITC mechanism, while Coupled Markets would require close cooperation to implement and deploy the necessary auctions and centralised despatch algorithms.

c. The relative merits of each approach in relation to **costs and regulatory burden** remain to be investigated.

1.7 This assessment is summarised in the table below.

Table 1-1: summary of the assessment of the three main options

Criterion	Framework Guidelines Driven	Merged Markets	Coupled Markets
Efficient use of cross-border capacity			
Contractual congestion	xx	x	✓
Pancaking	xx	✓	✓ LT implicit xx LT explicit
Maximising available capacity	(x)	(✓)	✓
Investment incentives for TSOs	-	xx	-
Long-term contracts and investment incentives			
Impact on long-term long-distance transport arrangements	xx	x	x LT implicit xx LT explicit
Impact on delivery point in Gas Supply Agreements ("GSAs")	-	xx	xx LT implicit - LT explicit
Other impact on long-term GSAs	-	-	x
Promotion of liquid trading and transparent spot prices			
Concentration of trading	x	✓	✓✓
Impact on the role of the TSO			
Tariffs	-	xx	-
Balancing	-	xx	x
Ease of implementation			
Harmonisation of national rules	✓✓	xx	-
Changes in TSO responsibility	✓✓	xx	xx
Cost and regulatory burden	TBD	TBD	TBD

Conclusions and Recommendations

1.8 Each of the options discussed has its own costs and benefits as the basis for a target model. The choice of target model therefore depends on which of the different issues affected are in fact the most material.

1.9 The Framework Guidelines Driven model would be most appropriate if one believes that:

- Capacity hoarding and contractual congestion are not a major problem, or can be effectively solved within the Framework Guidelines Driven framework (either through the implementation of UIOLI/UIOSI mechanisms or through the introduction of over-selling of capacity, as discussed later in this report);
- Secondary capacity trading can give a reasonably efficient allocation of capacity;
- The use of explicit capacity does not materially reduce the amount of capacity that can be made physically available to the market;
- Distortions due to pancaking are not a significant problem;
- Having a relatively large number of hubs does not lead to unacceptably low liquidity; and
- Regulatory stability is valued very highly, and/or one mistrusts the capacity of the industry, regulators and public authorities to achieve timely and effective reform.

1.10 The Merged Markets model would be most appropriate if one believes that:

- Capacity hoarding and contractual congestion are a major problem, and hard to solve via UIOLI/UIOSI or over-selling;
- Distortions due to pancaking are a significant problem;
- Physical congestion is and will remain relatively limited within the chosen regional areas, or can be made so at acceptable cost via new investments, so that re-despatch costs within the region will be at an acceptable level;
- Having a relatively large number of hubs may be significantly detrimental to liquidity; and
- Industry, regulators and public authorities are well placed to implement the model, in particular by merging entry/exit zones across TSO and MS border, and can achieve timely and effective reform.

1.11 The Coupled Markets model would be most appropriate if one believes that:

- Capacity hoarding and contractual congestion are a major problem, and hard to solve via UIOLI/UIOSI or over-selling;

- Secondary capacity trading is unlikely to give a reasonably efficient allocation of capacity;
- Distortions due to pancaking are a significant problem;
- Physical congestion is or may become significant;
- The future location of physical congestion is uncertain;
- Centralised despatch can significantly increase use of available physical capacity;
- Having a relatively large number of hubs may be significantly detrimental to liquidity; and
- Industry, regulators and public authorities are well placed to implement the model, including resolving the technical challenges of adapting market coupling to natural gas markets.

1.12 A key recommendation of this report is therefore for regulators and other stakeholders to undertake further analyses, in particular to develop the necessary evidence base for a decision on the choice of target model.

1.13 On the side of the regulators (in particular via ERGEG/ACER) these analyses should include:

(1) Updated analysis of the extent of contractual congestion in different parts of the EU, and a view on the potential for the problem to be solved by UIOLI/UIOSI and/or over-selling mechanisms;

(2) Analysis of the extent of price convergence at different hubs, and of liquidity at different hubs and the likely impact on liquidity of “merging hubs” via the Merged Markets or Coupled Markets models;

(3) More detailed analysis of the regulatory requirements (in particular, degree of harmonisation required) for each model; and

(4) Analysis, in close consultation with market players, of the costs and regulatory burden associated with each model.

1.14 On the side of the TSOs (in particular via the European Network of Transmission System Operators ("ENTSOG")) these analyses should include:

(1) The extent of physical congestion, in particular within likely candidates for merger of entry/exit zones under the Merged Markets model, and associated to that, the likely extent of re-despatch costs in various merged zones;

(2) The likely increase in transmission capacity, if any, that would arise from Coupled Markets;

(3) The impact on revenues of merging various entry/exit zones, and possible implications in relation to investment incentives and inter-TSO compensation; and

(4) Development of the technical requirements for applying market coupling to natural gas markets.

1.15 On the side of gas producers, importers and merchants (i.e. the usual parties to long-term gas sales agreement), analysis of how each of the models would impact existing long-term contracts, based on worked-up legal analysis for typical relevant clauses in such contracts.

Section 2

Introduction

2.1 There are important challenges facing the future development of European gas markets. The EU's 2020 targets commit Member States to renewable sources contributing 20% of final energy consumption and to have greenhouse gas emissions fall by 20% by 2020. The European Commission's ("The Commission's") recent energy infrastructure package highlights some of the challenges for investment in infrastructure to integrate wind and other low-carbon sources of generation onto the European electricity networks and in improving interconnection between Member States. The increase of wind generation and other intermittent sources is likely to have knock-on impacts on gas, with demand for gas becoming increasingly flexible in response to the availability of renewable sources of generation energy.

2.2 Currently, the European gas market is characterised by long-term contractual arrangements with gas producers often outside of the EU, for the delivery of specific volumes of gas at specified points on TSO networks. Transport of gas is still, in some cases, governed by transit arrangements that limit the potential for gas-on-gas competition in some Member States. Market arrangements remain highly fragmented, with many separate transmission systems and limited harmonisation between the TSOs. While gas hubs, where gas is traded on a spot or short-term basis are emerging across Europe, liquidity remains low in many parts of Europe, and flexibility is provided via TSOs having direct access to gas storage or the flexibility in long-term contacts.

2.3 The third European energy package, due to be transposed into national legislation by 3 March 2011, sets a new regulatory framework for the completion of a single European market for gas. It highlights the need for non-discriminatory and market-based arrangements in the design of the European gas markets and for greater harmonisation of the current national arrangements. It also creates a new Agency for the Cooperation of European Regulators ("ACER") and new statutory roles and responsibilities for TSO's, and provides for a range of European 'network codes' to be developed to remove barriers to cross-border trade. The European Council has called on ACER, national regulators and TSOs to accelerate their work so as to achieve a completed internal energy market by 2014.

2.4 In this context, the idea of a target model is to set a 'holistic' vision for how Europe can move from its current fragmented state into an integrated European market, where gas will be traded such that it flows from low-priced to high-priced areas in order to maximise social welfare, including through enhanced security of supply. The target model will have to consider all of the key aspects of market design, such as how gas will be traded between market participants, how participants will access transport capacity, what charges they will face for transport capacity or using the network to transport over long-distances and what arrangements market participants will face for balancing the gas being put in and taken off the system. This paper is a contribution to this debate; it considers the options for integrating European markets, gives an initial assessment, and recommends further analyses.

2.5 The first consideration, preliminary to any development of options, is whether the current approach, relying on the foreseen development of Framework Guidelines but without any new over-arching vision for regulatory change (i.e. a "momentum-driven" approach, which we refer to in this paper as **Framework Guidelines Driven**) is the best way to achieve a single European gas market, or whether the development of an alternative over-arching vision, embodied in the target model, can help to guide the process towards a better outcome[3]. To date, the focus of the European debate has been on making more efficient use of interconnector capacity. Certain points on the European gas networks suffer from "contractual congestion" that is where the network capacity is fully booked but not being used and is not made available (or only made available on less commercially attractive terms) for other parties to use. ERGEG, acting on behalf of ACER, has recommended that capacity at interconnection points should be made available to all shippers via an auction. Also, instead of shippers buying capacity to 'exit' one transmission system and capacity to 'enter' another, there should be a single capacity product and nomination of gas flows at any given point. The Commission is also consulting on rules to release the capacity being held but not being used so that it can be made available to other shippers. The Framework Guidelines Driven approach is based on the assumption that if shippers are better able to access cross-border capacity and market-based rules are used within each 'balancing zone', then cross-border trading will increase so that all cross-border capacity is efficiently utilised.

3 We do not imply, therefore, that the gas target model should in any way replace the Framework Guidelines. The question rather is whether it should simply make explicit what we view as the current approach, or alternatively, whether it should provide a rather different vision, which would then lead the Framework Guidelines to be developed in a potentially different direction.

2.6 A key question is whether this will suffice or whether other approaches are required? One alternative would be merging the current balancing zones into a larger pan-European or a series of **Merged Markets.** The Commission would like to see the separate charging regime to transit gas removed and replaced with charges based on entry and exit from the European transmission system. This raises the question of the optimal size of the entry/exit zone, in which a single market price would be determined? It would be theoretically possible, though not necessarily desirable, to have a pan-European entry/exit zone with a single European price but a starting point may be the existing 'regional approach' to develop based on gas regional initiatives: North West Europe (bringing together NBP, TTF, Zeebrugge, Gaspool and Peg Nord as "Herring Hub"), South region (Peg Sud, Spain and Portugal) and South East Europe around Baumgarten and PSV. Common arrangements for trading gas, accessing network capacity and balancing gas flows would need to be developed for each 'merged market'.

2.7 Another approach is to '**couple**' the gas markets in a way similar to the target model, which has been developed for the European electricity markets. Instead of merging markets, the approach integrates markets via 'an implicit' auction that determines cross-border flows based on the price differential between the two price areas, at a specific period in time. A central platform, often an exchange will determine the direction of the gas flows between two or more areas based on the differences in the market prices (which are simultaneously determined via an auction process). Interconnection capacity is then used to flow gas from low-priced to high-priced areas based on the bids to trade gas made by market participants. Under this approach, the focus would be on the coupling arrangements at the interconnection points: a central platform for bids and offers, an algorithm to determine gas flows and governance arrangements at interconnection points rather than the detailed trading rules within each price zone.

2.8 Under either approach, the likely evolution would be to begin with regional arrangements and evolve towards a pan-EU model: a single pan-EU entry/exit system, harmonised regional entry/exit zones (linked either by explicit capacity arrangements or market coupling), or a single market coupling platform for all of the EU (analogous to Nordpool for the Nordic region). These transitional issues are not the main focus of this paper, but their importance should not be underestimated.

2.9 In considering these alternative approaches for a future target model for the European gas market, it is important to assess how well they contribute to the aims of the Third Package in creating a well-functioning single market and their impact on the current gas trading arrangements. This paper considers the extent to which each of the options will improve the efficiency in the use of interconnector capacity and will lead to the creation of more liquid trade markets, which will allow a market price for gas to emerge. It also considers the impact of the options on the existing long-term contracts for the supply of gas and on European security of supply. Finally, it considers implementation issues, and what changes may be required to current arrangements, including to the role of TSOs. Some approaches may require a higher degree of harmonisation of wholesale markets while others may focus more on the interconnection points.

2.10 Each approach has its advantages and disadvantages; the purpose of this paper is to contribute to the ERGEG process by setting out some of the key issues for debate. It will be useful to further assess the impact of implementing either of these approaches at some of the interconnection points across Europe. However, it is important to set the direction now, if we want to see an integrated European gas market.

Section 3

Requirements for a gas target model

Criteria for assessment

3.1 At highest level, it is clear that the target model should be developed with the aim of promoting competition, security of supply, and the rapid and efficient completion of the internal gas market. At a more detailed level, we consider five key criteria, derived from these high level goals, against which possible options for the gas target model should be assessed:

(1) the promotion of efficient use of cross-border capacity;

(2) the impact on long-term contracts and on investment incentives upstream;

(3) the promotion of liquid trading and transparent spot prices;

(4) impact on the role of TSOs; and

(5) ease of implementation.

3.2 We discuss these criteria below.

The promotion of efficient use of cross-border capacity

3.3 The promotion of efficient use of cross-border capacity is central to the EU's long-term strategy of creating a competitive internal gas market. By using interconnections efficiently, shippers in one country can compete in other Member States more easily. This is important as former vertically integrated incumbents are still dominant in many national markets.

3.4 However, the efficient use of cross-border capacity has proven difficult due to contractual congestion[4], as has been documented in the Sector Inquiry and subsequent investigations[5]:

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4 Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report), Paragraphs 48 and 69, 10 January 2007.

5 Paragraph 223, 'DG Competition report on Energy Sector Inquiry', 10 January 2007.

> "*It has...been found that although contractual congestion is common, most pipelines are not, in general, experiencing high levels of utilisation. In such circumstances, it would be expected that the relevant TSOs would be releasing interruptible capacity to the market. However, only on a small number of transit pipelines has a substantial amount of interruptible capacity been sold, indicating that these TSOs may not be maximising the efficient use of pipeline capacity.*"

3.5 The current system of explicit rights may also lend to a failure to maximise available capacity, because TSO capacity calculations do not 'net out' flows. For example, say shippers wish to transport 1,200 units of gas in one direction and 300 units of gas in the other, while the physical capacity of the interconnector is 1,000 units. Since the net flow is 1,200 – 300 = 900, because it has declared a maximum capacity of 1,000, this should be possible. However, the TSO may not allow all the nominated 1,200. This is known to be an issue in electricity markets (without market coupling).

3.6 In order to relieve contractual congestion, "anti-hoarding measures" such as UIOSI/UIOLI regimes have been put in place. However, this is difficult to do and has met with limited success. UIOSI/UIOLI regimes have been unpopular with many parts of the industry, in part because they require a point in time after which no 're-nominations' can be received ("gate closure") and a limitation on intra-day trading.

3.7 An alternative anti-hoarding measure of over-selling firm capacity (as used in the GB gas market) could be used[6]. However, this requires the right incentives on TSOs to over-sell capacity, and may be problematic if the TSO is highly risk-averse. The Commission is expected to bring forward soon proposals for congestion management provisions.

The impact on long-term contracts and investment incentives upstream

3.8 Long-term contracts are an important feature of European gas markets. A large proportion of contracts are long-term.

3.9 Many long-term contracts require the seller to deliver gas to a buyer at a specified delivery point. Any regulatory changes that interfere with this would impose great costs and uncertainty on the European gas industry, and arguably would weaken future upstream investment incentives.

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6 Over-sold capacity is firm if shippers are compensated for the financial loss of not physically delivering the gas. Simply reimbursing the cost of capacity does not make it firm.

3.10 Long-term contracts are important to investment in the transmission network. TSOs may run an open season process for investment in new infrastructure, only building new pipelines if enough shippers book capacity.

The promotion of liquid trading and transparent spot prices

3.11 Liquid trading and transparent prices are required to achieve an efficient allocation of resources as well as promoting entry and facilitating hedging. Liquid trading helps new entrants to enter the market. An illiquid market means that new entrants would struggle to find a partner for a trade and may not be able to purchase capacity or gas when needed. This may be a problem in a market dominated by national incumbents with long-term contracts already in place. Promotion of efficient use of cross-border capacity will in itself promote more liquid trading. Transparent price formation encourages greater participation in trading across a range of timeframes, by suppliers, traders and consumers.

3.12 The issues of liquid trading and transparent spot prices are inter-related. A liquid market is likely to produce transparent spot prices if trading takes place on an open platform, via an exchange or through appropriately regulated over-the-counter ("OTC") trading.

Impact on the role of TSOs

3.13 To charge for use of the network, market based mechanisms are preferred. ERGEG's framework guidelines recommend that capacity at interconnection points should be auctioned. Under an explicit system, the TSO receives the auction revenues for capacity. Under an implicit capacity trading mechanism, TSOs receive the difference in price between price zones. This is "congestion rent". However, under either approach there will need to be a common approach to charging arrangements at interconnection points.

3.14 The auction revenues or the congestion rents received by a TSO (either under an implicit or an explicit system) may be too little to recover costs, or may be excessively large relative to the costs of running the network. If an adequate amount of interconnection capacity was built, auction revenues or congestion rents may fall to zero. Therefore, an additional system charge may be needed to provide a return to TSOs.

3.15 Currently, each TSO receives revenues from the charges it applies to shippers directly, with no direct payments occurring between TSOs. Whether or not this is desirable, it is clear that having a price zone that encompasses more than one TSO and/or implicit capacity trading across TSO boundaries would very probably imply the need for payments between TSOs. For example, if it was possible to transport gas from the Netherlands to France by buying entry capacity from GTS and exit capacity from GRT Gaz, then one or both of these would need to compensate Fluxys for the costs of transporting gas through Belgium. If ITC is not used, then there may be unacceptable cross-subsidies due to some TSOs receiving a disproportionate amount of the charge for injecting or withdrawing gas from the transmission system ("entry/exit charge"). TSOs may also lack the incentive to invest in new pipelines if they cannot recover the cost of them. This issue has arisen in the Nordpool electricity market where investment decisions are still largely made on a national basis[7].

3.16 The choice of target model may also impact the TSO's role in balancing. Depending on the choice of model, there may be more constraints within a price zone ("intra-zone constraints") and therefore greater need for TSOs to undertake re-despatch (with correspondingly greater cost). Gate closure mechanisms also limit shippers' ability to enter a balancing market short-term if there is no explicit trading after the gate closure. Therefore, if a gate closure mechanism is used, the TSO will have to deal with any imbalances that remain in the system.

Ease of implementation

3.17 Ease of implementation is an important consideration as some changes to the gas market may be difficult to achieve, both practically and politically. Both the creation of large entry/exit zones and the adoption of market-coupling arrangements require extensive cooperation between TSOs, National Regulatory Authorities ("NRAs") and Member States. However, this process may be encouraged given that the Third Package stipulates the requirement of these bodies to cooperate.

3.18 There may also be a difference in what is achievable short-term, and what is possible long-term. Policymakers may determine that it is preferable to get some integration of markets in the short-term, rather than possibly achieving greater integration but after a number of years of struggling to harmonise markets.

[7] Moselle, B., "Reforming TSOs: Using the 'Third Package' Legislation to Promote Efficiency and Accelerate Regional Integration in EU Wholesale Power Markets", The Electricity Journal, Elsevier, vol. 21(8), pages 9-17, October 2008.

Section 4 Key issues for the target model

4.1 As we explain in Section 1, we consider that there are two key issues which define the possible alternative models for the gas market, namely the size of the price zone and how you trade capacity between zones.

Key issue 1: size of the price zone

4.2 It is useful to begin with some simple observations. Any entry/exit system creates a virtual hub, with an associated single price at that hub which applies in the whole area covered by the entry/exit system. Well known examples are the NBP price, covering all of GB, or the TTF price, covering all of the Netherlands. A price zone often coincides with an "operating zone", which is a transmission network that a TSO (or Independent System Operator ("ISO")) manages separately to other transmission networks. However, a price zone can cover more than one operating zone, or a TSO could have multiple price zones within an operating zone. A "balancing zone" is a zone within which all inflows of gas must be balanced with outflows of gas. This will essentially coincide with an entry/exit zone.

4.3 Most price zones within the EU are currently national or sub-national in size. They tend to be based on administrative borders rather than on technical or economic considerations. However, the general policy has been toward fewer balancing zones. France consolidated seven balancing zones in 2003 to five balancing zones in 2005 to three in 2009, while Germany reduced from 19 balancing zones in 2006 to 3 balancing zones by April 2011.

4.4 Given the ultimate goal of providing a single European gas market, larger zones have an obvious appeal. However, from an economic perspective there can be significant problems with large price zones. Creating large price zones may require the socialisation of significant intra-zone constraints via re-despatch by the TSO. This allocates congestion rents earned by TSOs to shippers, and can create distorted incentives that lead to inefficient outcomes and to undesirable cross-subsidies that create problems for regulators.

Problems with re-despatch

4.5 Constraints within the price zone will not be subject to different prices either side of the constraint. Therefore, to deal with the constraint, TSOs will have to engage in re-despatch and countertrading. This exerts a cost on the TSO which must be socialised across users of the transmission system. Persistent intra-zone constraints may also cause market distortions, as has been seen in a number of cases in EU power markets.

4.6 For example, gas suppliers could engage in 'exploitative' bidding for countertrades. Gas suppliers may submit high offers behind import constraints to extract high constrained-on payments. Gas suppliers behind the export constraint may submit low bids to extract high payments for being constrained-off.

4.7 Suppliers could also engage in output manipulation. Suppliers in import constrained areas may choose not to sell forward supply whose cost is below the forward market price, or supply in export constrained areas where the cost is above the forward market price.

4.8 Both methods are risky for gas suppliers if congestion does not occur, but if congestion is persistent, then such strategies would be profitable for suppliers[8]. We describe in Appendix 2 some related experience with the British wholesale electricity market.

4.9 Alternatively, smaller price zones could be considered. Using entry/exit charges for capacity, smaller price zones will display better locational pricing signals of constraints between zones. Congestion rents can be used to pay for new interconnection investment between price zones exhibiting large costs for capacity, or large differences in implicit prices. TSOs should be required to spend congestion rents on maintaining or investing in new interconnection capacity as TSOs may have an incentive to keep interconnectors constrained in order to earn congestion rents.

[8] Moreover, although these outcomes are unpalatable to regulators, it is hard to argue that they constitute abuse. Market participants are simply engaging in arbitrage between day-ahead prices (geographically uniform) and real time prices (prices in the balancing mechanism), which vary by location.

4.10 However, small price zones are likely to lead to distortions in transmission tariffs for cross-border flows (so called pancaking). A large proportion of the supply of gas in the EU comes from outside of the EU, must be transported across the continent and pass through many price zones before it reaches its final destination. If a shipper is required to pay an entry and exit charge each time gas is transited through a price zone, this may require a large number of separate charges and the overall effect is unlikely to be cost-reflective.

4.11 In theory, if all entry and exit chargers were cost reflective, the sum of all the entry and exit charges would be the same as if one charge had been made to transport gas across the continent. However, entry/exit charges may include socialised costs, which are not reflective of the shipper's use of the transmission system. There are also transaction costs involved in arranging a large number of contracts. A smaller number of larger price zones reduces this problem.

4.12 Persistent intra-zone congestion can also distort the incentives of TSOs. In some cases, the TSO may be tempted to avoid costly re-despatch by limiting capacity on the zonal borders so as to reduce gas flows that are creating internal congestion ("shifting congestion to the borders"). This kind of distortion has been seen in electricity markets, for example in the case of Svenska Kraftnät (the electricity TSO in Sweden).

4.13 Sweden had a single price zone despite the existence of significant internal constraints. Svenska Kraftnät therefore limited flows on the Danish border, despite the distortion on prices this would create on neighbouring systems. However, the European Commission opened proceedings against Svenska Kraftnät in April 2009 due to competition concerns. The Commission considered that this represented an abuse of a dominant position by the TSO as it did not treat domestic customers and foreign customers equally. In September 2009, Svenska Kraftnät agreed to split Sweden up into three price zones within the Nordpool electricity market by November 2011.

Key issue 2: implicit or explicit cross-border capacity allocation

4.14 There are essentially two models for the allocation of transportation capacity, plus a third hybrid approach:

(1) **Explicit allocation of capacity**. Shippers hold explicit physical transmission rights. These are allocated initially by the TSO (e.g. via auction), and can then be traded on a secondary market. There are therefore separate markets for capacity and for natural gas.

(2) **Implicit allocation of capacity**. There is a single market for capacity and energy combined. Buyers and sellers of gas make offers through a hub or exchange to buy or sell gas at specified times and locations, and at specified prices. The hub then produces a 'programme' for gas flows based on accepting bids so as to maximise surplus (the difference between the price buyers are willing to pay and the price sellers are willing to accept) while respecting system constraints. This procedure also produces locational prices. The price in two zones will be the same if there are no transmission constraints[9] that limit flows between the two zones (and will differ if there are such constraints).

(3) **Hybrid**. This is the approach used in implicit European electricity markets. Shippers hold long-term explicit, physical transmission rights, just as in point (1) above. However, nominations to use those rights must be made by the gate closure (e.g. the day before real time flows). After gate closure, remaining transmission capacity is allocated via the implicit method in point (2) above.

9 As discussed later in this paper, relevant constraints will include not only early transmission capacity but also other factors including minimum and maximum linepack and potentially gas quality constraints.

Explicit allocation of capacity

4.15 In an explicit system, shippers trade bilaterally and capacity would be allocated via explicit auctions. This represents the Framework Guidelines Driven approach under the Third Package. Under explicit auctions, capacity of the interconnector is auctioned to the market separately from the sale of gas. Explicit auctions are considered a simple method of allocating interconnector capacity that avoids discrimination and does not provide incentives for distorted behaviour (e.g. the retention of unused capacity by shippers ("capacity hoarding") under first-come first-served, over-bidding under a pro rata allocation). Explicit auctions for long-term capacity can also provide a good signal of capacity investment requirements. If an interconnector is congested, the value of scarce capacity will increase in an auction. A high price for capacity signals the need for investment to relieve the constraint.

4.16 An explicit system enables shippers to hoard capacity because it can be bought separately from the gas itself. Shippers can purchase capacity on an interconnector even though they know that much of the capacity they have contracted will not be nominated for use. Shippers may sign such long-term contracts in the expectation that the amount of gas they wish to transport may go up in the future, to provide a cushion for increases in cross-border gas demand, or because capacity was needed to transport gas in the past, but gas is no longer demanded cross-border so there is an excess of contracted capacity for the shipper. Shippers who own excess long-term capacity may not want to sell on to the secondary market as they may want to use their capacity in the future and may be reluctant to allow new entrants into the market by providing them with capacity. Such capacity hoarding needs to be prevented as unused capacity on an interconnector means that cross-border capacity cannot be allocated efficiently.

4.17 An important consideration is how and when to release spare capacity onto the market. One way of doing this is through a gate closure and a UIOSI/UIOLI mechanism. Before gate closure, shippers may freely trade capacity explicitly in the long-term market (subject to the total capacity of the interconnector) up to gate closure where they must nominate how much of the contracted capacity they wish to use. Shippers are required to sell any remaining unused capacity into the short-term implicit market.

4.18 In a UIOSI/UIOLI mechanism, at the end of trading, if there is any capacity that the shipper has not sold that they do not nominate for use on the day, then this is lost to the shipper. The TSO makes this available on the intra-day market. This gives an incentive to the shipper not to hoard capacity and to make it available to the market either day ahead or long-term.

4.19 However, gate closure is not the only possible measure. A TSO could be required to over-sell capacity on the assumption that a certain proportion of contracted capacity will not in fact be used. This is the current method used in the GB gas market, which does not have gate closure.

4.20 Over-selling of capacity is analogous to the common practice of airlines over-selling seats on planes. It is expected that a certain number of passengers who have booked seats will not make the flight, and therefore there will be enough seats for all the passengers who do make it to the airport to fly. In a similar manner, a TSO can sell more capacity than technically exists on the interconnector under the expectation that some of the capacity booked long-term by shippers will not be used.

4.21 However, if an airline's expectations are proved wrong, and more people turn up for the flight than there are seats available, a number of passengers will need to be paid not to fly. Similarly, the TSO would need to refund shippers who cannot be provided with capacity. The shipper can either be paid back the price they paid for capacity (reimbursement) or paid the auction price plus the difference in prices between the two markets, equal to the profit the shipper would have made (compensation). Compensation provides financially firm transmission rights. The regulator needs to provide adequate incentives for the TSO to accurately forecast the correct amount of over-selling so that there is no residual contractual congestion, and neither do many shippers need to be refunded.

Implicit allocation of capacity

4.22 In an implicit system, capacity itself is not traded, but shippers can implicitly buy capacity when trading gas at a hub or some other centralised system. The cost of capacity is implicitly part of the price shippers pay for gas. There is no separate market for capacity as it is purchased together with the gas.

4.23 Although not currently in place for gas, an implicit system is used in the Nordpool[10] and Central Western Europe Market Coupling ("CWE")[11] electricity markets. However, market coupling has been proposed by some market participants (e.g. the Anglo-Dutch power exchange APX-ENDEX[12]) for the North-West Europe natural gas market. We understand that Powernext is considering market coupling for France. If there is congestion, the price of capacity will increase, therefore the hub prices of gas will rise. Gas prices either side of a congested boundary should be different, the difference being the cost of the congestion.

4.24 The US electricity markets use a form of implicit capacity allocation known as nodal pricing. Bids and offers for electricity are submitted at different points in the system. The TSO runs a complex algorithm to determine the optimal security-constrained despatch and prices at each location. If the transmission pipeline is constrained at a certain location, the price for electricity at that location will increase, reflecting the high cost of capacity on that route.

4.25 A nodal pricing system for natural gas would be theoretically possible for Europe. However, we do not view it as realistic in the short or medium-term.

4.26 Under implicit allocation the issues of contractual congestion and UIOLI/UIOSI do not arise because shippers do not hold capacity rights. However, this does raise the question of how long-term contracts can be entered into.

4.27 Long-term contracts are agreed on the basis that the party transporting gas has 'physical rights' to capacity. However, in an implicit system, shippers do not have physical rights to capacity, but may have financial rights over capacity. That is to say they can be put into the same financial position as if they had physical rights to capacity. This can be done through the use of Contracts for Difference ("CFDs") and Financial Transmission Rights ("FTRs") (also known as Transmission Congestion Contracts ("TCCs")).

4.28 A CFD is an agreement to pay the difference between a commodity price and a pre-determined price. If the spot price goes down, the buyer of gas pays the seller the difference between the spot price and the price agreed in the CFD. This leaves both parties in the same position as if the spot price was the same as the price agreed in the long-term contract.

10 A market splitting regime between Norway, Sweden, Finland and Denmark.

11 A market coupling regime between France, Belgium, the Netherlands, Luxembourg and Germany.

12 Bert den Ouden, 'Market Development and Gas Exchanges', 23 March 2010.

4.29 Under an implicit approach, it is possible for prices to differ across price zone boundaries due to constraint costs. One possible use for a TSO's congestion rents is that TSOs may be required to sell FTRs to holders of long-term explicit contracts. An FTR gives the holder the right to bid into the local exchange, but to get the price at the exchange across the border (the difference paid for by the TSO from its congestion rents). FTRs are used in the Italian power market (which has a market-splitting system based on three price zones within Italy), as well as in US power markets based on nodal pricing.

4.30 There are four possible scenarios for trading long-term capacity. Box 4-1 below explains how these possible scenarios would work.

Box 4-1: possible scenarios for trading long-term capacity

Say Firm A (a gas producer) in one country agreed to supply Firm B (a gas distributor) in another country with 100 units of gas for 10 cents per unit.

Scenario 1: bilateral capacity trading, no congestion

In this scenario, the seller (Firm A) can fulfil its contractual obligation by buying firm transportation rights from A to B, and using it to deliver the gas. In return, the buyer (Firm B) pays 100 x 10 = 1000 to the seller.

Scenario 2: switch to implicit capacity allocation, but still no congestion

In this scenario, regulatory changes require all gas trading to be carried out through a hub or exchange. The seller and buyer can continue with the same long-term contract as before, provided they sign a CFD as a side-contract. The seller promises to pay the buyer the difference between the price of gas at the hub and the contract price (or if this is negative, the buyer pays the seller). This is analogous to a physical transmission right, since if the seller held a physical transmission right from A to B then it could get the price at point B by taking its gas to B and selling it there.

So now:

- the seller bids in to sell 100 units of gas to the hub at a very low price (e.g. zero);

- the buyer offers to buy gas at the hub at a very high price (e.g. 100);
- the hub announces the market price is (for example) 12;
- the seller receives 100 x 12 = 1200 from the hub. Under the CFD, it then pays 100 x (12-10) = 200 to the buyer;
- the buyer pays 100 x 12 = 1200 to the hub, but receives 200 from the seller;
- the net effect is that the buyer still pays 10 cents per unit to the seller, as per the contract.

Scenario 3: bilateral capacity trading, congestion

In this scenario, just as in scenario 1, the seller can fulfil its contractual obligation by buying firm transportation rights from A to B, and using it to deliver the gas. In return, the buyer pays 100 x 10 = 1000 to the seller. However, with congestion and bilateral capacity trading, it may be more difficult for the buyer to be sure of getting the required cross-border capacity, unless it has 'grandfathered' rights.

Scenario 4: implicit capacity trading, congestion

In this scenario, regulatory changes require all gas trading to be carried out through a hub or exchange, and in addition there is congestion between the buyer and the seller's areas.

The seller and buyer can continue with the same long-term contract as before, provided they sign a CFD side-contract and that the TSO sells FTRs. In this scenario therefore, to fulfil the contractual obligation:

- The seller buys from the TSO 100 units of FTRs from A to B;
- The seller bids in to sell 100 units of gas at A to the hub, at a very low price (e.g. zero);
- The buyer offers to buy gas at B from the hub, at a very high price (e.g. 100);
- The hub announced the market prices: say the price at A is 7, and the price at B is 12;
- The seller receives 100 x 12 = 1200 from the hub. Note

that the seller is getting the price at B, even though it is selling the gas at A: that is the effect of the FTR;

- Under the CFD, the seller then pays 100 x (12-10) = 200 to the buyer;
- The net effect is that the buyer still pays 10/unit to the seller, as per the contract.

Hybrid (long-term explicit, short-term implicit allocation of capacity)

4.31 It is possible to have a model with a mixture of implicit and explicit capacity allocation. A feature of the European gas market is the prevalence of long-term bilateral contracts. A target model could consist of long-term explicit contracts for capacity, while short-term trading of capacity could proceed on an implicit basis.

4.32 To have a mix of long-term explicit and short-term implicit capacity trading requires a gate closure mechanism between the long-term explicit market and the short-term implicit market. In the short-term the party responsible for the implicit allocation has to have control over all capacity that has not already been allocated via nomination of explicit rights, so that it can make an allocation via the auction mechanism (i.e. the auction of energy at specified locations as described above). This is in contrast to some (but by no means all) existing gas markets that allow for continuous (including real-time) re-nomination of capacity rights by shippers (e.g. in GB or the Netherlands)[13].

4.33 This gate closure would ensure that unused contracted long-term capacity is made available to the implicit short-term market and that the phenomenon of contractual congestion is avoided.

4.34 In the CWE market, there are long-term auctions for explicit capacity, with a gate closure between the long-term explicit and short-term implicit markets. Nordpool does not have a long-term market and all trading is done implicitly short-term, meaning that a gate closure is not needed between the long-term and short-term markets.

13 Note the contrast with electricity markets, where the need for second-by-second balance means that the TSO always manages despatch in real time. For historical reasons, gate closure in coupled electricity markets occurs day-ahead, but there is no reason to assume that the same would hold for gas market coupling.

Section 5 Possible options for the gas target model

5.1 We consider possible options for the gas target model in terms of the method of cross-border capacity trading and the size of the zone. Figure 5-1 below describes six possible options in the form of a matrix.

Figure 5-1: possible options for the gas target model

		Size of price zone		
		Medium mostly national	Big often super-national	Sub-national (prices at points not zones)
Cross-border capacity allocation	Explicit trading of capacity	Explicit trading of capacity. Emerging as "standard approach" in European gas market e.g. NBP, TTF. **Framework Guidelines Driven**	Merge current balancing zones. Explicit trading of capacity remains at borders. **Merged Markets**	Point to point capacity. e.g. US gas market. Not possible under 3rd Package. **Point To Point**
	Implicit trading of capacity	Zones as now, or re-chosen on an objective basis. Implicit auctions for cross-border capacity, like CWE and Nordpool in the electricity market. **Coupled Markets**	Implicit trading but with larger pricing zones. **Hybrid**	Nodal pricing e.g. US electricity market. **Nodal Pricing**

5.2 Based on the figure above, one can envisage three likely approaches to the gas target model:

(1) explicit transmission capacity combined with national/sub-national price zones (**Framework Guidelines Driven**);

(2) explicit transmission capacity combined with larger, regional price zones (**Merged Markets**); and

(3) implicit transmission capacity combined with national/sub-national price zones (**Coupled Markets**). We assume that at least for the present market coupling would be used for the allocation of short-term rights, while TSOs would continue to provide long-term explicit rights.

5.3 The three other approaches (Point To Point, Hybrid and Nodal Pricing) shown in Figure 5-1 are theoretically possible, but we consider them of less interest, for reasons explained briefly later in this section.

Option (1): Framework Guidelines Driven

5.4 This option is along the lines envisioned at the time of the development of the Third Package. In our view, it is the "momentum-driven" approach that will be followed in the development of the Framework Guidelines, unless the target model puts forward a different vision.

5.5 Under this approach, capacity is allocated via explicit auctions, separately from trading of gas itself.

5.6 TSOs could offer capacity on joint platforms and facilitate secondary capacity trading on this platform. Particularly important in this procedure, is the lower transaction effort and the integrated allocation of the capacity of both sides of a border, as there is a very tight timeframe in the allocation of day-ahead capacity.

5.7 Capacity at interconnection points would be allocated as bundled products via auctions. This means the exit and entry capacity at every point connecting adjacent entry/exit systems is integrated in such a way that the transport of gas from one system to an adjacent system is provided on the basis of a single allocation procedure and single nomination. The bundled product reduces the complexity for shippers in cross-border trading and helps reduce transaction costs through avoiding the need to buy entry and exit capacity in both zones.

5.8 Balancing zones would remain mostly national as presently, with some intra-national balancing zones merging into one national zone. Greater harmonisation is needed to facilitate increased cross-border trade.

5.9 If balancing zones remain much as they are now, a key challenge would be how to increase cross-border trade and overcome low levels of trading in some zones. For TSOs offering bundled capacity this means intensive cooperation. The intervals, lead times and processes of capacity allocation must be consistent at interconnection points. TSOs also need to harmonise the calculation of available capacity at interconnection points.

Option (2): Merged Markets

5.10 Capacity allocation would proceed on the same basis as option (1), but between larger price zones. The need for multiple TSOs to cooperate and harmonise rules within the larger price zone should help lead to TSOs cooperating and harmonising capacity allocation between zones.

5.11 Existing price zones would merge into bigger, regional price zones with fewer entry and exit points. Merging zones means there would be a common set of balancing rules but also consistent network tariffs and capacity allocation arrangements within the bigger zone.

5.12 The bigger the price zone the greater the number of localised constraints that will need to be managed within it and the more balancing tools will be required by the TSO to ensure system integrity. This trade-off places a limit on the expansion of zones as the costs of managing internal constraints increases, in particular if the merger of two zones internalises significant physical constraints. Therefore, the optimal size of these price zones would likely be regional rather than one price zone for all of Europe.

5.13 Boundaries of price zones would reflect the physical realities of the gas transmission network rather than the political boundaries of Member States or legacy arrangements within Member States (i.e. where a particular TSO has historically managed a particular network). Therefore, the size of these zones will vary where physical network constraints or indeed differences in gas quality may dictate a smaller market zone than in other parts of Europe.

5.14 To manage the transmission network within a regional zone, there could be one regional SO or close cooperation between national TSOs within the zone. A regional price zone would not necessarily require merger of ownership. If the regional balancing zone includes a number of TSOs there needs to be agreement between the TSOs on how the system is managed. It could be that a regional TSO is created or one of the TSOs is appointed as the main system operator to take advantage of operational efficiencies. For example, when the British Electricity Trading Transmission Arrangements ("BETTA") created a market for electricity across GB, National Grid ("NG") became the system operator for all of GB, but was only the TO for England and Wales.

5.15 This option requires the greatest degree of harmonisation. Within the price zone, all rules and regulations will need to be harmonised to ensure there is a level playing field across the price zone. This will be difficult as regional price zones will cover a number of TSOs, Member States and NRAs, and may contain separate balancing zones within the price zone. It is important that the TSO's role as the residual balancer is appropriately incentivised as it may be possible for some TSOs to exploit the linepack or imbalance of another neighbouring TSO within the price zone.

5.16 There is a possible variation of this option that arguably could be implemented without the same degree of harmonisation. One regional price zone could be created with explicit trading of capacity. There is a "supergrid" with a virtual hub giving one price across the prize zone, similar to NBP but on a wider scale. Shippers pay an entry charge for importing gas into the supergrid, and an exit charge for entering a TSO within the supergrid. Each TSO operates as a separate balancing zone with its own internal rules, but the same price exists across the supergrid and the constituent balancing zones.

5.17 This is analogous to a transmission system with multiple distribution systems. The price is determined in the transmission system (similar to the supergrid) which is one entry/exit zone. Shippers pay to exit the transmission system and enter the distribution systems (similar to the national TSOs in the supergrid model).

5.18 The extent of harmonisation required for this model requires further research.

Option (3): Coupled Markets

5.19 The essence of market coupling is the use of auctions with locational bids and offers. A central party (energy exchange, TSO, pool, or some grouping of such) runs an algorithm that matches bids and offers so as to maximise the gains from trade[14] while respecting transmission constraints. It does so via an algorithm that produces a single market price in each price zone. These prices will differ from zone to zone if physical congestion limits the ability for gas to flow from lower to higher priced zones.

5.20 At operational level, there are broadly two forms of implicit capacity trading that could be used at a national level: market coupling and market splitting. Both of these mechanisms are essentially the same, but approach the problem of creating implicit markets for capacity in different directions. Therefore, for simplicity we refer to this option as market coupling.

14 For the avoidance of confusion, in this context "trade" refers to all buying and selling of gas, whether or not it crosses borders.

5.21 Market coupling starts out as separate markets that are then coupled together as far as constraints allow, while market splitting starts out as one, super-national market that splits up into smaller price zones based on constraints. Therefore, there is little meaningful difference between these two forms, just a different direction of the process.

5.22 Under market coupling, shippers place bids and offers for gas in an auction at a hub or exchange within each price zone. This determines a spot price on each exchange. After gate closure, the information on bids, offers and capacity is shared between the exchanges and an algorithm is used to determine the flow between each price zone and the price in both market zones. If there are no constraints between the price zones, gas will flow from the zone with a low price to the zone with high price until prices are equalised across the market coupled region. This determines the capacity used on the interconnector.

5.23 However, if constraints exist between the price zones, the price of gas will differ between the zones. This gives the cost of the constraint. Therefore, the auctioning of capacity is implicitly included in the auction of gas at the hub. Prices reflect both the cost of gas and the cost of congestion. Therefore, market coupling is a dynamic approach to market integration, where market areas 'couple' and prices converge when there is sufficient interconnection capacity and markets 'split' and separate prices are formed when there is insufficient interconnection capacity.

5.24 Like market coupling, under market splitting capacity is traded implicitly. Unlike market coupling, bids and offers are placed in an auction on one, regional hub or exchange. Bids and offers are accepted as if there are no constraints on the network within the region. If the market is not capacity constrained, there will be one price across the regional zone.

5.25 However, after gate closure, if there are capacity constraints between zones within the region, an algorithm will determine different prices in different price zones and the gas flows between those zones. In export constrained zones prices will fall, while in import constrained zones prices will rise.

5.26 Capacity is traded implicitly under a market coupling/splitting approach, at least for short-term capacity. A hybrid can exist where long-term contracts still trade capacity explicitly. For example, the market coupling mechanism in the CWE electricity market allows for explicit trading of capacity using long-term bilateral contracts, but in the day-ahead auction capacity is traded implicitly. Long-term capacity could also be explicitly auctioned off at a hub or exchange.

5.27 Alternatively, a market coupling/splitting area could forego the use of explicit long-term contracts for capacity altogether. However, holders of existing long-term contracts could maintain financial rights over their transmission contract using CFDs and FTRs.

5.28 Market coupling/splitting signals congestion in cross-border capacity. Therefore, it can act as a transparent signalling mechanism for TSOs to invest in cross-border capacity if price differences are persistent. Congestion rents earned through these price differences can be used to part-fund the investment. The figure below shows the Nordpool spot market between 19.00 and 20.00 on 6 October 2008. As can be seen from the figure, there were considerable constraints between Denmark and Sweden and southern Norway. However, within Denmark and between Sweden, Finland and central Norway, prices were the same. If such a pattern persists then this shows that investment is needed on the interconnectors between Denmark and Sweden and Norway.

Figure 5-2: Nordpool spot prices between 19.00 and 20.00 on 6 October 2008

Source: Bjørndal, M., Congestion Management in the Nordic Electricity Market, 2nd Energy Economics Policy Seminar on the European Integration of Electricity Markets, 9 October 2008.

5.29 A market splitting zone will be large, often super-national in size. However, within the operational zone, market splitting may cause there to be multiple price zones, with capacity constraints at the border of each zone. Market splitting may result in price zones smaller than those currently exhibited in some areas where there are intra-price zone constraints. An example of this is the case of Svenska Kraftnät in Sweden[15].

5.30 Market coupling/splitting requires price zones within the market coupling/splitting area to harmonise the trading day, the time frame of products traded (for example, day ahead, intra-day etc.) and the time from over which inflows and outflows must be balanced ("balancing period"). However, harmonisation between price zones within a market coupling/splitting area does not need to be to the same extent as merging the price zones within that region.

5.31 With market coupling each price zone can retain a separate trading hub, but there will need to be cooperation between the zones in terms of similar trading rules at the hubs and physical interoperability of the networks to allow price convergence to occur. For the market coupling algorithm to be used effectively, cooperation is necessary between the hubs, requiring common balancing periods, common gate closure arrangements and common time-frames for implicit auctions of capacity. It is possible for a market coupling arrangement whereby only the flows are determined by the algorithm and each exchange calculates the price for the price zone separately. This is known as volume coupling and is not seen as a first best solution[16]. Volume coupling may be possible without the same degree of harmonisation as price coupling.

Other options

5.32 As shown in Figure 5-1 above, there are three other possible options. Below we discuss the features of the other possible models. However, as we explain below, we consider these models less relevant for a range of different reasons, and therefore do not discuss them in detail.

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[15] See paragraph 4.12.

[16] As prices are calculated separately, this may result in small discrepancies and/or adverse flows due to differences in the matching algorithms, the completeness of market data delivered to the market coupling algorithm, or the implementation of market rules. If these differences are more pronounced, the volume coupling will be looser and there will be less price convergence. Volume coupling is used by the European Market Coupling Company ("EMCC") between Denmark and Germany in the electricity market, and is the only example of volume coupling in Europe. This has proved difficult in practice and is not the preferred market coupling model.

Option (4): Hybrid model

5.33 The **Hybrid** model would be similar to option (3), but with larger price zones within the market coupling or market splitting area. In a sense this would be a 'hybrid' of the two previous approaches, since it would involve a policy of 'merging' some of the existing price zones into a single price zone and introducing market coupling between the Merged Markets.

5.34 A significant concern with this approach is the difficulty of implementing two radical changes. As discussed elsewhere in the paper, merging markets requires a high degree of harmonisation, and experience with similar projects in EU power markets suggests this will involve a great deal of time and resources. The same holds for the development of market coupling arrangements. The simultaneous adoption and implementation of both approaches therefore risks over-reach.

5.35 In addition to this practical concern, experience in the European electricity markets has suggested that larger price zones are not necessarily consistent with market coupling. Under the market coupling approach, the market price sends the signal as to whether gas should be imported or exported from that area. In a larger price zone, the market price will be formed based on shippers trading as if there are no constraints in the network, (any physical constraints will be managed separately by TSO), therefore the market price may send a signal for gas to be exported from the area, which may cause the cost of managing network constraints to increase further. As such, in the Svenska Kraftnät case, the European Commission called for the Swedish electricity market to be broken into a smaller number of price zones.

5.36 Moreover, given that price zones will already have been greatly harmonised within a market coupling/splitting area, there seems little basis to move to regional implicit markets for capacity. Indeed, it may be best to keep separate price zones even where prices are persistently the same. For example, a short-term emergency leading to the closure of an interconnector, or the need to reduce capacity to perform maintenance on an interconnector would lead to congestion. This could be dealt with using the algorithm if the zones were separate, rather than socialising the constraint costs within the price zone.

5.37 Where there are persistent intra-zone constraints, then market coupling will lead to pressure for the price zones to separate due to the costs of those constraints. This is possible in a market coupling mechanism, which is a dynamic way to couple markets together, rather than a permanent merger of markets.

5.38 For the reasons described above, we do not undertake further analysis of this option.

Option (5): Nodal Pricing

5.39 In a nodal pricing arrangement, bids and offers for gas are submitted at different points in the system. The TSO runs a complex algorithm to determine the optimal security-constrained despatch and prices at each location. If the transmission pipeline is constrained at a certain location, the price for gas at that location will increase, reflecting the high cost of capacity on that route. Such a system is used for the US electricity market.

5.40 Nodal pricing allows for differences in price at different possible locations. Locational pricing allows for gas producers and consumers to optimise their scheduling as well as providing information on bottlenecks in the system. Persistent differences in price also signal the need for investment to relieve constraints at expensive locations in the network.

5.41 Essentially, nodal pricing is simply an extreme version of market coupling, where the market is divided up into a large number of separate zones that can each have their own price if congestion means that the value of gas varies across many different locations. As such, the pros and cons of nodal pricing are similar to those for Market Coupling, with the added advantage of greater flexibility and accuracy in giving price signals, and the added disadvantage of much greater complexity.

5.42 We believe that even if nodal pricing is the desired end, it will be achieved through evolution via Coupled Markets[17]. We do not believe it is realistic to imagine adopting nodal pricing now as the target model, and for that reason we do not devote additional effort to its analysis in this paper.

Option (6): Point To Point

5.43 Point To Point capacity is similar to the regime currently in place in the gas market in the US (and in a sense, to the regime previously used for transit in some areas of the EU). Capacity on the transmission network is sold explicitly, the charge based on the amount of gas and the points where gas is injected and withdrawn from the system. Shippers buy gas separately from capacity. Each point effectively becomes its own zone.

5.44 Tariffs under a Point To Point capacity system are typically related to the distance the gas is transported through the pipe, though in principle one could combine Point To Point capacity with other charging methodologies. One positive of distance-based charging is that it removes the problem of pancaking for trans-continental gas flows.

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17 That is also a likely outcome in EU power markets. We note that in the US all the major regions have now adopted nodal pricing in wholesale power.

5.45 Capacity will be a physical right over a particular route, and since there is a cost to moving gas between any two locations, trading is likely to occur at a physical hub where transmission pipelines interconnect. Physical hubs develop where major pipelines and/or liquefied natural gas ("LNG") flows meet, for example Zeebrugge in Belgium or Baumgarten in Austria.

5.46 A Point To Point capacity model could provide locational signals to shippers indicating congestion, if tariffs were set to reflect congestion (e.g. via auction of capacity on specific routes). If a specific route was constrained, this would push up the price for capacity, both on the long-term primary market and short-term at the hub. Shippers may be able to find alternative routes or times to ship based on these signals.

5.47 Locational prices would then also provide signals about the need for investment. An open season procedure for new investment would also allow shippers to show interest in new transmission pipelines. Where a transmission route is constrained leading to high prices for capacity, shippers would be willing to sign long-term contracts for a new pipeline, expanding capacity and reducing capacity prices.

5.48 However, we do not consider Point To Point capacity to be desirable. For reasons developed in earlier debates, the use of Point To Point capacity in the EU would appear to limit the development of the internal gas market[18]. Moreover, in part because of these earlier debates, Point To Point capacity is not permitted under the Third Package, which stipulates that tariffs should not be dependent on transport route and that gas must be transported through zones rather than along contractual paths[19].

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18 See for example Lapuerta and Moselle. "Convergence of Non-Discriminatory Tariff and Congestion Management Systems in the European gas sector", 2002, a report for the European Commission.

19 Regulation (EC) No 715/2009, Recital 19.

Section 6 Assessment of the possible options

Criteria for assessment

6.1 As explained in Section 3, we consider that there are five key criteria against which possible options for the gas target model should be assessed:

(1) the promotion of efficient use of cross-border capacity;

(2) the impact on long-term contracts (including transition costs if a lot of long-term sales contracts have to be re-written) and on investment incentives upstream;

(3) the promotion of liquid trading and transparent spot prices;

(4) impact on the role of TSOs; and

(5) ease of implementation.

6.2 Below we assess the three main options developed earlier (Framework Guidelines Driven, Merged Markets and Coupled Markets) against each criterion in turn.

The promotion of efficient use of cross-border capacity

Framework Guidelines Driven

6.3 Under a Framework Guidelines Driven approach the problem of contractual congestion will remain significant for cross-border capacity. Anti-hoarding mechanisms (either UIOSI/UIOLI or over-selling) will be necessary to make spare capacity available.

6.4 Having smaller zones with explicit capacity gives rise to pancaking, which distorts cross-border trading. Shippers wishing to transport gas across the continent will have to sign contracts for multiple price zones, paying multiple entry/exit charges. Transaction costs may be inflated due to a high number of zones, and lead to potential cross-border transactions not taking place. This is likely to be a bigger problem in the gas market than the electricity market as gas is often transported long distances from the source and the market is characterised by longer term contracts than electricity. However, smaller zones do give more locational signals for investment as they do not cover wide, regional areas.

Merged Markets

6.5 With Merged Markets, the focus is on harmonising internally rather than at cross-border points. Merged Markets may help to free up more capacity because current cross-border points will become part of the internal transmission system, and so will no longer face the problem of contractual congestion.

6.6 However, Merged Markets will be more likely to contain intra-zone constraints. These constraints will have to be dealt with by the TSOs, and the costs socialised amongst all users of the network. Persistent internal constraints may also create distortions in the market due to the adverse incentives created by these internal constraints. Appendix 3 explains how intra-zone constraints can give rise to distortionary incentives for market participants.

6.7 Merged Markets reduce the problem of pancaking as gas will be transited across fewer price zones. However, price signals will be less locational as a single wholesale price will cover a wider area, meaning the signals for investment in certain locations are not as strong.

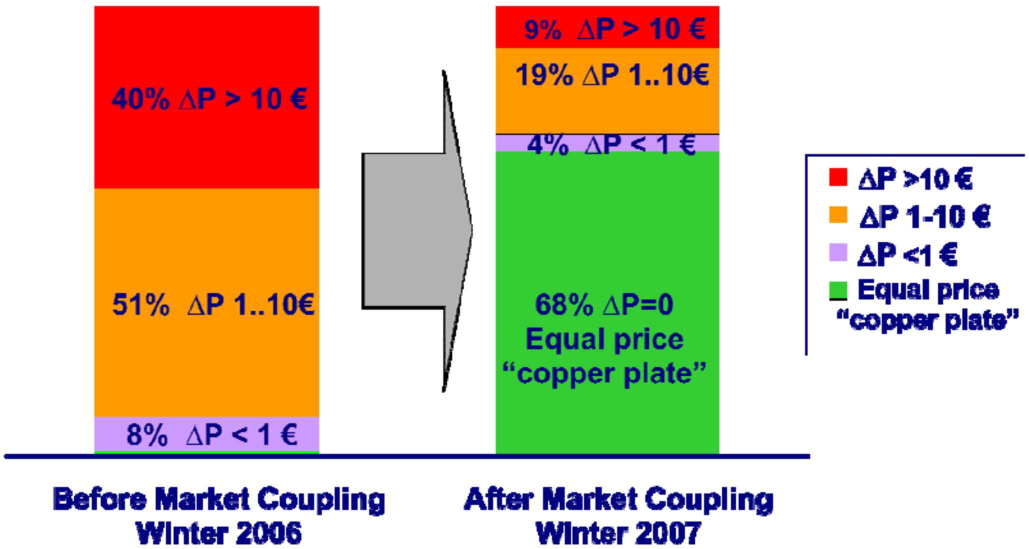
Coupled Markets

6.8 In a fully implicit capacity allocation mechanism, there is no problem with contractual congestion as long-term firm contracts cannot be made. All capacity is traded implicitly and the algorithm will determine all of the capacity to be used.

6.9 There is some evidence from the TLC[20] market coupling area that market coupling has been successful in increasing price convergence between price zones. Price convergence shows an efficient use of interconnector capacity as a difference in price would imply that shippers would try to arbitrage between markets if they could. Figure 6-1 below compares price convergence in the TLC market before and after market coupling.

[20] An electricity market coupling area consisting of France, Belgium and the Netherlands. Later expanded into CWE.

Figure 6-1: hourly price difference €/MWh between France and the Netherlands before and after the beginning of TLC market coupling



Source: APX.

6.10 There is an inherent tension (in a market splitting regime especially) between the creation of a larger price zone using a central hub to trade gas amongst a number of pricing areas, and the need to split into smaller price zones at congestion points. If there are a number of bottlenecks in the transmission network, then moving to a market splitting regime may result in smaller price zones. The same is true of a market coupling area, although the creation of smaller price zones also requires the creation of new hubs within each price zone.

6.11 As can be seen from the examples in Appendix 3, splitting price zones is preferable to a regime of counter-trading and re-despatch where persistent constraints exist. This provides price signals to increase or decrease output on either side of the constraint. Counter-trading and re-despatch costs are borne by the TSO and socialised amongst users of the network and so may not provide appropriate incentives for gas producers and shippers to relieve congestion.

6.12 A market coupling area also reduces the problem of pancaking. Gas transiting through a market coupling area will only enter and exit once, although the entry price in one price zone may be different to the exit price in another price zone if there is congestion. However, this benefit is limited if market coupling is only used for short-term trading.

The impact on long-term contracts and on investment incentives upstream

Long-term transportation contracts

6.13 Previous to the Third Package, some Member States had separate regimes for transit of gas, often based on Point To Point arrangements (and distance-based charges)[21]. The Third Package has stipulated that booking capacity should be based on an entry/exit charge[22]. It is specifically forbidden to base network charges on the basis of contract paths[23]. Therefore, under all options, there will need to be changes to existing long-term transit contracts based on Point To Point charges to fit an entry/exit regime.

6.14 The impact of the move from transit contracts will be the least severe under Merged Markets. New long-term contracts now have to be written for each entry/exit zone that the gas must be transported through. Therefore, with fewer price zones, Merged Markets mean that fewer contracts will need to be written.

6.15 The impact of Coupled Markets on long-term transportation contracts depends if an exclusively implicit model is used, or if the long-term market still has explicit trading of capacity. A long-term implicit market would have the same impact as Merged Markets, with new contracts needed for each market coupling area as there are no explicit charges for cross-border capacity within the market coupling area. However, if a long-term explicit market for capacity remains, the impact will be the same as for the Framework Guidelines Driven approach. Contract will need to be written for each price zone as capacity will still be explicitly traded between each price zone within the market coupling area in the long-term market.

6.16 Moving to an exclusively implicit capacity trading mechanism would mean that shippers would no longer have firm physical rights to capacity. However, holders of long-term contracts could still have financial rights to capacity through the use of FTRs, so buyers and sellers of gas would be in the same position as if physical rights existed[24].

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21 Historically such transit contracts often underwrote investments for long-distance pipelines.

22 Regulation (EC) No 715/2009, Recital 19.

23 Regulation (EC) No 715/2009, Article 13, paragraph 1.

24 See Box 4-1.

Long-term gas supply agreements

6.17 Under the Framework Guidelines Driven model, there should be little change to the gas supply agreement. Price zones are the same size as before, so the delivery point remains the same.

6.18 Under Merged Markets, the delivery point shifts to the border of the price zone, which becomes the new entry point for the gas. This may require some re-writing of contracts.

6.19 Under Coupled Markets, whether the delivery point moves or not is again dependent on if a long-term explicit market is maintained. A hybrid option leaves the delivery points the same, while an exclusively implicit market shifts the delivery point to the border of the market coupling area.

6.20 Market coupling requires the use of a platform to submit bids and offers for gas. This would impact any long-term gas supply agreements as firms would have to purchase gas on a hub rather than agreeing the price bilaterally. Therefore, alongside the use of FTRs for long-term transportation contracts, shippers will need to enter into CFDs as the gas price may be different on different local market coupling platforms.

6.21 Given that long-term transportation contracts will need to be changed anyway, also entering into CFDs and FTRs should not represent a large incremental transaction cost to shippers, nor should they cause a change in the incentives for TSO investment.

The promotion of liquid trading and transparent spot prices

6.22 Under the Framework Guidelines Driven approach, if neighbouring price zones are sufficiently harmonised, uniting capacity management through common cross-border capacity would enable trading activities to be concentrated on virtual trading points, which would improve liquidity. Such hubs have no physical location, but represent a market for injecting or withdrawing gas from any point on the transmission system. The NBP in GB is an example of a virtual hub. A hub is a marketplace for gas where buyers and sellers can exchange gas on a common platform. Gas can be auctioned off to the highest bidder at the hub, rather than sellers of gas trying to make non-transparent deals with buyers of gas individually. The hub may be run by an energy exchange, a TSO or some other body.

6.23 Trading on markets such as hubs is still emerging in Europe, but liquidity is still limited. However, the NBP is a very liquid market[25], and shows the potential liquidity that could exist under a Framework Guidelines Driven model.

6.24 However, a Framework Guidelines Driven approach risks fragmenting trading to a large number of illiquid hubs. Merging price zones with explicit capacity trading mechanisms under Merged Markets could facilitate the merging of hubs, for example the merger of NBP, TTF and Zeebrugge into one hub[26]. Liquidity would be concentrated on one, regional hub rather than remaining in separate markets, which may be dominated by an incumbent.

6.25 Implicit forms of capacity trading require the use of a trading platform such as a hub. Therefore, this may be preferable as it forces market participants to use a hub rather than trading bilaterally. Market splitting may produce an even more liquid market than market coupling as one central hub is used rather than separate hubs for each price zone. However, participants under market coupling will still trade with other hubs through the algorithm. Market coupling/splitting also concentrates trade at a specific point in time (i.e. before the algorithm is run).

6.26 A 2008 report for DG TREN concluded that[27]:

> "...*market coupling initiatives (e.g. Trilateral Market Coupling initiative) [have] increased liquidity and price signals in the European power market."*

6.27 There may be concerns that an implicit capacity trading mechanism cannot function efficiently in areas where high concentration and low existing levels of trade mean that a dominant market participant might be able to manipulate and distort the algorithm. On the other hand, the experience of the Belgian electricity market within TLC suggests introducing a market coupling regime will itself lead to greater liquidity. A power exchange (Belpex) was introduced for market coupling to take place, and was successful despite Belgium having no power exchange before market coupling. Therefore, the lack of an existing liquid market should not be a barrier to the creation of a market coupling area.

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25 Ofgem, 'Liquidity in the GB wholesale energy markets', 8 June 2009, Appendix 3, Paragraph 1.7.

26 The concept of merging NBP, TTF and Zeebrugge is sometimes known as the Herring Hub.

27 K. Rademaekers et al., 'Review and analysis of EU wholesale energy markets: historical and current data analysis of EU wholesale electricity, gas and CO_2 markets', 9 December 2008, Page 7.

Impact on the role of the TSOs

6.28 In a larger price zone, such as a Merged Market, any system charges will need to be harmonised across all TSOs within the price zone. Depending on the flows in the system, different TSOs may not experience similar costs for maintaining the transmission system. Also congestion rents within a price zone are unlikely to be evenly distributed amongst TSOs. This could undermine investment incentives for TSOs where the additional revenues from investment from one TSO would flow to other TSOs within the price zone.

6.29 Merged Markets containing a number of TSOs may require ITCs in order to compensate TSOs for transiting gas across their network and to coordinate investment incentives. For example, TSOs on the perimeter of a price zone may receive entry and exit charges, while a TSO in the centre of the price zone transits the gas, but does not receive any entry/exit revenues. They need to be compensated for the cost of maintaining a transmission network to deal with these gas flows that would not exist if the TSO was an isolated system.

6.30 It is not clear how an ITC mechanism should function and how revenues should be distributed across TSOs. The European electricity market has attempted to introduce an ITC mechanism, but this has been fraught with difficulty and the current mechanism does not appear to be a first best solution to the problem. The obligations for regional cooperation in the Third Package[28] should ensure a better process this time, but it will still be difficult to get TSOs and NRAs to agree on an efficient mechanism.

6.31 Merged Markets may also lead to higher tariffs because more congestion costs will be socialised. Tariffs will be less cost-reflective as more costs are socialised across all network users and, therefore, there will be greater cross-subsidies.

6.32 With larger sized zones, the TSOs must also take a greater role in balancing. There will be more intra-zone constraints for TSOs to contend with, requiring re-despatch and balancing. There may be more than one TSO in each balancing zone, requiring harmonisation of balancing rules and cooperation between TSOs on balancing.

[28] Regulation (EC) No 715/2009, Article 12 and Directive 2009/73, Article 42.

6.33 With Coupled Markets, there is no trading of gas or capacity after the algorithm has been run. Therefore, unless there is some sort of hybrid (with short-term, post algorithm explicit capacity made available for balancing purposes) shippers will be unable to balance injections and withdrawals after the market coupling has taken place. Therefore, the TSOs will be responsible for balancing after the market coupling algorithm has been used. This could be through TSO to TSO balancing, or through bilateral deals with shippers in a short-term market.

6.34 Under Coupled Markets, a consistent approach to ‘System Charges’ at interconnection points will also need to be harmonised. For example, if such charges were applied by one price area but not in the neighbouring one, this will distort cross-border gas flows. In electricity market coupling, the view is held that no additional use of system charge should be applied to interconnector flows, since any charge will prevent complete convergence of prices between neighbouring markets. Therefore, the price in each area will need to take account of any congestion internally or at the interconnection points.

6.35 A smaller price zone under a Framework Guidelines Driven approach would allow for NRAs to have greater discretion when setting system charges as they would not need to be as harmonised with other TSOs in a super-national price zone. Smaller price zones are also likely to have higher congestion rents. However, there does need to be a common approach between TSOs at interconnection points.

Ease of implementation

6.36 For cross-border competition to develop, it is necessary that compatible rules apply on both sides of every interconnection point. Adjacent TSOs responsible for the particular systems must establish consistent rules so that market integration is held up as little as possible by capacity management problems. Moreover, it is clear that identical rules at every cross-border point between the European gas markets will minimise the shippers' transaction effort and maximise access transparency and efficiency. Uniform rules at every point would also mean uniform rules on both sides of every point.

6.37 The focus for the Framework Guidelines Driven approach would therefore continue to be to encourage trade across interconnection points by ensuring capacity allocation rules on interconnection points are compatible, moving towards harmonised rules and to improve the efficient use of the interconnectors. However, there does not need to be internal harmonisation, meaning a Framework Guidelines Driven approach requires lower implementation costs than the other options.

6.38 A larger zone requires greater cooperation and harmonisation between TSOs within the price zone. One can view this as an obstacle that is difficult to overcome to have a functioning regional price zone, or a way of forcing TSOs to cooperate effectively, which would not be possible if TSOs are operating either side of a price zone boundary. However, one must recognise that experience in merging markets in electricity (e.g. the BETTA programme that merged the Scottish market with that in England & Wales, or the Single Electricity Market ("SEM") programme that created an all-island market in Ireland) shows it be a time-consuming and resource-intensive process.

6.39 It is also important to recognise the respective difficulties of implementing an implicit capacity trading mechanism or a regional explicit capacity trading mechanism. A regional explicit capacity trading mechanism requires a high degree of harmonisation. This may take a great deal of time to achieve as TSOs, NRAs and Member States will need to agree on common rules and regulations. However, such a process may happen organically under the Third Package and does not represent a big leap from the Framework Guidelines Driven option of explicit capacity trading with national sized price zones. In fact, this process has already begun in countries that formerly had many small balancing zones (e.g. Germany), and this momentum could continue cross-border if encouraged by a target model.

6.40 An implicit capacity trading mechanism, such as market coupling, does not require the same degree of harmonisation; it focuses more on the interconnection points. However, changing the structure of the market so that capacity is not traded separately will be difficult to implement without political will or drive from the TSOs. This has been the case in the European electricity markets where TSOs voluntarily formed the CWE market coupling area and the Nordpool market splitting area.

6.41 In addition, it is clear that important technical work would be required to develop a market coupling algorithm for natural gas, bearing in mind significant relevant differences between gas and electricity (e.g. the greater interdependence between different time periods—in natural gas, decisions about flows now affect linepack and therefore the ability of the system to transport gas at a later date).

6.42 It would appear that there is a trade-off between the short-term and long-term. Regional explicit markets require a great deal of harmonisation to achieve, which will take many years. However, market coupling has the potential to take place relatively quickly, and may achieve an increase in the efficient use of cross-border capacity as soon as market coupling is implemented.

6.43 The relative merits of each approach in relation to costs and regulatory burden remains to be investigated.

Summary of assessment

6.44 Table 6-1 below summarises the assessment of the three main options for the gas target model against our assessment criteria.

Table 6-1: summary of the assessment of the three main options

Criterion	Framework Guidelines Driven	Merged Markets	Coupled Markets
Efficient use of cross-border capacity			
Contractual congestion	xx	x	✓
Pancaking	xx	✓	✓ LT implicit xx LT explicit
Maximising available capacity	(x)	(✓)	✓
Investment incentives for TSOs	-	xx	-
Long-term contracts and investment incentives			
Impact on long-term long-distance transport arrangements	xx	x	x LT implicit xx LT explicit
Impact on delivery point in GSA	-	xx	xx LT implicit - LT explicit
Other impact on long-term GSAs	-	-	x
Promotion of liquid trading and transparent spot prices			
Concentration of trading	x	✓	✓✓
Impact on the role of the TSO			
Tariffs	-	xx	-
Balancing	-	xx	x
Ease of implementation			
Harmonisation of national rules	✓✓	xx	-
Changes in TSO responsibility	✓✓	xx	xx
Cost and regulatory burden	TBD	TBD	TBD

Section 7 Recommendations

7.1 Each of the options discussed has its own costs and benefits as the basis for a target model. The choice of target model therefore depends on which of the different issues affected are in fact the most material. Below we describe the issues that will determine which option is preferable.

Framework Guidelines Driven

7.2 The Framework Guidelines Driven model would be most appropriate if one believes that capacity hoarding and contractual congestion are not a major problem. The Framework Guidelines Driven approach maintains the cross-border bottlenecks where contractual congestion could appear. If one believes that any contractual congestion that is present can be effectively solved through the implementation of a gate closure with UIOLI/UIOSI mechanisms or through the introduction of over-selling of capacity, then the Framework Guidelines Driven approach may also be appropriate.

7.3 For a Framework Guidelines Driven model to provide an efficient allocation of capacity, secondary capacity trading must be able to provide a reasonably efficient allocation.

7.4 The Framework Guidelines Driven approach utilises an explicit capacity trading mechanism. For a Framework Guidelines Driven approach to be appropriate, the use of explicit capacity must not materially reduce the amount of capacity that can be made physically available to the market.

7.5 Under a Framework Guidelines Driven model, the European market will consist of a large number or price zones, mainly national in size. Crossing a large number of price zone borders could lead to pancaking. Therefore, the Framework Guidelines Driven approach is only appropriate if one believes distortions due to pancaking are not a significant problem.

7.6 A large number of small price zones risks fragmenting the market into a number of hubs (one for each price zone). This could lead to low liquidity on each hub due to the relatively small market size. Therefore, one must believe that having a relatively large number of hubs does not lead to unacceptably low liquidity.

7.7 The Framework Guidelines Driven model provides the highest degree of regulatory stability amongst all the options. If this is valued very highly, and/or one mistrusts the capacity of the industry, NRA and other public authorities to achieve timely and effective reform, then the Framework Guidelines Driven model may be preferred.

Merged Markets

7.8 The Merged Markets model would be most appropriate if one believes that capacity hoarding and contractual congestion is a major problem, and hard to solve via UIOLI/UIOSI or over-selling. Merged Markets helps to overcome this problem by internalising some of the borders that would otherwise suffer from contractual congestion, meaning that anti-hoarding mechanisms are not necessary at those borders.

7.9 Merged Markets also reduce the number of price zones that gas must cross if being transited long-distance. If one believes that distortions due to pancaking are a significant problem, then Merged Markets would be appropriate.

7.10 Intra-zone constraints within a Merged Market will require re-despatch to relieve the congestion. The costs of re-despatch would be socialised amongst all network users. If one believes that physical congestion is and will remain relatively limited within the chosen regional areas, or can be made so at acceptable cost via new investments, then re-despatch costs within the region will be at an acceptable level. Therefore, there is unlikely to be distortions caused by intra-zone constraints.

7.11 If one believes that having a relatively large number of hubs may be significantly detrimental to liquidity by fragmenting the market, than Merged Markets may be preferable as liquidity will be concentrated on a small number of hubs.

7.12 Merged Markets require harmonisation and a great deal of cooperation in order to merge price zones, as demonstrated by similar exercises in merging power markets (BETTA, SEM). If one believes that the gas industry, NRAs and public authorities are well placed to implement the model, in particular by merging price zones across TSO and Member State borders, then a Merged Market will be possible.

Coupled Markets

7.13 The Coupled Markets model would be most appropriate if one believes that capacity hoarding and contractual congestion are a major problem, and that it is hard to solve via UIOLI/UIOSI or over-selling. An implicit trading mechanism solves this problem because all unused rights are made available to the market via the market coupling/splitting mechanism.

7.14 Similarly, the market coupling/splitting mechanism finalises capacity allocation close to real time (or earlier, if applied over longer timeframes) in a way that should ensure efficient allocation. Therefore, if one believes that secondary capacity trading is unlikely to give a reasonably efficient allocation of capacity, Coupled Markets would be preferable.

7.15 Under Coupled Markets, the European market would be made up of a small number of large market coupling areas (each comprising a number of price zones). Therefore, if there is no long-term explicit market, shippers will only need to buy explicit rights across a small number of borders (or none, if coupling is used for all of the EU). Therefore, Coupled Markets is appropriate if one believes distortions due to pancaking are a significant problem.

7.16 The market coupling algorithm allocates flows of gas based on the available capacity on the interconnectors and the bids and offers on the market coupling platforms. If physical congestion is or may become significant problem, then Coupled Markets addresses this by ensuring all capacity is utilised: TSOs are able to allocate more capacity, because they have more visibility of the expected pattern of flows.

7.17 If physical congestion isn't a problem, then prices across the market coupling area will converge. However, Coupled Markets is flexible because if physical congestion occurs in the future, prices will diverge and incentives for shippers to transport gas from one price zone to another change. Therefore, if one believes that the future location of physical congestion is uncertain (for example due to new sources of gas) Coupled Markets would be appropriate.

7.18 Coupled Markets concentrates liquidity. Even if each price zone has a separate trading platform, the bids and offers are matched using the central algorithm where physical capacity allows it. Therefore, if one believes that having a relatively large number of hubs may be significantly detrimental to liquidity, Coupled Markets would be appropriate.

7.19 Coupled Markets requires a great deal of cooperation, regulatory changes and technical barriers to overcome. Therefore, Coupled Markets is only possible if industry, NRAs and public authorities are well placed to implement the model, including resolving the technical challenges of adapting market coupling to natural gas markets.

Recommendations

7.20 A key recommendation of this report is therefore for NRAs and other stakeholders to undertake further analyses, in particular to develop the necessary evidence base for a decision on the choice of target model, based on the issues outlined above.

7.21 We expect analysis by NRAs should come via ERGEG/ACER. Such analysis should include:

(1) an updated analysis of the extent of contractual congestion in different parts of the EU, and a view on the potential for the problem to be solved by UIOLI/UIOSI and/or over-selling mechanisms;

(2) an analysis of the extent of price convergence at different hubs[29], and of liquidity at different hubs and the likely impact on liquidity of merging hubs via the Merged Markets or Coupled Markets models;

(3) more detailed analysis of the regulatory requirements (in particular, degree of harmonisation required) for each model to determine the extent of the regulatory changes required; and

(4) an analysis, in close consultation with other market participants, of the costs and regulatory burden associated with each model.

7.22 On the side of the TSOs at a European level via ENTSOG, analyses should include:

(1) the extent of physical congestion, in particular physical congestion within likely candidates for merged price zones under the Merged Markets model, and associated to that, the likely extent of re-despatch costs in various merged zones;

(2) the likely increase in transmission capacity, if any, that would arise from Coupled Markets (for example caused by TSOs agreeing the available capacity or from the lack of contractual congestion);

(3) the impact of merging various price zones on revenues received by TSOs (for example the reduction in entry/exit charges or congestion rents received by TSOs), and the possible implications in relation to investment incentives and ITC; and

(4) the development of the technical requirements for applying Coupled Markets to natural gas markets and the costs of any changes needed to meet these technical requirements.

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29 One useful starting input would be recent work by Rudolph Harmsen and Catrinus Jepma at the University of Groningen: see www.europeanenergyreview.eu/index.php?id=2695.

7.23 On the side of gas producers, importers and merchants (i.e. the usual parties to long-term gas sales agreement), analysis is needed of how each of the models would impact existing long-term contracts, based on a worked-up legal analysis for typical relevant clauses in long-term transportation contracts and gas supply agreements.

Appendix 1 Legislative context

Introduction

A1.1 In this Appendix, we set out some of the legislative context to the gas target model.

A1.2 The Third Package for natural gas became law in September 2009 to come into force in March 2011. The purpose of the Third Package was to foster an internal market for natural gas within the EU. The aim of the internal market is[30]:

> *"to deliver real choice for all consumers, new business opportunities and more cross-border trade, so as to achieve efficiency gains, competitive prices, and higher standards of service, and to contribute to security of supply and sustainability".*

A1.3 The Commission felt that despite previous European legislation, there were still obstacles for the sale of gas on equal terms and that "*non-discriminatory network access and an equally effective level of regulatory supervision in each Member State* [did] *not yet exist*"[31]. This followed an investigation by the Commission's DG Competition in January 2007[32], which highlighted that the 'Second Package' did "*not provide the necessary framework for achieving the objective of a well-functioning internal market*"[33].

A1.4 Currently the European market has a different market design in every Member State, with low market shares for market participants outside of their home markets and price differentiation between national markets/hubs[34]. There is clearly some way to go to achieve an internal market for natural gas within the EU.

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[30] Directive 2009/73/EC, Recital 1.

[31] Directive 2009/73/EC, Recital 4.

[32] 'DG Competition report on Energy Sector Inquiry', 'Prospects for the internal gas and electricity market' and 'Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report)', all 10 January 2007.

[33] Directive 2009/73/EC, Recital 5.

[34] CEER vision for European gas target model, 3 December 2010, Slide 3.

A1.5 The directive of the Third Package highlights the importance of cross-border interconnections and Merged Markets, as well as the need for common rules[35]:

> *"The development of a true internal market in natural gas, through a network connected across the Community, should be one of the main goals of this Directive and regulatory issues on cross border interconnections and regional markets should, therefore, be one of the main tasks of the regulatory authorities, in close cooperation with the Agency where relevant.*
>
> *Securing common rules for a true internal market and a broad supply of gas should also be one of the main goals of this Directive. To that end, undistorted market prices would provide an incentive for cross-border interconnections while leading, in the long-term, to price convergence".*

Entry/exit charges

A1.6 One of the key measures introduced in the Third Package is the stipulation of entry/exit charges, which effectively removes the separate regimes for transit that exists in some Member States. Gas must be transported "*through zones instead of along contractual paths*"[36]. Entry/exit charges are favoured because they are seen to facilitate the development of competition as gas can be traded independent of its location. This was based on the preference of most stakeholders at the European Gas Regulatory Forum in 2002 (the Sixth Madrid Forum).

A1.7 Although "*tariffs should not be dependent on the transport route*"[37], for completeness, when considering all possible options for the gas target model we have included such options where tariffs would depend on the location gas was transported. However, we bear in mind that, under the Third Package, a target model for gas will have to be based on entry/exit charges.

Cross-border capacity allocation

A1.8 The regulations of the Third Package do not state a preference for how capacity should be allocated cross-border, other than that they should be "*non-discriminatory, market based solutions*"[38]. TSOs should promote energy exchanges, although it is not stipulated whether these shall be virtual or physical hubs.

35 Directive 2009/73/EC, Recitals 57 and 58.

36 Regulation (EC) No 715/2009, Recital 19.

37 Regulation (EC) No 715/2009, Recital 19.

38 Regulation (EC) No 715/2009, Article 12, paragraph 2.

A1.9 ERGEG has produced a pilot Framework Guideline for capacity allocation[39]. This outlines the need for cooperation between TSOs to bundle capacity between TSOs and to establish virtual interconnection[40]. The Framework Guidelines also set out how TSOs should determine firm and interruptible capacity, how that capacity is allocated (i.e. by auction) and the standard auction mechanism. The gas target model should coincide with the views of the Framework Guideline.

A1.10 The regulations do not stipulate whether cross-border capacity should be allocated explicitly or implicitly. In fact, the door to implicit auctions for capacity is left open by the legislation as TSOs should "[pay] *due attention to the specific merits of implicit auctions for short-term allocations*"[41]. A gas target model should consider whether an explicit or implicit allocation of short-term capacity is preferable.

A1.11 The regulations point out that physical congestion is "rarely" a problem, but may become one in the future[42]. However, there is "substantial" contractual congestion[43]. Contractual congestion prevents the efficient use of cross-border capacity, leading to unnecessary additional costs for European shippers and hindering the free flow of gas and the development of the internal market. Therefore, appropriate mechanisms need to be in place to free up unused capacity, with users allowed to resell contracted capacities and TSOs obligated to offer unused capacity to the market. Therefore, a target model should address the appropriate mechanism for releasing unused capacity.

Regional cooperation

A1.12 The Third Package stresses the need for cooperation between TSOs and regulators in order to foster an internal market. The regulations establish ENTSOG to "*ensure optimal management of the gas transmission network in the Community*"[44]. On cross-border issues, NRAs are required to "*closely consult and cooperate with each other*" and to exchange information[45].

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[39] Revised Pilot Framework Guideline on Capacity Allocation Mechanisms, 7 December 2010, ERGEG.

[40] Sections 1.4 and 2.4, Revised Pilot Framework Guideline on Capacity Allocation Mechanisms, 7 December 2010, ERGEG.

[41] Regulation (EC) No 715/2009, Article 12, paragraph 2.

[42] Regulation (EC) No 715/2009, Recital 22.

[43] Regulation (EC) No 715/2009, Recital 21.

[44] Regulation (EC) No 715/2009, Recital 16.

[45] Directive 2009/73/EC, Article 42, paragraph 1.

A1.13 However, the Third Package recognises that progress toward greater integration may be on a regional basis at first, rather than on an EU wide basis. Cooperation between Member States and NRAs to integrate their markets at one or more regional levels is seen as a "first step" in creating a liberalised internal market[46]. This includes ensuring "*consistency of their legal, regulatory and technical framework and ... integration of the isolated systems forming gas islands*"[47].

A1.14 Under the Third Package TSOs should set up "regional structures" compatible with the overall structures within ENTSOG. A regional investment plan should be published every two years and investment decisions may be made based on that plan[48].

A1.15 Although the Third Package emphasises the need for regional cooperation between Member States, NRAs and TSOs, it is important to note that the Third Package does not stipulate that there should be regional system operation or regional TSOs, the geography of the Merged Markets nor that price zones should be merged. These topics are left open for a gas target model.

Third Party Access and transparency

A1.16 The Third Package also reinforces the need for minimum Third Party Access ("TPA") standards to transmission systems, storage facilities and LNG facilities[49] [50] and the need for equal and transparent access to information. Better information should allow market participants to assess overall supply and demand in the market and understand the reasons for price movements[51].

Balancing rules

A1.17 Balancing rules are being determined by framework guidelines independent of the gas target model. However, to facilitate cross-border trade of balancing gas, the regulations stipulate that[52]:

46 Directive 2009/73/EC, Article 7, Paragraph 1.

47 Directive 2009/73/EC, Article 7, Paragraph 1.

48 Regulation (EC) No 715/2009, Article 12, Paragraph 1.

49 Regulation (EC) No 715/2009, Recital 10.

50 Directive 2009/73/EC, Chapter VII.

51 Regulation (EC) No 715/2009, Recital 24.

52 Regulation (EC) No 715/2009, Article 21, Paragraph 4.

> *"Member States shall ensure that transmission system operators endeavour to harmonise balancing regimes and streamline structures and levels of balancing charges in order to facilitate gas trade."*

A1.18 However, the regulations are silent on the exact form the harmonised balancing regimes should take, although balancing charges should be market based.

Long-term gas supply contracts

A1.19 The European natural gas market is characterised by a large number of long-term bilateral contracts (typically 10 to 15 years in length). Such gas supply agreements may consolidate the position of incumbent firms and help cause contractual congestion. However, there is a desire to avoid regulation that results in existing contracts becoming invalid as this creates regulatory uncertainty and changing contracts will cause transaction costs.

Long-term transportation contracts

A1.20 Long-term transportation contracts can help finance new investment in the transmission network. The Third Package stipulates that[53]:

> *"long-term contracts will continue to be an important part of the gas supply of Member States and should be maintained as an option for gas supply undertakings....It is therefore necessary to take into account long-term contracts in the planning of supply and transport capacity of natural gas undertakings".*

A1.21 Therefore, it is important to consider the impact alternative options for the gas target model will have on long-term transportation contracts and investment incentives, and how to accommodate long-term contracts into the model.

Interaction with other work-streams arising from the Third Package

A1.22 Some framework guidelines have already emerged from the Third Package process. The gas target model should not supersede new framework guidelines on balancing, capacity allocation, or transmission tariff structures but should be complementary with them, with particular emphasis on cross-border capacity allocation and balancing.

[53] Directive 2009/73/EC, Recital 42.

A1.23 At the 18th Madrid Forum in September 2010, the European Commission and regulators, cooperating with TSOs and other stakeholders, were invited to initiate a process establishing a gas target model. ERGEG and CEER has invited stakeholders to participate in a call for evidence to better understand the definition and scope of the gas target model, and this offers some insight into what areas a gas target model should consider.

A1.24 CEER's call for evidence states that in 2010 (at the 4th Regional initiative Annual Conference in Brussels) the European Commission introduced the concept of possible market coupling between all Member States by 2015[54]. Therefore, a form of market coupling should be investigated as a possible option for the gas target model.

A1.25 ERGEG started to develop a conceptual model for the European gas market in the framework of the pilot framework guidelines on capacity allocation. They considered the overall goals of the model to include[55]:

" • *Effective implementation of entry/exit systems;*
- *Facilitating cross border market integration into an efficient and effective competitive gas market at the Community level;*
- *Efficient capacity allocation procedures including market based mechanisms when demand exceeds the offer;*
- *Efficient usage of pipeline capacity, especially for cross-border flows of gas between trading points in Europe, with the aim to integrate national gas markets, including limiting (physical and contractual) congestions;*
- *Improving the integration of trading points leading to a convergence of market prices between neighbouring markets, reflecting market risks and supply/demand imbalances; and*
- *Improving security of supply by fostering the appropriate network, storage and LNG regasification capacity enhancement as well as upstream investments aimed at supplying the European gas market."*

54 CEER Vision Paper for a conceptual model for the European gas market, 3 November 2010, Page 6.

55 CEER Vision Paper for a conceptual model for the European gas market, 3 November 2010, Page 7.

A1.26 CEER consider that, following the Commission's sector inquiry[56], there is a debate about whether integration of European markets means that balancing zones should be merged, or whether balancing zones should be coupled together[57]. Indeed, CEER have asked stakeholders whether balancing zones should be merged, and if coupling of price zones is appropriate for gas[58].

A1.27 Therefore, it appears that ERGEG/CEER recognise that one of the key arguments that the gas target model should address is the degree to which price zones should become larger, and how trading should occur between price zones, with market coupling one of the capacity trading options to consider.

A1.28 CEER also recognise the need for there to be some harmonisation provided by the gas target model, and they pose the question to stakeholders about what level of harmonisation the model should provide[59].

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56 DG Competition Report on Energy Sector Inquiry, 10 January 2007.

57 CEER Vision Paper for a conceptual model for the European gas market, 3 November 2010, Page 7.

58 CEER Vision Paper for a conceptual model for the European gas market, 3 November 2010, Question 7.

59 CEER Vision Paper for a conceptual model for the European gas market, 3 November 2010, Question 4.

Appendix 2 Intra-zone congestion in the British wholesale electricity market

A2.1 This appendix considers the problems of intra-zone congestion in the British electricity market as an illustration of the problems that may arise when price zones are merged.

A2.2 In April 2005, BETTA merged the England and Wales electricity market with the Scottish market. However, there was congestion on the border between Scotland and England.

A2.3 After gate closure, NG (as the TSO) runs a balancing mechanism to deal with imbalances in the system and transmission constraints. Re-despatch is used to deal with constraints. NG accepts offers to increase output from generators in the import constrained area and bids to reduce output in the export constrained area.

A2.4 Although limited transmission capacity was acknowledged when the markets merged, the level of congestion costs has exceeded expectations. The levels of forecasted Scottish constraints for 2009/10 are over three times those experienced in the first year following implementation of BETTA[60]. At face value, one could take this as evidence of an abuse of a dominant position.

A2.5 However, socialising constraints creates incentives for this kind of behaviour, even for firms without a dominant position. Generators in the import constrained area have an incentive to bid at the same level as the cost of the last generator to be constrained-on. This raises the bids of all cheaper generation as a new competitive benchmark is set. For generators in the export constrained area, the last generator running sets the new competitive benchmark. Generators will bid at this low price even if they would make a loss at this price. This is because generators know they will get constrained-off and so receive the difference between the forward price and their balancing bid. Even generators that would find it un-economical to run at the national spot price will enter the market to be constrained-off.

60 Ofgem, 2009, “Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals”.

A2.6 In April 2008, Ofgem launched an investigation into the behaviour of Scottish Power ("SP") and Scottish and Southern Energy ("SSE") on suspicion that they were abusing a dominant position in power generation in Scotland and exacerbating the constraints. However, in January 2009 Ofgem ended their investigation on the basis that other actions by the regulator (such as Transmission Access Review) were better placed in dealing with problems of capacity allocation on the England-Scotland border. Ofgem did not conclude whether or not the increasing constraint costs were a result of an abuse of a dominant position of SP and SSE[61].

61 Ofgem, 2009, "Competition Act Investigation into Scottish Power and Scottish & Southern Energy".

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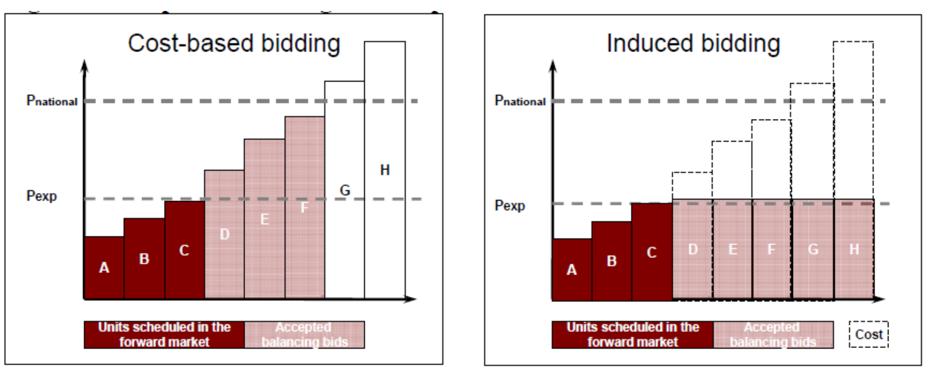
Appendix 3 Distortionary incentives caused by intra-zone constraints

A3.1 Intra-zone constraints require the TSO to engage in re-despatch to relieve the constraint. This can give rise to incentives for market participants that distort the market. This appendix explains in detail how such distortionary incentives may arise.

A3.2 In the export constrained area, if a gas supplier expects to be constrained off, the supplier will bid even if supply of gas would be uneconomical given the current price. This is in the expectation that the TSO will buy back gas from them and so the gas will not be physically supplied. This exacerbates the constraint. The cost of the last supplier injecting gas sets a new benchmark for bids for all suppliers whose costs are above this benchmark, including those for whom it would be uneconomical to supply at the zone-wide price. They will get constrained off, with a profit equal to the zone-wide price minus the last accepted bid. This is shown in Figure A3-1 below.

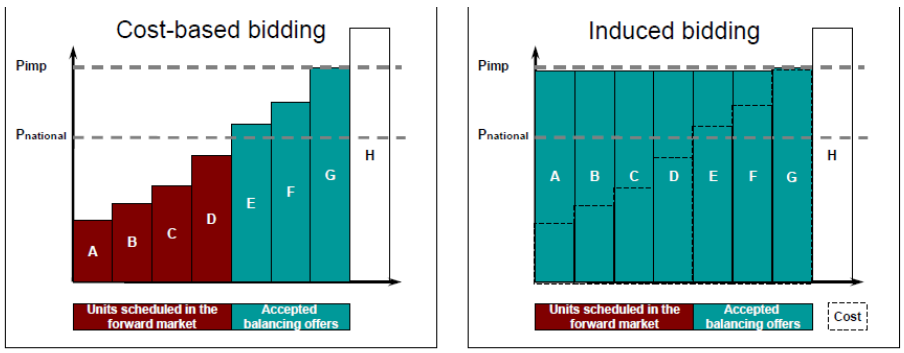
Figure A3-1: competitive bidding in the export-constrained area



Source: Figure 4, Perekhodtsev, D. and Cervigni, G., "UK Transmission Congestion Problem: Causes and Solutions", 6 January 2010.

A3.3 In the import constrained area, the supplier may not offer gas in the forward market even though it would be economical to do so in the expectation that in the short-term market, the TSO will pay them more to inject gas into the system to relieve the constraint. This increases the cost to the TSO of relieving the constraint. Such exploitative bidding is only possible if the constraint is persistent as the suppliers risk having to supply gas below cost, or not supplying gas at all when it would be profitable to do so, should there be no congestion. If all other suppliers in the import constrained area acts the same way, the price will rise to match the cost of the most expensive constrained-on supply. This is shown in Figure A3-2 below.

Figure A3-2: competitive bidding in the import-constrained area



Source: Figure 3, Perekhodtsev, D. and Cervigni, G., "UK Transmission Congestion Problem: Causes and Solutions", 6 January 2010.

A3.4 In the long-run, such bidding incentives can also create adverse investment incentives. Export constrained areas may build inexpensive investments that are expensive to operate to get paid not to supply. Therefore, it is important that price zones are not merged into larger zones without relieving constraints that will become persistent bottlenecks within the new regional price zone. For example, since BETTA created an electricity market for all of GB in 2005, constraint costs on the interconnector between Scotland and England have risen from £70 million in 2005/06 to over £200 million in 2009/10[62].

62 Ofgem, 2009, "Addressing Market Power Concerns in the Electricity Wholesale Sector – Initial policy Proposals".

Appendix 4 Implications for cross-border balancing

A4.1 Transmission systems must balance the amount of gas injected into the system with the amount taken from the system. This can be done using flexible gas within the price zone, or from across the border in neighbouring zones. A target model should facilitate the trading of cross-border balancing gas. Balancing periods should be the same across price zone borders. Currently, different price zones operate different balancing periods, usually either hourly or daily. This can create distortions as shippers may use gas from a system with daily balancing to ensure they are in balance in a neighbouring system with hourly balancing. If a daily balancing period is adopted in common, the start of the balancing day should also be aligned.

A4.2 There are broadly two possibilities for trading balancing gas across borders. Shippers could trade with each other for balancing gas across the border. A shipper in one price zone could agree to sell balancing gas to a shipper in a neighbouring price zone by purchasing capacity explicitly. This relies on adequate capacity being made available on the intra-day market. Gas trading could take place on a liquid daily/intra-day wholesale market, or a separate balancing market. Storage and LNG or other sources of flexible gas are often used for balancing and shippers may have long-term contracts in place for the use of such facilities.

A4.3 Shipper to shipper trading of balancing gas is more likely to take place under an explicit capacity trading regime as shippers will have firm physical rights and the possibility to trade bilaterally with other shippers. It may be possible to have some sort of shipper to shipper trading of balancing gas in a partially implicit regime, where intra-day trading for balance gas between shippers is allowed on an explicit basis, with some interconnection capacity reserved for this.

A4.4 In an implicit market, shipper to shipper trading of balancing gas can only occur if there is intra-day market coupling. The liquid market coupling platform should help facilitate trading for such balancing gas. However, if market coupling happens day ahead and there is no further trading, then balancing must be left to the TSO. It may be possible to have some sort of shipper to shipper trading of balancing gas in a partially implicit regime, where intra-day trading for balance gas between shippers is allowed on an explicit basis, with some interconnection capacity reserved for this.

A4.5 An alternative possibility is for TSOs to trade flexible gas directly with one another. Based on bids and offers for flexible gas in their own market, TSOs could exchange information on prices in their markets and then use available interconnector capacity to trade flexible gas. A TSO with an excess amount of gas in its system can sell to a TSO with a deficit of gas. Such trading of balancing gas is likely under an implicit capacity trading regime because gas trading will be done centrally (for example at a hub) and TSOs will already be cooperating closely in a market coupling or market splitting model. If the market coupling regime has a gate closure, this may be necessary as shippers will not be able to trade balancing gas with one another after the gate closure.

A4.6 TSO to TSO trading of balancing gas is also possible with explicit capacity trading. In a Merged Market the TSOs will have a bigger role in managing intra-zone constraints. Therefore, it may be useful for TSOs within the merged price zones to have a TSO to TSO balancing arrangement. However, for TSO to TSO balancing, there are only two market participants. Therefore, regulators need to ensure efficient arrangements between the TSOs using some sort of price mechanism.

A4.7 In electricity markets, a TSO to TSO model is often used because in many markets there is a gate closure. After this point in time, only TSOs can trade. Part of the reason why TSO to TSO trading is used is that it is often felt that fast responses to imbalances are need in electricity and it is better to have a TSO to TSO model to deal with these. Due to the physical nature of gas, speed of response may be slower.

A4.8 A hybrid of these options is possible where shippers buy and sell flexible gas from the TSOs. TSOs act as the market maker for shippers wishing to trade balancing gas. This may be necessary if the explicit balancing market is not very liquid, with TSOs providing that liquidity. However, shipper to TSO trading can also be used in a market coupling model with the TSO entering the market at the market coupling platform.

A4.9 One possible barrier to cross-border balancing is national security of supply. Some Member States may be reluctant to allow flexible gas, such as stored gas, to leave the country in case of some national emergency.

A4.10 The issue of cross-border balancing arrangements requires further analysis, going beyond the scope of this report.

Glossary

ACER	Agency for the Cooperation of European Regulators
Anti-hoarding measures	Measures used to prevent shippers hoarding unused transmission capacity
Balancing period	The specified time period over which inflows of gas must match outflows of gas e.g. one hour, day, week or month
Balancing zone	A transmission network area within which each shipper is obliged to match its inflows and outflows of gas over a the balancing period
Baumgarten	Austrian gas hub
BETTA	British Electricity Trading Transmission Arrangements
Capacity hoarding	The retention of unused capacity by shippers
CEER	Council of European Energy Regulators
CFD	Contract for Difference
The Commission	The European Commission
Congestion rent	Rents earned by TSOs caused by congestion
Contractual congestion	Where shippers hoard capacity by signing capacity contracts but not nominating all of the capacity for use. This gives the appearance that the interconnector is congested, preventing other shippers from gaining access to capacity.
Coupled Markets	Implicit transmission capacity allocation combined with national/sub-national price zones. Bids and offers for gas are submitted to a platform in each price zone before an algorithm determines the price and gas flows between price zones.
CWE	Central Western European Market Coupling, encompassing the electricity markets of France, Belgium, the Netherlands, Germany and Luxembourg

Distribution network	A network of low and medium pressure pipelines used to distribute gas from the transmission network to consumers
EMCC	European Market Coupling Company, a volume coupling area between Nordpool and CWE
Energy Sector Inquiry	Together 'DG Competition report on Energy Sector Inquiry', 'Prospects for the internal gas and electricity market' and 'Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report)', all 10 January 2007.
Entry/exit charge	A charge for injecting or withdrawing gas from a transmission system
Entry/exit zones	An transmission network area subject to an entry or exit charge to inject or withdraw gas from the transmission network
ENTSOG	European Network of Transmission System Operators
ERGEG	The European Regulators' Group for Electricity and Gas
EU	The European Union
Explicit capacity trading	Where capacity is sold separately to gas
Financial transmission right	The right to receive the financial return that would be produced from moving gas from one point to another (i.e. the price difference between the two points)
Fluxys	Belgian TSO
Framework Guideline	Guidelines produced by ERGEG to set objective principles for European network codes
Framework Guidelines Driven	A system of explicit transmission capacity allocation combined with national/sub-national price zones
FTR	Financial Transmission Right (same as a TCC)
Gaspool	German gas hub
Gate closure	The point at which all nominations for use of transmission capacity must be received. After this point by definition no re-nominations are possible. Typically TSOs will then implement anti-hoarding measures whereby unused capacity is subject to either UIOSI or UIOLI.

GB	Great Britain
GRT Gaz	French TSO
GSA	Gas Supply Agreement
GTS	Dutch TSO
Herring Hub	A gas hub formed from the merger of the NBP, TTF, Zeebrugge, Gaspool and Peg Nord gas hubs
Hub	An exchange for natural gas
Implicit capacity trading	Where capacity is not sold separately to gas
Inter-zone constraints	Where there is excess demand for capacity on an interconnector between price zones
Intra-zone constraints	Where there is excess demand for capacity on a pipeline within a price zone
ISO	Independent System Operator
ITC	Inter-TSO Compensation
LNG	Liquefied Natural Gas
Locational prices	Where price differs based on the location of entry/exit. The smaller a price zone, the more locational a price
Market coupling area	A group of price zones with a market coupling regime between them
Market splitting	Implicit transmission capacity allocation combined with national/sub-national price zones. Bids and offers for gas are submitted to a central platform an algorithm determines the price and gas flows between price zones
Market splitting area	A group of price zones with a market splitting regime between them
Member State	One of the 27 member states of the European Union
Merged Markets	Explicit transmission capacity allocation combined with larger, regional price zones
NBP	National Balancing Point, the British gas hub
NG	National Grid

Nordpool	The electricity market splitting area encompassing Norway, Sweden, Finland and Denmark
NRA	National Regulatory Authority
Operating zone	A transmission network that a TSO or ISO manages separately to other transmission networks
OTC	Over-the-counter
Over-selling	Selling more than the technical capacity of an interconnector on the assumption that some contracted capacity will not be used
Pancaking	Distortions caused by paying a number of tariffs to cross-multiple borders between price zones in order to transit gas long distance
PEG Nord	Point d'Echange de Gaz North, French gas hub
PEG Sud	Point d'Echange de Gaz South, French gas hub
Physical congestion	When more gas is nominated to be transmitted through a pipeline than is technically possible
Physical right	The right to transmit physical gas
Price zone	An area of a transmission network where there is a single price for all gas (at the wholesale level), such as the NBP or TTF. Coincides with an entry/exit zone.
PSV	Punto di Scambio Virtuale, Italian gas hub
Re-nomination	When shippers make further nominations for the use of short-term capacity, or change already nominated capacity
Second Package	Together Directive 2003/55/EC and Regulation (EC) No. 1775/2005
SEM	Single Electricity Market covering the island of Ireland
Shifting congestion to the borders	Limiting cross-border flows of gas in order to limit inter-zone congestion
Socialisation	Spreading the costs of transmission amongst all users of the transmission system
SP	Scottish Power
SSE	Scottish and Southern Energy

Svenska Kraftnät	A Swedish electricity and gas TSO
Supergrid	A virtual price zone above national price zones
TCC	Transmission Congestion Contract (same as a FTR)
Third Package	Together Directive 2009/73/EC and Regulation (EC) No. 715/2009
TLC	Tri-Lateral Market Coupling encompassing the electricity markets of the Netherlands, Belgium and France
TPA	Third Party Access
Transmission network	The network of pipelines used to transmit gas from suppliers to distribution networks and across border
TSO	Transmission System Operator
TTF	Title Transfer Facility, the Dutch gas hub
UIOLI	Use-it-or-lose-it. If a holder of capacity rights does not use it, they will lose rights to this capacity, which is re-sold on the secondary market.
UIOSI	Use-it-or-sell-it. If a holder of capacity rights does not use it, they will have to re-sell on the secondary market.
Zeebrugge	The Belgian gas hub