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AN AMERICAN MODEL FOR THE EU GAS MARKET?

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Abstract

It is generally believed that the American model is not suitable for Europe, yet North America is the only large and working competitive gas market in the world. The paper shows how its model could be adapted as a target for market design within the European institutional framework.

It starts from analysis of the main peculiar economic features of the gas transportation industry, which should underpin any efficient model. After the Third Package is properly implemented the EU will share several building blocks of the American model: effective unbundling of transportation and supply; regulated tariffs which, for long distance transportation, are in fact largely related to capacity and distance; investments based mostly on industry's initiative and resources, and the related decisions are increasingly made after open and public processes.

Yet Europe needs to harmonize tariff regulation criteria, which could be achieved through a monitoring process. National separation of main investment decisions should be overcome, possibly by organising a common platform where market forces and public authorities interact with private suppliers to require existing and develop new capacity, whereas industry competitively offers its solutions. Such platform would allow for long term capacity reservation, subject to caps and congestion management provisions. Auctions and possibly market coupling would play an important role in the allocation of short term capacity but a limited one in long term.

Market architecture and the organisation of hubs would also be developed mostly by market forces under regulatory oversight. The continental nature of the market suggests a likely concentration of trading in a very limited number of main markets, whereas minor markets would have a limited role and would be connected to major ones, with price differences reflecting transportation costs and market conditions. Excessive interference or pursuit of political goals in less than transparent ways involves the risk of slower liquidity development and higher market fragmentation.

With this view as a background, regulatory work aimed at completing the European market should be based on ensuring the viability of interconnections between current markets and on the establishment of common platforms and co-ordinated tariff systems, fostering the conditions for upstream and transportation capacity development.

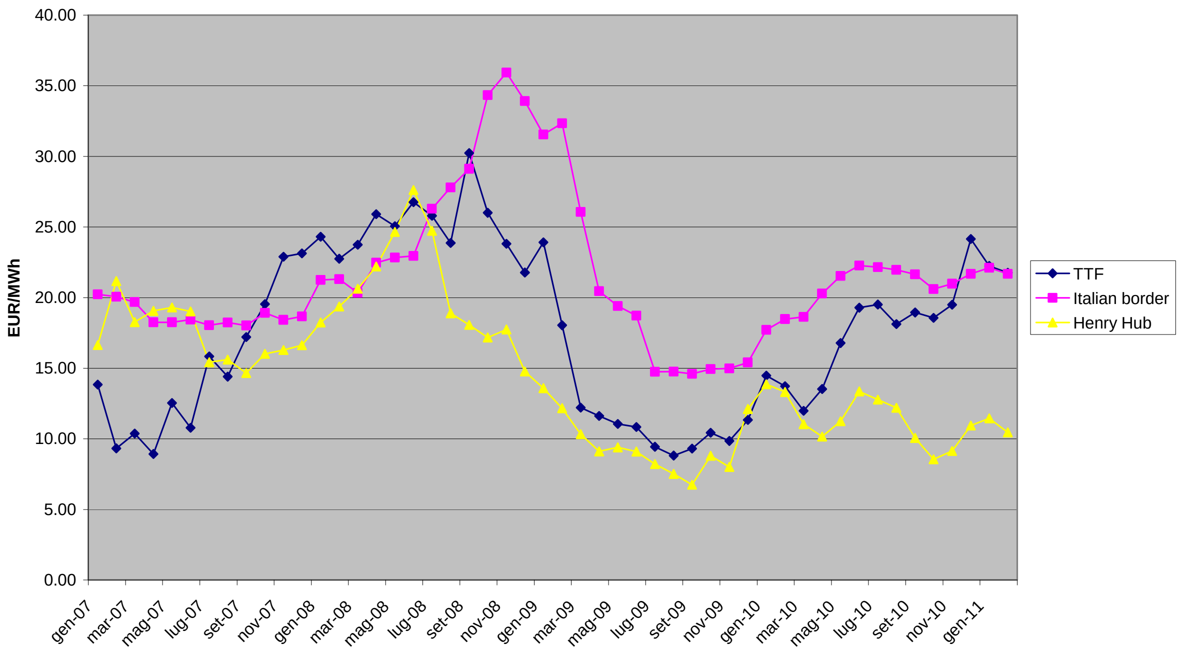
Keywords

Hubs; Infrastructure; Target model; Network tariffs; Gas market design; Capacity allocation

1. Introduction. Why an American Model? What American Model? *

Despite the MECOS model advocated by Jean – Michel Glachant in the FSR Working Paper "*A vision of the EU gas target model: the MECOS*", the most natural reference of a target model for the European market is the North-American model. Unlike any other theoretical model that may be proposed, this is a working model, which has been developed as the result of a long historical process, and is widely regarded as a success story. It has delivered secure supplies at prices which have been generally lower than those found in Europe, despite objective supply costs (in terms of production and transportation distance) that have been roughly the same, at least before the shale gas boom of the last three years, when the gap has indeed deepened (Graph 1). Yet the fact that innovation leading to the shale development has been more effective in North America is no chance, but it is just another positive feature of the industry. Although it must be partly attributed to the peculiar U.S. upstream regime where any underground production belongs to the land owner (rather than the State as in Europe), it also shows that the private sector does not fear undertaking substantial investment in North America, as it knows that it will be able to transport the product to the market, and sell it.

Chart 1 - U.S. and European wholesale prices



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Trading has developed in the U.S. and Canada far more than in any European hub[1] and the development of market centres based on hubs is playing a major role in the development of industry efficiency, in a way that is only starting to be faintly imitated in Europe.

Notwithstanding these undisputed positive outcomes, the American model is usually dismissed as not applicable in the institutional framework of the EU. Each observer from the Eastern shore of the Atlantic usually points at his preferred features of the American models as the reasons of its success, and complains that this is missing in Europe. For example, regulators usually mention the arm lengths' operation of pipelines and supply, and the political unity of the U.S. The gas industry focuses on the federal rather than state nature of regulation and its continuous reliance on distance based tariffs, with Transmission System Operators notably underlining America's more generous rates of return allowed on transportation activities as the main triggers for its significant pipe-to-pipe competition, as well as abundant capacity that underpins its far more vibrant gas commodity market[2]. In any case, it would be wrong to take up only some features of the American model, which – although not perfect – draws its success and appeal probably from the combination of its regulatory choices rather than any single feature.

Leaving aside the discussions about the American "preferred features" of the various stakeholders, there is a widespread agreement that the EU market (even after implementation of the Third Package) lacks the main institutional features that would allow it to imitate the American model. In fact Europe is notably characterised by:

- no ownership unbundling provisions;
- no single continental regulatory authority;
- mandatory entry-exit rather than tariff based tariffs;
- mostly national or sub-national TSOs rather than long distance interstate pipelines.

Since these characteristics are clearly not present in the current market organisation, and will not be found even after full implementation of the Third Package, there is a widespread tendency to dismiss the American model as not applicable in Europe (lately on this Moselle, 2011), but only as a possible source of "lessons", which are mostly bound to be promptly forgotten[3].

This paper will challenge such widespread conclusion. It will show:

- which lessons are most relevant and should be recalled and possibly imported from the North American experience: these will be listed as Propositions;
- how these lessons could be turned into a target model which, while fully respecting the Third Package, retains the main features that have fostered the American success in terms of competition and trading development;
- what would be the main consequences of such model for the regulatory framework of the EU, and in particular for the priorities of the European Network Code that should be developed and adopted according to the Third Package.

For ease of discussion, the target model that will be developed will be nicknamed the EURAM (European American Model). The meaning of any description of the EURAM should not be misinterpreted. It is inspired by the following:

1 The North-American forward market is 2,600 times as large as the European one, according to Makholm (2011).

2 The predominantly national nature of production has also been noticed. Whereas this is no reason for (e.g.) the Alberta based producer to give in to U.S. customers, the most competitive and market friendly organisation of import sources has helped to integrate it into a single market space, where this has been less easy with at least some of Europe's external suppliers.

3 A valuable attempt to draw such lessons can be found in Correljé et al. (2009).

Proposition 1. The target model is the structure that the gas market organisation will assume as a consequence of the joint pressure of market and regulatory forces.

The North American liberalisation experience, as well as the shortest European one, has shown that regulators, however powerful, cannot tailor the market to their own wishes[4]. Rather, the resulting market design is the joint product of different forces, which interact to yield a certain outcome. Thus, the optimal behaviour of public institutions should consider how industry (in its various sectors) and other stakeholders (finance, national governments, external market forces, end user representatives etc.) may interact with regulatory efforts by National Regulatory Authorities, the European Commission, and Competition and Security of Supply Authorities). The interaction of such forces occurs against the background of the industry's inherent features, which are worth recalling before starting to outline the EURAM.

2. Some preliminary analysis and an outline of the next sections

The regulation of any industry is mostly based on its underlying economic nature. However in the case of gas, some misunderstanding of such nature (or disagreement, whatever it may be) is often the source of lasting disputes between regulators and industry. Considering the scope of this study, the most important part of the industry to be analysed is transportation, with some attention paid to services that are strictly related to it, like those of the LNG chain and storage, and to wholesale trading based on this underlying infrastructure.

To understand the main relevant economic features of gas transportation[5] it is useful to compare them with those of two other energy carriers, object of a similar regulatory debate: electricity and oil. A synoptic view is provided in Table 1 and can be summarised by the following:

Proposition 2. The economically relevant features of gas transportation lie in an intermediate position between those of electricity, where transmission is basically a monopoly, and oil transportation, which is mostly competitive.

The American experience reinforces this interpretation of the natural gas industry as located between electricity and oil. On the other hand there is a tendency to see the gas industry as more similar to electricity, which may be true for national and relatively isolated markets, but not for a continental market[6].

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4 See Makholm (2006, 2011); for an illustration how it developed see also Jensen (2007).

5 In this paper "transportation" and "transmission" have the same meaning. In the EU legal language the official word is "transmission", however its use carries the risk of neglecting the differences between gas and electricity transmission.

6 This tendency can be clearly noticed if one considers that the regulatory framework defined by the electricity and gas directives in the EU is fundamentally similar. On the other hand, the U.S. and Canada have a much larger federal role and a basically independent regulation of the gas industry from that of power, whereas the latter is mostly state based. Whatever opinion can be held about this difference, it is clearly consistent with the fact that natural gas travels on average much more than electricity, with some 60% of gas consumed in Europe crossing at least one MS border and nearly 30% at least two, against less than 10% of electricity crossing one or more borders. Historically, the original development of European gas regulation in the U.K. may also contribute to explain such patterns, as the isolated U.K. gas market shares more of the electricity features than the European Continental gas market, with a far smaller transmission sector serving end users from mostly national and "close" sources.

Table 1. Some economic features of three energy carriers and its regulatory consequences

	Electricity	***Natural gas***	***Oil derivatives***
Long distance transportation costs	High	Medium	Low
Prevalent transportation range	Mostly national	Mostly continental	Global
Transportation flexibility	Low	Medium (via LNG)	High (via shipping)
Flow predictability	No	Yes	Yes
Weight of transportation in value chain	Low	Medium	Low
Transportation congestion	Common	Rare	Negligible
Storage	Very costly (pump)	Moderate cost	Low cost
Regulatory control	High	Medium	Low
Trading hubs	Agreed with regulators	Defined by market forces / regulators	Defined by market forces

The table illustrates Proposition 2 by highlighting several features of gas transportation. It is less costly (per energy unit) than electricity but more than oil's; as a consequence of which it travels on a normally much broader scale. Its flows are predictable, like oil's, and its storage is feasible at reasonable costs, though harder than for oil derivatives'. Thus its balancing requirements are less strict than power's and its logistics is also less demanding. In fact the increasing share of LNG in gas transportation has increased the flexibility of trading arrangements, reducing the weight of fixed pipelines, with LNG playing the marginal[7] role. This role is often amplified, as it provides a competitive pressure fostering a more flexible use of pipelines as well. It is worth recalling that oil pipelines play a large role in oil transportation, yet their regulation is hardly needed, except in limited areas.

Flows are predictable in gas, unlike in electricity: this avoids or sharply reduces the need for the complex arrangements that have been adopted in the power sector to either account for actual flows or to allocate their costs correctly and deal with network externalities, including the well known ITC or

[7] "Marginal" is used here with the economics meaning of being the last unit that is delivered (or the first that is withdrawn) from a market in order to restore equilibrium (e.g. to achieve price alignment between markets).

Inter-TSO Compensation mechanism. This greater flexibility entails important consequences for the ways gas markets are and should be organised (see section 6).

The bearable, though high costs of gas transportation and its predictability have led to the continental range of gas transportation, and an increasing intercontinental trade. Since gas, rather than electricity, is normally transported internationally, its transportation is a major source of competitive advantage and a terrain of entrepreneurial initiative. Reduction of this to a centrally planned process would amount to losing a major share of the industry's efficiency potential. To sum up, as the American experience has widely shown:

Proposition 3. Competition in gas transportation is a major source of efficiency and should therefore be accounted for and promoted in the most suitable way within a target model

In fact, even in Europe, competition between gas transportation routes occurs. For example, there are at least five major projects competing to take gas across the "Southern Corridor" from the Caspian production basin. Russian production aimed for western Europe may use the existing Ukraine-Slovakia, Belarus-Poland routes, as well as the new Baltic and possibly a future Balkan way. Similar competition is developing for Southern Mediterranean gas, often from the same sources, as well as for North Sea gas. Most of these options are also competing with LNG terminals.

Originating from external sources and producers, but far from stopping at the EU borders, competitive routes extend well inside the EU. The choice of any of them entails important consequences on investment in EU pipelines and their interconnections, and affects their regulation. For example, construction of the Nord Stream has also required construction of two large pipelines (NEL and OPAL) to connect it to other major consuming areas. The availability of MEDGAS has triggered the development of more capacity between Spain and France. Any new major pipeline providing more supplies in South-Eastern Europe would probably require capacity reinforcement in the adjacent EU Member States. The way to address this issue has been rather different in the US and in the EU so far, and will be discussed in detail.

Unlike in the U.S., competition in transportation has been slowed down in Europe by the lack of "interstate" pipeline companies, by limited (legal only) unbundling, weak regulatory enforcement of the unbundling rules (notably managerial and functional unbundling), and by regulatory practices that have privileged short term price reductions to long term investments (Correljé et al., 2009).

In fact, most European TSOs have a national or sub-national nature, and some even enjoy national monopoly rights under a licensing regime. However this does not usually[8] exclude them from taking part in the continental competition. For example the historical transit systems of Central and Eastern Europe are at risk of losing their historical cross border flows, possibly without being compensated by the national tariff revenue.

Thus, pipeline (and LNG) competition cannot be neglected. The challenge is how to include it as an essential feature of the target model. It is challenging, but necessary, to adapt the American style (but also natural) pipe to pipe (and to LNG) competition to the European gas industry organisation, based on national or even sub-national TSOs. On the other hand, such competition should not be overrated: incumbent TSOs retain a cost advantage over competitors that may well discourage competition from newcomers, and such competition is (in the U.S. as well) a complement rather than a substitute of regulation. This is more true, the smaller the relevant market is. Nevertheless, European market

[8] The competitive pressure is not the same everywhere. For example TSOs of large systems which are mostly "sinks" rather than transit areas may feel a very limited pressure and develop in a relatively easier way, driven by national demand. This has been the case e.g. in Britain, France, Italy. However new sources and streams can modify this reality: all of these systems are currently exposed to growing opportunities of providing cross border services, which may well affect their business model if the chance is taken up, and lead to strain if it is missed.

integration and the development of some infrastructure competition go hand in hand: neglecting it would reduce the pressure towards an efficient gas market.

As for the limited unbundling, this has mostly allowed the retention of substantial integration between transportation and supply, with major investment decisions by TSO often subordinated to the interests of sister supply companies[9]. In the last decade such integration, together with the regulatory uncertainty triggered by the successive “packages”, has certainly contributed to curbing investment and led to less capacity than a fully unbundled market would have realised. TSOs often had no incentive to develop capacity likely to be used by their parents' competitors, which in a few cases have actually put the brakes on investments.

The next section will show how this situation may evolve.

The development of competitive transportation initiatives under stronger unbundling rules is likely to further increase transportation capacity. However, in the difficult first decade of market liberalisation physical congestion has been limited – unlike in the power sector. It is likely that once new and effective congestion management practices will have eliminated at least some of the remaining contractual congestion, and thanks to the competitive threat of new pipelines and LNG terminals, such capacity may further develop and cases of congestion will become even less common. Again, there is a profound structural difference with the power case, where high transmission costs and loss of power limit the scope of long distance trading and the price alignment between markets. The North American experience has shown that:

Proposition 4. Under a supportive, market-oriented regulation, gas pipeline capacity is normally abundant and not congested.

This does not mean that there is never any congestion, and we will see that some should be expected to remain anyway (see below, sub-section 6.3.1). At this point, it is worthwhile to point out that the North American system has delivered more capacity than the European one, for a number of reasons ranging from its federal regulation, its rate of return regulatory approach, its full unbundling and the private nature of TSOs (Correljé et al., 2009). The target model should consider this proposition as the basis for the definition of the regulation of pipeline capacity development and allocation, including the relative role of open seasons, auctions, and regulated tariffs. This will be developed in sections 4 and 5, with the latter devoted to the tariff problem, as the current entry exit model followed in Europe may create some difficulties.

Finally, it is worth noting that the multidimensional development of competition has allowed North-American regulators to rely on a less tight grip on the industry to pursue an efficient development of competitive markets. In fact, most of the trading arrangements and particularly the market design has been developed by the industry under regulatory control. In particular, hubs and the related market centres have experienced an impressive development[10], allowing them to take the lead in the industry's operations, including the main directions of resource allocation, dispatching, and the provision of services like balancing and storage.

This development has generally followed rather different models from those of the power industry, in accordance with the different physics and economics of the carriers. To sum up:

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9 Communication from the Commission "Sector Enquiry under Article 17 of Regulation (EC) No 1/2003 on the gas and electricity markets (final report)" - COM(2006) 851.

10 Huygen, Bos and Van Benthem (2011), section 3.

Proposition 5. The location, services and role of organised markets are most efficiently defined by industry under regulatory control, rather than by central planning.

Section 6 will draw some consequences for the EURAM, focusing on the way markets will be organised, and how they will be connected. Finally, the paper will examine the interactions between the various building blocks of the EURAM and their high level consequences for the current process of outlining Framework Guidelines that will drive the development of the European Network Code.

3. Unbundling

Unbundling is certainly the issue that has received the largest media interest during the discussion on the Third Package, and the related simplified views have often caused confusion. Several commentators have interpreted the outcome as if the EU had given up ownership unbundling, and expect most integrated gas companies to retain control over their networks, notably in the form of the ITO (Independent Transmission Operator) as described by Chapter IV of Directive 2009/73.

In fact, the implementation of the Third Package is currently (June 2011) in its first stage. Whereas several Member States (like France, Germany, Italy and others) have indicated their preference for the adoption of the ITO model, it would be wrong to think that the unbundling issue is over, and that the Third Package will not have a substantial impact on the behaviour of the European transmission industry.

In fact, the Third Package and the evolution of markets and industry organisation are substantially modifying the incentive structure the industry will face. Yet, the outcome cannot be entirely predicted as some key variables have not yet been decided, notably on the regulatory side. To understand how the industry may evolve, it is worth noticing a few points.

(a) Several Member States have already opted for full ownership unbundling, or have in fact fully unbundled their TSOs: Belgium, Denmark, Hungary, Netherlands, Spain, U.K.. These countries provide an important group of fully unbundled TSOs, which are likely to behave with the goal of maximising profits from their independent business, rather than from continued quasi-integration of transmission and supply. Being subject to regulated tariff or revenue schemes these companies are likely to pursue the only way they can in order to grow, that is by expanding their business and competing for further transportation services. Whereas some part of such growth is targeted at the faster developing markets of emerging economies, part of their efforts is likely to be devoted to Europe as well.

(b) Financial markets have long expressed their preference for fully unbundled companies. The main reasons of such preference are.

(b1) the regulatory risk that is pending on any company which may be suspected of abusing its market position, including the risk of a forced dismantlement by its national government or via a Fourth Package; and

(b2) the unclear rating to be attributed to integrated companies, with the low risk of the regulated business blurred by the much higher risk of a supply business involving substantial exposition to upstream events and price swings: this confusion limits the leverage capacity of the transmission activity and increases its borrowing costs[11]. So far, this preference has been often outweighed by the benefits of integration. However such benefits are likely to shrink, as outlined in the next few points (d) and (e).

(c) A related issue is the increasing financing cost, notably in an era of tighter credit. Pressure to reduce debt burdens and the opportunity to accumulate financial power for more strategic business

[11] See for example Knight Vinke on Eni: http://www.knightvinke.com/media_centre/eni/

acquisitions is leading several major gas and power companies to divest regulated businesses. Less important assets have gone first, like tightly regulated distribution and power networks. However, debt growth and emerging opportunities may put another weight in favour of selling TSOs as well, notably if neutral owners (like pension or private equity funds) can be found so that the benefits of integration are not transferred to competitors.

(d) Regulatory action by competition authorities, notably by the European Commission, has limited the scope for keeping markets tightly closed by under-investing in entry capacity[12]. This strategy is becoming even more stringent as the EU is about to introduce tighter congestion management provisions, and NRAs are increasingly requiring the adoption of open seasons - which reduce the integrated company's control on capacity growth - and auctions - which open up more existing capacity.

(e) Regulatory pressure by NRAs will of course be strengthened by the implementation of the Third Package, particularly in case the Integrated Transmission Operator (ITO) option is chosen, which is unprecedented and therefore highly uncertain in its impact. It may be expected that the ITO will be in any case (e1) less prone to the mother company's requirements; (e2) under tighter regulatory control, notably as regards investment decisions, with competing stakeholders' needs taken more seriously; and (e3) subject to heavier red tape burdens, through various programmes enforced by Third Package implementing legislations and NRAs in order to secure more effective separation (*Chinese walls*). Moreover, even though in principle the tariff treatment of ITOs should not differ from those of fully unbundled TSOs, some regulators may in fact (within the scope of their discretion) allow higher returns and other benefits to TSOs that are freed from suppliers' control.

All of these factors may foster the choice of ownership unbundling by companies, even though national legislation would allow them to continue with ITOs. Wherever ownership remains integrated, it is likely that a more independent TSO behaviour will emerge. Since at least some companies will compete for more transportation services, even integrated ITOs will be stimulated to fight back.

Turning to the original inspiration of this paper, that is the American model, it could be noticed that even the U.S. fall short of full ownership unbundling. In some case holding companies control both transportation and supply companies, though their operation is totally independent. After implementation of the Third Package, the structure of the European gas industry may not be very different from North America's as far as unbundling is concerned.

For these reasons, by and large, it can be expected that TSOs in Europe will become more active in capacity development than they have been in the previous decade. This development may take several forms, the most common ones being the mergers (as already implemented or attempted by Gasunie and MOL); and the development of special vehicles like joint ventures aimed at new projects: examples are UK Interconnector, the Nord Stream and its onshore branches (OPAL, NEL), as well as those proposed for Nabucco, South Stream and other Southern Corridor projects. However, as the interest in a renewed infrastructure business increases, full cross border mergers should not be ruled out even for state owned TSOs, notably as clear business opportunities show the benefits of such mergers rather than their political costs. After all, the same has happened with the important mergers that have characterised major energy supply companies in the last decade, leading to the sale of major “national champions” to foreign interests.

A rather different, intriguing opportunity for TSOs in a future integrated gas market is to offer transportation financial rights, instead of physical long term capacity, as has happened in some power markets (PCG, 2009). TSOs are in fact in the best position to offer this opportunity, which would be a hedging tool for shippers and provide a valuable alternative to long term contracts. However this

[12] Action has been taken notably against GdF (later GdF-Suez), E.On-Ruhrgas and Eni, leading to various remedies to reduce market control by large and integrated incumbents.

option would be available to large TSOs controlling capacity over entire routes rather than to those with a merely national scope. Such opportunity may offer a further incentive to TSO merger and consolidation, although it is not for the near future.

These tendencies point towards a possible development of some European equivalent of the interstate companies that have born most of the North American system, at least for action on the incremental transportation needs. Even if these developments do not necessarily require integrated companies to sell their integrated TSOs, they increase the pressure on them, and may well further shift the balance that is already being affected by the above listed factors.

The scope of such developments is of course related to the demand for new infrastructure to supply the European market. The demand-supply balance depends on a number of uncertain issues that are beyond the scope of this paper, but have been analysed in more detail, e.g. by Correljé et. al. (2009) and IEA (2008). Among others, it is worth recalling issues like (on the supply side) the steady decline of EU production; the uncertainty about North African supplies and the increased costs of Russian E&P; the multiple difficulties of reaching Caspian and Middle Eastern resources; the uneasy development of European unconventional gas resources; the expected cyclical tightening of the LNG market. On the demand side, the strength of industrial recovery, and particularly the uncertain success of the sustainability policies and of the competing renewables and nuclear industries and of CCS.

Overall, it seems that perspectives for transportation demand increases are substantial and justify the attitude of companies that decide to choose the best organisational, governance, regulatory and financial position that would prompt an aggressive strategy. It is now time to consider whether and how the European regulatory framework could make such endeavours succeed.

4. Long term capacity and new infrastructure

4.1 The rationale for long term capacity rights

Reasons why long term capacity (LTC)[13] should be granted to willing shippers derive from the market vision, as it has been outlined in more detail within the FSR study by a forthcoming paper by CIEP. Shortly, due to the decline of its domestic production and of its closer external sources, Europe is expected to consume more gas produced in increasingly remote or costly fields (including new gas sources within the EU), and transported by long distance pipelines or as LNG, requiring huge investments that can only be depreciated over long time spans, normally in the order of decades rather than years.

Such developments often need new transmission infrastructure. However, even if sufficient gas infrastructures are available within the EU, both external and domestic producers should be reasonably sure that they can obtain access to the pipelines they need to supply their end customers. They should be able to contract access for a sufficient period of time and at conditions that are reasonably stable. They should also be protected from the behaviour of competitors seeking short term opportunistic gains, for example by seeking control of some essential facility. And they should be safeguarded from opportunistic behaviour of regulators of end use markets or intermediate (transit) countries, who may be tempted to take advantage of their position (more on this in section 5).

The reason why such long term capacity (LTC) rights are needed by suppliers of natural gas and not by suppliers of other commodities (e.g. oil and its derivatives) is not related to the large size of the investments involved in exploration and production, but to the fixed nature of the infrastructure. For, if

[13] To avoid any further misunderstanding it should be clarified that within this study LTC has a different definition than in European legislation. In the latter *long term* encompasses any capacity product above one year. In this study a distinction is introduced between long term, above at 5 or more years, and intermediate term, which is between one and five years.

their gas cannot be transported by such pipelines, the producers cannot redirect it to other markets, unlike producers of coal and crude oil and products. As a consequence,TSOs, transmission system capacity holders, possibly supported bt their NRAs could exploit the vulnerable position of the suppliers and such a risk would badly affect investment decisions, with adverse consequences on long term supplies to the EU.

The problem does not occur to the same extent in the LNG market, as LNG can in principle be diverted to other destinations. However the LNG market, despite a remarkable flexibility improvement in the last few years, is still far from the liquidity conditions that are typical of oil and coal markets. Any conclusions of the present section are mainly referred to pipeline transportation but may also be applicable to LNG terminal to the extent that such market still suffers from some rigidity.

Traditionally the problems arising from the fixed nature of pipelines has been solved by reserving capacity on a long term basis on either dedicated or shared pipelines. The reform of capacity allocation in most EU Member States has normally preserved all or a substantial part of these long term transportation rights. In the traditional model, gas was sold by long term commodity contracts associated with LTC rights, with the seller taking the price risk by means of a pricing mechanism based on prices of competing fuels (in the absence of any independent gas price setting). At the same time the buyer, which was normally an integrated company active in a net importing country, takes the volume risk, as it is required to pay the minimum contractual amounts anyway, under a *take or pay* clause.

After the gas market liberalisation and in particular after the development of independent gas markets where gas prices are established as a result of trading, without direct reference to competing fuels, long term contracting could be regarded as no longer necessary. If markets are liquid, any amount supplied by individual producers can be sold on them and long term contracts, though still useful, are less essential. Yet, they are likely to stay on although on a smaller scale and possibly with slightly shorter durations, as shown by the experience of oil markets, as well as in the most liquid gas markets like North America or the U.K. (Lapuerta, 2011).

However, if the need for long term capacity contracts is less pressing when markets are liquid, there remains a problem for the gas transportation industry. If it is no longer integrated with suppliers, this industry draws its income from the sale of capacity rights and cannot develop new infrastructure, or even ensure the maintenance of existing one, unless a reasonable share of its investment costs are covered by LTC contracts. This is another striking feature of the North American model, where liberalisation has brought about a decoupling of commodity contracts and capacity rights. Whereas the use of long term commodity contracts has declined substantially, long term capacity rights have survived, supplemented by shorter term transport products (Makholm, 2006).

In Europe, LTC rights have been criticised as a source of contractual congestion causing market foreclosure, notably if capacity could not be transferred to third parties. Yet, the right to use pipelines on a long term basis to supply the market should not be confused with the right of leaving the pipeline empty, even when other suppliers are willing to fill it with other, possibly cheaper gas. Hence actions have been taken by competition authorities to free up such capacity, and lately the EC has given priority to congestion management, through a proposed amendment to Regulation 715/2009[14]. The stronger the available congestion management mechanism, the easier can LTC rights be awarded, with the ensuing capacity enhancement benefits.

It is worth noting that even countries at the forefront of the liberalisation process, like the UK, have introduced the right to reserve capacity on a long term basis (up to 16 years) at border points. On the other hand TSOs fear that network users may be hardly interested in buying capacity long term, if they can reasonably hope to buy it later at lower prices.

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14 http://ec.europa.eu/energy/gas_electricity/consultations/20110412_gas_en.htm

To wrap up, the vision underpinning the target model is a gas market where investment in upstream sources could and should be undertaken without any fully guaranteed market. Traders may still decide to opt for long term contracts based on their preferred take or pay and indexation clauses, but these would be independent of capacity contracts. Consequentially, this vision underscores the right for, on the one hand, the suppliers to reserve capacity on a long term basis, without seeing this right jeopardised at low cost, as it may happen if capacity were fully allocated through short term auctions. On the other hand, it recognizes the related right of the TSO of selling their capacity long term to underpin the recovery of their necessary investments.

It is not possible to prove that such vision maximises social welfare. It is rather a pragmatic intermediate stance, in between the wishes of producers who would call for secure markets and those of short term traders who would call for full flexibility of supplies[15].

Without any further discussion, it may be interesting to recall that a similar problem has been present in the discussion of the Electricity target model, where the reservation of long term capacity and its pros and cons has been discussed, and some interesting approaches have been proposed including the role of financial transmission rights[16].. It is too early to say whether such tools may take the role of physical LTC contracts. It may happen when TSOs have a more widely recognised independent role, so that they are interested (and can be trusted) to offer financial instead of physical capacity rights.

The rest of this chapter discusses the related problems and the possible solutions.

4.2 Issues in long term capacity allocation

There is clearly some overlap between reasons for LTC allocation and the issues regarding new or reinforced infrastructure. After all, both the allocation of existing and the creation of new capacity address similar problems: shippers are interested in the capacity. They are happy to book the capacity available, but if this is found to be physically congested they should have the right to invest in its expansion by any relevant TSO, on a level playing field with their competitors. This right has long been recognised, and several provisions have appeared in the various directives[17]. Yet, these have long been ineffective and the Energy Inquiry has noted this regulatory gap, notably concerning interconnections between transmission systems.

The process of building and booking capacity on new infrastructure may not be basically different from LTC allocation, although new capacity would have a certain lead time – usually of some years - before its definition and completion. This section focuses on long term allocation of existing capacity, and will show how this process may interact with the development of new capacity, promoted by market forces and defined notably through open seasons.

In this respect a major issue must be addressed. In the current European legal framework, for reasons related to the political fragmentation and particularly to the prevalence of imports from outside the EU, capacity reinforcement processes are not driven only by market demand, but also by long term capacity planning, underpinned by a security of supply rationale, or by other political goals. For example, the process may be driven by the political will to supply new areas, or by an energy policy decision to promote gas consumption for environmental reasons. Moreover, policy makers may want

[15] Yet, this approach is supported not only by the mentioned British experience but also by the wide support emerging for long term capacity allocation rights in the recent call for evidence launched by ERGEG on the target model.

[16] PCG (2009), in particular see slides 40-54.

[17] The most compelling provision are now found for ITOs in Directive 2009/73, Article 22. In the old Directive 203/55, Article 21(2) read "Member States may take the measures necessary to ensure that the natural gas undertaking refusing access to the system on the basis of lack of capacity or a lack of connection makes the necessary enhancements as far as it is economic to do so or when a potential customer is willing to pay for them".

to foster new investment if they fear that TSO decisions lead to suboptimal investment, as they are too much affected by the interests of suppliers that have not yet fully unbundled their TSOs. It should be recalled that full ownership unbundling of pipelines is only found in a minority of Member States.

All of these factors suggest that in Europe, unlike in North America, the treatment of LTC allocation cannot be seen as a purely commercial process. The challenge is to set up a pragmatic mechanism where market forces and legitimate public concerns interact on a common and usually international decision framework.

The next problem of LTC is of course how long it should be. The longer the reservation, the larger the risk that capacity is hoarded by some strong players, including market incumbents and external producers, thereby reducing competition in the affected downstream markets.

It is paramount that any LTC allocation should be strictly related to an effective CM procedure. It could be said that the longer capacity can be reserved, the more effective its release mechanism for short term use should be, to be enforced whenever capacity is not used. Shippers (and the producers behind them) should in a position to use their LTC, but cannot use such right to prevent entry by competitors that are based on cheaper short term resources.

It is also clear, as stated for example in ERGEG's Draft Framework Guidelines on Capacity Allocation, that only market based solutions are considered acceptable for entry points into any Entry-Exit Transmission System (EETS); with the choice being restricted to either explicit or implicit auctions for physical capacity, and possibly to that between physical and financial capacity. This Framework Guideline does not however define which auctions should be used for LTC and other allocation processes, which is one of the tasks of the current discussion.

The duration(s) of LTC rights should be decided by market consultation. Typical durations are up to 20 years, also by considering what is often done in the case of new infrastructure, where the rationale underpinning the LTC allocation is similar. Nevertheless, since the CM system may be only partly effective and the risk of capacity hoarding may be substantial, it may be reasonable to *cap* LTC, by setting a maximum percentage of total capacity to be auctioned, or (with the same effect) by reserving capacity to medium and short term allocation. A proposed (purely illustrative) structure could allow up to 70-80% LTC, with at least 10-20% mid-term (1-4 years) and at least 10% short term. The consultation may also consider intermediate durations (e.g. 5,10 years), but the risk of straining the market by introducing too many regulatory decisions on durations and caps should be avoided[18].

The most difficult problems however arise when the topology of gas transmission is considered. Whereas EU Member States have already used auctions for the allocation of LTC on individual entry points of a single EETS, substantial problems emerge whenever this process is extended to a few interconnected EETS. Shippers are normally interested not only to reserve capacity at each interconnection point, but also to book capacity along several EETS at the same time. In fact they are often interested in supplying a market that is separated from the gas source by several intermediate countries and their EETS, where they may only partly (or not at all) be interested in supplying end users in those countries. Thus, they would like to be in a position to bid to reserve capacity on the entire route to the final (even the remotest) market of the chain, without being particularly interested in the intermediate exits.

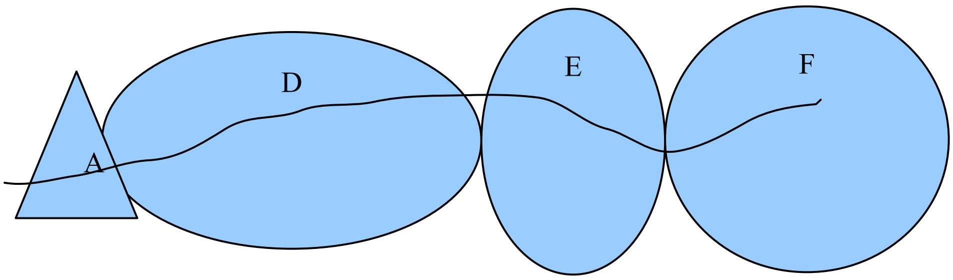
[18] Implementation could also consider delivering longer terms as strings of multiple shorter term products, as already done in the U.K.: these details go beyond the scope of the present study. It is interesting to notice that a similar discussion is found in the Electricity Target Model discussion : see PCG (2009), slides 38-42.

It is worth noting that co-ordinated auctions on border capacity[19] along the route would represent a necessary condition for such capacity to be booked, but not a sufficient one. For example, even with co-ordinated auctions, other shippers could outbid the first one on a limited section of the routes, possibly a single interconnection, and make its reservation at least partly useless. As in any poorly designed market, opportunistic forces would step in and secure control of bottlenecks, with a view to resell them at higher prices. Therefore, joint allocation is necessary rather than simple coordination.

To understand the problem the reader may look at the stylised Graph 1. A shipper (denominated: 1) would like to supply mostly market F from an external source (e.g. a source in a non EU producing country A), and therefore bid on interconnections AD, DE and EF on the pipeline connecting the markets. However a shipper 2 wishing to supply mostly market D could outbid shipper 1 on the (congested) AD interconnection and make it useless any reservation of DE and EF by shipper 1.

A cascading auction design may in principle solve this case, with capacity DE auctioned after AD, and EF after DE. However, it would fail to address any more realistic case.

Graph 1



Let us now assume that the system topology is closer to that of Graph 2, where six markets and three external sources are shown, located both "east" and "west" of the markets. This Graph would be a more suitable representation of the problems occurring in the European transmission system, where gas is fed from all cardinal points as well as from inside the Union, and with the possibility of both commercial (backhaul) and physical (reverse) flows.

It is clear that if there are several sources, markets and interconnections, the potential number of combinations which shippers may be willing to reserve is potentially very high. No practical auction design could probably be devised for all of them to represent a reasonably transparent market, taking due account of the need by shippers to book capacity on routes comprising several neighbouring systems rather than individual ones. In the example of Graph 2 there are at least 18 combinations if the possibility of multiple routes is ignored, and there may be more than three times as many if these are included. In the actual European grid system, even with some consolidation of markets, hundreds of auctions would be required to address all combinations that shippers may actually be interested in booking. This is hardly feasible, and if implemented, would undoubtedly create huge transaction costs and uncertainty, for shippers, TSO and regulators.

Further, even if such combinations could be auctioned, they would probably yield a much lower than optimal total transmission capacity, as the bookings would probably depend on the ordering of the auctions. As a result some interconnections could be neglected and others overbooked. On the other hand, it is hard to define a ranking for the auctioning of combinations.
Two approaches may be envisaged to address this problem: single auctions and open subscription procedures.

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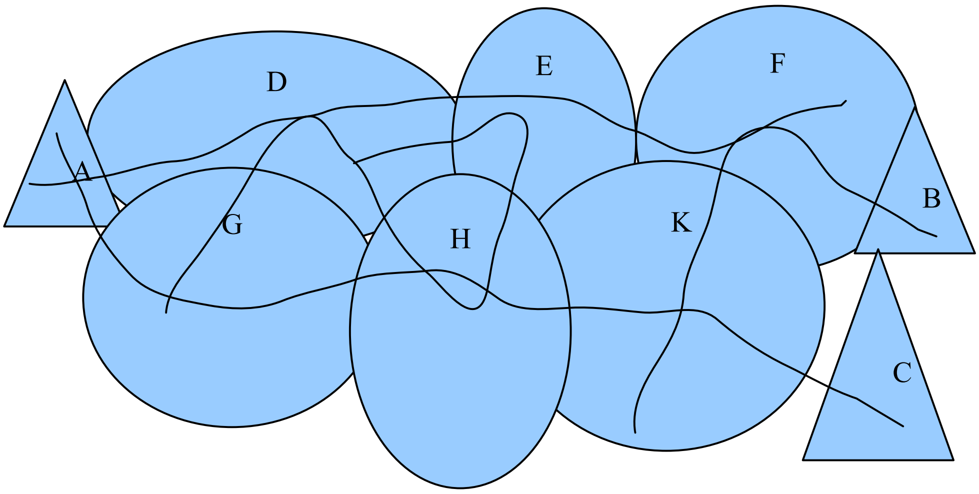
[19] In this discussion, any cross border capacity is assumed to be "bundled", i.e. the same capacity is allocated on both sides of the border

Graph 2



4.3 Solutions to the long term capacity allocation problem: individual auctions and open subscription processes

A first solution to the above described problem may lie in the *separate reservation* of interconnection capacity only. In such case TSOs would simply auction interconnections (including entry points into the Union), and leave any other co-ordination effort to shippers. This would reduce the number of auctioned points to a more manageable level, in the order of few tens. However, it would hardly provide the kind of LTC allocation sought by shippers, for several reasons.

The main problem is that, as already noticed, shippers may need several adjacent interconnection, but may not succeed to reserve the same capacity on all of them. Therefore the mechanism should foresee at least some possibility to downgrade the reservations, and would leave someone rationed. For example, in the Graph 2 example, with two shippers wishing to supply market H from source C, shipper 1 could win all capacity between C and K and shipper 2 all capacity between K and H. A bilateral bargaining would follow, with a substantial incentive to collude. Eventually, competition authorities may be flooded with requests to merge shippers like 1 and 2, driving a process of increasing concentration among the suppliers.

Auctions are a world where learning is essential. For example after a certain outcome the bidders may "be punished" by competitors if the bid was inappropriate. A single LTC auction defining capacity for a number of years does not allow for any such learning process and may therefore resemble a lottery rather than leading to a rational outcome.

A further complication potentially affecting any auction design, but particularly a single auction round for all interconnections, is related to speculators who may try to enter the bid for selected points, with a view to reselling them at a later stage. Some countries have already limited this risk by requiring not only financial guarantees (which would not deter large financial institutions), but also the availability of long term contracts for subscribers, which may be conditional on getting the LTC. This issue is not simple but it has been addressed with some success by regulators in Europe, like in Italy.

Thus, single interconnection point auctions for LTC are a possible but most likely not the best solution. Another solution could be devised by extending and experience of capacity reservation for new infrastructure, through O*pen Subscription Processes*.

The main steps of such process are described below and could be seen as an extension and generalisation of open season processes. At some point, several open season launched by TSOs may converge into a public open subscription process (OSP), but for the sake of simplicity and considering the existing differences, these will be regarded as separate for the current illustration. Moreover, as stated in section 1, the development of infrastructure by private initiative is a basic pillar of the American model, which should be preserved in Europe as well: in fact most of European infrastructure has been developed by market based initiatives rather than public decisions, even though in many cases developers were state-owned. The integration of market based initiatives within (and to some extent channelling into) a public process is a variant aimed at addressing Europe's limited political integration, weak degree of unbundling and limited availability of local gas resources. The proposed OSP is (with the entry-exit tariff system, discussed in section 5) the main divergence of the EURAM form the actual North American model, and is developed to allow for specific EU features.

From an economic viewpoint it could be argued that an efficient gas transmission system should not generate any long term congestion, with capacity being increased up to the equilibrium level where willingness to pay for it equals its development costs, which in turn would be the basis of regulated tariffs. In fact even in the current, far from optimal, organisation physical congestion in Europe occurs in just a few cases. It is well possible that almost all LTC requests could be satisfied at the regulated tariff[20]. The following proposal is based on that vision.

The process should be launched in a co-ordinated way. It is likely to last for several months, and should be repeated, perhaps every other year, with a view to offering capacity that may be released from the expiration of existing allocations[21], or new pipelines.

The OSP would be a process where private market players, as well as bodies mandated by public authorities, may take part.

A platform would be established where all (private or public) stakeholders make binding capacity commitments, so that TSOs and others can finance and maintain or enhance existing capacity, or require to build new assets.

The following main steps could be envisaged:

Step 1. Technical capacity assessment. A first decision is related to the capacity that should be offered. In fact available (firm) capacity at interconnection points is not independent of how other (parallel or converging) lines are used. The first step should therefore be the development of a common grid capacity model (The same basic requirement has been requested in the electricity sector).

The model should define not only total capacity to be offered, but also the implicit capacity usage at interconnections, which would be the basis for individual TSO capacity allocation and related rights and obligations, including for tariff purposes. Current ENTSOG work, including for preparation of the Ten Years Network Development Plan, is already proceeding in this direction.

It is worth noticing that the implementation of a single grid model, however time consuming, is likely to increase total available capacity with respect to what emerges from sum of capacity calculated at single interconnections, due to the restrictive assumptions that must be taken concerning capacity of interconnected pipelines[22].

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20 possibly allowing for limited reinforcement (e.g. by adding compressors). However technology requires that beyond a certain level a capacity increase can only be attained by doubling a pipe rather than by increasing compression, larger pipes or looping. But demand may not justify such a jump in capacity supply. This may be the source of remaining congestion in some cases.

21 including legacy contracts. The GTM does not however discuss the treatment of such contracts, but it is is assumed that there will be some

22 This has been experienced on a smaller scale in Austria, where the allocation of capacity by a common grid manager has led to a capacity increase with respect to allocation by each of five concurring TSOs.

Step 2. Non binding capacity market survey. Once the grid capacity model is available shippers could be invited to state their (firm and interruptible) LTC requirements, in terms of source and destination (e.g. ZZ Gwh/day from B to H). At this stage no auction process is envisaged: shippers would only state their peak capacity demand at the published regulated tariff for the required sources and destinations.

Any meaningful decision by shippers on how much capacity to request would in principle require that shippers know such tariffs for the whole duration of the LTC allocation. This is probably too long to ask of any regulatory process. However, considering the limited scope of capacity cost as a part of total gas value, it may be enough to require tariff updating criteria in line with the best EU practices. These involve regulatory periods where tariff updating criteria are defined in advance for periods of 3-5 years, linked to inflation rates and predetermined productivity improvements, except in special cases; and even periodical regulatory reviews involve some broad criteria for splitting of further productivity improvements between TSOs and shippers, but exclude any risk of sudden and groundless tariff change[23].

Step 3. Capacity supply assessment. Once LTC requirements are fed in, TSOs would apply the common grid model and state the maximum available transmission capacity that can be offered. This calculation is performed with a view to satisfying the highest commercial transportation demand, without prejudice to the routing. It is not a path based calculation, therefore it cannot be performed for any single TSOs or even a subset of them. If any route or interconnection is congested so that the requested capacity cannot be offered, the concerned TSOs may agree and submit proposals for the reinforcement of the requested route. The process should be transparent, so that concurrent options may be proposed by competing companies or their groupings. It is expected that within such process TSOs would also publish the indicative cost of capacity, notably in case investment is required or the current capacity tariffs are inadequate for any reasons. In general such costs should be consistent with the tariff setting criteria, but proposed tariffs would differ as new investment may be necessary.

Step 4. Binding bids. Once costs are known for all proposed links, market players are invited to submit their requests. This step is not basically different from the binding phase of an open season and would be in fact regulated in a similar way. Capacity contracts may be signed with the appropriate financial guarantees and ship or pay obligations. Such contracts could be defined for LTC rights to existing capacity as well as for new capacity.

Submission of bids and purchase of capacity should not be necessarily limited to commercial shippers. On the contrary, TSOs of systems located "downstream", which have a legitimate interest in the availability of transit capacity, should be allowed to bid and reserve capacity, also "on behalf" of their users. Indeed, an innovative, competition-friendly solution to reinforce long term capacity without too much appropriation by market players could be booking by TSOs of transit beneficiaries ("downstream" systems), paid by their regulated tariffs. However its implementation may not be easy, as TSOs are not normally entitled to book capacity on other systems, and their regulators (or governments) should allow and instruct them to do so.

Where any such public service obligation is foreseen, TSOs (or other market players, e.g. last resort suppliers) could also reserve capacity in transit systems, possibly at the request of governments, NRAs, or other authorities in charge of security of supply pursuant to Regulation No. 994/2010[24].

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[23] More on tariffs will be said in the next section.

[24] The participation of public institutions in an open subscription or open season process is not entirely without risk. Before investment decisions they may well offer subsidies to new infrastructure to attract shippers, with a view to increasing tariffs later when shippers are stuck to it. However, this risk is lower under an open process than in a less transparent and public decision mechanism.

In any case, capacity contracts would be signed for all matching interconnection capacity between the TSOs that are needed for the route required by the shippers, which would have requested capacity within Step 2, and be presented with bids within Step 3, as described above..

If a capacity enhancement is required, a by-product could be an auction of existing capacity, limited to the period during which capacity remains congested, with winners getting priority allocation in the ensuing increased capacity. Such auction would concern the selected route to be allocated as a single (one stop shop) firm LTC service.

It is worth recalling that if caps on the LTC share are enforced, the routes are deemed to be congested if total capacity emerging from the optimal capacity model falls short of the required medium and short term margins[25]. This LTC capping requirement suggests avoiding too high reserve margins as this would increase the risk of LT congestion.

If TSOs or the relevant NRAs disagree on the choice of the routes to be up for auction, the Third Package has a remedy. ACER may decide according to Article 8 of Regulation 713/09. However this article envisages long times for such decisions: up to one year after the time for NRA to acknowledge their disagreement. Whereas these implementation details are beyond the scope of the study it is worth noticing that such times would be too long for a swift decision on the meaningful auction. Any delay would be suffered by the upstream investments processes that the LTC allocation is supposed to foster, and eventually by the availability of competitive resources for European consumers. Thus, moral suasion could be used to select the routes to be auctioned, but it seems preferable to foresee a more cogent process as part of the Network Coded CA rules, with an explicit role for swift decisions by the appropriate authority on the scope for auctions.

Step 5. Auctions for long term congested routes. In case binding capacity bids do not reach the minimum size needed for the necessary capacity reinforcement, the interconnection or route could remain congested. This should be the exception rather than the rule, and should only happen in cases where demand exceeds maximum available capacity by only a small amount, which does not justify the investment. In such case combined auctions may be held for the selected congested routes only. Since the whole process is likely to be repeated, possibly after a couple of years, it may be preferable to limit the auction to a relatively shorter time – or shippers themselves may prefer to book capacity for a shorter time (e.g. two years) if they know that the process will be repeated and they will be able to get LTC rights at a later stage, or seek another route.

4.4 Concluding remarks

The outlined approach is based on TSOs normally acting to offer capacity to the market, as it is the rule in North America. This should normally happen by decentralised action, based on market initiative. However, the still incomplete unbundling and the fragmentation of the European transmission system justify the proposal to integrate the capacity market with an Open Subscription Period, where capacity for the necessary routes (from sources to sinks) would be offered by a centralised process based on a common, agreed flow model.

Moreover, the proposal acknowledges that capacity shortage should be an exception rather than the rule in an efficient system, which is the only meaningful basis for a target model. Therefore, if capacity is insufficient, a procedure to enhance it is the most logical answer. Auctions should be limited to few cases where capacity is short and there is not enough demand to increase it, or where capacity cannot be reasonably increased due to technical discontinuities and environmental constraints.

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[25] For example, if LTC is requested for 60 Gwh/d on a certain route and a cap on LTC at 75% is enforced, the route is congested if it cannot deliver at least 80 Gwh/d.

The proposed approach also acknowledges that auctions are an excellent market based solutions in case of repeated allocations, as it happens for short and mid term products, but not for long terms ones, as the prize would be too large and the learning process about the pricing terms would barely occur. There is a high risk of further capacity hoarding, which may not be entirely avoided even by congestion management procedures. This risk must be prevented and not just cured.

Therefore, the proposed approach minimizes the scope of auctions. Capacity should be as far as possible be allocated at the regulated tariff (or tariffs in line with the regulated tariff criteria) to those who have a legitimate interest into it, excluding any purely financial interest. The use of auctions should be limited to special cases of routes, comprising several interconnection and offering virtual, non path-based capacity, jointly offered by participating TSOs and consistent with capacity margins reserved by TSOs for mid and short term allocations. For the selection of such routes a transparent and relatively swift process should be devised.

The current work on the TYNDP has already provided significant building blocks for an effective open subscription process. However the TYNDP is no decision tool. It is of course possible to envisage a totally new model where the development and maintenance of gas transport infrastructure would fall totally outside market criteria and be subject to decision by planning authorities, possibly preceded by informal market consultation. However this model would be at odds with the basic assumption of the EURAM, which underlines the possibility and opportunity of infrastructure development driven by market forces, though with possible integration by public authorities to address market failures. A total network planning model would also be probably not desirable, and extremely difficult to implement at EU level, and possibly against the legal framework of several Member States, recognising free enterprise rights in gas transmission within the limits set by Directive 2009/73.

In the EURAM view, such integration requires a common and transparent framework, to avoid the dual risk of government subsidisation of “pet” projects and of free riding by market forces in the hope that governments would intervene to pay for missing infrastructure. The TYNDP would remain as an extremely useful building block and a benchmark scenario for decision making by both private and public decision makers.

Tariff regulation would remain. Transport market competition may be expected to appear for new capacity, and possibly for the allocation of LTC to existing pipes. But once the pipeline is built, regulation is necessary to protect network users from being exploited once they have invested into related supply infrastructure (exploration, production and upstream pipelines of LNG chains), which makes them dependent on the transmission pipelines. This justifies some more in-depth analysis of tariffs in the target model, which is the subject of the next section.

Further, it should be emphasized that despite the availability of a common platform where LTC rights on the required routes could be booked, mostly at regulated tariffs or through binding bids, several market players may prefer to “free-ride”, or wait until capacity is developed at somebody else's cost, or possibly by public institutions, with a view to purchasing it later at auctions on a short term basis. This is a typical “public good” problem of common networks, as it may lead to underinvestment. However, it need not be solved necessarily by public money. At least two regulation remedies may be suggested against it:

(i) any subsequent purchase of capacity may be subject to a reservation price, which would be equivalent to the regulated, cost based tariff. This reduces the incentive to wait, as nobody could get capacity “for free” or as a “sale”;

(ii) furthermore, TSOs may be allowed to apply an “early bird” pricing principle, where capacity sold on a long term basis is priced at a discount with respect to the reservation price of capacity sold in medium and short term auctions. This would also stimulate LTC purchases and bids for new capacity by market players.

Finally, someone could ask what would be the role of exemptions in investment decisions taken within the proposed Model. Exemptions are clearly not the favourite solution for pipelines across EU territory: in principle they are allowed only for LNG terminals and interconnectors. LNG terminals may be awarded exemptions if TSOs and other operators do not want to invest in them by taking the necessary risk to invest under TPA, which is high as it is less easy to retain users with LNG terminals than with pipelines. On the other hand, in most cases LNG terminals enhance market competition, therefore their exemption – though awarded on case by case basis – is likely to be justified in most cases[26].

Interconnectors crossing the territories of other jurisdictions are more problematic. Their segregation from the host country system could entail a loss of efficiency and security of supply, and the same could be said of the virtual segregation provided by the exemption. further, they would be totally excluded from the competitive market and may try to pre-empt competition, hence the doubts which have been often raised by NRAs against this tool (ERGEG, 2007, 2009). If a satisfactory LTC allocation mechanism is developed, investors and NRAs may well agree on using them as a more satisfactory tool than exemptions.

5. Network tariffs in the target model

5.1 Entry-exit vs. distance based tariffs

Among the most remarkable features of the North American model is the regulation of interstate pipeline tariffs by a single federal agency (FERC). Such tariffs are normally set on a point to point, distance-related basis. These are important features of the North American model and have been underlined as important for its success[27]. Yet, both of these features are apparently at odds with the European institutional framework, and are at the root of the common dismissal of the North American model as not suitable for Europe. Indeed tariff setting responsibility lies with NRAs according to Article 41 of the Gas Directive; and tariffs must be set separately for each entry and exit points.

Since, at first sight, the differences between the European and American tariff criteria and responsibilities are striking, it seems useful to analyse them in some detail, in order to understand if reasons for each approach are purely historical, and to understand whether they are really so different.

From a theoretical perspective, the main reason for a "federal" rather than "state" (or national, in the EU) regulation of tariffs is clearly to avoid exploitation of transit flows by systems that lie between the main producing and consuming areas. It is clear that if transit flows dominate those heading for the local market, it is in the interest of intermediate systems to set tariffs well above costs, as the benefits of such behaviour for the transit jurisdiction would easily outweigh that of the highest impact of transportation tariffs on "local" consumers[28]. A state regulator would be inevitably attracted towards such behaviour as well.

This problem can take more subtle versions than the pure exploitation of a transit location. NRAs of systems with dominant cross border flows would be legitimately worried by costs swings that may occur in their systems as a consequence of falling cross border flows, which they would not accept to see on the shoulders of their citizens. It can be argued that this is a logical counterweight of the

[26] In the U.S. LNG terminals are now almost fully deregulated by the FERC.

[27] Makholm (2006, 2011); also, European TSOs have often shown their preference for distance-based tariffs, which are seen as the only cost reflective type.

[28] This happens even if tariffs are perfectly fair and do not discriminate between transit and internal consumption. In fact an entry-exit tariff structure may also discriminate against transit flows.

benefits that transit systems attain in terms of economies of scale, but this may not persuade the NRAs. This issue is analysed in more detail in an Annex.

Whereas in principle the difficulties are the same on both sides of the Atlantic, solutions have been different. In the U.S. and Canada, the regulation of long distance (interstate) flows has long been transferred to the federal level, so that no such exploitation of the geographical position of transit states is allowed. In Europe, whereas the regulatory power lies with NRAs, the Third Package has brought about rather explicit provisions banning any such practices, which were in any case clearly against the spirit of the single market and could in principle (even before the third package) be pursued by some more general EU single market legislation. These provisions are now included in Article 13 of Regulation 712/2009[29] and the main issue is how to implement them. Once this is done, in spite of the different institutional frameworks, it could be said that the different responsibilities would be no reason to regard the European tariff system as fragmented, as compared to North America. Network users would rely on reliable tariffs based on fairly consistent principles, and any remaining difference between TSOs would be based on objective reasons and not probably exceed those existing between (e.g.) U.S. and Canadian tariffs, which have not been prevented the organisation of a common North American market.

It is worth remarking that, irrespectively of any mandatory implementation of consistent and non discriminatory tariff systems, the practice of European NRAs has shown a tendency to converge towards common practices, and network tariff setting is a rather consolidated business. Most differences can be regarded as minor, notably for the setting of allowed revenues, whereas more differences exist on tariffs structures[30].

The issue of tariff structure, and notably the difference between entry-exit and distance based tariffs is less simple, as it is related to the technicalities of tariff setting. In fact entry- exit tariffs are a rather complex subject, particularly regarding the allocation of costs to entry and exit points. In short, the entry-exit tariff methodology can be seen as a generalisation of the original point-to point tariff system, which allows tariffs to adequately account for the multiple and often variable flows that are found in modern, liberalised systems, including the distinctions between physical and commercial flows[31]. In fact, entry-exit tariffs are often related to actual distance, with longer routes being priced higher than shorter ones. These tariffs tend to be similar to the “special case” of distance related tariffs in case of mostly unidirectional flows, but tend to diverge in case of uncertain flows, e.g. with gas coming from various direction according to technical and economic reasons, often changing across seasons. In such cases entry-exit tariffs are less distance-related but tend to be “closer” to postage stamps. Now, a closer look at the European network shows that systems where transit prevails have mostly unidirectional flows, except in emergencies[32]; while the (usually bigger) systems with no or little transit are characterised by mixed flows. These latter systems are often the “final sinks” of the European network where most gas is consumed[33].

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29 “Tariffs [for network access] or the methodologies used to calculate them, shall facilitate efficient gas trade and competition, while at the same time avoiding cross-subsidies between network users [...] shall neither restrict market liquidity nor distort trade across borders of different transmission systems. Where differences in tariff structures or balancing mechanisms would hamper trade across transmission systems […] transmission system operators shall, in close cooperation with the relevant national authorities, actively pursue convergence of tariff structures and charging principles, including in relation to balancing”.

30 where, understandably the Gas Regulation requires NRAs to pursue convergence. A thorough analysis of European practices is provided by KEMA-REKK (2009).

31 In particular and notably on a medium range scale, the liberalisation of markets has brought about backhaul flows, i.e. commercial flows which go against the prevalent physical flows, and which should therefore be priced differently, as they contribute in some way to reduce the need for physical flow.

32 Examples of such systems are Austria, the Czech Republic, Slovakia, Bulgaria and (with a lower transit dominance) Belgium, the Netherlands, Poland, Romania.

33 Examples of such systems are: Germany, the U.K., France, Italy, Spain, and Hungary.

Therefore, if tariffs are fair, as required by the mentioned Gas Regulation provisions, they should in fact be very similar to distance-based ones for long distance flows, which are mostly unidirectional as they are defined by the objective location of gas fields and markets. In other words, for long distance flows including transit across several systems, a fair entry-exit tariff system would be extremely similar to a distance based one. For shippers aiming to supply the big end-of-the-chain or "sink" markets, such tariffs would work just like distance based ones; they would simply add as many (import) entry and (re-export) exit tariffs as the number of intermediate systems used.

We can therefore conclude that, if properly implemented, the adoption of entry-exit tariffs at the level of each system (or Member State) does not preclude the capacity market to work as in the North American model, as far as long distance transportation is concerned[34].

Thus, regulated tariffs could avoid any exploitation of monopoly power by TSOs, while at the same time fostering economic investment, and not excluding that wherever possible pipelines (or their groupings) compete for flows by selling their existing capacities at lower prices than the regulated ones, or by developing new capacity.

The rest of this section will be devoted to discussing how the implementation of such fair and effective tariffs could be monitored within the European institutional framework. Two special sub-sections will be devoted to the analysis of issues that deserve closer attention:

- the case of tariffs for merged systems, which is important for those systems which may plan to merge – for reasons outlined in the section;
- the case of entry-exit tariffs in systems dominated by transit, which may raise special problems which could, if not properly addressed, jeopardise the use, development and even the proper maintenance of such systems.

5.2 Tariff harmonization across the European market

In the EURAM, cross border trade would still involve the payment of an exit and an entry fee. However in case of auctions for cross border capacity entry (and cross border exit, once capacity is bundled) tariffs could be partly replaced by auction prices, even though the regulated tariffs should be retained as reserve prices. This would probably require the (up or downward) adjustment of exit tariffs, or the creation of an investment fund into which any positive difference between auction prices and regulated tariffs would be poured[35].

The increased transparency and integration of the market could possibly trigger greater attention towards issues that have been relatively neglected so far, as network users have been involved in the acquisition of capacity, without being able to be bothered by its price. For other users, capacity costs were a transfer to a controlled transport affiliate, rather than a genuine outlay.

As unbundling and market integration progress, a greater concern for cost reflectivity and fairness of tariffs is likely to emerge. Moreover, as new congestion management procedures are expected to relieve contractual congestion problems, capacity becomes more abundant, and TSOs more independent of suppliers, cost awareness by shippers is likely to increase, as well as demand for closer monitoring of the capacity pricing behaviour of "foreign" systems. even if regulated by their NRAs.

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[34] Commodity markets would however be organised in a different way, as entry-exit tariffs are naturally associated with virtual rather than physical hubs: these will be discussed in the next section. A different conclusion, although starting from similar worries, is found in P. Hunt (2008). However his proposals are not compatible with the Third Package legal framework.

[35] If market coupling is introduced (see below), the same could happen with the congestion rent earned by the administrative process from arbitraging between the markets.

Since institutional responsibility for tariffs including cross border flows lies with NRAs in the EU, any ex-ante harmonization effort can only be based on moral suasion. This could be accompanied by monitoring efforts, which could be the basis for action in case the fairness requirements of the Gas Regulation were violated. In the current legal framework such action could only be taken by the European Commission, presumably after a request by affected stakeholders. However, a systematic monitoring, benchmarking and publication of tariff setting criteria would greatly facilitate such task. This could include:

- costing criteria used for TSOs, including asset valuation methods, rates of return and their components, depreciation and operational expenditure, losses and fuel costs;
- cost allocation criteria between entry and exit points and between capacity, commodity and any other tariff driver;
- criteria for the updating of tariffs, normally occurring on an annual basis and by applying a multi-annual incentive scheme;
- transition provisions linking any two consecutive regulatory periods.

It is worth noting that if the resort to auctions is limited for long term capacity (see section 4), and congestion is unusual, then the scope of deviations from regulated tariffs would be limited.

On the other hand, if a substantial amount of capacity is sold long term and at regulated prices it becomes important not just how tariffs are regulated now, but also the procedures for their updating, and even the process that is supposed to maintain regulatory stability, beyond the change of NRA personnel and national laws[36] Although transmissions tariffs are a relatively small component of the gas value chain, even a perception of unexpected and unjustified future tariff changes could represent a serious increase in regulatory uncertainty, and a blow to investment in new gas sources and transmission projects. Whereas national laws cannot be affected, some EU-level provision like the European Network Code could help reducing such risk.

The monitoring of tariff criteria could be included among current ACER responsibilities within the current legislation. It could be seen as part of the implementation of its responsibilities under Articles 7(4), 7(7) and 10 of Regulation 713/2009. Otherwise, monitoring could be promoted by the European Commission.

5.3 Tariffs within merged market areas

It has been suggested that market areas, identified by entry-exit systems, are merged, notably to increase market liquidity[37]. In case of such mergers, a single tariff system should apply. Trading occurring at a virtual hub on the common network requires a single system of entry and exit tariffs in and out of the network, which is the physical infrastructure underpinning the hub. In the pooled/merged networks some operational functions should be run by a common grid manager, acting as an Independent System Operator (ISO) in the sense used in American power systems.

Such grid manager would allocate capacity or dispatch flows, including for balancing purposes, but it would not necessarily own and operate assets; it thus would represent only a tiny part of total network costs. Therefore, for TSO revenues and their regulation, the impact could be very limited. A large part of the assets and personnel would still belong to the participating TSO and could be regulated by the relevant NRA, as before the merger. It is however likely that, with the TSOs being

[36] A typical point raised by TSOs' bosses when they face regulators is: “You are the best regulator in the world, but my investment cannot be recovered before your term expires. How can I be sure that your successor will be as good as you and respect it?“

[37] Such mergers could also be limited to parts of the merging networks, e.g. the main long distance pipelines, as implicit in the “trading region” option of the MECOS model, see FSR (2011), § 1.3.1.2.

joined into a common system, the respective NRAs and network users could be more sensible to any differences in the treatment of tariff components (like asset valuation criteria and rates of return), so that some further harmonization is likely to be promoted.

Much stronger is the expected impact on tariff design within the common market area. Allowed revenues of all participating TSOs should be pooled and the revenue raised by jointly set entry and exit tariffs. Therefore, tariff setting criteria would have to be agreed among the participating NRAs, including (among others):

- how to define, bundle entry and exit points, and possibly regroup some of them as virtual ones;
- how to split revenue between entries and exits;
- how to allocate costs to each point;
- how to split revenue between capacity and commodity components, and recover fuel costs;
- the length and timing of tariff periods and the dates of their periodical updates.

Once these decisions have been taken revenues should be collected and split between participants, including the small share of the ISO. This could be named an Inter-TSO Compensation (ITC) mechanism, however it would be far simpler and less controversial than what has been implemented in the power sector under this name. In fact, it would simply amount to collecting common tariffs and reallocating the revenue according to mostly pre-determined shares. Tariffs related to lower level pipelines could be directly left to each TSO.

The pooled tariff decision would obviously yield different rates than present ones. In fact the whole tariff structure would be overhauled in the participating countries, with a potential impact on the tariffs paid by local customers. This is likely to become a major concern of NRAs, and a source of resistance against the merger by negatively affected parties (shippers, end users, NRA).

Whereas it is relatively easy to assure revenue neutrality of the reform towards TSOs, the same may not be true for end customers. For example, customers near the borders of the new market area could experience some price increases, while "central" parts could benefit. Fears of such changes could possibly slow down the reform process and the creation of larger market areas (or common trading regions). Nevertheless, the impact would in any case be very minor, as transmission tariffs represent only a very limited share of the end user price; usually less than five per cent. The impact of the necessary transmission tariff reform would clearly be lower, particularly on small customers where the weight of distribution and retail price components is dominant. Moreover, some "postalisation" approaches could be applied to exit tariffs to smooth the impact, although this could create distortions and should better be seen as a transitional measure[38].

Annex. The transit tariff problem

Transit is no longer a legal concept in EU, yet it remains an economic reality entailing a typical tariff problem. As a matter of fact in several Member States or systems (notably among smaller ones), transit is larger or similar in size to domestic consumption[39].

In such systems downstream demand swings may lead to sharp variations of transit flows, whereas the related costs are mostly fixed. The reason for the sharpest demand swings may be either that end use demand falls in the final destination markets, or competition leading to usage of alternative

38 Postalisation of exits amounts to setting a single national exit tariff, which implies some cost rolling. This has been implemented in France under an EE system. For more details and a simulation of the likely outcome of such merged systems see GRI-SSE (2008).

39 See fn. 34 above.

sources routes and infrastructure[40]. Such events may develop slowly, but nonetheless lead to potential unit cost increases within the transit countries.

The problem is normally related with fixed costs, as losses and fuel gas (also known as *shrinkage)* are usually covered as a separate item, in kind or as a variable charge. However, if these costs are covered by capacity related charges the problem is exacerbated). In any case, costs would be borne by the remaining users. In case of flow swings a tariff revenue risk arises.

Under a "revenue cap" tariff, the TSO has a guaranteed revenue; but if transit falls more costs must be borne by domestic consumers, whose tariffs may notably increase. Thus, this solution is not usually supported by NRAs[41].

On the other hand, under a price cap, the risk would fall on TSOs, which may incur into heavy losses: this solution is therefore opposed by the TSO itself.

The problem has some consequences not only for the end users of the concerned transit countries, but also for the development and maintenance of existing pipelines. If the tariff system involves significant risks for its developers, its commercial development is less likely.

For a fair analysis of this problem it should be acknowledged that host countries (and their TSOs) do benefit from transit in several ways:

- by the creation of jobs, profits, and land use rights for the local economy;
- by reduced transmission costs from economies of scale;
- if transmission cost allocation is not fair, some hidden cross subsidies from transit to local consumers may occur, possibly supported by the NRA.

As noticed, the cost allocation under entry-exit tariffs is a very technical methodology, with some differences in implementation across Europe. Monitoring by ACER and/or agreed Guidelines may be useful to avoid discrimination, notably against cross border flows: therefore such cross subsidies should be ruled out in a target model discussion.

It is however useful to get some preliminary idea of the size of the economies of scale benefits, as the jobs, profits and land use rights are unquestionable remuneration of services rendered by the host country, including any nuisance from the pipeline. To estimate these benefits let us take a stylized representation Eustream system, the largest transit system in Europe, with an entry capacity in Eastern Slovakia (Vel'ke Kapuśany) of over 12 Mcm/hour, which carries gas of mostly Russian origin to the Western border of the country, with two exits into the Czech Republic and Austria, taking gas directly or indirectly to several other destinations. The length of the system is about 500 Km in Slovakia.

Now, as a mental experiment, let us assume that transit from Russia into West had followed different routes (e.g. through Hungary or Poland), leaving the Eustream pipeline for the service of the Slovak and Czech Republics only. In such case, transmission costs for these countries could be estimated at ca. 75% higher, due to the loss of economies of scale. This could be called the *stand alone cost*.

The recent historical Eustream entry monthly load factor has been between 43.7% and 91.4% between 2004 and 2010 (excluding the January 2009, which was affected by the Ukrainian crisis), averaging 66.7%. For example, if the average load factor were at its historical minimum the unit cost would be 50% higher. Currently expected booked capacity for 2015-16 and 2019-20 would yield 50-

[40] For example, in the last few years a relative decline of Russian supplies to Western Europe, crowded out by cheaper Norwegian gas and LNG, has entailed a declining load factor of some large Central and Eastern European pipelines.

[41] Moreover, if this amounted to increasing unit costs of transit, it could also further damage the competitiveness of the pipeline, triggering a vicious circle. However this is probably a minor effect, as competition depends mostly on the price of the gas that uses the pipeline.

65% higher unit costs. It may be noticed that in such case the unit cost, though higher, would still be lower than the stand alone cost.

Under long term capacity allocation with ship or pay clauses transit shippers bear most of the costs: the risk is largely transferred by transit systems to shippers, who in turn would probably move it further towards the end users of their supplied (downstream) markets. This point reiterates the case for long term capacity allocation as a way of shifting some risk onto shippers.

However not all capacity can be booked on a long term basis. Shippers may prefer to keep some flexibility, as pipe-to-pipe competition (and LNG, new unconventional gas production etc.) may drive them to other infrastructure, and booked transit on existing pipelines may fall as a consequence. Further, allocation of too much capacity on a long term basis could hamper the development of trading and spot markets and jeopardise competition. Congestion management provisions reduce the related risk, but also to some extent the appeal of booking long term.

It is also worth noting that similar risks are borne by larger countries or TSOs, but in such cases the risk is often split between domestic (not cross border) TSOs, shippers and end users, and represents a smaller problem.

A typical solution is to limit the revenue cap to a certain guaranteed capacity component of costs, usually comprised between 50 and 90%. The remaining revenue would be raised by a capacity and/or commodity related tariff, with risk falling on TSOs. Examples of this approach can be found e.g. in the U.K., Italy, Poland, Hungary, Ireland.

A reasonable split between the guaranteed revenue cap share of costs and the risk falling on the TSO could be based on the stand alone concept. Following this principle, tariffs of the transit country should never be increased beyond the level of the stand alone cost, calculated on average historical flow, with any further risk falling on the TSO. A capacity and/or commodity related tariff would cover the remaining revenue, if flows occur, with the commodity tariff including fuel costs and losses.

6. Market architecture

6.1 The development of gas markets in North America and Europe

In commodity markets, the organisation of markets is a business itself. Commercial ventures compete to develop market platforms and offer services that are used by market players. Liquidity is probably the best "output" of a market and the main summary definition of its various actual products.

Markets have been usually developed where some objective conditions existed, mainly at the crossroads of commercial routes, or where abundant supplies attracted buyers. Gas has been no exception: markets have been developed mostly at junctions (hubs) of major pipelines and possibly near other important resources (production fields, storage sites, LNG terminals).

In the information technology era, the capability to organise markets has become a more important factor than physical locations where prices are set, with financial market operators often extending their reach to commodities (notably in the New York and London cases). Oil is a typical example, even in Europe, with much organised trading occurring in the London Metal Exchange (LME), even if most products are related to deliveries at ports like Rotterdam.

On the other hand electricity, which has much higher transportation costs per energy unit and a peculiar logistics that make it a comparatively shorter range good (see section 2), has developed a much different market organisation. Its limited long distance trade allows for the development of many hubs, typically on a national basis. Since flows are hardly predictable hubs are virtual rather than physical. Production (generation) is potentially less concentrated, allowing for a significant liquidity even on a relatively small market scale. Any expansion and cross border integration of power markets has started from these specific characteristics.

As discussed in section 1, gas lies somewhere between oil and electricity. Its production is only feasible where allowed by geology; therefore producers are often fewer than in electricity, like in the oil industry. Transportation costs are lower, however, than in power although usually higher than in oil. Jointly considering these features, it can be expected that a lower number of commercial hubs will develop in a given area than in the power market, although possibly more than in the oil market.

If we look at North America, we can see an important number of hubs[42], but four features emerge. First, these hubs have been developed by private industry rather than at governmental or regulatory initiative. Secondly, hubs are very different in relevance; an unquestioned leader has emerged (Henry Hub), with other medium or small hubs used for local trading, with less liquid products. Thirdly, the capacity products and related derivatives are mostly traded in financial centres that are often far away from the physical hubs location (which, as for oil, is mainly a pipeline node).

Fourthly, market centres associated to hubs have expanded their services and actually taken up several functions, which in the European organisation are mostly TSO prerogatives. This has happened out of competitive advantage: for example, a hub where a large number of shippers have positions, with large pipeline connections, storage and possibly LNG resources, is in a potentially better position for the provision of services like gas parking, loaning, balancing, top-up and top-down etc., that have developed as the modern, often virtual equivalent version of the traditional storage services[43].

It is likely that a similar pattern will emerge in Europe. A certain number of hubs, and possibly a ranking, will emerge, with the most liquid ones providing more sophisticated services than pipelines, and the latter providing the physical transportation, co-ordinated by the market centres. Whereas the technical pipeline dispatching may stay with TSOs, the commercial dispatching would in fact increasingly move to the market centres. Several gas companies in Europe are well aware of this perspective and have actively promoted the establishment of hubs and market centres.

Yet, the development of hubs in Europe has often been related to political intervention. Several governments have at least verbally pursued the goal of turning their country (or a specific location within their country) into a European gas hub. Whereas this is a legitimate ambition, it should be clear that it cannot be successfully achieved by all.

In fact, the organisation of markets in Europe has so far followed rather different patterns (Jensen, 2007; Jepma, 2011). In some cases (U.K., Italy and to some extent the Netherlands) the preferred model has been closer to the electricity market, with centralised trading occurring both at the exchange and over the counter. There have been no more attempts establish mandatory pooling as in the original (but dismissed) British power market design. The innovation of the virtual hub, located on a transportation network, has facilitated this approach, with trade progressively moving towards the virtual trading point and away from the less liquid physical locations where it had previously started.

In other cases, hubs have been developed mostly by industry with limited regulatory involvement. These have been based both on virtual points (as in Germany and France) and on physical points (as in Zeebrugge or Baumgarten).

To be sure, it should be clear that having a local gas hub is not necessarily the best policy option to get the cheapest gas supplies, notably if the local market cannot afford it. The risk is clear: governmental efforts to establish "national" hubs may lead to excessive fragmentation of the European market, with too little liquidity in each hub, thereby strengthening the market power of (EU and

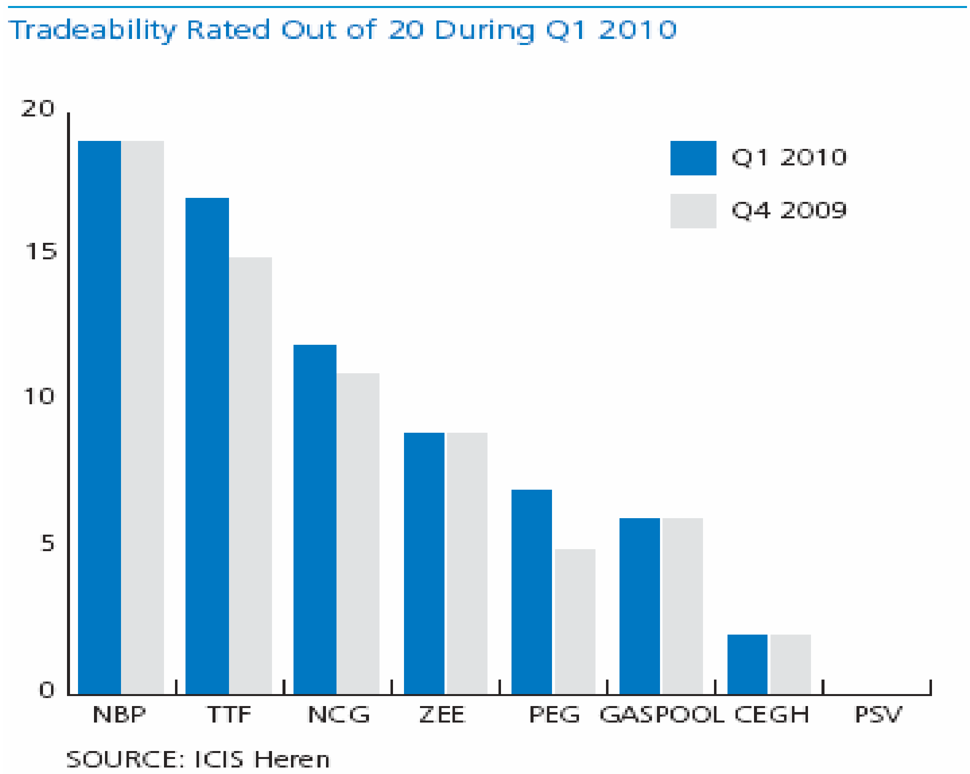
[42] See Jensen (2007), p. 119. For instance, Platt's normally reports prices of six main U.S. hubs.

[43] Huygen, Bos and Van Benthem (2011), section 3.

external) suppliers. This cost adds to the investment and running costs of the hubs themselves. The North American experience also shows that several locations that are not hubs, but closer to cheaper hubs, enjoy lower prices than hubs located farther away from the cheapest sources.

In Europe, decisions about hubs should also consider the opportunities to attain the necessary liquidity, which cannot be artificially produced. Liquidity will appear where the suitable supply and demand conditions will materialise, like pipelines, LNG terminals, storage sites, and production and in the presence of sufficient traders and customers. Liquidity requires capacity, which can only be developed by the ways discussed above (section 4) and – if available but locked by legacy contracts – made accessible by congestion management procedures. Shortcuts may be elusive.

Chart 2



6.2 Connecting market areas

To understand the best options for the European market design, let us see which ones are available.

Some of the available options will be only summarised, as an in-depth presentation has been provided in more details by the MECOS model (FSR, 2011). Whereas the basic options are similar to those outlined by the MECOS, the analysis will somehow differ.

Let us consider a market area, considered as a single entry-exit national or sub-national area with one or more balancing zones. If such an area has few supply sources, poor liquidity and/or lack of competition, with the Herfindahl-Hirschmann index (HHI) displaying values above 5000, it is not likely to become a liquid and competitive market. To improve its liquidity, several remedies may be considered. Let us examine them in turn.

(i) Boost supply competition. If markets are too small or do not have a sufficient liquidity, it may be a matter of relatively tight and/or concentrated supply. Since Europe is surrounded by relatively abundant supplies, and the geographical position of most EU countries is hardly different with respect to such supplies, it means that either capacity is too limited, or is not available, or supply is too concentrated. Governments and regulators may then act to solve supply structure problems first, by increasing competition, for example by forcing industry splits or by a significant gas release program, as some Member States did in the past. It is beyond the scope of this study to discuss how this could be done.

The promotion of competition by some form of gas release has been pursued by several Member States (U.K., Italy, Spain) and to a lesser extent by competition authorities as a remedy for mergers (Germany, Austria), but results have been uneven. Nevertheless, for a small market, it may be inadequate to promote competition and foster liquidity if access to varied upstream supplies is simply not feasible. Thus, this is hardly a solution that could be recommended in general, but it may be useful in a few cases.

<u>(ii) Reinforce import infrastructure.</u> This maybe the best solution, although it will not produce immediate effects due to the (increasingly long) lead times of new infrastructure construction. Furthermore, it runs the risk of causing large and inefficient costs, notably if it is decided on a national basis. We have seen in section 4 how this could be done most efficiently through the joint participation of market forces and government institutions. If enough physical capacity is available but commercially congested and supplies are concentrated, any further capacity increase would be useless and inefficient: existing capacity should be freed first. Moreover, increasing capacity is sometimes a necessary but may not be a sufficient condition. It depends on which infrastructure is improved; for example LNG terminals have recently provided access to relatively liquid markets, but in other cases the dominant positions of local as well as remote suppliers may actually be strengthened.

An important lesson of the North American experience is that relatively abundant capacity allows for easier competition. However, this capacity should be “effective” and it should actually connect sources and markets. If this is not provided by interstate pipelines, like in North America, the solution lies in the definition of LTC on routes combining several TSOs, along the lines suggested in section 4 above, rather than through initiatives by individual Member States which may fail to address the necessary entire routes to sources.

<u>(iii) Connect to a larger, more efficient and competitive market</u>. This can be done by opening up existing but commercially congested capacity. This may be particularly effective for countries with relatively large but “fully booked” interconnection capacity. The way to do it will be discussed below. This can be called the “shopping mall” approach, as it recalls the option of citizens living in a smaller town where they cannot find the goods (or the prices) they would like. So, if they want better deals they can visit the shopping mall of a larger neighbouring city. If this is the preferred approach, the town administration's best policy is to improve connection with the existing neighbouring shopping mall, rather than promote its own.

This approach has the disadvantage of losing some national independence[44], but it is simple and can be attractive and efficient. In fact, a typical example of its application is the Irish Republic, which is in fact attached to the U.K. market through an abundant and flexible connection. In this way the Irish system can “shop” in its biggest neighbouring market as much as it wants, while still keeping its own balancing and tariffs system.

<u>(iv) Merge with another market area so that the market size increases.</u> This would presumably require the establishment of at least a common grid manager, operating like an ISO, with tightly co-ordinated gas day procedures and common balancing practices. It is most likely that in such case an inter-TSO tariff compensation mechanism should be established, which is not technically difficult, but

[44] In the example, the administration of the smaller town cannot, for example, decide the working hours of the shopping mall, but must accept those set by the larger city.

it may prove politically hard if some participants feel that they are discriminated or if cross-subsidization arises (see section 5.3).

For this option, different experiences have been reported. It has been noticed (Sisman, 2011) that the recent merger of German market zones has entailed a reduction of total offered capacity. In France, the proposed merger of the Northern and Southern GRT zones would require substantial costs, which is just another way of raising the same point. On the other hand, E-Control, the Austrian NRA, has reported that co-ordinated operation of five Austrian TSOs has led to a capacity enhancement (GRI-SSE, 2008).

Moreover, language and legal barriers may create co-ordination difficulties[45]. The implementation difficulties can be substantial, particularly, between partners from different Member States. It is easier if a natural leader exists, for example a larger TSO or an incumbent supplier, which is ready to act as market maker in the new merged market, or as a balancing shipper in interconnections. In such cases, however, the risk is a limited improvement of the competition in the merged system. It seems that in both cases - and more seriously in case of a full merger - a strong political will is necessary to overcome opposition by TSOs with a national rooting and by those NRAs, representing users who may suffer from cross subsidies.

If the expected impact of the merger is a more competitive market, and hence lower prices, the same resistance may materialise as against a gas release programme. This is to be expected, but the highly technical content of the merger make such resistance easier. Yet, the prize for the merger could be the attraction of new suppliers and investments into the concerned countries, but this is often of more interest to consumers than to suppliers. However, doubling or tripling the market size does not always ensure an increase in its competitiveness, particularly if all competitors lean heavily on the same external sources.

A solution cannot be found for a general case. Depending on the conditions of networks, the pattern of gas supply, the presence close and more remote connections, and the political attitude towards national control over market development, a different choice may be preferred. From a European perspective, it is important to remind that in any case some hubs are bound to grow more and to become much more liquid than others. Indeed, a too large number of hubs may reduce overall liquidity, entail fragmentation and ultimately favour external suppliers. For example, there would be fewer arguments to move towards hub-based pricing and away from oil indexation, as a current but not easy path seems to be suggesting (Stern, Rogers, 2011). In other words, if the chosen market design entails a slower hub liquidity growth, the points of those who resist against switching to hub-based prices would be strengthened.

In North America, the smaller hubs survive for “local needs” and players know that if price differences grow above certain thresholds they can (virtually) move their trading to the larger ones, where fixed costs of participation are more costly but prices (net of transportation costs) may be lower and products more flexible and tailored to the player's needs. Even in Europe, it can be expected that in the long run only a handful of hubs will survive, with possibly on or two continental leaders. In fact, the reduction of the number of hubs would be an indicator of successful market integration rather than the opposite.

An obvious question arises about the nature of hubs. Can virtual, entry-exit type hubs have similar connections as the typical North American physical hubs? Are future hubs all virtual, or is there a room for physical ones?

[45] The MECOS model has proposed the “trading region” approach, which is a variant of the previous case where only the “higher level” part of the network is merged and is used as the platform for the virtual hub, whereas balancing remains in the lower level networks, known as “end user zones”. This approach requires less co-ordination than a full merger and may be technically easier and politically more acceptable

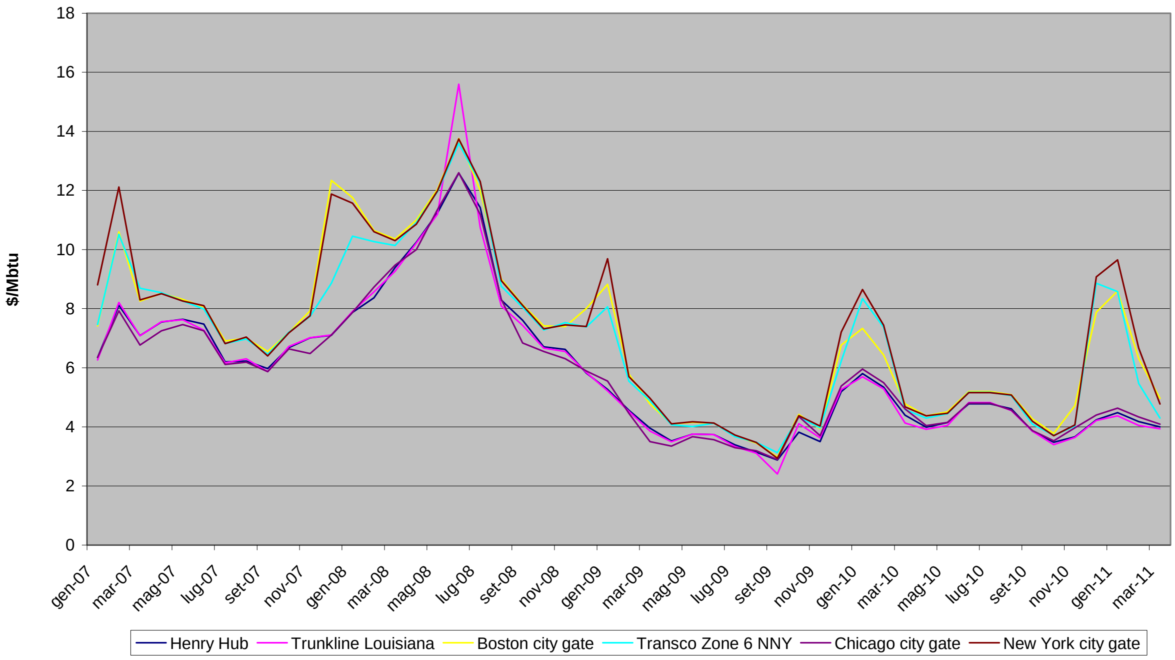
The answer to the first question can be obtained starting from the discussion of entry exit tariffs (section 5). It has been noticed that for major, long distance connections a properly designed entry-exit tariff is likely to be very similar to a distance based tariff. Therefore, the “cost distance” between hubs should be approximately the same as under a distance based tariff. In equilibrium conditions with reasonably good competition, prices should follow long run marginal costs; they cannot be permanently below such costs if shippers must pay TSOs for transportation. Otherwise, sooner or later the TSOs will collapse. Only in the short term prices can get closer than transportation costs, as players may exploit already paid capacity and even the direction of flows between hubs may be uncertain. This has recently happened between adjacent virtual hubs of North-West Europe, however this is not the case when hubs are significantly far apart, as the US experience shows (Chart 3), and cannot be the rule, as transportation costs must be recovered sooner or later.

As for the second question, it seems likely that trading will move from physical interconnections to virtual hubs, if the latter are available. This has happened in all markets where a virtual hub has been introduced. Furthermore, if interconnection capacity is bundled, “flange” trading at borders would become impossible. This has a technical rationale; in most cases border points have no technical or economic meaning, but are just a conventional point of a pipeline. It is perfectly rational if such trading disappears. The case may be different with regard to external borders and LNG terminals, but even in such cases trading has shown a tendency to move toward the more liquid, virtual hubs.

Whatever the basic liquidity, it will improve if several trading points are practically merged into one, as happens with the introduction of a virtual hub. Yet, it is worth recalling that, just as not all physical interconnections can become hubs, the same is true for virtual market areas. This does not preclude their possibility to obtain the best from the integrating European market.

In some cases, forcing hubs to be virtual and relating them to an existing or newly developed network may slow down rather than speed up the development of market hubs. For example, it may be difficult to replace the Baumgarten hub by a virtual one, as this would possibly require some kind of merger of neighbouring Member States’ markets, which may be a lengthy process. Another example could be in the Balkans, where a natural location for a physical hub (outside the EU) could be in the Istanbul area, where several major pipelines interact near an LNG terminal and a storage site. Such hub could benefit the neighbouring EU Member States as well, even though it would not be organised as an entry-exit market area.

Chart 3 - US Hub prices (Source: Platt's)



6.3 The relationships between hubs and market areas

6.3.1 On persistent congestion

It has been taken for granted so far that, as requested by European legislation and summarised by ERGEG's definition, all market areas in the EU will be entry-exit zones, connected by auctions.

Such definition is not at odds with the EURAM. As we have seen so far, entry-exit tariffs, if properly determined, would not hamper the development of the integrated market.

Usually the entry-exit system would also entail an entry-exit capacity allocation system. In such systems entry capacities may be allocated separately from exits. To understand if this is a problem, two types of exits should be considered:

- exits to domestic end user zones of each entry-exit area: These are normally uncongested. If (as it usually happens) exit capacity is related to the end user (rucksack principle) and transferred in case of supplier switch, there is no exit congestion and any non discriminatory allocation method is suitable;
- exits to other systems: If these are "bundled" with the entry into the "next" system we are back to the problems discussed in subsection 4.2, where interconnections were analysed. In fact, if an exit from a system must be booked (or offered) only in connection with entry into the next, the interconnection path is restored as the object of capacity allocation[46].

Therefore, capacity allocation between market areas is not a problem even if organised as entry-exits.

[46] This could be a single physical pipeline, or a virtual system of adjacent pipelines providing similar services, e.g. connecting markets D and E in Graph 2 of subsection 4.2.

It may be recalled that under a properly working capacity market, as described in section 3, capacity is likely to be relatively ample (Proposition 4). Such proposition has an important caveat and a corollary:

Proposition 4.1. Under economically efficient behaviour, congestion between market areas will never vanish; therefore prices will not permanently align.

Proposition 4.2. If capacity is large, auctions would be often redundant: their outcome would yield zero prices.

To understand Proposition 4.1 the reader may want to consider Graph 3. Increasing capacity at any interconnection involves a growth in costs, presumably at higher than proportional rates. If at an early stage marginal capacity costs decline due to economies of scale[47], this is reverted as economies of scale are exhausted. New pipelines are probably costlier due to increasing permitting difficulties and the unavailability of the easiest transit areas. Yet, more capacity has benefits through the reduction of congestion costs: for example, congestion reduces market liquidity and competition, triggering the "deadweight" welfare losses of monopoly or other less than competitive markets (or even capacity rationing, in some cases). However the marginal benefits of more capacity diminish as congestion is increasingly reduced. this happens steeply at first, and may even vanish beyond a certain level.

The economic optimum capacity is at the minimum total cost, which is where the marginal benefits of reducing congestion equal marginal capacity costs. If this equilibrium is achieved by market forces, the benefit of reducing congestion is measured by expected market price differences. In a market like North America, shippers would bid in open seasons to increase capacity if they think that they can exploit it by reaching higher priced markets[48]. Hence, congestion would never disappear completely, and it is likely to appear, notably in peak demand periods, through the seasonal cycle, as clearly shown in Chart 3 above. Prices in Northern US hubs are well aligned to Southern ones in summers, but far higher in winter when capacity gets congested.

However if public authorities are allowed to enter the capacity market, as it is plausible in Europe, they could take into account the deadweight losses of reduced competition in their decisions. This would lead to a higher valuation of congestion costs (in Graph 3, a higher and/or steeper congestion cost curve) and hence to a higher optimal capacity.

Whereas the EURAM has suggested that public authorities could intervene into a single capacity market platform alongside private bidders, so that a basically market based mechanism is preserved, they may also intervene by including increased returns on investments, lump sum transfers, capacity payments to national TSOs or other market players, and direct investment, provided they are compatible with state aid provisions (which is far from obvious).

Yet, congestion is most likely to remain at least during seasonal peaks in mature systems. Moreover, the long lead times of demand and supply adjustments in energy markets will easily entail situations where capacity is "too large" (as it was planned with a larger past or future market in mind) or temporarily congested. Thus, price alignment would in general be limited. Any assessment of the market integration effectiveness should indeed consider transportation costs[49].

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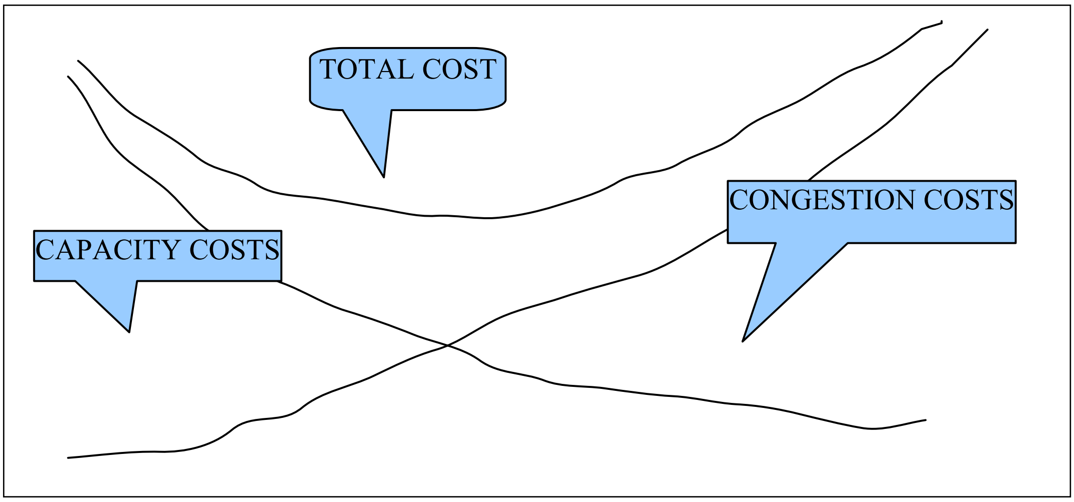
47 In other words the 2nd derivative of the cost function is negative with respect to capacity

48 In no way this decision could be driven by short term auction results. Short term congestion is just a very limited indicator for bidders that must form price expectations over long term as necessary to repay the investment costs.

49 For example, it can hardly be expected that in the long term wholesale prices would be the same in the U.K and in Romania. Since willingness to pay is probably higher in the former due to higher per capita income, the proof of ineffective market integration would rather be the case where Romanian prices are higher than U.K.'s even though total supply costs to both countries is similar.

Graph 3



The corollary (Proposition 4.2) is that, since capacity is likely to be abundant in most cases, auctions would likely yield zero prices. This may seem obvious, but it implies that auctions could never be a permanent way to remunerate TSOs. Otherwise, TSO revenues would end up coming mostly from exits and – since exits to other systems would be bundled to entries into (and auctioned with) them - these costs would fall mostly on domestic exits. This would be a problem for systems where a significant part of transportation occurs across the border (see the Annex to section 5) and may trigger serious protest from local consumers.

For these reasons, the role of auctions would actually be limited in the EURAM – as it is in North America. TSOs would be mostly remunerated under LTC, with contracts granting them most of the required income, as discussed in section .3. Normally such capacity would be paid by regulated tariffs, which should be cost-reflective.

6.3.2 On auctions

Whatever the role of auctions in the target model, it is clear that in general they provide the best capacity allocation mechanism that market players would be willing to use, wherever capacity is scarce. In the electricity sector, a long discussion has been held about the relative merits of explicit and implicit auctions (see e.g. De Vries, 2004) , and also about the different ways implicit auctions can be arranged, including market coupling, either organised as price coupling or volume coupling; market splitting; and locational marginal (also known as nodal) pricing. Some attempts have also been done to analyse the possible extension of implicit auctions to gas markets (De Joode et al., 2007).

Unfortunately, there is no such experience in natural gas markets. Use of explicit auctions has been significant (but not dominant) in gas capacity markets and often successful in some cases, notably in the U.K. (McDaniel, Neuhoff, 2002; Logue, 2010). But even in this case, long term marginal costs, the traditional base of regulated prices, are used as reserve prices for the auctions. In other cases, auctions have been mostly launched by TSOs at their discretion, with differentiated and fragmented capacity products, leading to little improvement in market transparency and efficiency: this may be the reason why several regulators in continental Europe have been less enthusiastic. They fear that incumbents may control markets by ensuring control of an essential facility at a relatively low cost, and have preferred prorating (or some form thereof) as a way to open capacity to market newcomers.

Auctions remain in principle the most efficient way of efficiently addressing congestion, and are most useful as an essential feature of congestion management. This is extremely important in the practical case of present markets, although in the target model it is expected to play a reduced, mostly deterrence role. Under a market based CM procedure, any unused capacity[50] would be lost (UIOLI) or better sold (UIOSI) to the highest paying bidders (in an explicit auction); or to the best bidders in the "coupled" destination market (under an implicit auction).

The main theoretical advantage of implicit auctions as developed in the power sector are that capacity is automatically transferred to the best bidder in the commodity market, that is to the supplier who is in the position to serve customers at the best price. This should automatically exclude the feared risk that any market player hoards capacity in order to supply the market at higher prices[51].

The case for the introduction of market coupling has been often referred to (I) lack of price alignment between hubs and (II) existence of adverse flows, that are gas flows from pricier towards cheaper markets, against economic logic (Neveling, 2011). In the current European gas markets, price differentials are often hidden: for example several Eastern and Central European countries have higher prices than Western ones. Yet these are not formed in open markets, but through oil-indexed long term contracts, for delivery by suppliers with large market power (or even monopolists). The lack of flows from the cheaper markets, leading to price alignment, is often attributed in part to the obligation stemming from take or pay clauses, and partly to difficulties in getting the (often virtual) capacity necessary for the implementation of (mostly backhaul) supplies from Western sources. The former problem is likely to be solved as demand grows and existing contracts are phased out, though it may be a long process. However a clear tendency towards hub based and away from oil-indexed prices has been noticed (Stern, Rogers, 2011). As for the lack of backhaul capacity, this is in principle a relatively simple matter that regulation should be able to solve even without auctions, but as an essential part of the CM mechanism.

On the down side, implicit auctions involve significant transaction costs, particularly as they are new for the gas industry. For example, in power markets they are usually applied to markets with gate closure, whereas gas markets are accustomed to continuous trading. So any adaptation would be costly. Further, costs would be related to the establishment of the market offices in charge of arranging the coupling, by countertrades or other measures.

The physics of gas transportation is another reason why market coupling for day ahead markets is less likely to play a large role in gas. In the power sector where market coupling was first applied, commodity trading focuses at day ahead because that is the optimal point to schedule generation. This is not the case in natural gas, which can take days to reach the markets from the original sources. Therefore, day ahead markets in large continental markets may have a more limited role[52]. It may be worth reflecting on the fact that in the U.S. most market transactions involve monthly transaction and happen within a scheduled week every month, known as the "market week". Accordingly, many pipelines require monthly balancing only. A forced restriction of continental gas market operation to the daily dimension may entail a loss of technical efficiency.

The main difficulty however is that market coupling and other implicit auctions require organised and liquid markets in all participating market areas, which is not necessarily everywhere the case as noticed above. Moreover, if only a handful of liquid hubs remained in Europe, the problem of allocating cross border capacity would be different from that of connecting adjacent areas. Obviously,

50 The discussion of how to define unused capacity is in practice very important and widely discussed at present in the EU, due to its efficiency as well as equity impacts; but its details go beyond the scope of the target model discussion

51 In multiple power markets there is a further benefit: the algorithm would also track the best allocation of capacity among the nodes, which cannot be defined ex-ante as it is driven by the physical laws of electricity transmission. This benefit would not be applicable to gas markets where capacity can be defined ex-ante. This point was highlighted by Laurens De Vries in a private seminar.

52 This may not be the case of relatively small and isolated gas markets, relying on significant local resources.

in the former case it would hardly be a problem, with abundant capacity allocated to applicants, as in the mentioned U.K.-Ireland case.

Others argue however that market coupling does not require liquid markets but may help providing liquidity, quoting the example of some less liquid electricity markets (APX-Endex, 2011). However, market coupling can redistribute resources, but cannot create them. Liquidity can spill over to an adjacent, less liquid market if the former is "very rich", so that it is not substantially "impoverished" by ceding part of its resources to a neighbour.

To sum up, the costs of implementing market coupling should be traded off against the benefits of implicit auction. This trade-off may be represented by a picture like that of Graph 3, with resort to market coupling on the horizontal axis. Curves would have a different meaning. Increased use of market coupling would increase allocative efficiency, but involve some substantial transaction costs.

For these reasons it cannot be predicted whether implicit auctions will be used in the target model, let alone in generalised manner. It is worth recalling that, whereas North America has been at the forefront of adopting and developing implicit auctions for the power market, it has so far refrained from extending them to natural gas[53]

In any case, the contribution of implicit auctions would be presumably limited to day ahead markets, where a small, though important part of trading would occur. An important role for market connection would also remain with other short and medium term auctions (for capacity products up to 4-5 years), where some problems similar to those of LTC allocations may arise. In particular, market players may be interested in multi-country routes (or link chains) rather than in single interconnections, and may fear to bid for a connection if they are not sure to get the "next" one.

On the other hand, auctions for link chains clash with the problem of choosing the relevant links without unduly straining the market. Tentatively, such auctions may follow the same links chosen for LTC through steps 1-4 of the open subscription period suggested in section 4. This is consistent with the natural development of capacity product auctions, where shorter term products should be allocated after the longer term ones, and using any capacity which is left from them. Auctioning of individual interconnections would then be available on a day ahead basis.

However, in medium term auctions, difficulties would be more serious than for LTC rights, where any possible conflict between sources could be eased by the development of new capacity. In the technical reality, capacities are not set by the size of pipelines and compressor power only, but may change depending on the interaction of pipelines. Interdependence may be high and agreement on the flow model used to define capacity may not easily be reached. The risk of disputes may suggest less ambitious solutions, like the requirement to coordinate auctions, possibly with prevailing downstream interconnections be offered after long term ones; and to sell conditional products, allowing bidders to withdraw if they do not manage to win the necessary downstream capacity.

However serious these issues may appear in theory, it should never be forgotten that markets will find their own solutions, alongside those suggested by regulators, as has happened in North America. Even in the relatively advanced and liquid North-western EU market, the last two years have seen a much more effective capacity market, which has actually achieved remarkable price alignment without much regulatory intervention. Capacity has been mostly traded on secondary markets, and swaps and the diversion of LNG tankers between terminals has done the rest.

[53] Although it is hardly an economic rationale, it can be noticed that the much stronger European electricity industry has to some extent managed to extend its own paradigms towards natural gas restructuring, whereas in North America the primarily state governed power industry has remained much weaker and is confined to a much smaller reach, notably after the Enron collapse. This is a contrast with the more federal oriented gas industry, which still linked substantially to the politically powerful oil industry.

7. The consequences of the EURAM for the European Network Code process

The most important goal of the Gas Target Model study is to provide guidance to the process of drafting the European Network Code, indicating its main priorities and how the various parts of the process would interact. This is important, particularly, in the early stages of the establishment of the Framework Guidelines, which require the greatest involvement of NRAs, ACER, ENTSOG, the European Commission, and assisting Committees.

It is clear that the driving requirement would be the integration and connection of market areas, which should not be confused with the establishments of hubs and organised markets centres.

The connection of markets should be at first achieved by freeing up currently frozen capacity, mainly through congestion management procedures. These are not a fundamental feature of a gas target model, but they should still be present to play a secondary and deterrence role. However, they are considered crucial for the transition towards the GTM, as outlined in several points of the present paper, which pictures a world where TSOs offer, ensure and manage capacity as their main and exclusive mission. In particular, congestion management should include the availability of backhaul capacity along lines with a prevalent flow. The discussion of how to organise market based CM is out of the scope of this study.

Next to CM is the elimination of any further barriers that have in the past slowed down cross border trade. This requires at least the harmonisation of.

- cross border allocation practices through the generalisation of Interconnection Point Agreements and Operational Balancing Agreements;
- standardisation of at least some capacity products;
- energy units;
- standard formats;
- the gas day and its main deadlines;
- any remaining interoperability issues.

Although these are often highly technical issues that may not raise political enthusiasm in the same way as unbundling, their speedy solution is probably just as necessary. Again, details go beyond, but a detailed scoping and roadmap should be defined within the ENC process.

A major way of connecting markets in the EURAM would be through the development of an efficient capacity market. This would be greatly facilitated by the development of TSO unbundling along the lines of the Third Package and possibly through the choice of the ownership unbundling option, as several Member States have already done and financial and capacity markets would foster. However, this paper has stressed that a generalisation of full ownership unbundling is not necessary for the implementation of the EURAM. It rather emphasizes the push on a more competitive, transmission development oriented TSO behaviour.

It goes without saying that this should be one of the NRA's main priorities, as an effective ITO regulation could possibly trigger such behaviour, or even the sale of TSOs by market incumbents, and thus a reorganisation of the transportation industry, with mergers and acquisitions, as has already occurred in the gas supply business.

The development of efficient infrastructure, as well as upstream (E&P, LNG and pipeline) investment, would also be greatly helped by the sale of bundled and co-ordinated long term capacity, allowing shippers to ensure access from sources to markets. Given the current structure of European TSOs, it has been suggested to foster this process by developing a platform for LTC rights, to be structured as an open subscription period open to all market players as well as to other TSOs, including those mandated by public authorities for the fulfilment of PSOs.

Such process would resemble open seasons rather than auctions; it could be repeated at a certain frequency (e.g. every two years) and lead to the development of new capacity if necessary, in addition to that fostered by normal market processes through TSO-driven open seasons. This would certainly require a significant effort by both the regulators and the TSOs. It would not be against the current development, but could be rooted in the experiences of the TYNDP, the FG on capacity (which currently offers very little guidance on this) and the Guidelines of Good Practice on Open Seasons.

A further pillar for new infrastructure development, the maintenance of existing systems and its efficient use, would be the tariff structure. The Third Package offers some detailed requirements on tariff methodologies. It has been shown in this Chapter that the entry-exit tariff model would be fully consistent with a continental and efficient capacity market, mostly based on regulated tariffs. Yet the risk of transit flow exploitation remains serious, as is recognised by the Third Package, and should be tackled.

A dedicated FG is therefore probably necessary to define criteria for costing and tariff updating - even though these are already reasonably advanced thanks to the spread of best practices among NRAs - and for tariff structures, which have been not very transparent so far. The FG may define some general criteria (or Guidelines of Good Practice), which may be subject to systematic monitoring by ACER or the EC, without any loss of national sovereignty on tariffs and methodologies as confirmed in the Third Package, but also with the identification of benchmarks where the EC may take action in case of discriminatory tariffs violating the provision of the European Regulation 713.

The ENC in co-ordination with other important current processes (EMIR, REMIT) may also define the criteria for a minimum playing field of market operators, and possibly a set of minimal products for market trading. However, the process should avoid any top down definition of political or regulatory criteria on which hubs and organised market centres should be devised. As noticed in section 6, a main message of the EURAM (taking up the main lesson of North American experience) is that such hubs will be very limited in number and their detailed market design would be the product of market forces. Thus, a subsidiarity principle should prevail in hubs decisions. The high risk of political interference would be in fragmenting liquidity, which would enhance the market position of (mostly external) suppliers vis-à-vis the European industry and its consumers.

Likewise, a strict subsidiarity principle should rule the way markets are interconnected, starting from the awareness that even if market zones can be organised as entry-exit systems, this does not mean that any of them could also become a liquid market. On the contrary, a decision should be made on a case by case basis, with a view to enhancing market competitiveness, on whether to connect markets by

- expanding physical capacity to attach less liquid markets to larger ones and/or to new supply sources;
- merging the areas, possibly by pooling the higher level part of their systems;
- linking the areas by auctions, including implicit ones, with market coupling as the natural candidate.

Again, current FGs and the related ENTSOG work would be fully consistent with this approach: Auctions as a permanent CM tool would be needed anyway, and congestion is never going to entirely vanish. However any solution has its proper costs that should be considered against the assumed benefits of greater integration. The analysis should consider in particular the contribution of market based solutions, including swaps, LNG re-routing, and the secondary capacity market, which are likely to further develop as unbundling progresses, and could be fostered by appropriate measures. Further harmonization of technical rules and other CM provisions that are currently under discussion may greatly enhance the connection of market areas.

Finally, the balancing provisions, though more technical in scope, should be devised in a way not to foreclose potentially efficient market design options, consistently with the above considerations on hubs, market zones and their connections. For example, it should be possible to purchase balancing resources from other market zones and hubs. Market based balancing should not be a way of devising a restrictive market design, nor of forcing mandatory pools.

It seems that in the target model devised by the current draft FG, balancing responsibilities are significantly moved from TSOs to shippers. This would however require the availability of balancing services and resources, which cannot be in all shippers' portfolio: otherwise balancing may become a new essential facility, which gives market power to its holders. In the EURAM, as in North America, balancing services are often provided by market centres: this is just another reason to allow an efficient development of the hubs, and not an artificial one. Such tendency does not exclude that pipelines could still offer balancing services, but this possibility will be shrinking as TSOs lose control of the gas they transport, possibly including the linepack.

Yet, balancing requirements in the EURAM are a potential tool of pipe to pipe competition. Pipelines with adequate resources may well offer easier balancing conditions to attract customers.

8. A summary and comparison of the MECOS and EURAM models[54]

The MECOS (FSR, 2011) model is based on three pillars:

1. Enable liquid and competitive markets
2. Connect markets
3. Secure the operation of markets

The three pillars are underpinned by the promotion of efficient economic investments.

1. In the MECOS each entry-exit zone would be also a single price zone, where trading on a spot and forward basis would occur so that price signals are provided. If the market in a zone is not adequately liquid and competitive, it should improve its liquidity, by either developing new supply infrastructure or by merging with another hub so that a minimum market size and suppliers' abundance is achieved. The merger may be full (including for balancing and tariff purposes) or limited to a higher level trading region, with balancing and retail trade left to lower level zones.
2. Markets would be connected up to the point where either prices are aligned or the existing interconnection capacity is fully used. This would be achieved first of all by the introduction of enhanced supply and trading conditions, based on further harmonisation of market rules, the gas day and its procedures, gas quality, and on reinforced congestion management provisions. Markets would be connected by auctioned long, medium and short term capacity products. If pilot implementations are successful, day ahead markets may be also connected by market coupling.
3. The enhanced trading conditions would also include the set-up of coordinated and conditional auctions for long distance transport (*link chains*). Long term capacity contracts would be allowed and could use the link chains. Moreover, in order to ensure security of supply, TSOs should be allowed to book and pay “fallback” capacity in other systems, to be used in case they cannot use their usual supply routes.

All pillars would be underpinned by realizing economic investments directed at improving interconnections and overcoming congestion between and within markets. The MECOS includes proposals for the definition of economic investments, based on open seasons and benefits from reduced price spreads between market zones.

The EURAM, broadly inspired by the adaptation of the U.S model to the EU framework, pursues three main objectives:

[54] The comparison is provided for readers' convenience, however the summary of the MECOS are the only responsibility of the author.

1. The development of ample supply and transportation capacity
2. The development of hubs as allowed by market forces
3. The connection of market zones

The first objective is pursued by promoting the most effective unbundling of TSOs from supply affiliates, with a view to fostering the supply of capacity. This may require the establishment of a common European platform for long term capacity, where market players and public institutions may bid through a multiple step process for the reservation of capacity on required routes, offered by TSOs on a competitive basis. Wherever capacity bids justify it, this process would also lead to investment. Due to their lasting relevance, harmonised tariff criteria would be set up and monitored at a European level. The share of total capacity that could be reserved long term would be capped so that medium and short term capacity trade may develop.

Hubs would be developed where justified by market forces, but not every market area would be a hub. Prices would be mainly defined in the emerging dominant hub(s), with minor ones related to them by regulated tariffs or auction prices.

Market zones would be connected, at first through effectively reinforced congestion management provisions and harmonisation of market rules, the gas day and its procedures, and gas quality. Auctions (subject to tariffs as reservation prices) including implicit ones could be used as an efficient way of connecting markets, but their use would be probably limited to cases where allocation at regulated tariffs and secondary trading would create congestion.

The main areas of agreements of the models are:

- the need for harmonised (or enhanced) trading conditions including effective congestion management;
- the need to allocate capacity on a long term and long distance basis by providing linked chains to willing shippers, possibly with participation by foreign TSOs pursuing public objectives;
- the efficiency of connecting market areas by auctions, including implicit auctions if they can be proved feasible in gas markets.

However, the models have a rather different emphasis on how to ensure efficient investment. The MECOS is based on objective criteria defined by regulators, while the EURAM privileges the promotion of a market based capacity market, though with the participation of public bodies as well. Further, auctions are seen as a generalised connection tool in the MECOS, whereas the EURAM expects them to play a more limited role.

As a consequence of this vision, although several aspects of the ENC could be the same, priorities would differ. The MECOS stresses the need to develop and merge market areas everywhere. The EURAM privileges the connection of market areas between them and with hubs through abundant capacity, which may be sold at regulated prices if not congested. Under the MECOS, NRAs would devote significant efforts to zone mergers wherever hubs are not liquid. Under the EURAM, they would rather focus on market rules harmonisation.

Further, the MECOS sees a mostly regulated or planned development of capacity, whereas the EURAM favours market developments integrated by public intervention, with a role for competition between infrastructures. At EU level, both models would start from the existing Capacity Allocation FG. However, the MECOS would generalise the implementation of auctions and support efforts for the introduction of market coupling into gas markets. The EURAM would extend the CA FG to create a common platform for the capacity market, to be linked to the regulation of open seasons. Further, the EURAM would suggest drafting Guidelines of Good Practice on tariffs.

The models clearly disagree on several issues. In particular, he MECOS regards any market areas as bound to become a liquid virtual hub or part thereof and denies that trading in a cross-border market may be a suitable option. The EURAM claims that few hubs may be expected to survive in Europe, supports the greatest efforts in the opening up of full access to such hubs by any other market zone, and warns against any political decision to develop inefficient hubs.

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