CONVERGENCE OF NON-DISCRIMINATORY TARIFF AND CONGESTION MANAGEMENT SYSTEMS IN THE EUROPEAN GAS SECTOR

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1 Introduction and Executive Summary

The European Commission has commissioned this report from *The Brattle Group*. The purpose of the report is to:

- Describe the European gas transmission network and the physical flows, including capacities and potential points of congestion.
- Recommend tariff principles that respect the Gas Directive.
- Develop principles for capacity definition, allocation and congestion management.
- Provide recommendations concerning the financing of new infrastructure within the liberalised internal gas market.

We have cooperated closely with Member State authorities and regulators and the European gas industry. We have conducted meetings and discussed many issues with the Council of European Energy Regulators (CEER), Gas Transmission Europe (GTE), and the German authorities/administration. We have also enjoyed useful informal discussions with individual Member State regulators and industry representatives. Our study acknowledges and aims to complement the ongoing work of CEER, the Madrid Regulatory Forum, and Member State authorities.

We begin with a description of the physical system (Section 2), identifying the major transportation routes, showing storage capacities, and assessing the potential for congestion in Member States. We then discuss alternative definitions of firm transportation service (Section 3), compare alternative tariff methodologies (Section 4), and discuss alternative ways of defining capacity and their implications for flexibility and congestion management (Section 5). Section 6 describes alternative mechanisms for capacity allocation, assessing their implications for congestion management. We then discuss alternative approaches to congestion forecasting (Section 7), and to the financing of new infrastructure (Section 8).

Description of the Physical System

- The extent of *cross-border physical congestion is currently rather limited* in the European high-pressure gas transmission system. However, this conclusion cannot be extrapolated to congestion within individual Member States.
- Some of the maximum flow rates published by GTE contain *significant errors*, suggesting that there has not yet been sufficient verification of information published by TSOs. Published maximum flow rates should therefore be *subject to further careful verification*.
- Published available capacity figures should be calculated according to *agreed standard methodologies, and subject to careful verification*.
- To ensure that appropriate resources are devoted to these calculations, they should be certified as correct by a senior officer of the TSO.

Firm Transportation Service

- No pipeline can provide an absolute guarantee of physical delivery, because there is always a possibility of mechanical problems, such as compressor failure, that would prompt interruptions. Physical firmness is inherently a probabilistic concept: what a pipeline defines as "physically firm" service is in reality service with a very low probability of interruption.

- The optimal degree of physical certainty for a TSO's firm service depends on a balancing of costs and benefits. Beyond a certain point, the incremental costs of increased certainty outweigh the incremental benefits. Moreover, different consumers place different values on incremental certainty.

- Financial guarantees (*i.e.,* contractual provisions specifying compensation for non-delivery) can provide an effective complement to physical firmness.

- Some TSOs define firm capacity by reference to the reservation of physical capacity along the contract path. Four factors may make this an inappropriate definition of firmness: i) physical capacity reservation may offer little incremental firmness while raising costs significantly, in a manner not desired by customers; ii) financial mechanisms can help meet customer desires for certainty at lower cost, iii) it presents a potential barrier to competition, and iv) it risks discrimination against smaller shippers, especially (but not only) in immature markets.

- An alternative approach involves "total network service" where the TSO taps the system's ability as a whole to transport gas. This ability flows from the properties of "meshed network operation", *i.e.*, the synergies between different flows, as well as the TSO's access to tools such as linepack, storage, interruptible transportation contracts, and operational balancing agreements.

- Examples of "total network service" include US practice, the capacity buyback system of Transco, the requirement under the new VV Gas for German TSOs to provide backhauls along unidirectional pipes, and the "hub-to-hub" service provided by EnCana in Canada.

- We recommend that TSOs should be required to provide network service, at appropriate tariffs, while ensuring a continued high level of security of supply. Our recommendation implies that (i) transfer capacities should be *estimated based on modelling of physical flows,* (ii) TSOs should be required to publish a *full assessment of their network capabilities* under different operating conditions, (iii) TSOs should be encouraged to *offer financially firm transportation rights,* (iv) *network service tariffs should reflect the physical flows that a contract entails, rather than physical capacity along the contract path*.

- In a mature market with liquid forward trading of gas over appropriate timeframes and at multiple hubs, shippers may be able to "self-provide" network service. However, newly liberalised European gas markets do not yet have liquid gas trading. Moreover, in many cases the TSO will remain uniquely well-placed to efficiently combine the variety of available tools.

Alternative Tariff Types

We distinguish explicitly between two aspects of a tariff system: *tariff type* and *capacity type*. It is possible to define capacity one way, and to set tariffs another way. For example, in both Ireland and the UK the *tariff* type is entry-exit, *i.e.*, the charge for transportation service is the sum of an entry charge and an exit charge. However, in Ireland *capacity* is point-to-point: shippers hold contracts that specify start and end-points, with no flexibility to change one or the other. In the UK capacity is entry-exit: shippers hold separate contracts allowing them to inject and withdraw gas at specified entry points regardless of the destination of the gas, and to withdraw gas at specific exit points regardless of its origin. Table 1 provides some examples of different combinations of tariff and capacity types seen in practice.

Table 1: Examples of Different Combinations of Capacity and Tariff Types

		Tariff type		
		Distance-based	Entry-Exit	Postal
Capacity type	Point-to-Point	Germany	Ireland	Spain
	Entry-Exit		UK	For electricity, most EU TSOs
	Postal			Some US pipelines

Our discussion of tariff types does not consider capacity types, which we discuss in a separate section. We focus on the relative merits of distance-based tariffs (charges proportional to contract distance) and entry-exit tariffs.

- Criteria for the choice of tariff type include cost-reflectivity, the promotion of competition, impact on long-term investment, transparency, and "articulation" (*i.e.*, the ease of combining a given tariff type across multiple TSOs).
- Cost-reflectivity has fundamentally different implications depending on projected system growth and the existence of actual or prospective congestion.[1]
  - With growth or congestion, capacity is scarce and tariffs face the primary challenge of ensuring efficient allocation. The relevant cost concept is *prospective*, related to scarcity value and the marginal cost of construction (*long-run marginal cost*).
  - With no growth or congestion, the primary role of the price mechanism is to allocate the fixed costs of previous investments among system users. The

[1] When gas throughput is growing then the prospect of congestion is always present in the absence of correctly-timed system expansions.

relevant cost concept is *retrospective*, related to the allocation of costs already incurred (*average cost*). It emphasises *cost allocation* methodologies designed to correspond to intuitive notions of fairness.

  – In both cases tariffs must ensure that pipelines expect to recover their costs (including a fair return on investments). However, in the first case a large part of fixed cost recovery can come from scarcity/congestion charges (and the relatively small remainder from an additional component of the total tariff).

- In a system that is growing significantly—as is the case in most of Europe—and/or suffers from significant congestion, tariffs should principally reflect long-run marginal costs. Complex network interactions imply that long-run marginal costs are unlikely to be closely proportional to contract distance.

- Distance-based tariffs are therefore unlikely to be cost-reflective in many EU networks, given current and expected growth.

- Distance-based tariffs can be cost-reflective for long pipelines with unidirectional flows. They can also be cost-reflective where firm service is defined as requiring the TSO to reserves physical capacity along the contract path. However, as discussed above, this is unlikely to be an appropriate definition.

- However, in other circumstances distance-based systems *no longer provide cost-reflective charges* and are therefore potentially *discriminatory*. In particular they advantage larger system users whose contract portfolios can reduce transportation charges without any corresponding reduction in real system costs.

- Theoretical analyses imply that, provided negative entry and exit charges are allowed, it is always possible to set entry and exit charges so that tariffs reflect long-run marginal costs for network service. We interpret this result as establishing a *reasonable initial presumption in favour of entry-exit* when long-run marginal cost is the dominant cost concept.

- However, this presumption is subject to a number of *significant caveats*:

  – Excessive reliance on theoretical arguments may be dangerous, because they rely on a number of assumptions concerning optimal planning, perfect foresight, optimal despatch etc that may not hold in practice.

  – Implementation of negative entry and exit charges may present difficulties.

  – Consequently, it may in practice be difficult for entry-exit charges to reflect marginal costs fully. For example, without allowing for negative charges it may be difficult to reflect the costs imposed by internal congestion.

  – Moreover, the theoretical claim applies to marginal costs and does not hold when the aim is to set entry and exit tariffs to reflect average (rather than marginal) costs.

- The presumption in favour of entry-exit should therefore be subject to a series of checks. The TSO and authority responsible for tariff-setting should together:

    – Clearly define a methodology that can be applied to measure the costs associated with any physical transportation path (*e.g.*, Transco's LRMC).

    – Calculate indicative entry and exit charges so that the tariff for any given contract is as close as possible to the corresponding costs (*i.e.,* the costs that arise from the corresponding physical flows).

    – Examine the resulting charges for signs of any major divergence from cost-reflectivity. Publication of the indicative charges will allow shippers the opportunity to point out any such divergences.

    – If there are major problems, consider modifications that would ensure broad cost-reflectivity with minimum loss of the considerable other advantages of entry-exit, some of which we discuss below.

- Entry-exit tariffs are superior to distance-based in the promotion of trade, liquidity and gas-to-gas competition. However, distance-based charges have not prevented the development of liquid markets at trading hubs such as Zeebrugge in Belgium and various points in North America.

- Entry-exit tariffs can be used to signal expected future congestion at specific entry and/or exit points, and therefore provide effective signals for efficient investment more easily than distance-based tariffs. However, locational methodology is not the key issue in this regard. Entry-exit tariffs *per se* are not a sufficient guarantee of efficient long-term signals, while experience in North America demonstrates that distance-based tariffs need not impede efficient long-term investment.

- Distance-based tariffs can be transparent with relatively little effort. However, entry-exit systems can also be implemented with an equal level of transparency. This criterion should therefore not be given any significant weight in choosing between the two. Moreover, if distance-based tariffs are adjusted to provide appropriate backhaul discounts, then the calculations become extremely complex and transparency will be difficult to maintain.

- Distance-based tariffs present fewer problems of "articulation" across TSOs, *i.e.*, they are easier to combine across multiple TSOs. With entry-exit, significant problems can arise with "articulation". Two alternatives are possible:

    – TSOs can agree on a single ("multi-area") entry-exit system covering their combined network, as in the cross-border electricity flows in the EU (and with analogous inter-TSO payments).

    – Each cross-border interconnector can be an exit point for one system and an entry point for another.

- The first approach encounters the problem of determining inter-TSO payments. The second risks creating a problem of pancaking if the border-point charges are high. If the border-point charges are low, then it becomes similar to the first approach and encounters the same problems. Moreover, the synergies between interconnected systems mean that the appropriate entry-exit charges can be quite different when the two systems are considered together.

- We conclude that to ensure effective articulation across systems, regulators and TSOs may eventually need to consider the creation of "multi-area" entry-exit charges, with inter-TSO payments. The use of distance-based charges avoids certain complications in combining tariffs across borders. However, simplicity cannot outweigh factors such as cost-reflectivity and the promotion of competition and trading liquidity.

- Pipe-to-pipe competition can in theory substitute for regulation as a means of setting tariffs. However, the nature of the industry makes effective competition difficult. The use of "market-based rates" should therefore be subject to rigorous tests to confirm the absence of market power.

Overall Recommendations

- We recommend a presumption in favour of entry-exit tariffs, based on the advantages of cost-reflectivity and the promotion of competition.

- However, the presumption in favour of an entry-exit system should be subject to several checks. TSOs and national authorities should:

    - Clearly define the measure of costs that will be applied to derive tariffs.

    - Calculate indicative entry and exit charges, and examine the resulting charges for signs of any major divergences from cost-reflectivity.

    - If there are major problems, consider modifications that would ensure broad cost-reflectivity with minimum loss of the other advantages of entry-exit.

    - Before implementing entry-exit tariffs at the TSO level, consider issues of inter-TSO articulation, and establish a process to obtain the necessary degree of co-ordination.

- Each TSO should have the right to argue in favour of alternative systems, by providing objective evidence that specific features of the system and flows create problems for entry-exit tariffs. National authorities should be obliged to give rigorous consideration to such evidence, and to publish their analyses.

- The use of "market-based rates" should be subject to rigorous tests to confirm the absence of market power, applying the same principles and methodologies used in merger analyses.

Alternative Capacity Definitions

- The choice between alternative definitions of capacity ("capacity types") is independent of choice of tariff type (*e.g.*, a TSO could combine postal tariffs with a point-to-point capacity definition).
- The choice between different capacity types entails a fundamental trade-off between allowing shippers greater flexibility in system use and maximising the amount of firm capacity that can be sold.
  - Less flexible systems such as point-to-point capacity in some circumstances allows the TSO to sell more firm capacity.
  - More flexible systems such as entry-exit foster efficient trade, market liquidity and gas-to-gas competition, as well as secondary trading of capacity.
- Flexibility is important for lowering entry barriers and fostering the development of competition. It is therefore of particularly high value in liberalising markets. Maximising the amount of firm capacity that can be made available is of particular importance when capacity is relatively scarce.
- Because of our earlier findings concerning the absence of congestion in the European system, the presumption should be in favour of more flexible definitions (while bearing in mind the possibility of congestion within Member States). In particular, the preference of the CEER and other parties in favour of entry-exit is a reasonable starting point in most Member States.
- If an entry-exit system is not appropriate for a particular network, then we recommend that TSOs and national authorities identify the minimum reduction in flexibility that is necessary to solve the problems. Relatively minor, tailor-made adjustments to an entry-exit system may be able to eliminate its defects. We do not see how point-to-point capacity could be an appropriate remedy for perceived problems with an entry-exit system.
- Of the capacity definitions currently used in Europe, point-to-point capacity provides the least flexibility to shippers. It is *always unnecessarily restrictive*, because of the availability of alternative approaches that preserve all the advantages imputed to point-to-point while allowing greater flexibility to shippers. Examples of such approaches include the "segmentation" applied by Gastransport in the Netherlands, and the system of primary and secondary receipt and delivery points used in the US.
- TSOs may not always have the appropriate incentives to choose among alternative capacity systems. We therefore recommend that regulatory authorities be closely involved in these decisions.
- A TSO should provide objective evidence that its proposed definition of capacity represents a reasonable trade-off between capacity availability and flexibility. Capacity definition systems should be analysed using gas flow models that estimate the interaction between capacity availability and different degrees of flexibility. TSO should share these models with regulatory authorities, and regulators should develop their own modelling capabilities. The

Commission and CEER should share their experiences concerning their analyses of the trade-offs between alternative capacity definition systems.

Capacity Allocation and Congestion Management

- The appropriate mechanism for allocating capacity depends on the extent of congestion.
- We distinguish contractual congestion from physical congestion. Contractual congestion describes situations where contracts have already been signed for all available capacity, even if the network can easily accommodate all physical demands that can reasonably be anticipated. Physical congestion refers to the physical difficulty of the network accommodating demand.
- When there is no physical or contractual congestion, the choice of mechanism is relatively unimportant, and we recommend "first-come, first-served" as the simplest approach.
- When there is contractual but not physical congestion, we recommend a one-off "*ex ante* capacity release" programme for unused capacity, which would examine the needs of existing capacity holders. Any capacity in excess of the amount needed to serve contracted customers, to meet the needs of captive customers, and to meet any PSOs, should be released.
- Furthermore, when there is contractual congestion and a customer switches supplier, the TSO should grant access to the competitor and transfer the resulting capacity payments to the existing holder of the capacity. We call this an "automatic resale" policy.
- A "capacity goes with the customer" policy would avoid monopolisation in the presence of contractual congestion, but if the policy does not compensate gas suppliers for the value of transportation capacity that they sacrifice upon losing customers, then we cannot recommend it as the best policy for gas networks.
- We recommend measures to facilitate secondary markets for transportation capacity. Once markets develop a sufficient diversity of shippers, secondary market trades should suffice to handle contractual congestion. Capacity release and an automatic resale policy would no longer be necessary.
- In the absence of physical congestion, auctions are not necessary and are likely to present more costs than benefits. In a transparent market, the absence of physical congestion should be evident with or without an auction.
- Physical congestion should be addressed by a combination of auctions and a requirement for capacity release by dominant shippers. The auctions should be designed to avoid competitive problems, including the potential bidding advantage of a vertically-integrated supply business, and the prospect of monopolising the auctioned capacity. Shippers who release capacity in the auctions should receive the associated revenues. When markets become sufficiently competitive, capacity release should not be obligatory.
- Regulatory authorities should be able to insist on network expansion if it is economically justified. A customer's willingness to pay for expansion should be viewed as proof that expansion is justified.

- Capacity can be defined in ways that improve congestion management. We recommend that TSOs and regulators examine carefully the potential for such measures. Imbalance tolerances that vary with ambient temperature or over the course of a year can improve the total flexibility available for a given amount of annual capacity. TSOs should also update their analyses of capacity availability frequently, publish the results, and offer short-term spare capacity for sale on a short-term basis using transparent and non-discriminatory nomination procedures. TSOs can also increase shipper flexibility and improve congestion management by offering interruptible capacity for sale.
- Regulators and TSOs should investigate the appropriateness of a "financially firm" service, which contemplates some possibility of physical interruption but offers to compensate shippers financially. Financial compensation can encourage the TSO to offer more capacity for sale overall, and can also improve long-term congestion management and system planning. However, TSOs should only offer financial compensation under conditions that do not invite market power abuse by shippers or traders.
- Gas release programmes should be accompanied by capacity release programmes.

Forecasting Congestion

- Regulators and TSOs play an important role in forecasting congestion. The publication of all information that is relevant to congestion is necessary to provide a level playing field for shippers. Otherwise established shippers will have an inherent advantage over potential competitors.
- We recommend the publication on a regular basis of the following information that is not yet standard in Europe: a) Continuous updates of available capacity on a network, b) historical annual peaks and annual demand for major entry and exit points or zones, c) forecasts of annual peaks and demand at major entry and exit points or zones, d) investment plans for expanding capacity at specific points over an extended time horizon.
- Regulators or TSOs should develop computer models of the major pipeline networks in Member States that would be available for shippers can acquire.
- We recommend that CEER co-operate with GTE toward the development of a computer model of the European natural gas pipeline system, which shippers could acquire.
- Auctions and secondary markets should be viewed as important instruments for stimulating competition among shippers in congestion forecasting. Over the long run, such competition can be expected to improve the quality of forecasting.
- Auctions and secondary markets will be most useful for forecasting congestion if they involve long-term rights to transportation capacity. Third-party access regimes should involve a mix of long-term and short-term transportation rights.
- Price caps would suppress the ability of auctions and secondary markets to assist in forecasting congestion, without protecting end-users.

Financing New Infrastructure

- Co-ordinated planning by governments, regulators and TSOs should retain a key role in identifying, authorising, and financing new investments in the presence of market power or in light of market uncertainty during the transition to liberalisation.
- Co-ordinated planning studies should look to market signals as useful indicators of the economic merits of new investments. Regulators should adopt measures that foster the creation of market signals, such as auctions, secondary trading, or "open season" processes, because they can help identify attractive new investments.
- Regulators should test their cost of capital estimates by analysing the volatility of share prices for regulated pipeline companies that are listed on public stock exchanges.
- Regulators should not presume that a company has a lower cost of capital simply because the government, rather than private investors, is the owner. Finance experts recognise that low government borrowing rates understate the total cost of capital for government-owned companies.
- Regulators should estimate the equity risk premium by reference to actual historical returns earned by investors in a large sample of countries, as opposed to any particular Member State in isolation.
- Regulators should consider using competitive bidding processes to determine regulated rates. Such processes can help finance new investment by avoiding potential errors in the regulator's estimate of the cost of capital. Such processes can also help the investment climate by introducing an improved allocation of risk between project developers and infrastructure users.
- Regulators should consider authorising new infrastructure projects even if they are not identified as necessary by a co-ordinated plan, as long as the projects satisfy certain conditions designed to promote the public interest: a) protection of rate-payers from volume risk, b) avoiding distorted incentives that may arise from existing tariff systems, c) avoiding adverse effects on the existing network, d) ensuring no abuse of market power.
- Regulators should watch for six problems that can be associated with the market power of a new project: a) deliberately designing the project to offer less total capacity than optimal b) pre-emptive expansion to deter competitors, c) deterring other efficient projects, d) introducing inappropriate vertical integration, e) monopolisation of capacity, and f) charging excessive prices.
- Instead of rejecting projects that present potential market power problems, regulators should consider possible undertakings that could remedy the problems. Potential remedies include: a) securing long-term contracts with end-users prior to initiating construction, b) conducting competitive tenders for the project, c) auctioning capacity in the project, d) commitments to reasonable rates and non-discrimination.

- Market-based rates are not reasonable in the presence of market power. If the owner of an existing network has market power, permitting it to charge market-based rates cannot be necessary to promote independent investments in new infrastructure.

- When project sponsors request exclusive or nearly exclusive access to a new infrastructure investment, regulators should first determine whether the request is motivated by a deficiency in the tariff regime, or if the request would have an adverse effect on competition.

2 Description of Physical System

2.1 Major Transportation Routes

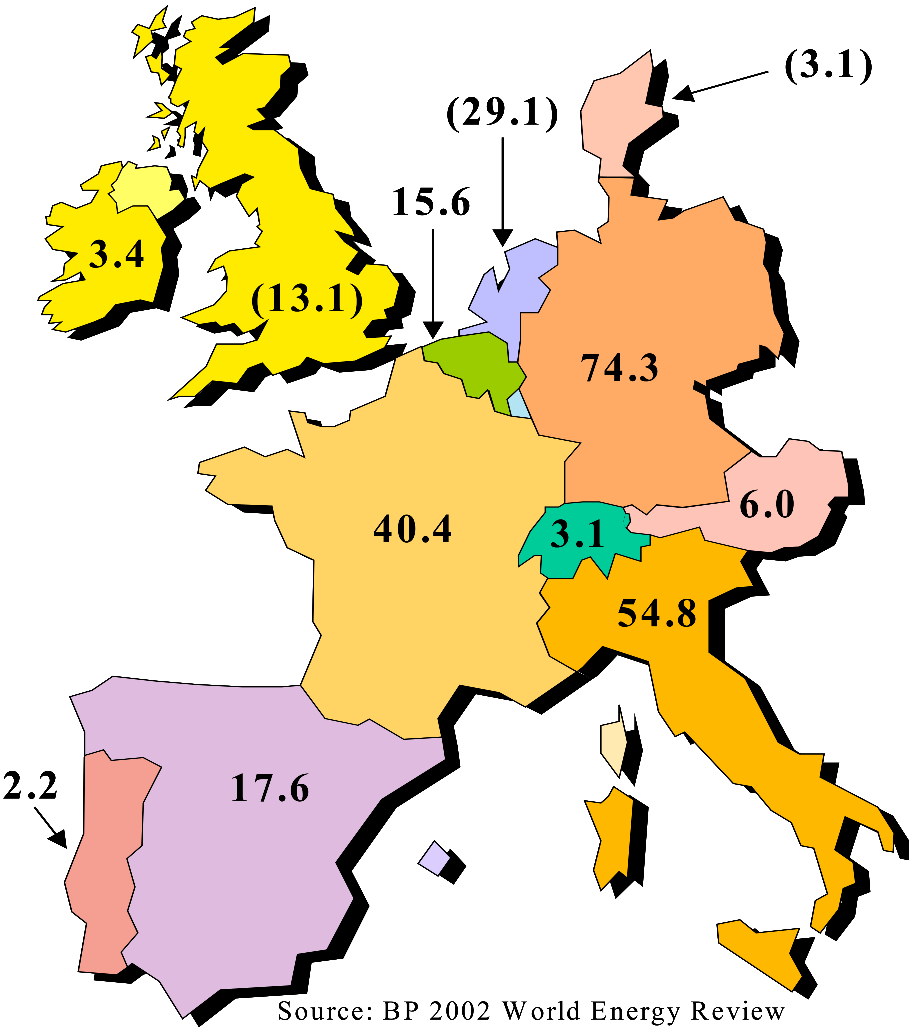
As a first step in describing the physical system, we identify the major transportation routes using a number of alternative criteria of importance for the development of the internal energy market:

- Relationship to major European markets
- Transportation capacity
- Volume of gas currently transported
- Price differentials between neighbouring countries
- Impact on supply concentration

Relationship to major European markets

A natural criterion is to concentrate on the major routes that link the most significant European producers and import points to the most significant European importers. Figure 1 below shows the net exports/imports of selected Member States.

Figure 1: Year 2001 Natural Gas Imports (Exports) (BCM)



According to this criterion, route selection should focus on transportation of gas from the largest exporters: Norway (not shown on the map), the Netherlands and the UK, to the largest importers: Germany, Italy and France.

Transportation Capacity

GTE provides estimates of the maximum hourly flow rate at each cross-border node. Table 2 shows these data.

Table 2: Capacities at Cross-Border Nodes (BCM/yr)

Location	From	To	Maximum Gross Flowrate	Availability Code
Loughshinny	UK	Ireland	9.1	R
Bacton	UK	Belgium	20.1	R
Zeebrugge	Belgium	UK	8.8	G
Zeebrugge	LNG	Belgium	7.6	Y
Zeebrugge	Norway	Belgium	14.0	R
Dunkerque	Norway	France	12.0	Y
Emden	Norway	Netherlands	13.1	Y
Emden	Norway	Germany	8.8	Y
Dornum	Norway	Germany	21.0	R
Zelzate	Belgium	Netherlands	10.5	G
Oude Statenzijl	Netherlands	Germany	29.8	Y
Dragor	Denmark	Sweden	2.0	Y
Ellund	Denmark	Germany	2.9	R
Mallnow	Poland	Germany	24.5	R
Sayda	Czech Rep.	Germany	13.6	G
Olbernhau	Czech Rep.	Germany	4.4	Y
Waidhaus	Czech Rep.	Germany	34.2	G
Oberkappel	Austria	Germany	4.4	R
Burghausen	Austria	Germany	2.8	G
Baumgarten	Slovak Rep.	Austria	39.9	Y
Baumgarten	Austria	Slovak Rep.	no transit	R
Mosonmagyarovar	Austria	Hungary	11.5	G
Murfeld	Austria	Slovenia	1.9	Y
Arnoldstein / Tarvisio	Austria	Italy	23.0	R
Gorizia	Italy	Slovenia	1.5	G
Gorizia	Slovenia	Italy	0.2	R
Mazara del Vallo	Tunisia	Italy	30.5	G
Panigaglia	LNG	Italy	3.5	R
Fos-sur-Mer	LNG	France	5.5	Y
Barcelona	LNG	Spain	10.5	Y
Cartagena	LNG	Spain	2.4	Y
Tarifa	Morocco	Spain	9.4	R
Huelva	LNG	Spain	3.9	R
Badajoz	Spain	Portugal	3.1	R
Tuy	Portugal	Spain	0.4	R
Imatra	Russia	Finland	7.0	R
Col de Larreau	France	Spain	2.3	R
Montoir	LNG	France	10.0	G
Blaregnies L	Belgium	France	8.1	Y
Blaregnies H	Belgium	France	13.1	Y
Gries Pass	Switzerland	Italy	16.2	G
Wallbach	Germany	Switzerland	10.5	R
Obergailbach	Germany	France	12.7	Y
Remich	Germany	Luxembourg	1.7	G
Petange	Belgium	Luxembourg	0.5	Y
Bras	Belgium	Luxembourg	1.7	Y
Esch /Alzette	France	Luxembourg	0.2	R
Bocholtz	Netherlands	Germany	9.1	R
Zevenaar	Netherlands	Germany	21.9	R
Winterswijk	Netherlands	Germany	13.1	R
s'Gravensvoeren	Netherlands	Belgium	9.6	R
Hilvarenbeek	Netherlands	Belgium	27.2	R
Obicht	Netherlands	Belgium	1.8	Y
Kiefersfelden	Germany	Austria	0.9	R
Eynatten	Belgium	Germany	6.1	G
Lasow	Poland	Germany	1.6	Y
Revythoussa	LNG	Greece	1.9	G
Kula	Bulgaria	Greece	3.5	G
Lanzhot	Slovakia	Czech Republic	56.9	G
Velke Kapusany	Ukraine	Slovakia	92.0	Y
Oltingue	France	Switzerland	-	-

Notes & Sources:
Based on data available on the GTE website www.gte.be on 28.06.02.
Availability code definitions: "G"=capacity available; "Y"=capacity available depending on size of request; "R"=only very limited or no capacity available; "-"=no data available yet.

Table 3 below shows cross-border capacities at a more aggregated level (state-to-state rather than by pipeline).

Table 3: Pipeline Capacities (BCM/yr)

To:	From: Austria	Belgium	Denmark	France	Germany	Italy	Netherlands	Norway	Portugal	Spain	Switzerland	UK	Total Import Capacity
Austria					0.9								40.8
Belgium							38.5	14.0				20.1	80.3
Denmark													0.0
Finland													7.0
France		21.3			12.7			12.0					61.5
Germany	7.2	6.1	2.9				73.9	29.8					198.2
Greece													5.4
Ireland												9.1	9.1
Italy	23.0										16.2		73.4
Luxembourg		2.2		0.2	1.7								4.0
Netherlands		10.5						13.1					23.7
Norway													0.0
Portugal										3.1			3.1
Spain				2.3					0.4				28.8
Sweden			2.0										2.0
Switzerland					10.5								10.5
UK		8.8											8.8
Total Export Capacity	43.6	48.9	4.9	2.5	25.8	1.5	112.5	68.9	0.4	3.1	16.2	29.3	720.4

Notes & Sources:
Based on data available on GTE's website on 28.06.02.
Only countries in Western Europe are shown in Table but total capacities include imports to and exports from all countries.

If we class the most important import transportation routes (taken to include more than one pipeline) as those with capacity to transport 10 BCM or more per year, Table 3 shows that the most important routes are those that transport gas from:

- Austria to Italy
- Belgium to France, and to the Netherlands
- Germany to France and to Switzerland
- The Netherlands to Belgium and to Germany
- Norway to Belgium, France, Germany and the Netherlands
- Switzerland to Italy
- The United Kingdom to Belgium

Volume of Gas Currently Transported

Table 4 below shows volumes of gas transported between different states by pipeline.

Table 4: Year 2001 Gas Trade Movements (BCM)

To	From	Denmark	France	Germany	Netherlands	Norway	United Kingdom	Total Imports
Austria				0.3		0.5		0.8
Belgium				0.2	7.6	5.1	0.3	13.2
Finland								0.0
France					5.8	12.9	1.3	20.0
Germany		2.2			20.2	19.9	3.3	45.6
Greece								0.0
Ireland							3.4	3.4
Italy					7.1	1.1		8.2
Luxembourg				0.4	0.4			0.8
Netherlands						5.5	7.5	13.0
Portugal								0.0
Spain						1.2		1.2
Sweden		0.9						0.9
Switzerland			0.3	1.8	0.6			2.7
United Kingdom					0.5	2.2		2.7
Total Exports		3.1	0.3	2.7	42.2	48.4	15.8	112.4

Source: BP World Energy Review 2002.

If we class the most important import transportation routes as those that transport 5 BCM or more per year, Table 4 shows that the most important routes within Europe are those that transport gas from:

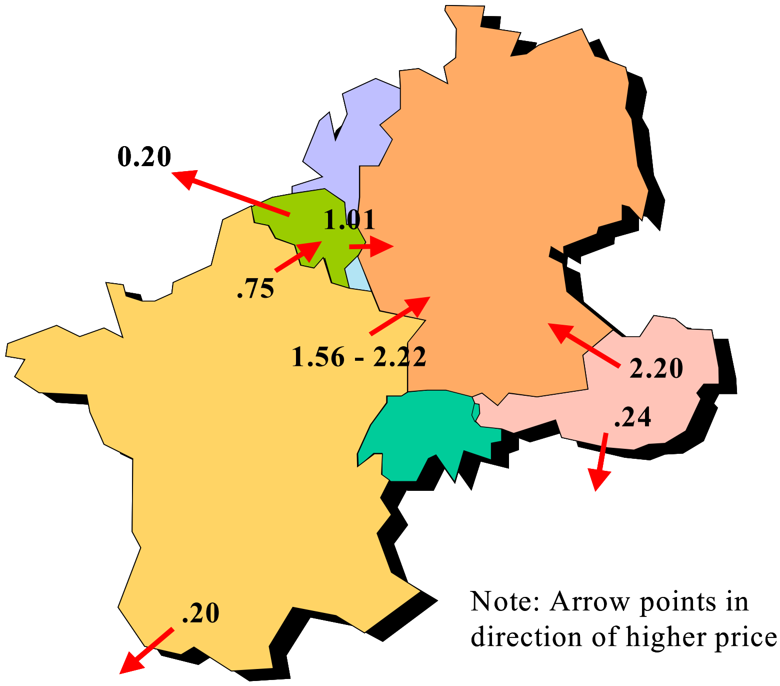
- The Netherlands to Belgium, France, Germany and Italy
- Norway to Belgium, France, Germany and the Netherlands
- The United Kingdom to the Netherlands

Price Differentials between Neighbouring Countries

Eurostat publishes enduser prices for natural gas in each Member State. By definition this price includes transportation and other system charges. Rather than engage in a complex and unsatisfactory exercise to estimate average transportation charges, we have focused on the prices paid by very large consumers who consume according to a flat profile (8,000 hours), and where possible have focused on consumers located near the relevant geographical border.[2] For these consumers, transportation charges will be a relatively small proportion of the delivered price. Figure 2 below shows the winter cross-border price differences. The most notable price differences are those between Germany and its neighbours.

[2] Eurostat Statistics in Focus – Environment and Energy, Gas Prices for EU Industry on 1 January, 2002. No figures given for the Netherlands.

Figure 2: Winter Gas Price Differentials for EU Industry (€/GJ, Eurostat 1.1.02)[3]



Impact on Supply Concentration

The "Draft Strategy Paper" of the Madrid Forum's Joint Working Group[4] laid out a vision for the liberalised European gas market. This vision included a principle objective of promoting consumer choice among different gas suppliers, described as *real supply-side competition*. The issue of supply-side competition focuses special attention on routes from major supply countries. For example, one important factor in furthering EU gas market liberalisation is the abolition of GFU and consequent opening up of upstream competition in Norway.

2.2 Storage Capacities

The amount of storage capacity in each country varies widely throughout the EU as shown in Table 5. One of the benefits that storage provides is the opportunity for domestic peak-shaving. Countries that have a high level of storage capacity relative to domestic demand are best equipped to perform this peak-shaving. This position means there is less need for them to keep cross-border capacity free just to manage peaks in demand. The figures in Table 5 suggest that

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[3] We selected prices (consumer type, geographical location within country) to compare on the basis of proximity to border, and data availability. For example, for the UK-Belgium price comparison we selected the UK London price because of the regions listed London is the closest to Bacton (the point where the interconnector with Belgium joins the UK). We selected consumer type I4-1 for that comparison because it is the largest consumer type for which prices are available for both the UK (London) and for Belgium.

[4] "A Long-term vision of a fully operational single market for gas in Europe - a Strategy Paper (Draft)", prepared by the Joint Working Group of the European Gas Regulatory Forum, 28.1.2002.

Austria, Denmark, France, Germany and Italy are the countries that can afford to be less reliant on cross-border capacity for meeting peaks in demand.[5]

Table 5: Capacity of Storage Facilities

Country	Annual Demand (BCM) [A]	No. of Storage Facilties [B]	Storage Volume BCM [C]	Storage Volume Equivalent No. of Demand Days [C]/[A]x365
Austria	7.2	5	2.3	116
Belgium	15.9	3	0.7	15
Denmark	4.6	2	0.8	64
Finland	4.1	0	0.0	0
France	42.4	15	11.1	96
Germany	83.2	42	18.6	81
Greece	2.0	1	0.1	14
Ireland	4.1	0	0.0	0
Italy	68.7	8	15.1	80
Luxembourg	0.8	n/a	n/a	n/a
Netherlands	40.8	3	2.5	22
Portugal	2.4	n/a	n/a	n/a
Spain	18.0	2	1.0	20
Sweden	1.0	0	0.0	0
UK	97.0	8	3.6	13
Total	392.1	89	55.7	52

Notes & Sources:
[A]: Taken from Eurogas' Annual Report 2000. Calculated as sum of indigenous production, net imports, and net withdrawal from stocks.
[B],[C]: Situation on 1 January 2001. Data taken from Eurogas' Annual Report 2000, p.22.

2.3 Analysis by Jacobs Consulting

Jacobs Consulting has used the above data and other data to perform a series of analyses of the European system:

- *Hardware Analysis.* Comparison of the physical maximum flow capacity at each cross-border point, as published by GTE, with the pipeline diameter(s), obtained from public sources.
- *Regional Analysis*. Comparison of specified maximum capacities with cross border capacities and net imports of EU countries, to help identify possible bottlenecks and/or excess capacity.

[5] The same conclusion applies to the Netherlands and the United Kingdom, because of the flexibility provided by domestic production.

- *Temperature Analysis*: Comparison of specified maximum capacities with historical flow rates published by GTE, as an alternative means of identifying possible bottlenecks and/or excess capacity.

The report from Jacobs Consulting is attached as Appendix II. Here we reproduce its main conclusions:[6]

- Comparison of the actual net average exports and imports for the year 2001 with the physical capacities shows that import capacities of all countries are more than sufficient for average net imports. The same holds for the exporting countries. So on an average basis no congestion is expected at present on a country-to-country basis.

- When the difference between import and export capacity, which we call "net import" capacity, is small relative to actual net imports, flexibility has to be created inside the country itself. One option is gas storage. If the ratio of net import capacity over actual imports is 2 or higher,[7] then flexibility can be imported. If the ratio is closer to 1, then flexibility must be obtained domestically.

- The Netherlands is the main exporter of flexibility. Germany, Belgium and Ireland are the main importers of flexibility.

- Effectively the transport capacity of gas from the north and east to France and the Iberian peninsula is limited. This might cause congestion if/when gas from north-west Europe or Russia is required. For instance the total installed pipeline import capacity of Spain at the France/Spanish border is 2.3 BCM per year, whereas the net Spanish consumption is 17.6 BCM per year.

- Results of the regional analysis suggest that France is a congestion country for gas transported from Russia and north-western Europe to France and the Iberian peninsular. Also Switzerland seems to be a congestion country for gas transported from western Europe to Italy.

2.4 Corrections to GTE Capacity Figures

Our discussion of the Jacobs Report with GTE revealed that some of the maximum flow rates published by GTE need significant correction. The figures in question relate to cross-border capacities on German pipelines. Ruhrgas has kindly provided us with information regarding necessary corrections:[8]

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[6] The report notes that its conclusions should be viewed as indicative given the lack of data.

[7] Typical Dutch off-take patterns, with variations from summer to winter, suggest a ratio of peak to average daily demand of at least 2. For the whole of Europe the peak to average ratio is 1.8 ("EU Security of Supply" study, April 1998, Wood Mackenzie).

[8] Unfortunately time did not allow for these corrections to be incorporated into the Jacobs Report.

- The maximum flow rate for Oude Statenzijl should be 2.70 mn Nm3/h instead of the 3.40 mn Nm3/h published by GTE.
- Because only two of the five compressors in the pipeline connecting Poland and Germany at Mallnow (Frankfurt an Oude) have been installed to date, the maximum hourly flow rate at Mallnow (Frankfurt an Oude) should be 1.82 mn Nm3/h.
- The maximum flow rate for Sayda should be 1.26 mn Nm3/h instead of the 1.55 mn Nm3/h published by GTE.
- The maximum flow rates published by the GTE for Burghausen and Oberkappel cross-border points are correct. However, these only apply when the points are not used simultaneously. The maximum flow rate for both points together is the Oberkappel maximum flow rate of 0.5 mn Nm3/h.
- The cross-border point at Lasow (Görlitz) actually transfers gas from Germany to Poland and not from Poland to Germany as indicated on the GTE map.

For some of the cross-border points these corrections are very significant. Taken together, they reduce the total maximum import capacity for Germany from 198 to 175 BCM/yr as shown in Table 6.

Table 6: Import Capacity for Germany's Cross-Border Points

Point Number	Point Name	GTE Published Figure (pre 27 June 2002)	GTE Published Figure (post 27 June 2002)	Corrected Figure (Ruhrgas)	Difference (new GTE - Ruhrgas)
GTE Incorrect (mn Nm3/h)					
11	Oude Statenzijl	3.4	3.4	2.7	0.7
14	Mallnow (Frankfurt/Oder)	3.1	2.8	1.8	1.0
15	Sayda	1.6	1.6	1.3	0.3
18	Oberkappel	0.5	0.5	0.5	0.0
19	Burghausen	0.4	0.3	0.0	0.3
55	Lasow (Görlitz)	0.2	0.2	-0.2	0.4
GTE Unchanged (mn Nm3/h)					
8	Emden	1.0	1.0	1.0	0.0
9	Dornum	2.4	2.4	2.4	0.0
13	Ellund	0.3	0.3	0.3	0.0
16	Olbernhau	0.5	0.5	0.5	0.0
17	Waidhaus	3.9	3.9	3.9	0.0
47	Bocholtz	1.0	1.0	1.0	0.0
48	Zevenaar	2.5	2.5	2.5	0.0
49	Winterswijk	1.5	1.5	1.5	0.0
54	Eynatten	0.7	0.7	0.7	0.0
Total Import Capacity (mn Nm3/h)		**23.0**	**22.6**	**20.0**	**2.7**
Total Import Capacity (BCM/yr)		**201.7**	**198.2**	**174.9**	**23.2**

2.5 Conclusions and Recommendations

From the work of Jacobs Consulting we draw an overall conclusion that:

- *The extent of cross-border physical congestion is currently rather limited in the European high pressure gas transmission system.*

In our discussions GTE confirmed that it accepts this conclusion, while pointing out that the analysis and conclusion are limited to cross-border congestion, and should not be extrapolated to assume a lack of congestion within the systems of individual TSOs. Nor should the analysis be extrapolated forward. GTE believes that expected growth in consumption implies a strong need for new investment, and stresses the importance of a sound investment climate.

- The work of Jacobs Consulting, together with the subsequent constructive input of GTE, has also been of great importance in revealing mistakes in some of the published maximum flow rates, as discussed above.
- Published maximum flow rates should therefore be *subject to further careful verification*. GTE has pointed out that "the data published from TSO's can be reviewed in most cases by national authorities which are in charge of monitoring the access to the network, and in other cases are subject to the analysis of counterparts interested in negotiating transportation services". However, the problems with the German data described above indicate that to date verification has not been adequate.

Many GTE members are now publishing, or intend to publish, figures for available capacity. Since calculation of available capacity is significantly more complex than the calculation of maximum flow rates, our recommendation will apply even more strongly in this case:

- Published available capacity figures should be calculated according to *agreed standard methodologies, and subject to careful verification*. To ensure that appropriate resources are devoted to these calculations, they should be certified as correct by a senior officer of the TSO.

3 Firm Transportation Service

Many TSOs argue that provision of firm capacity from A to B requires the TSO to reserve physical transportation capacity along the contract path. For example, the latest VV Gas states that:[9]

> The network operator shall keep available an agreed transportation capacity over the year for the actual route section between the entry and exit points corresponding to the agreed maximum hourly capacity in m^3_n usable by the customer.

In contrast, alternative approaches to capacity definition recognise that TSOs can and should make use of the portfolio of tools and assets at their command. In complex inter-linked networks such as those of most European TSOs, this portfolio includes the whole system of inter-meshed flows, system resources such as linepack, storage, interruptible transmission customers, operational balancing agreements with neighbouring TSOs, and similar arrangements that can be facilitated by the increased inter-operability that is one of the goals of the Gas Directive.

This "total network service" approach implies that provision of firm transportation capacity does not always require reservation of an equal amount of physical capacity along the contract path. Physical point-to-point capacity is one of the tools used by TSOs for delivering gas, but not the only one. Efficient provision of firm transportation capacity entails appropriate use of all the capabilities of the network.

Differences in service definition have important implications, both for operational practice and for tarification. As far as tariffs are concerned, cost implications arise from reserving physical capacity for a particular contract path, regardless of the actual gas flow. Under certain conditions,[10] the costs associated with reserving physical capacity are roughly proportional to contract distance. If such physical capacity reservations were reasonable, then distance-based tariffs would seem reasonably cost-reflective.

We expand on these issues in this chapter, and make recommendations concerning the appropriate type of firm service in a newly liberalized gas market. In the next chapter we discuss the appropriate tariffs for firm service.

3.1 Firm Physical Capacity Rights

No pipeline can provide an absolute guarantee of physical delivery, because there is always a possibility of mechanical problems, such as compressor failure, that would prompt interruptions. Physical firmness is inherently a probabilistic concept: what a pipeline defines as "physically

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[9] Clause 6.1.3, Associations' Agreement on Third-Party Access for Natural Gas (VVII), 3.5.2002 (unofficial English translation).

[10] For example, problems of congestion or differences in pipeline flow capacity or utilisation could distort the proportionality to distance. For a technical exposition of the costs associated with transportation on pipeline sections see the BET study "Factors Affecting the Cost of Natural Gas Pipeline Capacity: Brief Study", Aachen, 9 April 2002 (authors Dipl.-Geol. Andrea Möller and Dr.-Ing. Wolfgang Zander) (kindly provided to us by Ruhrgas).

firm" service is in reality service with a very low probability of interruption. *Force majeure* clauses in transportation contracts, network codes or related documents explicitly recognise a possibility of interruption, as does the new gas Verbändevereinbarung Gas II (VV Gas II) in Germany.[11]

Beyond some point it becomes inefficient to increase the certainty of delivery. As an extreme example, the probability of interruption in any pipeline system can be decreased by building a duplicate back-up network. However, the incremental cost would in general clearly outweigh the incremental benefit.

It is therefore a false dichotomy to distinguish "pure firm" from other types of service. Rather, there is spectrum of firmness. The TSO's firm service offering must by definition be close to the high end of this spectrum, but it cannot be appropriate to expend limitless resources attempting to approximate 100% certainty. Rather, the issue is to determine the appropriate level of physical certainty that should be associated with a TSO's firm service offering, based on a balancing of the associated costs and benefits. It should moreover be borne in mind that for many consumers financial guarantees of delivery may be an appropriate complement to physical firmness. For such customers, the concept of "financially firm service" may enable the TSO to provide firm transportation more efficiently.

The distinction between firm financial transmission rights and firm physical transmission rights is common in electricity. Firm financial rights guarantee that the TSO will provide the shipper with the financial benefits of physical transmission. For example, if transmission is between two hubs with well-established spot prices at each, then the financial benefit of transmission (from the lower to the higher price hub) is equal to the difference in spot prices.

3.2 Physical Capacity Reservation

As noted above, some TSOs define firm capacity by reference to the reservation of physical capacity along the contract path. This definition provides a high degree of certainty of delivery, although it cannot provide an absolute guarantee. There are however a number of factors that may make this an inappropriate definition of firmness. For many system users it may provide high reliability but at excessive cost. Specifically, we note:

- Other tools available to the TSO may permit comparable firmness at lower cost. Efficient network operation generally entails a whole portfolio of tools available to the TSO.
- The "one size fits all" approach is also unlikely to reflect the variety of customer needs.
- It ignores the potential role for financial mechanisms to help meet customer needs at lower cost.

[11] Clause 2.3.4 of Annex 6 ("Technical Conditions for Access to Natural Gas Pipeline Networks") of the new VV Gas II states that "if the transportation capacity available to the network operator falls below the requested and contractually agreed transportation capacity, the network operator shall advise the shipper accordingly, providing details on the likely duration, the scope and cause of such a transportation reduction".

- It presents a potential barrier to competition, risks discrimination against smaller shippers, especially in immature markets.

We illustrate these problems with a hypothetical example.[12]

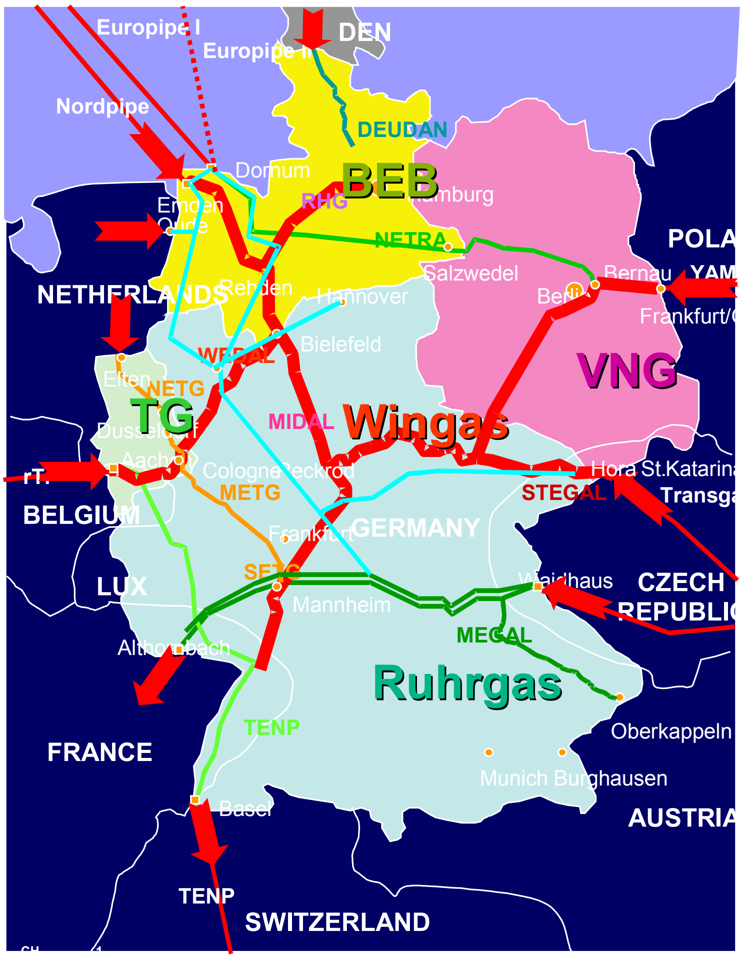
Example. Suppose a shipper injects gas at Aachen near the Belgium-Germany border to serve a customer located in Germany, close to Waidhaus on the Czech-German border (see Figure 3 below). The contract involves a long distance for transportation, since Aachen and Waidhaus are on opposite sides of the country. However, given the massive volumes of gas that flow into Germany at Waidhaus[13] and on into/through Germany, the physical flow will be very different—simple examination of the dominant flows suggests that the gas injected at Aachen may be consumed in the western part of Germany, in France, Switzerland or Italy. It is extremely unlikely that it would ever be delivered to anywhere near Waidhaus. In effect, the gas injected at Aachen will be "automatically" swapped for gas injected at Waidhaus.[14]

[12] We have chosen a specific example for the sake of concreteness. However, the details of the example are hypothetical, and should not be interpreted as reflecting any views concerning any particular TSO or Member State.

[13] According to GTE data, the Waidhaus interconnector has an import capacity of about 34bcm/yr.

[14] Physically speaking, the Waidhaus gas will go to the consumer located near Waidhaus, while the Aachen gas will end up going to a consumer who would otherwise have consumed the Waidhaus gas (unless, as is quite likely, this gas is involved in an additional "automatic swap"). This swap is automatic in the sense that it is accomplished simply by letting gas flow through the system in the natural/most efficient way, without any contracting (or any conscious attempt to effect the swap).

Figure 3: German Pipeline Map



Under the definition of firm capacity discussed above, this contract would nonetheless require the TSO to reserve physical transportation capacity along the contract path. TSOs who choose this definition argue that it is essential for the provision of firm service, since the TSO would not otherwise be able to guarantee transportation in the event that, for example, the Waidhaus interconnector failed to supply gas for whatever reason. However, as we explain below, in many circumstances this is likely to be an inappropriate requirement.

Incremental Contribution to Firmness

In analysing the appropriateness of requiring physical reservation of capacity in this example, one key question is the likely impact of that reservation in reducing the probability of interruption. If, in the absence of physical reservation of capacity, the probability of interruption becomes relatively high (*e.g.*, some number of days per year) then the loss of firmness is likely to be rather significant (this service would better be classified as an interruptible service). However, the increased probability of interruption may be extremely low, calling into question the high cost involved.

Potential Inefficiency and High Cost

Reserving physical capacity is inefficient if it ties up significant investments that would only be required under extremely unlikely events. Moreover, reserving physical capacity ignores the alternative instruments for supporting firm gas deliveries in a meshed network, such as multiple flows, storage, linepack, interruptible contracts, and operational balancing agreements. For example, given the flows of gas and overall flexibility of the German gas system, only in the most extreme circumstances would the TSO need to rely on physically transporting gas from Aachen to deliver gas at Waidhaus.

Physical capacity reservation can therefore risk imposing inefficiently high costs on shippers. The TSO may well be able to achieve a comparable level of security by more economical means. Moreover, the high cost of physical capacity reservation may be more than some shippers are willing to pay for the incremental benefits. Many shippers will prefer alternative means of ensuring security of supply—for example, by installing dual fuel capabilities, increasing output inventory levels to lower the cost of interruption, or purchasing storage.

Financial Guarantees

Rather than tie up capacity in costly long-term investments, the TSO might be able to provide shippers with an equivalent or superior level of security via financial guarantees. For example, in the case described above, the TSO might guarantee the shipper financial compensation if something prevents the delivery of gas from Eynatten to Waidhaus. Financial compensation in this case would logically be related to the difference in border prices between the Belgian and Czech borders. Naturally the tariff for firm service would in this case include the expected cost of the financial guarantee. However, the cost of the guarantee would logically be far less than the cost of reserving physical capacity from Eynatten to Waidhaus.

Barrier to Competition

Physical capacity reservation also risks hampering the development of competition, by entailing tariffs based on contract distances. In the example above, reserving physical capacity might imply that distance-based tariffs are cost reflective, but such tariffs would make it difficult for the customer located near Waidhaus to obtain competitive offers from any party other than the relatively small number of firms that actually move gas through Waidhaus.

Risk of Discrimination

Insisting on physical capacity reservation also risks discrimination, because a shipper with a large contract portfolio could perform "internal" swaps within the portfolio to approximate a more efficient transportation service. For example, suppose that the large shipper already has gas flowing in at Waidhaus, and already has customers in all parts of Germany. Suppose as previously that it now signs a new gas purchase agreement that delivers the gas at Aachen, and wishes to serve a new customer located near Waidhaus. It can simply use the Aachen gas to serve some of its customers located close to Aachen, and use some of the Waidhaus gas to serve the new customer.

Insisting on physical capacity reservation therefore risks *discrimination between small and large players*, at least until liquid trading hubs develop (as we discuss below, with liquid gas trading hubs and forward markets there is less cause for concern with discrimination). A useful analogy can be drawn with the proposal under the second electricity Verbändevereinbarung to divide Germany into two "trading-zones", one covering the North and another the South of the country, and apply a special charge, the "T-component", to any transaction between parties located in different zones. Although the details are different, in this case too a company with a large portfolio of contracts or assets could use that portfolio to reduce its total tariff by "off-setting" flows in opposite directions.

The European Commission took the view that "this system was incompatible with European competition law…[The] T-component was discriminatory since it would have provided to large German electricity suppliers with the possibility to balance counter-directed flows and thus to avoid the payment of the T-component, whilst this possibility was in practice not available to smaller market actors or foreign suppliers".[15]

Conclusion

Some shippers may require the high level of physical certainty provided by a physical capacity reservation along the contract path. However, in many circumstances this is likely to be too restrictive a definition of firm service. The high costs associated with this definition are likely to outweigh the benefits, relative to an alternative service that employs all appropriate physical and financial tools available to the network operator. Defining firm service to involve physical capacity reservation along the contract path risks inefficiency, and may discriminate against smaller shippers in a newly liberalised gas market.

3.3 "Total Network Service"

Efficient network use should involve all the tools available to the TSO to provide firm service. The tools to provide this broader "total network service" include "meshed network operation", *i.e.*, the synergies between different flows, as well as the TSO's access to storage, linepack, interruptible transportation contracts, and operational balancing agreements and other forms of inter-TSO co-operation. We suspect that in the hypothetical Aachen-Waidhaus flow discussed above it might be possible to supply service at a level of firmness acceptable to the consumer without physically reserving capacity for the flow.

Examples

TSOs in the United States do not require reservation of physical capacity along the contract path. Rather, the total firm capacity of the TSO is calculated based on modelling of system flows. All inter-state pipelines in the US are required to file "flow diagrams" each year that show system flows, together with calculations of firm transportation capacity. These calculations are not explicitly probabilistic, but rely on network simulation of the system's capabilities on peak flow days. Because TSO's are able to (and do in practice) take into account their ability to use inter-meshed flows and other system resources, the total transportation capacity is, in general, greater

[15] "Competition Policy and Liberalisation of Energy Markets", Alexander Schaub, Director General for Competition, European Commission, European Utilities Circle 2000, 23 November 2000, Brussels.

than the sum of individual pipeline capacities, particularly on pipeline systems with network characteristics.

Total network service can involve a mixture of physical transport capacity, storage, and explicit trades. One example is the "hub-to-hub" service that EnCana has provided since 1994 between two major gas market centres: the AECO Hub in Alberta and the Union Gas Hub at Dawn in south western Ontario. Customers wishing to despatch gas at the Alberta Hub for delivery to the Union Gas Hub can purchase hub-to-hub services. EnCana takes delivery and title of the customer's gas at Alberta, and transfer title of gas that is physically at the Union Gas Hub to the customer. Related services include load factor conversion, which allows a customer to deliver a volume of gas at the Alberta Hub, and to take deliveries over a longer time period at the Union Gas Hub. The service is mainly used by gas shippers and marketers, with prices negotiated on a customer-by-customer basis due to the large number of variations to services on offer.

EnCana provides the service using a mixture of swaps, physical transportation capacity, and storage. EnCana owns physical transport capacity in the pipeline between the hubs, and will use it if it is more profitable to transport gas than to conduct a swap between the delivery and supply locations. The availability of storage facilities at both the Alberta and Union Gas Hubs increases the reliability of the service. EnCana can take delivery of gas even if there are no third parties who wish to purchase the gas at the point of destination, by simply injecting the gas into storage for sale at a later date. By withdrawing from storage, EnCana can also provide gas to the customer even if no shippers at the time are willing to sell gas at the point of origin. In North America, gas storage was initially important to help compensate for the lack of liquidity in liberalised markets. However, the use of storage has declined as market liquidity has increased.

In addition to these physical tools, EnCana guarantees delivery financially. In the unlikely event of a physical impediment to contract performance, the contract stipulates that the customer will be paid for the 'missing' gas at rates that exceed market value, but that the service provide does not view as excessive.

Finally, we note that in Germany the new VV appears to require TSOs to provide a form of network service for backhauls:[16]

> Generally, it shall also be possible to agree transportation capacity in the opposite direction to the physical gas flow. The network operator may put the use of such transportation capacity under the proviso that the physical conditions allow such transportation to take place in the relevant case.

As we understand this clause, it would imply that in cases where it is physically impossible for gas to flow in the opposite direction to that of the dominant flow, the TSO would nonetheless be obliged to offer transportation, but could interrupt if gas did not flow in the forward direction in sufficient quantities to make the normal "implicit swap" possible.

[16] Associations Agreement on Third-Party Access for Natural Gas (VVII), 3.5.2002, section 3. While we endorse this part of the VV, we believe it should also specify discounts for backhauls along the lines discussed later in this report.

3.4 Potential Concerns

Security of Supply Implications

Some TSOs argue that reservation of physical capacity along the contract path is essential to ensuring security of supply. However, US practice shows that security of supply can be maintained while making use of other network resources, including inter-meshed flows. As described earlier, inter-state pipelines in the US publish "flow diagrams" and accompanying calculations that establish the amount of firm capacity that can be guaranteed using all network resources. Publication of these calculations is a regulatory requirement that ensures security of transmission capacity.

A closely related debate during the US liberalisation process concerned the ability of unbundled TSOs to ensure security of transmission capacity using network resources. A key point in this debate was a "technical conference" organised by the FERC. From comments received at the conference the FERC concluded that "there are a number of operating and contractual tools to ensure that the pipeline, its customers and its shippers will take the necessary actions to maintain the reliable operation of the system—and those tools are not theoretical or speculative. They are in use today," and that "[i]n light of the views expressed at the technical conference, the Commission is confident that the pipelines can unbundle their services and, by retaining operational control of their systems, transport gas…on a basis that is just as adequate and reliable as the current, bundled, city-gate, firm sales service".[17]

Full and effective utilisation of network resources by a TSO retaining operational control of its system therefore does not therefore imply any reduction in security of supply standards. Rather it provides the opportunity to enhance security of supply by allowing TSOs and individual consumers to make full use of the available portfolio of security of supply tools.

In the short term, no change in service definition can affect aggregate security of supply, since the same gas flows and infrastructure remain in place. In the longer term, changes in service definition can enhance security of supply by providing better incentives and by prioritising deliveries more efficiently. Changes can also damage security of supply if they create disincentives for efficient investment.

When all consumers are obliged to purchase a service that involves physical capacity reservation along the contract path, they have little incentive to invest in alternative security of supply tools (*e.g.*, dual fuel capabilities, higher output inventory levels, storage). Allowing consumers to choose among alternative services with differing levels of security therefore enhances security of supply, by facilitating efficient interruption. For example, at present many TSOs impose *pro rata* sharing of gas in circumstances when firm supplies are curtailed. However, some consumers holding firm capacity rights will value firm delivery more highly than others. Security of supply is therefore enhanced by the introduction of multiple service offerings that prioritise deliveries more efficiently.

[17] FERC Order 636, p.53 and p.91.

It is however essential to avoid any measure that discourages TSOs from efficient investment. Chapter 8 discusses at length appropriate mechanisms to ensure efficient investment in new infrastructure.

Network Service via Trade

Some GTE members have argued that there is no need for a TSO to provide network service, because shippers can obtain it indirectly via trades. In the example above, the shipper injecting gas at Aachen could swap its gas with a shipper that holds gas at Waidhaus, avoiding the need to purchase transportation from Aachen to Waidhaus.

However, this argument assumes a mature competitive gas market, with liquid trading of forward contracts at hubs at major locations. In those circumstances the hypothetical shipper might be able to simply sell gas into the "Aachen hub" and purchase gas at the "Waidhaus hub".[18] TSOs would not be involved. The example of EnCana cited above shows how a third party could facilitate such "virtual transportation" between hubs.

At present most European markets are at the early stages of liberalisation, and opportunities to arrange such transactions are limited. Parties may wish to obtain transportation over months or years, while most trading at present is limited to spot contracts. Even if it were possible to find an appropriate counterparty, the associated "transaction costs" (finding the counterparty, negotiating, contracting, monitoring) would be very high. In some cases the main potential counter-party for an entrant seeking to serve a new customer will be the incumbent that has until now supplied that customer, and who therefore has an obvious economic disincentive to engage in the transaction.

Liquid trading of forward contracts will likely take years to develop. Moreover, even in the presence of a liquid market, the TSO will most likely have unique access to a broad portfolio of tools that facilitate network service. The example of EnCana cited above is somewhat unusual—even in the mature gas markets of North America relatively few third party "virtual transport" services are available.

As liberalisation progresses, regulators should therefore check whether market liquidity is sufficient to make network service available to all on an equal basis. If so then there may be less cause to insist on the provision of network service by the TSO.

A related concern is that network service requires the TSO to act as a gas trader rather than a pure transporter. However, this concern is misplaced. No matter how service is defined, in a meshed network transportation generally involves an "implicit swap" of gases: the molecules of gas that a shipper's customer receives are rarely the same molecules that the shipper injected. However, this does not rely on the TSO to act as a gas trader by carrying out any kind of swap

[18] The cost of "transporting" gas between hubs would therefore equal the difference in prices at the two hubs (so would be negative in one direction).

arrangement. It simply reflects the physical flow of gas in the system, which can be thought of as performing "automatic swaps".[19]

Breach of Contractual Commitments

Provision of network service does not imply any breach of contractual commitments. One concern might be that a TSO would breach its commitments by diverting gas belonging from one shipper to another. However, a TSO obviously cannot commit to provide a customer the same gas molecules that its shipper injects. The TSO's commitment is to deliver an equivalent amount of energy (with appropriate technical parameters), which network service does not threaten in any way.

3.5 Recommendations

No TSO can give an absolute guarantee of physical delivery. However, efficient system operation entails using all the tools at the TSO's disposal to provide firm transportation capacity. In general therefore, provision of firm transportation between two points does not require reservation of an equal amount of physical capacity along the contract path.

This conclusion has implications both for network operation and for tariffs. We recommend that:

- Transfer capacities should be *estimated based on modelling of physical flows*. For example, even on a unidirectional A-to-B pipe, the TSO should offer firm service from B to A if modelling indicates that the overall network can ensure delivery of gas from B to A with an appropriate level of certainty. In electricity TSOs routinely calculate transfer capacities on this basis.
- To facilitate this recommendation, TSOs should be required to publish a *full assessment of their network capabilities* (*e.g.*, maximum flow capabilities at each major node) under different operating conditions.
- TSOs should be encouraged to *offer financially firm transportation rights*.
- *Tarification for network service should reflect the physical flows that a contract entails, rather than physical capacity along the contract path*. We discuss the implications in detail in the next chapter.

3.6 Conclusions and Recommendations

- No pipeline can guarantee 100% physical firmness, because there is always a probability of mechanical problems that would interrupt service.
- The optimal level of physical certainty for firm service will depend on the associated costs and benefits. Beyond a certain point, the incremental costs of increasing certainty

[19] We note also that the "pure transporter" concept is potentially misleading, since for system balancing purposes the transporter will be a holder of gas.

outweigh the incremental benefits. Moreover, consumers place different values on incremental certainty. Financial guarantees can provide an effective complement to physical firmness.

- Some TSOs define firm capacity by reference to the reservation of physical capacity along the contract path. Four factors may make this an inappropriate definition of firmness: i) physical capacity reservation may offer little incremental firmness while raising costs significantly, in a manner not desired by customers; ii) financial mechanisms can help meet customer desires for certainty at lower cost, iii) it presents a potential barrier to competition, and iv) it risks discrimination against smaller shippers, especially in immature markets.

- An alternative approach involves "network service" where the TSO takes advantage of the system as a whole to transport gas, including the synergies between different network flows as well as the TSO's access to storage, linepack, interruptible contracts, and operational balancing agreements.

- Examples of network service include the primary-secondary points system used in the US, the capacity buyback system of Transco, and the requirement under the new VV Gas for German TSOs to provide backhauls along unidirectional pipes.

- TSOs should be required to provide network service, at appropriate tariffs, while ensuring a continued high level of security of supply. Our recommendation implies that (i) transfer capacities should be *estimated based on modelling of physical flows*. (ii) TSOs should be required to publish a *full assessment of their network capabilities* under different operating conditions. (iii) TSOs should be encouraged to *offer financially firm transportation rights*. (iv) *network service tariffs should reflect the physical flows that a contract entails, rather than physical capacity along the contract path.*

- In a mature market with liquid forward trading of gas over appropriate timeframes and at multiple hubs, shippers may be able to "self-provide" network service. However, newly liberalised European gas markets that do not yet have liquid gas trading. Moreover, in many cases the TSO will remain uniquely well-placed to efficiently combine the variety of available tools.

4 Alternative Tariff Types

We distinguish explicitly between two aspects of a tariff system: *tariff type* and *capacity type*. It is possible to define capacity one way and set tariffs another way. For example, in both Ireland and the UK the *tariff* type is entry-exit, *i.e.*, the charge for transportation service is the sum of an entry charge and an exit charge. However, in Ireland *capacity* is point-to-point: shippers hold contracts that specify start and end-points, with no flexibility to change one or the other. In the UK capacity is entry-exit: shippers hold separate contracts allowing them to inject and withdraw gas at specified entry points regardless of the destination of the gas, and to withdraw gas at specific exit points regardless of its origin.

As these examples show, it is quite possible for two systems to have the same tariff type but different capacity types. Conversely, it is equally possible for two systems to have different tariff types but the same capacity types. The choice of tariff type and the choice of capacity type are therefore potentially independent. Table 7 provides some examples of different combinations of tariff and capacity types seen in practice.

Table 7: Examples of Different Combinations of Capacity and Tariff Types

		Tariff type		
		Distance-based	Entry-Exit	Postal
Capacity type	Point-to-Point	Germany	Ireland	Spain
	Entry-Exit		UK	For electricity, most EU TSOs
	Postal			Some US pipelines

Not only are the choices potentially independent, they also entail different criteria. For example, cost-reflectivity is the key issue for tariff type, while user flexibility is important with regard to capacity type.

We therefore examine the two aspects separately. This section focuses on the *implications of alternative tariff types*, while Section 5 analyses capacity type. We apply a series of criteria to compare different tariff methodologies, focusing on the choice between distance-based tariffs, which were introduced in many Member States in the first stage of liberalisation, and entry-exit tariffs,[20] which are now in use or being discussed for a number of Member States, and which have been endorsed by Member State regulators.

[20] "Postage-stamp" tariffs can be thought of as a special case of entry-exit tariffs (with the same entry tariff at every entry point, and the same exit tariff at every exit point).

4.1 Criteria for Comparison

Recent work by Member State regulators has done much to develop criteria for selecting between different tariff methodologies. The Conclusions of the Fifth Madrid Forum state that:[21]

> The Forum adopted the following principles which shall apply to all tariffs or charges for the use of gas transmission networks, which shall:
>
> a) be cost reflective and based upon a robust modelling of flows and the network;
>
> b) facilitate efficient gas trade, facilitate market liquidity and gas-to-gas competition;
>
> c) ensure high levels of transparency;
>
> d) provide effective and timely signals encouraging efficient long-term investment in transport infrastructure;
>
> e) take into account the specificities and market characteristics of different networks;
>
> f) provide a fair return on investment for the TSOs;
>
> g) appropriate oversight;
>
> h) any differences in tariff conditions applied to different customers for similar services should reflect underlying costs.

The 2001 Bergougnoux report[22] commissioned for the French Commission de Régulation de l'Electricité (CRE) developed an extensive list of criteria:

- Simplicity
- Level of transparency for the regulator
- Non-discrimination
- Cost-reflectivity
- Possibility of "perverse effects" on investments
- Secondary market for capacity, treatment of congestion
- Articulation between systems (*i.e.*, impact on cross-border trades when a given system is used in each of two neighbouring countries)
- Compatibility between systems (*i.e.*, impact on cross-border trades when two different systems are used in neighbouring countries)

While these are all important issues, our major focus is on cost-reflectivity. We view cost-reflectivity as a fundamental criterion because it is the key condition for non-discrimination.[23] We

[21] Conclusion 8 of "Conclusions of the fifth meeting of the European Gas Regulatory Forum", Madrid, 7-8 February 2002.

[22] "Rapport du Groupe d'Experts sur la Tarification de l'Accès Aux Résaux de Transport et de Distribution de Gaz", April 2001, available from www.cre.fr.

[23] See our previous report for the Commission ("Methodologies for Establishing National and Cross-Border Systems of Pricing of Access to the Gas System in Europe", February 2000) for extensive discussion on this point.

therefore begin with an extensive discussion of the concept of cost-reflectivity and its application to alternative systems. However, other criteria listed above are also of great importance, and we discuss each one either later in this chapter, or in the following one.

4.2 Cost-Reflectivity, Marginal and Average Costs

Cost-reflectivity has fundamentally different implications depending on system growth and actual or prospective congestion.[24] With growth or congestion, capacity is scarce and tariffs face the principle challenge of ensuring efficient allocation.[25] With no growth or congestion, the primary concern is allocating the costs of previous network investments among system users.

For a system that suffers congestion, or expects significant growth, *prospective* costs are important, related to scarcity value and the marginal cost of construction. Incremental demand can raise prospective costs by requiring reinforcements, or by increasing the likelihood of requiring reinforcements, or by accelerating the date when reinforcements will be required, as the new flow brings total peak volume closer to maximum capacity. Setting tariffs to reflect prospective costs is key to *efficiency*: if the prospective costs of incremental flows are high on route A, but low on route B, then efficient prices should reflect that difference to encourage route B relative to route A.

In the absence of congestion however there are no efficiency implications to the choice among alternative pipeline routes. Tariffs should have a *retrospective* focus, allocating the costs of existing investments in ways that correspond to intuitive notions of fairness. Allocation methods should consider the extent and nature of system use by customers. For example, in a long uni-directional pipe of uniform size and without congestion, distance-based charges are intuitively fair.

Tariff Implications

The discussion above implies that appropriate tariffs will in theory have two components: a scarcity charge, and an additional charge to ensure full recovery of fixed costs. The scarcity charge can be set based on a market-clearing mechanism such as an auction, or on marginal cost calculations.[26] If the scarcity charge already recovers fixed costs precisely, then no additional

[24] When gas throughput is growing then the prospect of congestion is always present in the absence of correctly-timed system expansions.

[25] At least in a newly liberalised market. With sufficiently liquid secondary markets in capacity, any distortions in primary allocation can be rectified through secondary trading.

[26] In the UK Transco uses the first of these options to set entry charges at congested entry points, and the second to set exit charges. In theory, in an optimally-planned system (and ignoring issues of indivisibilities) LRMC and the long-run value of scarcity should be identical. If scarcity value is greater than LRMC then it is optimal to build more, and vice-versa.

charge is required for cost recovery.[27] Otherwise additional charges must be applied to recover the balance of fixed costs (*i.e.*, that part of fixed costs not recovered from scarcity charges) and thus ensure overall revenue recovery (the "NPV test"). The aggregate tariff can therefore be conceived of as the sum of two components:

Tariff = "Scarcity charge" + "Charge to recover balance of fixed costs"

In systems that are growing or that suffer significant congestion, the "scarcity charge" will tend to dominate the tariff. Cost-reflective charges will therefore largely reflect long-run marginal cost and/or scarcity value. The long-run marginal cost of increased flows from A to B depends on the necessary system reinforcements and additions, which derive from overall system planning and depend on the whole set of system flows and system capabilities, as discussed in the previous chapter. In complex inter-meshed systems, long-run marginal costs are therefore unlikely to be proportional to contractual distance.

4.3 Distance-Based Tariffs

Under a distance-based tariff system, the total transportation charge is proportional to the distance between the injection and withdrawal points.[28] Distance-based charges can be cost-reflective in certain circumstances. Our discussion in the preceding chapter implies that tariffs based on contractual distance may be reasonable when the TSO reserves physical capacity along the contract path, provided that the shipper wishes to pay the cost of reserving capacity. However, the only reliable proof of shipper demand for physical capacity reservation would require free customer choice from among other alternatives that are offered at cost-reflective rates.

However, in general most networks in the EU are sufficiently complex and inter-meshed that an efficient TSO will rely on a variety of tools to provide firm service, as discussed in the previous chapter. When transportation does not imply physical capacity reservations along the contract path, then distance-based tariffs can still give cost-reflective charges for long pipelines with unidirectional flows.

However, in more complicated networks with multiple entry and exit points physical flows will deviate significantly from contractual flows. In these instances, distance-based systems *no longer provide cost-reflective charges* and are therefore potentially *discriminatory*. We illustrate with a simple numerical example.[29]

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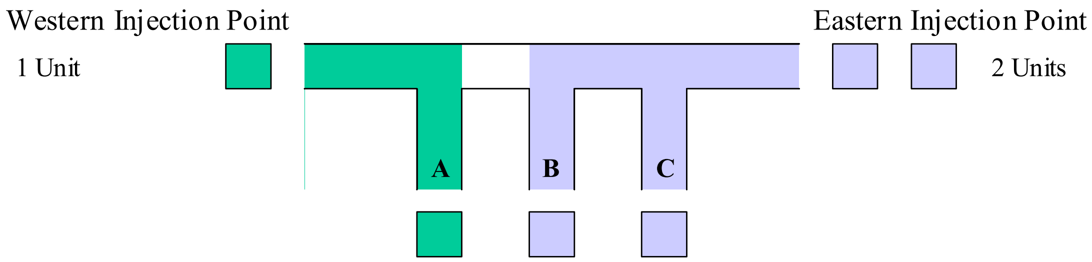
[27] Prior to the introduction of auctions, all entry and exit charges in the United Kingdom were based on LRMC estimates. Transco believed that charges based purely on LRMC coincided closely with the aggregate revenue requirement of the system. However, Transco applied a "multiplier" to LRMC-based prices to ensure revenue recovery. We do not discuss here the problem of over-recovery.

[28] Subject in some cases to certain modifications, in particular to take account of pipeline diameter.

[29] This is a simplified version of an example found in the Bergougnoux report cited at note 22. While the example shown is an indicative and hypothetical one, the logic can be applied to a number of EU Member States, including (but by no means limited to) France.

Figure 4: Simple Network with Two Injection Points and Three Off-take Points



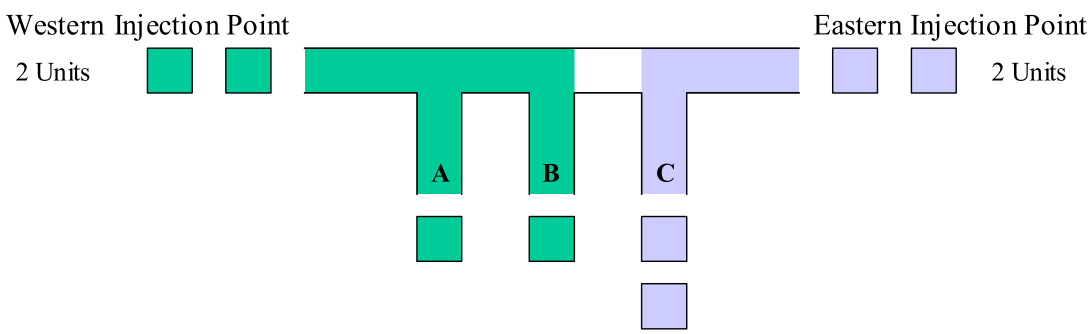
Suppose that the system is initially as shown in Figure 4 (where each "small square" represents a unit of gas), and that a single supplier ("the incumbent") serves all three customers. The tariff is assumed to be one Euro per unit of gas per unit of contractual distance. Table 8 shows the transportation charge that the incumbent supplier would pay to serve each customer, with a total transportation charge of 4.

Table 8: Transportation Charges Faced by Incumbent Supplier

Customer	Quantity	Distance	Tariff
A	1	1	1
B	1	2	2
C	1	1	1
		Total	4

Assume next that consumer C needs to increase its load by one unit, and that to meet this extra demand it has two options. It could either extend its contract with the incumbent supplier, or it could sign a new contract with an entrant. Assume that regardless of the consumer's chosen option, the contractual source of additional gas will be from the western entry point. However, the physical gas that customer C receives would actually originate from the eastern injection point as shown in Figure 5. The gas flowing "from the West to C" actually flows physically as far as B, and gets from B to C via a backhaul.

Figure 5: Additional Unit of Gas is Injected at Western Entry Point



With distance-based charges the incumbent supplier in our example has an advantage over the entrant in serving customer C for the additional unit of gas, because it can design its transportation contracts to minimise total charges. The incumbent's new contracts would state that the gas entered from the west serves customers A and B, and the gas from the east serves customer C. By doing this, the supplier would pay a transportation charge of 5 for supplying all three consumers, as shown in Table 9. In effect, the transportation charge to the incumbent supplier for supplying the additional unit of gas would be 1 (the difference between its new total transportation bill of 5, and the old one of 4).

Table 9 : Transportation Charges Faced by Incumbent Supplying Incremental Unit of Gas

Customer	Quantity	Distance	Tariff
A	1	1	1
B	1	2	2
C	2	1	2
		Total	5

In contrast, the entrant in our example does not inject any gas from the east and so is unable to optimise transportation contracts. It would therefore face a transportation charge of 3 to serve customer C, as shown in Table 10.[30] This is the case even though customer C receives all its gas from the eastern injection point, while customers A and/or B consume the physical gas input by the entrant.

Table 10: Transportation Charges Faced by Entrant Supplying Incremental Unit of Gas

Customer	Quantity	Distance	Tariff
A			
B			
C	1	3	3
		Total	3

We conclude that because of the higher transportation charge the entrant faces compared to the incumbent, *distance-based tariffs discriminate against the entrant*. The specific mechanism of discrimination is sometimes referred to as the *"portfolio effect"*, because it arises from the incumbent's advantage in contract optimisation from the large portfolio of supply sources and customers.

Finally, we note as in the preceding chapter that with trading hubs at both ends of the system enjoying liquid forward trading of gas over the relevant timeframe, the entrant could avoid the higher charge by itself carrying out a swap transaction. However, this is not the case for most European gas markets at present. In the example above, the only potential counter-party for a

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[30] It could be argued that the tariffs need to be reduced as volume increases, so as to prevent over-recovery. However, this does not affect the conclusion. Moreover, many pipelines set tariffs so that forecast volume changes over time do not change the unit tariff.

swap would be the incumbent supplier, and this presents clear problems since the incumbent has little incentive to help its competitor obtain new customers.

Implications for Backhauls

Backhauls present the clearest example of transactions where physical and contractual flows differ radically. Our analysis has clear implications for backhaul tariffs. In the presence of congestion, efficiency requires discounts for backhauls relative to forward-hauls. Backhauls impose low or even negative system costs whenever the system faces actual or potential congestion in the absence of reinforcements. By reducing the net flow in the forward direction, the backhaul postpones the need for potentially costly system expansion and therefore imposes a low marginal cost to the system, or may offer a net marginal benefit.[31] Perhaps the cost would seem high for a backhaul if the TSO insisted on reserving physical capacity in the direction of the contract to ensure security of supply. However, we indicated previously that physical capacity reservations risk imposing inefficiently excessive security levels. Efficiency would imply an extremely low charge for backhauls and perhaps a somewhat lower level of physical certainty with respect to delivery.

Even on a non-congested system, failure to provide discounts for backhauls is not cost-reflective. Consider again the example above, where the entrant effectively serves the customer at C via a backhaul from B to C. Since the entrant's physical flows do not use the path from B to C (and he chooses not to reserve physical capacity on that path), he should receive a discount. While it is true that without the pipe from B to C he would not be able to serve the customer at C, it is also true that without it he would not need to serve that customer—all the "western gas" would serve customers at A and B.

GTE has previously supported distance-based tariffs, but in adopting this position has not intended to imply a rejection of discounts for back-hauls. As an organisation, we understand that GTE does not yet have a formal position on backhauls. Some individual GTE members agree that there are reasonable arguments for providing discounts for backhauls. This implies support by some GTE members for a mixed system, where tariffs for forward-hauls would be based on distance, but discounts could be offered for backhauls. In the absence of back-haul discounts we would conclude that distance-based tariffs are clearly unreasonable.

One possible alternative would be a mixed system with appropriate backhaul discounts. For this to be acceptable the TSO would have to forecast the physical flows of each contract, and then apply the mixed distance-based charges and backhaul discounts to those physical flow forecasts to determine the tariff. Ensuring transparency for such a system would be a challenge in many cases. However, it cannot be rejected without considering specific network characteristics and other factors that we discuss below.

[31] The costs associated with backhauls are also poorly correlated with distance.

4.4 Entry-Exit Tariffs

Under an entry-exit system, the total transportation charge is the sum of separate charges for entry and exit capacity. The charges can vary by entry and exit point, and should be set to make the total charge for any transportation route as close as possible to the associated cost. Exact implementation depends *inter alia* on the cost concept applied. For example, in the UK Transco used to set entry-exit tariffs to make the cost of transportation on any route as close as possible to the "long run marginal cost".[32] However, a similar methodology could be applied using average costs or another cost allocation methodology if the absence of congestion made long-run marginal cost irrelevant.

Certain theoretical analyses of pipeline tariffs imply that, *provided negative entry and exit charges are allowed*, it is always possible to set entry and exit charges so that tariffs reflect long-run marginal costs for network service. The technical arguments behind this claim are laid out in Appendix II. However, we interpret it as establishing a *reasonable initial presumption in favour of entry-exit* when long-run marginal cost is the dominant cost concept, subject to a number of *significant caveats*:

- Excessive reliance on theoretical arguments may be dangerous, because they rely on a number of assumptions concerning optimal planning, perfect foresight, optimal despatch etc that may not hold in practice.
- Implementation of negative entry and exit charges presents difficulties. A standard transportation contract essentially provides a shipper with a "call option" on transportation capacity: they have the right but not the duty to use it. With negative charges the shipper must, in return for being paid to hold capacity, take on the duty to use it when required to do so by the TSO, as well as the right to use it at will. However, these difficulties are not necessarily insuperable—negative entry charges are seen in electricity markets, where generating units can take on an obligation to run at certain times.
- Consequently, it may in practice be difficult for entry-exit charges to fully reflect marginal costs. In particular, without allowing for negative charges it may be difficult to reflect the costs imposed by internal congestion.
- Moreover, the theoretical claim applies to marginal costs and does not hold when the aim is to set entry and exit tariffs to reflect average (rather than marginal) costs,[33] as illustrated by the following hypothetical example.

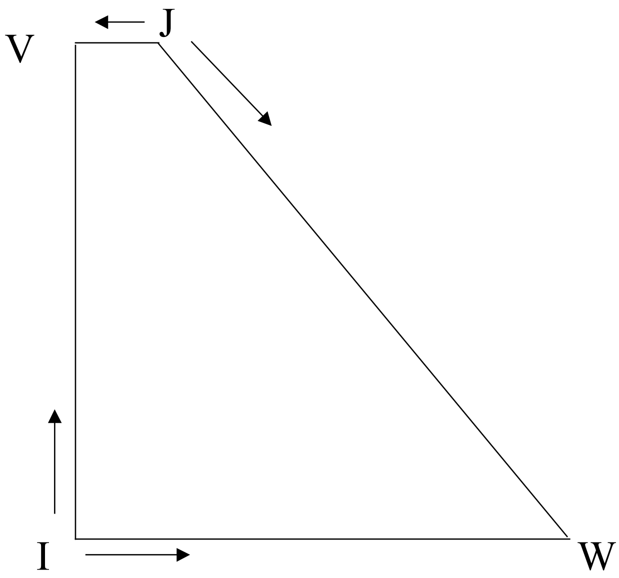
Example. Figure 6 shows a hypothetical system with two entry points (I and J) and two exit points (V and W). Suppose that the average cost of transportation is the same along IV and IW,

[32] Transco used a computer programme to set charges so that the deviation of tariff from long run marginal cost, (weighted) averaged over all routes, was a small as possible (using a sum of squares criterion). It now uses auctions to set entry capacity charges, but retains the old methodology to set reserve prices and exit charges.

[33] Economists typically argue for prioritising efficiency charges on the grounds that an unfair allocation of costs can always be rectified by other means (*e.g.*, countervailing transfers), while the costs imposed on society by inefficiency are irrecoverable.

but the average cost of transportation along JV is much lower than along JW.[34] If in this instance the goal is to set charges so that tariffs reflect average costs, then the charges for using IV and IW must be the same, which necessitates equal exit charges at V and at W. However, this implies that the charge for using JV is the same as the charge for using JW, despite the assumed difference in average costs. In this example it is not possible to set entry and exit charges so as to fully reflect average costs.

Figure 6: Entry-Exit Charges and Average Costs



Conclusions

No reasonably practical tariff system can perfectly reflect costs. In our first report for the Commission we argued that:[35]

> To respect the principle of non-discrimination, tariffs should reflect costs in a broad sense…It is unreasonable to expect more than broad cost-reflectivity, since the complexity of gas transmission and distribution, and the presence of fixed and sunk costs, rule out the exact measurement and allocation of costs to individual transactions.

The theoretical argument touched on above provides a basis for an initial presumption that entry-exit tariffs can be designed to reflect long-run marginal costs broadly, subject to a number of caveats. Proponents of entry-exit argue that in practice it can be made reasonably cost-reflective, and that it has numerous other advantages, including in particular the promotion of

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[34] To simplify the exposition we ignore here the potential circularity: tariffs reflect costs, but tariffs also affect flow volumes and therefore can change average costs. The example can be extended to reflect this added complexity without changing the fundamental conclusion.

[35] "Methodologies for Establishing National and Cross-Border Systems of Pricing of Access to the Gas System in Europe", *The Brattle Group*, February 2000, p. 29.

trading and competition.[36] At the last Madrid Forum a large number of participants indicated a preference for entry-exit systems, asserting that entry-exit best meets the objectives agreed at the Forum and cited earlier in this section:[37]

> The representatives of the CEER, the Commission, consumer organisations, traders and GEODE considered that an "entry-exit" tariff structure would in principle meet the above general criteria [cited on p. 36 above] and best facilitate the development of competition in the European gas market.

The example of Transco demonstrates that entry-exit can be implemented as a successful tariff system, at least in the conditions that apply in the UK.

We therefore recommend that:

- There is a reasonable initial presumption in favour of entry-exit as a tariff system, subject to a series of checks that must be applied.
- The TSO or authority responsible for tariff-setting should:
  - Clearly define a methodology for measuring the costs associated with any physical transportation path (*e.g.*, Transco's LRMC).
  - Calculate indicative entry and exit charges so that the tariff for any given contract is as close as possible to the corresponding costs (*i.e.,* the costs that arise from the corresponding physical flows).
  - Examine the resulting charges for signs of any major divergence from cost-reflectivity. Publication of the indicative charges will allow shippers the opportunity to point out any such divergence.
  - If there are major problems, consider modifications that would ensure broad cost-reflectivity with minimum loss of the considerable other advantages of entry-exit, including those described below.

4.5 Further Major Criteria

Gas Trade, Market Liquidity and Gas-to-Gas Competition

We already described above the potential issues of discrimination associated with distance-based charges. By comparison, entry-exit charges should automatically produce lower charges for back-hauls and approximate the results of the automatic swaps that we described above. Shippers therefore would not require large portfolios of customers to optimise transportation contracts in an effort to reduce total charges. By eliminating the disadvantage of small shippers, entry-exit

[36] Some other commonly cited advantages such as the facilitation of secondary trading of capacity relate (in our terminology) to "capacity type" rather than "tariff type", and are therefore discussed in chapter 5.

[37] Conclusion 10 of "Conclusions of the fifth meeting of the European Gas Regulatory Forum", Madrid, 7-8 February 2002.

tariffs foster entry, and the gradual development of gas trading, liquidity, and increased gas-to-gas competition.

Distance-based charges might risk discourage liquidity by fragmenting gas trading. In an entry-exit system a seller is willing to sell to any buyer, and a buyer to buy from any seller, irrespective of their relative locations. From a trader's point of view, all trade occurs at a single "virtual hub" (referred to in the UK as the "National Balancing Point"). Under distance-based tariffs, equivalent liquidity may rely on the existence of specific physical points that large quantities of diversely held gas pass through, such as the Zeebrugge hub. Without such a hub, under distance-based tariffs market participants will have incentives to find a trading partner located as close to them as possible, so as to minimise transportation charges.

We therefore conclude that entry-exit tariffs are superior to distance-based in the promotion of trade, liquidity and gas-to-gas competition. However, distance-based charges have not prevented the development of liquid markets at trading hubs such as Zeebrugge in Belgium and various points in North America.

Signals for Long-Term Investment

Entry-exit tariffs can be used to signal expected future congestion at specific entry and/or exit points, and therefore provide effective signals for efficient investment more easily than distance-based tariffs. However, locational methodology is not the key issue in this regard (see our extensive discussion later in this report). Entry-exit tariffs *per se* are not a sufficient guarantee of efficient long-term signals, as shown by the example of St. Fergus in the UK (where the absence of long-term capacity has inhibited investment). Moreover, experience in North America demonstrates that distance-based tariffs need not impede efficient long-term investment.

Transparency

The most transparent tariff system that we know in Europe is that of Transco, which publishes sufficient information to allow any third party to reproduce its calculations in great detail. However, this example should not be viewed as confirming the superior transparency of entry-exit systems. Rather the superior transparency of the UK system reflects good practice on the part of both Transco and *Ofgem*. The distance-based tariffs used in many Member States are much less transparent than the UK tariffs, not because they are distance-based but because the TSO has not provided the necessary information on tariff methodology, or the requisite data to check the calculations.

If we set aside these issues it is clear that distance-based tariffs are conceptually simpler, and the calculations required more straightforward, and easier to reproduce. Setting distance-based tariffs requires little more than dividing a revenue requirement by expected "distance-times-volume". In contrast, entry-exit tariffs can be determined using many alternative methodologies. In the UK entry tariffs are set by auction, and exit tariffs by estimating the Long Run Marginal Cost, with adjustments to ensure overall cost-reflectivity (the "NPV test"). It was initially difficult for many market participants to fully understand the system. Other entry-exit systems allocate specific parts of the network to specific entry or exit points, and then derive the charges based on the cost of the specified assets. Yet other approaches are possible.

We therefore conclude that *distance-based tariffs can more easily be made transparent*. However, the UK example shows that *entry-exit systems can be implemented with maximum transparency*. In practice therefore this criterion should not be given any significant weight in choosing between the two. Finally, we note that if distance-based tariffs are adjusted to provide appropriate backhaul discounts, then as discussed earlier the calculations become extremely complex and transparency will be difficult to maintain.

"Articulation" Across Multiple TSOs

By "articulation" across TSOs we refer to the ease of combining a given tariff type across multiple TSOs. Here postage-stamp tariffs give rise to the well-known problem of "pancaking". In contrast, for distance-based tariffs no significant difficulties arise in combining tariffs across TSO borders.

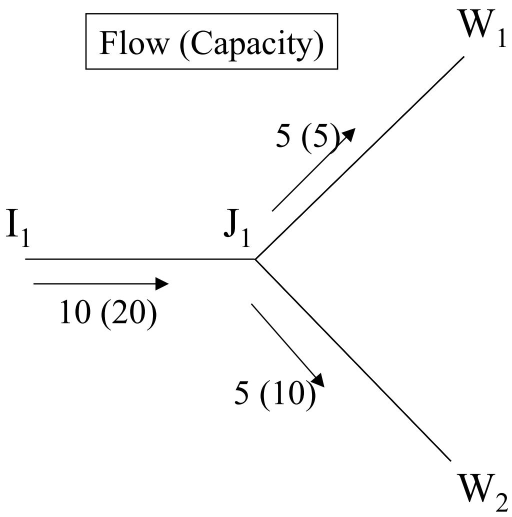
With entry-exit, significant problems can arise with "articulation". Two alternatives are possible:

- TSOs can agree on a single ("multi-area") entry-exit system covering their combined network, as in the for cross-border electricity flows in the EU (and with analogous inter-TSO payments).
- Each cross-border interconnector can be an exit point for one system and an entry point for another.

The first approach encounters the problem of determining inter-TSO payments, an issue that has presented some difficulty in the context of cross-border electricity flows. The second approach risks pancaking if the border-point charges are high. If the border-point charges are low then it becomes similar to the first and encounters the same problems. Moreover, combining two systems in this way presents an additional and more subtle problem because of the impact of extending "network service" across borders to multiple TSOs (an extension that has potentially significant benefits). We illustrate with a hypothetical example.

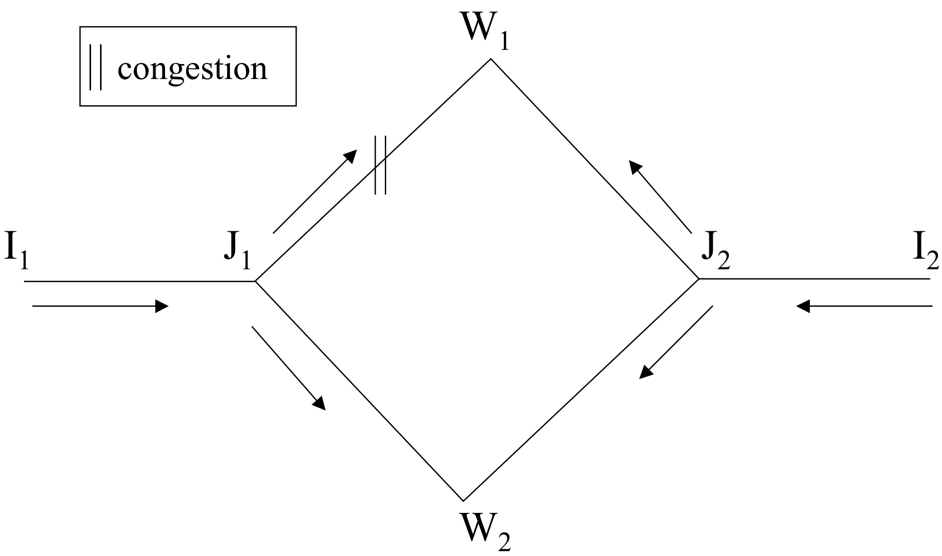
Example. Consider the single network shown in Figure 7 below, with a single injection point I_1, a "junction" J_1, and two offtake points W_1 and W_2. Given the flows and capacities shown, the branch from J_1 to W_1 is congested. The exit charge at W_1 should therefore be higher than at W_2 to reflect this congestion: the marginal cost of sending gas from J_1 to W_1 is significantly higher than the marginal cost of sending from J_1 to W_2, because the first transaction requires network reinforcements while the second does not.

Figure 7: Single Hypothetical Network



Now suppose however that the network shown above meets a neighbouring network, as shown in Figure 8.

Figure 8: Combined Networks, Capacities and Flows



Because of the potential for network service across the two networks, the marginal cost of sending gas from J_1 to W_1 is *not* significantly higher than the marginal cost of sending from J_1 to W_2. One can transport additional gas from (for example) J_1 to W_1 without system reinforcements, by means of a swap: send additional gas from J_1 to W_2, reduce the flow from J_2 to W_2 and increase the flow from J_2 to W_1. Joining the two systems therefore fundamentally changes the appropriate entry-exit charges, *even though in this example no gas flows across the borders*.

Effective articulation across systems may therefore require the creation of "multi-area" entry-exit charges, with inter-TSO payments. **This requires a high level of co-ordination between**

TSOs, with full industry support**.** In this context we note that efficient use of networks itself requires extensive co-ordination in the form of inter-operability arrangements, operational balancing agreements etc Inter-TSO cooperation is therefore fundamental to the European gas industry.

The same analysis applies at the national level where the national system is divided among multiple TSOs, notably in the case of Germany. The use of distance-based charges in Germany clearly avoids significant complications in combining tariffs across borders. However, it appears improbable that the administrative simplicity could outweigh factors such as cost-reflectivity and the promotion of competition.

Criteria in Bergougnoux Report

The Bergougnoux report contains extensive and valuable discussion of the different criteria outlined above. It compares postage-stamp, distance-based and entry-exit systems and concludes that:[38]

- *Postage-stamp tariffs must be rejected for the French system*, despite their advantages in terms of simplicity and transparency, because they would entail unacceptable distortions to competition and economic signals.
- *Entry-exit tariffs have a very clear superiority over distance-based* on a number of dimensions: transparency for the regulator, non-discrimination between entrants and incumbent, more realistic representation of gas flows, facilitation of secondary trading of capacity, congestion management and short-term market access.
- It would then be natural to recommend entry-exit tariffs. However, *for the French system entry-exit also entails distortions* arising from the need to impose positive entry and exit charges, when the marginal costs of certain flows may require negative charges.
- The report therefore introduces the concept of “nodal pricing”, a system that has *the same form as an entry-exit system* but can *avoid the problems created by the need for positive charges*.

We reproduce (in unofficial translation, and with some modifications) a summary of the report’s findings concerning the relative merits of alternative systems in Table 11 below.[39]

[38] See pp.14-15 and p.97 of the Bergougnoux Report cited at footnote 22.

[39] Based closely on Table 3, p.96 of the Bergougnoux report cited at footnote 22.

Table 11: Summary of Bergougnoux Analysis of Alternative Systems

	Distance-Based Tariffs	Entry-Exit Tariffs	Postage-Stamp Tariffs
Ease of use	Quite good	Good	Very good
Level of transparency for the regulator	Difficult to determine	Good	Very good
Scope for discrimination			
Cost of transport	High	None	None
"Portfolio effect"*	High	Moderate	Moderate
Cost-reflective	Not, in general	Criticisable at least in certain cases	Bad for large systems
Possibility of "perverse effects" on investments †	Possible	Possible	High if network extends over wide area
Ease of trading in secondary capacity market	Quite difficult	Quite easy	Quite easy
Articulation between systems ‡	Good	Moderate	Measures needed to avoid pancaking
Compatibility between systems ‡	A priori, no practical problems for tariffs. "Perverse effects" possible		Serious difficulties

* The "Portfolio Effect" is described in Appendix 1.
† Inefficient bypass and location of new demand and supply constitute 'Perverse Effects'
‡ Articulation measures the effect of the same tariff system being shared by two bordering countries. Compatibility problems might arise when two bordering countries utilise different tariff systems.

Comparing our own analysis to that of the Bergougnoux report we note that:

- The Bergougnoux analysis confirms that a postal system has sufficient problems to be effectively ruled out for most Member States, unless required and justified by domestic policy considerations.
- We argued above that distance-based tariffs are more transparent than entry-exit. Bergougnoux argues that they are more difficult to use and *less* transparent for the regulator. However, we believe there is no real divergence of views since Bergougnoux's arguments regarding ease-of-use and transparency for the regulator relate to the rigidity of point-to-point capacity—a point on which our discussion in the next chapter concurs.
- We agree with Bergougnoux on the cost-reflectivity of the different systems. Entry-exit is the *most cost-reflective* of the commonly applied methodologies.
- The possibility of perverse effects on investments exists for all systems. With regard to postal and entry-exit systems, we have previously proposed specific mechanisms to remove the incentives for "inefficient bypass".[40]

[40] See "New Pipeline Authorisation and Third-Party Access Tariffs for the Natural Gas Network in Ireland", July 2000, available from the website of the Irish Department of Public Enterprise.

Further Criteria

Finally we note some further criteria that deserve mention. Security of supply and environmental protection must be considered in the development of energy policy. However, a cost-reflective and non-discriminatory tariff system is most likely to encourage entry of new supplies from diverse sources and to foster market growth, accelerating the environmentally beneficial shift toward natural gas. While there may be a place for additional measures to ensure security of supply, these should occur through explicit interventions using competitively neutral mechanisms (*e.g.*, PSO levies to ensure that an additional supply source can be made competitive). They should not affect the initial choice of tariff type.

The terms of reference for this study include a requirement to "develop a tariff structure that support a safe and reliable operation". While safety and reliability are also crucial, this is really an issue of the level of tariffs, which should be adequate to compensate for the necessary operating and capital costs involved in ensuring ongoing safe and reliable operation.

4.6 Pipe-to-Pipe Competition

Our discussion here has implicitly assumed that tariffs will be set by a regulatory or quasi-regulatory process. However, some TSOs argue that they face sufficient actual or potential competition in gas transmission from other domestic and/or international networks that regulation is unnecessary. The competitive process can be relied on to ensure that transportation tariffs are cost-reflective.

Different commentators and parties have taken quite different positions with regard to pipe-to-pipe competition. Some believe that natural gas transmission is a "natural monopoly", *i.e.*, is most efficiently provided by a single firm that can take advantage of economies of scale and the benefits of co-ordinated network planning and operation. According to this view, pipe-to-pipe competition risks wasteful duplication and under-utilisation of facilities, under-sizing of pipes, and inefficient co-ordination across networks.

Others believe that any such costs are outweighed by the advantages of infrastructure-based competition, which can obviate the need for costly and potentially inefficient regulation, promote flexibility and innovation, and give more "genuine" incentives for efficient and effective operation of transmission businesses.

It is beyond the scope of this paper to analyse these trade-offs. Here we simply analyse the implications of pipe-to-pipe competition for tarification.

In principle pipe-to-pipe competition can be sufficient to ensure competitive pricing and non-discriminatory access to pipelines. However, gas transmission is an industry that faces obvious barriers to the development of competition. Scale economies mean that the efficient scale of entry (*i.e.*, the appropriate size of network/pipeline that an entrant must build) is very large. Entry therefore necessarily entails large sunk costs,[41] that constitute a barrier to entry.[42] Someone seeking to build a new pipeline in competition with an existing pipeline must make a very large irreversible capital investment, with a long lead time and no guarantee of recovery.

High barriers to entry mean that competitive discipline on pricing must come from actual rather than potential competition. In contrast, in industries where entry costs are very low even a firm with a 100% market share might in theory be unable to raise prices above competitive levels without provoking rapid entry from competitors.[43] In the gas industry, proof of competition must entail signs of existing active competition, such as the number of independent players, market shares and concentration indices.

Number of Independent Players

In most industries with high entry costs, effective competition is thought to require at least four or five competing firms.[44] The presence of just two competing pipelines cannot therefore be considered as evidence of a competitive industry. In this respect we cannot agree with the conclusions of the recent study by Prof. Dr. Knieps.[45] Prof. Knieps appears to argue that the presence of more than one player implies that the market is highly competitive, either through actual or potential competition:[46]

> The owner of a monopolistic bottleneck facility will have stable market power even if all market players are perfectly informed, all customers are prepared to switch their supplier and small changes in price lead to a shift in demand. It is therefore necessary to ensure non-discriminatory access to the bottleneck through tailor-made bottleneck regulation. In all other

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[41] For example, in 1997 operating costs for Transco in the United Kingdom were at most £65 million (Transco, *Activity Based Costing Review of 1997*, p. 7), less than 15% of its total 1997 target revenue of £457 million (Transco*, Transportation Ten-Year Statement*, 1997, p. 123). Someone seeking to build a new pipeline in competition with an existing pipeline must make a very large irreversible capital investment, with no guarantee of recovery.

[42] Nobel laureate economist George Stigler defined a barrier to entry as "a cost of producing (at some or every rate of output) which must be borne by a firm which seeks to enter an industry but is not borne by firms already in the industry" (Stigler, G.J., "Barriers to Entry, Economies of Scale, and Firm Size", in G.J. Stigler, *The Organization of Industry*, Irwin, Homewood Il, p.69 (cited in "Competition on Germany's Gas Transmission Pipeline Networks", Prof. Dr. Günter Knieps, March 2002).

[43] This is the so-called "contestable markets" theory. Whether or not this theory describes other industries, it cannot apply to natural gas transmission, since it relies on the absence of sunk costs (see for example discussion by Professor R.J. Gilbert in Schmalensee and Willig, eds., *Handbook of Industrial Organization* (Amsterdam: North Holland) 1989, Vol. I, p. 527).

[44] For example, both EU and US competition authorities use the HHI concentration index. An HHI value above 2,000 (which corresponds to five equally sized firms) is generally regarded as indicating a high level of market concentration.

[45] See "Competition on Germany's Gas Transmission Pipeline Networks", Prof. Dr. Günter Knieps, March 2002.

[46] Knieps, p.8.

network areas, however, the situation is totally different because there is active and potential competition.

and:[47]

> If it can be shown that regional network operators (level 3) and/or local distribution companies (level 4) can choose between at least two different operators of supraregional gas transmission networks, then it is no longer absolutely necessary to have access to the pipelines of a particular supraregional gas transmission company, which in turn means there is no bottleneck situation at the gas transmission level.

This analysis appears to see no middle ground between 100% monopoly and a competitive market. However, the presence of two competing players does not demonstrate either a high level of competition or the absence of high barriers to entry.[48]

Tests for Competition

We recommend that before authorising rates for existing pipelines set on the basis of pipe-to-pipe competition (so-called "market-based rates"), the relevant authority should carry out a series of checks that go well beyond the presence of two pipes. It is beyond the scope of this paper to describe such analyses in detail. However, we recommend that as in the United States, the relevant authorities should check for the existence of market power by applying the same principles and methodologies used in merger analyses.[49] These tests should be applied whether the potential for competition arises from domestic or international competitors. *Inter alia* they should consider:

- Whether independent pipelines transport gas from the same location to the same delivery point.
- Concentration of ownership of pipelines.
- Concentration of ownership of capacity.
- The existence of excess capacity.
- Common ownership links among infrastructure owners or capacity holders.

The report of Prof. Knieps includes detailed discussion of the potential for partners in jointly-owned pipelines to provide competition. The report describes the large number of suppliers that

[47] Knieps, p.19.

[48] Moreover, we believe that the reasons for choosing between *ex ante* regulation and the application of general competition law are rather more complex, depending on factors such as the complexity of the industry and the likelihood of irreversible harm from anti-competitive behaviour.

[49] The criteria established by the US Federal Energy Regulatory Commission (FERC) for interstate pipelines to be allowed to charge market-based rates were set out in "Alternatives to Traditional Cost of Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines", 74 FERC para 61, 076 (1996). The FERC reviews each request for market-based rates on a case-by-case basis. To date no request has been granted.

are "technically" able to compete with German firms because they own transportation rights on national supraregional transmission pipelines. For example:[50]

> Technically, it is possible to market natural gas destined for Italy also in Germany because with SNAM's utilisation rights on the TENP system, they already have a pipeline. The same applies to the sale in Germany of natural gas destined for France by GdF through the MEGAL pipeline system. In principle, this provides opportunities of choice between different gas transmission companies in the catchment area of the project companies' pipelines.

However, competition that is possible "technically" or "in principle" is not an adequate basis for allowing market-based rates. Many problems might arise that prevent such potential competition:

- The contractual framework around such joint venture ("project company") pipelines might not allow for example SNAM to use the TENP to compete within Germany.[51]
- The volumes transported by *e.g.* SNAM through TENP may be already largely committed in Italy. For SNAM to sell significant volumes of gas within Germany it would therefore need to acquire additional capacity on TENP. Such capacity may not be available, or may require the consent of the joint venture partner who might be unwilling to agree if they believed it would be used to supply German customers.
- To sell gas to German customers SNAM would either require access to the "spur" lines that lead off the TENP, or would have to build its own spurs. Its joint venture partner might be unable to provide access (lack of capacity), or unwilling (because it naturally does not wish to help a competitor). To build its own spur SNAM might also require consent from its joint venture partner, which might not be forthcoming.

One cannot therefore view these lines as providing potential competition without knowing whether such obstacles exist.

In summary, although pipe-to-pipe competition can in theory substitute for regulation as a means of setting tariffs, the nature of the industry makes effective competition difficult. The use of "market-based rates" should therefore be subject to rigorous tests to confirm the absence of market power.

4.7 Conclusions and Recommendations

- In a system that is growing significantly—as is the case in most of Europe—and/or suffers from significant congestion, tariffs should reflect long-run marginal costs. Our discussion of "network service" in the previous chapter implies that this is unlikely to be closely proportional to contract distance. Distance-based tariffs are therefore unlikely to be cost-reflective in many EU networks, given current and expected growth.

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[50] Knieps, p.22.

[51] Such contracts may be considered no longer valid under competition law. However, national authorities should be certain that they will no longer be respected.

- Distance-based tariffs can be cost-reflective for long pipelines with unidirectional flows. They can also be cost-reflective where firm service is defined as requiring the TSO to reserves physical capacity along the contract path. However, as discussed above, this is unlikely to be an appropriate definition.

- However, in other circumstances distance-based systems *no longer provide cost-reflective charges* and are therefore potentially *discriminatory*. In particular they advantage larger system users whose portfolio of contracts can be used to reduce transportation charges without any corresponding reduction in real costs to the system.

- Theoretical analysis of pipeline tarification implies that, provided negative entry and exit charges are allowed, it is always possible to set entry and exit charges so that tariffs reflect long run marginal costs for network service. We interpret this result as establishing a *reasonable initial presumption in favour of entry-exit* when long run marginal cost is the dominant cost concept.

- However, this presumption is subject to a number of *significant caveats*: excessive reliance on theoretical arguments may be dangerous, because their assumptions may not hold in practice, and implementation of negative entry and exit charges may present difficulties. Moreover, the theoretical claim applies to marginal costs and does not hold when the aim is to set entry and exit tariffs to reflect average (rather than marginal) costs.

- The presumption in favour of entry-exit should therefore be subject to a series of checks. The TSO and authority responsible for tariff-setting should together:

    - Clearly define a methodology that can be applied to derive the costs associated with any physical transportation path (*e.g.*, Transco's LRMC).

    - Calculate indicative entry and exit charges so that the tariff for any given contract is as close as possible to the corresponding costs (*i.e.,* the costs that arise from the corresponding physical flows).

    - Examine the resulting charges for signs of any major divergences from cost-reflectivity. Publication of the indicative charges will allow shippers the opportunity to point out any such divergences.

    - If there are major problems, consider modifications that would ensure broad cost-reflectivity with minimum loss of the considerable other advantages of entry-exit.

- Entry-exit tariffs have a significant advantage in the promotion of trade, liquidity and gas-to-gas competition.

- Neither distance-based nor entry-exit tariffs has a strong advantage in terms of transparency or impact on investment.

- Distance-based tariffs present fewer problems of "articulation" across TSOs, *i.e.*, they are easier to combine across multiple TSOs. With entry-exit, significant problems can arise.

- Regulators and TSOs should eventually consider the creation of "multi-area" entry-exit charges, with inter-TSO payments. The use of distance-based charges clearly avoids significant complications in combining tariffs across borders. However, simplicity cannot outweigh factors such as cost-reflectivity and the promotion of competition.

- Pipe-to-pipe competition can in theory substitute for regulation as a means of setting tariffs. However, the nature of the industry makes effective competition difficult. The use of "market-based rates" should therefore be subject to rigorous tests to confirm the absence of market power.

Recommendations

- We recommend a presumption in favour of entry-exit tariffs, based on the advantages of cost-reflectivity and the promotion of competition and trading liquidity.

- However, implementation of entry-exit tariffs should be subject to rigorous checks. TSOs and national authorities should:

    - Clearly define the measure of costs that will be applied to derive tariffs.

    - Calculate indicative entry and exit charges, and examine the resulting charges for signs of any major divergence from cost-reflectivity.

    - If there are major problems, consider modifications that would ensure broad cost-reflectivity with minimum loss of the considerable other advantages of entry-exit.

    - Before implementing entry-exit tariffs at the TSO level, ensure that issues of inter-TSO articulation have been properly considered, and design a process to establish the necessary degree of co-ordination.

- Each TSO should have the right to argue in favour of alternative systems, by providing objective evidence that specific features of the system and flows create problems for entry-exit tariffs. National authorities should be obliged to consider such evidence, and publish their analyses.

- The use of "market-based rates" should be subject to rigorous tests to confirm the absence of market power, applying the same principles and methodologies used in merger analyses.

5 Alternative Capacity Definitions

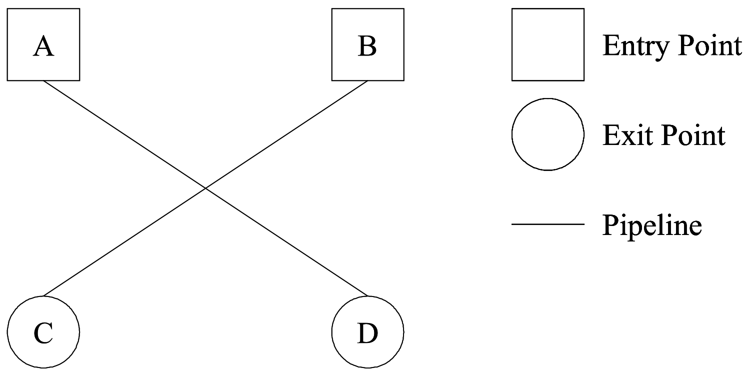
As discussed in the previous chapter, we distinguish explicitly between *tariff type* and *capacity type*. This chapter focuses on the *implications of alternative capacity types*. We apply a series of criteria to compare different types, with particular focus on the relative merits of less flexible definitions (*e.g.*, point-to-point capacity) versus more flexible (*e.g.*, entry-exit).

Capacity systems such as "point-to-point" or "entry-exit" are best understood as alternative types of transportation contracts, each involving a different bundle of rights and obligations between the TSO and the shipper. These contracts entail different trade-offs between the goals of fostering competition, promoting liquidity, and managing congestion. In this chapter we describe alternative contract types, specify the rights involved in each, analyse the trade-offs involved, and make recommendations concerning their use.

5.1 Different Degrees of Flexibility

We focus on three types of firm capacity contract: postal, entry-exit and point-to-point. We illustrate each type by reference to Figure 9, which shows a hypothetical pipeline system with two entry points (A and B) and two exit points (C and D). As noted in chapter 3, it is not necessary for the tariff type to match the definition of capacity rights.

Figure 9: Hypothetical Network



1. *Postal* – A postal transportation contract gives shippers the right to enter gas at any entry point (A or B), and take it off at any exit point (C or D). Under this system, shippers can change entry or exit points without the need to sign new transportation contracts.

2. *Entry-exit* – An entry capacity contract ties shippers to specific entry points, but gives them access to customers who have booked exit capacity at any exit point. In our example, a shipper might be bound by contract to enter gas at point A, but once its gas enters the system it can be delivered to any one who has signed a separate exit contract at either points C or D. The shipper would not have the right to enter gas at

point B unless it signed a new contract. The same holds for exit capacity, *mutatis mutandis.*[52]

3. *Point-to-Point* – A point-to-point transportation contract gives shippers the right to enter gas at a particular entry point and to take it off at a particular exit point.[53] If a shipper held a contract for transportation from A to C, it would not be able to switch either entry or exit points unless it obtained a new transportation contract, sacrificing all the revenues initially paid for the path A to C. The shipper's transportation contract therefore ties it to the route A-C, without any ability to switch to other routes such as A-D, B-C or B-D.

In some circumstances it may also be desirable for a TSO to offer contracts giving the shipper the *obligation* as well as the right to flow gas. In particular, a TSO may wish to provide discounts or even pay a shipper for backhauls, which we define as transport in the opposite direction to dominant flows, which can avoid or postpone the need for costly system expansion. The Bergougnoux report identified specific routes in the French system where negative charges might be appropriate rewards for backhauls.[54]

5.2 Benefits and Costs of Flexibility in Capacity Definition

Below we describe first the benefits and then the costs associated with defining capacity in a more or less flexible way. We identify a key trade-off: greater flexibility fosters competition, but can reduce the amount of capacity that can be made available. The appropriate choice therefore depends *inter alia* on the extent of congestion in the system. A high level of congestion will argue in favour of less flexible definitions, while with a low level it makes sense to offer more flexibility.

Benefits of Flexibility

The flexibility offered to shippers in terms of location of injections and withdrawals is important for the development of competition.[55] Offering flexibility reduces the competitive significance of a shipper's size. Under an inflexible point-to-point system, shippers with a large portfolio of customers have a competitive advantage. A large customer base enables the shipper to perform internal swaps that maintain high utilisation of the particular entry and exit points identified in its transportation contracts. By contrast, a shipper with only one customer may waste transportation capacity if the customer consumes much less gas than anticipated. The shipper

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[52] As noted previously, it is therefore perfectly possible to have system (as in Ireland) where *tariffs* are entry-exit, but capacity definition is point-to-point.

[53] Where multiple routes are available between a given pair of points, the contract may also specify which route the gas will follow.

[54] In particular, injections at Fos ("dans le scénario de référence…les coûts marginaux de transport à partir de Fos, calculés sur la base des prix nodaux, apparaissent…assez fréquemment négatifs.") (Bergougnoux report cited at footnote 22, pp.100-102).

[55] Other forms of flexibility, such as the provision of short-term contracts, are also important in this respect.

may try to sell the transportation capacity that is no longer needed, but a point-to-point system makes it difficult to find a buyer. The transportation capacity will only have value to another shipper who is interested in precisely the same combination of points. By contrast, postal *capacity rights* offer value to all shippers on a network, regardless of the location of their customers or the entry points used. Postal capacity rights therefore facilitate trading, and reduce the likelihood that a small shipper may end up wasting transportation capacity.[56]

Flexibility of capacity definition can be expected to increase competition for two reasons. Flexibility permits shippers to start out small in a market and see if they can compete successfully, take market share away from others, and grow gradually. In the absence of flexibility, a shipper could not enter a new market without initially suffering a potentially serious competitive disadvantage relative to an established shipper with a large customer portfolio. The new shipper in a system might have to tolerate financial losses until it reached a significant size. The prospect of such losses can deter entry into markets. Second, flexibility can increase competition by encouraging secondary trades of transportation capacity. As we explain in the sections on congestion forecasting and financing new infrastructure, liquid markets for transportation capacity send valuable market signals. For example, if long-term transportation capacity sells for a significant premium in a secondary market, it indicates potential congestion. Potential congestion has implications for the strategies of gas supply businesses. More generally, competitors in a market can use market signals as a guide for formulating their business strategies. Companies will be more likely to enter a market on which important information is readily available.

The choice of capacity definition therefore entails a trade-off. Restrictions on flexibility therefore impede the development of competition and trading, and confer an artificial advantage on large shippers. On the other hand, in many systems there may be a cost to offering flexibility. Offering greater flexibility can reduce the amount of firm capacity that a TSO can sell, and can frustrate congestion management. We therefore focus on these issues below.

Costs of Flexibility

The flexibility provided to shippers can affect the amount of firm capacity available. We illustrate this using a second hypothetical example. Figure 10 depicts a second meshed pipeline network that has 3 entry points (A, B and C) and 2 exit points (D and E). The pipelines spanning A-E and C-D have a capacity of 2 units each, while the other pipelines spanning B-D and B-E have a capacity of only 1 unit each. In this example, the demand for gas is 2 units at each of the exit points D and E, giving total demand of 4.

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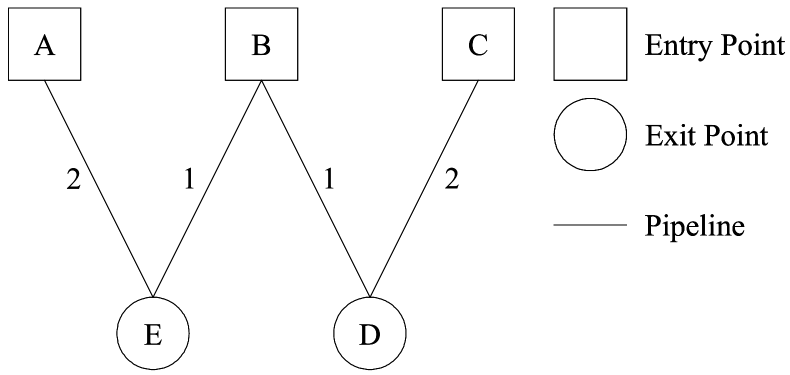
[56] To avoid any potential confusion, recall that this discussion refers to postal capacity rights (defined in section 5.1 above) and *not* to postal tariff systems.

Figure 10: Hypothetical Network



Below, we outline the amount of firm capacity that a TSO can sell on the network depicted under the 3 types of capacity contracts.

1. *Postage-stamp* – The TSO can sell only 1 unit of firm capacity, otherwise it risks being unable to fulfil its firm commitments. If the TSO sold 2 units of firm capacity, it could not satisfy nominations to transport 2 units of gas from point B to customers at point D. After the TSO sells 1 unit of firm capacity, the remaining 3 units of demand at points D and E must be met using interruptible capacity.

2. *Entry-exit* – The TSO can sell 5 units of firm entry capacity: 2 units at each of points A and C, and 1 unit at point B. Otherwise the TSO will be unable to meet all its firm commitments. If the TSO sold 2 units of firm entry capacity at point B, it could not honour nominations to transport both units to customers at point D. A shipper also requires exit capacity. After selling 5 units of entry capacity, the TSO can sell 4 units of firm exit capacity: 2 units at each of points D and E. Because the TSO knows demand at D is 2 units, it can sell 2 units of firm exit capacity, no matter where the gas comes from.

   Although 5 units of firm capacity is more than enough to meet total demand, there is still a risk of inefficiency. If the efficient outcome involves 2 units of gas flowing from B, then the scarcity of firm entry capacity at B would be inefficient.

   Interestingly, in this example the TSO can permit a customer at D to sign a contract for 2 units with someone who owns 2 units of entry capacity at A, even though it is physically impossible to flow 2 units of gas from A to D. The TSO knows that, if D signs for 2 units with A, then E's consumption of 2 units can only involve two contractual possibilities: either 2 units of gas from C, or one from B and one from C (both can't come from B, because the TSO has only permitted one unit of entry capacity at that point). In either case, the gas that is contracted to supply E will physically flow to D and vice-versa.

3. *Point-to-Point* – The TSO can sell 6 units of firm point-to-point capacity: 2 units on each of A-E and C-D, and 1 unit on each of B-D and B-E. Because point-to-point capacity specifies particular entry and exit points, the TSO can, at the expense of high inflexibility, maximise its potential sales of firm capacity.

This hypothetical example illustrates that the amount of firm capacity the TSO can sell depends on the type of capacity contracts it offers. Allowing greater flexibility in capacity contracts may reduce the amount of firm capacity the TSO can sell. The postage-stamp capacity definition is the most flexible possible, but allows the TSO to sell the least amount of firm capacity. Point-to-Point is the least flexible type of capacity contract. It allows the TSO to sell the largest amount of firm capacity, but at a cost in terms of flexibility and liquidity (for example, as described above the ability of a customer at D to purchase gas from a shipper at A).

In a longer-term perspective the same analysis can be interpreted as saying that allowing greater flexibility will increase the amount of infrastructure needed, and therefore the overall system cost, since with a more flexible capacity definition more infrastructure is required to assure the same amount of firm capacity.[57] The key issue is then to evaluate this greater cost against the benefits provided by greater flexibility.

Efficient Trade, Market Liquidity and Gas-to-Gas Competition

The use of entry-exit to define capacity rights provides significant benefits for efficient trade, market liquidity and gas-to-gas competition. These benefits are well-known, and can be illustrated by the success of Transco's entry-exit system in fostering trade at the NBP. By separating out entry and exit capacity, the system automatically creates a single *homogeneous* commodity that can be traded on equal terms by all system users, in the form of "gas at the NBP" or "entry-paid gas". By "making all gas equal", the system maximises the number of parties able to trade with each other, giving increased *market depth*. Because any two parties can trade irrespective of location, entry-exit capacity fosters *anonymity*.

Trading of Capacity on Secondary Market

Entry-exit fosters *capacity trading* on the secondary market, by creating a small number of homogenous commodities (one for each entry or exit point), rather than the hundreds or thousands that exist under point-to-point (one for each combination of entry and exit points).

5.3 Trade-Off Between Benefits and Costs

We conclude that the choice of tariff system involves a trade-off between maximising the amount of firm capacity that can be sold, and providing shippers flexibility to foster efficient competition and liquid trading. It is efficient for the TSO to maximise the firm capacity available for sale, because it encourages network utilisation and can help avoid congestion, and in the longer-term lowers overall system cost. But maximising flexibility is also desirable to foster the development of competition and the liquid trading of pipeline capacity. At one extreme lie inflexible point-to-point contracts, which allow the TSO to sell the most firm capacity but stifle trading in capacity rights (and are unnecessarily restrictive under all circumstances, as discussed

[57] Note that this refers to the flexibility offered to customers through alternative definitions of capacity. This point should therefore be distinguished from our discussion of "total network service" in chapter 3 above. As we discuss there, the increased flexibility that a TSO applies in "producing" firm transportation capacity using the full capabilities of an inter-meshed network will reduce costs.

above). At the other extreme lie postage-stamp capacity contracts, which can create congestion needlessly while simultaneously maximising flexibility for shippers.

The relative merits of different systems will depend both on network topology and on the extent and nature of congestion. In a highly congested system the value of additional capacity may be so high as to justify the use of a relatively inflexible capacity definition, while maximum flexibility would be appropriate for a slack system. For example, if every pipe in Figure 10 had capacity of 4 or more, then it would be possible to sell 4 units of postal capacity, enough to meet total demand for capacity while allowing maximum shipper flexibility.

TSOs and regulatory authorities should therefore evaluate this trade-off in the context of the particular network. In the context of the European system, the general absence of congestion (as described earlier in this report, and subject to the caveats noted there) implies a presumption in favour of *more flexible definitions*. In particular, *the preference of the CEER and other parties in favour of entry-exit is a reasonable starting point* in most Member States, because entry-exit systems facilitate trading and have some ability to reflect constraints.

However, TSOs should be allowed to demonstrate that entry-exit systems on their particular networks would create more costs than benefits because of constraints or reductions in the total capacity that can be sold on a firm basis. If an entry-exit system is not appropriate for a particular network, then we recommend that TSOs and national authorities try to identify the minimum reduction in flexibility that is necessary to solve the problems. Relatively minor, tailor-made adjustments to an entry-exit system may be able to eliminate its defects. *We do not see how point-to-point capacity could be an appropriate remedy* for perceived problems with an entry-exit system. As we explain below, the "pure" point-to-point capacity definition used by some European TSOs is always unnecessarily restrictive.

TSOs may not always have the appropriate incentives to choose among alternative capacity systems. Increasing the amount of available capacity may harm their marketing affiliates by fostering competition from entrants. Where the pipeline's revenues are not effectively regulated, increasing the amount of available capacity may also lower its profits, by reducing the value of existing capacity. *We therefore recommend that regulatory authorities be closely involved in these decisions.* The technical nature of the factors involved, and their potential impact at the operational level will require close co-operation with TSOs.[58]

A TSO should provide *objective evidence* that its proposed definition of capacity represents a reasonable trade-off between capacity availability and flexibility. Evidence should include the results of gas flow models that estimate the impact of different systems on capacity availability. TSOs should share these models with regulatory authorities. Regulators should also develop their own modelling capabilities. We also recommend that the Commission and/or CEER perform bench-mark studies evaluating these trade-offs and the particular decisions taken. They should invite GTE to join in developing appropriate criteria.

[58] If a Member State has a large number of independent TSOs then it may be more appropriate to develop a set of guidelines to be applied, with an effective regulatory oversight mechanism to ensure proper implementation.

5.4 Superior Alternatives to Point-to-Point Capacity

At the beginning of liberalisation most of the European gas industry adopted point-to-point capacity definition for its third party transportation contracts. This was perhaps a natural choice because such contracts are analogous to the long-term bundled contracts that dominated the industry pre-liberalisation. However, in our view *point-to-point capacity definition is always unnecessarily rigid*, because of the availability of alternative approaches that preserve all the advantages imputed to point-to-point while allowing greater flexibility to shippers.

There are many ways to add flexibility to point-to-point contracts. One natural approach is to say that a shipper who signs a contract for transportation from A to C subsequently has the right to nominate a different entry and/or exit point if physically feasible. Many contracts in North America allow shippers to designate several "primary" and "secondary" entry and exit points. In the above example, a shipper might be allowed to designate A and B as its primary entry points. If so, then it would have a firm right to switch from A to B. The same shipper may be permitted to choose either C or D as a primary exit point, but the other one would be a "secondary" exit point. If such a shipper wanted to switch deliveries from C to D, then the TSO would allow the switch if feasible. Typically the secondary exit point has priority over simple interruptible service.[59]

A second example of how flexibility can be added to point-to-point contracts is provided by the practice of "segmentation", where the shipper can break a contract path up into its constituent segments, or combine different segments into a single path. This approach has recently been adopted by Gastransport Services in the Netherlands. Gastransport Services divides its high pressure ("HTL") pipeline system into a series of "sections" and "nodes", and allows shippers to book capacity on individual sections, which it can then combine:[60]

> Individual shippers will be free to contract capacity on particular sections as they see fit in order to facilitate their gas trading operations. They will, for example, be free in the first instance to contract only for the HTL sections relating to their entry points and to add new sections beyond the first node at a later stage.

Shippers in the Netherlands can also break up contracted service into components. Gastransport provides an example where a shipper has contracted for capacity on segments 1 -> 2, 2 -> 3 and 3 -> 4, and then sells part of its capacity on 2 -> 3 to another shipper.[61]

Pipelines in the United States are also required to provide additional flexibility in their point-to-point contracts by allowing a similar form of "segmenting", whereby the owner of capacity

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[59] That is, the TSO will if necessary interrupt an interruptible customer to fulfil a request to switch to a secondary point. For more details of implementation on one North American pipeline see Appendix I.

[60] Gastransport Services, "Indicative tariffs and terms and conditions for gas transport and necessarily related services 2002", p.12.

[61] Gastransport Services, "Indicative tariffs and terms and conditions for gas transport and necessarily related services 2002", p.12.

from A to B has the right to convert it into separate capacity from A to an intermediate point M, and from M to B.[62]

These alternative approaches preserve all conceivable benefits of point-to-point capacity, while allowing greater shipper flexibility. We conclude that pure point-to-point capacity is always an indefensibly restrictive form of service offering.

5.5 Conclusions and Recommendations

- The choice between alternative definitions of capacity ("capacity types") is independent of choice of tariff type (*e.g.*, a TSO could combine postal tariffs with a point-to-point capacity definition).
- The choice between different capacity types entails a fundamental trade-off between allowing shippers greater flexibility in system use and maximising the amount of firm capacity that can be sold.
    - Less flexible systems such as point-to-point capacity in some circumstances allows the TSO to sell more firm capacity.
    - More flexible systems such as entry-exit foster efficient trade, market liquidity and gas-to-gas competition, as well as secondary trading of capacity.
- Flexibility is important for lowering entry barriers and fostering the development of competition. It is therefore of particularly high value in liberalising markets. Maximising the amount of firm capacity that can be made available is of particular importance when capacity is relatively scarce.
- Because of our earlier findings concerning the absence of congestion in the European system, the presumption should be in favour of more flexible definitions (while bearing in mind the possibility of congestion within Member States). In particular, the preference of the CEER and other parties in favour of entry-exit is a reasonable starting point in most Member States.
- If an entry-exit system is not appropriate for a particular network, then we recommend that TSOs and national authorities identify the minimum reduction in flexibility that is necessary to solve the problems. Relatively minor, tailor-made adjustments to an entry-exit system may be able to eliminate its defects. We do not see how point-to-point capacity could be an appropriate remedy for perceived problems with an entry-exit system.
- Of the capacity definitions currently used in Europe, point-to-point capacity provides the least flexibility to shippers. It is *always unnecessarily restrictive*, because of the availability of alternative approaches that preserve all the advantages imputed to point-to-point while allowing greater flexibility to shippers. Examples of such approaches include the "segmentation" applied by Gastransport in the Netherlands, and the system of primary and secondary receipt and delivery points used in the US.

[62] FERC Order 637.

- TSOs may not always have the appropriate incentives to choose among alternative capacity systems. We therefore recommend that regulatory authorities be closely involved in these decisions.

- A TSO should provide objective evidence that its proposed definition of capacity represents a reasonable trade-off between capacity availability and flexibility. Capacity definition systems should be analysed using gas flow models that estimate the interaction between capacity availability and different degrees of flexibility. TSO should share these models with regulatory authorities, and regulators should develop their own modelling capabilities. The Commission and CEER should share their experiences concerning their analyses of the trade-offs between alternative capacity definition systems.

6 Capacity Allocation and Congestion Management

Non-discriminatory capacity allocation and effective congestion management are essential for the creation of an efficient and competitive internal gas market. The issues involved are particularly important with regard to cross-border flows, because the capacity at many interconnectors has already been fully booked. Because most gas in Europe travels long distance and crosses national borders, the lack of capacity at interconnectors is a major barrier to entry in a number of Member State gas markets.

Figure 11: GTE Traffic Lights

The extent of unavailability is illustrated in Figure 11 above, which shows part of the GTE "traffic light" map described earlier.[63] The high proportion of red and amber lights indicates scarcity at many interconnection points. However, this does not necessarily indicate a problem with physical congestion. As we saw in section 2 above, physical congestion is rather limited. The majority of GTE red and amber lights simply reflect that most or all capacity is already booked, even if not fully utilised. We describe such a situation as "contractual congestion".

[63] It should be noted that some GTE members publish or are moving toward publication of ATCs rather than traffic lights.

We analyse the conditions under which contractual congestion might justify denying access to a shipper. Consider the following hypothetical example:

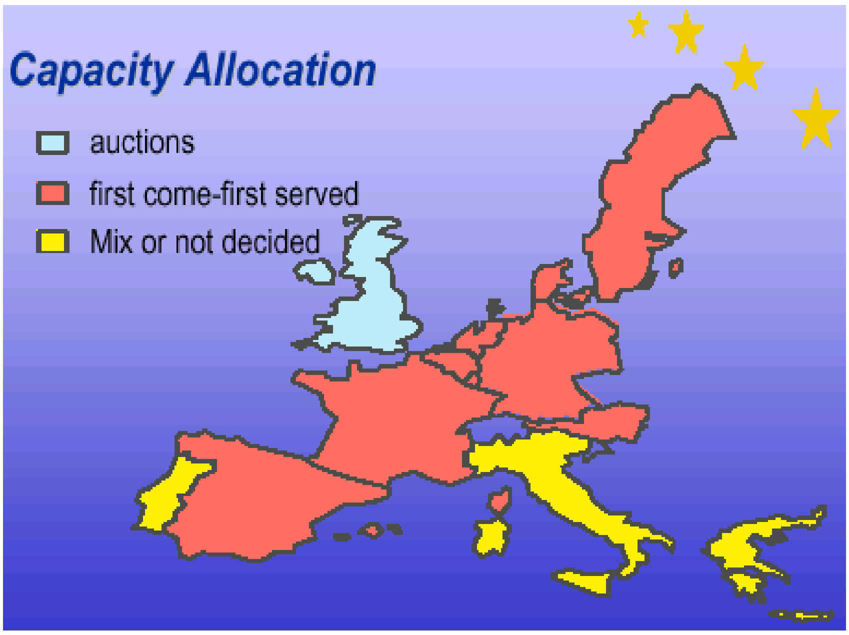
1. An existing supplier has a ten-year capacity contract that produces a "red light".
2. The relevant customer is not legally bound to the supplier.[64]
3. The customer seeks a competing offer.
4. The competing offer would involve gas from the same source, simply replacing the existing supplier.

In this case it is clear that contractual congestion should not prevent access to the competitor. The network would obviously be capable of handling the competitor's gas. To deny access would permit the existing holder of the capacity to monopolise access to the customer. We analyse how alternative methods of allocating capacity could address such simple situations, and more complex ones that involve contractual congestion, as well as cases of "physical" congestion where the network simply cannot handle all proposed gas flows.

6.1 Choice of Capacity Allocation Mechanism

As Figure 12 below shows, there is currently no uniform methodology for capacity allocation in EU gas markets. The most common method has been "first-come, first-served", but other methods are in use or have been used, such as auctions in the United Kingdom, "beauty contests" in Ireland, and pro-rata rationing in Italy.

Figure 12: Capacity Allocation Methodologies (GTE, Feb 2002)



[64] To avoid complications, suppose also that the loss of this customer will not create problems with regard to the existing supplier's "take-or-pay" commitments.

Each method has merits and disadvantages, and there is no "best" overall solution. Specific market conditions, including the current level of market liberalisation and the degree of capacity scarcity, determine the appropriate choice of capacity allocation technique. In a mature competitive market with effective unbundling of the pipeline from any affiliates, the particular choice of method may be relatively unimportant, because liquid secondary markets can ensure the efficient final allocation of capacity. However, the allocation method may be crucial in a newly liberalising market. In particular, the appropriate choice of capacity allocation mechanism will then depend fundamentally on the extent and nature of congestion. Recall that we have distinguished between:

- *Physical Congestion:* existing physical flows at peak periods use all (or nearly all) available capacity.
- *Contractual Congestion:* the system is *not* physically congested, but all (or nearly all) available capacity is taken up in long-term contracts.

Below we discuss in turn the cases of no congestion, contractual congestion, and physical congestion.

6.2 No Congestion

If neither contractual nor physical congestion exists, "first-come, first-served" is an appropriate mechanism of capacity allocation. The absence of scarcity prevents competitive problems from arising. It might be argued that "first-come, first-served" would still be deficient relative to other mechanisms because it fails to create the same market signals as an auction, or as other mechanisms that might induce secondary market trading.[65] However, a complete lack of congestion should be apparent to a transparent market with or without auctions and secondary-market trading. As we indicated above, in the absence of congestion the auction price should be equal to the reserve price, if there is one, or equal to zero if there is no reserve price. Since auctions tend to be more costly and burdensome than "first-come, first-served", we see little reason to recommend them in this situation.

6.3 Contractual Congestion

We make two recommendations in relation to contractual congestion:

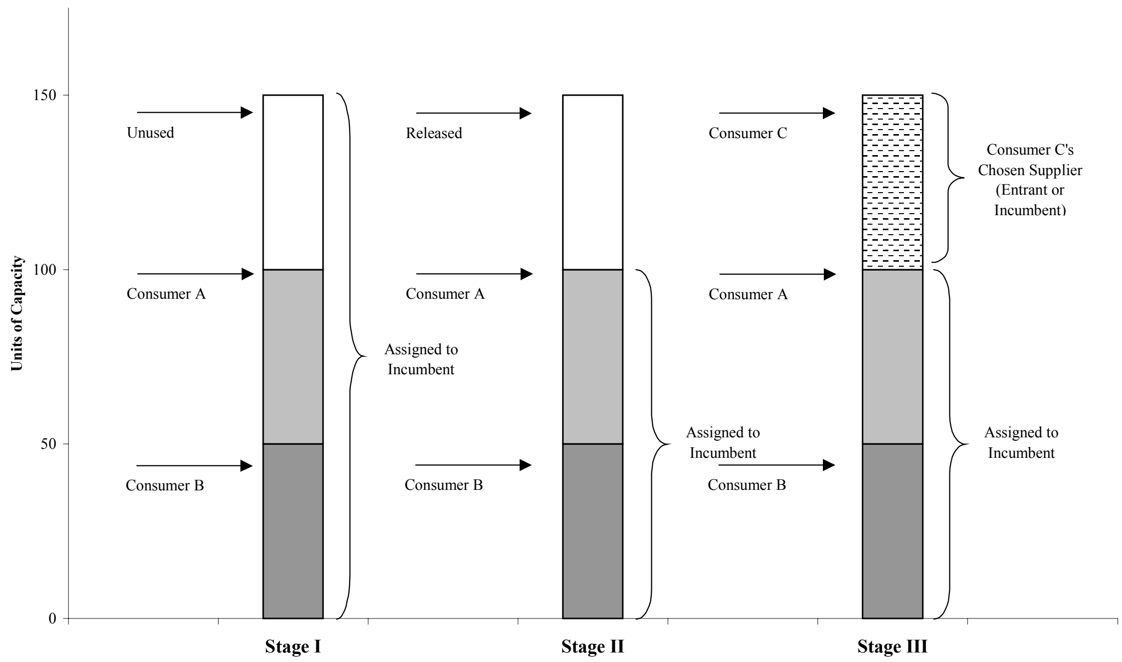
1. A "one-off" *ex ante* release of capacity that the incumbent has booked in excess of its contracted needs with end-users, both for current and future deliveries.
2. A rule for "automatic resale" of capacity when a customer switches.

[65] An effective but highly artificial approach to fostering secondary trading would be allocation by lottery, which would induce trade between lottery winners and lottery losers who valued the capacity more highly than the winners. We would not recommend such an approach.

Ex Ante Capacity Release

Figure 13 illustrates our proposal for *ex ante* capacity release. Stage I in Figure 13 shows a situation where one supplier has secured all available capacity, but only has enough demand to utilise part of the capacity. We propose that the capacity holder be required to release the capacity held in excess of its requirements, as shown in Stage II. An eligible customer would then be free to purchase gas from either the existing supplier or a competitor, as shown in Stage III.

Figure 13: Ex Ante Capacity Release



A key issue here is to determine the needs of the existing capacity holder. We recommend that:

- The regulator authority have the power to obtain relevant information concerning the existing end-user contracts and gas supply contracts of the capacity holder, and that the confidentiality of the information be maintained.
- The term “existing contracts” should include contracts with independent customers that are signed but have not yet started (for example where a power station is under construction and has committed contractually to future purchases).
- However, “existing contracts” should not include prospective customers who have not yet signed binding commitments. At times a customer may sign a non-binding “memorandum of understanding” before committing to purchase gas.
- Prior to full market opening, the regulator should commission an objective, independent study to assess the amount of capacity needed to meet the potential peak demand of the captive market. The regulator should have the power to obtain all necessary data from the TSO and from the supplier of non-eligible customers. The CEER may wish to adopt a

harmonised definition of potential peak demand that considers uncertainties such as the "1-in-20 winter".

- A similar process should be used if capacity must be dedicated to specific Public Service Obligations.[66]

Our capacity release proposal meets key goals of the Gas Directive. It prevents discrimination by removing a barrier to entry, and fosters competition by allowing multiple shippers to compete to serve customers.

Either a TSO or an affected supplier may object that our proposal interferes with existing contracts. We should clarify that our capacity release proposal rests on the perception that existing contracts create a competitive problem. European competition law does not permit contracts or contractual features that prevent the development of competition. We therefore do not recommend intervening with contracts except on grounds that are consistent with existing European law. Other transitional measures such as the gas release programmes implemented in some MS invoke similar legal principles.

Automatic Resale

The *ex ante* release may free up sufficient capacity to remove contractual congestion. However, further measures may be required if capacity release is never implemented, if its implementation is not sufficient to remove contractual congestion, or if contractual congestion returns in the future. We consider four possible approaches to dealing with ongoing contractual congestion:

1. "*Just Say No*", *i.e.*, deny access to new applicants for capacity.
2. *Interruptible Capacity*. Offer the needed capacity to applicants on an interruptible basis.
3. "*Automatic Resale*". Allow an applicant to purchase capacity, but on the condition that the TSO subsequently transfer the applicant's capacity payments to the existing capacity holder. This prevents the TSO from collecting twice for the same capacity, and compensates the existing capacity holder for the released capacity. The transaction would have the same effect as if the existing capacity holder sold the capacity directly to the competitor, but the TSO would handle the transaction.
4. "*Capacity belongs to the Customer*". Another possible solution is to "reconfigure" contracts so that capacity belongs to the customer rather than the supplier or shipper. Customers could then switch suppliers at will, since the necessary transportation capacity would always be automatically available.[67]

[66] In general we propose this process as a one-off event. However, where ongoing PSOs require dedicated capacity, the capacity estimates should be reviewed periodically.

[67] This approach can be seen in the UK, where large consumers generally hold their own exit capacity. The Italian regulator has also expressed an interest in implementing this approach.

The first of the four options ("just say no") would frustrate the development of competition. Access should not be denied because someone has already booked all available capacity, given that the network can accommodate the competitors' proposed flows. Recall that here we are discussing cases of simple contractual congestion in the absence of physical congestion. Denying access in such cases would conflict with the goals of the Gas Directive.

In theory, a potential competitor could propose to purchase capacity from an existing shipper on a secondary market, even if the TSO refused to sell capacity. We encourage measures by TSOs that would encourage the development of secondary markets, such as standardising transportation contracts with provisions that make them easily tradable, and organising electronic bulletin boards. However, secondary trading can only solve contractual congestion in markets that already have a great diversity of shippers. In a diverse, competitive market, any shippers with excess capacity will automatically have an incentive to release it in a secondary market. Only one shipper with excess capacity might resist a secondary-market trade: the shipper who stands to lose the customer to the competitor. Even then, the shipper who is losing market share should understand that a refusal to sell excess capacity would not block the competitor anyway, since the competitor could purchase the capacity from a number of others. While secondary markets present a long-term solution to contractual congestion, in many Member States one shipper still dominate the control of existing capacity. The dominant shipper could successfully block competitors by refusing to trade excess capacity, and would therefore have no commercial incentive to release the capacity.

The second option, for the TSO to provide the capacity on an interruptible basis, has certain merits. It would free capacity "on demand" and lead to increased capacity utilisation, while maintaining the priority of existing contracts in the event that physical congestion arises. Moreover, it would reduce the incentives for existing capacity holders or TSOs to exercise market power by withholding capacity. However, offering access only on an interruptible basis would introduce unnecessary uncertainty to competitors. If there is no physical congestion, then the TSO knows that it can honour the flows requested by competing shippers. There is no reason for the TSO to deny requests for firm transportation when the TSO knows that they can be honoured.

We *recommend the third approach of "automatic resale"*. This approach ensures that capacity is always efficiently allocated and utilised, contributing to the development of a fully competitive market. It replicates the effect of a direct sale from the existing capacity holder to the competitor, while avoiding the problem that the existing capacity holder might not voluntarily undertake such a sale, or only at an exorbitant price, for anti-competitive reasons. Automatic resale limits contractual rights because it proceeds without the consent of the existing capacity holder. However, it occurs only under conditions in which refusal to resell the capacity would be anti-competitive.

The fourth approach, "capacity belongs to the customer", also has several merits. It appears to offer an elegant solution to the problem of monopolisation. If the customer controls the capacity, then no shipper can ever monopolise the capacity. However, this approach has significant drawbacks. It would require significant restructuring of existing contracts. Many customers lack either the necessary expertise or desire to handle gas transportation. Market practice would doubtless evolve to give shippers the role of agents who manage capacity on behalf of customer-owners, but there could be a messy initial phase. Moreover, if customers know that they will retain control of their capacity in perpetuity even as they switch shippers, then customers will not have any incentive to sign long-term capacity contracts. Although short-term transportation contracts are important for efficient natural gas markets, so are long-term contracts. As we explain in Section 7 below, long-term contracts are important for the creation of market signals that facilitate the management of *physical* congestion. Perhaps this problem could be solved by requiring customers to make long-term financial commitments to the TSO if they want to be assured of long-term capacity availability. However, experience indicates that even large customers lack the necessary expertise to make long-term decisions concerning transportation capacity. Gas markets will perform best if suppliers retain the responsibility for making long-term financial commitments to secure transportation capacity. Suppliers will have no incentives to undertake long-term commitments if they know that they will lose the capacity rights without compensation whenever a customer chooses to switch suppliers.

We therefore prefer the approach of automatic resale, because it leaves suppliers with incentives to sign long-term transportation contracts. Although a supplier might lose the capacity if customers decide to switch, the supplier will at least receive compensation for its long-term capacity payments. The supplier will therefore not be deterred from signing long-term contracts. Long-tem contracts would at least assure the supplier of available capacity if the supplier can manage to keep the customer. Long-term contracts would still protect the supplier from the possibility that physical congestion would arise over the horizon of the contract.

Extension to Complex Networks

The discussion above is easiest to understand where the capacity that is dedicated to a particular customer can be readily identified. However, in complex networks it may be difficult to match transportation capacity to particular customers. If a customer is in the centre of a country that imports gas from many several entry points, and where the customers purchase gas from a supply affiliate of the TSO, then the possibility of matching capacity to the customer will depend on the state of unbundling. Many vertically-integrated suppliers have already unbundled their accounts, but have not yet unbundled their use of the transportation network. They have not yet signed formal transportation contracts with their TSO affiliates that would assign "point-to-point" capacity combinations matching gas sources to particular customers. Even if unbundling proceeds to include transportation contracts, under some capacity definitions it might still be impossible to match transportation capacity to particular customers. With "entry-exit" transportation rights, it might not be clear which entry point should be involved in our automatic resale proposal for particular customers. Allowing the incumbent supplier to decide which gas serves which customer might not be reasonable. The incumbent might deliberately link its most attractive customers to the sources of gas where competitors do not have access. The customer should be allowed to decide which gas source was serving it, as long as the customer's choice does not involve a route that is physically congested. Choice of a physically congested route could force customers to adjust gas flows inefficiently. As long as the customer's choice is limited to contractually congested routes, the incumbent will remain able to adjust gas flows as it desires in response to the loss of a customer.

Regulators should also consider establishing rules in advance matching capacity to customers. At the beginning of the year, an existing supply business might propose to the regulatory authority that for every customer lost to competitors in the north of the country, the automatic resale mechanism should involve capacity from entry point A, and customers in the south should be associated with entry point B. The regulator would assess the reasonableness of this proposal, or derive its own proposal, and make a final determination. The regulator would logically consider factors such as network dynamics, the existing suppliers' contracts for gas imports (including take-or-pay provisions), and the potential for competitors to acquire gas supplies from different sources. Matching transportation capacity to particular customers may in some cases be a significant task for the regulator, but can facilitate the development of competition.

We conclude that the optimal policy involves the ex ante release of transportation capacity and, in the event that capacity congestion recurs, a policy of automatic resale. Automatic resale would involve the TSO granting capacity to the applicant, but transferring the capacity payments to the initial capacity holder. The allocation of entry points to particular customers should either be at the customer's discretion or be decided in advance by the regulator, with input from the incumbent gas supplier.

Ex Post Capacity Release

Another alternative involves "ex post" capacity release. Instead of releasing excess capacity before receiving requests from potential competitors, a Member State may simply have a law giving the regulator or competition authorities the power to force capacity release if competitors are refused access. The TSO would deny access based on contractual congestion. It would not matter that the network could handle the physical flows requested because a competitor's transaction was just a "replacement flow", or because the TSO knew that the existing capacity holder could not possibly obtain sufficient customers to require full utilisation.

Ex post capacity release could in theory work as effectively as ex ante release. In practice, however, it could raise several problems: delays to competitors, legal costs for competitors, dragging particular customers against their will into administrative proceedings, and publicity for transactions that competitors and customers would like to keep confidential. As we indicated above, we also see no reason why the TSO should deny access to competitors when it knows that the network can accept the gas. We therefore prefer the combination of a one-time ex ante capacity release, and an ongoing rule of automatic resale. Ex post measures can also be useful as supplementary tools, but should not be the focus of regulatory policy.

6.4 Physical Congestion

A different situation arises when demand exceeds the physical ability of the network. Suppose that a pipeline is already at full capacity, and that a new gas-fired power station will be constructed within a short timeframe. A simple capacity release programme as described above would not solve the problem of congestion.

We have considered four (not necessarily mutually exclusive) approaches to capacity allocation in the face of physical congestion:

1. *Auctions*. When new capacity becomes available, allocate it via a non-discriminatory auction procedure.

2. *Secondary Trading Among Shippers.* Do not auction capacity, but design transportation contracts to be easily tradable, and perhaps facilitate secondary traders with an organised forum such as an electronic bulletin board.

3. *Secondary Trading Among Customers*. Under this solution, capacity would belong to customers, who would be free to trade it among themselves. In our example above, the new power station could obtain capacity from an existing end-user who was willing to curtail gas consumption at a mutually acceptable price.

4. *"Capacity Release Through Auctions".* The regulatory authority would require existing holders of long-term capacity to release some percentage of their booked capacity, which would then be reallocated via auction.

The first approach would help ensure the non-discriminatory allocation of capacity to the user who valued it most. Auctions could also provide valuable market signals and could foster the development of a secondary market, since the auctioned contracts would necessarily be standardised and therefore easily tradable. However, if existing capacity holders do not participate in the auction, then perhaps the amount of capacity offered in the auction would be insufficient. The power station project in our example might suffer delays or cancellation waiting for sufficient capacity to surface in an auction.

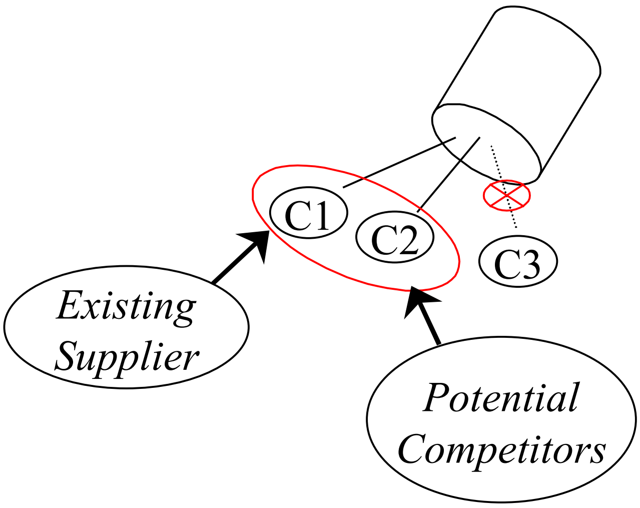
The second proposed solution, secondary trading among shippers, could reallocate capacity more rapidly than an auction. Our hypothetical power station could obtain needed capacity without waiting for a scheduled auction. However, as we indicated with respect to contractual congestion, this solution is only appropriate in markets that have already developed a diversity of shippers.

The third proposed solution, secondary trading among customers would solve the problem of anti-competitive behaviour. Customers in Member States are sufficiently diverse to avoid problems with the monopolisation of transportation capacity. However, as discussed earlier, we believe that it is inappropriate to place all transportation capacity in the hands of end-users.

We recommend the fourth proposed solution, *capacity release through auctions*. This has the advantages of an auction discussed above, but release of capacity by dominant shippers would ensure that sufficient capacity were available in the auctions to have a significant impact on the market. Of course, the auctions should be designed to avoid competitive problems, which include the potential advantage of a vertically-integrated supply business that we discussed above, and also the prospective monopolisation of capacity in the auction. Experience indicates that it can be useful to impose caps on the total amount of capacity that any one company can purchase at the auction.

Our fourth solution also makes sense in conjunction with our recommendations for contractual congestion. Our package of recommendations can accommodate the potential transition from contractual congestion to physical congestion. For contractual congestion, we recommended an automatic resale policy. This policy would no longer make sense after the emergence of physical congestion. With physical congestion we confront the situation depicted in Figure 14 below. In this case an automatic resale policy might allow competitors access to customers who already had transportation capacity (customers C1 and C2 in Figure 14), but would not solve the problem of access to potential new customers such as the hypothetical power station that we discussed above (customer C3).

Figure 14: Physical Congestion



When discussing an automatic resale policy, we explained that compensating the original capacity holder would preserve shipper incentives to sign long-term transportation contracts. Shippers would sign long-term contracts as protection against the subsequent emergence of physical congestion. Physical congestion would cause the market value of the capacity to rise above its regulated price. If a shipper signed a long-term contract prior to the emergence of physical congestion, then the shipper would make money by paying only the regulated price but realising the full market value once the congestion arose. Our proposed policy of capacity release through auctions would still permit shippers to perceive the market value of long-term capacity. We would propose that the auction proceeds go to the TSO for new capacity it makes available, and to initial holders for the capacity that they release in the auctions. In this manner, financial incentives would persist for shippers to sign long-term contracts in anticipation of physical congestion.

Our proposed capacity release should only involve shippers who had a dominant share of the relevant capacity. Shippers who have an insignificant market share should not be forced to release capacity. Such shippers would have natural commercial incentives to release capacity in any event if it were efficient to do so. Small shippers should be allowed to offer capacity in auctions if they wish, but participation should not be obligatory. Capacity release should only be required of dominant shippers because they do not have automatic incentives to release capacity when it is efficient to do so. The logical extension of our proposal is that capacity release should not be required at all in markets that are sufficiently competitive as to lack any dominant shipper. A TSO or regulator may still prefer auctions in competitive markets because of the increased transparency and liquidity that they can provide relative to secondary market trades. However, if the market is already competitive then capacity release by shippers should not be an obligatory component of the auctions.

Capacity Expansion

Expanding the network also helps address physical congestion. Regulatory authorities should have the authority to insist that the TSO expand the network if it is economically justified. A customer's willingness to pay for the expansion should be deemed proof that expansion is indeed economical.[68] TSOs who claim that expansion is not economical should be required to present objective evidence to the regulatory authority. In this context we note the potential role for long-term capacity auctions to provide important market signals concerning the value of capacity expansion, which we discuss further in Section 7.

6.5 Capacity Definition and Congestion Management

In the previous section we described the trade-off between different forms of capacity definition, which entails a choice between allowing greater flexibility and increasing the total amount of firm capacity that can be made available. In some circumstances TSOs may be able to increase flexibility without reducing available capacity, and *vice versa*, and in situations of physical congestion this may be of great importance. For example, most systems can afford to provide much greater flexibility on "normal" days than on peak flow days. It may therefore make sense to accompany capacity definitions with balancing tolerances that vary over the course of the year, or that depend directly on ambient temperature. Gastransport Services has suggested such an approach in the Netherlands. This approach would allow the TSO to make more flexibility available in the summer months than if the TSO were compelled to offer precisely the same amount of flexibility every day of the year. *We therefore recommend that TSOs and regulators examine carefully the potential for such measures***.**

TSOs can also help mitigate congestion problems by offering short-term services, interruptible services, and by offering firm services that compensate shippers financially in the event of interruption. Short-term services permit a TSO to take advantage of the increasing certainty that arises as a particular day approaches. The amount of firm capacity that can be made available at the beginning of the year is generally less than the amount that can be made available a month or a day in advance. TSOs should therefore implement a "rolling release" programme like that used by Transco for entry capacity in the UK and El Paso Natural Gas Company in the United States.[69] The process would be something along the following lines:

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[68] The Gas Directive gives Member States the right to impose such an obligation on TSOs. "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 shall make the necessary enhancements as far as it is economical to do so or when a potential customer is willing to pay for them." (Art. 17)

[69] We describe the El Paso system in Appendix I (If the El Paso example is not unique but standard US practice then please present it so). A similar approach is also taken by *e.g.*, E.On, RWE, Tractebel and TenneT for electricity interconnectors.

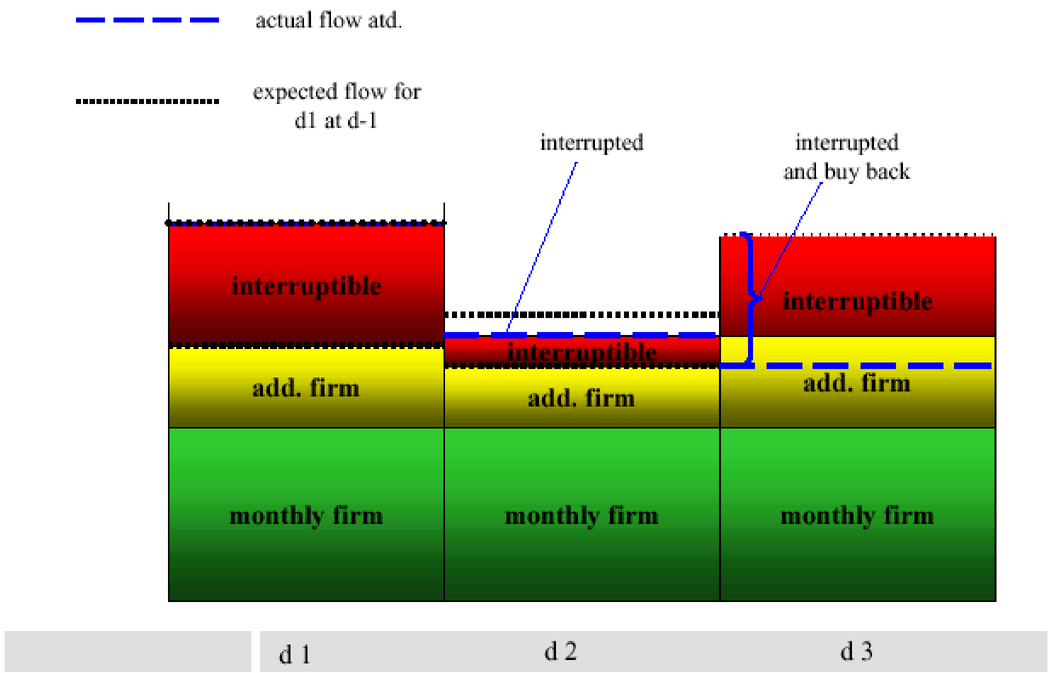
- At the beginning of the year, engineers estimate how much firm capacity (in physical terms) they feel confident will be available over the year.[70] The TSO releases that quantity for sale to shippers (on a monthly and/or annual basis).

- Toward the end of each month, engineers repeat their calculations for the coming month. If they are now confident that a greater amount of capacity will be available, then the TSO also offers the extra capacity to shippers in a monthly capacity contract.

- Each day engineers repeat their calculations for the coming day. If they are confident that a greater amount of capacity will be available, then the TSO makes the extra capacity available to shippers for that day.

- As in the Transco system (illustrated in Figure 15 below[71]), it may be desirable to introduce a system where the engineers take slightly greater risks in estimating available capacity, provided the TSO can buy back firm capacity when it has sold too much. However, this is only practical in a mature market with many shippers willing to compete to sell capacity back to the TSO.

Figure 15: Transco NTS Entry Capacity Allocation



[70] This depends on a complex set of technical parameters: "from a technical perspective the capacity of pipeline is determined by a complex set of different technical design parameters as well as the underlying flow scenario. Once these parameters are fixed the capacity is mainly a function of delivery and redelivery pressures. On the other hand, the technically available capacity between different nodes does not only depend on the specific design parameters and the pressure differentials but also on the assumptions about off-takes and assumptions about certain scenarios for deliveries into the system" (GTE Capacity Report, 20.6.2001).

[71] From GTE presentation on "Allocation of Capacities" at Fifth meeting of the European Gas Regulatory Forum, Madrid, 7-8 February 2002.

The examples of Transco and El Paso demonstrate that approach can work in natural gas markets. However, most TSOs in Europe only offer annual capacity contracts, and therefore do not consider variations in capacity availability over the short term.[72] More efficient capacity utilisation can be achieved if a TSO offers short-term services, and updates the availability of short-term capacity as conditions change from day to day. The success of these systems relies on implementing transparent and non-discriminatory nomination rules. The guidelines for good practice could play a useful role in specifying such rules, standardising their timing and frequency.

Interruptible service can also improve congestion management. A TSO can offer interruptible service without having to predict the system's ability to handle extreme demand conditions or potential changes in the direction of flows. Interruptible service therefore promotes full pipeline utilisation that can alleviate congestion.[73] In our previous report for the Commission, we discussed the importance of short-term capacity services and interruptible service for the development of effective competition in gas supply. The value of these services lay largely in the provision of increased flexibility to shippers. Here we stress that these services can increase shipper flexibility while also serving as important congestion management tools.

Congestion management can also improve if TSOs enhance their firm service contracts to compensate shippers financially in the event of interruption. We have seen some cases where the standard transportation contract describes "firm" service, but the liability provisions prevent the TSO from bearing the full economic consequences of interruption. Such provisions reflect the protective instincts of most TSOs' lawyers. A TSO's market power over transportation service typically leaves shippers no choice but to accept such provisions. We believe that such limitations to a TSO's liability compromise congestion management, without really helping the TSO financially.

When a TSO's financial liability is minimised, the TSO could conceivably fail to take its firm service obligations seriously. However, in our experience the opposite tends to happen: the TSO takes its obligations quite seriously. The TSO understands that interruption will cause shippers serious financial damage, since the liability clauses of the contract do not offer full compensation for interruptions. The TSO foresees that service failures will cause significant harm to its reputation. From a congestion management perspective, the TSO adopts significant caution to avoid "over-selling" firm capacity. The TSO only offers the amount of capacity that it anticipates can always be satisfied. However, this may not lead to optimal congestion management.

In some cases, it will be more efficient to increase the TSO's financial liability when the TSO interrupts firm customers. If the liability clause of a transportation contract offers full financial compensation for interruption, then the TSO will have efficient incentives to evaluate the risks of

[72] The Guidelines for Good Practice adopted at the Fifth Madrid Forum state that TSOs shall "offer both long-term and short-term firm services on demand (flexible duration and starting date of service) and interruptible service when firm capacity is not available and no liquid secondary market exists".

[73] In the absence of congestion , interruptible service brings with it the problem of "flight from firm" but the problem can be handled by restricting the amount of the total capacity that the TSO will offer on an interruptible basis.

declaring too much firm capacity available. Imagine that offering an extra 2 MCM/day in firm capacity would entail a 1% risk of interruption. The TSO should still be motivated to offer the capacity if it can compensate shippers fully for an interruption without sacrificing more than 1% of the incremental capacity revenues involved. Compensating the shipper perfectly would prevent a deterioration of the TSO's reputation in the event of interruption.

The United Kingdom capacity system works in the manner we have described above. The TSO offers firm capacity that might not actually be available. However, shippers are compensated perfectly for interruptions. If the TSO cannot offer all its firm commitments, the TSO will buy back capacity at market prices. When a shipper sells capacity back to the TSO, the shipper effectively volunteers to accept an interruption. Since the interruption occurs at a price offered by the shipper, we know that the shipper must perceive the price as representing full compensation or more. As long as Transco satisfies its financial commitments when buying back the capacity, Transco does not lose the faith of market participants. In the absence of such a regime, Transco may well have hesitated to offer any firm capacity that risked interruption.

Compensating shippers adequately for interruption is also important from the perspective of long-term efficiency and system planning. Pipeline congestion should indicate that transporting gas along a particular path is valuable, either because the supply source is relatively attractive or because customer demand is growing. Failure to compensate shippers for interruptions can distort the appropriate relationship between congestion and market value. As a pipeline becomes more congested, the likelihood of interruption increases, either because the pipeline has sold too much firm capacity, or simply from increased risk of compressor failure or other problems. If a TSO offers no compensation for interruptions, then the TSO may actually undermine the financial value of capacity as it becomes congested. Shippers will consider the possibility of financial loss from interruption as an offset to the value of the transportation service. Secondary market trades would occur at a depressed price. The economic value retained by the particular gas source can suffer as a result, and system planning may also be distorted. Mistaken capacity expansion decisions can occur if the financial impact of shipper interruptions obscures the true potential value of the transportation service.

Transco's system of measuring financial compensation is only appropriate in liquid, competitive markets. If a shipper has market power, the TSO will be exposed to abuse. A shipper with market power or a trader in an illiquid market could inflate the spot price of gas, or the spot price for transportation capacity on the secondary market, to exaggerate the compensation required. Even in the United Kingdom there have been concerns that shippers have sufficient market power at particular entry points to insist on unreasonably high prices when Transco buys back capacity. However, the problems with the Transco system do not undermine the general concept of financial compensation for interruption. The Transco experience shows that financial compensation should not be linked either to shipper bids or to prices that could be manipulated. In the presence of shipper market power, the appropriate level of financial compensation must either be specified *ex ante* in the transportation contract or tied to an index that the relevant shipper cannot manipulate.

6.6 Capacity Release and Gas Release

Our recommendations above include two proposals for "capacity release": the *ex ante* release programme in the case of contractual congestion, and the release of scarce capacity in the case of physical congestion. Capacity release is in some respects similar to implementing a gas release programme, as seen most recently in Spain, and possibly soon to be implemented in Germany.[74] It is beyond the scope of this report to discuss gas release programmes in any detail. However, in many Member States scarcity of transportation capacity and scarcity of wholesale gas tend to coincide, and it would therefore be at the very least sensible to combine a gas release programme with capacity release.

6.7 Alternative Methods of Allocating Capacity

Finally we discuss the two main methods of capacity allocation currently used in Europe: "first-come, first-served" and auctions. Our analysis examines the relative merits of each, and discusses some issues that arise in their implementation.

First-Come, First-Served

As noted above, the "first-come, first-served" method is currently used in most Member States. It has the advantages of simplicity, ease of implementation, and low cost. However, in a newly liberalised market it can also present difficulties as indicated in the simple example above involving a "red light". "First-come, first-served" facilitates "capacity hoarding" by suppliers, who can sign transportation contracts in excess of their needs to thwart access by potential competitors. Vertical integration exacerbates this problem, because acquiring excess capacity is costless to a company that simultaneously owns the TSO and a supply business—the tariff paid by the supply business to the TSO becomes simply a transfer between affiliates.

Example. Suppose that a pipeline has total capacity of 10 MCM/day, and has an annual transportation tariff of €0.01/m^3/day. Suppose also that one company simultaneously owns the pipeline and a supply business, that the supply business already holds 4MCM in long-term transportation contracts, and that competitors are likely to purchase 2MCM. If the pipeline's supply affiliate purchases the additional 6MCM then the "first-come, first-served" system would allow it to exclude competition from the market. If the supply affiliate were not vertically integrated then the total cost of the purchase would be €60,000 per day (calculated as 6 million x 1 Eurocent). However, vertical integration means that the total cost to the parent company is zero until the day that the competitors would have arrived. At that point, the parent company can be

[74] Other liberalising markets have implemented similar schemes, including the UK. The recent DG Tren discussion paper ("Discussion Document on Long-Term Contracts, Gas Release Programmes and the Availability of Multiple Gas Suppliers", presented at Madrid Forum Feb 2002) discusses the issue and describes relevant experience in some detail. We understand that in Germany a gas release programme would occur in connection with a possible E.On-Ruhrgas acquisition.

said to incur the cost of foregoing transportation revenues from the competitors, which would be no more than €20,000 per day.[75]

In addition to thwarting competition, capacity hoarding can distort the price paid for capacity in secondary trades. In the absence of published information on physical flows, capacity hoarding may also send potentially misleading signals concerning the extent of congestion.

A second problem arises with first-come, first-served when capacity is scarce and the TSO does not publish sufficient information. If one supply business dominates a market, then the supplier will have a persistent advantage in buying new transportation capacity. Holding most or all existing supply contracts, the dominant supplier knows when they will expire and therefore when is the optimal time to apply for additional transportation capacity. This problem arises regardless of vertical integration.

To mitigate these problems, *we recommend that where first-come, first-served is used it should be accompanied by measures to prevent hoarding: an initial release of hoarded capacity (as described earlier in this section); timely publication of information on actual and historical physical flows and capacity availability, in a simple and easily-accessible format; and some form of use-it-or-lose-it provision***.** The Recommendations on Guidelines for Good Practice adopted at the last Madrid Forum include a number of useful measures along these lines (*e.g.*, measures to deter capacity hoarding; publication of physical and available capacities on a regular/rolling basis).[76]

Auctions

Transco in the UK currently uses auctions to allocate entry capacity. A recent regulatory proceeding for the allocation of interconnector capacity in Ireland could be viewed as a combination of an auction and a "beauty contest".[77] Auctions appear to have become the standard allocation method for scarce cross-border capacity in the electricity industry.[78] Correctly-designed auctions avoid discrimination and foster liquidity and the development of secondary markets. Although the Transco auctions have been subject to criticism, the main focus of complaints has been on the specifics of auction design.

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[75] The incumbent supplier pays €60,000 to the pipeline, but this does not impose a net cost on the parent company. However, by purchasing the remaining capacity the supplier prevents the pipeline from selling the estimated 2MCM/day to an entrant, for which it would have received €20,000.

[76] See Annex II to "Conclusions of the fifth meeting of the European Gas Regulatory Forum", Madrid, 7-8 February 2002.

[77] For additional detail on the auctions used in the UK and Ireland see respectively Ofgem, *Transco's NTS System Operator incentives 2002-7 – Final Proposals*, December 2001, and the website of the Department of Public Enterprise.

[78] Auctions are in use or about to be introduced for interconnector capacity between Germany (E.On and RWE) and the Netherlands, Germany and Denmark, Belgium and the Netherlands, France and Belgium, France and Italy, and France and the UK.

Auctions are sometimes accused of leading to higher gas prices for consumers. However, this claim is misleading. The value of transmission capacity is equal to the difference in prices at the two ends of a pipe.[79] In a competitive auction of scarce capacity, the auction price will approximate this value. Perhaps the pipeline capacity could be sold for even less than its value, as might occur if the capacity were pro-rated among applicants. However, selling the capacity for less than its value would not prompt lower end-user prices. The market would be unstable at a lower end-user price, because demand would exceed supply. Suppliers would respond by raising end-user prices until demand matched supply. The end-user price would therefore be the same as with an auction, but the shippers who obtained the capacity for less than its value would perceive a wind-fall.[80]

Auctions of scarce capacity can however create a problem of excess revenue recovery, if the value of the capacity exceeds what would be required to give a fair rate of return on the investment. In our previous report for DG TREN we recommended that any excess revenue from auctions should be kept in a fund to cover the costs of future capacity expansions, an approach that has since been implemented in the Netherlands for electricity interconnector auctions.[81]

Compared to other methods, auctions also tend to be costly and difficult to design and implement properly. Moreover, if not designed properly, auctions can discriminate in favour of vertically-integrated undertakings. If a TSO's supply affiliate is allowed to participate in the auction, then the supply affiliate will have an advantage in the bidding. As noted above in our discussion of first-come, first-served, when a supplier purchases capacity from its pipeline affiliate, the true cost to the integrated company is simply the revenue that the pipeline forgoes by failing to sell the capacity to a third party.

Example. Imagine a pay-as-bid capacity auction with two bidders: the pipeline's supply affiliate, and an independent supplier. Suppose first that the supply affiliate bids 10 Euros and the independent supplier bids 8. The supply affiliate wins and pays 10 to the pipeline. However, the true cost to the owner of the supply affiliate and pipeline is only 8 (assuming that there is no requirement to "recycle" the 10 for future capacity expansions as described above). The payment of 10 is just a transfer of funds among affiliates. The true cost to the integrated undertaking is the failure to receive the 8 Euros that the independent supplier would have paid if it won the auction. Suppose second that the bids had been reversed: the supplier affiliate bids 8 and the independent

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[79] This applies equally in "traditional" and "new" market settings, although the price discover mechanisms may be quite different. For example, before market liberalisation, the value of capacity might be measured as the difference between the border price indicated by long-term contracts, and the "market value" at the factory gate determined by alternative fuels. In a liberalised market the value of capacity may be determined by examining basis differentials between hubs.

[80] The auction does "make a difference", but the difference only involves the allocation of the pipeline's value between shippers and the pipeline. End-user prices are not affected.

[81] A natural alternative would be for the government to keep the scarcity rents. To the best of our knowledge this has never been proposed for the energy industry, although we understand that the UK government has recently suggested such an approach with regard to scarce "slots" at congested airports.

supplier bids 10. Then the independent supplier wins the auction, and its cost is really 10. The mechanism therefore fails to provide equal treatment to the two parties.

We conclude that auctions are not useful if there is no capacity scarcity. Without scarcity the auction price will always be the reserve price if there is one, or zero if there is no reserve price, and in that case an auction therefore simply adds needless complication.

6.8 Conclusions and Recommendations

- The appropriate mechanism for allocating capacity depends on the extent of congestion.
- We distinguish contractual congestion from physical congestion. Contractual congestion describes situations where contracts have already been signed for all available capacity, even if the network can easily accommodate all physical demands that can reasonably be anticipated. Physical congestion refers to the physical difficulty of the network accommodating demand.
- When there is no physical or contractual congestion, the choice of mechanism is relatively unimportant, and we recommend "first-come, first-served" as the simplest approach.
- When there is contractual but not physical congestion, we recommend a one-off "*ex ante* capacity release" programme for unused capacity, which would examine the needs of existing capacity holders. Any capacity in excess of the amount needed to serve contracted customers, to meet the needs of captive customers, and to meet any PSOs, should be released.
- Furthermore, when there is contractual congestion and a customer switches supplier, the TSO should grant access to the competitor and transfer the resulting capacity payments to the existing holder of the capacity. We call this an "automatic resale" policy.
- A "capacity goes with the customer" policy would avoid monopolisation in the presence of contractual congestion, but if the policy does not compensate gas suppliers for the value of transportation capacity that they sacrifice upon losing customers, then we cannot recommend it as the best policy for gas networks.
- We recommend measures to facilitate secondary markets for transportation capacity. Once markets develop a sufficient diversity of shippers, secondary market trades should suffice to handle contractual congestion. Capacity release and an automatic resale policy would no longer be necessary.
- In the absence of physical congestion, auctions are not necessary and are likely to present more costs than benefits. In a transparent market, the absence of physical congestion should be evident with or without an auction.
- Physical congestion should be addressed by a combination of auctions and a requirement for capacity release by dominant shippers. The auctions should be designed to avoid competitive problems, including the potential bidding advantage of a vertically-integrated supply business, and the prospect of monopolising the auctioned capacity. Shippers who release capacity in the auctions should receive the associated revenues. When markets become sufficiently competitive, capacity release should not be obligatory.

- Regulatory authorities should be able to insist on network expansion if it is economically justified. A customer's willingness to pay for expansion should be viewed as proof that expansion is justified.

- Capacity can be defined in ways that improve congestion management. We recommend that TSOs and regulators examine carefully the potential for such measures. Imbalance tolerances that vary with ambient temperature or over the course of a year can improve the total flexibility available for a given amount of annual capacity. TSOs should also update their analyses of capacity availability frequently, publish the results, and offer short-term spare capacity for sale on a short-term basis using transparent and non-discriminatory nomination procedures. TSOs can also increase shipper flexibility and improve congestion management by offering interruptible capacity for sale.

- Regulators and TSOs should investigate the appropriateness of a "financially firm" service, which contemplates some possibility of physical interruption but offers to compensate shippers financially. Financial compensation can encourage the TSO to offer more capacity for sale overall, and can also improve long-term congestion management and system planning. However, TSOs should only offer financial compensation under conditions that do not invite market power abuse by shippers or traders.

- Gas release programmes should be accompanied by capacity release programmes.

7 Forecasting Congestion

TSOs have traditionally played an important role in forecasting congestion, and should continue to do so. Regulators can also play an important role, publishing studies concerning forecast demand relative to the physical capacity of a network. Shippers should also be involved in forecasting congestion. Accurate forecasting can give particular shippers a significant competitive advantage. It is therefore important to ensure that either TSOs or regulators publish the information necessary for shippers to compete effectively in forecasting congestion. GTE publishes information related to contracts, but not physical congestion. GTE should reconsider publishing significantly more information to facilitate congestion forecasting by shippers. The extent of information published by Transco should be a model for other TSOs to follow. We also recommend the creation of an integrated European network model along the lines of the computer model published by Transco.

Congestion forecasting by shippers can generate market signals to supplement the planning function of TSOs and regulators. In the previous section we supported the use of auctions to address physical congestion. Auctions can generate useful market signals concerning anticipated congestion. We also recommend measures to foster the creation of secondary markets that can send market signals concerning anticipated congestion. Auctions and secondary markets should involve a mix of short-term and long-term contracts. We explain the problems that can arise in regimes that rely exclusively on contracts of a particular duration. We also recommend that regulators refrain from imposing price caps on secondary market trades. Price caps impair the ability of secondary markets to send important signals for congestion forecasting.

7.1 The Importance of Forecasting by Shippers

A shipper can acquire a significant competitive advantage by forecasting congestion accurately. Pipeline congestion creates a divergence between the market price for gas from different geographic areas. If gas supplies are constrained from some sources but not from others, the market price will only reflect the cost of the gas from the unconstrained sources. Forecasting the constraints on different gas sources is therefore critical for anticipating the market price of delivered gas. Knowledge of congestion allows a shipper to make intelligent decisions concerning the acquisition of gas from different sources, and concerning the acquisition of pipeline and storage capacity.

Public policy should promote competition among shippers in forecasting. If shippers have the opportunity to make or lose significant sums of money based on their relative forecasting skills, competition will tend to promote sustained improvements in forecasting.

7.2 Auctions and Secondary Markets

Even if a particular shipper's forecast remains internal to the company, auctions and secondary markets permit the market as a whole to learn the key results of shipper forecasts. The market price paid for long-term pipeline capacity at an auction implicitly reveals the value that shippers perceive for the capacity in the future, which depends primarily on congestion. Secondary market trades work in the same way. If secondary capacity trades reveal a significantly higher price than the TSO's regulated rate, then the market indicates that shippers are forecasting congestion.

Some industry participants have resisted the development of secondary markets. They view secondary markets as instruments for speculation, and they disapprove of profits earned from speculation. However, it is a fundamental mistake to prohibit profits from secondary market trades. Interfering with secondary markets can distort competition in congestion forecasting, and can undermine its benefits. Price caps provide a classic example of seemingly reasonable measures that actually deprive consumers of the benefits of competition.

Price caps have been imposed on secondary market in the United States. For many years, the FERC prohibited shippers from reselling capacity at any price that exceeded the regulated price of a pipeline network. The price caps made it more difficult for shippers to profit from reselling pipeline capacity, but did not make it impossible. Shippers developed the practice of reselling pipeline capacity and gas together in a bundle. The sales contract would indicate that the pipeline capacity was being sold at the regulated price, but the price for the gas would be unusually high. In reality, the contract would hide the value of the pipeline capacity in the gas price. The price caps did not protect consumers, but simply deprived the market of transparency. Clearer market signals would have resulted from lifting the price caps, and from allowing pure capacity trades to indicate the true value for the transportation capacity.

Another concern with secondary markets involves the prospects of monopolistic abuse. Concerns with market power are distinct from a general dislike of speculation. However, experience indicates that it is best to address market power with specific structural and behavioural rules, as opposed to prohibiting secondary markets. As indicated in the previous sections, we support structural measures to prevent hoarding and to encourage a competitive allocation of capacity.

Experience indicates the importance of using a mix of long-term and short-term contracts to generate competition among shippers in forecasting congestion. For several years the United Kingdom had a transportation regime that relied primarily on short-term contracts. The initial entry capacity auctions were only for short durations. The auctions provided useful short-term signals concerning congestion, but not long-term signals. Even if the auction prices for a particular entry point were particularly high, Transco could not rely on the price as a long-term congestion management tool. A high price for one-year capacity rights cannot indicate whether it makes economic sense to invest in relieving congestion. Investments in congestion management typically rely on additional compression or laying new pipes. These investments have extended useful lives, and it often takes more than one year of congestion relief to justify the underlying costs. It can be extremely costly, if not impossible, to move these investments to other geographic areas if their initial need proves to be short-lived. Even if short-term congestion is high, it can be difficult for the TSO or regulator to know whether it makes economic sense to invest in increasing capacity.

Long-term transportation contracts foster competition in long-term congestion forecasting. When a TSO offers a contract for five years of transportation capacity, shippers inherently compete in their views of future congestion over a five-year period. Shippers who reject the offer of a five-year contract will make money if they are correct that no congestion will arise.

Similarly, by rejecting the offer shippers can lose considerable sums if they are mistaken about future congestion. Other shippers may make the correct decision, accept the five-year contract, and acquire a competitive advantage. We conclude that it makes sense to offer long-term transportation contracts as a tool to promote competition in long-term congestion forecasting. The contracts can generate market signals if offered directly in auctions, as Ofgem now contemplates, or if they are traded in secondary markets.

While we promote the use of long-term transportation contracts, exclusive reliance on long-term contracts is unwise. Electric power plants often prefer long-term gas arrangements, but many industrial customers prefer to sign only annual contracts with shippers. It is important for shippers to obtain pipeline capacity of the same duration that customers demand in their supply contracts. Otherwise new shippers cannot enter the market without incurring significant risks of unutilised capacity. Even if vertically-integrated supply businesses are seemingly placed in the same situation of risking unutilised capacity, they do not bear the same risk as new shippers. The transportation affiliate of a vertically-integrated supply business can sell unutilised capacity more easily than a new shipper in the market. Secondary markets can and should permit long-term capacity contracts to be broken up and resold in pieces of shorter duration. However, secondary markets take some time to evolve. In the transition to liberalisation it remains important for TSOs to offer a mix of short-term and long-term contracts that reflects shipper needs.

7.3 Necessary Information

Information disclosure is critical to the development of competition in congestion forecasting. If a particular supply business has superior access to relevant information, successful competition may not develop. Vertically-integrated incumbents have superior knowledge relative to entrants. Effective management unbundling and Chinese walls can ensure that incumbent supply businesses do not have an advantage acquiring additional information. However, the recent history of mixed management means that many incumbent supply businesses are likely to have employees with significant information and expertise relevant to forecasting congestion. Even the large size of incumbent supply businesses grants an advantage in forecasting, as it grants them inherently superior knowledge concerning total market demand. We conclude that it is essential to publish relevant information, to place potential entrants on an equal footing and encourage the development of effective competition in congestion forecasting.

We have reviewed the information currently available in European gas markets, and conclude that Transco provides a model for other TSOs to follow in publishing information. Transco has for years published a 10-Year Statement, which provides detailed maps of the network, forecasts of average and peak supply at each entry point, forecasts of annual throughput and peaks for the system and for each exit zone, and planned network investments by location. Transco also publishes recent historical information on annual and peak flows in different parts of the network. The Ten-Year Statement has also traditionally provided significant transparency concerning the tariff methodology, allowing shippers to estimate how tariffs might change depending on future demand.

Transco has also sold third-parties a computer model, *Transcost,* which provides useful information to foster competition in congestion forecasting by shippers. The *Transcost* model allowed shippers to analyse the way that the forecast flows over the next ten years on the Transco system prompted investments and influenced the entry-exit prices at each point. If shippers disagreed with the forecasts, they could type in alternative prospective flows and see on the computer screen precisely which points of the network would require reinforcement to accommodate the incremental demand. The computer model would also estimate the costs of the reinforcements using relevant parameters and algorithms for choosing among investment alternatives. To our knowledge, no other gas market in the European Union provides the same level of information relevant to congestion forecasting by shippers. Many gas market participants argue that such information is commercially confidential, but the commercial success of Transco over the past few years would seem to indicate that ample publication does not threaten a TSO's business. We recommend that regulators and TSOs develop computer models of their pipeline networks like Transcost that shippers can acquire.

Outside the United Kingdom, few TSOs or regulators publish any of the categories of information that Transco publishes. The International Energy Agency and Eurostat provide monthly data concerning the gas market in each country. For each Member State, the IEA indicates the amount of gas production, domestic consumption, exports, and imports that are imported from each other country, although with significant delay. The European Commission has produced long-term forecasts for these data in the *European Union Energy Outlook to 2020,* and has also commissioned an important study with demand projections, estimates of the availability and cost of reserves in both the EU and in countries that export to the EU, and an assessment of pipeline infrastructure needs.[82] In addition, GTE's map indicates the maximum technical capacities at major import points to each Member State and the amount of contracted capacity. However, we already indicated above that the GTE map's traffic-light system indicates contractual congestion but not physical congestion. GTE has provided some information relevant to physical congestion. In the last Madrid forum, GTE provided data concerning historical peak flows at cross-border routes. However, the data only concerned one week of unusually high demand that occurred several years ago. It remains impossible to know the historical annual peak demand or even average demand on key cross-border routes for the past decade. Still lacking in most Member States are important categories of information, such as:

1. Historical annual throughput and peak flows at major entry and exit points or zones.

2. Forecasts of throughput and peak flows at major entry and exit points or zones.

3. Investment plans for expanding capacity at specific points over an extended time horizon.

4. Updated data on booked capacity, including capacity booked for future years.

In the United States data on capacity availability is published daily, as we indicate in Appendix I concerning El Paso Natural Gas. Gaz de France published capacity at six major entry points, including the Montoir LNG facility in April, and once again in the beginning of June. Gaz de France is unusual in providing forecasts: it provided one figure for the available capacity at each of the six entry points during each of the next six months. In the Norwegian portion of the

[82] Observatoire Mediterraneen de l'Energie, *Assessment of Internal and External Gas Supply Options for the EU, Evaluation of the Supply Costs of New Natural Gas Supply Projects to the EU and an Investigation of Related Financial Requirements and Tools* (this study has been performed as part of the ETAP programme).

North Sea, gas holders can access timely information on available capacity by subscribing to an online service. We recommend similar programmes involving continual publication of revised capacity availability figures throughout Europe.

Effective competition in new infrastructure projects could benefit significantly if more information is published concerning existing networks and forecast developments. Regulators can help by performing detailed studies and publishing the results as well as the underlying data.

The creation and publication of a detailed computer model concerning the European pipeline network would be an important tool for helping companies to consider new infrastructure projects. CEER could play a useful role in seeking information from Member States and sponsoring an initiative in this area. However, its success will inevitably require significant co-operation from GTE.

7.4 Conclusions and Recommendations

- Regulators and TSOs play an important role in forecasting congestion. The publication of all information that is relevant to congestion is necessary to provide a level playing field for shippers. Otherwise established shippers will have an inherent advantage over potential competitors.
- We recommend the publication on a regular basis of the following information that is not yet standard in Europe: a) Continuous updates of available capacity on a network, b) historical annual peaks and annual demand for major entry and exit points or zones, c) forecasts of annual peaks and demand at major entry and exit points or zones, d) investment plans for expanding capacity at specific points over an extended time horizon.
- Regulators or TSOs should develop computer models of the major pipeline networks in Member States that would be available for shippers can acquire.
- We recommend that CEER co-operate with GTE toward the development of a computer model of the European natural gas pipeline system, which shippers could acquire.
- Auctions and secondary markets should be viewed as important instruments for stimulating competition among shippers in congestion forecasting. Over the long run, such competition can be expected to improve the quality of forecasting.
- Auctions and secondary markets will be most useful for forecasting congestion if they involve long-term rights to transportation capacity. Third-party access regimes should involve a mix of long-term and short-term transportation rights.
- Price caps would suppress the ability of auctions and secondary markets to assist in forecasting congestion, without protecting end-users.

8 Financing New Infrastructure

We make several recommendations to facilitate the financing of new investments. Currently, the predominant method of financing new investments involves co-ordinated planning and assurances of cost recovery. The government, regulator or TSO performs studies concerning the need for new infrastructure. The government or regulator approves investment decisions in accordance with the plan, and assures the TSO of cost recovery through regulated tariffs. If the utilisation of the new infrastructure is less than anticipated in the plan, the TSO is allowed to raise tariffs.

Reliance on co-ordinating planning is reasonable, and will continue to be necessary for many investments. We recommend that governments, regulators and TSOs continue to perform planning studies, and continue to require investments as indicated by the plans. In many cases investments are best financed by assuring cost recovery through regulated tariffs.

However, we recommend certain enhancements to current planning methods. Regulators should supplement planning with market signals. Long-term contracts and secondary markets can be used to supplement co-ordinated planning. As we indicated in the section on congestion management, secondary markets generate competition among shippers to forecast market developments. Secondary markets can improve the investment environment by helping to identify attractive opportunities.

We suspect that many regulators have under-estimated the cost of capital for network infrastructure. We are concerned that these estimates may threaten the incentives to expand existing infrastructure. We provide some preliminary conclusions on the cost of capital.

We recommend that regulators also explore alternatives to cost-based regulation for financing new investments. Competitive tenders or capacity auctions can play useful roles in setting rates for the use of new infrastructure. In particular, they can avoid the problems with potential mistakes in estimating the cost of capital.

Regulators should authorise projects even if they are not identified as necessary in a central plan, if they meet the following conditions:

1. The project sponsors are willing to proceed without an assurance of cost recovery through regulated tariffs.

2. The regulator determines that the economics of the project are not motivated by distortions in the tariff system for the existing network. For example, a "postage-stamp" tariff may motivate investments in inefficient new projects.

3. The regulator determines that the project would not interact with existing infrastructure in a manner that threatens economic or technical problems.

4. The regulator determines that the project does not raise market power issues, or the regulator obtains commitments from the project sponsors that would successfully prevent the abuse of market power.

If all the conditions above are met, then we see no reason to restrict investment authorisations to the perceived needs of a central plan. We dedicate a significant amount of analysis to the four conditions above, as they present complex issues. In particular, the issue of market power lies at the heart of the choices for authorising, financing and planning new investments. We recommend some guidelines for analysis. We discuss the common misperception that pipelines must charge "market-based rates" for existing infrastructure to encourage the construction of new infrastructure by third parties.

Some project sponsors seek exclusive or privileged access to the capacity of new infrastructure, and argue that such access is necessary to make the returns of the project attractive. Regulators should be careful with such requests, because the requests may reflect other problems. A request for exclusive or privileged access can be motivated by: a desire to avoid the effect of a regulator's mistake in estimating the cost of capital, a desire to exercise market power, or a desire to take advantage of distortions created by the existing tariff system. We illustrate and examine each of these potential problems.

8.1 Co-ordinated Planning

Co-ordinated planning is typically inspired by the problems presented by monopolies. If a pipeline network is a monopoly, then the owner does not have natural incentives to expand the network efficiently. If a monopolist network owner does not build the new capacity demanded by the market, then no one else will. The volume of gas transported to market will be less than the total demanded, which permits the price of gas to rise. The monopolist can maximise profits by deliberately building insufficient capacity.

We have not described all the effects of market power on investment decisions. Economists recognise that under some circumstances monopolists may even prefer excessive investment as a way to pre-empt competitors from entering the market. However, it is not important to understand all the dimensions of market power. The key point is that market power distorts investment incentives.

Regulation typically eliminates the ability to abuse market power. Regulators set prices by reference to costs, which eliminates a TSO's ability to raise prices by restricting capacity. Customers benefit from lower prices. Unfortunately, cost-based regulation cannot restore the efficient investment incentives that market power distorts. Cost-based rates prevent abuse, and can even replicate average competitive prices in the long-run, but do not reflect imbalances between supply and demand. In competitive markets, prices are at times significantly higher than underlying costs, and at times significantly lower depending on the relationship between supply and demand. The dynamics of competitive markets are critical to motivating efficient investments.

Cost-based rates can even introduce the possibility of other distortions to investment decisions. If the regulator over-estimates investment costs (which we define to include a reasonable return on capital) when setting rates, then the TSO will find new investments attractive. If the regulator under-estimates investment costs, then the TSO may hesitate to invest. If the regulator estimates investment costs perfectly, then the TSO may be indifferent between investing and not investing. The regulator's estimate of investment costs becomes a key financial incentive facing the TSO. If market power distorts investment incentives, and cost-based rates do not solve the problem, then it seems logical to rely on formal planning studies to identify appropriate new investments. The government or regulator either authorises or requires investments in accordance with a formal economic study.

Even in the absence of market power, there are reasons to believe that co-ordinated planning should play an important role in European gas markets. The transition to liberalisation can be characterised by regulatory and competitive uncertainties, which can deter investment sufficiently to create serious imbalances between supply and demand. Co-ordinated planning is the only way to diagnose whether regulatory uncertainty or other factors may be interfering with the proper functioning of a market.

8.2 Market Signals

Auctions and secondary markets provide useful avenues for supplementing formal planning studies. We discussed above the importance of competition among shippers in forecasting congestion. Even as regulators and TSOs perform central planning studies, they should consider what the market is saying about potential congestion. If long-term capacity contracts sell for a premium at an auction or secondary market, the regulator or TSO knows that market participants are willing to stake their financial success on a forecast of future congestion. Such signals should be entitled to considerable weight because they arise in competitive circumstances. Shippers who err in their forecasts will be punished financially by the relative success of competitors.

In contrast, regulators and TSOs do not have natural financial incentives to produce the best forecasts possible. Our experience has been that both regulators and TSOs perform planning studies in good faith, trying their best to find the correct answer. However, it would be unwise to predict that this will consistently be the case. Too many outside pressures can affect the planning studies performed by regulators and TSOs. For example, TSOs and regulators may feel pressure to overestimate future demand, if they fear intense political pressure in the event that significant congestion develops. On the other hand, regulators and TSOs may be concerned that authorising too much investment can have negative political repercussions if average transportation costs rise significantly as a result. Although we can think of reasons why TSOs and regulators might tend either to overstate or understate future congestion, it would not be reasonable to speculate that opposing tendencies perfectly offset each other, providing a set of external pressures that reflect no bias in the aggregate. We conclude that significant importance should be assigned to congestion forecasts developed by the purchases and sales of long-term transportation contracts by shippers. Such transactions occur under direct financial pressure to derive the most accurate estimates possible of future congestion.

Regulations for the authorisation of new projects can usefully supplement central planning with market signals. For example, if a regulator or TSO is uncertain that a certain pipeline expansion project is worthwhile, an "open season" can be conducted prior to authorising the project. An "open season" refers to a process conducted before a project's construction, in which the TSO attempts to secure long-term commitments from shippers for the purchase of a significant portion of the project's capacity. A regulator could make project authorisation contingent on the TSO first selling a certain fraction of the capacity in the open season process.

8.3 The Cost of Capital

When regulators choose to set regulated rates, they must decide on an appropriate cost of capital for new infrastructure. The cost of capital is the rate of return that investors can expect from investments of equivalent risk in competitive markets. High estimates of the cost of capital can attract excessive investment, while low estimates can deter necessary investment. We have reasons to believe that the cost of capital allowed by several regulators for new infrastructure projects is too low.

In setting the cost of capital, regulators often reason that natural gas transportation faces little competition. The absence of competition means little risk, which implies a low cost of capital. However, few regulators have empirically tested the implications of low risk on the cost of capital for natural gas networks. Many experts in corporate finance agree that the cost of capital is best measured by examining the actual volatility of stock prices for natural gas pipelines. The United Kingdom, Canada, and the United States are the only countries with natural gas pipelines whose stock has been liquidly traded for an extended number of years. Evidence from the volatility of stock prices in these countries suggests a significantly higher cost of capital than adopted by many Member State regulators. We propose that regulators analyse evidence concerning the stock price volatility of these companies to estimate the cost of capital.

We have also noted some common misperceptions concerning the cost of capital, which appear to be biased toward selecting low estimates for natural gas pipeline companies. One is that the cost of capital is lower for pipelines that have significant government ownership. The logic would appear to be that the government can raise capital by issuing low-cost government bonds. However, this logic is mistaken. If a government investment turns out not to be lucrative, the government can maintain solvency by raising taxes. The government's tax authority is the main explanation behind the low interest rates on government bonds. However, the government's tax authority does not mean that a pipeline has less risk when owned by the government. The government's tax authority simply means that the government does not fully bear the risk of its investments. Taxpayers bear a significant portion of the risk. An appropriate estimate of the cost of capital for government-owned pipelines would include the risk borne by taxpayers in addition to the risk borne by the government. Finance experts have analysed the issue and concluded that there is no reason to anticipate lower total risk for government-owned investments as opposed to private investments.

Another misconception involves the risk of the stock market as a whole. Regulators often measure the cost of capital by first estimating the premium necessary to compensate investors for risks in the stock market as a whole relative to safe investments in government bonds. This premium is generally known as the "equity risk premium". The regulator then estimates the cost of capital based on the pipeline's perceived risk relative to the stock market as a whole. If the regulator underestimates the equity risk premium, then it is likely to underestimate the cost of capital for the pipeline. Some regulators have estimated equity risk premiums that are significantly lower than the actual premiums earned internationally in the stock market relative to government bonds. We believe that this is likely to underestimate the true equity risk premium and therefore understate the true cost of capital for natural gas pipelines.

One mistake involves the regulator focussing on the stock returns earned in just one Member State in isolation as opposed to the stock returns earned internationally. Historical stock returns in some Member States have been quite low relative to bonds, but the statistical evidence indicates that this is most likely the result of random factors that are unlikely to repeat in the future. Moreover, the international nature of capital markets in the European Union suggest that it would now be mistaken to view any one country in isolation. We recommend that regulators measure the cost of capital by looking at the actual historical returns earned in the stock market by a broad sample of countries, as opposed to a particular Member State in isolation.

Another mistake concerning the equity risk premium involves a departure from historical stock returns to rely on surveys of the investment community. Evidence indicates that survey results vary extremely widely depending on the nature of the questions asked and the particular people asked. Yet a third mistake concerning the equity risk premium comes from the speculation that stock market risk is now much lower than before. If correct, such speculation could warrant using significantly lower figures than implied by historical data. However, we are sceptical that there is any reason to perceive lower risk in the stock market today than historically. Many financial theorists did develop such theories in the 1980s and 1990s, but the theories were predominantly driven by high stock prices. Stock prices during this period rose to extremely high levels relative to the forecast earnings of publicly-traded companies. Finance theorists noted that a significant decline in stock-market risk could be one possible explanation to reconcile high stock prices with modest earnings projections. However, another possible explanation for high stock prices was simply “irrational exuberance”—that the market was overvalued. A rigorous discussion of this debate is beyond the scope of this paper, but after scrutinising the various theories for lower stock-market risk, and examining the recent evidence concerning the poor performance of stock markets since March 2000, we conclude that it is speculative to assume that stock-market risk is significantly lower now than in the past. We therefore recommend that regulators measure the equity risk premium by reference to actual historical stock returns.

8.4 Alternatives to Cost-Based Regulation

We describe two approaches to setting regulated rates that would eliminate the need for the regulator to estimate the costs of a project, including the cost of capital. Both approaches would use market processes to determine reasonable rates for new infrastructure projects that would not imply an exercise of market power. Both approaches would transfer risk away from consumers.

One approach is to ask for competitive tenders from potential builders of the infrastructure. The regulator would ask each potential builder to propose a tariff for the life of the project. The regulator would award the project to the company that bid the lowest tariff.

Another approach involves allowing the TSO to construct the project and manage it, but asking the TSO to offer a minority equity stake, that does not carry management rights, to an independent investor pursuant to a competitive process. For example, the TSO might offer a 20% participation for sale to investors. The 20% stake would require the investor to pay for 20% of the initial capital and subsequent expenses, and would also entitle the investor to receive 20% of the tariff revenues. Potential investors would bid for the right to acquire the equity stake by stipulating the lowest tariff that they would accept. The tariff for the entire project would be set by reference to the bid for the minority equity stake.

Both approaches effectively create a competitive process where investors project the potential costs of the project, its prospective utilisation, and its risks. The regulator does not have to estimate these items. The key difference between both approaches is that the auction of the minority equity stake in the project does not rely as much on detailed contracts. Tendering the entire project would typically require elaborate contracts specifying the technical characteristics of the project, and stipulating penalties for deviations from quality standards. Otherwise a natural concern arises that the winner of the tender will simply be the company who offers the lowest quality. The second approach offers an elegant solution to the difficulty of specifying quality standards in a competitive tender for constructing new infrastructure. The TSO continues to control the project, and the competitive process does not generate competition among potential project developers to sacrifice quality. However, this approach does require that several potential bidders fully understand the project proposed by the TSO.

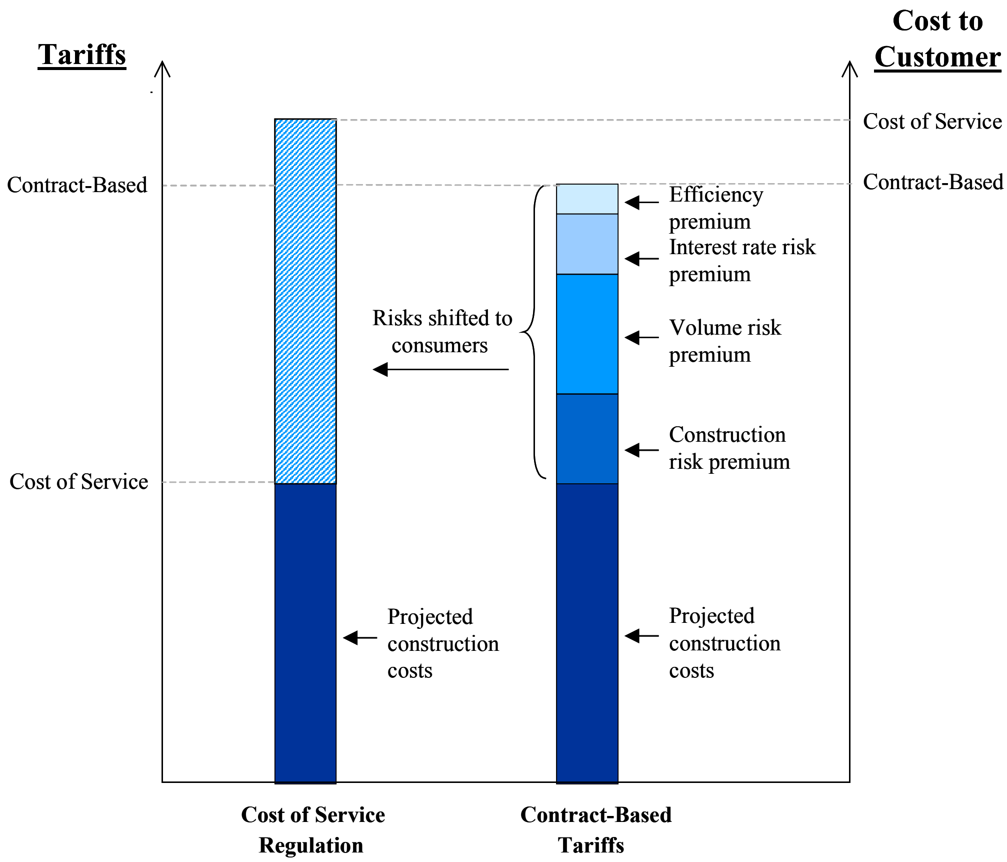
There are strong reasons to believe that tariffs determined via a competitive bidding process might be higher than tariffs under traditional cost-of-service regulation. However, regulators should not reject competitive bidding processes out of fear of higher tariffs. Tariffs might be higher under competitive bidding processes for desirable reasons. If the regulator has underestimated the cost of capital when applying typical "cost-of-service" regulation, then the resulting tariffs might be lower, but at the same time the regulator's underestimate would harm the climate for new investment. Higher tariffs from a competitive bidding tariff might be a good thing.

Another reason to anticipate higher tariffs from a competitive bidding tariff would involve the allocation of risk. An important feature of such tariffs is that they typically allocate significant risk to the project developer. When a bidding process establishes a tariff for a project prior to its construction, then the fixed nature of the tariff means that the project sponsor cannot secure extra compensation if there are cost over-runs, cannot raise tariffs if volumes prove to be less than initially anticipated, and cannot raise tariffs if interest rates end up higher than anticipated when the bid was made. The winning bidder therefore bears all these risks.

In contrast, cost-of-service regulation typically allocates these risks to consumers. If the construction costs prove to be more than initially anticipated, then the regulator simply sets higher rates as long as the cost overruns were not the result of negligence. If demand for the project ends up being lower than initially anticipated, then the regulator simply raises the rates. If interest rates rise significantly in the future, the regulator also responds by raising rates.

If tariffs are higher under a competitive bidding process than under traditional cost-of-service regulation, it does not mean that the total costs to the consumer are higher. Figure 16 below illustrates that the total costs to the consumer under cost-of-service regulation are not limited to the tariffs paid for using the infrastructure. The total costs to the consumer also include the cost of the risk associated with the project. Unfortunately, the cost imposed by the risk may be easy to ignore because it is intangible. Under a competitive bidding process, described in Figure 16 as producing "contract-based" tariff revenues, the tariff may be higher but the consumer does not have to incur the additional risk.

Figure 16: Risk Allocation and Project Finance



In general, project developers can be expected to do a better job than the customer at bearing project-related risks. Project developers have expertise concerning construction costs and market forecasting. Allocating construction risk to the project developer also motivates it to minimise construction costs. Volume risk provides an incentive to ensure maximum deliverability. Project developers also develop expertise in assessing interest rate risk. By contrast, consumers are poorly equipped to bear these risks. A consumer would likely be willing to pay more to avoid these risks than a project developer would require as compensation for bearing them. Overall then, the allocation of risk to the project developer could result in lower total costs to consumers than under traditional regulation.

We conclude that regulators should explore competitive bidding processes as an alternative to traditional rate-setting techniques. Regulators should not be deterred from such processes by the prospect of higher rates. Higher rates may simply reveal that the regulator had underestimated the cost of capital under cost-of-service regulation, which would have hurt the investment climate. Higher rates may also simply reflect the transfer of risk from consumers to project developers. Because consumers tend to be poorly-equipped at bearing infrastructure risk, the transfer of risk to project developers may leave consumers better off as a whole despite paying a slightly higher initial tariff.

8.5 Authorising New Projects

We recommend that regulators authorise new projects even when not identified as necessary in a co-ordinated plan, as long as the projects can satisfy certain conditions. The conditions address the primary concerns of regulators to protect consumers, to promote efficiency, and to avoid the abuse of market power.

Accepting Volume Risk

Regulators may be concerned that a new project may be insufficiently utilised in the future. Traditional rate-making techniques would protect a project from under-utilisation. Rates are determined by measuring the annual revenues that investors need each year to compensate both for operating costs and capital costs. The revenue requirement is divided by forecast throughput to derive rates. If throughput falls, the revenue requirement is divided by smaller volumes and rates increase. The technique effectively protects the project against volume risk, instead allocating the risk of insufficient utilisation to consumers. Regulators would logically hesitate to insure projects against volume risk if they are not identified as necessary in a co-ordinated plan. We recommend that one condition for authorising such projects be the willingness of the project developers to proceed without protection against volume risk. The project developers could commit to fixed tariffs based on volume forecasts that imply significant utilisation of the project. The developers would forego any ability to increase the tariffs if actual utilisation subsequently proved to be less than forecast. In exchange for such commitments, the regulator should permit the project developers to retain the benefits if utilisation subsequently proves to be higher than forecast. In setting rates for such projects, regulators should also recognise that incurring volume risk raises the cost of capital for the project.

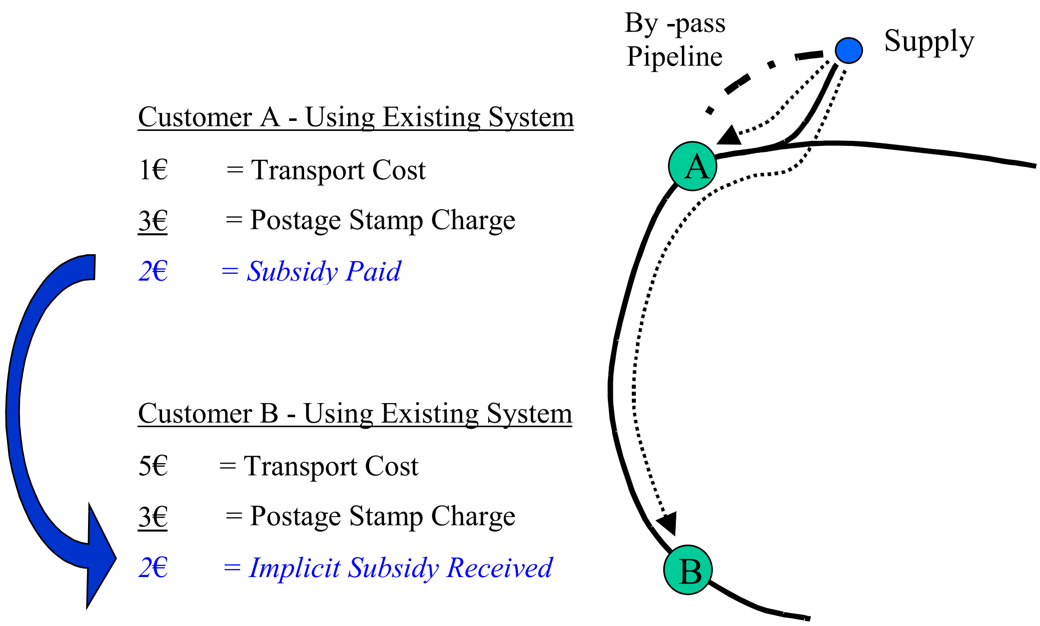
Distortions in Tariff Systems

Before authorising a new project that is not identified as necessary by a co-ordinated plan, regulators should ensure that the project's economics are not motivated by distorted incentives that arise under the existing tariff system.

Below we illustrate how a postage-tamp tariff system might motivate an inefficient new project. The project is a "bypass" pipeline built with the intent to serve customer A. The assumed postage-stamp tariff of €3 exceeds the system's cost of serving customer A, which is only €1. The postage-stamp tariff effectively requires customer A to subsidise customers elsewhere on the system. Figure 17 shows customer B receiving the implicit subsidy.

The subsidy imposed on customer A by the postage-stamp system could attract an inefficient new project. A new by-pass pipeline could incur costs of up to €2 in serving customer A, but could still be commercially viable. Even though the by-pass pipeline had higher costs than the €1 incurred by the existing system in serving customer A, the by-pass pipeline could attract customer A by offering to charge somewhat less than the full postage-stamp rate of €3. Basically the by-pass pipeline would appear attractive as a way for A to avoid the subsidy paid to other users under the existing system. Not only is the bypass pipeline inefficient, but disconnecting A from the system would force the regulator to increase the average postage stamp tariff charged to the remaining customers.

Figure 17: Potential Inefficient Bypass Under a Postage-Stamp System



A regulatory authority should confront these issues before deciding upon the authorisation of new projects. One approach would simply be to deny licences to projects such as the one depicted in Figure 17. Another approach would be to authorise such projects, but only on the condition that they pay licence fees that are high enough to eliminate the distorted incentives.

To continue with the example, the regulator could impose a licence fee on the by-pass pipeline if it disconnects customer A from the system. The regulator could recognise that the current system effectively requires A to pay a subsidy of €2. The regulator could require the project to replace the subsidy paid by A, if A disconnects from the system. In this manner, the new project would only be commercially viable if it actually had lower average costs than the existing network in serving customer A.

Interactions with Existing Infrastructure

A logical concern of regulators is that new infrastructure does not produce unintended effects on either the utilisation or the technical capabilities of existing infrastructure. If a project is not part of a co-ordinated plan, then prior to authorisation regulators should confirm that the project will not compromise the operation or commercial viability of existing infrastructure. For example, project developers might propose a new investment that would offer new supplies to the market, but risk frequent interruptions. If so, the regulator should ensure that the project does not compromise the security of supply of the existing system. A new project may also reduce the utilisation of the existing system. Regulators should ensure that a new project does not harm the users of the existing system by causing their rates to increase.

Market Power

Government authorities should examine several potential market power problems before authorising projects that are not part of a central plan. Even projects that may appear to enhance the competitiveness of a market, such as a new interconnector with a neighbouring country, can give rise to legitimate market power concerns. Regulators should carefully analyse the potential for market power abuse before authorising new projects.

If clear rules for analysing market power are not followed, seemingly attractive independent projects could produce inefficient outcomes for society. For example, project developers may propose a new interconnection with a neighbouring country, but prefer a size for the project that is significantly smaller than would be optimal for society. Project developers might not fund a new interconnector privately unless they anticipate that, after the interconnector's construction, price differentials will still persist between the relevant markets. Price differentials provide the fundamental source of value for a new interconnector. If the price differentials disappear, no one will be willing to pay for an interconnector on an on-going basis. From society's perspective, however, it may be more efficient to build an interconnector of sufficient size to unify markets and eliminate price differentials entirely. Economies of scale mean that it may be much more efficient to build a large interconnector than to authorise first a small one that would soon prompt a need for constructing a second parallel interconnector. This is effectively a problem of market power, if the project developers are considering an investment of sufficient size to change the equilibrium prices between markets.

A careful analysis indicates that the potential behaviour of the project sponsor can raise five primary concerns:

- *Insufficient capacity*. The sponsor may have incentives to maximise profits by installing less capacity than would be optimal. This is the problem that we discussed above with respect to a hypothetical new interconnector. Such behaviour would force shippers to compete for the insufficient capacity available on the market. The project sponsor might exercise market power by deliberately limiting the amount of capacity involved.

- *Pre-emptive deterrence.* Authorising independent projects without scrutiny could provoke a rush to build, if the first project to commence construction would deter other potential projects. The project that can commence construction the soonest cannot be expected to coincide invariably with the most efficient. Moreover, the project sponsor may have unfair advantages in the ability to identify and implement projects on a timely basis.

- *Inappropriate vertical integration.* If a project sponsor also competes in the supply business, the project's market power might be abused to discriminate in favour of the sponsor's supply affiliate. Safeguards should be implemented to ensure that the project offers non-discriminatory third-party access.

- *Monopolisation of capacity.* Even if a project does not present the problem of vertical integration, regulators should examine whether supply competition would be adversely affected if one party used all the available capacity of the project. If so, regulators should consider imposing caps on the share of capacity that any one user can book in a facility.

- *Abuse of market power in negotiations.* The sponsor may seek to charge unreasonable rates for use of the proposed facility.

Member States should allow regulators to address market power problems by seeking appropriate commitments from the project sponsors. We identify several specific measures that can prevent market power problems:

- *Show of Contracts.* This approach would postpone project authorisation until the sponsors could demonstrate that they obtained a threshold level of long-term contracts with third-party users of the project. Compared to a system of automatic authorisations, this approach would prevent a simple rush to build the first project. Rather, any project would have to prove attractive to large shippers first. If customers are suspicious of a proposed project, they simply will not sign contracts and the project will not be authorised.

- *Competitive tenders.* Allow third parties to submit competing proposals for the project.

- *Auctioning capacity.* Commitments by the project sponsor to auction capacity.

- *Equity partnering.* Asking the project sponsor to undertake a competitive search for the equity partner who can accept the lowest long-term tariff schedule in exchange for its investment. We discussed this above as an innovative alternative to cost-based regulation. Regulators should view this option as a way of protecting against market power abuse.

- *Commitments to non-discrimination.* Commitments by the project sponsor to a "most-favoured nations" tariff policy where all users pay the same price.

Industry participants often make casual references to "pipe-to-pipe" competition, and to competition between natural gas and alternative fuels. For project authorisation, regulators should use rigorous analyses of competition and potential problems. In chapter 4 we propose guidelines concerning the analysis of market power.

8.6 Market-Based Rates

Some industry observers believe that existing pipelines should charge "market-based" rates. The reasonableness of market-based rates depends on the existence of market power. If a pipeline network has market power over natural gas transportation, then market-based rates would permit the abuse of shippers and consumers. Regulators should approve market-based rates only if they conclude that the relevant pipelines face effective competition.

We have heard the argument that, even if a pipeline owner has market power, charging market-based rates would be desirable public policy to motivate the construction of new infrastructure by independent companies. However, new infrastructure projects would not be in the public interest if their only financial motivation was to avoid market power abuse by the owner of existing infrastructure. The exercise of market power typically involves rates that are sufficiently high to prevent the full utilisation of existing infrastructure. Reducing rates in these circumstances would be preferable to the construction of additional capacity, and would promote the full utilisation of existing investment.

Perhaps a Member State may have reasons to promote the construction of new infrastructure by independent third parties, even if existing infrastructure is not fully utilised. Even so, however, market-based rates would not be necessary for implementing the policy. The Member State could finance investment in such cases by integrating the new projects within a co-ordinated tariff regime for the entire natural gas system.

Imagine that previous tariffs have almost fully recovered the costs of existing infrastructure, so that future cost-based rates would be extremely low. Imagine as well that new infrastructure could only be financed with significantly higher rates. In these circumstances the regulator could offer the new infrastructure the ability to collect the higher rates, but the resulting payments would not be charged to users as a separate tariff for the new infrastructure. Instead, users would pay the same tariff whether they used the new or existing infrastructure. The comprehensive tariff would be calculated to reflect the average of cost-reflective rates for the new and existing infrastructure owners. The tariff revenues would then be divided up among the various owners in proportion to their underlying costs.

Such a scheme is now being used in Spain to finance new LNG terminals. New terminals have higher costs than the existing terminals that have been largely amortised. The new terminals are financed by integrating them into a uniform tariff system covering all terminals. Importers of LNG face the same tariff at each terminal whether it is old or new, and the resulting tariff revenues are distributed among the different owners of the terminals in proportion to each owner's costs. The owners of the existing, largely-amortised terminals receive less than the owners of the new terminals. Users end up paying for the average costs of an LNG terminal, rather than paying for the highest price necessary to finance the most recent terminal.

8.7 Requests for Long-Term Capacity Reservation

Some companies propose new projects such as LNG terminals, asking for permission to reserve all or a substantial portion of the capacity for themselves over an extended period. Although we cannot say that such requests are uniformly unreasonable, we warn that they may not be necessary for the successful financing of new infrastructure. Such requests may reflect underlying problems with the market or with the regulatory system.

A request for long-term capacity may reflect a problem with the regulatory system. The regulatory system may not offer tariffs that are sufficient to compensate for the underlying investment. In such cases, no company would propose a new investment primarily as a source of future tariff revenues. However, a project sponsor could overcome the deficiency of tariff revenues if it became the principal or exclusive user of the investment. In this case, the project sponsor would simultaneously pay the tariff as the user of the facility, and collect the tariff as the owner of the facility. Simultaneous ownership and use of the facility would convert the tariff into an internal transfer payment with little economic significance. If insufficient tariffs are the key motivator to a project sponsor's requests to reserve long-term capacity in a project, then the best response may be to revise the tariff system. The requests for long-term capacity reservation would recede, the project would still be financed successfully, and use of the infrastructure could be allocated to several different parties, improving the competitive environment.

Requests for long-term capacity may also reflect a desire to monopolise access to a terminal. Regulators should analyse the market implications of allocating the terminal's capacity to a fewer as opposed to a larger number of market participants. The request of the project sponsor should only be granted if it does not have a significant adverse impact on competition. Conferring market power cannot be the optimal way to finance new investment.

8.8 Conclusions and Recommendations

- Co-ordinated planning by governments, regulators and TSOs should retain a key role in identifying, authorising, and financing new investments in the presence of market power or in light of market uncertainty during the transition to liberalisation.
- Co-ordinated planning studies should look to market signals as useful indicators of the economic merits of new investments. Regulators should adopt measures that foster the creation of market signals, such as auctions, secondary trading, or "open season" processes, because they can help identify attractive new investments.
- Regulators should test their cost of capital estimates by analysing the volatility of share prices for regulated pipeline companies that are listed on public stock exchanges.
- Regulators should not presume that a company has a lower cost of capital simply because the government, rather than private investors, is the owner. Finance experts recognise that low government borrowing rates understate the total cost of capital for government-owned companies.
- Regulators should estimate the equity risk premium by reference to actual historical returns earned by investors in a large sample of countries, as opposed to any particular Member State in isolation.
- Regulators should consider using competitive bidding processes to determine regulated rates. Such processes can help finance new investment by avoiding potential errors in the regulator's estimate of the cost of capital. Such processes can also help the investment climate by introducing an improved allocation of risk between project developers and infrastructure users.
- Regulators should consider authorising new infrastructure projects even if they are not identified as necessary by a co-ordinated plan, as long as the projects satisfy certain conditions designed to promote the public interest: a) protection of rate-payers from volume risk, b) avoiding distorted incentives that may arise from existing tariff systems, c) avoiding adverse effects on the existing network, d) ensuring no abuse of market power.
- Regulators should watch for six problems that can be associated with the market power of a new project: a) deliberately designing the project to offer less total capacity than optimal b) pre-emptive expansion to deter competitors, c) deterring other efficient projects, d) introducing inappropriate vertical integration, e) monopolisation of capacity, and f) charging excessive prices.

- Instead of rejecting projects that present potential market power problems, regulators should consider possible undertakings that could remedy the problems. Potential remedies include: a) securing long-term contracts with end-users prior to initiating construction, b) conducting competitive tenders for the project, c) auctioning capacity in the project, d) commitments to reasonable rates and non-discrimination.

- Market-based rates are not reasonable in the presence of market power. If the owner of an existing network has market power, permitting it to charge market-based rates cannot be necessary to promote independent investments in new infrastructure.

- When project sponsors request exclusive or nearly exclusive access to a new infrastructure investment, regulators should first determine whether the request is motivated by a deficiency in the tariff regime, or if the request would have an adverse effect on competition.

Appendix I: El Paso Natural Gas

The El Paso system revises its measure of available capacity each day in response to demand conditions. The system publishes a "steady-state" measure of capacity, which is the amount that El Paso believes can be offered continuously, despite potential variations in the nominations of shippers. El Paso does not define capacity on a single point-to-point basis. Instead, each transportation contract offers the shipper multiple entry and multiple exit points. The multiple points are classified as either "primary" or "secondary". El Paso is not supposed to sell more primary capacity than the system can handle, while it remains free to oversell secondary rights. The primary points in a shipper's contract are available on a firm basis, while the secondary points are subject to availability. However, the secondary points still maintain priority over purely interruptible service. This system allows shippers flexibility without placing excessive limitations on the amount of capacity that El Paso can offer. El Paso's steady-state measure of capacity considers the commitments to honour primary points.

Each day, El Paso goes through a process intended to maximise available capacity. El Paso first receives nominations from shippers. El Paso checks whether each shipper's nominations comply with the rights specified in the relevant transportation contracts. El Paso then undertakes a matching process, to ensure interoperability with interconnected pipes. If a shipper nominates 1 million cubic metres at a point of interconnection with another TSO, El Paso will verify that the same volumes have also been nominated on that TSO's system. After excluding nominations that exceed contract requirements or that do not have matching nominations on interconnected systems, El Paso uses a publicly-available software package (the "Stoner" model) to assess the capability of its system to handle the remaining nominations. If necessary, El Paso curtails nominations downward by priority class, starting at the western end of its system and working east, because the predominant flow is from east to west. First the interruptible nominations are cut, then if necessary the nominations at shippers' secondary points, and then the primary points.

Curtailing some nominations can create spare capacity because of system dynamics. After the initial round of curtailments, El Paso re-examines the curtailed nominations to check whether some can be reinstated. El Paso follows an organised process for examining the potential to reinstate curtailed nominations. El Paso then notifies shippers of the accepted nominations, and also of any spare capacity that was never used up by the nominations, or that the curtailments may have made available, even after incorporating the reinstatements. El Paso accepts a second round of nominations after publishing this information, and then repeats the nomination verification and curtailment process.

We endorse several broad concepts that are reflected in the El Paso system, and that are not yet standard in European gas markets:

1. Capacity defined in a way that attempts to balance two competing objectives: providing shippers with flexibility, and avoiding an excessive limitation on the network's ability to make capacity available. If all transportation contracts gave postage-stamp rights, then El Paso might not be able to sell as much capacity in annual firm contracts. On the other hand, defining capacity purely on a single point-to-point basis would not give shippers flexibility.

2. Capacity availability is examined daily, and revised in accordance with nominations. After analysing initial nominations, the system discloses how much additional capacity it could accept, and invites a second round of nominations.

The El Paso system is an important source of gas supply to California. Many complaints that are associated with the California energy crisis have involved the El Paso system. Prominent litigation is under-way concerning claims of anti-competitive abuse. We do not take any position on the litigation in this report. We simply note that the complaints have focused on anti-competitive behaviour and rather detailed rules rather than the broad characteristics of the system that we have described above.

Appendix II: Derivation of Entry-Exit Charges

In chapter 4 we claimed that provided negative charges are allowed, it is in principle always possible to set entry-exit charges that reflect Long Run Marginal Cost (LRMC).[83] In this appendix we explain in more detail the methodology for setting entry and exit tariffs, and provide an informal demonstration that the methodology ensures the tariffs reflect LRMC.[84] The theoretical analysis is based on an idealised model of pipelines that ignores a number of real-world factor such as the lumpiness of investments ("indivisibilities"), uncertainty, and the difference in timeframes between transportation decisions and the lifetime of transportation assets.

As a starting point, we establish two propositions about LRMCs that are key to what follows.

Proposition 1. *If the LRMC of transporting gas from point A to point B is X, the LRMC of transporting gas from B to A is –X.*

For example, shipper 1 might want to move one cubic meter of gas from A to B, which results in an extra investment of 3 being required to expand pipeline capacity for the extra cubic meter of gas flow. Shipper 1 would be charged a price of 3 for the transport, to reflect the LRMC of moving the extra volume of gas. If shipper 2 wanted to move a cubic meter of gas from B to A, this would result in a decrease in flow in the pipeline of one cubic meter. Due to the decrease in flow, no extra investments in pipeline capacity would have to be made, and shipper 2 has produced a saving of 3, the LRMC of pipeline expansion. Therefore shipper 2 will be charged -3, to reflect the saving shipper 2 has brought about by wanting to transport gas from B to A.

In this example, no extra investment is required, and this is reflected by the fact that the two tariffs cancel each other out i.e. there is no net payment to the pipeline operator. Another way to think about this is that rather than expanding pipeline capacity, the pipeline operator would be prepared to pay a shipper to reduce their flows, and the maximum the pipeline operator would be prepared to pay is the cost of the pipeline expansion.

Proposition 2. *With optimal flows, the LRMC is the same on all alternative routes between points A and B.*

The simplest case is where there are only two alternative routes between points A and B, route 1 and route 2. If the LRMC on route 1 was less than the LRMC on route 2, it would make sense to increase the capacity of route 1, until the LRMC on route 1 increased to the same level as route 2. A practical example may be that route 1 can easily and cheaply be de-bottlenecked by removing an orifice meter in the line, whereas route 2 would require large sections of the line to be looped. Investments would be made in de-bottlenecking route 1, until the cost of the next de-bottlenecking project was the same for both routes. At this point, the LRMC for both routes is the same.

[83] In a gas pipeline network, the LRMC can be thought of as the infrastructure investment which would be required to transport the additional, or marginal, volume of gas through the network.

[84] For a more formal demonstration see Annex 11 of the Bergougnoux report cited at footnote 22. We interpret their "nodal pricing" as entry-exit pricing with possibly negative entry and exit charges.

Exposition of entry-exit tariff setting methodology

1. Calculate LRMC along each route in the network.
2. Choose any entry point in the network. Label it A, and set the entry tariff at A arbitrarily to zero. As we will see later, the choice of a zero entry tariff for point A can be changed later, but the absolute size of the tariff at A is not important for the methodology.
3. Take any exit point. Label it Z, and set the exit charge equal to the LRMC from A to Z. The choice of the route from A to Z is not important, as by Proposition 2 all routes from A to Z will have the same LRMC.
4. Similarly for every other exit points, set the exit charge equal to the LRMC from A to the exit point. This sets the exit charge for all points in the network, and means that for any path from A to an exit point, the entry charge plus the exit charge will be equal to the LRMC.
5. We must now set the entry charge for all the other entry points B, C etc. Take point Z (or any other exit point). For entry point B, set the entry charge equal to LRMC of going from B to Z, minus the exit charge at Z. Repeat this for all entry points C, D etc. This process will set the charge for all entry points in the network.

We now have entry and exit charges for all the points in the network.

Proposition 3. *For any entry point B and exit point Y on the network, the sum of the entry tariff at B and the exit tariff at Y will equal the LRMC of transporting gas from B to Y.*

Proof: We must prove this for the general case of moving gas from entry point B to exit point Y. We want to prove that the entry tariff at B plus the exit tariff at Y is equal to the LRMC of moving gas from B to Y.

According to steps 3 and 5 in the methodology above:

Entry charge at B = (LRMC B→Z) – (LRMC A→Z) (1)

Here (LRMC B→Z) represents the LRMC of moving gas from entry point B to exit point Z and (LRMC A→Z) represents the LRMC of moving gas from entry point A to exit point Z, where A is the point that was selected in step 2 above, and Z the point that was used in step 5.

According to step 4 in the methodology above:

Exit charge at Y = (LRMC A→Y) (2)

According to Proposition 2, the LRMC between two points by two alternative routes must be the same, hence:

(LRMC A→Y) = (LRMC A→Z) + (LRMC Z→B) + (LRMC B→Y) (3)

By Proposition 1,

(LRMC Z→B) = - (LRMC B→Z) (4)

Using equations 4 and 2 in equation 3 we get:

Exit charge at Y = (LRMC A→Z) - (LRMC B→Z) + (LRMC B→Y) (5)

The final step is to show that adding the entry charge at B and the exit charge at Y will equal the LRMC of moving gas from B to Y. Adding equations 1 and 5 we get:

Entry charge at B + Exit charge at Y =

(LRMC B→Z) – (LRMC A→Z) + (LRMC A→Z) - (LRMC B→Z) + (LRMC B→Y)

= (LRMC B→Y)

This completes the proof.

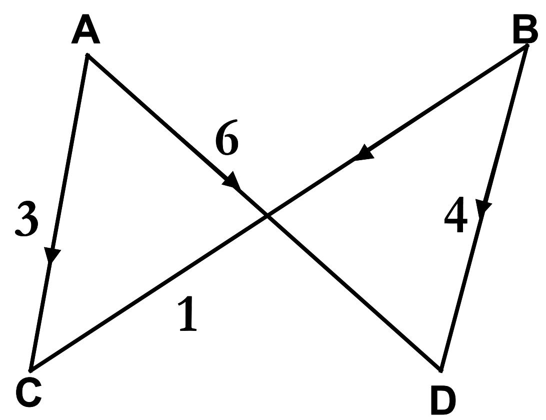
Numerical Examples

In order to illustrate the methodology outlined above, we will give two numerical examples of entry-exit tariff calculations for a network. The examples also illustrate an important point: in some cases, the methodology gives one or more negative entry or exit charge. Sometimes this problem can be removed (Example 1), in other cases it cannot (Example 2).

Example 1

Figure 18 illustrates the network for which we calculate the entry and exit tariffs. The numbers on the diagram represent the LRMC of gas transport along each segment.

Figure 18



Following the methodology, the entry tariff at A is set to zero, and the exit tariffs at C and D are set at 3 and 6 respectively, representing the LRMC of gas transport from A to C and D.

Arbitrarily choosing C as our reference exit point, we can calculate the entry tariff at B as:

Entry tariff at B = (LRMC B→C) – Exit tariff at C = 1 -3 = -2

The entry charges are therefore 0 at A and –2 at B, and the exit charges 3 at C and 6 at D. It is easy to check that *for every route, the entry and exit charges add up to the LRMC.*

However, we now have a negative entry charge at B, which implies *the pipeline operator actually pays the shipper to enter the gas at point B*. As discussed earlier in the report, this could create problems, so it would be desirable to have positive tariffs if possible. In this case it is possible to remove the negative charge.

To do so we can simply add a positive number to all the calculated entry tariffs, and subtract the same number from all the exit tariffs, *leaving the total costs of any transport route unchanged, but with all tariffs positive*. In this example, we can add 2.5 to all the entry tariffs and subtract 2.5 from all the exit tariffs. Table 12 shows the initial and adjusted tariffs.

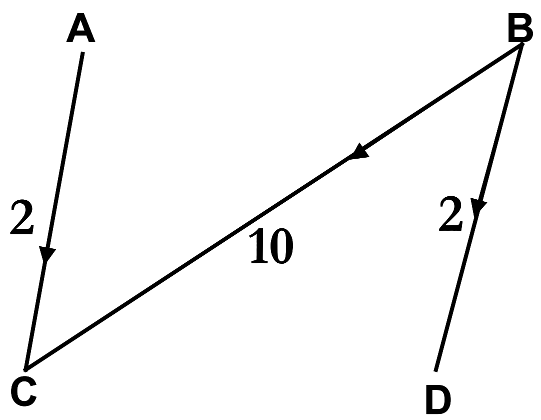
Table 12: Adjusted Entry and Exit Tariffs

Entry/Exit Point	Tariff Pre-Adjustment	Adjusted Tariff
A	0	2.5
B	-2	0.5
C	3	0.5
D	6	3.5

Example 2

In the previous numerical example, we corrected the situation where one of the tariffs was negative, but this example will illustrate that it is not always possible to do this. Figure 19 illustrates the network for which we perform the entry-exit tariff calculation.

Figure 19



Once again we set the entry tariff at A equal to zero, and the exit charge at C equal to 2. The setting of the exit charge at D is given by:

Exit tariff at D = (LRMC A→C) - (LRMC B→C) + (LRMC B→D)

Hence the exit tariff at D is equal to -6.

The entry tariff at B is again calculated as (LRMC B→C) minus the exit charge at C, which gives an entry charge at B of 8.

The calculated charges are summarised in Table 13. Given that we have a negative exit charge, we would like to add a positive number to the exit charges and subtract a positive number from the entry charges, such that we have only positive tariffs. However, the tariff at entry point A *is already zero*, such that subtracting any positive number from the entry charge at A will result in a negative entry tariff. In this situation, it is not possible to adjust the entry and exit tariffs such that we will only have positive tariffs, and we are left with at least one negative tariff.

Table 13: Entry and Exit Tariffs

Entry/Exit Point	Tariff
A	0
B	8
C	2
D	-6

It is worth noting that the cause of the negative tariff is the high LRMC along the B to C route, as compared to the other routes. Congestion would be responsible for a high LRMC of expansion, as all the cheaper expansion projects have already been undertaken.

Appendix III: Report by Jacobs Engineering

The Brattle Group
London

Base line analysis of the European Gas System

Convergence of non-discriminatory tarification systems of access to the gas system and congestion management across Europe

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1. INTRODUCTION AND SUMMARY OF CONCLUSIONS

1.1 INTRODUCTION

One aim of the study “Convergence of non-discriminatory tarification systems of access to the gas system and congestion management across Europe” contracted to the Brattle Group by EC DG TREN is to identify the most important gas transportation routes and to make a preliminary assessment of possible congestion on those routes.

The following method is chosen:
1. Determination of the main transport routes and main transport capacities on those routes. Validation of these capacities.
2. Determination of total import and export capacity on a country-by-country basis using the data generated in step 1.
3. Comparison of the net import or export capacity with actual year 2001 natural gas imports. The ratio of net capacity to actual year 2001 data is used to make preliminary conclusions on congestion for transportation of gas through a country.
4. Comparison of peak flow capacities in cross-border pipelines with the maximum capacity. This gives an idea of the potential congestion during peak flows in individual cross-border pipelines.

The objective of this document is to:
1. elaborate the current approach using public data,
2. check the public data for consistency and suggest items to be clarified,
3. provide preliminary congestion conclusions for verification or comments

1.2 ANALYSIS

Based on public data three analyses have been performed:
1. Hardware analysis:
   Identification of main transport routes, transport capacities and pipeline diameters. Comparison of specified maximum capacities with diameters of pipelines. Identification of those pipelines where the stated transport capacity is low compared to an overall transport capacity based on a simple diameter estimate. For these lines a check on data is suggested.
2. Regional analysis:
   Comparison of specified maximum capacities with net average imports of EU countries.
3. Temperature analysis:
   Comparison of specified maximum capacities with actual peak flow rates based on December 1996 data.

1.3 SOURCES

- maximum capacities: GTE map and website
- pipeline diameters: Ruhrgas map
- cross-border capacities: GTE Gas Flows presentation, Madrid (GTE-gas-pres.pdf)
- net import of EU countries and cross-border capacities: The Brattle Group
- December 1996 flow rates: GTE presentation, Madrid
- Additional data provided by GTE

1.4 RESULTS

Based on these rough data a high level analysis has been performed. Conclusions are indicative and preliminary. Detailed information is necessary to perform a thorough analysis.

1.5 SUMMARY OF CONCLUSIONS

On a country-by-country basis the import and export capacities are compared with data on actual average and peak gas consumption. During the investigation a number of assumptions and indicative data are used. This document summarises assumptions and defines items to be verified.

From the current analysis the following **preliminary** and **indicative** conclusions on the **present situation** at **cross-border points** result:

- Comparison of the actual net average exports and imports for the year 2001 with the capacities show that import capacities of all countries are more than sufficient for average net imports. The same holds for the exporting countries. So on an average basis no congestion is expected on a country-to-country basis.
- Using typical Dutch off-take patterns with variations from day to night and from summer to winter, the ratio of peak to average demand is at least 2. For the whole of Europe the peak to average ratio is 1.8 ("EU Security of Supply" study, April 1998, Wood Mackenzie and the University of Dundee). When the ratio of the difference between import and export capacity and net imports is small (near to 1), flexibility has to be created inside the country itself. One option is gas storage.
- When the ratio of the difference between import and export capacity and actual net import is large flexibility can be imported. A high ratio means that the installed transport capacity for importing a peak flow is available and can be used in times of peak demand.
- The Netherlands is the main exporter of flexibility. Germany, Belgium and Ireland are the main importers of flexibility.

- Effectively the transport capacity of gas from the north and east to France and the Iberian peninsular is limited. This might cause congestion when gas from north-west Europe or Russia is required. For instance the total installed pipeline import capacity of Spain at the France/Spanish border is 2.3 BCM per year, whereas the net Spanish consumption is 17.6 BCM per year.
- Results of the regional analysis suggest that France is a congestion country for gas transported from Russia to France and the Iberian peninsular. Also Switzerland seems to be a congestion country for gas transported from western Europe to Italy.

2. HARDWARE ANALYSIS

2.1 ANALYSIS

In the table below the maximum flow rates (column 5, max capacity) come from the GTE map and the diameters D1-D5 come from a Ruhrgas publication. For interconnections with multiple pipelines the ”effective pipeline diameter” is calculated as shown in the last column. The specified maximum capacities are compared with the effective pipeline diameter for those points.

Table 1: maximum capacity and pipeline diameter at cross-border points.

Nr	Location	From	To	max cap mio Nm3/h	Code	D1 [“]	D2 [“]	D3 [“]	D4 [“]	D5 [“]	Eff. Diam.
1	Loughshinny	UK	Ireland	1,04	R	24					24,0
2	Bacton	UK	Belgium	2,30	R	40					40,0
3	Zeebrugge	Belgium	UK	1,00	G	48					48,0
4	Zeebrugge	LNG	Belgium	0,87	Y	36					36,0
5	Zeebrugge	Norway	Belgium	1,60	R	40					40,0
6	Dunkerque	Norway	France	1,37	Y	42					42,0
7	Emden	Norway	Netherlands	1,50	Y	42					42,0
8	Emden	Norway	Germany	1,00	Y	32	40				51,2
9	Dornum	Norway	Germany	2,40	R	48					48,0
10	Zelzate	Belgium	Netherlands	1,20	G	36					36,0
11	Oude Statenzijl	Netherlands	Germany	3,40	Y	24	16	24	30	36	60,0
12	Dragor	Denmark	Sweden	0,23	Y	24					24,0
13	Ellund	Denmark	Germany	0,33	R	20					20,0
14	Mallnow	Poland	Germany	2,80	R	56					56,0
15	Sayda	Czech Rep.	Germany	1,55	G	36	36	24			56,3
16	Olbernhau	Czech Rep.	Germany	0,50	Y	32					32,0
17	Waidhaus	Czech Rep.	Germany	3,90	G	36	48	44			74,4
18	Oberkappel	Austria	Germany	0,50	R	32					32,0
19	Burghausen	Austria	Germany	0,32	G	32					32,0
20	Baumgarten	Slovakia	Austria	4,56	Y						0,0
21	Baumgarten	Austria	Slovakia	0,00	R						0,0
22	Mosonmagyarovar	Austria	Hungary	1,31	G						0,0
23	Murfeld	Austria	Slovenia	0,22	Y						0,0
24	Arnoldstein/Tarvisio	Austria	Italy	2,63	R	42	36				55,3
25	Gorizia	Italy	Slovenia	0,17	G	20					20,0
26	Mazara del Vallo	Tunisia	Italy	3,48	G	48	48				67,9
27	Panigaglia	LNG	Italy	0,40	R	30					30,0
28	Fos-sur-Mer	LNG	France	0,63	Y	32					32,0
29	Barcelona	LNG	Spain	1,20	Y						0,0
30	Cartagena	LNG	Spain	0,27	Y						0,0
31	Tarifa	Morocco	Spain	1,07	R	48					48,0
32	Huelva	LNG	Spain	0,45	R	26					26,0
33	Badajoz	Spain	Portugal	0,35	R						0,0
34	Tuy	Portugal	Spain	0,04	R						0,0
35	Imatra	Russia	Finland	0,80	R	32					32,0
36	Col de Larreau	France	Spain	0,26	R	26					26,0
37	Montoir	LNG	France	1,14	G	32					32,0
38	Blaregnies L.	Belgium	France	0,93	Y	36					36,0
39	Blaregnies H.	Belgium	France	1,50	Y	40	36				53,8
40	Gries Pass	Switzerland	Italy	1,85	G	48	34				58,8
41	Wallbach	Germany	Switzerland	1,20	R	36	36				50,9
42	Obergailbach	Germany	France	1,45	Y	36					36,0
43	Remich	Germany	Luxembourg	0,19	G						0,0
44	Petange	Belgium	Luxembourg	0,06	Y	12					12,0
45	Bras	Belgium	Luxembourg	0,19	Y	16					16,0

46	Esch/Alzette	France	Luxembourg	0,02	R						0,0
47	Bocholtz	Netherlands	Germany	1,04	R	38					38,0
48	Zevenaar	Netherlands	Germany	2,50	R	36	36				50,9
49	Winterswijk	Netherlands	Germany	1,50	R	40					40,0
50	s'Gravensvoeren	Netherlands	Belgium	1,10	R	36					36,0
51	Hilvarenbeek	Netherlands	Belgium	3,10	R	36	36				50,9
52	Obicht	Netherlands	Belgium	0,20	Y	16					16,0
53	Kiefersfelden	Germany	Austria	0,10	R	16					16,0
54	Eynatten	Belgium	Germany	0,70	G	40					40,0
55	Lasow	Poland	Germany	0,18	Y	16					16,0
56	Revythoussa	LNG	Greece	0,22	G						0,0
57	Kula	Bulgaria	Greece	0,40	G						0,0
58	Lanzhot	Slovakia	Czech Rep.	6,50	G	28	48	44	44		83,4
59	Velke Kapusany	Ukraine	Slovakia	10,50	Y	32	32	40	48	56	95,3
60	Oltingue	France	Switzerland	-	-	36					36,0

Data provided by GTE at June 27, 2002

2.2 CONCLUSIONS OF HARDWARE ANALYSIS

Based on a rough first order analysis Jacobs Consultancy expects a linear relation between the square of the pipeline diameter and the design flow capacity. Due to the limited data available publicly the following items have not been considered in this analysis:

- Average gas pressure at the cross-border points mentioned
- Compressor stations
- Topology of the network and distance to off-take or injection points

Including these items would be appropriate in a more detailed analysis. Given the purpose of the current analysis, to verify the available data and identify possible data that has to be checked, including these items is not relevant. Furthermore detailed analysis show that the increase of capacity with diameter is not with the power of 2 but slightly stronger. This also does not influence the conclusions of this analysis.

The comparison of capacity and diameter is done by a graphical comparison of the capacity with the square of pipeline the diameter (see figure). An overall guideline could be that the max capacity is 2 MCM per hour per square meter of pipeline cross-section area. This relation reasonably fits the line connecting the upper points in the graph.

If points do deviate strongly from this line, the indicated max capacity is seen as low and a check on available data is required. This method is also used for the grouped capacity of cross-border pipelines where the capacity is compared to the square of the effective diameter.

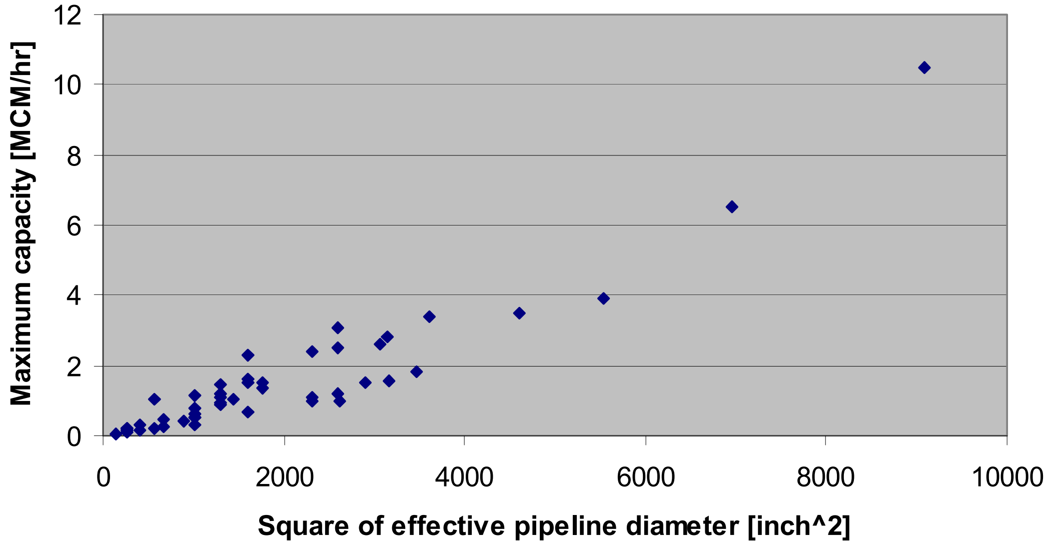

Figure 1: Maximum capacity versus square of pipeline diameter

The expected linear relation between maximum capacity and the square of the effective pipeline diameter is indeed found. No extreme deviations are found. Cross-border pipeline diameters as specified in Table 1 should be checked by the applicable institutions. Not all cross-border pipeline diameters could be found in publicly available data. Furthermore the max. hourly flow rates (million Nm3/h) specified in the table attached to the European gas network grid map are interpreted as design flow rates and not an actual flow rates. The cross-border capacity from France to Switzerland should be checked.

3. REGIONAL ANALYSIS

3.1 ANALYSIS

In the regional analysis the total yearly imports (exports) and the country-to-country cross-border capacities are used to draw preliminary conclusions on flexibility and the possible occurrence of congestion.

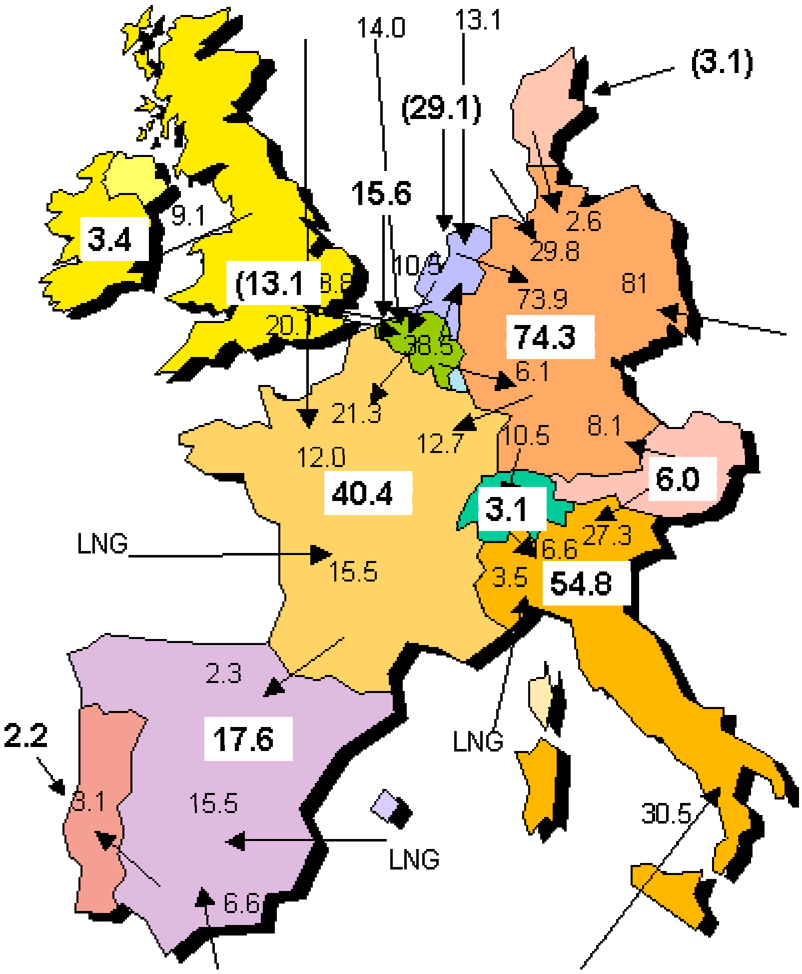

Figure 2: Year 2001 natural gas imports and exports (BCM/yr) and country to country cross-border transport capacities (BCM/yr)

Figure 2 shows:

- net imports per country in BCM/yr (in large bold font),
- net exports per country in BCM/yr (in large bold font between brackets) and
- the most important crossborder capacities in BCM/yr (arrows with numbers in small font)

The annual capacities are derived from the 2001 GTE daily capacities by adding them up per country to country and multiplying by 8760 (hrs/yr).

Analysis of this data leads to preliminary conclusions on three items:

- Congestion on the import side
- The import/export of flexibility
- Congestion on the gas transit side

Conclusions are preliminary and do not take into account the availability of gas storage, line-pack and peak to average ratios. When in the analysis below congestion is mentioned the 'congestion on an average basis' is meant

Import congestion

When comparing only the import capacity with the net yearly gas imports, a prediction of the possibility of congestion on an average basis of gas flow into a country can be made. For exporting countries the same analysis can be made for export congestion. When the conclusion of a country analysis is that congestion on an average basis cannot be expected for a certain country, import or export congestion is still possible when there is a large difference between the average flow and the peak flow. In that case the applicable country is large importer (or exporter) of flexibility.

Flexibility

With the data as shown in Figure 2, it is possible to calculate the ratio of the difference in import and export capacity divided by the net yearly gas imports. Assuming a roughly equal utilisation of the capacities, this ratio is an indicative measure of net import capacity to actual annual consumption. If this ratio is high it could be a sign that flexibility is also contracted. If the ratio is close to one no flexibility can be imported. Congestion at peak demand can occur mainly when insufficient storage capacity is available in countries with a relatively low ratio.

Transit congestion

For a given country the import capacity from one neighbour country can be compared with the export capacity to a second country. For instance the import capacity from Poland to Germany is 81 BCM per year whereas the export capacity from Germany to France is 12.7 BCM per year. So, at a maximum 12.7 BCM/yr can be transported from Poland to France, which is equivalent to 16% of the Poland/Germany import capacity and to 6.2% of the total German import capacity.

In the following tables a country-by-country analysis is presented. Conclusions 1, 2 and 3 respectively refer to import congestion, flexibility and transit congestion.

Germany		
Total import capacity	201,7	BCM/year
Total export capacity	25,7	BCM/year
Net imports	74,3	BCM/year
Ratio diff capacity/net import	2,37	

Conclusions:

1 German import capacity is large compared to yearly net imports. Therefore no import congestion into Germany is expected.
2 Ratio diff capacity/net import is high. Therefore not only gas but probably also a lot of the flexibility is imported.
3 German export capacity is relatively small. Therefore no large transit flows through Germany are possible and transit congestion can be expected when gas from Russia is to be transported to France or Spain (transit through Italy or Switzerland is not possible)

Denmark		
Total import capacity	0	BCM/year
Total export capacity	4,4	BCM/year
Net exports	3,1	BCM/year
Ratio diff capacity/net export	-1,42	

Conclusions:

1 Denmark is an export country. The export capacity is 1.4 times the average exports, export congestion may be possible.
2 Ratio diff capacity/net import is low, probably not much flexibility is sold.
3 Transit congestion is not applicable.

UK		
Total import capacity	8,8	BCM/year
Total export capacity	29,3	BCM/year
Net exports	13,1	BCM/year
Ratio diff capacity/net export	-1,56	

Conclusions:

1 At this moment the UK is an export country. According to data provided by the DTI (Department of Trade and Industry) the UK will change to an import country in the coming years. At this moment the export capacity is 2.2 times the average exports, no export congestion is expected.
2 Ratio diff capacity/net import is not very high, probably only limited flexibility (to Ireland) is sold.
3 Transit congestion is not applicable.

Ireland		
Total import capacity	9,1	BCM/year
Total export capacity	0	BCM/year
Net imports	3,4	BCM/year
Ratio diff capacity/net import	2,68	

Conclusions:

1 Irish import capacity is almost three times the average imports, no import congestion is expected
2 Ratio diff capacity/net import is very high, flexibility will be bought
3 Transit congestion is not applicable.

Netherlands		
Total import capacity	23,7	BCM/year
Total export capacity	112,5	BCM/year
Net exports	29,1	BCM/year
Ratio diff capacity/net export	-3,05	

Conclusions:

1 The Netherlands is an export country. The export capacity is almost 4 times the average exports, no export congestion is expected
2 Ratio diff capacity/net import is very high. The Netherlands is a large exporter of flexibility.
3 Transit congestion is not applicable.

Belgium		
Total import capacity	80.3	BCM/year
Total export capacity	48.9	BCM/year
Net imports	15.6	BCM/year
Ratio diff capacity/net import	2.01	

Conclusions:

1 The total import capacity is more than 5 times the net annual imports. This is also due to the large transit flows through Belgium. Still no import congestion into Belgium can be expected.
2 Belgium import capacity minus export capacity is two times the average imports. Therefore flexibility is imported from the Netherlands
3 The import capacity from producers in NL, UK and Norway is 72 mio Nm3/hr (with an additional 7.6 mio Nm3/hr for LNG), and the export capacity to net importers France and Germany is only 27 mio Nm3/hr. Therefore transit flows through Belgium are limited and transit congestion may be expected. On the other hand alternative routes are available: Germany and France have a direct connection with Norway, and Germany has a very large connection with NL.

France	
Total import capacity	61.5BCM/year
Total export capacity	2.5BCM/year
Net imports	40.4BCM/year
Ratio diff capacity/net import	1.46
Conclusions:	
1 France's import capacity is only 1.5 times the annual net imports. Figures improve slightly when the 15.5 mio Nm3/hr LNG import capacity is considered. Still import congestion is possible when insufficient flexibility can be created inside of France.	
2 Ratio diff capacity/net import is small, not much flexibility can be imported. Therefore most of the required flexibility has to be created inside France.	
3 Transit capacity to Spain is almost zero and import capacity of gas from Russia is very limited. Transit congestion can be expected when gas from Russia is to be transported to or through France.	

Switzerland	
Total import capacity	19.3BCM/year
Total export capacity	16.6BCM/year
Net imports	3.1BCM/year
Ratio diff capacity/net import	-1.97
Conclusions:	
1 Switzerland is a net importer with large transit flows. The import capacity is significantly larger than the net imports. Therefore no import congestion is expected.	
2 Because of the large import and export capacities conclusions on flexibility cannot be drawn.	
3 The export capacity is calculated from an estimated import capacity from France of 1 mio Nm3/hr (row 60, table 1, Oltingue: diameter 36", estimated capacity 1 mio. Nm3/hr). Because there is no physical connection between France and Italy, transit congestion may be possible when large transit flows from north-western Europe to Italy are required.	

Austria	
Total import capacity	40.8BCM/year
Total export capacity	40.3BCM/year
Net imports	6.0BCM/year
Ratio diff capacity/net import	0.08
Conclusions:	
1 Both import and export capacity are very large, Austria is a large transit country. Import congestion in relation to the relatively low net imports cannot be expected.	
2 Because of the large import and export capacities conclusions on flexibility cannot be drawn.	
3 Transit congestion depends entirely on the consumption of gas from Russia and north-western Europe.	

Spain	
Total import capacity	26BCM/year
Total export capacity	3.1BCM/year
Net imports	17.6BCM/year
Ratio diff capacity/net import	1.30

Conclusions:

1 Spanish import capacity is sufficiently large compared to the annual net imports. No import congestion can be expected.
2 The ratio of diff capacity/net import is small, therefore any required flexibility has to be created in Spain
3 Transit capacity to France is almost zero. Therefore the import capacity of gas from north-west Europe is very limited. Transit congestion can be expected when gas from north-west Europe or Russia is to be transported to Spain.

Portugal	
Total import capacity	3.1BCM/year
Total export capacity	0BCM/year
Net imports	2.2BCM/year
Ratio diff capacity/net import	1.41

Conclusions:

1 The import capacity is small but sufficient compared to yearly net imports. Therefore no import congestion can be expected.
2 The import capacity is small compared to yearly net imports, not much flexibility can be imported.
3 Transit congestion is not applicable.

Italy	
Total import capacity	77.9BCM/year
Total export capacity	1.5BCM/year
Net imports	54.8BCM/year
Ratio diff capacity/net import	1.39

Conclusions:

1 The import capacity is small but sufficient compared to yearly net imports. Therefore no import congestion can be expected.
2 The import capacity is small compared to the yearly net imports, not much flexibility can be imported. Therefore the required flexibility has to be created inside Italy.
3 Transit congestion is not applicable.

3.2 CONCLUSIONS OF REGIONAL ANALYSIS

The follow overall conclusions can be drawn:

- Comparison of the actual net exports or imports for the year 2000 with the capacities show that import capacities of all countries are more than sufficient for average net imports. The same holds for the exporting countries. So on an average basis no congestion is expected.
- Using typical Dutch off-take patterns with variations from day to night and from summer to winter, the ratio of peak and average demand is at least 2. When the ratio of the difference between import and export capacity and net imports is small (near to 1), flexibility has to be created inside the country itself, e.g. by storage.
- When the ratio of the difference between import and export capacity and net imports is large flexibility can be imported. A high ratio means that the installed capacity for importing a peak flow is available and can be used in times of peak demand.
- The Netherlands is the main exporter of flexibility. Germany, Belgium and Ireland are the main importers of flexibility. This follows from a comparison of ratios of net export capacity to the actual value used in the year 2001. These values are listed below:
  - Netherlands -3.05
  - Germany 2.37
  - Belgium 2.01
  - Ireland 2.68
- Effectively the transport capacity for gas transported to France, Spain and Portugal is limited. This can cause congestion when gas from north-west Europe or Russia is required. For instance the total installed pipeline import capacity of Spain at the France/Spanish border is 2.3 BCM per year, whereas the net consumption in Spain is 17.6 BCM per year.
- As in the regional analysis it can be concluded that France is a congestion country of Russian gas transported to France, Spain and Portugal. Also Switzerland is a congestion land of gas transported from western Europe to Italy. The data on Switzerland need more detailed analysis to clarify the large difference between export and import capacity.

Flexibility

In the analysis above the flexibility ratio (ratio diff capacity/net import) is used to determine if a country is an importer or exporter of flexibility, or if the flexibility is created inside the country. As a result of this analysis it can be expected that the importers of flexibility have a relative low storage factor (storage capacity as a percentage of annual net imports). On the other hand countries with less possibility to import flexibility are expected to have a higher storage factor. From table 2 it can be concluded that France and Italy have a relative high storage factor. The storage factor of Ireland and Belgium is virtually zero. Despite the large possibility to import flexibility the storage factor of Germany is relatively high.

The storage factor as defined above is not relevant for exporting countries. In those countries the storage capacity should be compared to the annual consumption to see if it is used for providing flexibility.

The required flexibility of a country depends on the average to peak ratio of the demand, which is not the same in all EU countries. A corrected flexibility ratio can be calculated containing both imported flexibility and flexibility from local storage. The corrected flexibility ratio more or less represents the amount of flexibility required by a country.

The flexibility ratio in counties with large transit flows is not very representative. Because of the high storage factor in Austria it can be expected that not much flexibility is imported.

Table 2: Storage capacity and storage factor

Country	Net import [BCM]	Storage volume [BCM]	Storage factor [%]	Flexibility ratio	Corrected flex ratio
Germany	74.3	18.6	25	2,4	2,6
Denmark	-3.1	0.8			
UK	-13.1	3.6			
Ireland	3.4	0.0	0	2,7	2,7
Netherlands	-29.1	2.5			
Belgium	15.6	0.7	4	2,0	2,1
France	40.4	11.1	27	1,5	1,7
Switzerland	3.1	-			
Austria	6.0	2.3	38		
Spain	17.6	1.0	6	1,3	1,4
Portugal	2.2	n/a			
Italy	54.8	15.1	28	1,4	1,7

4. TEMPERATURE ANALYSIS

4.1 ANALYSIS

With the temperature analysis congestion at peak demand is analysed. Therefore the Dec 1996 peak flows provided by GTE are taken, and extrapolated forward to 2000 by applying average growth rates. The extrapolated peak flows are compared with the maximum transport capacities to check if expected peak flows are significantly above the maximum capacity, see Figure 3.

In the table below the inland consumption of European countries in 1996 and 2000 is given. Based on that data, an extrapolation factor for the observed flow rates in December 1996 is calculated. When an extrapolation factor below 1 is found, the value 1 is used. With the application of extrapolation factors a conservative (high) peak demand is used for the analysis.

Table 3: European gas consumption in 1996 and 2000 per country.

PRODUCT	Natural Gas (Million Cubic Meters)				
FLOW	A) Gross Inland Consumption (Calc)		B) Gross Inland Consumption (Obs)		
TIME	1996	2000	1996	2000	
COUNTRY					**Extrapolation factor**
Austria	7.971	7.535	7.971	7.709	**0,96**
Belgium	13.850	16.828	13.951	16.821	**1,21**
Denmark	4.197	4.905	4.192	4.906	**1,17**
Finland	3.650	4.196	3.649	4.195	**1,15**
France	38.091	40.995	37.217	40.463	**1,08**
Germany	97.389	91.413	89.558	87.747	**0,96**
Greece	42	2.053	42	2.052	
Ireland	3.228	4.013	3.227	4.013	**1,24**
Italy	56.184	70.407	56.184	70.407	**1,25**
Luxembourg	695	757	695	757	**1,09**
Netherlands	52.300	48.315	53.060	48.764	**0,92**
Norway	3.372	3.882	3.372	3.882	**1,15**
Portugal	10	2.380	10	2.363	
Spain	9.462	15.730	9.462	15.631	**1,66**
Sweden	919	881	880	881	**0,98**
Switzerland	2.902	2.971	2.902	2.971	**1,02**
UK	90.012	103.339	88.569	101.486	**1,15**

Note that the consumption in Austria, Germany, Netherlands and Sweden has decreased since 1996.

The extrapolation factors for Portugal and Greece have not been calculated. They are very high, mainly due to the very low consumption in 1996. For the temperature analysis they are not relevant.

Table 4: December 1996 flow rates at cross-border points.

N°	Location	from	to	flowrate Nm3/day	Extrapolation factor with increased demand	Extrapolated flowrate mio Nm3/day	Max capacity mio Nm3/day
1	**Loughshinny**	UK	Ireland	5,000,000	1,24	**6.22**	**24.96**
2	**Bacton**	UK	Belgium	0	1,21	**0.00**	**55.2**
3	**Zeebrugge B-UK**	Belgium	UK	0	1,15	**0.00**	**24**
4	**Zeebrugge LNG-B**	LNG	Belgium	11,838,295	1,21	**14.33**	**20.88**
5	**Zeebrugge No-B**	Norway	Belgium	37,162,369	1,21	**44.98**	**38.4**
6	**Dunkerk**	Norway	France	0	1,08	**0.00**	**32.88**
7	**Emden No-NL**	Norway	Netherlands	42,300,000	1,00	**42.30**	**36**
8	**Emden No-Ge**	Norway	Germany	16,034,773	1,00	**16.03**	**24**
9	**Dornum**	Norway	Germany	0	1,00	**0.00**	**57.6**
10	**Zelzate**	Belgium	Netherlands	0	1,00	**0.00**	**28.8**
11	**Oude Statenzijl**	NL	Germany	39,600,000	1,00	**39.60**	**81.6**
12	**Dragor**	Denmark	Sweden	4,100,000	1,00	**4.10**	**5.52**
13	**Ellund**	Denmark	Germany	4,978,940	1,00	**4.98**	**7.92**
14	**Frankfurt/Oder**	Poland	Germany	0	1,00	**0.00**	**67.2**
15	**Sayda**	Czech R.	Germany	18,824,090	1,00	**18.82**	**37.2**
16	**Olbernau**	Czech R.	Germany		1,00	**0.00**	**12**
17	**Waidhaus**	Czech R.	Germany	62,219,654	1,00	**62.22**	**93.6**
18	**Oberkappel**	Austria	Germany	6,169,500	1,00	**6.17**	**12**
19	**Burghausen**	Austria	Germany	816,892	1,00	**0.82**	**7.68**
20	**Baumgarten**	Slovakia	Austria	61,858,287	1,00	**61.86**	**109.44**
21	**Baumgarten**	Austria	Slovakia			**0.00**	**0**
22	**Masonmagyarovar**	Austria	Hungary	1,235,477		**1.24**	**31.44**
23	**Murfeld**	Austria	Slovenia	3,291,972		**3.29**	**5.28**
24	**Arnoldstein Tarvisio**	Austria	Italy	37,420,410	1,25	**46.89**	**63.12**
25	**Gorizia**	Italy	Slovenia	1,467,720		**1.47**	**4.08**
26	**Mazara**	Tunisia	Italy	69,032,370	1,25	**86.51**	**83.52**
27	**Panigaglia**	LNG	Italy		1,25	**0.00**	**9.6**
28	**Fos sur Mer**	LNG	France	10,600,000	1,08	**11.47**	**15.12**
29	**Barcelona**	LNG	Spain	20,100,000	1,66	**33.31**	**28.8**
30	**Cartagena**	LNG	Spain	200,000	1,66	**0.33**	**6.48**
31	**Tarifa**	Morocco	Spain	12,700,000	1,66	**21.05**	**25.68**
32	**Huelva**	LNG	Spain	2,000,000	1,66	**3.31**	**10.8**
33	**Campo Major**	Spain	Portugal			**0.00**	**8.4**
34	**Tuy**	Portugal	Spain		1,66	**0.00**	**0.96**
35	**Imatra**	Russia	Finland		1,15	**0.00**	**19.2**
36	**Port de Larau**	France	Spain	4,600,000	1,66	**7.62**	**6.24**
37	**Montoir**	LNG	France	14,200,000	1,08	**15.36**	**27.36**
38	**Blaregnis L**	Belgium	France	20,452,709	1,08	**22.12**	**22.32**
39	**Blaregnis H**	Belgium	France	41,603,383	1,08	**45.00**	**36**
40	**Griespass**	Switzerl.	Italy	18,006,640	1,25	**22.57**	**44.4**
41	**Wallbach**	Germany	Switzerland	26,868,750	1,02	**27.51**	**28.8**
42	**Obergailbach**	Germany	France	26,200,000	1,08	**28.34**	**34.8**
43	**Remich**	Germany	Luxembourg	0	1,09	**0.00**	**4.56**
44	**Petange**	Belgium	Luxembourg	1,185,167	1,09	**1.29**	**1.44**
45	**Bras**	Belgium	Luxembourg	1,583,760	1,09	**1.73**	**4.56**

N°	Location	from	to	flowrate Nm3/day	Extrapolation factor with increased demand	Extrapolated flowrate mio Nm3/day	Max capacity mio Nm3/day
46	**Esch / Alzette**	France	Luxembourg	304,840	1,09	**0.33**	**0.48**
47	**Bocholtz**	Netherlands	Germany	24,000,000	1,00	**24.00**	**24.96**
48	**Zevenaar**	Netherlands	Germany	46,900,000	1,00	**46.90**	**60**
49	**Winterswijk**	Netherlands	Germany	43,600,000	1,00	**43.60**	**36**
50	**s'Gravenvoeren**	Netherlands	Belgium	27,426,347	1,21	**33.20**	**26.4**
51	**Hilvarenbeek**	Netherlands	Belgium	43,401,006	1,21	**52.53**	**74.4**
52	**Obicht**	Netherlands	Belgium	1,772,254	1,21	**2.15**	**4.8**
53	**Kiefersfelden**	Germany	Austria	516,460	1,00	**0.52**	**2.4**
54	**Eynatten**	Belgium	Germany	0	1,00	**0.00**	**16.8**
55	**Gorlitz**	Poland	Germany	0	1,00	**0.00**	**4.32**
56	**Revythoussa**	LNG	Greece	0		**0.00**	**5.28**
57	**Kula**	Bulgaria	Greece	0		**0.00**	**9.6**
58	**Lanzhot**	Slovakia	Czech R.	115,498,750	1,20	**138.60**	**156**
59	**Velke Kapusany**	Ukraine	Slovakia	176,027,192	1,20	**211.23**	**252**

Note: for points 58 and 59 a conservative 20% increase is assumed despite the decreased consumption in Germany.

Adjusted flow rates and maximum capacity are also compared in the figure below.

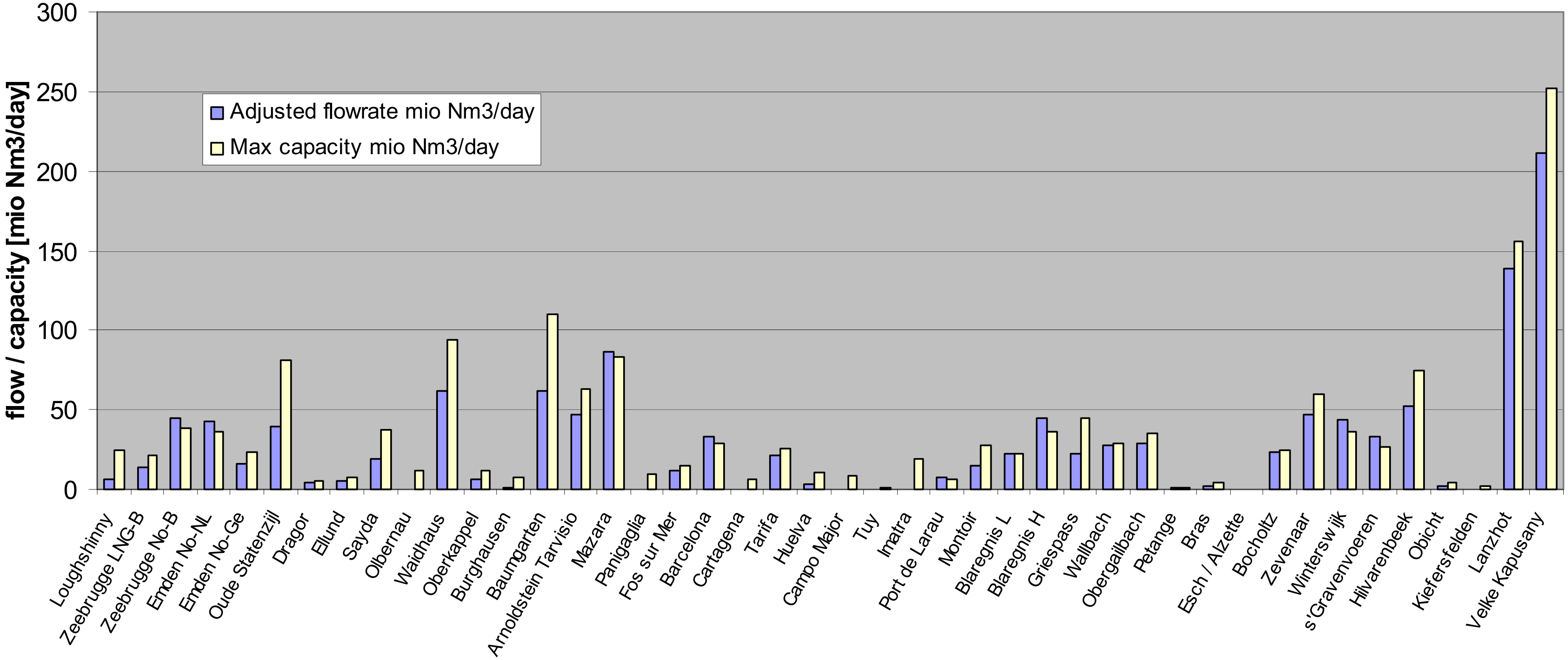

Figure 3: extrapolated flow rate and max capacity at cross-border points in mio. Nm3/day

4.2 CONCLUSIONS OF TEMPERATURE ANALYSIS

This temperature analysis is based on the December 1996 data. Results of the analysis should be interpreted integrally. At a specific cross-border point the actual situation may differ significantly from the general picture. However, the overall conclusion remains that expected peak demands can be accommodated with the maximum available transport capacities together with the available storage capacities.

The following general conclusions can be drawn:

- Generally the maximum available capacities are sufficiently large to accommodate the adjusted flows under extreme conditions.
- Germany is known as a large importer of flexibility, resulting in a high peak demand. Nevertheless, there are no bottlenecks found in supplying Germany.
- The maximum capacity to France, Italy and Spain is used. In these countries most probably storage facilities have to be used to secure supply.

Maximum capacities are reached at the following cross-borders:

- Norway to Netherlands and Belgium
- Netherlands to Belgium
- Belgium to France
- Germany to France and Switzerland
- Morocco to Spain
- Tunisia to Italy