Study on

Cross-Border Electricity Transmission Tariffs

by order of the

European Commission, DG XVII / C1

Final Report

Aachen, April 1999

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Executive Summary

In consequence of the directive 96/92/EC on the internal electricity market, the EU member states are currently developing new arrangements or improving existing ones for the required open access to electricity transmission systems. In this process, the question arises if and in which way the solutions developed on the national level have to be harmonized or supplemented by additional international arrangements, in order to provide open access also to cross-border electricity transactions under fair and non-discriminatory terms, according to the directive, with the objective to create a true internal electricity market.

The scope of this study is to identify the most essential issues that have to be addressed in this concern, and to discuss possible solutions. The study mainly focuses on transmission pricing, but the issues of congestion management and, to a minor extent, settlement of transactions are also addressed because of their importance for internal market development. This report can be roughly subdivided into three parts:

- an analysis of basic terms of network costs and network pricing, congestion management and transaction settlement, including a chapter on the technical background of electricity transmission, and the identification of issues relevant to cross-border-transmission (chapters 1-5),
- an overview of existing cross-border open access arrangements in electricity transmission and other areas of economy, a qualitative and quantitative comparison of current national transmission tariffs in 9 European states, and a survey of proposals and positions of the electricity industry, particularly the transmission system operators (TSOs), the regulators and the transmission system users, on solutions for cross-border transmission access arrangements in the member states plus Norway and Switzerland (chapters 6-8), and
- a comprehensive discussion of possible solutions for cross-border transmission pricing and congestion management, based on existing or proposed concepts, taking account of the basic objectives derived from the electricity directive, and including recommendations from the authors' point of view (chapter 9).

As regards transmission pricing, the analysis shows that all existing or proposed concepts comprise charges that are exclusively imposed on the TSOs' local network users, not on users in other TSO areas. In most countries, these charges are com-

pletely non-transaction-based, i. e. related only to individual network users irrespective of their commercial relationships. These charges cover the major part of the total transmission costs and are basically subject to subsidiarity in terms of structure and magnitude. To avoid distortions of competition in the internal market, it appears however important to harmonize at least the underlying principles of cost allocation towards generation and consumption/distribution, as far as possible, but with limited urgency. The authors recommend to allocate at least a small part of total costs towards generators in order to facilitate the introduction of locational price signals.

The crucial issue in the discussion on cross-border transmission pricing regards possible payments across borders to be made by TSOs or market actors to other TSOs, in order to compensate for use of international transmission capacities or to improve fairness and economic signals. Out of the wide range of possible solutions to this aspect, two approaches are worked out to be most reasonable and consistent, satisfying the partly contradictory objectives of cost-reflectivity and promotion of competition to different degrees:

- International compensation could be granted by payments on the TSO level, avoiding the introduction of transaction-based charges towards single market actors or aggregates of transactions. These payments could be recovered in various ways, ranging from a Europe-wide flat surcharge for all network users to an individualization towards the involved importers or exporters. While more socialization of course would reduce the signal function of charges, individualization could appear unfair and imply critical barriers to trade. In general, this concept is very practicable and beneficial as regards market development, but it is not able to provide path-oriented economic signals in relation to distance, for instance.

- Alternatively, the interconnected systems could be subdivided into tariff areas, supposedly in more or less accordance to the existing control areas, and surcharges be imposed on aggregates of transactions, declared by each generator, supplier or trader for each area. These area-to-area charges, fixed in matrix form, could be intended to reflect use of international transmission systems in relation to distance, or to give direct price signals towards relieve of congestion. Drawbacks of this approach are certain restrictions to practicability and predictability of charging, especially for internationally operating traders and power exchanges, and the fact that even small transaction charges could seriously affect economic trading opportunities, thus jeopardizing the internal market development.

It is also conceivable to combine certain features of these approaches, for example by adopting mainly the first one, but including additional transaction-based surcharges and discounts on severe cases of congestion on area borders, or by including transaction charges for use of DC links between different areas. Whichever solution is actually chosen, the authors consider a precise and quick harmonization of any such cross-border payments or charges crucial, in terms of structure and magnitude.

As regards congestion management, it is recommended to distinguish between two kinds of congestion: the severe cases of frequently congested bottlenecks as far as they are simply to identify because located on „system cuts“, and the more complex cases located somewhere inside the remaining parts of the interconnected systems.

For the first kind of congestion, transaction-based procedures appear best suited in order to provide incentives to market actors and to limit the congestion costs. Such procedures could include declaration of (aggregates of) transactions across the bottlenecks, direction-dependent surcharges and discounts on transmission charges, and, for example, proportional sharing of the limited capacities among the involved actors in case of actual congestion. The revenues from the surcharges could be used to finance network reinforcement to eliminate the bottlenecks.

The remaining type of congestion should better be handled by non-transaction-based measures, e. g. by counter trading, with the arising costs being more or less socialized among the market actors. This requires however close cooperation between TSOs in terms of data exchange, identification of congestion and of appropriate countermeasures, and agreements on allocation principles of congestion costs.

Since these coordination requirements can probably not be met right away without time-consuming preparations, arrangements of a more transaction-based kind appear necessary for a limited transitional period. Great emphasis should however be put on harmonized procedures as market-oriented and transparent as possible, with refusal or curtailment of transactions being only ultimate solutions.

The actual development of detailed open access arrangements requires careful weighing up between partly contradictory objectives like practicability and cost-reflectivity. In case of doubt, the authors would tend towards prefering more practicable solutions to promote market development in the initial phase, since experience shows that later refinements and modifications will be inevitable in any case.

Aachen, 30th April 1999

(Univ.-Prof. Dr.-Ing. Hans-Jürgen Haubrich) (Dr.-Ing. Wolfgang Fritz)

1 Introduction

1.1 Scope of the Study

In consequence of the directive 96/92/EC on the internal electricity market [1], the member states of the EU are developing new arrangements for their electricity markets including technical and commercial rules for the required open access to transmission and distribution networks. One of the main issues to be addressed is network pricing, i. e. the development of methods for calculation of charges to be paid by network users to network operators.

In principle, setting up new arrangements for open access is a matter for subsidiarity. However, in view of the close interconnection of European electricity transmission systems, the interaction of different national arrangements might in certain aspects lead to conditions under which a real internal market is difficult to establish. Thus a minimal set of common rules or a certain degree of harmonization of national rules might be necessary.

It is the aim of this study to provide the analytical basis required to develop suitable common arrangements particularly for the issue of network pricing with respect to cross-border transactions.

Because the arrangements for open access to *distribution* networks have only little relevance to the issue of cross-border transactions in Europe and can therefore be treated subsidiarily without significant demand of harmonization, this study focuses exclusively on the transmission level as defined in the electricity directive [1]. Geographically, however, the scope of the study is not restricted to EU member states, but includes Norway and Switzerland where the electricity industries are already or will soon be liberalized, and whose transmission systems are closely integrated with those of the EU members. For simplicity, this geographical scope is referred to as „Europe“ throughout this report.

In particular, the study comprises

- an overview of the most important technical background information on European transmission systems and their interconnections and cooperation frameworks, (chapter 2),

- an analysis of general terms and principles of network costs and network pricing, i. e. cost elements, parameters of costs, methods applied in the existing national tariff models to determine cost elements and to allocate them to different users of the transmission system, and objectives of network pricing (chapter 3.1-3.3),
- the identification of those aspects of network costs and pricing that are particularly relevant to cross-border transactions, and of the potential problems that might arise in the absence of a minimum set of common rules (chapter 3.4),
- an overview of possible arrangements for two other issues of essential importance with respect to open access, i. e. congestion management and settlement of transactions, and the identification of aspects relevant to cross-border transactions (chapters 4 and 5),
- a description of existing pricing concepts for cross-border transactions in the electricity industry (USA, Scandinavia, England/Scotland, Germany, and the UCPTE transit agreement, chapter 6.1) as well as in other branches of economy (post and telephone, chapter 6.2),
- a quantitative comparison of electricity transmission tariffs in different European countries for a few representative transmission cases including cross-border transactions (chapter 7),
- an analysis of proposals and remarks on transmission pricing with respect to cross-border transactions in Europe that have mainly been made by transmission system operators (TSOs), regulators, and electricity consumers and traders (chapter 8), and
- a comprehensive discussion of possible models for network pricing as well as congestion management with respect to European cross-border transactions, resulting in recommendations towards reasonable solutions (chapter 9).

It must be stated from the beginning that it is not possible to create generally optimal solutions to these topics, because the relevant objectives are partly contradictory. This is particularly true for the (politically influenced) weighing of the objective to quickly develop a true and active internal market in electricity on the one hand, and the objectives to individually treat each network user as fair as possible, to leave as much as possible space for subsidiarity, and to create appropriate long-term incentives to the market actors on the other hand. Therefore, the authors try to outline a „band-width“ of reasonable solutions for the near future rather than to vote for a specific „ideal“ long-term solution.

Compared to the scope of work defined in the study contract, the main chapters and sub-topics have been rearranged and newly titled in a way that has turned out more appropriate and more effective during the work and reporting process.

This final report has been preceded by an interim report, submitted to the orderer on 23rd February 1999, extracts of which have been distributed to the concerned parties throughout Europe on 1st April 1999 after gaining approval and including remarks from the orderer. This distribution has resulted in a multitude of valuable comments which have been taken into consideration during preparation of this final report.

1.2 Meetings

During the work period, the following meetings with the orderer and the other concerned parties have been held in order to acquire a broad basis of proposals, arguments and points of view, necessary for a comprehensive discussion of the subject.

Date	Place	Participants (Company/Association/Authority)
02.12.98	Brauweiler	DVG (German TSOs' association)
10.12.98	Aachen	VIK (German industrial energy consumers' assoc.)
21.12.98	Aachen	VKU (German municipal utilities' association)
22.12.98	Brussels	DG XVII
08.01.99	Brussels	IFIEC (Internat. Feder. of Industrial Energy Consumers)
11.01.99	Düsseldorf	Atel and EGL (Swiss TSOs)
11.01.99	Düsseldorf	VASA Energy (power trader)
18.01.99	Essen	Steering committee of TSO organizations and Eurelectric
28.01.99	London	Electricity Association (British utilities' association), and members (NGC, Eastern Group, National Power, Scottish Power)
02.02.99	Boppard	VIK members
03.02.99	Frankfurt	VDEW (German utilities' association)
03.02.99	Frankfurt	EnBW Transportnetze and Bayernwerk Hochspan-

		nungsnetz (German TSOs)
04.02.99	Brussels	REN (Portuguese TSO, UCPTE president) and Electrabel (Belgian TSO)
08.02.99	Den Haag	ERSE (Portuguese regulator)
08.02.99	Den Haag	DG XVII
09.02.99	Stockholm	Svenska Kraftnät (Swedish TSO), Vattenfall (Swedish utility) and Svenska Kraftverksföreningen (Swedish generators' association)
11.02.99	Aachen	EdF (French TSO)
26.02.99	Brussels	DG XVII (presentation of interim report)
26.02.99	Brussels	Enron (power trader)
04.03.99	Aachen	PreussenElektra Netz (German TSO)
12.04.99	Paris	EdF (French TSO)
21.04.99	Brauweiler	RWE Energie (German TSO)
23.04.99	Neuss	Steering committee of TSO organizations and Eurelectric

Further discussions with experts and organizations not included in the above list have not been possible due to financial and time limitations. Additional correspondence has however been carried on with representatives mainly from Italy, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and UK.

1.3 Overview of General Issues of Open Access

The main instrument of the electricity directive for introducing more competition in the electricity supply sector and for creating an internal electricity market is the separation („unbundling“) of the activities concerning the operation of transmission and distribution systems from the other activities (explicitly only from generation) of the vertically integrated electricity companies at least in terms of accounting, combined with the requirement that all actors must be given access to the transmission and distribution networks on fair and non-discriminatory terms („open access“). The network operation remains in a more or less monopolistic state, subject to some form of governmental regulation, while the other activities like generation, trade, and supply are stepwise opened to competition.

The implementation of unbundling and open access creates new interfaces between market actors and network operators as well as new tasks that have not existed as distinct tasks so far, but have been embedded in the activities of the vertically integrated electricity companies. The main three issues that have to be addressed on the national as well as on the international level, in terms of allocating the responsibilities, developing rules how to proceed, defining rules for data exchange, and allocating the arising costs, are as follows:

1. The **technical implementation** of open access comprises mainly

   – the admission of new actors to access existing networks,

   – the incorporation of access cases into the planning phase of network operations, i. e. the prediction of the network situation in order to recognize critical situations, as well as their incorporation into the actual operation phase,

   – the reaction to predicted or actual violation of technical constraints („congestion management“), mostly transmission capacity constraints of lines and transformers,

   – the programming of the control area regulators and the provision of other ancillary services, and possibly

   – the announcement of network capacities available for further transactions („available transfer capability“, ATC).

2. There must be a mechanism for **settlement** of the actual metered quantities of electricity fed into or taken out from the networks. This comprises in particular the

settlement of electricity needed to level out unavoidable imbalances between generation and consumption.

3. For recovering costs of network assets and operation and of ancillary services, **network access charges** have to be determined.

In order to develop clear, practicable, and understandable arrangements, these issues should, as far as possible, be treated separately. Indeed, the public discussion on open access arrangements partly suffers from unnecessary mixing of these issues, due to the fact that this sort of separation is new. However, for some reasons, an accurate separation of these aspects is not even possible:

- Depending on the selected procedures for congestion management, additional costs can arise for the network operators that can, but need not be recovered as a part of network access charges. In turn, network charges can be attempted to give incentives towards avoidance of congestion, which may have an influence on the necessary procedures for congestion management.

- There is a close relationship between the settlement of balance energy and the technical task of system regulation (frequency control), which is usually regarded an ancillary service whose costs are recovered through a part of network access charges.

Strictly speaking, this study is only devoted to the third aspect (network pricing). However, because of their importance for the internal market development, the issues of congestion management and settlement of transactions are also addressed in a general way in chapters 4 and 5. Throughout the discussion of existing and proposed arrangements for cross-border open access in chapters 6-9, the topic of congestion management is treated in parallel with the main topic of network pricing, but with minor comprehensiveness. Therefore, the conclusions and recommendations concerning congestion management are necessarily less concrete and less detailed than those concerning network pricing.

2 Technical Background

2.1 AC Transmission Systems

2.1.1 Interconnected Transmission Systems in Europe

With the exception of only few lines (see chapter 2.2), the European electricity transmission systems are high-voltage three-phase AC („alternating current") networks. The boundary between transmission and distribution networks is not precisely defined in terms of their nominal voltage, but basically the networks with voltages of 220 kV and above are considered transmission networks. The main tasks of transmission systems are the long-distance transport of electricity from large power plants to the subordinate distribution networks, the large-area balancing of loads, the direct supply of few very large power consumers, and the exchange of power between electricity companies for several reasons.

The latter aspect has promoted the development of extensive interconnections of national transmission systems. Today, the transmission systems within the scope of this study are operated in 4 internally synchronous subsystems of different size, i. e. UCPTE, NORDEL and the British and Irish Grid Systems, being connected by DC interconnections except for Ireland, as shown in fig. 2.1.

There are many advantages of interconnecting transmission systems, the most important of which are listed below:

- enhancement of technical quality of supply („power quality") in terms of reliability, frequency stability and voltage stability,
- reduction of necessary generation and, partly, transmission reserve capacities,
- utilization of economic optimization potentials with respect to differences in generation technology, i. e. hydro-generation and thermal generation plants. Accordingly, cross-border exchanges of power have played an important role since long, as illustrated by fig. 2.2 for UCPTE.

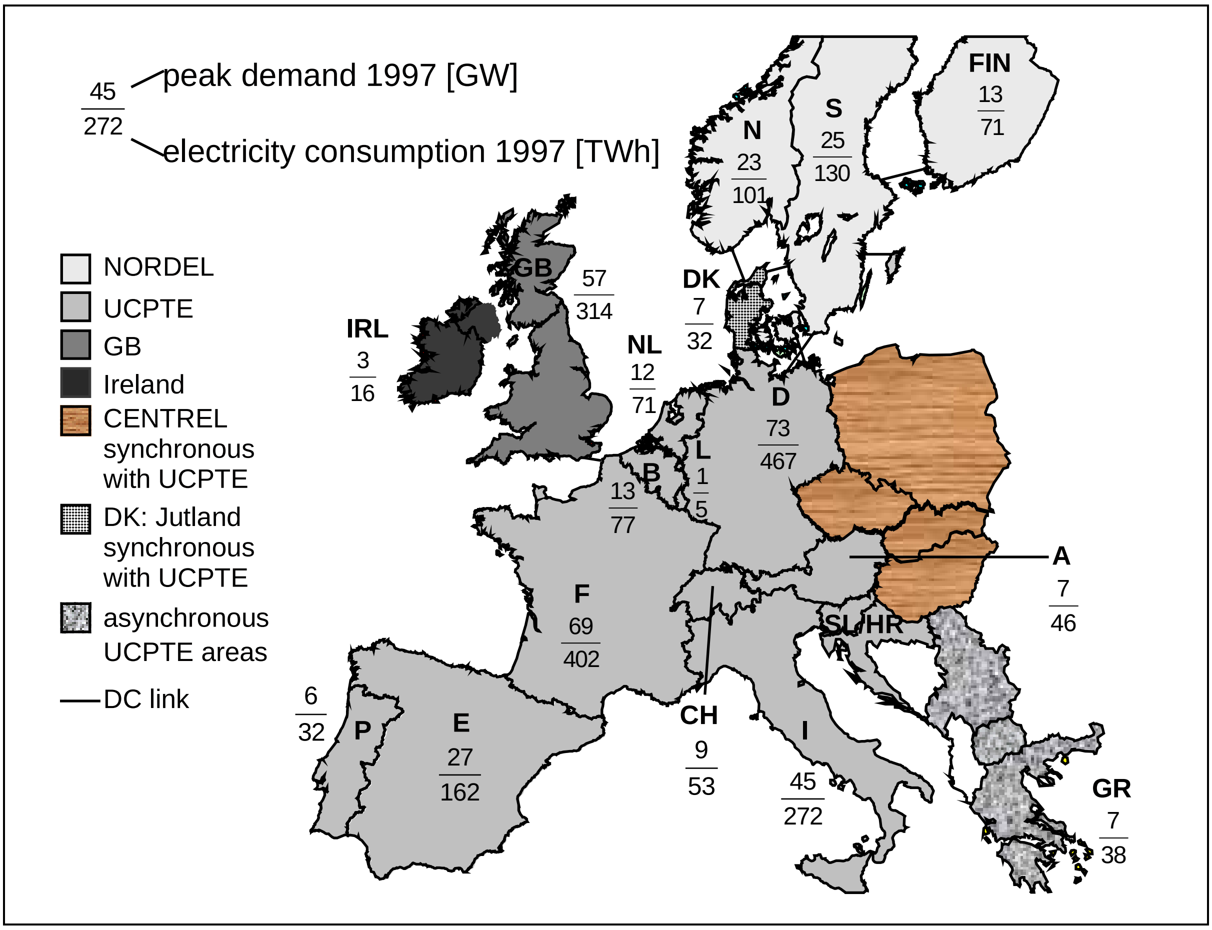

Fig. 2.1: Interconnected AC transmission systems in Europe

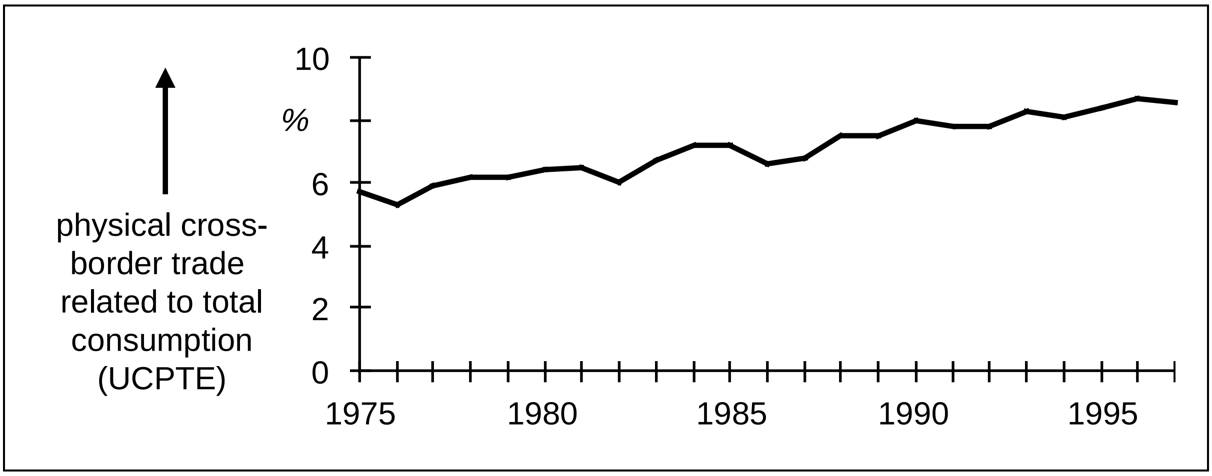

Fig. 2.2: Development of physical cross-border trade in UCPTE (share of energy consumption that has been traded across at least one border)

In view of today's requirements to power quality and power price, the existence of interconnected transmission systems is indispensable. Nevertheless, the European interconnections have always been operated in a federalistic way, which is not necessarily changed by the electricity directive: it is the responsibility of each TSO to plan and operate his own network, of course taking account of the interactions with the neighbouring networks. The corresponding organizations like UCPTE and NORDEL must not be considered centralized authorities for operational decisions, but associations for discussion and agreement of common rules.

The number and size of TSOs per country differ throughout Europe. While most countries have exactly one TSO, Austria and Germany for instance have several ones.

2.1.2 Power Flows

From a technical point of view, the components of AC transmission systems are mostly „passive“ elements that do not allow any control of the power flows across them. Rather, the pattern of power flows is determined „naturally“ by the electric parameters of lines and transformers, the network topology, i. e. the way lines and transformers are connected in substations, and the patterns of power injected into or extracted from the network by generators and consumers.

Of course, there are some instruments for influencing power flows, like voltage controllers, transformer tap changers, switches within the substations and so-called FACTS elements („Flexible AC Transmission Systems“), but during normal system operation, the means of controlling power flows without affecting power quality or increasing power losses are very limited. This is also true for power flows on interconnection lines across borders because there is no technical difference between AC lines within a TSO’s area and those across borders.

For the illustration of natural power flow patterns, two cases of power transport within the UCPTE interconnection have been simulated, one from Northern France to Netherlands (fig. 2.3), the other one from Northern France to Italy (fig. 2.4). In both cases, an additional power injection of 1000 MW at the source location and an additional power extraction of same magnitude at the sink location have been assumed, based on real UCPTE load flow data reflecting the winter peak load situation of January 1998. The figures show the percentages of the major shares of the additional power flowing through third countries. The simulation demonstrates that large parts of the interconnected power system are considerably affected by such transports. It should be noted that the relative shares of power flows do not significantly depend on the absolute magnitude of the transports.

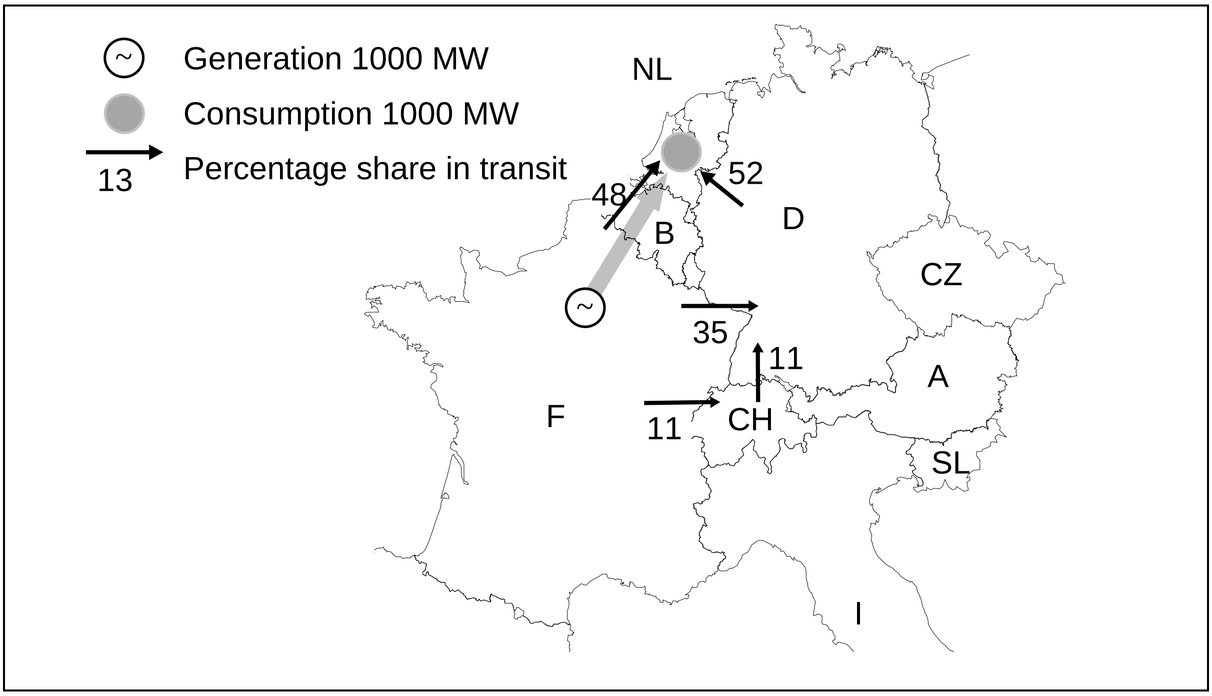

Fig. 2.3: Power flow distribution of a 1000-MW-transport from Northern France to Netherlands (simulation results; only major flows shown)

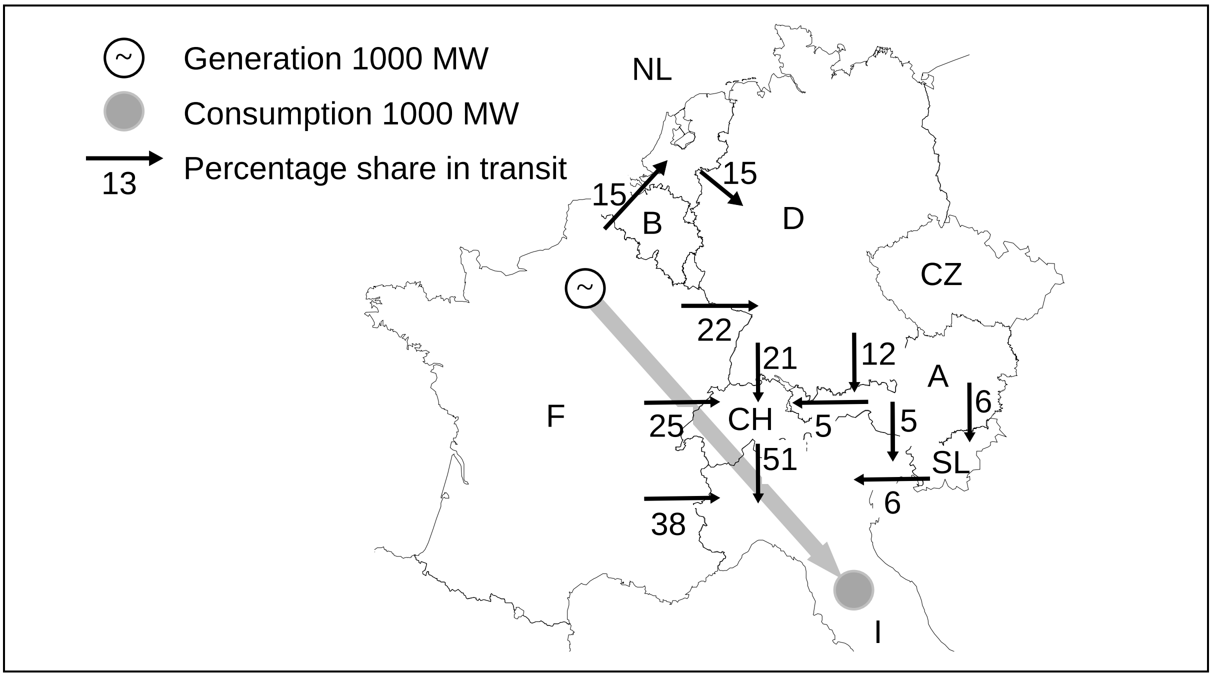

Fig. 2.4: Power flow distribution of a 1000-MW-transport from Northern France to Italy (simulation results; only major flows shown)

Power flows through transmission systems caused by transports between other systems are either called „transit flows“ or „loop flows“. There is no strict definition of these terms, but usually transits are considered to flow through systems on the „direct“ path from source to sink or the path that has been arranged by contracts between market actors and TSOs („contract path"), whereas loop flows are those flowing through the remaining systems.

It is important to recognize that loop flows are even caused by transports within a single, neighbouring TSO's area. This type of loop flows will be called „neighbourhood loop flows" throughout this report. The problem of loop flows affecting third systems is thus not exclusively related to cross-border transactions, although its relevance is of course higher in an environment with massive cross-border trade.

Moreover, in a meshed synchronous interconnection, loop flows affect not only a few TSOs, but *all* TSOs unless they are connected to the remaining system by only one line. Of course, the loop flows may be very small in some systems, but almost never equal to zero. Reversely, it is not possible in a meshed AC network to identify a limited number of power injections or extractions that contribute to the power flow on a specific line, because *all* injections and extractions affect *each* line flow to some extent.

2.1.3 Losses

The operation and use of network equipment is inevitably associated with energy losses. The greater part of total losses is usage-dependent: the loss contribution of each line or transformer is approximately proportional to the square of the power flowing on it. A smaller, but still considerable part of the losses is almost constant, not depending on actual power flows. In total, losses in the European transmission systems are normally in the magnitude of 1-2 % of the total power transported. The relative additional losses of additional transports can however be much higher.

Losses of course have to be recovered by additional generation. In a liberalized environment, network operators usually buy energy from generating companies for this purpose and thus have to deal with costs of losses. Alternatively, additional energy can be injected into the system by the market actors, but this is only possible on the basis of average loss coefficients, so that the network operators still have the responsibility to care for the actual losses.

2.1.4 Reactive Power

It is a special characteristic of AC networks that active power flows are associated with the demand and with flows of so-called reactive power. This is power oscillating back and forth between generation and consumption with system frequency. It does not result in any transport of real power in average, but causes additional losses in lines, transformers and generators. Therefore, network operators attempt to minimize reactive power transports, which also has a positive effect on the voltage situation. To do this, positive or negative reactive power must be co-produced in generators or special network devices for compensating reactive power resulting from the operation of lines and transformers. The generation of reactive power is associated with additional equipment costs and additional losses.

Within the scope of this study, reactive power is only relevant as a cost element in the context of voltage control which is one of the ancillary services to be offered by network operators. It should be noted that reactive power cannot be transported over long distance by technical and economic reasons and thus is rather an issue of regional importance.

2.1.5 Technical Constraints

The transmission capacity of any network element is technically limited. The most relevant limits with respect to cross-border transactions are the upper limits of currents on lines and transformers, but other constraints like voltage limits or stability requirements can also be reasons of infeasibility of system states. Because infeasible system states could result in damage to network equipment and/or partial or complete system breakdown, measures for ensuring system security have to be taken well in advance. This comprises security assessment in the long run to identify necessary network reinforcement, in the medium and short run to foresee critical operational situations (operations planning phase), and in the actual operation phase to identify and remedy imminent or actual constraint violations.

In the medium and short run, the countermeasures that can be taken by network operators on their own to avoid or remove constraint violations are quite limited. If they are not sufficient, measures must be taken that somehow influence the consumption and generation patterns. Consumption, however, can hardly be controlled, and disconnecting consumers from the system is only an ultimate emergency measure in view of imminent severe breakdowns.

Throughout this report, situations where constraint violations are foreseen in the operations planning phase or the actual operation phase and require measures that have an effect on generation or, seldom, consumption patterns, are denoted as **congestion**, and the tasks of detecting congestion and arranging for sufficient countermeasures as **congestion management**. Defining appropriate rules for the latter task is a topic of essential importance in the context of arrangements for cross-border trade (see chapter 4).

It should be clearly recognized that, in contrast to many other areas of economy, reaction to short- or medium-term congestion in electricity transmission systems can neither be postponed, because overloading cannot be handled by giving „wait“ signals, nor be restricted to transmission capacity reinforcement, because that can take many years. Therefore, for instance, the comparison with means of transportation like buses or aircrafts, where capacities can be quickly extended or relocated, is not adequate.

A very important consequence of the „natural“ power flow in AC transmission systems is the fact that the maximum transmission capacity between two areas connected by several lines cannot be determined by simple addition of the single lines’ transmission capacities. Rather, the total capacity will normally be smaller than the sum of individual line capacities. Moreover, a clear definition of such an area-to-area transmission capacity is not even possible because it depends on the locations (or the distribution) of source and sink in the respective areas, unless all the interconnection lines are connected to the same connection point in each area.

Therefore, the average loading values and the sums of transmission capacities of single interconnection lines shown in fig. 2.5 must be regarded very carefully as a crude, simplified overview of the situation of cross-border power flows. As a comparison, it is not unusual that the normal loading of transmission lines is only in the magnitude of 10-30 % as has been calculated for a German TSO some years ago. Therefore, while high degrees of utilization like on the Italian border to France and Switzerland clearly indicate locations of bottlenecks, lower degrees of utilization are not necessarily an indicator of unused capacities. Particularly, the average values shown here do not reflect the fluctuations of power flows over time.

2.1.6 Power Balancing

Because electric power can hardly be stored, the amount of generated power must precisely follow the demand, i. e. consumption plus losses, in each instant of time. This requires generation reserves and regulation mechanisms in different time scales, commonly denoted as power balancing in this report. If generation and demand are not equal, the system frequency rapidly increases or decreases, which is only acceptable within a very tight band-width around the nominal frequency of 50 Hz in Europe. Therefore, power balancing includes the task of frequency control.

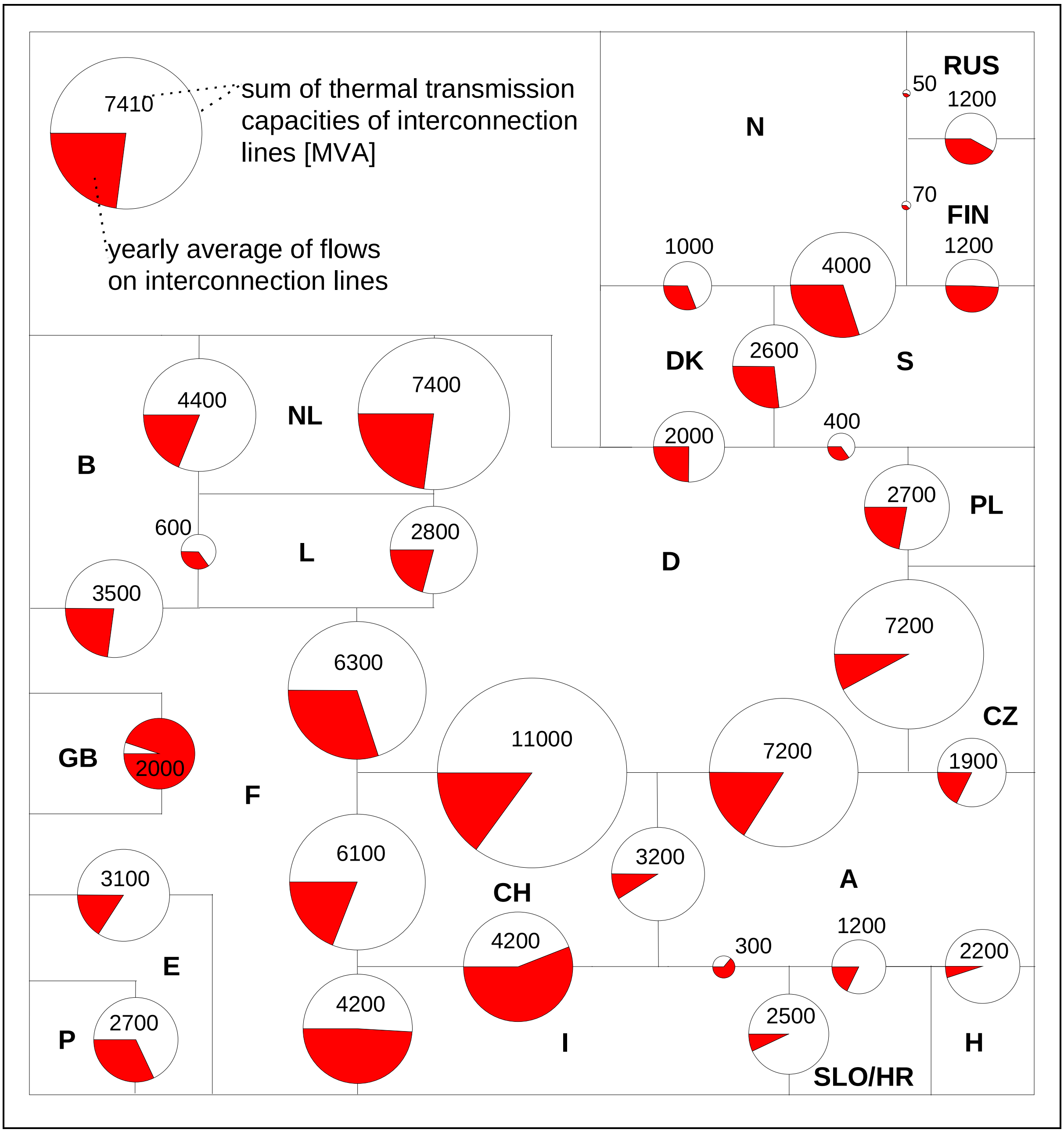

Fig. 2.5: Approximation of average loading of interconnection lines between European transmission systems and sums of thermal transmission capacities for 1997/98

In a synchronously interconnected transmission system, a power surplus or deficit in one part of the system inevitably affects the whole system because frequency is always uniform in the complete interconnection. Therefore, rules and quality demands concerning frequency control cannot be exclusively defined subsidiarily, but require a considerable degree of harmonization. This is particularly true for the short-term balancing with activation times of seconds or minutes, which has to be performed more or less automatically. It is the responsibility of the TSOs to ensure that sufficient regulating power and appropriate regulators are available in their respective system areas in order to meet the commonly agreed quality standards.

This does not mean that the TSOs have to possess generation capacities for regulating power themselves. Rather, they can „buy“ such reserves from any generation companies within or partly even outside their areas, as far as the technical requirements of power regulation can be met.

In UCPTE, for instance, short-term balancing is composed of three levels: a very fast decentralized automatic frequency control in some of the power plants („primary control“), a centralized automatic load-frequency control in each TSO’s control centre („secondary control“), and the manual activation of additional short-term reserves, also coordinated in the control centres. The secondary control particularly fulfills the task to compensate the power surplus or deficit in *that* part of the system where it has occured. To do this, each TSO’s power regulator needs as input data the planned amount of power to be exchanged with the interconnected system in hourly intervals. For this reason, the borders between TSO areas can only be traded across by programmes, not „by demand“, in contrast to the supply of end consumers within the countries, which is almost generally done by demand. These facts are important to keep in mind when developing a concept of settlement of cross-border transactions (see chapter 5).

2.1.7 Ancillary Services

TSOs have the responsibility to provide a number of ancillary services, even if a part of them could (and will) also be provided by other actors. There is no uniform definition of ancillary services, but those listed below, partly already mentioned above, are the most important ones and are more or less commonly agreed:

- voltage control, i. e. procurement of reactive power and installation and operation of voltage control equipment
- provision of additional reactive power for customers or distribution networks according to individual demand
- frequency control, i. e. short-term power balancing
- precautions for system restoration after large failures, particularly procurement of sufficient black start capability (generators that can be started when disconnected from the network)
- metering and settlement

Sometimes, even the actual operation of transmission systems, taking place in the control centres, is considered an ancillary service. To the authors' mind, this is rather an integral part of the TSOs' main task, not an ancillary service.

A difficult and not yet clarified question is if the procurement of reserve power, needed in case of power deficits to replace the power provided by the mechanisms of frequency control, should be part of the TSOs' responsibility, or if this task can completely be left to competition.

On the one hand, reserve power could be treated as a market element that should, but need not be contracted by each customer from any provider. Because reserve power is not activated earlier than approximately one hour after a failure, time is sufficient to disconnect from the system, in emergency, those customers who are supplied from the power plant that has caused the deficit and who have not contracted reserve power.

On the other hand, it might become very difficult or even impossible in a liberalized environment, including anonymous markets like power exchanges, to keep account of the quantities of reserve power associated with each unit of power traded and supplied.

This issue will not be discussed further in this report, but it will become a very essential issue that at least requires careful observation of the market development, even if its discussion can be postponed for a while because at present, the generation capacities are sufficient.

2.2 DC Interconnections

In addition to synchronous AC interconnections, several high-voltage DC („direct current") lines have been built in Europe to link different interconnected systems to each other or to islands, for example between England and France, between Denmark and Norway/Sweden, between Germany and Denmark/Sweden and between Italy and Corsica, and further ones are planned. Reasons to choose DC technology in certain circumstances are

- to connect different AC interconnections in an asynchronous way, for example to avoid stability or short-circuit current problems,
- to cross long submarine distances, which is not possible in AC technology, or
- to have control over the power exchanged between two areas.

The costs of DC links are however much higher than those of AC links, because AC/DC converter stations are needed on both sides to integrate the lines into AC transmission systems. Apart from that, laying submarine cables is very costly, anyhow. For example, the cost of building the Baltic Cable of 250 km length between Germany and Sweden has been approximately a quarter billion Euro, half of which is due to the converter stations. Including costs of operation and losses, this results in transport costs in the magnitude of 0.5 to 1.0 cent/kWh, even when the utilization is very high.

With respect to power flow, DC lines crucially differ from AC lines in being „active“ network elements: the converter stations, today consisting basically of high-power semiconductors, are directly controlled, so that the power flow across a DC line is not the result of network topology and generation/consumption patterns, but is determined by a programme that has to be input into the controller. Therefore, the amount of power to be exchanged via each single DC line has to be given in advance for each instant of time.

For this reason, the problem of loop flows does not exist in the case of DC lines. Correspondingly, it is quite simple to determine which market actors contribute to the power flow on a DC line, because all desired transports have to be reported in advance for being aggregated and programmed. In other words, the physical transmission path is, in contrast to AC systems, identical to the contract path.

This fact can be regarded a justification to treat open access to DC lines separately and differently from the AC part of the transmission system, if this makes sense for technical or economical reasons. It is important to recognize that differences in open access arrangements *would* be a problem if there existed AC lines *in parallel* to DC lines, i. e. when DC lines could be „by-passed“, possibly causing congestion on the AC path and leaving the DC path poorly utilized. Such cases however do not exist in Europe at the moment.

Generally, it has to be clarified if the requirement of giving open access applies to DC interconnections in the same way as to AC systems, at all. On the one hand, DC lines are also transmission lines, merely based on a different technology, on the other hand, they can be regarded similar to a generator and a controllable consumption of equal size. The authors tend to voting for open access on DC lines, too, as far as this is compatible with existing long-term contracts, but it is not in the scope of this study to go into detail on this aspect.

3 Network Costs and Pricing

3.1 Network Costs

The costs arising from transmission system operation can be subdivided into cost elements in more or less detail. For the purpose of network pricing, it is usually sufficient to distinguish the following cost elements:

- **Costs of construction, maintenance and operation of network equipment**

  This is the major part of network costs. It comprises implicit costs, made up of the depreciation of the fixed assets, the finance charges and the allowed return on proprietary capital, as well as explicit costs.

  The network equipment can be further divided into one part that only serves the individual connection of network users and the remaining part commonly used by several or many network users. Drawing the boundary between these two parts bears some difficulties and is not done uniformly in all countries.

- **Costs of losses** (see chapter 2.1.3)

- **Congestion costs** (see chapters 2.1.5 and 4)

- **Costs of ancillary services** (see chapter 2.1.7)

All of these cost elements can comprise shares of common costs like administration costs that are allocated among all the „services“ offered by a TSO.

Acceptable level of costs

It is not unusual that the costs accepted as a basis for network pricing are not identical to the costs identified through the TSOs’ accounting principles. In particular, it is common understanding that costs should be recovered through network charges only so far as they are necessary for an economic system operation with technically sufficient quality. Practically, this „acceptable“ level of necessary costs is however very difficult or even impossible to determine, because costs depend on a large variety of parameters, causing significant differences in costs of different systems, which is not necessarily due to „uneconomic“ system planning and operation (cf. comparison of transmission tariffs in Europe, chapter 7):

- Of course, the technical structure of a transmission network impacts its costs. The most relevant parameters are the overall load density and the geographical homogeneity of generation and consumption patterns, the resulting average physical transport distance of power from generation to final consumption, the desired degree of redundancy in topology (e.g. network meshing) and equipment ratings, the requirements to power quality in terms of frequency and voltage stability, and the technical characteristics and power profiles of generation and consumption.

  It is important to realize that, in contrast to this, the *size* of a network is not a direct parameter of its per-unit costs, i. e. very small networks can have the same costs per kWh of total supplied energy as very large networks. Thus, the merger of two neighbouring networks would only marginally decrease the per-unit costs, due to rationalization opportunities.

- Nevertheless, even structurally similar networks can considerably differ in costs, mainly due to differences in the average age of the equipment, the magnitude of overhead costs, the financing conditions and the allowed return on investment, and, more general, the unique legal, geographical, economical and technical background and history of each transmission system.

Therefore, instead of trying to „synthesize“ the justifiable cost level, many regulators analyze the costs reported by the TSOs and try to exclude unnecessary cost elements or to identify potentials of rationalization. Often, as one possible form of regulation, the accepted level of costs is *in total* reduced each year by a percentage derived from a formula that reflects rationalization potentials and general economic development.

In whichever way network costs are reviewed and modified by national regulators or maybe by agreements among the electricity industry, the term network costs throughout this report refers to the finally accepted costs that become the basis of network pricing. The definition of the acceptable level of costs is mainly a matter for subsidiarity and is not further discussed in this report. Of course, if the pricing rules to be developed for cross-border transmission should include any payments between TSOs or between network users and foreign TSOs, the same general rules concerning the acceptability of cost levels should apply to these payments as to the national transmission tariff of the TSO where the costs arise, in order to avoid discrimination of cross-border trade.

Further classification of transmission costs

For network pricing, it may be useful or even necessary to classify the transmission cost elements into different categories, which may also include further splitting of some cost elements. A well-known possibility is to distinguish between **fixed** and **variable** costs with respect to actual transmission system utilization. This comes very close to, but is not identical to the concept of long-run and short-run marginal cost of using the system. Rather, marginal cost is the *change* in cost due to a small change in the underlying parameter, i. e. the system utilization. Long-run marginal costs can therefore be regarded the marginal changes in fixed costs, and short-run marginal costs the marginal changes in variable costs.

Without going too deep into this discussion, it can roughly be said that

- costs of network equipment are mainly fixed costs, because network capacity cannot be adjusted in the short run and maintenance and operation costs are hardly dependent on the actual use of the system,
- costs of losses can be split into a smaller fixed part concerning constant or voltage-dependent losses, and a greater variable part concerning current-dependent losses,
- short-term congestion costs (i. e. those that do not concern network reinforcement) are exclusively variable costs because if the system were not used at all, there would not be any congestion,
- costs of ancillary services are partly more or less fixed (voltage control; precautions for system restoration), partly variable (reactive power supply; metering and settlement) and partly of mixed nature (frequency control).

Another possibility of cost classification that is often discussed in the context of cross-border transmission pricing is the distinction between the **„vertical“** transport of power from generators to final consumers or to distribution networks, and the **„horizontal“** transport of power within the transmission level. This classification is motivated by the attempt to separate these two transport services in an open access environment and to allocate each of them the corresponding transmission costs.

The problem is that practically, these two services cannot be clearly separated from each other. Of course, transmission networks have traditionally been built to serve primarily the vertical transport service. This has however always included horizontal transports to a certain extent. The average transmission distance has never been zero, and the advantages of interconnections would not have been possible without horizontal transports.

Therefore, the only separation that makes sense in this respect is the one between costs that are more or less *exclusively* caused by the vertical supply service and costs that are caused by both vertical and horizontal transports.

Roughly, the following cost elements can be allocated primarily to vertical transports:

- costs of individual connections of network users to the transmission system,
- costs of network equipment connecting transmission and distribution networks, i. e. transformers and the corresponding shares of the substations, and
- costs of ancillary services, because most of these services do not relate to any form of transport at all, but are determined by generation and consumption characteristics. The only ancillary service that is influenced by the actual situation of power transports is voltage control, which would however be necessary also if no horizontal transport took place at all, and which is associated with relatively small costs.

The remaining cost elements are thus allocatable to both vertical and horizontal power transports:

- costs of transmission lines, transformers between different transmission voltage levels, and the corresponding shares of substations, excluding network equipment belonging to individual network users' connections,
- costs of losses, and
- congestion costs, because they are commonly caused by all transport activities in a non-discriminatory open access environment.

This allocation can however not solve the crucial point, i. e. the „isolation" of the costs exclusively caused by horizontal transports. The authors are not aware of any easy method to do this. Splitting the costs according to the relation of power transits across a system and the total power supplied through it would at least not be an objective way, because the result would significantly depend on the size of the system. More complicated methods, based on power flow computations and line lengths, might be conceived, but are not further developed within this report (cf. chapter 9.1.2.3).

3.2 Objectives of Network Pricing

The main objective of network pricing is the **recovery of network costs** as far as they are accepted by the regulators (see above), plus a reasonable return on investment. This objective can be achieved in many ways; there is sufficient space for additional requirements and objectives.

One essential requirement to network pricing results from the networks being natural monopolies: the charges must be **verifiable** for parties other than the network operator himself, and they must be **non-discriminatory** in a way that network users under equal conditions have to pay equal charges. It should be recognized that non-discrimination is not a trivial objective to fulfill and to assess because the definition of „equal conditions“ (location, electric path, time, power, etc.) can be very complicated.

In addition to this, many further objectives can be tried to achieve when developing a network pricing concept:

- To **promote competition** by presenting the network user a predictable, stable and practical-to-apply framework of charges. This comprises for instance
  - that the charges are transparent in a way that they can be easily calculated or looked up by the network users with good accuracy in advance of negotiating a possible transaction in order to foresee the financial consequences,
  - that the determination rules of charges are transparent to all actors in order for them to get an impression under which circumstances the charges might fluctuate,
  - that fluctuations of charges are reasonably small in the short and medium term, at least if market actors are not given the opportunity of hedging against such fluctuations by means of financial contracts related to network charges,
  - that the demand of information on the individual case of network access for calculation of the charges is reasonably low, and
  - that the system of charges is consistent as a whole, by handling all sorts of network access in a similar way. On the European level, this means in particular that the pricing methods for cross-border transactions must be compatible to the different national concepts of network pricing developed under subsidiarity.
- To provide appropriate price signals towards **efficient use of the network**. According to economic theory, this can be achieved by making charges reflect as precisely as possible the costs caused by each individual network access. This

demand for **cost-reflectivity** can be understood both towards each single network user and towards collectives, e. g. all users connected to a specific network. Apart from the creation of price signals, cost-reflectivity can also be justified more generally from the desire to handle network users as **fair** as possible according to the causation principle.

- To provide appropriate price signals for the network operators towards **efficient operation and expansion of the networks**. The international experience however shows that this objective is very difficult to fulfill because it strongly interferes with the basic requirement of more or less complete network cost recovery. It seems questionable if it is possible to promote efficient decisions of network operators exclusively by economic mechanisms or if this rather requires obligations imposed by some sort of network operations licences.

It is important to recognize that these objectives are partly contradictory. In particular, a great amount of discussion about both the national network tariffs and the charges for cross-border transactions is devoted to finding a balance between the objective to promote competition, demanding for simple pricing methods, and the objective of cost-reflectivity, usually aiming towards more complicated concepts.

For this reason, it is obvious that a generally optimal approach to network pricing cannot exist, not even within a single country. Similarly it is not possible to find for each partial aspect of this topic an ideal solution that matches all interests. Therefore a network pricing concept should be developed and assessed as a whole, as far as the principle of subsidiarity allows.

3.3 Methods of Cost Allocation and Pricing

In principle, the determination of network charges is a simple procedure, consisting of three steps:

1. determination of the „acceptable“ network costs to be recovered by charges,
2. subdivision of the costs into cost elements and allocation to different types of network users, transmission services and tariff components, and
3. division of these fractions of costs by the corresponding quantities of network utilisation (sums of power and/or energy transported).

In practice, there is however a multiplicity of ways to design network charges [2-4]. The main possible features of pricing concepts are presented below, including their most important *general* pros and cons, not related only to cross-border transmission. A more specific discussion of issues relevant to cross-border pricing can be found in chapters 3.4 and 9.

Tariff components

Each existing transmission tariff is subdivided into several tariff components in more or less detailed correspondence to the cost elements outlined in chapter 3.1. The main component that reflects network equipment costs will in this report be called „charge for use of transmission system“, the other components are named in accordance to the respective cost element. The question how many tariff components should be distinguished requires weighing up between simplicity (→ few components) on the one hand and transparency and cost-reflectivity on the other hand (→ many components).

In addition to network cost related charges, it is common practice in many countries to raise politically motivated surcharges to cover taxes, stranded costs in the generation sector, subsidies to renewable energy utilization, etc., which are invoiced together with network charges. Because these charges are not directly related to the use of networks, it is quite obvious that they should only be paid by those network users who are connected to the system where the surcharges are raised. Therefore, if any cross-border payments between market actors and/or TSOs should take place in the context of cross-border transmission, these should be kept free of such surcharges.

Moreover, to create a level playing field, it is recommendable to agree on clear rules on which sort of network use, generation or consumption, these surcharges are imposed. For instance, it might be agreed to allocate them fully to consumption, which appears to be the usual choice in many countries. Such harmonization would avoid the effect that in case of cross-border trade, depending on the direction, the surcharges might be paid twice or not at all. However, the same limitations must be made according to necessity and difficulties of such harmonization as with respect to cost allocation of use-of-system charges (cf. end of chapter 3.4).

Apart from the issues mentioned above, these surcharges have no relevance to cross-border transmission and therefore need not further be discussed in this report.

Transaction-based versus non-transaction-based pricing

The most significant feature of pricing models is the relation either to commercial transactions of electricity from a source to a sink (also known as **point-to-point-**

tariffs) or to the network access of single network users, independent of the commercial relations among them (known as **point-tariffs** or **entry/exit-tariffs**).

The transaction-based approach requires knowledge of the locations of source and sink for calculating the charges payable for a specific transaction. It is not important which one of the transaction contractors will pay the charges or if they share them. The payment of the charge gives the contractors the right to perform exactly the transaction that the charge has been determined for. When this concept is chosen, network charges can depend in some way on the path between source and sink, for example by incorporating parameters like the geographical distance, the number of network regions affected, or the voltage levels incorporated in the electric path. (However, the latter aspect is basically only important for *distribution* charges, because *transmission* charges usually cover all transmission voltage levels in common.)

In the non-transaction-based approach, on the other hand, the payment of charges gives an individual network user the right to trade with any other market player within the complete range of validity of the tariff system. (Concerning distribution charges, this implies that the charges implicitly cover costs of all voltage levels that the network user potentially accesses, i. e. usually all levels from the his connection level up to the transmission level). It is not possible to take account of a connection path in this model because the charges are independent of commercial relationships. Instead, the tariffs can be differentiated region-wise or even substation-wise to include locational price signals. Since non-transaction-based charges are not paid „in common“ by generators and consumers, a clear definition of charges for each of these types of actors is necessary. The way costs are split between generation and consumption offers an additional degree of freedom in designing the pricing model, as discussed later.

There are many general advantages of non-transaction-based pricing with particular respect to non-discrimination and promotion of competition:

- It is much easier to verify non-discriminatory treatment of network users because for this purpose it does not require the existing supply situation to be decomposed into a large number of single transactions, which is not a trivial task.
- Changes of supplier are easier and can be done quicker because they do not affect the network charges.
- The information demand for calculation of the charges is necessarily very low and does not include information on commercial relationships, which makes the

calculation simple, practicable and better understandable for all market actors and better satisfies the confidentiality needs, compared to transaction-based models.

- *Transaction-based* charges, due to their relation to the path between source and sink, may give the impression of reflecting a transaction's actual effect on physical power flows. They are therefore likely to evoke conflicts in individual cases where the physical effect of a transaction is easy to see and is *not* satisfactorily reflected by the charges. For instance, two transactions in opposite direction cancel out each other physically, but transaction-based charges would have to be paid twice (unless they are direction-dependent).

  Such examples may also create the suspicion that network operators receive charges for transports that, physically, do not take place at all, which might result in an overcompensation of network costs. Of course, this could be avoided by reducing the charges correspondingly, but it will then be very difficult to give evidence that the objective of cost recovery is exactly satisfied.

  These problems can be avoided by non-transaction-based pricing.

- Power trading on the wholesale level is usually done by compiling purchases and sales to portfolios, not by contracting single source-to-sink transactions. An allocation of sources and sinks would have to be created „artificially“ for the purpose of transaction-based charging, which is not only an additional complexity, but can involve the consequence that traders do not know the sum of due transmission charges before termination of trade for a specific period in time. This is a form of „ex-post“ pricing which can generally be considered adverse to transparency.

- The latter argument is particularly true for anonymous markets like power exchanges. Although transaction-based transmission charging might not be absolutely incompatible with power exchanges (cf. trade with other goods), it will at least impose considerable complexities compared to completely non-transaction-based arrangements.

For these reasons, many countries have decided for non-transaction-based transmission pricing concepts, e. g. UK, the Scandinavian states, Portugal, Austria and the Netherlands.

Nevertheless, there are also advantages of transaction-based pricing, essentially due to the fact that the incorporation of the specific path between source and sink in the calculation of charges makes it easier to reflect the individual use of the system by a transaction:

- The charges for transactions over very short distance could be reduced compared with the average charges, to give incentives for supply from generation located nearby, or to prevent network users from constructing direct lines. (The latter argument however concerns mainly distribution networks because direct lines in the transmission level are very unlikely.) Similarly, the charges for transactions over very long distance could be higher than average charges to reflect the fact that, at least in simplified models or in statistic average, transmission costs increase with the distance. The objective of this might be „individual“ cost-reflectivity for fairness and for providing signals towards effective transmission system utilization.

- Surcharges for transactions across congested areas could be introduced in order to give direct incentives to relieve congestion.

- Charge elements for networks which are affected by transits (or loop flows) could be directly included, covering a part of the transiting networks’ costs. This would relieve the tariffs paid by those network users connected to the transit networks, which could be regarded a form of „collective“ cost-reflectivity.

Some of these aspects have made the German utilities and consumers associations decide for transaction-based charging in their agreement signed in May 1998. Partly, reflections like this have also been made in Italy.

It should be noted that there are very different possible degrees of introducing transaction-based charges, each associated with an individual combination of the above-mentioned pros and cons. For instance, charges can relate to single transactions, to balances of a trader’s transactions or even to balances of all transactions in a TSO area. Moreover, it can be required to define source and sink location by substation, by region, by country, or even to define only if a transaction is domestic or international. Some of these possibilities might not even be really transaction-based. A more detailed discussion of this aspect with special respect to cross-border transmission is given in chapter 9.

Negotiated versus fixed charges

The electricity directive leaves it up to subsidiarity if the network charges are fixed and published or if they are negotiated for each individual case of network access. Obviously, power trade will better develop in a framework of charges as predictable as possible, in order for the market actors to foresee the financial consequences of their commercial decisions. This would best be met by fixed and published tariffs. On the other hand, negotiated charges are better suited to avoid single cases of hardship. As a compromise, the possibility of negotiation could be provided in addition to publication of fixed charges, but this would make some form of supervision necessary to avoid discriminatory misuse of this possibility.

Marginal costs versus average costs

In principle, incentives towards efficient decisions of market players can best be given if charges are based on the marginal costs (see chapter 3.1) rather than on average costs. Examples for this are the long-run marginal investment related use-of-system charges in England/Wales and the short-run marginal loss coefficients in Norway and Sweden.

In detail, however, the calculation of marginal costs can be quite complicated, and some aspects incorporate short-run plus long-run marginal costs. In addition, the objective of exact recovery of network costs can hardly be fulfilled if all charges are based on marginal costs; there should be at least one average cost element to cover the (positive or negative) difference between marginal and average costs.

It can be observed as a reasonable approach in some countries to start with a simple tariff, mainly based on average costs, and to begin including marginal cost elements when experience grows and significant changes in network utilisation make more sophisticated concepts necessary.

Options of cost allocation

Out of the multiplicity of possibilities of cost allocation to the different collectives of network users, the most important aspect within the scope of this study is the allocation towards generation and consumption for non-transaction-based tariff components.

In principle, this overall cost allocation can be done in any non-discriminatory manner, because in the end, it is of course the final consumption who pays for the complete costs. In a limited system like an island with a uniform ratio of cost allocation to generation/consumption throughout the complete system, the actual value of this ratio is practically unimportant. For the sake of simplicity, it might then be argued to allocate the complete cost to one side, e. g. the consumption side, as is actually done for example in Finland and Austria, at least concerning the use-of-system charges.

This issue becomes however more interesting when the ratio of cost allocation is not uniform within one system or among interconnected systems. Besides a lack of harmonization, this might be justified by inhomogeneities between the geographical distribution of generation plants and consumption. If, for instance, the costs were completely allocated to consumption, the consumers in an area with extensive generation surplus might complain about too high use-of-system charges in their area, caused by the generators that produce power for external consumers.

Another reason for allocating at least a minor part of costs to generation might be to create a „dummy“ charge element that can, if necessary, be used to include locational price signals towards generators. Of course, this would also be possible if the average of cost allocated to generators were zero, by introducing positive and negative charges, but it is practically easier if their is a general charge element for generators.

In fact, many countries have decided to allocate up to 50 % of the costs to generation. The implications of the cost allocation ratios being different throughout Europe will be discussed in chapter 3.4.

Another aspect of relevance concerns the charging of intermediary traders. In a non-transaction-based tariff, it is quite obvious that no charges should be imposed on intermediary trading, because the complete network costs are covered by charges at both sides of the transmission chain, i. e. the generator and the consumer or distributor. Since these charges include the right to use the complete system for trading, there would not be any justification to collect additional charges from additional traders within the transmission chain. Thus, it would not matter how often a unit of energy is traded before it leaves the transmission network.

If, similarly, intermediary trade would be free with respect to transaction-based charges, the objectives of transaction-based pricing, i. e. the creation of price signals and cost-reflectivity, would be totally undermined. For instance, intermediary traders could take over all long-distance transports „for free“, so that long-distance charges effectively would not have to be paid. It would thus be necessary for intermediaries to define allocations of source and sink locations, even if they are „artificial“ (cf. chapter 3.3) and to pay charges accordingly. This of course would mean that transmission charges would accumulate if energy was traded several times before leaving the transmission system.

Reference of charges to power (kW) and/or energy (kWh)

Each charge element can be related either to the electric power or the energy transported, or to an appropriate mixture of these reference quantities. The height of power transported can be defined in various ways, e. g. the individual peak power of a generator or consumer or the power during the system peak period. The energy related charge elements are often distinguished with respect to season (winter/ summer tariffs) or daytime (day/night tariffs).

This issue is solved very differently in the existing European network pricing models, partly due to historical tariff structures that are not desired to change radically. A detailed discussion of the pros and cons of charges related to power or energy is out of the range of this study, because this is mainly a matter for subsidiarity. In brief, it can be stated that energy-related charges are usually easier to understand, to compare and to deal with, particularly with respect to short-term trade; a reasonable argument for power-related charges is however the provision of incentives towards a well-balanced and efficient network utilization since the investment costs of networks are mainly power-related, too.

3.4 Aspects Relevant to Cross-Border Transmission

Although transmission pricing is primarily a matter for subsidiarity, the existence of a variety of different arrangements in Europe may lead to certain conflicts that can only be solved by developing a minimum set of common rules. These conflicts can have different reasons:

- The development process of national pricing concepts in Europe is in very different states: while some countries have collected years of experience and have accordingly adapted their arrangements already several times, some other countries do not even have completed a first approach, due to delays in their liberalization process. The discussion throughout this study is however based on the assumption that national transmission tariffs will soon exist in all affected countries (or better, in all TSO areas).

- The different national arrangements might be partly incompatible with respect to cross-border transmission.

- Even if the arrangements are compatible to each other, they might not satisfactorily fulfill all the politically agreed objectives concerning the internal market development.

On this background, the sections below shall identify which specific problems may occur and which issues therefore have to be discussed on European level in order to find common rules.

Co-existence of transaction-based and non-transaction-based tariffs

If a transaction takes place with, for example, the source located in a system with entry/exit-tariff, and the sink located in a system with a transaction-based tariff, the information demands for calculation of charges will be different for source and sink. This however need not be a problem in itself because each of the involved network users is exposed to the same charging conditions as if he had a transaction *within* his respective transmission system: the „source“ user will have to pay the entry charge to his TSO, and the „sink“ user a charge for a transaction from the system boundary of his TSO to his own location.

A problem may arise from this situation if the source is an anonymous international market and the sink user is therefore not able to indicate the source location and a corresponding location on the system boundary. This problem would however apply to all connectees of the system with transaction-based tariff wishing to access anonymous markets, and would have to be solved there subsidiarily.

A more critical conflict would arise if any TSO located „in-between“ would insist on receiving charges for the transit through his network. Apart from the harmonization demands that such a transit charge brings along in itself, which are discussed in the next section, the detection of the transit and the calculation of the corresponding charge would require information that would not be available from the „source“ user being located in the system with entry/exit-tariff. (This situation is even worse when both involved users are located in systems with entry/exit-tariff.) The consequence of such a conflict would be that either the transiting TSO would not even be informed about the transaction and not receive any charges, or that the „source“ user had to report *additional* information to the transiting TSO, and would be confronted with the additional complexities of transaction-based pricing.

This example shows that if *any* of the European TSOs raises charges on transits (or even loop flows) through his system from foreign market actors, this will severely affect the transmission access conditions of actors located in systems with non-transaction-based tariff. This alone should be reason enough that the issue of transit charges cannot be completely left up to subsidiarity.

Remuneration for transits

In view of the objective of „collective“ fairness to network users, the desire of TSOs appears justified to receive in some way an appropriate financial remuneration for transits and loop flows through their system caused by foreign market actors, even if up to now, in a non-liberalized environment, those flows have partly been tolerated without financial compensation. In fact, some European TSOs are heavily burdened by loop flows already today, as shown in fig. 3.1 for UCPTE and NORDEL. This problem can gain even more importance in a liberalized market.

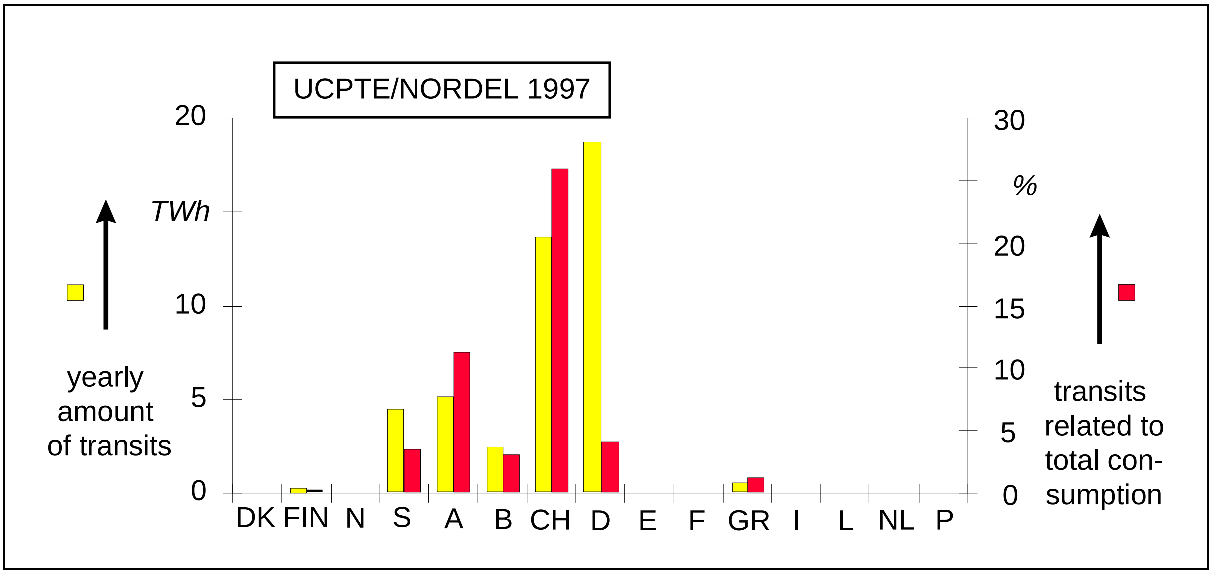

Fig. 3.1: Amount of transits in transmission systems within UCPTE and NORDEL, calculated from yearly total amounts of in-flows and out-flows

Such a remuneration mechanism can however cause some severe problems:

- If transit charges are imposed on single actors, with a magnitude comparable to the national transmission charges, the transit charges will add up to a considerable size when a „chain“ of several TSOs is included in a transit. This well-known „pancaking“ would obviously be a very effective barrier to long-distance trade.

- In absence of common definitions of the cost elements to be recovered by transit charges, these might be misused to allocate extensive cost to foreign actors.

- If transit charges are not precisely predictable, for example because participation factors of the affected TSOs have to be calculated for each individual case or because at least one TSO has decided for negotiated charges in general, cross-border transactions will become financially risky and complicated to carry out.

Apart from these problems, transit charges, as far as they are transaction-based, bring along the general disadvantages of transaction-based charging mentioned in chapter 3.3 and should therefore be very carefully designed, weighing up between pros and cons. It is important to recognize that the remuneration of transiting TSOs itself does not necessarily require transaction-based charges, but can also be achieved by compensation payments between TSOs.

In conclusion, it can be stated that any form of financial compensation for transits and loop flows should only be introduced on the basis of detailed common rules concerning at least the involved cost elements and the magnitude of compensation, the degree of individualization of the payments (relation to single actors or collectives), the resulting demands of transaction information, the requirements to transparency, and of course rules for the determination of the amount of transits and loop flows that payments have to be made for.

Allocation of other cost elements to foreign actors

Similar reflections as for transit costs apply of course to each other cost element that might be partly allocated to foreign actors. This may particularly be the case for congestion costs and costs of losses because they are considered allocatable to „horizontal" transports (see chapter 3.1). The issue of congestion costs is further discussed in chapter 4.

Allocation of non-transaction-based charges

The structure and magnitude of any non-transaction-based tariff components in the national transmission tariffs like entry/exit use-of-system charges or charges for ancillary services do not have any direct impact on cross-border transactions because such charges apply to each network user separately, with no reference to contractual relationships. However, the way of allocation of such charges to generation and consumption can have an overall effect on competition: since the generators will have to incorporate in their power pricing the costs arising from the network charges they have to pay, generators with low network charges will have a competitive advantage compared to those with high charges.

For example, a country allocating transmission costs practically completely to consumers or distributors, like Finland, creates for his generators the best possible conditions with respect to export opportunities. Sweden, in contrast, allocates approximately half of the costs to generation, creating a competitive disadvantage for Swedish generators in comparison to the Finnish ones.

In view of the objective to create a level playing field for generators, it must be discussed if, and possibly to what extent, the allocation rules associated with non-transaction-based charges should be harmonized. In advance of the further discussion of this issue in chapter 9, some general aspects can already be stated:

- A harmonization like that can be considered less urgent than the development of common rules concerning any charges that TSOs may allocate to foreign market actors, because the latter have *direct* impact on the implementation of open access, not only an overall influence on competitive advantages. Fortunately, it does not appear necessary to address these two issues at the same time because they are not inter-related.

- There are many other national burdens for generators like taxes, personnel costs or environmental requirements that are not harmonized, either, and therefore cause distortions to competition, too.

- A harmonization of cost allocation rules would mean to force modifications on national tariffs, which are partly laid down in laws, making any changes difficult and time-consuming. A *perfect* harmonization must remain a vision for distant future, anyway, because it would affect practically *all* features of national tariffs.

4 Congestion Management

4.1 Concepts of Congestion Management

In general, it is in the responsibility of a TSO to detect or to predict cases of congestion in his transmission system, because he is the only one to know precisely the actual state and the technical limitations of his system. To be able to predict congestion, the TSO needs to be given information from the market actors about their planned behaviour during the period under review. This is particularly true for the generation plans, because the use of generating plant is completely governed by market rules in a liberalized environment and thus not predictable for the TSO.

Consumption, in contrast, can neither be controlled significantly, nor will it radically change due to market activities. Therefore, in principle, consumption can be continued to be predicted by forecast methods which are relatively accurate. The only problem for TSOs is that they cannot predict the demand of distributors by such methods if there is generation connected to the distribution networks. This requires some form of cooperation between TSOs and distribution network operators in order to obtain reasonable predictions of the distributors' demand.

Transaction information, i. e. allocations of sink and source locations, does *not* appear necessary for the task of detecting congestion. Much more important is a good prediction of the situation *outside* a TSO's system, because the activities in neighbouring or even remote systems can considerably influence the own system's power flow.

Once congestion is detected in a transmission system, countermeasures must be taken to resolve the situation. Normally, the final result of such measures will be a shift in the generation pattern, because the reduction of supply or even disconnection of consumers can only be measures for emergency cases, i. e. severe congestion cases detected in the actual operations phase, when time is too short to determine any other countermeasures. In whichever way the necessary changes in generation are provoked, additional costs will usually arise for the responsible actors because the „unconstrained“ generation schedules are, at least in theory, supposed to be economically optimal in a well-functioning market.

In detail, there is however a multiplicity of possible procedures for congestion management, that differ mainly in respect of the two questions

- which actors are made responsible to find a solution to the congestion case, and
- which actors are allocated the financial risk associated with congestion,

according to which the overview below is structured. The objectives of developing an appropriate concept for congestion management are, similar to those of transmission pricing, in the first place non-discrimination, promotion of competition and cost-reflectivity in terms of fairness and price signals. Again, the latter objectives are partly contradictory, whereas non-discrimination must be ensured generally.

4.1.1 Responsibility of Finding a Solution to Congestion

The different approaches to congestion management can be classified, in analogy to the concepts of network pricing, into transaction-based and non-transaction-based approaches. In the **transaction-based** approaches, the responsibility to resolve the congestion is transferred to the market actors whose planned transactions would cause the congestion. This is achieved by the following procedure:

1. All market actors declare the planned transactions to the respective TSOs, meeting strictly defined deadlines that may be differentiated according to the duration or size of transactions.
2. These declarations include data necessary for the TSOs to perform security assessment in different time scales, in order to detect congestion (see above).
3. If a TSO detects congestion that cannot be resolved exclusively by network-related countermeasures, he has the right to refuse or curtail one or more of the transactions that contribute to the congestion, according to priority rules that have to be defined. Otherwise, he has to accept the declared transactions.
4. In case of refusal or curtailment of transactions, the involved actors have to change their trading positions in order to make their trades feasible.

By transfering responsibility to the final actors, this concept creates a very strong incentive to avoid congestion, i. e. to adapt trading activities to the physical capacities of the transmission system. Such a concept has for example been adopted by the German TSOs in the first version of their Grid Code [5]. It has, on the other hand, severe disadvantages with respect to promotion of market development:

- The process of declaration, assessment and acceptance/refusal of transactions is time-consuming and particularly difficult to apply to short-term trade.

- The fact that information on transactions has to be declared is adverse to practicability, and some market actors are afraid of confidentiality problems as long as TSOs are not corporately unbundled.

- The risk of transactions being refused after their assessment makes definite and quick decisions by the market actors impossible. Correspondingly, they will have to include conditional clauses in their transaction contracts, allowing for cancellation of the contracts in case network access is denied. This is obviously very critical to market development. In order to relieve this problem, a concept of „available transmission capability" values (ATC) to be published by the TSOs can be introduced. Such values, updated each time the „booking" status of the transmission system changes, would help actors estimate if an additional transaction were likely to be accepted or not.

- Even more critical, the definition of priority rules is a very sensitive issue. Several forms of prioritization are conceivable [6], none of which seems to be really optimal:

  – Up to now, understandably, TSOs tend to give contracts of their power marketing affiliates priority over transactions declared by other actors. This is of course a severe form of discrimination that cannot be further accepted.

  – Most commonly, transactions are prioritized according to the time of declaration, i. e. on a „first come, first served" basis. This corresponds, for instance, to making reservations for means of transportation. The problem is that this approach allows transmission capacities to be blocked by long-term reservations. Even if the contractors of long-term transactions are forced to renotify their actual capacity demand each day, short-term trade, which has a very important task for market liquidity, is clearly handicapped by this approach.

  – Different levels of „firmness" of transactions can be introduced. The higher the firmness, the higher is the priority of a transaction, but the higher is also the use-of-system charge to be paid. This approach is market-oriented because it gives market actors a chance to influence the likelihood of transactions being accepted by paying corresponding charges. It will however not be sufficient in case one of several transactions of equal firmness has to be selected for curtailment.

  – Priorities can be given in accordance to the physical power flow contribution of transactions to the congestion. To analyze the implications of this alternative, it is useful to introduce a distinction between two kinds of congestion that will also be referenced later in this report:

Congestion of bottlenecks that cannot be by-passed on parallel paths, like the group of interconnection lines between Spain and France, will be called **„simple“ cases of congestion**, because those transactions that contribute to the congestion are easy to determine in these cases: each transaction across the congestion contributes fully to it, either positively or negatively. All other transactions practically do not affect the congestion, at all. Such bottlenecks are located on „system cuts“ that divide the interconnected system in two parts.

In contrast to this, **„complex“ cases of congestion** are those located somewhere within the meshed transmission system, where parallel paths exist, e. g. on the border between France and Belgium.

In „simple“ cases of congestion, a prioritization according to flow contributions would not make much sense because the *relative* contributions of those transactions in the congested direction would all be 100 %, related to the respective size of the transactions. Therefore, a „ranking“ of contributors would not be possible. Rather, it appears reasonable to curtail *all* contributing transactions proportionally in such cases, as an alternative to prioritization.

In „complex“ cases, the identification of physical contributors is more difficult, because it requires power flow computations, and the number of transactions contributing to a congestion is very high (cf. chapter 2.1.2), so that a threshold would have to be defined below which contributions are neglected. In such cases, the relative contributions of transactions would be different and could thus be used for prioritization: the higher the relative contribution, the lower would be the priority of a transaction, i. e. the higher the likelihood that it had to be curtailed. This would make sense because it would identify those transactions whose curtailment were most effective.

– Priorities can be sold by TSOs in an „auction“ procedure. This would also be market-oriented, but probably time-consuming and requiring strict deadlines and rules. In addition, this approach creates an income to TSOs that is hardly predictable and not associated to a specific cost element. Moreover, auctions appear only applicable to „simple“ cases of congestion as defined above, because otherwise conflicts due to differences in „relative contribution“ would arise.

These disadvantages can be avoided by the **non-transaction-based** concepts of allocating the responsibility to resolve congestion. Mainly, two different models are applied in practice:

1. The **TSO** is made responsible to identify appropriate changes in the generation pattern that would relieve the congestion. To arrange for the necessary counter-measures, the TSO must be given the right

   - to oblige generators to change their dispatch accordingly (**„redispatch“**), like in the mandatory pool system of England and Wales [7], or

   - to purchase and sell equal amounts of energy from/to market actors in order to act on dispatch indirectly (**„counter trading“**), like in Sweden [8].

   Of course, the TSO must then have access to information on market and generation in terms of *possible* countermeasures and their prices. This concept is practiced, for instance, in England/Wales and within Sweden.

2. In case a **power exchange** exists, its market area can be split into different bid areas with limited exchange capacities between the areas. When these transfer capacities are congested, power prices will become different in different areas. In particular, the power price will be higher in areas that receive power across the congested connection, because this source is constrained. This will indirectly affect generation patterns in a way that the congestion is relieved. This **market splitting** concept is currently practiced by Nordpool, the Scandinavian power exchange, on a day-ahead basis [8].

The latter approach solves the problem in an elegant way, but is only applicable when sufficient power exchanges are established with market areas covering the possible locations of congestion. In addition, it may cause conflicts with respect to fairness of allocation of the financial risk, as far as *bilateral* trade across a congestion is allowed in addition to trade through the power exchange (cf. next chapter). Moreover, it cannot be applied in the actual operation phase.

Also the more frequently discussed concepts of redispatch and counter trade have some significant drawbacks:

- There is no risk of transactions being refused or curtailed, so it is more difficult to set out incentives for avoidance of congestion towards the market actors.

- Situations may occur where the single TSO is not able to find sufficient counter-measures to resolve the congestion problem.

- The TSO will initially have to bear the costs arising from countermeasures. Of course, these costs must be recovered through some form of congestion-related charges to network users.

Besides, it should be mentioned that the publication of ATC values is not necessary in a purely non-transaction-based arrangement for congestion management, because in this concept, the market actors are given the impression of transmission capacities being infinite, i. e. all transactions can somehow be accomodated, and the TSO has the responsibility to make this possible. Thus, the market players will not be interested in actually available capacities. (However, for other purposes like market analysis, ATCs may still be informative.) Similarly, it makes no sense to introduce different degrees of firmness under such an arrangement, because all access is then considered firm access.

4.1.2 Allocation of Financial Risks of Congestion

In the **transaction-based** approach to congestion management, the unavoidable financial consequences of congestion are simply allocated to those actors whose transactions are refused or curtailed, because they have to curtail an attractive deal and maybe substitute it by a less attractive one. The TSO does not have to take over any financial risk.

The **market splitting** approach allocates the cost surplus to the collective of network users located in the „deficit“ area that receives power over the congested lines. In particular, the surplus is only paid for the power purchased from the power exchange. Therefore, if also bilateral transactions across the congestion are allowed to take place, market actors can „by-pass“ the payment of congestion costs and thus undermine this model, which would have to be avoided in an appropriate way.

If the **redispatch** or **counter trading** concept is chosen, there are several possibilities of further allocating the congestion costs from the TSO to the network users:

- Even in these non-transaction-based approaches, the cost allocation can be done in relation to transactions. The necessary procedure would, similarly to the one described in chapter 4.1.1 for the transaction-based approach, begin with the declaration of transactions and the security assessment, but in case of congestion, the TSO would be responsible to identify and arrange appropriate countermeasures in terms of redispatch or counter trading, instead of curtailing a transaction. The arising costs would then be allocated to the transaction having caused the congestion.

Compared to the complete transaction-based model, this one has the advantage that the TSO „helps“ the market actors in finding a solution to the congestion problem. This would reduce the risk of having to cancel a transaction in case of congestion, but not the financial risk, so that the incentive to avoid congestion would still exist. A prerequisite of this is that the TSO is actually motivated to seek for the economically optimal solution.

In analogy to the different possibilities of prioritization described in chapter 4.1.1, different models of transaction-based congestion cost allocation could be developed, including for example the allocation to *all* transactions physically contributing to a congestion.

- In case of redispatch, a part of the financial risk can of course easily be allocated to the generators, by not paying their „lost profit“ for those units that have to be reduced in generation, but this solution does not appear very fair. (This is currently the case in Spain where congestion is also handled by redispatch through the power exchange.)
- The congestion costs can be fully socialized by including them in the TSO’s use-of-system charges. This would of course not include any incentives towards avoidance of congestion.
- As an intermediary solution, congestion costs could be partly socialized, for example by allocating them to all consumers on the „deficit“ side of a congestion, in the same way as is done automatically by the market splitting approach.

To give an impression of the magnitude of congestion costs, table 4.1 shows the total yearly congestion costs in the transmission systems of England/Wales, Norway and Sweden and the resulting per-unit costs, related to the countries’ total yearly energy consumption. The per-unit costs are very small compared with the overall transmission system charges (cf. chapter 7). This implies that congestion costs are less important than often suggested. A full socialization of costs in this magnitude would not even be realized by market actors. However, it must of course be kept in mind that these values need not be representative for all European countries, and congestion costs might abruptly increase due to liberalization in the meshed UCPTE interconnection.

Country	TSO	Congestion costs [Euro/year]	Totel energy consumption [TWh/year]	per-unit con-gestion costs [Cent/kWh]
England/Wales	National Grid Company	37 million	320	0.0120
Norway	Statnett	5 million	120	0.0042
Sweden	Svenska Kraftnät	1 million	150	0.0007

Table 4.1: Congestion Costs in England/Wales, Norway and Sweden (approximate values for 1998; source: TSOs)

4.2 Aspects Relevant to Cross-Border Transmission

The issue of congestion management is as relevant to cross-border transmission as to domestic transmission. After the markets have been opened, congestion is even more likely to occur between different transmission systems than inside one system because the systems have traditionally been designed to serve primarily the reliable supply within their limited areas, not to accomodate extensive cross-border trade.

Rules have thus to be developed for both aspects discussed above, the responsibility of finding a solution to congestion and the allocation of the arising costs. Particularly in the UCPTE interconnection, the existence of a multitude of TSOs introduces additional complexities to these tasks. The authors consider it essential that detailed common rules and procedures are developed instead of trying to solve this issue in subsidiarity, because congestion management is necessarily much more linked to the physical characteristics of the interconnected system than network pricing.

The following aspects make congestion management with respect to cross-border transmission a particularly difficult issue:

- The detection of congestion is more difficult because each TSO can only observe and control his own sector of the interconnection. If a TSO is not sufficiently informed about cross-border transactions that might affect him, he will be unable to detect possible congestion in his system due to loop flows. Only during the actual operation phase, he will observe the loop flows, but then it may be too late to react. This effect is closely related to the „contract path“ philosophy of network access and has practically occurred for example in Belgium in August 1997, due to a significant physical transport from France to Netherlands which was caused by a chain of contracts *not* including the Belgian TSO. It has already been shown in fig. 2.3 that the Belgian system is heavily affected by such a transport. In conclusion, common rules of data exchange for security assessment are urgently needed.

- If transaction-based congestion management is chosen, the multitude of TSOs involved may make the process of declaration, assessment and acceptance or refusal of transactions slow and burdensome. Precise procedures and deadlines would have to be defined to avoid this.

- If congestion is to be resolved by redispatch or counter trading, the amount of countermeasures available in those systems where congestion has been detected may be insufficient. For such cases, agreements on „international“ countermeasures are needed. It must also be specified which TSOs then have the responsibility to seek for a coordinated solution.

- Finally, if congestion has been managed successfully, possibly including international countermeasures, rules for congestion cost allocation to the involved TSOs must be found. The further cost allocation from TSOs to market actors may allow a certain degree of subsidiarity.

5 Settlement of Transactions

Up to now, the vertically integrated utilities have had the complete responsibility of settling the electricity they have supplied to their customers, which did not imply any difficulties in terms of metering or data exchange. Under the new arrangements, this situation has changed: the metering data can primarily be accessed by the network operators, but the producers or traders are supposed to settle the supplied energy with their customers.

At first sight, it might appear that the only necessary consequence is to let network operators transfer the metering values to the respective suppliers who could then do the settlement, but that would not be satisfactory at all, because no verification would take place if the amount of energy supplied to a customer and settled with him were equal to the amount of energy generated (or purchased) by the supplier. On the contrary, it is even very unlikely that these amounts are equal, because imbalances between generation and consumption occur permanently. Due to this unavoidable existence of imbalances, settlement is actually a difficult task in a liberalized environment, requiring considerable efforts in data exchange and management.

Technically, imbalances between generation and consumption are compensated by the mechanisms of power balancing within each control area as described in chapter 2.1.6. It should be recognized that it is much more economical to balance a large collective of network users as a whole, than if each actor, e. g. a small supplier with own generation, tried to compensate the imbalances between his generation and sales individually, because imbalances of different actors partly compensate each other. However, this makes some form of ex-post settlement of imbalances necessary, not only for fairness, but also to avoid misuse: if imbalances were not settled at all, suppliers might deliberately generate less than they sell, and fill the gap with free balance power.

For the task of settlement of imbalances, a unit has to exist in each control area that can be a department of the corresponding TSO like in Sweden, or a separate authority or company like in Finland, or a sub-function of the central pool like in England/Wales. This unit has to have access to the metering values of all the network users within the control area. There are two principle methods to settle imbalances [9]:

1. Each single network user is requested to declare, in advance, his generation or consumption schedule to the settlement unit. During the settlement process, the difference between the schedule and the metered generation/consumption is evaluated and settled. This however does not make much sense because it would require consumers to develop schedules, which is almost impossible, and it would result in extensive amounts of imbalances being settled.

2. The metered generation and consumption quantities are first aggregated according to the commercial relationships between the market actors, and only the remaining imbalances are settled. For example, a supplier with own generation would be settled for the difference between his generation plus purchases and his sales. This would avoid the need of consumption schedules and reduce the total amount of imbalances settled.

Although the development of open access arrangements including settlement procedures is still going on in most European countries, the second of the above approaches is likely to be implemented in more or less similar way throughout Europe because of its advantages. In the following, it is therefore supposed that a settlement unit exists in each control area, and imbalances are settled only with respect to aggregates of network users.

It should be noted that the mandatory pool concept in England/Wales matches the above description only partly because (almost) all generation is sold through the pool, not through bilateral contracts. Therefore, the pool itself is actually the only actor having to deal with an imbalance of generation and consumption. The other actors are either pure generators or pure suppliers/consumers and thus have no individual imbalances. With respect to settlement and imbalances, the pool concept is therefore quite elegant.

In systems allowing bilateral trade, possibly in addition to a power exchange, the pricing of imbalances, done by the settlement unit, is particularly difficult. On the one hand, the price for a „positive“ imbalance, i. e. if unscheduled energy has been *taken* from the remaining system, and the compensation for a „negative“ imbalance, i. e. if unscheduled energy has been *injected* into the remaining system, should not be too different, in order to avoid dramatic accumulation of payments due to frequent imbalances. On the other hand, the price must be high enough and the compensation low enough to avoid the possibility of misuse by the market actors, i. e. the deliberate production of imbalances with the aim to achieve economic advantages. As the Scandinavian example shows, imbalance pricing is significantly facilitated by existence of a power exchange which yields a reference price.

Relevance to cross-border transmission

In the settlement concept outlined above, a network user can normally not choose which settlement unit is responsible for him, because the allocation of network users and settlement units is given by the control areas. (It must be noted that it is technically possible, but costly, to „cut out“ a network user from one control area and to allocate him to another one. This should be done only in exceptional cases.)

The consequence of this is that each of the contractors of a cross-border transaction will be treated separately by the respective settlement unit in the control area that he is connected to. The transaction itself must therefore be defined by a schedule that is considered firm: each of the involved settlement units will suppose that the scheduled amount of power has actually been injected or extracted on the „other“ side of the transaction. Otherwise, the settlement of each cross-border transaction would require cross-checking among the settlement units to determine the actual imbalance between power injection and extraction of a transaction, which would be very burdensome and time-consuming. (By the way, it is important to recognize that *transiting* countries do not play any role in the settlement process of cross-border transactions. Also, they do not have to incorporate transits in the programming of their control area regulators.)

The fact that, in this concept, cross-border transactions can only be implemented on the basis of schedules is not too much a restriction, because most cross-border trade will be wholesale trade which is anyhow based on schedules. If a single consumer wished to be supplied from abroad directly, i. e. with no trader in-between, he would have to split his demand into a scheduled part and the unscheduled, remaining part, the latter of which would unavoidably have to be delivered by a local supplier and settled by the local settlement unit.

To make the above outlined concept work, two essential requirements have to be met:

- In each control area, a settlement unit must exist, usually as a part of the corresponding TSO. If, however, this prerequisite is not met, trade *within* the control area will not work properly, either.

- Each TSO must accept that he is responsible for power balancing for the whole of the network users connected to his control area, no matter if they trade with domestic actors or across the border. The same must apply for the activity of the settlement unit.

- The settlement rules in each area must be fair. This applies particularly to imbalance pricing. The experience has shown that inappropriate pricing of imbalances can result in extensive imbalance payments, which would very effectively prevent cross-border trade from being economically worthwile. Of course, fair pricing can easiest be provided if a power exchange exists.

  Another possibility would be to allow market actors to maintain „imbalance accounts“ on which imbalances can partly compensate over reasonable periods of time. Doubtless, such accounts would have to be differentiated in time zones according to the system load, in order to prevent actors from trying to compensate over-consumption in periods of low power price with under-consumption in periods of high power price.

  This concept of imbalance accounts is not new; it has since long been (and will continue to be) practiced for example between UCPTE members to balance the unavoidable very-short-term „unscheduled exchanges“ across interconnection lines within the metering interval of one hour.

- To further reduce the amount of imbalances being settled, the national transmission access rules should allow short-term adjustments to cross-border transaction schedules until approximately one hour ahead of actual operation.

If this concept were implemented, an extensive exchange of metering data across borders could be avoided.

6 Existing Concepts for Cross-Border Open Access

6.1 Electricity Transmission

6.1.1 USA

In the USA, the Federal Energy Regulatory Commission (FERC) has set up the framework for liberalization of the electricity sector by its orders 888 („Promoting wholesale competition through open access non-discriminatory transmission services by public utilities") and 889 („Open access same-time information system and standard of conduct") in 1996. This comprises instructions for network pricing, according to which each TSO has to publish non-discriminatory tariffs for both the transaction-based „point-to-point-service" and the non-transaction-based „network service" to its users.

By now, many independent system operators (ISOs) have been established, which had been aimed at, but not been prescribed by FERC. An ISO operates the networks belonging to several adjacent TSOs. Inside the ISOs' areas, network access predominantly appears to be handled in a non-transaction-based manner. According to the FERC orders, ISOs have to publish „non-pancaked rates pursuant to a single, unbundled, grid-wide tariff" for network access.

Charges for transactions crossing the borders of ISO areas or, if there is no ISO, TSO areas are however transaction-based. For example the ISOs of California and the Midwest raise charges for export and transit in addition to the regular charges, which besides are always allocated to the consumption side of a transaction. Therefore, for each cross-border transaction, the source and the sink as well as the contract path between them have to be declared. Charges for transactions crossing several areas will thus „pancake".

For administration of network access on a federal basis, the internet-based „open-access same time information system" (OASIS) has been implemented. It is used to publish ATC values, to make network capacity reservations for transactions, and to calculate the resulting transmission charges. To reduce the administrative effort, standard transmission services have been introduced with different reservation deadlines and different degrees of firmness. In case of congestion, the information available through OASIS is used to determine transactions for curtailment, according to a priority list based on reservation dates and types of service.

The crucial drawback of this transaction-based concept is that, up to now, OASIS is exclusively limited to contract paths. Loop flows through networks not included in the contract path are not taken account of, neither for payment of transit charges nor for detection of congestion and determination of appropriate countermeasures. Due to this fact, it can for example happen that firm transactions have to be curtailed because of loop flows being caused by non-firm transactions.

This disadvantage has been recognized and partly been addressed [10, 11]. The Eastern Interconnection for instance has developed a physical flow based transmission information system that takes account of bottlenecks by modelling them as „flowgates“. For each transaction, the contributions to power flow on the flowgates are evaluated. Currently, an „interchange distribution calculator“ is developed which in case of congestion identifies those transactions for curtailment that physically contribute to the congested flowgate.

6.1.2 Scandinavia

The electricity industries in the Nordic countries are characterized by close cooperation. Since 1996, Sweden and Norway operate a common power exchange, the Nordpool, which is also participated by actors from Finland and Denmark. The network tariffs in Norway, Sweden and Finland are strict point-tariffs which are fixed and published. Partly, this is also true for cross-border transactions between these three countries: there is no cross-border charge in addition to the local network access charges with respect to power traded through Nordpool. In addition to that, however, some bilateral cross-border contracts still exist that are charged for according to special cross-border tariffs, but these tariffs are intended to be phased out in the next years to make the point tariff system consistent.

The fact that this concept does not allow a direct dependency of charges on parameters of the electric path like the distance, in order to increase individual cost-reflectivity, is broadly accepted; rather, this is considered sensible because distance is not regarded a good parameter for reflecting the individual amount of network utilization. Instead, to provide price signals for efficient choice of location and efficient system utilization, the tariff elements are differentiated locationally and, partly, according to time zones.

The issue of remuneration for transits is of particular interest for Sweden, being the country between Norway and Finland. Up to now, there is no mechanism of financial compensation for transits. This situation is currently under review because in the long run it is not considered fair that the Swedish network users take all the costs related to transits. Possibly, there will be in future an agreement that the Swedish TSO collects payments for transits from the Norwegian and Finnish TSOs, based on physical flows across the borders. This issue is however considered of minor importance because the effect of these payments on the overall network charges for Swedish actors will be only marginal.

The proportions of costs allocated to generation and consumption differ considerably in the Scandinavian transmission system, especially since Finland has moved to an almost complete cost allocation towards consumption (fig. 6.1). In general, it is considered sensible to let these ratios converge, but the need for a quick an strict harmonization is not seen, also in view of the fact that there are other charge elements like taxes that are not harmonized, either.

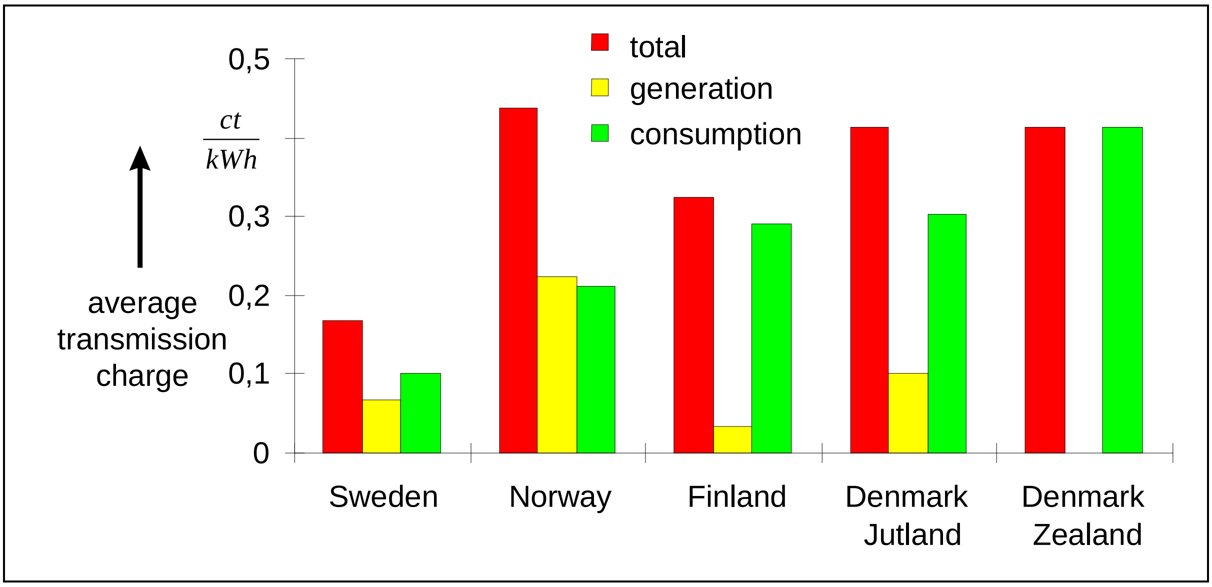

Fig. 6.1: Transmission cost allocation in Scandinavian countries (charges calculated from total revenues and amount of power transported)
Source: Svenska Kraftnät, April 1999

Congestion management is also done in a non-transaction-based way in Scandinavia, i. e. by market splitting and counter trading. Up to now, each TSO is exclusively responsible to manage congestion in his own area with his own resources. This has so far proved sufficient. However, Sweden and Norway are currently developing arrangements for a common counter trading scheme. This of course requires very close cooperation between the TSOs.

In general, the experience has been made that liberalisation has only caused minor changes in the overall power flow pattern in the Nordic transmission system, although power trade has very well developed and a large part of the consumers have changed their suppliers. The relevance of precautions for congestion has therefore turned out lower than initially envisaged.

For the TSOs to be able to perform load flow calculations for security-oriented network operation, the market players in Scandinavia have to provide a minimum set of information on the physical generation pattern that results from all transactions. Data on individual commercial transactions is not exchanged with the network operators. For the purpose of settlement, each country has established a settlement centre, either as an independent company or as a part of the national TSO. This centre, of course, needs to know which metering point is commercially related to which „balance responsible trader“ for the daily settlement procedure (cf. chapter 5).

6.1.3 England and Scotland

The interconnections between England and Scotland are mainly used to trade power from the Scottish utilities, which are still vertically integrated, to the pool of England and Wales. For this transaction, the Scottish utilities pay charges to the National Grid Company (NGC) of England/Wales in the same way as generators directly connected to the NGC grid. There is no real open access across this border up to now.

6.1.4 Germany

The structure of the German transmission network, being operated by 8 TSOs, somehow resembles the structure of the European transmission network. Therefore an analysis of the German concept of open access might be useful for the purpose of this study. However, experiences collected so far are not sufficient for a well-founded evaluation. The current concept, which is transaction-based with respect to both network pricing and congestion management, has been criticised in various aspects and is currently undergoing a process of re-discussion which might lead to a more market-oriented solution.

Particularly, it is discussed to let network access not be related to single transactions any more, but to aggregates of transactions to be defined by generators, suppliers or traders, and to define geographical „trading hubs“ according to which transactions may be aggregated. This would imply non-transaction-based access *within* the areas associated to the hubs, in terms of charges and congestion management. For the hub-to-hub trade, a matrix of fixed transaction charges is thought of, reflecting the horizontal transport costs of transiting areas, and thus being indirectly distance-related. The number of hubs would be in the magnitude of the number of TSOs. Such modification of the open access concept would obviously be more practicable, but cannot finally be evaluated because it is still under development.

One general positive aspect already included in the existing arrangements is the intention to present to the transmission network users a *consistent* concept of access nation-wide, associated with a scheme of compensation payments between TSOs that need not be transparent to the network users. For this purpose, the TSOs are represented by their association DVG.

6.2 Other Areas of Economy

A comparison of cross-border open access arrangements in other areas of economy with those in electricity transmission must be viewed with reservations because of significant differences in the respective technical and organizational structures. Below, concepts adopted in the areas of post, telecommunication and traffic are analyzed, emphasizing the specific characteristics of service and their influence on the resulting tariff structures.

6.2.1 Post

Costs of postal service can be divided into components for transport and for delivery of postal matters. While delivery costs prove to be of fixed magnitude, depending on type and weight of matters, at least part of the transport costs is distance-related. Nevertheless, national point-tariffs are charged throughout, resulting in the term „postage stamp tariff“ being used whenever an equivalent tariff structure is discussed in other areas of economy. Usually, the sender is charged, exclusively.

The World Postal Union, covering almost all countries of the world, has fixed guide-lines that guarantee free passage and non-discriminatory transport of postal matters [12]. Harmonization has been done by defining standard postal matters according to type and delivery speed, in order to permit cross-border service. Moreover, the guidelines prescribe fixed charges for international postal service that have to be paid by the originating country to the receiving and the transiting countries, in order to cover the costs of delivery and transport, respectively. (Transiting countries are those where an intermediate step of transport takes place.)

Therefore, international postal service is charged according to a transaction-based tariff, depending on the country where the addressee is located, reflecting distance-related transport costs and distinguishing, additionally, between different types of conveyance. To ensure cost-reflectivity, the bilateral payments depend on both weight and number of postal matters exchanged. A clearing office determines bilateral net-payments each year, levelling out mutual service.

Due to differences in national tariffs, the prices for international service are asymmetrical. Since postal matters can be transported also by customers themselves, this allows customers near borders to bring their matters to the country with the lowest prices.

In order to provide a consistent level of quality of supply, minimum requirements for delivery speed are fixed and controlled by the World Postal Union, and, in Europe, penalty payments in case of exceeding the limits act as incentives.

6.2.2 Telecommunication

Up to now, settlement of cross-border telecommunications service is done according to so-called accounting rates [13, 14], that are re-negotiated bilaterally between system operators each year. The originating operator who collects charges from his customer pays to the terminating operator an agreed amount per minute of traffic, known as the settlement rate, which is normally about half the accounting rate. In contrast to electricity transmission, telecommunication services in opposite directions do not cancel out each other. However, balancing of opposite services between each two operators is done annually to calculate net payments.

Developed countries tend to generate more outgoing international traffic to less developed countries than vice-versa, resulting in significant net payments of developed to less developed countries. Because the degree of development is reflected by the quality and thus the cost of telecommunication service, developed countries offer a kind of subsidy to the less developed countries. Besides, it has been generally accepted by most operators and regulators that the unpublished settlement rates between most countries in the world comfortably exceed the costs incurred by termination of international telecommunication service. This settlement system has been suitable in an environment of international service provided mainly by monopolistic operators.

The costs for termination of telecommunication service consist of three basic cost elements: the distance-related transmission element reflecting a part of the network costs of the involved networks, the element for costs of the international exchange, i.e. switching of the international circuit, and the element for costs of the national extension, comprising the national exchanges for the delivery of international calls. An improved concept of cross-border pricing used in Europe and the Northern part of Africa tries to reflect these cost elements.

The European Commission has forced the liberalization of interconnection services between operators by directives since 1st January 1998, demanding open access on a transparent, non-discriminatory and cost-orientated basis. Nevertheless, arrangements for the settlement of interconnection services are still under discussion. Moreover, discontinuation of the accounting rate system would be a political issue, because many less developed countries are not willing to accept the renunciation of the benefits of the current pricing system.

One possibility is to maintain the accounting rate system, but to decrease prices according to a „best current practice“ price level that is assumed to reflect the costs. As a first step, US regulators have declared price caps for current accounting rate negotiations, and have suggested target costs or benchmarks based on current national tariffs in order to fix objective accounting rates.

However, there is broad agreement that bilaterally negotiated accounting rates are neither cost-orientated nor suitable in a market of increased third party access to network facilities. For this reason, it is discussed to introduce fixed tariffs for each of the cost elements. This would result in transaction-based total charges.

6.2.3 Traffic

On the one hand, the European Commission has set up directives for the liberalization of **railway transport** that demand unbundling of infrastructure and transport facilities in vertically integrated companies and non-discriminatory open access, and that define allowable parameters for charges, e.g. distance, quality requirements (infrastructure, speed, interruptibility), or requirements towards specific routes. On the other hand, space is left for subsidiarity as regards parts of the tariff structure and the share of costs being covered by state subsidies, making tariffs diverge [15]. Moreover, liberalization is not confirmed in all countries. Therefore, companies and regulators consider harmonization a crucial issue for introduction of open access to Europe-wide railway infrastructure.

As a first step, the concept of the European North-South Freight Freeways has been developed in a project of the European Commission, the ministers of transport of the participating countries (Austria, Germany, Italy, Netherlands and Switzerland) and participating railways, as well as the Scanways project of Scandinavian countries and Germany. Benefits of these projects are the access to European railway networks at short notice and the resulting high transport speed because of short cross-border stops. However, the project is limited to the provision and allocation of particular train paths with defined timetables. The total charges are determined by pancaking of national tariffs.

According to political orientations, the existing tariff systems for **road transport** are quite divergent. Partly, the whole infrastructure is provided by the states, partly the costs are recovered by charges, sometimes generally depending on types of roads, sometimes being imposed only on specific, particularly expensive roads. Postage stamp tariffs („vignette“) are applied as well as point-to-point tariffs („péage“). Moreover, charges can depend on parameters like weight, type, height or length of vehicles.

7 Comparison of Existing Transmission Tariffs

7.1 Overview

The existing transmission tariffs diverge remarkably throughout Europe in terms of structure as well as magnitude. This is made evident by the comparison presented in this chapter. Besides charges for network access within specific nations, the comparison comprises some cases of cross-border transmission according to current (bilateral) arrangements.

The countries taken into consideration in the comparison are Austria, England/Wales, Finland, Germany, Netherlands, Norway, Portugal, Spain and Sweden. In these countries, transmission tariffs have already been published. Due to the complexity and diversity of the tariff structures applied, realistic transmission cases must be defined in order to perform a meaningful comparison. The following cases are included in the comparison:

Customer type	Peak power	Utilization
Industrial customer	100 MW	6500 h/a
Distribution company without own generation	1000 MW	5500 h/a
Distribution company with 50 % generation on distribution level	1000 MW	5500 h/a

Table 7.1: Network access cases for the comparison of transmission tariffs

The first two transmission scenarios are chosen to point out the influence of energy- and power-related tariff components on the total charge. The third case is chosen to demonstrate the impact of gross and net tariff components. The complete generation in the first two cases and 50 % of the generation in the third case is supposed to be connected to the transmission grid, too.

The charges calculated here refer only to the transmission level, excluding charges for transformation down to the distribution networks. Air distance of transmission is assumed to be below any distance thresholds of the German pricing model. Charges for demand of reactive power are not taken into account.

It is attempted to illustrate, as far as possible, the subdivision of total charges into the components for use-of-system, for recovery of losses and for ancillary services. The definitions of ancillary services are not uniform (cf. chapter 2.1.7), but mostly, there is agreement on the following most important ancillary services: frequency control, voltage control and provision of black start capability for system restoration after large failures. If not mentioned otherwise, it is assumed that the charges for ancillary services are contained in the use-of-system charges. If additional services are included in the tariff components for ancillary services, this is mentioned in the description of the national tariff. Congestion costs are, as far as possible, excluded from this comparison because they are usually not recovered by an explicit tariff component.

All charges are determined in exclusion of value added tax or any country-specific surcharges for stranded costs, renewable energy utilization etc. The applied exchange rates are from 09.04.99.

7.2 Description of Tariff Structures

Austria

The Austrian point tariff published on 18.02.99 is uniform for the major part of the country except for Western regions. Only the tariff for the main part of Austria is considered here. Charges for use-of-system, containing already several ancillary services, and charges for losses are allocated to the consumer. While the energy-related loss charge applies to the total energy consumption, the use-of-system charge is divided into an energy-related gross component and both energy- and power-related net components. Reference quantity for the latter component is the average value of the 3 individual annual peak demands. For simplicity, this value is obtained here from the peak demand by multiplication with a „simultaneity factor“ derived from curves having been determined for the former version of the German tariffs.

Ancillary services as regards primary and secondary control are charged to the generator as gross components. If energy is designated for export, the loss charge has to be paid in addition by the generator.

England/Wales

For England and Wales (jointly denoted as „England“ in the following), the calculations are based on the point tariff of the National Grid Company (NGC) from April 1998. The use-of-system charges are locationally differentiated into 12 areas for comsumption charges and 16 areas for generation charges. The consumption charges are related to the average demand during the 3 peak demand intervals of the system, represented here by multiplication of the individual peak demand with the simultaneity factor mentioned above. The generation charges are related to the peak generated power. All tariff components apply to gross power and energy. The costs of ancillary services and losses are taken account of by average costs having been calculated by NGC.

Finland

The point tariff in Finland charges most costs to the consumer, while generators only pay for a part of costs of losses. Both charges have to be added in order to determine total charges for a transaction. The national transmission operator charges a nationwide uniform tariff (state: Nov. 1998 - Dec. 1999) that exclusively consists of energy-related components. The use-of-system charge consists of a gross element that applies to the total consumption of a customer, and a net element that varies with regard to time, being represented here by an average value. The same is true for the loss charge for consumers, while the loss charge for generators is constant. Loss charges are net components. The charge for ancillary services, which is a gross component, covers costs of necessary generation reserve and frequency control.

Germany

The current German transmission tariff is a point-to-point tariff. A distance-related charge is applied in case the air distance exceeds 100 km. In the comparison of national tariffs, this charge element is not taken into consideration, but in the comparison of cross-border transmission cases, the air distance is assumed to be 300 km.

The comparison takes into account the tariffs of the 6 non-municipal German TSOs Bayernwerk, EnBW, PreussenElektra, RWE, VEAG, and VEW. In the comparison of national tariffs, the tariffs of these 6 TSOs are averaged.

The use-of-system charges consist of both energy-related and power-related net components. Losses are charged for by energy-related net components. Charges for ancillary services are either energy-related or both energy- and power-related gross elements, applied on the total consumption. The charge for ancillary services covers the costs of voltage control, frequency control, system restoration as well as operation of the transmission grid.

Netherlands

The Dutch TSO charges according to a uniform point tariff (state: 1999), consisting of a use-of-system charge including costs of losses and related to peak demand, and two different charges for ancillary services, one of them applied to net energy supplied from generators in the transmission network, the other one applied to the peak demand covered from generators connected to a distribution network.

Norway

The structure of the Norwegian transmission tariff (state: 1997) is similar to the Finnish one. The use-of-system charge comprises two power-related elements, one of them applied to total demand and generation (gross component), the other one applied on net demand at the connection point. While generators have to pay according to their peak supply, consumption is charged according to the share in system peak demand. Therefore, the above-mentioned simultaneity factor is again applied.

The energy-related charge for losses is based on marginal costs and is determined by multiplying the actual energy price with a loss coefficient. The loss coefficients for generation and consumption vary with regard to location (5 areas) and time, being taken into account here by average values.

Portugal

The current Portuguese transmission system tariff for that part of the market that is already opened to competition consists of two gross components charged to consumption and comprising costs of ancillary services. The first component is energy-related, the second one power-related and based on the average demand during monthly system peak hours, represented in this comparison by the individual peak demand multiplied with the simultaneity factor.

Losses have to be recovered by additional power injection according to loss coefficients. These have not been published so far, therefore they are estimated on the basis of loss coefficients and energy prices from Spain.

Spain

The Spanish point tariff (state 1999) for the wholesale daily market published by the government does not charge generators, at all, but allocates all costs to the consumers. The tariff consists of an energy-related and a power-related gross component, both of which vary with regard to time. Time periods are chosen to represent different load factors of the total system. The tariff components are represented here by average values, and the relevant power is determined through the simultaneity factor.

An hourly updated uplift term for congestion costs and costs of ancillary services has to be paid by market actors buying energy on the wholesale daily market. In 1998, this term had an average of 5 % of the average final energy price.

Losses have to be included in the total acquisition bids to the wholesale market according to coefficients published by the system operator. In this comparison, costs of losses are calculated by multiplying the estimated value of loss coefficients with the average energy price.

The Spanish tariff comprises exit charges that have to be paid for exports, whereas imports are not charged. The export charges are structured similar to the use-of-system charges.

Sweden

The structure of the Swedish transmission tariff is similar to those of Finland and Norway. It is a point tariff that comprises a power-related use-of-system charge, an energy-related loss charge based on marginal loss coefficients and a small participation fee for the „balance service“. All charges are net elements.

The use-of-system charge is latitude-dependent in a linear way. Generators pay more in the North, due to a generation surplus, and less in the South, due to a generation deficit. Conversely, consumers pay more in the South and less in the North.

The charge for losses is determined by multiplying a time- and location-dependent loss coefficient with a time-dependent price of „loss energy“. In this comparison, an average value is determined for the loss charge.

7.3 Results

7.3.1 National Tariffs

The results of the comparison of the national transmission tariffs are presented in fig. 7.1-7.3. As far as possible, the calculated average charges are split into the components for use of the transmission system, ancillary services and losses. Components that are not explicitly shown are included in the use-of-system charge. It has to be taken into account that the loss charge in Norway and Sweden is based on marginal costs of losses and thus does not reflect actual costs of losses. The components for ancillary services have to be regarded with reservations, too, because they are differently defined in different countries.

Obviously, the average charges in all three cases vary considerably among the countries, covering approximately a range of factor 10 between the lowest (Sweden) and the highest charges (Spain). Differences in charges between the first two cases are due to differences in the utilization time between these two cases, which of course has an influence on average charges per kWh *only* if power-related charge elements are included.

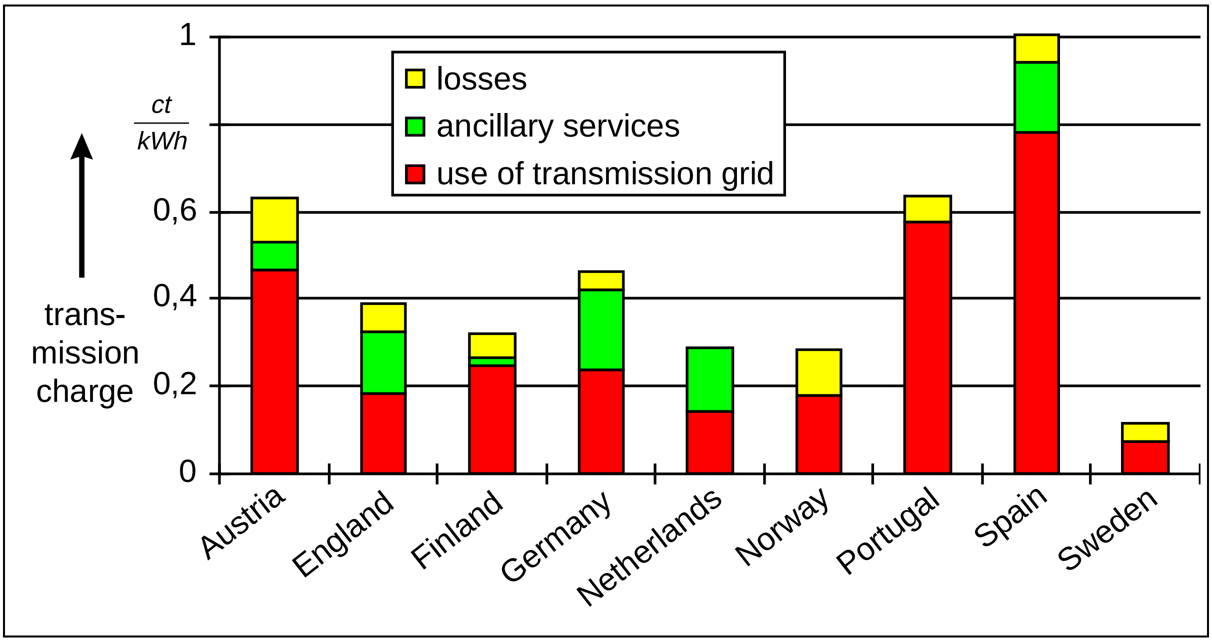

Fig. 7.1: Average transmission charges for the industrial consumer case

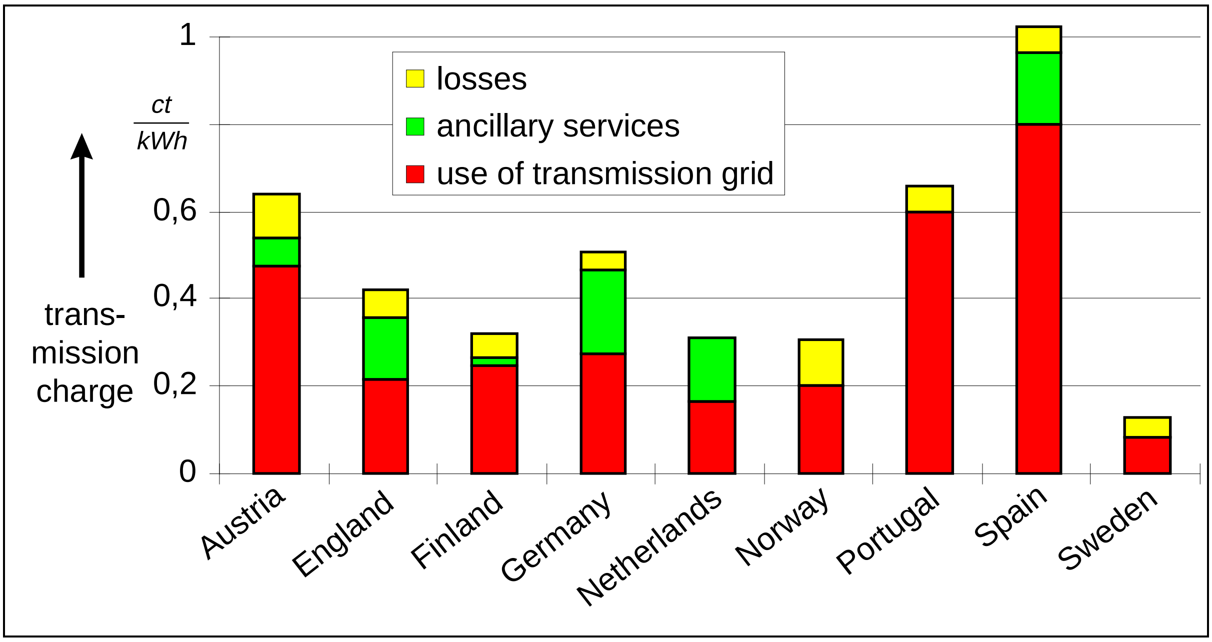

Fig. 7.2: Average transmission charges for the case of the distribution company without own generation

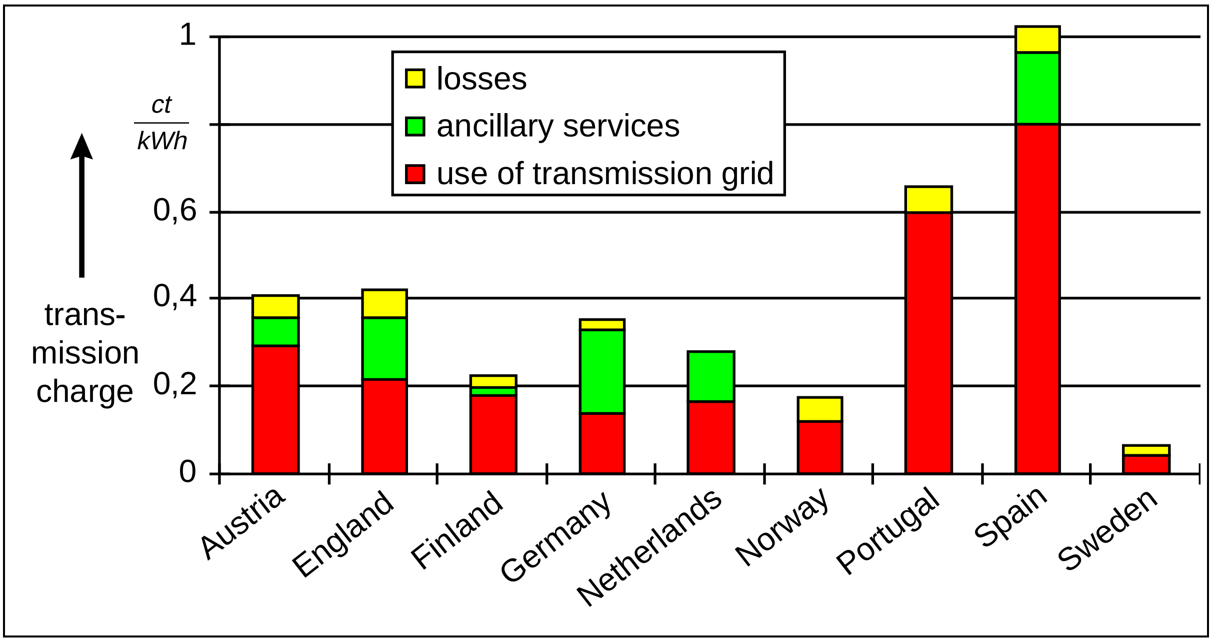

Fig. 7.3: Transmission charges for the distribution company with 50 % generation on distribution level

Except for Spain and Portugal, all tariffs include net components of different magnitude, applied only to the power flow at the connection to the transmission grid. This makes the average charges per kWh of consumption decrease, if the distribution company partly covers the demand from own generation capacities in the distribution network (see fig. 7.3).

For checking the above results, average revenues per kWh of power transported can be calculated. These data are available to the authors for four countries:

Country	England	Finland	Norway	Sweden
Average transmission revenue	0,44 ct/kWh	0,31 ct/kWh	0,23 ct/kWh	0,17 ct/kWh

Table 7.2: Average per-unit revenues from transmission charges

The average revenues are approximately equal to the average charges shown in fig. 7.1-7.3, which confirms the calculations. (Remark: The average revenue value for Norway is lower here than in fig. 6.1 because Norway has recently published new tariffs, that have not been taken into account in this comparison.)

7.3.2 Cross-Border Transactions

The case of the industrial consumer is taken as a basis for discussion of various issues concerning cross-border transactions in this chapter. First, the impact of differences in cost allocation principles to generation and consumption is demonstrated by the example of the Scandinavian countries Finland, Norway and Sweden which all apply a strict point tariff without cross-border charges in addition to the local network access charges (cf. chapter 6.1.2). The total charge for a cross-border transaction consists of the generation and consumption charges of the respective countries. Fig. 7.4 clearly shows the asymmetries in total charges resulting from differences in cost allocation.

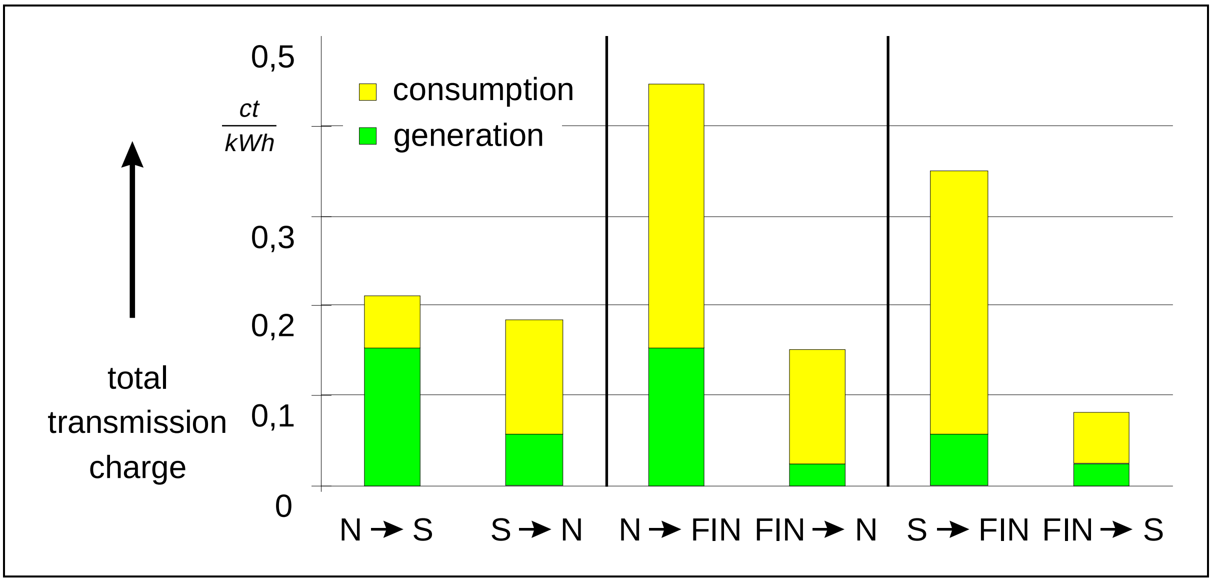

Fig. 7.4: Average charges for cross-border transactions in Scandinavia for the industrial consumer case

As an example of the interaction of transaction-based and non-transaction-based tariffs, cross-border transmission charges have been calculated for transactions between Germany and Austria, assuming a transmission distance within Germany of 300 km. The German part of the charges covers the transmission between the German-Austrian border and the connection point of the network user; the Austrian part covers the entry/exit charge of the network user. The results are shown in fig. 7.5, with the German distance-related charge element being explicitly displayed.

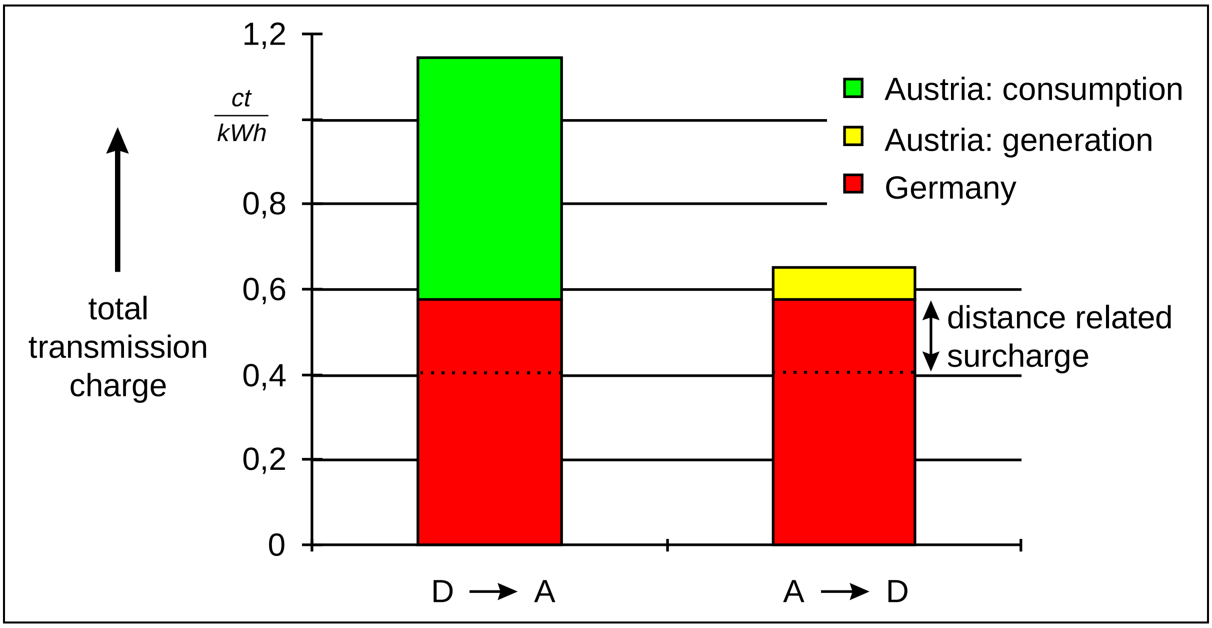

Fig. 7.5: Average charges for an examplary cross-border transaction between Austria and Germany for the industrial consumer case

In Spain, a specific surcharge is imposed on exports, whereas exports from Portugal to Spain are free of additional charges. The results of this asymmetry are demonstrated by the comparison of examplary cross-border transactions between these two countries (fig. 7.6). The difference in use-of-system charges for consumers in these countries is partly compensated by the Spanish export charge. This situation is viewed as provisional by Portuguese authorities and is under review by a bilateral working group.

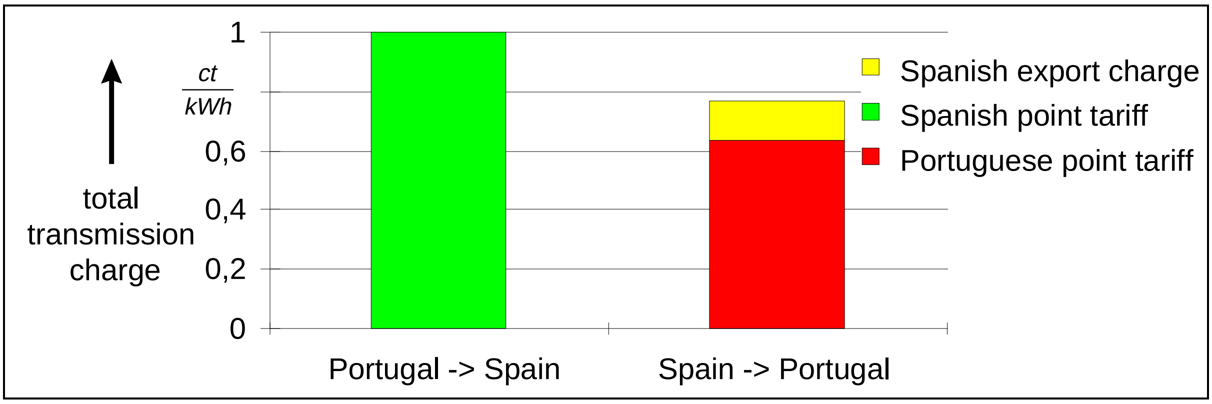

Fig. 7.6: Average charges for cross-border transactions between Portugal and Spain for the industrial consumer case

8 Proposals

8.1 Proposal of European TSOs

The European TSOs, represented by their associations UCPTE, NORDEL and the British and Irish Grid Systems, have agreed on a common proposal for handling cross-border transactions which is discussed here in the draft version of 23rd January 1999 [19]. This paper has been prepared by the steering group „International Exchanges of Electricity“ representing the above TSO organizations and EURELECTRIC.

This proposal puts great emphasis on the objectives of cost-reflectivity and of maximal subsidiarity. With respect to **network pricing**, the central idea is to split each TSO’s tariff in at least three components, one of them reflecting the network costs exclusively caused by the local access of generators („G“), the second one reflecting the costs caused by local access of consumers or distributors („L“), and the third one reflecting the costs of „horizontal“ transport („T“), caused by all kinds of network access including transits.

According to the proposal, the component T, which represents the main difference from other proposals, should be related to transactions, but the definition of the term „transaction“ is very broad: it can for example denote single transactions between one consumer and one generator or supplier, aggregates of all transactions belonging to one supplier, or even aggregates of all transactions with the source or sink located in one TSO area. It appears questionable if the co-existence of such different definitions of transactions were practically workable. This might at least have the consequence that, in the end, *all* market actors throughout Europe would have to adhere to the most restrictive definition selected in any country. For example, if a country A in the middle of the interconnected system selected the „single transaction“ approach and all the others selected the „country-wise aggregation“ approach, information on single transactions would still be necessary for all transactions that affected country A. The TSOs’ proposal does not go into detail on such a situation.

In the proposed cost component method, the charge for a transaction would consist of the G and L components in the source and sink area, respectively, plus the T components of all TSOs whose networks are affected physically by the transactions, each multiplied with a participation factor that reflects the proportion of power flowing through the respective network. Adding the T components of the affected TSOs would result in a sort of „shallow“ pancaking which the proposal considers a good approximation of the actual costs allocatable to a transaction. The intensity of this effect would probably be reduced if many TSOs decided to relate the T component to TSO-wise aggregates of transactions.

To make the approach more practicable, it is suggested that the T components are always collected by a market actor’s local TSO who would then be responsible of further distributing the charges to the other affected TSOs. In particular, the „importing“ TSOs should always be the ones to pay charges to the transiting TSOs, so that the transit charges would finally fall back to the consumption side of a transaction.

The proposal gives almost no details on the calculation of the TSOs’ participation factors. It leaves open if these factors have to be calculated individually for each transaction, which would be time-consuming and make charges unpredictable, or if they have to be published in advance, for example in matrix form. The statement that the network model for calculation of the factors should include all known transactions indicates that it is intended to take place individually after declaration of each transaction.

A model for calculating participation factors can be found in the UCPTE rule for handling long-term transits [20]. This however is quite complicated and therefore indeed only applicable for long-term transactions.

For the sake of practicability, the proposal suggests to introduce threshold values for participation factors below which a TSO’s participation is considered to be neglectable, so that the TSO is not entitled to receive a transit charge. Similarly, charges are not intended to be imposed on „neighbourhood loop flows“, as far as they do not cause congestion.

To avoid discrimination or misuse of the concept for hampering international trade, it is intended to harmonize the calculation methods of the T components. In the current version, the paper gives however no clues on the expected magnitude of these charges.

With respect to the cost allocation towards generation and consumption, i. e. the ratio of G and L, harmonization is urgently recommended in the proposal, as far as differences cannot be technically justified. Similarly, a harmonization of the allocation principles of ancillary service costs is strongly recommended, to avoid charging twice for these cost elements.

A large part of the TSOs' proposal is devoted to the issue of technical implementation of open access including **congestion management**. The main objectives pursued in this issue are the avoidance of arrangements based on the contract path philosophy, and again the principle of subsidiarity.

The proposal clearly votes for the transaction-based approach to congestion management as described in chapter 4.1. It is considered a matter for subsidiarity to develop the necessary priority rules, possibly taking account of degrees of firmness, the time of declaration (first come, first served), the physical flow contributions, or auctions. To the authors' mind, it must be severely doubted if this degree of freedom towards the individual choice of rules for congestion management, including also the broad definition of the term „transaction“, would lead to a practicable approach, at all. The only harmonization demand that is clearly recognized in the proposal is towards the information requirements and deadlines of declaration and acceptance/refusal of transactions.

The proposal allows TSOs to additionally arrange for non-transaction-based countermeasures to congestion, like redispatch or counter trading, within their own system boundaries, and to pass on the resulting costs to their connectees. It appears however hardly understandable why any TSO should do that in case of congestion caused by cross-border transactions, when the other TSOs would not do it.

In addition, the proposal declares that the TSOs intend to publish non-binding ATC values for the exchange between each two countries or between blocks of countries. Without doubt, this is very useful for market actors, at least in case of the transaction-based congestion management concept. However, it is outside the scope of this study to go into detail on the ATC issue.

In conclusion, the broadness of this proposal and the fact that it credits itself with being flexible enough to encompass any other proposed approach are considered quite critical by the authors of this report, because no evidence is given that a really practicable solution will develop on this basis. The proposal requires a considerable amount of further specification and harmonization to avoid diverging national solutions, adverse to the internal market development.

8.2 Proposal of British Electricity Industry

The Electricity Association, representing the British generation, transmission and distribution companies, has made a proposal for cross-border transmission pricing

[21] that has been further specified in a note following a discussion in the context of this study [22].

This proposal aims at a compromise between a pure point-tariff and a transaction-based tariff, justified by the opinion that on the one hand, physical and commercial flows are indeed very different and charging related to the electric path between source and sink therefore is not necessarily cost-reflective, but that on the other hand, quite obvious cases exist where distance-related pricing *would* be more cost-reflective than a pure point-tariff.

It is therefore proposed that charges are mostly independent from commercial transactions, with the only exception that network users must declare for pricing purposes if the energy they generate (or consume) is for export (or from import) or not. For energy crossing the own system boundary, the TSO would be allowed to raise a surcharge or grant a discount, reflecting for example the costs of interconnection circuits, or the financial compensation paid to or received from other TSOs as a remuneration for transit costs, or the costs of congestion.

The information if generated power is for export or domestic consumption and if consumed power is from import or domestic generation is anyhow considered necessary for the TSOs to set up their control area regulators.

Payments between TSOs should, according to the proposal, be based on actual physical flows between each two interconnected TSOs. The height and direction of these bilateral payments should be adjusted in such a way that finally the transiting countries receive an appropriate compensation.

As a reasonable contribution to collective cost-reflectivity, it is suggested that if for example a TSO has to do payments for power flowing out of his network because this is the predominant direction of flow, this TSO should allocate these costs to the generators in his network, because their export activities mainly contribute to this power flow. Nevertheless, the way in which TSOs actually passed on such payments would of course be a matter for subsidiarity.

8.3 Proposal of Swiss TSOs

The Swiss TSOs have expressed their own reflections on cross-border transmission pricing and congestion management in a paper [23] that has partly influenced the current version of the proposal of the European TSOs described in chapter 8.1.

The Swiss TSOs are convinced that only a non-transaction-based framework for cross-border trade will really leave sufficient space for subsidiary solutions in the member states because a transaction-based approach requires more information about each transaction and is therefore more restrictive from the point of view of the network users.

The proposal however emphasizes that a scheme of financial remuneration for transits and loop flows is essential to achieve collective cost-reflectivity. It gives some ideas on how to develop such a scheme:

- Compensation payments should be based on metered physical flows across tie-lines and take place between each two neighbouring TSOs. In order to obtain a consistent concept of payments, the paper suggests that, generally, the TSO *receiving* a flow should pay to the TSO *exporting* a flow, independent of the cost allocation principles within the countries.
- The payments are proposed to consist of two elements, one of them reflecting the costs of tie-lines (including DC links) and maybe costs of losses caused by cross-border transactions, and being related exclusively to the power flow across the respective tie-lines. This element would however be of minor importance except for DC links.
- The second element should reflect a part of the transmission network costs that is considered allocatable to „horizontal“ transports, similar to the T component of the TSOs’ proposal. It should be related to the amount of transits and loop flows across a TSOs area and be allocated to the imported power flows across all tie-lines in an appropriate way.

  The calculation of the total amount of transits and loop flows should incorporate the metered tie-line flows and, possibly, the total amounts of domestic generation being intended for export and domestic consumption being covered by import, similar to the proposal of the Electricity Association. If necessary for a reasonable identification of transits, it is even considered justifiable to take into account the destination or origination TSO area of each cross-border transaction. This would however introduce a certain degree of relation to transaction.

  The scheme should be designed in a way that the transiting countries will receive payment and the importing countries will have to pay. This includes that payments will accumulate when a chain of TSOs is affected, resulting in a sort of shallow collective pancaking.

The proposal does not yet give a consistent suggestion for such a compensation scheme; the elaboration of suitable arrangements is still going on. It has been considered to incorporate the method of „power flow tracking“ [24, 25], which is supposed to objectively yield a matrix of „physical“ contributions of importers and exporters to transits. This method is further discussed in chapter 9.1.2.2.

The Swiss proposal does not go into detail about the share of network costs to be covered by the T component. It is however considered crucial to harmonize the rules for this allocation or even the absolute height of the charge.

A harmonization of the ratios of cost allocation towards generation and consumption is regarded less important because they are expected to converge themselves to a certain extent, driven by the pressure of market players complaining about inconsistencies. Special emphasis is put on the remark that this issue can and should be addressed completely separately from the issue of financial compensation for transits.

With respect to congestion management, the proposal clearly votes for a concept of Europe-wide counter trading because the transaction-based approach is not considered practicable. Consequently, it is proposed that all cross-border transmission access should be firm access. The TSOs are expected to develop common rules for counter trading that involve the responsibility for identifying and performing „international“ countermeasures.

8.4 Position of Scandinavian Electricity Industry

Although the NORDEL members support the TSOs’ proposal (chapter 8.1) at least as an acceptable model for a limited transition period, they would prefer arrangements for European cross-border trade to be more similar to the Scandinavian concept which has proved practicable and appropriate. This has been expressed in a discussion with the authors and in a written comment on the TSOs’ proposal in the draft version of 14th January 1999 [26].

In general, the Nordic TSOs consider the TSOs’ proposal to be too diffuse and broad to give evidence that it will actually support an efficient internal electricity market. They remark that technical problems are partly exaggerated and that solutions existing elsewhere are not sufficiently taken into consideration. For example, similar concerns with respect to network security and congestion management have been raised in Scandinavia at the beginning of liberalization as today in continental Europe. These concerns turned out to be hardly justified because the experience has been made that trade did not significantly change the physical flow patterns in the NORDEL interconnection. Of course, this experience need not be transferable to UCPTE.

In particular, the following aspects are regarded as important:

- From the point of view of the market actors, there should not be any transaction-based tariff elements except for special well-defined cases like priority agreements (which are not further defined in the comment). Any payments for remuneration of transit costs should take place between TSOs; preferably between neighbouring TSOs on the basis of physical tie-line flows. It is considered essential to completely eliminate the contract path principle from the pricing arrangements. If price signals are required, locational differentiation of entry/exit charges is strongly recommended instead of distance-related charging.

- Also for congestion management, non-transaction-based countermeasures should be prefered to the transaction-based approach, because the process of declaration, assessment and acceptance/refusal of transactions is considered unpracticable. Nevertheless, the existence of the possibility to make long-term transmission capacity reservations is supported, including daily-renotification of the actual capacity demand. Correspondingly, the publication of daily ATC values is supported, too.

- Evidence should be given that the proposed model is supportive of short-term trade on an international spot market, which is considered crucial for the internal market development.

8.5 Position of Italian, Portuguese and Spanish Regulators

During the European Electricity Regulatory Forum in Florence in October 1998, the regulators of Italy, Portugal and Spain have presented a common position on different issues of cross-border trade in Europe, including proposals for a transmission pricing framework [27]. This position has been put in more concrete form in a new paper [28] in conjunction with comments on the TSOs' draft proposal from Jan. 1999.

In general, the regulators put great emphasis on the objective of promoting international trade. To achieve this, they consider it crucial to guarantee independency of TSOs by requiring corporate unbundling rather than unbundling only in terms of accounting, and they strongly recommend to establish a European organization of independent TSOs. Another general recommendation is to eliminate any need of negotiation from transmission access arrangements, even if the electricity directive principally allows negotiated access.

With respect to the TSOs' proposal, the regulators welcome the fact that a first common proposal exists, and that this proposal is in line with some of their own basic positions, but they are concerned about its broadness and the lack of pressure for harmonization because this gives opportunity to development of unnecessarily complex and incompatible solutions among the European countries. Although the regulators agree on the opinion that the growth of the internal market will rather be a gradual process and that harmonization of national arrangements cannot be achieved abruptly, they expect more precise proposals on the final goal to avoid misuse and developments in adverse direction.

Concerning the issue of transmission pricing, the regulators strongly recommend to eliminate any sort of pancaking, even the shallow pancaking suggested by the TSOs' cost component method. Instead, network users should only have to pay the access charges of their local TSO. The only additional charges that should be allowed to be raised in relation to transactions should be those reflecting costs of losses and costs of congestion management (including network reinforcement, if necessary) as far as they are cause by cross-border transactions. Such charges should however only be intended to give economic signals to market actors, not to recover substantial parts of the TSOs' costs. The position paper however provides no details on a possible structure of such charges, except for the statement that contract path thinking should be strictly avoided.

To provide remuneration for transit costs on the TSO level and/or to collect financial reserves for necessary network reinforcment measures, the regulators propose to introduce a small, Europe-wide, flat surcharge to be paid by each network user independent from any commercial relationships between market actors, and to distribute the collected money to the respective TSOs on the basis of objective parameters.

The position paper expresses the opinion that a harmonization of national tariffs would be desirable to create a level playing field without competitive distortions. A need of harmonization is in particular recognized with respect to the principles of cost allocation to generation and consumption, the reference of tariff components to energy or power, and the definition of the voltage levels belonging to the transmission system.

The regulators' proposal does not go into much detail on the issue of congestion management. Generally, it is stated that the technical access rules should be as complex as necessary for secure system operation, but that this complexity should not be transferred to the pricing arrangements. Rather, pricing and technical issues should be treated as separately as possible.

More concrete, the regulators recommend not to accept any form of reservation or prioritization of physical transmission capacities, but to prefer solutions in terms of economic signals to avoid or relieve congestion. If refusal or curtailment of transactions is unavoidable, the reasons should be made transparent to facilitate verification by the market actors. As a substitute for reservation rights, instruments of financial hedging against the individual risk of curtailment of transactions should be created.

As an additional remark towards confidentiality of information, the regulators recommend to assess very carefully the actual confidentiality of any information given to the TSOs by the market actors, and not to restrict distribution of information that is not really confidential, because, on the other hand, the distribution of information is considered very important for providing real transparency.

8.6 Positions of Energy Consultative Committee, Consumers and Traders

A joint working group of the Energy Consultative Committe (ECC) of the European Commission and the European division of the International Federation of Industrial Energy Consumers (IFIEC) has prepared a proposal on cross-border transmission pricing in February 1999 [29]. It puts strong emphasis on the development of a true internal market and the compatibility of transmission arrangements with international spot markets.

The proposal is a clear vote for a strict entry/exit tariff, where each network user would only have to pay his local TSO’s access charge to obtain the right for electricity trade throughout Europe without any further charges. The tariffs should be published and predictable in order to provide transparency. With respect to the allocation of costs towards generation and consumption, the proposal considers a split of 50%/50% fair. As a desirable goal for the future, the proposal envisages the convergence of national tariffs, which could finally result in a unique „Europan postage stamp“ for transmission access.

To remunerate TSOs for their transiting activities, compensation payments between TSOs, based on measured physical exchanges, are suggested to take place. As a more general aspect, also this proposal strongly recommends the establishment of an association of European TSOs to address all issues of cross-border transmission access.

The power trading company Enron has formulated recommendations to cross-border transmission arrangements in a recent position paper [30] that are very similar to the ones mentioned above. The only exceptions to strict entry/exit tariffs that are considered reasonable are supplementary charges in special cases like DC interconnections or severe and permanent cases of congestion. For the latter cases, the paper suggests auctions for transmission capacity as a market-oriented solution to congestion management.

As a general aspect, the paper lays great emphasis on equal treatment of existing long-term contracts and arrangements on the one hand, and transactions made by new actors on the other hand. It is considered unacceptable that transmission capacities are blocked by „old“ transactions and only the remaining capacities are opened to competition.

9 Discussion and Recommendations

In this chapter, those issues in terms of transmission pricing and congestion management that have been identified as relevant to cross-border transmission in chapters 3 and 4 will be further discussed under consideration of the existing and the proposed concepts for cross-border transmission, presented in chapters 6-8. From this discussion, recommendations will be attempted to derive, as far as this is possible and sensible from the authors' point of view. It has been said already in the beginning that these recommendations cannot aim towards an „ideal" concept, but can only outline a band-width of reasonable solutions and point out their respective pros and cons. On this basis, the involved parties could commonly develop a starting solution, carefully weighing up between the different contradictory objectives.

The structure of the discussion is oriented towards the main cost elements, i. e. use-of-system costs, costs of losses, costs of ancillary services and congestion costs, including the discussion of congestion management concepts.

9.1 Charges for Use of Transmission System

Obviously, the use-of-system charges are the main elements of all existing electricity transmission tariffs (cf. chapter 7), and they represent the crucial point in the discussion on cross-border open access arrangements. The most important aspect to be decided is if there should be transaction-based charge elements or not, and, possibly, how they should be structured. However, all proposals accept that at least a part, supposedly even the major part, of the use-of-system costs should be covered by non-transaction-based charges, i. e. entry/exit charges imposed on all physical power injections (generation) and extractions (consumption or distribution) independently from each other. These charge elements are called „G" and „L" components in the TSOs' proposal and are the subject of chapter 9.1.1. The issue of transaction-based use-of-system charges will be discussed in chapter 9.1.2. Finally, chapter 9.1.3 gives some additional recommendations on charging for use of DC interconnections.

9.1.1 Network Access Charges for Generators and Consumers

In chapter 3.4, it has been pointed out that especially the ratio between the sum of costs allocated to generation and the sum of costs allocated to consumption plays an important role with respect to competitive neutrality. If this ratio significantly differs among different countries, competition will be somehow distorted. Strictly speaking, the same is true for most other features of the corresponding tariff components, e. g. the reference to power or energy. This has been recognized by the South European regulators who call for a harmonization also in this respect (chapter 8.5). However, to the authors' mind, the discussion should first focus on the question of the overall cost allocation ratios, and more detailed harmonization requirements should be addressed in a second step.

From the analysis of the proposals made, it can be stated that the urgency of a harmonization of the cost allocation ratios is viewed very differently. Some proposals consider the harmonization as urgent as the general introduction of open access rules, some others expect that a certain harmonization will take place automatically in course of time, not requiring any specific efforts. On the one hand, there is agreement that the convergence of the cost allocation ratios should be welcome, but on the other hand, the effect of competitive distortions appears less dramatic if compared with other similar competitive imbalances that are more or less accepted. It must be kept in mind that this issue, in contrast to other decisions concerning open access arrangements, has no relevance to *practicability* of network access, but only to *economic efficiency* of trade between certain pairs of countries.

The automatic process of convergence that is envisaged by some parties is supposed to be driven, on the one hand, by generators complaining about competitive disadvantages if they have to pay more use-of-system charges than generators in other countries, and, on the other hand, by consumers or distributors complaining about their use-of-system charges being too high because of transmission capacities being caused by a generation surplus in their area. (In continental Europe, the countries with the most extensive generation surplus are France and Denmark, as shown in fig. 9.1.) Since, however, it is difficult to identify explicit additional transmission system costs that are exclusively caused by the surplus of generation, the authors would expect the pressure towards small generator charges to be stronger, so that the result of this convergence process might be an allocation of more than 50%, but less than 100% towards consumption.

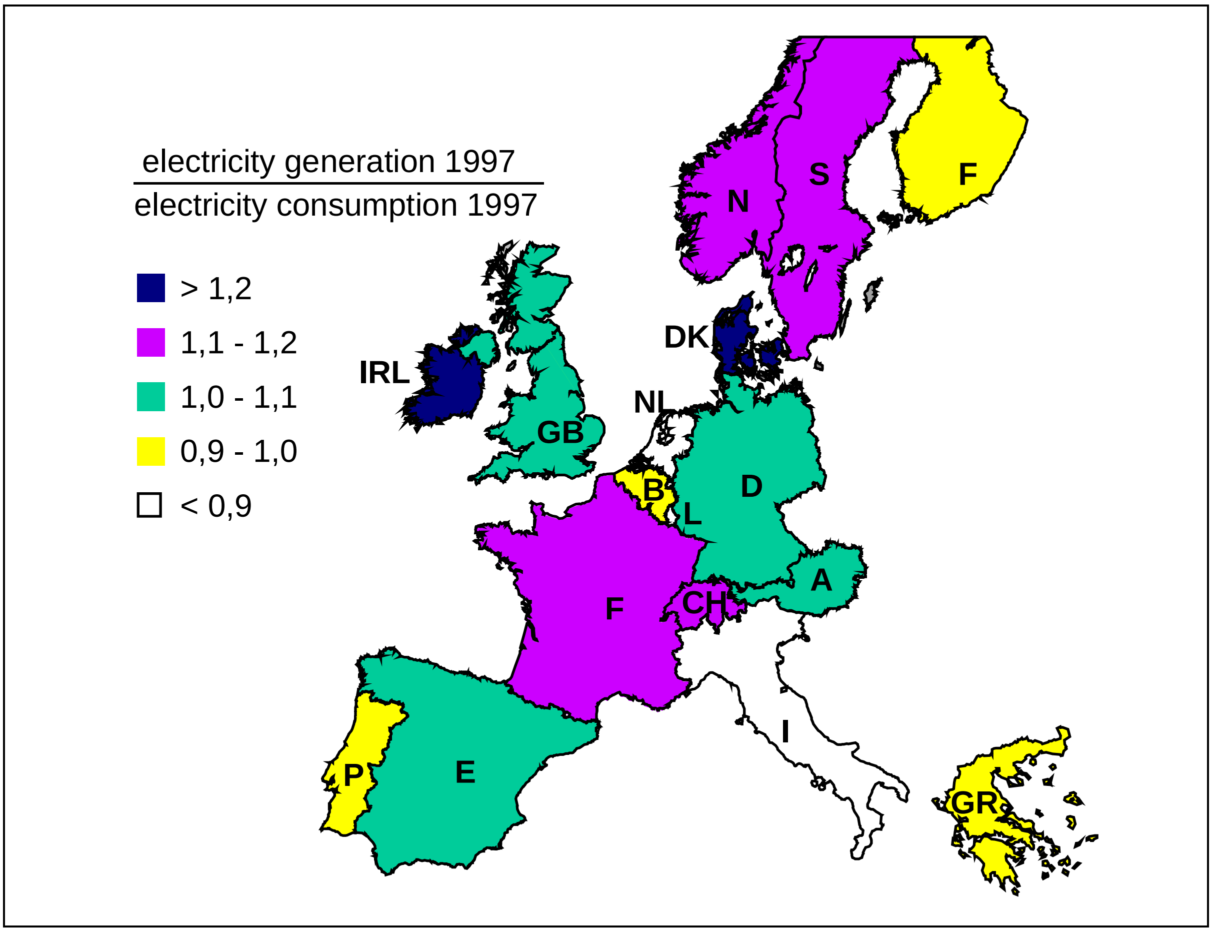

Fig. 9.1: Relations of total electricity generation and consumption in Europe (1997)

A trend towards complete cost allocation towards consumption is not very likely because some countries will try to keep or to introduce generator charges in order to have at least the opportunity of incorporating locational signals.

In conclusion, it would of course make sense to the authors to use the existing degrees of freedom in the national tariff models to achieve a certain harmonization of the cost allocation principles, and to agree on a broad direction on this issue as an orientation for countries that have not yet completed their transmission tariffs, but it does not appear essential in the short term to undertake great efforts towards such harmonization. This should rather be an objective to achieve over a couple of years.

If the cost allocation ratio is chosen, there is still considerable degree of freedom in designing the national use-of-system charges in terms of differentiation according to location and/or time zones. This opens space for subsidiary solutions that should take into consideration the need of incentives towards effective use of the system. Generally, the goal should be to design charges as uniform as possible, for the sake of practicability and neutrality to competition, but as differentiated as necessary to include appropriate price signals.

In the same way, the desire expressed by ECC and IFIEC to make charges converge throughout Europe in course of time, aiming at a „European postage stamp“, can of course be understood and justified from the consumers’ and traders’ point of view, but need not be economically justified since there are good reasons for differences in specific transmission costs in different regions of Europe. Moreover, in view of today’s differences in height of tariffs (cf. chapter 7), a concept of uniform use-of-system charges would require such extensive compensation payments between TSOs that it cannot be considered realistic, at least in the short and medium term.

9.1.2 Transaction-based Charges or Compensation Payments

9.1.2.1 Justification

Before different possibilities of introducing transaction-based charges or at least compensation payments related to horizontal transports are discussed, the main arguments for justification of such tariff elements are discussed below and generally evaluated from the authors’ point of view.

1. In a liberalized environment, it cannot be accepted that TSOs and, in consequence, their local network users are burdened with extensive transits or loop flows, caused by market actors located in other transmission system areas, without receiving any financial remuneration. Of course, there are usually no direct additional costs *exclusively* caused by transits or loop flows, but for the objective of a „fair“ cost allocation on the TSO level, it appears well-justified to allocate a part of the costs of existing network equipment to such flows. Strictly speaking, the financial remuneration should apply to *any* sort of transits and loop flows, even to „neighbourhood loop flows“. It is, however, very difficult to identify who is the originator of such flows, as discussed in chapter 9.1.2.3.

2. Transaction-based charge elements are often considered useful to provide price signals to the market actors towards the objective of efficient transmission system utilization. As far as a charge is related to the actual physical effect of a transaction, it can in fact be expected to have such a direct signal function. In those few cases where the physical effect of a transaction is easy to identify, such charge elements appear very sensible (see below, 3rd item). If however a charge is related to more abstract parameters derived from the source-to-sink path, like the geographical distance, it will hardly be justifiable as a correct signal with respect to individual cases, but only with respect to the statistic average of all cases. This is explained below on the basis of exemplary simulation results.

With the aim to quantify the distance-dependency of single transactions' effects on power flow, the authors have performed systematic simulations of transactions within the UCPTE interconnection. Based on real UCPTE load flow data reflecting the forecast-based winter peak load situation of January 1998, equally-sized transactions of 100 MW and 1000 MW have been simulated for each possible pair of source and sink locations out of a reasonable selection of locations throughout the network. (100-MW-transactions could be considered representative for the supply of single industrial customers, 1000-MW-transactions rather for large aggregates of consumers.) For each transaction, the resulting change in total transmission losses compared to the base case has been determined as a reasonable measure for transaction-related network utilization. The result diagrams (fig. 9.2 and 9.3) show these loss changes, relative to the transaction size, over the air distance between source and sink. Each dot represents one transaction.

As expected, there is no direct relation between distance and loss changes that could be identified by drawing a curve through the single dots. An individual transaction can relieve (negative loss change) or increase (positive loss change) the overall system loading with almost equal probability. For the individual case, distance would therefore be totally useless as a parameter to identify the actual physical influence on system utilization.

In statistic average, however, a certain degree of increase of loss changes with increasing distance can well be recognized, as illustrated in fig. 9.2 and 9.3 by the floating average curves. Obviously, this effect becomes even clearer with increasing size of transactions.

These simulation results show, for the example of geographical distance as the most frequently discussed parameter of electric paths, that the relation of charges to such abstract parameters can, if at all, introduce economically correct signals only with respect to the *average* of large numbers of transactions, but not with respect to *individual* transactions. Therefore, such charging is likely to evoke conflicts in those individual cases where it obviously does not reflect physical reality correctly.

In general, it should be realized that it is usually not the operational network utilization *itself,* but the choice of location of new generating facilities that is attempted to influence indirectly by such transaction-based charge elements. This however can also be achieved more directly by locational differentiation of generators' network access charges.

In conclusion, to the authors' mind, the argument of transaction-based, path-dependent charges serving as price signals towards efficient network use appears rather weak and should not be used to justify any additional complexity in cross-border transmission pricing.

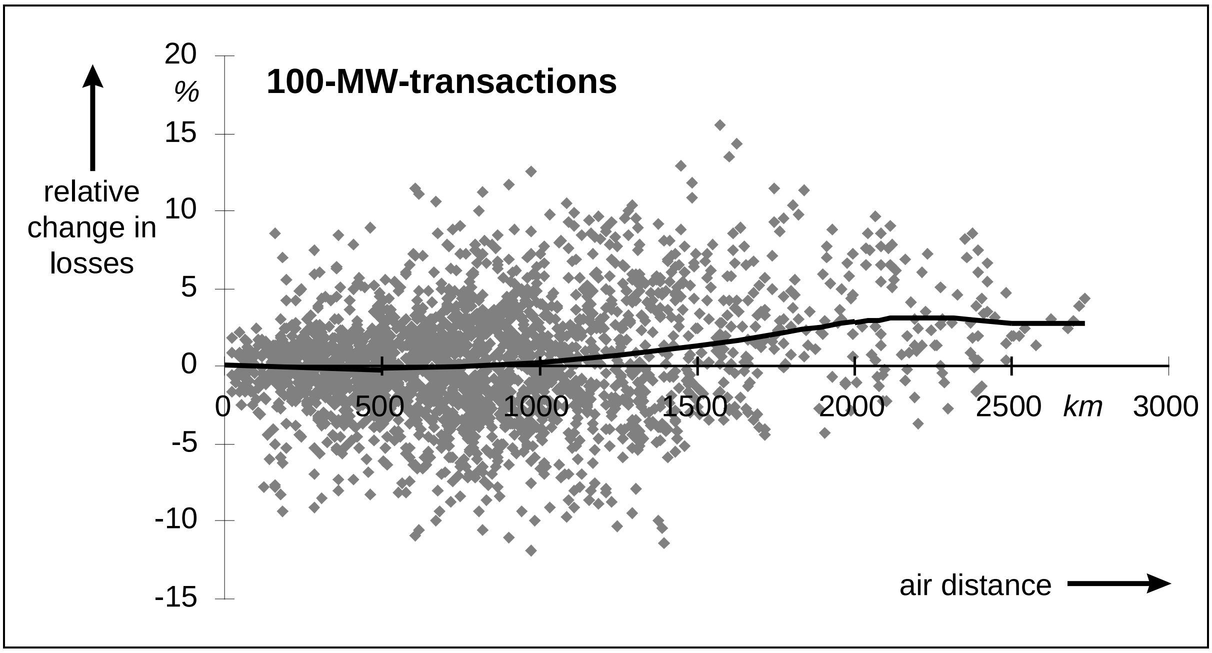

Fig. 9.2: Simulation results of 100-MW-transactions in the UCPTE network

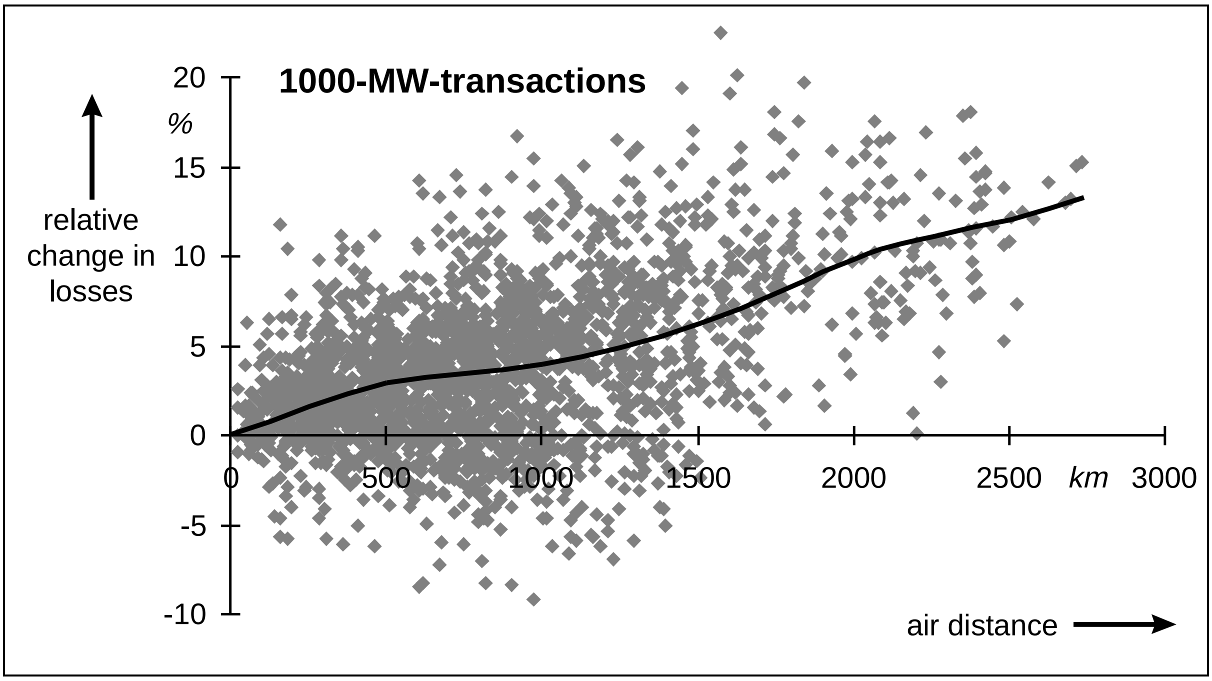

Fig. 9.3: Simulation results of 1000-MW-transactions in the UCPTE network

3. In cases where the physical effects of transactions are easy to determine, transaction-based surcharges (or discounts) can in fact provide direct price signals. This is particularly interesting for „simple“ cases of congestion as described in chapter 4.1.1, where each transaction across the bottleneck contributes to its power flow either by 100% or by -100%. In such cases, transaction-based, but also direction-dependent (i. e. positive or negative) surcharges that are directly related to the congested path can be applied to „control“ the power flow in a market-oriented manner.

4. Apart from all reflections on economic signals towards market actors, it is frequently considered „fair“ to make charges distance-dependent, at least with respect to long-distance transactions. In view of the simulation results presented above, this intuitive viewpoint, as far as related to individual transactions, can not be justified by physical reality, but only by the idea of a „fictitious line“ connecting source and sink, whose costs would of course increase with distance in a linear way.

   If all market actors adhered to this interpretation of fairness, this argument would in fact be important to take into consideration, but this is not the case. For example, the proposal of ECC and IFIEC clearly votes for a pure entry/exit tariff without any transaction-based charges, so that the resulting lack of fairness would be accepted.

9.1.2.2 Discussion of Reasonable Solutions

It has already been emphasized in chapter 3.4 that there is a multiplicity of possibilities to design transaction-based charges or compensation payments. The number of reasonable, consistent and possibly acceptable models is however relatively small. In this chapter, four different solutions on this issue are presented and evaluated with respect to the justifications outlined above and the general pros and cons of transaction-based pricing discussed in chapter 3. The solutions are presented in the order of increasing relation to transactions.

(A) Non-transaction-based pricing *without* inter-TSO compensation

In this extreme solution, no transaction-based charges are imposed on cross-border transmission, at all, and no financial compensation takes place on the TSO level, either. This implies that each TSO recovers his network costs exclusively from his own connectees. Although being very simple and practicable, this solution is not considered acceptable by the authors because of the lack of fairness concerning the cost allocation to transits and loop flows.

(B) Non-transaction-based pricing *with* inter-TSO compensation

This alternative includes financial compensation payments for transit and loop flow costs between TSOs, which however are still not passed on to the network users on a transaction basis, but are included in the TSOs' use-of-system charge calculation. This solution that is close to the Swiss proposal (chapter 8.3) does not imply any additional complexities from the network users' point of view, compared with solution A. With respect to the objectives of verifiability of cost recovery, non-discrimination and promotion of competition, as outlined in chapter 3.2, this is clearly considered the most recommendable solution by the authors. The only drawback is that the arguments calling for transaction-based charging, like direct price signals towards avoidance of congestion, are not satisfied.

There are many ways to develop an inter-TSO compensation scheme. Some reflections on this issue are presented in chapter 9.1.2.3, but it is not in the scope of this study to develop a consistent, detailed concept for this. In this context, the introduction of a Europe-wide, flat surcharge as an alternative solution for the „input" side of such a compensation scheme, as proposed by the South European regulators, should also be taken into consideration.

(C) TSO-specific surcharge on cross-border transactions

As the slightest conceivable form of relation to transaction, it could be required from each network user inside a TSO's area to state if the actor he is trading with is located in the same area or in another area, i. e. if the energy he consumes is imported or purchased from a „domestic" source, or if the energy he produces is for export or for domestic supply. Based on this information, the TSO could impose a surcharge or, if it makes sense, grant a discount on the energy crossing the border. This model that corresponds to the British proposal (chapter 8.2) would *not* make any reference to which TSO area the transaction partner were actually located in.

The main reason to introduce such a surcharge would be to have an instrument to individualize the financial compensation that a TSO has to pay to other TSOs for transits and loop flows. This would provide a little more individual fairness than the solution B because only those actors who are actually doing cross-border transactions would be allocated a share of the transit costs. A TSO could even decide to allocate these charges only to importers or only to exporters in his area, depending on which sort of transaction mainly caused the transits through other TSOs' areas.

However, the more these payments are individualized, the higher will the financial burden be for the involved market actors, which can be interpreted as an incentive to avoid international trade. This aspect will further be analyzed in chapter 9.1.2.3.

It should be remarked that if a TSO *received* payments from other TSOs for transits through his own system, it would *not* make sense to individualize these by granting discounts on cross-border trade to his local network users, because all his connectees should benefit from this compensation. In general, it is important to note that this solution is not able to *substitute* the inter-TSO compensation payments, because the information to be given by market actors is not sufficient for a correct allocation of transit costs.

To a certain degree, this concept could be used to introduce direct, positive or negative price signals for severe, „simple“ cases of congestion, as far as these are located on the boundary of a TSO's area. For example, Italy could decide to raise a surcharge on all imported energy, which might help reduce the power flows on the congested lines to Italy. However, only congestion at the boundaries of the source and the sink country could be taken into account, not congestion between transiting countries. For example, if Spain and France raised surcharges on power flowing across their border, this would not affect actors trading from Germany to Portugal, although the power they trade would inevitably cross the Spanish-French border, too.

Of course, TSOs could also use such surcharges to cover parts of their network costs, for example those costs arising from interconnection lines. At first sight, this might appear interesting for DC lines, but again, this would impose a problem if „remote“ network users traded across the same connections, because there activities would not be subject to these charges.

The objectives of fairness and of price signals towards efficient network utilization could be met by such a charging model only in very rudimentary manner, because it would only bring an advantage to „domestic“ trade over „international“ trade.

Although hardly transaction-based, this solution already brings along some of the general disadvantages of transaction-based pricing in very slight form. For instance, the problem of cross-border counterflows being charged twice might arise. More important, participants of an internationally acting power exchange would not know the exact amount of due cross-border charges before the daily close of exchange, because only after that, the exchange could figure out the surplus or deficit of traded energy per TSO area, which is relevant for the cross-border charges. This would not make trading at the power exchange impossible, but introduce a slight form of unpredictability of transmission charges.

The information demand of this model itself is however *not* a problem to trade, because the amounts of energy imported or exported must be reported to the local TSO anyway. They are needed for technical reasons, i. e. cross-checking of the programmes of the control area regulators in case of programme imbalances.

A problem of different kind might be seen in the political impression caused by this concept: the cross-border charges might be considered a sort of customs duties, which is of course adverse to the spirit of an internal market. Particularly, if a country decided to allocate these charges mainly towards importers, the impression of the political intent to „privilege“ the own energy on the international market might arise.

In conclusion of the above-said, this concept does not appear a really logical and consistent extension of the solution B, because additional objectives like price signals and individual fairness can only be fulfilled rudimentarily, which does not justify the slight increase in complexity for instance towards the operation of a power exchange. The only reasonable application of such cross-border surcharges is apparently the individualization of inter-TSO compensation payments towards importers, exporters or both of them. If this is done transparently enough to avoid the impression of custom duties for electricity, this might be a sensible modification of solution B.

(D) Matrix of area-to-area charges for aggregated transactions

If more emphasis is put on the fulfillment of *all* the objectives discussed in chapter 9.1.2.1, one step further towards transaction-based pricing has to be made by taking into consideration the information *from* which *to* which area energy is to be transmitted. It must be recognized that this is *slightly* more information than actually needed for technical purposes: it would be theoretically sufficient for the TSOs' cross-checking of their regulator programmes if each actor reported his total imports and exports per area, and not the pair-wise relations between them. The pricing concept proposed here requires however that allocations in pairs of source and sink areas be made, which is an additional, but not a too dramatic requirement for all actors with sales or purchases in three or more areas at the same time.

If transmission pricing is based on such area-to-area transactions,

- the issue of remuneration for transits can be solved without additional inter-TSO compensation payments, by designing the charges and the corresponding principles of revenue allocation in a way that transiting countries receive payments in total. (It should be noted that this model does *not* take account of „neighbourhood loop flows“; cf. chapter 9.1.2.3).

- surcharges or discounts as price signals related to „simple" cases of congestion can be imposed on those pairs of areas whose connection paths include bottle-necks.
- distance-related pricing can be introduced, as far as this is considered reasonable in order to provide price signals or just to improve fairness of pricing. Of course, distance can only be taken into account in an area-to-area manner, but this should be sufficient for these purposes.

For the sake of practicability and predictability, such transaction-based charges should be pre-defined and published in form of a matrix of fixed area-to-area charges that are not subject to extensive fluctuations over time. Any need of negotiation should absolutely be avoided. In order to limit the additional demand of information from market actors, it can be recommended that the pricing areas be more or less identical to the technical control areas. It would not matter to the market actors if several control areas were put together to one pricing area, but the contrary would impose additional complexity.

In view of the variety of objectives that these charge elements could be intended to fulfill, there are many possibilities to design the matrix of charges. For example, in correspondence to the TSOs' proposal, transit costs of all TSOs affected by transactions from one area to another could be included, in combination with participation factors calculated for example on the basis of the „empty" network model. This would directly give hints towards the necessary coefficients for distribution of *revenues* resulting from these charges, which can be considered a third dimension „behind" the tariff matrix. Although these distribution principles do not matter for the market actors, they must be clearly defined in advance to avoid conflicts and delays among TSOs.

Price signals against congestion should rather be derived from differences in market energy prices, or by „trial and error" in an iterative process in order to get bottlenecks free of congestion, but well utilized.

For the market actors, the reflections that have lead to a certain charge matrix are practically irrelevant. The only issue of importance is the actual magnitude of the charges, because these reduce the trading margins resulting from differences in market prices throughout the internal market. It must be recognized that such charges have a very direct impact on economic trading opportunities and thus on internal market development. If, for example, distance plays such a significant role that average charges between neighbouring areas are of same magnitude as typical energy price differences, economic trading opportunities of actors will be limited to their local and the directly neighbouring pricing areas. In general, distance-related pricing must be considered a form of pancaking, and in combination with the area-to-area approach, it can easily make the internal market break up into a number of separate sub-markets.

Of course, it would be economically optimal to orient such transaction-based surcharges exactly towards the marginal costs caused by a specific transaction, but it appears practically impossible to derive the individual marginal costs, as has been discussed several times throughout this report. Neither can the network costs be split objectively into horizontal and vertical transport costs, nor can the individual effects of a transaction be determined without major computation efforts, nor are the average effects of transactions in relation to distance a reasonable and consistent measure for pricing.

For this reason, setting up the charge matrix requires very careful weighing up between the intended scope of the internal market and the benefits of transaction-based and, in particular, distance-related pricing. Taking account of typical distances and price margins of today's international electricity trade in Europe, the authors have the impression that distance-related transaction surcharges should not exceed a roughly approximated upper limit of about 0.03 cent per kWh and 100 km if they are intended not to impose severe restrictions on trading opportunities in relation to the present situation.

Of course, the approach discussed above is associated with some of the general drawbacks of transaction-based pricing:

- The problem of counterflows being charged twice becomes more obvious than in solution C, because the international trading activities are completely decomposed in area-to-area transactions. However, this problem can be relieved if charges are not applied to single transactions from network user to network user, but to aggregates of transactions defined by generators, suppliers or traders.

  Moreover, there may be actors making an additional business by further aggregating transactions of different actors in order to achieve reductions of charges to be shared among the involved actors. This would not be adverse to the concept, because it might lead over time to a situation where the transactions finally charged are more or less identical to physical flows across interconnection lines. By the way, it depends on the structure of the charge matrix if the activity of such „transmission aggregators“ will lead to a great number of „neighbourhood transactions“ (if the charges are *progressively* distance-dependent) or to a small number of „long-distance transactions“ (if the charges are *degressively* distance-dependent).

- For internationally operating traders or power exchanges, it will become necessary to decompose their trading activities into „artificial“ area-to-area transactions for pricing purposes. This will require a charge minimization tool in order to find the optimal allocation. Indeed, this should not be a great problem of practicability, but the fact that the due charges are not known before close of trading will introduce a certain degree of unpredictability to the participants.

- In contrast to non-transaction-based solutions, this solution requires intermediary traders to also pay transmission charges, which is obviously more complex for them.

Summing up the above discussion, it can be stated that solution D is an acceptable and consistent approach as far as the different justifications for transaction-based pricing are considered important. It consists in fixed area-to-area charges imposed on aggregates of transactions, published in matrix form. It involves however slightly higher demand of information from market actors than technically absolutely necessary, and brings along a part of the disadvantages of transaction-based pricing. If it should be applied, greatest caution must be recommended with respect to the magnitude of charges, in order to avoid unnecessary market limitations.

From the authors’ point of view, this solution particularly makes sense with respect to the avoidance of „simple“ cases of congestion. The incorporation of distance-related elements is regarded rather critical by the authors, but could be accepted if the charges were reasonably small. The remuneration for transits and loop flows could also be achieved by an inter-TSO compensation scheme like in solution B.

Finally, it must be said that, of course, many more solutions with an even higher degree of relation to transactions can be designed. However, they would not at all appear acceptable to the authors because of the increasing drawbacks of transaction-based pricing.

9.1.2.3 Reflections on Inter-TSO Compensation Schemes

To develop a scheme of inter-TSO compensation payments for transits and loop flows, several issues have to be addressed:

- the way of collection of payments („input side“): identification of TSOs whose connectees are supposed to have caused the transits / loop flows, determination of the relevant amounts of energy that payments have to be made for, fixing of the per-unit price to be paid on these amounts of energy, and, possibly, methods of individualization of a TSO's payments towards specific groups of his connectees;

- the way of distribution of collected revenues („output side"): identification of TSOs who are burdened with transits / loop flows, determination of the relevant amounts of energy that payments can be received for, and fixing of the per-unit price for these amounts of energy. (As mentioned before, an individualization of received payments to specific groups of network users would not make sense.)

In general, two possibilities of identifying transits and loop flows and the corresponding amounts of imports and exports that have caused them should be distinguished:

1. The basis for compensation payments can be the metered **physical flows** across the interconnection lines between TSO areas. In order not to neglect rapid changes in the loop flow patterns, these could be registrated, for example, each hour, as a basis for an hourly „settlement" of loop flows. In these measurements, all types of loop flows including neighbourhood loop flows are included and cannot be separated from each other.

   This is a very objective method, which has, on the other hand, the consequence that the power flows through a TSO area cannot be separated according to the contractual situation. For example, if a physical flow of power P through an area was actually due to an import P on the one side and an export P on the other side of the area, it would still be identified as a transit, although it were originally an import/export combination.

2. An alternative would be to base compensation payments on **TSO-wise aggregates of transactions**. This would require all actors to report their area-to-area transactions like in solution D discussed above. These would be aggregated by each TSO to obtain net energy exchange values with each other TSO, for example on an hourly basis. Apart from the additional information demand, this has the disadvantage of not being really objective, because these aggregates depend on the amount of implicitly existing „circle trades".

As regards the **input side**, the source and sink TSOs of cross-border transactions (or better, their connectees) will usually be the ones considered to cause transits and loop flows. Therefore, on the basis of *physical measurements*, those TSOs with net imbalances of in-flows and out-flows can be identified as contributors to the overall amounts of loop flows, with the magnitude of the imbalance being a measure for the contribution. It is important to recognize that this does *not* reflect neighbourhood loop flows, because these are *not* caused by net importers or net exporters, but by geographical imbalances of generation and consumption *within* a TSO's area. Therefore, the causation of neighbourhood loop flows cannot be identified correctly by physical flows, which is a significant drawback. However, the authors consider the problem of neighbourhood loop flows less important, so that this drawback could be accepted.

On the basis of *TSO-wise aggregates of transactions*, the identification of TSOs contributing to transits / loop flows can incorporate the information how much energy is traded from each area to each other area, which allows, for example, to distinguish in the above-mentioned case between an import/export combination and a real transit. However, this would come close to contract path thinking. To avoid this, the contributions would alternatively have to be evaluated only according to net imports or net exports, similarly as on the basis of physical flows, but without including neighbourhood loop flows.

In general, three ways of collecting payments with different degree of socialization towards network users can be conceived:

1. Payments can be collected from all network users throughout Europe by a small flat charge like proposed by the South European regulators. This concept would, at least on the „input side“, totally socialize the costs of transits and loop flows, interpreting these as a consequence of interconnection that has to be born by all users because all users benefit from the interconnection of transmission systems. This solution would be very practicable, and the surcharge could be expected to be very small.

2. In any of the ways outlined above, those TSOs whose connectees have caused the transits / loop flows could be identified, and payments could be collected only from these TSOs. As far as these TSOs would just include the payments in there network costs, recovered by all their connectees' use-of-system charges, this would mean a partial individualization towards the user collectives of specific TSOs. Since it could happen that only few TSOs had to make considerable payments, the per-unit surcharges for the involved users would be much higher than the flat charge discussed above, supposed the total amount to be collected stays the same. On the other hand, this alternative offers at least weak price signals towards those who trade internationally.

   In whichever way the contributions to transits / loop flows are determined for this solution, it must be decided if payments are collected from the generation or the consumption side or both, in analogy to the choice of cost allocation ratios in national tariffs. To improve fairness, it is recommendable to chose a similar allocation as for the national tariffs, as far as these are somehow harmonized in this respect. Otherwise, it could happen that the network users in an export country paid for transit costs „caused“ by the corresponding importers, and vice-versa.

3. As a modification of solution 2, the TSOs who have to do payments could internally individualize these payments

   – towards generators and consumers in their system in accordance to the allocation key selected for the compensation payments, e. g. towards only the consumers if payments are only collected from the „receiving“ TSOs, or even

   – only towards those amounts of energy that have been imported or exported by the local network users.

   At least the latter solution must be regarded very critical with respect to internal market development, because the corresponding amounts of energy are comparatively small, so that the per-unit surcharge would be accordingly high for the involved users, acting as a clear incentive towards avoidance of cross-border trade. Such a cost allocation would not even be fair, because the importers or exporters in few areas with import/export imbalances would pay for the complete „European“ transit costs, while actors in balanced areas would not contribute, at all.

As regards the **output side**, a measure for transits and loop flows has to be found. On the basis of physical flow measurements, this could be the smaller value of the sum of in-flows on the one hand and the sum of out-flows on the other hand. The Swiss proposal (cf. chapter 8.3) suggests to further subtract from that value the reported amount of imports or exports, respectively, in order to distinguish between import/export combinations and real transits. This would however be a less objective measure because it depends on the degree of aggregation of transactions within a country.

Based on aggregates of reported transactions, the resulting transits and loop flows would have to be calculated in accordance to pre-defined participation factors, similar to those needed for solution D in chapter 9.1.2.2 for the distribution of revenues made through the transaction charge matrix.

An elegant idea to combine the collection and the distribution of payments would be to introduce bilateral payments between each two neighbouring TSOs, as proposed by the Swiss TSOs, based on measured flows on the corresponding interconnection lines, and maybe on reported imports/exports in each TSO area. In detail, however, the methods proposed in [24, 25], having been thoroughly assessed by the authors, still need some further elaboration because they imply problems in practicability or objectivity of cost allocation when „circle flows“ occur, i. e. when the power flow situation cannot be represented by a directed graph, which is not unusual. Nevertheless, the authors believe that a consistent approach can be developed on this basis.

Probably, the most difficult task when developing an inter-TSO compensation scheme is fixing the per-unit **prices** to be paid on the input side and those to be received on the output side. If the latter were found, the „input price“ could be adjusted in a way to achieve exact cost recovery, so that the problem can be reduced to quantifying the per-unit costs of transits and loop flows.

It has already been pointed out in chapter 3.1 that there is no unique way to split transmission system costs into costs of horizontal and vertical transport services. As a possible solution, it could be imagined to split the costs according to the sum of „power flow kilometres“ (products of power flows and line lengths) allocatable to vertical supply on the one hand and horizontal supply on the other hand, but this would not only imply extensive data and computation requirements, but also the difficulty of defining the „normal“ situation of vertical supply, which will always be somewhat arbitrary. Moreover, this splitting would depend on the power flow situation which fluctuates permanently.

Instead of or in addition to a part of costs of the existing network equipment, costs of necessary network reinforcement measures could also be included into such payments, in order to give the involved TSOs incentives to actually carry out such measures.

In conclusion, the above reflections show that a number of important and difficult issues arise when developing an inter-TSO compensation scheme for transits and loop flows, and that a multiplicity of solutions can be envisaged with different effects on practicability and fairness. Since this topic mainly touches the TSOs themselves, being the ones to primarily pay and receive the financial compensation, the authors expect that the task to develop an appropriate solution can basically be delegated to the TSOs. However, a crucial aspect with respect to overall internal market development is the allowable degree of individualization of the compensation payments. This aspect should be given major attention in the process of developing a pricing concept for cross-border transmission.

9.1.3 Charges for Use of DC Interconnections

Based on the technical characteristics of DC interconnection lines between AC transmission systems, described in chapter 2.2, it is obvious that in contrast to AC transmission pricing, a high degree of individual cost-reflectivity in charging for use of DC lines can easily be achieved, since the necessary information on transactions across the lines have to be reported in advance, anyway, for the programming of the converters. Moreover, as far as (groups of) DC lines represent „cuts“ in the system, it is not possible for market actors to by-pass them. In this aspect, DC lines can be regarded similar to „simple“ cases of congestion.

On this background, the authors would consider it well acceptable to raise separate, transaction-based charges for transports over DC lines, reflecting the exceptionally high costs of these lines. If the solution of an area-to-area transaction charge matrix (see above) were chosen, such DC line charges could easily be incorporated into the matrix. These charges could even be direction-dependent in order to provide price signals towards good utilization of the lines and to avoid double charging for transactions in opposite direction.

9.2 Remuneration for Costs of Losses

As regards the recovery of transmission system losses in the context of cross-border trade, it must first be decided if network users should compensate for losses financially or „energetically“, i. e. by injecting additional amounts of energy, calculated from loss coefficients and the magnitude of a transaction. Since the energetical compensation can only be correct in average and thus cannot substitute the TSOs’ responsibility to care for the actual losses, the financial compensation appears more practicable and should be preferred, which is also confirmed by practical experiences. It is of course important then to demand TSOs to purchase energy for recovery of losses from the most economic sources available.

Since costs of losses are primarily variable costs, it could be suggested to allocate them more individually than the use-of-system costs, in order to provide price signals towards reduction of losses. From the simulation results presented in chapter 9.1.2.1 as well as other investigations [31], it can be concluded that the individual contributions of market actors to the amount of transmission system losses can hardly be reflected by abstract parameters of transaction paths, like distance, but more accurately by locational loss coefficients for each single network user, as practiced for example in Norway and Sweden. This would mean to introduce a non-transaction-based charge as a component of national transmission tariffs which are of course subject to subsidiarity.

With respect to the harmonization demand of charges for losses, the reflections concerning use-of-system charges for generators and consumers (chapter 9.1.1) can be applied, correspondingly. If, additionally, any form of remuneration for transit costs is introduced by an inter-TSO compensation scheme or transaction charges imposed on market actors, it appears recommendable to include a part of costs of losses into those costs identified as costs of transits and loop flows.

9.3 Remuneration for Costs of Ancillary Services

In chapter 3.1, the costs of ancillary services have been identified as a part of the costs allocatable to vertical supply. They should thus be covered completely through the national transmission tariffs and not have any impact on inter-TSO payments or transaction charges for market actors, which is a matter of broad consense.

Again, a harmonization of the cost allocation towards generation and consumption can clearly be recommended, as far as practically possible, for the objective to create a level playing field. Therefore, the question of causation of the different ancillary services has to be addressed. Although these services are generally necessary for the overall function of the transmission system instead of being demanded by specific network users, some hints can be derived from reflections on the reasons why these services are needed, at all:

- The frequency control service is justified both by outages on the generation side and by demand fluctuations on the consumption side. In detail, as regards the regulation mechanisms in the UCPTE system, primary control is predominantly needed to balance generator outages in a way that other generators are not affected by critical frequency drops, while secondary control is due both to generator outages and demand fluctuations, the latter being usually more relevant.

- Voltage control, as far as in the TSOs' responsibility, is primarily needed due to technical characteristics and security concerns of the transmission systems. Its cost allocation should therefore follow the allocation of network equipment costs.

- Precautions for system restoration are necessary because large disturbances can occur in the transmission system or on the generation side. Consumers can hardly be identified to cause such disturbances.

- Metering and settlement costs can, in contrast, be individualized easily.

According to these reflections, a differentiated allocation of costs of ancillary services is recommendable if strong emphasis is put on the causation principle; for the sake of practicability, the authors would however consider more uniform approaches, like full cost allocation of ancillary services to either generation or consumption, to be acceptable, as well, particularly to facilitate harmonization.

9.4 Congestion Management and Allocation of Congestion Costs

Similar to transmission pricing, there is a multiplicity of possible solutions to the issue of congestion management, each having its specific pros and cons. Therefore, this chapter is not intended to develop in ideal solution, but to roughly outline an approach that appears reasonable to the authors. A lot of details must remain open, since this topic is only in the margin of the scope of this study.

In view of the objective to support internal market development by promoting competition, congestion management should best be totally non-transaction-based, concerning the responsibility of finding appropriate countermeasures as well as the allocation of the financial risk (cf. chapter 4). If one or more power exchanges covering all TSO areas existed, the market splitting approach like operated by Nordpool could be adopted, but realistically, this will not be the case in the near future. Even if there were power exchanges accessible by each market actor in each TSO area, this approach could still create problems if bilateral trade across the critical, possibly congested lines were allowed in addition to trade through the power exchange.

Therefore, redispatch or counter trading would have to be applied. Since these two approaches are very similar, only the counter trading option is further analyzed below because it does not require TSOs to have a right to change generators' dispatch, but only a right to trade. This appears more generally applicable.

However, this solution would not provide any incentives towards avoidance of congestion, and could evoke major problems in case of large and more or less permanent cases of congestion, because the involved TSOs would have to trade against the congestion permanently, thus creating extensive costs which could even be increased through strategic misuse by market actors, e. g. generators raising the prices of generating capacity that is frequently needed to relieve the congestion. In such cases, the question of congestion cost allocation would gain major importance. It is even conceivable that the measures of counter trading would not be sufficient in extreme cases to relieve the congestion, at all, at least in course of time when generating patterns change. (Today, theoretically, the available countermeasures *must* be sufficient if capacities are not „blocked“, because today’s dispatch is obviously feasible.)

For such cases, the transaction-based approach to congestion management would be much better because it forces the market actors to look for feasible solutions themselves, and thus to arrange their trades in accordance with existing transmission capacities.

While this can still not justify the *general* decision for a completely transaction-based congestion management concept for all types of congestion, which would appear unnecessarily restrictive, and be considered a barrier to trade by many involved parties (cf. chapter 8), such a concept might well be an acceptable solution for *„simple“* cases of congestion as defined in chapter 4.1.1. In these cases, the practicability problems of the transaction-based approach are considerably reduced, because the physical contribution of transactions to the congestion can be easily determined without any computation, thus requiring less detailed information, and the problem of prioritization can be avoided, for example, by sharing the congested capacities between all the involved market actors. In addition, very effective price signals towards relieving the congestion can be given by corresponding surcharges and discounts in such cases (cf. chapter 9.1.2.2). Finally, the revenues resulting from these charges could be used to finance necessary reinforcements to remove the bottlenecks.

It should be recognized that this would represent a kind of market splitting, too, but without involvement of a power exchange. The result would be practically the same, i. e. the subdivision of the market in two parts (for one bottleneck), between which a positive or negative transport charge is raised, such that, ideally, the bottleneck is always fully utilized, but not congested.

Technically, „simple“ cases of congestion can be identified as groups of congested lines that are more or less parallel, have the same power flow direction most of the time, and connect two parts of the interconnected system that are not or only weakly linked otherwise. Fortunately, many or even most of the critical cases of severe and permanent congestion seem to be such cases. From technical considerations and recent discussions, at least the borders between Spain and France and between Germany and Denmark as well as the Northern border of Italy represent (potentially) congested „system cuts“ of that kind, in addition to the DC links between the different interconnected systems, i e. between England and France and between Germany/Denmark and Denmark/Norway/Sweden.

Therefore, it appears reasonable to the authors to adopt different methods of congestion management for different kinds of congestion: the „simple“, severe cases could be handled in a transaction-based way, as outlined above, and counter trading could be the solution for all other cases that occur *within* the parts of the transmission system that are separated by the congested system cuts.

This requires, of course, a very careful investigation of potential „simple“ cases of congestion. The above list can only give some first hints. The definition of such bottlenecks would have to be revised periodically, in order to avoid *unnecessary* restrictions to the internal market. For the same reason, the number of bottlenecks treated this way should be as small as possible.

Within those parts of the interconnected systems where counter trading were intended to be practiced, covering „complex“ cases of congestion on borders between TSO areas as well as inside single areas, a high degree of cooperation between TSOs and harmonization of procedures would be necessary:

- Rules and the required infrastructure for exchange of data like generation plans and cross-border exchange balances would have to be established to give each TSO the chance to assess network security and to detect congestion within his system, and to avoid negative consequences of contract-path thinking.

- The selection of appropriate measures of counter trading would have to be coordinated at least bilaterally between each two neighbouring TSOs, and information on the available countermeasures would have to be spread. A central coordination should be tried to avoid at least in the beginning, until experience has been collected about if the federalistic approach is suited also for this task. The initial responsibility of seeking a solution by counter trading could be given the TSO in whose system congestion has been detected. However, clear rules about the right to make use of countermeasures in other systems would have to be provided.

- The allocation principles of the resulting congestion costs would have to be clarified. Logically, costs should *not* be allocated in a transaction-based way. In principle, the possible solutions to this issue are very similar to the allocation of transit costs, i. e. the „input side“ of an inter-TSO compensation scheme as described in chapter 9.1.2.3:

  – Full socialization towards all network users in the complete part of the interconnected system as defined by the „bottleneck cuts“, resulting in a very small surcharge without any price signal function.

– Partial individualization towards specific TSOs, resulting in surcharges for all of their connectees. In analogy to the compensation scheme for transit costs, the identification of TSOs whose local users have caused the congestion by cross-border trade could be based on the evaluation of physical flows or TSO-wise aggregates of transactions.

– Further individualization of costs from these TSOs towards either the generators or the consumers or even only the exporters or importers in their areas, resulting in possibly significant payments for these actors and accordingly strong incentives. This would however be questionable from the point of view of fairness, because few actors are allocated the complete financial risks associated with congestion.

Again, the selection of a cost allocation method requires weighing up between practicability, magnitude of financial burdens for single network users, fairness and the creation of price signals.

Recommendations for a transitional period

Realistically, the approach to congestion management outlined above cannot be implemented right away without considerable, time-consuming preparations. The development of the necessary rules and procedures requires extensive discussion and possibly contracts between TSOs, and the software and communication infrastructure for the required data exchange and the coordination of countermeasures must first be established.

Therefore, it appears unavoidable to accept, as a transitional solution, a more transaction-oriented treatment of congestion throughout at least the UCPTE interconnection. However, similar to transmission pricing, such a solution should under no circumstances be based on single transactions, but rather on aggregates of transactions defined by generators, suppliers or traders for each TSO area. Otherwise, practicability would be seriously affected.

If congestion is detected due to declared transactions, it should first be the TSO’s task to seek for reasonable solutions by countermeasures that are available to him, and to socialize the costs or to allocate them to all those actors who mainly contribute to the congestion. Only in case this is not succesful, a transaction should be refused or curtailed, and the reasons should be made transparent and verifiable to all involved parties. The procedures and deadlines for congestion management should as fast as possible be harmonized.

A sophisticated system for capacity reservations, however, does not appear desirable to develop because it would establish a concept that is not regarded appropriate for the long term. An important issue in this context that has already gained major public attention and must be clarified rather on a legal or political than on a technical level is the role of existing long-term contracts, associated with long-term transmission capacity reservations.

Especially for a transitional solution like this, the effort of the TSOs to develop rules for non-binding ATC values can clearly be welcome, because such values give market actors a chance to estimate themselves if a transaction may cause congestion or not.

9.5 Conclusions

This chapter summarizes the most important findings of the discussion in chapters 9.1 - 9.4 and the authors' main recommendations.

It is broadly agreed that the major part of the TSOs' network costs, including costs of ancillary services and a part of costs of losses, are recovered by TSO-specific transmission tariffs that are exclusively relevant to network users connected to the respective transmission system. They have no direct impact on cross-border transmission, because they apply either to individual network users in a non-transaction-based way, or to the „transaction“ between a network user and an appropriate location on the system boundary, if they are transaction-based.

The structure and magnitude of such tariffs are almost fully subject to subsidiarity. The desire of some market actors to move towards uniform tariffs throughout Europe is rather unrealistic, at least in the short and medium term. If necessary for creating economic signals, TSOs can even differentiate their tariffs according to location or time.

However, an aspect of considerable importance as regards the internal market development may be the *overall* impact of differences in the national tariff structures on competition. In particular, it appears desirable to harmonize the principles of cost allocation towards generation and consumption, in order to create a level playing field for all market actors. While a tendency can be observed to allocate major parts of the total costs towards consumption, the authors consider it reasonable to introduce at least small charges for generators, too, that can be used to give locational price signals. A *perfect* harmonization of the cost allocation principles is *not* realistic in the short term, due to practical difficulties, but is also not considered by the authors as crucial for market development as other aspects discussed below.

In addition to the national tariffs applied separately to each network user in case of cross-border transactions, practically all involved parties call for, or would at least accept, some concept of payments across borders, either as compensation payments on the TSO level or as transaction-based surcharges for cross-border trade, in order to satisfy the objectives of fair remuneration for costs of transits and loop flows, provision of economic signals towards efficient network utilization and avoidance of congestion, and fairness of cost allocation in terms of relation to distance of transactions. Out of the wide range of possible solutions for such payments or charges, the authors consider the following two approaches most reasonable and consistent under consideration of the general objectives of transmission pricing:

- Compensation for costs of transits and loop flows, plus the corresponding share of costs of losses, could be granted by payments on the TSO level, avoiding the introduction of transaction-based charges towards single market actors or aggregates of transactions. These payments could be recovered in various ways, differing mainly in the degree of socialization, for example by imposing a flat charge on all European network users, or by imposing a surcharge on the connectees of only those TSOs with net exports or net imports in their area, or even by imposing surcharges only on the involved exporters or importers. While socialization of course reduces the signal function of charges, individualization can appear unfair and imply critical barriers to trade.

  While this concept is very practicable and beneficial as regards market development, it is not able to provide path-oriented economic signals and distance-related cost allocation towards market actors.

- If the latter objectives are desired to be better satisfied, the interconnected system could be subdivided into tariff areas, supposedly in more or less accordance to the existing control areas, and surcharges could be imposed on transactions from each area to each other area, on the basis of aggregates of single transactions to be reported by each generator, supplier or trader for each area. These charges would have to be published in matrix form, for instance, to provide high transparency. This concept would allow to introduce, on an area-to-area basis, any form of charges to reflect distance-related transport costs, to collect payments for compensation of transiting TSOs or to give direct price signals towards relieve of congestion between areas.

An essential drawback of this approach is its higher demand of information, implying practicability problems especially for internationally operating traders and for international power exchanges in terms of reduced predictability of transmission charges. Moreover, the transaction charges would have to be fixed very carefully, because already small charges could seriously affect trading opportunities, jeopardizing the development of a true internal market.

It is also conceivable to combine certain features of these two approaches. For example, it appears reasonable to adopt mainly the first, non-transaction-based approach, but to include transaction-based surcharges (and discounts) on severe cases of congestion on area borders (see below). Similarly, area-to-area charges could be well suited to incorporate charges for DC links between different areas. Generally, it can well be accepted if DC links are treated separately from AC transmission systems because of their technical characteristics and their exceptionally high costs.

Whichever solution is actually chosen, the authors consider it crucially important to precisely harmonize any such payments or charges for cross-border transmission in terms of structure and magnitude as soon as possible.

As regards concepts for congestion management and allocation of the resulting costs, it is recommendable to distinguish between two kinds of congestion: the „simple“, but severe cases of permanently congested bottlenecks located on „system cuts“ where the physical contributions are easy to determine, and the „complex“ cases located somewhere inside the remaining parts of the interconnected systems, which are practically affected by each and every transaction throughout the system to a certain extent.

For the first kind of congestion, transaction-based procedures appear better suited than countermeasures like redispatch or counter trading, because the latter would compile extensive costs without setting out appropriate incentives to the involved actors. Such procedures could include declaration of (aggregates of) transactions across the bottlenecks, surcharges and discounts on transmission charges in dependence of the direction of a transaction, and, for example, proportional sharing of the limited capacities among the involved actors in case of actual congestion. The revenues from the surcharges could be used to finance network reinforcement to eliminate the bottlenecks. Of course, the number of cases treated like this should be as small as possible in order to prevent the market from being split in many submarkets.

The remaining type of congestion should better be handled by non-transaction-based measures, e. g. by counter trading, with the arising costs being more or less socialized among the market actors. This requires however close cooperation between TSOs in terms of data exchange, identification of congestion and of appropriate countermeasures, and agreements on allocation principles of congestion costs.

Since these coordination requirements can probably not be met right away without time-consuming preparations, arrangements of a more transaction-based kind appear necessary for a limited transitional period. Great emphasis should however be put on harmonized procedures as market-oriented and transparent as possible, with the TSOs being responsible to seek for counter trading solutions at least in their own areas, and with refusal or curtailment of transactions being only ultimate solutions.

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