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SECOND REPORT

TO THE COUNCIL AND THE EUROPEAN PARLIAMENT

ON HARMONISATION REQUIREMENTS

Directive 96/92/EC
concerning common rules for the internal market in electricity

(presented by the Commission)

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SUMMARY

I. Introduction

This report is the follow up to the first report[1] to the Council and the European Parliament on harmonisation requirements pursuant to Article 25 (1) of Directive 96/92/EC concerning common rules for the internal market in electricity[2] (hereinafter referred to as "electricity directive" or simply "the Directive"). According to Article 25, the first report had to be submitted within one year following the entry into force of the Directive on 19 February 1997. At that early stage of the two year implementation phase it was unclear which structural choices several Member States would take in order to implement the Directive. Based on the discussions with Member States at the biannual meetings of the "Follow-up Group for the implementation of the electricity directive", the Commission identified the issue of promotion of renewables as the main focus of the first report on harmonisation requirements. However, the Commission was already aware that there might be several other areas, which are not specifically addressed by the Directive, but nevertheless might require harmonisation or at least which deserve regulatory attention to guarantee the proper and efficient functioning of the internal electricity market.

In this light, the Commission proposed that there should be not one report on harmonisation requirements, but that at least a second report would be drafted in the light of experience after finalisation of the implementation at national level of the Directive. This approach had been supported by the Council.

It is the objective of this second report to draw the attention of the Council and the European Parliament to a wide range of already existing or expected obstacles within the single market of electricity. This report is structured in three parts.

The first part deals with the need to ensure that the implementation of the electricity directive does not result in 15 liberalised but separate and rather isolated electricity markets, thereby failing to create one common market. It is the creation of one common market which is expected to produce the benefits from synergies, scale economies and shared resources throughout the EU. Thus, obstacles to the cross-border trade of electricity among Member States have to be actively addressed. This report therefore focuses on three issues, first the availability of transmission capacity over the interconnectors between Member States, second, the necessity to establish a system of non prohibitive, but rather trade facilitating, crossborder transmission tarification, and, third, the issue of crossborder exchanges of electricity with third countries.

The second part of this report discusses whether there is a need for regulation of the electricity network at the European level, in particular in order to address the cross-border issues discussed in part one.

Part three considers the necessity to ensure a level playing field on the EU internal market for electricity, addressing therefore, structural issues that might lead to important distortions of the conditions of competition between Member States. To a large extent

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[1] COM(1998) 167 final, 16.3.1998
[2] OJ N° L27/20, 30.1.1997

this will be achieved through the application of the competition rules of each Member State and those of the Community. However, some areas might create structural distortions, which cannot be tackled by the competition rules alone. The present report examines three such areas, without prejudice that there might exist an even wider field of problems. The issues covered in this report are environmental standards in electricity generation, accounting standards for nuclear decommissioning, and taxation. The main issue raised in this respect is whether the different standards in each Member State, which were acceptable in times of monopolistic electricity generation prior to the electricity directive, have become too heterogeneous in the light of competition after liberalisation.

The issue of the preceding report, namely the promotion schemes for renewable based electricity production, is not further examined in this report, as the discussion that followed the report has already led to a series of concrete follow-up actions which are continuing at present.

This report does not intend to draw final conclusions on the issues raised. It does not claim to be exhaustive in the selection of questions, nor to cover all aspects of the issues discussed. The questions addressed by this report are so far reaching that the following chapters can only draw the attention to the problems and, in some cases, indicate some first lines of reflection. Concrete follow-up of the individual issues raised will be decided upon by the Commission in the light of the outcome of the subsequent discussions with the Council and the European Parliament, and comments received from interested parties in response to this document.

II. Obstacles for cross-border trade of electricity

Although the electricity directive does not cover specific rules for cross border transactions, it cannot be concluded that this issue can be solved by relying exclusively on national measures. On the contrary, only through joint action at the Community level can the problems raised in this area be adequately addressed. It was in the logic of a gradual approach to implementing the internal electricity market that specific issues have to be addressed after the principal strategic implementation choices have been made by the Member States. This is also the raison d'être for Article 25 of the Directive, on which this report is based.

The issue of cross-border transmission tarification and other possible obstacles to free and effective trade have already been the subject of active preparatory work by the Commission. To-date the following actions have been undertaken:

- The Commission raised its concern about the functioning of cross border exchanges at the 3rd meeting of the follow-up up group for the implementation of the electricity directive on 13/14 May 1998. In parallel, the Commission and the Council presidency created the European Regulation Forum in Florence, which has already convened twice, in February and in October 1998. At these meetings, available interconnector capacity and crossborder transmission pricing have been recognised as key issues, for which an adequate solution is a prerequisite for the functioning of a real single market in electricity. It had been agreed to encourage the independent transmission system operators (TSOs) to coordinate their actions via a new representative association of all independent European TSOs, and to develop an adequate system of crossborder tarification and settlement in the light of the development of the competitive internal electricity market. It was agreed that the Commission support this process by inviting the independent transmission system operators for a coordination meeting in Brussels, which took place on the 21 January 1999.

- At that meeting, the TSOs in coordination with EURELECTRIC, the official representative of the EU electricity industry including production and distribution, presented their commitment to create a European Association of TSOs (ETSOA). It is intended that by July 1999 this representative body will be established, first as an association of the already existing grid associations UCPTE, NORDEL and the British and Irish grid systems.

- A working group of UCPTE, NORDEL, British NGC and Irish Grid presented a draft paper on their proposals for rules for International exchanges of electricity.[3] This draft proposal has been submitted to the Energy Consultative Committee for discussion, and has been forwarded to national governments, regulators, and has been made generally available.

- Furthermore, the Commission has launched an independent study on cross-border electricity transmission tariffs in order to evaluate the different proposals, including the above mentioned draft proposal of the TSOs. The final report is expected for May 1999; interim results of the study have already been taken into account for the analysis in this report.

Evidently, the issue of crossborder electricity trade does not only concern electricity exchanges between Member States, but also electricity trade with third countries. A harmonised approach to access rules for electricity from third countries is of key importance in the light of the common commercial policy and the related international obligations of the EU. The issue deserves careful and urgent clarification, as important non-EU potential electricity exporters and transit countries are already engaged in electricity commerce with the EU and may, in due course, request full and non-discriminatory market access including the right to directly supply eligible customers through network access, introduced by the electricity directive.

1. Available interconnector capacity

1.1. Introduction

[3] draft "International Exchanges of Electricity - Rules proposed by the European Transmission System Operators", 14.1.1999

Interconnectors are the bridges between the national or, in some cases, regional electricity systems. They are of critical importance for the single electricity market, as the capacity of these interconnectors will often not be sufficient for the expected increasing power trade after liberalisation. Thus, interconnectors tend to be in many cases bottlenecks of the European transmission system. Moreover, in contrast to "normal" bottlenecks within the territory of one TSO, interconnectors involve by definition two TSOs. In order to ensure an economically optimal usage of available capacity, as well as fair and non-discriminatory access for all system users, a new level of coordination between the TSOs needs to be established. In the past, trade over these interconnectors has only taken place between mostly vertically integrated TSOs for their own commercial interest. Trade was either used as a guarantee mechanism for the purposes of reserve, e.g. within the continental European UCPTE system, or was based on long term power purchase contracts between the vertically integrated TSOs. After entry into full application of the electricity Directive in 19 February 1999, TSOs have to be managed as independent entities, unbundled at least in management terms from any commercial interests in generation, trade or supply of electricity. Thus, reservation of capacity for long-term contracts will compete with short-term needs for the transactions of eligible customers and traders. In the absence of sufficient interconnector capacity and if the allocation rules are not harmonised, or at least to a high degree compatible, consumers will be confronted with higher costs and more refusals of network access then would be justified by the real physical constraints. The electricity directive does not set specific rules, neither for the management of scarce interconnection capacity nor for the development of new interconnection lines. Thus, this chapter contemplates whether there is the need for further harmonisation requirements to address the following set of questions:

1.2. The management of existing interconnection capacity:

How can available transmission capacity (ATC) be maximised in the short run?

What are fair and non-discriminatory rules for allocating scarce transmission capacity?

How should TSOs deal with long term capacity reservations arising from long term power purchase contracts, in particular those concluded by themselves prior to the entry into force of the Directive?

1.3. Encouraging the construction of new interconnection capacity.

How can it be ensured that the system creates sufficient incentive for building new interconnection lines in the light of the increased needs of the single market for electricity?

How can it be ensured that economically correct price signals for the use of scarce interconnection capacity are given to system users?

These questions are examined in sections 1.2 – 1.3 below. Conclusions drawn from this examination are contained in section 1.4.

1.2. The management of existing cross-border interconnector capacity

The electricity directive states in Article 8(1): *The transmission system operator shall be responsible for dispatching the generating installations in its area and for determining the use of interconnectors with other systems.*

In the light of this basic responsibility, it is expected that the TSO will assume the following tasks and operating principles:

1.2.1. Maximising available transmission capacity

Pursuant to Articles 17(5) and 18(4) of the Directive, requests for network access may only be refused on grounds of lack of transmission or distribution capacity (apart from clearly defined situations relating to public service obligations or reciprocity). It has always been understood that "lack of capacity" in this respect refers to lack of physical capacity. Unjustified contractual blocking[4] or insufficient capacity due to a lack of coordination efforts between neighbouring TSOs do not, in principle, justify refusal of access. In other words, a duty exists on the TSO to ensure that interconnections are used in the most efficient possible manner.

One of the most effective ways to maximise available transmission capacity is to "off-set" counterdirected transmission requests[5]. To this effect, TSOs must cooperate in a way to superimpose counterdirected transmission requests. Only the resultant overall physical flow can cause congestion and a possible refusal of access. Thus, by deduction, any transmission constraint can only exist for transmission in the congested direction, as counterdirected flows over the same bottleneck free up capacity and reduce transmission losses. This consideration is examined in detail below in chapter 2.5. with regard to congestion pricing.

Whereas coordination in form of simple superposition of counterdirected flows should not produce any significant additional costs, remaining bottlenecks could further be freed up through coordinated redispatching, countertrading or market splitting (in case of spot markets)[6] by the TSO, however, thereby producing additional costs. Nonetheless, as TSOs should be able and entitled to pass on these costs to the network users, economic theory and existing practice, e.g. in Scandinavia, suggest that the TSOs should engage in such redispatching or countertrading measures, thereby increasing overall synergies of the common market.

1.2.2. Fair and non discriminatory allocation of scarce transmission capacity

Article 8(2) of the Directive states that "... *the use of interconnectors shall be determined on the basis of criteria which may be approved by the Member State and*

[4] see below 1.2.3.

[5] see annex for definition.

[6] see annex for definitions.

which must be objective, published and applied in a non-discriminatory manner which ensures the proper functioning of the internal market in electricity."

It has been outlined above that a system could and should be set up, comparable to the Scandinavian practice, which avoids curtailing or refusing single transaction requests through measures taken by TSOs, such as redispatching of generation plants, countertrading, or market splitting on either side of a bottleneck.

However, it must be acknowledged that such a system might not be realised in the very near future and that even then, some severe bottlenecks (often referred to as "flowgates") may persist due to net flow in one direction exceeding the capacity of the interconnector in question. This would make it necessary to limit or refuse transmission requests until additional interconnections capacity could be constructed.

In such cases several approaches to rationing limited capacity can be distinguished:

- first come first serve: if capacity limit is reached no more requests are accepted;

- pro rata rationing: all requested transactions are carried out but each transaction quantity is cut by the same percentage;

- merit order: based on giving up confidentiality, the cheapest kWh transactions are prioritised;

- renewable priority: transactions originating from a renewable based electricity source are given priority;

- bidding or auctioning for scarce capacity.

Within the scope of this report it is not intended to analyse and evaluate each of these mechanisms according to criteria such as non-discrimination, efficiency and trade encouragement. It is, however, easy perceivable that a substantial obstacle to trade would exist, when at a given interconnector Member State A applied "first come first serve" whereas Member State B applied e.g. "pro rata rationing with renewable priority". Thus, a minimum of coordination or harmonisation among the TSOs of the different Member States is crucial. It appears clear case that some form of Community action may be necessary to ensure a satisfactory solution of this cross-border problem.

1.2.3. Long term reservation of transmission capacity

A particular problem in the context of allocation of transmission capacity is the issue of long term reservation of transmission capacity. Long term reservations have the potential to exclude other market participants from using interconnectors for their imports of electricity. The problem becomes even more sensitive if the TSO is part of a vertically integrated company which itself benefits from a long term electricity purchase or selling contract for which it claims the necessity of long term capacity reservation.

(1) The evaluation of capacity reservation agreements

The starting point of any such analysis is the question whether there is a need to combine firm electricity supply or purchase contracts with a reservation of corresponding transmission capacity. Indeed, it could be argued that such a capacity reservation is not necessary to ensure that the parties of an electricity purchase contract can at any time fulfil their contractual obligations. In the event of insufficient transmission capacity, the seller could, for example, simply buy the quantities that it can not transmit over the bottleneck at the market on the customer's side of the bottleneck. The additional costs incurred by such a measure would theoretically be the same as if the TSO would auction the interconnector capacity.

Moreover, with regard to the overall volume, the transmission market is clearly subordinated to the generation market. Transmission has, thus, a supportive or arbitrage function in order to contribute to the optimisation of the generation market. The TSOs which are, usually, at the same time responsible for dispatching of generation and for allocating transmission capacity, are in the best position to optimise the transmission market as a function of the optimisation in the generation market. In order to provide for a maximum of flexibility, reservation of transmission capacity should be avoided as far as possible. In particular at the current stage of early development of a European market for electricity it appears premature to permit speculation with irrevocable transmission rights. This could undermine the coordination role of the TSO, and could create the blockage of significant transmission capacity. Market players could purchase capacities at strategic bottlenecks and withhold and thus block this capacity, e.g. to bid up the value of the transmission right, or simply to prevent competitors or new market entrants from using the line.

Agreements between undertakings which may affect trade between Member States and which have as their object or effect to prevent, restrict or distort competition within the common market are prohibited under Article 85 EC Treaty. Furthermore, any abuse by an undertaking of a dominant position in a substantial part of the common market is prohibited under Article 86 EC Treaty.

The Commission will enforce these provisions where necessary in order to warrant a smooth functioning of the internal market in electricity. It will examine the contracts governing the use of interconnectors with a view to evaluate to what extent these restrict competition within the meaning of Articles 85 or 86. In doing so the Commission will apply the general principles for the assessment of vertical restrains of competition.

The following parameters will be important for the analysis of the transmission market in question:

- the share of the contracted capacity in relation to the relevant overall available interconnector capacity for electricity imports

- the extent to which the capacity of the relevant interconnectors is reserved for exclusive use by one or several parties

- the extent to which the capacity is reserved long-term

- the duration of any such reservation

- whether there exists congestion

- the procedure adopted by the owner of the capacity when attributing it

- the impact of a capacity constraint on the supply markets connected by the link. Particular attention will be paid, for example, to cases where an interconnector constitutes the sole available transmission opportunity towards any given market on which competition is already limited (for example, markets with a monopolistic supply structure).

The fact that the Commission intends to carry out an assessment of the contracts governing the use of interconnectors does, of course, not mean that all capacity reservation agreements restricting competition are illegal. Indeed, the Commission is fully aware of the fact that the conclusion of capacity reservation agreements may be indispensable for example in order to make the construction of a new interconnector at all feasible.

The Commission will for the time being assess contracts on a case-by-case basis and take adequate measures in order to fulfil the objectives of the Treaty and the Directive. These measures will help provide guidance to the operators as to the compatibility of capacity reservation agreements with the rules applicable.

(2) Potential solutions

It is not the intention of the Commission to set out already now precise guidelines as to capacity reservation agreements.

However, experience in other countries and in other markets has shown that there exist several options which could lead to a better "liquidity" of the transmission market than the current transaction-based approach.

In this respect it appears appropriate to underline the difficulty of accepting capacity reservation more restrictive than in terms of "priority rights". This is also referred to as a "use it or loose it" rule for capacity reservations or simply as a prohibition for withholding capacity. In practise the holder of such a long-term priority reservation has to notify, e.g. 24 hours in advance, whether it will use the reserved capacity. Thus, the capacity portion which it does not use increases the short-term available transmission capacity for spotmarket transactions of other network users. Such a rule is practised in the Scandinavian Nordpool. This approach is also shared by most of the OECD regulators, such those of the US or Australia.

It appears appropriate that any such priority reservations should become transparent for regulators and in an adequate form, taking account of confidential business data, also for the remaining market participants, in order to improve their knowledge about critical bottlenecks. Such reservation data, aggregated in categories according to different terms, including short-term indication of unused reservation, should be listed in a transparent register, accessible to all market participants, using appropriate online technologies.

On the basis of such a register or matrix, any eligible consumer, supplier or trader could receive information whether a transaction from TSO X to any other TSO might face a constraint and therefore potentially create additional costs.

In the US, an Internet based "open access same time information system" (OASIS) has been established. It constantly publishes the available transmission capacities and, thus, allows for a transparent and non-discriminatory approach to capacity reservation, allocation and pricing for strategic interconnector bottlenecks.

connection point of generator/supplier in:

customer

delivery from: to:	TSO 1	TSO 2	TSO 3	TSO n
TSO 1		- total capacity - reservations - unused reservations	- total capacity - reservations - unused reservations	- total capacity - reservations - unused reservations
TSO 2	- total capacity - reservations - unused reservations		- total capacity - reservations - unused reservations	- total capacity - reservations - unused reservations
TSO 3	- total capacity - reservations - unused reservations	- total capacity - reservations - unused reservations		- total capacity - reservations - unused reservations
TSO n	- total capacity - reservations - unused reservations	- total capacity - reservations - unused reservations	- total capacity - reservations - unused reservations	

1.3. Encouraging the construction of new interconnection capacity

The importance which the Commission attaches to the further development of strategic electricity interconnectors is based on the identification of such interconnector projects in the light of the objectives of the EU transeuropean network policy, established in Article 129b-d of the Treaty. Article 129b mentions as explicit objectives, amongst others, the promotion of an open, competitive market, the interoperability of national networks and the principle of network access.

Article 2.10 of the electricity directive defines that *"'interconnectors' shall mean equipment used to link electricity systems"*. For the following point it is, however, useful to distinguish between (1) interconnectors which are pure connection points between two existing neighbouring systems, and (2) interconnectors which represent a proper physical line, e.g. submarine cables, and which are often constructed and financed as separate projects or joint ventures. Most of the reflections of this chapter apply to investment intensive interconnector projects, thus dealing with interconnectors that represent a significant physical cable in itself.

1.3.1. Respecting unbundling

Because of the existence of monopolistic supply areas until recent years, the often vertically integrated electricity companies had only limited interest in building significant interconnection lines. If, nevertheless, important line projects were built, they were often connected to long term electricity supply contracts.

Article 7(6) of the Directive introduces the unbundling of management by requiring the TSO to be independent at least in management terms, from other activities of a vertically integrated electricity undertaking, such as generation and distribution. Article 7(5) requires that *the TSO may not "discriminate between system users or classes of system users, particularly in favour of its subsidiaries or shareholders."* Article 14 of the Directive introduces the requirement to separate the accounts according to generation, transmission, distribution and other activities.

Therefore, the light of these unbundling obligations, one has to strictly differentiate whether an interconnector, and indeed any other transmission line is built in the interest and on the account of the independent TSO or in the interest and on the account of a producer or distributor. It could probably infringe Article 7(5) and 7(6) of the Directive, if the independent TSO built an interconnector line in order to realize the benefits from a potential electricity supply opportunity.

Thus, there might be concern that either a TSO in such circumstances would not act independently and favour commercial interests of its vertically integrated activities or, otherwise, that not enough capital will be found to invest in important interconnector capacity of benefit to competitors of the vertically integrated company. The concern does not appear justified, as the Directive does not undermine the possibility for any line constructor or operator to recover the full costs of its investment through adequate transmission fees. However, the investment decision to construct a new interconnector may, in an "unbundled world", either originate in the transmission service interest of the TSO itself, thereby amortising the line purely through transmission fees, or in the electricity trade interest of a producer or distributor, thereby at least partly amortising the line through trade margins. Thus, if a vertically integrated company at the same time constructs an interconnector line and pursues a commercial interest via selling or buying electricity over this line, particular regulatory attention has to be dedicated to the correct unbundling of accounts, i.e. the correct distribution of investment costs to revenue from electricity trading and to revenue from transmission fees.

1.3.2. Direct lines

Under the rules of the electricity directive it is not just possible that new interconnectors are built as part of the TSO system, but also as direct line according to Article 21. This raises concerns about the coordination with the TSO system, in particular with regard to non-discriminatory access.

Necessarily, one has to differentiate between two types of direct lines. First, those in the narrow sense of Article 21, namely those connecting producers or suppliers with subsidiaries or eligible customers. Typically such a line would only have one connection point to the interconnected system, the second end point being a power plant or a consumer.[7] In that case third parties cannot use the line for other purposes than direct supply contracts with the direct line owner. In these cases network access and remuneration questions are not of general interest.

Second, however, one could imagine that an interconnector project, connecting two TSO systems, could be legally structured as a direct line. For example, the generating or sales parts of a vertically integrated company might build a direct line to a distribution company within another TSO area. The distributor may be a subsidiary of the vertically integrated company – being the purchaser in the sense of Article 21 of the Directive, and having, therefore, the right to build a direct line. In that case, the direct line would, indeed be an interconnector, being itself connected at both ends to interconnected systems. Such a line can potentially be used by third parties. As the Directive does not provide for any exception from the obligation to grant access to the interconnected network, non-discriminatory access to third parties has to be given. Equally, the rules of Article 14 of the Directive concerning the unbundling of accounts would have to be respected by a vertically integrated company, engaging in such an interconnection construction. Even if the construction interest originated in the production or distribution activity, it would appear logical to attribute the interconnector to the transmission activity.

1.4. Conclusion

From the above analysis the following preliminary conclusions can be drawn:

- Transparency of available transmission capacity between the TSOs is of key importance. To provide all market participants with the data they need to plan their transactions and to avoid discrimination, an information system should be established by the European TSOs.

- For the short term allocation of bottlenecks, rationing or auctioning mechanisms are envisagable, with a clearly identified need to harmonise the allocation rule, on both sides of each interconnector.

- Long term reservation of transmission capacity should be regulated and restricted to the right of priority use of the line with the obligation to make unused capacity available to the short term market.

- In order to encourage the construction of new interconnector lines, or the reinforcement of transit lines, it could be necessary to provide for timely limited exceptions from the general rules under case by case regulatory control. This could

[7] It is also possible that an eligible customer, which is already connected to a supplier, builds a second line to another supplier as a direct line. In such a case access for a third party could be imaginable.

allow for ship or pay contracts or for specific toll-routes, comparable to the highway system. This being said, it must be maintained that any new line, irrespective whether constructed as part of the TSO's system or as direct line according to Article 21 of the Directive, is fully subject to the principle of third party access, as soon as it is connected to the interconnected system.

A two level approach can be considered in order to implement these conclusions:

(1) Issues such as discriminatory allocation of interconnector capacity as well as long term capacity reservation over interconnectors will have to be addressed by the Commission pursuant to the competition rules in close collaboration with national regulators to on a case by case basis. If necessary, supportive published guidelines might be developed.

(2) A more formal approach, which could cover redispatching and flow superposition rules for crossborder exchanges as well as the publication and transparency rules for available interconnector capacity might be envisaged through amendments of the price transparency directive 90/377/EEC and the transit directive 90/547/EEC. The price transparency directive could include the transparency requirements concerning available transmission capacity as well as transmission fees (see next chapter). Concerning the allocation rules for interconnection capacity, including priority rules and regulatory control of exceptions, an amendment of the transit directive could be the adequate platform. Alternatively, as both the price transparency and the transit directive became in some respects obsolete after the adoption of the electricity directive 92/96/EC, they could both be replaced with one new directive concerning open access rules.
At present, the Commission has reached no concrete conclusions on these possible approaches. This will be determined in the light of the comments received on this report, notably from the Council and the European Parliament.

2. Cross-border tarification and settlement

2.1. Introduction

Although the implementation phase of the electricity directive has expired on 19 February 1999, and whilst most Member States[8] have, indeed, implemented the directive, and although transmission capacity is physically available, for most eligible customers it is in fact organisationally and economically difficult to choose a supplier situated in another Member State, in particular if a third or forth Member State has to be transited. The reason for this is simple: there is no tariff framework for crossborder transactions. Each transaction has to be negotiated, and each concerned TSO will require a transmission fee, which is not necessarily coordinated with the transmission fees already payable to other TSO. Thus, the sum of all required transmission fees will

[8] According to Article 27(2) Ireland and Belgium have been granted a one year, Greece a two year supplementary period for implementation. (see brochure)

in most cases add up to a prohibitive amount, making it cheaper for the customer to stick with the local supplier. This is referred to as full or partial "pancaking".

It has to be recalled, at this point, that the physical flows of electricity do not follow contractual flows, particularly in the highly meshed network of continental Europe. It is, thus, an organisational challenge to create, on the one hand, a simple crossborder tarification system which encourages eligible customers to take advantage of the single market, complemented, on the other hand, with a settlement or clearing system among the TSOs, which allows them to redistribute the tariff revenues according to physically metered flows and according to complex intra TSO rules which do not have to concern the customers. Certainly, such a degree of coordination requires TSOs to be independent of the interests of production and commercial trading activities. It requires appropriate structures and commonly accepted rules.

At the current state of discussion, the key issues to be solved are:

- to reach an understanding which costs may be recovered in the access fees,
- to reach a conclusion with respect to nodal pricing vs. transaction related pricing,
- to agree on a pricing policy that does not involve "pancaking",
- to agree on a pricing policy for congestion.

2.2. Cost reflectiveness and other general pricing principles

(1) To promote the benefits of the single electricity market, network access fees should be transparent, simple, based rather on variable kWh than on fixed capacity payments[9] and as far as possible non-transaction based, in order to be compatible with spot-market and trading activities.

(2) Moreover, and most importantly, they should be globally cost reflective as TSOs have a natural monopoly. The commonly recognised conflict between the first mentioned principles leading to a simple and transparent approach, and the objective of cost reflectiveness, can be solved with a two level approach. On a first level, the overall cost base can be translated into simplified, ex ante defined, postage stamp oriented tariffs, established under regulatory control. On a second level, physical flow related, ex post measured and thus most possible cost reflective settlement can take place between the TSOs in order to compensate inaccuracies and a possibly unfair revenue distribution arising from the simplified ex ante tariffs collected from customers and generators. Clearly, such an approach needs regular feedback and flexible adaptation of the ex-ante tariffs according to the deviations measured in the settlement exercise.

[9] Perhaps, however, subject to the possibility of fixed capacity payments on a short-term basis.

(3) The cost base for the global amount of collected transmission fees of any TSO must be derived exclusively and in a verifiable manner from the accounts of the transmission activity, properly unbundled according to Article 14 of the Directive.

(4) Stranded costs relating to Article 24 of the Directive and costs of domestic public service obligations may only be charged to domestic consumers. The cost base for crossborder elements of transmission fees should exclude stranded costs or costs of ancillary services or public service obligations that are not directly related to the transmission service itself. Such costs should be invoiced as a transparent and separate item and may not affect transiting transmissions.[10]

(5) Transmission fees have to be determined **ex ante**, based on transparent assumptions concerning transmission quantities. Actual revenue from transmission equals ex-ante determined transmission fees multiplied by actually executed transmission quantities for any transaction based tariff elements. If, due to higher than estimated transmission quantities, the annual revenue exceeds the unbundled costs of the transmission activity, the transmission fees have to be adjusted.

Under regulatory control, a certain share of such a surplus could be left as profit to the TSO in order to give an incentive to manage higher transmission amounts than originally planned.

2.3. Non transaction based pricing versus transaction based pricing

Any charges on cross-border transmission must, as discussed above, be globally related to cost. As mentioned above, physical flows not only do not follow contract paths, in fact they bear little relation to distance in an highly meshed network, which according to economic models and studies should rather be compared with a common lake to which some add water and others take out water. It is irrelevant in terms of cost in such circumstances, whether the one who takes water from the lake (or electricity grid) is situated close to the one who puts water (or electricity) in, or is situated on the other side of the lake (or electricity grid). Thus, in order to calculate the transit cost of electricity, it is not possible to base calculations on contract flows, but on the actual costs incurred in carrying out the resultant physical flow.

Based on this generally low correlation between contract path and physical flow, the concept of non-transaction related (also "nodal tarification" or "connection point tarification") is increasingly being developed in contrast to transaction oriented approaches and is becoming increasingly accepted as an industry standard.

Transaction based tariffs require the network users to notify feed in point and consumption point for each concluded transaction. The transmission fee can then be calculated for each individual transaction according to distance oriented or contract path models. Non transaction based, or nodal tariff systems recover the network costs exclusively through connection or access charges for consumers and producers. The

[10] In normal circumstances, such changes should be levied only at one level, eg final customers

access fee does not change with the change of contract partner. Thus, the access fee gives an individual network user the right to buy or sell electricity to or from any other user within the system. This reflects the above picture of the lake, where the access price does not depend on the location from where water is being taken.

Non transaction based, nodal tariff systems, have clear advantages with respect to simplicity and easy for customers to change their supplier. Any gain of cost reflectiveness from transaction related systems is in reality questionable as shown by the above reflections. Furthermore, the disadvantage of transaction based systems lies clearly in the difficulty to combine such a system with power exchanges and spotmarket based systems.

A combination of a generally non-transaction based system with certain transaction-based passages could be imaginable for exceptional cases, if these transaction based passages are congested "flowgates" (see below 2.5) and if the additional information requested by the transaction based passage is limited to the minimum necessary.

2.4. Transit pricing without "pancaking"

At the meeting of the Regulators in Florence in October 1998, a price formula has been presented which aimed at avoiding the problem of cumulating national transmission fees when transmitting over several TSO areas ("pancaking").

Total transaction cost $T = a_1T_1 + a_2T_2 + ... + a_nT_n$

T_1 to T_n represent the full postage stamp tariff for one TSO, representing the full cost of the national transmission network. The coefficients a_1 to a_n are weighing coefficients, which take into account that in a crossborder transmission each TSO should only be allowed to charge for part of its total system costs in order to avoid pancaking. This is because even if electricity contractually (rather than physically) passes between two, three, or four networks, the real costs of transit bear no relation to the total transmission tariffs of all TSOs. The analogy of the lake is relevant in this respect.

Thus if the sum of the weighting coefficients a_1, a_2, to a_n were not allowed to be higher than 1, pancaking would be effectively avoided. However, full cost covering could not be guaranteed to TSO unless they effectively calculate compensation payments amongst each other to ensure that each TSO receives the appropriate part of overall tariff.

In January 1999, the European TSOs presented a proposal which modified the formula, insofar, as

Total transaction cost $T = G_1 + (T_1k_1 + ... + T_nk_n) + L_n$

G_1 would represent the share of the total TSO1 costs charged by TSO1 to the generator (source of the transaction) in its area, e.g. through a connection fee or postage stamp. L_n represents the respective partial fee for the consumer in the area of TSOn. The bracket term indicates partial transit elements T[11], weighted with a coefficient k if more than one TSO is concerned with physical transit flows.

The capping condition has been altered as it stipulates that each TSO must separate its total transmission fee in a generator connection element G, a consumer load connection element L and a transit element T, whereas the sum of G+T+L must not be higher that the total TSO costs.

Clearly, this approach leads to full cost recovery for each TSO. However, if this formula were directly applied towards the customers, it would lead to a "shallow pancaking", as the total fee will increase with each additional transit element T.

The presented approach leaves, however, three possibilities for application:

(1) to apply the formula to each individual transaction, based on individual flow simulations for assessing the transit elements;

(2) to apply the formula globally but still directly to customers, determining ex ante a fixed global postage stamp for the transit elements, settling ex post differences between TSOs;

(3) to apply the formula only for the inter TSO settlement, charging only connection fees to the customers (which may be higher because these connection charges include the inter TSO compensation payments to the transit networks).

Ad 1) The first option is clearly transaction oriented. Without ex ante available postage stamp tariffs for transit area, it is difficult for consumers to compare different offers from different suppliers. Thus it would not contribute to market transparency and discrimination would be difficult to control. It might significantly encumber the development of spot markets, which require the maximum possible non-transaction oriented approach

Ad 2) The focus of the discussion should be centred between the options 2 and 3. From the customers point of view any transit element, thus also case 2, represents at least a "shallow pancaking" as it results in a higher price for a transaction which passes over transit networks compared to a transaction of equal distance and network loss generation which would be situated in one TSO area only.

The question, therefore, is in which cases it could be economically and politically preferable not to rely on inter TSO compensation for transits but on direct recovery from network users, thereby jeopardising the nodal pricing approach with transaction based elements. This question must be answered from a cost perspective as well as from a European pricing policy perspective.

From a cost perspective, some argue that even if no physical transit flows result from cross-border contractual flows, there are costs of coordination and administration[12].

[11] Including T elements in areas of the generator and customer.

Furthermore, if an overall physical transit flow results, the transited network has a right to charge a part of its network costs to transits and so to finance a part of the infrastructure cost burden from their local network users. Thus, it is arguable that such transit elements should be charged directly to the customer as they reflect the actual cost distribution between TSO.

From a price policy perspective, any additional transit fee is comparable with a distance related pricing approach, which, according to model simulations, can hardly be justified, at least not for small and medium sized transactions. Option 2, thus, does not follow the above quoted idea of the common lake. Only, if the transited network is congested because of the transiting transactions, a price signal, direction sensitive, makes economic sense. This is further discussed in the next chapter.

Ad 3) Thus, whereas it is fully recognised that transited networks are entitled to receive cost recovery from transits, there are strong grounds to argue that this should be accomplished at the level of inter TSO compensation payments. Only if the transits contribute to congestion or if the transits should openly pay for the construction of transit or interconnector lines (see 1.3.2.) an ex ante determined global transit postage stamp, possibly direction oriented, may be justified.

Any such ex ante calculation of the proportion of this transit postage stamp in relation to the domestic "connection stamps" must be based on transparent, objective and verifiable criteria, e.g. net physical transit flows in relation to locally connected generation and consumption capacity.

2.5. Congestion pricing

Pricing for congestion is closely related to the allocation rules for available transmission capacity. The fundamental question is whether to refuse access and thus to curtail transmission if the physical capacity limit is reached or whether to establish a bidding or pricing system for situations where transmission capacity becomes scarce. The refusal of access approach has the disadvantage that it requires the identification of specific transactions and that it might not be the least discriminatory way to allocate the capacity.

If it is sought to avoid refusal of access, redispatching, countertrading or auctioning mechanisms will create specific costs reflecting the differential cost of electricity on either side of the congestion. In theory all mechanisms should produce the same cost result.

The exact costs can only be charged *ex post* based on the measured costs of countertrade or redispatch or outcome of auctionings. However, *ex ante* predictions of these costs on the basis of the published ATC information should be provided for. As a general principle, the consumer should always have the choice between paying these extra costs of congestion resolution or rather accepting a refusal of the transmission.

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[12] Which are, however, low compared to total network costs.

Experience from the Nordpool suggests that the costs of congestion resolution do not even reach 1%[13] of the total transmission costs (infrastructure costs). Thus, the actual cost impact of the system chosen is limited and emphasis should be put on a simple and trade encouraging approach.

Consequently, in general, it does not appear sensible to permit ex ante congestion avoiding price signals which would break the principle of cost reflective and cost capped transmission fees. This would complicate the administrative and regulatory control and possible interfere with subsidiarity regarding national approaches to price regulation.

However, for specific severe predominantly **one directional** bottlenecks, a transparent and non-discriminatory *ex ante* congestion fee could be acceptable in order to avoid the curtailing of transactions. Logically, counterdirected transactions, which open up new capacity and reduce transmission losses should receive a price incentive, e.g. a reimbursement for avoided costs. Any overall proceeds from such fees (or auctionings) must be separated from the TSO cost recovery and put into a ring-fenced fund, which is, e.g. earmarked for construction of interconnection reinforcements[14].

For the financing of specific interconnector projects, such as submarine cables or specific transit cables, a separate transaction oriented "toll" could be acceptable (comparable to specific road traffic passages such as tunnels or bridges).

Clearly, the analysis shows that there are several reasonable approaches to the congestion problem. It is exactly this variety of choices, which makes harmonisation or coordination indispensable. Both TSOs on either side of a congested interconnector need to apply compatible approaches. Otherwise many transactions could be unnecessarily be refused, not on grounds of lack of capacity but simply caused by poor coordination.

2.6. Conclusions

It is important to reach a rapid solution for the problem of cross border tarification as this seems to remain the major obstacle for exchanges within the internal market in electricity. Particular harmonisation requirements have been identified with regard to an agreement on the transit element as well as on congestion pricing for severe bottlenecks or "flowgates". The reflections suggested that a non transaction-based nodal tarification system, which relies to a maximum on inter TSO compensation and settlement in order to facilitate trade between eligible customers, producers, suppliers and traders, providing therefore for a tariff level applicable to customers and a settlement level allowing for clearing among TSOs, would have several advantages:

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[13] However, a figure of 0.1 % is more typical, e.g. in Sweden.

[14] However, this needs to be examined carefully, as their transaction-based congestion management is a partial contradiction to the nodal point approach explained above.

- it recognises the difference between contractual flows and physical flows, taking account of superposition and loop flows effects;
- it recognises the customers' need for simple and non transaction based tariffs which is opposed to the TSOs' need for exact and cost reflective remuneration,
- it gives customers ex ante tariffs for single transmissions and, at the same time, allows TSOs to settle ex post for the resultant sum of overlapping transmissions.

In the light of the discussions following this report, it is hoped to find a common view amongst EU regulators and governments as to the most appropriate way in order to make concrete progress. There after, two principle choices exist with respect to follow-up:

- action by industry in line with such a common view of the EU regulators and Member States;

- the adoption of legislation at Community level providing for clear rules regarding cross-border transmission tarification that must be followed by each Transmission System Operator.

These choices are not mutually exclusive: Community legislation might be adopted which could take into account interesting developments by ETSOA and national regulatory authorities.

No conclusion has as yet been made by the Commission on this issue. It will decide how to proceed in the light of comments received following publication of this report, notably from Council and the European Parliament. However, the Commission will actively continue work on this area to ensure that it is in a position, if and when necessary to propose legislative measures to the Council and the European Parliament.

3. Need for a common commercial policy towards third countries

3.1. Introduction

At the 4th meeting of the follow-up up group for the implementation of the electricity directive on 20 November 1998 the Commission has presented a detailed analysis of this issue. This chapter follows up the main findings.

With regard to market structure, only a few years ago, the grid system of UCPTE was physically separated from Central and Eastern Europe grids, and trade could only take place marginally via a few special DC (direct current) network links and only between monopolists. In that situation, no specific electricity trade rules were necessary, and indeed, no specific rules for electricity imports and exports exist on Community level. This issue could not be addressed within the electricity directive 96/92, inter alia because the directive is legally based on Article 100a.[15] The prior transit directive 90/547 and the Energy Charter stay within the concept of transit between monopolists.

In the last years two fundamentals have changed. First, on the legal level, the electricity directive breaks up the monopoly supply areas and forces the network operators to transport electricity purchased from third party suppliers to customers in "their own" area. Second, on the technical and business level, the network operators have gradually developed links and extended the UCPTE grid system to non-EU member states. Thus, on the basis of legal and technical developments, electricity trade with third countries will no longer be a marginal phenomenon, but a real and significant opportunity.

As a consequence, it appears possible that producers outside the EU, if they are GATT members (or have ratified the Energy Charter), might endeavour to claim free access to all eligible customers in the EU whilst having the possibility to maintain monopoly rights in their domestic territories, thus, de facto, preventing any trade in the opposite direction.

However, at present, the legal possibility of non-EU companies to claim access to the eligible customers in the EU is unclear. Significant arguments exist for and against the possibility, pursuant to GATT, for Member States to refuse imports from third countries on grounds of reciprocity. Indeed, in certain Member States, provision for such refusal exists in national law.[16] The reasons for the introduction of this possibility for refusal are as follows:

- the fundamental contradiction would result that a more restrictive trading regime would exist for EU companies compared to non-EU undertakings;
- the reason why the "reciprocity" clause has been introduced in the Directive is to permit Member States to liberalise most or all of domestic customers, without exposure to unfair competition. As a consequence, many Member States are committed to go further than the 25 % minimum[17]. If "unfair" trade develops significantly with third countries, this trend may be stopped, or even reversed;
- in certain countries outside the EU, planning constraints are looser, and environmental standards and social obligations are less stringent that the minimum EU requirements. Nonetheless, electricity supply from such countries is economically possible. A tendency may exist, particularly for non-EU firms, to take

[15] When the Commission explained in 1988 the necessity of directives for common rules for the electricity and gas markets in the Working Paper "The Internal Energy Market", COM (88)238 final, the issue of external trade had already been raised: "In the energy sphere, the Community should therefore adopt a **common external and commercial policy** to enable it, where necessary, to obtain reciprocal concessions from its partners, on the lines of the Uruguay Round. This notion of **reciprocity** is essential."

[16] The Commission presented to Member States at the 4th follow up group for the implementation of the electricity directive on 20.11.1998 an analysis of the legal context and the economic relevance of imports from third countries: E.g. the transport capacity of the existing interconnectors to non-EU countries could allow imports up to 70% of domestic generation capacity in the case of Austria, 48% in the case of Greece, 17% in the case of Germany, and approx. 10% in the case of Sweden, Finland and Denmark.

[17] Germany 100 %, Sweden 100 %, Finland 100 %, United Kingdom 100 %, Austria 50 %, The Netherlands 100 %, Spain 100 %, the remainder to be decided.

advantage of these circumstances to build generating capacity outside the EU to supply eligible clients in the EU;

- if neighbouring countries wishing to access the EU market would be obliged to themselves liberalise, this could have a number of benefits, notably environmental benefits as old generating capacity is more rapidly replaced by cleaner, more efficient new generation facilities, and improved domestic competitiveness in our neighbouring countries;

3.2. Suggested approach

It appears necessary that the market opening, as required by the electricity directive, creates a level playing field based on commonly respected rules and standards. In this light, the directive provides (i) pursuant to article 3 the principle of equivalent market opening, (ii) pursuant to article 19(5) the possibility of reciprocity between Member States and (iii) pursuant to article 25 the obligation for the Commission to report additionally on harmonisation requirements. If the principle of equivalent market opening and reciprocity is accepted between the Member States themselves, it appears logical to equally apply it to third countries that wish to participate in and benefit from the internal electricity market. Such a reciprocity based approach should be discussed on three levels:

(1) equivalent quantitative market opening percentages (concept of article 19(5) of the Directive)
(2) equivalent qualitative market access conditions relating to unbundling, transmission fees, grounds for refusal of access, dispute settlement (concept of equivalent market opening in article 3(1) of the electricity directive)
(3) equivalent environmental standards in electricity production would be a further step to achieve a level playing field and to prevent unfair competition. As GATT/WTO rules do clearly not authorise import restrictions based on "environmental dumping", this level of reciprocity could only be achieved through bilateral agreements.

As mentioned above, it is unclear whether GATT rules allow any reciprocity based approach. If Member States take recourse on exception clauses (GATT Articles XX, XXIV, Article 36 of the EU Treaty, Electricity Directive Article 3), a complex and uncertain legal situation would evolve. In order to avoid such legal uncertainty, bilateral agreements or understandings could be concluded between the EU and third countries enabling the establishment of a reciprocity-based framework ensuring equivalent market opening and a level playing field.

Such an approach based on bilateral understandings on the basis of reciprocity would create advantages for both the EU and third countries:

- It would promote a faster market opening in those third countries, which are interested in a full market integration. For accession candidates and Europe

Agreement countries, this would promote the taking over of the acquis communitaire.

- For those third countries that consequently will benefit from a legally certain supply opportunity in the EU electricity market, long term planning and financing will be facilitated. This will allow new financing opportunities such as discounting power purchase agreements.
- This will create new investment opportunities, thereby contributing to increased economic growth and employment.
- This will promote the process of modernisation, efficiency increase and CO2 reduction in CEEC and other third countries.
- Finally, it will help to prepare the ground for a consistent environmental policy, opening possibilities for new instruments in the context of the Kyoto commitments and the internalisation of external costs.

It has to be noted that the opening of any eventual negotiations with third states can only be made within the framework of a Council mandate on the basis of the procedure of article 228 of the Treaty. At this stage, the Commission has not yet reached any conclusion as to whether such a mandate should be requested from the Council. In the light of the reactions it receives following the publication of this report, in particular from the Council and the European Parliament, the Commission will determine how to procede.

III. Regulation of the Electricity network at the European level

1. Introduction

Each Transmission System Operator (TSO) is responsible for an essential service that is, in many respects, a perfect monopoly. In terms of regulation this raises three essential issues: (i) possible discrimination by a vertically-integrated TSO in terms of access prices and conditions to the network for competitors, (ii) excessive pricing, and (iii) taking all reasonable steps to meet demand from customers via network reinforcement.

Many of these issues can and should be dealt with at the national level. Indeed, in this respect Article 22 of the directive requires Member states to *"create appropriate and efficient mechanisms for regulation, control and transparency so as to avoid any abuse of dominant position .... "*.

2. The existing role of the Commission

However, a number of issues arising in this respect require an active role to be taken at the European level:

- The regulation of TSOs is both difficult, and, for many Member States, a new challenge. The Commission plays an important role in ensuring the active exchange of information, experience and expertise between national regulators and competition authorities. Equally, in order to favour the creation of a true common market, ideally the same regulatory test and standards should be applied throughout the Community. Whilst it is not appropriate to propose the harmonisation of regulatory approaches at the national level, an active policy of convergence through benchmarking is clearly appropriate. These objectives are pursued notably via the organisation of the bi-annual meeting of EU electricity regulatory forum in Florence. The Commission should continue to play this facilitating role.

- Whilst Article 20(4) provides that *"in the event of cross-border disputes, the dispute settlement authority shall be the dispute settlement authority concerning the system of the single buyer or the system operation which refuses use of, or access to, the system"* in many cases it will be the competition rules of the EU Treaty that are applied in such cases.

- Moreover, in cases of submarine interconnectors, the responsibility of both involved national regulators could be insufficient in order to provide for effective regulation of access tarification, capacity reservation and refusal of access. In such cases, EC law would necessarily have to be directly applied.

- Whilst, in principle, disputes at national level in terms of network access should be resolved by national regulatory or competition authorities, the EU competition rules are applicable to such cases in the event that an appreciable effect on trade between Member States results. Where complaints are received by the Commission in such cases, close co-ordination between the Commission and national authorities is vital.

At present the inter-action between Commission and Member State competition policies is working effectively. No significant need for harmonisation measures has, therefore, been identified.

3. Cross-border transmission tarification

However, with respect to cross-border transmission tarification systems and trade-related mechanisms, neither national regulatory action, nor Community action under the competition rules, is fully able to address the issues concerned. As discussed above, the Commission is presently examining the different options available for the establishment of a single EU-wide cross-border tarification methodology. Such an issue can not be dealt with properly at national level, because it is not possible for any potential single EU tarification mechanism, or indeed in due course the actual tarification levels, to be regulated by 15 different authorities, each with possibly conflicting views.

EU competition policy, which in any event does not prevent contemporaneous national regulation, is also limited in terms of both procedure and remedies in relation to such issues. The reason for this flows notably from the fact that, as mentioned above, the TSO owns a perfect monopoly. It is becoming increasingly recognised that, in these circumstances, the prices and conditions charged by a TSO must be fixed by a regulatory authority, and cannot simply be left to the TSO itself, subject to ex-post control by a competition authority. A competition authority can only, for example, prohibit excessive pricing once this has been proven through a judicial or administrative procedure. A competition authority cannot, therefore, require, ex-ante, a TSO to pass possible efficiencies on to consumers through lower prices. For these reasons, transmission prices are set by regulatory authorities in all EU countries save Germany which, alone, relies on the competition authority to act as a price limiting mechanism.

This same issue, therefore, arises at EU level: "which authority is going to regulate the mechanisms and, more importantly, in coming years, the actual prices charged by the European TSO's in terms of cross-border tarification ?". It is worth noting in this respect that the importance of such tarification will gain in coming years as cross-border transactions increase in number. In reacting a conclusion on this issue, the following questions need to be answered:

- Whilst, in theory, each national regulatory/competition authority might have jurisdiction to deal with cross-border tarification issues insofar as they concern imports and, possibly exports, is it acceptable to have 15 potentially conflicting decision-making processes contemporaneously treating this issue? Would such an approach not frustrate the objective of having one single EU-wide tarification system for the whole EU ?

- Is it possible to rely at Community level simply on EU competition rules to resolve this issue despite the fact that (i) almost all jurisdictions world-wide now accept that competition policy is an inadequate instrument to regulate transmission tariffs and (ii) the application of the competition rules does not exclude the potential conflict and multi-disciplinary issues outlined above ?

In order to deal with this issue, two possible approaches appear to exist:

- Through some mechanism, such as the EU Electricity Regulation Forum, co-ordinated by the Commission, endeavour to reach consensus between EU regulators and the European Commission which, at present, can only act pursuant to the competition rules on the approach to take regarding cross-border tarification methodology and levels.

- Envisage some form of new regulatory instrument to be administrated by the Commission, or via the establishment of a "European Regulator".

Both of these approaches have advantages and disadvantages. The first approach has the advantage that it requires no new institutions, treaties, or rules. However, in substance, it has the drawback that it lacks exactly such formal rules – it relies on the unanimous consensus of all 15 Member State regulatory authorities, and, at least at EU level, lacks legal authority to impose ex-ante decided cross-border tariffs. In this respect, therefore it requires de-facto agreement, by industry, to respect conclusions reached through this method. Equally, any decisions might only be taken once all parties[18] had agreed, making it difficult to envisage how rapid decisions might be made.

The latter approach has the main disadvantage of requiring at least a new regulatory instrument at Community level. Its clear advantage, however, is to create, at European level, a regulatory instrument equivalent to that which has been, or is in the process of being, established in almost every single EU Member State.

The Commission has reached no conclusion at present as to the appropriate way forward. The purpose of the Harmonisation Report on this issue, therefore, is to commence debate and, in particular, to solicit the views of the Council and the European Parliament.

[18] 15 Member States plus the Commission

IV. Ensuring a level playing field in the European electricity market

The third part of this report examines possible distortions of competition within the internal market as a result of diverging legal standards, mainly affecting the cost of electricity generation.

It is evident that there are various factors and circumstantial conditions which will lead to different costs of electricity production in the different Member States. Many of these factors are of structural, historical nature or represent political choices of the Member States. It cannot be the intention of this report to suggest harmonisation of such general factors.

Moreover, the rules of the EC Treaty, in particular those concerning competition, are an adequate framework to address many market distortions in the electricity sector after liberalisation. However, some specific and complex areas might deserve not only a case by case approach, but also a more general discussion. This chapter focuses on three specific areas, which have been recognised to influence the cost of electricity production. First, environmental standards, second, accounting standards for nuclear decommissioning and, third, taxation with respect to energy products as well as to corporate tax schemes which specifically benefit electricity companies. Evidently, this selection of issues is not exhaustive.

1. Environmental standards in electricity production

1.1. Introduction

Environmental standards, mainly those focussing on air pollution, are able to substantially influence the choice of generation technology and the cost of electricity generation. This chapter discusses the existing secondary EU legislation as well as the new developments. As environmental standards are already covered by EU legislation the need for further or accelerated harmonisation steps in the light of the liberalised internal electricity market are to be discussed in the context of EU environmental policy.

1.2. Existing Legislation

There are three main directives dealing with large combustion plants.

1. The Directive on Combating Air Pollution from Industrial Installations of 1984 (Directive 84/360) established the first European framework for dealing with air pollutant emissions from industrial plants, and introduced a number of important principles, such as:

   - prior authorisation of construction or substantial modification of industrial processes;

- use of Best Available Technologies Not Entailing Excessive Cost (BATNEEC).

This Directive will be repealed on 30 October 2007 and replaced by Council Directive 96/61/EC (see below). The development of best available techniques could be an important tool for meeting Kyoto emission reduction targets.

2. The Directive on controlling of Emissions from Large Combustion Plants (LCPD), 1988, is a "daughter" directive to Directive 84/360 and sets out emission standards for particulates, SO_2 and NO_x, and emission ceilings for SO_2 and NO_x.

   A key feature of this Directive is the setting of emission standards for new plants larger than 50 MWt, irrespective of the fuel used. A number of derogations are permitted for plants operating for less than 2200 hours per year, for power plants in Spain and for indigenous lignite fired power plants. Emission standards for new plants are also applicable to plants extended by at least 50 MWt. The LCPD did not contain SO_2 emission standards for new coal-fired plants between 50 and 100 MWt - a 1994 amendment to the LCPD introduced an emission limit of 2000 mg/m^3.

   The Directive also set targets (known as "emission ceilings") for the reduction of total national emissions of SO_2 and NO_x from existing plants, based on 1980 emissions. These targets extend to 2003. A standard percentage reduction was set for most countries. Certain Member States were allowed derogations from this requirement to take account of reductions achieved before 1980 or their state of economic development. The ceilings and corresponding percentage reductions are set out in the Directive.

3. Council Directive 96/61/EC of September 1996 concerning Integrated Pollution Prevention and Control (IPPC) requires the introduction of an integrated environmental licensing system, which will apply to a range of industrial process, including power stations larger than 50 MWt. This must be implemented in Member States by 30 October 1999. The regime must be applied to all new plant and substantial changes to existing plant and must be extended to all existing plant by 2007 at the latest. The competent authorities in each country must ensure that all appropriate preventive measures are taken against pollution, in particular through application of the best available techniques. For a technique to be considered "available" according to the definition of "best available techniques" provided in the Directive, it must be developed on a scale allowing implementation in the relevant industrial sector under technically and economically viable conditions, taking into consideration the costs and the advantages. The best available techniques for each industry will not be prescribed but will be assessed by the competent authorities, based on site - and plant-specific factors.

   Permits must specify emission limit values for releases to air and water and include, where necessary, appropriate measures ensuring protection of the soil and ground water and measures regarding the management of waste generated by the installation. Emission limit values should take into account the potential to transfer pollution from one medium to another and must be based on the best available techniques, without prescribing the use of any technique or specific technology but taking into account the technical characteristics of the installation concerned, its geographical location and the local environmental conditions.

The Directive also sets as a general principle that necessary measures are taken upon decommissioning to avoid any pollution risk and return the site of operation to a satisfactory state. Competent authorities must take this into account when determining permit conditions.

1.3. New Developments

The following developments will affect pollution control for power plants in the EC.

Air Quality

There is now a common position (No 57/98) on the first daughter Directive on ambient air quality under the 1996 Framework Directive (96/62/EC of 27 September 1996) which proposes stringent new national caps for SO_2 and NO_x and particulates and lead.

These are based on critical loads analysis and the draft strategy aims to achieve by 2010 a 50% closure of the gap between the critical load and the level of ecosystem protection in 1990. This strategy is now set out in a Common position (57/98), adopted by the Council, that establishes limit values, margins of tolerance and in the case of SO_2 alert thresholds, for SO_2, and NO_x, particulates and lead.

Acidification

There is now a common position (61/98) that aims to reduce SO_2 emissions across the EC by placing restrictions on the sulphur contents of certain liquid fuel products (heavy fuels oils and gas oils) used in power stations and industry. There are possibilities for derogations to this Directive for regions where air quality objective are respected and where emission of SO_2 do not contribute significantly to exceedance of critical loads of acidification. This impacts on power plants burning heavy fuels oil and gas oil.

Revision of LCPD

A third development is the revision of the Large Combustion Plants Directive – 88 /609/EEC. The central elements of this proposal are

- updating of emission limit values for combustion plants coming into operation after 2000
- extension of the scope to gas turbines
- updating of the scope of fuels covered by clarifying relationship with waste incineration Directives and encouraging use of biomass
- promotion of combined heat and power
- updating of provisions concerning abnormal operating conditions

- reinforced monitoring requirements and updating provisions on emission inventories

Water

Power stations normally require large quantities of water to function. The IPPC Directive will deal in an integrated way with emission to air, soil and to water. However, in addition to this Directive, a Commission proposal for a framework Directive on water (COM (97) 49 as amended by COM (97) 614) would set standards and the mechanisms for ensuring that limit values under the IPPC Directive are observed. This would also apply to power plants.

Waste

Waste from power station (mainly from coal fired plant) will be covered by the IPPC Directive and will be covered by the EC's existing legislation on waste.

Kyoto Protocol

Under the Kyoto Protocol the EC and its Member States are committed to reducing greenhouse gases (ghg) emissions by 8% by 2008-2012 in relation to 1990 levels. The power sector is a major and growing source of emissions in the Community accounting for around 30% of EU CO_2 emissions. It is not clear at this stage to what extent the constraint on ghg emissions could influence trade in electricity. There are many scenarios which demonstrate that electricity trade could help to meet Kyoto targets by for instance optimising electricity generation at the regional level, flattening of the load curve which could take inefficient peaking plants out of service and increasing the potential for intermittent renewables. On the other hand it may well be that some Member States that have power sectors with different CO_2 intensities may, in the present policy framework, face problems in reconciling both trade and environmental objectives related to Kyoto. The best known case is associated with the electricity trade between Denmark, Norway and Sweden that have very different electricity sectors

1.4. Conclusion

In the light of the above it is clear that the Commission is actively examining the measures that need to be taken at Community level to ensure equivalent competitive conditions as a result of environmental requirements. It will continue to pursue this line, notably with respect to the adoption of the revision of the LCPD. Planned reductions in both traditional pollutants and in greenhouse gas emissions may indeed impact power generation in Member States. However, the differing energy structures, both in terms of technical choices and organisation, render a detailed analysis of impacts impossible at this stage.

2. Standards for nuclear decommissioning

2.1. Introduction

The issue of decommissioning or dismantling of nuclear power plants is included in this report because of the specific effects relating to the different financing and accounting approaches. It is not intended to question the different organisational and technical approaches towards decommissioning.

The main costs of nuclear power generation include capital investment, fuel, ongoing generation and maintenance costs, plus, and this is the main difference to other types of generation, the costs for nuclear waste storage and future dismantling costs.[19] It is evident that the evaluation of these latter costs is rather complex. Depending on the valuation of these cost factors and the legal obligation to calculate provisions into the electricity prices, the resulting prices of nuclear sources have considerable bandwidth. Regarding liquidity, thus looking at generators from a cash flow perspective, the timing of the payments related to the costs is significantly different for nuclear electricity generation compared with other types of generation. A nuclear power generator has to make provisions for substantial future payments, namely the costs of nuclear waste storage and dismantling. With regard to its future financial obligations, the generator itself or a separate entity will seek to invest the cash surplus which is collected through provisions or other levies.

Thus, nuclear generators can be seen as trustees for funds to cover future decommissioning costs. Since electricity generators have to compete with each other as of 19 February 1999, diverging regulatory approaches to the management of decommissioning funds may cause substantial market distortions.

2.2. Current decommissioning approaches

There is no specific EC legislation on the decommissioning of power plants. However, as regards power plants that would be covered under the IPPC Directive, eventual decommissioning would need to be taken into account when authorisation is being sought.

With the exception of Directive 96/29 EURATOM laying down basic safety standards for the protection of the health of workers and the general public against the dangers arising from ionising radiation, and Directive 85/337/EEC amended by Directive 97/11/EC on the assessment of the effect of certain public and private projects on the environment, there is no specific EC legislation on the decommissioning of nuclear power plants.

A close overview of the age of Europe's nuclear facilities reveals that the first years of the next century will see a rapid increase in the number of such facilities reaching the end of their lifetime.

[19] This chapter focuses on decommissioning costs because of the diverging accounting and financing methods. Costs associated with waste storage related to the current operation of the plant are in that sense similar to pollution generated by other forms of power generation.

In the European Union, nuclear decommissioning techniques have been under development for two decades and are becoming a mature technology. For a few reactors, decommissioning activities are currently on going and will contribute in the development of a fully mature industrial activity.

The development of common views within the EU on the decommissioning of these facilities should result in a better protection of the population and of the environment, and in a more standardised technological practice allowing e.g.: a reduction of the waste volumes and the decommissioning costs.

The outcome from an EC consultation[20] indicates that there are differences in the approach to decommissioning by Member States. In some areas, there is a potential for improvement and harmonisation at the European Union level. Therefore, with the aim of European co-operation, harmonisation of policies, and development of common views, as emphasised by the opening and the deregulation of the electricity market within the Member States, it would be a significant benefit to have Community common approaches for the decommissioning of nuclear facilities.

The electricity directive 96/92/EC opens for the first time competition in the European electricity market, not only at the production level, but also at the supply level. The need for transparency in the electricity-producing companies' accounts foresees a clear need for a full integration of the end of life decommissioning costs.

Different situations exist among the Member States for the financing of decommissioning, e.g. simple provision in the accounts of the electricity companies allowing reinvestment of the collected funds for other than decommissioning purposes, segregation of collected funds outside the sphere of the company, or a complete State organisation and management of decommissioning by separate specialised, mostly publicly owned companies.

Moreover, the amount of yearly funding required, the requirements as to when and how decommissioning has to be accomplished and the applied calculation methods and discount rates differ substantially between Member States. This situation questions the principles quoted above and could lead to distortion and discrimination between the new competing nuclear electricity producers from different Member States.

Decommissioning costs are clearly seen as part of the electricity production costs. They may not be cross-subsidised from the transmission activity nor be directly subsidised via state aid to the extent that they are incompatible with the EU Treaty.

Provided that financial provisions have been built up throughout the operating life of a nuclear facility, the costs per kWh should be relatively low and should not significantly influence electricity charges or lead to unfair competition between producers.

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[20] *EUR Report 18.860 (1999) Nuclear Safety and the Environment: Decommissioning of nuclear installations in the EU.*

The steps to be taken in determining financing requirements include identifying the decommissioning strategy to be applied and preparing detailed costs estimates that include appropriate risk margins. Sound decommissioning financing will also increase the public acceptance of the potential legacy to the future generations. The benefit of this approach is to ensure that money is available when immediate decommissioning occurs, and that financial burdens and risks are not imposed on future generations should any decommissioning activities be deferred to a later date.

If needed, the estimated funds should take into account stated plans for reusing some of the existing installations for new nuclear purposes.

If appropriate financial provisions have not been built up over time, there is a potential risk that producers could choose to elect the cheapest decommissioning strategy rather than make a balanced judgement on all the relevant factors, e.g. safety and environmental issues.

2.3. Suggested approach

The Commission services believe

- that the Member States should apply transparency of the financing plans and of its calculation method, that the required full amount of the fund/provision be identified, including the complete decommissioning process the waste management and final disposal costs,
- that these full decommissioning costs be included in the selling price of the kWh (internalisation of costs) with the potential exception of historical nuclear liabilities associated, for example, with national research or defence facilities for which clear specific financial arrangements should be taken at national levels,
- that the fund/provision be secured and controlled by the mandated national authorities,
- that the fund/provision be dedicated to decommissioning purposes, and nothing else,
- and that the full funding be available at the foreseen time (fixed in licence) of the final shutdown of the facility.

It has to be emphasised that most of these principles can be derived either from the unbundling requirements of the electricity directive or from the competition rules of the EC Treaty. Nevertheless, due to the specific aspects of decommissioning and the importance for the level playing field in the European electricity market, a harmonised approach could be beneficial. In this context, the role of the Euratom treaty needs to be taken into account.

3. Taxation

3.1. Indirect taxation

1. There are 2 systems of indirect taxation which apply to electricity. The first is VAT which is largely harmonised at Community level, and the second is a series of national single stage taxes which currently are not regulated at Community level.

2. According to the general provisions of the sixth VAT Directive of the Council (n° 77/388/EC of 17 May 1977), the standard VAT rate applies to electricity. In practice, the level of the standard rate varies between 15% and 25%. Nevertheless, according to Article 12(3)(b) of the same text, Member States may apply a reduced rate of no less than 5% to supplies of electricity provided that no risk of distortion of competition exists. It is the Commission that takes a decision on the existence of this risk and allows for the derogation. Greece applies the reduced rate to electricity on that basis since 1st January 1999.

   Moreover, current Community law does not allow the application of different VAT rates to electricity, depending on the means of production such as "*green electricity*". The sixth directive lays down a fundamental principle that cannot be infringed, according to which a single rate applies to a product. Thus, it is not evident, under current legislation, to make a distinction according to the way in which the electricity is produced.

3. In its proposal for a Directive restructuring the Community framework for the taxation of energy products (COM(97)30) the Commission is proposing that the scope of taxation harmonised at Community level shall be extended from mineral oils to cover other competing sources of energy namely; coal, coke, lignite, bitumens and products derived from them, natural gas and electricity. The scope of the proposal is to improve the functioning of the internal market whilst at the same time offering Member States the possibility to better attain national objectives of employment, environment, transport and energy policy.

   The Commission has proposed that electricity shall be taxed at the level of output. When electricity is traded between Member States this principle means taxation in the country where the electricity is finally consumed and accordingly, electricity could be traded without tax. The currently proposed system of taxing output does not however provide for differentiation on the basis of the quality of fuel used but it allows Member States to differentiate levels of taxation on the basis of type of user (e.g. industry-household).

   However, in the light of a possible certification system for renewable based electricity producers - an option discussed within the framework of promotion schemes for renewables - a differentiated taxing of electricity from such certified renewable based generators could be possible.

   Nevertheless, under the proposal (COM(97)30) Member States that wish can, for environmental purposes, apply additional taxation to inputs. In order to encourage their development the Commission proposes that Member States be authorised to refund to the producer of electricity from renewable sources all or a part of the tax paid. Any such approach has to be in line with the state aid rules of the EC Treaty.

A Member State taxing inputs may not discriminate imported electricity. If a determination of the input factors for the foreign produced electricity is not possible (which is indeed difficult without harmonised certification system) the importing Member State would only be able to tax imported electricity at the lowest rate applicable to domestic production following the recent Judgement of the European Court of Justice in the case of Outokumpu Oy v Finnish Customs (Case no C-213/96).

Although the new proposal does not provide for completely harmonised tax rates it is hoped that a combination of a steady increase in minimum rates and the fact that maximum rates will be constrained by concerns of competitivity will result in a closer approximation of rates over a period of time. The Commission has proposed minimum levels of taxation of 1 ECU per MWh rising to 3 ECU per MWh in 2002.

3.2. Direct taxation

In the field of corporation tax there is no harmonisation of tax bases on which corporation tax is levied. In this context, it does not appear appropriate to propose a harmonisation of tax bases only for electricity companies. However, already today, a potential problem exists from a state aid point of view if a specific exemption of direct tax is applied only for public or national companies. This problem has already been taken up by the Commission. By letter of 6 March 1998 Member States have been asked to inform the Commission about the existence of tax arrangements which derogate from the ordinary rules as far as electricity undertakings are concerned. The replies have been preliminarily studied, and in some cases further investigation will be necessary. Due to the complexity of the specific tax systems in the Member States, no overall conclusions can be presented at this stage.

3.3. Conclusion with respect to Taxation

In this light of the above, it appears that the issues relating to taxation are presently being actively dealt with by the Commission. Work regarding direct taxation will continue, and the Council is encouraged to seek rapid agreement on the draft Directive restructuring the Community framework for the taxation of energy products.

Annex: Definitions

'Offsetting or superimposing counterdirected flows': If over an electricity line between A and B one contract is concluded to transport e.g. 100 MW in direction A and a second contract over the same time is concluded to transport e.g. 80 MW in direction B, than only 20 MW have to be physically transported in direction A. Thus, counterdirected contractual flows can be superimposed in order to cancel each other out. Consequently, the contractual capacity of an electricity line can be significantly higher than its physical capacity.

'Dispatching of generation': As the total capacity of power plants is, unless during absolute peak hours, not necessary to cover electricity demand, some mechanism has to be set up to decide which power plant should operate and which plant should be idle or on stand by. The selection or drawdown of the power plants for generation is called dispatching. Usually, it is the independent system operator that makes this decision according to objective and non discriminatory criteria (merit order).

'Countertrading': If despite superimposing of counterdirected flows the resulting physical flow reaches the capacity of the transmission line, a situation of congestion or bottleneck exists in the resulting direction. Any further contractual transaction in the congested direction can only be carried out, if at the same time e.g. the system operator arranges a corresponding contractual flow in the opposite direction. To achieve this the system operator has to purchase or sell electricity from generators, or even consumers, that are willing to increase or decrease generation/consumption.

'Redispatching': This is an alternative to resolve an existing bottleneck, similar to 'countertrading'. In case of 'redispatching' the system operators of the concerned areas do not engage in offsetting trading contracts, but directly change the dispatching order of the power plants to create overall electricity flows which remain within the limits of the transport line constraints.

'Market splitting': This is another alternative to deal with a bottleneck, usually applicable in systems which already have a common spotmarket. As a reaction to the occurrence of a congestion, the market operators provide for the possibility that there are different spotmarket prices on either side of the bottleneck. Thus, electricity in the area which is oversupplied becomes cheaper than electricity in the undersupplied area. Consequently less market participants are interested to purchase from the area which becomes more expensive and the resulting flow over the bottleneck is reduced.

'Transaction oriented tariff': Equivalent to 'point-to-point tariff', this method of tarification calculates a transmission fee on the basis of information about entry point ('source') and exit point ('sink') of the electricity contract. Thus, if an eligible customer shifts from supplier A to supplier B, the parties would have to recalculate the transmission fee depending on the location of the new supplier.

'Non transaction oriented tariff': Equivalent to 'point of connection tariff' or 'nodal tariff', this tarification methodology divides the overall transmission system costs

exclusively to separate connection fees (or network access fees) for the producer and the consumer. Thus, the connection fee for an eligible customer remains the same, irrespective of a change of supplier.

'Postage stamp': This expression is used to describe a transmission or access fee which does not depend on the distance of the transaction. Usually a postage stamp tariff would also be a non transaction oriented tariff. Nevertheless, additional 'transit' postage stamps for specific situations are imaginable.

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