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TOWARDS A COMMON EUROPEAN ELECTRICITY MARKET

Paths in the Right Direction ... Still far from an Effective Design[†]

ABSTRACT. This paper analyses the future organization of cross border trade in the European electricity market. The draft Regulation "on Conditions for Access to the Network for Cross-Border Exchanges in Electricity" issued in March 2001 by the European Commission together with related documents produced by the European association of Transmission System Operators (ETSO) and the Council of European Electricity Regulators (CEER) until that date constitute the backbone of this analysis. The paper examines whether the economic principles contained in these documents suffice to design a working European electricity market and if not, what is missing. It concludes that these principles need to be completed by harder measures in order to induce the "real integrated single market" of electricity claimed by the Commission. In short, the principles may be necessary, but they are unlikely to be sufficient.

KEY WORDS: cross border trade, electricity restructuring, internal electricity market, transmission access

1. INTRODUCTION

As repeatedly stated by the European Commission (EC), the goal of the Internal Electricity market (IEM) is "the creation of a real integrated single market, as opposed to a situation characterized by fifteen more or less liberalized but largely national markets" (explanatory memorandum of EC (2001a) and similar statements for instance in EC (2001b), FRF (2000a) or EC (1998)). The Directive 96/92 EC and its transposition into national law by the Member States constituted the first step to that goal. In order to further proceed towards the objective, the EC initiated the Florence Regulatory Forum EC (2001c) in 1998: "The Forum convenes twice a year at the European University Institute near Florence and consists of national regulatory authorities, Member States, European Commission, Transmission System Operators, electricity traders, consumers, network users, and

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power exchanges. The Forum was set up to discuss issues regarding the creation of a true internal electricity market that are not addressed in the Electricity Directive. The most important issues addressed currently at the Forum concern cross border trade of electricity, in particular the tarification of cross border electricity exchanges and the allocation and management of scarce interconnection capacity."

Taking stock of the work achieved in Florence, the EC decided in March 2001 to introduce two new legislative proposals. The intent was to submit them to the Council to be held in Stockholm that same month. The legislation consisted of

(i) a draft Directive "amending Directives 96/92/EC and 98/30/EC concerning common rules for the internal market in electricity and natural gas" EC (2001d).
(ii) a draft Regulation "on conditions for access to the network for cross-border exchanges in electricity in the internal electricity market" EC (2001a).

The Council declined to discuss these proposals. The alleged reason is the opposition of France, supported by Germany to the proposed 2005 deadline for the completion of the IEM. This setback may not stop the overall IEM process (Stockholm European Council: Presidency Conclusions 2001), but it will certainly slow it down. This delay is an opportunity for examining the draft legislation as well as supporting ETSO documents and CEER views. This analysis is the objective of this paper: it focuses on the draft Regulation with the view of assessing whether, possibly completed by ETSO and CEER views, it provides the basis of the "real integrated single market" claimed by the Commission.

One can indeed expect difficulties. European electricity systems were restructured pursuant to directive EC96/92 (EC 1996) which leaves a lot of flexibility to Member States to restructure their electricity market and does not organize access to the network (see EC (2001e) for a review of the transposition in the Member States and EC (2001f) for an EC analysis of the status of the Internal Energy Market; see also Hancher (1998) and Glachant (2000) for independent analysis of the subject). It is possible that the transposition of the Directive into national law entailed sufficient compatibility for the individual electricity and services markets to assemble into a "real integrated single market". But the complexity of electricity makes this outcome unlikely. The Commission is more optimistic: it states in the Explanatory Memorandum of the draft Regulation EC (2001a), that "It was in the logic of a gradual approach to implementing the internal electricity market that specific issues remain to be addressed after the principal strategic implementation choices have been made by

Member States". Whatever one's own opinion on the evolution towards the IEM, most will admit that it is now urgent to check that the process converges and if not to take further harmonization steps. Convergence towards a good market design is not spontaneous: as argued by Hogan, "the market cannot solve the problem of market design" (Hogan 2000). In this sense, France's rejection of the 2005 deadline for the completion of the IEM is a paradoxical opportunity: the available documents do not convey much evidence that we have the institutional instruments to complete the Internal Electricity Market.

The objective of this paper is to substantiate this claim. Specifically, we want to assess whether the draft Regulation introduces a well-tuned mix of markets and controls compatible with an integrated electricity market. In order to conduct this analysis, we examine the different articles of the draft Regulation and comment their potential contribution to a "real integrated single market". The conclusion of the analysis is most often that the principles stated in the draft Regulation go in the right direction but need to be drastically strengthened. There remain a lot of fundamental questions to sort out and many opportunities to derail the process. Do ETSO and CEER documents clarify the situation? They do, but they are also much too soft. More specifically, most of the proposals of the draft Regulation are sound. But they can only be effective if there are implemented through a sufficient rich set of locational and real time prices. This set of prices is what one does not see in the available documents. How do we arrive at this conclusion? By formally seeking for certain flaws namely market incompleteness. What are exactly these flaws? This is taken up in the next section.

This paper does not discuss market power or asymmetry of information, even though these phenomena are overwhelming in power systems. Market power justified and asymmetry of information complicated the regulation of the former electricity monopolies; they still pervade all restructuring experiences. Taking them into account complicates the analysis. Specifically, market power and asymmetry of information can only further degrade the functioning of badly designed markets. Any shortcoming identified before taking market power and asymmetry of information into account will persist and be aggravated if these phenomena are taken on board. We therefore focus on the shortcomings of the current design proposals that already appear when market power and asymmetry of information are neglected. In short, overlooking these phenomena does not invalidate our diagnosis; it only makes it more benign.

The paper is organized as follows. A brief introduction to market incompleteness and to its potential dangers is given in Section 2. Section

3 sketches the methodology adopted in the paper: in brief, we assume a bilateral organization of the market and reason on stylized networks. The section also recalls some basic principles of electricity transmission. Section 4 discusses articles 2, 3 and 4 of the draft Regulation while Section 5 goes in some depth in articles 5 and 6. A few words on the other articles are given in Section 6 before the conclusions. The analysis relies on EC, ETSO and CEER documents. These are globally mentioned in the paper as the Florence documents. EC and ETSO documents can be downloaded from the web. They are explicitly referenced in the text. In contrast, CEER documents, although widely distributed, are not published. In order not to attribute to CEER views that cannot formally be proven to be theirs, we do not explicitly refer to CEER papers but simply give our views on various questions that are taken up in these papers.

A revised version of the proposal has been submitted by the Commission in June 2002. Other documents have also been issued by ETSO and the Forum met a few more times. A follow up paper will analyze these events. But its conclusion, at this time (Fall of 2002) can already be announced: "... closer! But still far from an effective design".

2. On Market Design

Creating an integrated electricity market across different control areas is a demanding task. It requires, not only opening access to cross border transmission facilities, but also to create markets to facilitate the use of these capacities. These markets involve the commodity (energy) and a range of associated transmission and ancillary services. Therefore, an integrated electricity market may also require an integrated market of other services. Which services and how to organize their market is the question debated in the Florence Regulatory Forum.

In order to get a first insight into these needs, consider what an integrated electricity system would have required in the regulatory days. For reference purposes, call the System Operator in charge of this integrated system a Perfect System Operator (PSO) and assume that this PSO is not limited by numerical, computational or communication constraints: its technical capabilities encompass the whole European electrical system and it can do whatever it finds suitable to manage this system. This conceptual PSO controls all generators and demand side resources subject to the physical restrictions imposed by the electric system. Its obligations include, among others, to meet demand and reserve requirements as well as to satisfy network constraints.

Meeting all these obligations required a lot of controls. Restructuring the electricity system does not eliminate physical constraints; it only modifies the way they are tackled. This may suggest that substituting controls by markets requires a market for each physical resource formerly controlled by the PSO. This means a plethora of markets. Surely, this goes too far. One should not rely on markets to do things that current technology prevents them to do. The exact role of markets and controls should be carefully delineated. The question has been elaborated by Wilson (1999). He reasons that current technology does not permit to operate real time electricity markets. Physical realities therefore restrict the replacement of controls by markets. Electricity markets need to close before real time and relinquish real time operations to the System Operator. As a result, electricity markets are forward markets. "Real time" prices are computed ex post and depend on a mix of market actions (market participants' offer of ancillary services) and SO's controls (call upon these ancillary services). No restructuring experiment has so far been able to exclude SO's controls from intruding the market at some stage. California went as far as it could in untangling both. But all analyses of the recent crisis (see for instance Besant-Jones, J.E. and B.W. Tenenbaum (2001), Chandley, J.D., Harvey S.M. and W.W. Hogan (2000), Harvey, S.M. and W.W. Hogan (2001), Hogan (2001), Joskow (2001)) suggest that this may have been part of the causes of the meltdown. In short, markets never completely manage the electricity system. In economic parlance, the electricity market is always incomplete. This incompleteness is also present in cross border trade. Identifying the potential market incompleteness imbedded in the proposals of the Florence documents is the main objective of this paper.

Trade-offs between controls and markets pervade electricity restructuring whether in the commodity (energy) or the associated services (here cross border transmission). But there are limits to what trade-offs are allowed. Specifically, restructuring is flawed when physical control is removed without markets taking over or when physical control and prices of tight constraints overlap. Possibly less obvious, but certainly as important in the European context, restructuring will be flawed if the national commodity markets are incompatible with the organization of a market for cross border transmission services. As argued in the introduction, it is possible but unlikely that national designs are compatible with one another. Managing the seams between national markets may thus place a considerable burden on cross border transmission.

As for all components of the electricity system, controls or markets can rule cross border transmission. Call *explicit* a market of transmission services where such services are explicitly created, traded and priced. This is the case for example when rights/obligations to use part of a transfer capacity are created and a dedicated auction organized to trade these rights/obligations. This market is incomplete when the rights/obligations inadequately reflect the physical use of the network resources. This is the case when a fixed transmission capacity is traded while the transmission capacity available in real time is inherently variable and random. Incompleteness comes from the fact that one is trading a single non-contingent service while the network can only deliver contingent services. Introducing here a comparison that will be used repeatedly, it is like producing a range of truck models but trading only one abstract average truck. Incompleteness can be deeper. The market of transmission services may be missing. This happens for example when transfer capacities are not traded but allocated on the basis of some priority rule (e.g. first come, first served) and there exists no secondary market for these services. Both cases lead to an incomplete IEM, namely one where physical transmission resources are not fully or even not at all traded. But an IEM where transfer capacities are allocated on the basis of priority rules (that is not traded) is in a sense more incomplete than one where non-contingent transmission capacities are traded through an auction.

Implicit transmission markets arise when transmission services are bundled in the price of the commodity. The commodity is then traded locally in a way that reflects the price of the implicit transmission service. Implicit auctions, market splitting and nodal prices are implicit transmission markets. Implicit auctions require a pool, an organization that is not standard in Member States. The Florence documents refer to market splitting to claim either that it is too advanced for Europe (section III, 4 in the explanatory memorandum of EC (2001a)) or that the highly meshed network of continental Europe makes its implementation questionable ETSO (2001d). They do not refer to nodal pricing which is a more elaborate version of market splitting, even though it is ideally suited for highly meshed networks. Because of these different reasons and in order not to unduly extend the length of this paper, we do not elaborate on implicit transmission markets.

We shall argue that the proposals contained in the Florence documents introduce an incomplete explicit transmission market in the IEM and hence put this latter at risk. In some sense, this claim is compatible with statements of the draft Regulation that announce further steps, "... the draft Regulation provides for the subsequent adoption of guidelines detailing further relevant principles and methodologies" (section II in the explanatory memorandum of EC (2001a)). Something beyond the draft Regulation is needed. But it might be needed urgently.

Missing or incomplete markets do not necessarily have dramatic consequences, but they may. It all depends on the relative importance of the services that are incompletely traded. For instance, a sophisticated transmission market is not important if cross border trade does not develop. Similarly, not trading the real transmission resources does not matter if they are plenty of them compared to the cross border activity. But the risks created by an incomplete transmission market may sometimes materialize and seriously endanger not only the energy market but also the physical system itself. This will be the case if cross border trade develops and the transmission resources are tight compared to the demand for their use. More specifically and in direct relation with the discussion of this paper, consider the trading of non-contingent transmission capacities affected by random failures. There will be bottlenecks at some time and idle but valuable transmission possibilities at others. Unused valuable transmission resources are a true economic waste but it may be unnoticed. In contrast, bottlenecks are felt. They are acceptable if removed at a small cost or through exceptional and limited curtailments. But there are more critical situations. Removing a bottleneck may be quite costly when transmission constraints are severe. Curtailments may become recurrent when resources for removing bottlenecks are structurally missing or need to be procured by intrusive administrative measures. These situations develop from lack of capacity and/or perverse economic incentives that result from bad market design. They indicate that the restructuring process has failed.

Former experience in PECO (Hogan 1999) and the Californian meltdown show that the danger is real. True, the European Commission promises "a truly integrated market, which means, for instance, that Europe will avoid the type of problems currently faced by California, which have resulted from inadequate legal framework and inadequate production capacity" EC (2001b). But former Governor Wilson also announced at the time a "vibrant" electricity industry in California. Surely, the current draft legislation is not the final word and discussions at the Council of Ministers and the European Parliament leave room for improvements. But this is no guarantee that the legislation will work: recall that both houses of the California legislature unanimously passed Assembly Bill 1890 in 1996. Political statements are useless in complex technical matters. And quick political fixes only make the situation worse. Nothing can replace an a priori careful identification of features of the market design that economic reasoning tells us are flawed. They may jam the Internal Electricity Market, and this notwithstanding the stew of free market and public service rhetoric that comes with the legislation.

3. The Method of Analysis

3.1. *A Market Organization*

Pools and bilateral trade constitute the two main organizations of restructured electricity markets. The current status of the IEM (see EC 2001e) indicates that the bilateral organization dominates, at least initially in the EU. For the sake of simplicity we limit ourselves to this latter model. In this organization, marketers trade electricity through bilateral transactions. They also request transmission services, among them cross border transmission to complete their deals. The problem is thus one of allocating cross border transmission resources to bilateral transactions. Keeping in line with the draft Regulation, we assume that this allocation should be done by market mechanisms.

Cross border transmission lines link the different control areas of the European electricity system. Each control area is run by a separate TSO. Except for Germany, domestic transmission services in continental Europe are regulated and priced according to a postage stamp mechanism. There is thus no mention of working markets of domestic transmission services. This contrasts with the recommendation to organize cross border transmission on a market basis. This difference of approach may be justified on the ground that domestic network capacities are deemed globally sufficient and that domestic re-dispatching or counter trading can easily accommodate occasional bottlenecks. We take stock of this assumption and suppose away bottlenecks in the domestic grids. This simplifying assumption is implicit in most Florence documents. It can and should be revisited at some point. It is briefly questioned in this paper when discussing Articles 2 and 8 of the draft Regulation. There is a general consensus that TSOs should coordinate their actions when it comes to cross border trade. The exact nature of this coordination is not fully specified yet but the Florence documents sketch what is aimed at. A useful proposal by ETSO to coordinate auctions of transfer capacities (ETSO 2001b) is mentioned later. This document published one month after the draft Regulation constitutes the starting point of our forthcoming follow up analysis.

Exchanges exist in various European places and new ones are planned. Transmission constraints have an impact on the price in these power exchanges. But we posit that the current state of development of the IEM does not permit to price cross-border transmission constraints on the basis of differences of energy prices in the exchanges. We instead adopt the view that a good market of transmission services is a prerequisite to achieve meaningful electricity prices in the exchanges, but not the other

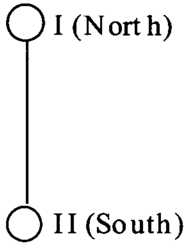

Figure 1. The North–South example.

way around. This attitude complies with ETSO's conclusions that market splitting of the type operated in Scandinavia cannot be used for assessing transmission prices in the highly meshed continental network (ETSO 2001d). The relative illiquidity of the European exchanges compared to Nordpool also supports that position. On more fundamental grounds, some Nordic voices (Bjorndal and Jornsten 2001) now also question the zonal pricing implied by Nordpool market splitting.

3.2. *Two Stylized Networks*

Flaws appearing in stylized examples do not vanish in the real world. We therefore conduct the analysis on two very schematic networks. In order to simplify the discussion, we neglect losses and work with the standard DC load flow approximation of the load flow equations. The first network, commonly called the North-South model, is depicted on Figure 1. It consists of two nodes or control areas separated by a transmission capacity. This example has been used in various texts of the literature (Wu et al. 1996; Oren 1997; Joskow and Tirole 2000). It is also used occasionally in ETSO papers (e.g. ETSO 2001a). The second example, depicted on Figure 2, was introduced in Chao and Peck (1998). Except when stated otherwise, we follow these authors and assign generation at nodes 1, 2 and 4 and demand at nodes 3, 5 and 6. We suppose rounded marginal generation costs of 10, 20 and 30 euro/Mwh at node 1, 2 and 4 respectively.

Different groupings of the six nodes into control areas illustrate various zonal patterns in the overall market. A two control area example is obtained by grouping nodes 1, 2, 3 and 4, 5, 6 in zones *I* and *II* respectively (Figure 3).Alternatively, we obtain a four-control area system if nodes 3 and 4 respectively constitute zones *I* and *II* while zones *III* and *IV* respectively consist of nodes 1, 6 and 2, 5 (Figure 4).

Kirchoff's laws direct electric flows. Power Distribution Factors (PDF) offer a particularly simple representation of these physical laws. In order

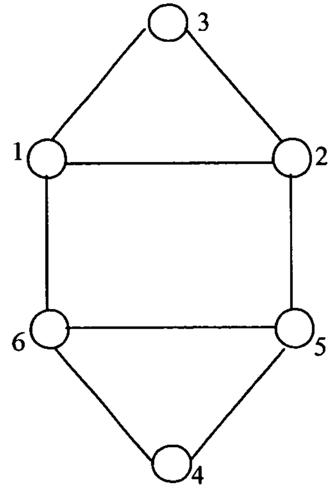

Figure 2. The six node example.

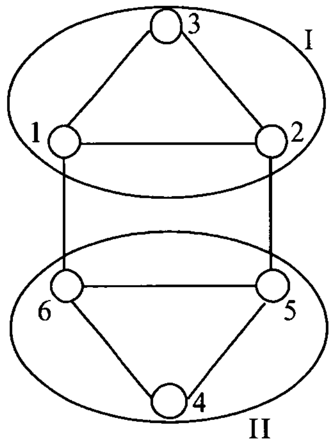

Figure 3. The six node/two zone example.

to illustrate the use of PDFs, suppose as Chao and Peck (1998) that the impedance of all lines but (1-6) and (2-5) is 1 while lines (1-6) and (2-5) have an impedance equal to 2. The PDFs derived from the DC load flow approximation are given in Table I.

They can be interpreted as follows:

(i) A unitary (1 Mw) injection in node i with off-take at some fixed but arbitrary reference "hub" node (here taken as node 6) entails a flow equal to $\mathrm{PDF}_{(mn)i}$ in line (mn). The flows in the different lines resulting from a unitary transaction from node i to 6 are accordingly given by the PDFs of column i in Table I.

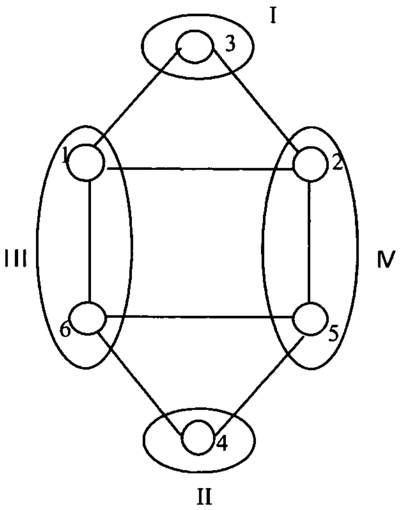

Figure 4. The six node/four zone example.

TABLE I

PDF coefficients.

	Node 1	Node 2	Node 3	Node 4	Node 5
$PDF_{(23)}$	−0.1250	0.1667	−0.4792	0.0208	0.0417
$PDF_{(31)}$	−0.1250	0.1667	0.5208	0.0208	0.0417
$PDF_{(12)}$	0.2500	−0.3333	−0.0417	−0.0417	−0.0833
$PDF_{(56)}$	0.2500	0.3333	0.2917	0.2917	0.5833
$PDF_{(64)}$	−0.1250	−0.1667	−0.1458	−0.6548	−0.2917
$PDF_{(45)}$	−0.1250	−0.1667	−0.1458	0.3542	−0.2917
$PDF_{(25)}$	0.3750	0.5000	0.4375	−0.0625	−0.1250
$PDF_{(16)}$	0.6250	0.5000	0.5625	0.0625	0.1250

(ii) A unitary transaction from node i to node j entails a flow in line (mn) equal to the difference $PDF_{(mn)i} - PDF_{(mn)j}$. As an example the flow in line (1-6) due to a unitary transaction from node 1 to 2 is equal to $0.125 = PDF_{(1\text{-}6)1} - PDF_{(1\text{-}6)2}$.

3.3. *Some Questions*

The paper considers three types of questions. The first one is the very theme announced in the introduction: does the draft Regulation, possibly completed by ETSO and CEER papers, suffice to induce a "real integrated single market"? We conclude that the documents provide good principles but remain far from offering an effective design of the electricity market. More is needed to reach the objective. In other words, even though the principles may be necessary, "The rules contained in the Regulation are as simple as possible and are limited to what is necessary to regulate in EC legislation, in compliance with the principle of subsidiarity" (section I in the explanatory memorandum of EC (2001a)) they may remain far from sufficient.

The practical applicability of the various proposals is a second issue of interest. Good principles are useless when too difficult, if not impossible, to implement. We thus also try to pinpoint recommendations that are likely to result in a deadlock because they cannot be applied in practice. Referring to the same statement of the explanatory memorandum of the draft Regulation, the proposed rules are not "as simple as possible".

Jurisprudence develops by logically deducting new principles from old ones. The US experience shows that this can be a particularly rich process in electricity restructuring. A third objective of the paper is thus to try to pinpoint articles of the draft Regulation that have a strong imbedded but still hidden power. And indeed, there seems to be a lot of potential in the draft Directive. But developing this potential may require quite involved reasoning.

4. Articles 1 to 4

Articles 1 to 4 of the draft Regulation offer straightforward but fundamental economic principles.

4.1. *Article 2: Loop Flows and Cross Border Trade*

4.1.1. *Loop flow are part of transit and there may be congestion on the grid*

By stating that loop flows are part of electricity transit, paragraph 2(a) of Article 2 strengthens the definition adopted in earlier and more general legislation or international agreements. It also makes it applicable to electricity.

'Transit' of electricity means a physical flow of electricity hosted on the transmission system of a Member State, which was neither produced nor is destined for consumption in that Member State; this definition includes transit flows which are commonly denominated as 'loop-flows' or 'parallel flows'.

Loop flows are important features of cross border electricity trade. We briefly recall their physical nature on the six-node/four-zone example

(Figure 4). Consider a unitary transaction (1 Mw) between control areas *I* and *II* (e.g.from generation node 4 to demand node 3). This transaction entails flows of 0.5 Mw through both control areas *III* and *IV*. Kirchoff's laws make it difficult for the TSOs and impossible for the marketers to modify these flows. Specifically, the System Operators can redirect the transit flows into the two control areas by changing the topology of the network or by modifying the characteristics of the lines through phase shifters. These actions are beyond the control of the marketers who can only select the origin and destination of their transactions but not the transit path.

Here is a more extreme situation. Consider a unitary transaction between the two neighboring areas *I* and *III* (e.g. from node 1 to node 3). Kirchoff's laws imply that 0.0625 Mw of this transaction ($PDF_{(2\text{-}5)3} - PDF_{(2\text{-}5)1}$) flows through line (5-2) of zone *IV*. In other words, a transaction between two adjacent areas partially flows through other areas. It spreads through the whole grid. Directive 96/92/EC does not elaborate on this pervasive effect. But the definition of Paragraph 2(a) of Article 2 does so in a way that reconciles physical and commercial realities. The recognition that loop flows are part of transit is fundamental. Most of this paper is about the implication of this physical reality. Paragraph 2(b) of Article 2 introduces a first consequence namely congestion:

'Congestion' means a situation in which an interconnection linking national transmission networks cannot accommodate all transactions resulting from international trade by market operators, due to a lack of capacity.

Congestion is a key issue in electricity markets; we further discuss its physical nature before elaborating on the definition adopted in the draft Regulation.

4.1.2. *The physical notion of congestion*

Physically, congestion arises when a transmission resource is saturated. This can happen in different ways. Congestion in the North South network (Figure 1) occurs when the flow between the two zones saturates the single line linking them. This is akin to congestion of a single road linking two areas except for one major difference: queues are not possible in electricity with the consequence that the network collapses whenever there is a traffic jam.

Consider the more complex case of the six-node/two-zone meshed network (Figure 3) and assume that lines 1-6 and 2-5 respectively have 180 and 200 Mw thermal limits, all other lines having an infinite capacity. Congestion arises when it is impossible to further transfer electricity from zone *I* to *II*. Because of Kirchoff's laws, this may happen when one of

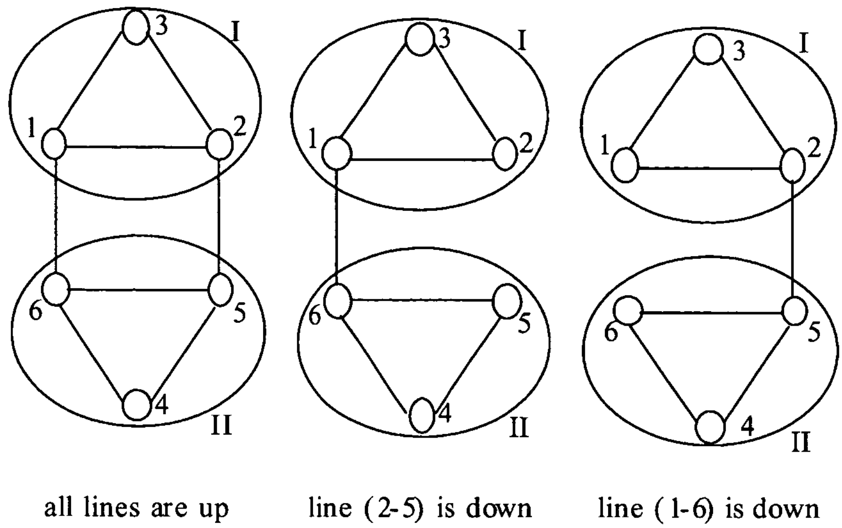

Figure 5. n-1 criterion.

the lines (say 2-5) is saturated even though the other (say 1-6) still has idle capacity. Take the case where one wishes to transfer power from node 2 in zone *I* to node 5 in zone *II*. The transaction is limited to 320 Mw ($200/(PDF_{(2\text{-}5)2} - PDF_{(2\text{-}5)5})$ with line 2-5 saturated and 60 Mw of unused capacity remaining in line 1-6 (the flow on this line is 120 Mw equal to $320*(PDF_{(1\text{-}6)2} - PDF_{(1\text{-}6)5})$). Even though one of the lines has spare capacity, physical laws prevent the Systems Operators from using it. In short, the transmission capacity between the two zones is not the sum of the capacities of the two lines.

Reliability adds a further complication. For reliability reasons, electricity networks are commonly operated according to the n-1 criterion. This principle provides that a dispatch is only deemed feasible for the network if the flows that it entails are feasible in each contingency where a line defaults (Figure 5).

Apply this notion to the interconnection between zones *I* and *II*. There is congestion whenever the flow between zones *I* to *II* in any of the two default states saturates the remaining operating tie lines. Consider again the above example of a transfer from node 2 in zone *I* to node 5 in zone *II*. The transaction will be limited to 180 Mw even though only 67.5 and 112.5 Mw flow in lines 1-6 and 2-5 in the normal state. The physical limits of the lines in the default states are reached even though none of the lines of the interconnection is at capacity in the normal state. As will be seen later, more exotic circumstances may add to the strangeness of congestion.

4.1.3. *An ambiguous definition of congestion*

Paragraph 2 recognizes congestion where an interconnection cannot accommodate "transactions resulting from international trade by market operators due to a lack of capacity". Paragraph 2 defines neither international trade nor interconnection. We interpret "international" as "cross-border". Directive 96/92/EC (EC 1996), which applies to the draft Regulation defines "interconnectors" as "equipment used to link electricity systems"; this is almost the language of paragraph 2b. We use "interconnection" in the sense of a set of interconnectors linking two electricity systems and broadly identify the saturation of the "interconnection" with a saturation of at least one of its constituting "interconnectors". Are these definitions adequate?

Consider the North South example first. The physical congestion is well captured by the definition: the line between North and South is saturated if and only if the interconnection linking North and South "cannot accommodate all transactions resulting from international trade by market operators, due to a lack of capacity".

Consider now the example of a meshed grid constructed on the six-node/two-zone example. Assume two domestic and one international transactions. Domestic transactions in zones *I* and *II* respectively trade 1000 Mw from node 1 to node 3 and 1000 Mw from 4 to 6. The international transaction *I-II* trades 100 Mw from node 1 to 6. Altogether the flow in line (1-6) amounts to 187.5 Mw (62.5 Mw from domestic transaction *I*, 62.5 Mw from domestic transaction *II* and 62.5 Mw from the international transaction). The thermal limit of line (1-6) is 180 Mw, which implies that it is saturated (an excess flow of 7.5 Mw in one of the interconnectors). This congestion is recognized by the definition of paragraph 2 to the extent that "all transactions resulting from international trade cannot be accommodated". But one may as well argue that it is impossible to accommodate the national transactions! Each transaction indeed entails a flow of 62.5 Mw in line (1-6) and it is the sum of them that saturates it.

Suppose now that domestic transactions increase by 50% while international trade disappears. The flow in line 1-6 is still 187.5 and there is still congestion in the physical sense. But the interconnection trivially accommodates all international trades since there is none. Is this a congestion in the sense of paragraph 2? No apparently but the paradox disappears and the physical congestion is indeed recognized if "international trade" is replaced by "trade". One can also find bizarre that the internal market singles out certain transactions on the sole ground that they are international.

As a last example, suppose that line 1-2 in zone *I* has a thermal capacity of 250 Mw (this is one of the few cases in this paper where we consider saturation of a domestic line) and consider the previous domestic transaction of 1000 Mw in zone *I*. These 1000 Mw going from node 1 to node 3 entail a flow of 291.7 Mw on line (1-2), which exceeds its thermal limit. This domestic transaction prevents any international trade from node 1 to zone *II*. There is a lack of capacity in the network, but not on the "interconnectors" linking the two control areas. This lack of capacity occurs without any international transaction. Is this a congestion in the sense of the draft Regulation? One can always argue that it all depends on the exact definition of interconnection and hence on the computation of transfer capacity. Alternatively, one can argue that this excess flow on a domestic line should first be removed by domestic measures and that congestion in the sense of paragraph 2 only occurs when there is an international transmission. But, all this is not defined in the draft Regulation. Moreover, as will be argued later, the notion of transfer capacity is itself inherently ambiguous and the differentiation between domestic and international transactions unnatural in a "real integrated single market".

Do cases like this occur in practice? They surely do. In periods of low demand, Svenska Kraftnät occasionally reduced the capacity on the interconnectors between Denmark and Germany because of congestion on its domestic grid. This is particularly noteworthy as Sweden is generally recognized as having a strong system with little congestion and ample counter trading resources. As another example, TenneT attributed some limitations on the interconnection between Belgium and the Netherlands in the winter of 2000 to the damages caused by a storm to the domestic French grid.

4.2. *Article 3: Network Externalities Should be Internalized*

Loop flows are almost textbook examples of economic externalities. They result from an agent's action and influence (limit or enhance) the possibilities of other agents to act. Standard economics recommends internalizing externalities. This is also what Article 3 of the draft Regulation does, at least to some extent. Specifically, paragraph 1 states that

> Transmission system operators shall receive compensation for costs incurred as a result of hosting transit flows of electricity on their network.

Paragraph 2 further requires that

> 'The compensation referred to in paragraph 1 shall be paid by the operators of national transmission systems from which transit flows originate and/or the systems where those flows end.

The first principle is sound but the second is controversial.

4.2.1. *Who should pay for transit costs?*

Consider the six-node/four-zone example (Figure 4) and a transaction from zone *II* (generation at node 4) to zone *I* (demand at node 3). Zones *III* and *IV* may incur costs because of this trade. The draft Regulation requires that these costs be compensated. This is in line with economic reasoning. Who should pay the compensations? The draft Regulation states that the operators of those systems from which transit flows originate and/or those systems where these flows end should pay these costs. ETSO disagree (ETSO 2001f). Economic reasoning supports ETSO's position: those who are responsible for the costs should pay. TSOs *I* and *II* did not cause transit costs and hence should not be liable for them. TSOs will thus charge these costs to domestic users in their control area. But they can do so in different ways. One approach is that *I* and *II* recover these costs from the marketers who caused them. This does not create distortion of competition. But TSOs *I* and *II* could also socialize these costs. This distorts competition and hence the incentives to trade.

The European Commission apparently recognized the danger at the November 2000 meeting of the Florence Regulatory Forum when it argued, "it is not possible to accept 'that the potentially different approaches at Member State level do not result in distortion of the IEM' " (FRF 2000b). The Draft Regulation does not go that far: it states in Section III.1 of the explanatory memorandum "apart from exceptional cases, it is technically not-yet-possible to identify whether and to what extent an individual exporter/importer causes transits. Therefore, the draft Regulation does not foresee a mechanism whereby individual exporters or importers are directly held responsible for transit flows". This says that it is not-yet-possible to charge transit costs to those who caused them. Needless to say large transit costs would be a stumbling bloc to the IEM if they cannot be properly internalized. A nodal system would remove this stumbling block. But the Florence documents do not consider nodal prices.

4.2.2. *Incremental costs of transit or transmission*

Suppose we neglect this difficulty, would paragraphs 1 and 2 suffice to define a good organization of cross border trade? Not really: one still needs to compute the "cost incurred as a result of hosting transit flows of electricity on their networks". This is handled in Paragraph 6:

> The costs incurred as a result of hosting transit flows shall be established on the basis of the forward looking long-run average incremental costs (reflecting costs and benefits that a network bears from hosting transit flows compared to the costs it would bear in the absence of such flows).

The introduction of average long run incremental costs (ALRIC) confirms a jurisprudence initiated in telecommunication. The principle also looks reasonable: those suffering incremental costs because of transit should recover them. But ETSO (ETSO 2001f) asks for clarifications on this statement. How should ALRIC be determined? The draft Regulation only provides a definition; is this really operational? Take the (uncontroversial) definition of incremental costs given in Hunt and Shuttleworth (1996): "Incremental cost is sometimes used instead of marginal cost, when referring to the cost of an increment of use sustained over a long period. It is the difference between total system costs with and without the increment in use". Computing the incremental cost of some transmission activity therefore requires comparing the cost of transmission systems for some increment of transmission activity sustained over a long period. But Paragraph 6 requires selecting a sensible increment of *transit flows* not of transmission flows. It accordingly demands to choose an incremental transit activity sustained over a long period.

We illustrate the situation on the six-node/four-zone model and focus on the network of control area *IV* (nodes 2 and 5 and line (2-5)). For the sake of this illustration, we temporarily locate a generator at node 3 in zone *I* and a demand in node 4 of zone *II*. We assume that zone *II* imports from zones *I* and *III*, while zone *IV* does not import (consumption in node 5 is equal to generation at node 2). All transactions that use the grid of zone *IV* demand the same network service namely an injection at node 2 and an off-take at node 5. Zone *IV* incurs transit costs because of the transactions *III-II* and *I-II*. According to paragraph 2, these need to be compensated by the TSOs of zones *I*, *II* and *III*. The compensation mechanism first requires the TSO of zone *IV* (or another agent) to select an "increment of (transit) use sustained over a long period" for both transactions *III-II* and *I-II*. Doing this in a sensible way is certainly a challenge given the current stage of development of the IEM; but suppose it can be done.

By definition, the end result of the computation of the average long run incremental cost depends on the size of the "increment of use sustained over a long period". There is no reason why this should be the same for the transits from *III* to *II* and from *I* to *II*, neither for control area *IV* own use of its network. There is thus no reason for the ALRIC of both transits to be the same or to be equal to the ALRIC of zone *IV*. Does the draft Regulation then imply that TSO *IV* can charge two different ALRICs to TSOs *II-III* and *I-II* for the same use of the network (injection in node 2 and off-take in node 5)? Does it also mean that TSO *IV* is allowed not to charge anything for its own use of the network in case the ALRIC of its own transactions were zero? This looks like plain discrimination.

At least, it is not an equality of treatment. The obligation to separately compensate for flows due to transit and domestic transactions on the basis of their individual ALRIC adds to the drawbacks of charging TSOs, and not marketers, for transit costs.

Note that both paradoxes immediately disappear if the ALRIC is computed once for the global *transmission* activity irrespective of whether it is transit or domestic transmission. In other words, the difficulty disappears if domestic and international transactions are put on an equal foot, something that appears quite reasonable in a "real integrated single market". Any distinction between domestic and transit flows is bound to introduce, via the ALRIC, an inequality of treatment between domestic and other uses of the network. Any further distinction between different transit sources is bound to introduce, for the same reason, an additional differentiation of treatment between transits. This is not surprising: ALRIC is an ad-hoc substitute of long run marginal cost. But it does not inherit all its good properties, especially when it comes to send non-discriminatory signals. Marginal costs are by definition non-discriminatory, but average long run incremental costs are not.

4.2.3. *What should incremental costs include?*

The difficulty of computing "forward looking long run average incremental costs" is further exacerbated by disagreements among participants to the Florence Regulatory Forum as to what to include in these costs: losses, congestion and/or investments? First principles provide an answer. Long run average incremental costs are substitutes of long run marginal costs. The determination of the former should therefore follow the logic of the latter. Standard reasoning reckons that marginal investment cost should, under usual economic assumptions, be equal to the sum of marginal congestion and losses costs. Transpose this principle to incremental costs: incremental investment costs must be approximately equal (strict equality cannot be guaranteed with incremental costs) to the sum of incremental congestion and losses costs. Either one, that is investment or the sum of congestion and losses costs can thus equivalently be used as the relevant incremental cost. Maybe indivisibilities and economies of scale of the lines justify preferring investment costs. This can be debated on rational grounds. But any other mix, such as the sum of investment and losses costs, as is sometimes proposed, cannot be economically justified.

4.2.4. *Can one really compute incremental costs in an interconnected system?*

It remains to compute the relevant incremental investment (or sum of congestion and losses) costs. Is this easy? Participants to the Florence Regulatory Forum have expressed the wish to have unambiguous rules to identify investments due to loop flows and transits. Such rules would allow one to charge the costs of these investments to the market participants that benefit from them. But these ideal objectives are probably impossible to reach. It is indeed difficult, if not impossible, to effectively identify who benefits from a reinforcement in a strongly meshed network. One can certainly devise rules and procedures, but the difficulty is to make them economically meaningful. A preliminary question is whether TSOs should compute incremental cost individually, that is neglecting network externalities or cooperatively, that is taking them into account. The resulting cost is likely to be too high, if not completely arbitrary, in the first case. It will require a supra national organization (e.g. ETSO) in the second case. In both cases, a difficult allocation problem (a cooperative cost allocation game problem) will have to be solved to share the cost among the benefiting parties. Are we sure we can do this in a sensible way? The bets are that the measurement and use of the average long-run incremental cost will be plagued by considerable arbitrariness and hence be prone to litigation.

4.2.5. *Can ETSO compute incremental costs?*

ETSO asked clarifications about the use of long run incremental costs. This is not a surprise. ETSO did not really think in terms of incremental costs so far. This is best illustrated in the provisional tariff now discussed since the fifth Florence Regulatory Forum (see FRF 2000a, 2000b, 2001). ETSO (see ETSO 2000b, 2000c) derived the export charge by allocating existing costs, not by computing forward-looking incremental costs. The whole notion of horizontal network, which underlies this export charge, is a rephrasing of cost allocation into cost causality. The language may have a flavor of incremental cost but the bottom line is cost allocation. These computations suggest that ETSO is still far from a sensible implementation of average long-run incremental cost of transmission, let alone of transit. And not surprisingly so because the difficulties are real.

4.2.6. *To sum up on ALRIC*

There exists an extensive experience with Average Long Run Incremental Cost in the UK. It shows that the notion must be validated in each particular case. Its applicability to the more complicated context envisaged by the draft Regulation remains untested at this stage. Various authors have already pointed out that the ALRIC is not a clear-cut notion (Laffont and Tirole (2000) discuss the approach in the case of telecommunication and argue that its application is subject to considerable discretion (see pp. 148 and the subsection "4.4.1 Discretion in the Measurement of the ALRIC")). Specifically in the context of the draft Regulation, the application of ALRIC to transmission requires to define an "increment of use sustained over a long period". This is a challenging task in the current unstructured IEM. Selecting this increment of use for transit (and possibly even individual transits), not for transmission further adds to the complication. Not only is the approach questionable in theory, it may turn out counter productive in practice. But even when assuming that this can indeed be done, it remains to compute the incremental costs of each grid for the different increment of transit transactions. The pervasive externalities of the power grid make this a daunting task. In short, those proposing the approach should provide evidence that it can indeed be implemented. If our reading of the draft Regulation is correct, this rule is not "as simple as possible".

4.3. *Article 4: There are Charges for Accessing the Network*

Article 4 elaborates on the structure of the access charges to the network. Access charges have been extensively debated in the industrial economics literature. But, except for congestion pricing this literature does not offer anything special to electricity. Not surprisingly, the draft Regulation therefore limits itself to general remarks.

4.3.1. *Sound but too general principles*

Paragraph 1 of Article 4 states that

> Charges applied by national grid-operators for access to national networks shall reflect actual costs incurred, and shall be transparent, approximated to those of an efficient network operator and applied in a non-discriminatory manner. They shall not be distance related.

Except possibly for the restriction imposed by the last sentence, these are very sound albeit quite general objectives. But ETSO (2001f) sees inconsistencies and seeks clarifications about the efficient network operators. The reference to distance related tariffs might not help either. Paragraph 1 bans distance-based tariffs. But it is an established policy in the UK to use models that minimize Mw.Km (a measure that includes a distance criterion) in order to derive long term incremental cost based locational signals. One should also note that the minimization of Mw.Km was extensively used in the past to get a first cut into network investments. Efficient network operators, like EdF resorted to these models. Distance has thus a real, albeit involved, relation with incremental network costs. The prohibition of distance related access charges should therefore not be total. Banning distance based cost allocation is certainly economically justified. But one should not prohibit the computation of incremental cost on the basis of distance.

Paragraph 2 of Article 4 deals with the problem of the allocation of access charges between generators and consumers. It states that

> Generators and consumers (load) may be charged for access to national networks. The proportion of the total amount of the network charges borne by generators shall be lower than the proportion borne by consumers. Where appropriate, the level of the tariffs applied to generators and/or consumers shall provide locational signals, and take into account the amount of network losses and congestion caused.

These principles open many options. Specifically, access to the network can take the form of linear or non-linear tariffs or of sophisticated menus or sums of such tariffs. Sum of linear tariffs are common in practice: they include prices for energy (the commodity) and maximal demand (the demand charge). Non-linear tariffs also include a fixed component. Their efficiency properties are extensively discussed in the regulatory economics literature. Both the fixed and variable components of the linear or non-linear tariffs can include the locational signals mentioned in Paragraph 2. These locational signals can depend on congestion and losses.

Some of these options have been discussed in the Florence Regulatory Forum, others not. Specifically, the choice between linear and non-linear access charges did not retain much attention. In contrast, the respective charges paid by consumers and generators have been extensively debated. Some insist that generators pay an access charge; others argue that only consumers should pay. This obviously creates a distortion of competition that is hard to accept in the IEM. Generators that need to pay access charges in their home system suffer a competitive disadvantage compared to those that operate in a system where the consumer pays the entirety of these charges. This harmonization problem is well recognized in the explanatory memorandum of the draft Directive that devotes a whole section to the problem of the "Harmonization of national network charges". It is commonly admitted that generation is more price responsive than load. This justifies the suggestion that it is most efficient to recover network costs on load. This position seems to be gaining ground but is not fully embedded in the draft Directive that simply requires that

> The proportion of the total amount of the network charges borne by generators shall be lower than the proportion borne by consumers.

Full harmonization is thus unlikely to be achieved, with inevitable consequences on competition.

4.3.2. *What about locational component?*

The introduction of a locational component in the access charge is another issue of debate. In principle, locational components should be based on incremental costs that include losses, congestion (which are opportunity costs) or investment costs. They should not include existing network costs. But some participants to the Florence Regulatory Forum do not seem to accept these basic principles. Only after an agreement is reached on this fundamental issue, can one envisage to tackle the economic and computational problem raised by the inclusion of a locational component in the access charge.

4.3.3. *The other aspects*

The other paragraphs of Article 4 discuss technically less difficult, but still sometimes institutionally controversial issues. Paragraph 3 states that

> Payment and receipts resulting from the inter-transmission system operator compensation mechanism set out in Article 3 shall be taken into account when setting the tariffs for network access. Actual payments made and received as well as payments expected for future periods of time, estimated on the basis of past periods shall be taken into account.

This suggests that TSOs will not be a for profit organization, or at least that their profit will be regulated. This raises the usual question of providing the right incentives to TSOs (e.g. the incentive to offer maximal transfer capacities (see below)).

Paragraph 4 states that

> Exporters and importers shall not be charged any specific tariff in additional to the general tariffs for access to national networks.

This should exclude in the long run the ill designed export charge that is part of the provisional tariff (FRF 2000a, 2000b, 2001).

Finally, paragraph 5 states that

> There shall be no specific network charge on individual transactions for transits of electricity covered by the inter-transmission system operator compensation mechanism set out in Article 3.

This is similar in spirit to paragraph 4: specific tariff to export and import, or tariffs that depend on the nature of the individual transaction are not justified in a "real integrated single market".

5. ARTICLES 5 AND 6

5.1. *Article 5: The System is Based on Transfer Capacity*

Articles 5 and 6 deal with congestion, that is with the physical, but hopefully occasional, segmentation of the "real integrated single market". A good treatment of congestion is of central importance in a market that one ideally wishes not to be segmented. Article 5 introduces the main tools foreseen for this purpose.

Paragraph 1 of Article 5 assigns the responsibility of the transmission systems to the TSOs:

Coordination and information exchange mechanisms shall be put in place by transmission system operators to ensure the security of the networks in the context of congestion management.

Furthermore, as stated in paragraph 2,

The safety, operational and planning standards used by transmission system operators shall be made public. This publication shall include a general scheme for the calculation of the total transfer capacity and the transmission reliability margin based upon the electrical and physical realities of the network. Such scheme shall be subject to the approval of the national regulatory authority.

In stating these obligations, paragraph 2 also introduces the notion of "transfer capacity" which appears again in Paragraph 3:

Transmission system operators shall publish estimates of available transfer capacity for each day, indicating any available capacity already reserved. These publications shall be made at specified time intervals before the day of transport and shall include in any case week-ahead and month-ahead estimates. The data published shall include a quantitative indication of the expected reliability of the available capacity.

Loop flows, congestion and transfer capacities are cornerstones of the draft Regulation. But they are of quite different nature. Loop flows and congestion are physical realities irrespectively of their definition. Transfer capacity is just the opposite. It is a construct that may only be loosely related to physical and economic realities irrespectively of the effort made to define it. Transfer capacity only exists insofar as it is defined to exist. But the definition may be useless and even misleading. The draft Regulation makes an important contribution to the achievement of a "real integrated market" by introducing loop flows and recognizing their impact in congestion. But it stops short of drawing the full conclusion of this first step. Transfer capacity like incremental cost is a convenient but fundamentally ambiguous concept.

5.1.1. *TSOs must publish information on transfer capacities*

The grid creates externalities between market participants. These take the form of loop flows. Article 2 of the draft Regulation recognizes these externalities. A minimal requirement to tackle externalities is to provide information about them. What information? Pollution, which is the most widely discussed externality, can serve as a point of comparison. Environmentalists provide key information on pollution by constructing climatic, atmospheric pollution and river quality models. The aim of these models is to assess how much antropogenic gas, SO2 and No_x emissions or waste water the ecological system can assimilate.

Paragraphs 1 and 2 of Article 5 require something similar from TSOs namely to ascertain the injections and off-takes sustainable by the grid and to indicate how one arrives at these figures. The capabilities of the grid depend on "safety, operational and planning standards" as well as on "transmission reliability margin". TSOs need therefore also document these aspects. But paragraphs 2 and 3 say more: they demand that the capability of the grid to accommodate injections and off-takes in different zones be expressed in terms of transfer capacities (TCs).

Take the six-node/two-zone example to illustrate what is at stake. The transfer capacity from zone *I* to *II* is meant to measure the maximal flow of electricity that can go from the former to the latter. As shown on Figure 6, this obligates TSOs to implicitly construct a North-South representation of the six-node network and to compute the maximal quantity of energy that can reliably flow from North to South.

Consider now the more complex example of the six-node/four-zone network. A representation of the network in terms of transfer capacity demands that the TSOs construct an equivalent four node network such as depicted on Figure 7 and assign figures of transfer capacities to the pairs *(I-III)*, *(I-II)*, *(III-IV)*, *(III-II)* and *(II-IV)* in both directions. Paragraph 2 subjects this computation to the review by national regulatory authorities. Last, it obligates TSOs to publish transfer capacities each day and estimates of these transfer capacities well in advance. It also requires "a quantitative indication of the expected reliability of the available data". Can all this be done with a reasonable degree of confidence? This raises two questions. Can this be done at all? If yes, do TSOs have the incentive to do it properly? We first turn to this latter point.

5.1.2. *On TSOs incentives*

First note that TSOs need information from one another in order to compute transfer capacities. But data on each other's grid and operational practice is a domain where the past may have left some asymmetry of

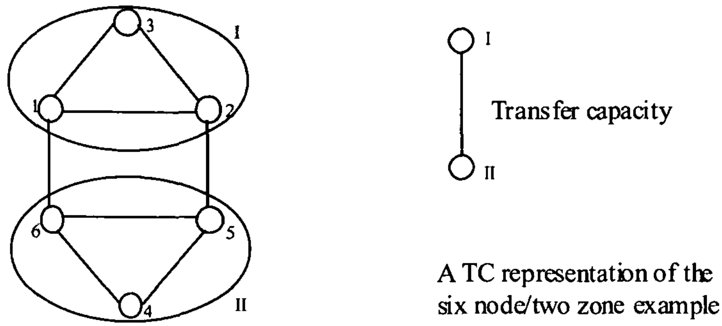

Figure 6. Transfer capacity for the six node/four zone example.

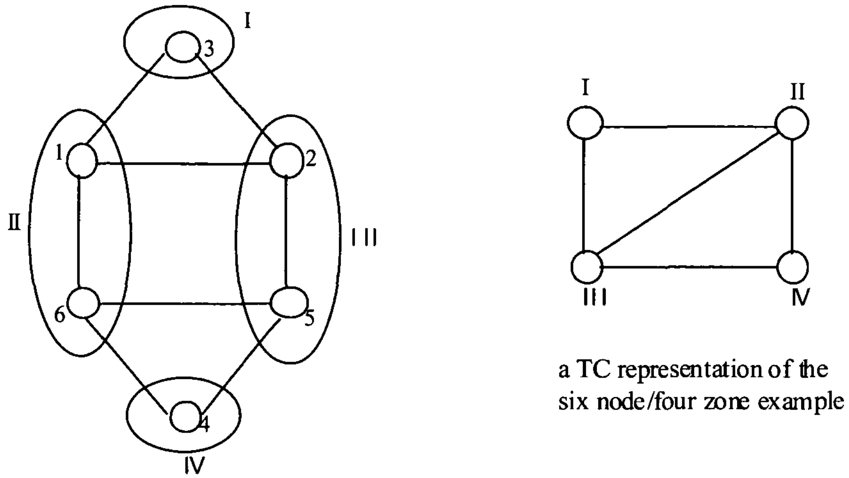

Figure 7. Transfer capacity for the six node/four zone example.

information. TSOs may also be of various levels of sophistication. Last, the current legislation permits the coexistence of different relations between TSOs and the incumbent generators. All this would be irrelevant if TSOs only worked for the common good. This is what ETSO assumes from its members (ETSO 1999, pp. 4–5). But it is not a common economic hypothesis.

We may alternatively consider the possibility that TSOs behave like other economic agents, that is, that they pursue their own goals given the incentives that they are subject to. There is little evidence that significant attention was given to the design of proper TSOs' incentives. In any case, the subject is poorly understood in the literature. Participants to the Florence Regulatory Forum have recognized at least part of the danger (and maybe much more) when they advised to construct a European load flow model. This construction may require the inception of a European TSO, possibly only endowed with the limited but crucial responsibility to assemble relevant network information. This European load flow model would also allow one to check that the figures produced by the national TSOs are consistent.

5.1.3. *On transfer capacity*

Does the draft Regulation set the right objective when it requires TSOs to compute and publish transfer capacities? ETSO says both yes and no with equal vigor. It first proposed to use transfer capacity in November 1999 (ETSO 1999). The organization advised at the time, "no better notion could be worked out by TSOs, simple enough to be used by non-specialists". But it also accompanied this statement with some caveat: "in many cases they (Net transfer capacity or NTCs) may be a somewhat ambiguous information ... to help market agents in managing the risk of transaction curtailment, NTC publication could include indications on upper or lower bounds, statistical uncertainty of published values and dependencies on numerous factors such as other cross-border exchanges in other directions". To be certain that users are sufficiently cautioned on the danger of using transfer capacities (ETSO 2000a) gives a detailed explanation of the difficulties of computing transfer capacities. Probably most astounding for "non specialists" is the property that 100 Mw from zone *I* to zone *II* is not necessarily equal to 100 Mw from zone *I* to zone *II*!! It may depend on which TSO computed the 100 Mw (page 11 in ETSO 2000a).

The core of the difficulty raised by transfer capacities lies in the fact that they do not obey usual arithmetic: "it makes no sense to add or subtract the NTC values given in the NTC table, as each value corresponds to a specific set of assumptions regarding power inputs and outputs" (p. 7 in ETSO 2000a). Specifically, this means that 100 Mw from zone I to zone II plus 100 Mw from zone *I* to zone *II* is not necessarily equal to 200 Mw from zone *I* to zone *II*. In the same way, 100 Mw from zone *I* to *II* is not necessarily compensated by 100 Mw from zone *II* to *I*. The reason of this strange behavior can be traced very easily. The use of the transfer capacity depends on the precise origin and destination of the transactions. ETSO (2000a, p. 5) states that "the resulting T(otal)TC- value ... is to be interpreted as the expected maximum volume of generation that can be wheeled through the interface between the two systems, which does not lead to network constraints in either systems, if future network conditions and especially generation scenarios were perfectly known in advance". Put it in other ways, in order to compute the maximal use of the network, one needs to make assumptions on the use of the network!! This definition is restated and elaborated in ETSO (2001a, p. 6).

Note with reference to the above discussion over congestion that ETSO, in contrast with the draft Regulation, does not limit itself to constraints on the interconnection; it also considers "network constraints in either system". As the draft Regulation though, it computes TTC by seeking limitations in transfers from zone to zone and hence also places a priority of international transactions with respect to domestic ones. As argued above, this thinking does not really look compatible with a "real integrated single market" (the use of "wheeling" is a clear indication of the underlying reasoning).

Notwithstanding the strange properties of transfer capacities, the draft Regulation obligates TSOs to announce values of transfer capacities. It is no surprise, but it should be illuminating, that ETSO wishes to refrain from making any commercial commitment on services subject to such unusual arithmetic. Why should then marketers trust a transmission concept that TSOs do not trust themselves?

5.1.4. *Transfer capacities make sense in radial networks*

Consider first the simple case of the North South example with perfectly reliable lines. Marketers willing to inject in North and withdraw in South need a certain amount of line capacity services from North to South. Because lines are supposed perfectly reliable, the service can be firm. It is also perfectly homogenous: 100 Mw of line capacity from North to South for marketer A is the same as 100 Mw of line capacity from North to South for marketer B and the sum of these services is 200 Mw. Transfer Capacity is perfectly defined and obeys usual arithmetic. Referring to the words of ETSO, it is not an "ambiguous information" and there is no need to caution marketers about the dangers of using this information. TSOs are thus able to define the total capacity every day and to perfectly predict their future values. Trading these line capacities completes the market.

Reliability complicates things but keeps them manageable. Consider the same North-South example and assume now that two lines of identical capacities but subject to forced outages link the two zones. The TC between the two zones remains well defined but is now contingent on line failures. A marketer willing to trade 100 Mw from North to South can no longer secure a firm 100 Mw capacity. But it may obtain alternatives. The marketer can procure 100 Mw of capacity contingent on the state of the network (this would be an unusual contract). Or it can purchase 100 Mw of transmission service North–South with different levels of priority and pay accordingly. Another possibility is to get an insurance contract that pays some compensation in case the network or part of it is down. This insurance contract can be replaced by a financial contract with payoff depending on the electricity prices in North and South. Last, the marketer can secure back-up incremental and decremental generation in both areas. In short, 100 Mw of transfer capacity is no longer a well-defined service but it can be completed by more complex services (such as 100 Mw from North to South with first priority) that are well defined.

Contracts for contingent services associated with additional insurance or financial contracts allow marketers to trade risk, something which is of the essence in an uncertain environment. These contingent contracts also obey standard arithmetic: a contract of high priority does not add up to a contract of low priority, but two contracts of the same priority add up. As a result, marketers are not given "indications on upper or lower bounds, statistical uncertainty of published values and dependencies on numerous factors such as other cross-border exchanges in other directions". They are offered a set of contingent contracts that, if in sufficient number and diversity, allow them to trade risk. Trading these contracts completes the market.

Contingent services are common place and the trend is to tailor them more and more to customers' needs. This may make life more difficult for non-specialists but TSOs can train them (see for instance PJM training material on http://www.pjm.com/). Every business requires some learning and there is no reason why the complex electric commodity would be an exception. This more intricate environment can be illustrated on a truck example. Suppose that two marketers A and B want similar trucks delivered at the same time. Assume that the manufacturing line is subject to breakdown. Because of these failures, the manufacturer cannot commit to deliver the trucks on a given date. But it can offer a contract that specifies that it will temporarily supply a replacement vehicle in case the truck is not delivered at the agreed date. Alternatively, truck rental companies may provide that type of contract. These contracts allow one to trade risks and complete the market.

In short, reliability complicates the task of the TSOs and of the marketers but does no make it impossible. Transfer capacities are still amenable to market operations. TSOs can no longer announce firm daily transmission capacities and both TSOs and marketers have to deal with risks. But there is nothing very special in this. There are plenty of services that are not guaranteed and for which one creates insurance or hedging instruments.

TABLE II

TC as a function of the origin and destination of the cross border transaction.

1-6	1-4	1-5	2-6	2-4	2-5	3-6	3-4	3-5
288	320	360	360	355	320	320	355	355

5.1.5. *Transfer capacities are ill defined in meshed networks*

In contrast, loop flows make TCs truly ambiguous. In order to see this, consider the six-node/two-zone problem. The TC between zones *I* and *II* is no longer well defined as it depends on the pattern of loop flows. As Table II illustrates, TC changes with the trades that it is meant to allow. In ETSO's wording "The Total Transfer Capacity TTC, (that) is the maximum exchange programme between two areas compatible with operational security standards applicable at each system if future network conditions, generations and load patterns were perfectly known in Advance" (ETSO 2001a, p. 6).

This dependence of TC on flows has important consequences. First note that, in contrast with the two-node example, a marketer no longer uses a transfer capacity from zone *I* to zone *II*. Marketer A who wants to trade 100 Mw from 1 to 6 will have no use of 100 Mw from 2 to 5. Transmission service from *I* to *II* is not what TSOs produce either. 100 Mw from 1 to 6 and 100 Mw from 2 to 5 require different uses of the transmission network. A TSO is not indifferent between both. Therefore, "1 Mw transmission capacity" from *I* to *II* is not a physical transmission service whether for the grid operator (the TSOs) or for the users (the marketers). If 100 Mw from *I* to *II* is not the service produced and consumed, what is that service and how will the market find its price and quantity?

There has been considerable controversy in the US on the subject of congestion management (see the flow gate debate on http://www.ksg.harvard.edu/hepg/index.html and http://www.stoft.com/x/flowgate/). But the recourse to transfer capacity is not a contender in those discussions because it is a priori clear that it cannot solve the problem. The difficulty introduced by TCs can be stated very simply: a TC market does not trade the physical services that marketers use and TSOs produce. It trades something else, namely a synthetic (derivative) transmission service (the TC) without trading the underlying physical services (line uses or point to point transmission services). It is like trading a stock index with varying weights without trading the securities and not knowing the weights. The market is incomplete. The truck example may again illustrate the situation.

Suppose that two wheat marketers require trucks equipped with special features. Marketer A wants a truck with features A while marketer B uses a truck with features B. Would the truck producer promise delivery with an ETSO like statement that in order "to help them in managing the risk of not being delivered the truck they want, they will be given indications on upper or lower bounds on the number of trucks with different features that can be produced, statistical uncertainty of published values and dependencies on numerous factors such as the amount of trucks of a certain type that the company has to manufacture that year"? Would the production plan simply record a demand for two trucks, ignoring the additional features? If manufacturing and assembling features A and B only place minor strains on the production facilities, the manufacturer may indeed plan its production without bothering about features until the last moment. It will carefully distinguish between features A and B otherwise. But in any case, it will deliver a truck with features A to client A and features B to client B.

How does this apply to transmission services? The principle is simple: one need not worry about differentiating transmission services from 1 to 6 and from 2 to 5 if the transmission system is over-sized. Trading transmission capacity will suffice. The market is incomplete but this is not important. In contrast, the difference between the two transmission services is crucial if the grid is tight. Neglecting this difference and aggregating the two services into one makes market incompleteness consequential. Unfortunately, cross border transmission capacities are tight.

To sum up, paragraph 3 of Article 5 raises many important questions. TSOs may indeed announce transfer capacities the day ahead, but this may be of little relevance for the "real integrated single market". Most energy transactions are planned well before the day ahead in a pure bilateral system. And because TSOs may only have to give indicative values of TCs before that time, one can expect that these transactions will suffer from the uncertainty associated to the transmission capacities.

Is it possible to hedge these uncertainties? This would be too long to argue here. But note that the uncertainties affecting TC values because of loop flows are of a completely different type than those normally encountered in financial or insurance markets. Specifically they are not the consequences of equipment failure or weather variations. These uncertainties arise because Kirchoff's laws prevent transmission capacities to be exactly computed until the very moment the transactions that use them take place.

5.1.6. *Transparency does not solve the problem, but it may help uncover it*

TC is thus a central piece of the design of the real integrated market desired by the EC, but it may also be its Achille's heel. The draft Regulation tries to render the notion as acceptable as possible. Surely, it is necessary to indicate how TC is computed. And it is also essential to revise the computation often. This may be a burden but it is necessary. The problem is that it might be far from sufficient. Transfer capacities is an economically flawed notion when the grid is tight. The best one can hope for is that the transparency recommended by the draft Regulation helps uncover this logical flaw.

5.2. *Article 6: Address Congestion with Market Based Solutions*

Paragraphs 1 and 2 are the core of Article 6. They state that

> network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals to the market parties and transmission system operators involved. Transaction curtailment procedures shall only be used in emergency situations where the transmission system operator must act in an expeditious manner and re-dispatching or counter-trading is not possible. Market actors which have been allocated firm capacity shall be compensated for any curtailment of this firm capacity.

These paragraphs contain three key statements. We successively examine each of them.

5.2.1. *On the need for market solutions*

Market based congestion relief seems natural today. But this has not always been the case. The first ETSO document on congestion management (ETSO 1999) indeed considered a proposal that ruled access to transfer capacities through priorities. The proposal was formally rejected and no longer appears in the draft Regulation or in recent ETSO's documents. But its underlying rationale is still present in the background. It may thus be interesting to revisit this priority based congestion management proposal. Our aim is not comprehensiveness or historical interest; but we believe that the discussion may illustrate the nature of the non-market based reasoning that still pervades, admittedly in much weaker form, current transmission proposals. We exclude economic bid based rules from this discussion, as these are true market solutions. We instead focus on rules like first come first serve or proportional allocation, which are pure quantitative instruments and do not contain any economic signal.

As argued above, the notion of transfer capacity embeds an incomplete transmission market. We here claim that an allocation of transmission capacity on the basis of priority rules is the most extreme case of this

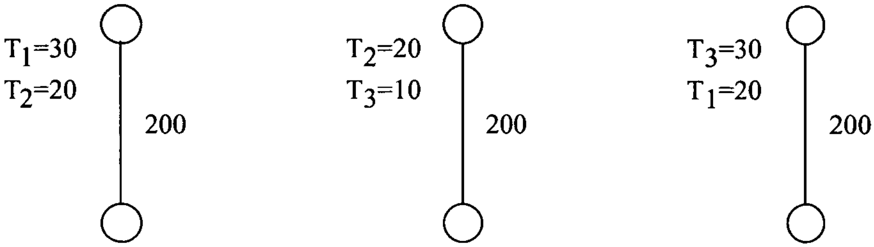

Figure 8. Allocation of TC through priority rules.

incompleteness: it creates an energy market with no market for transmission services. To see this, consider the two-node example with perfectly reliable lines. As argued before, transmission capacity is here a well-defined economic resource. Marketers demand and TSOs supply reservations of line capacity. Trading these line capacity reservations completes the market. What if line capacity reservations are not traded but allocated through priority rules? The market becomes incomplete. To get a first insight into this situation, consider a sample of trade patterns on the North-South example. Transactions T_1, T_2 and T_3 (100 Mw each) respectively have gross margins (before paying for transmission) of 30, 20 and 10 euros/Mwh. Figure 8 shows the transactions that obtain line capacity reservation in each possible allocation of transmission capacities based on priority rules.

All patterns are compatible with quantitative priority rules. But only the one that gives the capacity of the line to the higher margin transactions is the outcomeof an efficient operation of the power system. What is the problem? Again, it is both simple and deep: marketer T_3 wishes to trade any transmission right that he/she would obtain from a priority based rule with a marketer who does not have any capacity reservation but makes a higher margin on his/her transaction. But the priority-based system does not permit this trading and hence this arbitrage. Therefore, the absence of arbitrage on the transmission market distorts competition in the commodity market. In the parlance of the introduction, the market is incomplete because the market for transmission services is missing. As can be seen from these trade patterns, priority rules also introduce a fundamental indeterminacy in the market. There is no way to tell who will gain access. All outcomes are equally plausible. Only one is economically efficient and compatible with the desired operation of a "real integrated single market" but there is no way to insure that it will emerge from the process. Note that power dispatchers would never have run their system on the basis of priority rules in the days of regulation. But interestingly enough, the Californian restructuring force the ISO to use quantity-based procedures to deal with congestion!

5.2.2. *Auctions are a step in the good direction. But just one step*

Priority based congestion management restricts spatial arbitrage. Alternative, market based solutions are thus necessary. This is what paragraph 1 of Article 6 acknowledges. Different methods initially introduced in ETSO (1999) and later elaborated in various documents are summarized in the appendix of the draft Regulation. The explicit auction of TCs is the first market-based proposal in ETSO (1999). ETSO describes it in these terms "Marketers bid for parts of the NTCs (recall that ETSO was referring to Net Transmission Capacities)" "The bids are stacked, highest bid first, until NTC is completely used". "A transmission market clearing price is calculated and each participant pays this". "Once the TC is completely used, either the process is stopped, or there is some re-dispatching, according to the level of the clearing price and the process may go on with the extra trade possibilities". TC auctions exist in various places at the time of this writing (see ETSO 2001e, p. 14). We discuss the underlying principle on our stylized networks.

Consider first auctioning the capacity of a perfectly reliable line joining the two nodes of the North–South example. As argued in the introduction, current technology does not allow for real time auctions of TCs. By necessity, the auction is a forward market where marketers express their valuation of the line capacity. Under ideal economic assumptions, the outcome of this market is almost akin to a dispatch that operates generators in economic order, subject to tie-line capacity constraints. But there is one difference: the TC auction is a forward market while the dispatcher operates in real time. Does a forward market perfectly substitute a real time dispatch? No! As is well known demand and supply of electricity is continuously and randomly changing over time. Deviations between forward and real time transactions are almost inevitable. They need to be handled in one way or another. Well articulated (complete) forward contracts that specify recourse actions in response to deviations can play that role. The design of such contracts has not been explored so far in electricity. In any case, this seems too much beyond the current state of discussion to be considered here. The inception of a balancing mechanism that operates in real time is the only remaining solution. This mechanism can be administratively managed (with penalties) or take the form of a spot market. Neither the draft Regulation, nor the draft Directive foresees this spot market. ETSO and CEER documents do not mention it either. Most likely it is left to national discretion.

Member States have different attitudes with respect to the creation of a spot market. A sound interpretation of the principle of subsidiarity would have required that the design of this real time market be decided at European level (in this case ETSO level) and not be left to Member States. This is not what happened. One may thus conjecture that administratively determined penalties will rule deviations between forward and real time transactions in many continental markets. But it is a spot energy and transmission market that would best permit marketers to arbitrage between the forward market and real time operations. An administrative balancing system distorts the prices in the forward market because it construes price expectations on administratively defined penalties. A forward TC market without a real time balancing market, (or a set of well articulated contracts on deviations) is thus an incomplete market, even in the two-node example. Only when deviations in supply and demand between the auction and real time do not exist, will the market be complete. What is the problem? It is very similar to the one mentioned about priority based allocation of transmission services: administratively regulated penalties in real time, that is economically meaningless real time prices, limit or distort marketer's arbitrage possibilities. But arbitrage is the driving force of the "real integrated single market" in a bilateral system. It is that very essential activity which is affected.

As argued above, line outages make transfer capacities more complex but not impossible to manage through the market. Contingent transmission services need to be defined to accommodate line failures. Additional insurance or hedging contracts are also needed to complete the market. This is doable but is foreseen neither in the draft Regulation nor in ETSO proposals that only recommend that the definition of TCs "take reliability into account". What is the underlying physical phenomenon? Contingencies may change network resources in real time. This adds to the deviations that develop between the closure of the forward market and real time operations. This is not a new phenomenon but an enhancement of the one that already results from demand randomness, as we just discussed. It increases the recourse to adjustments and hence adds to the distorting effect of an administratively organized balancing mechanism.

5.2.3. *Can TC auctions work in tight grids*

Consider now a meshed network such as the six-node/two-zone example. As argued before, TC is now an ambiguous notion. TCs cannot be defined independently of the transactions that demand them. And because one auctions TCs and not transaction dependent TCs there is no guarantee that network resources will be granted to the transactions that value them most.

In other words, the TC market might be in equilibrium without supply and demand of network resources balancing.

To illustrate this point, suppose that the TSOs agreed on an overall TC of 300 Mw from zone *I* to zone *II* (a value chosen between the max and the min TCs found in Table II that reflects assumptions on "future network conditions, generations and load pattern"). Assume two transactions A and B respectively from 1 to 6 and from 2 to 5, both of 300 Mw, contending for the transfer capacity. Transactions A and B are respectively valued at 30 euros/Mwh and 10 euros/Mwh. The equilibrium on the TC market is to allocate 300 Mw to transaction A at a TC price of 30 euros/Mwh. But this does not fit with the 288 Mw available for a transaction from 1 to 6. The equilibrium on the TC market is not an equilibrium for the network resources because the demand and supply of these resources do not balance. Revert now the assumption on the valuation of the transaction, that is, assume A and B are respectively valued at 10 euros/Mwh and 30 euros/Mwh. The equilibrium of the TC market is to allocate 300 Mw to B at a price of 30 euros/Mwh. But this does not saturate the 320 Mw available for transactions from 2 to 5. The price of transmission should thus be zero and not 30 euros/Mwh. Again, the equilibrium on the TC market is not an equilibrium of network resources because the price of unused resources is positive. In short, in no case is the equilibrium on the TC market an equilibrium of the real network resources: either the quantities or the price do not fit.

This mismatch can be interpreted in terms of the truck example. Trading TCs is like trading trucks without special features even though customers and production planning demand these features. There will be a mismatch in the supply and demand of special features. How important is the mismatch? It all depends on the capacity of the network. It is not very serious if the network is over-sized. It may be overwhelming when cross border trade possibilities are limited. ETSO is well aware of this possible mismatch when it mentions in the reference to the conclusion of the auction: "either the process is stopped or there is some re-dispatching . . .". ETSO therefore recognizes the disequilibrium and suggests removing it by re-dispatching. A similar concern appears in ETSO's discussion of transactions involved in several congestions "as an example, transactions could be handled through an optimal power flow ... This needs a strong co-ordination between the TSOs involved." What does strong coordination mean? We shall come back to that issue when discussing proposals 4 and 5 of ETSO (1999).

5.2.4. *In short: There are two flaws*

A straight TC auction introduces two flaws (in the sense of missing or incomplete markets) in the market design. One already appears in the forward TC market. Except when the network is over-sized, the auction does not guarantee that demand and supply of physical transmission resources match. The demand and supply of TCs may balance but transfer capacities are not physical network resources. Also, the price of TCs is not the opportunity cost (and hence the economically meaningful price) of the used network resources. Locational arbitrage is thus distorted. TCs are claimed to simplify the work of marketers. The reality is that they prevent them from properly arbitraging the commodity between different sources and destinations. Worse, this limitation already appears in the forward market where time is not a constraint for achieving full arbitrage. This drawback is to be appreciated considering that marketers are key agents in a bilateral organization of the market and the driving forces of the "real integrated single market".

The second flaw derives from the absence of a balancing market that relates energy and transmission in real time. Current restructuring indicates that one will often have at best an administratively organized balancing system. The consequences are twofold. First, there is no relation between energy and transmission prices in real time because deviations are administratively priced. This implies that real time energy prices in different locations can be inconsistent in the sense that they allow for un-exploited arbitrages. Second, these non-market based real time prices create inadequate expectations in the forward market and hence further perturb its operations. Again, this flaw distorts or limits the arbitraging activity of the marketers.

To sum up, one is bound to find a discrepancy between the TCs allocated by the auction and the real use of network resources (loop flows effect). This discrepancy may be exacerbated by outages and deviations between the forward market and real time operations (randomness effect). Further discrepancies arise if different types of auctions are run in different places at different times. This latter issue is recognized in ETSO (2001b). These problems have been extensively discussed and elaborated in the nodal vs. flow gate debate in the US. One cannot escape them and any attempt to do so will backfire.

The claim that transfer capacities simplify the work of marketers is misleading. True, marketers may find it difficult to simultaneously discover prices on the transmission and energy markets because of their complex interrelation. But doing away with physical realities is no simplification. It is possible to bundle the energy and transmission markets and hence keep transmission prices integrated in the price of the commodity. This is an implicit transmission market. It requires a nodal system, a solution that is not envisaged in the Florence documents even though it exists both in theory and in practice. Surely, leaving part of the price discovery to a computer program restricts the role of the marketers. But this is more benign than distorting price discovery by forcing an inadequate mechanism on marketers on the ground that "it can be used by non specialists". Alternatively, one may remove the need for the transmission market by (possibly uneconomically) expanding the transmission capacities. To sum up, a TC auction is a step in the good direction in the sense that it introduces a transmission market. But it is just one step: because TCs are not physical network resources, the transmission market fails to trade the real resources offered by the grid.

5.2.5. *Re-dispatch offers a remedy*

The forward TC auction may thus lead to unbalances between supply and demand of physical network resources. The resolution of the mismatch may be left to the real time balancing mechanism. Alternatively, one may try to already resolve part of it forward, using other instruments. This alleviates the burden placed on the balancing mechanism and hence improves the final outcome of the process: the less one resorts to an administratively organized balancing system, the smaller real time operations distort marketers' expectations. Is this possible?

ETSO suggests it is when it states, "either the process is stopped or there is some re-dispatching . . .". The TSOs organization even goes further when it states, "as an example, transactions could be handled through an optimal power flow ... This needs a strong coordination between the TSOs involved." This suggestion directly moves us into proposals 4 and 5 of ETSO (1999). We can indeed quickly dispose of market splitting, which is proposition 3 in ETSO (1999) as it is judged either too difficult to implement in the near future (EC 2001a) or inadequate for strongly meshed networks (ETSO 2001d). Proposals 4 and 5 have a dual role; they can be seen as stand-alone congestion management methods or as complements of the TC auction. In the language of the introduction, they complete the forward market by reducing the unbalance between the supply and demand of physical network resources that results from the sole auction of TCs.

Single zone re-dispatching

Single zone re-dispatching is the fourth congestion management method proposed in ETSO (1999). The principle is to find resources (incremental and decremental injections) in the "constrained TSO's own control area" necessary to relieve (part of the) congestion due to Cross Border Trade. The concept is easily illustrated on the two stylized networks.

Take the North–South example first. Counter-trading requires TSOs to change their dispatch in North and South respectively while keeping export and import from these nodes unchanged. This is clearly impossible. The method is thus inoperative in this example. But it can work in a meshed network. Consider the six node/two zone example and assume the same transactions as in section 4.1.3), namely 1000 Mw from nodes 1 to 3 in zone *I*, 1000 Mw from nodes 4 to 6 in zone *II* and 100 Mw from node 1 in zone *I* to node 6 in zone *II*. Suppose that TSOs assert again a Transfer Capacity of 300 Mw from zone *I* to zone *II*. The above transactions are compatible with the transfer capacity. Indeed, by definition none of the domestic transactions require TCs from *I* to *II* and the international transaction only demands 100 Mw, well below the 300 Mw announced in the auction. But loop flows entail a load of 187.5 Mw on line (1-6) therefore creating a congestion on that line. Counter-trading allows TSO to remove this congestion by re-dispatching 60 Mw ($7.5/(PDF_{(1\text{-}6)1} - PDF_{(1\text{-}6)2})$) between nodes 1 and 2 (recall that, except when stated otherwise, generation is located at nodes 1, 2 and 4). The resulting shift of 7.5 Mw from line (1-6) to line (2-5) removes the congestion. The re-dispatch does not change the total energy transferred from zone *I* to zone *II* but it makes it compatible with the thermal constraints of the lines.

Counter-trading induces a re-dispatching cost of 600 euros (obtained as $60*(20 - 10)$; recall from Section 3.2 that marginal generation costs are assumed to be 10, 20 and 30 euros/Mwh at nodes 1, 2 and 4 respectively). Re-dispatching costs are well recognized by ETSO. The organization suggests allocating these costs to those agents responsible for them namely "i.e. market players involved in extra cross-border transaction". This is in line with the definition of congestion in the draft Regulation that attributes congestion on the interconnection to international transactions. In the example, the reasoning leads to allocate the whole re-dispatching cost to the sole international transaction even though the three transactions contribute to exactly the same flow (62.5 Mw) on the congested line. Attributing the cost of re-dispatching to international trade gives domestic transactions all property rights on inter-ties, an assumption that is hardly compatible with the "real integrated single market".

As argued above, one can also and equally arbitrarily contend that the loop flows induced by the domestic transactions are at the origin of the congestion. Socializing re-dispatching costs over all marketers is an alternative to assigning them to some transactions arbitrarily defined as responsible for the congestion. ETSO rightfully recognizes that socializing re-dispatching costs eliminates any price signal (it gives the right price signal in the example but this is fortuitous). There is unfortunately no alternative to the dilemma as long as one does not consider nodal pricing. One shall either arbitrarily assign responsibility of congestion costs to certain transactions or socialize them over all transactions. The price signal is meaningless if not misleading in the first case; it is absent in the second one. This is hardly a market solution!

But something can hopefully be made of single zone re-dispatching if and when combined with TC auctions. As argued above, TCs do not correctly describe physical network resources. But they should at least provide some information about them. If so, a TC auction would not necessarily eliminate bottlenecks but it may reduce them. One can thus hope to arrive at smaller re-dispatching costs after the auction is completed. Combining both tools may thus be a reasonable idea. Will it work? We do not know. It does not work in this example where the auction does not ration the use of network resources: one offers 300 Mw of TCs and the demand for them is only 100 Mw. A mix of market splitting and counter-trading works in the mildly meshed grid of the Nordic system (see ETSO 2001d). The sole re-dispatching did not work in PECO (Hogan 1999) and certainly not in the predefined zones of California. There is thus some hope but no certainty. In any case, the simple two-node North–South example illustrates one potential cause of failure of pure re-dispatching: the method can become awfully costly, if not totally inoperative, when re-dispatching resources are scarce.

Cross border counter trading or coordinated re-dispatching (CCR)

Cross border counter-trading is the fifth proposition of ETSO (1999). It extends the previous approach to re-dispatching across border constraints. The name counter-trading comes from the possibility offered to TSOs to buy congestion relief from one another. Coordinated re-dispatching aims at the same result, without resorting to markets, but relying instead on coordinated actions of the TSOs. The rationale for extending re-dispatching to cross-border counter-trading or re-dispatching is immediate: it facilitates the removal of congestion.

Take the North–South example: it is impossible to relieve congestion by having each TSO re-dispatch in its own control area. Cross-border counter-trading makes this possible. It has also implications in meshed networks. Consider again the six-node/two-zone example and the transactions of section 4.1.3 (1000 Mw from nodes 1 to 3 in zone *I*, 1000 Mw from nodes 4 to 6 in zone *II* and 100 Mw from node 1 in zone *I* to node 6 in zone *II*). As indicated in that section, this trade pattern leads to an excess flow of 7.5

Mw in line (1-6). Re-dispatching 60 Mw from node 1 to 2 in the same zone can remove this congestion at a cost of 600 euros. Cross-border counter-trading achieves the same result by trading 13.3 Mw (7.5/($PDF_{(1-6)1}$ − $PDF_{(1-6)4}$)) between generators 1 and 4 at a cost of 266.6 euros (obtained as 13.3∗(30 − 10)).

Cross-border counter-trading may also drastically increase TCs. But there remain two difficulties. One is directly carried over from single-zone re-dispatching: what should one do with the cost? ETSO (1999) proposes, "the cost of CCR should be allocated to the market participants responsible for the bottleneck". This is the same, in principle sound but in practice inapplicable, recommendation as in single zone re-dispatching. All transactions that induce a flow on some line are responsible for the bottleneck and any attempt to assign this responsibility to one or another agent is arbitrary. If cross-border counter-trading sufficiently increases TCs at a small cost, then "allocating" these costs to all participants is fine. But cross-border counter-trading, very much like single zone counter-trading, may induce perverse incentives to create congestion in order to be called upon to relieve it (Hogan 1999). Gaming or genuine transmission limitations may render the method devastating if the cost of counter-trading is high and socialized over all participants. The second difficulty is to organize trade between TSOs (see Cadwalader et al. 1999). This may require considerable organizational work. The issue is not alluded to in the Florence documents.

Re-dispatching and counter-trading, whether operated on their own or in combination with a TC auction, have an interesting property. In contrast with TCs that need to be defined before real time, counter-trading can be operated both forward and in real time. Securing re-dispatching resources is like procuring an option traded in the forward market and exercised in real time. Because of this character of option, re-dispatching and counter-trading, in contrast with TCs may have the potential of organizing a complete market. Needless to say, this is only possible with a real time market, that is a balancing market. None of the Florence documents provides any clue as to whether this interesting property will be explored or taken advantage of.

This persisting invocation of a missing balancing market suggests the following remark. The allocation of costs to those responsible for them is a recurrent theme in the Florence documents but no viable proposal is offered to perform this allocation. It is suggested that the creation of a spot market and the settlement of congestion costs on the basis of these spot prices is the only way to allocate costs without being discriminatory. Any other solution is arbitrary, inefficient and possibly prone to gaming especially if re-dispatching resources are scarce. Also, do not count on administrative intrusion for increasing re-dispatching resources. It can only create regulatory uncertainty and reduce agents' incentive to enter and play the market in an economic sound way.

5.2.6. *Curtailment remains possible*
Paragraph 2 of Article 6 addresses curtailments

Transaction curtailment procedures shall only be used in emergency situations where the transmission system operator must act in an expeditious manner and re-dispatching is not possible.

Emergency situations are a fact of life. But the power system should not live in a continuous state of emergency. Can the "real integrated single market" suffer from curtailments? Yes! Specifically, curtailment will happen whenever there is a mismatch between the supply and demand of transmission resources in the forward market and this mismatch cannot be resolved by counter-trading whether single-zone or cross-border. Curtailment also happens whenever deviations between the forward market and real time transactions are too large to be accommodated by the balancing mechanism.

Why would these outcomes ever occur? As argued above, the forward TC market is inherently incomplete because transfer capacities do not reflect the intricacies of meshed networks. The end result is an unbalance between the supply and demand of network resources in the forward market. Were it not for recourse actions this would already imply curtailment. We also argued that deviations between the closure of the forward TC market and real time transactions are inevitable. This may further increase the imbalance between supply and demand of network resources and hence the risk of curtailment. Load relief resources callable in real time mitigate but do not eliminate those risks. Curtailment eventually occurs when there is not enough load relief resources to resolve the sum of these unbalances. Can this happen? Yes, it suffices that the incentives to provide the load relief resources are too low. Worse, as extensively argued by Chandley and Hogan (2000) in the Californian case, there may sometimes be incentives not to provide load relief resources. Whether this will be so in the European system is difficult to appraise without knowing the details of the implementation (see article 7 and the questions that remain to be solved). But some general principles can be given.

Load relief resources can be procured by intrusive measures or proper remuneration. Intrusive measures may work in the short run. They create unbearable regulatory uncertainty and destroy the market in the long run. What about remuneration? First note that some plants can serve the energy, congestion relief and balancing markets. The remuneration obtained in each of them determines the allocation of their capacity between these markets. Do we have the adequate mechanisms to do this arbitrage? This does not look so. Consider first congestion relief. An adequate remuneration mechanism requires to charge those who are responsible for the recourse to those services (those who create congestion) and to remunerate those who provide them. This can be done with a spot market but is difficult otherwise. Specifically, allocating re-dispatching costs to those responsible for congestion is hopeless as long as there is no locational spot market. The best one can hope for is to spread the costs on all agents. But one may be wary of the result. Agents that cause large congestions in some location but are only charged an average congestion cost have no incentive to reduce their troublesome transactions. Similarly, those which provide valuable congestion relief services while at the same time having to pay some average congestion costs have little incentive to make these services available. This creates a mismatch between the supply and demand of congestion relief services that comes on top of the mismatch between demand and supply of network services. This is a source of curtailment. Gaming further adds to the problem but is not discussed in this paper.

Balancing services are no better. Prices charged for deviations are here the key element. A spot market should give the right signal to more or less extensively rely on the balancing market but administratively determined penalties do not. Low deviation penalties entail an excessive demand for balancing services compared to the supply. This leads to curtailments. Too high penalties unduly increase the price of unbalances and hence uneconomically reduce them. At least, this does not induce curtailment. Whether these outcomes will materialize remains to be seen. It all depends on the fine details of the system and we know nothing about these fine details yet. But PECO and California show that these bad outcomes are not only mental experiments: they happen.

5.2.7. *Curtailments shall be compensated*

The last sentence of paragraph 2 states that

> Market actors which have been allocated firm capacity shall be compensated for any curtailment of this firm capacity.

Compensating curtailments is in line with economic reasoning. But it immediately raises the question as to how curtailment will be organized and the compensation computed. In other words, does one have the means to curtail firm TCs in an economic sound way and offer a market-based compensation for curtailment? Or will this be administratively organized? By definition, re-dispatch will have exploited whatever economic curtailment possibility is available (decrementable load). One must conclude that real time unforeseen curtailment will be administratively managed. But one cannot probably hope for anything better. The key question is then, how will it be compensated?

It is impossible to compute a market based compensation without real time prices and hence a balancing market. The compensation will thus be administratively computed. This is akin to administratively pricing balancing services. Both introduce inconsistent prices in the real time market and hence distort expectations in the forward market. This has an impact. Inadequately compensated curtailments and inadequate balancing prices (most likely regulated prices) concur to distort the arbitrage activity of the marketers. TCs and the absence of balancing market may ease marketers' life if there is no curtailment. But they may make it miserable if curtailments are frequent and improperly compensated. The end result is predictable: trade that is curtailed too often and improperly compensated will decrease. This will solve the congestionproblem but not in the sense intended by the European Commission: quantitative non-economically based restrictions combined with administratively determined compensations are incompatible with a "real integrated single market".

5.2.8. *TSOs will maximize the amount of TCs on the market*

Paragraph 3 states that

> The maximum capacity of the inter-connectors shall be made available to market operators, complying with safety standards of secure network operation.

It is not clear that TSOs have an incentive to maximize the capacity of the inter-connectors. TSOs are likely to be regulated as not for profit organizations while being liable in case of failure to deliver the promised TCs. Declaring inter-connector capacity available implies risks if one is compelled to compensate for it when it fails to be there. TSOs can admittedly be held liable for line failures that decrease the available capacity. But they cannot reasonably be held responsible for modifications of transactions that change transfer capacity.

In consequence, one can probably induce TSOs to undertake the right maintenance in order to optimize TCs with respect to line failures. But one cannot design incentives for maximizing TCs contingent on the loop flows effects and hence on marketers' transactions. TSOs who are required to pay compensations in case of curtailment, will reserve part of line capacities and procure ancillary services to guarantee these TCs. They may indeed have strong incentives to stay on the safe side, offer little TCs and possibly use intrusive means to reserve load relief resources. Alternatively, but more or less equivalently, they can make TCs available at the last moment, with the result that it is impossible for marketers to conclude long-term contracts on the energy market. None of this will maximize TCs. ETSO (2001f, p. 4) is obviously well aware of these questions when it announces "a compensation of market participants would force TSOs to keep up higher security margins that consequently would decrease market liquidity".

5.2.9. *Other paragraphs are less worrisome*

The other paragraphs of Article 6 raise fewer questions even though they would deserve a more extensive discussion than allowed in this paper. Paragraph 4 imposes that

> Any allocated firm capacity that will not be used, shall be reattributed to the market.

This prevents holders of transmission capacity to withhold it from the market therefore exerting market power. This subject is extensively discussed in the literature, particularly by Joskow and Tirole (2000).

Paragraph 5 requires that

> Transmission system operators shall, as far as possible, net the capacity requirements of any power flows in opposite direction over the congested interconnection line in order to use this line to its maximum capacity. In any event, transactions that relieve the congestion shall never be denied.

This may create difficulties (see ETSO 2001f, p. 4) but it is a direct consequence of the requirement to maximize the amount of TCs.

The last paragraph 6

> Any rents resulting for the allocation of interconnection capacities shall be used for . . .: (a) guaranteeing the firmness of the allocated capacity, (b) network investments, (c) reduction of network charges. These rents ... shall not constitute a source of extra profit to the transmission system operators.

confirms the suggestion that the TSOs are likely to be operated as not for profit organizations. It eliminates the long run incentive of the TSOs to restrict transmission capacities in order to increase rents. But it also eliminates the short run incentive to maximize TCs.

6. THE OTHER ARTICLES

Articles 5 and 6 go in the right direction. But they will not suffice to the task. An important question is whether one can be satisfied with the principles as currently stated or whether one should attempt to push them to their logical conclusion. Just think of the consequences of a Court insisting that compensation of curtailment be market based because compensation is part of the congestion management and that this latter should be market based. This could have far reaching consequences. It could force the introduction of a balancing market in order to allow for market-based compensation. This would in turn open the way to other systems of congestion management not currently discussed in the Florence documents. Deduction has considerable power. Also, one can deduct before the facts and hence take advantage of the delay imposed by the Stockholm meeting of the Council. One can also deduct after the facts when complaints are brought to Court and damage is done. In both cases, deduction will move us beyond the current proposals.

Article 7 gives some mixed encouragement in this respect. It recognizes that the process is far from finished. It lists open questions that need to be sorted out such as "details of the determination of the transmission system operators liable to pay compensation for transit flows ...", "details of methodologies to determine the amount of transit hosted and export/import of electricity made, ...", "details of the methodology to determine the costs incurred as a result of hosting transit of electricity, ...", "the participation of national systems which are interconnected through direct current lines ...". Some of these questions, if treated rigorously, should entail significant advances in the reasoning.

With regard to national tariffs, Article 8 also states that

> national regulatory authorities shall insure that national tariffs and methodologies of congestion management are set and applied in accordance with this regulation ...

This may also have potentially far reaching consequences if the management of congestion of interconnection is truly market-based.

In contrast one may be skeptical about the virtues of the "comitologie" mentioned in the explanatory memorandum of the draft Regulation. Committees perform quite differently depending on whether they are in charge of finding a solution to technical and economic problems or achieving a political consensus by playing down these difficulties. In any case ETSO expresses concerns (ETSO 2001f) about not being represented in the "regulatory Committee": "The potential lack of high level technical expertise may also lead to inefficient or even dangerous politically driven decisions for the operations of the European electrical system". More directly to the point ETSO demands that "appropriate dispute mechanisms are put in place and that the liabilities of the Commission, Regulators and transmission systems operators are appropriately defined for each Member State".

7. CONCLUSION

The EC, supported by the participants to the Florence Regulatory Forum, is currently proposing principles for organizing cross border transmission. These are important steps that go in the right direction. But they fall short of a full market design. The proposed system is far from handling the constraints of the transmission systems in general and of cross border capacities in particular. In economic parlance, these markets are too incomplete. But even so, it is of the essence to move ahead and to start thinking about the full consequences of these principles.

Specifically, ETSO should start working in terms of incremental cost and drop allocated costs that cannot send any meaningful price signal. This is technically (conceptually and computationally) burdensome. And maybe working with incremental cost will turn out too difficult of even impossible. If so, one should report why and move to another concept or simplification. In all cases, one should avoid pretending to do something that one does not do: markets respond to real not intended price signals. The auction of Transfer Capacity provides a market mechanism for allocating interconnections. But it is not sufficient for dealing with loop flows, contingencies and deviations from the forward market. Cross-border counter-trading provides the adequate technological basis to resolve the residual mismatch. But it should be cast in a proper market framework. This may lead to a nodal price system, a notion that is conspicuously absent from the Florence documents. In general the language of the Florence Regulatory Forum appears much too soft. However, systematically exploring the consequences of a combination of TCs and cross-border counter-trading or re-dispatching and keeping the logical consequences of a "real integrated single market" in mind can produce significant results.

But before being developed, the principles should not be further weakened during the legislative process. Specifically, the now common but misleading interpretation of subsidiarity that wants to leave controversial issues to Member States has been often invoked in the Florence Regulatory Forum, fortunately not always with success. National artifacts do not complete an incomplete market. This is especially true in an interconnected electricity system where the very meaning of subsidiarity mandates a high level of market harmonization. This is why, before thinking of strengthening the language, it is necessary to ascertain that the discussion of the draft Regulation in the Council and the Parliament does not water the current document into a set of useless if not dangerous statements. Even if the prospects look reasonable there are reasons to be worried. In this respect, the introduction of the reference to "international" transactions in the definition of congestion of Article 2, compared to previous versions of the draft Directive is certainly worrisome. The difference between the current version of the draft regulation and what will ultimately come out of the institutional EU process will be a strong indication on how serious one is about implementing a "real integrated single market".

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