The diversity of design of TSOs[1]

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Abstract

It is puzzling today to explain diversity and imperfection of actual transmission monopoly designs in competitive electricity markets. We argue that transmission monopoly in competitive electricity markets has to be analysed within a Wilson (2002) modular framework. Applied to the management of electricity flows, at least three modules make the core of transmission design: 1° the short run management of network externalities; 2° the long run management of network investment; and 3° the coordination of neighboring Transmission System Operators for cross border trade. In order to tackle this diversity of designs of TSOs, we show that for each of these modules, three different basic ways of managing them are possible. Among the identified twenty seven options of organisation, we define an Ideal TSO. Second, we demonstrate that 1°monopoly design differs from this Ideal TSO and cannot handle these three modules irrespective of the "institutional" definition and allocation of property rights on transmission; while 2°definition and allocation of property rights on transmission cannot ignore the existing electrical industry and transmission network structure: they have to complement each other to be efficient. Some conclusions for regulatory issues of transmission systems operators are derived from this analysis of network monopoly organisation.

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I. INTRODUCTION

Economists and engineers know quite well how the Transmission System Operator (TSO) should implement its three main missions to manage the flows of electricity, that is to say as for (1) the short-term management of electricity flow externalities, for (2) the development of the grid (Brunekreeft *et al*., 2005), and for (3) coordinating neighboring TSOs in order to deal with border effects (Glachant *et al*., 2005). We assume that an ideal TSO should have been designed gathering the most efficient implementation of these three tasks. However that knowledge seems to have been ignored, or underused, by the designers of many electricity markets, since there is a wide diversity of designs of worldwide TSOs (Sioshansi and Pfaffenberger, 2006).

The framework designed in this paper aims at explaining the diversity of designs of TSOs for managing power flows. One could then understand why inefficient options to manage power flows are so often implemented. Doing so, this framework could help to foster competitive reforms and to guide the regulatory action toward TSO weaknesses.

Our assumption here is that the governance structure of the transmission grid, namely the ownership of the network assets and the choices of regulation of power market, TSO and network infrastructures, imposes compatibility constraints on the various implementations of the TSO's missions.

To analyze the variety of options of TSOs, we use a modular analysis of a TSO based on an analytical framework rooted in Baldwin and Clark (2002), Glachant and Perez (2007) and Baldwin (2008). The four relevant modules for management of power flows are the three aforementioned missions of the TSO, as well as the governance structure of transmission. We will demonstrate that the governance structure of transmission explains the diversity in how TSOs are set up, as well as the discrepancies in their results.

Our paper is organized as follows. In section II, we present the three independent missions of the TSO, to wit the operational modules of TSOs, as well as the various possible implementations. We then define the "ideal TSO" as the sum of the most efficient implementations on each issue. In section III, we define and higlight the role of the governance structure of transmission and we demonstrate that incorporating this new element in the framework introduces compatibility constraints on the implementations of the TSO's operational modules. The governance structure becomes a fourth module, key in our analysis. In section IV, we conclude on the way the regulatory action should tackle the complementarity between the governance structure of transmission and the implemtations of the TSO's missions to manage power flows.

II. MODULAR ANALYSIS OF TSO-S

The management of electricity flows by Transmission Grid Operators comprises three principal missions with durations lasting from the very short term (several minutes to several hours) to the very long term (five to twenty years). These missions can be examined in a modular analysis framework that is analogous to that developed by Wilson (2002) to study markets for electricity. The three core missions split into three different transaction domains, providing the reference modules for our analytical framework. First, in the shortest time horizon, we have the short-term management of externalities between flows of electricity. Second, over a longer horizon, we have planning the development of the transmission grid (Brunekreeft *et al*., 2005). Finally, since electric transmission grids are increasingly open to direct transactions between each other, a third element is the management of border effects across TSO zones (Glachant *et al*., 2005).

Thus, we can distinguish between the behaviors of the TSOs in the management of each of these three transmission modules by the extent to which they internalize externalities in the pricing system. Consequently, the ideal TSO is defined as the combination of optimal variants for each of the three modules.

II. A. MODULE 1: SHORT-TERM MANAGEMENT OF ELECTRICITY FLOWS

The principal mission of a TSO with respect to electricity flows is their short-term management, principally owing to the externalities associated with congestion on the grid and power losses. This first mission is central to system operation[4] (SO). It encompasses several variants (with varying degrees of integration) of system operation and the energy market, so as to internalize network externalities. The three options for doing that task are: nodal pricing, redispatching and zonal pricing.

II. A. 1. Nodal pricing

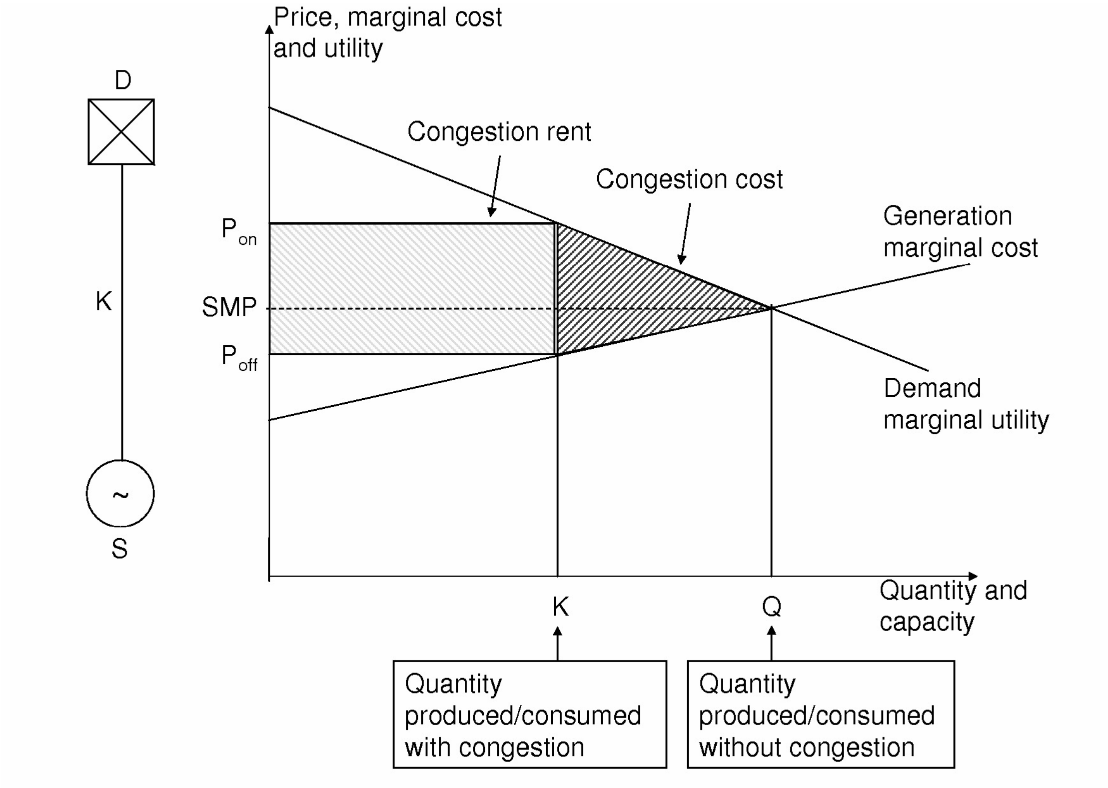
The optimal solution for a perfect allocation of the grid's limited capacity is a well-known issue in the electrical industry. Schweppe *et al*. (1988) demonstrate that efficient dispatching can be obtained thanks to a system of nodal pricing considering the externalities of the grid as constraints of the market clearing[5]. Nodal energy pricing yields a different price at each node of the grid. These nodal prices indicate where it is preferable to generate or consume an additional megawatt, given the losses and capacity constraints on the grid. The differences between nodal prices reflect the social value of the externalities on the grid. They also generate a surplus for the TSO, who is the intermediary collecting the prices demanded from users injecting power and those withdrawing power from the gird. The grid's capacity constraints limit the maximization of the social surplus. This results in a social cost, called "congestion cost" in the DC approximation[6] for a lossless grid (see fig. 1).

Figure 1 Representation of nodal pricing on a congested two-node grid

[4] Which also includes balancing generation and consumption in real time or near real time. However, the real-time balancing of supply and demand has been excluded from our modular approach. The reason why we do so is that while balancing is de facto administered by the TSO, this real-time market is much more an essential component of the market design and market sequencing (Saguan, 2007; Glachant and Saguan, 2006) than a mission inherent in the transmission system.

[5] Theoretical analyses generally only account for congestion and losses, and rarely consider the network voltage constraints (Caramanis *et al*., 1982).

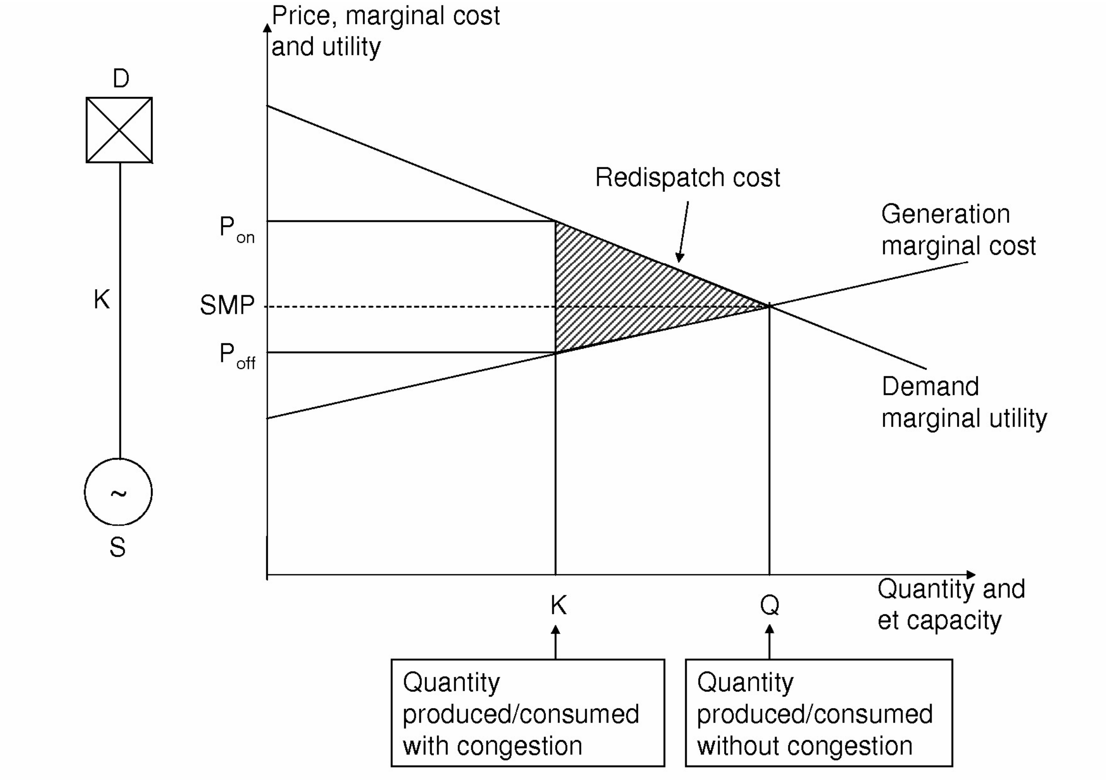
[6] The DC approximation only accounts for the flow of active power and an approximation to the behavior of the grid computed from linear equations. In this case, only congestion (and losses) constrain nodal pricing.



II. A. 2. *Redispatching*

Other procedures can be implemented to manage congestion on the transmission grid. Thus, on the initiative of the TSO congestion externalities can also be managed through a direct modification of the list of dispatched power plants. This is called redispatching. This procedure for managing electrical flows and their externalities thus operates outside of the electricity market (see fig. 2).

Figure 2 Representation of redispatching on a congested two-node grid



In this second solution for managing network congestion, the electricity market receives no economic signal containing information on the constraints on the grid, and the market for power continues to operate as if there were no losses nor constraints on the network. All market participants pay, or are paid, a market price that is called the "System Marginal Price" and unconstrained by conditions on the grid. However, some generators or consumers are called by the TSO after the energy market clearing (outside of the "Merit Order") to increase (and then paid P_{on}) or to decrease (and then paid P_{off}) to manage the externalities of flows of electricity. The ensuing redispatching cost is assumed by the TSO in the short term. Nevertheless, directly or indirectly this cost is generally socialized *ex post* in the grid access fee. Thus, only the redispatched entities receive direct economic signals on the existence of constraints on the grid's transmission capacity.

II. A. 3. Zonal pricing

The last solution we will study here is the zonal pricing of network externalities as an intermediate solution between the two extreme cases of nodal pricing and redispatching. Externalities can then be managed with varying degrees of precision, depending on the strength of the economic signal transmitted to agents on the market to inform them of the state of constraints on the grid. *De facto*, the zonal pricing scheme combines the nodal pricing and the redispatching methods (Bjørndal and Jørnsten, 2001; Ehrenmann and Smeers, 2005). On one hand, the main ("structural") congestions are managed with nodal pricing of energy with the grid broken down into zones equivalent to "big nodes"[7]. On the other hand, the temporary congestions are managed with redispatching, and their costs are directly socialized in the grid fees.

To conclude, table 1 presents the three short-term solutions for managing transmission grid externalities, classifying them by their level of integration of system operation and electricity market, as well as by the level of socialization of the costs of externalities.

Table 1 Short-term methods for managing the externalities of electricity flows

Methods for managing externalities	**Level of integration between system operation and energy market**	**Level of socialization of the costs of externalities**
Nodal pricing	*High*	*Low*
Zonal pricing	*Average*	*Average*
Redispatching	*Low*	*High*

We will now turn on this the second module of the TSO core activities, the development of transmission grid.

[7] Hedging instruments have been designed to cover the volatility of nodal or zonal prices (Hogan, 1992). These are forward contracts, typically called "Financial Transmission Rights" (FTRs). The owner of such a contract may receive a congestion rent associated with the price differential between two nodes: a "sink" node and a "source" node.

II. B. MODULE 2: DEVELOPMENT OF THE TRANSMISSION GRID

In our framework, the second mission of the TSO is the long-term development of the electricity transmission grid. In principle, short-term management of the externalities of electricity flows can inform the TSO and network users on the constraints associated with the current state of the grid's operations. However, in the long term, the TSO should also make efficient investments to eliminate all constraints that are economically excessive.

This mission of developing the transmission grid presents a complex issue for TSO. First, we have to assume that the TSO is sufficiently responsible and efficient to invest in reducing the social costs imposed by network externalities or, equivalently, in maximizing the social surplus. The problem is that, as we also know, the short-term signals sent by constraints on the grid are generally inadequate to effectively guide the long-term siting of economic agents on the grid. Finally, the surplus received by the TSO from short-term system operation fees does not fully cover the costs of the entire grid developement. The reason is that the indivisibility[8] of the equipment lines and the economies of scale, in conjunction with the risk aversion of the engineers running the grid, are at the root of this economic inadequacy of the short-term signals (Pérez-Arriaga *et al*., 1995; Joskow and Tirole, 2005). Thus the solution is that short-term pricing signals must be completed by long-term locational signals, known as "grid access fees" (Green, 2003). These grid access fees allow the TSO to recover the full costs of investments in grid infrastructures (Pérez-Arriaga and Smeers, 2003).

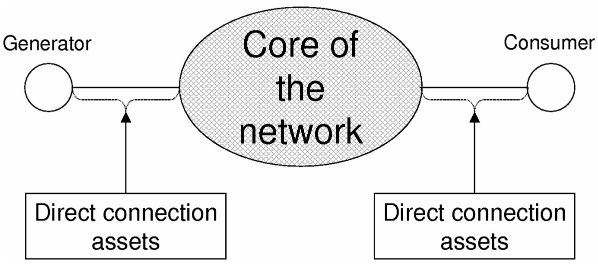
So the tasks of the TSO as for the development of the grid are twofold. First the TSO must account for the response of the grid's users to locational signals (short- and long-term) and the expected evolution of the consumption and generation of electricity across the network. Second the TSO must arbitrate between short-term operating costs, observed or expected on the basis of new requests for grid connections, and the costs of long-term investments in the transmission grid. All other things being

[8] Indivisibility arises from the fact that some amounts can only assume discrete values. This is notably the case for electricity transmission lines, the capacity of which cannot be augmented by marginal increments.

constant, these computations must yield a maximization of the social surplus (Pérez-Arriaga and Smeers, 2003).

It is important here to distinguish the core of the existing grid and the need of brand new lines to connect news users, new generators (for instance windfarms or Combined Cycle Gas Turbines) or new consumers (see fig. 3). The billed infrastructures in this case are both the connection infrastructures themselves (connecting a user to existing equipment) and the reinforcement of the grid to handle the increased flows induced by new users.

Figure 3 Distinction between connection lines and core of the network



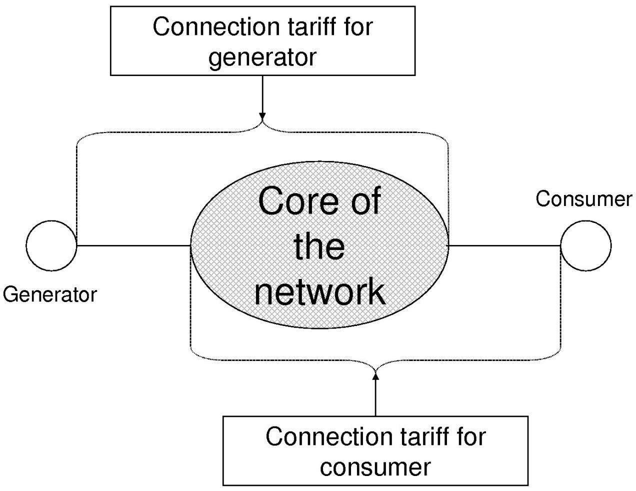
There are three broad alternative methods[9] for allocating grid costs development: deep cost, shallow cost, and zonal allocation method (Hiroux, 2005). Publication of forecasts of the transmission grid connection capacity by the TSO can contribute an additional locational signal for the users' choices. However, this information does not negate the value of the three methods since we are not limited to a binary, all or nothing, signal. Indeed, the capacity of a grid's nodes (or zones) to receive connections is its nodal (or zonal) ability to accept consumption or generating hook-ups without creating new congestion. There is thus only the grid cost allocation method to inform on users how much they must pay in reinforcement costs if they decide to rely on the posted new-connection capacity. Hereafter these methods will be classified by the level of incentives they provide.

[9] Other intermediate methods are also possible as a combination of these three major ones.

II. B. 1.   Deep cost allocation method

The cost of expanding the grid can be allocated as “deep cost” with a fee charged to each individual user for each new connection or significant expansion of use. In this case, the full costs of all new infrastructures will be directly imputed to network users, and new connections or changes in utilization[10] will trigger new investments from the point of view of the TSO. This deep cost method is contestable on a theoretical basis, since the grid costs that are associated to the lumpiness of the transmission line capacity are individually allocated to the users of the grid (Fox-Penner, 2003). Moreover, this method only partially internalizes the externalities of investments in the grid, as users are not compensated when their connection generates positive externalities for the grid (see fig. 4).

Figure 4 Deep cost allocation method



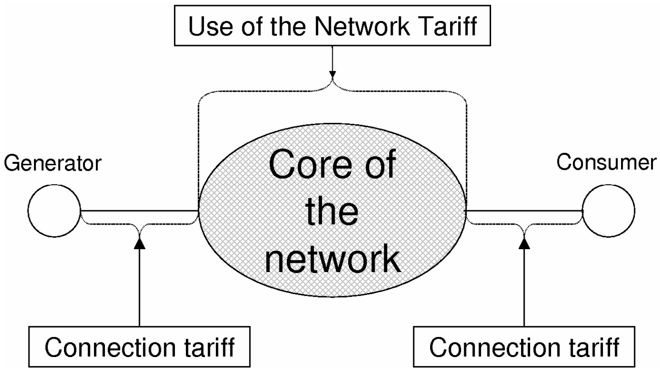
II. B. 2.   Shallow cost allocation method

Another method for allocating costs, called the shallow cost, only charges new users, or those who increase their use of the grid, for a small portion of the cost (shallow cost) imposed on the grid. This portion only covers the price of the infrastructure necessary for connecting them. Conversely, all the required reinforcements to the grid's internal equipment (thus, to the “core of the grid") are socialized

[10] For whatever reason: a local increase in consumption, a new connection, increased generating capacity of an existing power plant, etc.

across all grid users in the general grid access fee (Use of System, or UoS tariff[11]). With this shallow cost pricing method, new users are effectively given an incentive to install near to the core of the network. However, they have no incentive to account for the effective capacity of the grid's various segments to accept new connections (cf fig 5).

Figure 5 Shallow cost allocation method



II. B. 3. Zonal allocation method

A final method, called zonal allocation method, starts from the shallow cost of connecting to the grid in order to account for direct connection costs. However, this is completed with a grid usage fee that is differentiated by the zone of the grid. The costs of grid development are thus indirectly imputed to its users by separately signaling the structural capacity to receive connections for each zone of the grid. Many variants are possible here. From the perspective of the grid, this is an active method, since positive externalities from connections can be internalized (fully or in part) in the grid access fee (Olmos Camacho, 2006).

In conclusion, we present a table with the various solutions for allocation grid development costs, classifying them by how they distribute the costs between hook-up fees and grid use fees, and by how they internalize externalities.

[11] The boundaries of the definition of the Use of System tariff varies widely with the rules of the network. Principally, this fee covers the costs of grid infrastructures and maintenance, as well as the costs of operating the system (balancing, system services, losses and congestion when they are socialized).

Table 1 Methods for allocating the costs of grid development

Allocation methods	Connection fees [as a % of the grid's costs]	Usage fees [as a % of the grid's costs]	Externalities internalized by the method
Deep cost	100	0	Negative externalities
Shallow cost	~0	~100	Distance to the grid
Zonal	0 < x < 100	0 < (1-x) < 100	Negative externalities; and indirectly positive externalities

We now turn to the third task, and module, of the TSO, the coordination among them.

II. C. MODULE 3: THE COORDINATION AMONG TSO-S

The third mission of TSOs is to coordinate, in order to internalize parallel external flows and border effects[12]. This allows the TSO to make optimal use of all the resources of the interconnected grid, facilitating arbitrage and promoting the merging of the markets in their zones. Coordination between TSOs requires both coordinating the short-term management of grid externalities and coordinating developments on the grid. The problem of compensation amongst the parties to be coordinated is not considered here[13].

There are two ways to coordinate neighboring electricity markets in the context of a market for electricity: uniformization or combination (Glachant *et al.*, 2005). As to the former, uniformization implies that both TSOs choose the same methods for short-term management of electricity flows and grid development, on each grid and at their interconnections, and that they share at least a minimum set of information on the state of their networks (see Cadwalader et *al*. (1999) for the short-term coordination of externalities management in electricity flows). As to the latter, coordination by combination requires the establishment of gateways between TSOs to allow the coexistence of individual mechanisms that differ between zones and that are, by extension, more difficult to coordinate.

[12] Called spillover effects by Costello (2001).

[13] and has yet to be addressed in the literature.

If we abstract from the cost of implementing coordination, uniformization is always efficient, while combination is nothing other thant a “second-best” solution. Nonetheless, depending on the cost-benefit relationship of implementing the various coordination methods, coordination by combination, or sometimes even no coordination at all may be the optimal solution (Costello, 2001). Indeed, the need for coordination between neighboring TSOs and the effectiveness of the chosen method vary with the topology of the grid. The more enmeshed and interconnected the grids are, the more it is efficient to coordinate to internalize border effects (Costello, 2001).

In conclusion, the various coordination solutions for managing border effects among neighboring TSOs are summarized in the following table.

Table 3 Coordination solutions at the borders between neighboring TSOs
(classified by the extent to which they internalize border effects)

Coordination at the borders between neighboring TSOs	**Level of internalization of border effects**
No coordination	Low
By combination	Average
By uniformization	High

II. D. AN IDEAL TSO

Among the twenty seven possible designs of TSO (combinations of the three modules with three different options for each of the three modules), the optimal implementation of the three modules presented above constitutes an ideal TSO for the management of electricity flows on the transmission grid. This type of TSO sends economic signals to grid users to ensure their efficient utilization of the network. It also develops the grid efficiently and coordinates with neighboring TSOs to ensure optimal management of the border effects between their systems.

First, grid externalities are managed by the nodal pricing of power in the short term. This permits efficient dispatching of power plants and allocation of the grid's capacity (Schweppe *et al*., 1988). Second, in the long term, the goal of a responsible TSO is to develop the grid to maximize the social surplus. To invest efficiently, the TSO must determine the social cost of externalities and arbitrate between this cost and that of investments in the grid. To ensure efficient siting of the users of the grid despite externalities and the indivisibility of grid investments, the preferred method for allocating the grid's cost is the zonal allocation method, completed by the publication of capacities to host new connections. Third, methods that send locational signals, such as nodal pricing, are appropriate for internalizing grid externalities. They are also appropriate for internalizing border effects between several TSOs (Glachant *et al*., 2005), provided they exchange the information and data required for coordination (see Cadwalader *et al*., 1999, for the short-term coordination of externalities management in electricity flows). In conclusion, an ideal TSO must combine the methods for managing its core missions as follows:

Table 2 Characteristics of an ideal TSO

Missions of the TSO	**Ideal implementation**
1 - *Short-term externalities management*	Nodal pricing
2 - *Development of the grid*	Zonal allocation method and publication of new-connection capacity
3 - *Coordination at the borders*	By uniformization

III. COMPATIBILITY OF THE MODULES OF THE TSO

If we assume that the TSO is efficient and benevolent then there will never be a compatibility constraint between the three modules we have analyzed. If it is not, benevolent, any TSO may encounter contradictions between its own goals, influenced by its governance structure, and the ideal methods for it to exercise its missions. Moreover, the energy regulatory body may also have to deal with ambiguities in the government's energy policy and seek to reconcile contradictory goals. The most likely situation is that the TSO's governance structure will generate compatibility constraints[14] between the operational modules of the TSO..

First, we demonstrate that the governance structure of electricity transmission principally results from the unbundling of the grid from the generation and commercialization aspects of power. Thus, unbundling the transmission grid simultaneously affects the regulation of the transmission monopoly and the market design, which is subject to the externalities of electrical flows. Subsequently, we demonstrate that governance of the transmission grid impacts on existing compatibility constraints between the various implementations of the TSO's three missions.

III. A. THE GOVERNANCE STRUCTURE OF THE ELECTRICITY TRANSMISSION GRID

The consequences of unbundling the electricity transmission grid go beyond the guarantee of free and unrestricted access to the network. The process of implementing the unbundling also constitutes the basis for the "governance of transmission" and thus delineates the compatibility constraints on the procedures for actualizing the TSO's missions. We will first look at the elements impacting on the choice of procedure for unbundling the ownership of the transmission grid. Then we will address the consequences of the process of unbundling on the governance of the TSO and its regulation. Finally, we will examine the impact of government policy, governance, and the regulation of transmission on the market design associated with the externalities on electricity flows.

III. A. 1. Unbundling the ownership of the transmission grid

Unbundling the transmission grid from generation and supply activities is usually considered indispensable (Glachant and Lévêque, 2005; Rey and Tirole, 2007). This unbundling always includes system operation. However, unbundling ownership of the transmission grid[15] requires the ability to force the incumbents to cede their network assets. Furthermore, withdrawal from system operation is easy

[14] also called "institutional complementarity" in Pagano, 1993; and Aoki, 2001.

[15] If Transmission Ownership is not integrated with System Operation, Transmission Ownership may, or may not, be bundled with another part of the power supply chain.

enough for a legal authority to impose it in a deregulation process. Indeed, operating the system represents a relatively low volume of investment and work, though it can be employed strategically by incumbents to impede entry by competitors. In opposition, complete divestment of all transmission grid infrastructures can be more difficult to impose. The grid ownership is a guaranteed and a long term source of revenues for the incumbent, and may thus play a key role in the finances and the market value of the firm. The security of income associated with transmission infrastructures is attractive in the context of cyclical uncertainty on electricity markets. Moreover, ownership of the transmission grid may allow incumbents to strategically protect their installed base of generating facilities during any major network development plans.

The choice of unbundling the grid may also be impacted by other determinants, principally technical ones. If the ownership and operation of a network on the scale of a continent[16] or a subcontinent[17] are highly fragmented between many distinct TSOs, then parallel flows of electricity create many "border effects" between these TSOs. If these border effects are not sufficiently internalized, they can reach values that are critical for the security of the system[18]. Unbundling the grid in ownership and in operation in each of the TSO’s zones may not be efficient enough to solve the peculiar problems of “border effects”.

One solution, then, is to withdraw the “system operator” function from the incumbents and consolidate it over a larger geographical zone encompassing several electrical zones under the direction of a new Independent System Operator (ISO) or Regional Transmission Organization (RTO). It is worth to notice that the creation of these regional system operation zones can occur without completely modifying the historical structure of the ownership of the grid. A compromise that can be offered to the incumbents is that they retain ownership and maintenance of their grids in exchange for the creation of an independent regional operator to run them. Horizontal integration of system operation over large zones thus allows border effects between the former zones of the incumbents to be internalized (Costello, 2001; PJM, 2004).

[16] For instance, the United States or the Continental Europe.
[17] For instance Scandinavia or South-eastern Europe.
[18] Especially in the context of increased volatility associated with commercial trade in electricity.

We can distinguish between two types of TSO here: a “heavy” and a “light” TSO. A “heavy TSO” (“TOSO” for Transmission Owner and System Operator) owns the grid infrastructures it operates, while a “light TSO” (“SO” for System Operator) does not. The term “TSO” is thus a generic term encompassing both of them.

In conclusion, it is the magnitude of the horizontal effects at the borders between zones of neighboring TSOs, as well as the effective potential for imposing vertical restructuring of assets in the electrical chain, that frame the modalities of unbundling the transmission grid.

III. A. 2. Governance and incentive regulation of transmission

The modalities of how the transmission grid is unbundled have consequences for both the governance of electricity transmission and its regulation as a monopoly. The governance of a light TSO impacts its regulation and the industrial structure of the electricity sector. It is, in fact, difficult for a regulator to provide strong incentives to a light TSO, owing to its financial shallowness (few assets, little equity, low revenues). This is why light TSOs are usually not-for-profit organizations that are partly self-governing within the framework of an *ad hoc* statute (Barker *et al*., 1997). A not-for-profit light TSO allows for direct or indirect participation of the network’s owners and users on the assumption that there is no danger of collusion or of the organization being captured by a single interest group. This is typically the scenario of stakeholder participation in ISO governance in the United States.

Conversely, in the case of “heavy” TSOs, the regulator can impose incentive regulation on the TSO’s controllable costs in order to fix the monopoly’s income. In fact, in terms of assets, equity, and revenues, the potential financial risks of incentive regulation are acceptable to heavy TSOs (Joskow, 2006).

III. A. 3. The governance of transmission and market design associated with the externalities of electricity flows

As the system operator, the TSO is the principal architect of the market design associated with the management of electricity flows. The governance of transmission has an impact on the design of the market that handles the externalities associated with electrical flows. Furthermore, government policy and the action of interest groups can also act at this stage. The regulator, in turn, must account for government policies seeking to reconcile incompatible objectives. For example, locational signals that are economically efficient from the perspective of the network may hamper the development of wind power, since wind farms are usually far from consumption centers and existing grids, thus necessitating additional investment. The regulator may also have difficulty implementing a “rational agenda” because of the cost of change that the new rules on market design can induce for stakeholders of the electricity market. The regulator may then have to deal with “political economy”. That is to say that he may have to implement suboptimal market rules, because there are the only ones with redistribution of costs and benefits acceptable to stakeholders (Perez, 2002 and 2004). To conclude, the market design associated with externalities in electricity flows may be suboptimal, not only because of the unbundling of grid ownership, but also because of an inconsistent energy policy handed down from policy makers and for reasons of political economy.

When the system operator is a “heavy” TSO, participants in the electricity market have no direct stake in its governance. Consequently, the TSO is better placed to defend its own interests during the conception of the market design. To the contrary, at the time of formulation of the market design, a light TSO is neutralized, at least in principle, by the participation of stakeholders that are assumed to be balanced. During the construction of broad regional markets, light TSOs should be less sensitive to incompatibilities between prior market designs, because their own financial interests weigh little in their mission of inter-zonal coordination.

The governance of TSOs is the product of a compromise between controlling costs, the market design associated with externalities from electricity flows, and coordination between TSOs. The capital base of heavy TSOs allows the regulator to encourage it to significantly cut its controllable costs. However, the financial stakes associated with these infrastructures may have an impact on the market associated with externalities, as well as the process of coordinating with other TSOs. Conversely, a light TSO can more easily coordinate with its neighbors, but is harder to motivate.

III. B. COMPATIBILITY CONSTRAINTS BETWEEN THE MODULES OF THE TSO

The governance of transmission defines the compatibility constraints between the implementations of the three missions of the TSO. We will examine the three types of constraints on compatibility that are the most significant in the context of a competitive wholesale market for electricity. First, a TSO must be sensitive to incentives, so as to ensure efficient development and operation of the grid. Second, siting signals are of real significance to users for ensuring the coordination between users and the capacity of the network to accept new connections despite the vertical unbundling of the transmission grid. Finally, coordination between TSOs must allow efficient use of all transmission grids, both between and within zones, whatever their topological enmeshment and the boundaries on ownership of the infrastructure.

III. B. 1. Compatibility constraints attributable to incentive regulation

The incentives for the TSO to administer and invest in its grid vary with the combination of governance structure and the method used for short-term externalities management. According to this method, the management of these externalities can generate a rent or cost for a TSO. Moreover, we must also consider the robustness of this method in the event of market power being exercised by users of the grid, since this can lead to mistakes in investment.

Each method for managing externalities is vulnerable to the exercise of market power by one of the actors indispensable to the security of the grid. This type of behavior can lead to misguided estimates of the need for investments (Joskow and Tirole, 2005). The redispatching method is considered the most sensitive to market power, since it socializes the cost of local congestion (Harvey and Hogan, 2000). When users of the grid do not assume the cost of the externalities they cause, they are able to manipulate how congestion is managed and significantly bump up the social cost of externalities (Green, 2004).

Nodal pricing, for its part, leads to efficient dispatching of the grid's users and, to some extent, their choice of siting. However, as to the TSO's own investment decisions, congestion rent provides a counter-incentive signal. Indeed, nodal pricing can provide an incentive to a profit-maximizing TSO to prolong congestion (Pérez-Arriaga *et al.*, 1995). Similarly, with zonal pricing, the TSO benefits from inter-zonal congestion but bears the cost of intra-zonal congestion (Glachant and Pignon, 2005). We conclude that a TSO that internalizes electricity flow externalities through nodal pricing should be subject to more stringent regulation to ensure that it takes care to correlate its profit maximization with the maximization of social surplus.

The redispatching method is considered inefficient for internalizing the externalities of electricity flows. However, in its defense, it directly imposes the cost of congestions resulting from system operation on the TSO. Moreover, the TSO can extrapolate the long-term evolution of congestion from the requests for connections it receives. Consequently, the TSO can maximize profits by comparing the short-term cost of congestion with the long-term cost of investing in, and maintaining, the grid. As mentioned above this private maximization procedure is equivalent to maximizing social surplus (Pérez-Arriaga and Smeers, 2003). In this case, the regulator itself has easy access to congestion costs through the intermediation of the TSO. Therefore, he can verify their consistency with siting decisions and the volume of the network investments.

Whatever method is used to manage externalities, the regulator could also force the TSO to compute the social cost of externalities. The regulator would thus have access to data formatted to provide a basis for investments in the network. This would also facilitate the detection of local market power. However, only a heavy TSO can support incentive regulation for the cost of externalities. Conversely, for a light TSO that is not-for-profit and partly self-regulated, nodal pricing is a better option than redispatch. This type of TSO is insensitive to the amount of the congestion rent, since it does not capture this rent owing to its not-for-profit status. This status does not keep it from continually computing the social value of externalities.

III. B. 2. Compatibility constraints attributable to locational signals

The allocation of network costs is determinant if users are to appreciate the grid's constraints and effective connection opportunities. Investments in the grid are very expensive. Consequently, efficient siting of the network users may conflict with other goals such as promoting the establishment of wind power, facilitating the connection of new entrants and entrenching the equalization of rates, options that are all conducive to opting for the shallow cost allocation method of grid cost across all users.

Furthermore, whatever the method of short-term management of externalities, it cannot provide economically efficient signals in the long run, since it is constrained by regulation. Of course, nodal pricing is most appropriate short-term externalities management method for emitting long-term siting incentive signals. If the short-term management of externalities is ensured with redispatching, on the other hand, only the redispatched units are informed of the congestion. However, nodal prices do not measure the impact an expansion of the grid between two nodes has on other nodes. Therefore, these are not efficient long-term signals for the precise siting of the actors. Even when formal property rights, such as the Financial Transmission Rights (FTRs) of Hogan (1992), are created, they feature similar limitations[19].

In addition, because of economies of scale, nodal pricing does not generate sufficient revenues to cover all infrastructure costs of the grid, which is exacerbated by the indivisibility of the network equipment (Pérez-Arriaga *et al*., 1995). Furthermore, some externalities are not internalized by nodal pricing, such as the reliability or security of the system. There is no method that can fully internalize the externalities and indivisibilities of investments in the grid (Joskow and Tirole, 2005, Smeers, 2006).

As a result, a locally differentiated grid access fee is always required to address problems arising from indivisibilities and externalities associated with investments in the grid. On the one hand, a deep cost pricing of connections to the grid does not internalize the positive externalities of these connections. On the other hand, shallow cost pricing only encourages users to move nearer to the grid, but not to choose the best sections thereof. Only the zonal allocation method makes it possible to internalize the externalities of investments in the grid while simultaneously providing siting incentives to users.

In the matter of access to price signals, users of the network may have to pay *ex ante* to know whether they will be able to connect to the grid and how much it will cost. For the TSO applying shallow

[19] unless the new investor receives the algebraic sum of all the FTRs that it creates or "makes possible" (Bushnell-Stoft, 1997).

cost or zonal pricing, this information can be acquired cheaply. Conversely, for the TSO using the deep cost method, this same information may be very expensive and only available after a hook-up has been requested, since the TSO needs to conduct case by case network analyses subsequent to actual connection requests. Consequently, advance posting of the grid's capacity to accept new connections makes this cost allocation method the most transparent for users. Nonetheless, this type of information may be difficult to compute when the nodes' capacities for accepting new connections are interdependent and vary from one request to the next. If the capacities for new connections are available, they cannot all simultaneously be realizable.

In conclusion, price setting options on the grid seem quite limited and contrains the possible choices. Whatever method is chosen to manage the externalities in the short term, an additional rate is necessary to generate a locational signal that internalizes the indivisibilities and externalities of investments in the grid. Posting the availability of capacities for new connections yield more transparency of the method for allocating costs for the users.[20] This issue of posting sitting information relies on the regulator's agenda who must handle this trade-offs and be careful to give all the users the best available information.

III. B. 3. Coordination compatibility between TSOs

The governance of TSOs encompasses the methods implemented for managing externalities and for emitting long-term siting signals, whether uniformized or combined by the TSOs. Some choices in uniformization and coordination between TSOs are preferable because they facilitate coordination and provide more information by yielding better internalization of externalities. Thus, in Cadwalader *et al.* (1999) we find the coordination of two systems using nodal pricing. According to Marinescu *et al.* (2005), it is more difficult to coordinate two systems using redispatching for their congestions. In this case, coordination may require a gateway between the TSOs. Such mechanisms already exist for the short-term management of externalities (such as: priority given to historical contracts; first come, first served; explicit

[20] However, these price- and volume-based signals may only have a limited impact on users' siting decisions, since they are also constrained by primary energy resources, such as water, wind, coal, gas, etc.

auctions; etc.). However, those methods that are best for internalizing externalities, and thus border effects, should be preferred.

Consequently, even coordination between TSOs has an institutional dimension. Since it modifies organizational structures and grandfathering arrangements, it must be supported by the respective governance structures of the different TSOs. Failing this, we cannot imagine how TSOs would be able to set up coordination mechanisms. For example, how would they exchange the required data? In addition, their modules for externalities management (congestions and losses) and grid development can also prove poorly suited to each other if they only internalize some of the border effects.

Thus, there is a need for a regulatory authority with jurisdiction over all TSOs requiring coordination. At the least, this authority would need to push for the implementation of rules for compensation associated with each step in the progression of the coordination. In the most developed version, this authority can guide coordination by combination toward coordination by unformization thanks to an implementation of appropriate new methods (Glachant *et al*., 2005). The room for regulatory action to compensate the weaknesses of the module compatibilities is then a core issue.

IV. CONCLUSION

Our modular analysis has demonstrated that the institutional framework creates compatibility constraints on the performance of the TSO's missions for managing the flows of electricity and the associated externalities. Its conclusions are more qualified than those in other studies (Boucher and Smeers, 2001; Ehrenmann and Smeers, 2005).

Some of the management methods actually implemented are markedly suboptimal relative to an ideal TSO. But these methods are good enough in the institutional context that frames their implementation. Also, regulation may curb the inefficiencies in some cases probably for two reasons. First, the institutional context may limit the set of methods effectively available for implementation to suboptimal solutions. Indeed, institutional constraints frame the technical-economic methods for managing electrical flows on the transmission grid. Second, regulation of the network monopoly could complete these methods by reducing inefficiency, unexpectedly making satisfactory results possible. This may take the form of imposing *ad hoc* incentives on some selected classes of decisions, or imposing new decision criteria. Consequently, methods for managing power flows that diverge from the optimum must nevertheless be considered, as they may be the only ones attainable given the context. Thus, additional rules can be designed to limit the initially undesirable effects.

Naturally, optimal solutions remain a goal to strive toward when allowed by the institutional bases (Boucher and Smeers, 2001; Ehrenmann and Smeers, 2005), since they facilitate the creation of vast market zones. Nonetheless, in a context of subsidiarity between public authorities that are not strongly hierarchical, the feasibility of coordinated modifications to industrial structures and national technical rules is limited to short and infrequent windows of opportunity (Glachant *et al.*, 2005). Consequently, suboptimal solutions may be destined to last and it is necessary to subject them to more exhaustive examinations (Pérez-Arriaga and Olmos, 2005; Marinescu *et al.*, 2005; and ETSO and Europex, 2008).

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