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TRANSMISSION RIGHTS ALLOCATION IN THE ELECTRICITY INDUSTRY

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Abstract*

This paper investigates transmission capacity allocation and congestion management in restructured electricity industries. Physical characteristics of electricity transmission and the high volatility of demand cause strong and unavoidable network externalities, which impose real time central coordination in grid operations. Even tough the role of the transmission system operator as a key institution in the emerging competitive markets is widely recognized, the extent of the central control and market management that is needed to assure system reliability and no discriminatory access to the grid is still debated. Two organisational forms have been widely discussed by scholars and implemented in real electricity markets: the first one is an unbundled solution based on separate markets for energy and for physical transmission rights; the second one is an integrated transmission/dispatch model based on locational marginal cost pricing and financial transmission rights. This paper considers the main theoretical features of the two models as a solution to the externalities market failure and compares their possible advantages and drawbacks in implementation.

Assuming perfect competition and no transaction costs the two models are theoretically equivalent, even though the centralized solution offers better guarantees in implementation for lower transaction costs and efficient transmission capacity allocation. Removing the perfect competition assumption the equivalence between the two approaches from both an efficiency and welfare perspective is restored only with the introduction of a *use it or lose it* rule.

The analysis includes also, as a case study, an original appraisal of the approach recently proposed by the Market Operator for the Italian restructured electricity market. The proposal is a variation of the integrated energy/transmission model whose crucial elements are a non compulsory centralized wholesale spot market, *market splitting* and *counter trading.*

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CONTENTS

INTRODUCTION

This paper investigates transmission capacity allocation and congestion management in restructured electricity industries. The issue is relevant in the context of liberalized electricity markets in which the traditional monopolistic structure has been replaced by unbundling in generation and transmission. Transmission network is typically perceived as natural monopoly as well as an essential facility for competing participants in the market. Since control of the transmission grid can create advantages for some competitors at the expense of others, transmission is independently operated by a transmission system operator (TSO) that offers non discriminatory open access to standardized transmission services.

The electricity industry is characterized by high volatility of demand, non storability of electricity and strong unavoidable network externalities in case of congestion. Due to these characteristics transmission plays a crucial role in both supporting market trading and offering a reliable service. The establishment of the TSO as a key institution in the emerging competitive electricity markets is intended to ensure the necessary level of coordination in grid operations. However the extent of centralized control and market management by the TSO is a debated point from both a theoretical and practical perspective.

A variety of approaches have been proposed for electricity market design; they all are characterized by a certain degree of reliance on market processes. However two organisational forms and their possible variations have been widely discussed by scholars and implemented in real electricity markets: the first one is an unbundled solution based on separate markets for energy and for physical transmission rights; the second one is an integrated transmission/dispatch model based on locational marginal cost pricing and financial transmission rights.

This paper considers the main theoretical features of the two models as a solution to the externalities market failure and compares their possible advantages and drawbacks in implementation.

The first section of the paper compares the models assuming perfect competition and no transaction costs.

In the second section of the paper the analysis is extended to more realistic sets. The perfect competition assumption is removed to consider how the definition of the transmission rights (both financial and physical) and their allocation affect the behaviour of electricity generators with market power.

On the grounds of the theoretical issues presented in the past sections, the third section attempts a critical appraisal of the current proposal for transmission rights allocation and congestion management in the Italian electricity sector. The Italian Market Rules offer an interesting application of a variation of the centralized model discussed in the first parts of the paper.

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I: NETWORK EXTERNALITIES AND TRANSMISSION RIGHTS ALLOCATION

1.1 Special features of the electricity industry

Electricity markets have experienced a widespread restructuring wave in the last years. As with other utilities natural monopoly elements interact with potentially competitive services. The traditional monopolistic structure of the industry has been replaced by competition in generation and supply. Transmission network is perceived as natural monopoly as well as an essential facility for competing participants in the market. Transmission is therefore typically operated on a regional level in an integrated way by a single regulated firm. This process is usually viewed in terms of a shift from vertically integrated monopolies subject to direct public control to competitive markets in which functionally specialized firms are subject to light regulation. The shift was promoted by innovation in technology that promoted entry trough a reduction in the minimum scale of production in generation. The diminished economies of scale are mainly due to smaller efficient plants based on combined-cycle gas fired generation technology.

The industry reforms adopted around the world have brought to a variety of solutions in market design. However in all cases some significant features that distinguish the electricity industry from others have played a major role in defining the structure of market institutions:

- intertemporal and random variability of demand;
- non storability of electricity;
- strong network interactions (loop flow);
- displacement: electricity shipped on the network is physically homogeneous.

The demand for electricity has a seasonal, daily and hourly dynamic driven by both cyclical and stochastic components. The high volatility of demand and the impossibility to practically storage electricity have two main consequences. The first implication is that the value of energy is very volatile on a temporal dimension and, in case of congestions in transmission, also on a spatial dimension. The second consequence is that in an interconnected network the demand and supply of electricity must be balanced simultaneously over time at every point of the network to avoid power outages.

The level of coordination required to keep the balance at each point and at each time of the system is dramatically increased by the presence of strong unavoidable network interactions. Electricity transmission follows the physical path of least resistance unless switches are installed to stop or restrict flows. A local variation of demand or supply affects power flows throughout the interconnected system. In addition no one using the same grid can own energy *per se* as the path followed by the electricity injected can not be controlled.

Due to these characteristics transmission plays a crucial role in both supporting market trading and offering a reliable service. The challenge in restructured market is therefore to replace a vertical integrated structure with competition upstream and downstream while ensuring the necessary level of coordination in grid operations.

1.2 Network interactions and externalities

Transmission network consists of high voltage power lines connecting different locations. Electricity flows on these lines in directions determined by physical laws, essentially following the path of least resistance at the margin (Schweppe 1988). This implies that power can not be neither exactly controlled nor tracked as it moves following different parallel directions between source and destination. Since the lack of complete control on power flows is an unavoidable reality, to respect the physical limits restricting the amount of power that lines are allowed to carry is a particularly complex issue. This is true especially in case of congestion. A transmission link is congested when net demand exceeds its safe transfer capacity. Possible actions to deal with congestion are either a reduction of demand in the congested direction or an increase of counter flows in the opposite direction.

These technical features are crucial to understand the role of network externalities, a major source of difficulty in regulation of electricity transmission. Network interactions, named loop flow, give rise to complex multilateral network externalities. Loop flow doesn’t cause any concerns when lines are not congested. In that case there is no conflict among different users of the grid: the decision to use an interface by a generator or a trader is not affected by others using the network and it doesn't affect anyone else's possibility to use the network. On the contrary in case of shortage of capacity injection/withdrawal decisions by a user are not independent of other users' production/consumption decisions. In that case, profitable bilateral contracts between any particular pair of generators and electricity consumers will generally affect other generators and consumers in the grid. However the effect can be either a positive or a negative one (the costs incurred by a third party can either be increased or decreased). This direct effect, not mediated by prices, is the network externality caused by congestion.

Designing institutions in a restructured market open to competition requires finding a solution for this multilateral network externality problem, potentially a major source of inefficiency in the market. The traditional solution to the externalities problem was the integrated monopoly who owned all generators and transmission facilities and was able to dispatch the system internalising all possible interactions in the grid. The management of possible conflicts relied on non market solutions. In the liberalized market with open access to the transmission grid the fundamental question is how far is it possible to go from the integrated model, which means how pervasive the role of the transmission system operator (TSO) should be.

In order to address this problem I first consider the effect of network interactions in the definition of the transmission service in the contest of a restructured electricity market.

1.3 Network interactions and the definition of the service

A key ingredient for competition in the electricity market is open access to the transmission grid, a natural monopoly perceived as an essential facility. Open access to the grid for buyers and sellers of power requires a system of capacity allocations, that is a set of rights and rules to govern the use of the transmission network.

Capacity reservations matching with actual flows can be defined, allocated and traded when referred to an isolated line connecting two points. However in the case of a meshed network the loop flow complication makes the analogy with the two points case misleading. This is the main reason why a traditional *contract path* approach can not be appropriate in the restructured unbundled market. A *contract path* definition of the transmission service represents transmission from one point of the network to another in terms of a conventional "contractual" path. In reality, due to the network interactions the actual flow of power can be completely different from the contracted path. This mismatch between the contract and reality implies that negative as well as positive externalities to third parties are not captured. When the system is constrained generators not apparently involved in the contract path may be forced to redispatch in order to guarantee the reliability of the system. As a consequence, the price for the transmission service can not be cost reflective as it doesn't consider the costs possibly incurred by other users of the grid.

An attempt to get a closer match between contract and reality is made by the *link based* approach. This method tries to track the flow of power on the network in order to identify the matching rights that should actually be acquired for each transaction. For a any given set of inputs/outputs in the grid it is possible to compute the total flows across each line. It follows that, under certain simplifying assumptions, it would be possible to allocate appropriate share of the flows to each transaction. The access to the grid could thus be defined in terms of these tradable physical rights which transmission users should hold in order to use the lines. The *link based* approach obtains the result of defining transmission rights that are better related to reality but at the cost of creating a very complicated method: even for a simple transaction it is necessary to recognize all possible links in different contingencies in order to identify all possible rights needed by a trader. Again network interactions are a major source of complication: the flows that can be attributed to a particular transaction depends on others' inputs and outputs on the grid and will be changing over time according to the usage of the system. As a consequence, a bilateral transaction for a long term supply might require the generator to acquire thousands of link based rights to anticipate the many possible conditions that might exist during the length of the contract.

The simplest approach for a practical implementation is the *point to point* reservation of capacity combined with a feasibility criterion. In this case the reservation of transmission capacity allows the user to inject power into a specific point and to withdraw a corresponding amount in another point of the system. Within this specification of the service it is not necessary to detect the actual flow of power. The flows are implicit and the collection of point to point reservations is subject to an overall feasibility criterion. The advantages of this approach are that: *i)* a transmission service defined in this way is compatible with long term contracting; *ii)* the requirement for implementation is not to track the flows but an overall feasibility criterion. The transmission system operator has to determine if a given set of inputs and outputs would be simultaneously compatible with the physics of the network.

Summing up the open access required by the unbundling of the activities in the electricity industry requires to specify the transmission service. The traditional *contract path* approach is not adequate after removing the vertically integrated structure of the market as it doesn't take into account the effects of network interactions. A *link based* approach would consider explicitly the complications due to loop flow to better match contracts with physical reality. The drawback is that this model requires a cumbersome tracking of possible flows into the network under different contingencies. The *point to point* approach seems to be more attractive for implementation because it doesn't try to assess the effect of each transaction but relies only on an overall feasibility criterion.
Identified the *point to point* approach as the more compatible with a restructured market the next step is to consider the possible alternative institutional solutions to the externality problem.

1.4 Transmission capacity definition and property rights

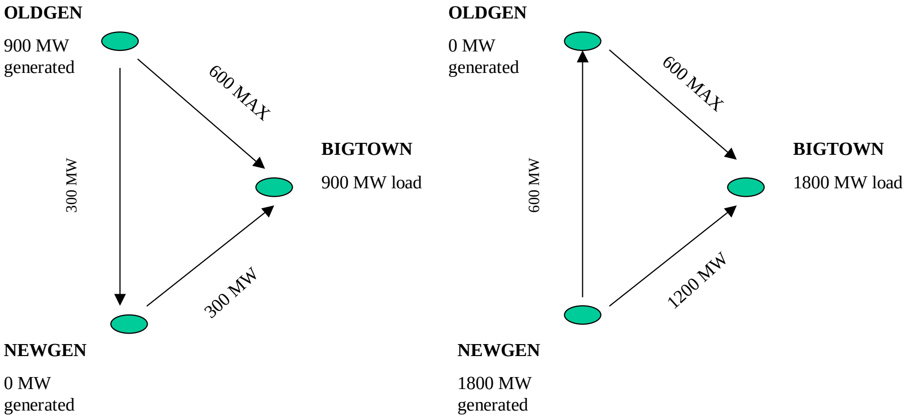
Externalities are a source of inefficiency: the first welfare theorem is violated and the competitive markets equilibrium might not provide the Pareto optimal solution.
Typical solutions to the externality problems alternative to vertical integration (which correspond to the traditional monopoly setting in electricity) are: *i)* a centralized solutions in which a Pigouvian central planner internalise the effect of externalities and is able to fix quotas and taxes such that the first best outcome is restored; *ii)* a decentralized solution in which a well defined set of property rights allow the bargaining parties to reach an optimal agreement, or alternatively, a missing market for

the activity generating the externality is created. From a theoretical point of view the centralized and the decentralized solutions are both able to solve the market failure.

In the special case of electricity, network interactions and the high variability of demand make it impossible to identify a well defined set of tradable and enforceable property rights and, without a workable set of property rights it is not possible to solve the externality relying on a competitive market.

To explain why this is the case I follow a Hogan's example on a simple three nodes network which is the minimum case needed to observe the effects of network interactions.

Example 1: The Interface Transmission Capacity



Case 1: the interface capacity is 900 MW

Case 2: the interface capacity is 1800 MW

Example 1. Consider an interface consisting of two generating locations (OLDGEN and NEWGEN) and one consumption site (BIGTOWN). Assume OLDGEN is the low cost generator. The two generating locations are at the same distance from the BIGTOWN, but the line connecting OLDGEN and BIGTOWN is constrained to the maximum of 600 MW, while the other one is not constrained. The transfer capability of the interface can not be univocally determined since it depends on the configuration of load at BIGTOWN. The panels show two extreme cases: in the first the maximum capacity of the interface is 900 MW while in the second it is 1800MW.

In the first panel the load at BIGTONWN is satisfied by the low cost generator at OLDGEN. This is the maximum possible load that can be satisfied if electricity is generated by the low cost generator OLDGEN. Because the physical low governing electricity transmission, 600 MW flows on the line OLDGEN-BIGTOWN while 300 MW flows on the line OLDGEN-NEWGEN-BIGTOWN, which is twice as long as the other. An increase in demand could not be satisfied without reducing generation at OLDGEN because the constrained line is congested (it is being used at its maximum)[1]. It follows that if production is satisfied by OLDGEN the maximum available capacity on the interface is 900 MW.

The second panel shows the other extreme case: 1800 MW transmission capacity on the interface. A load of 1800 MW at BIGTOWN could be satisfied only by generation at NEWGEN and no generation at OLDGEN.

Variability of demand in electricity can make either of the two panels the relevant one in a certain time. Since demand is not exactly predictable it is not possible to establish in advance what will be the transmission transfer capacity on an interface in a certain moment in time. Moreover in one case it is optimal for OLDGEN, the low cost generator, to be dispatched, in the other it is optimal to have NEWGEN active in order to satisfy the demand.

The problem is further complicated in a real network by the interconnection among the various interfaces. It follows that variability of demand and loop flows make it impossible to find a stand alone measure of transmission capacity. This seriously limits the possibility to allocate physical transmission rights that give the holder the option to exclusively use part of the grid. The first source of difficulty is that the entity of the right can not be univocally computed: if the available capacity can not be defined it can not even be partitioned. Moreover even if a right was allocated (for example the minimum capacity, 900 MW in the example above) it would not be possible to

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[1] Suppose there is a 60 MW increase in the load at BIGTOWN. If this increase would be satisfied by production at NEWGEN this would imply: 340 MW on the NEWGEN-BIGTOWN path, 280 MW on the NEWGEN-OLDGEN path and 620 MW on the OLDGEN-BIGTOWN path. This breaks the feasibility limit on the constrained path.

guarantee the holder the possibility to use the line in any circumstances. As in the case of the simple interface presented before, to meet different load levels without violating the feasibility constraint, might require one generator or the other to be active. Since only the transmission system operator can know the load and the available capacity at each time, none of the generators could be assigned the right to use the line exclusively without a loss of efficiency.

The lack of a set of workable transmission rights implies that the market is inherently incomplete and efficiency can not be reached by fully decentralized trading among agents. This is the crucial difference with respect to other sectors with externalities and this is why a high degree of coordination is unavoidable in electricity transmission even when decentralized solutions are experimented.

The models to be confronted in electricity are not therefore a fully decentralized model against a centralized one, but alternative models in which the transmission system operator is involved at a different extent. The fundamental problem in electric transmission is, indeed, that real time balancing and security reasons requires control by a single authority that can use resources obtained on a spot basis or, failing that, ancillary services to guarantee reliability.

I consider in the following paragraph two alternative approaches: one in which energy and transmission markets are integrated and a second one in which the role of the TSO is restricted to strictly a coordination role.

1.5 Two theoretically equivalent solutions to deal with the externalities

A variety of approaches have been proposed for electricity market design; they all are characterized by a certain degree of reliance on market processes. I focus on two extreme stylised organizational forms, while several alternatives might lie in between: the first one is an unbundled solution based on separate markets for energy and for physical point to point transmission rights; the second one is an integrated transmission/dispatch market.

The simplest unbundled model consists of separate markets for energy and transmission coordinated by the TSO. The necessity of the role of the TSO is acknowledged in this model but is reduced as far as feasibility limits permit. The focus is on the flexibility for the users of the system in optimising their operations while leaving the TSO the responsibility to protect system reliability. This is achieved by both subjecting the outcome from the forward markets to an overall feasibility test and allowing the TSO to intervene with real time operations whenever the reliability of the service is at risk.

The organization of the system takes the form of trading in separate markets: energy and transmission markets[2]. These markets work in sequence and clears separately so that the unbundled solution provides separate, although interdependent, prices for transmission and energy[3]. Each price is the one clearing that specific market. Each participant schedules his energy and transmission resources to fulfil his sales or purchases and then presents to the TSO balanced schedules for input/output point to point reservations. The possibility to implement the outcome (joint operating schedules) arising from decentralized trading can be evaluated only by the TSO: the feasibility of each trade of point to point capacity reservation can be assessed only simultaneously knowing all other allowed transactions. The process can be thought of as an iterative one: until the outcome from the forward market does not pass the feasibility test, which means that all the anticipated congestions are solved, the TSO has to require participants to adjust their trading arrangements. Unanticipated congestions that may arise due to various contingencies (for example temporary unpredictable fluctuations in production and demand) are accommodated by the TSO with real time operations.

The second model is based on integration of energy and transmission in the attempt to reproduce the Walsarian equilibrium. The focus in this case is on the gain in efficiency that can be expected from tight coordination of the market by the TSO. The TSO directly manages the integrated market following an optimisation procedure: the objective is to maximize the overall surplus in the economy subject to capacity and operational constraints (economic despatch problem).

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[2] There can be a third market for reserves which I am not considering for simplicity.

[3] In the two main organizational forms for the unbundled markets the counterpart in trading is either another market participant (trading based on bilateral transactions) or the market manager (private auction market).

A formal specification of the problem would be:

$$\text{Max}\,(x_1,\ldots.x_I;\,q_1,\ldots.q_J) \qquad \sum_m \left[\sum_{i=1}^{I} U_{i,m}(x_{i,m}) - \sum_{j=1}^{J} C_{j,m}(q_{j,m}) \right]$$

$$\text{s.t.} \sum_m \left[\sum_{i=1}^{I} x_{i,m} - \sum_{j=1}^{J} q_{j,m} \right] = 0$$

$$K \left[\sum_{i=1}^{I} x_i - \sum_{j=1}^{J} q_j \right] \leq b$$

where U_i is the quasi linear utility function for each of the I consumers and C_j is the cost function for the each of the J suppliers. The formulation reproduce the standard maximization problem of the Marshallian aggregate surplus with additional constraints representing the feasibility condition for transmission on the electric grid. The overall surplus is calculated summing up the surplus in each node[4] m in the network.

The first constraint requires the balance between overall consumption and production. In the second expression matrix K represents the set of line flows and technical features determined by electrical laws which meet the various physical limitations of the system. The constraints expressed by matrix K require the feasibility of the set of inputs and outputs of power in the system. The overall set of constraints therefore guarantees that all network interactions are internalised and that load is always met.

The solution of the economic despatch problem yield a set of prices that meet the market equilibrium condition. Ignoring losses, in the absence of network constraints there would be a single market clearing price in the system. In this case none of the feasibility constraints in K would be binding and all the related shadow prices would equal zero. On the contrary congestion in the grid creates the differences in locational prices (or nodal prices) reflecting the differences in locational marginal costs. The nodal price arising form the optimisation procedure reflects three components: *i)* the energy component is equal to the marginal cost to serve the next increment of demand at the node that can be produced from the least expensive generator in the system; *ii)* the congestion component is positive only if the transmission constraint is binding and is given by the difference between the marginal cost of the additional energy that can be

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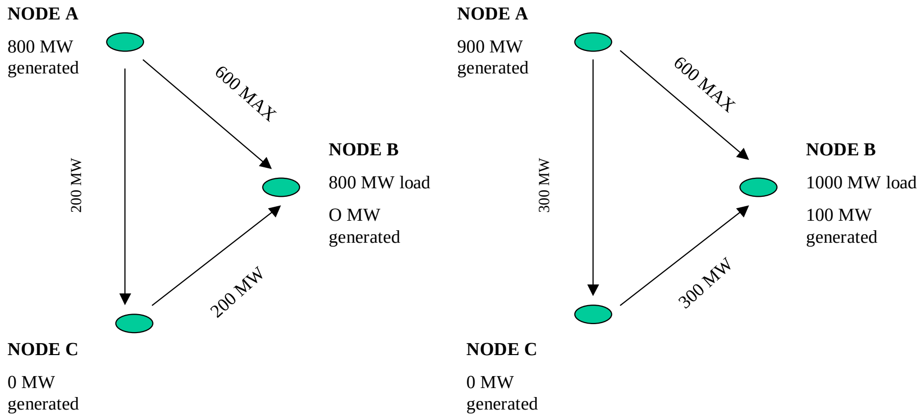
[4] A node is a term applied to the intersection connecting paths.

delivered at that location and the marginal cost of the least expensive generator; *iii)* the cost of losses.

In a sufficiently interconnected system even a single constraint could give rise to a different price at every location. I provide an intuition for this result through the following example.

Example 2: Nodal Pricing



Case 1: no congestion

$p_A = p_B = p_C = 1$

Case 2: congestion

$p_A = 1$; $p_B = 3$; $p_C = 2$

Example[5] 2. Consider a three node network in which the line connecting A and B is constrained at 600 MW; there is no restriction for transmission on the lines A-C and C-B. Assume that generation at each of the three nodes is characterized by different marginal costs: $MC_A=1$; $MC_B=3$; $MC_C=5$. Assume inelastic demand at node B.

Case 1: the load at B is 800 MW. There is no congestion in this case and the demand can be met by the least cost generator in A. The optimal prices are: $p_A= p_B= p_C=1$.

Case 2: the load at B is 1000 MW. In this case the low cost production at A can not satisfy the overall demand because the line A-B is constrained at 600 MW. It follows

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[5] For simplicity I do not consider losses due the resistance encountered by transmission of power over wires. Incorporating losses the market equilibrium prices would be slightly different even in the case with no congestion. However for the purpose of this example incorporating losses would not change the main point.

that the optimal despatch would require 900 MW generated at A and 100 MW generated locally at B. The cheap plant at A is “constrained off”, which means that not all the power that could be generated at this plant can be used. Conversely the higher cost plant at B is “constrained on” because of congestion. The prices solving the optimal despatch problem are in this case $p_A= 1$; $p_B= 3$; $p_C=2$. Congestion make the prices different and the transmission right on the line A-B has implicit value: $(p_B-p_A)*600=2*600$

For an intuition about how the locational price at C is derived assume two additional MW supplied at C. This would allow a reduction of 1 MW at A and the replacement of 1 MW of expensive generation at B[6]. The net saving for the system is therefore (1+3)/2 which is exactly the marginal value of additional generation at C or, equivalently, the nodal price at C. Since the marginal cost of generation at C is higher than this price the generator at C doesn’t run.

In practice the TSO doesn’t know neither the utility of agents nor the cost functions of firms. However the TSO in the integrated model is responsible for running the wholesale spot market for power in which participants both on the demand and the supply side submit bids to either offer or purchase energy at each node for each hour (or half hour) of the following day. Each supply bid defines the minimum price at which the generator would accept to run the plant at that hour. Ordering the supply/demand bids specifying price and quantity, the TSO obtains an approximation of the demand function and of the industry supply function at each node for each hour. Under the competitive assumption no market participant can significantly affect the price and the economic despatch problem is solved maximizing the net value of transactions, which corresponds to the area lying vertically between the aggregate inverse demand and supply curves. Under standard assumptions the problem is thus equivalent to the above formulation provided that the demand and supply functions ordered from the bids are a good approximation of the real demand and supply for power in the economy.

The optimisation procedure determines the equilibrium prices at each node for each hour of the day, the total quantity produced and the merit order for generators, that is the collection of generators marginal costs from the least to the most expensive. Generators

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[6] Ideally the system would prefer to use both the two additional MW to replace the expensive generation at B, but this is not possible because it would violate the transmission constraint (the flow on the line A-B would be 602 MW in that case).

will be dispatched according the merit order which implies that the demand is always met by the least cost generation taking into account network constraints.

The integrated model guarantees simultaneously both efficiency and physical feasibility. The TSO has full control over real time despatch which permit to internalise the externalities and accommodate contingencies in the most efficient way. Congestion is solved by the TSO adjusting the dispatch such that the most highly valued use of the grid is provided. The scarce resource, transmission capacity on the congested interfaces, is not traded or priced explicitly. The opportunity price to transfer energy between two points (two nodes) in the system is derived as the difference between the nodal prices of energy at each location.

From a theoretical perspective the integrated and the unbundled models are equivalent, one being the dual of the other: not considering the transaction costs and assuming perfect competition in both generation and load the outcome from the decentralized solution, which feasibility is assured by the TSO, is equivalent to the one derived in the centralized solution. Since in both cases the externality failure is dealt with by the TSO the equivalence between the centralized and the decentralized approach is restored[7].

1.6 Comparison between the two models

Although theoretically equivalent, the two approaches are different in implementation. The decentralized solution suffers of two major drawbacks: possible inefficiency due to the non simultaneous clearing of the markets and high transaction costs.

In the unbundled model markets do not clear simultaneously. To what extent this reality can seriously prevent an efficient outcome is controversial. An efficient result would produce the first best outcome for the energy market: demand would be met by least cost generators in each time period and at each location in the system. For the transmission market the clearing price for each point to point reservation would obey to the opportunity cost pricing principle: the value of transmission for a megawatt from

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[7] I provided here the intuition for this result on the basis of economics principles. A formal proof can be found in Harvey, Hogan, Pope (1997). See also Wilson (2002).

one point to another is given by the difference between the price of energy at each location. If the market for transmission and the market for energy are poorly coordinated it is not plausible to expect such a result. A trader on the transmission market would have to buy the right for point to point physical delivery of power having expectations about the value of energy in the two locations. For example it would be worthwhile for a generator to buy the transmission from point A to point B at the opportunity price (p_B-p_A) if its marginal cost of producing in A was lower than p_A. To make such a judgement the generator would need to predict accurately enough the two prices. Coordination between the two markets would imply the continuous possibility for participants to adjust their trading on the transmission market in order to take into account the developing opportunities on the power market. The process can be thought of as an iterative one in which: first, market participants schedule attempted injection/withdrawal programmes, as a result of a run of the energy market; second, the system operator publishes the corresponding set of prices to use the transmission system for each couple of nodes, that will be charged to market participants scheduling injections/withdrawals in those couple nodes (for each couple of node, such price equals the difference in the energy price paid/received by the system operator to redispatch generators in order to solve the congestions resulting from the aggregate programme); third, a further energy market session is run in which market participants negotiate changes of the previously agreed injection/withdrawal programmes, given the transmission prices set by the system operator; as a result of this energy market session a new set of programmes is sent to the system operator that publishes the new set of corresponding transmission prices. The process continues until convergence, i.e. until the energy price difference between each couple of nodes (determined by the negotiation among market participants) equals the transmission price between those two nodes (set by the system operator).

Such an iterative process would recognize the strong link between price of energy and value of transmission. The higher the degree of coordination the more similar the unbundled model would be with respect to the centralized model. However tight coordination between the two unbundled markets would be quite cumbersome in implementation. Indeed, since in the unbundled model the markets clears in sequence the possibility of having an efficient result relies mainly on rational expectations. Even though such an assumption is too strong it is possible to argue that frequent repetitions of markets with the same participants can improve the ability of agents to make sufficiently accurate predictions of prices for both energy and transmission.

The second concern about the unbundled model is about transaction costs. Feasibility constraints of market outcome are not taken into account by participants: users of the grid can not predict possible conflicts among schedules. This imply that transaction costs are very high because the TSO has to ask participants to modify the trading outcome until the feasibility test is passed. This procedure is necessary in order to guarantee the reliability of the system and to avoid highly inefficient real time actions for congestion management.

With respect to both these issues the integrated model offers better guarantees for implementation: transaction costs are significantly lower and efficiency is achieved. Integrated markets save the transaction costs of trading physical transmission constraints. Solving for economic despatch demand is met by low cost generation and the value of transmission reflects the opportunity cost of power transfer between two different locations. The standard concept of competitive equilibrium is extended for products across multiple locations. The efficient pricing criterion (price equal to marginal cost) applies in finding the least cost despatch of power grid given utility of consumption and the cost of production at each location. Network interactions are fully internalised and congestion is faced at the lower cost possible for the system. Efficient locational prices will both signal appropriate levels of consumption and supply and will encourage the appropriate levels and locations of new generation and transmission investments.

However the efficiency properties of the integrated model relies heavily on the assumption that the information obtained from the bids in the spot market allows the TSO to get a good approximation of demand and supply functions in the market. With respect to this issue a crucial point in both theory and practice of electricity market design is the definition of the wholesale pricing rule. Electricity wholesale markets can be described and analysed as multiunit auctions. Alternative auction forms have been considered, notably uniform price auctions, Vickrey auctions and discriminatory auctions. Since electricity auctions are multi-unit procurement auctions in which demand is elastic and uncertain, the revenue equivalence theorem doesn’t apply. It follows that a comparison among alternative pricing rules is particularly difficult in this setting.

In electricity market design uniform price auctions have been favoured for long because they allow to identify the price clearing the market (or system marginal price). In a uniform price auction, indeed, all units are sold at the a market clearing price such that the total amount demanded is equal to the total amount supplied. Market prices are therefore determined by the bid price of the marginal accepted unit. However a greater dissatisfaction with the uniform price form[8] has stimulated the theoretical debate about the optimal pricing rule.

Auction theory has highlighted the efficiency properties of Vickrey auctions in multiunit settings. Assuming perfect competition, in a Vickrey auction the revelation of the privately known value is a weakly dominant strategy for players. In the context of electricity this implies that, in absence of market power, bidding at marginal cost is a weakly dominant strategy for generators. Truthful biddings will reproduce the real merit order and allow for an efficient economic despatch. Removing the perfect competition assumption recent studies suggest that discriminatory (or pay as bid) auctions perform better than uniform price auctions in reducing market power[9]. Nevertheless, theory hasn’t yield yet definite answers about the comparison of alternative auctions designs for wholesale power market and the presumed better performance of a discriminatory or a Vickrey auction with respect to a uniform price auction is still controversial[10]. Moreover pricing rules which entail some kind of price discrimination often encounters political obstacles in implementation since non discriminatory pricing requirements are often included in legislation.

A further crucial advantage of the integrated model is that it allows for congestion pricing. The variation of prices by location reflects transmission congestion. The

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[8] For example Klemperer suggested that collusive equilibria can arise when infinitely divisible quantities of homogeneous units are auctioned in a uniform price auction. Interpreting electricity price auctions according to this model imply that equilibria characterized by very high profits and prices can arise in the wholesale market. Klemperer P. (2000) “*Why every economist should learn some auction theory*”. Nuffield College, Oxford.

[9] Federico, G.; Rahman (2001) “*Bidding in an electricity pay as bid auction*”. Working paper Nuffield College, Oxford.

[10] Fabra, N.; Von Der Fehr, N.; Harbor, D. “*Modelling Electricity auctions*”, The Electricity Journal 2002. They use a discrete multi unit auction model to compare uniform, discriminatory and Vickrey

problem of pricing transmission taking into account congestions is solved in the nodal prices approach. In the unbundled system I argued above that the outcome from the transmission market is either inefficient (in case of poor coordination between the market for energy an the market for transmission) or intractable (in case a high degree of coordination is attempted through an iterated system). On the contrary nodal prices define implicitly the efficient price for transmission. Transmission of a megawatt from A to B can be indeed thought as a sale at the source and a purchase at the delivery point. The cost of transmission is thus given by the difference of the prices clearing the market for energy in the two locations. If the line is not constrained the price for power in the two locations would be the same and equal to the least cost of producing an additional megawatt; if the connection is instead congested the prices would be different and the difference would equal the price for congestion.

1.7 Physical and financial transmission rights

The integrated energy/transmission model overcomes the problem of transmission capacity definition by avoiding a physical definition of the transmission right. A physical transmission right would entitle the market participant to the exclusive use of the corresponding fraction of capacity on the line. The centralized economic despatch doesn’t allocate explicitly the physical right to transport a predefined quantity of power on a certain line or interface. On the contrary the physical rights to use the grid are automatically assigned by economic despatch to those users who provide the system with the highest value. The transmission right definition that suits an integrated approach is indeed a financial one rather than a physical one[11].

Financial transmission rights can be defined as point to point transmission rights (from a source location to a delivery location) but an holder of a financial transmission contract can not prevent others from the use of the system. Since they are purely financial instruments, they are perfectly compatible with the efficient despatch: the TSO

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auctions for electricity under a variety of assumptions. The main finding is that the welfare ranking of the different auctions is inherently ambiguous.

determines which generators will be dispatched according to the merit order, but the financial benefit from the use of the congested line accrues to the holder of the financial right. It follows that the actual use of the system and the financial benefit from its use are separated. Nevertheless the financial and physical perspective are linked: the payment obtained by the holder of the financial transmission right is exactly the financial benefit that the holder of the corresponding point to point physical right would obtain by selling the right to use the congested grid to the least cost generator. The value of the financial right is indeed the opportunity cost of transfer capacity between the two locations or, equivalently, the difference between the nodal prices: the rights to use the line have the same value in any competitive market no matter how they are defined. The theoretical equivalence between the decentralized model coordinated by the TSO and the integrated model under the hypothesis of perfect competition and no transaction costs carries the equivalence in the financial and physical interpretation of the transmission rights.

Financial transmission rights are a crucial completion of the centralized approach along with the electricity spot market run by the TSO and the nodal prices arising from the optimisation procedure. The role of financial transmission rights is indeed fundamental in the centralized model for two main reasons: they provide a convenient way to deal with congestion rents and they allow to reconcile short run efficiency with long term risk management.

When the transmission interface is constrained nodal prices are different at each node. Within the interface capacity limit, power produced by the least cost generation region is purchased by the TSO, transmitted and sold at the high price region. A congestion rent arises from the difference between the amount paid by the TSO to buy energy from generators and the revenue from selling it[12]. If the TSO was allowed to keep the congestion rent he would have the perverse incentive to manipulate despatch and prevent capacity expansion in order to increase its revenue. The ultimate result would be inefficient despatch and insufficient investments in transmission capacity. Financial

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[11] Hogan (1992) and also Lyson, Fraser and Parmesano (2000). However the linkages between pool-based dispatch and financial transmission rights as well as between decentralized markets and physical transmission rights are not absolute (Bushnell 1999).

[12] In example 2 case 1 no congestion rent arises: power is purchased at $p_A=1$ at A and is sold at $p_B=1$. In case 2 instead the TSO purchases power for (900*1)+(100*3) and sells it for (3*1000); it follows that the TSO gets a congestion rent of (900*2).

transmission rights provide a solution by redistributing transmission rents to participants in the market trough the allocation of transmission congestion contracts[13]. Such a contract between the TSO and a market participant provides that the revenue arising from congestion on a certain line will be transferred to the contract holder. This approach eliminates the adverse incentive on the TSO which can not take advantage from inefficient dispatching and, at the same time, allows for long term allocation of transmission rights.

The economic despatch problem focuses on short term efficiency: given the high variability of demand and supply conditions during the same day the optimal dispatch allocate implicitly the physical right to use the system to least cost generation on a hourly basis. On the contrary, transmission congestion contracts allow for long term allocation of financial transmission rights. Indeed, supply contracts between generators or traders and customers have a long term horizon and refer to a fixed price. It follows that variation in nodal prices in the wholesale market exposes participants to a double price risk: a first one related to fluctuations in demand and supply condition and a second one strictly related to possible congestions. Transmission congestion contracts deal with this second risk in the context of a pool based despatch model[14]. By purchasing a transmission congestion contract from the TSO the generator can fix the value of transmission. The generator or the trader can therefore predict the maximum cost he will incur in supplying a customer located at a different node. It follows that traders who are fully hedged with transmission congestion contracts are guaranteed full protection from the vicissitudes of congestion pricing. To illustrate the hedging properties of transmission congestion contracts I provide the following example.

Example 3. Suppose a generator is located at A and has MC=5/MWh. He supplies a customer located at B according to a long term contract with fixed price.

The generator purchases from the TSO a financial transmission right equal in megawatt size to his generating capacity. The price for the corresponding transmission congestion contract is equal to the difference in the nodal prices per MWh arising in case of

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[13] Financial transmission rights defined as transmission congestion contracts have been proposed by Hogan in 1992.

[14] In the decentralized model physical transmission rights guarantee the holder access to the market he wishes to transact in. A generator can therefore hedge against locational price risk associated with energy transactions in a given area (Bushnell, 1999 and Lyons, Fraser, Parmesano, 2000).

congestion, say 10MWh. The generator will be therefore able to predict a maximum cost of 15/MWh to supply the customer at B whether he is despatched or not.

Case1: the generator is not despatched. Suppose the nodal price at A is p_A=4/MWh and therefore cheaper generation is despatched. Suppose price at B is p_B=17/MWh. The value of the financial right is 13/MWh and this is what the generator receives from the TSO. Since he is not dispatched he receives the payment for having implicitly sold the right to use the grid to a more efficient generator. The net cost of supplying the customer at B is therefore 14/MWh instead of 27/MWh for the generator holding the financial transmission right.

Case 2: the generator is despatched. The nodal price at A is greater than the generator's marginal cost. He is despatched and has the right to withdraw power at B. The cost for the supply is therefore 15/MWh in this case.

Either case 1 or 2 may be the relevant one in a certain hour of the day, but in neither case the cost of supply will exceed 15/MWh.

Even though it would be possible in principle to have transmission congestion contracts privately supplied, the private market may fail to provide them because they are risky. Typically the transmission congestion contracts will be provided by the TSO trough an auction. Since the income from the auction is more predictable than the congestion rent and the TSO can afford offering the contracts. The set of transmission congestion contracts that can be issued by the TSO is any set that corresponds to a feasible power flow. Restricting the set of auctioned contracts to a feasible set allows for bilateral trading in a secondary market.

In conclusion, the integrated energy/transmission model allows for efficient use of transmission capacity in the short run by implicitly allocating it to the least cost generation. The nodal prices emerging from the centralized optimisation procedure reflect the marginal cost of generation at different locations in the system. Differences between nodal prices may arise in case of congestion and reflect the opportunity cost of transmission. Hedging from these price differences is possible for generation by holding long term financial transmission rights which allow for long term transactions. Financial transmission rights guarantee the economic value of transmission but do not determine the actual flows which is dictated by economic despatch.

II: TRANSMISSION RIGHTS AND MARKET POWER

In the long run, imperfect competition in power markets stems from economies of scale and other entry barriers (for example environmental and institutional ones). Competition is imperfect in intermediate time frames because production is capital intensive and do not adjust quickly enough to variations in supply and demand conditions. Competition is inherently imperfect on short time scales because of technical rigidities on the supply side and inelastic demand. It follows that market power issues are fundamental in electricity market design. In this chapter I extend the analysis presented in the last one by removing the perfect competition assumption to consider the role played by transmission rights allocation in imperfect competition contests.

The interconnection capacity between regions or countries was historically developed to provide security of supply. In the context of restructured electricity market transmission plays an additional and fundamental role in promoting energy trade. Transmission rights definition and allocation affects indeed competition in electricity markets in both a long and a short run perspective. In the long run additional transmission capacity has a similar role to additional generation in increasing competition in isolated nodes on the network. The institutional framework, congestion pricing and transmission rights play a crucial role in providing information and incentives for efficient transmission expansion. In the short run, instead, congestion pricing and transmission rights should provide efficient allocation of scarce transmission capacity. Since the available capacity in the network is fixed and limited, one or more lines on the network can become congested and can not accommodate the inelastic demand for power. It follows that few generators inside the congested area may have market power when interconnection is constrained.

The focus of this chapter is on the short run perspective in order to consider how the definition of the transmission rights (both financial and physical) and their allocation affect the behaviour of electricity generators with market power. The key policy question arising as a consequence is how this scarce capacity should be made available to mitigate market power concerns.

2.1 Market power in a physical rights system

A first approach to deal with shortage of capacity is to create and allocate tradable transmission rights that entitle the holder to the exclusive use of the congested interface. The market for these physical rights determine the market clearing prices for congestion. Even thought a decentralized approach involving separate markets for energy and physical transmission rights has been criticized on the grounds of the difficulties arising in implementation, the model is theoretically equivalent to the centralized approach under the assumption of perfect competition and no transaction costs. I consider here market power concerns in a decentralized electricity market in which physical transmission rights are defined and used to allocate scarce capacity on congested lines. Since the incentives for generators are mainly the same in the simple two nodes case and in a meshed network, I focus on a single line connecting two locations.

Two node case with symmetric costs. The main concern arising in case of physical transmission rights relate to the ability to withhold transmission capacity from the market place. In case of a line connecting two generators with same marginal costs, physical transmission rights can be used to exercise market power. In a competitive context the transmission value would be zero. Nevertheless Bushnell (1999) provides examples for three cases in which generators may have an incentive in strategically manipulate the use of capacity on the interconnecting line:

- The withholding of transmission capacity can increase the value of local generation resources. In the extreme case in which the local generator holds all the transmission rights over the interconnecting line, he has an incentive in withdrawing physical rights from the market in order to generate the monopoly quantity and having the monopoly profit on his local market.
- The withholding of transmission capacity can increase the value of the transmission rights. Even thought the right to use the grid is not held by the local generator as in the previous case, there can be an incentive in withdrawing capacity from the market. If there is no generation at the delivery node the

transmission right holder has an incentive in restricting the flow on the line in order to induce the monopoly price on the demand node. The artificial constraint increase the difference of the equilibrium price at the two nodes and therefore the value (equal to the opportunity cost) of transmission.

- The withholding of generation output can capture the congestion revenue that would otherwise accrue to the owner of the transmission right. Suppose there is a single firm owning all generation at the supply node and no generation at the demand node. The generator at the supply node doesn’t hold the transmission right. A profitable strategy would be to restrict production at the supply node until congestion is eliminated. As a consequence the value of transmission is now zero since there is no congestion and the price at the demand node is higher (because supply is restricted). In this case the strategic manipulation doesn’t utilise transmission rights at all, but involve withholding of generation capacity at the supply node.

In all three cases there are two relevant sources of revenue: from selling power and from transmission. Strategic manipulation of the transmission right allows generators to get extra profit form either the first or the second stream of revenue.

Two node case with asymmetric costs. In a more general framework Joskow and Tirole (2000) focuses on incentives for generators with different marginal costs to exercise market power with their generation. Suppose the North or exporting region has lower production costs than the South or importing region. The generators in the South (G_2) are owned by a single firm that has market power, while the generators in the North behave (G_1) competitively. There is a transmission line with fixed capacity K connecting the two nodes. The optimal strategy for generator G_2 is to purchase all the rights on the connecting line and do not resell them to the first generator. Since the rights are physical ones the generator controls the transmission line and has to choose both: how much of the intermediate service (transmission) to provide to generator G_1 and how much local output to produce. The generator faces therefore a typical Coasean dilemma: if G_2 decides how many rights to sell to G_1 in the first stage and then in a second stage how much power to produce he will tend to overproduce in the same way as the durable good monopolist floods the market in the second stage of the game. The standard solution applies here: the best strategy for the generator is vertical integration because in this way the generator can commit his ex post supply. Under vertical integration generators with market power in the importing region can use physical rights to substitute the more expensive local production with cheap generation form the North[15]. By preventing other firms from using the line the generator keeps an exclusive relationship with consumers in the South and fully utilize the available capacity at his own advantage (there is no capacity withholding in this case). On the contrary if the firm is prohibited from reselling power produced in the North (non commitment case), he has an incentive to withhold physical rights to reduce the capacity of the constrained transmission link. However, the monopolist hasn't an exclusive relationship with the consumer in the South in this case: G_2 will sell transmission rights to G_1 in the first stage and in the second he will tend to floods the market to maximize profits given the output in the North. Therefore even thought to allow for reselling maximize production efficiency (because cheap generation substitute higher cost production with cheaper generation in the commitment case) the welfare is not maximized because total production is higher in the non commitment case.

2.2 Market power in a financial rights system

In a nodal pricing system participants in the market face the risk of differences in locational prices arising in case of congestion. Financial transmission rights defined as transmission congestion contracts provide hedges against price risk. Under the perfect competition assumption, the centralized model has several advantages in promoting the efficient use of the grid and in pricing congestions. In imperfect competition contests concerns arise about the ability of the optimisation procedure to still provide the welfare maximizing outcome. Since financial transmission rights provide their owners congestion payments but not physical control of transmission paths, withholding physical capacity from the market place is not an available strategy for generators. Nevertheless, even though a financial transmission right holder can not directly

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[15] The demand is assumed to be higher than total transmission capacity and the constraint is therefore binding.

influence the despatch decisions of the TSO he has an extra financial incentive in manipulate the price at that node. The point is explained in the following case.

Two node case with asymmetric costs. The framework is the same as before but the single generator in the South is allowed to hold financial rights. The financial transmission right holder is paid the price difference between the two nodes for the fraction of capacity in his transmission congestion contract (assume the generator holds a fraction $\alpha_2 \in [0,1]$ of the K financial rights available on the interconnecting line). The congestion rent enters directly in the objective function of the generator at the South node G_2:

$$\pi_2(\alpha_2) = \max_{p2} \{G(p_2) + \alpha_2 F(p_2)\}$$

where $G(p_2)$ is the profit from generation at the South node against the residual demand curve $q_2 = D(p_2) - K$ and $F(p_2)$ is the value of the financial right: $F(p_2) = (p_2 - p_1^*)$ with p_1^* competitive equilibrium price at the North node.

If no rights were defined G_2 would impose the monopoly price given the residual demand for his local market. The introduction of the financial right gives him an extra incentive to increase the price on his local market. Formally the equilibrium price arising from the maximization problem will be $p_2(\alpha_2)$ increasing continuously in α_2 from the monopoly level arising in case of no rights to a maximum when $\alpha_2 = 1$ (in this case the firm holds all the rights and faces the total demand instead of the residual one). The higher is the fraction of rights held by generator G_2 , the higher is his incentive in restricting the output and increase the price: the firm sacrifices some profits from selling more power to get extra profit from congestion[16]. The value of the financial rights is a function of the price p_2. Joskow, Tirole (2000) analyse the case in which the financial rights are auctioned off by the TSO in a pay as bid auction and show that generators will get a positive amount of rights by playing a mixed strategy. Gilbert, Neuhoff and Newbery (2003) extend the analysis to the oligopoly case and compare results from uniform price and discriminatory price rules in auctions for transmission

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[16] The implicit assumption here is that a monopoly at a node sets the price at that location by bidding an appropriate supply schedule.

rights (either financial or physical). They prove that uniform price auctions mitigate market power, but the set of assumption under which this result holds is quite restrictive. However, under full information and no uncertainty, competitive traders adopt a more aggressive bidding strategy in a single price auctions. In presence of efficient arbitrageurs, therefore, importing generators get a lower amount of transmission rights which mitigate their market power.

2.3 Comparison between financial and physical rights under imperfect competition

The analysis can be extended to cover alternative market power configurations and meshed networks. Joskow, Tirole (2000) provides for additional cases and for some extensions to meshed networks, Gilbert, Neuhoff and Newbery (2003) consider the extensions to oligopoly and further develop the meshed network cases. However the discussion presented in the above paragraphs highlights the logic of the incentive issues common to all possible extensions. In addition it also allows to extend the comparison between financial and physical rights systems that concluded the first section of this paper to consider further differences arising in the non competitive context.

Financial rights systems and physical rights systems mainly differ because a physical transmission right holder can effectively restrict capacity on the interconnecting line and cause production inefficiency. On the contrary in a financial transmission right system production efficiency is always assured since holders of rights can not affect physical despatch. However the behaviour of the generator with market power reduces welfare with respect to the no rights benchmark because the ownership of transmission rights enhances his market power and increases prices. Nevertheless the welfare performance is even lower with physical transmission rights system because production inefficiency is an additional concern in this context. However production efficiency is possible in this last model in two circumstances: the first one is the non commitment case discussed above and the second consider the introduction of a *use it or lose it* provision. This rule provides that the transmission right holder loses the exclusive right on the unused capacity. Spare capacity can then be allocated to other users by the TSO. This rule provides the most powerful incentives for physical rights holder not to withhold capacity from the market place. If properly applied, therefore, this rule would prevent from the inefficiencies arising from withholding in both the symmetric cost and the asymmetric cost cases. It follows that the introduction of this rule mitigates market power and restore the equivalence between the financial right system and the physical right (case with commitment) from both an efficiency and welfare perspective[17].

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[17] The use it or lose it provision has been widely adopted in the natural gas industry while its introduction in the electricity market arises some concerns in implementation. Even thought the tight time constraints make it difficult to enforce the provision, it has been adopted by some European regulators.

III: TRANSMISSION RIGHTS ALLOCATION IN THE ITALIAN ELECTRICITY MARKET: AN ANALYSIS OF THE CURRENT PROPOSAL

3.1 The liberalization of the electricity industry in Italy

The European electricity industry has undergone major changes in the last decade due to intensive programs of deregulation. Since the approval of the Directive 96/92/EC by the European Parliament and the Council on the 19th December 1996, a restructuring wave has crossed Europe to carry out the project of an Europe wide electricity market based on common rules. Member states implemented and integrated the European guidelines provided in the Directive by country specific piece of legislation.

In Italy the liberalization process started in 1999 with the Legislative Decree no. 79/99, which draw the fundamental lines for restructuring the Italian electricity industry. The reform states the vertical unbundling of the incumbent firm Enel which has been partially privatised and split into separate companies functionally specialized in the generation, transmission, distribution and supply activities. Even tough all these companies refer to the same group, Enel Holding, and the ownership is therefore integrated, the legislator provided for specific measures to reduce the incumbent's dominant position. The Decree imposed a 50% ceiling on generation and import market share which implied the divestiture of 1500 MW of Enel's generation capacity. To ensure open access to the grid for all players on a non discriminatory basis, the decree entrusted a public owned company with the management of the transmission system (GRTN, Gestore della Rete Nazionale), even though the incumbent Enel keeps the ownership of the network.

As regards the wholesale market design, the Italian legislator opted for the institution of a pool market governing economic despatch. Participants from the supply side are generators and importers, while participants from the demand side are eligible customers[18], the Single Buyer, distributors and traders. The Decree provided for the

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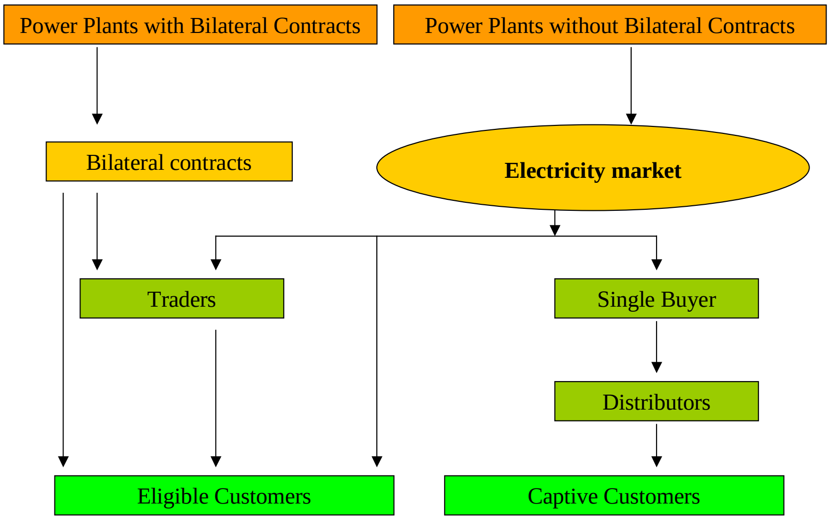
[18] Eligible customers are consumers who are legally enabled to chose the supplier. Eligibility depends on the level of consumption. Customers whose annual consumption doesn't reach the legal threshold are captive costumers.

Single Buyer as an institution entrusted to procure electricity-generating capacity and guarantee electricity supply to the captive costumers. In accordance with the Regulator’s directions, the Single Buyer shall negotiate contracts of sale with electricity distributors.

Even though the Italian legislator opted for the centralized model, decentralized trading is not completely excluded: bilateral contracts are indeed possible provided that they are approved by the Regulator[19]. According to the institutional design the economic management of the electricity market shall be entrusted to a Market Operator (GME, Gestore del Mercato Elettrico), a company set up by GRTN.

The institutional design of the Italian electricity market is summarized in figure no.1.

Figure 1: The liberalization of the Italian Electricity Sector



The Market Operator is in charge of issuing the market rules, which specify the responsibilities of the Market Operator and the obligation of electricity producers and importers not opting for bilateral trading. Even thought the Legislative Decree no.79/99 fixed for the 1st January 2001 the start of the Italian pool, the reform has not been

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[19] The authorisation may be denied or conditioned whenever the contracts jeopardize competition or security and efficiency of the electricity supply system.

implemented yet. The lack of a clear political line about the future market design and the strong opposition to market based pricing from high demand industrial consumers have greatly delayed the expected pool market. Nevertheless, the market rules proposed by the Market Operator have already received the final approval by the Regulator first and then by the Ministry of Industry on the 9th May 2001.

This last section of the paper analyses the proposed Market Rules which will define the future Italian electricity market. A complete analysis of all the crucial dimensions would go beyond the purposes of this work which will therefore focus only on the aspects relevant for the transmission allocation problem. The next paragraph illustrates the proposal while the following one offers a critical appraisal of the proposed model on the grounds of the theoretical issues presented in the past sections.

3.2 The current proposal for transmission rights allocation

GME proposed with the Market Rules approved on the 9th May 2001 an integrated energy/transmission model which is intended to both maximize the value of transactions on the wholesale market and, at the same time, to efficiently allocate transmission capacity in case of congestion.

In the restructured electricity market GME is entrusted to directly manage the wholesale power market. Supply offers (by thermal unit, by hydro plant or by border) and demand bids (load by point of withdrawal) will be collected in the Day Ahead Energy Market for each of the 24 hours of the next day[20]. From the demand/supply schedules submitted the GME will draw the aggregate demand and supply curves and solve for the optimisation problem. Maximizing the value of transactions under the feasibility restrictions the procedure yields the optimal prices which satisfies the demand with the least cost generation given the physical transmission constraints. Since the chosen pricing rule is a uniform price, in case none of the transmission constraints is binding

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[20] Supply and demand hourly bids presented in the Day Ahead Market can then be modified by players in the Adjustment Market. Since the Adjustment Market operates according to the same rule as the Day Ahead Market, I restrict the discussion to this last market.

the algorithm provide a single national price clearing the market. Congestion cases are instead solved with a *market splitting* procedure:

- GRTN divides the national territory into geographic zones;
- demand bids and supply offers are considered on a zonal basis taking into account the maximum transfer capacity between different zones;
- a market clearing price is defined for each zone separately (*zonal market clearing price*) with the price of the importing zone grater than the price for the exporting zone. Perfect arbitrage would give the same price for each zone in case of no congestion. Nevertheless in case of limits to power transfers between zones the difference in prices reflects the opportunity cost of transmission.

The proposed market design, therefore, closely follows the centralized model presented in the first section of this paper. However the Market Rules propose for congestion management a variation of the pure nodal pricing paradigm and aggregate different nodes into zones. The optimisation algorithm produces in this case a much smaller number of equilibrium prices, one for each zone instead of one for each node. GRTN splits the Italian transmission network into six zones each of which is perceived as a separate market. Within each zone congestions are not expected to be systematic on the basis of network transmission simulations. On the contrary, all the zones are considered connected to each other by transmission links with a limited transfer capability. Shortage is therefore expected to be likely between zones and difference in zonal prices is expected in many hours of the day. Even though congestions are not expected to be systematic within zones and the implicit transmission allocation of transmission rights in the Day Ahead Market takes into account network constraints between zones, the injection/withdrawal schedules arising form the Day Ahead Market still need the GRTN intervention during the day to be implemented. To solve further congestions and or to allocate unused capacity GRTN can manage congestions with *counter trading actions. Counter trading* is operated through a specific market, the Congestion Management Market in which market participants bids for increase or decrease of injections or withdrawals. Participation in this market allows player who got a transmission right[21] in the day ahead transactions to obtain a financial compensation in case injections/withdrawal schedules can not be implemented.

The outlined proposal for congestion management based on *zonal pricing* and *counter trading* has been criticized in the political debate on the basis of the following argument: zonal price differentiation would expose some customers (those located in high cost areas) to higher prices without the relevant authorities having been given time to remove the causes of systematic congestion by the sitting of new lines or generating plants. GME response to this criticism was to propose a three years interim solution according to which generators are paid the zonal prices while customers pay a national-wide uniform price. The interim solution is part of the Instructions presented to the Ministry of Industry on the 18th January 2002.

3.3 Critical notes on the current proposal

GME's Market Rules propose a centralized model in which energy and transmission are integrated in order to provide the welfare maximizing economic despatch. The design and rationale for the chosen approach closely follows the centralized theoretical model presented in the first chapter. However the proposed solution differs from the pure integrated energy transmission model in three main crucial dimensions:

1. it is a zonal model rather than a nodal one
2. it is not a pure centralized model since bilateral trading is allowed
3. the interim solution provides for a uniform (nation wide) purchase price with multiple (regional) sell prices

I briefly discuss in what follows the impact of the highlighted differences on the market design.

Zonal versus nodal model for congestion management. The zonal model has been applied in a number of restructured energy markets in the USA and in the NordPool[22] in Europe. The main reason why it has been preferred to the nodal model is that it greatly reduces the number of prices and it is therefore easier to understand for players. It is a

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[21] As discussed in the first chapter participants to the centralized market whose bids are accepted are implicitly allocated a financial transmission right.

[22] The Nordpool system manage the power markets of Sweden, Norway, Finland and Denmark.

discussed point, however, whether the simplified zonal model is able to reproduce the short term efficiency properties of the nodal paradigm. The integrated energy/transmission model with nodal prices provides for the short term efficient allocation of transmission capacity and gives players the correct signal for future expansion of both generation and transmission capacity. Since the prices calculated on a zonal base are load weighted averages of the nodal prices located within each zone, both the zonal and the nodal models send congestion price signals through location based marginal cost pricing. Moreover both models assign implicitly financial transmission rights to the least cost available generation according to an optimisation procedure. The most significant difference between the two models is, indeed, the level of aggregation of the various locations. It follows that the arguments in favour of one model or the other mainly focus on the evaluation of the trade off between complexity and maximum theoretical efficiency. The zonal model indeed reduce the complexity, but aggregation and averaging of the within zone prices might reduce efficiency. The higher level of aggregation of nodes into zones is perceived as a reasonable balance between theoretical efficiency and commercial manageability when congestion costs within zones are deemed to be small, infrequent and not hedgeable. Nevertheless this last point, on which arguments in favour of the zonal approach are based, is still debated. For example Hogan (1999) points out that aggregation of nodes into a zones can be appropriate only in case of radial networks[23], while in the much more realistic case of meshed networks the loop flow complication is not sufficiently taken into account by the zonal aggregation. The definition of a zone becomes indeed more problematic in case of real networks where indirect effects of distant constraints would justify different nodal prices within the same zone. In addition even though it is perceived so by participants to the market, complexity in operations is not reduced by adopting a *market splitting* procedure because exact aggregation requires first knowing the disaggregated flows. Zonal definition relies therefore on a simplified assumptions and simulation of power flows which do not necessarily reflect reality. The possible mismatch between the simplified model and real network operations gives rise to unexpected congestion phenomena within zones.

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[23] A radial network can be represented as a set of lines radiating from a hub. This kind of configuration do not present the loop flow effect.

For the Italian market design GME deemed the zonal approach more suitable for a liberalization process at its very beginning. Few zonal equilibrium prices based on locational marginal costs where deemed to provide sufficient incentives for an efficient use of the grid, while reducing the relevant prices to a manageable number. However GME acknowledged the limit of the zonal pricing and the possibility of within zones congestions by instituting the Congestion Market for *counter trading* actions.

Bilateral trading. The Decree 79/99 allows for decentralized trading. To avoid perverse incentives for players which can choose both bilateral trading and participation to the pool, the Regulator provided that bilateral transactions are subjected to the same economic incentives with respect to congestion pricing. The Resolution of the Electricity and Gas Regulator no. 95/01 states, indeed, that bilateral transactions are charged the difference between the market prices arising in the zone in which power is injected and in the zone in which power is withdrawn. The provision follows the line of reasoning discussed in the first chapter of this paper: a condition for decentralized trading and central trading to be equivalent is that in both cases congestion pricing is equal to the opportunity cost of transmission, which corresponds to the difference in the locational prices based on marginal costs of supply. The solution adopted makes therefore compatible the simultaneous presence in the same market of both physical transmission right (allocated in case of bilateral trading) and financial transmission right (allocated implicitly to participants to the pool).

The interim solution provides for a uniform purchase price with multiple sell prices. The uniform price solution was promoted by the Ministry of Industry because zonal price differences were perceived as unfair as resulting from past opposition of local authorities to the sitting of new lines or generating plants. Nevertheless one of the advantages of introducing locational pricing is to provide an efficient signal for transmission and generation capacity expansion. In the intention of GME the interim solution would provide the correct incentives for investments and give the local authorities extra time to reverse their strategy. However the cost of allowing for a national uniform price for consumers is a significant complication in the optimising procedure. GME maximizes the net value of transactions in the spot market exactly as in the locational pricing problem but besides the demand and supply balance constraint and the network constraints there are additional equilibrium conditions and a budget balance condition. The resulting optimisation procedure is therefore much more complicated than the standard zonal model proposed for the long term market design.

In conclusion the Italian proposal for the restructured electricity market is a variation of the integrated energy/transmission model based on a centralized wholesale spot market for power which allows also for decentralized trading. Crucial elements for congestion management are *market splitting* with *locational marginal cost pricing* and *counter trading*. Players opting for either bilateral transactions or participation to the pool market pay a congestion price which reflects the opportunity cost of using the scarce transmission capacity. The model is therefore expected to provide efficient price signals even though averaging of prices into zonal aggregation might reduce the efficiency properties of the nodal pricing approach.

CONCLUSIONS

This paper considered the role of transmission network externalities in the debate over whether competitive electricity systems should be organized around bid-based centralised pools with financial transmission rights or separate markets for energy and for physical transmission rights.

From a theoretical perspective the integrated transmission/energy model and the unbundled models consisting of separate markets are equivalent, one being the dual of the other: not considering the transaction costs and assuming perfect competition in both generation and load, the outcome from the decentralized solution, is equivalent to the one derived in the centralized solution. Even though the role of the TSO is much more pervasive in the centralized model, in both cases the externality failure is dealt with by the TSO and the equivalence between the centralized and the decentralized approach is restored.

Although theoretically equivalent, the two approaches are different in implementation.

The decentralized solution suffers, indeed, of two major drawbacks: possible inefficiency due to the non simultaneous clearing of the markets and high transaction costs. On the contrary, the integrated energy/transmission model implies lower transaction costs and allows for efficient use of transmission capacity in the short run by implicitly allocating it to the least cost generation. The nodal prices emerging from the centralized optimisation procedure reflect the marginal cost of generation at different locations in the system. Differences between nodal prices may arise in case of congestion and reflect the opportunity cost of transmission. Hedging from these price differences is possible for generation by holding long term financial transmission rights which allow for long term transactions. Financial transmission rights guarantee the economic value of transmission but do not determine the actual flows which is dictated by economic despatch.

When the perfect competition assumption is removed to allow for generators with market power, financial and physical rights systems mainly differ because a physical transmission right holder can effectively restrict capacity on the interconnecting line and cause production inefficiency. On the contrary in a financial transmission right system production efficiency is always assured, even though the behaviour of the generator with market power reduces welfare with respect to the no rights benchmark because the ownership of transmission rights enhances his market power and increases prices. The equivalence between the financial right system and the physical right (case with commitment) from both an efficiency and welfare perspective is restored with the introduction of a *use it or lose it* rule.

Both the centralized and the unbundled model have been widely applied in real electricity market. An interesting application of the integrated approach has been proposed by the Market Operator for the Italian restructured electricity market. The Italian proposal is a variation of the integrated energy/transmission model based on a centralized wholesale spot market for power which allows also for decentralized trading. Crucial elements for congestion management are *market splitting* with *locational marginal cost pricing* and *counter trading*. Players opting for either bilateral transactions or participation to the pool market pay a congestion price which reflects the opportunity cost of using the scarce transmission capacity. The model is therefore expected to provide efficient price signals even though averaging of prices into zonal aggregation might reduce the efficiency properties of the nodal pricing approach.

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