Is combination of nodal pricing and average participation tariff the best solution to coordinate the location of power plants with lumpy transmission investments? [1]

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Abstract

This paper evaluates the opportunity and efficiency to introduce a two-part tariff to coordinate the location of power plants with lumpy transmission investments. Nodal pricing sends the short run component of such a two-part tariff and we study the case where the average participation tariff sends the long run one. We argue that this solution is helpful because the average participation tariff tackles lumpiness of transmission capacity while being as cost-reflective as possible. Our proposition is evaluated based on a double optimization model where a TSO minimizes the transmission cost while a generator minimizes its own cost that may take into account network constraints and include the average participation tariff. Numerical simulations are performed on a two-node network evolving during twenty years with increasing demand. The joint implementation of nodal pricing and the average participation tariff stays the best combination to coordinate as efficiently as possible the generation and transmission investments, although the optimal set of generation and transmission investments may not be reached because of transmission lumpiness. The simulations show also that implementing locational network tariffs is prioritary over implementing nodal pricing to coordinate more efficiently the location of generation with lumpy transmission investment. In the considered examples, the average participation tariff allows a more efficient location of generation even when the congestion management scheme being redispatch sends no short run locational signal.

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1 Introduction

One could think of relying on the well-known marginal pricing to expand both generation and transmission capacity in the liberalized electricity industry (Crew *et al.*, 1995; Stoft, 2006). One invests so as to equalize short run and long run marginal costs of both generation and transmission. If these convenient assumptions prevailed in the power system, the generator would invest so as to equalize the marginal generation capacity cost with marginal generation cost. And the TSO would do the same equalizing the marginal transmission capacity cost with marginal congestion cost. Nodal pricing as market-based pricing of transmission service could then govern transmission investment and the location of generation (Hogan, 1992; Bushnell-Stoft, 1996, 1997; Chao-Peck 1996). We underline here that applying this principle to the coordination of generation and transmission investments is not possible.

The transmission of electricity suffers many economic properties that make the application of these principles impossible. It combines both economies of scale and espescially lumpiness of capacity (Brunekreeft, 2004). As Joskow and Tirole (2005) show, lumpiness combined with the short run locational signals from nodal pricing result in an underincentive for a merchant investor to reinforce the network. And Stoft (2006) shows that even if the transmission investment is optimal, nodal pricing can lead to inefficient location of generation because of of the economic properties of the transmission of electricity. Besides, some other less efficient options to operate the system are often implemented, although they send less short run locational signals (Green, 2004). In brief, not only system operation may not send short run locational signals but also these signals are not sufficient to coordinate the location of generation with lumpy transmission investments.

The usual way to comply with these difficulties is to implement a two-part tariff. The first part of this tariff should be nodal prices to ensure an efficient short run use of the network (Schweppe *et al.* 1988). The second part is network tariffs. These later aim at sharing the cost of transmission infrastructures among the network users, especially the generators, in the most cost-reflective way. Well-designed network tariffs incentivise the generators to locate efficiently on the network and thus to maximize social welfare (Pérez Arriaga-Smeers, 2003). The problem is that network tariffs are hard to design. A lot of different network tariffs have then been proposed (Olmos, 2006). Even if none of them may achieve the same coordination between generation and transmission investment as a vertically integrated utility does, they can nevertheless considerably improve the coordination between the generation and transmission investments. However few power systems have implemented long run locational to guide the location of generation. For instance, only five of the thirty five ETSO[4] members implemented locational network tariffs (Brattle Group, 2004).

This paper only focuses on the average participation tariff for the three following reasons. First it has been extensively studied from a static point of view (Kirschen *et al.*; 1996, Bialek, 1997; Rubio-Pérez Arriaga, 2000) while its dynamic interaction with generation and transmission investments was neglected so far (Olmos, 2006). We are then going to study the average participation tariff in this dynamic relationship. Second the average participation tariff has an

[4] European Transmission System Operators

interesting property since it coincides with the Shapley values. Shapley value guarantees that the average participation tariff is a fair, symmetric, stable and acceptable allocation of cost for all the users of the network (Bialek-Kattuman; 2004). Third reason, the efficiency of the average participation tariff for coordinating generation and transmission investments has never been studied whether it is implemented with or without short run locational signals (Olmos, 2006; Stoft, 2006) and we think that network tariffs can send long run locational signals that should overcome the difficulty to incentivise the location of generation when transmission investment is lumpy.

This paper investigates the efficiency of the average participation tariff to coordinate transmission and generation investments whether it is implemented with or without nodal pricing. The model we use in this paper is in the vain of the Sauma-Oren one (2006a, b) but it differs on four points. First, Sauma and Oren do not consider network tariffs and nodal prices is the unique locational signals that they study. Second, the simulations of Sauma and Oren take into account lumpiness of transmission investment while their model does not. Third, Sauma and Oren consider uncertainty and imperfect competition of generation. Last they consider that the TSO acts under the constraints of generation investments and their optimization problem is an Equilibrium Problem with Equilibrium Constraints (EPEC).

In contrast, this paper considers network tariffs and studies their efficiency to locate generation investments. The model used to carry out this study includes lumpiness of transmission investments. These two points make the optimization problem non-convex and hard to solve and results this problem on a real and complex power system may be hard to analyze. The following simplifications are then made. The network used in this paper is a two-node one. There is no uncertainty. The TSO and the generators have perfect information on investments, capacities and value of short run and long run locational signals. The TSO is perfectly regulated. The generators behave competitively. This paper does not assume the TSO acts under the constraints of the generation investments because the transmission investments may face local opposition and not be built. The generators may then locate their plants under the constraints of impossible transmission investments. The coordination problem studied in this paper is not an EPEC. It is a double optimization one, to maximize the generation profit and to minimize the cost of the network.

The paper is structured as follows. Section 2 presents the options of locational signals that will be studied in the following sections, that is to say, for the short run locational signals 1° nodal pricing and 2° redispatch (that sends no locational signal), and for the long run ones, 1° the average participation tariff or 2° no tariff. Section 3 models a liberalised system where a TSO and a generator must coordinate to minimize their own costs. Section 4 analyzes the results of simulations and shows that joint implementation of nodal pricing and the average participation tariff stays the best combination to coordinate as efficiently as possible the generation and transmission investments. And section 5 concludes on the limited efficiency of short and long run locational signals to coordinate generation and transmission investment.

2 Locational signals between transmission and generation investments in a liberalised power market

In the liberalised system, generation and transmission need signals to coordinate the location and timing of their investments. The system operation and the network tariffs can send such locational signals. Some options to operate the power system signal congestion. Similarly, some options of network tariffs are designed for the generators to take into account the cost of the network and the reinforcements that may result from their investment decisions. But other options of network tariffs or system operation do not send any locational signals and are nevertheless implemented. This section presents what seems to us, the most and the least efficient options of short and long run locational signals and their theoretical effects on coordination between generation and transmission investments.

2.1 Short run system operation and coordination of investments

Different options to operate the power system are possible. The most efficient option is nodal pricing. This option gives a different price to power depending on the network congestion and on the node where power is generated or consumed (Schweppe *et al.*, 1988). The nodal price is the local economic value of power and includes the generation cost and the congestion cost. Recurring differences in nodal prices reveal the structural network congestions. Nodal pricing incentivises the generators to use efficiently the available transmission capacities. Thus nodal prices are short run locational signals and participate in coordinating generation and transmission investments.

But nodal pricing or even its zonal version is not always implemented. Although redispatch is the least efficient option to operate the system, the TSO may have to implement it (Green 1997a, Bompard *et al*. 2003). In this case, after the energy market closed, the TSO modifies the generation scheduling to manage congestion. The congestion cost following the change in generation scheduling is then generally socialised. In this means of managing network congestion, the electricity market receives no locational signal containing information on the constraints on the grid, and the market for power continues to operate as if there were no constraints on it. The generators do not take into account the network constraints in the location of their new plants.

Besides, short run locational signals alone cannot coordinate efficiently generation and transmission investments. Owing the volatility of nodal prices, one usually relies on transmission rights to distinguish a long run locational signal among the short run ones. The most used ones are the *Financial Transmission Rights* (FTRs). The FTRs send distorted locational signals for three reasons. First the market participants do not correctly anticipate the economic value of FTRs and add them an excessive risk premium (Siddiqui *et al*., 2005). Second the FTRs are allocated assuming the system operation is simpler than in reality (O'Neill *et al*., 2006). These simplifications also distort the locational signals of FTRs (Lesieutre-Hiskens, 2005; Joskow-Tirole, 2005). Third lumpiness of transmission reinforcements depreciates the short locational signals from nodal pricing (Stoft, 2006). Long run locational signals must then complete the short run ones to overcome these three difficulties.

2.2 Long run network tariffs and coordination of investments

Different designs of network tariffs are possible. The simplest option of network tariff is called *generation-spur only* (CER, 2004). The generators are then required to pay only for the line that connects them to the network and not for any other lines of the network. This method has a weak theoretical efficiency. It only incentivises the generators to be close to the network. An efficient network tariff would incentivise the generator to locate plants while taking into account the available transmission capacity and the transmission upgrading that may be needed to accommodate them. However, at least half of the European TSOs apply *generation-spur only* (ETSO, 2007).

The TSO can also implement network tariffs that vary between locations. These locational differences of tariff incentivise the generators to connect in areas where it does not create too much congestion or in areas where it relieves congestion (Pérez Arriaga – Smeers, 2003). This paper studies such a network tariff called the average participation tariff. The average participation tariff allocates the cost of the network depending on the total use of the network by each generator. To calculate the network used by each generator, the power flows are traced from generation to load to identify the lines and the share of their capacity used by each generator to supply load. The tracing rule used to calculate the average participation tariff links the inflows and the outflows in each node such that the inflows equally distribute in the outflows as illustrated by fig. 1 (Bialek, 1997).

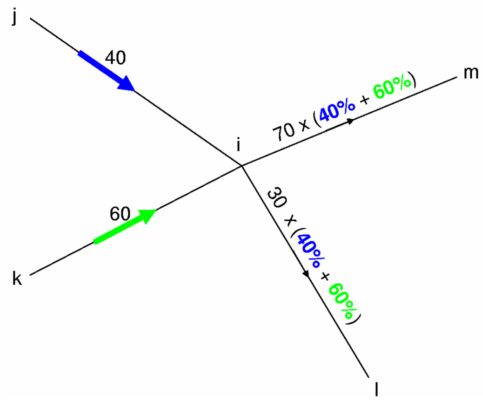

Fig. 1. Sharing principle.

The flow through the node i is 100 MW. 40% come from line j-i and 60% from line k-i. The sharing principle states that the outflow of 70 MW of line i-m comes from 40% of the line j-i that is to say 28MW and from 60% of the line k-i that is say 42 MW. Similarly, the outflow of 30 MW of the line i-l comes from 40% on line j-i that is to say 12 MW and from 60% of the line k-i that is to say 18 MW.

Different approaches have been proposed to calculate the average participation tariff. Bialek (1997) proposes a matrix approach to calculate the average participation tariff. Kirschen *et al.* (1996) proposes a graph approach where the network and the power flows describe an oriented graph. The cost allocation consists then in following the power flows from generators to consumers respecting the sharing principles. Other studies have applied the average participation tariff to real networks and compared the resulting network tariffs with other cost allocation principles (Olmos, 2006; Olmos-Pérez Arriaga, 2007). The coordination provided by the average participation tariff has never been studied from the point of the view of the investment dynamics (Olmos, 2006; Stoft, 2006). The following sections aim at evaluating the efficiency of the average participation tariff to coordinate generation and transmission investments.

More generally, the following model evaluates the efficiency of different combinations of options to operate the system (redispatch and nodal pricing) and of network tariffs (no tariff[5] or the average participation tariff).

3 Model of transmission and generation investment in a liberalised power system

In a liberalised power system where the TSO and the generator are unbundled, they both invest to maximize their own objective. However the transmission investments and the location of generation remain strongly interdependent. They must coordinate to maximize the social welfare. Locational signals implements this coordination.

The first part of this section presents the problem used to evaluate the efficiency of locational signals to coordinate generation and transmission investments. The second part of this section models for this simple case the objective function of the TSO and the generator to make investment decisions, and the interaction between the locational signals and their investment decisions.

3.1 Problem data

To evaluate the efficiency of the locational to coordinate the generation and transmission investments, the system of fig. 2 is studied for twenty years.

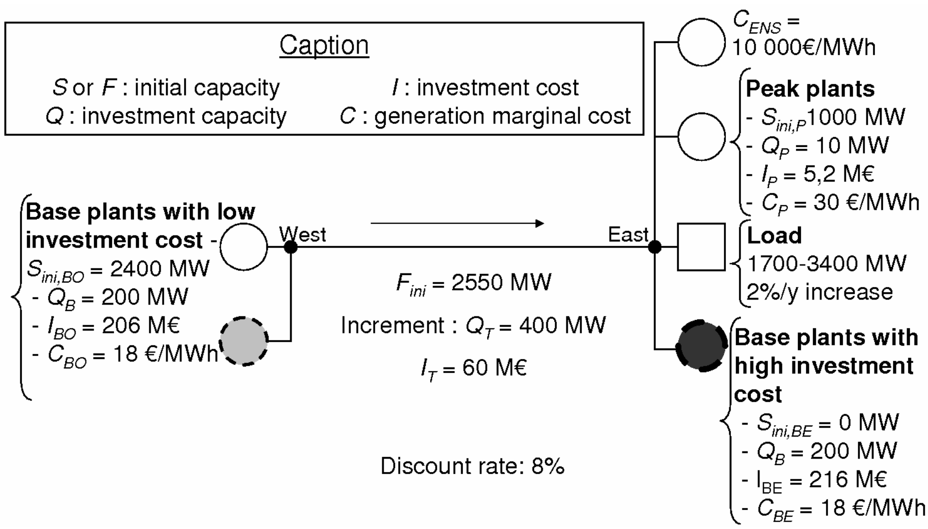

Fig. 2. Modeled system.

Load has the five following characteristics. 1° It is located to the east. 2° Over the year, load is described by a linear load duration curve. 3° The first year, load varies between 1700 MW and 3400 MW. 4° Minimum and maximum loads increase by 2% each year. 5° It is inelastic. The last two assumptions about load are usual ones in investment planning.

Generation has the following characteristics. Base and peak plants (respectively indexed *B* and *P*) generate power. When the total generation capacity is not enough to supply demand, there is Energy Non Supplied (ENS). In the model, a plant located at the same node as load and with

[5] The option with no tariff assumes that the generator is located exactly at the node where he must be connected. Then there is no need of a connection line.

the same capacity as load stands for the ENS. This plant has a cost (C_{ENS}) of 10 000 €/MWh to reflect the economic loss of power for demand[6]. The peak investments are decided by arbitrating between the opportunity to build a new peak plant and the opportunity to shed load and so to have a quantity of Energy Non Supplied (Stoft, 2002).

The marginal cost of peak generation is 30 €/MWh. The investment cost of this generation type is 5.2 million euros[7]. The marginal cost of base generation to the east (indexed E) C_{BE} is 18 €/MWh while to the west (indexed W) C_{BW} is 18 €/MWh + ε, where ε is very small. Such a little difference ε between the base generation cost to the east and to the west avoids that there is an indetermination on the plant (to the west or to the east) that is first in the merit order. The generator can choose to invest in two types of base plants, both of them with a unit generation capacity Q_B of 200 MW. The first type of base plants is located to the west and costs I_{BW}. It is 5% cheaper than to locate a plant to the east with an investment cost I_{BE}. The investment cost of a new base plant is 206 million euros to the east and 216 million euros to the west. But the plants to the west are far from load. Reinforcing the transmission network may then be needed to connect a plant to the west. The unit capacity of the network investment Q_T is 400 MW and costs I_T is 60 million euros. The generator can then have to pay for a share of the cost of the network if he connects to the west. The costs are discounted over years by a discount rate of 8%.

As load grows over time, the generator and the TSO could build no more than one investment each year for each type of investments. And these investments are lumpy with a capacity of (i.) 10 MW for a peak plant, (ii.) 200 MW for a base plant to the east, (iii.) 200 MW for a base plant to the west, or (iv.) 400 MW for a network investment. The initial transmission capacity is 2550 MW. The initial generation capacity of base plants is 2400 MW and the initial capacity of peak plants is 1000 MW.

The choice of marginal and investment costs for the base plants avoids that the decision to locate a plant modifies the energy mix (between base and peak plants and ENS), since this paper only focuses on the effect of short run and long run locational signals on the location of new plants. At the same time, the peak plant and the ENS give realism to our model. If there is congestion, the peak plants and the ENS substitute to base plants to the west.

3.2 General presentation of the model

The model measures the efficiency of different locational signals to coordinate generation and transmission investments in the liberalised power system. These investments must coordinate to minimize the social cost of the whole system.

In a vertically integrated utility, the location of generation obviously takes into account the constraints and the reinforcement projects of the network. Similarly, when reinforcing the network, the transmission investments of the integrated utility take into account not only the congestion cost but also the location of new plants. In a liberalised system, when the TSO and the generator are unbundled, the generator takes into account the network constraints and the network reinforcements to locate plants only through the short-run and long term locational signals if they

[6] Stoft (2006) conjectures that the cost of the Energy Non Supplied can surely vary of a factor three. The value of this cost commonly retained is 10 000€/MWh (Stoft, 2002).

[7] For these numerical simulations, the data for the generation costs are similar to the data used by Stoft (2002, page 124). The investment costs are then calculated assuming that the discount rate is equal to 8%.

are implemented. And the TSO reinforces the network to minimize the sum of the investment cost and of the congestion cost that result from the location of power plants.

The global problem of coordination between generation and transmission investments is split in four steps as shown on fig. 3.

The first step is the optimization problem of the system operation. The TSO operates the power system to minimize the short run generation cost while respecting the network capacity constraints. The TSO can send short-run locational signals depending on the implemented option to operate the system. Besides, the TSO uses this step to know the congestion cost. The subsection 3.3. presents this step of the model.

The second step deals with the long term optimization problem from the results of the system operation in the previous step. The TSO is assumed perfectly regulated and benevolent. She invests to minimize the sum of the network investment cost and the congestion cost. The TSO is also assumed to anticipate perfectly the generation investments. The subsection 3.4. presents this step.

In the third step, the TSO calculates the network tariffs. Depending on the implemented option, long term locational signals can then be sent. The subsection 3.5. presents this step.

The fourth and last step is the generation investment decision. The generator is assumed to have neither a short-run market power nor a long run one. Therefore, it is similar to consider a unique and benevolent generator or several competitive ones. To locate plants, the generator considers the locational signals from the system operation and the network tariffs. The generator is also assumed to anticipate perfectly the network capacity and the value of potential locational signals. The subsection 3.6. presents the problem of minimization of generation cost.

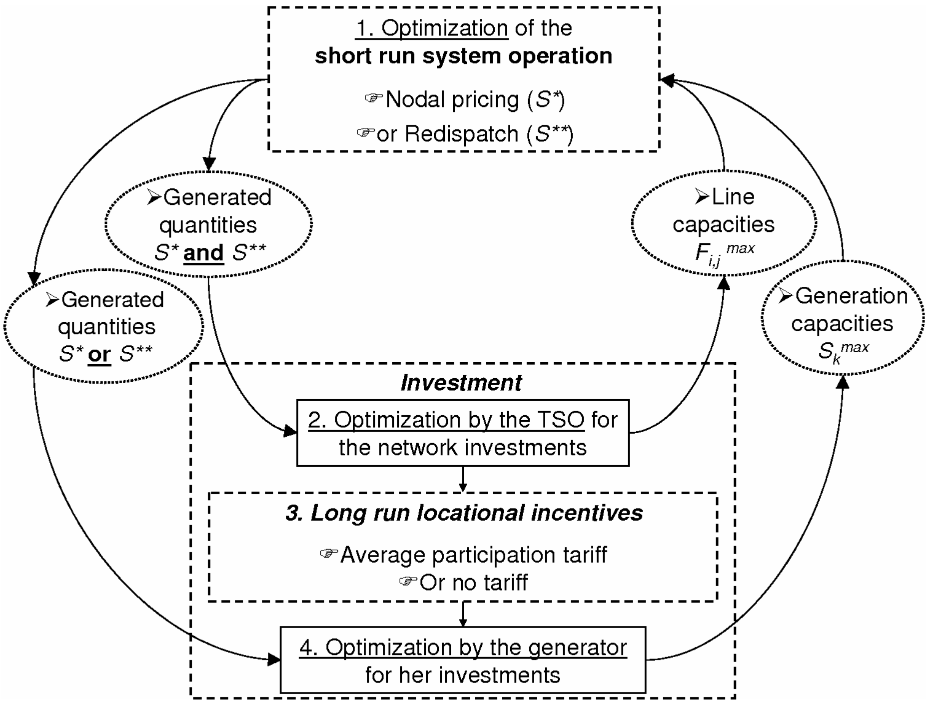

Fig. 3. Box representation of the model.

3.3 Model of system operation

This paper considers that only two options can be implemented to operate the power system. The system can be operated either by nodal pricing or with a one-price market followed by redispatch. This short-run step of the model calculates for each plant[8] k the generated quantity S_k. The constraints of the optimization problem are the maximal generation capacity $S_k^{\max}$ of each plant k, the balance between generation and load D. Depending on the option chosen to operate the system, these constraints may also include the maximal capacity $F_{\max}$ of the unique transmission line in our example. C_k is the short run generation cost function of each plant k. The generator is assumed to have no market power and bids in a competitive way. Transmission is assumed lossless. The generated quantities in a nodal market can be found solving the problem defined by the equations 1 to 4 (Bompard *et al.*, 2003) and S^* stands for these quantities.

$$\min_{\bar{S}} \left(\sum_k C_k(S_k) \right) \tag{1}$$

s.t.

$$\forall k \in \{BW; BE; P; ENS\} \quad 0 \le S_k \le S_k^{\max} \tag{2}$$

$$\sum_k S_k = D \tag{3}$$

$$S_{BW} \le F_{\max} \tag{4}$$

If redispatch is implemented, the generator minimizes the generation cost under the constraints of its maximal capacity but without taking into account the network capacity constraints. Since the generator is paid or pays its marginal cost when redispatched, the redispatch does not change the profit maximization of the generator. Her profit is only related to the one-price energy market that precedes the redispatch step. The profit maximization of the generator when redispatch is implemented can be modeled by the equations 5 to 7 as follow. S^{**} stands for the quantities that would be generated if congestion was not taken into account.

$$\min_{\bar{S}} \left(\sum_k C_k(S_k) \right) \tag{5}$$

s.t.

$$\forall k \in \{BO; BE; P\} \quad 0 \le S_k \le S_k^{\max} \tag{6}$$

$$\sum_k S_k = D \tag{7}$$

Repeating the step of system operation for each hour h and each year y of the studied period, the TSO and the generator decide their investments.

3.4 Model of network investment

The TSO is assumed benevolent. She invests to minimize the sum of the network investment

[8] Indexed *BW* for base investment to the west (far from load), *BE* for investment of base plant to the east (near load), *P* for investment of peak plant (to the east) and *ENS* for the Energy Non Supplied.

cost and the congestion cost (Stoft, 2006). Without market power from generators, this minimization is equivalent to the maximization of the social welfare for given generation investments (Pérez Arriaga-Smeers, 2003). The TSO calculates the congestion cost for the studied period from the generated quantities $S^*_{k,y,h}$ that take into account the network capacity constraints, and the generated quantities $S^{**}_{k,y,h}$ that do not take into account these constraints. The quantities S^* and S^{**} are then deduced from the previous step.

The congestion cost $CC_{y,h}$ for an hour h of a year y is the sum for all the plants k of the variations in cost induced by the limited network capacity. The congestion cost can then be defined as follows:

$$CC_{y,h} = \sum_k \left(C_k\left(S^*_{k,y,h}\right) - C_k\left(S^{**}_{k,y,h}\right)\right) \tag{8}$$

For the two-node node network considered in this paper, the TSO increases the capacity of the unique transmission line to minimize the cost of investment and the congestion cost. The transmission investments are assumed lumpy and they all have the same capacity Q_T. For each year y of the studied period, the decision variables of the network investment δ_y are binary. If δ_y equals one, the capacity of the line increases by Q_T MW the year y. If δ_y equals zero, the capacity of the line stays the same for the year y. Each network investment (with a capacity of Q_T) costs I_T. The costs are discounted by a rate a.

The network investment problem for the TSO is the following one:

$$\min_{\delta_y} \sum_y (1+a)^{-y} \left[\delta_y I_T + \sum_k \sum_h \left(C_k\left(S^*_{k,y,h}\right) - C_k\left(S^{**}_{k,y,h}\right)\right)\right] \tag{9}$$

Such that the system operation determines the generated quantities $S^*_{k,y,h}$ that take into account congestion, and $S^{**}_{k,y,h}$ that do not take into account congestion

The solution of this optimization problem gives the moment when the network investments must be done given the congestion cost. The capacity of the line is calculated for each year y knowing the decision variables of network investment δ_y. Assuming the initial transmission capacity of the line is F_{ini}, the capacity $F_{max,yc}$ of the line for the year y_c can be calculated as follows:

$$F_{\max,y_c} = F_{ini} + Q_T \sum_{y=1}^{y_c} \delta_y \tag{10}$$

The constraints in the system operation then depend on network investment decisions.

Because of vertical unbundling, the TSO can no more directly act on the location of generation. But he can influence it reinforcing the network and sending locational signals, especially long term ones.

3.5 Calculus of the average participation tariff

This paper considers only two options for the network tariff. When the first option is implemented, the generator does not pay any network tariff. When the second option is implemented, the generator pays an average participation tariff.

In the considered example, the average participation tariff can be easily calculated. The flow tracing is obvious because there is only one line. Only the power plants to the west use the transmission network to supply load to the east. Only these plants to the west pay a network tariff. The level of the tariff is calculated in three steps. The average participation tariff is calculated from the Maximum Allowed Revenue (MAR) and the MAR is calculated using the equations 11 to 13 (Joskow, 2006).

First, the Regulated Asset Base (RAB) is calculated from one year to another taking into account the investments of the last year and the depreciation of the existing lines that are not still completely depreciated.

$$RAB(n) = RAB(n - 1) - Annuities(n - 1) + Investments(n - 1) \tag{11}$$

The depreciation annuity is a simple division of the investment cost by the depreciation period decided by the regulator.

$$Annuity = Investment\ cost\ /\ Depreciation\ period \tag{12}$$

For the considered two-node network, the depreciation annuity is calculated assuming that the new network investments are depreciated over forty years and the initial transmission capacity is depreciated over thirty years from the beginning of the study.

The MAR is calculated from the depreciation annuities, from the RAB and from the return on investment[9]. In the present case, the return on investment *WACC*[10] is assumed to be equal to 7,5%.

$$MAR(n) = RAB(n) \text{ x } WACC + Annuities(n) \tag{13}$$

The average participation tariff is calculated from the MAR. Moreover, to allocate optimally the cost of transmission lines, only the cost of the used share of lines should be allocated to the users responsive to the locational signals. To the contrary, the cost of the unused share of lines should be allocated to the users the less sensitive to locational signals since the unused share of the line is linked to the lumpiness of the transmission capacity (Pérez Arriaga-Smeers, 2003). These users of the network are a priori those that are already little responsive to price signals, that is to say consumers. As a result, the power plants that use the network are assumed to pay only 50% of the cost of the used share of the transmission capacity.

The calculation of the tariff has just been presented. Previous subsections modeled the objective function of the TSO and the main options of system operation. The following subsection presents the objective function of the generator.

3.6 Model of generation investment

The generator is assumed to have no market power. The objective of profit maximization is

[9] The regulator usually decides the return on investment.
[10] *Weighted Average Cost of Capital*

then similar to cost minimization. The generator invests in order to minimize the sum of short run generation cost and generation investment costs and of the network tariff.

As seen in 3.3, the generation operation cost can take into account congestion or not depending on the chosen option to operate the system. As seen in 3.5, the generator can also have to pay an average participation tariff, depending on the chosen option for network tariff and on its location.

To invest, the generator arbitrates between these two costs and the generation investment cost. The generation investments are assumed lumpy. The unit capacity of the base (respectively peak) investments is Q_B (resp. Q_P). For each year y of the studied period, the decision variables of the generation investment $\delta_{k,y}$ are binary. If $\delta_{k,y}$ equals one, the generation capacity of the plant k increases by Q MW[11] the year y. If $\delta_{k,y}$ equals zero, the generation capacity of the plant k stays unchanged the year y. The investment cost of the plant k equals I_k. The discount rate is a. Then the generation investment problem is as follows:

$$\min_{\delta_{k,y}} \sum_y (1+a)^{-y} \left[\sum_k \left(\delta_{k,y} I_k + Tarif_{k,y} + \sum_h C_k \left(S_{k,y,h} \right) \right) \right] \tag{14}$$

Such that the system operation determines the generated quantities $S_{k,y,h}$

The solution of this problem gives the moment when and the location where the generator must invest. The capacity of a generation plant k can be calculated for each year y from the decision variables of this investment $\delta_{k,y}$. Assuming the initial generation capacity of the plant k is $S_{ini,k}$, the capacity $S_{k,max,yc}$ of this plant for the year y_c can be calculated as follows:

$$S_{\max,k,y_c} = S_{ini,k} + Q \sum_{y=1}^{y_c} \delta_{k,y} \tag{15}$$

The constraints for the system operation then depend on generation investment decisions.

The fundamental elements of the coordination problem are now defined. The following subsection models how they interact.

3.7 Interaction between locational signals and transmission and generation investments

Sauma-Oren (2006a, b) assume the investment decisions for generation and transmission are sequential with a priority given to the generation investments. With their assumption, the TSO must reinforce the network taking into account the investment decisions of generation.

However, it is interesting to consider situations where the TSO cannot invest. It is a current situation because of the oppositions to building of new power transmission lines. In such situation, the generators must adapt the location of their new plant to supply load despite the network constraints.

As a result, we made no assumption about generation or transmission investing sequentially first. Different equilibriums can then be observed for the problem of generation and transmission investments in the liberalised power system. This assumption of non-sequential investments allows to highlight non-linear effects of network tariffs and of transmission capacity lumpiness[12].

[11] Q being Q_B or Q_P depending on the plant k being a base or peak one.

[12] The lumpiness of the generation investments induces nonlinearity too but to a lesser extent given the parameters of the numerical example (see 2.1.).

The problem of coordinating generation and transmission investments is then a double minimization, respectively of the objective function of the TSO and of the generator, as follows:

$$\begin{cases} \min\limits_{\delta_y} \sum\limits_{y} (1+a)^{-y} \left[\delta_y I_T + \sum\limits_{k}\sum\limits_{h} \left(C_k\left(S*_{k,y,h}\right) - C_k\left(S**_{k,y,h}\right)\right)\right] \\ \min\limits_{\delta_{k,y}} \sum\limits_{yt} (1+a)^{-y} \sum\limits_{k} \left[\delta_{k,y} I_k + Tarif_{k,y} + \sum\limits_{h} C_k\left(S_{k,y,h}\right)\right] \end{cases} \tag{16}$$

Such that the system operation determines the generated quantities $S_{k,y,h}$

This optimization problem has three important features. First the investment variables are binary. Second the calculation of the tariff is an average one. These two first features create non-convexity. Lastly, this problem is a double optimization. These features prevent us from solving this problem with analytical tools. That's why the equilibrium conditions of this problem are studied with numerical simlations. A genetic algorithm[13] fits particularly well to solve investment problems in the power system (Latorre *et al.*, 2003) and to solve a double optimization problem such as (18) by search of dominant point (Srinivas-Deb, 1995).

To define a set of dominant points, the following double optimization problem is deemed,

$$\begin{cases} \min\limits_{\delta_y} F\left(\overline{\delta_y}, \overline{\delta_{k,y}}\right) \\ \min\limits_{\delta_{k,y}} G\left(\overline{\delta_y}, \overline{\delta_{k,y}}\right) \end{cases} \tag{17}$$

where F and G respectively stand for the objective function of the TSO and of the generator in the present case.

It is said that a point $\left(\overline{\delta_y}^*, \overline{\delta_{k,y}}^*\right)$ dominates another point $\left(\overline{\delta_y}^\S, \overline{\delta_{k,y}}^\S\right)$ if

$$\begin{cases} F\left(\overline{\delta_y}^*, \overline{\delta_{k,y}}^*\right) < F\left(\overline{\delta_{yt}}^\S, \overline{\delta_{y,t}}^\S\right) and\, G\left(\overline{\delta_y}^*, \overline{\delta_{k,y}}^*\right) \le G\left(\overline{\delta_y}^\S, \overline{\delta_{k,y}}^\S\right) \\ or\, F\left(\overline{\delta_y}^*, \overline{\delta_{k,y}}^*\right) \le F\left(\overline{\delta_y}^\S, \overline{\delta_{k,y}}^\S\right) and\, G\left(\overline{\delta_y}^*, \overline{\delta_{k,y}}^*\right) < G\left(\overline{\delta_y}^\S, \overline{\delta_{k,y}}^\S\right) \end{cases} \tag{18}$$

The dominant points dominate all the other possible points in the meaning of (18). The set of dominant points is called the Pareto Front and they are the different equilibriums solutions to the problem of double optimization (17). Since the two criteria we want to optimize are contradictory, there exist several equilibriums. The example on fig. 4 illustrates such a situation, where the x-axis and the y-axis respectively stand for the value of the function F and G for the points $\left(\overline{\delta_y}, \overline{\delta_{k,y}}\right)$. The Pareto front is the set of points that are the nearest to the bottom left corner of fig. 4, that is to say the clear squares.

[13] A genetic algorithm is a search technique used in computing to find approximate solutions to optimization problems. Genetic algorithms are global search heuristics that use techniques inspired by evolutionary biology such as inheritance, mutation, selection, and recombination, applied to a population of potential solutions for the given problem.

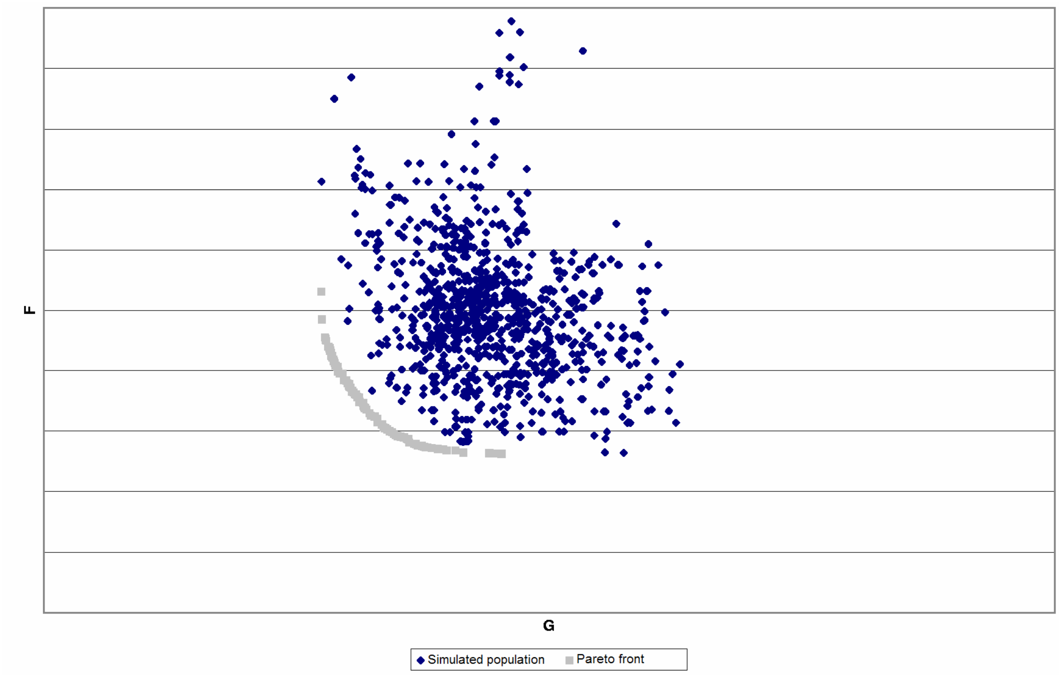

Fig. 4. Pareto front of a double minimization.

The following section evaluates with this algorithm the efficiency of short run and long run locational signals to coordinate the generation and transmission investments on the example of a two-node network.

4 Results and analyses

This section presents the results and analyses of the simulations. First the generation and transmission investments of a benevolent integrated utility, her achieved coordination and social cost define a benchmark. Second this benchmark is compared to the social cost and the coordination achieved in a liberalised system where locational signals coordinate generation and transmission investments.

4.1 Benchmark of a benevolent integrated utility

The efficiency of locational signals is measured and compared to the optimal investment strategy of a benevolent integrated utility as a benchmark. Such a utility minimizes the total cost of the power system, that is to say the sum of the network investment cost, the generation investment cost and the short-run generation cost under the constraints of the network capacity.

$$\min_{\delta_y,\delta_{k,y}} \sum_y (1+a)^{-y}\left[\delta_y I_T + \sum_k \left(\delta_{k,y} I_k + \sum_h C_k\left(S^*_{k,y,h}\right)\right)\right] \tag{19}$$

Such that the system operation determines the generated quantities $S^*_{k,y,h}$

With the data presented in section 2., the social cost of the optimal solution of this problem is

6.05 billion euros[14]. The most efficient location of generation is to the east near load.

4.2 System equilibrium without locational signals

To analyze the efficiency of locational signals to coordinate generation and transmission investments, the worst case is studied first, when neither short run locational signals nor long run ones are implemented. Congestion is managed with redispatch and the generator pays no network tariff.

Each equilibrium is characterized by the value that the objective functions of the TSO and the generator take. Each equilibrium is then positioned in the plan defined by these two objective functions (fig. 5).

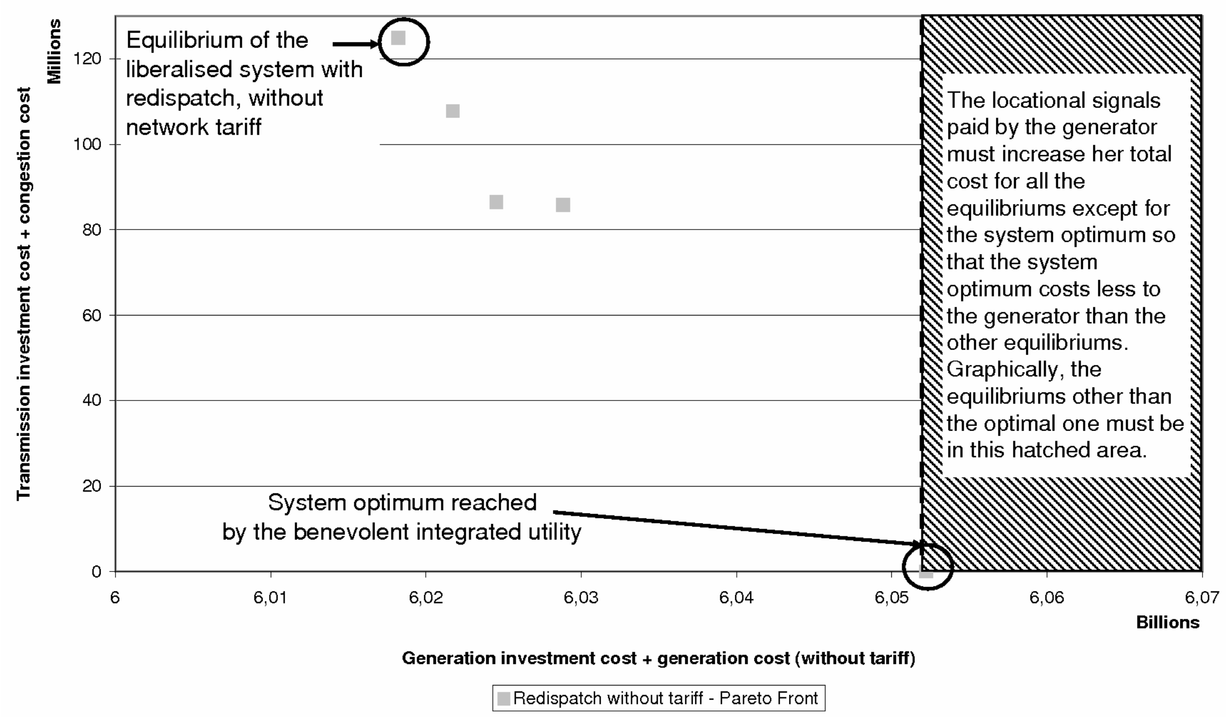

Fig. 5. Equilibriums of the investment problem in a liberalised system without locational signal.

There are multiple equilibriums for this double minimization because the cost of the network can decrease if the generation cost ingeniously increases[15]. This happens because the generator is not informed of the transmission cost her locational decision induces. The equilibrium circled at the bottom of fig. 5 is the same investment strategy as the optimal one. This equilibrium has the smallest cost of the network. The social cost of the other equilibriums is greater than the social cost of the optimum. In a liberalised system, the generator wants to minimize her costs. This equilibrium is the point the more to the left on fig. 5.

The locational signals coordinate efficiently generation and transmission when they penalise

[14] We obtain this result with a genetic algorithm too.

[15] If the generator builds her base plants near load, her investment costs are greater but there is no need to reinforce the network.

sufficiently the generator if he does not locate in accordance with the social cost minimization. For the generator to take optimal investment decisions, the suboptimal generation investments must be more expensive to her than the optimal ones. The locational signals must lead the suboptimal points to the right of the system optimum, in the hatched part of fig. 5. The effect of nodal pricing to coordinate the generation and transmission investments is now studied.

4.3 Efficiency of nodal pricing to coordinate generation and transmission

In this sub-section, the generator pays nodal pricing but no network tariff. As previously, the equilibriums of this problem are positioned in a plan defined by the objective function of the generator for the x-axis and by the objective function of the TSO for the y-axis. To evaluate the effect of nodal pricing, these equilibriums are compared with those without locational signal in fig. 6.

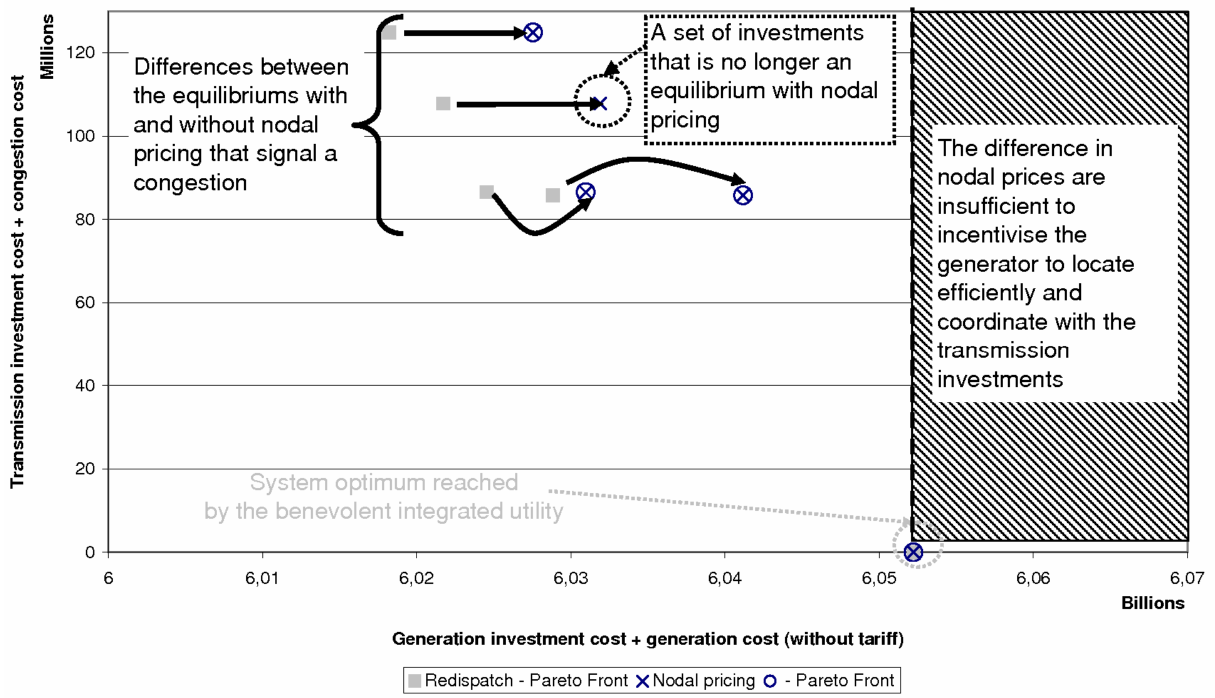

Fig. 6. Equilibriums of the investment problem in a liberalised system without tariff. Comparison of the equilibriums with and without nodal pricing.

The equilibriums reached with redispatch are the clear squares whereas those reached with nodal pricing are the dark crosses. Fig. 6 shows that only one of the suboptimal equilibriums with redispatch loses its quality of equilibrium when it is evaluated with nodal pricing. It is the only cross that is not inscribed in a circle.

The arrows between the equilibriums with redispatch and with nodal pricing stand for the effects of nodal pricing on the cost for the generator. Fig. 6 shows also that nodal pricing penalises the generator for all the equilibriums except for the optimal one (where there is no congestion givent the transmission investment in this case). The penalties are too small because all the equilibriums with redispatch except one are still equilibriums with nodal pricing.

Fig. 6 shows also that nodal pricing does not eliminate preferentially the equilibrium with the highest cost of the network. Nodal pricing penalises weakly this equilibrium. Lumpiness of the transmission capacity creates this effect. For this investment strategy, the generator builds all her base plants to the west far from the load. The TSO is forced to increase the transmission capacity. And the lumpiness of these network investments decreases the difference in nodal pricing so that the generator faces no price difference. The generator is then only partially informed of the consequences of her behavior, which induce network investment costs. For this example, we can conclude that nodal pricing poorly coordinates the location of generation and lumpy transmission investments. The two following subsections analyze now if long term locational signals increase coordination between generation and transmission investments.

4.4 Efficiency of the average participation tariff to coordinate generation and transmission

In this subsection, the generator must pay for the network he uses through the average participation tariff, whether there is congestion on the network or not. To analyze the effect of the average participation tariff, the system is first assumed to be operated with redispatch.

To evaluate the coordination reached with the average participation tariff, the related equilibriums are positioned in the same plan as before (objective function of the generator for the x-axis and objective function of the TSO for the y-axis – fig. 7). These equilibriums can then be compared with those without average participation tariff.

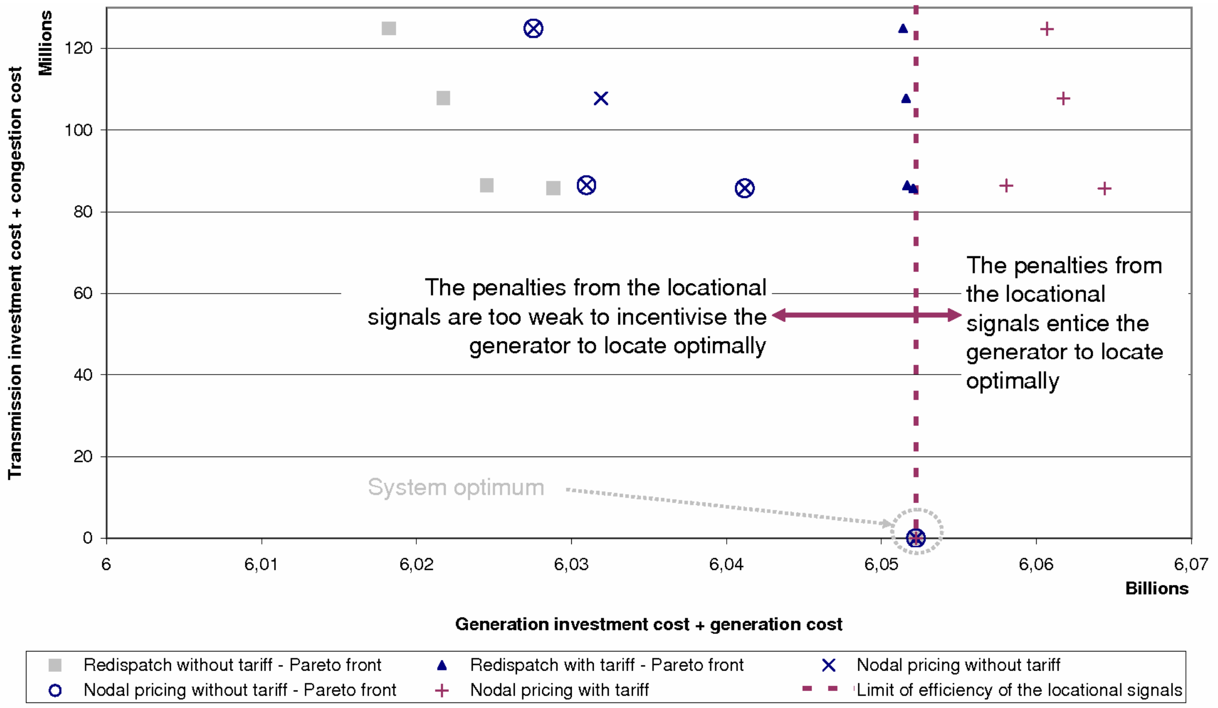

Fig. 7. Equilibriums of the investment problem in a liberalised power system.
Comparison of the equilibriums without tariff, with tariff, and with tariff and nodal pricing.

The equilibriums reached with redispatch and without average participation tariff are the clear squares whereas those reached with redispatch and average participation tariff are the dark triangles. Fig. 7 shows that every investment strategy without the average participation tariff remains equilibrium with average participation tariff. The average participation tariff then fails in incentivising an efficient location of the generator, although with average participation tariff the inefficient equilibriums are now very close to the point where the generator finds it less profitable to choose these investment strategies.

The system is now assumed to be operated with nodal pricing and the generator must pay the average participation tariff for the power plant far from load to the west. To evaluate the coordination reached when nodal pricing and the average participation tariff are jointly implemented, the related equilibriums are positioned in the same plan as before and compared with the equilibriums calculated previously. The equilibriums reached with nodal pricing and without average participation tariff are 'x' crosses whereas those reached with nodal pricing and average participation tariff are '+' crosses.

Previously, we have shown that the implementation of one locational signal is not sufficient. Whereas now, fig. 7 shows that the joint implementation of nodal pricing and the average participation tariff constraints the generator to choose the generation investment strategy that minimizes the social cost. Therefore, the implementation of the short run and long run locational signals optimally coordinates the transmission and generation investments in this case.

4.5 A case of inefficient location of generation caused by the average participation tariff

The average participation tariff can also lead to inefficient location of generation in some particular situations. Consider a case where the initial transmission capacity is not 2550 MW anymore but 2700 MW without modifying the other data of the problem. The optimal social cost (if a benevolent integrated utility were investing) is then 6.04 billion euros[16]. The optimal set of generation and transmission investments is then the following one. The efficient location of generation is to the east, near load, except for the first investment of a base plant and no transmission is needed. Fig. 8 shows why this is the optimal set of generation investments.

[16] This optimization was also realized with a genetic algorithm.

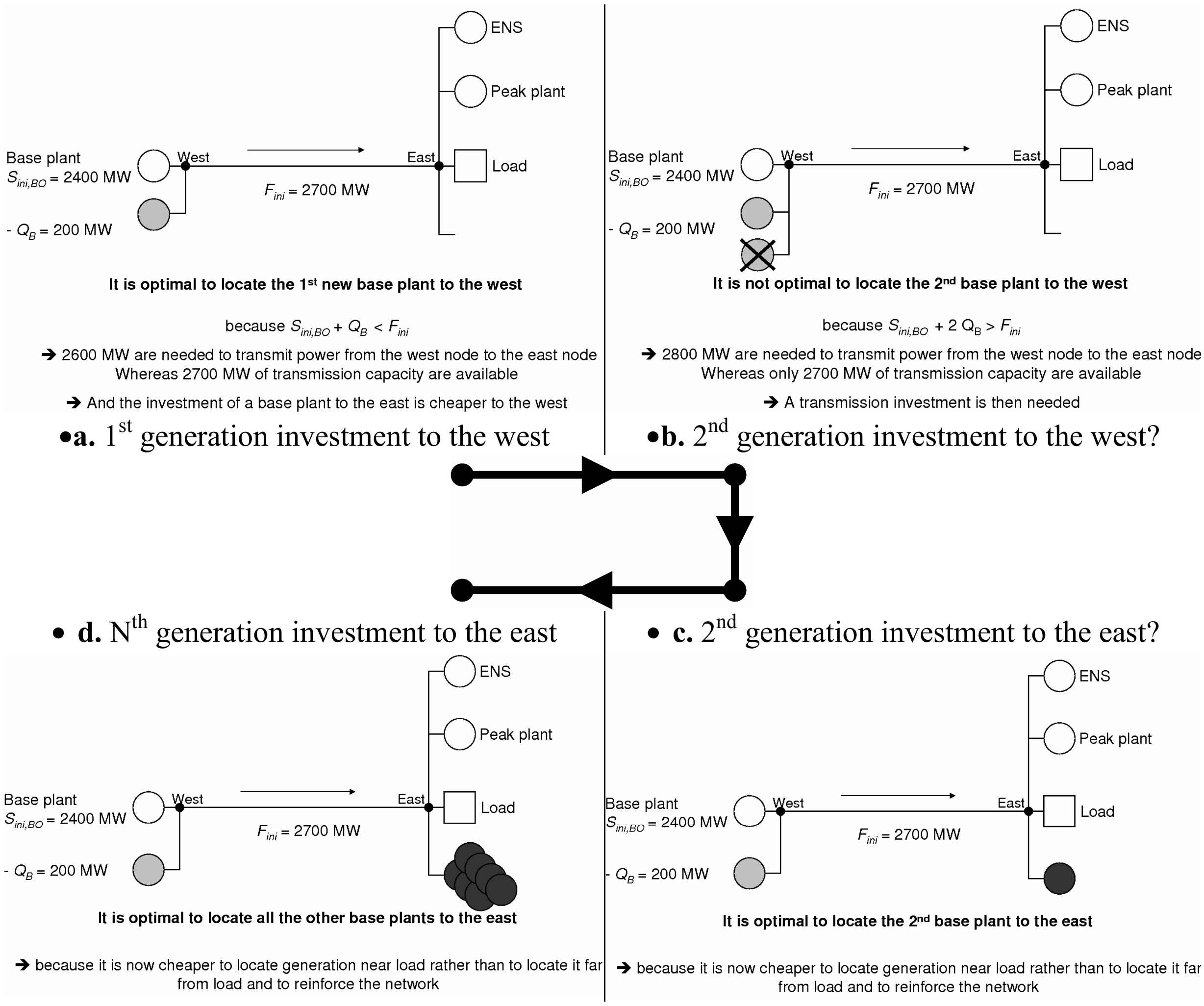

Fig. 8. Optimal sequence of generation investments when the initial transmission capacity is 2700 MW

The initial transmission capacity is 2700 MW while the initial generation capacity to the west far from load is 2400 MW. As a consequence, there are 300 MW of available transmission capacity. It is a sufficient capacity to transmit generation of only one new base plant with a unit capacity of 200 MW (fig. 8.**a.** and **b.**). For the following generation investments, the investment cost is greater to the east than to the west. But the location of generation to the west would require to reinforce the network to ensure that generation can supply load. As a result, it is cheaper to locate generation near load (fig. 8.**c.** and **d.**).

Consider now the same system when transmission and generation are unbundled. To evaluate the coordination reached with the average participation tariff in this case, the equilibriums of the investment problem are positioned in the same plan as before (objective function of the generator for the x-axis and objective function of the TSO for the y-axis – fig. 9). These equilibriums can then be compared with those without average participation tariff[17].

[17] Only the equilibriums with redispatch are considered because there is no congestion on the transmission network, except a little one on one equilibrium only.

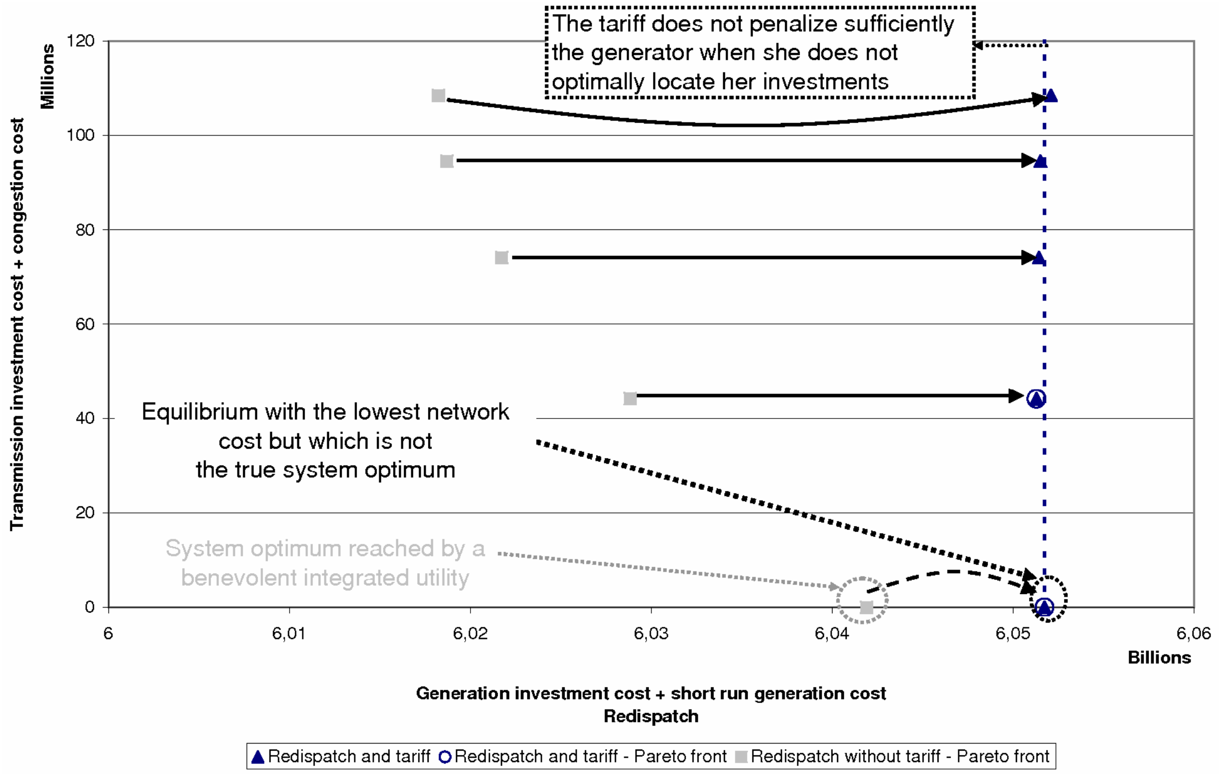

Fig. 9. Impact of the average participation tariff on the coordination between generation and transmission investments

The clear squares stand for the equilibriums with redispatch and without tariff. When the average participation tariff is implemented, the equilibriums become the dark triangles. And the circled triangles are the points that form part of the Pareto front in this case. The arrows between the equilibriums without tariff and those with the average participation tariff illustrate the effect of the network tariff on the cost for the generator.

When the generator pays the network tariff, there are only two equilibriums left, represented by the circled triangles on fig. 9. The three other equilibriums without tariff are no more equilibrium with the average participation tariff. Either the tariff makes these generation investment plans more expensive than those corresponding to the global optimum or the equilibriums with tariff now dominate the equilibriums corresponding to these generation investment plans. Fig. 9 shows that the average participation tariff generally incentivises the generator to invest near load, but not sufficiently in some situations. This simulation shows also that it is not sufficient to focus only on the equilibrium that minimizes the objective function of generator. Of course, this equilibrium without tariff is not an equilibrium anymore with tariff. But the tariff does not ensure that the generator chooses the generation investments that lead to the global optimum of the system.

Besides, the equilibrium of lowest cost (dashed circled on fig. 9) does not correspond to the optimum reached by the benevolent integrated utility, because the network tariff penalises unfortunately the generator for the optimal generation investment. All the optimal base plant investments locate to the same node as load, except the first one because at the beginning of the studied period 300 MW of transmission capacity are available (fig. 8). But, the equilibrium of lowest cost when generation and transmission are unbundled does not correspond to the optimal investment plans, because the generator does not realize this first investment far from load. This investment far from load would be more expensive to her than to locate all her base plants to the same node as load. Locating one plant far from load would indeed force her to pay the network tariff. Of course, the network tariff improves the coordination between generation and transmission investments. But, there is no guarantee that it allows to reach the optimum of the system.

Table 1 eventually sums up the above studies of the efficiency of locational signals to coordinate the location of generation with lumpy transmission investment.

Table 1 Efficiency of combined short and long run locational signals on the above examples

		Options for short run locational signals	
		Redispatch	Nodal pricing
Option for long run locational signals	No tariff	Multiple equilibriums, which are all suboptimal except one	Could suppress some suboptimal equilibriums but not necessarily the worst one
	Average participation tariff	Keep the most efficient combinations of generation and transmission but not only the optimal one	Could reach optimum but can also lead to inefficient but pareto-improving location of generation

5 Conclusions and perspectives

Considering a benevolent TSO and a competitive generator, this paper examines the efficiency of the locational signals sent by nodal pricing and average participation tariff to coordinate the location of generation with lumpy transmission investments. These locational signals are shown to coordinate the generation and transmission investments with a variable efficiency because of their interactions with lumpiness of transmission investment.

The nodal pricing is seldom sufficient to coordinate the generation and transmission investments because lumpiness of transmission investment greatly decreases the differences in nodal prices that should signal congestion. This result must be all the more highlighted that the considered characteristics of transmission investment are quite advantageous as for the ability of nodal pricing to coordinate generation and transmission investments. Indeed the transmission investments were assumed only lumpy while in reality they also exibit economies of scale. Moreover, the generator were assumed to anticipate perfectly locational signals while in reality this anticipation may be hard because lumpy transmission capacity may induce a dramatic change in nodal prices after transmission investments.

The implementation of the average participation tariff does not ensure that the generation and transmission investments is eventually optimal, because it is hard to take into account the lumpiness of transmission investment while respecting cost reflectivity. The average participation tariff then includes lumpiness only imperfectly. But implementing this tariff signicatively improves the coordination between generation and transmission investments. The joint implementation of nodal pricing and the average participation tariff stays the best combination to coordinate as efficiently as possible the generation and transmission investments. The simulations show also that implementing locational network tariffs is prioritary over implementing nodal pricing to coordinate more efficiently the location of generation with lumpy transmission investment. In the considered examples, the average participation tariff allows a more efficient location of generation even when the congestion management scheme is redispatch.

Future researchs will have to confirm the results of this work. First one could extend the study of average participation tariff on larger and meshed network. One could then precise the effect of parallel flows in the coordination process between the location of generation and lumpy transmission investments. Besides, one could reproduce the work of this paper to study the interaction between investments and the marginal participation tariff, which is the network tariff applied in Great Britain (Green, 1997b). One could also compare the efficiency of average and marginal participation tariffs to extend the existing comparisons of these network tariffs (Olmos, 2006; Olmos-Pérez Arriaga, 2007). Moreover, to make the behavior of generators more realistic, one could consider market power and model the difficulty that they may feel to evaluate the evolution of nodal prices after investment of lumpy transmission capacity. One should also consider other investment situations where the location of generation modifies not only the investment cost but also the marginal generation cost. Lastly, to exemplify the effect of network regulation, one should modify the objective function of the TSO to cost-of-service regulation or to implementable incentive regulation schemes (Stoft, 2006). One could then evaluate the impact of regulation on the coordination between generation and transmission investments.

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