

# Cost Recovery in Congested Electricity Networks

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**Abstract** Large scale investments in European electricity networks are foreseen in the next decade. Pricing the network at marginal cost will not be sufficient to pay for those investments as the network is a natural monopoly. This paper derives numerically the socially optimal transmission prices for cost recovery, taking into account that electricity networks are often congested, while allowing for market power in generation. The model is illustrated with a Stackelberg game for the Belgian electricity market.

**Keywords** Cost recovery · Energy networks · Market power · Investments

## Kostendeckung in überlasteten Stromnetzen

**Zusammenfassung** Hohe Investitionen in Europäische Stromnetze sind in der nächsten Dekade zu erwarten. Eine Preisfestlegung für das Netz zu Grenzkosten wird für

die Finanzierung dieser Investitionen nicht ausreichen, da das Netz ein natürliches Monopol ist. Dieser Artikel leitet numerisch die gesellschaftlich optimalen kostendeckenden Übertragungspreise unter Berücksichtigung einer häufigen Überlastung der Stromnetze unter gleichzeitiger Zulassung der Marktmacht bei der Erzeugung ab. Das Modell wird mittels eines Stackelberg-Spiels für den Belgischen Strommarkt veranschaulicht.

## 1 Introduction

Significant investments in the high voltage network will be necessary in the next decade. Two forces drive those investment needs: Cross-border transmission lines are essential to further integrate the European energy market as current cross-border connections are chronically congested and the integration of renewable energy sources in the network will require significant network upgrades to deal with intermittency problems. The cost of those network upgrades are significant and need to be recovered from network users. The International Energy Agency (IEA 2006, p. 148) estimated the cost of electricity transmission investments to be \$159 billion for Europe. Given the stringent renewable energy and CO<sub>2</sub> targets, today's estimates are likely to be larger.

As electricity networks are natural monopolies, charging consumers a price equal to their marginal impact on the network will not suffice to cover the full network cost. Indeed, there are large scale economies and providing network services to one extra user will be cheaper than the average cost for providing the existing users.

This paper derives how network users should be charged for network usage, taking into account those economies of scales and that (parts of) the network might be congested.

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Our paper takes a social planner's viewpoint and focuses on short run efficiency of network operation.

The main message of the paper is how cost recovery and efficient network usage can be combined. Energy producers and consumers pay an injection charge and a take-off charge respectively. Efficient network usage requires that no additional transaction specific charges are imposed, i.e. once a connection charge is paid, grid users can freely use the network as long as the network is uncongested. For cost recovery, consumers and generators should pay a network connection charge which is inversely proportional to the demand and supply elasticity respectively, i.e. the charge should be independent of how they use the network. Hence the paper derives a generalization of the marginal nodal prices (Schweppe et al. 1988).

We then extend the discussion to the case where generation firms have (local) market power. In that case the network operator might want to "subsidize" those firms to increase production and/or to reduce grid congestion. This might improve overall welfare.<sup>1</sup>

The interaction of cost recovery, congestion management and (local) market power are hard to disentangle in an analytical model. Therefore, the model is illustrated numerically for the Belgian electricity market. We model a Stackelberg game in which in stage 1 the network operator sets transmission charges and in stage 2 generators compete while taking transmission charges as given. Three scenarios are studied: a reference case in which we assume a network operator without budget constraint (i.e. the cost recovery issue is absent) and perfect competition in generation. The second scenario adds a budget constraint, while the last scenario drops the assumption of perfect competition and assumes Cournot competition.

The next section reviews the literature on transmission pricing and modeling market power in the energy markets. Sections 3 and 4 describe the structure of the model and the data. Section 5 discusses the simulation results and, finally, Sect. 6 concludes.

## 2 Literature Review

A large part of the literature on pricing electricity networks has focused on ensuring the efficient usage of the network but has neglected cost recovery.

### 2.1 Nodal Spot Prices

The seminal result of Schweppe et al. (1988) is that optimal transmission prices should be zero if the network is not congested. With congestion, transmission prices should be set

according to the peak load pricing rule (see also Hsu 1997). Transmission prices should reflect the opportunity cost of using the transmission line. These are the so-called congestion charges or marginal nodal congestion charges.

Green (2004) compares the welfare effects of two other pricing rules with this first best benchmark. He compares a system of nodal prices, uniform prices and a hybrid, in which generators face nodal prices but consumers face a uniform price. He finds that moving from uniform prices to optimal nodal prices could raise welfare by 1.5% of the generators' revenues. Moreover, doing so would also provide investment signals. Our approach differs from Green's approach as we only use nodal prices, while considering the impact of a budget constraint. A study similar to Green's was made by Bjorndal (2000), who compared the efficiency of different types of zonal pricing schemes.

### 2.2 Cost Recovery

There is a lively debate on how network costs, in particular the cost of network upgrades, should be allocated to the users of the grid. For instance, the integration of massive amounts of renewable energy requires investments in under-sea cables to connect wind farms, the procurement of additional reserve capacity, more flexible transformers etc. The costs of such upgrades are not always allocated to the final users. Knight et al. (2005) give an overview of the current practices in several EU Member States. Most of these mechanisms allocate the cost of the existing network to all users and allocate the (average or marginal) costs of upgrades to the users of the extensions. Some proposed allocation methods suggest that firms should only pay for small network upgrades that are directly related with their usage (for instance the local transformer), while other methods define upgrade costs in a very broad sense. Firms would then have to pay 'deep connection charges', that is, they would need to pay for upgrade costs caused in the entire network.

Swider et al. (2008) argue that grid connection costs of renewable energy should be socialized. A related discussion is how network cost should be allocated between countries when there are imports, exports and transit flows (Olmos Camacho and Pérez-Arriaga 2007). One of the problems that arise is that contractual obligations and transit flows do not take into account the physical properties of the underlying network. Non-contracted loop-flows, i.e. flows which are the result of energy trades, do not only affect the importing and exporting country, but affect third countries as well (Daxelet and Smeers 2005). In contrast with current practices in Europe, our model acknowledges the physical properties of the network, and fully takes into account loop flow.

The operation of the transmission network is a natural monopoly, featured by decreasing average costs as transmis-

<sup>1</sup> In practice such payments might take the form of must-run contracts.

sion output increases.<sup>2</sup> Setting the price of network services equal to the marginal cost would generate insufficient revenue to cover costs. This is a well known problem in markets with increasing returns to scale, which is often neglected in the electricity literature and which is where the paper contributes. In order to cover costs, the network operator is required to increase transmission charges. A welfare maximizing network operator will do this in a deadweight loss minimizing way, i.e. using Ramsey prices (Ramsey 1927). Transmission tariffs are set inversely proportional to the demand and supply elasticities at the different nodes, meaning that the network operator will not only charge the users of a particular transmission line, but all users in the network.

Note that a truly welfare maximizing pricing mechanism would imply using a two-part tariff. However, we assume that the network operator does not do this, despite the fact that in many countries, it is common practice to charge a transmission fee with a fixed and a variable component. We have two motivations for this choice. First, the linear tariff assumption can be interpreted as the case where a two-part tariff is being used of which the fixed charge is insufficient to fully recover fixed transmission costs. In that case, the remainder of the costs needs to be covered by the usage charge. Second, in most cases the ‘fixed’ part is not completely fixed. It depends on actual network usage and therefore still creates a deadweight loss.<sup>3</sup> In the absence of distortion-free instruments, it then remains optimal to use a form of Ramsey prices.

Our paper is most in line with, who also study cost recovery. They look at three models where costs are allocated proportional to different measures of network usage. They present simulation results for the Spanish market. Contrary to our paper, they assume that generation firms are perfectly competitive and that consumers do not react to the additional transmission charges used to cover costs. Advantages and disadvantages of the different methods are highlighted but no global welfare standard is used to compare different scenarios.

### 2.3 Congestion and Market Power

In energy markets, generators often have (local) market power, for instance in a so called load pocket.<sup>4</sup> In situa-

tions where firms have local market power, the network operator might find it optimal to subsidize production as this might create additional benefits in the market, for instance by reducing congestion. Note that, as a consequence, the network operator will have to increase transmission charges for other network users in order to balance his budget. Thus, subsidizing production is not necessarily welfare improving as it comes at a cost. This also happens in practice. A network operator, realizing that some firms have market power, will often sign ‘must run’ contracts with those firms, offering them long term contract at a preferential rate of return on their extra production.

The contribution of our paper is to allow for such types of (local) market power and to derive optimal transmission prices in that case. The results are similar in spirit to those found by Buchanan (1969) and Barnett (1980). They study the optimal taxation of externalities when there is market power in the output market. Typically the Pigouvian taxes, which are supposed to correct the externality, will be lower than under perfect competition due to the additional market failure (market power). Our paper is different as our regulator faces a budget constraint.

### 2.4 Modeling Market Power

Before describing the model itself, we briefly review the relevant literature of imperfect competition in generation. Two approaches have been developed in the specialized literature to model imperfect competition in such a multi-good market: the multi-unit auction and the supply function equilibrium approach.<sup>5</sup> One of the major drawbacks of both approaches is that the spatial structure of the electricity market, and therefore the impact of transmission constraints, is often omitted. Both are quite difficult to apply in a market with transmission constraints. One notable exception is the work of Hobbs et al. (2000) who restrict themselves to linear supply functions. Most researchers therefore opt for some kind of Cournot market, while dropping some of the multi-good aspects of the actual market.<sup>6</sup>

<sup>2</sup>This *output* includes the transport of electricity, but also other functions, such as the provision of reliable electricity supply (operation of reserve power and balancing markets) and of qualitative power (e.g. voltage level, frequency stability).

<sup>3</sup>The fixed part often depends on the maximal usage of the network over a certain time period, or the average use of the network over a time period. As the fixed part is a function of the actual use of the network, users will take it into account when they make their decision about how much transmission they want to use. They will transport less electricity than the welfare optimum, and deadweight loss is created.

<sup>4</sup>A load pocket is an area where there is insufficient transmission capability to reliably supply 100% of the electric load without relying

on generation capacity that is physically located within that area. It is the result of high concentrations of intensive power use inevitable in a big city and limitations, known as constraints, on the transmission system that limit the ability of load to be served by generating resources located remotely. This definition was taken from ‘<http://www.uspowergen.com/2008/02/27/what-is-a-load-pocket/>’.

<sup>5</sup>See for instance the models of von der Fehr and Harbord (1993) for the multi-unit action approach. The supply function equilibrium concept is based on Klemperer and Meyer (1989). Holmberg et al. (2008) show that a multi-unit discrete supply function equilibrium might converge to the continuous supply function concept.

<sup>6</sup>This choice is supported by an empirical study of Wolak and Patrick (2001) who suggest that Cournot competition is an appropriate representation of the electricity generation market. Willems et al. (2009) compare supply function equilibria and Cournot models and show that

In this paper generators behave *à la* Cournot in the energy market but are price takers in the transmission market. This is inspired by the models of Smeers and Wei (1997) and Wei and Smeers (1999). Both papers consider Cournot behavior in generation, but Smeers and Wei (1997) assume that generators perceive transmission prices as being set on the basis of congestion pricing, whereas Wei and Smeers (1999) assume regulated pricing as the basis for transmission pricing. The current model differs from Wei and Smeers (1999) in that the transmission charges are set by the network operator rather than by a regulatory rule. We assume that the welfare maximizing transmission firm also takes into account market imperfections in electricity generation when setting its transmission prices.

The electricity market is modeled as a Stackelberg game. Mathematically, this gives rise to an Mathematical Program with Equilibrium Constraints (Luo et al. 1996). Such models are becoming more and more common in the simulation of the electricity markets, but often the timing of the game is reversed: generators bid in stage 1 and the network operator balances the network in stage 2. See for instance (Ehrenmann 2004; Gabriel and Leuthold 2010; Hobbs et al. 2000 and Neuhoff et al. 2005)

In order to solve the numerical optimization problem, we relax the complementarity conditions of the second stage and use several starting values to be confident that we are close to the global optimum. For a comparison of different methods to solve MPEC problems see Fletcher and Leyffer (2002).

### 2.5 Long term efficiency

In our paper we do *not* study the *long term incentives* for investments in generation capacity. We restrict ourselves to short run efficiency. Cossent et al. (2009) and Joskow and Tirole (2005) discuss some of the challenges we face regarding the long term integration of renewable energy into the network. We need a regulatory scheme that gives both long and short term incentives to investors to invest in new generation capacity as well as to the network operators to upgrade networks. The coordination of investments in generation and transmission assets is still an unsolved problem.

Nevertheless, we hope that the qualitative results of our paper will hold also in the long run, if the short term demand and supply elasticities are replaced with their long term equivalents. This remains for further study. Dijk et al. (2009) look at the impact of network pricing on the dynamic efficiency of investments in the electricity sector in a

stochastic two stage oligopolistic model. It is shown that social and private incentives are not aligned and that additional regulatory instruments are required. Their model takes congestion into account, but cost recovery is neglected.

## 3 The Model

Define the sets  $F$  and  $G$  as the sets of generation firms and generation plants. Let  $G_f$  be the set of generation plants owned by generation firm  $f \in F$ . With  $I$  being the set of network nodes,  $G_i$  denotes the generation plants at node  $i \in I$ , and  $G_{fi}$  the generation plants at node  $i$  owned by firm  $f$ . Furthermore, let  $A$  be the set of transmission lines in the network.

For notational simplicity, the model will be further described as if it concerned a one period model, i.e. a model that does not distinguish between peak and off-peak periods. However, the numerical simulations in Sect. 5 differentiate between peak and off-peak demand in a 4-period model.

The model distinguishes three types of players: consumers, generation firms and the network operator.

*Consumers* are price takers. At node  $i$ , they consume  $s_i$  units of electricity. Their inverse demand for electricity, denoted as  $p_i(s_i)$ , is downward sloping and concave. Consumer prices include compensation for both the generation and the transmission of electricity.

*Generation firm*  $f \in F$  maximizes profits, while acting as a price taker in transmission. At node  $i$ , it owns the generation plants  $g \in G_{fi}$ .

Electricity generation in *plant*  $g$  is  $q_g$  and the generation cost is  $C_g(q_g)$ . Total generation costs are convex, with fixed generation costs suppressed to zero. The generation capacity of plant  $g$  is labeled  $\bar{q}_g$ . Output should be nonnegative and cannot exceed available generation capacity. Therefore, we have  $0 \leq q_g \leq \bar{q}_g$ .

The *network operator* or *transmission company* maximizes social welfare and sets a nodal transmission charge  $\tau_i^c$  for consumers and  $\tau_i^p$  for generators.<sup>7</sup> This is the per unit amount generators and consumers have to pay for injecting and taking power from the grid, respectively. Note that these charges can be different. For instance, a generator who generates electricity in node  $i$  and sells electricity in node  $j$  will pay  $\tau_i^p + \tau_j^c$ . However, the optimal transmission charges are not uniquely defined.

First, take a node  $i$  at which no consumers are connected. For that node, the consumer transmission price  $\tau_i^c$  does not

there are not significant differences between both models when one looks at the available market data. Other studies using Cournot competition are Borenstein et al. (1999, 2000), Borenstein and Bushnell (1999), Cardell et al. (1997), Hogan (1997), Oren (1997) and Stoft (1997).

<sup>7</sup>Within the set of linear price structures, this is the most general assumption. It encompasses a number of 'price structure' options as special cases. For example, only charging consumption, only charging generation, a separate but uniform tariff for generation and consumption and one uniform tariff for both generation and consumption as the most extreme case.



play a role and it can safely be set equal to zero. The same is true for nodes without generation. Here,  $\tau_i^p$  is not uniquely defined and the charge is set equal to zero.

Second, we can without loss of generality set one of the charges equal to zero because it is only the sum of the consumer and generation transmission charge, and not its composition that is important. The network operator has therefore one degree of freedom in setting the transmission charge components. This can easily be checked by noting that one can uniformly increase all generation tariffs with  $t$  and decrease all consumer tariffs with  $t$  without changing the sum of the charges. We can therefore arbitrarily fix one transmission price in one node equal to zero. This is done for the consumption charge in the swing node, i.e.  $\tau_i^c = 0$  with  $i = \text{swing node}$ .

Finally, note that the model implicitly assumes that the charges need to be paid for all consumption and generation, even if generation and consumption are located at the same node. A generator in node  $i$  who sells electricity locally does not use the transmission network, but will have to pay a transmission payment  $\tau_{ii} = \tau_i^c + \tau_i^p$ . We will call this charge the price wedge in node  $i$  as it creates a wedge between the consumer's price and the generator's price.

The model has two stages. In the first stage, the transmission operator sets transmission prices. In the second stage, generation firms play a Cournot game in which transmission prices and their competitor's quantities are assumed as given. The next subsection describes the second stage of the game.

### 3.1 The Second Stage

Each firm  $f$  observes the transmission charges  $\tau_i^p$  and  $\tau_i^c$  as set by the network operator and plays a Cournot game. A firm  $f$  collects revenue by selling  $s_{fi}$  units of electricity at node  $i$  at the per unit price  $p_i$ . Firms also set the production level  $q_g$  ( $g \in G_f$ ) at each of their plants. Their competitor's sales in node  $i$ , denoted by  $\tilde{s}_{-fi}$ , are taken as given. Apart from generation costs, firms also pay a transmission cost  $\tau_i^p$  for injecting electricity to the network at node  $i$ , and  $\tau_i^c$  for the delivery of electricity to node  $i$ . This results in the following profit function for generation firm  $f$ ,

$$\Pi_f^{Gen} = \sum_{i \in I} (p_i - \tau_i^c) \cdot s_{fi} - \sum_{i \in I} \sum_{g \in G_{fi}} [C_g(q_g) + \tau_i^p q_g]. \quad (1)$$

The nodal price  $p_i$  that is received by generator  $f$  depends on the total sales in that node, i.e.

$$p_i = p_i(s_i),$$

$$s_i = s_{fi} + \tilde{s}_{-fi}$$

where the tilde indicates that the variable is considered as given. In (1), the first term reflects revenues from electricity

sales net of transmission charges paid at the consumption nodes. The second term reflects generation costs and transmission charges to put the electricity on the network. Summarizing, we have the following maximization problem for a generator:<sup>8</sup>

$$\begin{aligned} \text{Max}_{s_{fi}, q_g (g \in G_f)} \quad & \Pi_f^{Gen} = \sum_{i \in I} (p_i - \tau_i^c) \cdot s_{fi} \\ & - \sum_{i \in I} \sum_{g \in G_{fi}} [C_g(q_g) + \tau_i^p q_g] \\ \text{s.t.} \quad & 0 \leq q_g \leq \bar{q}_g \quad (\underline{\mu}_g, \bar{\mu}_g) \quad \forall g \in G_f, \\ & \sum_{i \in I} s_{fi} = \sum_{g \in G_f} q_g \quad (\lambda_f^p), \\ & s_i = s_{fi} + \tilde{s}_{-fi} \quad \forall i \in I. \end{aligned} \quad (2)$$

As noted before, the first constraints reflect generation capacity constraints. The second constraint represents the energy balance at the firm level, i.e. total output should equal total sales. The last constraint represents demand. This constraint has no multiplier as it is substituted into the objective function and the other constraints before derivatives are taken.

The following first order conditions are then derived:

$$\frac{\partial C_g(q_g)}{\partial q_g} + \tau_i^p + \underline{\mu}_g - \bar{\mu}_g = \lambda_f^p \quad \forall g \in G_{fi}, \quad \forall i \in I, \quad (3)$$

$$p_i + \frac{\partial p_i(s_i)}{\partial s_i} s_{fi} - \tau_i^c = \lambda_f^p \quad \forall i \in I. \quad (4)$$

These are the standard first-order conditions for profit maximization, i.e. as long as generation constraints are not binding, marginal revenue equals marginal cost in all market segments. The Lagrange multiplier of the energy balance constraint  $\lambda_f^p$ , is the value of energy in the network for generation firm  $f$ . This value is different for every firm.

Cost minimization requires that each firm equalizes the sum of the marginal cost and the generation charge at all generation plants. Profit maximization requires that marginal revenues net of consumption charges are equalized.

Note that each firm's reaction function with respect to the sales  $s_{-fi}$  and the transmission charges,  $\tau_i^c$  and  $\tau_i^p$  can be derived from (2), (3) and (4).

The multipliers  $\underline{\mu}_g$  and  $\bar{\mu}_g$  are positive, and satisfy the complementarity conditions:

$$\begin{aligned} \underline{\mu}_g &\geq 0, & \underline{\mu}_g \cdot q_g &= 0, \\ \bar{\mu}_g &\geq 0, & \bar{\mu}_g \cdot (\bar{q}_g - q_g) &= 0. \end{aligned} \quad (5)$$

<sup>8</sup>Note that in this formulation nodal sales of the generators can become negative. Generators can act like arbitrageurs that buy electricity in one region and sell it in another. They will, however, still take into account the effect on the marginal revenue in both regions. Therefore, with a limited number of firms, not all price differences will be arbitrated away. As the number of generation firms increases, arbitrage will improve.

### 3.1.1 Electricity Transmission

The model captures the technical features of the electricity system, especially at the level of electricity transport. Electricity transport is subject to physical constraints. These constraints have an impact on the power flow through the network and therefore potentially also on the pricing of transmission services. In this paper we concentrate on active power and we adopt a simplified DC flow model without losses.<sup>9</sup>

Each line  $a \in A$  in the network is characterized by a transmission capacity  $Q_a$ . Denoting the flow over the line  $a$  as  $Q_a$ , we must have

$$Q_a \leq \bar{Q}_a \quad \forall a \in A. \quad (6)$$

Transmission must not be larger than the available transmission capacity.

The flow over a line  $a$  depends on the injection and the extraction of electrical energy in *all* the nodes of the network, except in the swing node. The flow on line  $a$  is equal to:

$$\sum_{i \in I / \{\text{swing node}\}} \theta_{a,i} (q_i - s_i) = Q_a \quad (7)$$

with  $s_i, q_i$  the total consumption and generation in node  $i$ , respectively:

$$s_i = \sum_{f \in F} s_{fi} \quad \forall i \in I, \quad (8)$$

$$q_i = \sum_{g \in G_i} q_g \quad \forall i \in I. \quad (9)$$

The flow over a transmission line is a linear function of the net injections at all nodes. The variables  $\theta_{a,i}$  are the power transmission distribution factors (PTDFs). The factors  $\theta_{a,i}$  describe how much a transaction from node  $i$  to the swing bus will change the flow on line  $a$ . For example, a transaction of size  $F$  from node  $i$  to node  $j$  can be decomposed as a transaction from node  $i$  to the swing node and a (negative) transaction from the swing node to node  $j$ . The impact of this on line  $a$  then equals  $F \times (\theta_{a,i} - \theta_{a,j})$ . The PTDFs are determined by the physical properties of all the lines and the layout of the network.

Equations (6)–(9) describe the transmission possibilities of the network, i.e. they define the production feasibility set of the network operator.

<sup>9</sup>Such a model assumes that line resistance is small relative to reactance, that voltage magnitudes are the same at all nodes, and that voltage angles between nodes at opposite ends of a transmission line are small. Engineers often use the linearised model of the network for long term planning. See Schweppe et al. (1988).

The alternative, AC-power flow, was used in a previous version of the program, but did not give fundamentally different results.

### 3.1.2 Security of Supply

The network operator also needs to secure the supply of electricity. A minimal requirement for this is that, if unexpectedly a line goes out of service the remaining lines should still be able to transport all supplied electricity. This is the “ $n - 1$ ” rule. The network operator will check that for all contingencies  $k \in K$  the network is still capable of accommodating all flows.

For instance, if during contingency  $k$  the line  $a \in A$  breaks down, then the set of the remaining lines  $A \setminus \{a\}$  should be able to transport the power over the network. After a contingency, the flows redistribute themselves over the network, and these new flows should still be feasible given the thermal constraints of the remaining lines.

Taking into account the security of supply for all contingencies  $K$ , the following equation needs to be added to the network equations (6)–(9):

$$\sum_{i \in I / \{\text{swing node}\}} \theta_{a,i}^k (q_i - s_i) \leq \bar{Q}_a \quad \forall a \in A, \forall k \in K. \quad (10)$$

For notational simplicity, we will assume that the set of contingencies  $K$  also includes the case where all lines are available, such that we can drop equations (6) and (7). Equations (8)–(10) describe the feasible set for transmissions on the security constrained network.

## 3.2 The First Stage

The network operator maximizes welfare subject to a budget constraint. He sets the consumption and generation transmission charges ( $\tau_i^c$  and  $\tau_i^p$ ), which can be differentiated over the nodes. It is assumed that the cost of providing transmission services is separable into operating costs and capacity costs. In the present model, operating costs and network losses are neglected. Therefore, only the capacity costs  $B$  remain.<sup>10</sup>

The profit of the network operator is then equal to:

$$\Pi^{tr} = \sum_{i \in I} (\tau_i^c s_i + \tau_i^p q_i) - B. \quad (11)$$

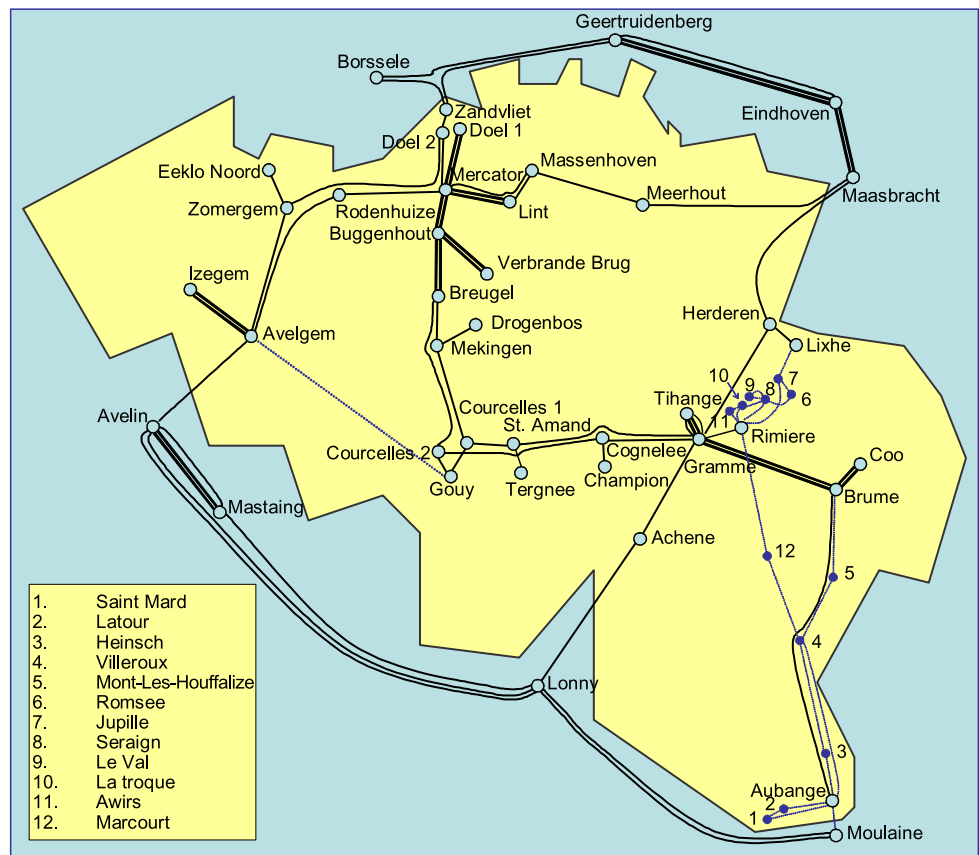
The first term between brackets is the revenue of selling transmission services to consumers at node  $i$ . The second term is the revenue of selling transmission to the generators at node  $i$ . The last term represents capacity costs. By assumption, capacity costs are fixed.

The network operator maximizes

$$W = \sum_{i \in I} \int_0^{s_i} p_i(t) dt - \sum_{g \in G} C_g(q_g) \quad (12)$$

<sup>10</sup>It was noted before that  $B$  can also be interpreted as being the fraction of the transmission firms costs that needs to be collected via usage charges, i.e. net of the revenues collected via the standing charge of a two-part tariff.

**Fig. 1** The Belgian high voltage network, situation in 2002



subject to the *energy balance* at the firm level,

$$\sum_{i \in I} s_{fi} = \sum_{g \in G_f} q_g \quad \forall f \in F \quad (13)$$

the *Cournot behavior* (*Sales-Production*),

$$p_i(s_i) + \frac{\partial p_i(s_i)}{\partial s_i} s_{fi} - \tau_i^c = \lambda_f^p \quad \forall i \in I, \forall f \in F, \quad (14)$$

$$\frac{\partial C_g(q_g)}{\partial q_g} + \tau_i^p + \underline{\mu}_g - \bar{\mu}_g = \lambda_f^p \quad \forall i \in I, \forall f \in F, \forall g \in G_{fi}, \quad (15)$$

$$\begin{aligned} \underline{\mu}_g &\geq 0, & \underline{\mu}_g \cdot q_g &= 0, & q_g &\geq 0, \\ \bar{\mu}_g &\geq 0, & \bar{\mu}_g \cdot (\bar{q}_g - q_g) &= 0, & q_g &\leq \bar{q}_g \end{aligned} \quad (16)$$

the *network equations*

$$\sum_{i \in I / \{\text{swing node}\}} \theta_{ai}^k (q_i - s_i) \leq Q_a^k \quad \forall a \in A, \forall k \in K \quad (17)$$

$$s_i = \sum_{f \in F} s_{fi} \quad \forall i \in I, \quad (18)$$

$$q_i = \sum_{g \in G_i} q_g \quad \forall i \in I, \quad (19)$$

and the *budget constraint*:

$$\sum_{i \in I} (\tau_i^c s_i + \tau_i^p q_i) - B = \Pi^{tr} \geq 0. \quad (20)$$

## 4 Data and Calibration

Before continuing with the simulations, we discuss the data that were used as an input for the model. Also, the calibration procedure will be described. The choice of the technical features of the transmission grid and of the available generation plants is inspired by the Belgian electricity system.

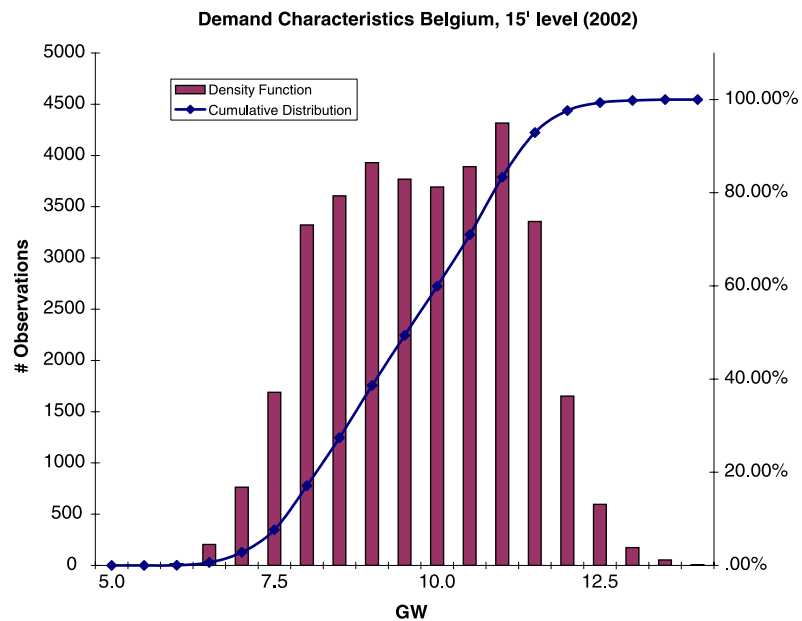
### 4.1 The Network

Figure 1 shows the network that has been modeled. It consists of 55 nodes and 92 lines and includes all the Belgian 380 kV and 220 kV transmission lines, but also some 380 kV lines in The Netherlands and France because they are important for the flows inside the Belgian network. The full lines on the graph are 380 kV lines, the dotted lines are 220 kV lines. The line between Gouy and Avelgem represents several lines of the 110 kV network that connect both nodes.<sup>11</sup>

We impose the  $n - 1$  rule for all Belgian 380 kV lines, except for some loose ends. Imposing the  $n - 1$  rule for these latter lines makes no sense when we do not include lines

<sup>11</sup>Network data was kindly provided by Peter Van Roy and Konrad Purchala of the K.U.Leuven Electrical Engineering Department. More detailed information on origin and destination, voltage level, admittance, thermal capacity... is available upon request.

**Fig. 2** Histogram of electricity demand in Belgium in 2002  
(Source Elia)



at lower voltage levels that can accommodate the flows in case of a failure of the 380 kV line. Also, the  $n - 1$  rule is not imposed for the interconnections with France and The Netherlands and for the lines within these countries, because sufficient or adequate information is lacking.

#### 4.2 Electricity Generation

The total generation capacity connected to the grid is 14475 MW. Of this capacity, approximately 1070 MW consists of smaller generation plants which are not included in the model. These are mainly combined heat and power generation units (970 MW), and some small hydro units (90 MW). We assume that in any time period, 50% of these plants produce electricity. The remaining production capacity (13405 MW), is spread over 51 generation units, which are modeled in the paper based upon data of the year 2002.<sup>12</sup> Each generator is assumed to have constant marginal production costs  $C_g$ .

In the simulations, we assume three Cournot players, having a market share in generation capacity of 43%, 34% and 23%, respectively.<sup>13</sup>

<sup>12</sup>Some of the data was kindly provided by Leonardo Meeus and Kris Voorspools of the Departments of Electrical and Mechanical Engineering, respectively. Data was also taken from several editions of the BFE statistical yearbook and the annual report of Electrabel. Data are available from the authors upon request.

<sup>13</sup>One firm received all nuclear power plants, while the remaining power plants were allocated to two competitors of more or less equal size. Both these firms received a mix of generation technologies. Joint ownership of generation plants was excluded and only one generation firm is allowed per generation node.

Each player maximizes profit, taking into account plant characteristics. Generation decisions are described by the first order conditions (3) and the complementarity conditions (5). The player's complementarity conditions are non-linear, which makes the optimization problem non convex.

Three plants are *pumped storage plants*, i.e. they can store energy in the form of a water reservoir. When generation costs are low, these plants consume electricity and pump water to a higher level. When generation costs are high, the reservoir is emptied and electricity is produced. The underlying decision process is not modeled in this paper. We assume that these plants generate electricity during peak periods at a marginal cost of €13 per MWh, and we count them as part of the consumption side during the off-peak periods.<sup>14</sup>

#### 4.3 Electricity Demand

The model has been calibrated on the basis of Belgian data for electricity demand in 2002.<sup>15</sup> In that year the average demand was 9.52 GW. Total yearly demand in Belgium is 83.4 TWh per Year. Figure 2 presents a histogram of demand in Belgium. The histogram is based on periodical observations with a length of 15 minutes. The highest and lowest observed demand levels were 13.7 GW and 5.8 GW, respectively.

<sup>14</sup>A better modeling of the pumped storage plants would require taking into account the capacity constraint of the water reservoir, and to make the generation and consumption decisions endogenous.

<sup>15</sup>The network of one part of Luxembourg forms an integral part of the Belgian network. Demand levels for that part are included in the model here.



Obviously, the demand for electricity is not constant over time and in order to take this into account, the numerical one-period model has been extended to a 4-period model. Currently, the model does not take full account of the potential links that could exist between these four periods. Taking these links into account would certainly enrich the model and this is seen as a priority for further research.

At least four of such potential links can be identified. First, cross-substitution can take place between time periods. For example, demand for electricity during the night will not only depend on the price in the night, but also on the price that is charged during the day. In this model it is assumed that these cross-substitution effects are zero. There is thus no intertemporal substitution.

Second, consumption and generation decision for the pumped storage plants create a link between periods and can be endogenized.

Third, intertemporal production constraints exist for generation, because generators can increase or decrease output only at a certain speed (ramping constraints). Starting up and shutting down generators is costly and requires time. Finally, the transmission firm is maximizing welfare and is subject to a budget constraint. This constraint creates an intertemporal link as the marginal welfare cost of obtaining revenue should now be equal over time periods.<sup>16</sup> In this paper, only this last effect is taken into account.

#### 4.4 Network Operator

The network operator has total costs of  $B = \text{€}649\text{M}$  per year (Source: Annual report ELIA, 2002). Capital costs are about 50% of the total costs, the other 50% being operating costs, such as wages and network maintenance costs. Wages and network maintenance costs are not directly related to the amount of MW transported over a line, they are inherent to the existence of that line. Therefore, as we could not find a more detailed description of the cost function of the network operator, we assume all costs to be fixed. Network losses are neglected in the model. Clearly, these would depend on the actual use of the network. With a total electricity demand of 83.4 TWh in 2002, the average cost of the network operator is €7.78 per MWh.

#### 4.5 Calibration

The calibration of the model involves three steps. Each of these three steps is described below.

<sup>16</sup>Note that there would be no (binding) budget constraint if the network operator would be a profit maximizer.

##### 4.5.1 Fixing Periodic Aggregate Demand and the Length of Each Period

The first step is to decide about the level of electricity demand in each of the four periods and about the length of each period in a standard year. This has been done on the basis of the data presented in Fig. 2. This figure shows how often a certain demand level occurs in the Belgian market. We will consider 4 periods with average demand levels fixed at 8, 10, 11.5 and 12.5 GW. The length of each time period is then set such that the cumulative distribution function of the 4 periods approximates the observed cumulative distribution function (Table 1). As 500 MW of this demand is provided by small generators, the demand level as seen by the generators in our model is fixed 500 MW lower. Thus, the demand levels used to calibrate the demand functions are 7.5, 9.5, 11 and 12 GW.

##### 4.5.2 Fixing a Reference Price for Each Period

Given the periodic electricity demand derived in the first step, we minimize the production costs to supply this demand. Here, it is assumed that pumped water storage can only be used in periods one and two. In periods three and four, pumped storage plants pump water into a reservoir.

Via this procedure, we obtain the marginal production cost for each period. The obtained values are increased with the average costs of the network operator (€7.78 per MWh) to obtain a reference price for each period (Table 1).

##### 4.5.3 Fixing Periodic Electricity Demand in the Consumption Nodes

In the third step, we derive for each node a linear demand function. The price elasticity of demand is assumed to be  $-0.2$  in all nodes and all periods.<sup>17</sup> Total demand is distributed proportionally over the different nodes on the basis of the demand data in Van Roy (2001) and the reference prices are calculated in step 2. This information is sufficient to derive for each consumption node the parameters of the linear demand function.

<sup>17</sup>The own price elasticity is based on estimates found in the literature. Lijesen (2007) provides a survey of studies that estimate short term price elasticities. These estimates range from  $-0.071$  to  $-1.113$ . Koichiro (2010) estimates the price response in the Californian energy market. He compares electricity demand of consumers in the same neighborhoods facing different type of prices because they belonged to different utilities. He obtains marginal price elasticities of  $-0.18$  to  $-0.20$  during the California electricity crisis in 2000, and in the range  $-0.135$  to  $-0.211$  for the full time period (1999 to 2006).

**Table 1** Calibration of the 4 time periods

Period	Observed demand (GW)	Period length		Model demand (GW)	Reference price (€ per MWh)
		(hr)	(%)		
1	12.5	208	2.4%	12.0	45.2
2	11.5	1759	20.1%	11.0	37.9
3	10.0	3410	38.9%	9.5	35.6
4	8.0	3383	38.6%	7.5	27.0
Average	9.6	8760	100.0%	9.1	33.0

**Table 2** Exogenous generation levels at the foreign nodes (Negative numbers are loads)

The Netherlands	
<i>Node</i>	
Maasbracht	−731 MW
Geertruidenberg	−368 MW
Borssele	99 MW
TOTAL	−1000 MW
France	
<i>Node</i>	
Avelin	543 MW
Lonny	34 MW
Moulaine	423 MW
TOTAL	1000 MW

#### 4.6 Transit

The model also takes into account that the Belgian grid is used for relatively large transit flows. These flows are generally directed from France to The Netherlands and, as a first approximation, we assume an exogenous transit flow of 1000 MW from the south to the north. This transit is assumed to occur in all periods. The foreign generation and load nodes are summarized in Table 2.

## 5 Simulation Results

This section discusses the results of three simulation runs. Section 5.1 discusses the first best case, with perfect competition in generation and no budget constraint for the network operator. The following subsections subsequently drop one of these assumptions: Sect. 5.2 adds a budget constraint for the network operator, Sect. 5.3 adds imperfect competition in generation.

### 5.1 First Best

In the first best the network operator does not face a budget constraint and generators are competing competitively, but the transmission capacity is limited. Table 3 shows the simulation results for a representative hour in each period. It gives total welfare, the surpluses for the economic agents, the network operator costs, the generation level and the multiplier of the budget constraint (which in this case is zero by definition). Period 1 represents peak demand, periods 2 and 3 have intermediate demand, and period 4 has off-peak demand. The column “Average” gives the values for an average hour over the course of the year, taking into account the length of each period.

Table 4 shows aggregate values for all time periods and for the full year. Consumption in the low and the high demand period are 7734 MW and 11657 MW, respectively. Total annual production is 79791 GWh.<sup>18</sup>

In Table 4, the indicated prices are wholesale prices, covering generation as well as transmission. If all transmission charges would be set equal to zero, then in all periods the network capacity would be insufficient to satisfy the demand for transmission. Thus, congestion is an issue in the four periods, and network use must be charged in order to solve capacity problems. A welfare maximizing network operator will set charges such that distortions are minimized. The best way to do this is to tax the effective use of the network, but not the ‘intra-nodal’ trade, i.e. the network operator will set the price wedge equal to zero, i.e.  $\tau_{ii} = 0$  ( $\tau_i^c = -\tau_i^p$ ). The reason for this is simple: setting a positive price wedge  $\tau_{ii} = \tau_i^c + \tau_i^p > 0$ , increases the distortion in the local market at node  $i$ , but only has an indirect effect on the network flows that cause the congestion. Note that this only makes sense for nodes at which both generators and consumers are connected. If not, the price wedge does not play a role.

These congestion charges allow the network operator to collect a revenue equal to €13 300 per hour in the low de-

<sup>18</sup>This is lower than the 83.4 TWh that was used to calibrate the demand functions. The reason for this is that we neglected the network constraints when we were calibrating. The network constraints reduce demand for electricity.

**Table 3** First best, results for a representative hour

First best		Average	Period 1 2,4%	Period 2 20.1%	Period 3 38.9	Period 4 38.6%
Length of the period	%					
Welfare	(k€ per hr)	908.6	1647.5	1256.3	1003.4	586.9
Consumer surplus	(k€ per hr)	772.4	1301.8	1031.7	837.1	539.8
Producer surplus	(k€ per hr)	170.8	305.2	230.6	194.1	107.9
Profit network operator	(k€ per hr)	−34.5	40.5	−5.9	−27.8	−60.8
Revenue network operator	(k€ per hr)	39.5	114.6	68.2	46.3	13.3
Fixed cost network operator	(k€ per hr)	74.1	74.1	74.1	74.1	74.1
Multiplier budget constraint	(€ per €)	–	–	–	–	–
Total generation	(MWh per hr)	9108	11657	10880	9403	7734
Average price	(€ per MWh)	32.2	48.0	37.9	35.5	22.4
Minimum price	(€ per MWh)	18.5	26.1	23.2	17.6	15.4
Maximum price	(€ per MWh)	76.4	121.7	91.7	92.6	46.8

**Table 4** First best, aggregate results

First best		Sum	Period 1 208	Period 2 1,759	Period 3 3,410	Period 4 3,383
Length of the period	hrs					
Welfare	(M€)	7959	342	2210	3422	1986
Consumer surplus	(M€)	6766	270	1815	2855	1826
Producer surplus	(M€)	1496	63	406	662	365
Profit network operator	(M€)	−303	8	−10	−95	−206
Revenue network operator	(M€)	346	24	120	158	45
Fixed cost network operator	(M€)	649	15	130	253	251
Multiplier budget constraint	(€ per k€)	–	–	–	–	–
Total generation	(GWh)	79790	2420	19138	32067	26165

mand period and €114 600 per hour in the peak demand period. Aggregated over the four periods, the network operator would cover 53% of its fixed costs by charging these congestion charges. Note that hourly congestion revenue is mainly collected in the periods 1, 2 and 3. (See Table 6.) Congestion is low in period 4, so congestion revenue is rather low in that period.

The congestion charges are node specific. They depend on how much consumption in a node affects the flows on the congested lines. In fact, the network operator uses the standard nodal pricing model. As a consequence, consumers at different nodes will pay different prices for electricity. In the low demand period, prices range between €15 and €47 per MWh. In the peak period, the price range is €26 to €122 per MWh.

Note that at first sight, one would expect that at times of low demand, the network is more likely to be uncongested. This is however not necessarily the case as in periods of low demand only base-load plants are running and, therefore, the ‘average distance’ between consumption and generation

nodes can increase compared to periods of peak demand. As a result the network is used more.<sup>19</sup> In the case of a contingency, flows are rerouted to a greater extent, as there is often no generation to provide the electricity locally.

## 5.2 Second Best

In the second best case, the network operator is faced with a budget constraint. Congestion charges now need to be increased above their first best level in order to obtain sufficient revenue to cover the remaining 47% of the network operator’s cost.

These transmission prices will result in increased wholesale prices and thus reduced demand in all periods. Aggregate demand (and generation) decreases by 1.5% to 78,592 GWh. Prices are now in the range of €18 and €47

<sup>19</sup>Of course, this depends on the location of the base-load plants in the network. If base-load plants are not distributed homogeneously in the network congestion is larger.

**Table 5** Second best, results for a representative hour

Second best		Average	Period 1	Period 2	Period 3	Period 4
Length of the period	%		2,4%	20.1%	38.9	38.6%
Welfare	(k€ per hr)	908.3	1647.1	1256.0	1003.0	586.7
Consumer surplus	(k€ per hr)	749.0	1270.5	1001.4	811.6	522.7
Producer surplus	(k€ per hr)	159.3	282.6	214.1	179.1	103.3
Profit network operator	(k€ per hr)	0.0	94.0	40.5	12.4	−39.3
Revenue network operator	(k€ per hr)	74.1	168.1	114.6	86.5	34.8
Fixed cost network operator	(k€ per hr)	74.1	74.1	74.1	74.1	74.1
Multiplier budget constraint	(€ per k€)	17.3	17.3	17.3	17.3	17.3
Total generation	(MWh per hr)	8971	11521	10722	9262	7612
Average price	(€ per MWh)	34.8	50.8	40.7	38.3	24.7
Minimum price	(€ per MWh)	21.7	29.7	27.0	21.0	17.9
Maximum price	(€ per MWh)	76.8	122.8	93.0	92.6	46.8

**Table 6** Second best, aggregate results

Second best		Average	Period 1	Period 2	Period 3	Period 4
Length of the period	hrs		208	1,759	3,410	3,383
Welfare	(M€)	7957	342	2209	3421	1985
Consumer surplus	(M€)	6561	264	1761	2768	1768
Producer surplus	(M€)	1395	59	377	611	349
Profit network operator	(M€)	0	20	71	42	−133
Revenue network operator	(M€)	649	35	202	295	118
Fixed cost network operator	(M€)	649	15	130	253	251
Multiplier budget constraint	(€ per k€)	17.3	17.3	17.3	17.3	17.3
Total generation	(GWh)	78590	2392	18861	31585	25753

per MWh in off-peak hours and of €30 and €123 in peak hours.

On average, the network operator needs to collect €74 100 per hour. Table 5 shows that the network operator collects €168 100 per hour during the peak period, and €34 800 per hour during base load periods. He makes sure that marginal deadweight loss of collecting revenue is equal in all the four time periods. Collecting €1 000 of extra revenue creates a deadweight loss of €17.3.

The network operator increases transmission tariffs, in order to cover his costs. The solution to this problem is known as Ramsey pricing. The basic idea is that prices are increased in a way that minimizes distortions, which amounts to applying price increases that are inversely proportional to the demand elasticities.

The use of Ramsey prices has two effects. On the one hand, the higher transmission prices will decrease the total demand for transmission. On the other hand, the pattern of the flows over the network will change. In the first best, transmission quantities depend on the price levels and the

marginal production costs. In the second best, transmission quantities will also depend on the demand and supply elasticities.

### 5.3 Strategic Behavior of Generators

The last simulation looks at how imperfect competition influences the second best model. Now, all three limitations are present: transmission constraints, market power in generation and a budget constraint for the grid operator. Market power in generation is modeled as Cournot competition. Table 7 presents the results aggregated over the four periods. The results do not come as a surprise. *Ceteris paribus*, less competition reduces welfare.

The multiplier of the budget constraint measures the net cost of giving one Euro to the network operator. The effect is about twice as large with Cournot as with perfect competition. There are two reasons for this. As total demand drops by almost 30% from perfect competition (= the second best) to the Cournot model, the network operator needs

**Table 7** Aggregate results of the 4 scenarios

Scenario		First best	Second best	Cournot
Welfare	(M€ per yr)	7959	7957	7310
Consumer surplus	(M€ per yr)	6766	6561	3778
Producer surplus	(M€ per yr)	1496	1395	3532
Profit network operator	(M€ per yr)	−303	0	0
Revenue network operator	(M€ per yr)	346	649	649
Fixed cost network operator	(M€ per yr)	649	649	649
Multiplier budget constraint	(€ per k€)	–	17.3	30.6
Total generation	(GWh)	79,790	78,590	59,691
Average price	(€ per MWh)	32.2	34.8	75.7
Minimum price	(€ per MWh)	18.5	21.7	68.7
Maximum price	(€ per MWh)	76.4	76.8	92.1

to increase the transmission tariffs with 30% in order to obtain the same revenue. At the same time, transmission prices create a larger deadweight loss, as there is already a deadweight loss due to the strategic behavior of the Cournot players.

The average price for electricity increases from €34.8 per MWh under perfect competition to €75.7 per MWh in the Cournot setting.

In an oligopoly with 3 players, welfare is about 8% lower than with perfect competition. Consumer surplus drops by 42%, producers' surplus more than doubles.

In the Cournot model, the location of the firms in the grid might be important in determining the market power of the generators. If firms have geographically dispersed production capacities, the effect of congestion might be much smaller than when firms are geographically concentrated.

Also the ownership structure of generation capacity might affect the market outcome. If all firms own a diverse portfolio with base load and peak load plants, then each firm will have an incentive to withhold some production capacity at the margin, as it will increase the price it receives for the infra-marginal plants. In the opposite case where one firm only owns base load plants and another firm only peak load plants, there are fewer incentives to reduce production. These effects of location and ownership remain a topic for further research.

## 6 Conclusions

This paper looks at the socially optimal transmission prices in a congested network with imperfect competition in electricity generation and a network operator facing a binding budget constraint. It shows that generators and consumers have to pay different transmission prices at the social optimum. These differences reflect the fact that the network

operator needs to collect revenues and that the generation sector is not competitive.

The model in this paper allows imperfect competition in generation, but assumes that generators are price takers in the transmission market. The network operator is a Stackelberg leader who sets transmission price before generators decide about generation and sales. The model is illustrated with three simulation runs: a first best scenario (limited transmission capacity), a second best scenario (a binding budget constraint), and a second best scenario with Cournot competition in generation. The parameterization of the model is inspired by the technical characteristics of the Belgian electricity system. It includes the Belgian high voltage transmission grid and the lines in France and the Netherlands which are important for the Belgian network. The network is presented as a linearized DC-load flow model. Transmission is limited by the thermal constraints of the lines and  $n - 1$  security constraints are imposed.

The model provides a framework that can help policy makers to design transmission tariffs. It shows how prices should be set in response to changes in market power. The model links some of the standard regulation literature on Ramsey pricing with the electricity literature on optimal pricing of transmission networks. The qualitative results that come out of the model can be very informative, but some reservation is at place if one would consider implementing such a pricing scheme. There are a number of reasons for this.

We assume that generators are price takers in the transmission market, while, in practice, generators might abuse their locational market power. Other types of models are needed if such market behavior exists. (See for example Borenstein et al. (2000).)

The model neglects entry in generation, and only derives short run optimal prices. These prices might not give the



right long run incentives for investing in new generation capacity.

The network operator is assumed to have perfect information about generation costs and demand. In practice, this information is not readily available. Any mechanism to allocate transmission capacity will have to take into account this information asymmetry.

The network operator might not be maximizing welfare, but rather profits or the interests of some political pressure groups. This is the reason why the network operator is regulated and is limited in setting transmission prices. A companion paper studies the strategic behavior of the network operator (Pepermans and Willems 2006).

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