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Where should generators be built in a zonal electricity market?

A numerical analysis of administratively determined investment signals

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Abstract. The location of electricity generation assets within a power system involves a fundamental trade-off: is it better to place generators at sites where generation costs are low, or should generators be situated close to consumers? This question is particularly relevant for wind turbines and solar photovoltaics, whose availability strongly varies between regions. If market prices reflect network constraints, the prices provide a locational signal. This is not the case in zonal markets with uniform prices. There, regulators can intervene by other means, such as administratively determined network tariffs that vary by location and are paid by generators. In this work, I examine such regulatory locational instruments using a novel bi-level electricity market model. In the first stage, the regulator determines a locational signal. In the second stage, generators decide on investment and dispatch while accounting for the regulatory signal and the zonal electricity price. For an exemplary network, I find that the introduction of regulatory locational instruments significantly lowers the cost of electricity supply.

Keywords: locational signals, zonal electricity markets, investment incentives, bi-level optimization, OR in energy

Highlights

- Even if the dispatch is suboptimal, a better placement of generators can lead to cost savings and welfare gains.
- In the test network, the optimal placement in a zonal market corresponds to the optimal placement in a nodal market if the redispatch mechanism is frictionless.
- Optimal locational investment signals differ by generation profile, which is not the case in most real-world applications.
- The proposed bi-level model allows for the representation of intrazonal network constraints while maintaining a uniform electricity price.
- Locational signals do not always harm the deployment of renewable energy sources.

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1. Introduction

The decarbonization of the power sector has profound implications for the geographical distribution of generators. Because the resource potential of wind and solar energy differs strongly between regions, these energy sources are often concentrated, usually far from consumption centers. To cope with the new spatial generation patterns of the energy transition, the network infrastructure must be extended, which is costly and takes many years. A trade-off thus arises between placing generators in remote areas, where generation costs are potentially low, or close to consumption centers with higher generation costs.

The best-known approach to providing locational signals is probably locational marginal pricing, also known as nodal pricing. In locational markets, the price of electricity reflects the marginal cost of supplying energy at each location (Schweppe et al., 1988). Locational prices reflect network constraints and lead to optimal dispatch incentives. Hypothetical nodal prices with perfect foresight of all market participants and without regulatory risks and the abuse of market power result in welfare-optimal investment incentives.

Power systems organized as zonal electricity markets lack such locational price signals. In these systems, the markets and network are operated independently of each other. Whenever the market outcome is technically infeasible, the power plant dispatch is modified through an out-of-the-market redispatch to resolve network congestion. Various studies have shown that zonal electricity markets create suboptimal investment incentives. In particular, when the redispatch is cost-neutral for the affected market participants, the generators' profits are independent of the network costs (Ambrosius et al., 2020; Bertsch et al., 2016; Ding and Fuller, 2005). This may lead to increasingly constrained transmission systems. For example, in Germany, the UK, and Sweden, wind resources are concentrated in the northern part of the country, while load centers are in the south. Consequently, the costs of network congestion management have risen sharply over the last years (Bundesnetzagentur, 2020; Staffell et al., 2021). Similarly, wind power is located far from consumption in Spain, which has led to significant overinvestment in the transmission network (Costa-Campi et al., 2020).

In response to the rising costs of congestion management, regulators have interfered in the market. Many have introduced locational signals that (dis-)incentivize investments in certain regions. In practice, such signals are implemented as (deep) grid connection charges, grid usage charges, a location-specific component in capacity mechanisms, or renewable support schemes (Eicke et al., 2020). In contrast to prices established in wholesale electricity markets, most of these regulatory signals are static (i.e., they do not change over short periods of time). This is reasonable if the aim is to affect investment decisions, for which well-predictable and steady price signals are helpful. However, time-invariant signals do not reflect quickly changing market situations and therefore do not result in optimal dispatch decisions. Administratively determined connection charges, potentially leading to better siting of generators in a zonal market, can hence be seen as an alternative approach.

Academic literature on the effect of regulatory locational signals in zonal markets is scarce. Tohidi et al. (2017) modeled regulatory transmission charges based on the marginal responsibility of generation investment on transmission network investment costs and found that such signals result in efficiency gains. Grimm et al. (2019) studied the effect of regionally differentiated network charges, which are paid by generators. They concluded that these charges have a significant impact on the siting of generation capacities but no significant effects on welfare or network expansion. Schmidt and Zinke (2020) analyzed the effect of geographically differentiated network charges paid by onshore wind energy. The authors found that although these charges lead to overall welfare improvement, it is

challenging to design them in a simple and cost-reflective manner. Vom Scheidt et al. (2022) demonstrated that locational signals for electrolyzers can reduce congestion management costs by up to 20% compared to the benchmark case without hydrogen. In all three abovementioned works, the locational signals were determined by modeling nodal electricity prices. Grimm et al. (2019) investigated locational signals based on average nodal electricity prices, and these signals are therefore uniform for all technologies. Schmidt and Zinke (2020) estimated locational signals as the difference between nodal and zonal market values. Vom Scheidt et al. (2022) did not explicitly determine a signal but analyzed the effect of siting electrolyzers based on modeled nodal prices. The implicit assumption of these three papers is that the welfare-optimal placement of generators is the same in zonal and nodal markets, although the prices diverge (and thus lead to different dispatch and eventually investment incentives). In this paper, I show that this assumption holds only when the out-of-the-market redispatch results in no additional costs.

The objective of this paper is to analyze the long-run equilibrium of optimally placed generators in a zonal electricity market. It focuses on locational signals for generators because consumers are less likely to respond to price incentives due to their comparatively low demand elasticity. Methodologically, I apply numerical modeling to study this problem, for which no analytical solution has yet been found. For a small numerical example, I compare the outcome of a zonal electricity market with a welfare-optimal locational investment signal to the benchmark of an integrated planner and to a reference case with a zonal market but without a locational signal. While the setups of an integrated planner and the reference case of a zonal market have often been analyzed, the equilibrium resulting from optimal investment decisions in a zonal market has not yet been modeled. I propose a novel bi-level power market model. In the first stage, the regulator chooses a location- and technology-specific price signal with the aim of maximizing social welfare. The regulator anticipates the second stage, in which generators decide on investment and dispatch while accounting for the zonal electricity price and the regulatory signal. The model can be interpreted as a Stackelberg game in which the regulator is the leader, and the participants of the power markets are the followers.

The main contribution of this paper consists of three findings regarding the optimal placement of generators in a zonal market. First, the strongly simplified case study provides an example in which inadequate investment incentives from the zonal market can be compensated by administratively determined price signals. This lowers costs and improves welfare, even when dispatch incentives remain suboptimal. This may indicate that a regulatory intervention in the form of locational investment signals mitigates some of the drawbacks of zonal pricing if the regulator has good information about the relevant costs. Second, locational signals do not always harm the deployment of renewable energy sources. In the numerical example, a better siting of generators increases the endogenous share of renewable generation, although some renewable generators are relocated to sites with lower resource availability. Third, I show that welfare-optimal investment signals differ by technology, which is often not the case in real-world instruments.

In what follows, I first present the economic and technical setups used throughout the paper (Section 2). Then, I introduce the implementation of an integrated planner as a benchmark (Section 3) and that of a zonal market with regulatory investment signals (Section 4). Section 5 introduces the case study and presents the results, which are further discussed in Section 6. Section 7 summarizes the main findings and provides conclusions.

2. Economic and technical setup

In this section, I present the notation and economic setup used throughout the paper. A summary of the nomenclature is presented in Annex A.1.

I consider a set of equidistantly discretized time steps $T = \{t_1 \dots t_{|T|}\}$, an electricity transmission network with a set of nodes $N = \{n_1 \dots n_{|N|}\}$, and the set of transmission lines between nodes $L = \{l_{n_1-n_2} \dots l_{n_n-n_m}\}$. The number and location of network nodes are given exogenously, but the capacity \bar{f} of each line, which limits the maximal power flows, is determined endogenously. With the costs of extending each transmission line c_l^{grid} , the network costs NC are

$$NC = \sum_{l \in L} \bar{f}_l \cdot c_l^{grid} \quad (1)$$

The investment and dispatch of generators are the decision variables of the model. The problem is formulated as a linear greenfield model (i.e., I assume no initial generation capacity). The set of candidate generation technologies is called $Z = \{z_1 \dots z_{|Z|}\}$. Some generators are limited by an availability factor $\alpha_{t,z,n}$, which varies over time and with location and can be interpreted as the wind or solar potential or as power plant outages. No constraints that limit the flexible operation of generators (i.e., no unit commitment and no ramping or minimum load constraints) are introduced. The technologies differ by their variable costs $c_{z,n}^{var}$ and their investment costs $c_{z,n}^{inv}$. The investment costs have two components: technology-specific fixed costs ($c_{z,n}^{fix}$) and costs that rise linearly (with slope m_s) with the installed capacity C of each technology at each location.¹ The *generation cost* (GC) includes the investment and dispatch costs:

$$\begin{aligned} GC &= \sum_{z \in Z, n \in N} \int_0^C c_{z,n}^{fix} + C_{z,n} \cdot m_s \, dC + \sum_{t \in T, z \in Z, n \in N} (G_{t,z,n} \cdot c_{z,n}^{var}) \\ &= \sum_{z \in Z, n \in N} C_{z,n} \cdot (c_{z,n}^{fix} + \frac{1}{2} \cdot C_{z,n} \cdot m_s) + \sum_{t \in T, z \in Z, n \in N} (G_{t,z,n} \cdot c_{z,n}^{var}) \end{aligned} \quad (2)$$

I assume a price-elastic electricity demand $d_{t,n}$. It depends on the endogenous electricity price λ_t , the exogenous reference demand $d_{t,n}^{ref}$, and the reference price p_t^{ref} . The following inverse demand function at each location is a linear function, with price elasticity ε at the reference demand and reference price (Annex A.4):

$$p_{t,n}(d_{t,n}) = p_t^{ref} \cdot \left(1 - \frac{1}{\varepsilon} + \frac{d_{t,n}}{\varepsilon \cdot d_{t,n}^{ref}} \right) \quad (3)$$

For simplicity, I introduce the parameters $a_{t,n}$ and $s_{t,n}$:

$$p_{t,n}(d_{t,n}) = a_{t,n} + s_{t,n} \cdot d_{t,n}, \quad (4)$$

with

$$a_{t,n} = p_{t,n}^{ref} \cdot \left(1 - \frac{1}{\varepsilon} \right) \text{ and} \quad (5)$$

$$s_{t,n} = p_{t,n}^{ref} \cdot \frac{1}{\varepsilon \cdot d_{t,n}^{ref}}. \quad (6)$$

¹ These rising costs can be interpreted as the reduced profitability of sites at increasing deployment (e.g., due to limitations in land availability). They are necessary to apply locational steering through price signals. Without increasing marginal costs, a locational signal in one region would lead to a relocation of all dispatchable generation capacity.

The gross consumer surplus (GCS) is the benefit consumers obtain from consuming electricity. It can be pictured as the area below the inverse demand function and can hence be derived as the integral of the inverse demand function between zero and the realized electricity consumption. Thus, the consumer surplus is:

$$GCS = \sum_{t \in T, n \in N} \int_0^{d_{t,n}} p_{t,n}(u) du = \sum_{t \in T, n \in N} \left(a_{t,n} \cdot d_{t,n} + \frac{1}{2} s_{t,n} \cdot d_{t,n}^2 \right). \quad (7)$$

3. The integrated planner

The integrated planner describes a setup in which dispatch and investment incentives are optimal. It serves as a benchmark and can be interpreted as the outcome of a welfare-maximizing integrated planner or as a perfectly functioning nodal market with optimal network investment.² The mathematical solution to this problem is well known; it results from the maximization of social welfare (SC). Social welfare is the difference between the gross consumer surplus and the cost of the electricity supply, which comprises generation and network costs:

$$\begin{aligned} SW &= GCS - GC - NC \\ &= \sum_{t,n} a_t \cdot d_{t,n} + \frac{1}{2} s_t \cdot d_{t,n}^2 - \sum_{z,n} C_{z,n} \cdot \left(c_{z,n}^{fix} + \frac{1}{2} \cdot C_{z,n} \cdot m_s \right) - \sum_l \bar{f}_l \cdot c_l^{grid} \end{aligned} \quad (8)$$

Several constraints limit the feasible space of the problem. *Kirchhoff's first law* constitutes the conservation of power flows and determines the flows in and out of each node. This constraint corresponds to the nodal energy balance.

$$\sum_z G_{t,z,n} - d_{t,n} = \sum_{l \text{ out}} f_{l,t} + \sum_{l \text{ in}} f_{l,t} \quad \forall t, l, n \quad (9)$$

Kirchhoff's second law describes the distribution of flows across transmission lines depending on the voltage angles at each node. The distribution is modeled according to the direct current approach for lossless transmission, which is a linear approximation of the voltage phase angle θ at each node. This simplification is well accepted in the literature (Chao and Peck, 1996; Neuhoff et al., 2005; Purchala et al., 2005).

$$f_{i \rightarrow j,t} = B \cdot (\theta_{i,t} - \theta_{j,t}) \quad \forall t, (i, j) \in N \quad (10)$$

To obtain unique physical solutions, the voltage phase angle θ is fixed at an arbitrary node $n^* \in N$:

$$\theta_{n^*,t} = 0 \quad \forall t \quad (11)$$

Transmission flows are limited by an upper bound, which is determined endogenously.

$$f_{i \rightarrow j,t} \leq \bar{f}_{i \rightarrow j} \quad \forall t, (i, j) \in N \quad (12)$$

Furthermore, the generation of each generator is limited by the installed capacity and its availability (Equation 13). Generation, capacity, and electricity consumption cannot become negative (Equations 14–16), and I assume an upper limit of the installable capacity (Equation 17).

$$G_{t,z,n} - \alpha_{t,z,n} \cdot C_{z,n} \leq 0 \quad \forall t, z, n \quad (13)$$

$$-G_{t,z,n} \leq 0 \quad \forall t, z, n \quad (14)$$

² In practice, also nodal markets do not lead to optimal investment decisions as Brown et al. (2020) show.

$$-C_{z,n} \leq 0 \quad \forall z, n \quad (15)$$

$$-d_{t,n} \leq 0 \quad \forall t, n \quad (16)$$

$$C_{z,n} - \bar{C}_{z,n} \leq 0 \quad \forall z, n \quad (17)$$

4. Regulatory investment signals in a zonal market

In this section, I compare the previously described benchmark to the case of a zonal electricity market in which generators are optimally placed. In this section, I describe the assumptions behind this setup and how it is implemented.

4.1. The regulatory investment signal

I begin by examining an investment signal that affects the placement decisions of generators but not (directly) their dispatch. To satisfy this criterion, the signal comes in the form of capacity-based charges—that is, charges for the nameplate capacity (i.e., per MW connected to the network).³ A real-world example is the British “Transmission Network Use of System” charge.

To define the welfare-optimal locational signal, I describe how a locational signal affects social welfare (Figure 1). In the first step, the regulatory authority defines the locational signal, which imposes a cost on the generators. Because generators are driven by profit maximization, their investment decisions are affected by this signal (second step). Where and how many new generation assets are built influences how much electricity needs to be transmitted. In the third step, the transmission system operator (TSO) optimizes network investment and operation. Social welfare is the difference between gross consumer surplus and the cost of the electricity supply (i.e., power generation and network costs).

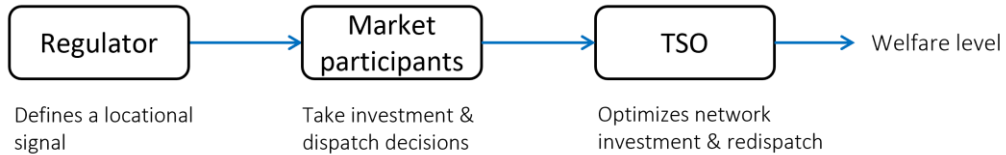


Figure 1: Effect of locational investment signals on social welfare

The fact that the regulator and the TSO have the objective of maximizing social welfare⁴ allows for simplifying the problem: both agents can be merged. The tri-level problem is reduced to a bi-level problem; in other words, the first and the third levels of the tri-level problem become the outer problem of the bi-level model. An implicit assumption is that the regulator and the TSO can anticipate how market participants respond to the regulatory investment signals. In the inner problem (the former second level), generators decide on the investment in generation assets and their dispatch while accounting for the regulatory locational signal and the price resulting from a zonal power market. Figure 2 shows the model setup and the most important decision variables.

³ Some power systems also apply energy-based location-specific charges (Eicke et al., 2020). In this paper, I study the effect of better placement decisions and therefore refrain from instruments that also affect the dispatch (more directly than via altered investment decisions). Yet, subject to minor modifications, the presented model can also be applied to energy-based locational instruments.

⁴ How to incentivize TSOs to maximize social welfare is an ongoing debate (Egerer et al., 2015; Joskow, 2008; Khastieva et al., 2020). In this paper, I assume that TSOs are perfectly regulated.

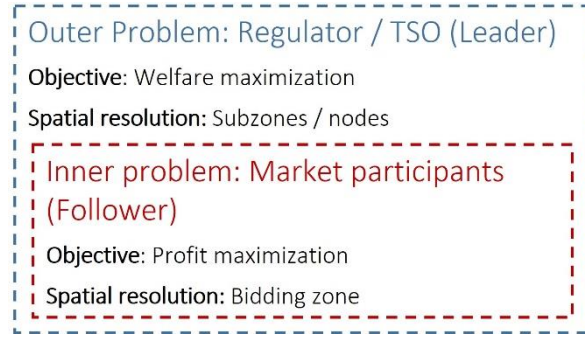


Figure 2: The interaction between the regulator, TSO, and market participants as a bi-level model

A feature of this model formulation is that the regulator and the TSO account for the network topology, while the participants in the zonal electricity market do not. The application of bi-level models is common when studying the interactions between the electricity market and network investment. Daxhelet and Smeers (2007), Jenabi et al. (2013), Egerer et al. (2015), and Schill et al. (2015) applied a bi-level model structure to analyze the effect of incentive regulation for network operators. The generation and transmission expansion (GATE) model first presented in Grimm et al. (2016) features a similar setup and is most similar to the model presented in this paper. It has been applied to study the effect of market zone splitting (Grimm et al., 2021), the cost-optimal balance between network expansion and network management measures (Grimm et al., 2021), and investment incentives for flexible demand (Ambrosius et al., 2018).

In what follows, I present the mathematical formulation of the two levels and the solution strategy.

4.2. Outer problem: Determination of locational signal, line expansion, and redispatch

The outer problem describes the decision space of the regulator and the TSO in an electricity market in which the price P_t is uniform across all nodes. Although most constraints of the benchmark also hold in the zonal market, two differences arise: the uniform electricity price affects the price-elastic demand for electricity, and the dispatch of generators resulting from the market clearing is no longer cost-efficient. In this section, I briefly describe the effects of these two differences on the model.

First, the determination of the market clearing price affects the price-elastic electricity demand. With the constraint of a uniform price, the inverse zonal demand function is

$$P_t(D_t^{spot}) = A_t + S_t \cdot D_t^{spot} \quad (18)$$

with

$$A_t = \frac{\sum_{n_{st,n}} \frac{a_{t,n}}{n_{st,n}}}{\sum_{n_{st,n}} \frac{1}{n_{st,n}}} \text{ and} \quad (19)$$

$$S_t = \frac{1}{\sum_{n_{st,n}} \frac{1}{n_{st,n}}}. \quad (20)$$

This formulation exploits the fact that the zonal electricity demand D_t^{spot} is the cumulative demand at all nodes within the zone.⁵ Based on this formulation, the gross consumer surplus in a zonal market is

$$GCS_{zonal}(D_t^{spot}) = \sum_{t \in T} \int_0^{D_t^{spot}} P(u) du = \sum_{t \in T} \left(A_t \cdot D_t^{spot} + \frac{1}{2} S_t \cdot D_t^{spot^2} \right) \quad (21)$$

A second issue is that the dispatch of generators and consumers resulting from the zonal market clearing does not reflect the transmission network. To avoid excessive network expansion, the TSO can limit network congestion by modifying the dispatch through an out-of-the-market redispatch: generators and consumers are ordered to alter their schedules to reduce the need for network expansion. I assume a profit-neutral redispatch, as implemented in the Austrian, Swiss, and German markets, which does not affect the spot market behavior or investment decisions. Downward dispatched generators ($R_{t,z,n}^{down}$) keep their profits (although without generating) but must repay their saved variable production cost. Analogously, generators that are upward dispatched ($R_{t,z,n}^{up}$) are compensated for the higher variable production cost.⁶ The compensation of generators thus results from the differences in variable costs. Consumers that are ordered to alter their consumption are compensated with the foregone consumer surplus. The compensation is hence the difference between the gross consumer surplus resulting from the demand at the spot market price ($GCS_{zonal}()$) and the gross consumer surplus of the realized electricity consumption after redispatch measures ($GCS_{zonal}()$). I assume a frictionless redispatch mechanism, which means that no costs other than compensation payments arise.⁷ The redispatch costs (RC) are thus:

$$RC = \sum_{t \in T, n \in N, z \in Z} (c_{z,n}^{var} \cdot [R_{t,z,n}^{up} - R_{t,z,n}^{down}]) + GCS_{zonal}(D_t^{spot}) - GCS_{zonal}(D_{t,n}^{real}) \quad (22)$$

The objective function of the outer problem is the maximization of social welfare. Based on the previously introduced specifications for a zonal market, the social welfare can be expressed as

$$\begin{aligned} SW_{zonal} &= GCS_{zonal}(D_t^{spot}) - GC - NC - RC \\ &= \sum_{t,n} A_t \cdot D_{t,n}^{real} + \frac{1}{2} S_t \cdot D_{t,n}^{real^2} - \sum_{z,n} C_{z,n} \cdot (c_{z,n}^{fix} + \frac{1}{2} \cdot C_{z,n} \cdot m_s) \\ &\quad - \sum_{t,z,n} c_{z,n}^{var} \cdot (G_{t,z,n} + R_{t,z,n}^{up} - R_{t,z,n}^{down}) - \sum_l \bar{f}_l \cdot c_l^{grid} \end{aligned} \quad (23)$$

The feasible space of the outer problem is limited by the inner problem of the profit maximization of market participants. In addition, the network constraints are resolved in the outer problem. The power flow constraints are the same as in the benchmark model hold (Equations 10–12), but the energy balance also accounts for the out-of-market redispatch:

$$\sum_z [G_{t,z,n} + R_{t,z,n}^{up} - R_{t,z,n}^{down}] - d_{t,n}^{real} = \sum_{l \text{ out}} f_{l,t} + \sum_{l \text{ in}} f_{l,t} \quad \forall t, l, n \quad (24)$$

The downward dispatch is limited by generation because only previously dispatched generation can be lowered.

⁵ The parameters A_t and S_t are calculated by summing the demand at each node (cf. Grimm et. al., (2016)). The formulation makes the implicit assumption that some electricity is consumed at all nodes.

⁶ The foregone profits of downward dispatched generators are not explicitly compensated. Because profits in the long-term equilibrium are zero, this compensation is covered in the (unaltered) investment cost.

⁷ This formulation can be interpreted as mandatory or a cost-based redispatch, where the TSO has perfect information on the (private) costs.

$$R_{t,z,n}^{down} \leq G_{t,z,n} \quad \forall t, z, n \quad (25)$$

The upward redispatch is limited by the available capacity that does not already generate.

$$R_{t,z,n}^{up} \leq P_{z,n} \cdot \alpha_{t,z,n} - G_{t,z,n} \quad \forall t, z, n \quad (26)$$

4.3. Inner problem: Generation investment and spot market

The inner problem describes the profit-maximizing behavior of agents in a zonal market. I assume a perfectly competitive market—that is, all agents are price takers. Generators invest in generation capacity and use this capacity for electricity generation. Generators account for the locational instrument $I_{z,n}$ introduced by the regulator because it affects their profit. Consumers choose the level of electricity consumption that maximizes the consumer surplus. Because storage is not included in the model, all generated electricity is consumed at the same time step. The revenues of the producers equal the costs of consumers, which allows simplifying the combined producers' and consumers' profits to

$$Profits = \sum_t GCS_{zonal}(D_t^{spot}) - \sum_{t,z,n} G_{t,z,n} \cdot c_{z,n}^{var} - \sum_{z,n} \left[C_{z,n} \cdot \left(c_{z,n}^{fix} + \frac{1}{2} \cdot C_{z,n} \cdot m_c + I_{z,n} \right) \right] \quad (27)$$

The network costs do not appear in this equation because they are not internalized and hence do not affect the decisions of the market participants.

The same constraints on generation capacity and availability apply as in the benchmark (Equations 13–17). By contrast, the energy balance is determined at the zonal level (Equation 28). The dual variable of the zonal energy balance corresponds to the zonal electricity price.

$$D_t^{spot} - \sum_{z,n} G_{t,z,n} = 0 \quad : P_t \quad \forall t \quad (28)$$

Table 1 summarizes all decision variables and constraints of the outer and inner models. All equations of the combined model are shown in Annex A.3.

Table 1: Overview of the outer and inner problems

	Outer problem	Inner problem
Actor	Regulator and TSO	Generators and consumers
Objective function	Social welfare	Producers' and consumers' profits
Decision variables	Transmission investment Out-of-market redispatch Locational instrument	Dispatch of generators Investment in generators Consumption level
Constraints	Power flow constraints Nodal energy balance Redispatch constraints Inner problem	Zonal energy balance Capacity and generation constraints

4.4. Solution strategy and model reformulation

The choice of the welfare-maximizing locational signal in the outer problem depends on and affects the inner equilibrium. Such bi-level problems are inherently nonconvex and more difficult to solve than single-level problems. A common solution is to reformulate the bi-level model into a single-level model by replacing the inner problem with its optimality (Karush-Kuhn-Tucker [KKT]) conditions.⁸ The reformulation results in a mathematical program with equilibrium constraints (MPEC) (Annex A.3).

The model features two non-linearities: quadratic terms and complementarity constraints. Because MPECs are NP-hard (Jerolow, 1985), they are typically converted into mixed-integer linear programs (MILP), which are easier to solve. In this paper, the complementarity constraints were linearized with the Fortuny-Amat (or “Big M”) method presented by Fortuny-Amat and McCarl (1981). The resulting problem is a mixed integer quadratically constrained problem (MIQCP), which can be solved to global optimality by commercial solvers. The linearization does not affect the result significantly. The linearized inner model yields the same numerical results as the equivalent mixed complementarity problem (MCP) formulation.

Due to its numerical complexity, the presented approach is not suitable for large-scale applications. However, the model captures a long-term equilibrium in which the generators are optimally sited. In this way, the structural properties of locational investment signals can be analyzed.

5. Case study

Next, I apply the model to an illustrative power system to highlight the characteristics of a welfare-optimizing locational signal.

5.1. Setup

The illustrative power system is very loosely designed after Germany. The system comprises two regions interlinked by a transmission line. I call these regions North and South. The greenfield model allows investment in four stylized technologies: wind, solar, baseload, and a peaking technology. The variable costs and the constant component of the investment costs are presented in Table 2. The primary purpose of this cost increase is to yield a unique solution.

Table 2. I assume an increase in capacity costs of EUR 0.33 per kW per additional GW of each technology at each location. This cost increase corresponds to a rise in the marginal capacity costs of EUR 10 per kW when 30 GW are installed and is therefore small compared to the fixed costs of any considered technology. The primary purpose of this cost increase is to yield a unique solution.

Table 2: Assumptions of variable and fixed costs

	c^{var}	c^{fix}
	€/MWh	€/kW p. a.
Base	40	300
Peak	70	110
Onshore wind	0	100

⁸ This is possible because the inner problem is a concave-quadratic maximization subject to linear constraints. Hence, the Karush-Kuhn-Tucker (KKT) conditions are both necessary and sufficient for optimality.

The network capacity is modeled endogenously and is based on investment costs of EUR 200 per MW, km, and annum and a 700-km distance between the two regions.⁹ To calculate consumer welfare and price-elastic electricity demand, I assume a reference price of EUR 55 per MWh. The availability factors and the reference load vary over time in hour-by-hour granularity in 10 timesteps. The two conventional technologies are assumed to always be available. The availability of wind and solar power differs between the two locations and is loosely calibrated using data from northern and southern Germany. The reference demand is, on average, three times higher in the southern region than in the northern region. All used time series are displayed in Annex A.2. The price-elasticity of demand ε at the reference load and reference price is -0.05 . A 10% increase in the electricity price leads to a reduction of demand by 0.5%, which corresponds to the short-term price elasticity of the electricity demand in Germany, as estimated by Hirth et al. (2022).

I compare three different setups to study the welfare-optimal siting of generators in a zonal system:

- The *reference case* describes the equilibrium arising in a single market zone. The dispatch and investment decisions of generators and consumers are based on a uniform electricity price. There is no regulatory investment incentive.
- The setup *investment signals in a zonal market* represent a case in which investment incentives are optimal given the foreseeable suboptimal dispatch incentives that result from a single-price zone.
- The *integrated planner* serves as a theoretical benchmark. In this setup, dispatch and investment incentives are optimal. This can be interpreted as the outcome of a welfare-maximizing integrated planner or as a hypothetical nodal market with optimal network investment.

In the latter two scenarios, the network costs are at least partially borne by the generators. In contrast, the non-internalized network costs in the reference case create an exaggerated incentive for electricity consumption, thereby reducing welfare. To avoid such structural bias, I introduce a uniform charge on generators (i.e., neither location- nor technology-specific) that maximizes social welfare but does not (directly) affect their geographical distribution. This scenario was implemented using the same bi-level model as the second setup.

The three equilibria are implemented in GAMS and solved with CPLEX.¹⁰ The benchmark model can be solved within less than a second on a conventional computer. The two setups applying the bi-level model require runtimes of a few seconds (Locational instrument) and several minutes (Reference) due to the integer variables introduced by the linearization and the quadratic objective function. In all three cases, a unique solution exists.

5.2. Optimal placement and welfare analysis

In the case study, the optimal placement of generators in a zonal market corresponds to the optimal placement of the integrated planner (or perfect nodal market), despite a different dispatch. This is

⁹ This corresponds to the new German HVDC line Südlink, whose cost estimates are of the order of EUR 10 B for a 4000-MW network capacity over approximately 700 km, assuming a 40-year depreciation and a 5% interest rate.

¹⁰ All code and input data are available at: <https://github.com/anselm-eicke/Locational-investment-signals>

due to the assumption that the redispatch mechanism is frictionless. Another interesting observation is that although the locational signal imposes additional costs on renewable energy sources and pushes them to less profitable sites, the endogenous—and thus cost-efficient—share of renewable generation slightly increases from 21.4% to 21.5% when investment signals are introduced. This is a direct benefit of the better siting of conventional generators.

Comparing the cost components of electricity supply emphasizes the rationale for introducing regulatory investment signals (Figure 3). In the reference case, generation costs are lowest because private investors minimize these costs without accounting for network costs. When a locational signal is introduced, generation costs are higher because less profitable sites are deployed. Yet, this cost increase is more than compensated by a reduction in network costs: the overall costs decline by 4.3%. Although the same cost reduction applies in the case of an integrated planner, the cost components are different: no out-of-market redispatch is required; however, the market clearing accounts for the network constraints, which leads to slightly higher generation costs. Since the redispatch mechanism does not result in additional costs (by assumption), the overall cost of the electricity supply is the same in both scenarios.

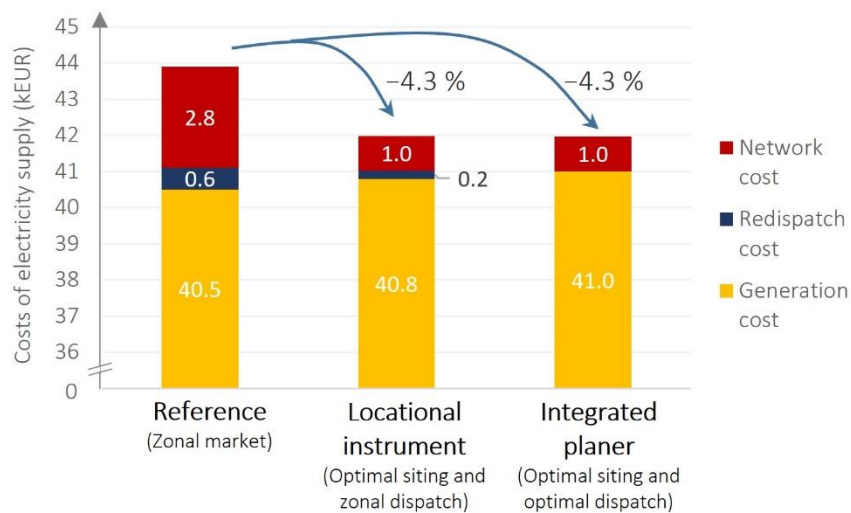


Figure 3: Cost of electricity supply in the three scenarios (frictionless redispatch)

The comparison of social welfare shows that the locational instrument results in a welfare gain of 0.7% compared to the reference scenario (

Table 4). The introduction of locational investment signals leads to the same welfare gains as those of an integrated planner or a perfect nodal market. This is due to the assumption that the out-of-market redispatch is frictionless.

5.3. Design of the regulatory locational signal

The presented methodological approach allows us to determine the welfare-optimal locational investment signal in the long-run equilibrium. This is presented in

Table 3 and is the unique solution. It can be interpreted as follows: a positive locational signal (i.e., a charge on the generators) implies that the respective technology increases network costs when operated under zonal dispatch. Conversely, a negative signal, equivalent to a subsidy for generators, indicates that the generation profile reduces transmission congestion. Note that the signal is specific to the underlying power system.

Table 3: Welfare-optimizing locational signal in €/kW (positive values imply additional costs for generators)

	North	South
Base	12.3 €	2.8 €
Peak	−13.5 €	−9.5 €
Solar	1.4 €	2.8 €
Wind	11.1 €	0.8 €

The calculated locational signal is plausible. For baseload and wind, the signal is higher in the north than in the south. This can be explained by the structurally higher demand in the southern region. In addition, wind has higher capacity factors in the north, which incentivizes the construction of more wind turbines in this region, resulting in more line congestion by northern turbines than by southern turbines. By contrast, the locational signal incentivizes a shift in solar generation from the south to the north, despite the on-average higher energy demand in the south. This can be explained by the higher solar potential in the south, which results in a high simultaneity of generation and makes a shift of solar panels to the north attractive from a system perspective. For peaking plants, the locational signal is a subsidy, which is higher in the north than in the south. This implies that peaking plants in the north relieve line congestion when responding to a zonal electricity price, which is in fact the case: electricity flows from the south to the north during in two hours.

In the case study, not all types of generators should be pushed to the south, despite a structurally higher electricity demand there. Consequently, the locational signal should ideally be technology specific. A sensitivity analysis reveals that the cost savings and welfare gains of a technology-agnostic instrument are about 35% lower compared to those of a technology-specific instrument (Table 4, Scenario IV).

A second sensitivity analysis suggests that even an imperfectly calculated signal is likely to reduce costs and increase social welfare. A signal that is 20% higher (lower) than the optimal signal still achieves 84% (89%) of the benefits of the optimal signal (Setups V and VI in Table 4).

Finally, I also modified the instrument such that it affects the variable cost of generation and not the investment costs—that is, the signal is expressed per generated energy in €/MWh (Setup VII in Table 4). This yields the same geographical distribution of generation assets as in the case of a capacity-based instrument. This is plausible because the energy-based instrument does not affect the dispatch order of the generators. The difference in variable costs imposed by the signal is below the difference in the variable costs of the technologies in the model.

Table 4: Overview of scenarios and results

No.	Setup	Market		Results (in k€)					
		Nodal market	Zonal market	Generation costs	Network costs	Redispatch costs	Total costs	Gross consumer surplus	Welfare
I	Reference		x	40.5	2.8	0.6	43.9	331.7	287.8
II	Locational signal		x	40.8	1.0	0.2	42.0	331.7	289.8
III	Integrated planer	x		41.0	1.0	-	42.0	331.7	289.8
IV	Technology agnostic signal		x	40.6	1.7	0.4	42.6	331.7	289.1
V	Locational signal too high (+20%)		x	40.9	1.0	0.4	42.3	331.8	289.4
VI	Locational signal too low (-20%)		x	40.7	1.3	0.2	42.2	331.7	289.6
VII	Energy-based locational signal		x	40.9	1.0	0.2	42.1	331.9	289.8

6. Discussion

In this sample case, the investment decisions of a central planner or the investment incentives of a perfect nodal market can be replicated using a combination of the zonal electricity price and an administratively determined investment signal. Such an intervention lowers the overall cost of the power supply and increases welfare, even when dispatch incentives remain suboptimal. However, the benefit of locational investment signals depends on the characteristics of the power system: the smaller the structural mismatch between generation and demand, the lower the welfare gains and cost savings. In addition, the benefits of an optimal distribution of generators depend on the reference case. In a zonal market without regulatory intervention, the placement of generators is often arbitrary. In the sample case study, for example, the distribution of conventional generators is purely driven by the rising capacity costs. Yet, other drivers of the spatial allocation of generators can similarly be accounted for in the model when they can be monetarized.

Another interesting finding of the analysis is that locational signals do not necessarily harm the deployment of renewable energy sources. In the numerical example, a better siting of generators increases the share of renewable energy sources in total generation, although some wind turbines and solar farms are relocated to sites with lower resource availability. While this is certainly not always

the case, the model provides an example in which locational signals even support the energy transition. To achieve this, locational signals must also be applied to (existing) conventional generators. They could, for example, be relevant when deciding on the withdrawal of baseload generators from the system (e.g., in a phaseout of coal-fired generation).

The numerical example also highlights that despite a structurally higher electricity demand in the south, not all types of generators should be incentivized to relocate to the southern region. Consequently, welfare-optimal investment signals may differ by technology. This is in line with Costa-Campi et al. (2020), who argued that the technology type and generation profile affect how much the location of the generator impacts flows in the transmission network. However, contrary to this finding, most real-world locational instruments are not technology-specific (Eicke et al., 2020). Depending on the system's characteristics, this may result in significant welfare losses. In the case study, for example, a technology-agnostic instrument yielded about 35% lower cost savings and welfare gains compared to the optimal technology-specific instrument.

The findings rest upon strong assumptions—including, above all, decent information on the regulator's side of the relevant costs and thus an optimal signal. In practice, a lack of information on future investments, commodity prices, changing weather patterns, technology developments, and political influence will lower the benefit of administratively determined locational signals. Therefore, the numerical results mark the upper bound of the benefits of a welfare-optimal siting of generators in the presented system. Despite these limitations, the sensitivity analyses suggest that even imperfect signals may reduce the cost of electricity supply compared to the highly suboptimal setting of a zonal power market without any additional investment signals.

A practical barrier to the introduction of administrative locational investment signals is that they increase the cost of power generation because they impose (on average) additional costs on generators. This can yield challenges when introducing locational signals across interconnected power systems—for instance, in the EU. Market distortions may occur along borders between systems that apply locational instruments and those that do not. For this reason, generation charges were mostly abolished in the EU (Meeus and Schittekatte, 2020). The findings of this paper provide some, albeit limited, evidence to reopen the discussion on generation charges.

7. Summary and conclusions

In this paper, I introduced a novel bi-level market model of the interplay between a welfare-maximizing regulator and profit-maximizing private companies. The model is used to analyze the optimal geographical distribution of generators in zonal markets and the regulatory intervention necessary to arrive at this optimal distribution.

By applying the model to a test case, I found that a location- and technology-specific charge on generators may increase social welfare and lower overall system costs. Under the (strong) assumption of a frictionless redispatch mechanism, the optimal placement of generators fully compensates the shortcomings of a zonal market design. This suggests that regulatory locational signals should be considered in zonal markets, especially when the renewable potential differs strongly within the market area. I also showed that locational signals do not necessarily harm the deployment of renewable energy sources. In the numerical example, a better siting of generators even increases the endogenous renewable share, although some renewable generation is relocated to sites with lower resource availability. Although this finding is system-specific, the example falsifies the claim that locational signals (always) disadvantage renewable energy. Finally, the welfare-optimal locational

signal is not only location-specific but also technology-specific. Due to their different generation profiles, some technologies result in much higher network costs than others, which is reflected in the deviating level of charges. This implies that locational signals should ideally differentiate between technologies, which is not the case for most real-world instruments.

I see three main avenues for further research in the field of regulatory investment signals in electricity markets. First, the employed model is not suitable for application to a large-scale real-world power system due to its numerical complexity. Improving the mathematical solution strategy would allow it to be applied to larger and more realistic systems. This could, for example, be accomplished through a decomposition of the model as in Ambrosius et al. (2020). An alternative improvement of the model would be to include non-linear constraints for generators, which would show inefficiencies resulting from the redispatch. A second interesting field of research is the empirical analysis of the effects of a locational instrument that was introduced in practice. Is it possible to quantify the effect on investment decisions? Third, another potential avenue is to develop alternative methodological approaches to calculating locational signals—for example, based on the marginal responsibility of generators in transmission flows. While this has been analyzed in the past (e.g., Tohidi et al., 2017), surprisingly little recent research has been conducted in this area, despite the increasing relevance of locational signals in the context of the energy transition.

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Annex A1: Nomenclature

Sets	
t	Hour
z	Technology
n	Subzone / node within the power system
Decision variables	
$G_{t,z,n}$	Generation of technology z in hour t and at node n
$C_{z,n}$	Installed capacity of technology z at node n
$d_{t,n}$	Electricity demand at each node (accounting for price elasticity)
D_t	Electricity demand of the entire pricing zone (accounting for price elasticity)
$f_{l,t}$	Power flow from node n to node m
\bar{f}_l	Installed capacity of transmission line l
$R_{t,z,n}^{up}$	Upward redispatch
$R_{t,z,n}^{down}$	Downward redispatch
$I_{z,n}$	Locational instrument (parameter in the inner problem)
$p_{t,n}$	Electricity price, also dual variable of the energy balance
Parameters	
$\alpha_{t,z,n}$	Availability of technology tec in hour t and node n
$c_{z,n}^{var}$	Variable cost of electricity generation for tec at node n
$c_{z,n}^{fix}$	Fixed costs of electricity generation for tec at node n
$c_{z,n}^{instr}$	Energy- or capacity-based location- and technology-specific network charge
c_l^{grid}	Network investment costs
c^{red}	Redispatch costs (only applies when no frictionless redispatch)
$d_{t,n}^{ref}$	Reference level of electricity demand (prior to price response of demand)
ε	Price-elasticity of demand at the reference point
m_s	Increase of the capacity costs at higher shares of the respective technology
$\bar{C}_{z,n}$	Upper limit for the installable capacity of tec at node n
Derived quantities	
SW	Social welfare
CGS	Gross consumer surplus
GC	Generation costs

Note that the distinction between variables and parameters is ambiguous because some variables of the outer problem are parameters in the inner problem.

Annex A2: Reference load and resource availability

Hour	Reference load (in MW)		Wind availability (in %)		Solar availability (in %)	
	North	South	North	South	North	South
1	5700	38740	43%	31%	0%	0%
2	3060	42080	24%	16%	20%	8%
3	2840	51310	20%	10%	36%	30%
4	22260	38900	20%	15%	18%	10%
5	16130	46970	12%	13%	0%	0%
6	29240	31410	6%	8%	0%	0%
7	28340	31500	11%	8%	2%	2%
8	6170	54070	17%	16%	19%	30%
9	21310	32410	24%	24%	32%	44%
10	10260	37370	29%	32%	11%	26%
average	14531	40476	21%	17%	14%	15%

Annex A3: Model formulation

Inner problem with corresponding dual variables

$$\begin{aligned}
 & \max_{G_{t,z,n}, P_{z,n}, D_t^{spot}} \sum_t GCS_{zonal}(D_t^{spot}) - \sum_{t,z,n} G_{t,z,n} \cdot c_{z,n}^{var} - \sum_{z,n} \left[C_{z,n} \cdot \left(c_{z,n}^{fix} + \frac{1}{2} \cdot C_{z,n} \cdot m_c + I_{z,n} \right) \right] \\
 \text{s.t.} \quad & D_t^{spot} - \sum_{z,n} G_{t,z,n} = 0 & : P_t & \forall t \\
 & G_{t,z,n} - \alpha_{t,z,n} \cdot C_{z,n} \leq 0 & : \overline{\mu_{t,z,n}^G} & \forall t, z, n \\
 & -G_{t,z,n} \leq 0 & : \underline{\mu_{t,z,n}^G} & \forall t, z, n \\
 & C_{z,n} - \bar{C}_{z,n} \leq 0 & : \overline{\mu_{z,n}^C} & \forall z, n \\
 & -C_{z,n} \leq 0 & : \underline{\mu_{z,n}^C} & \forall z, n \\
 & -D_t^{spot} \leq 0 & : \underline{\mu_t^D} & \forall t
 \end{aligned}$$

Lagrange function of the inner problem

$$\begin{aligned}
 \mathcal{L}(G_{t,z,n}, P_{z,n}, d_{t,n}, \overline{\mu_{t,z,n}^G}, \underline{\mu_{t,z,n}^G}, \overline{\mu_{z,n}^C}, \underline{\mu_{z,n}^C}, \lambda_t) \\
 = & - \sum_t GCS_{zonal}(D_t^{spot}) + \sum_{t,z,n} G_{t,z,n} \cdot c_{z,n}^{var} + \sum_{z,n} \left[C_{z,n} \cdot \left(c_{z,n}^{fix} + \frac{1}{2} \cdot C_{z,n} \cdot m_c + I_{z,n} \right) \right] \\
 & + \sum_t \lambda_t \cdot \left[\sum_n D_t^{spot} - \sum_{z,n} G_{t,z,n} \right] + \sum_{t,z,n} \overline{\mu_{t,z,n}^G} \cdot [G_{t,z,n} - \alpha_{t,z,n} \cdot C_{z,n}] \\
 & - \sum_{t,z,n} \underline{\mu_{t,z,n}^G} \cdot G_{t,z,n} + \sum_{z,n} \overline{\mu_{z,n}^C} \cdot [C_{z,n} - \bar{C}_{z,n}] - \sum_{z,n} \underline{\mu_{z,n}^C} \cdot C_{z,n} - \sum_t \underline{\mu_t^D} \cdot D_t^{spot}
 \end{aligned}$$

Joint problem

Equations of the outer problem

$$\begin{aligned}
 & \max_{I_{z,n}, \bar{f}_l, R_{t,z,n}^{down}, R_{t,z,n}^{up}, t,n} \sum_{t,n} GCS(D_t^{real}) - \sum_{z,n} C_{z,n} \cdot \left(c_{z,n}^{fix} + \frac{1}{2} \cdot C_{z,n} \cdot m_s \right) \\
 & \quad - \sum_{t,z,n} c_{z,n}^{var} \cdot (G_{t,z,n} + R_{t,z,n}^{up} - R_{t,z,n}^{down}) - \sum_l \bar{f}_l \cdot c_l^{grid} \\
 \text{s.t.} \quad & f_{i \rightarrow j,t} = B \cdot (\theta_{i,t} - \theta_{j,t}) & \forall t, (i,j) \in N \\
 & \theta_{n^*,t} = 0 & \forall t \\
 & f_{i \rightarrow j,t} \leq \bar{f}_{i \rightarrow j} & \forall t, (i,j) \in N \\
 & \sum_z [G_{t,z,n} + R_{t,z,n}^{up} - R_{t,z,n}^{down}] - d_{t,n}^{real} = \sum_{l \text{ out}} f_{l,t} + \sum_{l \text{ in}} f_{l,t} & \forall t, l, n \\
 & R_{t,z,n}^{down} \leq G_{t,z,n} & \forall t, z, n \\
 & R_{t,z,n}^{up} \leq P_{z,n} \cdot \alpha_{t,z,n} - G_{t,z,n} & \forall t, z, n
 \end{aligned}$$

Complementarity formulation of the inner problem

$$\begin{aligned}
 & \frac{\partial \mathcal{L}}{\partial G_{t,z,n}} = c_{z,n}^{var} + \overline{\mu_{t,z,n}^G} - \underline{\mu_{t,z,n}^G} - \lambda_t = 0 \quad \forall t, z, n \\
 & \frac{\partial \mathcal{L}}{\partial C_{z,n}} = c_{z,n}^{fix} + m_s \cdot C_{z,n} + I_{z,n} - \sum_t \overline{\mu_{t,z,n}^G} \cdot \alpha_{t,z,n} + \overline{\mu_{z,n}^C} - \underline{\mu_{z,n}^C} = 0 \quad \forall z, n \\
 & \frac{\partial \mathcal{L}}{\partial D_t^{spot}} = -A_t - S_t \cdot D_t^{spot} - \underline{\mu_t^D} + \lambda_t = 0 \quad \forall t, n \\
 & D_t^{spot} - \sum_{z,n} G_{t,z,n} = 0 \quad \forall t \\
 & G_{t,z,n} - C_{z,n} \cdot \alpha_{t,z,n} \perp \overline{\mu_{t,z,n}^G} \\
 & -G_{t,z,n} \perp \underline{\mu_{t,z,n}^G} \\
 & C_{z,n} - \bar{C}_{z,n} \perp \overline{\mu_{z,n}^C} \\
 & -C_{z,n} \perp \underline{\mu_{z,n}^C} \\
 & -D_t^{spot} \perp \underline{\mu_t^D} \\
 & \lambda_t \text{ free}
 \end{aligned}$$

Annex A4: Inverse demand function

For the analysis, I assume a linear inverse demand function with a negative slope ($b < 0$)

$$p(d) = a + b \cdot d,$$

which is equivalent to the following demand function

$$d(p) = -\frac{a}{b} + \frac{1}{b} \cdot p.$$

Using the definition of demand elasticity ε

$$\varepsilon = \frac{\delta d}{\delta p} \cdot \frac{p}{d} = \frac{1}{b} \cdot \frac{p}{d},$$

I obtain slope b and intercept a

$$\begin{aligned}
 b &= \frac{p^{ref}}{d^{ref}} \cdot \frac{1}{\varepsilon} \\
 a &= p^{ref} - b \cdot d^{ref}.
 \end{aligned}$$

and finally the following (nodal) demand function

$$p(d_{t,n}) = p_{t,n}^{ref} \cdot \left[1 - \frac{1}{\varepsilon} + \frac{d_{t,n}}{\varepsilon \cdot d_{t,n}^{ref}} \right].$$