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Working Paper

Redispatch Markets in Zonal Electricity Markets: Inc-Dec Gaming as a Consequence of Inconsistent Power Market Design (not Market Power)

Market-Based Redispatch in Zonal Electricity Markets

Inc-Dec Gaming as a Consequence of Inconsistent Power Market Design (not Market Power)

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Abstract – In zonal electricity markets, such as Europe's, system operators relieve congested power lines within bidding zones using out-of-market measures. One such measure is "redispatching" power plants, i.e. increasing the output of one power station while decreasing the output of another. Traditionally, generators have often been legally obliged to participate in redispatch and were subsequently compensated by the system operator for costs incurred. In recent years, with increasing pressure on power grids, numerous proposals have been made, including one by the European Commission, to organize redispatch through voluntary markets. In this paper, we introduce a simple graphical model of a zonal spot market with a locational, voluntary redispatch market to show that such a market-based solution should not be used in this setting. We solve the model explicitly by determining optimal bidding strategies and Nash equilibrium prices. We show that market parties anticipate the redispatch market and bid strategically in the spot market – the so-called increase-decrease game. As a result, grid congestion is aggravated, producers extract windfall profits, financial markets are distorted, and perverse investment incentives emerge. Despite claims to the contrary, we show that such gaming is possible absent market power, i.e. if all generators ultimately bid marginal cost. At the root of the problem is inconsistent power market design: combining a regional with a locational market yields undue arbitrage opportunities that rational firms exploit. We conclude that such inconsistent market design should be avoided.

This paper builds on research undertaken with Consentec, Connect Energy Economics, Ecofys, Fraunhofer ISI and Stiftung Umweltenergierecht in the project "Untersuchung zur Beschaffung von Redispatch" for the Federal German Ministry of Economic Affairs and Energy (No. 055/17). Project findings are published as Neon & Consentec (2018) and Connect Energy Economics (2018). This paper does not constitute a project deliverable. We thank Kristin Walter, Nils Saniter, Christoph Maurer, Bernd Tersteegen, Marco Nicolosi, Barbara Burstedde, Markus Graebig, Eva Schmid, Frauke Thies, Simeon Hagspiel, Samuel Glisman, Anselm Eicke, Tarun Khanna, Christoph Neumann, Catrin Jung-Draschil, Bernhard Hasche, Fabio Genoese, Charles Payement, Fabian Joas, Gerard Doorman, Philip Baker, Julia Radecke, Joseph Hefele, and Rebecca Lordan-Perret for inspiring discussions and helpful comments.

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Summary

Redispatch markets. European wholesale markets for electricity are geographically organized in zones. System operators relieve overload of network elements within zones through a range of out-of-the market measures collectively called congestion management. (US-type locational marginal pricing systems do not need this.) One such measure is “redispatching” power plants, i.e. increasing the output of one power station while decreasing the output of another. Such redispatch can be organized in different way. One option is to rely on regulatory redispatch with an obligation for generators to participate and compensation based on costs. Another option is to use markets with voluntary participation. While Germany and other central European countries are using regulatory redispatch, proponents of market-based redispatch hope to attract additional participants, in particular consumers. In its latest legislative proposal, the European Commission suggested to introduce market-based redispatch across Europe. Several researchers and stakeholders have issued similar proposals, sometimes called “markets for flexibility” or “smart markets”.

Inc-dec strategy. The purpose of this paper is to explain the interaction between a locational redispatch market and the zonal spot market. Our main point is that when producers are able to anticipate redispatch market prices, they will change their bids on spot markets: they will bid strategically. Consider a producer located in a region with scarce electricity supply. Anticipating a high price on the redispatch market, that producer will overbid (hold back capacity) on the spot market in order to earn a higher price on the redispatch market. Generators in oversupplied regions face incentives for underbidding. This strategy is known as increase-decrease (inc-dec) gaming. Historically, inc-dec bidding is well-documented in California and Great Britain, but it also played a role in moving from zonal to nodal markets in other US power systems.

Consequences. Such strategic bidding is problematic, because of four reasons:

- It aggravates network congestion, increasing redispatch volumes and costs.
- Producers are able to extract windfall profits from small consumers and rate payers.
- It distorts financial markets, making hedging complicated if not impossible.
- It creates perverse incentives to build power plants in oversupplied regions.

No market power needed. It is often believed that inc-dec bidding is a consequence of market power. This is not the case. It is the dominant strategy of rational firms, even if all markets are perfectly competitive.

Conclusions. At the root of the problem is inconsistent market design: combining a zonal with a locational market yields undue arbitrage opportunities that rational firms exploit. We recommend not to introduce market-based redispatch.

The model. To study inc-dec bidding, we introduce a simple graphical model of a zonal spot market that is followed by a locational redispatch market. It comprises two nodes, an export-constrained North and an import-constrained South, that are connected through a single line. We study a single hour, assume power plants to be perfectly flexible, markets to be

competitive, and agents to have perfect foresight. We compare three market designs: nodal pricing, regulatory redispatch, and a redispatch market.

Optimal bidding. In the case of redispatch markets, firms anticipate redispatch prices and adjust their spot bids for these opportunity costs. Figure 1 shows their optimal spot bidding strategies. Power stations in the South overbid (price themselves out of the market) to subsequently sell energy in the redispatch market. They essentially optimize between the two market stages, selling at the higher-priced market. Generators in the North underbid (price themselves into the market) in order to subsequently buy back energy in the redispatch market. They earn a profit from carry trade between the two markets. This strategic bidding causes additional generation to be scheduled for production in the oversupplied North and less in the energy-scarce South, which means it aggravate congestion.

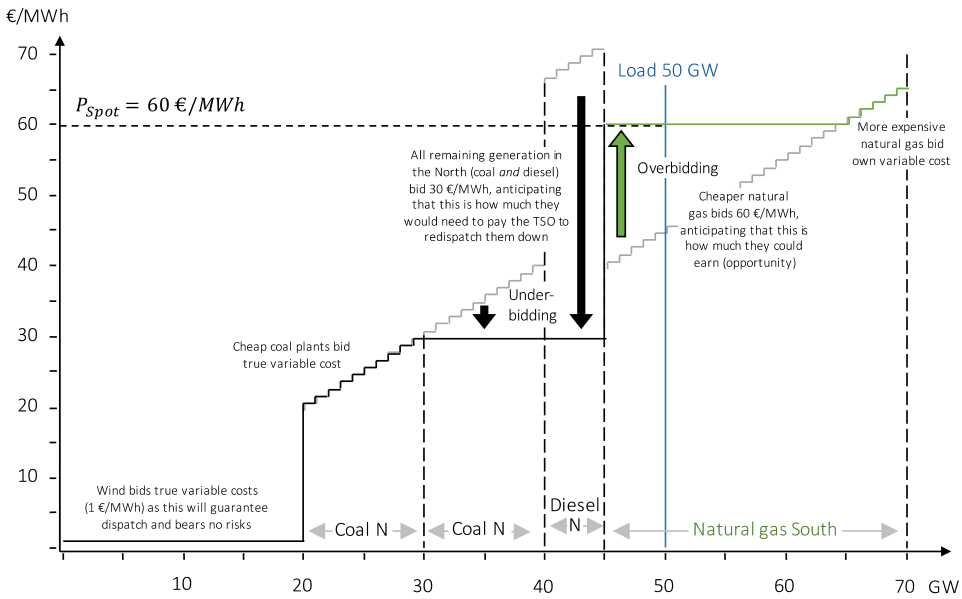

Figure 1. Spot market equilibrium with anticipation of redispatch markets.

Comparing results. Table 1 summarizes the outcome of these three market designs. What our model shows is that gaming increases redispatch volumes and redistributes rents from consumers to producers.

Table 1. Equilibrium outcomes for the single hour modeled under alternative market designs

	Nodal pricing	Regulatory redispatch	Redispatch market
Redispatch volume	0	10 GW	15 GW
Total cost for consumers (EUR)	2 100 000	2 700 000	3 450 000
Producer rents (EUR)	815 000	1 415 000	2 165 000

1 Introduction

Zonal electricity markets. European wholesale markets for electricity are organized geographically into so-called “bidding zones”. Within bidding zones, all generation and load is cleared at a uniform price and the system operator guarantees free trade between market parties. If the desired dispatch cannot be accommodated physically by the existing electricity grid, the system operator relieves congestion using measures outside of the wholesale market. These out-of-the-market transactions can be called “congestion management” (Hirth & Glismann, 2018, provide an overview). Congestion management includes a number of instruments such as switching operations in the power grid and “redispatch”. Redispatching power plants (or loads) means ordering plants upstream of the constraint to reduce output while asking plants downstream of the constraint to ramp up. Redispatch can be organized through regulatory obligations or voluntary markets.

Regulatory redispatch. In central European countries, regulatory redispatch prevails. Here, generators are legally obliged to participate in redispatch. Small, renewables-based, and combined heat and power generators are often exempted; also loads and small-scale storage assets are usually not obliged to participate. Redispatched generators are compensated for costs and forgone profits. Germany is among the countries that applies regulatory redispatch.

Market-based redispatch. An alternative is to conduct redispatch through a voluntary market. That is, power plants compete in a market for redispatch, separate from the wholesale electricity market. They bid their price at which they would be ramped up or down to relieve congestion.

Nodal pricing. The European “zonal spot plus redispatch” electricity market design stands in contrast to US “locational marginal pricing” (also called nodal pricing), where grid constraints are respected in the initial (security constrained) economic dispatch. As a result, redispatching is unnecessary.

Increased network congestion. Across Europe, pressure on transmission and distribution grids has increased in recent years expanding the need for redispatching services. This trend is expected to continue. The pressure on the grid is due to a combination of factors including the rapid expansion of renewable energy sources; the integration of electricity markets across national borders; the separation of historically integrated utilities that had ensured a close geographic match of consumption and generation; and, in Germany’s case, the phase-out of nuclear power. These factors result in longer distances between generation and demand, decentralized generation and new consumption – heat pumps and electric vehicles — and the need to smoothen variation in wind and solar generation over large areas. All this contributes to increased redispatching. Figure 1 shows the increase in Germany’s redispatch volumes and cost. 15 TWh of downward redispatch correspond to 2.5% of the country's electricity consumption.

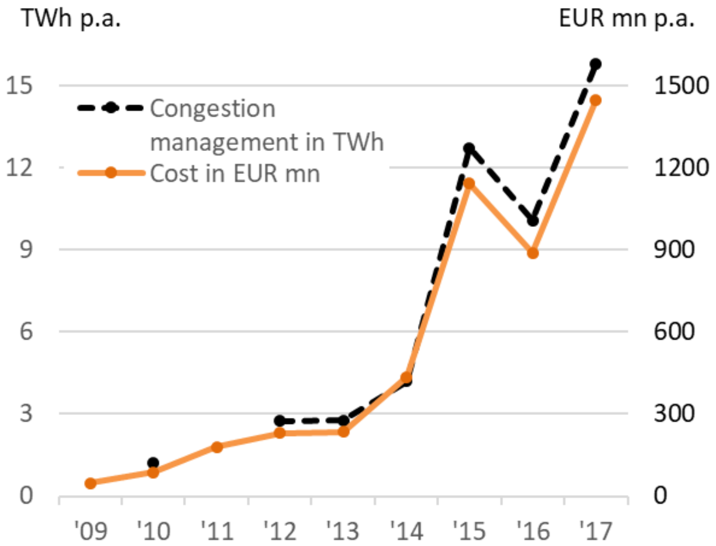

Figure 2. Increasing congestion management volumes (downward redispatch only, include renewables curtailment) and costs in Germany. Data from Bundesnetzagentur.[1]

Rationale for redispatch markets. Against this background, several stakeholders have proposed to change procurement of redispatch resources from the obligatory system to voluntary markets. The main reason for this is to increase participation in redispatch. System operators need more redispatch services at lower costs, so theoretically, making a competitive market will attract more producers. However, many of the new actors – storage facilities, active demands, combined heat and power plants – are difficult to integrate into regulatory redispatch because their opportunity costs are difficult to observe. For them, markets could provide the incentives to participate, ultimately leading to lower costs for rate payers. Advocates also believe voluntary redispatch markets could provide an incentive for investors to build power plants in regions that lack energy and facilitate redispatch across national borders within the EU. Finally, advocates argue that voluntary markets are preferable to administrative obligations.

Policy proposals. These proposals include:

- The most prominent proposal emerged from the European Commission's Clean Energy for All Europeans package. Article 12 of the proposed Electricity Market Regulation[2] suggests introducing "market-based redispatch". This proposal has been

1 https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netz_Systemsicherheit/Netz_Systemsicherheit_node.html

2 https://eur-lex.europa.eu/legal-content/DE/TXT/?uri=celex:52016PC0861

among the most contentious of the legislative package. The final agreement includes a number of derogations.

- In Germany, a large-scale research project called SINTEG provides the framework for a number of pilot projects for market-based congestion management. These include the projects Enera, C/sells (subprojects ALF, Dillenburg, Comax), Windnode, NEW 4.0 (subprojects ENKO and Smart Market) and Designnetz.
- The Netherlands is using a market called GOPACS (Grid Operators Platform for Congestion Solutions). The Dutch system operator expects to procure a significant share of its 2019 redispatch volume with this approach.[3]
- Other pilots and proposals include the markets Nodes AS, DA/RE, Flexrouter, Smart Nord, HeatFlex, Smile, and United Grid. See Radecke & Hefele (forthcoming) for an overview.

"Redispatch markets". These markets are sometimes called "markets for local flexibility", "smart markets", "market-based redispatch", among other things. For convenience, we call all of the above proposals "redispatch markets" regardless of the specific terminology used, as they all essentially use voluntary markets to relieve grid congestion. In its cleanest form (and as we will model them in this paper), redispatch markets are based on voluntary participation, unrestricted bidding and free price formation based on marginal clearing prices. Real-world "redispatch markets" often resemble regulatory redispatch more closely than such free markets despite their name. In other words, redispatch markets often combine pay-as-bid pricing with tight regulation that compels producers to bid marginal costs.

Inc-dec strategy. The purpose of this paper is to discuss the relationship between zonal spot markets and locational redispatch markets and why that relationship makes voluntary redispatch markets untenable. In such hybrid market designs, market participants can anticipate redispatch market prices and change their bids on the zonal spot market. Producers will price in the opportunity arising from the redispatch market. Such strategic bidding is problematic for several reasons, though we focus on two: it allows generators to extract windfall profits, and it *aggravates* congestion. For illustration, consider a generator located in a scarcity region. Anticipating a high price on the redispatch market, the producer will hold back capacity on the wholesale market in order to benefit from higher prices in the redispatch market, a strategy that is known as increase-decrease (inc-dec) gaming.[4] Withholding capacity increases line overload. Analogue incentives exist for market parties in surplus regions, further aggravating congestion.

Historical cases of inc-dec. Several markets have suffered in the past from inc-dec gaming. Due to the negative impacts of the bidding strategy, policy makers have typically responded with changes to the market design or regulatory intervention. Two cases have drawn particular attention in the literature: California and Great Britain.

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[3] https://gopacs.eu/nl/veelgestelde-vragen/

[4] The term "inc-dec" refers to the strategy that generators first increase and then decrease sales of power (Sarfati et al. 2018), and also to the California redispatch market where upward bids were called "incrementals" and downward bids "decrementals" (Stoft 1998).

California. California liberalized its electricity markets in 1996-98. During this liberalization, it introduced a zonal market with two bidding zones. Within-zone network congestion was managed with market-based redispatch (although that term was not used), incentivizing market parties, including Enron, to engage in the inc-dec game. As early as 1999, the Federal Energy Regulatory Commission warned that "the problem facing the ISO is that the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced." Gaming contributed to the energy crisis of 2000/01 during which the state suffered from a series of rolling blackouts. Consequently, California introduced locational marginal (nodal) pricing in 2009. Similar gaming had already caused the New England ISO and ERCOT to do the same. Hogan (1999), Harvey & Hogan (2001), Alaywan et al. (2004), Brunekreeft et al. (2005), and CAISO (2005) provide analyses of the California case.

Britain. Another case of inc-dec bidding occurred at the Scottish-English border, a part of the network that was increasingly constrained following expansion of wind power in Scotland. In 2012, the British regulator introduced the so-called Transmission Constraint License Condition to prevent further gaming by penalizing bids that result in "excessive benefits", which has been in place ever since. The Condition requires generators to bid marginal cost and prevents them from factoring in locational rents. To us, this seems nearly equivalent to regulatory redispatch with cost compensation. Ofgem (2012, 2016, 2018) and Konstantinidis & Strbac (2015) provide accounts of this case.

State of the theoretical literature. We are aware of a few papers on the interplay between zonal spot and locational redispatch markets and the emergence of the inc-dec game, in particular the work by Pär Holmberg and co-authors. Holmberg & Lazarczyk (2015) point out that inc-dec gaming is an arbitrage strategy that cannot be eliminated by improving competition in the market. They point out that zonal pricing combined with a market based redispatch gives arbitrage opportunities to producers. More recently and with new coauthors (Hesamzadeh et al. 2018 and Sarfati et al. 2018), Holmberg comes to similar conclusions. Using a numerical two-stage stochastic equilibrium model with imperfect competition, they find that "the inc-dec game is not due to the lack of competition, it is due to the misrepresentation of transmission constraints in the day-ahead market." These papers are methodologically sound and draw reasonable conclusions. Yet, being highly technical in nature, they have failed to impact the policy discourse. Connect Energy Economics (2018) discusses various was of implementing market-based redispatch, e.g. installing a dedicated market platform or using existing platforms such as the intraday market or procurement auctions for balancing energy. The authors conclude that inc-dec gaming is present in any of these forms. In contrast to these findings, Grimm et al. (2018) argue that assuming competitive markets "implies that we abstract from any inc-dec games" (footnote 8), which we believe to be an incorrect inference.

Terminology. Most academic literature uses the term inc-dec "gaming" to describe the behavior of firms. This stems from game theory, the branch of economics that studies strategic interactions. However, "gaming" also carries the connotation of the strategy to be illegal and/or complicated to exercise. Both are likely not the case, which is the reason we favor "inc-dec (bidding) strategy". One might also describe the behavior as "arbitrage trading", “optimization between two markets”, “pricing in opportunity costs” or one might even argue that firms “save flexibility for redispatch”.[5]

Contribution of this paper. The value added of this paper is to develop a simple, intuitive example of a zonal wholesale market with a locational redispatch market to demonstrate the incentives for inc-dec gaming and why it is so problematic. Using this model, we show the incentives introduced by redispatch markets, identify optimal bidding strategies, and determine Nash-equilibria and corresponding prices. We do all this without any mathematics or numerical modeling, relying on graphical solution techniques only. By illustrating the intuition behind the inc-dec gaming, we make clear to a broad audience why redispatch markets should be avoided. Despite its simplicity, we are able to use this same model to comprehensively discuss the consequences of inc-dec gaming, including impacts on financial markets and investment incentives. Next, we discuss the pre-conditions for gaming, including the predictability of congestion and the finding that market power is *not* a necessary condition for gaming to occur. We then discuss factors that could aggravate gaming (and its negative consequences) above and beyond the framework and assumptions we look at, such as when locational market power is present or demand entities are facing similar incentives. Finally, we evaluate suggestions to prevent gaming in redispatch markets before we conclude.

Findings. We conclude that current proposals for redispatch markets within zonal wholesale markets should not be adopted. They incentivize strategic bidding on the spot market which aggravates grid congestion, allows producers to extract windfall profits, distorts financial markets, and creates perverse investment incentives.

2 Model Setup and Benchmark Designs

In this section, we outline the physical setup of our model and the benchmark electricity market designs to which we compare redispatch markets with anticipation. The benchmark designs presented in this section are nodal pricing (Section 2.2) and regulatory redispatch with cost compensation (Section 2.3). Redispatch markets will then be introduced in section 3. Section 3.2 will add a further benchmark case, namely redispatch markets without anticipation. The latter, however, is not a Nash equilibrium and therefore a hypothetical case that serves to illustrate the impact of actors anticipating the redispatch market. Figure 3 visualizes the different benchmarks used throughout the paper.

[5] Consider the following case. A load entity learns that during particular hours the grid operator regularly requests flexibility (for example of the type to decrease load) for grid purposes. To be able to provide more grid-friendly flexibility (potential to decrease load), the load entity decides to shift higher production levels to these hours, in order to be able to then provide the demanded flexibility the grid operator needs. As a consequence, the load entity actually makes congestion worse and increases the amount of flexibility the grid operator has to purchase. This is what we describe as inc-dec gaming.

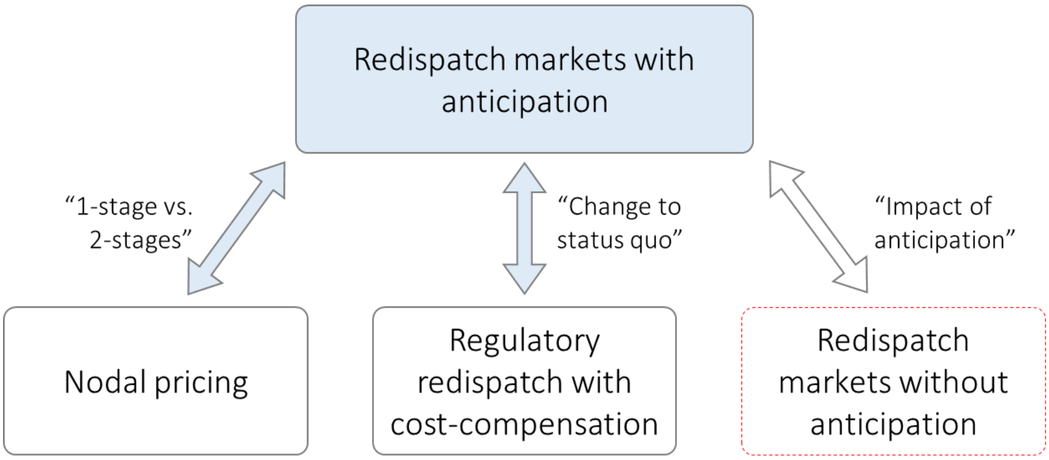

Figure 3. Comparing the different market designs. Redispatch markets without anticipation is not an equilibrium; the three other designs are.

2.1 Physical Setup of the Model

Network and market. We created a simple model—very loosely modeled after Germany—to illustrate inc-dec gaming. It is an isolated power system comprising two nodes, the export-constrained North (N) and the import-constrained South (S). These two nodes are connected through a single transmission line rated at 30 GW. The spot market is one single bidding zone (except under nodal pricing, when no bidding zones exist), in other words, a uniform spot market. We study a 1-hour snapshot of the market. We abstract from transmission losses and voltage limits. Figure 4 shows the network topology.

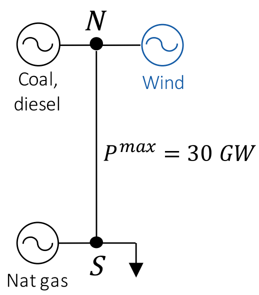

Figure 4. The simple network topology.

Demand and supply. In our model, the Northern node has three generation sources: wind (20GW), coal-fired power plants (20 GW), and diesel peakers (5 GW). As there is no load in the North, the direction of electricity flow will always be south-bound. The Southern node contains both the load center for the system, which is perfectly price inelastic, and 25 GW of natural gas-fired power plants. We abstract from ramping, start-up, or minimum load constraints. In total, 70 GW of generation capacity is available, hence capacity is abundant both on a system level and, given the transmission line capacity of 30 GW, on a nodal level. Figure 5 shows the supply stack of the system. Table 2 summarizes the core system parameters.

Actors and information. We assume profit-maximizing firms and full information, i.e. perfect foresight and the absence of information asymmetries. We divide the power plant capacity into 1 GW-units each owned by separate companies. Therefore, there is no market power in supply. Firms maximize profits individually, they do not collude.

Table 2. Load, generation and line parameters.

	North	South
Load	0	50 GW, perfectly price in-elastic
Generation capacity	• 20 wind parks of 1 GW each at variable cost of 1 €/MWh • 20 units of 1 GW coal-fired plants at variable costs of 21,22,23, … ,40 €/MWh • 5 units of 1 GW diesel peakers at variable costs of 66,…,70 €/MWh	• 25 units of 1 GW natural gas-fired plants at variable costs of 41, … , 65 €/MWh
Line capacity	30 GW	

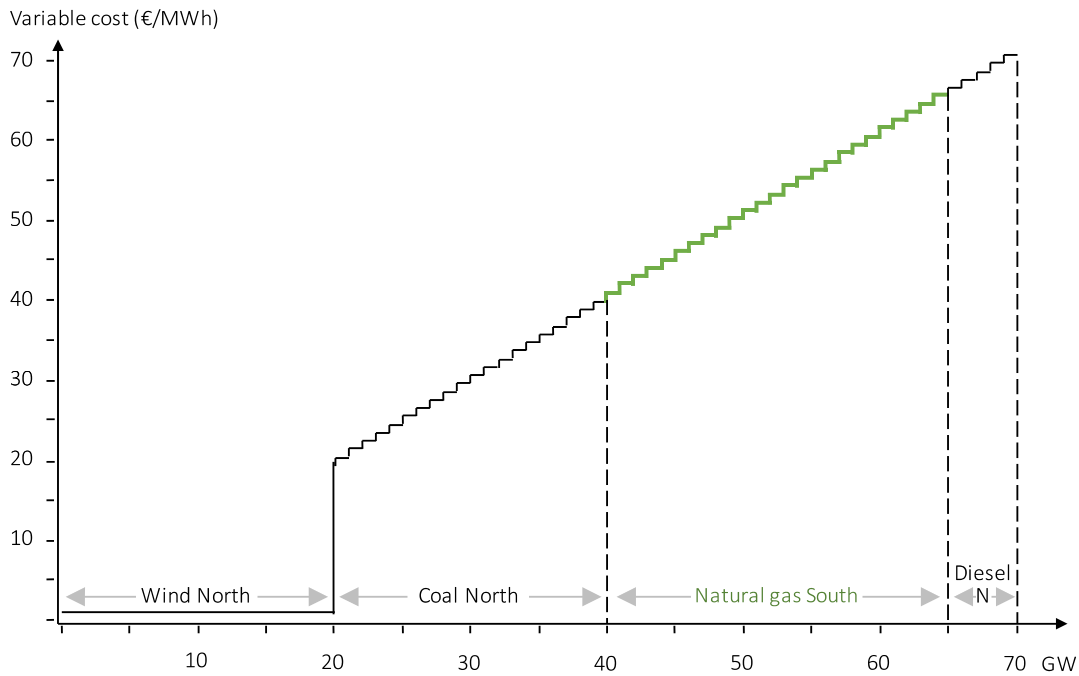

Figure 5. Variable costs ordered by size (merit order). Capacity connected to the South is depicted in bold green.

2.2 Nodal Pricing

Locational marginal pricing. As the first market design and one of our two benchmark cases, we study nodal pricing. Nodal pricing is a single-stage locational marginal pricing system without redispatch. Figure 6 displays supply and residual demand curves for the two nodes. The supply curves correspond to variable costs of power plants. As common practice, we represent demand and network constraints as residual demand curves for each node: price inelastic demand in the South is 50 GW, which can be either supplied locally or through (transmission-constrained) generation from the North. Residual demand in the North comes from physical (residual) demand in the South subject to transmission constraints.

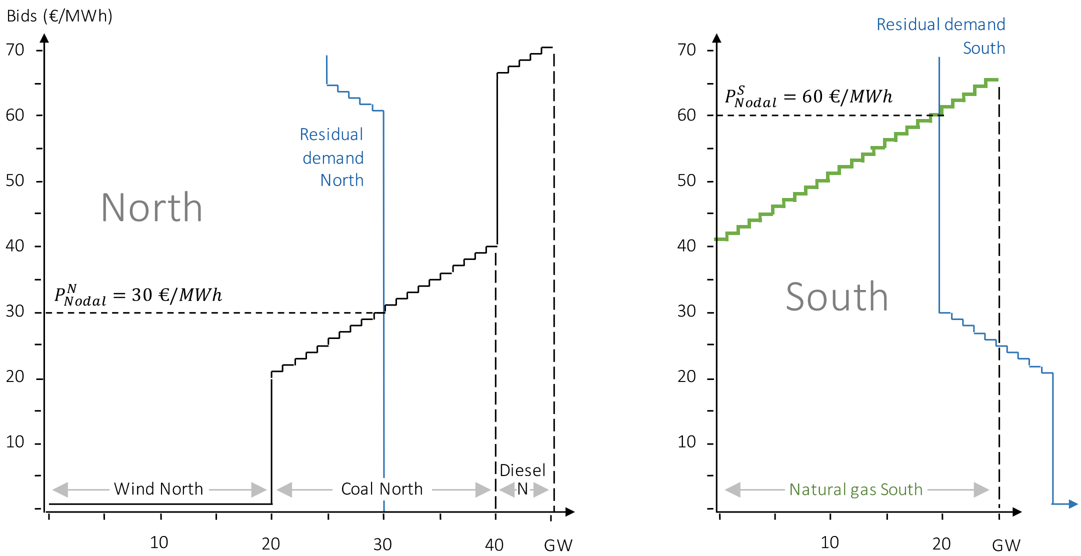

Figure 6. Variable costs ordered by size (merit order). Capacity connected to the South is bold green.

Market outcome. Table 3 shows the outcome of the nodal pricing markets. The dispatch corresponds to the security-constrained economic dispatch. The line is used at full capacity. The clearing prices are EUR 30 per MWh in the North and EUR 60 per MWh in the South. Neither node has an individual supplier that is pivotal, i.e. there is no market power. The congestion rent captured by the system operators equals 30 GW times 30 EUR per MWh, or EUR 900,000.

Table 3. Market result of the nodal pricing market.

	North	South
Price	$P^N_{Nodal} = 30\ €/MWh$	$P^S_{Nodal} = 60\ €/MWh$
Dispatch	20 GW wind 10 GW coal	20 GW natural gas
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Congestion rent	EUR 900,000	

2.3 Regulatory Redispatch with Cost Compensation

Spot separated from redispatch. As the second benchmark market design, we study regulatory redispatch with cost compensation. In this market design, spot markets and redispatch are two separate processes. First, the wholesale spot market clears at a zonal level. If the resulting dispatch can be accommodated by the grid, there is no need for redispatching. If the spot market dispatch violates network constraints (as it will in our example), the system operator issues redispatch orders to the generators. Though generators are legally obliged to participate in redispatch, they are compensated for all costs occurred and profits forgone. This setup reflects several central European markets as of today, including Germany and Austria.

2.3.1 Spot Market

Spot market. Figure 7 displays the spot market equilibrium. Absent market power, it is profit-maximizing for generators to bid variable cost – the spot market is incentive compatible. All production and consumption is cleared at a uniform price of $P_{Spot} = 50\ €/MWh$. All power stations with variable costs at or below this price are dispatched, which includes 20 GW wind and 20 GW coal capacity in the North. This results in a line flow of 40 GW, which is physically infeasible.

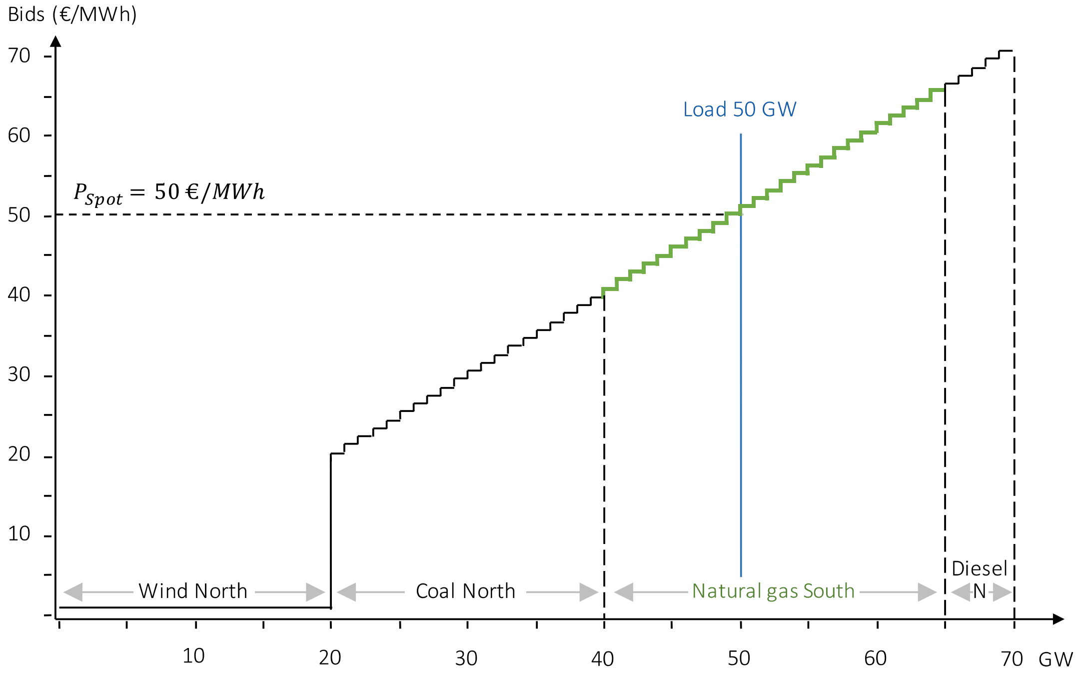

Figure 7. Spot market equilibrium in a regulatory redispatch with cost compensation setting.

2.3.2 Redispatch and Compensation

Redispatch. Following spot market clearing, the system operator redispatches resources to avoid line overload. The selection of plants follows the objective to minimize net redispatch costs. Hence the most expensive 10 GW of coal capacity are redispatched downwards (lowering generation) or "constrained off" while the cheapest idling 10 GW natural gas capacity are redispatched upwards (raising generation) or "constrained on".[6]

Compensation. All redispatched resources are reimbursed for costs incurred and profits forgone relative to the spot market equilibrium. This follows the logic of §13a of Germany's Energy Industry Act that says that the composition should be such that being redispatched "does not favor nor disfavor the market party economically". In the case of upward dispatch, the generator is paid its variable costs. In the case of downward dispatch, generators can keep spot revenues but have to surrender avoided variable cost. In the above example, total redispatch costs amount to EUR 200,000. We assume the system operator possesses perfect knowledge of costs. Figure 8 and Table 4 show redispatch outcomes.

[6] The terminology "(upward/downward) redispatch" can be found in Germany and EU texts as well as parts of the American literature while "constrained on/off plants" is more common in the UK context.

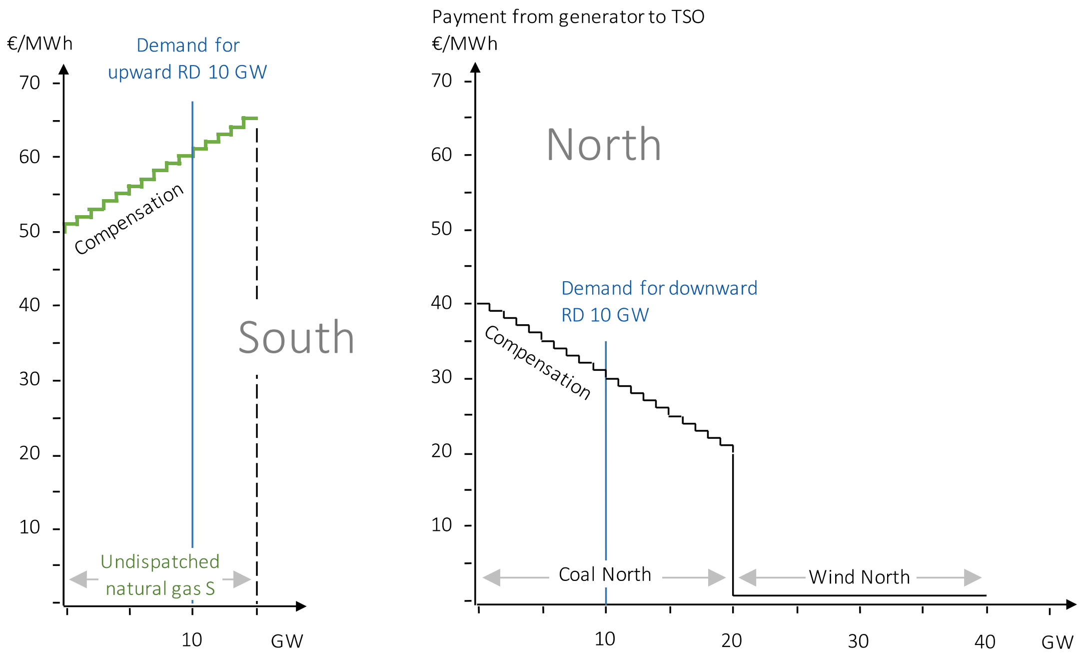

Figure 8. Regulatory redispatch with cost compensation.

Table 4. Outcome of regulatory redispatch.

	North	South
“Price”	Asset-specific	Asset-specific
Redispatch	10 GW coal ↓	10 GW natural gas ↑
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Net redispatch cost	EUR 200,000	

Comparison to nodal pricing. The final physical dispatch is identical to nodal pricing, but the financials differ. Instead of collecting congestion revenue as income, the market operator incurs net costs, which are passed on to consumers. Southern generators earn less and Northerners more than under nodal pricing.

Problems. There are a number of issues with regulatory redispatch based on cost-compensation, including information asymmetry and lack of participation incentives.

Information asymmetry. Regulatory redispatch with cost compensation, of course, requires the system operator to know availability and variable costs, both of which are private information of generators. In the case of thermal power plants, capacity and cost parameters can be reasonably estimated or derived from behavior, e.g. from recent spot bids. However, in the case of hydroelectricity, storage and, demand response, the information asymmetry is much more severe. Estimating the water value of a hydroelectricity plant or the willingness to pay of an industrial consumer is very challenging. Due to this complexity, the latest revision of compensation rules took Germany more than one year (see BDEW 2018b).

Participation incentives. Participants do not earn any profit, so there is no incentive to participate in the first place (hence the legal obligation). In the case of Germany, such obligation concerns only generation and storage assets, not loads. Moreover, small-scale generators and combined heat and power plants are de facto excluded. Without providing participation incentives, system operators are limited in the resources available and may have to resort to inefficient dispatch.

3 Inc-Dec Gaming in Redispatch Markets

After discussing two benchmark market designs, we now turn to redispatch markets. We first introduce the design of such a market and then derive the market equilibrium. We derive the equilibrium for two cases: when producers are unable to anticipate the redispatch market outcomes when bidding in the spot market, and if they are not.

3.1 Setup of the Redispatch Market

Two-tier market design. The power market comprises a zonal spot market that is followed by a nodal redispatch market. Hence, there are two separate markets for electricity that clear for every market time unit. First, the wholesale spot market clears at a zonal level. If the resulting dispatch can be accommodated by the grid, nothing else happens and the redispatch market is not invoked.

Redispatch market. If the network is congested, however, the system operator redispatches generation to resolve the congestion. This is done based on voluntary bids by market actors on a redispatch market; it can be thought of as a procurement auction. The redispatch market is locational, i.e. it has a nodal resolution – like a separate auction at every node. In our example, the system operator buys energy in the South and sells energy in the North, or more precisely, buys the Northern generators out of their contracts to produce. We assume marginal pricing (as opposed to pay-as-bid) in both market stages. The assumption of consecutive markets seems plausible because redispatch requirements can only be determined once the spot market equilibrium is known. For simplicity, we also assume bidding is constrained to integers (whole Euro amounts). Table 5 summarizes the market setup.

Table 5. Setup of the redispatch market.

	Spot market	Redispatch market

	Spot market	Redispatch market
Market time unit	1 hour	1 hour
Sequence	First	Second (after spot gate closure, but before real time)
Geographic granularity	Zonal (1 price)	Nodal (2 prices, North and South)
Pricing rule	Uniform pricing	Uniform pricing

3.2 Redispatch Markets without Anticipation

No-anticipation. In this section, we discuss a redispatch market that is not anticipated by generators when placing bids on the spot market. We believe this is what many proponents of market-based redispatch have in mind. It will turn out, however, that the outcome is not a Nash equilibrium and hence no stable solution.

Solution strategy. As markets are sequential and we assume no anticipation, the markets can be solved sequentially by forward induction. We start solving the spot market and proceed with the redispatch market.

3.2.1 Spot Market

Spot market. As above in the regulatory dispatch example, zonal load is 50 GW and all consumption and production is cleared at a uniform price. Bidding strategies and market outcomes are identical, resulting in congestion that must be resolved with redispatching.

3.2.2 Redispatch Market

Redispatch market. Because of the physical infeasibility of the spot market results, the system operator opens the redispatch market. Figure 9 and Table 6 summarize the market equilibrium.

South. In the South, all plants that are not yet dispatched offer upward redispatching. There is no market power as no supplier is pivotal, hence all suppliers bid their variable costs. As the cheapest 10 GW of natural gas capacity are already dispatched, the bid curve starts at EUR 51 per MWh. The system operator has a demand of 10 GW for upward redispatch. The market clears at a price of $P_{RD}^{S} = 60\ €/MWh$.

North. In the North, power plants are willing to pay the system operator to be redispatched downwards because that saves cost for fuel. The producers in the North essentially buy back energy. It is helpful to think of their bids as a demand curve and the system operator's redispatch quantity as the supply curve. The competitive equilibrium price is $P_{RD}^{N} = 30\ €/MWh$.

As a result, the system operator buys 10 GW in the South at a price of EUR 60 per MWh and receives EUR 30 per MWh for the 10 GW it sells in the North, resulting in net costs of EUR 30 per MWh or EUR 300,000.

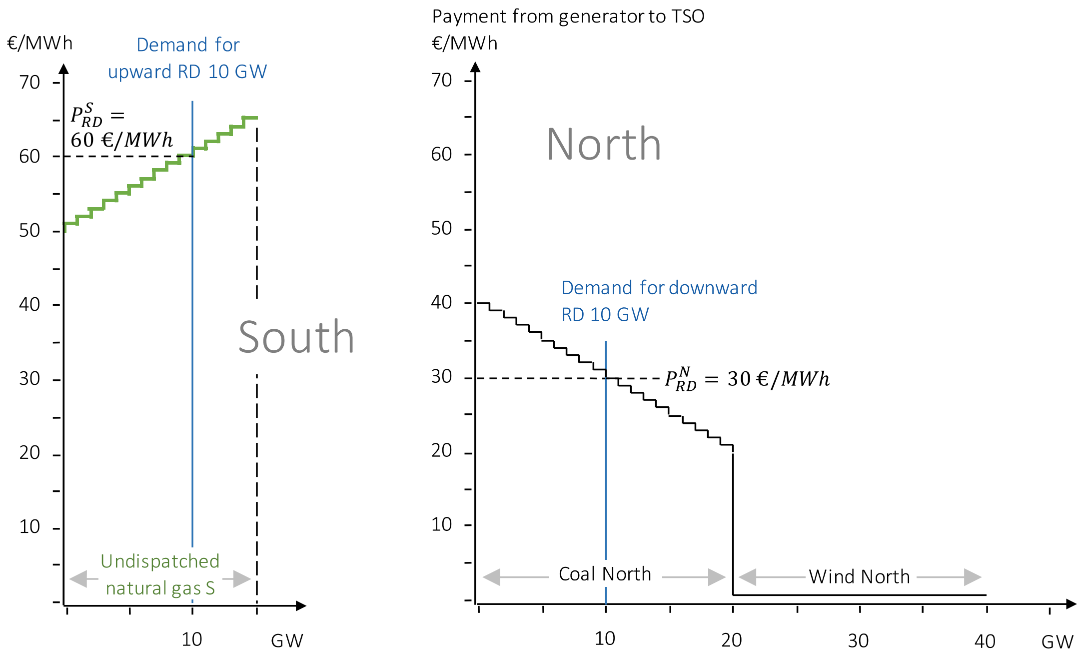

Figure 9. Redispatch market equilibria (without anticipation).

Table 6. Market result of the redispatch market (without anticipation).

	North	South
Price	$P_{RD}^{N} = 30\ €/MWh$	$P_{RD}^{S} = 60\ €/MWh$
Redispatch	10 GW coal ↓	10 GW natural gas ↑
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Net redispatch cost	EUR 30 per MWh = EUR 300,000	

Price setting rules. The prices on the redispatch market resemble those under nodal pricing. We assert that prices on redispatch markets, as a general rule, are identical to locational marginal pricing. In this sense introducing a redispatch market means introducing nodal pricing "through the back door" (on this observation, see also Neon & Consentec 2018).

No Nash equilibrium. We believe this outcome is how what proponents of redispatch markets envisioned. The zonal market works properly and undisturbed, while the additional redispatch market resembles nodal pricing in terms of equilibrium prices and incentives.

However, the crucial assumption behind this outcome is that generators *do not anticipate the redispatch market* when submitting bids to the spot market. However, this is not a Nash equilibrium: some generators in the South sold at a price of EUR 50 per MWh on the spot market. If they had waited for the redispatch market, they could have earned EUR 60 per MWh. Similar incentives exist in the North, as we show subsequently.

Zero foresight. Non-anticipation is plausible if and only if congestion occurs completely unexpectedly. In a situation such as Germany's, where congestion occurs frequently (several lines are congested more than 20% of the time) and that congestion can easily be predicted (see section 0), non-anticipation is a naïve assumption.

3.3 Redispatch Markets with Anticipation

Anticipation. We now assume that generators anticipate the redispatch market outcomes when placing bids on the spot market. In other words, generators factor in that there is a second market in which they can sell – or buy back – electricity when designing their bidding strategy for the spot market.

Solution strategy. We start by assuming redispatch market prices, then solve for equilibrium strategies using backward induction, and finally, check that the assumed prices emerge through forward induction, i.e. that expectations are confirmed. As a starting point, we use the above clearing prices $P_{RD}^{S} = 60\ €/MWh$ and $P_{RD}^{N} = 30\ €/MWh$, respectively.

3.3.1 Spot Market

Bidding strategy in the South. When bidding into the zonal spot market, generators in the South anticipate that they will be able to earn EUR 60 per MWh on the redispatch market. This opportunity cost sets a floor on their willingness to sell: cheap natural gas-fired power plants with variable costs below EUR 60 per MWh will *not* bid variable costs but instead overbid at EUR 60 per MWh. More expensive plants will continue to bid variable cost.

Bidding strategy in the North. In the North, generators anticipate that they will be able to be redispatched down if they pay the system operator a price of EUR 30 per MWh. These producers realize that they will be able to buy back electricity at this price. If they receive a revenue on the spot market that exceeds EUR 30, they will earn a margin. They will earn this margin regardless of their production costs because, in the end, they will not produce – these producers just trade electricity between the two market stages. Consequently, the more expensive coal and diesel plants with variable cost above EUR 30 per MWh issue bids of EUR 30; they underbid. The cheaper wind and coal plants bid variable cost. The spot market is no longer incentive compatible for all market players.

Spot market equilibrium. Table 7 and Figure 10 display bid curves and the resulting spot market equilibrium. No supplier has market power. The market clears at a price of $P_{Spot} = 60\ €/MWh$. All power stations with variable costs below this price are dispatched, which includes all generation in North, even the expensive diesel peakers. 5 GW of generation capacity from the South is dispatched. Because 20 GW of natural gas capacity had bid identical prices, the identity of dispatched plants is undetermined; we assume it is randomly drawn. This may not sound like an equilibrium, but it is: all bidders with bids of 60 €/MWh are indifferent between being dispatched in the spot market or not, because if they are not, they will earn the same price later in the redispatch market. The spot dispatch results in a line flow of 45 GW, hence the dispatch is physically infeasible. Note that the line overload has increased compared to the situation without anticipation.

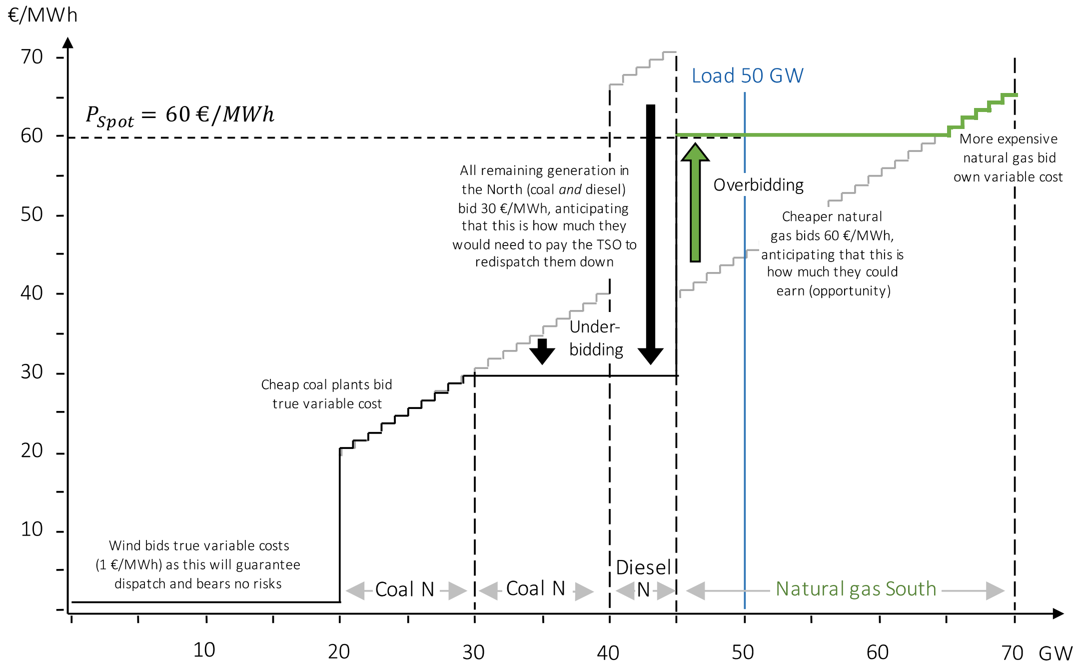

Figure 10. Spot market equilibrium with anticipation of redispatch markets.

Table 7. Market result of the spot market (with anticipation)

	North	South
Price	$P_{Spot} = 60\,€/MWh$	
Dispatch	20 GW wind 20 GW coal 5 GW diesel	5 GW natural gas
Market power	No pivotal suppliers	
Line flow	45 GW (infeasible)	
Congestion rent	-	

Nodal prices determine spot prices. In this specific example the spot market price is identical to the Southern redispatch market's price and thereby *higher* than in the spot price under regulatory redispatch. But this is not a general rule. In the Appendix, we present an otherwise identical example with load reduced to 40 GW in which the spot price will be identical to the Northern redispatch market's price and thereby *lower* than under regulatory redispatch. As a general rule, when the line is congested, spot prices seem to be determined as either one of the nodal prices (North or South). Which of the nodal prices sets the spot market price depends on whether generation in the cheaper node (ignoring transmission constraints) is sufficient to cover total zonal load. If the line is not congested, both nodal prices converge and set the spot price too.

3.3.2 Redispatch Market

Redispatch market. Because of the physical infeasibility of the spot market results, the system operator has to buy 15 GW of redispatch services. All generators bid their true variable costs. Given the redispatch market is the last stage, and we assume plants don't have market power there is no benefit to deviating from variable cost bidding. Figure 11 and Table 8 present the market equilibrium.

Clearing prices. In the South, there is 20 GW of total supply available for upward redispatch and the demand for upward redispatch is 15 GW. Because the identity of the winning bidders in the spot market had been undetermined and hence randomly chosen, different patterns of the supply curve could emerge. However, they all result in a clearing price of $P_{RD}^{S} = 60\ €/MWh$. In the North, the clearing price is $P_{RD}^{N} = 30\ €/MWh$.

An equilibrium. This market outcome is a Nash equilibrium: All expectations, in particular the assumed prices on the redispatch market, turn out to be correct and no actor has an incentive to change their behavior.

This is the inc-dec game. This bidding strategy is what is often called the "increase-decrease game". Power stations in the export-constrained North underbid, increase their output just to later decrease it in the redispatch market. Of course, physical output is not really increased and decreased over time; it is only schedules that change over time. You could say that Northern generators engage in carry trade, selling electricity at a high price to buy it back later for a lower price. In a sense, the Northern generators engage in "asset-backed short selling" – the generator can deliver the initial spot transaction physically but never intends to.

Gaming in the South. In the import-constrained South, generators engage in what you might call "dec-inc" gaming: they overbid, decreasing their scheduled output just to later increase it. Like the Northern generators, the Southern generators simply optimize between two markets, selling their output where it gets the best price. Essentially, both Northern and Southern generators earn profits from arbitrage between the two market stages. The exploitation of this arbitrage opportunity does not require market power nor collusion (not even implicit collusion): in our model, all three markets are perfectly competitive and producers act individually.

Consequences of gaming. Compared to the case without anticipation, the prices on the redispatch market are identical, but the redispatch volume is larger. Hence, the net cost of redispatching increases to EUR 450,000. While having zero impact on the final physical dispatch, gaming has important consequences otherwise: line overload is aggravated and generators extract windfall profits. These and further implications we discuss in detail in the following section.

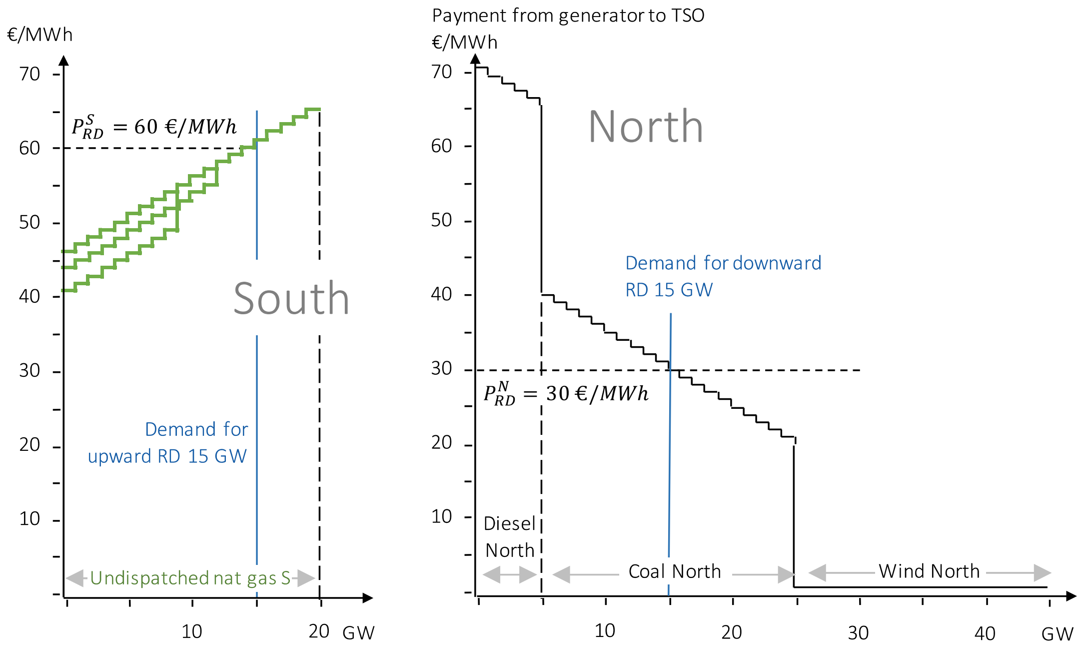

Figure 11. Redispatch market equilibria (with anticipation).

Table 8. Market result of the redispatch market (with anticipation).

	North	South
Price	$P_{RD}^{N} = -30\,€/MWh$	$P_{RD}^{S} = 60\,€/MWh$
Redispatch	10 GW coal + 5 GW diesel ↓	15 GW natural gas ↑
Market power	No pivotal suppliers	No pivotal suppliers
Line flow	30 GW (feasible)	
Net redispatch cost	EUR 30 per MWh = EUR 450,000	

3.4 Equilibria

Nash equilibria. The outcomes of the nodal pricing, regulatory redispatch and redispatch markets with anticipation cases all represent Nash equilibria. In these cases, there are no actors who, in light of the market equilibrium, would prefer to alter their bidding strategy. The outcome of the redispatch market without anticipation is not a Nash equilibrium. In light of the redispatch market outcome, several bids in the spot market turn out to be suboptimal. *Ex post*, agents would prefer their spot market bids to reflect the opportunity provided by the redispatch market. In other words, the case of no anticipation is not a stable equilibrium. It might occur briefly (say, for a few weeks) until market parties have learned how to optimize their bids or if congestion is difficult to anticipate. Given that no-anticipation is neither a stable equilibrium nor something over which policy makers have control, the policy choice really narrows down to three options: nodal pricing, regulatory redispatch with cost compensation, or redispatch markets *assuming* anticipation.

Clearing prices. Table 9 summarizes the market-clearing prices across the market designs. Regulatory redispatch can be understood as discriminatory pricing of first degree (individual prices for each producers), whereas nodal pricing and redispatch markets yield different prices for each node but not across producers connected to the same node.

Table 9. Market-clearing prices.

(EUR per MWh)	Nodal pricing	Regulatory redispatch	Redispatch market (with anticipation)
Clearing price for load (€/MWh)	$P^S_{Nodal} = 60$	$P_{Spot} = 50$	$P_{Spot} = 60$
Clearing price for generation (€/MWh)	$P^S_{Nodal} = 60$ $P^N_{Nodal} = 30$	$P_{Spot} = 50$ Asset-specific cost compensation	$P_{Spot} = 60$ $P^S_{RD} = 60$ $P^N_{RD} = 30$

Resource allocation and welfare. In our model, the final physical dispatch of power plants is identical across designs due to our initial assumptions. We assumed no information asymmetries between the system operator and the generators, which would impact regulatory redispatch. We also assumed no start-up and ramping constraints, which would turn timing and gate closure into relevant factors. Finally, we assumed perfect competition. If there were locational market power this would also impact dispatch in nodal pricing and redispatch markets with anticipation. Consumption is identical across designs, too. As a consequence, economic welfare, if narrowly defined as the sum of producer and consumer rents (see also Table 11 in Section 4.2), is identical across all three cases. However, in the following section we show that gaming will have broader welfare implications.

4 Implications and Consequences

In this section, we discuss the problematic consequences of strategic inc-dec bidding: congestion is aggravated, producers extract windfall profits, financial markets are distorted, and perverse investment incentives emerge.

4.1 Congestion is Aggravated

Making congestion worse. The existence – or more precisely, the anticipation – of a redispatch market leads market parties to submit spot market bids that *increase* the level of congestion. In our example, the line overload increased from 10 GW (regulatory redispatch) to 15 GW (redispatch markets with anticipation) as a result of the spot market plant dispatch, see Table 10.

Table 10. Clearing prices and rents.

	Nodal pricing	Regulatory redispatch	Redispatch market (with anticipation)
Redispatch volume	0 GW	10 GW	15 GW

Systematic pattern. This is not an artefact of the example but a systematic pattern. Parties located in scarcity regions are incentivized to withhold capacity from the spot market by bidding above marginal cost to then benefit from high prices for upward redispatch, thereby aggravating congestion. In turn, generators in oversupply regions are incentivized to overproduce by bidding below marginal costs, again aggravating congestion.

"Virtual congestion". The kind-of additional congestion resulting in the spot market from the incentives of redispatch markets can be considered "virtual" congestion, as it disappears again after redispatch. However, it may cause not only windfall profits but also operational challenges. System operators get a systematically biased picture of actual system conditions by studying the spot market outcome. Since a redispatch market can only be opened *after* gate closure of any zonal trading (see also Section 6.4), system operators will need to implement large volumes of redispatch quickly, which is challenging and may jeopardize operational security.

Aggravating, not creating congestion. In our example, strategic bidding aggravates existing congestion. However, producers would not benefit from withholding capacity from the spot market to *create* congestion in an otherwise uncongested situation. In that case, the price generators obtain on the redispatch market would not be above the spot market price but possibly below. Therefore, generators have no incentive to engage in the inc-dec game if the "ungamed" spot market is congestion-free. This would, however, change under market power (see section 6.1).

4.2 Windfall Profits

Rents. In Table 11 we summarize the distribution of rents among consumers and producers for the single hour that we study. There are two channels through which consumers pay for electricity: the price at which demand is cleared on the market and the cost or revenue of congestion management, which we assume is passed on to consumers through grid fees. In Table 11, these two channels are rows (1) and (2), respectively. The sum of (1) and (2) corresponds to total consumer expenditure (3) and also total generator revenues. Since final physical dispatch is identical across market designs, variable generation costs must also be identical (4), but generators' profits differ (5). In this example, shifting from regulatory to redispatch markets increases producer profits by 50%.[7]

[7] Recall that we have modeled a single hour. If you multiply these numbers by 8760 hours per year to get to annualized values, redispatch markets increases profits by EUR 7bn. Of course, the stylized nature of our model precludes drawing quantitative conclusions; however, these values are useful to estimate the economic importance of these policies.

Table 11. Rent distribution and costs for the single hour modeled.

(EUR)	Nodal pricing	Regulatory redispatch	Redispatch market (with anticipation)
Amount paid by loads for energy (1)	3 000 000	2 500 000	3 000 000
Congestion management cost (2)	-900 000 (congestion rent)	200 000 (redispatch cost)	450 000 (redispatch cost)
Total consumer expenditure = Revenues for generators (3=1+2)	2 100 000	2 700 000	3 450 000
Variable generation cost (4)	1 285 000	1 285 000	1 285 000
Total Producer rents (5=3-4)	815 000	1 415 000	2 165 000
Northern generators	625,000	1,370,000	1,975,000
Southern generators	190,000	45,000	190,000

4.3 Financial Markets

Today, the spot price is the price at which supply and demand are cleared; naturally, it serves as the basis for most future contracts.

Loss of underlying. As we show in our example, in times of congestion, the spot price converges to either one of the nodal prices. All consumption and generation are cleared at that nodal price. The spot market loses its meaning as a "lead" or "reference" market. This has direct implications for financial markets that usually use the spot market as an basis for future contracts. Generators who expect to earn a higher (nodal) price than the zonal spot price will not be willing to hedge at the expected spot price. Regulators have addressed this issue in most nodal pricing systems by introducing of trading hubs and financial transmission rights, both of which are lacking in all proposals for redispatch markets that we are aware of.

4.4 Investment Incentives

A rationale for redispatch markets. One argument in favor of market-based redispatch is that it attracts new entrants. This could be those existing assets that are not obliged to participate in regulatory redispatch such as small-scale or renewable generation, combined heat and power plants, storage assets, or loads. On the other hand, this could also be investment in new power generation capacity. The hope is, of course, to attract investment where it makes sense from a grid perspective: generation in scarcity regions and consumption in oversupply regions. At first glance, this expectation seems warranted. The equilibrium prices on redispatch markets, as we have shown, resemble locational marginal prices. So, if redispatch markets are comparable to nodal pricing as a credible investment signal, one might expect a local investment response. However, inc-dec gaming creates perverse investment incentives.

Locational rents. In our single-hour example, investment incentives in the South are as expected. To see this, compare the clearing prices for generation in three cases:

- Under regulatory redispatch, generation is cleared at the spot price of $P_{Spot} = 50€/MWh$, so any generation investment with levelized cost of electricity (LCOE) up to EUR 50 per MWh would be profitable.
- Under nodal pricing, the clearing price is $P^S_{Nodal} = 60€/MWh$, making additional investments feasible.
- Under redispatch markets, the relevant price is $P^S_{RD} = 60€/MWh$.

Perverse investment incentives. However, our model shows that redispatch markets also creates perverse incentives – it encourages investment in places where they are not needed. The arbitrage opportunity implies that it may be profitable to invest in the North only (or mainly) to play the inc-dec game. To see this, compare the incentives for generation in three cases:

- Under nodal pricing, the clearing price is $P^N_{Nodal} = 30€/MWh$. Only investments with an LCOE below EUR 30 are profitable.
- Under regulatory redispatch, generation is cleared at the spot price of $P_{Spot} = 50€/MWh$, so, compared to nodal price, there are incentives for over-investments.
- Under redispatch markets, two types of investments are profitable: plants with LCOE below $P^N_{RD} = 30€/MWh$ (plant investments with the intent to produce electricity), but also investments that are either profitable due to the higher spot price of $P_{Spot} = 60€/MWh$ or purely exploit the arbitrage opportunity (plant investments without intent to produce anything).

Ghost plants. The latter encourages investors to install low fixed-cost / high variable-cost generation (think of mothballed plants or retired ship engines) that have the sole purpose to participate in the inc-dec game. Such “ghost generators” would be a profitable investment as long as the per-hour fixed costs are smaller than the arbitrage earned per hour. Variable costs do not matter, as these plants will never generate power.

Ghost consumers. The same perverse incentive exists on the load side in the South. Investors are encouraged to connect loads for the sole purpose to engage in gaming. Such “ghost loads” might be mothballed industrial consumers, loads that do not fully utilize the capacity of their grid connection, or even dedicated electricity-consuming devices such as large water heaters. Keep in mind that they will never physically consume electricity, hence volumetric taxes and fees levied on consumption are not an issue.

Network over-investment. The grid operator also faces misleading investment signals. As redispatch volumes and costs increase significantly with market-based redispatch, they might be taken as an indicator of an overloaded grid by both the grid operator and the regulator. These signals could trigger the system operator to make larger network investments than otherwise.

5 Pre-conditions and Requirements

In this section we discuss the necessary conditions for inc-dec bidding to emerge as a dominant strategy. In particular, we point out that gaming is *not* a consequence of market power.

Meshed networks. Our model shows that inc-dec bidding does not require meshed networks. If networks comprise more than two nodes and are meshed, our core result – that redispatch markets incentivize gaming, in turn aggravating constraints and redistributing rents – remains robust, as market parties in scarcity regions still face incentives to overbid and in oversupply regions to underbid.

5.1 No Market Power Needed

Defining market power. Economically speaking, actors have market power if they can affect the market-clearing price with their production decisions. In practice, the European Commissions assumes markets are subject to market power if any individual suppliers has a market share of greater than 40%.[8] In electricity markets, market power is often assessed by determining if any individual generator was pivotal, i.e. if any individual generator was required to supply demand.

No market power. In our model, none of the suppliers are pivotal in any situation. Every generator acted as an atomistic price-taker, both on the spot market as well as on the subsequent redispatch market. In the South, each of the 25 generators has a market share of 4%, implying an Herfindahl-Hirschman Index of 400, way below all thresholds of concentrated markets. (We chose to use discrete capacity for ease of presentation. You could assume a continuous range of infinitely small producers without changing the results.) Firms do not collude (cooperate), either. This is a core result of our model: the inc-dec bidding strategy does not require market power nor collusion; it can be exploited by atomistic small market participants. Since market power is not required for the inc-dec bidding strategy, it can, conversely, also not be avoided with sufficient competition.

5.2 Predicting Network Congestion

The risk of inc-dec gaming. Absent perfect foresight, gaming carries a risk. If firms anticipate redispatch prices incorrectly, strategic bidding may result in losses or forgone profits. To consider the risk they are facing, assume suppliers bid in the spot market according to expected prices at the redispatch market of $P_{RD}^{S} = 60\ €/MWh$ and $P_{RD}^{N} = 30\ €/MWh$. In contrast to their expectations, assume that congestion does not materialize. For example, system operators could avoid congestion by using dynamic line rating or technical switching

[8] http://ec.europa.eu/competition/antitrust/procedures_102_en.html

operations elsewhere in the network to temporarily increase the line capacity. In this case, the Northern diesel generators who underbid in the spot market actually have to produce, taking a loss. Also, some Southern generators (those that were not randomly chosen to generate) forgo profits, a consequence of bidding above variable costs.

No perfect foresight required. If market actors are not certain whether congestion will occur, but are able to construct a possibility tree of possible outcomes, their bids will still be influenced by the possibility of gaming, even if not to the degree perfect foresight would enable. It would be rational to follow a strategy that yields the highest expected return.

5.2.1 Producers Can Predict Congestion

Prediction possible. As we argue in this section, we believe in the case of Germany, reasonably accurate predictions are possible and congestion can be regarded as at least to some degree structural. If congestion is structural[9], correct anticipation of redispatch will be the norm, rather than the exception.

Network model. When engaging in inc-dec bidding under perfect foresight, the dominant strategy is to bid redispatch clearing prices. Prices on the redispatch market coincide with prices in a nodal pricing system. To derive a profit-maximizing bid to the spot market, generators thus need to have a forecast of nodal prices. Such a forecast requires a load flow model at the granularity of individual lines and substations. These models are widely available, inexpensive, and can be calibrated using historic redispatch data.

Model availability. Researchers maintain European load flow models, including open source models such as ELMOD or PyPSA[10]. Commercial software to solve load flow models is a standard product and readily available. These models should be able to forecast grid congestion rather accurately, and hour-by-hour clearing of electricity markets should give analysis plenty of opportunity to calibrate and learn. Even today in the absence of redispatch markets, consultancy companies are offering forecasts of grid congestion to German market participants, mostly to predict renewable energy curtailment.[11]

Network operator congestion forecasts. In the current redispatch system, some grid operators announce warnings of likely redispatch even before the day-ahead. For example, the

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[9] Grid congestion is considered structural if it does not only occur sporadically but "is predictable, is geographically stable over time, and is frequently reoccurring under normal power system conditions" (as the draft EU Electricity Market Regulation defines it: https://eur-lex.europa.eu/proce- du-re/EN/2016_379).

[10] A list of open power market models is available at https://wiki.openmod-initiative.org/wiki/Open_Models

[11] Meteomatics EinsMan Forecasts (see http://meteomatics.com/display/NEWS/2017/02/07/Portfolio-individual+EISMAN-Forecasts), UBIMET EinsMan Prognose (see https://www.ubimet.com/en/services/ einsman-solutions/ as well as https://patents.google.com/patent/DE102017101265A1/en).

Swiss TSO Swissgrid publishes "congestion warnings" two days before real time.[12] A Northern German DSO, Schleswig-Holstein Netz AG, on the other hand publishes a list with wind speeds[13] at which grid related curtailment is to be expected at any given substation, implying a strong correlation between downward redispatch and wind speeds.

5.2.2 Econometric Prediction

Regression model. One can even predict congestion using simple econometrics. As a proof of concept, we have set up a regression model to predict hour-by-hour redispatch in Germany using regressors such as renewable generation, load, and lagged redispatch. Table 12 summarizes the model specification and data sources. All data used are in hourly granularity and taken from public sources.

Table 12. Congestion regression model specification

	Variables	Data Sources
Dependent variable	Redispatch volume (MW) as the sum of up and downward redispatch.	Own calculation based on Netztransparenz.de
Independent variables	Solar generation forecast in each German control area (MW)	ENTSO-E Transparency Platform
	Wind generation forecast in each German control area (MW)	ENTSO-E Transparency Platform
	Load forecast in each German control area and in CH, FR, AT (MW)	ENTSO-E Transparency Platform
	Year dummies	-
	EU ETS Emission Allowance Prices (EUA)	EIKON Data Service
	24h lagged redispatch volume	Own calculation based on Netztransparenz.de

Regression results. We use an Ordinary Least Squares regression model on data from the years 2015-18 (21,000 observations in total). Maybe most importantly in the context of this paper, the regression yields an adjusted R^2 of 48%. In other words, even with quite limited resources and a straightforward regression model, we can predict hour-by-hour redispatch volumes fairly well.

[12] Swissgrid, "Massnahmen von Swissgrid bei Gefährdung des stabilen Netzbetriebs": https://www.swissgrid.ch/dam/swissgrid/customers/topics/legal-system/operational-contracts/1/operating-agreement-PPO-appendix-5-V3-0-de.pdf

[13] Schleswig-Holstein Netz AG, Einspeisemanagementprognose anhand von Windmessungen, https://www.sh-netz.com/content/dam/revu-global/sh-netz/Documents/Energie_einspeisen/Einspeisemanagement/Windprognose_Einsatzberichte.pdf

Coefficients. We report our coefficient estimates in Table 13. Of the 23 regressors, all but three are statistically significant at the 5% level. Usually, the German grid is congested between the Northeast and the Southwest, especially in high wind / high load situations. Most signs are as expected: generation in the North or East, such as offshore wind or 50 Hertz onshore wind, tends to increase redispatch volume, while generation in the Southwest (Transnet) reduces redispatch. Electricity consumption in the Southwest (Transnet) as well as South of German borders tend to increase redispatch. The other two control areas (Amprion and TenneT) often lie on both side of the bottleneck, hence the small or insignificant impact of load and generation. Only one coefficient comes at a surprise: we had expected load in the 50 Hertz area to reduce redispatch, but the coefficient is positive. The size of certain coefficients is economically significant. For example, the estimate of 50 Hertz wind onshore implies a marginal curtailment rate of 5.5% (half of 11%, since our dependent variable is the sum of up and down redispatch).

Table 13. Coefficient estimate

Variable	Expectation	Coefficient	p-value
North / Northeast (upstream of constraint)			
Tennet Wind offshore	+	0.05	0.00
50 Hertz Wind offshore	+	0.76	0.00
50 Hertz Solar	+	-0.04	0.07
50 Hertz Wind onshore	+	0.11	0.00
50 Hertz Load	-	0.02	0.04
South / Southwest (downstream of constraint)			
Transnet Solar	-	-0.13	0.00
Transnet Wind onshore	-	-0.35	0.00
Transnet Load	+	0.14	0.00
Load CH	+	0.16	0.00
Load FR	+	0.01	0.00
Load AT	+	0.17	0.00
Cross-cutting			
Amprion Solar	0	-0.03	0.24
Amprion Wind onshore	0	-0.11	0.00
Amprion Load	0	0.00	0.79
Tennet Solar	0	0.10	0.00
Tennet Wind onshore	0	0.11	0.00
Tennet Load	0	-0.10	0.00
Year dummies			
2016	0	-429.95	0.00
2017	0	-153.07	0.00
2018	0	-829.49	0.00
Other variables			
EUA price	0	49.97	0.00
Redispatch(t-24)	+	0.28	0.00
Constant	0	-2456.64	0.00

Robustness. In the appendix, we list the results of another model specification that includes all forecasts squared without changing results qualitatively. Adjusted R^2 is slightly elevated to 51%.

Comparison to the literature. Comparing to the literature, Staudt et al. (2018) show that using an artificial neural network approach, congestion on a line can be predicted with a precision of 70%, based on data for the German TSO 50Hertz for 2015-2017. This shows that with more advanced modeling approaches compared to the one we use, even better prediction of congestion is possible. This underlines that congestion can be anticipated by market participants.

6 More Gaming

Our model does not capture all possibilities to game a redispatch market. In this section we discuss four ways how firms can extract further rents: exploiting market power, participation of loads in gaming, pure financial arbitrage, and a riskless strategy that can be played if a firm holds assets on both sides of the constraint.

6.1 Effects of Market Power

An example with locational market power. In our model, firms never have market power. Now consider the case of market power. To this end, we assume only 20 GW (instead of 25 GW) of natural gas-fired power generation to be installed in the South – the 5 GW of plants with highest marginal cost disappear. We also assume that electricity demand becomes perfectly price elastic at a backstop price of EUR 10,000 per MWh. All other assumptions remain as above.

Outcomes. Some outcomes remain unchanged while others will differ dramatically.

- Under regulatory redispatch, nothing changes: the zonal market equilibrium as well as redispatch remains the same.
- Under nodal pricing nothing changes in the North, while in the South all generators become pivotal, as overall capacity is just sufficient to supply load. Generators will be able to increase the price to EUR 10,000 per MWh, the price at which demand becomes elastic.
- Similarly, in redispatch markets, nothing changes in the Northern redispatch market, while in the Southern market generators will be able to increase the price to EUR 10,000 per MWh. Consequently, they will also bid that amount into the spot market. Hence, the spot market clearing price increases from EUR 60 per MWh to EUR 10,000 per MWh! This yields windfall profits not only for Southern but also for Northern power plants.

Further realism. Of course, the ability to exploit local market power depends on the elasticity of the residual demand function at this node. A more rigorous assessment of market power would need to consider that electricity demand is likely to be (somewhat) elastic at lower prices and that more generation capacity is available that can be used to relieve congestion. However, some of that capacity will be located at different nodes that have a lower load flow sensitivity on the congested line.

Redispatch markets vs. nodal pricing. Many authors have observed that zonal and nodal pricing are equivalent in the possibility of firms to exercise locational market power (if they have any), for example Harvey & Hogan (2001). What these authors really say is that nodal pricing and redispatch market are equivalent in that sense. In essence, regulatory redispatch is a way of regulating locational market power, among other things.

6.2 Demand Participation

Demand participation. In our model, we assumed demand was exogenous and perfectly price inelastic. In fact, the demand side can also follow an inc-dec strategy, further aggravating the problem. However, such gaming is more plausible for large, metered consumers (e.g., energy-intensive industry).

North. Consider an industrial load connected to the North with a true willingness to pay of EUR 200 per MWh. Anticipating a price on the local redispatch market of EUR 30 per MWh, the load will place a bid of that amount, effectively "withholding demand" on the spot market. This will further aggravate congestion, increasing the need to redispatch. On the redispatch market, the load will be able to buy electricity for EUR 30 per MWh.

South. Now consider an industrial load connected to the South that has a willingness to pay of zero, say, because the facility is closed during the holidays. In the above example, there is no incentive to game the market, because the price in the second market stage is identical to the first stage. However, it is straightforward to construct an example of a different hour with reduced system-wide demand of 40 GW (see Appendix). In that situation, the market-clearing spot price will be EUR 35 per MWh, followed by a Southern redispatch prices of EUR 55 per MWh. In that situation, there is an incentive for arbitrage: the load would "pretend to produce", buying electricity for EUR 35 per MWh on the spot market and sell it back to the system operator for EUR 55 per MWh. This behavior also aggravates congestion.

6.3 Financial Arbitrage

Pure financial arbitrage. In principle, one does not need to own physical assets to harvest the arbitrage opportunities arising from the two market stages. Any financial trader could take positions on the spot market to close them on the redispatch market. However, such "pure" financial arbitrage trading – not being backed by physical assets – could be prevented relatively easily through regulation. For example, system operators could make it a requirement in connection agreements that actors have to be able to physically fulfill any spot schedule. Preventing asset-based arbitrage (of the type presented in our model), however, is very difficult.

6.4 Riskless Arbitrage with Parallel Markets

Parallel redispatch and spot markets. In our model, we have assumed that the redispatch market opens only after gate closure of the spot market. If, in contrast, redispatch markets operate in parallel to spot markets, asset owners could benefit from arbitrage without facing risk.

Early gate-closure is costly. Opening the redispatch market after spot closure (as we have assumed in the model) comes at a price, however, because earlier gate closure times reduce short-to-real time trading options for market participants. In the German market, trading is currently possible up to 15 minutes before real-time. This is especially important to enable market participants to balance e.g. deviations of variable renewable energy output, but also short-term changes to demand by trading on the zonal intraday market. Redispatch, on the other hand, is currently carried out in parallel to markets (as late as possible but as early as necessary), with lead-time often multiple hours up to days ahead, depending on the start-up times of power plants to be re-dispatched. To avoid the riskless type of inc-dec arbitrage, this concurrency of intraday and redispatch markets has to be avoided. This can be done only by shifting the zonal intraday market's gate-closure time to an earlier point in time, as it seems impossible to manage all (and even aggravated) redispatch in the last 15 minutes before real time, the current gate-closure of German and other European intraday markets.

6.5 Riskless Arbitrage with Multiple Assets

Reporting strategic schedules. In our example above, we show inc-dec gaming entirely through market transactions. However, there are even easier ways of obtaining windfall profits from redispatch markets if either a single firm owns plants on both sides of the constraint or a firm is able to contract with companies on the other side of the constraint. After markets close (and, preliminarily, also in parallel) generators have to report to the system operator which power plants they plan to operate to fulfill their market-based and over-the-counter production obligations. They can use these schedules to engage in the inc-dec strategy.

Zero-risk gaming with two assets. If a firm owns both low variable-cost Southern plants as well as the high variable cost Northern plants, then it can play the inc-dec game at no risk. In the first version of schedules it sends to the system operator, it would report production from the high-cost Northern plants and no production from its low-cost Southern plants. If the system operator then opens redispatch markets to reconcile schedules with transport possibilities, the firm profits by reducing schedules in the North for a low redispatch price (30 EUR/MWh in the example) and increasing schedules in the South for a high redispatch price (60 EUR/MWh). If, however, there is no redispatch market (e.g. because the grid operator has managed to increase transport capacity of the grid through switching operations), the firm could simply report new schedules to the system operator to announce that it will produce with its cheaper Southern plants instead of the Northern plants.

7 Preventing Gaming

Preventing inc-dec bidding is not trivial. In this section we show that pricing rules such as pay-as-bid pricing do not prevent gaming, and that using regulatory redispatch as a fallback does not prevent it, either. We argue that inc-dec bidding is a lawful strategy that cannot be prevented through competition law.

7.1 Competition Law

Competition law. Inc-Dec gaming does not require market power nor collusion. Therefore, it seems unlikely that this bidding strategy violates competition law or market manipulation legislation. It is also unlikely to violate connection agreements. It is a legitimate, rational strategy that essentially means simply to price in opportunity costs.

Pricing in opportunity costs. The redispatch market is comparable to the balancing market in the sense that both markets represent opportunity costs that rational firms factor in when bidding on the spot market. A firm that expects to earn EUR X per MWh on the balancing market will be unwilling to sell electricity below that price on the spot market, regardless of its own variable cost. Similarly, anticipating a redispatch market, agents “withhold capacity” from the spot market in the same way they “withhold capacity” to supply the balancing market. In both cases, this seems to be a valid and lawful optimization strategy across markets rather than abusive behavior or market manipulation. The only difference is that in the case of redispatch markets, the market design does not incentivize a system optimal choice but instead one that aggravates the initial problem (congestion).

Preventing gaming. Being legitimate behavior, inc-dec bidding cannot be simply penalized, even if it can be detected.

7.2 Pricing Rules in the Redispatch Market

Pay-as-bid. Many proposed and existing redispatch markets use the pay-as-bid pricing rule. This stands in contrast to our model where we assumed marginal pricing (pay-as-cleared). Under perfect foresight both pricing rules yield identical outcomes. Under pay-as-bid, infra-marginal bidders will simply bid the variable cost of the marginal plant, instead of their own variable costs. Under imperfect information market participants would try to forecast the clearing price and set bids close to that price. As a means to prevent inc-dec gaming, pay-as-bid pricing is ineffective.

Constraint to bid same in both markets. A constraint that could, at first glance, be thought of curbing inc-dec gaming is that the regulator imposes on market parties to bid the same price into both the spot and the redispatch market. Even though our example above allowed producers to bid independently in each market, our results do not depend on that assumption. Market parties can bid exactly the same in both markets without changing the market outcome (quantities, clearing prices, profits). Imagine in the redispatch markets (with anticipation, Figure 11) producers do not bid their marginal cost but instead bid exactly the same as they have bid into the spot market (Figure 10). This would still result in the same redispatch market equilibrium. It is therefore not possible to curb inc-dec gaming by imposing such a constraint.

7.3 Regulatory Redispatch as Backstop

Markets for some. Many proposals for redispatch markets suggest leaving regulatory redispatch with cost compensation in place for those actors that are obliged to participate (typically large conventional plants) while introducing voluntary markets for all other actors, in particular loads. Based on initial economic intuition, this proposal appears to strictly improve welfare: producers will only participate if they can receive a net benefit. Furthermore, the system operator can use regulatory redispatch as a backstop for markets.

Inc-dec gaming prevails. However, this line of thinking neglects gaming. Even if it is only loads that face an incentive to game (recall 6.2), their strategic bidding will aggravate congestion. Again, the fallacy is to assume that spot market results remain unaffected by introducing redispatch markets. They will not. The small-scale plants and loads that can participate face an incentive to adjust their spot market behavior to incorporate opportunities on the redispatch market, aggravating congestion.

7.4 Regulating the Redispatch Market

Stopping gaming through regulation. To avoid the incentives for overbidding and underbidding on the spot market, one would need to remove any predictable profit opportunity on the redispatch market. One way to do this is to require a pay-as-bid rule with monitored bids that correspond to marginal costs. This would then resemble regulatory redispatch in all aspects but the name.

8 Conclusions

Strategic bidding. In this paper, we studied hybrid electricity markets that combine a zonal spot market with a nodal redispatch market. We show that if market actors – generators, storage owners, and loads, possibly even financial traders – are reasonably accurate at anticipating the outcome of the redispatch market, they will factor in this profit opportunity when designing a bidding strategy. It is then no longer a dominant strategy to bid variable cost, but to underbid (in oversupply regions) or overbid (in scarcity regions). Such strategic bidding is often called inc-dec gaming.

The consequences of inc-dec gaming. Inc-dec gaming has a number of problematic consequences. In particular, it:

- aggravates congestion and hence increases redispatch volumes,
- creates windfall profits and redistributes rents from rate payers,
- causes financial markets to decouple from spot markets, and
- creates perverse investment incentives.

Inconsistent market design. Despite what many people believe, it is *not* market power that ultimately drives inc-dec gaming. In our model, all parties act perfectly competitively, and yet we are able to show that gaming is the dominant strategy. At the root of the problem is inconsistent market design: combining a regional with a locational market yields undue arbitrage opportunities that rational firms exploit.

Mitigating gaming. Inc-dec gaming is difficult to mitigate. It does not require any market power and therefore is unlikely to violate competition law in the first place. Also, as we have shown, increased competition is nothing that will prevent gaming: it is not the case that competition levels out price differences across market stages. Using pay-as-bid (instead of uniform) pricing in redispatch markets will not stop gaming. Introducing redispatch markets for new actors (say, consumers) while keeping existing regulatory redispatch in place will do damage, too.

A bad type of nodal pricing. If congestion is predictable, introducing redispatch markets means *de facto* introducing nodal pricing – but a dysfunctional and costly type of nodal pricing: a proper institutional framework is missing (central dispatch, adequate market oversight, financial transmission rights, and more), and arbitrage trade allows market parties to extract windfall profits.

Consistent policy options. We show that electricity market design must be consistent. We see only two options. The first is to stick to bidding zones and relieve congestion within the zones through regulatory redispatch with cost compensation. This approach will minimize arbitrage opportunities to the utmost degree possible. However, this approach comes at the cost of lacking locational incentives. The other option is to introduce proper locational marginal pricing. Hybrid solutions – combining zonal spot markets with locational markets for redispatch – seem doomed to fail.

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Appendix: Reduced Load

The following figures depict the Nash equilibrium in spot and redispatch markets with anticipation if the level of load is reduced to 40 GW. At this level, the spot price converges to the nodal price of the Northern node. Changes are highlighted.

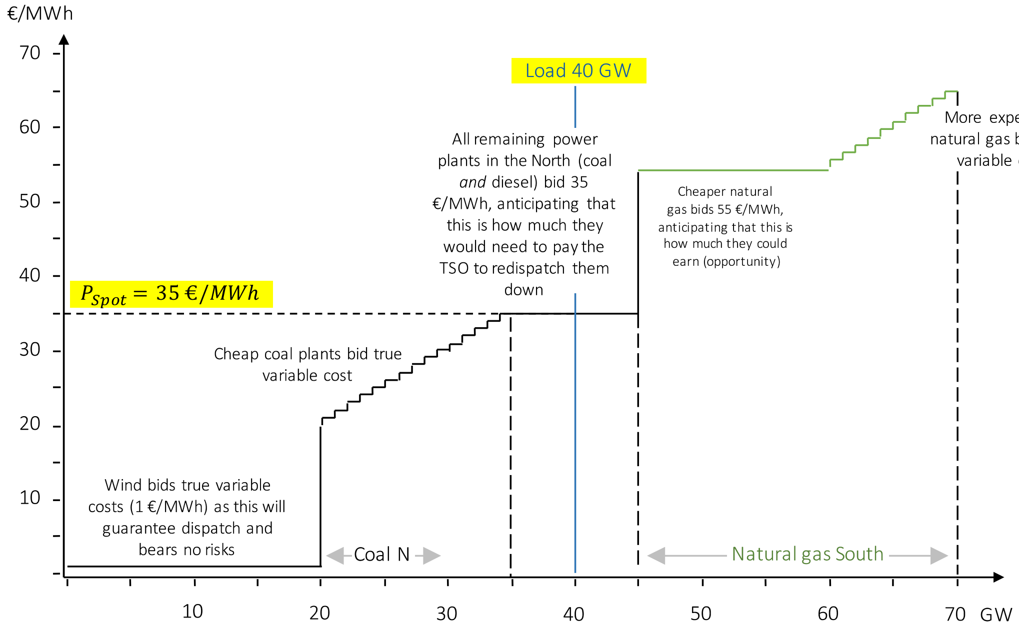

Figure 12. Spot market equilibrium (with anticipation).

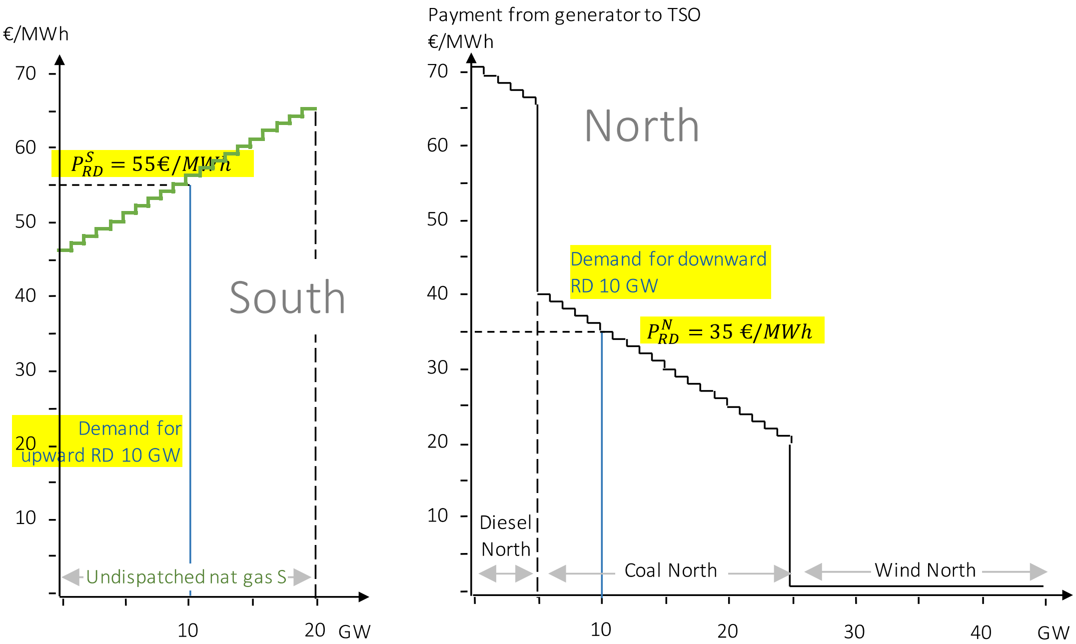

Figure 13. Redispatch market equilibria (with anticipation).

Appendix: Additional Regression Results

Table 14 shows results for a regression (in addition to that in section 5.2.2) that adds squared terms of all wind, solar and load time series. Using this specification, R^2 and adjusted R^2 both increase to 51%. The coefficients can, however, no longer be interpreted as intuitively as in the simple OLS regression, as the actual direction of the effect of an exogenous variable can only be determined by the joint effect of the linear and squared terms.

Table 14: Results for redispatch regression with squared terms

Variable	Coefficient	p-value
North / Northeast (upstream of constraint)		
50 Hertz Solar	-0.22	0.00
50 Hertz Solar Squared	3.0E-05	0.00
50 Hertz Load	0.24	0.00
50 Hertz Load Squared	-1.3E-05	0.00
50 Hertz Wind offshore	-0.60	0.00
50 Hertz Wind offshore Squared	2.1E-03	0.00
50 Hertz Wind onshore	0.10	0.00
50 Hertz Wind onshore Squared	1.6E-06	0.15
Tennet Wind offshore	-0.08	0.02
Tennet Wind offshore Squared	3.6E-05	0.00
South / Southwest (downstream of constraint)		
Load AT	-0.28	0.00
Load AT Squared	3.1E-05	0.00
Load CH	-0.12	0.37
Load CH Squared	1.6E-05	0.08
Load FR	-0.08	0.00
Load FR Squared	8.2E-07	0.00
Transnet Load	0.36	0.00
Transnet Load Squared	-1.5E-05	0.01
Transnet Solar	-0.13	0.12
Transnet Solar Squared	1.0E-05	0.62
Transnet Wind onshore	0.07	0.57
Transnet Wind onshore Squared	-3.5E-04	0.00
Cross-cutting		
Amprion Load	-0.13	0.02
Amprion Load Squared	3.5E-06	0.01
Amprion Solar	-0.05	0.43
Amprion Solar Squared	6.6E-07	0.94
Amprion Wind onshore	0.13	0.00

Variable	Coefficient	p-value
Amprion Wind onshore Squared	-4.5E-05	0.00
Tennet Load	-0.02	0.61
Tennet Load Squared	-1.5E-06	0.23
Tennet Solar	0.16	0.00
Tennet Solar Squared	-2.6E-06	0.61
Tennet Wind onshore	0.09	0.00
Tennet Wind onshore Squared	2.5E-06	0.01
Year dummies		
2016	-387.85	0.00
2017	-223.69	0.00
2018	-940.72	0.00
Other variables		
EUA price	45.11	0.00
Redispatch(t-24)	0.26	0.00
Constant	1851.78	0.00