Market-based redispatch in zonal electricity markets

Inc-dec gaming as a consequence of inconsistent power market design

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Abstract – European electricity markets are geographically organized in zones, which often resemble countries. Overload of power lines within zones have to be relieved through other means than the electricity market, e.g. so-called "redispatching" of power plants. Traditionally, this has often been done through administrative measures with generators being obliged to participate. In recent years, with increasing pressure on power grids, numerous proposals have been made to organize redispatch through voluntary markets, including a proposal by the European Commission to make such market-based redispatch obligatory. This paper develops a simple graphical example of a zonal wholesale market with a locational redispatch market that can be explicitly solved. Using this model, we show the perverse incentives introduced by redispatch markets, identify optimal bidding strategies and determine Nash-equilibrium prices. We show that rational market parties engage in the so-called increase/decrease game, aggravating grid congestion and earning windfall profits. In particular, we show that such gaming works even absent any (locational) market power. With the paper, we hope to inform the European energy policy debate at a crucial crossroads.

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1 Policy proposals for local “extra” markets

Zonal electricity markets. European wholesale markets for electricity are organized in “bidding zones”. Within bidding zones, all generation and loads are cleared at a uniform price for electricity. The system operator guarantees free trade between market parties connected to the same zone. If the desired dispatch cannot be accommodated physically by the existing network infrastructure, congestion is relieved by measures outside the wholesale market. These out-of-the-market transactions are called “congestion management”, the most prominent instrument being “redispatch”. European zonal electricity markets stand in contrast to US locational marginal pricing, where grid constraints are already considered in the initial economic dispatch.

Increased network congestion. In several parts of Europe, the pressure on transmission and distribution grids has increased in recent years, and is expected to grow further. This is due to a combination of factors, including the rapid expansion of renewable energy sources and the integration of electricity markets across national borders.

Various proposals. In this context, many stakeholders have proposed changes to the way redispatch is organized. Such proposals are sometimes framed as “markets for local flexibility”, but also carry a range of different labels. The most prominent proposal emerged from the European Commission’s Clean Energy for All Europeans package: Article 12 of the proposed Electricity Market Regulation[1] suggests to introduce “market-based redispatch”. This proposal is among the most contentious of the entire legislative package.

Local extra markets. What these proposals have in common is that they suggest to complement zonal wholesale markets with additional markets that have a locational granularity.

Existing markets. Such additional markets with local resolution embedded in a zonal electricity market design exist in various countries, including the following.

- In the UK, the “balancing mechanism” is used to both close gaps in the system-wide active power balance and to relieve network congestion (National Grid 2017). The UK system is accompanied by stringent abuse control mechanisms introduced in view of structural congestion. The abuse control instrument called Transmission Constraint License Condition targets behavior that exacerbates congestion (inc-dec gaming) as well as excessive pricing (Ofgem 2016), effectively abandoning the principle of voluntary market-based participation in case of prevalent structural congestion.
- The Nordic region (Sweden, Denmark, Norway) also uses bids into the balancing market for congestion management. If bids in the balancing merit order are used for congestion management, these are remunerated “pay as bid”, with the marginal price as lower bound (or upper bound, in case of down-regulation; ENTSO-E 2016).

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

- The Netherlands uses a redispatch market for congestion management. Administratively, it is also implemented as part of the balancing market, but as market participants provide different bids for the two purposes of activation (Tennet 2017), the redispatch market is effectively a distinct market with distinct merit-orders of activation.

Proposals and pilots. In particular in Germany and the Netherlands, a number of additional proposals have been suggested, several of which are implemented as pilot systems, including the following.

- As part of Germany's "enera" research project, the power exchange EPEX Spot has introduced locational intraday order books. In this system, bids on the intraday market may carry a locational identifier such that they can be used by system operators to reduce line overloads.
- A similar Dutch pilot is in operation, called the Intra-day Congestion Spread platform.
- The German research project C/sells is operating a local market for flexibility in Bavaria.
- TSO TransnetBW and DSO Netze BW operate the platform "DA/RE".
- Northern German DSO Schleswig-Holstein Netz and ARGE Netz have set up the flexibility market ENKO.
- In Eastern Germany, a joint TSO-DSO pilot platform has started operating in November 2018.

Rationale for flexibility markets. The ongoing transformation of electricity systems implies a number of changes that make incentive-based congestion management attractive: the number of generators and storage facilities is growing rapidly, an increasing share of generation and storage is connected to lower voltage levels, the internet of things and smart meters make price-elastic (small-scale) demand feasible, new types of electricity consumption – heat pumps and electric vehicles – at the same time increase the pressure on distribution grids and make smart consumption strategies feasible, and the increasing role of renewable energy tends to increase overall generation capacity. This is because renewable supply needs significantly higher generation capacity than traditional baseload technologies for the same amount of yearly generated energy due to their weather-dependency, leading to strong local production peaks at certain points in time (e.g. DENA, 2018, expects generation capacity for Germany to nearly triple until 2050). Furthermore, renewable deployment also tends to increase the geographic distance between generation and consumption, which puts additional strain on the transmission grid.

Redispatch markets. In the context of this paper, we call all of the above proposals "redispatch markets". We use this term regardless of the specific terminology used in individual countries. For example, in the case of the UK this covers the Balancing Mechanism while in Germany it includes market-based approaches to both Redispatch and curtailment of renewables, so-called *Einspeisemanagement*.

Research question. The purpose of this paper is to explain the fundamental interaction between locational redispatch markets and zonal wholesale markets. In essence, we show that anticipation of redispatch market prices will make parties change their zonal spot bids. Such strategic bidding is problematic not only because of windfall profits but because 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 through redispatch, a strategy that is known as increase-decrease (inc-dec) gaming. Withholding capacity increases line overload. Similar incentives exist for market parties in surplus regions.

State of the literature. There is a wide literature on the interplay between zonal spot and nodal redispatch markets and the emergence of the inc-dec game. In a theoretical setting, 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 located in export-constrained nodes. Those can increase their profit by increasing the output in the day-ahead market, decreasing it in the real-time market again. Other papers studying zonal spot and nodal redispatch markets include Konstantinidis & Strbac (2015) on the UK electricity market as well as Hogan (1999), Brunekreeft et al. (2005) and CAISO (2005) on the Californian electricity market and the Californian electricity crisis that subsequently led to the introduction of a nodal electricity market in the state.

Contribution of this paper. The value added of this paper is to develop a simple example of a zonal wholesale market with a locational redispatch market that can be explicitly solved. Using this model, we show the perverse incentives introduced by redispatch markets, identify optimal bidding strategies and determine Nash-equilibrium prices. We explicitly show the aggravating effect on congestion, determine the windfall profits extracted, and argue that spot markets lose incentive compatibility. In particular, we show that inc-dec gaming works even absent any market power, including locational market power. We do all this without any mathematics, relying on graphical solution techniques only. We conclude that local extra markets within zonal wholesale markets constitute an inconsistent market design that ought to be avoided. The purpose of this paper is not to provide a comprehensive discussion of redispatch markets, nor does it provide a review of all options to organize congestion management. Rather, it merely points out the problems arising from inc-dec gaming in zonal electricity markets with within-zone redispatch markets.

2 Example setup and benchmark solution

To lay out the principle workings of inc-dec gaming in electricity markets that combine zonal wholesale markets with locational redispatch markets, we construct a simple two node example with one congested line. We show that anticipation is at the core of the problem, identify consistent optimal bidding strategies and the Nash equilibrium, show that anticipation leads to an aggravation of line overload and to windfall profits, and show that inc-dec gaming does not require any market power, not even at a locational level.

We compare market-based redispatch to alternatives: nodal pricing and regulatory redispatch with cost compensation. For redispatch markets, a crucial aspect is the degree of anticipation of redispatch market outcomes in the spot market, hence we study four cases:

- Nodal pricing
- Regulatory redispatch with cost compensation
- Redispatch market with anticipation
- Redispatch market without anticipation

Before studying these cases, we introduce the physical setup of the example.

2.1 Setup of the example

Network topology. A simple example of one bidding zone with two nodes is sufficient to show most major issues that arise with redispatch markets. Our example is (very) loosely modeled after Germany. It consists of a snapshot of the market in a single time period, for example a single hour. There is a single bidding zone, which is not connected to neighboring zones. Within the zone there are two transmission system nodes, North (N) and South (S). The two nodes are connected through a single line rated at 30 GW. We abstract from transmission losses and voltage limits. Figure 1 shows the network topology.

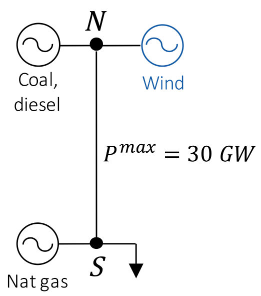

Figure 1. The simple network topology.

Demand. At the moment in time under consideration, only the South demands electricity (50 GW) while the North does not consume. Therefore, total zonal demand equals the Southern demand of 50 GW. Demand is assumed to be perfectly price-inelastic.

Table 1 summarizes core parameters.

Supply. Both the North and the South have generation: in the North, there is 20 GW of wind power producing at the moment, 20 GW coal-fired power plants and 5 GW diesel peakers; in the South 25 GW of natural gas-fired plants are connected. In total, 70 GW of generation capacity is available at short-run marginal costs between EUR 1 per MWh and EUR 70 per MWh. We assume all plants are perfectly flexible and no start-up or minimum load constraints are binding. Figure 2 shows the supply stack of the system. At the zonal level, capacity is abundant. All power plant capacity is divided in units (individual power plants) of 1 GW owned by separate companies each, so there is no market power in supply.

Table 1. 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	

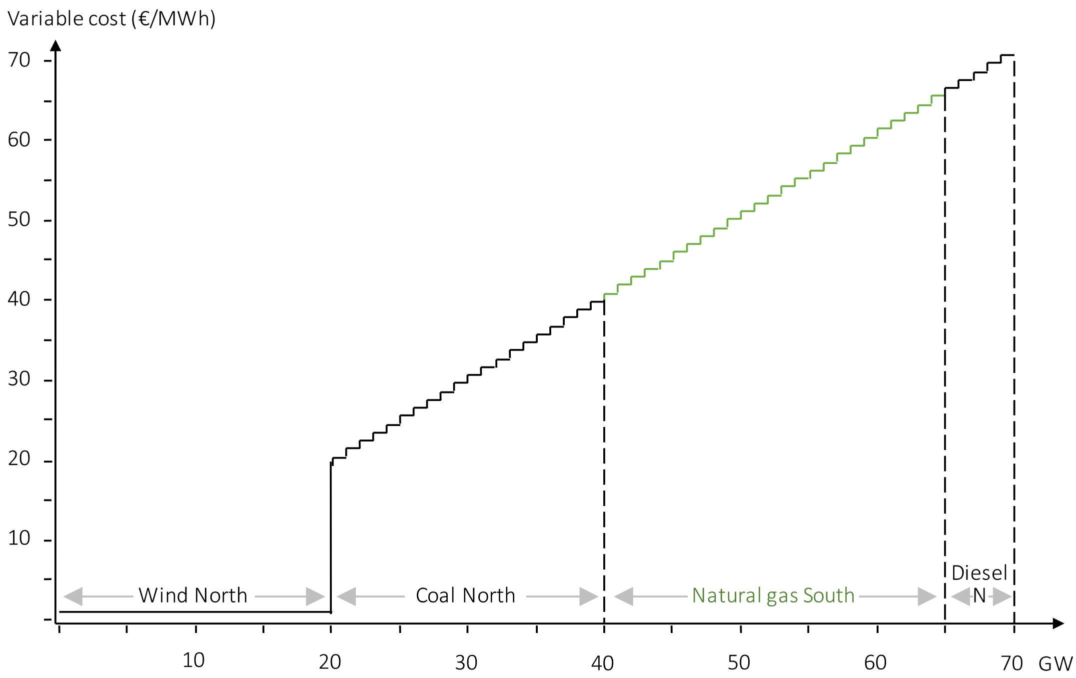

Figure 2. Variable costs ordered by size (merit order). Capacity connected to the South is green.

2.2 Nodal pricing

Before introducing the two-tier market structure of zonal wholesale markets and locational redispatch markets, we introduce two benchmark designs: nodal pricing and regulatory redispatch with cost compensation. These two systems represent the existing market design in many US and European markets, respectively.

Nodal Pricing. Nodal pricing is a single-stage locational marginal pricing system. Figure 3 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 within transmission constraints.

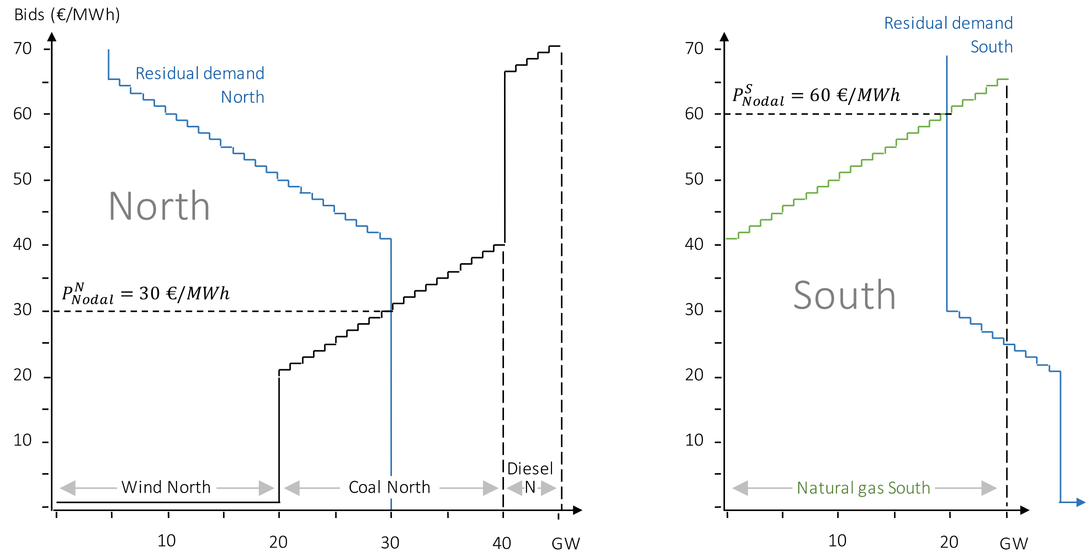

Figure 3. Variable costs ordered by size (merit order). Capacity connected to the South is green.

Table 2 shows the outcome of the nodal pricing markets. The dispatch corresponds to the security-constrained economic dispatch. The clearing prices are EUR 30 and EUR 60 per MWh, respectively. At neither node there is market power in the sense that an individual supplier is pivotal, i.e. no individual supplier is necessary to serve load. The congestion rent captured by the system operators equals 30 GW times 30 EUR per MWh, or 900 kEUR.

Table 2. 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	900 kEUR	

2.3 Regulatory redispatch with cost-compensation

Spot market and regulatory redispatch. 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, nothing else happens. If the network is congested, the system operator re-dispatches generation and/or load to resolve the congestion. This is done through redispatch instructions based on a legal obligation to redispatch. Market parties are compensated for all costs occurred and profits forgone.

2.3.1 Spot market

Spot market. Zonal load is 50 GW and all consumption and production is cleared at a uniform price. This setup reflects European day-ahead markets. Figure 5 displays the spot market, assuming that market parties do not anticipate any profit opportunity from the following redispatch process. No supplier has market power. There is 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, hence the dispatch is physically infeasible.

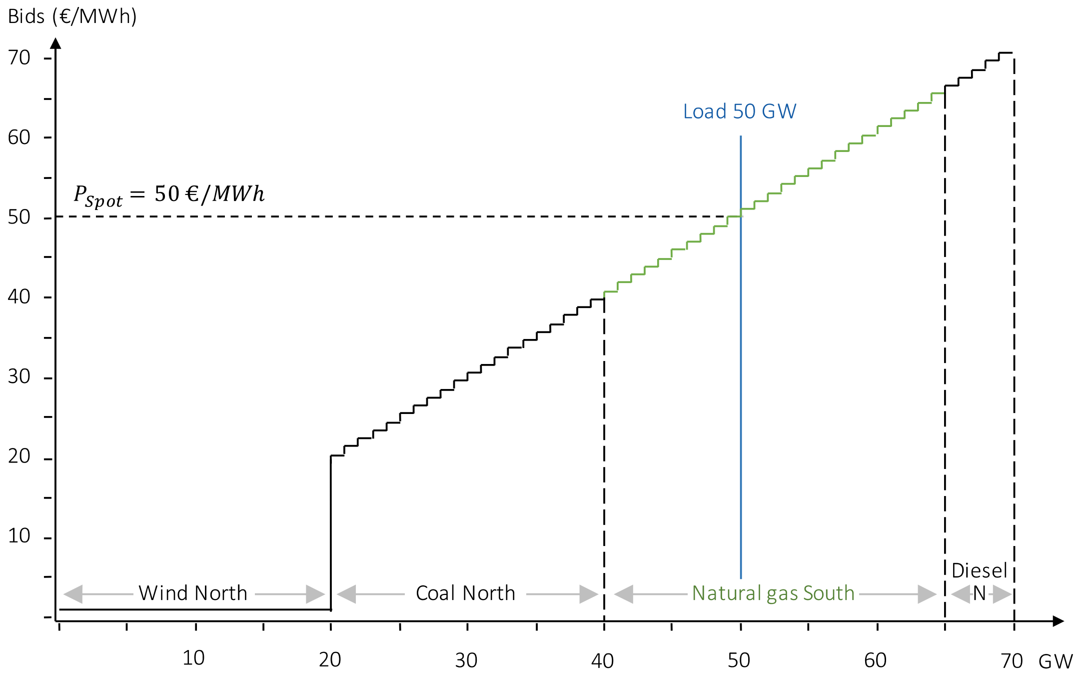

Figure 4. Spot market equilibrium without anticipation of redispatch markets.

2.3.2 Redispatch and compensation

Redispatch. Following spot market clearing, the system operator redispatches resources to avoid line overload. Therefore, she dispatches the most expensive 10 GW of coal capacity down while dispatching the cheapest idling 10 GW natural gas capacity up.

Compensation. All redispatched resources are compensated for costs incurred and profits forgone. In the case of upward dispatch (raising generation), this is the variable costs. In the case of downward dispatch (lowering generation), generators can keep spot revenues but have to surrender avoided variable cost. In the above example, total redispatch costs amount to EUR 200,000.

Comparison to nodal pricing. In this optimal case of perfect knowledge of costs and availabilities, this results in the same final dispatch as nodal pricing, yet with differing financial implications for both the system operator and market actors. Instead of collecting congestion revenue income, the market operator has to pay to compensate market actors for additional costs and forgone profits. Load in the South pays less than under nodal pricing, generators earn less. In the North, generators earn more than under nodal pricing.

Problems. There are a number of issues with administrative redispatch based on cost-compensation, the two most fundamental ones being the information asymmetry between generators and system operators and the lack of incentives for generators to participate in the first place. Furthermore, there are no incentives for a grid-friendly choice of location for new investments in power plants. This leads to an overinvestment into the grid in the long term. However, these issues are not visible in our reduced example.

Information requirement. Cost based redispatch, of course, requires the system operator to know the availability and variable costs of market parties, both of which is private information. In the case of thermal power plants, capacity and cost parameters can be reasonably estimated or derived from behavior, e.g. from spot bids the day before. There are numerous challenges in practice, such that revising the cost estimation procedure in Germany took more than one year (see BDEW 2018). 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 estimating the willingness to pay for electricity of an industrial consumer is very challenging.

Participation incentives. Maybe even more fundamental is the lack of incentives for participation. Parties participate in administrative redispatch only because they are legally obliged. 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. Such actors have no incentive to participate in redispatch, as the system does not provide any profit opportunities.

3 Inc-dec gaming in redispatch markets

After discussing two benchmark market designs without redispatch markets, we now turn to such markets. We first introduce the design of the market and then derive the market equilibrium, first without and then with anticipating agents.

3.1 Setup of the redispatch market

Two-tier market design. There are two separate markets for electricity that clear for every market time unit, such as one hour: the spot market and the redispatch market. First the wholesale spot market clears at a zonal level. If the resulting dispatch can be accommodated by the grid, nothing else happens. If the network is congested, the system operator re-dispatches generation and/or load to resolve the congestion. This is done based on voluntary bids by market actors on a redispatch market. That market is locational, i.e. it has a nodal resolution. We assume marginal pricing (as opposed to pay-as-bid) in both markets, as pay-as-bid could be expected to also converge to marginal pricing. This is because even under pay-as-bid individual market actors would try to price close to the marginal price. For simplicity, we assume markets to clear consecutively. This is a plausible assumption, as the demand for redispatch can only be determined once the spot market equilibrium is known. Table 3 summarizes the market setup. We furthermore assume bidding is constrained to integers (whole Euro amounts).

Table 3. Assumed setup of redispatch markets.

	Spot market	Redispatch market
Market time unit	1 hour	1 hour
Sequence	First	Second (after spot gate closure)
Geographic granularity	Zonal (1 market)	Nodal (2 markets)
Pricing rule	Uniform pricing	Uniform pricing

3.2 Redispatch markets without anticipation

In this section, we discuss the case without anticipation. We believe this is what many proponents of local markets for flexibility and market-based redispatch have in mind. In the following section we introduce the case of actors anticipating redispatch markets when bidding on the spot, which we argue to be the more relevant case.

Solution strategy. As markets are sequential and we assume no anticipation, they can be solved simply in sequence. We start solving the spot market and proceed with the redispatch market.

3.2.1 Spot market

Spot market. As above, zonal load is 50 GW and all consumption and production is cleared at a uniform price. Figure 5 displays the spot market, assuming there is no anticipation of the following market for redispatching. Table 4 reports equilibrium parameters. No supplier has market power. There is 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, hence the dispatch is physically infeasible. In all aspects, the spot market is identical to cost-based redispatch (2.3).

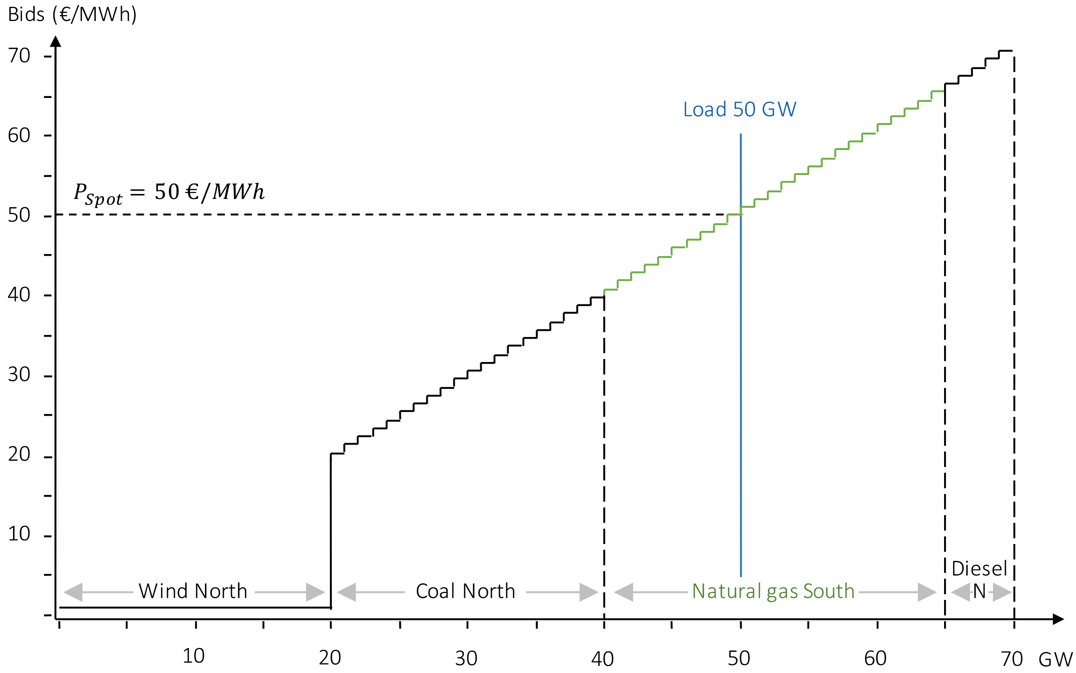

Figure 5. Spot market equilibrium without anticipation of redispatch markets.

Table 4. Market result of the nodal pricing market (without anticipation).

	North	South
Price	$P_{Spot} = 50\,€/MWh$	
Dispatch	20 GW wind 20 GW coal	10 GW natural gas
Market power	No pivotal suppliers	
Line flow	40 GW (infeasible)	
Congestion rent	-	

3.2.2 Redispatch market

Redispatch market. Because of the physical infeasibility of the spot market results, the system operator has to buy redispatch services on the redispatch market. This market can be thought of as a procurement auction that closes after the spot. Essentially it is not *one* market, but a separate auction at every node. In our example, the system operator buys energy in the South and sells energy (or buys the service "reduce output") in the North. Figure 6 displays the redispatch markets in the South and in the North and Table 5 summarizes the market equilibrium.

South. In the South, all plants that are not yet dispatched offer upward redispatching. As the cheapest 10 GW of natural gas capacity is already dispatched, the bid curve starts at EUR 51 per MWh. The system operator has a demand of 10 GW for upward redispatch. There is no market power as no supplier is pivotal, hence all suppliers bid their variable costs. 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 downward redispatch them, because then they save fuel costs. As we define prices as payments from the system operator to the generator, the bids that generators issue are minus their variable cost. There is no market power as no supplier is pivotal, resulting in a clearing price of $P_{RD}^{N} = -30\ €/MWh$. In the overall redispatch market, 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.

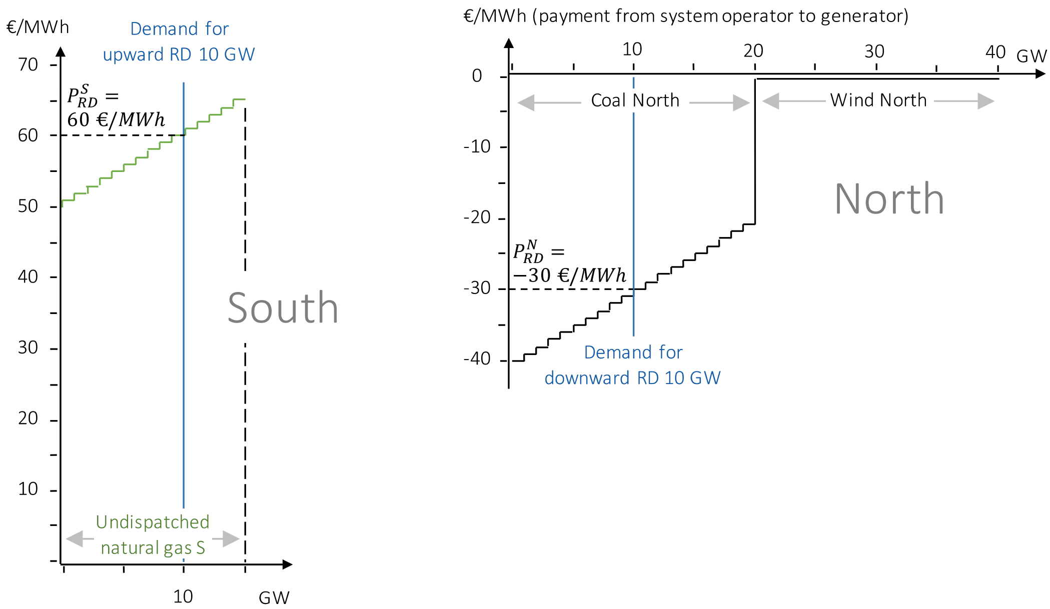

Figure 6. Redispatch markets equilibriums (without anticipation).

Table 5. 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	

An equilibrium? This situation is how we believe the proponents of local extra markets envision the outcome: the zonal market works properly and the additional redispatch market resembles nodal pricing in terms of physical dispatch. However, the crucial assumption behind this outcome is that generators *do not anticipate the redispatch market* when submitting bids to the spot market. This is a plausible assumption 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 the situations can be easily predicted (as congestion is strongly correlated with wind generation), this seems to be a naïve assumption. We therefore now turn to the case where generators anticipate the redispatch market.

3.3 Redispatch markets with anticipation

Solution strategy. We start by assuming the above clearing prices in the redispatch market of $P_{RD}^{S} = 60\ €/MWh$ in the South and $P_{RD}^{N} = -30\ €/MWh$ in the North. We then discuss the spot market and finally check if the actual redispatch market equilibrium coincides with the expectations (which it will). We assume profit-maximizing behavior of firms and full information. Furthermore, we assume only generators, not loads, engage in strategic behavior, so load remains stable and fixed (we discuss an extension to strategic loads in Section 5.1).

3.3.1 Spot market

Bidding strategy: South. In the spot market, generators in the South anticipate that they will be able to receive EUR 60 per MWh on the redispatch market. In other words, they have an alternative market to sell output. This opportunity (also referred to as "opportunity cost") sets a floor on their bidding behavior: cheap natural gas-fired power plants with variable costs below EUR 60 per MWh will *not* bid variable costs, but instead issue bids of EUR 60. In other words, they overbid. More expensive plants will continue to bid variable cost.

Bidding strategy: 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. If they receive a revenue at the spot that exceeds this amount, they make a margin. Consequently, the more expensive coal and diesel plants with variable cost above EUR 30 issue bids of EUR 30 per MWh – exactly the cost they will have to pay the system operator in the redispatch market to redispatch them down. In other words, they underbid their variable cost. The cheaper wind and coal plants bid variable cost.

Spot market equilibrium. Table 6 and Figure 7 display 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 20 GW wind, 20 GW coal, and 5 GW diesel capacity in the North. 5 GW of generation capacity from the South is dispatched, but because 20 GW of capacity had bid identically, the identity of the plants that are dispatched is undetermined. We assume the dispatch is determined randomly among those bidders. All those bidders with bids of 60 €/MWh are indifferent between being dispatched in the spot market or later in the redispatch market at the same price. In any case, this 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.

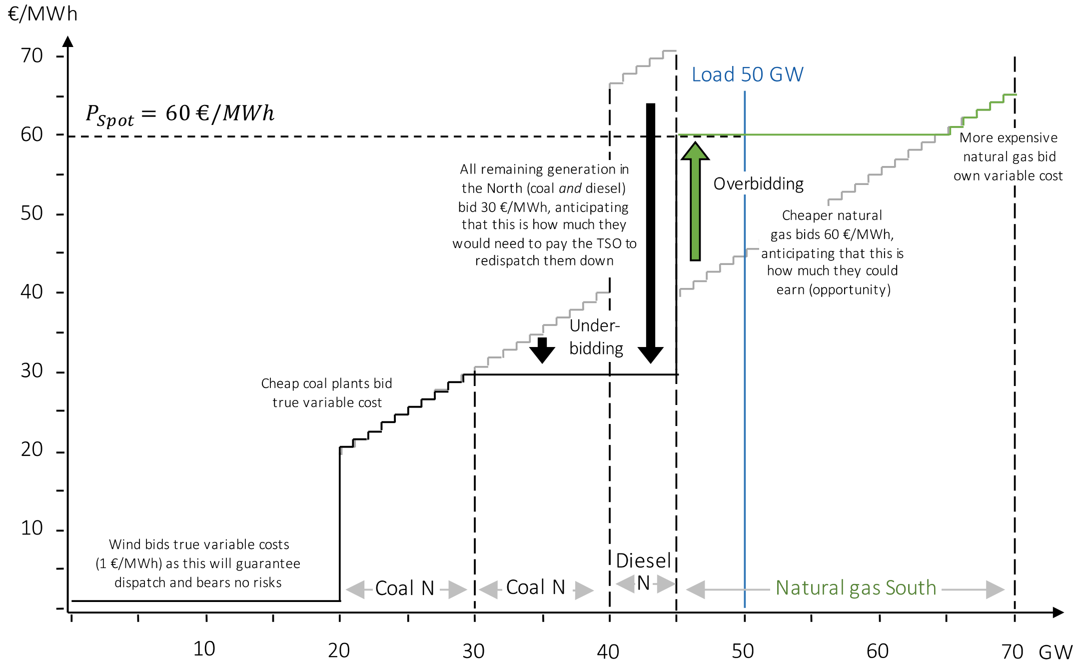

Figure 7. Spot market equilibrium with anticipation of redispatch markets.

Table 6. 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	-	

Spot price in comparison. Note that in this specific example the spot market price is identical to the Southern redispatch market's price and thereby *higher* than in the spot market with non-anticipated or 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 in the spot market with non-anticipated or regulatory redispatch. In the spot market with anticipation the price appears to always fall on either of the two nodal (redispatch) market prices (North or South) once congestion occurs. Which of the node determines the zonal price depends on whether generation in the cheaper node (ignoring transmission constraints) is sufficient to cover total zonal load.

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 true variable costs as there is nothing to be gained from deviating, given that this is the last market stage and we assume plants don't have market power. Figure 8 displays the redispatch markets in the South and in the North and Table 7 summarizes the market equilibrium.

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

North. In the North, when compared to the situation without anticipation, 5 GW of additional capacity is available to be dispatched downwards. This matches with the increased demand, such that the clearing price is the same: $P_{RD}^{N} = -30\ €/MWh$.

An equilibrium. This situation is a Nash equilibrium: All expectations have been confirmed and no actor has an incentive to change her behavior. In particular, note that in neither of the three markets – spot, RD-N and RD-S – any actor has market power.

Inc-dec gaming. This is the increase/decrease game: power stations overbid or underbid their marginal cost, anticipating their dispatch will be reversed in the redispatch market. Thereby, by increasing their output in the one market and decreasing output in the other, they are able to reap windfall profits. These additional windfall profits are borne by the system operator.

Impact of anticipation. 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.

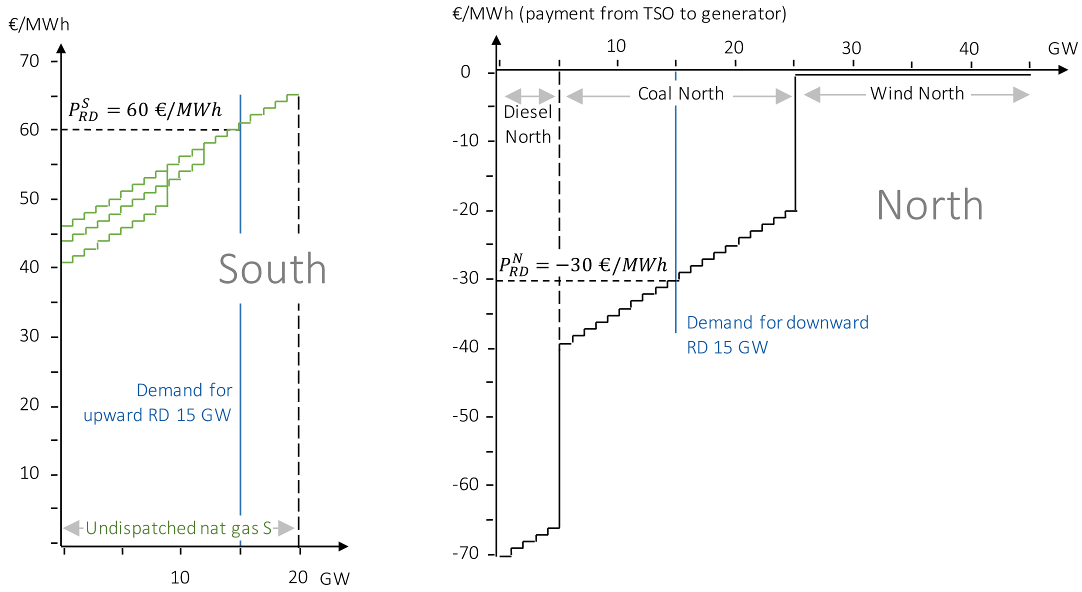

Figure 8. Redispatch markets equilibriums (with anticipation).

Table 7. 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	

3.3.3 Uncertainty and the risk of gaming

For power generators to engage in the inc-dec game, they need to anticipate congestion with some probability, because gaming is risky.

The risk of inc-dec gaming. To consider the risk they are facing, assume suppliers bid in the spot market according to assumed clearing prices at the redispatch market of $P_{RD}^{S} = 60\ €/MWh$ and $P_{RD}^{N} = -30\ €/MWh$. In contrast to their expectations, assume that the congestion does not materialize. In this example, you might imagine that dynamic line rating or technical switching operations elsewhere in the network temporarily increase the line capacity to 45 GW, such that the spot market equilibrium can be accommodated by the grid. In this case, the Northern diesel generators who underbid in the spotmarket actually have to generate without being redispatched down. As the spot market cleared below their variable cost, this means they lose money. Also, some Southern generators (those that were not randomly chosen to generate) forgo profits, a consequence of bidding above variable costs.

4 Implications and discussion

Many things can be learned from this simple model. We will discuss implications in this section, before discussing expansions of the model in the next section.

We believe the case with anticipation to be the most relevant case empirically for power systems with structural congestion. We therefore discuss consequences and implications of this case as compared to regulatory redispatch with cost-compensation.

4.1 Aggravated congestion

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.

Systematic pattern. In our example, the line overload increased from 10 GW to 15 GW. 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 to benefit from high redispatch prices, thereby aggravating congestion. Parties in oversupply regions are incentivized to overproduce, again aggravating congestion. In Section 5.1 we describe how loads also face perverse incentives, further increasing congestion in the spot market result.

Virtual congestion with real effects. 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, not only its financial implications are real. Another consequence is that operation of the system gets significantly harder. The system operator gets a highly flawed picature of actual system condition and desired flows by market parties at the stage of the spot market. Since a redispatch market can only be opened *after* gate closure of any zonal trading, in the little time that remains for redispatch, the system operator has to cope with a large part of the dispatch changing.

Aggravated, not created congestion. It is important to note that in a setting without market power (as in our example), inc-dec gaming can be used to benefit from congestion and thereby also to aggravate it. However, it would not be beneficial to withhold capacity from the spot market to create congestion in an otherwise uncongested situation. If generators would withhold congestion in an otherwise uncongested situation, the price they obtain on the redispatch market would not be above the spot market price, but possibly below, depending on the variable costs of the withheld generation. This would change in a setting with market power, but as long as bidding in the redispatch market happens competitively, market actors can only benefit from inc-dec gaming in an already congested situation.

4.2 Loss of incentive compatibility

Absent redispatch, competitive zonal spot markets feature incentive compatibility, i.e. the profit-maximizing strategy of all parties is to bid their true marginal cost. This is not the case anymore after the introduction of a redispatch market.

Distorted bids. In a market design with redispatch markets, parties have an incentive to submit spot market bids of either their marginal cost, or the respective redispatch price they anticipate at their node to emerge. This effect makes the spot market result harder to interpret as it is no longer a direct representation of underlying marginal costs, even in the absence of market power.

4.3 Spot market loses meaning

In times of congestion, the spot price converges to either one of the nodal prices. All consumption and generation is cleared at the nodal price. The spot market loses its meaning as a lead or reference market. This has direct implications for financial markets, which usually use spot market as a reference.

Spot market hard to predict. In our examples (the main example presented above and the example with reduced load in the Appendix) the spot market price always converges perfectly to one of the two nodal prices. However, this is dependant on the assumption that all market actors understand the incentives and act accordingly. If this is not the case for some of the market participants, the spot market result could become hard to predice and to some degree random. Given the high relevance of the spot market price for derived financial products, this is problematic.

4.4 Windfall profits for market participants

There are significant windfall profits from a market-based redispatch. Compared to both nodal pricing and regulatory redispatch, generators extract additional rents. Table 8 gives an overview of prices and rents in the three settings.

Table 8. Clearing prices and rents.

	Nodal pricing	Regulatory redispatch	Redispatch market (with anticipation)
Clearing price for load	$P_{Nodal}^{S} = 60\,€/MWh$	$P_{Spot} = 50\,€/MWh$	$P_{Spot} = 60\,€/MWh$
Clearing price for generation	$P_{Nodal}^{S} = 60\,€/MWh$ $P_{Nodal}^{N} = 30\,€/MWh$	$P_{Spot} = 50\,€/MWh$ Asset-specific compensation	$P_{Spot} = 60\,€/MWh$ $P_{RD}^{S} = 60\,€/MWh$ $P_{RD}^{N} = -30\,€/MWh$
Amount paid by loads for energy (€)	3 000 000	2 500 000	3 000 000
Congestion management cost (€)	-900 000 (congestion rent)	200 000 (redispatch cost)	450 000 (redispatch cost)
Revenues for generators (€)	2 100 000	2 700 000	3 450 000
Variable costs for generation (€)	1 285 000	1 285 000	1 285 000
Margin for generators (producer rents) (€)	815 000	1 415 000	2 165 000

4.5 No market power needed

Note that the above example, none of the suppliers was pivotal. Everyone acted as an atomistic price-taker. This underlines that the inc-dec game does not require market power and is possible to exploit also for atomistically small market participants.

4.6 Similarity to balancing market

In a sense, the behavior of agents when anticipating the redispatch markets can be compared to the behavior when anticipating markets for balancing energy.

Generators perspective. If a generator anticipates to be able to receive EUR X per MWh on the balancing energy market, she will bid that opportunity on the spot, rather than her true marginal 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 – from the perspective of generators this seems to be a valid optimization strategy across markets.

Misguided incentives. However, while in the balancing vs. spot market trade-off generators are incentivized to find the system optimal (and welfare optimal) choice between the two markets, this is not the case for redispatch and spot markets. The crucial problem is that in the case of redispatch, the incentivized across-market optimization is counterproductive and aggravates the problem (spot market congestion) as we have demonstrated above.

4.7 Avoiding inc-dec gaming

To avoid the incentives for overbidding and underbidding in the spot, one would need to erase any profit opportunity on the redispatch market.

If the redispatch market was based on pay-as-bid and bids were monitored and enforced to correspond to own marginal costs, the incentives for inc-dec would go away. But then the system would resemble administrative cost-based redispatch, with all its problems.

5 Expanding the model

While the highly stylized model of Section 2 can yield important insights into the nature of redispatch markets, in particular inc-dec gaming, the simplicity inhibits to study further interesting aspects. In this section we discuss verbally the consequences of adding more realism to the model. We will discuss demand participation in inc-dec gaming, market power and a richer network topology.

5.1 Inc-dec on the demand side

In the example of section 2, demand was assumed to be exogenous and perfectly price inelastic. In fact, the demand side can also participate in inc-dec gaming.

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" at the spot market. This will also aggravate congestion, increasing the need to redispatch. At the redispatch market, the load will be able to buy electricity for EUR 30 per MWh (the same price that generators pay to have their output reduced).

South. Now consider an industrial load connected to the South that has a willingness to pay of zero, say, because the facility is closed because of holidays. In the above example, there is no incentive to game the market. 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, well below the Southern redispatch price 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.

Financial arbitrage. In principle, one does not need to own physical assets to harness these arbitrage opportunities. Any financial trader could take positions on the spot market to close them on the redispatch market. However, such "pure" financial arbitrage trading – without any physical assets – could be prevented relatively easily through regulation. Preventing asset-based arbitrage is very difficult, as we have argued in section 4.7.

5.2 Market power

An example with local market power. In the example of section 2, generators never had market power in the sense that never a single generator was pivotal for electricity supply. 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. Concretely, we assume the 5 GW of plants with highest marginal cost to disappear. We 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. With our assumption about the demand function, generators will be able to increase the price to EUR 10,000 per MWh.
- Similarly, in redispatch markets, nothing changes in the Northern redispatch market, while in the Souther one 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, which leads to drastically increased profits for both Southern and Northern power plants.

Further realism. The ability to exploit local market power depends, of course, on the elasticity of the residual demand function at this node. In this example, demand is perfectly price inelastic up to EUR 10,000. In a more complex reality, two things will be different:

- Electricity demand is likely to be (somewhat) elastic at lower prices.
- More 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. We will discuss this case in the following subsection.

6 Conclusions

Market-based redispatch if congestion is rare and unpredictable. If congestion in electricity grids is non-structural and hence cannot be predicted with reasonable accuracy, combining zonal electricity markets with nodal redispatch markets (or other local “extra” or “flexibility” markets) could possibly be feasible.

Inconsistency if congestion is structural. However, the more relevant case in many European countries seem to be that of structural, predictable congestion in transmission and distribution grids. In this case, combining zonal electricity markets with local markets for dispatching is inconsistent. It provides an incentive for inc-dec gaming, leads to windfall profits, and is the de facto introduction of nodal pricing without the required institutional framework.

Implications. If one aims for local price signals, it seems more sensible to introduce “proper” locational marginal pricing, as operational in several US markets. If one wants to keep zonal electricity market design despite structural congestion, within-zone dispatch is likely better organized through processes that do not rely on bids and incentives.

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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.

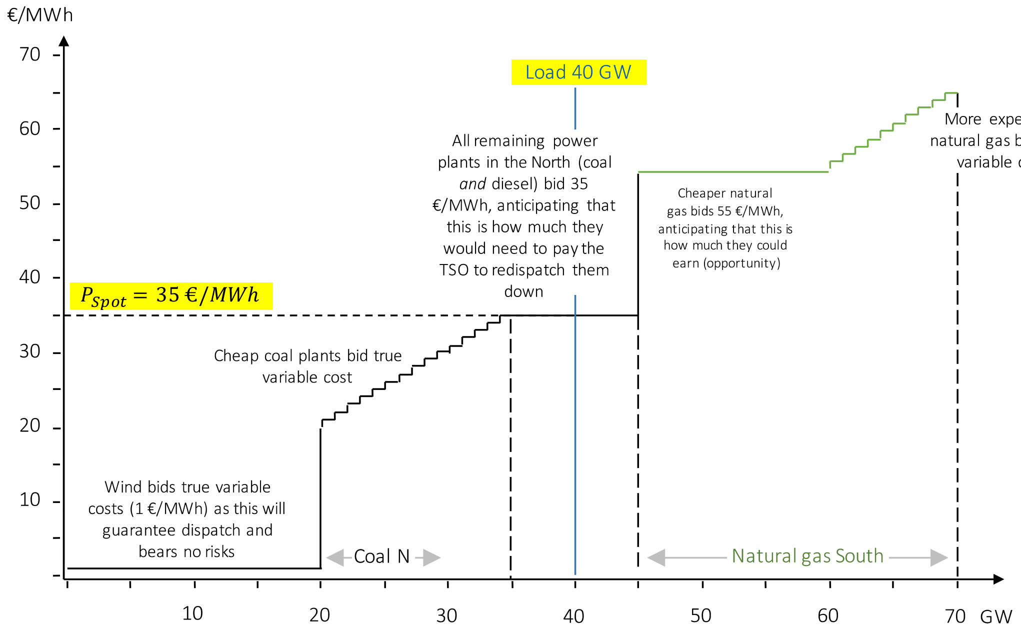

Figure 9. Spot market equilibrium (with anticipation).

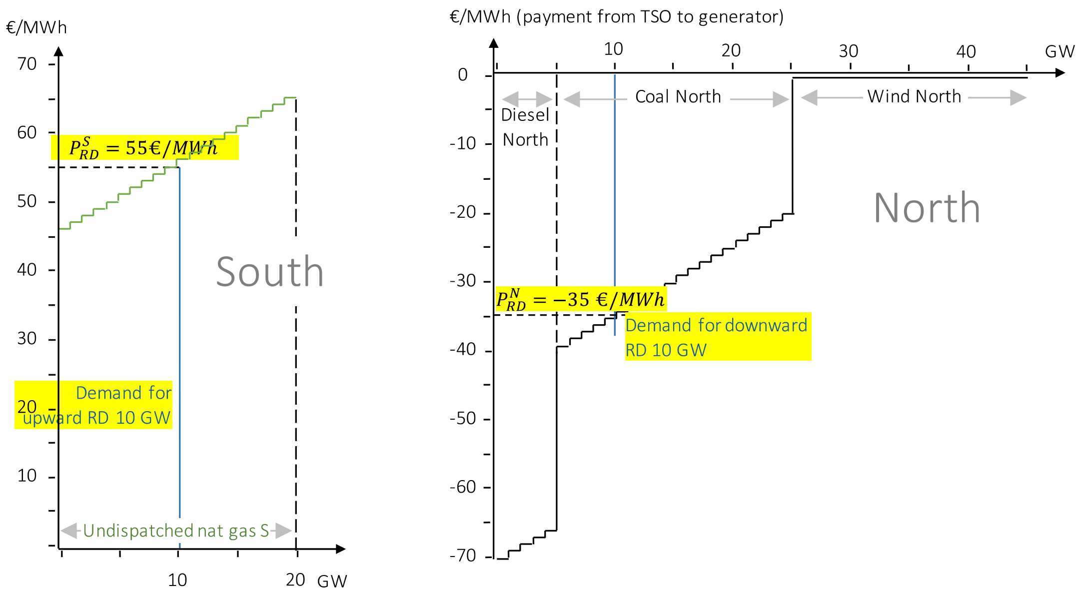

Figure 10. Redispatch markets equilibriums (with anticipation).