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NTNU
Norges teknisk-naturvitenskapelige universitet
Fakultet for økonomi
Institutt for industriell økonomi og teknologiledelse

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Kunnskap for en bedre verden

An analysis of mitigating measures for inc-dec gaming in market-based redispatch

Audun Midttun Systad, Jens Løken Eilertsen, Felipe Van de Sande Araujo, Ruud Egging-Bratseth

***Abstract*—Market-based redispatch (MBR) is a design intended to reward providers of flexibility in electricity markets. However, this design may present shortcomings, such as opening up for strategic manipulation. One such strategy, inc-dec gaming, has been claimed to aggravate congestion and reduce overall welfare in the market. The goal of this paper is two-fold. First, we develop a bi-level two-stage framework of the electricity market with a day-ahead market and a real-time redispatch market. On the basis of this framework, we construct an equilibrium problem with equilibrium constraints (EPEC) model. The model includes a continuous bid region and solution space, which can be solved by taking all levels and stages into consideration at once. We apply an intuitive solution method, parametrizing competitors' bids and utilizing a diagonalization approach until convergence. Second, we test the prevalence of inc-dec gaming, as well as if proposed mitigating measures may help alleviate the potential weaknesses of market-based redispatch. Results suggest that inc-dec gaming is an effective strategy only when local market power is present. When apparent, inc-dec gaming has strong adverse effects, while the introduced measures were able to mitigate these adverse effects. However, implementation of these measures introduces a trade-off between the incentives of the system operator, consumers, and producers.**

I. Introduction

THE INCREASED participation of renewable energy sources, while key to the green shift towards a future with lower carbon emissions, is adding more uncertainty to the electricity markets, due to source intermittency. The distributed aspect of new sources builds up the complexity and may stress the current balancing system.

To handle the increased stress on the balancing system, the system operator needs access to flexibility in the market to adjust to the intermittency, as well as efficient ways to handle congestion. Among the most commonly discussed designs to acheive this is market-based redispatch (MBR). There are strengths to this design in that it is a market-based design and could integrate more sources of flexibility than most competing designs. Additionally, flexibility providers are rewarded according to the service they provide the market. Meanwhile, critics of the design are fearful of its potential vulnerability to strategic manipulation from producers. Among these strategies is what is known as increase-decrease gaming (inc-dec gaming). In this particular strategy, producers would intentionally submit misleading bids in the day-ahead market with the sole intention of aggravating congestion and profiting off the redispatch market.

There are differing opinions in the literature about the scale of threat such strategic behavior represents to MBR. While some research concludes that MBR cannot be efficient, other authors have a more optimistic view [1]. Some proposed measures can be implemented into the market design to mitigate the adverse effects of inc-dec gaming. While some of these have been tested [2], a number of promising solutions still lack analytical testing in a proper framework for their effectiveness.

The purpose of this paper is two-fold. The first goal is to create a model that replicates the behavior of a system with MBR and investigate whether there are incentives for producers to engage in inc-dec gaming. Secondly, given that harmful gaming strategies are beneficial, we aim to implement some of the proposed mitigating measures into the model to see how this impact the producers' behavior as well as the market as a whole. To do this, the model needs to be able to take account for the incentives of each individual producer, which is possible with an equilibrium problem with equilibrium constraints (EPEC). A two-stage EPEC model was thus built, studied, and analyzed to find evidence of inc-dec gaming, before mitigating measures were introduced into the model and the changes were investigated.

A. Background

Electricity demand is steadily increasing in Europe. At the supply side, a rising share of intermittent renewable generation increases fluctuations and uncertainty as well as the need for transmission capacity. New intermittent renewable energy sources (RES) often have different geographical requirements than conventional generators and loads (for example a wind farm placed off-shore to be exposed to as much wind as possible), leading to them being built in different locations. As the existing transmission grid is built to transfer electricity from the conventional producers to consumers, the increase in supply from new locations add stress to the grid. Furthermore, the European Union (EU) aims to develop a fully integrated market across its internal borders [3]. An integrated market increases security of supply, as supply deficits in some part of a coupled network can be compensated by others sources (c.f., for contrast, the issues in the isolated Texas market in 2021, in which increased interconnection could have helped to alleviate some of the damage [4]). However, the increase in cross-border trade that comes with market integration may lead to more congestion on the transmission network. Most European cross-border transmission lines were originally built as emergency measures and were not meant to handle regular trade between countries. After integration, some interconnectors have become congested almost constantly [5].

Existing plans for infrastructure expansion are sufficient to accommodate future transmission needs for most situations

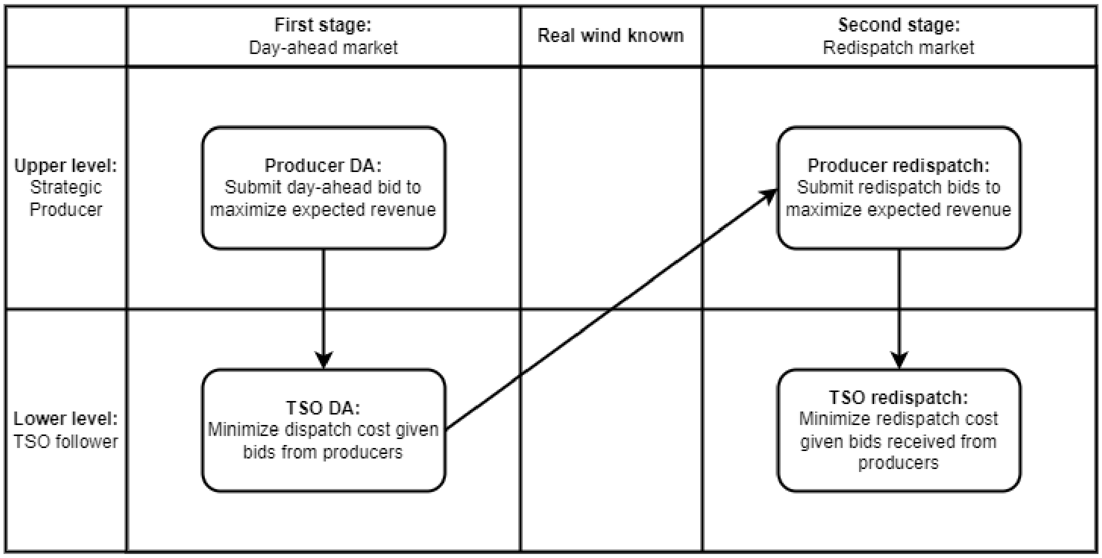

Fig. 1: To replicate the mechanics of market-based redispatch, the market clearing in the model can be divided into two levels (the producers leading, the TSO/consumers following) and two stages (day-ahead, with uncertainty and redispatch market when scenario becomes known).

[6], although this expansion is costly and takes time. Furthermore, accommodating for spikes in transmission capacity needs would require unwarranted over-investment in infrastructure to completely avoid congestion. As such, an efficient market design should have measures in place to manage congestion.

Many such measures are being discussed, some of a preventive nature, others corrective. Adopting nodal pricing leads to congestion management by a centralised system operator who is able to make an optimisation problem of the entire day-ahead, accounting for all line capacities (also within-zone) and solve for the optimal solution [7]. This is seen by many researchers as the best alternative [8] [9], and is used in markets such as the US and Australia. It does, however, lead to very volatile prices in small zones [10], and requires a fully integrated market, and would thus currently be a challenge to implement in the European market [11].

In Europe, where zonal design is employed, congestion management is a widely discussed subject. Under zonal design, the system operator ignores intrazonal constraints in the day-ahead market, similar to a copper plate within each zone. A separate market clearing, the redispatch market, happens in real-time, in which the transmission system operator (TSO) enforces the transmission constraints they ignored day-ahead, and call on market participants to readjust their production or consumption to end up in a feasible solution, compensating them in the process. This process is referred to as redispatch [12]. Market-based redispatch (MBR) and cost-based redispatch (CBR) differ in the way flexibility providers are compensated. In CBR, the TSO remunerate according to marginal costs provided by the producers that participate on redispatch. In MBR, however, market actors participate in a voluntary auction for flexibility, and the TSO then accepts bid in the redispatch market until all imbalances are corrected.

The European Union (EU) is moving towards market-based mechanisms for congestion management [13]. A main strength of MBR compared to other market designs such as CBR is that it allows for greater participation in the balancing markets. It can also work well in a partially integrated market, as is the case in the EU, where the heterogeneous electricity systems of many nations are being interconnected.

However, a main criticism of MBR is its potential vulnerability to gaming, i.e. strategic manipulation. One such gaming strategy is referred to as inc-dec. This entails bidding in the day-ahead market in such a way to aggravate congestion and collect increased profits in the redispatch market. In a deficit area, a supplier would bid themselves out of the day-ahead market by bidding higher than their marginal cost, thereby artificially increasing scarcity, in order to sell in the redispatch market at a premium. In a surplus area, (high cost) producers may instead bid themselves into the market by bidding lower than their marginal cost. This would lead to increased need for downward regulation in the surplus node, and the strategic producers can then be redispatched down and collect a profit based on the difference in price between the two market clearings. Such manipulations can undermine the potential of MBR to be part of an efficient market design [14].

The following literature review will cover the debate between MBR and CBR, with a focus on the inc-dec game and its potential solutions. We will then discuss some of the techniques used in modelling similar situations which will serve as basis for our framework, as well as the main contributions from this work.

B. Literature review

In a cost-based redispatch the system operator needs knowledge of the cost of production for every generator. It is even more cumbersome to compensate consumers, as one would then need to measure their utility of the electricity consumed, which is hard for the TSO to set a concrete figure to. In a market-based redispatch, on the other hand, any market participant can submit bids in the redispatch auctions according to their own perceived value of electricity, allowing for participation from smaller suppliers and loads [15]. The benefit of allowing smaller actors to participate in the redispatch market can be large. E-bridge estimates added flexibility access in the German distribution market to be 25 GW by 2030, potentially saving up to 20 billion EUR [1]. As well as saving cost, this extra flexibility can become a necessity, as certain research indicates that CBR will become insufficient to solve network congestion if congestion continues to increase [16]. Additionally, in a market design with MBR, those who offer up flexibility will get rewarded according to the market value of their flexibility. This can be viewed as a reward for offering needed services to the market [17] [18].

The main criticism of MBR is related to strategic behavior, such as inc-dec gaming, and its consequences. The most obvious consequence would be that disproportionate profits would be drawn to the producers who engage in gaming [19], while increasing the cost for consumers. Inc-dec game can be understood as the producers creating false need for flexibility, then offering it at a premium, and then collecting the market's reward as windfall profits. In the process, they create more congestion and reduce the overall welfare in the market [14]. There have been attempts at quantifying the economic damage of gaming behavior [14] [2] [20]. Results are mixed, showing either concern, or concluding that the consequences are but moderate, albeit still a possible threat to MBR implementation [20].

Another important point is the harmful investment incentives that inc-dec gaming could create. In principle, a market-based solution should lead to incentives to invest in generation where there is deficit and consumption where there is surplus as the prices would be more favorable there. However, the profits from strategic behavior could distort this objective and lead to investments in locations that would further aggravate congestion [21] [19]. This aggravation can be taken even further, where it could be profitable to build "ghost plants" with the sole purpose of gaming [22].

There are a couple of additional concerns brought up regarding MBR, such as the TSO's incentives. This concern was raised after researchers modelled CBR and MBR, keeping track of welfare in their models. It was there observed that the TSO minimizing redispatch cost under MBR did not always imply welfare maximization [15]. Another point of discussion is how to conciliate MBR with zonal pricing schemes. An argument in favour of zonal market designs is that there is a common price within a larger zone which serves as the underlying for financial contracts. With MBR, the zonal price fails to reflect the actual value of the electricity in the different nodes due to compensation in the redispatch market [14]. However, while this may be problematic, the case is not any stronger in CBR as the value of location within a zone is simply not reflected at all. The only system in which locational value is accurately represented is nodal pricing, but in this system, one would end up with different electricity prices for every small node, which is a highly volatile and non-liquid underlying for financial contracts [10].

It is here worth noting that CBR also has been found to have weakness to strategic manipulation [23] [11], and a research has even found evidence of gaming happening in German markets operating with CBR [24]. The counterpoint from advocates of CBR has been that this gaming is of another kind than the strategic abuse under MBR, and that it can be done by market actors without market power [22]. Evidence of gaming without market power has also been found by researchers trying to find mitigating measures to gaming using mathematical analysis [2].

An empirical study, meanwhile, found inc-dec to be very rarely occurring without market power [25]. The same study also conclude that in the cases of inc-dec gaming, the market and system operators were usually able mitigate it. One of these cases is the UK, where after observing inc-dec gaming, the Ofgem (the British government regulator for the electricity market) introduced bidding rules that penalized bids with "excessive benefits" [26]. While some describe this as CBR in disguise [14], others call it a light-touched regulatory measure [1], and has been described that the market experienced tremendous improvement.

According to [27], MBR could be efficient if structural congestion, e.g. line connections that over time remain congested, can be handled. Market splitting can potentially help solve this by dividing the zones so that structural congestion is minimized [28]. However, these zone configurations cannot remain constant over time due to fluctuations in network needs.

A couple potential mitigating measures for inc-dec are mentioned in [14], among them adjusting the transparency in the market or adding pricing rules such as pay-as-bid as opposed to the marginal accepted bid. However, they are quick to dismiss them, providing no further analysis than resonating how the authors themselves believe the mitigating measures would end up not being efficient.

One possible mitigation measure, called true zonal price [2]), forces the price of all nodes within a zone to be equal. While this measure has the intended mitigating effect, it leads to a significant inefficiency in the market and thus would do as much harm as good. Another solution with similar characteristics as true zonal price is referred to as the Norwegian solution [17]. Here, market behavior is monitored, and when a participant is observed gaming, the TSO forces their bids to be the same in the redispatch market as it is in the day-ahead. This way, actors caught gaming get restricted from doing so. It introduces a similar economic inefficiency as the true zonal price, but only when gaming is observed and only to actors who game. In practice in the Norwegian market, it has acted as a strong deterrent, and the rule need to be used very rarely.

The use of long-term contracts is also proposed as a mitigation measure. By signing long-term contracts for access to flexibility at a fixed price, the TSO can secure some reliable flexibility over the long term, reducing some of the need for redispatch and thus reducing the potential for inc-dec gaming. At the same time, they can have an open auction for any further needs for flexibility which allows for the participation of loads and smaller producers. From the viewpoint of larger producers, it could be beneficial to enter into the long-term contracts in order to secure stability in their revenues [29]. Redispatch based on capacity payments, as presented in [14], seems to stem from the same intention in that they aim to achieve some of the strengths of MBR while still limiting incentives of gaming. The implementation, although, is different. In this implementation, the TSO agrees on contracts to access flexibility from certain producers at a given price.

As far as we are aware, neither the Norwegian solution nor long-term contracts have been tested in an analytical framework prior to this work. The most relevant type of model for this application is likely an equilibrium problem with equilibrium constraints (EPEC) [2], that are agent-based mathematical models where the behavior of each agent in the system can be studied separately. This allows for replicating competitive behavior among producers, and thus represent a market. In a previous approach, presented by Sarfati and Holmberg (2020) [2], the bidding is done in prices, and not in quantity, which is best for studying inc-dec gaming, however, the producers are only allowed to bid from a discrete set of strategies in order to simplify the resulting model which is very complex.

Other similar applications of mathematical programs use quantity bids instead of price [30]. In [11], an EPEC is created for studying strategic producers in both nodal and zonal designs. They bring up the importance of perfect information of other players' costs and inner workings for the EPEC approach to work well. Also in [31] the authors solve a two-stage EPEC model to find equilibrium solutions in a congested network. They do so by parametrizing the solutions of other players and iteratively solve until an equilibrium is found. Strategic behavior in electricity market can also be analysed through mathematical programs with equilibrium constraints (MPEC) [32].

Some analytical approaches seem to find theoretical potential for manipulations (e.g. [2], [14]) while empirical accounts oftentimes are seeing less problems than what is theoretically possible (e.g. [25], [17]). One potential reason presented in [17] is that the theoretical models fail to capture the real risks of inc-dec gaming. Even if it is so, we believe there is value in putting some proposed mitigating measures into an analytical framework to see how they behave in a theoretical framework and possibly shed some light into what would be the expected real-world effect.

C. Contributions and Findings

To achieve this, we create an agent-based model of a market with similar characteristics to MBR. This model is then tested, first by exploring the inc-dec game to test for its proficiency. After inc-dec gaming is identified, we extend the model with proposed mitigating measures, namely long-term contracts and the Norwegian solution, which are yet to be tested in an analytical framework in the literature. We also model nodal pricing, to show the cause of inc-dec gaming in our model. These mitigating measures are implemented where inc-dec gaming is apparent, to gauge their efficiency, which is the first of four main contributions of this paper.

As previously mentioned, such an analytical framework must be able to replicate competitive behavior among actors in a market. As we have seen in literature, EPEC models provide an effective tool to do just that. However, there is a lack of such models considering bids in prices, which is the best option to examine inc-dec gaming. In the rare case with price bids, these are discretized [2]. A second main contributions is, therefore, the introduction of a continuous bid region and solution space for the EPEC. Furthermore, the model used in the work by Sarfati and Holmberg (2020) [2] is of a highly complex nature. Due to this, a third main contribution of our work was building a more intuitive EPEC model with price bids that are continuous, which makes for a more realistic model. We apply an intuitive method of solving the EPEC, by parametrizing competitors' bids and utilizing a diagonalization approach until convergence.

This was done through integrating the two levels (producer and consumer) and stages (day-ahead and redispatch market) into one compounded model. In this model, the producer faces the strategic decisions of bids in the day-ahead and real-time market. We solve the model by letting the producer present bids in the two markets simultaneously, by anticipating the different scenarios of a redispatch market as well as the TSO's responses to their bids, which is the fourth main contribution of this paper.

II. Mathematical Model

The model has two levels and two stages. The leaders in the model are the strategic producers, who maximize their own profit, anticipating the reaction of the follower, the TSO, in the system.

The first stage is the day-ahead market, wherein the TSO in a MBR system ignores transmission constraints within zones. Here, the producers submit their price bids and the TSO minimizes cost subject to total demand being fulfilled.

Between the two stages, the exact levels of intermittent RES production is revealed. In the model, these are represented by windmill producers with marginal cost of 0, who do not place price bids in the market akin to conventional producers. In the day-ahead, they have a forecast of supply, but can in the real-time end up in a finite amount of scenarios, with probability P_ω, of higher or lower capacities of production.

In the second stage, the TSO performs a second market clearing. In this clearing, however, intrazonal transmission constraints are reinforced so that the final zonal dispatch becomes feasible in the transmission network. Producers now submit prices at which they are willing to get upwards or downwards redispatched, and the TSO minimize the cost of redispatching generators until demand is met in all nodes while all transmission constraints are respected.

We then consider the viewpoint of a strategic producer ahead of their bidding decision in the day-ahead market. They are aware there will be two market clearings, so they wish to maximize their total profit from both stages by selecting bids for day-ahead as well as preparing bids for redispatch in all perceived scenarios. Knowing how the TSO will dispatch and then later redispatch in the market, the producer can predict the

TSO's response given the available capacity and bids from the producers in the network. Because of this, we let the producers present all bids initially, to allow for the model to be solved as a single problem for each producer. The TSO's response functions are then integrated into the producer's problem through KKTs to create an EPEC problem. The EPEC model is solved by iterating through the MPECs of all producers in the network and solving until their solutions converge to an equilibrium. This is done through diagonalization, where the bids of all producers except the one currently solving are parameterized, before the MPEC is solved for the current active producer. This is repeated until the solutions converge to an equilibrium among producers, where each bid remains unchanged. Lastly, to find potential other equilibria in the system, the feasible regions of bids are split up to find the best responses in each of the subsections.

The rest of this section progresses as follows. First, a mathematical model for all four component problems are presented. Next, the problem is compounded into an EPEC which perceives all four partial problems. It is important to note that while we present the four subproblems isolated, they are all part of the same EPEC. Lastly, the diagonalization algorithm is described.

A. Assumptions

First, we assume that the parameter values for transmission, generation capacities and marginal costs are known by all players. Considering uncertainty in renewable generation, all players know all possible future outcomes and their probabilities. Moreover, they are able to place one bid for each scenario in the real-time market, similar to Sarfati and Holmberg (2020) [2]. In the day-ahead market, each zone in the market is viewed as a single copper plate, allowing for limitless and lossless transportation of power across the lines. In practice, this means that intra-zonal transmission constraints are ignored, while inter-zonal constraints are in place. Day-ahead prices are set from the highest accepted bid. Next, in the real time market, as the transmission constraints must be enforced, we assume that producers are paid as bid. We disregard transmission fees and power losses due to transferring electricity via the transmission network, as these are not likely to affect the principles underlying the strategic bidding behavior.

The demand is assumed to be inflexible, meaning it remains unchanged regardless of price. It is assumed that total capacity is sufficient to meet demand, such that load shedding is not needed. In the opposite case, we assume the existence of curtailment, where not all adjustable supply is needed in the market and some potentially useful energy must go to spill.

Regarding the supply firms, it is assumed that they are profit-maximising, and that they anticipate the redispatch market and act accordingly. Suppliers act strategically to maximise profit and execute market power if possible and beneficial.

B. Nomenclature

Indices

$u \in U$ Set of conventional, flexible producers

$n \in N$ Set of power system nodes

$U_n \in U,$ Subset of generators in node $n \in N$

$n_u, u \in U$ Indexes the node n that u is in

$w \in W$ Set of windmill producers

$W_n \in W,$ Subset of windmill producers in node $n \in N$

$n_w, w \in W$ Indexes the node n that w is in

$z \in Z$ Set of day-ahead market zones

$\omega \in \Omega$ Set of scenarios in the real-time market

Parameters

$C^{T,DA}_{n,m}$ Transmission capacity from node n to m, day-ahead market. Set arbitrarily high if node n and m are in the same zone.

$C^{T,RT}_{n,m}$ Transmission capacity from node n to m, real-time market

C^P_u Production capacity for producer u

C^P_w Forecasted production capacity for producer w

$C^{RT}_{w,\omega}$ Production capacity for producer w in ω in the real-time market

$C^{B,L}_u$ Lower bid cap of producer u, both markets

$C^{B,H}_u$ Upper bid cap producer u, both markets

MC_u Marginal cost, generator u, day-ahead market

MC^+_u Marginal cost for upwards redispatch

MC^-_u Marginal cost for downwards redispatch

D^z_n Demand in node n, zone z, zero if n is not in z

P_ω Probability of scenario ω

ζ Flexibility-premium for long-term contracts

Q A small quadratic cost tiebreaker constant

Decision variables - day-ahead market

b^{DA}_u Bid price of u

$v^{DA}_{u,z}$ Dispatched volume for u to zone z

$v^{DA}_{w,z}$ Dispatched volume of w to zone z

$f^z_{n,m}$ Flow dispatched to zone $z \in Z$ from $n \in N$ to $m \in \{N|n \neq m\}$

π^{DA}_u Profit of u

c^{DA}_{TSO} Cost of the TSO

Decision variables - real-time market

$b^+_{u,\omega}$ Upward adjustment bid price of u

$b^-_{u,\omega}$ Downward adjustment bid price of u

$v^-_{u,z,\omega}$ Downward redispatch volume of u

$v^+_{u,z,\omega}$ Upwards redispatch volume of u

$v^{RT}_{w,z,\omega}$ Dispatched volume of w

$f^{z,\omega}_{n,m}$ Flow dispatched to zone z from $n \in N$ to $m \in N$

π^u_{DA} Expected profit of u

$c^{RT}_{TSO,\omega}$ Cost of the TSO

π_u Total profit of u for both markets

Dual variables - day-ahead market

$\lambda_{z,n}^{DA}$ Demand balance dual
$\mu_{u}^{DA,UP}$ Production capacity dual u, upper bound
$\mu_{u,z}^{DA,LO}$ Production capacity dual u, lower bound
$\mu_{w}^{DA,UP}$ Production capacity dual w, upper bound
$\mu_{w,z}^{DA,LO}$ Production capacity dual w, lower bound
$\theta_{n,m}^{DA,UP}$ Flow capacity dual, upper bound
$\theta_{n,m,z}^{DA,LO}$ Flow capacity dual, lower bound

Dual variables - real-time market

$\lambda_{n,z,\omega}^{RT}$ Nodal balance dual, RT
$\mu_{u,\omega,z}^{-,UP}$ Dual for downward adjustment of u, upper bound
$\mu_{u,\omega,z}^{-,LO}$ Dual for downward adjustment of u, lower bound
$\mu_{u,\omega}^{+,UP}$ Dual for upward adjustment of u, upper bound
$\mu_{u,\omega,z}^{+,LO}$ Dual for downward adjustment of u, lower bound
$\mu_{w,\omega}^{RT,UP}$ Dual for curtailment of w
$\mu_{w,\omega,z}^{RT,LO}$ Dual for lower bound of w
$\theta_{n,m,\omega}^{RT,UP}$ Flow capacity dual, upper bound
$\theta_{n,m,\omega,z}^{RT,LO}$ Flow capacity dual, lower bound

C. Day-ahead market, producer's perspective

Here, the sub-problem from the first stage, upper level in the EPEC is considered. The conventional producers seek to maximize their profit in the day-ahead market.

$$\underset{b_u^{DA}}{MAX}\ c_{TSO}^{DA} = \sum_{z \in Z} (\hat{\lambda}_{z,n_u}^{DA} - MC_u)\ \hat{v}_{u,z}^{DA}, \forall u \in U \tag{1.1}$$

Subject to bid caps enforced by the TSO:

$$C_u^{B,H} \leq b_u^{DA} \leq C_u^{B,H},\ \forall u \in U \tag{1.2}$$

Subject to the feasible region in the subsequent sub-problems.

D. Day-ahead market, TSO's perspective

Here, the sub-problem from the first stage, lower level in the EPEC is considered. In response to the bids submitted by the producers in the network, the TSO minimizes cost of dispatch in the day-ahead market. To split volumes when bids are equal, we add a quadratic cost tiebreaker:

$$\underset{v_{u,z}^{DA}, v_{w,z}^{DA}}{MIN} c_1^{TSO} = \sum_{z \in Z} \sum_{u \in U} (\hat{b}_u^{DA}\ v_{u,z}^{DA} + Q(v_{u,z}^{DA})^2) \tag{2.1}$$

The zonal demand has to be fulfilled:

$$\begin{aligned} D_n^z + \sum_{m \in \{N \setminus \{n\}\}} f_{n,m}^z - \sum_{m \in \{N \setminus \{n\}\}} f_{m,n}^z \\ - \sum_{u \in U_n} v_{u,z}^{DA} - \sum_{w \in W_n} v_{w,z}^{DA} = 0, \forall n \in N, z \in Z \end{aligned} \tag{2.2}$$

The TSO cannot dispatch producers beyond their production capacity, or windmills beyond their forecast of production capacity:

$$\sum_{z \in Z} v_{u,z}^{DA} \leq C_u^P,\ \forall u \in U \tag{2.3}$$

$$\sum_{z \in Z} v_{w,z}^{DA} \leq C_w^P,\ \forall w \in W \tag{2.4}$$

Lower bound on volumes dispatched:

$$0 \leq v_{u,z}^{DA},\ \forall u \in U, z \in Z \tag{2.5}$$

$$0 \leq v_{w,z}^{DA},\ \forall w \in W, z \in Z \tag{2.6}$$

Transmission constraint, wherein flow cannot exceed transmission capacity on line. As intra-zonal transmission constraints are disregarded in the day-ahead market, these are set arbitrarily high to prevent being constraining, but inter-zonal constraints still apply:

$$\sum_{z \in Z} f_{n,m}^z \leq C_{n,m}^{T,DA},\ \forall n, m \in \{N | n \neq m\} \tag{2.7}$$

Nonnegativity constraint for day-ahead flow:

$$0 \leq f_{n,m}^z,\ \forall n, m \in \{N | n \neq m\}, z \in Z \tag{2.8}$$

Subject to the feasible region in the other sub-problems.

E. Real-time market, producer's perspective

Here, the sub-problem from the second stage, upper level in the EPEC is considered. In the second stage, all producers submit bids for upward and downward redispatchment to maximize their own profit in the redispatch market:

$$\begin{aligned} \underset{b_u^+,\ b_{u,\omega}^-}{MAX} \pi_2^u = \sum_{\omega \in \Omega} P_\omega \sum_{z \in Z} ((b_{u,\omega}^+ - MC_u^+)\ \hat{v}_{u,z,\omega}^+ \\ + (MC_u^- - b_{u,\omega}^-)\ \hat{v}_{u,z,\omega}^-), \forall u \in U \end{aligned} \tag{3.1}$$

Subject to bid caps:

$$C_u^{B,L} \leq b_{u,\omega}^+ \leq C_u^{B,H},\ \forall u \in U, \omega \in \Omega \tag{3.2}$$

$$C_u^{B,L} \leq b_{u,\omega}^- \leq C_u^{B,H},\ \forall u \in U, \omega \in \Omega \tag{3.3}$$

Subject to the feasible region in the other sub-problems.

F. Real-time market, TSO's perspective

Here, the sub-problem from the second stage, lower level in the EPEC is considered. The TSO minimizes the total cost of redispatching producers upwards and downward, to ensure a feasible solution. Again, we add a quadratic cost tiebreaker:

$$\begin{aligned} \underset{v_{u,z,\omega}^+, v_{u,z,\omega}^-, v_{w,z}^{RT}}{MIN} c_{2,\omega}^{TSO} = \sum_{z \in Z} \sum_{u \in U} (\hat{b}_{u,\omega}^+\ v_{u,z,\omega}^+ \\ - \hat{b}_{u,\omega}^-\ v_{u,z,\omega}^- + Q((v_{u,z,\omega}^+)^2 - (v_{u,z,\omega}^-)^2)), \forall \omega \in \Omega \end{aligned} \tag{4.1}$$

This minimization is subject to a nodal balance ensuring demand is met in each node by available production and net flow to node:

$$\begin{aligned} \sum_{m \in \{N \setminus \{n\}\}} (f_{n,m}^{z,\omega} - f_{m,n}^{z,\omega}) - \sum_{u\ \in\ U_n} (v_{u,z,\omega}^+ - v_{u,z,\omega}^-) \\ - \sum_{u\ \in\ U_n} \hat{v}_{u,z}^{DA} - \sum_{w\ \in\ W_n} v_{w,z}^{RT} + D_n^z = 0, \\ \forall\ z \in Z, n \in N, \omega \in \Omega \end{aligned} \tag{4.2}$$

The TSO cannot invoke a downward adjustment of production larger than what was scheduled in the day-ahead market:

$$v_{u,z,\omega}^{-} \le \hat{v}_{u,z}^{DA},\ \forall u \in U, z \in Z, \omega \in \Omega \quad (4.3)$$

The TSO cannot redispatch a producer beyond their production capacity:

$$\sum_{z\in Z}(v_{u,z,\omega}^{+} - v_{u,z,\omega}^{-} + \hat{v}_{u,z,}^{DA}) \le C_u^P,\ \forall u \in U, \omega \in \Omega \quad (4.4)$$

$$\sum_{z\in Z} v_{w,z,\omega}^{RT} \le C_{w,\omega}^{RT},\ \forall w \in W, \omega \in \Omega \quad (4.5)$$

Transmission constraint, wherein flow cannot exceed transmission capacity on line:

$$\sum_{z\in Z} f_{n,m}^{z,\omega} \le C_{n,m}^{T},\ \forall n, m \in \{N|n \ne m\}, \omega \in \Omega \quad (4.6)$$

The flows are unidirectional and non-negative, thus there is a separate variable for the flow in each direction. We also need nonnegativity constraints for all flows and volumes:

$$0 \le v_{u,z,\omega}^{-},\ \forall u \in U, \omega \in \Omega, z \in Z \quad (4.7)$$

$$0 \le v_{u,z,\omega}^{+}, \forall u \in U, \omega \in \Omega, z \in Z \quad (4.8)$$

$$0 \le v_{w,z,\omega}^{RT}, \forall w \in W, \omega \in \Omega, z \in Z \quad (4.9)$$

$$0 \le f_{n,m}^{z,\omega},\ \forall n, m \in \{N|n \ne m\}, \omega \in \Omega, z \in Z \quad (4.10)$$

Subject to the feasible region in the subsequent subproblems.

G. The full EPEC model

We here merge the two levels and stages into one, by letting the producer maximize his expected profit from both stages at once, while the responses from the TSO are being anticipated in the form of KKTs introduced to the upper-level problem. Furthermore, this requires the producer to consider the version of the second-stage problems in each scenario they perceive.

Profit maximization as a linear combination of both day-ahead and redispatch profits:

$$\begin{aligned} \underset{b_{u,\omega}^{DA}, b_{u,\omega}^{+}, b_{u,\omega}^{-}}{MAX} \pi_u &= \sum_{z\in Z}((\lambda_{z,n_u}^{DA} - MC_u)\ \hat{v}_{u,z}^{DA} \\ &+ \sum_{\omega\in\Omega} P_\omega((b_{u,\omega}^{+} - MC_u^{+})\ \hat{v}_{u,z,\omega}^{+} + \\ &(MC_u^{-} - b_{u,\omega}^{-})\,\hat{v}_{u,z,\omega}^{-})) \end{aligned} \quad (5.1)$$

Bid caps for both stages, see equations 1.2, 3.3 and 3.2.

KKT conditions from TSO day-ahead:

$$\begin{aligned} 0 \le v_{u,z}^{DA} \perp \hat{b}_u^{DA} - \lambda_{z,n_u}^{DA} + \mu_u^{DA,UP} \\ + 2Qv_{u,z}^{DA} - \mu_u^{DA,LO} \ge 0,\ \forall u \in U \end{aligned} \quad (5.2)$$

$$\begin{aligned} 0 \le v_{w,z}^{DA} \perp -\lambda_{z,n_w}^{DA} + \mu_w^{DA,UP} - \\ \mu_{w,z}^{DA,LO} \ge 0,\ \forall w \in W \end{aligned} \quad (5.3)$$

$$\begin{aligned} 0 \le f_{n,m}^{z} \perp \lambda_{z,n_u}^{DA} - \lambda_{m_u,z}^{DA} + \theta_{n,m}^{DA,UP} \\ -\theta_{n,m,z}^{DA,LO} \ge 0, \forall n, m \in \{N|n \ne m\}\ , \forall z \in Z \end{aligned} \quad (5.4)$$

$$\begin{aligned} \lambda_{z,n_u}^{DA} f.i.s. \perp D_n^z + \sum_{m\in\{N\setminus\{n\}\}} (f_{n,m}^{z} - f_{m,n}^{z}) \\ - \sum_{u\in U_n} v_{u,z}^{DA} - \sum_{w\in W_n} v_{w,z}^{DA} = 0,\ \forall n \in N, z \in Z \end{aligned} \quad (5.5)$$

$$0 \le \mu_u^{DA,UP} \perp \sum_{z\in Z} v_{u,z}^{DA} \le C_u^P,\ \forall u \in U \quad (5.6)$$

$$0 \le \mu_w^{DA,UP} \perp \sum_{z\in Z} v_{w,z}^{DA} \le C_w^P,\ \forall w \in W \quad (5.7)$$

$$0 \le \mu_{u,z}^{DA,LO} \perp v_{u,z}^{DA} \ge 0,\ \forall u \in U, z \in Z \quad (5.8)$$

$$0 \le \mu_{w,z}^{DA,LO} \perp v_{w,z}^{DA} \ge 0,\ \forall w \in W, z \in Z \quad (5.9)$$

$$\begin{aligned} 0 \le \theta_{n,m,z}^{DA,UP} \perp \sum_{z\in Z} f_{n,m}^{z} \le C_{n,m}^{T,DA}, \\ \forall n, m \in \{N|n \ne m\} \end{aligned} \quad (5.10)$$

$$\begin{aligned} 0 \le \theta_{n,m,z}^{DA,LO} \perp \sum_{z\in Z} f_{n,m}^{z} \ge 0, \\ \forall n, m \in \{N|n \ne m\}, z \in Z \end{aligned} \quad (5.11)$$

KKTs from TSO redispatch problem:

$$\begin{aligned} 0 \le v_{u,z,\omega}^{+} \perp \hat{b}_{u,\omega}^{+} + 2Qv_{u,z,\omega}^{+} - \lambda_{n_u,z,\omega}^{RT} + \mu_{u,\omega}^{+,UP} \\ -\mu_{u,\omega,z}^{+,LO} \ge 0,\ \forall u \in U,\ \omega \in \Omega, z \in Z \end{aligned} \quad (5.12)$$

$$\begin{aligned} 0 \le v_{u,z,\omega}^{-} \perp -\widehat{b}_{u\omega}^{-} - 2Qv_{u,z,\omega}^{-} + \lambda_{n_u,z,\omega}^{RT} + \mu_{u,\omega,z}^{-,UP} \\ -\mu_{u,\omega,z}^{+,UP} - \mu_{u,\omega,}^{-,LO} \ge 0,\ \forall u \in U,\ \omega \in \Omega, z \in Z \end{aligned} \quad (5.13)$$

$$\begin{aligned} 0 \le f_{n,m}^{z,\omega} \perp \lambda_{n_u,z,\omega}^{RT} - \lambda_{m_u,z,\omega}^{RT} + \theta_{n,m,\omega}^{RT,UP} \\ -\theta_{n,m,\omega,z}^{RT,LO} \ge 0, \forall n, m \in \{N|n \ne m\}, \omega \in \Omega, z \in Z \end{aligned} \quad (5.14)$$

$$\begin{aligned} \lambda_{n\omega}^{RT}\ f.i.s. \perp \sum_{m\in\{N\setminus\{n\}\}} (f_{n,m}^{z,\omega} - f_{m,n}^{z,\omega}) \\ - \sum_{u\ \in\ U_n} (v_{u,z,\omega}^{+} - v_{u,z,\omega}^{-}) - \sum_{u\ \in\ U_n} \hat{v}_{u,z}^{DA} \\ - \sum_{w\ \in\ W_n} v_{w,z}^{RT} + D_n^z = 0, \forall z \in Z, n \in N, \omega \in \Omega \end{aligned} \quad (5.15)$$

$$\begin{aligned} 0 \le v_{w,z,\omega}^{RT} \perp -\lambda_{n_u,z,\omega}^{RT} + \mu_{w,\omega}^{+,UP} - \mu_{w,z,\omega}^{-,LO} \ge 0, \\ \forall w \in W, \omega \in \Omega, z \in Z \end{aligned} \quad (5.16)$$

$$\begin{aligned} 0 \le \mu_{u,z,\omega}^{-,UP} \perp v_{u,z,\omega}^{-} \le \hat{v}_{u,z}^{DA}, \\ \forall u \in U,\ \omega \in \Omega, z \in Z \end{aligned} \quad (5.17)$$

$$\begin{aligned} 0 \le \mu_{u,\omega}^{+,UP} \perp \sum_{z\in Z}(v_{u,z,\omega}^{+} - v_{u,z,\omega}^{-} \\ + \hat{v}_{u,z}^{DA}) \le C_u^P,\ \forall u \in U, \omega \in \Omega \end{aligned} \quad (5.18)$$

$$0 \le \mu_{w,\omega}^{RT,UP} \perp \sum_{z\in Z} v_{w,z}^{RT} \le C_{w\omega}^{P,RT},\ \forall w \in W, \omega \in \Omega \quad (5.19)$$

$$\begin{aligned} 0 \le \theta_{n,m,\omega}^{RT,UP} \perp \sum_{z\in Z} f_{n,m}^{z,\omega} \le C_{n,m}^{T,RT}, \\ \forall n, m \in \{N|n \ne m\}, \omega \in \Omega \end{aligned} \quad (5.20)$$

$$0 \le \mu_{u,z,\omega}^{-,LO} \perp v_{u,z,\omega}^{-} \ge 0,\ \forall u \in U, \omega \in \Omega, z \in Z \quad (5.21)$$

$$0 \le \mu_{u,z,\omega}^{+,LO} \perp v_{u,z,\omega}^{+} \ge 0,\ \forall u \in U, \omega \in \Omega, z \in Z, \quad (5.22)$$

$$0 \leq \mu^{RT,LO}_{w,z,\omega} \perp v^{RT}_{w,z,\omega} \geq 0, \ \forall w \in W, \omega \in \Omega, z \in Z \quad (5.23)$$

$$0 \leq \theta^{RT,LO}_{n,m,\omega,z} \perp f^{z,\omega}_{n,m} \geq 0, \\ \forall n, m \in \{N | n \neq m\}, \omega \in \Omega, z \in Z \quad (5.24)$$

H. EPEC Diagonalization algorithm

The EPEC is solved by letting each producer solve their MPEC, in a diagonalization approach. The MPEC is subsequently solved for each agent, with the bids of the other strategic bidders parameterized. This is repeated until an equilibrium is found, where bids deviate less than tol, or some maximum number of iterations $maxIter$ is reached. Before starting, the values of all bids are initialized to some feasible value in $b^{da,prev}_u$, $b^{pl,prev}_{u,\omega}$ and $b^{min,prev}_{u,\omega}$, respectively for each u.

Algorithm 1 Diagonalization Algorithm

```
i = 0
while i ≤ maxIter do
  ε^da, ε^pl, ε^min = 0
  for u ∈ U do
    Solve MPEC w.r.t. player u, maximizing π^u
    Subject to:
      1) Bid caps for both stages
      2) KKTs from TSO day-ahead problem
      3) KKTs from TSO redispatch problem
    ε^da = max(|b_u^da − b_u^{da,prev}|, ε^da)
    for ω ∈ Ω do
      ε^pl = max(|b_{u,ω}^pl − b_{u,ω}^{pl,prev}|, ε^pl)
      ε^min = max(|b_{u,ω}^min − b_{u,ω}^{min,prev}|, ε^min)
    end for
  end for
  if ε^da + ε^pl + ε^min ≤ tol then
    exit
  end if
  i += 1
end while
end
```

I. Mitigating measures

1) Long-term contracts: For long-term contracts, the bid variables in the real-time market are exchanged with a fixed compensation price per volume of redispatch offered by the producers whom have entered into the contract. The contracts are here designed such that the compensated price per volume offered in the real-time market is set to the day-ahead market price times a premium. This implies the following altering of the program for the relevant producers:

$b^+_{u,\omega}$, is set to $\lambda^{DA}_{z,n_u}(1+\zeta)$, for all u entering the contract,
$b^-_{u,\omega}$, is set to $\lambda^{DA}_{z,n_u}(1-\zeta)$, for all u entering the contract.

Where ζ is the premium paid for offering flexibility. In our setup, the long-term contracts are exogenously enforced, i.e. by the government, meaning producers cannot decide on the price, volume or whether to enter the contract or not. There are no volume limits incorporated in the contract.

2) Norwegian solution: The Norwegian solution is modeled in the same way as the long-term contracts. For producers playing the inc-dec game, the compensation price per volume of redispatch is set to the prevailing day-ahead market price:

$b^+_{u,\omega}$, is set to λ^{DA}_{z,n_u}, for all u participating in the inc-dec game,
$b^-_{u,\omega}$, is set to λ^{DA}_{z,n_u}, for all u participating in the inc-dec game.

3) Nodal pricing: Here, nodal constraints are accounted for in the day-ahead market. This is done by altering equation 2.7, such that: $C^{T,DA}_{n,m}$ is set to $C^{T,RT}_{n,m}$, or equivalently:

$$\sum_{z \in Z} f^z_{n,m} \leq C^{T,RT}_{n,m}, \ \forall n, m \in \{N | n \neq m\} \quad (6.1)$$

In the day-ahead market.

III. Implementation

To numerically test the developed framework, the model was applied to Chao and Peck six-node nework [33]. It is a popularly used example network used in research, for example by Sarfati and Holmberg (2020) [2] and is shown in Figure 2.

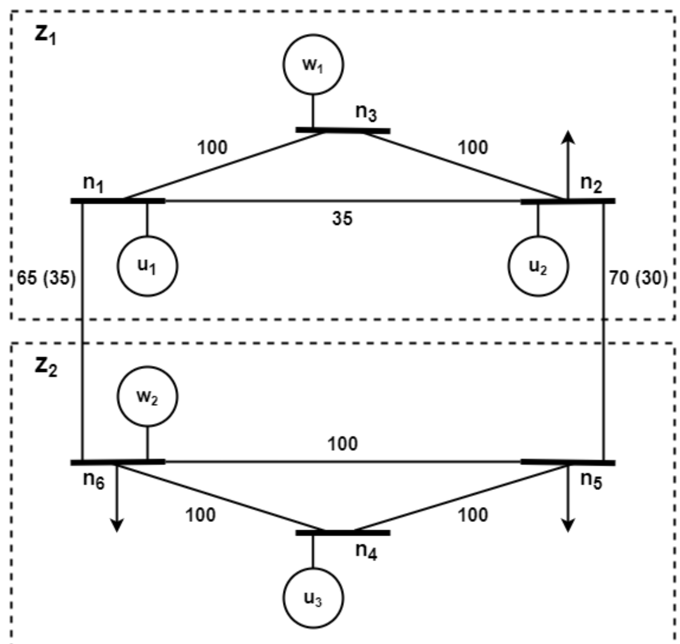

Fig. 2: A graphical representation of the network used to analyze the mitigation efforts. $C^{T,RT}_{n,m}$ for setup 1 is visualized in the figure, with adaptions for setup 2 in parenthesis. All transmission capacities are in MW.

Parameters were then chosen to display interesting mechanics with regards to congestion and potential for inc-dec gaming. In the interest of doing so, two sets of parameters were chosen. The parameters of setup 1 were replicated from a paper of Sarfati and Holmberg (2020) [2], with an exception in the marginal cost of upwards and downwards redispatch. We have chosen an extra cost of $+-10\%$, compared to the marginal cost in the day-ahead market. This cost is smaller than those chosen by Sarfati and Holmberg (2020)

[2]. Parameter values in setup 1 are set so that no node is dependent on the production from one conventional producer, implying that no producer has market power over any nodes. Compared to [2], we allow for continuous bid regions, whereas their bid regions are discretized. Setup 2 is the result of adjusting the parameters from setup 1 to include examples with market power (which promotes gaming). In the cases the parameter values in the two setups differ, the value in setup 2 is in parenthesis behind the value in setup 1 (for instance the transmission capacity between n_1 and n_6, which is 65 MW in setup 1 and 35 MW in setup 2). For both setups, the intra-zonal transmission capacity in the day-ahead market ($C^{T,RT}_{n,m}$) is set to 999 MW, while the inter-zonal transmission capacity is set to 130MW, similar to Sarfati and Holmberg 2020 [2].

The directional lines out of nodes represent the loads in the system, and for node 2, 5 and 6 their demand are respectively 120 MW, 60 MW and 100 MW. The parameters chosen for the producers can be found in Table I for setup 1 and Table II for setup 2. Worth noting is that the cost of redispatching upwards is higher than MC^{DA}_u due to the higher cost of adjusting production on short notice, while the value salvaged from downward adjusting production in the intraday, MC^{MIN}_u, is lower than MC^{DA}_u as generators are not able to recuperate sunk costs when reducing scheduled production. Parameters for the wind producers (who do not have a marginal cost and are not bidding like the conventional producers) can be found in table III, where the probabilities P_ω for scenarios ω_1 and ω_2 are each 50%. The quadratic cost tiebreaker constant, Q, was set to 0.00001. Finally, the line capacities are displayed in Figure 2.

TABLE I: Parameter values of Conventional Producers

	MC^{DA}_u	MC^{MIN}_u	MC^{PL}_u	C^P_u	$C^{B,L}_u$	$C^{B,H}_u$
u_1	11.5	10.45	12.65	150	5	30
u_3	10.5	9.45	11.55	250	5	30
u_2	13	11.7	14.3	150	5	30

Parameters for setup 1. All numbers in $\$/MWh$.

TABLE II: Parameter values of Conventional Producers

	MC^{DA}_u	MC^{MIN}_u	MC^{PL}_u	C^P_u	$C^{B,L}_u$	$C^{B,H}_u$
u_1	11	11	11	100	5	30
u_3	10.5	10.5	10.5	250	5	30
u_2	12	12	12	150	5	30

Parameters for setup 2. All numbers in $\$/MWh$.

The mitigating measures detailed in Section II-I were implemented into the system to measure their impact. The flexibility-premium for long-term contracts, ζ, was set to 5%. First, a long-term contract was implemented for only u_1. Second, they were implemented for both u_1 and u_3, in order to have a contracted flexibility provider in each zone. The model including the diagonalization was coded into GAMS with the network and parameters shown above, and then solved using the CONOPT 3 MPEC solver. From the diagonalization algorhitm, $maxIter$ was set to 1000, and tol to $10E-4$. The feasible regions of the bids were then split into smaller sections, finding the equilibrium in each section to investigate potential multiple equilibria. All cases were solved within 10 minutes and before $maxIter$ was reached.

TABLE III: Parameter values of Wind Producers

	C^P_w	C^{RT}_{w,ω_1}	C^{RT}_{w,ω_2}
w_1	30	36	24
w_2	37.5	45	30

Parameters for setup 1 and setup 2. All numbers in $\$/MWh$.

IV. Results and discussion

Here, results from the setups implemented and solved are presented and discussed. Sections IV-A and IV-B give an overview over results in the various setups. For each model, relevant metrics resulting from the equilibria found are presented. These metrics are:

- The expected profit for each producer,
- The total cost paid by the consumer,
- The total consumer surplus, in which the consumer is assumed to be willing to pay the upper bid cap for electricity in all cases,
- The TSO's rebalancing costs (resulting from counter-trading in the real-time market),
- The total social welfare.

A. Results from setup 1

The equilibria found are presented in Table IV, with resulting metrics in Table V, above the dotted lines. In setup 1, inc-dec gaming is not observed. Rather, producer u_2, with the lowest marginal cost, slightly underbids the marginal cost of producer u_1, winning all demand. Subsequently, there is no need for redispatch beyond what is needed due to the change in wind capacity.

In setup 1, the described strategy yields the highest profit for the producer with the lowest marginal cost, u_2. As u_2 is able to fulfill all demand, without congestion, the result is feasible in both markets, not accounting for the change in wind generation. Regarding the redispatch needed due to wind production, the two scenarios must be considered individually. In the first scenario, the wind production increases, causing a need for downwards redispatch. As u_2 is the only conventional producer that has sold power in the day-ahead market, it is the only producer that can offer downwards redispatch in the real-time market. As such, he has market power, and bids the approximately the lowest feasible bid, 5.002 $\$/MWh$, in order to maximize profit. In scenario two, the wind production is lower than what was scheduled, and any conventional producer may upwards adjust their production. As there now is competition, without any market power, u_2 wins the auction at his marginal cost for upwards adjustment of production, 11.55 $\$/MWh$. This is the most efficient market outcome, implying

TABLE IV: Optimal bid values in all setups analyzed

	u_1			u_2			u_3		
		ω_1	ω_2		ω_1	ω_2		ω_1	ω_2
	b_u^{DA}	$(b^+_{u,\omega}, b^-_{u,\omega})$	$(b^+_{u,\omega}, b^-_{u,\omega})$	b_u^{DA}	$(b^+_{u,\omega}, b^-_{u,\omega})$	$(b^+_{u,\omega}, b^-_{u,\omega})$	b_u^{DA}	$(b^+_{u,\omega}, b^-_{u,\omega})$	$(b^+_{u,\omega}, b^-_{u,\omega})$
Setup 1	11.506	5.002,5.002	11.555,11.555	11.496	5.002,5.002	11.554,11.554	11.506	5.002,5.002	11.555,11.555
Setup 2	15.997	30.000, 6.999	11.695, 5.000	15.996	30.000, 5.000	30.000, 5.000	15.995	30.000,5.000	11.696, 11.696
LTC (1)	11.000	11.550,10.450	11.550,10.450	10.999	11.000,11.000	11.000,11.000	11.000	11.000,10.999	30.000,11.000
LTC (2)	11.006	11.556,10.455	11.556,10.455	11.005	10.455,10.455	11.556,5.000	11.005	11.556,10.455	11.556,10.455
Nor.Sol.	15.854	15.854,15.854	15.854,15.854	15.854	15.854,15.854	15.854,15.854	15.854	15.854,15.854	15.854,15.854
Nodal	19.938	30.000,5.000	30.000,5.000	19.939	30.000,12.886	30.000,30.000	30.000	30.000,5.000	30.000,5.000

Results using setup 1 presented in first line. Results using setup 2 presented below the dotted line. Be aware that when no upwards (downwards) redispatch is needed, the corresponding bids, $b^+_{u,\omega}(b^-_{u,\omega})$, become irrelevant and should not be analysed, see section IV-C. All numbers in $\$/MWh$.

TABLE V: Social welfare values in all setups analyzed

	π_{u_1}	π_{u_2}	π_{u_3}	TSO Cost	Consumer Cost	Consumer Surplus	Total Welfare
Setup 1	0.000	243.567	0.000	44.234	3221.726	5178.274	5377.606
Setup 2	34.234	343.503	659.584	45.167	4479.015	3920.985	4913.138
LTC (1)	0.000	87.210	156.237	225.637	3080.019	5319.981	5337.791
LTC(2)	0.000	54.449	-64.540	7.419	3081.517	5318.483	5300.972
Nor.Sol.	352.019	158.335	425.572	0.000	4439.224	3960.776	4896.702
Nodal	893.902	503.060	1156.412	115.523	7192.781	1207.219	3645.070

Results using setup 1 presented in first line. Results using setup 2 presented below the dotted line. All numbers in \$.

that the market design works well in this setting. Table V supports this analysis, where u_2 is the only conventional producer earning a profit. The TSO has to pay an extra cost of redispatch, mainly due to the market power u_2 exhibits in scenario 1. This model has the highest total social welfare, indicating that it entails the most market efficient outcome.

As no redispatch is needed beyond the change in wind, our results suggest that when no producer has market power over any node, inc-dec gaming does not occur, as strategies obtaining inflated profits are dominated by more market efficient strategies. This result is contrary to what Sarfati & Holmberg [8] found, where inc-dec gaming was found in the same setup but with a lower marginal cost of upwards/downwards adjustment of production and a discretized bid region, as opposed to our continuous bid region. The strategy found by our model, where the lowest marginal cost producer wins the auction by just slightly underbidding their competitor, seems intuitive and rational, and was, therefore, expected. However, the discrepancy between the strategy found by Sarfati and Holmberg (2020) [2] and our model, was not fully expected. This discrepancy may be explained by the difference in discrete and continuous bid regions. In the discretized bid regions in [2] a producer knows that another producer has to bid a rather large amount, $0.5\$/MWh$ or even $1\$/MWh$ less to underbid them, rather than a very small positive amount. Consequently, the producer knows that it will not be better for their competitor to undercut them, and, therefore, the strategic producer has more power over the market. More power over the market makes markets easier to exploit and inc-dec more likely. This explains why discrete bid regions with a rather coarse grid make inc-dec gaming more likely, compared to finer grid or even continuous bid regions.

B. *Results from setup 2*

The equilibria found in setup 2 are presented in Table IV, with resulting metrics in Table V, below the dotted lines. In this setup, we experiment with new parameter values in order to investigate when inc-dec gaming may occur. Furthermore, mitigating measures are introduced to disincentivize inc-dec gaming and limit the negative effects.

1) Results from setup 2, absent mitigating efforts: In this solution we observe inc-dec gaming, where u_3, the producer with highest marginal cost, underbids the other conventional producers in order to increase his own volume in the day-ahead market. The same, but opposite, argument can be made for the two other producers, in zone 1. In the real-time market, congestion is present, requiring u_3 to be downwards redispatched, while u_1 and/or u_2 must be upwards redispatched. The producers are aware of this and are able to exploit it to gain large profits. This can be seen in row two table IV, where the bid for upwards adjustment is $30.000\ \$/MWh$, i.e. the bid cap, for all producers in scenario 1. Conversely, the bids for downwards adjustment are close to the lower bid cap, implying that producers are able to gain extraordinary profits. The strategic behaviour to gain large redispatch volumes is clear. Such behaviour is expected when producers are needed to meet the demand in a specific node and therefore have market power over the demand. Compared to setup 1, the producers are able to gain substantially larger profits, by increasing the cost for both the TSO and the consumer. The total social welfare is also lowered, which also partly is to be expected as the more constrained network implies that the producer with the highest marginal cost, u_3, has to produce to obtain a feasible solution.

2) Results from setup 2, long term contract for player one: For the long-term contract measure, the real-time market bids, for the producers that have entered into this contract, should be interpreted as the amount the producers are remunerated for each MWh they are redispatched in the real-time market.

By introducing long-term contracts in zone 1, for u_1, we find that inc-dec gaming is effectively mitigated in this zone. The TSO now has a cheaper alternative for redispatch, which yields significantly smaller profits to the gaming producers in this zone (see producer profit values for LTC (1) in table IV). An interesting finding is that the that long term contract incentivizes other producers in the same zone without a contract to outbid these contracts, as seen for u_2 here.

However, producer u_3 is still able to game the system, to obtain extraordinary profits. u_3 overbids the other producers in the day-ahead market, in order to get upwards redispatched in the real-time market. Due to congestion, volumes from u_3 are needed to fulfill demand in zone 2. This is exploited by u_3, which bids its upper bid cap $30\$/MWh$, see table IV, resulting in a high profit for u_3 and a high cost for the TSO. In sum, the measure has effect on gaming in the zone it is implemented, but not in other zones.

Nevertheless, the total social welfare is the highest for all mitigating measures here. This stems from a price of $11.000\ \$/MWh$ in the day-ahead market, which yields a large consumer surplus, while the high cost for the TSO is neutralized by the high profit for u_3.

3) Results from setup 2, long term contract for u_1 and u_3: By introducing long term contracts in both zones, gaming is effectively mitigated in the entire system. This can be seen in the lowered producers' profits and TSO cost for LTC (2) in table IV. As u_2 and u_3 have equal bids here, volumes are split half-half. This likely lowers the need for redispatch, compared to if only one producer was dispatched, as volumes are more spread out in the system. Such, results suggest that producers are incentivized to avoid congestion, rather than the opposite as is the case for inc-dec gaming. Also, as the TSO has contracted options for redispatch in both zones, the producer profits from the real-time market are very limited. In fact, in this setting, the feasible solution yields a negative profit for u_3. This is due to the payment of redispatch volumes described in the contracts being dependent on the day-ahead market price. Further, the market price is significantly lower than u_3's marginal cost, such that this feasible and optimal solution yields a negative profit for u_3. In a real-life setting the contract should of course be adapted such that u_3 is protected from a negative profit with a profitable and acceptable contract. By auctioning such contracts, the price and compensation may converge to an acceptable midpoint. Again, it is seen that not all producers have to enter into the marginal contracts, in order to mitigate gaming.

From table V, it is clear that the TSO's cost in the real-time market is very low, while the consumer cost also remains low, on the relative, due to a low price of power in the day-ahead market. Simultaneously, the producers make no expected profits in sum. Such, a trade-off between the producers' profits on the one side, and the consumers' and TSO's cost, on the other side, appears. This trade-off is important and must be considered when considering mitigating measures. Compared to the long-term contracts setup with only one producer, this trade-off can be analysed further; while the total welfare remains relatively constant, the profits are moved from the producer to the consumer and TSO, when comparing the two long-term contracts implementations.

4) Results from setup 2, Norwegian solution: With the Norwegian solution, producers playing the inc-dec game are assumed to be caught, and not be allowed to earn profit from the real-time market. The TSO cost which results from the real-time market is, therefore, zero, as expected. This is because the Norwegian solution sets the price of all volumes from gaming producers in the real-time market to the prevailing day-ahead market price, both for upwards and downwards dispatch. Given that the gaming producers are the only ones offering volumes in the real-time market, the total TSO cost from the real-time market has to be zero. The redispatch bids presented in table IV, for the Norwegian Solution, should here be interpreted as the price that each producer is compensated for each volume that he is upwards or downwards redispatched. As for all producers, the intraday compensation is equal to their day-ahead bid, meaning they are remunerated that same amount in the real-time market. This result is expected, as gaming producers are prevented from obtaining extraordinary profits. Consequently, and as can be seen in table V, the TSO's cost is lowered, but this comes at the expense of the consumers' surplus. Thus, the producers' profits remains high relative to the model in setup 2 without any mitigating measures. As can be seen in table IV, this is because the producers present relatively high, equal bids resulting in a split of volumes, where all gain high profits. Still, it is worth noting that both the consumers' cost and the TSO's cost are down, while the producers' profits are down and the total social welfare stays relatively unchanged, compared to the original setup 2 model. Thus, we again see a new balance of the trade-off described earlier, where profits are moved from the producers to the TSO and consumer. We can therefore argue that the Norwegian solution to some extent is effective at mitigating the adverse effects of inc-dec gaming.

5) Results from setup 2, nodal pricing: In this set up, both the day-ahead market and the redispatch market considers nodal pricing. Therefore, there is only need for redispatch between the two markets to manage the change in wind production. From table IV, it is evident that producer u_3 exploits the need for his volume in zone 2, and bids $30\$/MWh$ (the bid-cap) in the day-ahead market. Their profit is, therefore, substantially higher in the day-ahead market, than in the real-time market, compared to the other mitigation efforts. This result is not unexpected, as high spikes of prices in certain nodes are to be expected with nodal pricing, as discussed in section I-B. Further, this emphasises that the problem here does not lie in the market design, but rather in the congested transmission lines. Accordingly, nodal pricing only aggravates the ability to exploit market power in the day-ahead market and does not mitigate the extraordinary costs caused by local market power, even though it lowers congestion. As a result, the TSO's cost is relatively low, while we see increased consumer cost as well as a lowered consumer surplus and total social welfare. The consumer cost and consumer surplus metrics both stem purely from the cost of volumes in the day-ahead market. As the day-ahead price is substantially higher in both zones in this setup, compared to the others, the consumers' metrics are largely affected. Although the producers' profits make up for this to some extent, it is not enough to mitigate the effect on the total social welfare. A final point is that all producers bid $30\$/MWh$ (the bid-cap) for upwards redispatch in the real-time market, which causes the perhaps surprisingly high TSO cost, as there is no need for redispatch beyond the change in wind production.

C. General discussion & limitations

The results suggest that strategic producers will anticipate the market and price in the day-ahead market, and bid either slightly above, equal, or slightly below the anticipated price to bid themselves out of or into the market.

Comparing setup 1 to setup 2, the total social welfare is greater in setup 1 than in all the other setups and mitigating measures. This is due to a less constrained network, which on the one hand lets the producer with lowest marginal cost sell to all nodes without congesting the network, even in the real-time market. This is an intuitive result, as a less constrained network entails a larger feasible region and possibility of a better solution. On the other hand, the lower congestion prevents the need for upwards and downwards redispatch, beyond managing the change in wind production. Furthermore, a less constrained network makes congestion less likely, which again decreases the likelihood of inc-dec gaming. Overall, a less constrained network better facilitates competition and reduces the risk of market power exploitation which yields a more efficient market outcome, as evident by the high social welfare. Another distinction between setup 1 and 2, is the presence of inc-dec gaming in the latter. This result also partly comes from the finding that a continuous bid region makes inc-dec gaming less likely. By tightening constraints in setup 2, we indeed see inc-dec gaming, as well as increased consumer and TSO costs, and a lowered total social welfare, which again is expected. Mitigating measures manage to some degree to increase the total social welfare in setup 2, but not quite up to the level in setup 1. Perhaps indicating that a strengthening of the grid is the safest measure available to mitigate inc-dec gaming completely.

Overall, strategies that exploit market power in the real-time market, by bidding equal to their lower or higher bid cap, is seen in most models. However, when no market power was present in the real-time market, the redispatch market was observed to function well and efficiently.

For setup 2, a trade-off between the producers' profits on the one hand, and the consumers' and TSO's cost, on the other hand, was observed. For the original setup 2, without any mitigating measure, we found that profits were skewed towards the producers. While the Norwegian reduced the producers profits and the cost of the TSO, it came at the expense of a lowered consumer surplus. As a result, the total social welfare was similar to the original setup 2, but with a different trade-off. Regarding the two implementations of long-term contracts, both were able to improve the total social welfare notably. Again, the described trade-off was observed. By making one producer enter a long-term contract, the profits were moved somewhat from the producers to the consumers, while the TSO's cost remained high. By making one producer in each zone enter the long-term contract, the trade-off was moved even further, were we saw low very profits for the producers, and low costs for the TSO and consumer. The total welfare remained relatively unchanged between the two implementations. Such, the various implementations offer different versions of the described trade-off.

Comparing the various mitigating measures, the long term-contracts yield the highest total welfare, by moving profits from the producers to the TSO and consumer. This is an important trade-off that must be considered when implementing mitigating measures, as it is not evident where the trade-off between profits should lie. We see that the profits for the producers that have entered into these contracts are substantially lowered. Long-term contracts must be designed such that they are acceptable for both parties, the producer and the TSO. An interesting finding is that the that long-term contract incentivizes other producers in the same zone without a contract to outbid these contracts, as seen for u_2 in our model. In sum, the measure has effect on gaming in the zone it is implemented, but not in other zones.

The Norwegian solution yields the lowest extra cost for the TSO in the real-time market. At the same time it also yields an increased cost for the consumer, where producers bid similarly in order to split volumes, leaving the total social welfare approximately unchanged. For the nodal pricing model, u_3 is able to exploit his local market power in the day-ahead market, vastly increasing the consumer cost and producers profit. This leaves the total social welfare at the lowest of all models, despite a relatively low TSO cost, due to no redispatch being needed, beyond the change in wind production. This result highlights that the underlying problem identified in setup 2 causing a lower social welfare, compared to setup 1, lies not in the market design, but in the constrained transmission lines.

A possible limitation is that the model and setup allow for loop flows. As producers may want to aggravate congestion further by creating loop flows, to earn larger profits in the redispatch market, this can potentially have quite negative effects. This is a limitation as in a real-life setting, the TSO would be in control of the flows, which would likely prevent such arbitrary loop flows. We, therefore, analysed flows thoroughly in all models and setups, but found no evidence of such loop flows. Still, it is a possible limitation of the model that it is important to be aware of.

Another point is that some bids in the real-time market may appear less intuitive. From our analysis of the results, this stems from some producers not getting upwards or downwards redispatched, due to no volumes sold in the day-ahead market or no available capacity in that scenario. In these cases, the bid in the real-time market becomes irrelevant and is often dependent upon its initialization value. This also explains why a producers' up and down real-time market bids can be equal in a specific scenario.

When bids are approximately equal, as seen for the Norwegian solution, volumes are not always split exactly equally over the various producers. This is due to the nature of the tiebreaker, in which a very small difference in bids can lead to small differences in awarded volumes, when bids are approximately, but not exactly, equal. This effect and limitation is only seen for setup 2 and not in setup 1. To be explicit, we do not find that it affects the insights from the analysis.

Further, an inefficient market is identified in setup 2, Norwegian solution, where producers present high equal bids in order to split volumes and gain high profits. Intuitively, we find it hard to explain the price these end up at. The reader should be aware of this when comparing consumer cost and social welfare as it can affect the results to a certain extent.

V. Concluding remarks

We model a framework to capture the dynamics of inc-dec gaming, by dividing the electricity market into two stages and two levels, which makes for four intuitive sub-problems. First, we find that these sub-problems can be merged and solved together in a single model by constructing an EPEC, which can be solved for a continuous bid region and solution space. Second, this EPEC-model can be solved for both stages of the electricity market at the same time, letting the producer present the bids from the day-ahead and the real-time market simultaneously. Third, we apply an intuitive method of solving the EPEC, by parametrizing competitors' bids and utilizing a diagonalization approach until convergence. Fourth, we utilize this set-up to analyse inc-dec gaming and mitigating measures. We investigate inc-dec gaming under two setups, to apply for a meaningful analysis. In the first setup, no single conventional producer's production is needed to fulfill demand, that is, no producer has market power over any loads. Here, we find no evidence of inc-dec gaming, contrary to what was found by Sarfati and Holmberg (2020) [8]. This can be explained by the effect that a discretized bid region may give strategic producers more market power which again makes inc-dec gaming more likely, compared to a continuous bid region. In the second setup, where local market power is present, we find evidence of inc-dec gaming with adverse effects. These can to some extent be mitigated by implementing mitigating measures. Here, long-term contracts yield the highest total social welfare. An important finding is that it suffices that one producer in each zone enters into such a contract in order to mitigate gaming, as other producers strive to outbid these contracts. Another finding is that the measure has effect on gaming in the zone it is implemented, but not in other zones. The Norwegian solution proves quite effective at mitigating inc-dec gaming, although it has little effect on the total social welfare as the consumers' surplus is lowered. Further, our nodal pricing model emphasizes that the problem causing market exploitation is not the market design, but rather the more constrained and congested transmission lines. For all mitigating measures, a trade-off between the producers' profits on the one hand, and the TSO's and consumers costs, on the other hand, is observed. When inc-dec gaming is present, the implementation of mitigating measures alter this trade-off, by decreasing the profits for the producers, to lower the costs for the consumer and the TSO. The trade-off should be considered when implementing mitigating measures, to ensure that a fair balance of incentives is obtained.

For future research, we suggest to analyse the presence of inc-dec gaming in environments without market power further. This can be done by extending the proposed mathematical model further, for example by enlargening the network. To improve the transferability of results to a real-life setting, an European electricity market topology could be applied. Further, the stability of solutions may be improved by applying a disjunctive constraints approach and exploring other tiebreakers, to reduce the number of non-linearities.

Regarding mitigating efforts, we highlight long-term contracts as the most promising measure. We, therefore, suggest this to be examined more rigorously, e.g., by modelling an auction of such contracts to ensure that relevant parties find them acceptable. This would lead to a three stage EPEC.

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