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MARKET MECHANISMS FOR NEIGHBOURHOOD ELECTRICITY GRIDS: DESIGN AND AGENT-BASED EVALUATION

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Abstract

The increasing number of prosumers who both consume and produce electricity and the ongoing decentralization of the electricity system lead to the need for new market designs to allow for direct trading of electricity between neighbours. Most currently proposed mechanisms ignore the grid restrictions, which might result in an infeasible dispatch and threaten the system stability. We propose a mechanism that considers grid restrictions and finds the optimal dispatch without relying on a centralized entity such as an independent system operator to oversee the system. We compare the results of the proposed mechanism to a nodal pricing approach and evaluate the welfare distribution among market participants as well as the exposure to market power using agent-based simulation. We find that the welfare distribution does not depend on the technical specifications of the proposed bilateral pricing mechanism but on the grid topology and that the possibility to exercise market power is equally high as under nodal pricing.

Keywords: power market design, agent-based computational economics, local markets

1 Introduction

The digitalization of the energy system and the increased installation of distributed energy resources allow for a re-conceptualization from the former paradigm of buying electricity from large utilities to the concept of competitive neighbourhood electricity markets. This also allows a better integration and local coordination of EVs (Gust et al., 2016) and prosumers who both consume and produce electricity (Mengelkamp et al., 2017). This sparks the discussion on electricity market design for neighbourhood communities, also known as local markets. These are supposed to ensure more coordination of supply and demand in a geographically smaller area (Marzband et al., 2013) and to allow customers to trade their exceeding generation with their peers. Coordination of local demand from electric vehicles or trading among neighbours can be achieved using market mechanisms. In this paper we compare different market designs for such community grids with regards to welfare distribution and vulnerability to market power, while specifically respecting the grid restrictions. Researchers proposing trading mechanisms for local markets often ignore the network constraints (e.g., Ilic et al., 2012). Others consider the network side without proposing market mechanisms (e.g., Tsikalakis and Hatziargyriou, 2011). In (Staudt, Gärttner, Weinhardt, et al., 2018) the authors discuss two different congestion management mechanisms, which are designed to respect network constraints: Nodal pricing as proposed by Schweppe and Caramanis, 1988 and Hogan, 1992 and a multilateral mechanism introduced by F. F. Wu and P. Varaiya, 1999 and adapted to a distribution system by Qin, Rajagopal, and P. P. Varaiya, 2017, which we will hereafter call the bilateral mechanism. Nodal pricing in theory leads to an efficient dispatch (Green, 2007). However, it requires strict regulatory oversight of an Independent System Operator (ISO) who optimizes a pool of generation capacity and is the sole seller and buyer of electricity. While this approach is often implemented for transmission grids, it is not implemented for the distribution grid. Furthermore, an ISO restricts the freedom of choice with regards to suppliers as it always optimizes for the minimum cost solution. Such an ISO is not necessary for the implementation of the bilateral mechanism. In the proposed congestion management model, the system operator is only responsible for identifying grid restriction violations and communicating the necessary curtailment of the according trades to the market participants. This task can be performed by an information system. In (F. F. Wu and P. Varaiya, 1999) and (Qin, Rajagopal, and P. P. Varaiya, 2017) the authors show that when suppliers competitively bid their actual marginal production costs, the nodal and bilateral mechanism theoretically converge to the same efficient dispatch. However, they abstain from providing the actual market mechanism and consequently, do not evaluate the mechanism with regards to its market results in a competitive environment and under strategic bidding and also leave the practical implementation of trade formation through an appropriate information system (IS) to future research (Qin, Rajagopal, and P. P. Varaiya, 2017). With this paper we intend to fill this gap and introduce bilateral pricing as the according market mechanism. Therefore, we make two key contributions:

1. Designing a market mechanism based on the bilateral congestion management approach, that allows coordination without an intrusive central entity and allows for preference based electricity trading
2. Evaluating the design with regards to welfare distribution and market power and comparing it to a nodal pricing design using agent-based simulation

2 Related work

This contribution is based on four streams of electricity market and information systems research. We give a short introduction into each of these streams and point to related research.

Electricity market design and congestion management Congestion management in electricity markets was first introduced by Schweppe and Caramanis, 1988 with locational marginal pricing or nodal pricing. In this market design prices are centrally computed and differentiated depending on the congestion state and the location in the system. The concept has received further attention and additional instruments were added such as financial transmission rights which compensate the owner of transmission lines in case of congestion (Hogan, 1992). In theory nodal pricing leads to the welfare-optimal dispatch (Krause and Andersson, 2006). Under imperfect competition, frequently observed in markets with only few suppliers, the nodal pricing design maximizes the stated social welfare based on the observable offers rather than the actual marginal production costs (Shahidehpour, Yamin, and Z. Li, 2002). Besides nodal pricing, other forms of market designs have been established, namely zonal and uniform pricing (Berizzi et al., 2009). In uniform pricing markets, congestion is not considered during market clearing. This means that if congestion occurs, the transmission system operator (TSO) needs to take curative or emergency actions such as redispatch to make sure that the line limits are not violated (Staudt, Wegner, et al., 2017). The weaknesses of this approach are outlined by Staudt, Rausch, Weinhardt, et al., 2018. A compromise between the two approaches is zonal pricing, for which some nodes are grouped into bidding zones. Only grid restrictions between the zones are considered during market clearing while congestion within one zone is cured through curative measures (Trepper, Bucksteeg, and Weber, 2015). Nodal pricing is used in many system areas of the United States, while uniform pricing is the dominant market design in the European nation states. However, some European countries use a zonal approach such as Norway. The integrated European electricity market is also organized in zones (Staudt, Rausch, Weinhardt, et al., 2018). While nodal pricing usually requires all market participants to trade exclusively with the ISO, F. F. Wu and P. Varaiya, 1999 propose a design that allows individual bilateral trading which is only overseen by a system operator to ensure feasibility. In this paper we propose a market mechanism based on this congestion management mechanism to allow bilateral trading in a neighbourhood distribution grid without requiring an ISO.

Neighbourhood electricity markets Microgrids who act as a single controllable load to improve security of supply and resilience are an established concept (Lasseter, 2002). However, in this context, local markets with trading among participants are still a relatively immature topic from a research perspective. They have initially been proposed by Kamrat, 2001 and have gained in popularity with more decentralized generation (Hvelplund, 2006) and the possibility to trade among neighbours (Koirala et al., 2016). Previous research has already introduced the notion that microgrids and local markets can facilitate the sharing of local generation resources and demand side flexibility (Palensky and Dietrich, 2011). However, most proposed market mechanisms for neighbourhood electricity markets ignore the need for congestion management (Mengelkamp et al., 2017), which will become a larger concern in the future (Gust et al., 2016). Furthermore, market participants should ideally be allowed to trade according to their preferences as opposed to a mere optimization of the electricity costs as other characteristics than costs might be more important to individual customers (Tabi, Hille, and Wüstenhagen, 2014). In this paper we provide and evaluate such a mechanism.

Information systems in electricity markets Energy informatics is introduced as a research field by Watson, Boudreau, and Chen, 2010. It is a discipline that considers the use of information systems to reduce carbon emissions. We contribute to this line of research by introducing a model that allows a more decentralized use of renewable energy in the local market context. Kranz et al., 2015 point out that energy research in the IS community has often focused on the demand side. With this contribution we want to go beyond this field and incorporate an engineering and market design perspective. The need of information systems for a transition to a more sustainable energy system is described by Brandt, Feuerriegel, and Neumann, 2013 with the example of using synergies between renewable energy generation and mobility behaviour. In (Römer et al., 2012) the authors discuss that with increasing renewable generation, low-voltage grid stability might be at risk. They also outline possible roles and cooperation in future smart grids. Furthermore, Münsing, Mather, and Moura, 2017 propose to use a blockchain as an enabler for locational marginal pricing in local markets.

Agent-based evaluation of electricity market designs Part of this contribution relies on agent-based computational economics to evaluate the economic efficiency of the newly designed bilateral market design and to compare it to nodal pricing. Therefore, we use empirical and descriptive as well as normative agent-based computational economics as defined by Weidlich and D. Veit, 2008. Other contributions have previously evaluated market designs in electricity market research such as (D. J. Veit, Weidlich, Yao, et al., 2006) or compared different market designs (D. J. Veit, Weidlich, and Krafft, 2009). In other studies agent-based design has been used to evaluate market power in electricity markets (Staudt, Gärttner, and Weinhardt, 2018). In this study we rely on an agent reinforcement learning algorithm that was introduced and applied to electricity markets by Kimbrough and Murphy, 2013 and has been shown to replicate rational agent behaviour.

3 Market mechanisms

Our analysis is based on two mechanisms for congestion management and associated market mechanisms. The first is nodal pricing (also known as locational marginal pricing) with a centralized ISO who coordinates supply and demand and optimizes the power plant dispatch. The second is bilateral pricing based on (Qin, Rajagopal, and P. P. Varaiya, 2017). The load is modeled with a constant demand over different nodes which is inelastic, i.e., the load strives to cover its entire demand at minimal cost without price considerations, which is a common assumption in electricity market research (Weidlich and D. Veit, 2008). We also model the load as one collaborating entity trying to achieve the best overall solution. This assumption is further discussed in Section 4.3. Generators are assumed to have constant marginal generation costs.

3.1 Congestion management mechanisms

In theory both introduced mechanisms – nodal and bilateral – are congestion management mechanisms. To make them market mechanisms, pricing and trading rules need to be defined. In the following we describe these rules for nodal pricing and introduce the congestion management approach by Qin, Rajagopal, and P. P. Varaiya, 2017.

Nodal pricing mechanism Under a nodal pricing regime the ISO collects all submitted supply and demand bids and clears the market by solving an optimal power flow problem, thus minimizing the total generation costs. At the same time, operating limits of the electricity grid lines are respected. Therefore, congestion management is implicitly carried out during market clearing. In congestion situations when the consumer prices differ between nodes, congestion rent is being paid by the consumers. Under the assumption of a perfectly inelastic demand, minimizing the generation costs for supplying the full demand is identical to maximizing social welfare. In a nodal pricing design this also leads a maximization of consumer surplus given an inelastic demand. However, other market designs might lead to a higher consumer surplus but an overall lower social welfare. Social welfare is the sum of the economic surplus of all market participants and can be partitioned into consumer surplus, producer surplus and congestion rent.

In our simulation in Section 4 we employ a linearized direct current (DC) power flow approximation model to calculate nodal prices and to compute the line flows in the bilateral pricing model. This approximation achieves an acceptable trade-off between computational complexity and accuracy. A detailed representations of the underlying mathematical concepts can be found in (F. Li and Bo, 2007). The lossless DC power flow model relies on three fundamental assumptions: Line resistances are small compared to line reactances (loss is neglected), the voltage amplitude is equal for all nodes (in per unit values) and the voltage angle differences between neighboring nodes are small (van den Bergh, Delarue, and D'haeseleer, 2014).

The mathematical formulation for finding the optimal dispatch under perfect competition and a perfectly inelastic demand in a lossless system can be expressed as follows (F. Li and Bo, 2007):

$$\min \quad \sum_{i=1}^{N} c_i \cdot G_i \tag{1a}$$

$$\text{s.t.} \quad \sum_{i=1}^{N} G_i = \sum_{i=1}^{N} D_i \tag{1b}$$

$$\left| \sum_{i=1}^{N} GSF_{k-i} \cdot (G_i - D_i) \right| \leq Limit_k,\ k = 1,2,\ldots,M \tag{1c}$$

$$G_i^{min} \leq G_i \leq G_i^{max},\ i = 1,2,\ldots,N \tag{1d}$$

N	Number of buses
M	Number of lines
c_i	Generation cost (perfect competition) / ask price (oligopolistic competition) at bus i
G_i	Generation dispatch at bus i
G_i^{min}, G_i^{max}	Min. and max. generation output at bus i
D_i	Demand at bus i
GSF_{k-i}	Generation shift factor to line k from bus i
$Limit_k$	Transmission limit of line k

Under imperfect competition suppliers can exercise market power and submit bids above their marginal generation costs. In this case, the resulting dispatch of the nodal pricing mechanism might not equal the welfare-optimal solution, but instead maximizes the stated social welfare. This is identical to dispatching the cheapest possible generation pool (Fernandez-Blanco, Arroyo, and Alguacil, 2014). This is later simulated using computational agents that deviate from the marginal cost bidding strategy.

The corresponding nodal prices can be derived from the dual variables (Lagrangian multipliers) of the optimization problem's solution in the following way:

$$LMP_i = LMP^{energy} + LMP_i^{cong} \tag{2}$$

$$LMP^{energy} = \lambda \tag{3}$$

$$LMP_i^{cong} = \sum_{i=k}^{M} GSF_{k-i} \cdot \mu_k \tag{4}$$

LMP_i	Marginal price at node i
λ	Marginal price at slack node (Lagrangian multiplier of (1b)) = system energy price
LMP_i^{cong}	Marginal price of the network constraint
μ_k	Lagrangian multiplier of (1c) = sensitivity of the kth transmission line constraint

For nodal pricing we assume mandatory spot market participation as this is the case in practice, where in each round each supplier bids a single ask price for the entirety of her generation capacity. There are no other bilateral or multilateral trade agreements outside of the spot market trading. In case of perfect competition, suppliers bid their marginal costs and the centralized market clearing process results in the welfare-optimal dispatch (Krause and Andersson, 2006).

Bilateral pricing mechanism In the bilateral pricing mechanism trading among all market participants is completely liberalized and only restricted by the phyiscal grid contraints. The ISO is replaced by a System Operator (SO), whose sole responsibility is to ensure that the market outcome is feasible with respect to the line constraints. It can therefore easily be replaced by an information system. Please note that the System Operator is by no means equivalent to the ISO. It does not collect supply or demand bids or interacts in any way with the market other than calculating load flows, curtailing trades to feasible levels and communicating the system congestion state. The title system operator is adopted from Qin, Rajagopal, and P. P. Varaiya, 2017. The trading occurs through bilateral or multilateral contracts between supply and demand. In case of line limit violations after a trade, the SO uniformly curtails the prior trade until it is feasible. The curtailment is uniform to ensure the neutrality of the SO. No consideration of optimality is being done. After curtailment, the trading continues iteratively until no more beneficial trades can be identified, while always respecting the currently binding (in the following also 'activated') restriction. In their paper, Qin, Rajagopal, and P. P. Varaiya, 2017 show that such a mechanism in theory converges to the efficient dispatch that is achieved using a nodal pricing market design. In contrast to the nodal pricing market model, prices and dispatched generation are not centrally determined by an intrusive ISO but result from a sequential set of trades and curtailments (F. F. Wu and P. Varaiya, 1999). The bilateral pricing mechanism relies on bilateral trades based on individual rationality, i.e., a bilateral trade only occurs if it is beneficial for all parties. As a consequence, the resulting generation dispatch and paid prices are transparent and consider the forces of a free market, while at the same time adhering to the line constraints.

3.2 Bilateral pricing procedure

Qin, Rajagopal, and P. P. Varaiya, 2017 do no introduce a pricing and trading mechanism and the exact procedure of trades and curtailments also remains to be defined. Furthermore, the introduced mechanism has drawbacks such as the possibility of a deadlock. In this section we describe our proposed procedure for the bilateral market mechanism and discuss possible obstacles.

In the bilateral pricing model, individual generators offer supply contracts to the load. Such a contract consists of an ask price and a maximum generation capacity. The load can then choose which contracts to procure. The bilateral pricing model relies on the notion that the welfare-optimizing dispatch can be achieved through an iteration of trades between producers and consumers, necessary curtailments to ensure system stability and mutually profitable bilateral trades among producers. However, the SO operates the entire grid, meaning that no grid restrictions can be violated and no congestion can be induced as a strategic option. Gaming the market through consecutive trading and congestion management markets as it occurred in California (Alaywan, T. Wu, and Papalexopoulos, 2004) is ruled out as congestion is considered during market clearing. In the intermittent re-trading rounds trade only occurs among suppliers who find mutually profitable bilateral trades. A re-trade is profitable if a supplier can buy scheduled production from another supplier with a lower ask price. However, the sequence in which generation is procured from different suppliers might lead to an infeasible solution. A sequence is the order in which supplier contracts are accepted. The reason are path dependencies. One possible sequence would be the merit order, where the cheapest generators are dispatched first. Assuming for example, that generation from the cheapest generators has a strong congestion impact on a critical, activated line restriction, while expensive generators have a smaller but also congesting effect regarding this restriction. Then, re-trades will not occur as cheaper generators do not buy from more expensive generators, while procurement occurs from cheap generators first. Then, the critical restriction cannot be relieved while further procurement is impossible. In their proposed bilateral congestion management mechanism, Qin, Rajagopal, and P. P. Varaiya, 2017 allow the SO to curtail previously agreed trades without the consideration of compensation payments. In our mechanism we want to make sure that every performed trade is individually rational and that regulatory interventions are minimized. Therefore, in the proposed mechanism the demand explores

the outcome of every possible dispatch sequence. While the model ensures that the welfare-optimizing solution is achieved in one or more of the tested sequences, the final decision on which sequence to choose is made based on the resulting procurement cost incurred by the demand side from all sequences that cover the entire demand. This is because the welfare-optimal solution in the bilateral mechanism needs not necessarily maximize consumer welfare. A similar example but in a different context is illustrated by Grimm et al., 2018. For every individual trade we use a uniform price mechanism, meaning that the payment for each traded unit is determined by the most expensive unit in the overall trade. This is done assuming that trades will still be formed using exchanges or platforms to reduce the overall complexity meaning that a group of suppliers and loads might use an auction mechanism to find one clearing price for a whole set of delivery contracts. However, this rule only applies for trades with multiple suppliers. In the case of contracts between the load and one supplier or between two suppliers, the ask price of the selling supplier determines the trading price.
In order to calculate the factor by which a procurement trade or a re-trade of the previous round has to be curtailed for the overall market outcome to be feasible with respect to the line restrictions, the SO needs to solve a simple optimization problem. The objective is to uniformly curtail all new trades while allowing the maximum possible trade volume. The factor γ represents the fraction of the additional trade that remains after curtailment. By curtailing the additional trade so that the most severely violated line restriction is relieved, all other possibly violated restrictions are automatically relieved. The necessary minimal uniform curtailment is being calculated by solving the following optimization problem:

$$\max \quad \gamma \tag{5a}$$

$$\text{s.t.} \quad \sum_{i=1}^{N} GSF_{k-i} \cdot \left(\left(G_i^{prev} - D_i^{prev} \right) + \gamma \cdot \left(G_i^{\delta} - D_i^{\delta} \right) \right) \leq Limit_k \tag{5b}$$

$$0 \leq \gamma < 1 \tag{5c}$$

γ	Curtailment factor; fraction of the trade that remains after curtailment
G_i^{prev}	Generation before curtailed trade at node i
D_i^{prev}	Satisfied demand before curtailed trade at node i
G_i^{δ}	Additionally traded amount of energy produced at node i
D_i^{δ}	Additionally traded amount of energy consumed at node i
k	Index of most severely congested transmission line

As it is not necessarily optimal to procure from the cheapest suppliers first (as this might result in an infeasible solution) the load tests all possible sequences, to find the alternative that covers the entire demand at the lowest cost. This sequence does not necessarily lead to the efficient dispatch but there is always one sequence that leads to the efficient dispatch even if it is not rent-maximizing for the consumers. For each sequence, i.e., for all possible permutations of the set of suppliers, the load needs to run the entire market mechanism depicted in Fig. 1 to assess the overall cost. This is similar to a combinatorial auction where the sequence can be understood as the bought package by the consumer. We further elaborate on this in Section 4.3. This testing by the consumers might of course be computationally expensive. We also reflect on this problem in Section 4.3. The market mechanism itself consists of a recurring loop between procurement (i.e., consumers procure the pending demand according to the current sequence) and re-trades (generators re-trade among themselves in profitable bilateral trades determined by their bids). The procurement of pending consumer demand occurs according to the chosen sequence. This implies that consumers can choose their supplier bundle independently of price considerations and the algorithm intends to procure as much as possible from the preferred suppliers. The alternating loop repeats until the entire load is covered by a feasible dispatch. Once the trading process has reached a feasible dispatch covering the entire consumer demand, the suppliers can re-trade until no profitable re-trade can

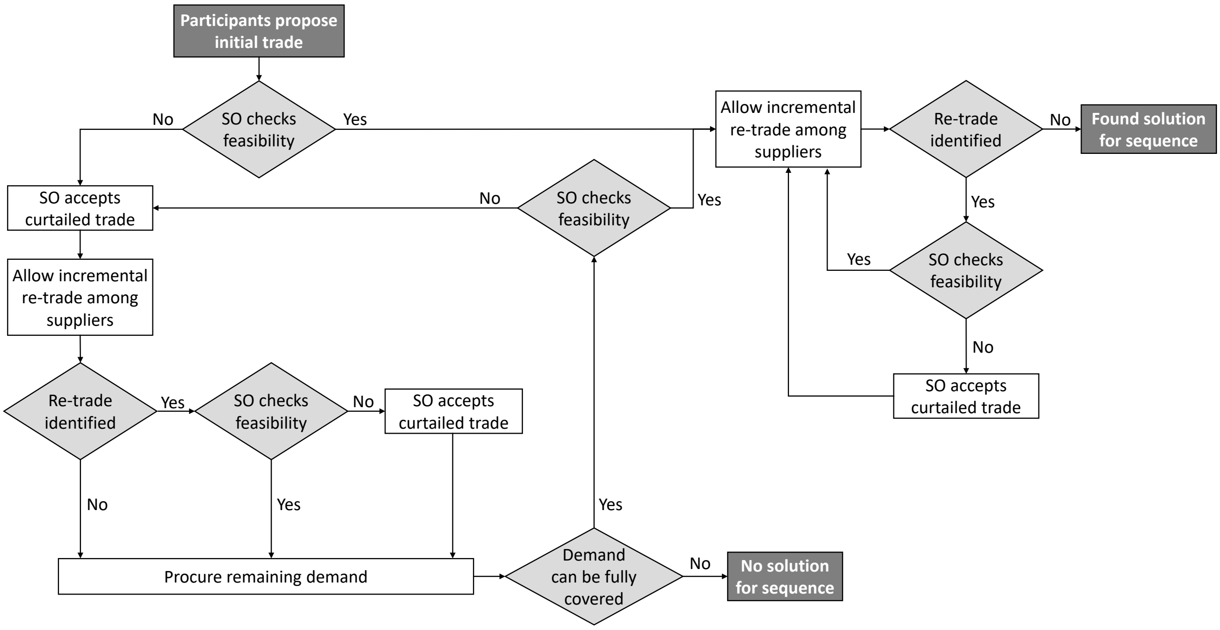


Figure 1: Conceptual Trading Diagram

be identified. The entire process is depicted in Fig. 1. The consumers are aware of all ask prices, the grid topology and they understand the interventions of the SO. Furthermore, they receive signals by the SO on the congestion state. The primary objective of the load is to cover the entire demand. The secondary objective is to achieve this at minimal cost. The suppliers intend to maximize their profit. They receive signals on the congestion state by the SO and are aware of their position in the grid. They sell and buy electricity if it is individually rational, i.e., if the price is higher than their marginal costs they sell their capacity and they buy it back if the offered contract is cheaper than their ask price. They can sell to the consumer and other suppliers and they can buy from other suppliers in re-trades. They continue their trading until no more beneficial trades can be identified that respect the activated constraint.

3.3 Re-trading

A few procedural decision need to be taken for the simulation. The suppliers check for re-trades in descending order depending on their ask price. In the case that the SO has activated a line restriction, only re-trades that ease this restriction are allowed. If such a trade is identified, it is executed with a trading volume limit of a specified increment of δ^{inc} MW, with δ^{inc} being sufficiently small. This is necessary as re-trading can lead to a deadlock, such that no more mutually profitable trades are possible while the demand is still not entirely covered. As a consequence, even if a larger trade volume between two suppliers is possible with respect to the suppliers' capacity limits, only the specified increment is traded. This assumption is further discussed in Section 4.3. As re-trading can only occur in one direction (from more expensive to less expensive generators), an oscillation state of the system is impossible. If no strictly positive amount can be profitably traded, the next-highest bidding supplier is considered. Every time a trade is found and executed, the re-trading sequence is interrupted and the SO checks the resulting dispatch for feasibility and, if necessary, curtails it to a feasible share of the negotiated trade. In case a curtailment occurs, the corresponding vector of generation shift factors of the affected line is identified and published such that in the subsequent trading round only trades that do not further violate the active line restriction are allowed. If there is no curtailment following an incremental re-trade, the following procurement allows unconstrained trades between the supplying generators and the demand side meaning that all active constraints are deactivated. The same is true for a procurement trade that is not curtailed.

3.4 Agent bidding and learning

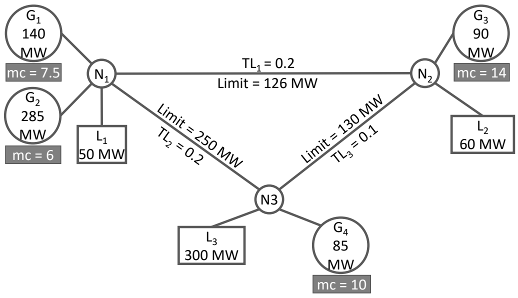
We compare the two described market models using an agent-based simulation to derive information about the impact of the market designs on behavioural aspects. Each supplier is individually modelled as an agent, who in each round submits her ask bid. Through her bid the supplier declares the price at which she is willing to sell her full generation capacity, which is limited by the supplier's marginal cost as the lower bound and a market price cap as the upper bound. The price cap is necessary to ensure that market controlling generators do not infinitely increase their ask prices. In the bilateral pricing the ask bid cannot be updated between trading rounds. The employed agent model implements a variation of the probe-and-adjust reinforcement learning algorithm first introduced by Kimbrough, 2011. It is used to simulate the generating agents' reactions to their observations of trading outcomes in a continuous action space. A variation of the algorithm has been used in the context of analyzing bidding behaviour on electricity markets and has been proven to converge (Kimbrough and Murphy, 2013). Our implementation uses the variation first employed by Staudt, Gärttner, and Weinhardt, 2018. In our variation of the algorithm, supplier agents submit bids, which are uniformly distributed over an interval around a base bid. The base bid remains constant for the duration of a fixed number of trading rounds, termed an 'epoch' by Kimbrough and Murphy, 2013. Over the course of an epoch, the supplying agents randomly deviate from their epoch base bid by small amounts. This aims to capture incremental actions taken by individuals to probe a continuous action space for superior strategies. In each trading round the suppliers submit their bids and record the profit resulting from that bid. As demand and supply are kept constant over the rounds, the simulation results are not diluted through differing optimal strategies and the agents learn to maximize their profits. Upon completion of an epoch, the agent adapts her epoch base bid based on the recorded bid-profit tuples and determines whether (and by how much) to increase or decrease her epoch bid for the subsequent epoch. In the simulation the next epoch's base bid is set to the mean of the top 50 % bids of the previous epoch in terms of the resulting profit. The exploration parameter around the epoch base bid is set to 1 and the initial epoch base bid is the marginal production cost of the generator.

4 Simulation results

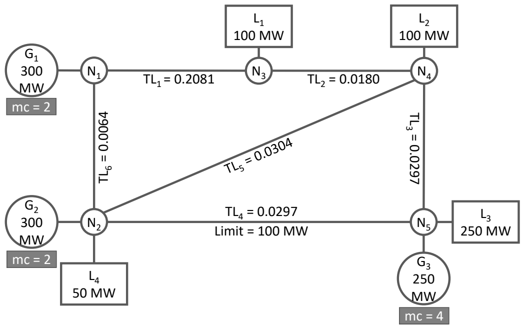
We test the two investigated market models in different reference grids. An overview of the used test grids is shown in Fig. 2. Additionally, we use the 56-bus grid example from Peng and Low, 2013.

4.1 Perfect competition

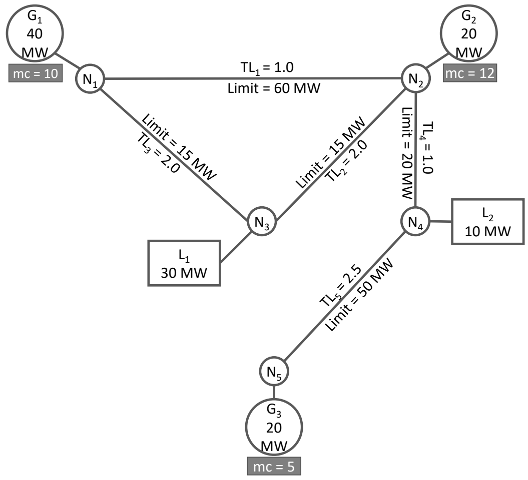
In this section we simulate the market models assuming perfect competition, meaning that all suppliers bid their marginal costs. Strategic competitive behaviour is addressed in the next section. We do so in order to assess the welfare distortions resulting from a change in the market design. We consider the consumer and producer surplus as well as the congestion rent and investigate how these payments are shifted with a change in the market design. We find that the dispatch chosen to minimize the consumer payments in the bilateral pricing mechanism for the introduced five example network topologies is equivalent to the nodal dispatch. Therefore, the overall welfare in both designs is the same. However, we are interested in the distribution to see if the bilateral approach favors either consumers or producers. Table 1 shows the simulation results. We find that the consumer surplus is increasing in all investigated examples. However, this is only due to a redistribution of the congestion rent as the producer surplus always increases as well. The division of the congestion rent among producers and consumers varies with the grid topology. The congestion rent is not uniquely distributed to the consumers as producers in congested areas might profit from the uniformly priced batch trades and receive higher prices than they would have under nodal pricing.



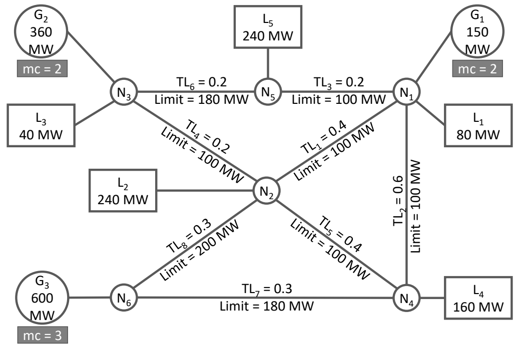
(a) 3-node example (Kirschen and Strbac, 2019)



(b) 5-node example (3 Gen., 4 Loads) (Krause, Beck, et al., 2006)



(c) 5-node example (3 Gen., 2 Loads) (own variation)



(d) 6-node example (R. Romero et al., 2002)

Figure 2: Simple Network examples

A more detailed assessment of the technical procedure of the bilateral market mechanism reveals no obvious relation between the need for re-trading or re-procurement and the division of the congestion rent as can be concluded from Table 2. This implies that the technicalities of the introduced market mechanism have no impact on the market results but that it depends on the network topology. One notable finding is that in the most complex example all 720 possible sequences terminate successfully, meaning that all demand can be covered regardless of the chosen sequence. In conclusion we find no considerable shift of welfare distribution other than the division of the congestion rent. Therefore, we can conclude that both designs are equally suited for market operation with regards to welfare distribution.

4.2 Strategic bidding

Electricity markets are often subject to market power as entry barriers in the form of initial investments are high and the electricity market was traditionally a regulated monopoly. Market power is even more of a threat in neighbourhood electricity markets (Staudt, Gärttner, and Weinhardt, 2018). In this section we assess how prone the proposed market models are to the use of local market power. We do so by allowing strategic bidding using the reinforcement algorithm introduced in section 3.4. We test our design on all but the 56 bus example from the previous section as this is computationally too complex to be simulated for a large number of simulation rounds. We find that the agent behaviour with regards to market power is very similar in both designs and that market power is exerted if possible showing even collusive behaviour in

	Pricing Scheme	Consumer Payments	Producer Revenue	Congestion Rent
3-bus example	**Nodal Pricing**	4050.00	3262.50	787.50
	Bilateral Pricing	3272.12	3272.12	0.00
	Difference	*-777.88*	*9.62*	*-787.50*
5-bus example (3 Gen., 4 Loads)	**Nodal Pricing**	1841.35	1688.86	152.49
	Bilateral Pricing	1772.28	1772.28	0.00
	Difference	*-69.07*	*83.42*	*-152.49*
5-bus example (3 Gen., 2 Loads)	**Nodal Pricing**	657.87	464.47	193.40
	Bilateral Pricing	480.00	480.00	0.00
	Difference	*-177.87*	*15.53*	*-193.40*
6-bus example	**Nodal Pricing**	2051.43	1913.67	137.76
	Bilateral Pricing	1987.81	1987.81	0.00
	Difference	*-63.62*	*74.13*	*-137.76*
56-bus example	**Nodal Pricing**	839.29	755.29	84.00
	Bilateral Pricing	826.82	826.82	0.00
	Difference	*-12.47*	*71.53*	*-84.00*

Table 1: Simulation results in perfect competition

	Initial trade feasible	Number of re-procurements	Number of re-trades	Share of solvable sequences
3-bus example	No	1	100	24/24
5-bus example (3 Gen., 4 Loads)	No	140	352	6/6
5-bus example (3 Gen., 2 Loads)	No	15	17	2/6
6-bus example	No	20	82	2/6
56-bus example	No	688	789	720/720

Table 2: Technical results of bilateral trading mechanism in perfect competition

terms of simultaneously increasing bids. In 3 out of 4 cases the consumer payment is slightly higher under bilateral pricing. Of these cases the largest difference is in the 6 bus example. However, if we consider the evolution of ask prices we find that they vary similarly for nodal and bilateral pricing. They only deviate during the evaluated final rounds because the bid evolution in the bilateral model is more volatile as temporal competition occurs. In the 5 bus example, the consumers pay considerably less in the bilateral model. However, we find that the ask prices in the bilateral model are also constantly rising, but somewhat slower than in the nodal case. For the 3 bus example and the other 5 bus example the behaviour under both market designs is similar. In the 3 bus case individual agents are more incentivized to act strategically. For reference, the evolution of ask prices is visualized in Fig. 3. Under nodal pricing Generator 4 is not incentivized to alter her behaviour as she profits from the centrally set market clearing prices. Under bilateral pricing the individual behaviour is more important and she increases her bid. Interestingly, under bilateral pricing Generators 1 and 4 compete for quantity. The ask prices of Generator 4 increase until they surpass the ask prices of Generator 1, which are bounded by Generator 2. After that the two curves move in parallel. This is one of the advantages of the bilateral design: Individual competition is more pronounced as individual actions have a stronger impact. This is the intended design of the bilateral mechanism that can potentially reduce market power: Under nodal pricing the local price is set by the marginal producer and every local generator receives this price for her full generation. In bilateral pricing, a cheaper local generator might still be in competition with other generators for demand that needs to be covered before the expensive generator claims her local market power rent. Detailed results can be found in Table 3. In Table 4 we show the average individual behaviour of generators over the last 1000

		Mean of last 1000 simulation rounds		
	Pricing Scheme	**Consumer Payments**	**Producer Revenue**	**Congestion Rent**
3-bus example	**Nodal Pricing**	5702.51	5670.52	31.99
	Bilateral Pricing	5713.62	5713.62	0
	Difference	*11.11*	*43.10*	*-31.99*
5-bus example (3 Gen., 4 Loads)	**Nodal Pricing**	9663.14	9578.30	84.838667
	Bilateral Pricing	9684.72	9684.72	0
	Difference	*21.58*	*106.42*	*-84.84*
5-bus example (3 Gen., 2 Loads)	**Nodal Pricing**	2482.08	2232.88	249.20
	Bilateral Pricing	866.23	866.23	0
	Difference	*-1615.85*	*-1366.65*	*-249.20*
6-bus example	**Nodal Pricing**	9026.93	8786.59	240.34
	Bilateral Pricing	10411.6482	10411.6482	0
	Difference	1384.71	1625.06	-240.34

Table 3: Simulation results under oligopolistic competition

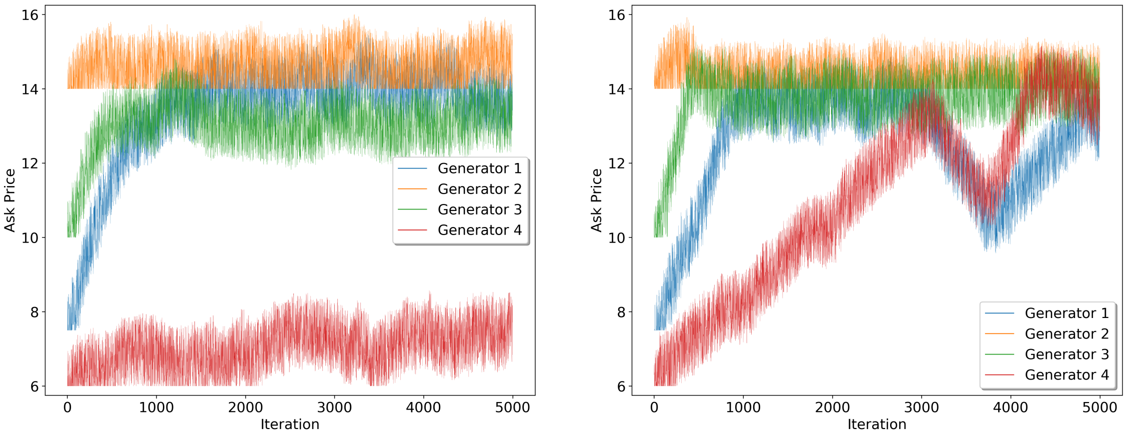
		Mean ask prices of last 1000 simulation rounds				
	Pricing Scheme	**Generator 1**	**Generator 2**	**Generator 3**	**Generator 4**	***Price Cap***
3-bus example	***Marginal Cost***	*7.50*	*14.00*	*10.00*	*6.00*	*70.00*
	Nodal Pricing	13.88	14.75	13.20	7.38	
	Bilateral Pricing	12.37	14.42	13.93	13.84	
5-bus example (3 Gen., 4 Loads)	***Marginal Cost***	*2.00*	*3.00*	*4.00*	-	*20.00*
	Nodal Pricing	3.46	19.08	19.50	-	
	Bilateral Pricing	19.20	4.89	19.61	-	
5-bus example (3 Gen., 2 Loads)	***Marginal Cost***	*10.00*	*12.00*	*5.00*	-	*60.00*
	Nodal Pricing	53.75	57.07	6.90	-	
	Bilateral Pricing	15.75	21.66	10.27	-	
6-bus example	***Marginal Cost***	*2.00*	*2.00*	*3.00*	-	*15.00*
	Nodal Pricing	3.40	11.59	11.49	-	
	Bilateral Pricing	12.88	12.87	13.50	-	

Table 4: Exercise of market power under oligopolistic competition

rounds. Especially in the most competitive case of the 3 bus example the behaviour is very similar. In the other cases we only observe small deviations. As we use uniform pricing for individual trades it is sometimes equivalent whether one or the other supplier submits a high bid. Therefore, we conclude that nodal pricing and bilateral pricing are similarly prone to the abuse of market power and that neither of the designs is superior over the other.

4.3 Discussion

This paper introduces bilateral pricing as a possibility of organizing neighbourhood electricity markets. This research gives way to interesting research directions. Some of the assumptions of this paper are therefore discussed in this section. We assumed the load to act as one entity. Especially, in neighbourhood electricity grids, this might not be a valid assumption. However, treating the individual loads as agents leads to problems in the bilateral design as several loads might compete for one distribution line. This can be addressed by introducing a redispatch mechanism with clearly defined rules that forces consumers into coalitions. If a deadlock of the system occurs, this deadlock could be cured through a redispatch intervention in the grid. The cost for this intervention can be attributed to the responsible parties for the congestion along clearly defined rules. This would incentivize consumers to act grid friendly and to coordinate among themselves. As electricity trading is a complex subject this would be performed



(a) Generator behaviour under nodal pricing (b) Generator behaviour under bilateral pricing

Figure 3: Ask prices of the of 3-bus example

by computational agents that act on behalf of the consumers. The same solution would be possible for the re-trading increment that needed to be defined to avoid a deadlock. If suppliers re-trade such that a deadlock occurs, they are responsible for the redispatch costs, which would incentivize them to trade in a grid friendly manner. Furthermore, more research is necessary on the combinatorial spirit of the sequence approach of the auction design. The sequence that allows for a complete clearing of the market could allow suppliers to bundle their generation and to offer it as a joint product that directly resolves the market coordination problem. This can be enriched by further product characteristics such as locality and sustainability. Such bundles could furthermore include flexibility products for example. Finally, the computational complexity of the bilateral trading needs to be addressed. First, if a mechanism such as the discussed redispatch design was to be adopted, the computational complexity would be greatly reduced as not all sequences would have to be calculated and a deadlock would be avoided by design. However, using the provided mechanism the calculation time for the 56-bus grid (Peng and Low, 2013) is 851 seconds for 720 sequences on a machine with 2.8 GHz and 8 GB RAM and therefore about 1.2 seconds per sequence. However, a complete grid requires many more sequences. Therefore, heuristics are needed that allow for a quick discovery of an optimal or nearly optimal solution.

5 Conclusion

In this paper we introduce bilateral pricing as a new market design for neighbourhood electricity grids based on the previous work of Qin, Rajagopal, and P. P. Varaiya, 2017 and provide a detailed description of the market mechanism. The provided market mechanism converges to the efficient nodal dispatch through bilateral trades between market actors. We test the proposed algorithm on several test grids against a nodal pricing mechanism and find that it converges to the nodal dispatch. We evaluate the changes in welfare and find no large distortions between the two mechanisms other than the division of the congestion rent. The exact distribution depends on the grid topology and not on the procedure of the algorithm. Furthermore, we test the strategic behaviour of agents given the two market designs. We find that both designs set similar incentives to exercise market power and that they both result in similar behaviour. Therefore, neither of the two mechanisms is superior with regards to both welfare distribution and the abuse of market power. However, the proposed bilateral pricing mechanism offers more freedom regarding the preferences of consumers and eliminates the need for an independent system operator. This contribution is therefore a step towards the implementation of neighbourhood electricity markets and the transition to a more sustainable decentralized electricity system.

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