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Design and evaluation of a multi-level reactive power market

Jan Bozionek[1], Thomas Wolgast[1,2*] and Astrid Nieße[1,2]

*Correspondence: thomas.wolgast@uni-oldenburg.de

[1] Carl von Ossietzky University of Oldenburg, Oldenburg, Ammerländer Heerstraße 114-118, 26129 Oldenburg, Germany

[2] OFFIS, Institute for Information Technology, Escherweg 2, 26121 Oldenburg, Germany

Abstract

The shift from conventional power plants on transmission level to distributed energy resources in the distribution grids requires procedures to enable efficient and economic reactive power exchange across different voltage levels. In this paper, we propose a multi-level reactive power market that enables reactive power provision from distributed energy resources to higher voltage levels. Each grid operator operates a local reactive power market and offers local reactive power potential, as an intermediary, to superordinate grid operators by passing on its aggregated cost curve and flexibility range. As a result, there is a low requirement of communication between the market participants and each grid operator is free to choose its local market rules as well as the optimization algorithm used. First results from a case study show that our decentralized market approach can realize an economically efficient multi-level reactive power provision that is close to a centrally computed optimal solution, without violating local grid constraints.

Keywords: Reactive power market, Ancillary service, System service, Reactive power procurement, Voltage regulation voltage control, TSO-DSO cooperation, Expected payment function, Optimal power flow, Decentralized market

Main text

Introduction

Provision of reactive power is essential for a reliable and secure operation of the electric power system (Barth et al. 2013). In addition to balancing purposes, grid operators require reactive power to perform voltage control and reduce active power losses (Koeppe et al. 2018). Traditionally, mainly large conventional generators and compensation devices are utilized by transmission system operators (TSOs) as flexible devices for reactive power balancing (Stock et al. 2018). However, with the ongoing transformation of the electric power system towards renewable and decentralized generation, the number of distributed energy resources (DERs) connected to distribution grids is rapidly increasing, whereas the number of large generators at the transmission level is decreasing (Zecchino et al. 2017).

This shift of generation units from the transmission to the distribution grids has led to operational and planning challenges for TSOs and distribution system operators (DSOs) (Silva et al. 2018). First, voltage violations in distribution grids appear more frequently, especially in times with high DER active power feed-in. Second, TSOs will have less access to flexible reactive power resources for balancing purposes and voltage regulation (Stanković et al. 2021). Grid expansion and the installation of new compensation devices are possibilities to overcome these challenges, but require high investment costs (Hinz and Möst 2018). Converter-connected DERs like wind turbines (WTs), photovoltaic (PV) systems, or charging stations for electric vehicles are capable of a flexible and fast reactive power provision almost independent from their active power feed-in (Samimi et al. 2017). Therefore, more efficient use of DERs for a flexible reactive power provision across grid levels offers another solution to the mentioned challenges, which is available at low or even zero investment costs (Kaempf et al. 2019). Hinz and Möst (2018) show that a flexible reactive power support from distribution grids to the transmission system would lead to technical as well as economical benefits for the TSO. Similar economic benefits can be found in Kaempf et al. (2015), where they compare costs of extra high voltage (EHV) level installed capacitors with costs for reactive power support from high voltage(HV) connected DERs to the TSO.

Currently, in most countries, DERs are obliged to provide reactive power on a mandatory basis to compensate their own voltage repercussions caused by active power feed-in (Talavera et al. 2015). Sometimes, they receive fixed remuneration for this service, but regulation varies strongly from country to country. This mandatory provision of reactive power often requires oversized converters, as operators try to avoid curtailment of active power feed-in (Wolgast et al. 2022). Additionally, it results in a lack of incentives for network operators to procure reactive power efficiently (FERC 2005). To achieve higher efficiency, the EU demands market-based procurement of ancillary services in the future, even in the distribution system (European Union 2019).

So far, many studies of local reactive power markets have been carried out (Wolgast et al. 2022), where the grid operator procures reactive power from local providers in a market-based way. However, these often face the problem of market power due to a small number of market participants. Further, they result in a power system where although the physical system is coupled, the markets are fragmented, because each grid operator optimizes its local system without considering the rest of the power system, which results in lack of efficiency and maybe even harmful effects in neighboring grids. Reactive power markets that encompass multiple grids and voltage levels would allow grid operators to procure reactive power from units in neighboring grids. That resolves not only the fragmentation and the market power problem, but also the monopsonistic nature of local markets by increasing the number of demanders (Wolgast et al. 2022). All these points can be expected to improve their general efficiency. Considering all these points, multi-level reactive power markets should be investigated due to both technical and economic benefits.

In this paper, we present a multi-level reactive power market approach that enables to couple multiple local markets to allow for market-based reactive power exchange across voltage levels, thereby making reactive power from DSOs available for TSOs, and vice versa. The main objective is to achieve an economically efficient reactive power exchange while complying with all constraints in all grids. In addition, the information flow between the market participants should be as low as possible to keep the organizational effort low and avoid high transaction costs. The main contributions of our multi-level reactive power market are:

- Participation of grid operators and reactive power providers from any voltage level in the system.
- Each grid operator can define its own local market rules, optimizing for its own objective and considering its constraints without interference of the other grid operators. That also makes our approach almost independent from regulations in the respective country, because the detailed market rules can be tailored exactly for the local systems and the respective regulations.
- Systematic comparison of the market results with the globally optimal outcome on long-term timeseries data, which demonstrates that our market results are close to optimal.
- Advances on how to approximate the cost function when aggregating flexibilities.

The outline of the remaining paper is as follows. In the state of the art section, we give a short overview of literature about reactive power markets and multi-level approaches. Afterwards, we describe our multi-level reactive power market procedure and how to determine the flexibility range and cost function for a complete grid. In the evaluation section, a case study and reference cases are presented for the analysis of our proposed market. Afterwards, simulation results of the market are presented and discussed. Finally, we close with a short conclusion.

State of the art

Several reactive power markets propose local market structures that enable grid operators to use reactive power flexibilities of their own grids. In these markets, a single system operator acts not only as the market operator, but also as the sole buyer of the reactive power, resulting in monopsonistic markets. One of the most-cited publications is from Zhong and Bhattacharya (2002). The authors introduce a local reactive power market where synchronous generators can offer reactive power to their grid operator, using a so called Expected Payment Function (EPF). The EPF consists of different cost components, including an availability payment, loss costs, as well as opportunity costs for the provision of reactive power. Their market is cleared by the grid operator with an Optimal Power Flow (OPF). To reduce market power of participants, some publications propose a zonal uniform pricing, e.g., Zhong et al. (2004), El-Samahy et al. (2008), and Singh et al. (2011). Rueda- Medina and Padilha-Feltrin (2013) consider the stochasticity of WTs and Madureira and Peças Lopes (2012) consider microgrids as reactive power providers. For a more comprehensive overview of reactive power market literature, refer to the recent survey from Wolgast et al. (2022).

To use reactive power flexibilities across multiple voltage levels, Talavera et al. (2015) develop an algorithm that allows a grid operator to determine its reactive power range at the coupling point to the superordinate grid. This is made possible by carrying out several OPFs with varying reactive power constraints at the grid coupling point. Further methods to determine the active and reactive power flexibility of a grid can be found in Heleno et al. (2015), Silva et al. (2018), and Stanković et al. (2021). The knowledge of the flexibility range enables a grid operator to include subordinate grids as fictitious compensators into their decision-making process. Sarstedt et al. (2020) go one step further and discuss hierarchical multi-level control strategies where multiple grid operators communicate their vertical flexibility range in the form of feasible operation regions. However, all mentioned methods focus solely on the technical feasibility and neglect economical aspects.

Some multi-level reactive power markets can be found in literature that focus on both technical as well as economical aspects. Sarstedt and Hofmann (2022) expand their previously mentioned approach by assigning costs to the feasible operation region at the grid coupling point and therefore allowing for its monetization. Doostizadeh et al. (2018) determine the reactive power flexibility range and additionally an EPF for a distribution grid, by carrying out several power flow calculations. That EPF enables the grid operator to participate in the reactive power market of its superordinate grid. In Doostizadeh and Ettehadi (2019), the authors expand their market model so that besides synchronous generators also DERs can participate. Pudjianto et al. (2019) propose a two-stage reactive power market, but instead of using power flow calculations, the authors use an OPF in their first stage to determine the flexibility range and the EPF of a grid. In the second stage of the approach, the superordinate grid operator carries out an OPF in which downstream grids are taken into account as virtual power plants. A very similar approach of market coordination is presented by Tang et al. (2019). The method comprises of four stages and starts with the TSO sending its reactive power request to the DSOs, which then simultaneously determine their flexibility ranges and EPFs to send them back to the TSO. Then the TSOs performs a network optimization before sending reactive power setpoints to the DSOs, which then perform a final network optimisation in their local system. Retorta et al. (2020) develop a multi-level reactive power market, where the TSO publishes its reactive power requirements, which must be met by the DSO by procuring reactive power in a local reactive power market. The authors provide a detailed description of the market communication process and enable the use of complex bids.

We identified the following research gaps: First, the mentioned approaches either only barely discuss the market rules of the local markets—e.g., Pudjianto et al. (2019) and Tang et al. (2019)—or specify them very precisely and strictly (Retorta et al. (2020)). However, the local markets are operated by different grid operators, which should be able to define their own market rules depending on the local circumstances and objectives. Therefore, the local market rules should remain unspecified and various kinds of local markets should be supported by the multi-level market. Second, in both Tang et al. (2019) and Retorta et al. (2020), the TSO defines its reactive power demand before the market price is set. That makes it difficult for the TSO to adapt the demand to the market price and therefore can work only for capacity markets. Third, none of the publications provide information about the performance of their approaches compared to reference cases or the theoretical optimum. Finally, none of them except Sarstedt and Hofmann (2022) discuss the possibility of more than two voltage levels. With this work and its contributions, we aim to expand the current state of the art regarding these research gaps.

Multi-level reactive power market design

In this section, we introduce a reactive power market that enables a multi-level reactive power provision while satisfying all local grid constraints. The approach allows for each grid operator to define its own local market rules and does not require exchange of any network topology data. First, we present some general assumptions for our reactive power market and discuss requirements to the local reactive power markets within the participating grid operators' systems. Afterwards, we describe the general multi-level market procedure in detail, including communication and payments between market participants. Lastly, we propose an algorithm to determine the reactive power flexibility range and an EPF for a complete grid.

Market assumptions

Following the standard reactive power market literature, the proposed market clearing takes place after an independently cleared active power market. Therefore, the resulting active power setpoints are assumed to be known when carrying out the reactive power market clearing. Since most reactive power EPFs from literature are approximately quadratic functions, we use quadratic EPFs for both the bids of DERs and grid operators. On the one hand, this reduces the amount of data that is exchanged between the market participants, on the other hand, convex functions can be used by a variety of optimizers and lead to shorter solution times of the optimization problem (Frank et al. 2012). Further, we assume exactly a single grid coupling point to the superordinate grid level for each grid and no horizontal grid coupling points, as it was done in similar approaches (Doostizadeh et al. 2018; Doostizadeh and Ettehadi 2019; Pudjianto et al. 2019; Tang et al. 2019; Retorta et al. 2020). Finally, each network operator presumes a voltage of 1 pu at the slack node when determining its reactive power flexibility range. This assumption is legitimate if an on-load tap-changing transformer is used, because the transformer can decouple the voltage of a grid from that of the superordinate grid, since the voltage on the low-voltage side can be adjusted. In Appendix A, we discuss possibilities how to expand our approach, if that assumption does not apply.

Local reactive power market

We further assume that every grid operator who participates in the multi-level reactive power market operates a local reactive power market. That local market is assumed to follow the widely used general approach of Zhong and Bhattacharya (2002), which was further advanced over the last two decades, e.g., in (Amjady et al. 2010; Rabiee et al. 2010; Samimi et al. 2015). The general procedure is always as follows: Reactive power providers—mostly generators—communicate their EPF to the grid operator. The grid operator collects the EPFs of all market participants and then solves an OPF to calculate the optimal procurement that minimizes reactive power costs and some additional objective, while ensuring satisfaction of various constraints. The general OPF can be represented by using the following standard form (Frank et al. 2012):

$$\min f(u, x) \tag{1}$$

$$\text{s.t.} \quad g(u, x) = 0 \quad \text{and} \quad h(u, x) \leq 0 \tag{2}$$

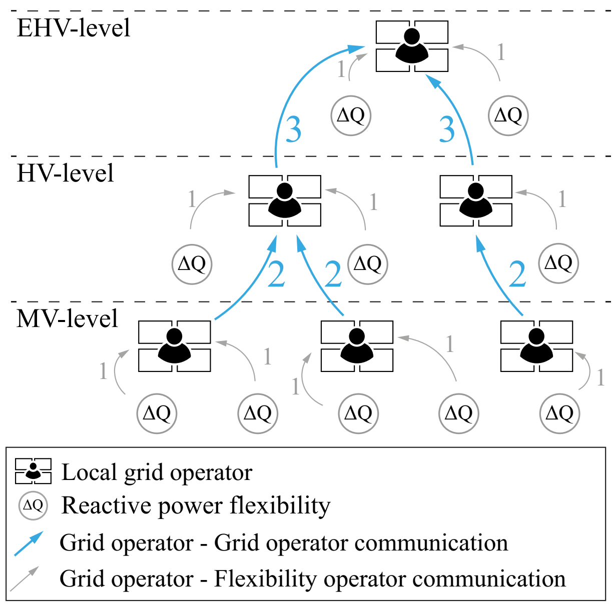

Fig. 1 Phase 1: Determination of EPFs for each grid operator by bottom-up principle (Numbered arrows indicate the chronological order of the communication steps)

with the objective function f, the equality constraints g, inequality constraints h, controllable system variables u, and dependent variables x. The details of objective function, constraints, and how the optimization problem is solved vary from publication to publication, but the general procedure is always the same. We see the same variety of choices for the market rules— e.g., pay-as-bid or uniform pricing—, which are part of the objective function. After the OPF calculation, the grid operator communicates the resulting reactive power setpoints to the providers and remunerates them according to the EPF.

Our multi-level reactive power market design allows to couple multiple such local markets without enforcing any specific market rules, as long as this general procedure is used. In their local markets, grid operators can take into account the EPFs—i.e., the bids—of providers in the optimization process, in addition to their other objectives, like for example loss minimization.

Multi-level market procedure

The general market procedure follows a hierarchical multi-level grid control strategy. Therefore, we have a strict separation of responsibilities and a single grid operator is responsible for all measures in its own system. The grid operator is assumed to have knowledge not only of relevant network models including grid, line and transformer models of its own system, but also has sufficient knowledge of the current system state through measurements or state estimation methods. Knowledge about the system of the other grid operators is not required.

Figure 1 shows the first phase of the reactive power market procedure, including the market participants and their interactions with each other. Exemplarily, the procedure is shown by the example of the EHV, the HV, and the MV levels. However, to be as broadly applicable as possible, the presented approach allows for any number of

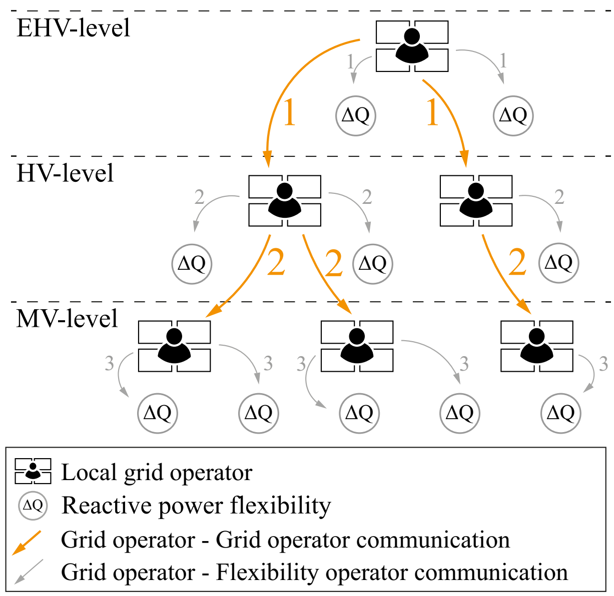

Fig. 2 Phase 2: Determination of reactive setpoints and payments by top-down principle

vertically stacked voltage levels, where each local grid may be controlled by a different grid operator.

The first step consists of the interaction between unit operators— i.e., reactive power flexibility providers—and their respective local grid operator. Participating reactive power providers send their flexibility range $[Q_{\mathrm{min}}, Q_{\mathrm{max}}]$, scheduled active power feed-in and reactive power bid in form of an EPF to their grid operator. Each market participant is free to choose its bid as long as it is compatible with the grid operator's optimization process.

With the data obtained, the DSOs of the lowest voltage level are able to determine their reactive power flexibility ranges, in compliance with their grid restrictions, and an EPF for their respective grid. This process can be seen as aggregation of reactive power flexibilities and is discussed in more detail in the next section. It is worth noting that grid operators could also include their own grid resources in this aggregation process and thus participate not only as intermediaries but also as active flexibility providers to other grid operators. Subsequently, the DSOs of the lowest voltage level send their flexibility range $[Q_{\mathrm{min}}, Q_{\mathrm{max}}]$, EPF, and scheduled active power at the coupling point P_{PCC} to their superordinate DSOs. As a result, the DSOs of the next higher voltage level are able to determine their flexibility ranges $[Q_{\mathrm{min}}, Q_{\mathrm{max}}]$ and EPFs as well, treating their subordinate grid operators as fictitious compensators. This bottom-up process continues sequentially up to the TSO.

The second phase of the reactive power market consists of the transmission of reactive power setpoints, as well as the execution of payments, following a top-down principle. The process is shown in Fig. 2 below.

After the TSOs have received EPFs and flexibility ranges $[Q_{\mathrm{min}}, Q_{\mathrm{max}}]$ of all their local market participants—i.e., local providers and subordinate grids—they carry out their OPF, considering all bids equally. They send the resulting optimal reactive power setpoints Q^{set} to providers within their system (grey arrows in Fig. 2) and to the subordinate DSOs (orange arrows). These reactive setpoints Q^{set} must be within the previously defined flexibility range of the respective provider g:

$$Q_{\min,g} < Q_g^{\text{set}} < Q_{\max,g} \qquad \forall g \tag{3}$$

As soon as a DSO has received the reactive power setpoint at the coupling point $Q_{\text{PCC}}^{\text{set}}$ from its superordinate grid operator, this grid operator also performs its OPF according to its own objective function, the local constraints, and the local bids. In this optimization, the following constraint is added to ensure that the requested reactive power setpoint at the coupling point PCC is achieved, i.e., the grid operator is now obligated to provide the previously offered reactive power to the superordinate grid:

$$Q_{\text{PCC}} = Q_{\text{PCC}}^{\text{set}} \tag{4}$$

Grid operators can determine the reactive power setpoints for flexibilities from their own grid and the downstream DSOs in this final optimization. The top-down process continues down to the DSOs of the lowest participating voltage level. The necessary remuneration R for the reactive power provision of the market participants can be determined by their respective EPFs:

$$R_g = \text{EPF}_g(Q_g^{\text{set}}) \qquad \forall\, g \tag{5}$$

Each grid operator is responsible for making the appropriate payments to providers from its grid and its subordinate grid operators. Each reactive power provider—unit or grid operator—is responsible to provide the requested amount of reactive power.

Four advantages arise from the aggregation process: Firstly, DERs with a smaller reactive power flexibility potential have an easier market access in the reactive power market of the higher grid level by being represented by their grid operator as an intermediary. This way, grid operators have also more reactive power potential to choose from in the market clearing. Secondly, conflicts of interest between grid operators are avoided, because they can include incurred costs such as active power losses in their EPF. There is also no possibility that the actions of one grid operator result in constraint violations within another grid operator's system. Thirdly, each grid operator can choose its own objective function and constraints for its local market. This way, for example, uniform pricing in one local market is possible and pay-as-bid pricing in another market. Finally, the increased number of market participants, reduces the overall market power potential of market participants.

Reactive power flexibility range and EPF of a single grid

To determine the reactive power flexibility range, an algorithm similar to the method presented in Talavera et al. (2015) is used. The procedure consists of an iterative application of OPFs in which the reactive power at the grid coupling point to the superordinate grid level is varied. The complete algorithm is shown in Fig. 3. In addition to the determination of the flexibility range, the algorithm also includes the calculation of an EPF and its quadratic approximation.

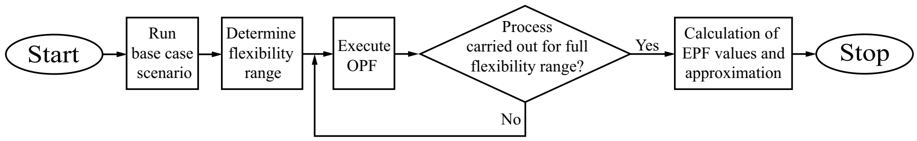

Fig. 3 Flow chart of the developed algorithm to determine the reactive power flexibility range and the EPF of a single local grid

Run base case scenario The first step of the algorithm consists of performing an OPF with no reactive power limits specified at the grid coupling point to the superordinate grid. The chosen objective function C of the local reactive power market does not need to be adjusted.

$$\min C \tag{6}$$

Further, the reactive power at the grid coupling point Q_{PCC} is without costs. Therefore, the minimum costs of a grid operator are determined as a base case scenario.

Determine flexibility range The next step is to determine the flexibility range $[Q_{\min}, Q_{\max}]$ of a grid, i.e., the minimum and maximum reactive power that can be provided by a grid without violating any network restrictions. This is implemented by taking into account linear costs for the reactive power at the coupling point Q_{PCC}. The objective function of the OPF is the following:

$$\min C = p^{\mathrm{Q}}_{\mathrm{PCC}} \cdot Q_{\mathrm{PCC}} \tag{7}$$

where $p^{\mathrm{Q}}_{\mathrm{PCC}}$ is the introduced linear price for reactive power at the coupling point and Q_{PCC} is the reactive power flow over the coupling point. The introduction of the linear price allows to determine the boundary points by means of two cost minimizing OPFs. In our work, we simply assume a linear price of $p^{\mathrm{Q}}_{\mathrm{PCC}} = -1$ €/MVAr and $+1$ €/MVAr. However, the absolute value of the assumed cost factors is irrelevant as long as a positive and a negative cost factor are used, because no other costs are specified in the objective function. The constraints remain unchanged compared to the normal OPF of the respective local system.

Execute OPFs for full flexibility range To determine the grid operator's costs in different scenarios, a selectable number of equidistant reactive power values—hereafter called scenario—within the flexibility range $[Q_{\min}, Q_{\max}]$ is chosen and for every scenario an OPF is performed. For this, the OPF is extended by the following constraint, which changes for every scenario s:

$$Q_{\mathrm{PCC}} = Q_s \qquad \forall\, Q_s \in [Q_{\min}, Q_{\max}] \tag{8}$$

This constraint restricts the reactive power at the coupling point Q_{PCC} to the given value within the flexibility range. After the OPF, relevant results for every scenario such as costs for the provision of the reactive power by the reactive power providers and other costs are calculated and saved. This way, the grid operator can determine its local costs

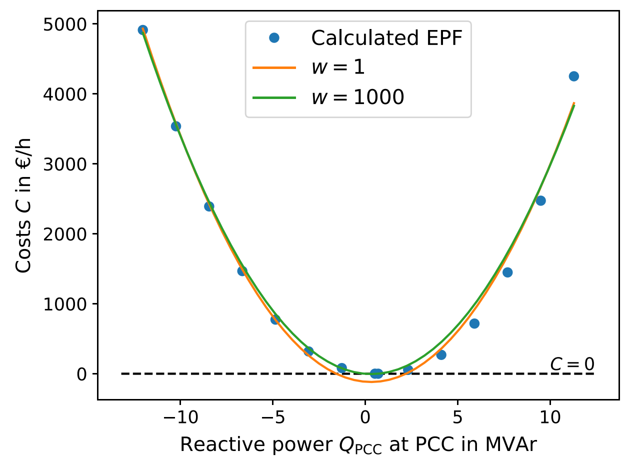

Fig. 4 Calculation result of an EPF and its quadratic approximation with different methods for a complete grid

for each possible reactive setpoint at the coupling point PCC that could be requested by the superordinate grid operator.

Calculation of EPF values and approximation The last step is to determine an EPF for the entire system and to approximate it as a continuous quadratic function. This EPF is intended to reflect the EPFs of the local market participants as well as additional costs due to the provision of reactive power across voltage levels, e.g., active power losses. Therefore, the EPF value for a specific scenario s is calculated, under consideration of the base case:

$$\mathrm{EPF}(Q_s) = C_s - C_{\mathrm{BC}} \qquad \forall\, s \tag{9}$$

where C_s are the costs of scenario s and C_{BC} are the costs of the base case scenario. Finally, a quadratic approximation is performed to determine a continuous and convex EPF, resulting in the advantages already mentioned in the assumptions section.

$$\mathrm{EPF}(Q_{\mathrm{PCC}}) = a_0 + a_1 \cdot Q_{\mathrm{PCC}} + a_2 \cdot Q_{\mathrm{PCC}}^2 \tag{10}$$

For the approximation, the weighted least squares method is used, in which the base case is given a stronger weighting ($w = 1000$). When using the least squares method without any weighting, it was found that this approximation method can result in negative EPF values in a few cases. In the reactive power market, this would mean that in addition to providing reactive power, the network operator would also make a payment to its superordinate grid operator. This is economically highly questionable, since in this case a network operator could simply submit a higher bid. Weighting the base case (cost minimum) stronger prevents negative EPF values that result from the small error in approximation. A second positive effect of this weighting is that the EPF is more precise around the base case, which is beneficial since these cases are more probable than the edge cases. In general, the weighting allows to weight more probable scenarios stronger to achieve better approximation for these scenarios, which is very helpful if predictions about expected reactive power demand are available.

In the following Fig. 4, a calculated EPF and the two mentioned quadratic approximation methods are shown: with and without stronger weighting of the base case.

Figure 4 shows that the calculated scenarios indeed form a quadratic function. Furthermore, we can see that the least squares method with a weighting ($w = 1000$) of the base case leads to a reduction of negative EPF values compared to no additional weighting ($w = 1$).

In this procedure, two implicit assumptions were made. Firstly, the quadratic approximation is assumed to be sufficiently precise to create the EPF. However, considering the potential complexity of power systems and OPFs, and also the potential of highly non-convex EPFs of the providers, there is the risk that the quadratic approximation is not sufficient. In that case, more complex functions need to be communicated and all implemented OPFs need to be able to deal with these cost functions. Secondly, we assume that each grid operator uses its own cost function directly as EPF, without any profit margin. This way, the grid operator is only an aggregator without intention to maximize its profit. If regulation allows for such profit, the cost function would provide only a lower boundary to determine the EPF, but some profit margin would need to be added. Since profit maximizing behavior of the grid operators in such scenarios is seen rather reluctantly (Brückl et al. 2016), we neglect that potential profit here and assume the grid operator only as aggregator. However, in principle, our approach would allow for active profit maximizing bidding of the grid operators without any adjustments required.

Case study

In the following, we present a case study to investigate the performance of our decentralized market approach in a multi-level energy system. The case study is guided by the three following questions: Does the multi-level market enable reactive power exchange across voltage levels? Can welfare be improved compared to conventional approaches? Is constraint satisfaction ensured in all local systems?

Test environment

The study of the market is carried out in Python using the power system analysis tool *pandapower*[1] (Thurner et al. 2018). The grid models for testing and timeseries data are taken from the *SimBench*[2] data set (Meinecke et al. 2020), which provides grid models from all voltage levels that are designed to be coupled with each other vertically. To build the multi-level model, we use the HV system with grid code `1-HV-urban-0-sw` and its 13 subordinate MV grids. Therefore, the model consists of two voltage levels. The 82 node HV grid contains local PV systems and WTs with a total installed power of 306 MW. Four different MV grid models are connected to the HV grid at several places. All together, 132 MW DER power are installed in the MV systems and each MV grid consists of about 100 nodes. In total, the multi-level grid model consists of 1470 nodes. Because of this already high number of nodes, we do not include a third voltage level, which would make the required calculations too demanding. We assume that all DERs participate as reactive power providers in their respective local market. To prevent

[1] https://pandapower.readthedocs.io/en/v2.2.0/, last access: 03/12/2021.

[2] https://simbench.de/en/, last access: 03/12/2021.

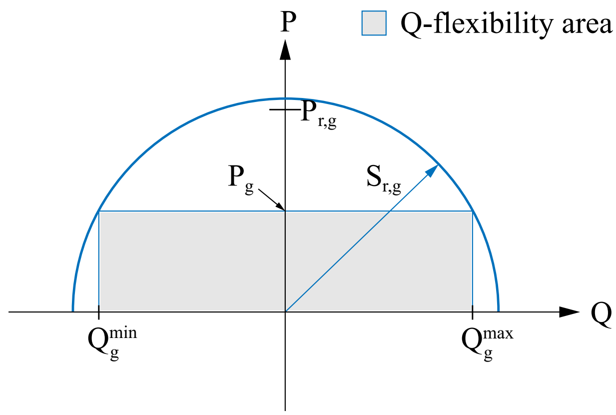

Fig. 5 DER reactive power capability curve based on Stock et al. (2020)

potentially infinite reactive power provision with unknown costs from the slack bus of the HV grid, we assume that all reactive power needs to be procured from the market, i.e., the reactive power flow over the EHV-HV coupling point is constrained to zero:

$$Q_{\mathrm{PCC}}^{\mathrm{EHV/HV}} = 0 \tag{11}$$

where $Q_{\mathrm{PCC}}^{\mathrm{EHV/HV}}$ is the reactive power flow over the HV-EHV coupling point, which is the slack bus. We also assume that the (LV) grid operators do not participate in the market, i.e., their reactive power demand is fixed according to the *SimBench* timeseries data.

Modelling assumptions for reactive power provision

In this section, assumptions are made regarding the modeling of the DERs that provide reactive power. First, the rated apparent power of each DER is calculated. We assume that all DERs can be operated with a $\cos(\varphi) = 0.95$ when providing their installed active power. The rated apparent power $S_{\mathrm{r},g}$ for the DERs can be determined using the following equation:

$$S_{\mathrm{r},g} = \frac{P_{\mathrm{r},g}}{\cos(\varphi)} = \frac{P_{\mathrm{r},g}}{0.95} \qquad \forall\, g \tag{12}$$

where $P_{\mathrm{r},g}$ is the installed active power of the respective DER. We presume the maximum active power feed-in of the time-series data as the installed power $P_{\mathrm{r},g}$ of the respective DER. It should be noted that this procedure results in each DER reserving a certain amount of reactive power. In a real market, this would not necessarily be the case. However, currently it is often the status quo, due to mandatory reactive power provision.

For each DER, the capability curve shown in Fig. 5 is used.

Based on this capability curve, the reactive power potential of a DER at a time step t, without reducing the active power feed-in, can be determined using the following equations:

$$Q_{g,t}^{\min} = -\sqrt{S_{\mathrm{r},g}^2 - P_{g,t}^2} \qquad \forall_g \tag{13}$$

$$Q_{g,t}^{\max} = \sqrt{S_{\mathrm{r},g}^2 - P_{g,t}^2} \qquad \forall_g \tag{14}$$

where $P_{g,t}$ is the active power feed-in and $S_{\mathrm{r},g}$ is the rated apparent power of a generator g.

For simplicity, we assume that all providers bid with their cost function as EPF. Contrary to the EPF presented by Zhong and Bhattacharya (2002), the possibility of reducing active power in favor of further reactive power provision is not considered here. In addition, no mandatory provision of reactive power is assumed. Therefore, the EPF is based solely on the active power loss costs incurred by the converter for providing reactive power. In Samimi et al. (2015), a cost coefficient of $0.3 \cdot 10^{-3}$ \$/((kVAr)^2 h) is determined for the loss cost region of converter connected DERs. The resulting EPF for all DERs is a quadratic function with a cost coefficient of 247 €/((MVAr)^2 h)[3] and is shown in the equation below.

$$\mathrm{EPF}_g = 447 \, \frac{€}{(\mathrm{MVAr})^2\mathrm{h}} \cdot Q_g^2 \qquad \forall\, g \tag{15}$$

For simplicity, we use this cost function for all reactive power providers. The exact costs would depend on the design and dimensioning of the respective unit.

It is further assumed that all wind farms of the HV grid consist of equally sized WTs. The number of WTs of each wind farm and the corresponding assumed installed power of a single WT can be found in Table 2 in Appendix B.

Local market clearing

This section presents the exact OPF used to determine the flexibility range of the grids and to clear the local reactive power markets. For simplicity, we assume that all local markets use the same OPF, which uses pay-as-bid pricing for reactive power provision. As discussed by Amjady et al. (2010), pay-as-bid limits the potential impact of market power abuse. Note, however, that pay-as-bid is not a prerequisite for the presented market approach.

The objective function of the OPF minimizes the loss costs and total payments to reactive power providers:

$$\min C = p^{\mathrm{P}} \cdot P_{\mathrm{L}} + \sum_g \mathrm{EPF}_g\left(Q_g\right) \qquad \forall_g \in G_{\mathrm{local}} \tag{16}$$

where P_{L} is the active power loss with an assumed price p^{P} of 51.01 €MWh[4], which was the reference price for power loss in Germany in 2020. The higher this price is, the higher the incentive for grid operators to procure reactive power for loss minimization.

The costs incurred by a grid operator due to payments to market participants are accounted for by the bids of all reactive power providers of a local grid in the form of their respective EPF_g.

The following equality and inequality constraints are used for all grids:

[3] Assumed exchange rate: EUR 1 = USD 1.2146.

[4] https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK08/BK8_05_EOG/52_Kostenpruefung/522_Verlustenergie/BK8_Verlustenergie.html, last access: 06/05/2022.

$$P_i = |V_i| \sum_{j=1}^{J} |V_j||Y_{ij}| \cos\left(\delta_i - \delta_j - \theta_{ij}\right) \qquad \forall_i \tag{17}$$

$$Q_i = |V_i| \sum_{j=1}^{J} |V_j||Y_{ij}| \sin\left(\delta_i - \delta_j - \theta_{ij}\right) \qquad \forall_i \tag{18}$$

$$V_i^{\min} \leq V_i \leq V_i^{\max} \qquad \forall\, i \tag{19}$$

$$L_{trf} \leq L_{trf}^{\max} \qquad \forall\, trf \tag{20}$$

$$L_l \leq L_l^{\max} \qquad \forall\, l \tag{21}$$

where $|V_i|$ and $|V_j|$ are the voltage magnitudes of bus i respectively j, $|Y_{ij}|$ the *ij*th element of the bus admittance matrix, δ the phase angle and θ_{ij} the angle of the *ij*th element of the bus admittance matrix. Constraints (17)–(21) are the loadflow equations, voltage, line and transformer limits. For all grids a voltage of 1 pu is set as nominal voltage and an admissible voltage band of ± 0.05 pu is chosen. The maximum permissible load of the transformers and lines is set to the respective *SimBench* default value for all grids.

When calculating relevant costs for the creation of the EPF, the constraint from Eq. (8) is added for the corresponding scenario s. Finally, the reactive power at the grid coupling point is restricted according to the set point received from the superordinate grid operator using Eq. (4), when clearing the local market.

Reference cases and evaluation criteria

Two reference cases are used for the evaluation of the reactive power market, which are presented in the following.

Optimal market In the Reference Case Optimal Market (RC OptMarket), it is assumed that instead of different grid operators of the individual networks, a single grid operator controls the whole multi-level system and can therefore realize a global reactive power market. This market can be cleared by this grid operator with a single OPF, considering the objective, constraints and assumptions of the previous sections.

Therefore, RC OptMarket represents the globally optimal solution in the presumed market system, if there was perfect cooperation and data exchange between all grid operators. This way, RC OptMarket can serve as a reference to test how close the results from the decentralized market are to the optimal results.

No market In Reference Case No Market (RC NoMarket), instead of a market, a mandatory provision of reactive power is assumed. Also, we presume no interaction of the grid operators, i.e., each operator optimizes its own system only. To ensure this, the reactive power at the HV/MV grid coupling points is limited, which results in the following additional constraint for the MV grid optimizations:

$$0.95_{\text{underexcited}} \leq \cos\left(\varphi\right)_{\text{PCC}} \leq 0.95_{\text{overexcited}} \tag{22}$$

In this reference case, the reactive power procurement is still carried out with an OPF. However, each grid operator only minimizes its active power loss costs, but no costs for reactive power are considered, i.e., the DERs' reactive power provision is now mandatory and without remuneration. Therefore, the following objective function is used for each grid:

$$\min\ C = p^{\mathrm{P}} \cdot P_{\mathrm{L}} \tag{23}$$

For each grid, the previously described constraints are used, except that the respective reactive power limit of the coupling point is added.

In summary, RC NoMarket stands for the status quo, with the addition of full mandatory reactive power provision and without any grid operator interaction and coordination. The full mandatory reactive power provision is necessary to allow for a fair comparison with the other two cases.

Implementation

To investigate the market for a large number of different conditions, the timeseries data of the *SimBench* data set is used. For the study, 5000 time points were randomly and independently selected. In accordance with the developed market, local market clearing is carried out separately for the various individual grids, i.e., only the local grid model is used for the OPF. However, the multi-level grid model of the entire grid is used to calculate the resulting power flows, to evaluate the market and to compare it with the reference cases. In this, the reactive power setpoints previously determined in the individual grids are specified for each provider. Then, a power flow calculation is performed for the multi-level grid model. Additionally, an on-load tap-changer optimization is carried out in this multi-level grid model, whereby the assumed voltages of 1 pu at the coupling points of the individual grids can be set for the market. The tap optimization is performed with the continuous step controller pre-implemented in *pandapower*, where the target voltage is set to 1 pu. The exact same decentralized procedure is used for RC NoMarket, i.e., determination of setpoints in the individual networks and subsequent power flow calculation with tap optimization in the multi-level grid model. For RC OptMarket, the reactive power setpoints are obtained directly from the optimization of the multi-level grid model.

Results

In the following, to answer our guiding questions from the beginning of the previous section, we demonstrate how our multi-level market influences reactive power exchange across voltage levels as well as the impact on welfare and constraint satisfaction.

Total reactive power provision

First, we investigate the impact on location and amount of reactive power provision. For that, a distinction is made between voltage levels when examining the reactive power provision, which allows for a locational differentiation where reactive power is supplied. The following equations were used to determine the total reactive power $Q^{\mathrm{total}}_{\mathrm{HV},t}$ and $Q^{\mathrm{total}}_{\mathrm{MV},t}$ respectively at time step t.

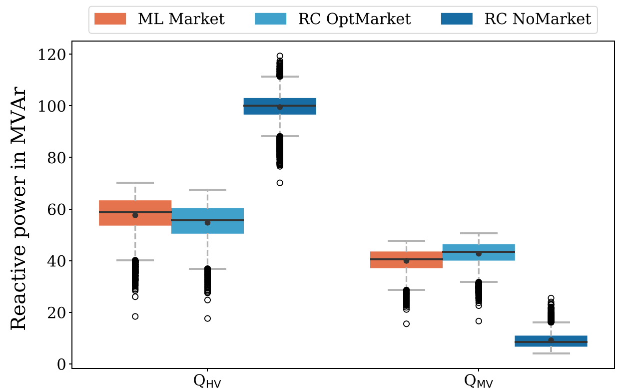

Fig. 6 Total reactive power provided by providers subdivided by the voltage levels (Average total reactive power provided: Multi-level market: 97.54 MVAr, RC OptMarket: 97.41 MVAr, RC NoMarket: 108.65 MVAr)

$$Q_{\mathrm{HV,t}}^{\mathrm{total}} = \sum_{g} |Q_{g,t}| \qquad \forall\, g \in G_{\mathrm{HV}} \tag{24}$$

$$Q_{\mathrm{MV,t}}^{\mathrm{total}} = \sum_{g} |Q_{g,t}| \qquad \forall\, g \in G_{\mathrm{MV}} \tag{25}$$

where $Q_{g,t}$ is the reactive power provided by the DER g at time t. G_{HV} and G_{MV} are the sets of all DERs connected to the respective voltage level. Summing up the absolute values of the reactive power provided by all DERs ensures that capacitive and inductive reactive power do not cancel each other out.

Figure 6 shows the total reactive power supplied by providers subdivided by the voltage levels. In the boxplot, the median of the 5000 steps is shown as a bar and the arithmetic mean is shown as a dot.

When comparing the market with the two reference cases, it is noticeable that the locational distribution and total amount of reactive power provision is very similar to RC OptMarket, but very different from RC NoMarket. Compared to RC OptMarket, more reactive power is provided on average by providers from the HV grid, but less by providers from the MV grids. RC NoMarket leads to a completely different distribution of the reactive power provision. Almost no reactive power is supplied by providers from the MV grids, but a great amount is supplied in the HV grid. Note, that for our proposed multi-level market and RC OptMarket, the total average amount of reactive power provided over both levels is almost identical, but approximately 11 % higher in RC NoMarket.

Total economic costs

An essential objective of the design of a reactive power market is that it should contribute to an economically efficient energy supply. In general, this means achieving the greatest possible welfare using the given resources. Therefore, the economic evaluation of the reactive power market is performed on the basis of the economic costs for reactive power provision. These costs include costs associated with the direct use of resources such as materials or labor, but not payments between the market participants involved.

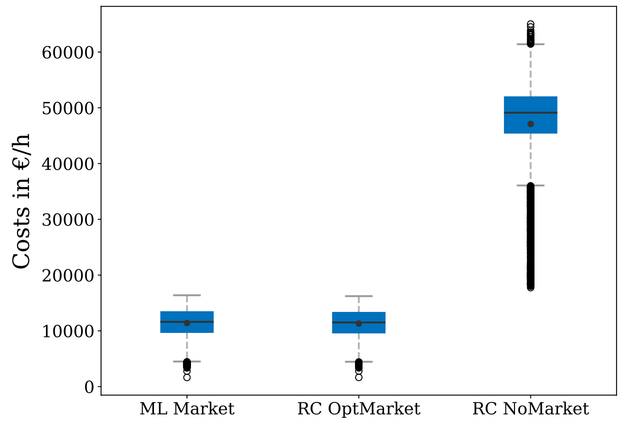

Fig. 7 Total economic costs of the reactive power provision (Average total costs: Multi-level market 11401.33 €, RC OptMarket 11302.60 €/h, RC NoMarket 47104.03 €/h)

In our model, these costs include the costs incurred by providers for the supply of reactive power and the grid operators' costs for active power loss due to reactive power flows. However, it is difficult to differentiate between loss costs due to active or reactive power transport. Therefore, the total loss costs of the complete grid are used, which increases the costs uniformly for the three cases. The total costs for a time step t are calculated using the following equation:

$$C_{\mathrm{Q},t} = p^{\mathrm{P}} \cdot P_{\mathrm{L},t} + \sum_{g \in G} \mathrm{EPF}_g(Q_{g,t}) \tag{26}$$

where $P_{\mathrm{L},t}$ are the total active power losses of the complete grid at time t. The EPF_g and the provided reactive power $Q_{g,t}$ is used to determine their costs for reactive power provision. As described before, the EPF used in our model contains only the providers' costs for active power losses in the converters.

The total economic costs of the reactive power provision are shown in Fig. 7.

The proposed multi-level market and RC OptMarket result in similar costs. Both the average total costs and the distribution of the costs are very similar for both cases, whereby our market leads to about 1% higher average costs compared to RC OptMarket. In RC NoMarket, however, the average costs and the spread are significantly higher. Keep in mind that in this case only costs of the grid operators and no bids from providers are included in the optimization, and that we have previously found that significantly more reactive power is provided in RC NoMarket.

Constraint satisfaction and loss minimization

Each grid operator aims to satisfy all its local constraints. That should not be sabotaged by the decentralized market. To investigate constraint satisfaction compared to the reference cases, we will first analyse the voltage magnitudes and then the line and transformer loadings.

Only the minimum and maximum voltage values of the individual grids are used for the investigation of the voltages. This is done because potential voltage violations can be adequately represented by the extreme voltage values. The extreme voltage values of the

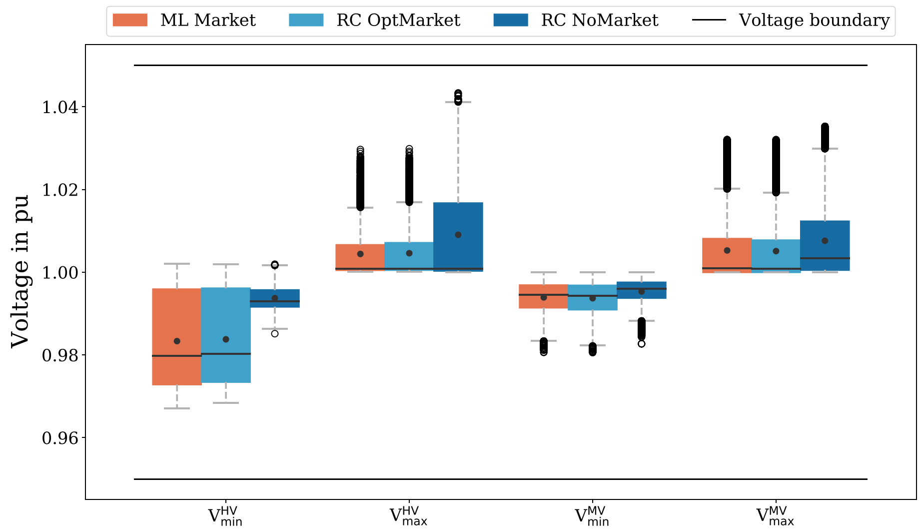

Fig. 8 Minimum and maximum node voltages of the individual grids, subdivided by the voltage level

individual network areas of the complete grid at time step t are determined using the following equation:

$$\begin{aligned} V^a_{\min,t} &= \min(\mathbf{V}_a) \\ V^a_{\max,t} &= \max(\mathbf{V}_a) \end{aligned} \tag{27}$$

where a stands for a network area of a specific grid operator and $\mathbf{V}_a$ is the vector of all voltage magnitudes within area a.

Figure 8 shows the minimum and maximum node voltage of each network area for each step t as a boxplot, subdivided by the respective voltage level.

There are no voltage band violations in all three cases. Similar voltages of the HV grid can be observed for the market and RC OptMarket, with the market having slightly lower minimum and maximum voltages on average. For RC NoMarket, both higher minimum and maximum voltages of the HV grid are present. In addition, a larger spread in the maximum nodes voltages and some extreme values close to the upper voltage boundary happen in RC NoMarket, compared to our proposed market and RC OptMarket. Similar voltage distributions can be observed for the MV grids. Market and RC OptMarket again result in similar voltages, but this time the average minimum and maximum voltages of the market are slightly higher than in RC OptMarket. Again, larger average extreme voltage values can be found in RC NoMarket.

As for the voltages, no violations occurred for the other constraints, i.e., transformer and line loadings. The mean values of the maximum transformer and line loadings are given in Table 1.

Looking at the average maximum loading of the HV/MV-transformers $\overline{L^{\mathrm{HV/MV}}_{trf,\max}}$, a slightly lower loading can be seen for our proposed market compared to RC OptMarket. Our market and RC OptMarket also have a very similar average maximum line loading $\overline{L^{\mathrm{HV}}_{l,\max}}$ of the HV grid with a slightly lower line loading for RC OptMarket. The same goes for the MV grids. Our market and RC OptMarket lead to similar loadings, with

Table 1 Mean maximum values of line and trafo loadings as well as total active power losses

	ML Market	RC OptMarket	RC NoMarket
$\overline{L_{trf,\max}^{\mathrm{HV/MV}}}$	7.45 %	7.69 %	5.00 %
$\overline{L_{l,\max}^{\mathrm{HV}}}$	34.69 %	34.53 %	28.26 %
$\overline{L_{l,\max}^{\mathrm{MV}}}$	21.79 %	22.54 %	17.50 %
$\overline{P_{\mathrm{L}}}$	2.516 MW	2.529 MW	2.253 MW

those of our market being slightly lower again. However, the by far lowest maximum line and trafo loadings occur in RC NoMarket.

Furthermore, the arithmetic means of the total losses $\overline{P_{\mathrm{L}}}$ of the multi-level system are shown in Table 1. Again, the market and RC OptMarket lead to similar results. However, the lowest losses occur in RC NoMarket.

Discussion

In this section, we discuss the results of our evaluation. For one thing, we answer the three guiding questions from our case study. Further, we discuss the important aspect of EPF approximation. Finally, we discuss benefits and drawbacks of our proposed multi-level market

Reactive power provision The previous chapter demonstrated that the proposed multi-level market leads to a similar amount of reactive power provision as the optimal solution of RC OptMarket. For both cases, the reactive power provision is far lower than in RC NoMarket. Furthermore, in RC NoMarket significantly less reactive power is provided by MV connected providers and instead more in the HV system. Due to the restricted $\cos(\varphi)_{\mathrm{PCC}}$ at the grid coupling points, the reactive power exchange is limited and the grid operators have to balance their grids locally. Secondly, the objective function of the grid operators can be a reason for the higher reactive provision. Since the grid operators in RC NoMarket do not take into account any bids—e.g., the costs of the providers—reactive power is supplied by the DERs as long as this leads to lower costs for the respective grid operator. In contrast, our multi-level market as well as RC OptMarket allow for reactive power exchange across voltage levels that benefits grid operators on both sides. This way, no reactive power is provided solely for balancing of individual grids when it brings no overall welfare gain. Further, grid operators can take into account the providers' cost through their bids and weigh costs and benefits of reactive power provision this way. All together, this results in 11% less required reactive power provision compared to RC NoMarket.

Reactive power costs We found that the average costs of our market were only minimally higher compared to the globally optimal solution of RC OptMarket, but significantly lower than RC NoMarket. Mainly, that can be attributed to the generally lower reactive power provision compared to RC NoMarket, as discussed before. In addition, the lowest unit operator costs occur when reactive power is equally distributed over all providers, due to the quadratic EPFs functions in our case study. A more uneven distribution of the provision between the providers and thus between the voltage levels leads to higher economic costs. The multi-level market enables coordination of the grid operators and therefore allows to find such cost efficient distribution of reactive power provision. In RC NoMarket, this is not possible, which leads to higher total costs, although the active power losses are far lower than in the other cases (compare Table 1), because the weighing of costs and benefits is neither possible nor incentivized, which results in disproportionally high reactive power costs. That demonstrates how RC NoMarket fails to find an economic trade-off between loss minimization and reactive power procurement.

Approximation of the EPF The slightly higher costs of our market approach compared to RC OptMarket result from deviations of the approximated EPF to the actual cost function. In our case study, the quadratic approximation leads to slightly higher EPFs values than those calculated, resulting in unintended profits for the MV grid operators (compare Fig. 4 as an example). The profits increase the HV grid operator's cost, when reactive power is procured from the MV grids. As a result, more reactive power in the market is supplied locally by providers in the HV grid and less by providers in the MV grids compared to RC OptMarket. In conclusion, the approximation error leads to non-optimal multi-level reactive power exchange, which results in the deviation from RC OptMarket.

Constraint satisfaction Regarding constraint satisfaction, we found that our market and RC OptMarket generally resulted in similar voltage distributions. However, for our market, the extreme voltages are slightly lower on average in the HV grid and slightly higher in the MV grids than in RC OptMarket. This can be explained by the fact that in the proposed market more reactive power (underexcited) is provided in the HV grid and less is provided in the MV grids, thus lowering the voltage level in the HV grid and increasing it in the MV grids. All together, in our case study, even less extreme voltage values occur, compared to RC NoMarket, because coordinated reactive power exchange between the grid operators is now possible. The average maximum HV/MV-transformer loading and average maximum line loading of the HV and MV grids were also very similar for the market and RC OptMarket, but significantly higher compared to RC NoMarket. This can be explained by the additional, and desired, reactive power exchange across voltage levels. In summary, our proposed market does not affect constraint satisfaction negatively, but achieves the same constraint satisfaction with less costs and reactive power usage. Although HV/MV transformer loadings and line loadings increase compared to RC NoMarket, this increase is limited by the use of OPFs which prevent constraint violations. However, if the lines and transformers are already highly loaded, our multi-level market may not achieve as good results, since additional transfer of reactive power would not be possible.

Benefits of the proposed multi-level market Besides the previously discussed benefits, our case study demonstrates that through the multi-level market, DERs from MV grids can provide reactive power to the superordinate HV grid. Thus, the market enables a multi-level reactive power provision. Compared to RC NoMarket, where the multi-level provision is limited according to current practices, the costs and total amount of reactive power provision are significantly lower. This confirms again that including the costs of the providers in a market-based way leads to a more economically efficient reactive power provision than mandatory provision. In addition, our market leads to very similar results as the optimal execution of a central market in RC OptMarket, regarding both technical and economic aspects. Therefore, we can conclude that our market allows economically efficient reactive power procurement close to the optimal solution, although no central OPF calculation needs to be performed, thus allowing for a decentralized optimization of the system. Another big advantage of our approach is that the exact market rules are free to choose for the participating grid operators. We already mentioned that each grid operator can choose its own local market rules. Additionally, our approach does not put constraints on the exact rules of the multi-level market itself. For example, the time intervals in which the grid operator exchange information could be set to daily, hourly or even on demand. The same applies to minimum bid size, the way to communicate the EPF and so on. The only requirement is that all participating grid operators agree on the rule set. That also allows to choose the market rules in such a way that they integrate well with existing markets, e.g., the wholesale energy market.

Drawbacks of the proposed multi-level market We found that the approximation of the EPF leads to unintended profits for the grid operators, which negatively affect the reactive power exchange. That demonstrates the importance of a good approximation of the EPFs. Any deviation from the actual cost function results in non-optimal results of the decentralized market. Furthermore, we neither considered transaction costs for the execution of the market nor providers' profits, when comparing with the reference cases. Transaction costs could increase total costs, especially by the execution of the grid operator' local markets, due to the potential participation of many small market participants. However, the larger the number of market participants, the smaller the possibility of market power and likewise its abuse. A larger number of market participants increases pressure on each individual supplier to submit bids that are closer to their true marginal costs, which improves efficiency of reactive power provisioning.

Conclusions

In this paper, we propose a decentralized multi-level reactive power market that enables reactive power provision from providers in different grids across multiple voltage levels. Each participating grid operator only requires knowledge about its own local system. To evaluate the market for a large number of load and generation profiles, timeseries data were used. The comparison with two reference cases showed that our market approach enables multi-level reactive power provision that is far more efficient than local optimizations of each grid operator, while complying with the local constraints of the grid operators. In addition, we found that our market leads to almost identical technical and economic results as a central optimization under consideration of the full multi-level grid model. Slight deviations occurred only due to the quadratic approximation of the EPFs of the grid operators. Therefore, we can conclude that our market achieves economically efficient reactive power provision across multiple voltage levels, if the local EPF can be approximated sufficiently.

Since the grid operators only have to communicate their reactive power range, cost function, scheduled active power flow, and the requested reactive power setpoints, the market can be implemented with a relatively low communication effort. Moreover, each grid operator is free to choose its local market rules, constraints, and the optimization procedure used.

The implementation of our market in the real world is quite simple, if there are existing local reactive power markets. If that is the case, neighboring grid operators simply need to agree on the respective time intervals for communication and reactive power provision—e.g., daily or hourly—and the EPF approximation to use—e.g., quadratic or linear. Regarding regulation, this requires that local markets and market-based reactive power exchange between grid operators are generally allowed by regulation.

A further technical requirement of our market is that there must be only one vertical grid coupling point between grids. To date, this assumption is required for all proposed multi-level reactive power markets proposed in the literature. Therefore, it should be investigated how grid-level reactive power exchange can be achieved with multiple vertical and horizontal coupling points. In our model, we have examined the market for a restricted situation in which none of the participating players can make profits. Therefore, detailed research should be conducted regarding the impact of profits made by providers as well as grid operators and the potential of market power of the participants. Finally, alternatives are required for the quadratic approximation of the cost functions, since it will not always be sufficient in more complex systems. One possibility to communicate prices would be non-convex polygons, which then require more advanced methods to perform the aggregation and optimization, for example meta-heuristic algorithms (Sarstedt and Hofmann 2022).

Appendix A

In the beginning, we based our approach on the assumption that the voltage at the interconnection point of two grids is at 1 pu. Since that assumption is not always valid and not every grid is equipped with on-load tap-changing transformers, an extension for the proposed market is presented here. This makes it possible to comply with the voltage restrictions of grids without on-load tap-changing transformers and thus enables their participation in the market. The additional communicative and computational procedures are shown in the following Fig. 9 and are performed before the proposed multi-level market procedure begins.

In a first step, in all grids, the flexibility providers send their planned active power feed-in to the grid operator. The grid operators of the lowest participating voltage level then determine their expected active and reactive power at the grid coupling point to their superordinate grid operator by performing a power flow calculation. In this calculation, they include all active power feed-ins and loads, as well as known reactive power requirements of loads, but neglect all flexible reactive power feed-ins by the market participants. This process continues up to the grid operators of the highest participating voltage level. The grid operators at the highest voltage level then also perform a power flow calculation including the data of the subordinate grid operators. This is used to determine the node voltages at the coupling points to the subordinate grids. This voltage information is passed on to the respective subordinate grid operators, which then perform another power flow calculation in which this voltage is assumed as the slack voltage. Subsequently, the local market processes take place. However, when determining the reactive power flexibility range, instead of a slack voltage of 1 pu, the estimated

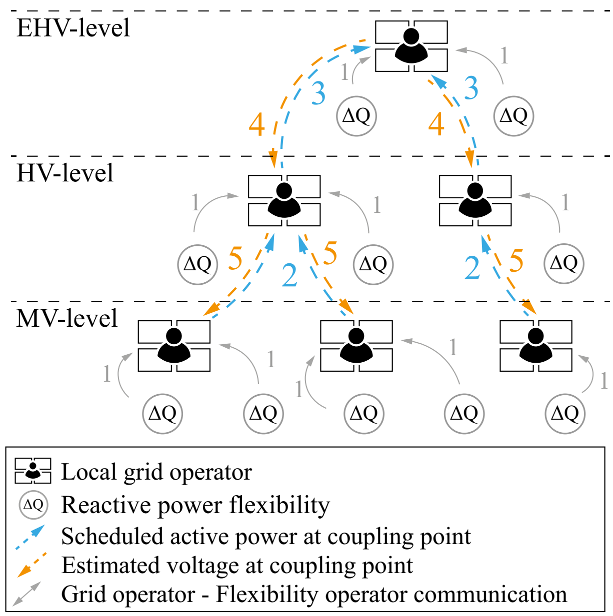

Fig. 9 Market extension: Additional information exchange in the case without on-load tap-changing transformers

voltage previously received from the respective superordinate grid operator is used. Note that this method does not result in perfect calculation of the slack voltages, which results in some deviations to the optimal market result. If a precise calculation of the slack voltage is required, the process can be repeated iteratively, including the planned reactive power flows.

Appendix B

See Table 2.

Table 2 Assumed number of individual WTs for the wind farms of the *SimBench* HV grid and resulting installed power of each unit

Identifier	N of WTs	P_{WT}^{inst} in MW	Identifier	N of WTs	P_{WT}^{inst} in MW
Sgen 80	5	2.614	Sgen 90	1	4.000
Sgen 81	3	2.760	Sgen 91	4	2.935
Sgen 82	4	2.518	Sgen 92	9	2.786
Sgen 83	4	2.893	Sgen 93	1	3.500
Sgen 84	4	2.713	Sgen 94	3	3.183
Sgen 85	8	2.944	Sgen 95	16	2.889
Sgen 86	3	3.127	Sgen 96	3	3.270
Sgen 87	4	2.698	Sgen 97	12	2.790
Sgen 88	12	2.790	Sgen 98	6	2.802
Sgen 89	3	2.907			

Abbreviations

DER	Distributed energy resource
DSO	Distribution system operator
EHV	Extra high voltage
EPF	Expected payment function
HV	High voltage
ML	Multi-level
MV	Medium voltage
OPF	Optimal power flow
PV	Photovoltaic
RES	Renewable energy resource
RC OptMarket	Reference case *Optimal Market*
RC NoMarket	Reference case *No Market*
TSO	Transmission system operator
WT	Wind turbine

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Author Contributions
Conceptualization: JB, TW, and AN; methodology: JB and TW; software: JB; validation: JB and TW; writing—original draft: JB and TW; writing—review and editing; JB, TW, and AN; visualization: JB; supervision: AN; project administration: AN; funding aquisition: AN. All authors have read and agreed to the published version of the manuscript

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Availability of data and materials
The datasets generated and/or analysed during the current study are available in the repository https://gitlab.com/digitalized-energy-systems/scenarios/multi_level_reactive_power_market_design

Declarations

Ethics approval and consent to participate
Not applicable

Consent for publication
Not applicable.

Competing interests
The authors declare that they have no competing interests.

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