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Reactive power management at the transmission–distribution interface with the support of distributed generators – a grid planning approach

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Abstract: This study introduces a grid planning approach for reactive power management at the transmission–distribution interface with the support of distributed generators (DGs). The main research question is: can reactive power management with DGs provide controllable reactive power with a very high availability and can this reduce or avoid the demand for additional reactive power compensators in a distribution grid section (e.g. mechanically switched compensators)? Therefore, an availability analysis of reactive power support is performed for different generation types at the distribution level, like hydro, thermal, wind and photovoltaic power plants. For the investigated case study of a real German distribution grid, reactive power management with the support of DGs could relevantly reduce the demand for additional reactive power compensation devices. However, the effectivity of DGs for reactive power support strongly depends on the applied grid planning rules and requirements at the transmission–distribution interface.

1 Introduction

Increased transport distances and the expansion of transmission capacities will increase the reactive power (Q) demand in the German transmission system significantly until the year 2030 [1]. Furthermore, the number of large conventional power plants, which are nowadays still a major reactive resource, will decrease within the next years in the German transmission system and new reactive resources will be required. In [1, 2] it is noted, that the overall reactive range in the transmission system will increase, and hence underexcited and overexcited [In this paper, the term underexcited operation describes a reactive import/consumption of a grid section or a distributed generator (DG), similar to a shunt inductor. The term overexcited operation describes a reactive export/generation of a grid section or a DG, similar to a shunt capacitor.] compensation equipment might be required, depending on the particular generation and demand behaviour and the respective grid locations. Different additional reactive resources are discussed in [1], such as the installation of additional Q compensators (e.g. static Var compensators), the use of planned high-voltage (HV) direct current converter stations or the utilisation of DGs connected to the distribution level.

The main objectives of advanced Q management studies in the transmission level are the prevention of voltage collapse and the improvement of voltage stability margins [3–7], the reduction of transmission losses [3, 8] and the development of concepts for reactive power markets [3, 4, 8]. Q management at the transmission–distribution (T–D) interface with the support of DG is a rather new research field, which is in Europe especially triggered by the further development of the regulatory framework by ENTSO-E. The new ENTSO-E Demand Connection Code (DCC) [9] (see Section 2.3) specifies additional Q requirements for distribution grid interconnections with the European transmission system, which can help the Transmission System Operator (TSO) to maintain voltage levels within specified limits, but might also lead to costly investments by the Distribution System Operator (DSO) for installation of additional reactive compensation equipment [10]. In a Belgium case study [11] it is shown, that an increased DG penetration can lead to unrequested operation points at the T–D interface according to the DCC requirements, if no additional measures are taken.

In Germany, ∼95% [12] of the capacity of renewable energy sources are connected to the distribution level [In Germany also the HV level (73–125 kV) is mainly considered as part of the distribution grid.], and hence a relevant potential for Q support by DG is expected. However, the DSO also faces several new challenges for Q management within his own service area; e.g. an increased degree of cabling, increased reverse power flows, and the application of DG Q control for local voltage support, which can significantly increase the Q flow within a distribution section [2]. In literature, basically two objectives for Q management at T–D interface are discussed [13]:

i. fixed Q limitation depending on active power exchange at T–D interface (e.g. a fixed power factor (PF) limit), and/or
ii. flexible Q setpoints at the T–D interface depending on the current controllable Q potential in the distribution level and the Q requirements in the transmission level.

In state-of-the-art, fixed Q limitations are usually requested at the T–D interface (see [14]) and some DG in the field can operate with a fixed PF, which can improve the Q exchange at the T–D interface. In several studies [15–18] also active control and optimisation approaches for DG Q management are developed, which can provide controllable Q exchange at the T–D interface. As outlined in [13] also a combination of these two objectives are reasonable. The flexible Q setpoint at the T–D interface can make optimal use of the variable Q potential of variable DG, like photovoltaic (PV) or wind generators and can be used to optimise the grid operation. Otherwise, the fixed Q limitation at the T–D interface can provide the required planning security for the grid operators. Whereat, the studies [15, 17, 18] mainly focus on grid operation challenges, only a few grid planning studies on Q management at T–D interface are known by the authors. The availability of DG Q support is analysed in [19] with on optimal power flow approach and in [16, 20] by an analytical assessment of DG measurement and simulation data. The availability of DG Q support is determined in [20] as annual reactive full load hours and

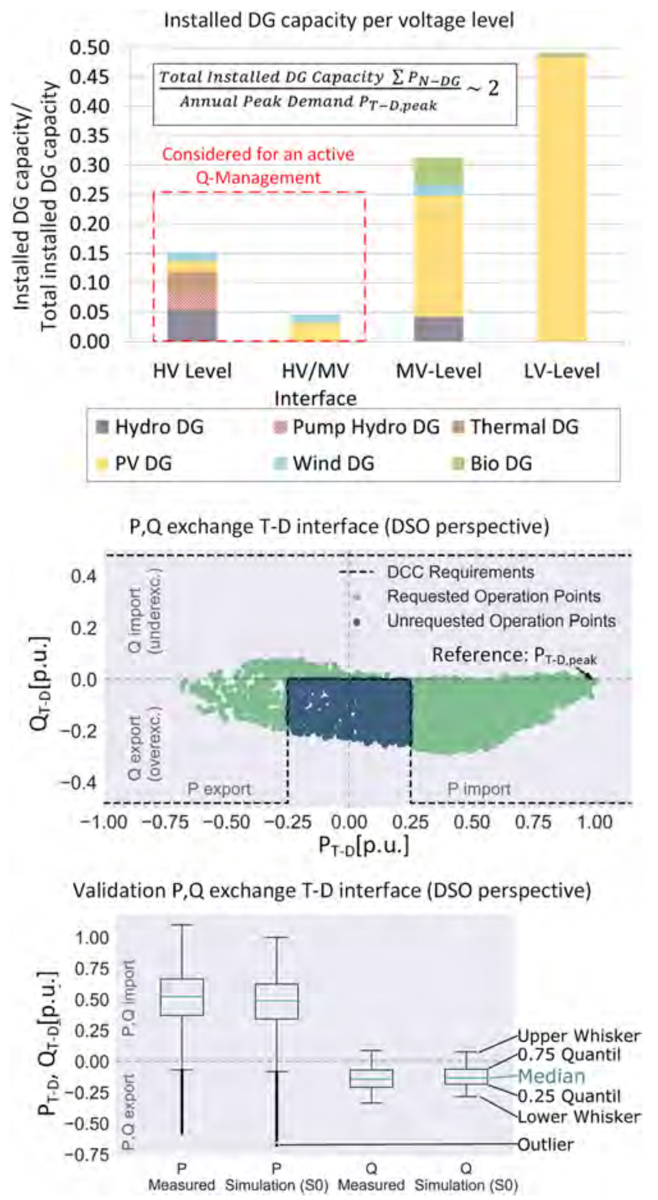

Fig. 1 *Characteristics of the case study area and simulation model*
Top: Installed DG capacity per voltage level. *Middle:* Annual P, Q exchange at the T–D interface for Scenario 0 (normalised by (2)). *Bottom:* Comparison of P, Q exchange at T–D interface for measurement and simulation data (Scenario 0) (normalised by (2))

in [16] as probability values for defined grid use cases. These approaches can determine the effectiveness of DG units and/or DG types for Q support at the T–D interface.

This paper complements the presented approach in [16] by complex annual quasi-static power flow simulations of the DG Q availability. Furthermore, a new approach is presented, which can support the grid planning process by DSOs, to identify the optimal additional Q compensation demand in the distribution level, with and without an active DG Q management. The analysis is performed for a HV distribution grid section of the German DSO Bayernwerk Netz GmbH, which achieves some of the highest PV penetration rates in Germany. The fixed Q limitations at the T–D interface in this paper are set according to the new ENTSO-E DCC [9], and relevant additional Q compensation demand is expected for the investigated grid section.

The paper is structured as follows: in Section 2, the applied simulation model and assumptions are described; in Section 3, an availability assessment of the DG Q support is performed for a relevant grid use case; in Section 4, the additional Q compensation demand is identified for the investigated grid section; and Section 5 discusses the results. The conclusion summarises main findings of this work.

Table 1 Overview on installed DG capacity at all voltage levels (normalized by the total installed DG capacity)

Voltage level	P_{NDG}, p.u.	Comment
total HV-DG	0.152	DG Q management considered
total HV/MV-DG	0.045	DG Q management considered
total MV-DG and LV-DG	0.803	DG Q management not considered
total DG	1.000	—

Table 2 Overview on installed DG units at HV level (normalized by the total installed DG capacity)

Name	P_{NDG}, p.u.	Comment
Thermal-DG1	0.029	
Pump-DG1	0.024	
Hydro-DG1	0.022	
PV-DG1	0.013	
Hydro-DG2	0.013	
Wind-DG1	0.009	
Pump-DG2	0.007	
Wind-DG2	0.005	
PV-DG2	0.005	
Thermal-DG2	0.005	
Hydro-DG3	0.004	
Hydro-DG4	0.004	inconsistent data, not considered
Hydro-DG5	0.004	
Hydro-DG6	0.004	
Hydro-DG7	0.003	
Total HV-DG	0.152	

2 Simulation model and assumptions

In this section, the investigated case study area (Section 2.1), the applied grid model (Section 2.2), the considered requirements at the T–D interface (Section 2.3) and the applied generator models (Section 2.4) are explained in detail. Finally, a short description of the simulation model validation (Section 2.5) and the normalisation of the results (Section 2.6) is provided.

2.1 Case study area

The investigated distribution grid section of Bayernwerk Netz GmbH covers an HV grid area (nominal voltage $V_{\mathrm{N}} = 110\,\mathrm{kV}$) and nine T–D grid coupling points (T–D GCPs), which connect the grid section with the transmission level ($V_{\mathrm{N}} = 220$ and $400\,\mathrm{kV}$). The nine T–D GCPs belong to the same grid zone, and in this paper, the power exchange at the T–D interface $P_{\mathrm{T-D}}$ and $Q_{\mathrm{T-D}}$ is shown as an aggregate over all nine T–D GDPs (see Fig. 1, middle).

Fig. 1 (top) shows also the installed generation capacity for the investigated grid section. The values are normalised to the total installed DG capacity in the investigated grid section. The total installed DG capacity exceeds the maximum peak demand of the investigated grid section $P_{\mathrm{T-D,peak}}$ by a factor of two and significant reverse power flows are already measured at the T–D interface (see Fig. 1, middle). The investigated grid section is situated in an area which achieves some of the highest PV penetration rates in Germany. And ~80% of the total DG capacity is installed in the LV and MV levels, with mostly PV installations. Nevertheless, in this paper, only DG systems in the HV level and at the HV/MV interface are considered for an active Q management. About 15% of the total DG capacity is installed in the HV level, with seven hydro power plants (Hydro-DG), two hydro pump storage plants (Pump-DG), two thermal power plants (Thermal-DG), two PV parks (PV-DG), and two wind parks (Wind-DG). At the HV/MV interface ~5% of total DG capacity is installed, with solely PV and wind parks. A detailed list of the generators connected to the HV and HV/MV interface is given in the Appendix (see Tables 1–3).

Table 3 Overview on installed DG units at HV/MV interfaces (normalized by the total installed DG capacity)

Name	P_{NDG}, p.u.	Comment
Wind-DG3	0.004	
PV-DG3	0.004	
PV-DG4	0.004	
PV-DG5	0.003	
Wind-DG4	0.003	
Wind-DG5	0.003	
PV-DG6	0.003	
PV-DG7	0.002	
Wind-DG6	0.002	
PV-DG8	0.002	
PV-DG9	0.002	
PV-DG10	0.002	
PV-DG11	0.002	
PV-DG12	0.002	
Wind-DG7	0.001	
PV-DG13	0.001	
PV-DG14	0.001	
PV-DG15	0.001	
PV-DG16	0.001	
PV-DG17	0.001	
PV-DG18	0.001	
PV-DG19	0.001	
total HV/MV-DG	0.045	

2.2 Grid model

The analysis in this study is performed by annual quasi-static power flow simulations with a temporal resolution of one hour. Real measurement data are provided by Bayernwerk Netz GmbH for the year 2014. The simulations are performed using the open source simulation tool Pandapower [21]. For the investigated grid section, a detailed grid model of the nine T–D GCPs, the HV level, and 87 HV/MV substations is applied. The transmission level (220–400 kV) is modelled with a simplified grid model, while the MV and LV levels are modelled by an aggregated PQ load at the MV busbar of the HV/MV transformer. Furthermore, the connections to external HV grids are modelled by PQ loads. The demand/generation of loads, generators, and connected grid sections are simulated by the annual PQ measurements at their respective nodes. The tap controllers of the EHV/HV and HV/MV transformers are controlled to their fixed nominal target values.

2.3 Requirements at T–D interface

In this paper, the Q requirements of the new ENTSO-E DCC are considered. In the ENTSO-E DCC and the related EU Commission Regulation 2016/1388 [9], basic Q requirements for distribution systems connected to the transmission level are specified. Article 15(2) [9] can be especially challenging to obtain for the respective DSO: ‘The relevant TSO may require that transmission-connected distribution systems have the capability at the connection point to not export reactive power (at reference 1 p.u. voltage) at an active power flow of <25% of the maximum import capability (…)’ DCC Article 15(2) [9].

Therefore, Fig. 1 (middle) shows the annual power exchange at the T–D interface and the considered DCC requirements for the investigated grid section. It can be seen that, currently, not all operation points at the T–D interface of the investigated grid section would be within the requested operational area according to the DCC requirements, hence Q management with DGs might improve the Q exchange at these locations. It should be highlighted that the DCC requirements do not correspond with the current requirements at the T–D interface of the investigated grid section. The national implementation of the DCC is still under discussion.

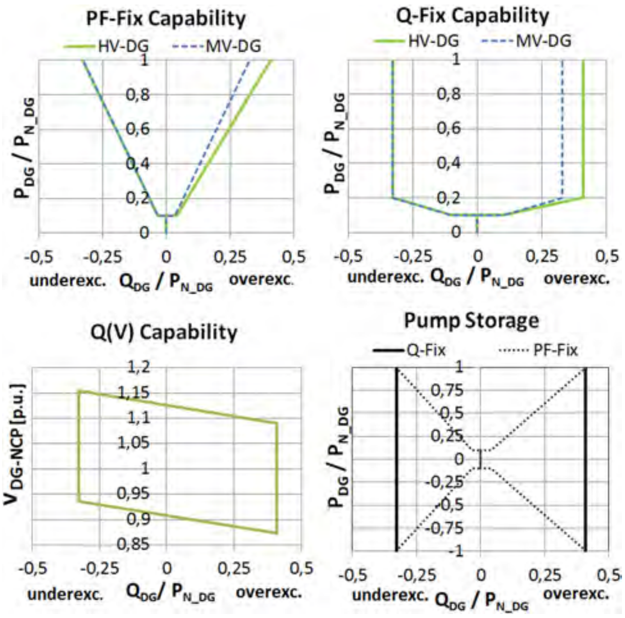

Fig. 2 *Applied DG Q capability characteristics*

Top left: PF-fix capability (Scenario 1). *Top right:* Q-fix capability (Scenario 2). *Bottom left:* $Q(V)$ capability (Scenarios 1 and 2). *Bottom right:* Capability of pump storage systems (Scenarios 1 and 2)

2.4 Generator models

In Germany, the requirements for generators are specified in the VDE AR-N 4120 [22] for HV DG and in the BDEW medium-voltage (MV) guideline [23] for MV DG. These guidelines specify, e.g. the Q capability of generators depending on the active power feed-in P_{DG} and the local grid voltage V_{DG}. In the simulation model, only DG at the HV level and the HV/MV interface are modelled in detail and are considered for an active Q management. The following scenarios are considered in the simulations:

- *Scenario 0:* Reference scenario: for HV DG the measured Q values are considered, for DGs at the HV/MV interface unity PF is considered.
- *Scenario 1:* Fixed PF requirement (PF-fix): the generators can provide a specified minimum PF (e.g. PF = 0.95 under excited or overexcited) (Fig. 2, top left). The pump storage plants can provide reactive power in generation and consumption mode with a minimum PF (Fig. 2, bottom right).
- *Scenario 2:* Fixed Q requirement (Q-fix): the generators can provide a specified maximum Q feed-in (overexcited and under excited) (Fig. 2, top right). For the pump storage plants a Q provision independent of the active power feed-in is considered (Fig. 2, bottom right).

For a PF-fix requirement (Scenario 1), the DG Q capability strongly depends on the active power feed-in P_{DG}. And for a Q-fix requirement (Scenario 2), the DG Q capability is widely independent of the active power feed-in P_{DG}. However, for P_{DG} below 10% of the nominal active power $P_{\mathrm{N-DG}}$, no controllable DG Q provision is considered (except Pump storages in Scenario 2). The set values for the minimum power factor and maximum reactive power of DG are set according to [22] (option 2) for HV-DG and [23] for DG at the HV/MV interface. Furthermore, a voltage dependent reactive power limitation for the DG systems is considered according to [22] (option 2) (see Fig. 2, bottom left). A limitation of the maximum apparent power of the DG systems is not considered. Therefore, the DG can provide the requested reactive power without a limitation or reduction of the active power feed-in. Furthermore, the internal generator losses are not in the scope of the paper (for detailed information on generator losses for Q provision see [24, 25]).

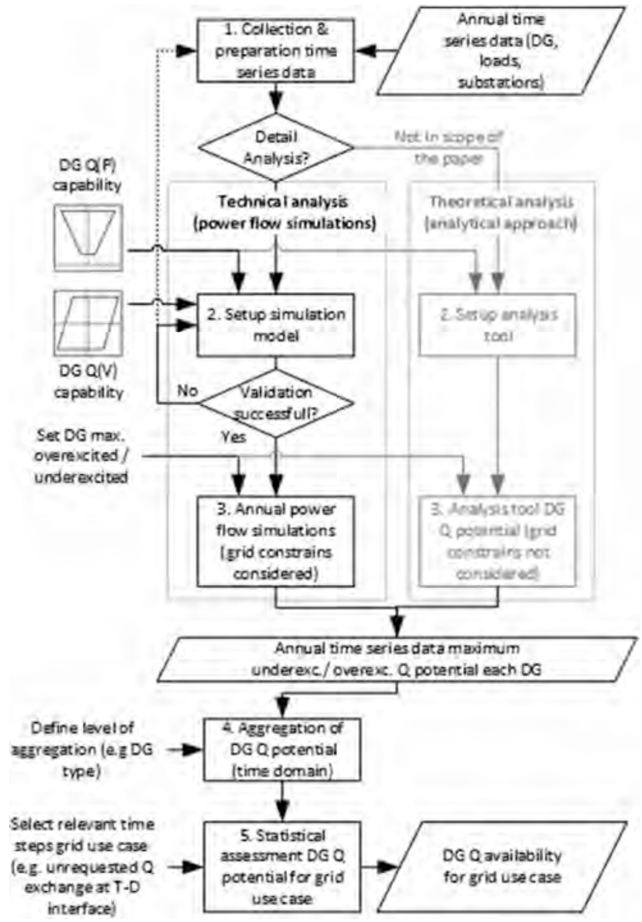

Fig. 3 *Applied methodology*

2.5 Simulation model validation

The applied simulation approach has high data requirements. Hence comprehensive data analysis and preparation is required. The data preparation is not in the scope of the publication. In the considered DG time series <0.6% of the annual values show a Not a Number (NaN) value. These NaN values are replaced by the last not faulty measurement value of the DG system. The grid model is validated by the measurement data of the active and reactive power flow at the T–D interface (see Fig. 1, bottom).

2.6 Normalisation of results

Some of the simulation results for the investigated grid section are confidential. Therefore, the results are presented by normalised values. The results of DG Q potential Q_{DG} and the DG active power feed-in P_{DG} are normalised by the nominal installed DG capacity $P_{\mathrm{N-DG}}$, whereat n is the total number of considered DG units

$$[P_{\mathrm{DG}}, Q_{\mathrm{DG}}][\mathrm{p.u.}] = \frac{\sum_i^n [P_{\mathrm{DG}_i}[\mathrm{MW}], Q_{\mathrm{DG}_i}[\mathrm{Mvar}]]}{\sum_i^n P_{\mathrm{N-DG}_i}[\mathrm{MW}]} \tag{1}$$

The P and Q exchange at the T–D interface $P_{\mathrm{T-D}}$, $Q_{\mathrm{T-D}}$, the Q deviation to the requested operation range at the T–D interface $Q_{\mathrm{T-D,out}}$ and the additional Q compensation capacity $Q_{\mathrm{T-D},x}$ are normalised by the annual peak demand at the T–D interface $P_{\mathrm{T-D,peak}}$ (see Fig. 1, middle and (2))

$$[P_{\mathrm{T-D}}, Q_{\mathrm{T-D}}][\mathrm{p.u.}] = \frac{[P_{\mathrm{T-D}}[\mathrm{MW}], Q_{\mathrm{T-D}}[\mathrm{Mvar}]]}{P_{\mathrm{T-D,peak}}[\mathrm{MW}]} \tag{2}$$

3 Availability assessment of reactive power provision by DGs

In this section, the availability of DG Q provision for relevant use case(s) is determined. Therefore, the following research questions are addressed:

- How much reactive power can be provided by DG systems when needed and what is their availability?
- Which DG systems can provide reactive power with a very high availability for the relevant use case?

3.1 Methodology

A time-series based approach is applied for the availability assessment of DG Q provision. The methodology of the assessment is shown in Fig. 3. In the first two steps, the time series data of loads and generators and the grid model have to be prepaired and validated. Furthermore, the reactive power capabilities of the DG need to be specified within the simulation model (see Section 2.4). The availability assessment can be performed by a theoretical and/or a detailed technical analysis.

In the theoretical analysis, the DG Q availability is solely limited by the $Q(P)$ capability of the generators and extensive grid simulations are not required. Hence, grid constraints (e.g. voltage limitations) for DG Q provision are not considered. However, the theoretical analysis can be a useful preliminary study to identify interesting DG units, DG types, grid regions, and/or voltage levels for Q management with DGs. An example of a theoretical analysis for the investigated grid section is given in [16].

For the technical analysis, annual load flow simulations are performed and the impact of DG Q provision on the grid operation can be studied. For the power flow simulation (step 3) no advanced control algorithms for DG Q management is necessarily needed, the control target is a maximum overexcited and/ or maximum underexcited operation of all controllable DG. In the applied case study only unrequested overexcited operation points at the T–D interface are determined (see Fig. 1, middle, dark green points); therefore only an underexcited operation of the generators is requested in this analysis. In the simulation, the DG Q provision might be additionally limited by the local voltage magnitude and the applied $Q(V)$ limitation curve of the generators. The aggregation of Q potential (step 4) can be performed using different criteria, for example by DG type, by voltage level, or by grid region. However, it is important to perform the aggregation of Q potential in the time domain in order to consider simultaneity effects of the generators. This is an advantage of the time-series based approach compared to fully probabilistic approaches because here the correlation of the DG units and loads is fully considered in the measurement data. Furthermore, it should be noted that the aggregation of the statistical outcome of DG Q potential is not reasonable, because this would assume a full simultaneity of the individual DG units and/or DG types (see e.g. (3)).

$$\mathrm{Min}(Q_{\mathrm{DG}i}(t) + Q_{\mathrm{DG}j}(t)) \neq \mathrm{Min}(Q_{\mathrm{DG}i}(t)) + \mathrm{Min}(Q_{\mathrm{DG}j}(t)) \tag{3}$$

Finally, the relevant grid use cases for the statistical assessment need to be specified. For the applied case study, only operation points with an unrequested Q exchange at the T–D interface are considered (see Fig. 1, Scenario S0, dark green points). However, the use case can be defined individually for different case studies, e.g. in [2] the DG Q potential was analysed for the annual peak demand and peak reverse power flow use case. Nevertheless, a reasonable number of annual time steps should be considered for the statistical assessment. This paper gives an overview of the DG Q potential for the defined use case and for a wide range of probability values:

- *Q potential with very high availability (e.g. 95–100%):* the minimum available DG Q potential for 95–100% of considered time steps.
- *Q potential with high availability (e.g. 80–90%):* the minimum available DG Q potential for 80–90% of considered time steps.
- *Q potential at median availability (50%):* Q potential is at least available for 50% of considered time steps.

• *Q potential with minimum availability (0%):* the maximum determined DG *Q* potential for considered time steps.

3.2 Results

In this paper, the availability assessment is shown for different DG types. Fig. 4 and Table 4 in the Appendix show the outcome of the availability assessment for the different DG types and the two investigated scenarios. For Scenario 1 (Fig. 4, top), the total DG *Q* potential (all DG types) with very high availability (95% perc.) reaches 0.10 p.u. of nominal considered DG capacity. A very high availability of *Q* potential is especially determined for the Hydro-DG with 0.014 p.u. (5% perc., Scenario 1). Furthermore, PV-DGs with 0.05 p.u. and Thermal-DG with 0.03 p.u. can provide a relevant DG *Q* potential with very high availability (0.95%, Scenario 1).

With the extended *Q*(*P*) capability of the DG systems in Scenario 2, the total DG *Q* potential with a very high availability (e.g. 95%, 0.22 p.u.) can be more than doubled compared with the conservative assumptions in Scenario 1. In particular, the pump

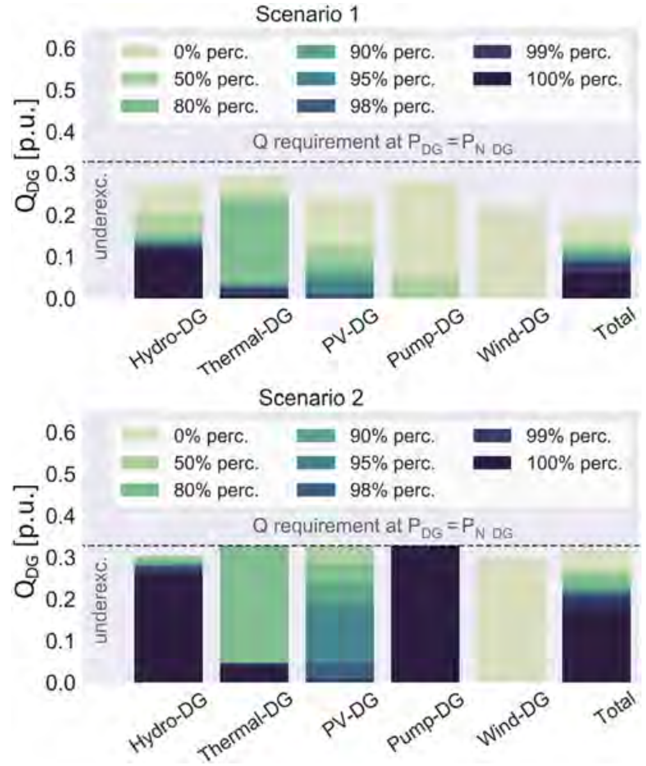

Fig. 4 *Overview results – DG Q potential (normalised by (1)) and DG Q availability for the defined use case*
Top: Results by DG-type (Scenario S1). *Middle:* Results by DG-type (Scenario S2)

storage systems (phase shift capability in Scenario 2) and DG systems operating frequently in partial-load range (especially PV-DG and Hydro-DG) can significantly increase their *Q* potential in Scenario 2. Therefore, a Q-fix capability (Scenario 2) significantly improves the contribution and availability of DG systems for a *Q* management in the distribution level.

The reasons for the partly high availability of *Q* provision by PV-DG are related to the defined use case. Unrequested operation points at the T–D interface usually only occur with a relevant DG feed-in, and PV is the dominant generation type in the analysed distribution grid (see Fig. 1, top). Therefore, unrequested operation points at the T–D interface usually occur with a relevant PV feed-in (see Fig. 5, top) and hence relevant PV *Q* potential. However, these results are strongly case study dependent and depend, e.g. on the generation portfolio of the grid section and the performance of individual DG units.

Furthermore, Fig. 5 (bottom) shows the operation range of the HV-DG. The HV-DG operate in a normal voltage range and the DG *Q* potential is not reduced by the local voltage magnitude V_{DG-NCP} (Fig. 5, bottom, right). Therefore, the DG *Q* potential is solely limited by the *Q*(*P*) capability of the generators (Fig. 5, bottom, left). However, in this study, only the normal switching state and the normal operation of the case study area is analysed and voltage limitations on the DG *Q* potential may appear for other switching states or in $n-1$ scenarios, which will be addressed in future studies.

Overall, the following priority list (according to the DG *Q* availability) for an active *Q* management with DGs is suggested for the investigated case study area and the defined use case:

1. *Hydro-DGs (Scenarios 1 and 2) and Pump-DGs (Scenario 2):* can provide a significant *Q* potential with a very high availability (95–100%).
2. *Thermal-DGs and PV-DGs (Scenarios 1 and 2):* can provide a relevant *Q* potential with very high availability (95%) and a significant *Q* potential with high availability (80–90%).
3. *Wind-DGs (Scenarios 1 and 2) and Pump-DGs (Scenario 1):* can solely provide *Q* flexibility with median or low availability (0–50%).

4 Assessment of additional reactive power compensation demand

This section focuses on the *Q* exchange at the T–D interface and the assessment of additional *Q* compensation demand in the case study area. The simulations and scenarios performed in this section are the same as those described in the previous one, and no additional simulations are required. The following research questions are addressed in this section:

• Is the *Q* exchange at the T–D interface within the specified limits?

Table 4 Overview of DQ *Q* potential (in p.u., normalised by (1)) and DG *Q* availability for different DG types and scenarios

Type	0%	50%	80%	90%	95%	98%	99%	100%
				Scenario 1				
hydro	0.27	0.20	0.16	0.14	0.14	0.13	0.13	0.11
thermal	0.29	0.25	0.23	0.04	0.03	0.03	0.02	0.01
PV	0.24	0.13	0.09	0.06	0.05	0.01	0.00	0.00
pump	0.28	0.05	0.00	0.00	0.00	0.00	0.00	0.00
wind	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00
total	0.20	0.14	0.12	0.11	0.10	0.09	0.08	0.06
				Scenario 2				
hydro	0.30	0.30	0.30	0.29	0.28	0.28	0.28	0.26
thermal	0.33	0.33	0.33	0.05	0.05	0.05	0.05	0.04
PV	0.33	0.33	0.28	0.24	0.18	0.05	0.01	0.00
pump	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
wind	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00
total	0.32	0.27	0.25	0.23	0.22	0.21	0.21	0.18

- Can an active DG Q management avoid or reduce unrequested Q operation points at T–D interface?
- Are additional Q compensators required within the distribution level, and how much Mvar are necessary?

4.1 Planning principles

So far, no general grid planning principles for an active Q management with DG are defined. Therefore, three different options for the assessment of additional Q compensation demand in the distribution level are suggested and analysed in this paper. The application of different planning principles is discussed in Section 4.

1. *Design of additional Q compensators on the annual worst case (0%):* The Q requirements at the T–D interface should be fulfilled for all annual operation points.
2. *Design of additional Q compensators on a certain percentage of annual values (e.g. 5%):* The Q requirements at the T–D interface should be fulfilled for e.g. 95% of annual operation points.
3. *Design of additional Q compensator on an estimated economic optimum:* The annuity of investments for additional Q compensation devices plus the annual penalty fee for unrequested operation points should be minimised.

4.2 Results

This subsection shows the results for the assessment of additional Q compensation demand in the investigated grid section for the different planning principles.

4.2.1 Design of additional Q compensators on the annual worst case (0%): Fig. 6 (top) shows the annual deviation at the T–D interface $Q_{\mathrm{T-D,out}}$ (sorted). In this approach the Q compensation demand is determined for the maximum Q deviation at the T–D interface and this leads to a rather high Q compensation demand of 0.25 p.u. (Scenario 0), 0.22 p.u. (Scenario 1), and 0.18 p.u. (Scenario 2). Furthermore, only DG systems (e.g. Hydro-DG) with a very high availability (95–100%) usually contribute to a reduction of the Q compensation demand.

4.2.2 Design of additional Q compensators on a certain percentage of annual values (e.g. 5%): Compared with the design on the annual worst case, this design approach leads to a significant reduced additional Q compensation demand (compare Fig. 6, 5%) of 0.11 p.u. (Scenario 0), 0.06 p.u. (Scenario 1), and 0 p.u. (Scenario 2). However, the Q requirements at the T–D interface will only be fulfilled for 95% of annual values with this additional Q compensation capacity.

4.2.3 Design of Q compensators on an estimated economic optimum: For this approach, a penalty fee for unrequested operation points at the T–D interface is considered. This is a common practice by TSOs to penalise unrequested behaviour at the T–D interface. The DSO can either continuously pay the arising penalty fee, or the DSO can decide to invest in new compensation devices to reduce or avoid the penalty fee. The scope of this planning approach is to identify the economic optimum between the payment of the penalty fee and the investment in new compensation devices. The cost assumptions for the penalty fee and investment costs are given in Table 5. For this analysis, an analytic approach is applied and no additional grid simulations are required. The reactive energy deviation at the T–D interface $E_{\mathrm{T-D},x}$ for different additional Q compensation capacities $Q_{\mathrm{T-D},x}$, can be derived from $Q_{\mathrm{T-D,out}}$ (see Fig. 6, bottom and (5)). With an increased $Q_{\mathrm{T-D},x}$ the energy deviation $E_{\mathrm{T-D},x}$ and the annual penalty fee C_{Fee} can be reduced (see (5) and (6)). However, the investment costs C_{Inv} will otherwise increase with $Q_{\mathrm{T-D},x}$ (see (7)). The goal of this approach is to identify the $Q_{\mathrm{T-D},x}$ which achieves a minimum total cost of C_{Fee} and C_{Inv} (see (9))

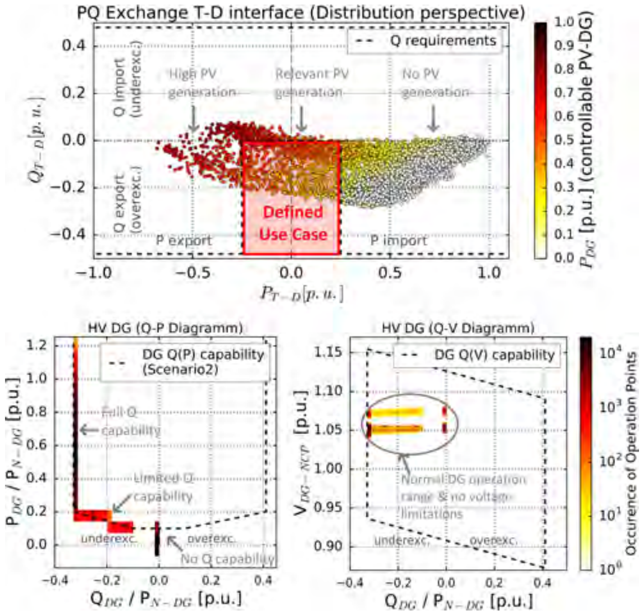

Fig. 5 *Detailed results – DG Q availability assessment*
Top: PQ exchange at T–D Interface (normalised by (2)) and PV feed-in of HV DG and HV/MV DG (normalised by (1)) for Scenario 0. *Bottom:* Operation range of HV DG (excluding Pump Storage) in Q–P diagram (left) and in Q–V diagram (right) for Scenario 2

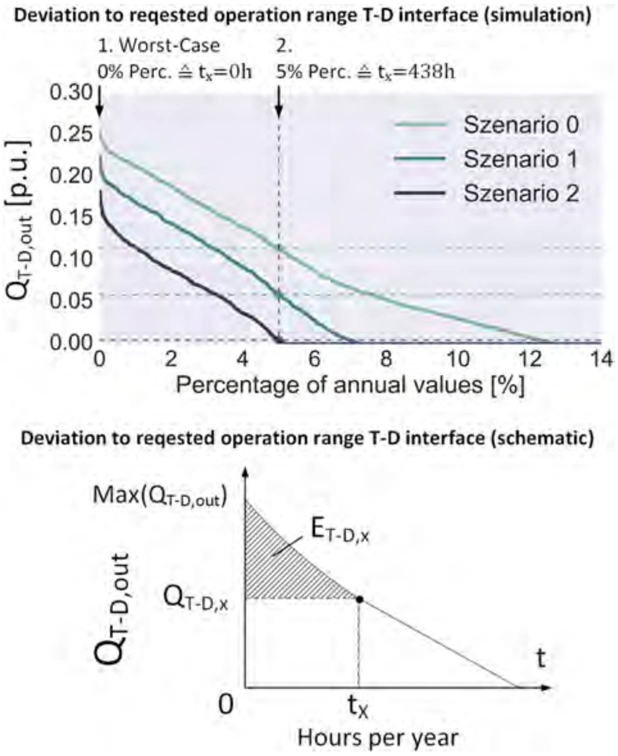

Fig. 6 *Q deviation to the requested operation range at the T–D interface*
Top: Simulation results (normalised by (2)). *Bottom:* Schematic diagram

$$Q_{\mathrm{T-D},x} = \{0, \ldots, \max(Q_{\mathrm{T-D,out}})\} \quad (4)$$

$$E_{\mathrm{T-D},x}(Q_{\mathrm{T-D},x}) = \int_{t=0}^{t_X} (Q_{\mathrm{T-D,out}}(t))\mathrm{d}t - Q_{\mathrm{T-D},x} \cdot t_X \quad (5)$$

$$C_{\mathrm{Fee}}(Q_{\mathrm{T-D},x}) = E_{\mathrm{T-D},x} \cdot c_{\mathrm{Fee}} \quad (6)$$

$$C_{\mathrm{Inv}}(Q_{\mathrm{T-D},x}) = c_{\mathrm{Inv}} \cdot Q_{\mathrm{T-D},x} \cdot A_{\mathrm{Inv}} \quad (7)$$

$$A_{\mathrm{Inv}} = \frac{(1+i)^n \cdot i}{(1+i)^n - 1} \quad (8)$$

$$C_{\text{Total}}(Q_{\text{T}-\text{D},x}) = C_{\text{Inv}}(Q_{\text{T}-\text{D},x}) + C_{\text{Fee}}(Q_{\text{T}-\text{D},x}) \quad (9)$$

where

- $Q_{\text{T}-\text{D},x}$: additional considered Q compensation capacity (in Mvar).
- t_X: number of hours per year, with a higher Q deviation at the T–D interface than $Q_{\text{T}-\text{D},x}$.
- $Q_{\text{T}-\text{D,out}}$: annual reactive power deviation to the requested operation range at the T–D interface (sorted, descending) (in Mvar).
- $E_{\text{T}-\text{D},x}$: reactive energy deviation to the requested operation range at the T–D interface in consideration of $Q_{\text{T}-\text{D},x}$ (compare Fig. 6) (in Mvarh)
- c_{Fee}: penalty fee for unrequested operation points at the T–D interface (in Euro/Mvarh).
- C_{Fee}: annual penalty fee for $Q_{\text{T}-\text{D},x}$ (in Euro/a).
- c_{Inv}: investment costs for additional Q compensation (in Euro/Mvar).
- A_{Inv}: annuity factor with interest rate i ($i = 5\%$) and lifetime of investment n ($n = 25$ years).
- C_{Inv}: annuity of investment costs for $Q_{\text{T}-\text{D},x}$ (in Euro/a).
- C_{Total}: sum of annuity of investment costs and annual penalty fee for $Q_{\text{T}-\text{D},x}$ (in Euro/a).

Fig. 7 (top) shows the C_{Total} in consideration of $Q_{\text{T}-\text{D},x}$ for the different Q-Management scenarios. With an increased $Q_{\text{T}-\text{D},x}$ the penalty fee reduces but the investment costs increases. The point indicates the $Q_{\text{T}-\text{D},x}$ with minimum total costs for each scenario. In the reference simulation S0, a $Q_{\text{T}-\text{D},x}$ of 0.08 p.u. can reduce the total annual costs by 18% compared with the status quo ($Q_{\text{T}-\text{D},x} = 0$). With an active DG Q-Management, the cost minimum is achieved at $Q_{\text{T}-\text{D},x} = 0.01$ p.u. (Scenario 1) or $Q_{\text{T}-\text{D},x} = 0\,\text{p.u.}$ (Scenario 2) and the DG Q management significantly reduces the additional Q compensation demand. Furthermore, the total annual costs can be significantly reduced by 43% for Scenario 1 and 69% for Scenario 2 at the identified cost minimum compared with the reference (S0, $Q_{\text{T}-\text{D},x} = 0\,\text{Mvar}$).

A sensitivity analysis for c_{Fee} and for c_{Inv} is shown in Fig. 7 (middle and bottom). An increased c_{Fee} or a decreased c_{Inv} lead to a cost minimum at higher $Q_{\text{T}-\text{D},x}$ values. Thereat, a double of c_{Fee} or a half of c_{Inv} lead to a $Q_{\text{T}-\text{D},x}$ of 0.16 p.u. compared to 0.08 p.u. in the base case assumptions. An overview of the identified Q compensation demand for the different planning approaches and assumptions is given in Table 6 in the Appendix.

5 Discussion of results

To now, detailed grid planning principles for an active DG Q management at the T–D interface have not been applied so far, and further discussions between the relevant stakeholders (e.g. TSO, DSO) are still required. If the Q requirements at the T–D interface are strict and unrequested operation points are generally not allowed, then the grid planning process should only focus on DG Q potential with a very high availability (100–95%) and on the maximum Q deviation at the T–D interface (worst case, Section 4.2.1). Eventually, a safety margin should also be considered in the grid planning process. However, this approach will likely lead to high investment costs for additional Q compensation devices at the distribution level. If unrequested Q operation points at the T–D interface are generally not forbidden but may cause a penalty fee for the DSO, a design of Q compensation devices on an economic optimum can be the most reasonable approach for the grid planning process (see Section 4.2.3). For a further increase of robustness and significance of the study, the presented analysis should be repeated for additional years and also future scenarios. Furthermore, it should be highlighted that the presented planning approach do

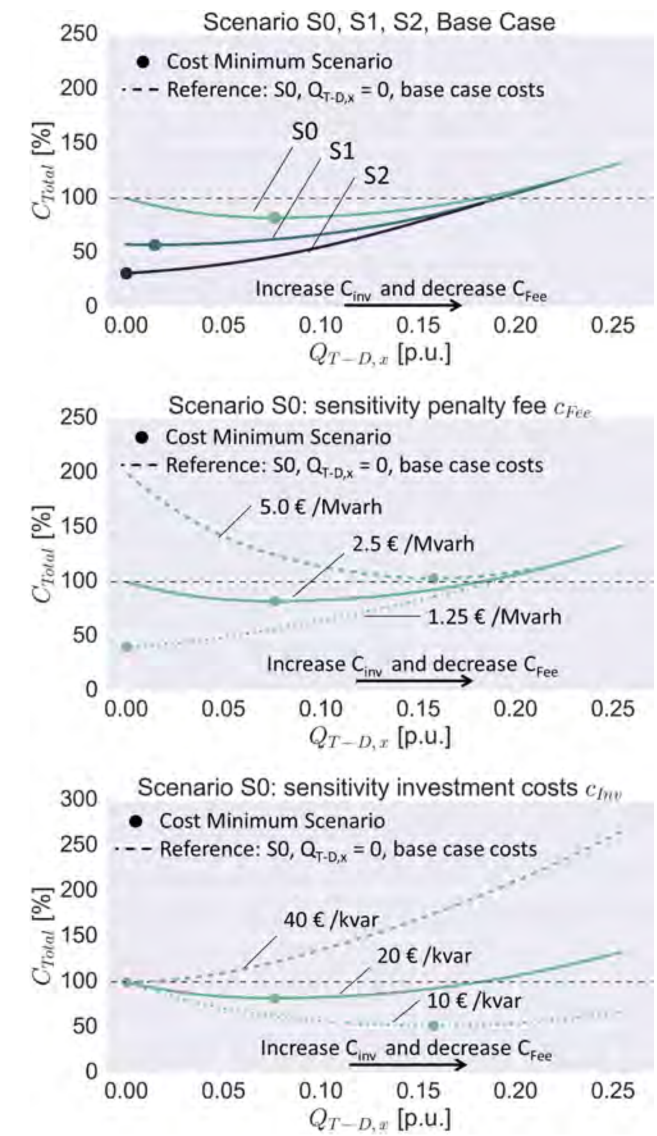

Fig. 7 *Total annual costs in consideration of an additional Q compensation capacity*
Top: Base case for Scenarios S0, S1 and S2. *Middle:* Sensitivity analysis for c_{Fee} (Scenario S0). *Bottom:* Sensitivity analysis for c_{Inv} (Scenario S0)

Table 5 Cost assumptions for c_{Fee} and c_{Inv}

	Low cost	Base case	High cost
c_{Inv}	10,000 Euro/Mvar	20,000 Euro/Mvar	40,000 Euro/Mvar
c_{Fee}	1.25 Euro/Mvarh	2.5 Euro/Mvarh	5.0 Euro/Mvarh

Table 6 Overview of additional Q compensation capacity (underexcited, in p.u., normalized by (2)) for different grid planning approaches and scenarios

Scenario	Design annual worst-case	Design on annual 5%	Design on economic optimum (sensitivity C_{Inv} and C_{Fee})					
			Low cost C_{Fee}	Base case	High cost C_{Fee}	Low cost C_{Inv}	Base case	High cost C_{Inv}
0	0.25	0.11	0	0.08	0.16	0.16	0.08	0
1	0.22	0.06	0	0.01	0.11	0.11	0.01	0
2	0.18	0	0	0	0.06	0.06	0	0

specify the required Q compensation capacity, but do not specify detailed configurations of the Q compensation devices (e.g. location(s), controllability). Therefore, further detailed studies are required in the grid planning process (e.g. loss, voltage, grid resonance and/ or contingency studies).

6 Conclusion and outlook

In this paper, a grid planning approach for DG reactive power management at the T–D interface is introduced. This approach identifies the DG reactive power potential and the DG reactive power availability for a defined use case. Furthermore, the presented approach can support the DSO to identify the demand for new reactive power compensators. Besides the dimensioning of additional compensators on an annual worst-case or an annual probability of reactive power exchange at the T–D interface, an economic planning approach of additional compensators is firstly presented. The economic planning approach minimises the annual penalty fee for unrequested reactive power exchange at the T–D interface and the investment costs for additional compensators. The applied methodology can be individually adjusted for different case studies and reactive power requirements at the T–D interface.

In the presented case study of a German distribution grid section, the requirements at the T–D interface are set according to the new ENTSO-E DCC. In the case study, some DG types (especially Hydro-DG, but partly also Thermal-DG, PV-DG and Pump storage systems) can provide controllable reactive power with a very high availability and DG reactive power management can reduce the demand for new compensators. However, in detail, the impact of DG reactive power management on the demand for new compensation devices also depends on the applied planning approach and the detailed reactive power requirements at the T–D interface.

In future studies, also the losses of compensators and DG for reactive power provision will be considered in the presented economic planning approach. Furthermore, the DG reactive power potential and availability at the T–D interface will be also studied in a comprehensive contingency analysis (e.g. for relevant n–1 scenario of the distribution grid section).

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8 Appendix

Tables 1–3 give an overview of the installed DG systems in the investigated grid section. Table 4 gives an overview of DG Q potential and DG Q availability for the different DG types and scenarios. And the identified additional Q compensation demand for the different grid planning approaches and scenarios is shown in Table 6.