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Reactive power market design for unutilized grid-forming assets to address power factor penalties in Turkiye

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ABSTRACT

The increasing penetration of small-scale PV distributed generation in medium-voltage networks has introduced unexpected challenges. While PV generation reduces the real power drawn from the transmission grid, the absence of monetization for reactive power means that reactive demand remains unchanged. This mismatch results in declining power factors and potential financial penalties for DSOs. A local reactive power market offers an alternative solution, not for voltage stability but specifically for maintaining the power factor. This paper proposes a reactive market framework tailored for Turkiye, covering its operational steps, market-clearing process, demand elasticity, payment structure, and mathematical model. The framework incorporates a ±10% forecast tolerance to discourage gaming and promote fairness. It introduces the concept of a sustainability threshold to ensure that energy sustainability remains central to the system operations. Finally, two key regulatory proposals are discussed to accelerate implementation: spatial aggregation of power factor limits to increase competitiveness and dynamic, seasonally-adjusted thresholds to reflect demand seasonality.

1. Introduction

As a result of the transition trend from the centralized to distributed generation concept, distributed energy resources (DER) have started to appear in medium-voltage (MV) distribution systems. Multiple small-scale photovoltaic (PV) systems are now connected to the MV grid, actively generating electricity (Abdullah et al., 2019). While the industry has been steadily gaining experience in the field deployment of DER units and technical challenges are increasingly addressed in academia and practice, certain financial aspects remain unresolved (González and Rendon, 2022; Johansson et al., 2020; Valova and Brown, 2022). Although monetizing real power generation is straightforward for most countries, the reactive power supply by DER units, especially PV inverters, generally requires additional policies for monetization (Siddiqui and Paliwal, 2025). In countries lacking financial regulations on reactive power, such as Turkiye, DERs typically supply only real power to the grid, which can result in technical issues like low power factor at the transformer level. The power factor is the ratio of real power to apparent power, ideally, it should be close to unity to decrease losses and increase the lifespan of grid assets. The low power factor, however, indicates the presence of excessive reactive power in the system, which leads to increased losses and inefficient utilization of the grid infrastructure (Passey et al., 2011).

In Turkiye, for example, distribution companies are subject to a financial regulation that mandates compliance with power factor requirements, with associated penalties for non-compliance. DERs can address this challenge. They can be used to maintain an acceptable power factor in distribution systems. Other devices, such as energy storage systems, synchronous generators, condensers, and even electric vehicles, can also be used as reactive power suppliers (Ahmadi and Foroud, 2013; Reddy et al., 2011; Biswas et al., 2016). However, without monetization for this service, a distribution system operator (DSO) typically installs reactors or capacitors on the relevant feeders as a technical solution for reactive power support (Takala et al., 2019), although this approach requires additional investment.

The direct investment often entails high upfront capital expenditures and the risk of spatial or temporal misallocation, in the context of mitigating the reactive power provision challenge (Anaya and Pollitt, 2022; Hung et al., 2014). An alternative to such capital-intensive measures is to develop a reactive power procurement model (Anaya and Pollitt, 2020). Various reactive power procurement models have also been proposed in the literature due to technological advances, regulatory changes, and the evolving dynamics of global electricity markets. One of these models is fixed price-for-quantity contracts, also known as Power Purchase Agreements (Wolgast et al., 2022; Rebours et al., 2007). Another is the cost-based purchase agreement model, in

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Nomenclature

A. Sets

Ω_T	Set of time intervals
Ω_{DC}	Set of distribution centers
Ω_E	Set of edges
Ω_B	Set of buses

B. Index

i	Nodes or lines
t	Time steps

C. Parameters

$P_{l,t}^D$	Net metering active demand at l at time t
$\overline{V_i}$	Maximum voltage magnitude at Node i
$\underline{V_i}$	Minimum voltage magnitude at Node i
r_{ij}	Line resistance of line from Bus i to Bus j
x_{ij}	Line reactance of line from Bus i to Bus j
μ	Sustainability Threshold
$\overline{S_i}$	Line flow capacity between Bus i and $i+1$
$\overline{Q_{i,t}^G}$	Reactive power forecast at time t
$\overline{P_{i,t}^G}$	Active power forecast at time t
$P_{i,t}^D$	Active power demand at ith Bus at time t
$Q_{i,t}^D$	Reactive power demand at ith Bus at time t

D. Variables

$Q_{i,t}^G$	Generator reactive power dispatch at Bus ith at time t
$P_{i,t}^G$	Generator active power dispatch at Bus ith at time t
$P_{ij,t}$	Real power flow on line from Bus i to Bus j
$Q_{ij,t}$	Reactive power flow on line from Bus i to Bus j
$V_{i,t}$	Voltage magnitude at Bus i
$L_{i,t}^P$	Active loss on line from Bus i to Bus j
$L_{i,t}^Q$	Reactive loss on line from Bus i to Bus j
S_ij	The line flow between Bus i and j
P_l^m	Monthly net metering active demand at l at time t
Q_l^m	Monthly net metering reactive demand at l at time t
$Q_{l,t}^D$	Net metering reactive demand at l at time t
r_l^{ind}	Inductive violation ratio
r_l^{cap}	Capacitive violation ratio
$\overline{r_l^{\text{ind}}}$	Maximum violation limit for inductive
$\underline{r_l^{\text{cap}}}$	Maximum violation limit for capacitive
$\underline{Q_t}$	Lower limits of the reactive power output of the DER
Q_{ind}	Total reactive energy consumption at violation points
P_{act}	Total energy consumption at violation points
ϕ	Phase angle
$\cos\phi$	Power Factor

E. Functions

$f(\underline{P_{\text{DER},t}})$	Real power based-Reactive power output function
$C_i(Q_{i,t}^G)$	Cost function of Q-supplier i

which compensation is provided for newly connected devices based on the reactive power capacity they make available to the system controller (Saxena and Kumar, 2016; Chung et al., 2004). This model incentivizes resource allocation to increase reactive power availability at critical nodes that significantly impact the voltage profile of nearby buses (Troncia et al., 2021). Another model is the capacity-based auction model, in which the DSO and pre-selected suppliers enter into long-term contracts, often awarded through annual auctions, to establish a stable ancillary services market for reactive power (Frias et al., 2008). These contracts may span multiple years to provide stronger investment signals to market participants and encourage sustained infrastructure development.

At the regional level, some models focus on grid-level strategies where a single utility is responsible for optimizing reactive power procurement within its network (Kargarian et al., 2011). These models generally consider the technical limitations of the power grid and the operational requirements to guarantee the physical delivery of the real and reactive power. A framework has been proposed to enable more decentralized decision-making. In one such model, reactive power providers submit their bids directly to the grid operator, who then determines a non-uniform pricing scheme through optimization (Jay and Swarup, 2021b).

Market-based models are considered the most prominent among the various approaches due to their flexibility and efficiency (Capitanescu, 2025). A well-known approach involves Optimal Power Flow (OPF) methods, in which reactive power providers submit piece-wise quadratic or linear cost functions reflecting their provision costs. The system operator aggregates these functions and solves the OPF to determine optimal reactive power dispatch while minimizing total system cost and satisfying all operational constraints (Dandachi et al., 1996).

Two main alternatives could also be considered: (i) regulated reactive power support with static pricing (Rabiee et al., 2009b; Rueda-Medina and Padilha-Feltrin, 2012a), or (ii) a competitive reactive power market with dynamic pricing (Zhong and Bhattacharya, 2003). Each approach presents trade-offs regarding flexibility, cost-efficiency, and long-term adaptability as summarized in Table 1.

While the regulatory mandates may ensure compliance, they typically overlook the marginal cost and technical capabilities of DERs (Anaya and Pollitt, 2020). Therefore, static pricing used to create incentives to follow the regulations often miscalculates the marginal cost of service. AS a result, it either creates inefficient cost allocation (Karthikeyan et al., 2013) or fails to motivate DER operators (Potter et al., 2023) to provide the needed reactive power support when and where it is most valuable.

In contrast, a market-based mechanism may provide a decentralized, flexible, and potentially cost-effective solution (Rabiee et al., 2009a). It allows DER owners to submit competitive offers for reactive power support based on real-time availability (Jiang et al., 2023). Such mechanisms may also distribute investment risks among multiple actors and incentivize technology adaptation (Mohammed et al., 2024), such as better solar forecasting and financial trading. However, the market-based approach does not mean it is the best solution. The practical implementation of local markets requires well-defined pricing signals and prevention methods to prevent free-riding or gaming in the market.

If the suppliers can monetize their reactive power generation as a profitable opportunity within a market mechanism, they would be willing to participate as market participants (Troncia et al., 2021). A reactive power market for the DERs can be structured similarly to a real power market. The initial design of such a reactive market can follow an Economic Dispatch (ED) approach with no network information (Appen et al., 2011). However, unlike transmission networks, distribution systems exhibit lower network stability (Jasmon and Lee, 1991). Therefore, designing a reactive power market without incorporating network constraints would not be appropriate. These constraints include thermal

Table 1
Comparison of investment and market-based approaches for reactive power procurement.

Criterion	Investment	Market-based approach
Cost Control	High initial cost but stable long-term expenses	Variable costs with short-term advantages
Reliability	High	Uncertain (depends on participant availability)
Flexibility	Low	High
Regulatory Compatibility	Easily integrated into tariffs	Requires a detailed regulatory framework
Risk Allocation	On the system operator	Shared among market participants

limits of cables to prevent overheating and voltage constraints to ensure voltages remain within operational limits.

Numerous reactive power market designs with network constraints have been proposed in the literature, with the primary objective of enhancing voltage stability (Rueda-Medina and Padilha-Feltrin, 2012b; Khandani and A., 2017; Roselyn et al., 2018). Unlike real power, however, reactive power cannot be transmitted over long distances, which gives it a distinct local character (Jasmon and Lee, 1991). This local nature introduces several challenges for market design. First, because reactive power effects are inherently local, control and balancing must be organized at the distribution level. In practice, the DSO generally carries out procurement, which creates a monopsonistic demand structure. On the supply side, only a limited number of qualified providers exist within each service zone, a situation that may concentrate market power and hinder competition (Wolgast et al., 2022). Second, the reactive power capability of inverter-based resources is constrained by their real power output. This coupling between active and reactive power, commonly represented by P–Q capability curves, often necessitates real power curtailment to provide additional reactive power. Such curtailment generates lost opportunity costs for suppliers, complicating the design of both bidding mechanisms and settlement rules. Third, introducing a transparent and reliable reactive power market presupposes an extensive measurement and settlement infrastructure. Although smart meters are commercially available, integrating them across all relevant nodes and ensuring compatibility with communication protocols and operational processes entails significant upfront and ongoing costs (Jay and Swarup, 2021a).

Against this backdrop, this study proposes reframing the market away from the conventional focus on voltage regulation and toward power factor compliance at the HV/MV transformer, the critical interface where transmission system operator (TSO) and DSO interactions occur. Shifting the market driver to power factor compliance addresses the above challenges as follows. Locational balancing is respected, yet procurement and settlement are consolidated at an operationally meaningful node that broadens the eligible pool of suppliers within the transformer's service area. The reliance on existing metering infrastructure reduces the need for costly smart meter deployment and simplifies settlement procedures. Furthermore, the market framework explicitly accounts for the coupling between real and reactive power by introducing compensation mechanisms for opportunity costs arising from potential real power curtailment. At the same time, the proposed forecast-tolerant settlement rules mitigate penalties for minor deviations. In this way, a power-factor-motivated reactive power market offers a practical and context-specific pathway for addressing structural shortcomings that have limited the feasibility of local reactive power markets.

The contribution of this study is to formulate a reactive-power market tailored to Turkiye's distribution context. The model transforms unutilized grid-forming assets into economically dispatchable resources to address power factor penalties at the HV/MV transformer, where TSO-DSO interaction materializes. First, the study reframes the objective from the conventional focus on voltage regulation to maintaining power factor compliance at the HV/MV interface, aligning the market product with the Turkish operational practices and penalty structures. Second, the paper specifies the market framework, including a mathematical model, clearing rules, and offer/bid formats for DER-provided reactive power, emphasizing competitive participation and tractable implementation by DSOs. Third, the study introduces a payment mechanism that couples opportunity-cost coverage with forecast-tolerant incentives via a $\pm 10\%$ settlement tolerance band, discouraging strategic manipulation while lowering participation risk for inverter owners. Finally, the paper includes two implementable policy pathways: (i) static and spatially differentiated tariffs and (ii) dynamic and temporally resolved market-based pricing. The discussion clarifies their flexibility, cost efficiency, and deployment complexity trade-offs, thereby providing regulators and DSOs with a practical roadmap for enabling local reactive-power markets that avoid net-metering-related penalties.

The paper is structured as follows. Section 2 introduces the technical motivation for obtaining reactive power support from DERs, emphasizing preserving the power factor at the HV/MV transformer interface where TSO–DSO interactions occur. This section highlights how the proposed design aligns with Turkiye's operational regulations, in which non-compliance directly imposes financial consequences on DSOs. Section 3 introduces the proposed reactive power market framework, describing its regulation and operation, the price mechanism, demand elasticity, and the tailored payment structure designed to ensure sustainable participation. A mathematical model is also presented to capture the analytical foundations of the proposed market. Section 4 discusses two key policy and regulatory proposals to accelerate the implementation of such a market in practice.

2. Shifting the motivation: Power factor as a market driver

In general, the technical motivation for obtaining reactive power support from DER units has been to maintain the voltage level within the desired range and ensure the distribution grid's secure operation. Accordingly, voltage regulation is the traditional motivation for the design of the reactive power market. However, this study shifts from that driver. It places the motivation not on voltage regulation but on maintaining the power factor at the HV/MV transformer interface, where the technical interaction between the TSO and DSO occurs. By doing so, the study aims to design a market mechanism consistent with the operational regulations in Turkiye, where lack of compliance with acceptable power factor has direct financial implications for DSOs.

2.1. Regulatory framework for reactive power

Reactive power management and compensation practices vary widely across countries. In the USA, reactive power from synchronous generators is considered an ancillary service eligible for compensation (Zhong and Bhattacharya, 2002a). Australia extends eligibility to synchronous condensers and emphasizes preventive measures to maintain stability amid rising renewable penetration. In contrast, Nordic countries such as Sweden do not provide compensation, requiring network companies to manage their own reactive power needs under system operation guidelines (Zhong and Bhattacharya, 2002a). A comparable approach exists in the Netherlands, where network companies procure reactive power individually through bilateral contracts, with payments limited to capacity rather than energy (Wolgast et al., 2022). In China, grid modernization projects continue to expand capabilities in this area (Uchchus, 2024).

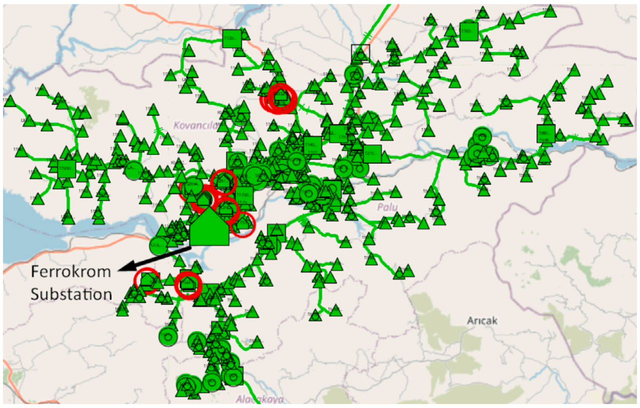

Fig. 1. Single-line diagram of the Ferrokrom MV substation region. Green markers represent consumption points and MV/LV distribution transformers, while circled in red indicate the locations of DERs.

2.2. Penalty mechanisms in Turkiye

The Turkish power grid is systematically structured based on voltage levels and areas of responsibility. The management of the transmission system, operating at voltages greater than 36 kV, falls under the responsibility of Turkish Electric Transmission Co. (TEIAS), the sole state-owned transmission system operator. Meanwhile, the distribution network operates at or below 36 kV and is divided into 21 geographic regions, each managed by a single licensed DSO.

In the Turkish distribution system, reactive power management is regulated within the legislation framework set by the Energy Market Regulatory Authority (EMRA). The Grid Code establishes monthly inductive and capacitive reactive energy limits for DSO-owned transformers. These limits are dynamic relative to the real energy consumption. Specifically, the ratio of the inductive reactive energy drawn from the transmission network in a month to the real energy consumption shall not exceed 20%. Similarly, the ratio of capacitive reactive energy injected into the network to the real energy consumption shall be limited to 15%.

Non-compliance with these limits subjects the DSO to financial penalties, as specified in the connection and system usage agreements with TEIAS. The penalties are scaled to the severity of the violation and settled monthly.

As of 2025, regulations concerning reactive power support provided by DERs in Turkiye are only for the transmission system. However, DERs connected to the MV distribution system are not yet subject to a mandatory reactive power support requirement. Due to the absence of such a requirement, DERs typically operate at a power factor of 1.00, using their assets for real power generation only. Consequently, DSOs require additional reactive power support to avoid penalties when reactive power limits are exceeded. A common approach to mitigate such violations is to invest in reactors when penalties result from excessive capacitive power, and capacitors when penalties result from excessive inductive power.

2.2.1. A Turkish DSO experience

To provide a practical perspective from a DSO, real data from the Ferrokrom substation are analyzed and presented in this subsection. The single-line diagram is shown in Fig. 1. This substation, located in Turkiye, is operated by Firat DSO. The MV network includes 60 unique PV power plants with a total installed capacity of 59.4 MW, whose locations are indicated with red circles in Fig. 1.

As illustrated in Fig. 2, the Ferrokrom region experienced recurring violations of capacitive power limits throughout 2023. Given the 15% threshold for the reactive capacitive energy ratio, this station exceeded the limit during most of the year. To address these violations and avoid penalty payments, Firat DSO invested in and deployed reactive power compensation hardware in March 2024. This system enables dynamic adjustment of the power factor, thereby improving grid stability and preventing potential penalty charges arising from reactive power limit violations. Following the deployment of reactors, the ratios have improved, as given in Table 2.

Table 2
Monthly reactive energy ratios for the Ferrokrom substation in 2023 and 2024.

Month	Year	Real Power Load (MWh)	Cap. Ratio (%)	Ind. Ratio (%)
September	2023	3.228	3.5%	–
October	2023	2.853	14.2%	–
November	2023	3.454	19.2%	–
December	2023	4.235	21.7%	–
January	2024	4.788	25.1%	0.00%
February	2024	3.193	24.6%	0.87%
March	2024	3.313	0.8%	7.13%
April	2024	2.283	0.6%	11.81%
May	2024	1.895	1.2%	13.04%

2.3. Technical background of power factor and DER's support

To determine the impacts of DERs on the power factor at the transformer level, consider a simple distribution network representation shown in Fig. 3, which has three load nodes and a DER node, where the point M is the location of the measurement.

Consider two scenarios for the active and reactive energy consumption measurement at point M: one without DER and one with a DER supplying only real power. The resulting power triangles are shown in Fig. 4. The key distinction between these two cases is the reduction in real power drawn from the transformer P_{net} due to the real power injected into the grid by the DER (P_{DER}). However, the net reactive power drawn from the transformer Q_{net} remains unchanged, since the DER neither generates nor consumes reactive power. The reduction in real power, while the reactive power stays constant, increases the phase angle (θ), consequently leading to a deterioration of the power factor ($\cos\theta$).

The equations that explain the power triangles in Fig. 4 are presented below.

$$Q_{\mathrm{net},t} = Q_{1,t} + Q_{2,t} + Q_{3,t} - Q_{\mathrm{DER},t} \tag{1}$$

$$P^1_{\mathrm{net},t} = P_{1,t} + P_{2,t} + P_{3,t} \tag{2}$$

$$P^2_{\mathrm{net},t} = P^1_{\mathrm{net},t} - P_{\mathrm{DER},t} \tag{3}$$

$$(\underline{Q_t})^2 \leq (Q_{\mathrm{DER},t})^2 \leq (\overline{Q_t})^2 \tag{4}$$

$$(\underline{Q_t})^2 = f(P_{\mathrm{DER},t}) = -(\overline{S_i})^2 + (\mu P_{\mathrm{DER},t})^2 \tag{5}$$

$$(\overline{Q_t})^2 = f(P_{\mathrm{DER},t}) = (\overline{S_i})^2 - (\mu P_{\mathrm{DER},t})^2 \tag{6}$$

where $P_{1,t}$ to $P_{\mathrm{DER,t}}$ are the nodal real power injections, while $Q_{1,t}$ to $Q_{\mathrm{DER,t}}$ are the nodal reactive power injections, $\underline{Q_t}$ and $\overline{Q_t}$ are the lower and upper limits of the reactive power output of the DER as a function of real power output, respectively, $P_{\mathrm{net,t}}$ and $Q_{\mathrm{net,t}}$. The net real power and net reactive power are measured at point M, respectively.

With no financial incentive to generate reactive power from the PV inverters, $Q_{4,t}$ is generally set to 0 by the suppliers. However, the inverters have technical capabilities to provide reactive power support. The actual physical relationship between the PV inverters' real and reactive power output is shown in Fig. 5.

The reactive power output of an inverter can be adjusted within its minimum and maximum limits based on the real power output from the PV system. Notably, $\underline{Q_t}$ and $\overline{Q_t}$ are not fixed values, as Q_t is a function of $P_{\mathrm{DER,t}}$ as given in Eqs. (5) and (6), respectively. Hence, the change in the real power generation alters the available range of reactive power output at any given time.

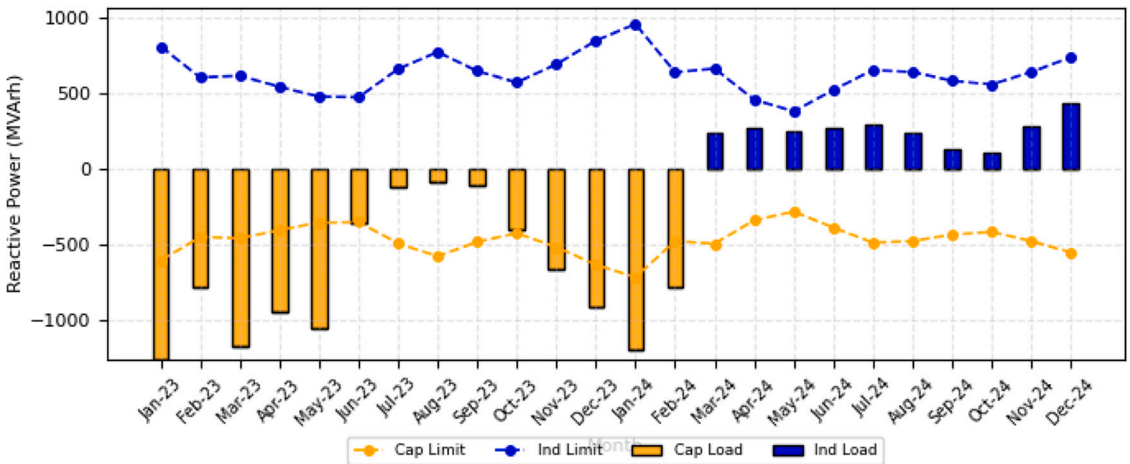

Fig. 2. Monthly reactive power profile at Ferrokrom during 2023 and 2024. Capacitive and inductive reactive power values are shown as stacked bars. Orange and blue dashed lines represent the regulatory reactive power capability limits.

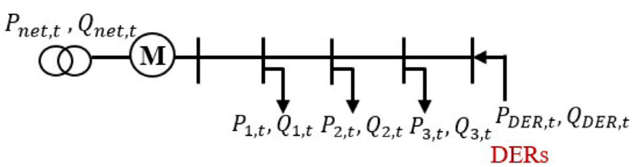

Fig. 3. A simple representation of the distribution network.

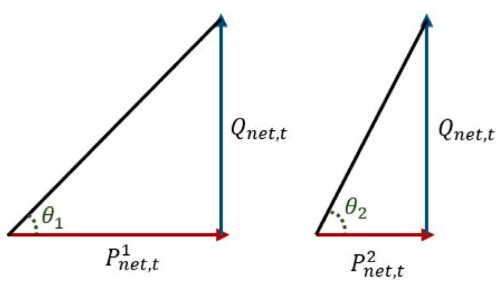

Fig. 4. Power triangle representation of active and reactive power consumption at point M, before (left) and after (right) the integration of a DER supplying only real power.

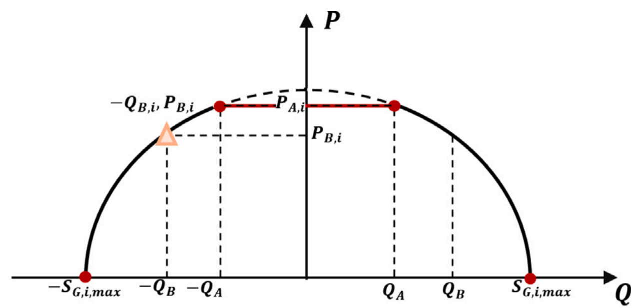

Fig. 5. Active and reactive power output curve of a PV inverter.

3. Proposed reactive power market framework

Reactive power markets exhibit distinct characteristics compared to fundamental power markets, necessitating specialized market designs. This chapter proposes a reactive power market framework in which the primary market driver is not voltage regulation, as in much of the literature, but the preservation of power factor at the HV/MV interface, where penalties are currently imposed in Turkiye. The framework first describes how the market operates in practice, detailing the roles of DSOs and PV-inverter owners and clarifying the sequence of actions taken from procurement to settlement. Recognizing that the market is inherently local and thus involves a limited number of suppliers, a pricing mechanism is proposed that promotes competitiveness while remaining consistent with the structural constraints of local provision. To ensure sustainable participation, a tailored payment structure has been developed to compensate suppliers fairly, covering opportunity costs and enabling continued engagement without financial loss. Within this payment design, a sustainability threshold is introduced as a safeguard against potential manipulation, thereby enhancing fairness and market resilience. Finally, the framework is supported by a mathematical model that captures the analytical underpinnings of the market, incorporating network data, system limits, and the technical constraints of inverter-based resources.

3.1. Operational steps

A buyer, multiple suppliers, and a market operator are required to ensure the operation of this market as shown in Fig. 6. In the proposed market, the DSO can act as both the system operator (buyer) and the market operator, although not mandatory, while the suppliers consist of small-scale PV inverters. The market operates with an hourly settlement period, and the proposed market model is solved for the next 24-hour horizon. The operation steps of the market (Fig. 7) are as follows:

1. TSO announces power factor limits to the DSO.
2. To establish a fair and transparent market environment, the DSO should first determine its price-elastic reactive power demand ($\overline{Q^D_{i,t}}$) for all t based on its reactive power requirements. It should also provide the forecasts of nodal real power demand ($P^D_{i,t}$). The grid topology must be submitted to the market platform since the market will be cleared with optimal power flow equations.
3. The market platform announces the hourly Q-needs based on the DSO's forecast.
4. Suppliers submit closed offers to the market platform. These offers should include real power generation forecast ($\overline{P^G_{i,t}}$), apparent power capacity ($\overline{S_i}$), and price function for reactive power generation ($C_i(Q^G_{i,t})$).
5. All parameters collected on the market platform are then transmitted to the market-clearing software, solving the market model described in Section 3.5.

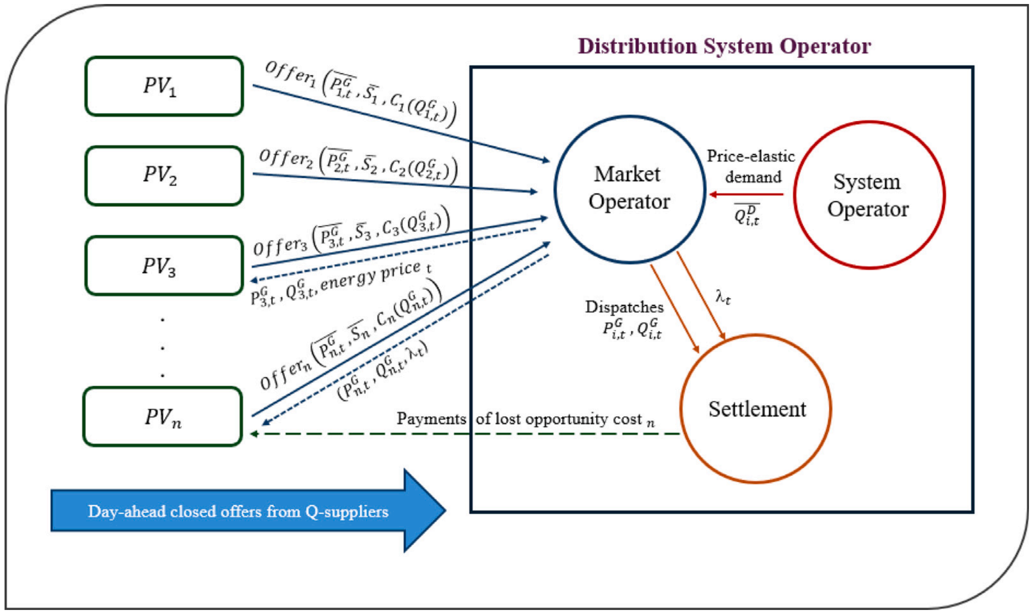

Fig. 6. Information exchange among the market parties.

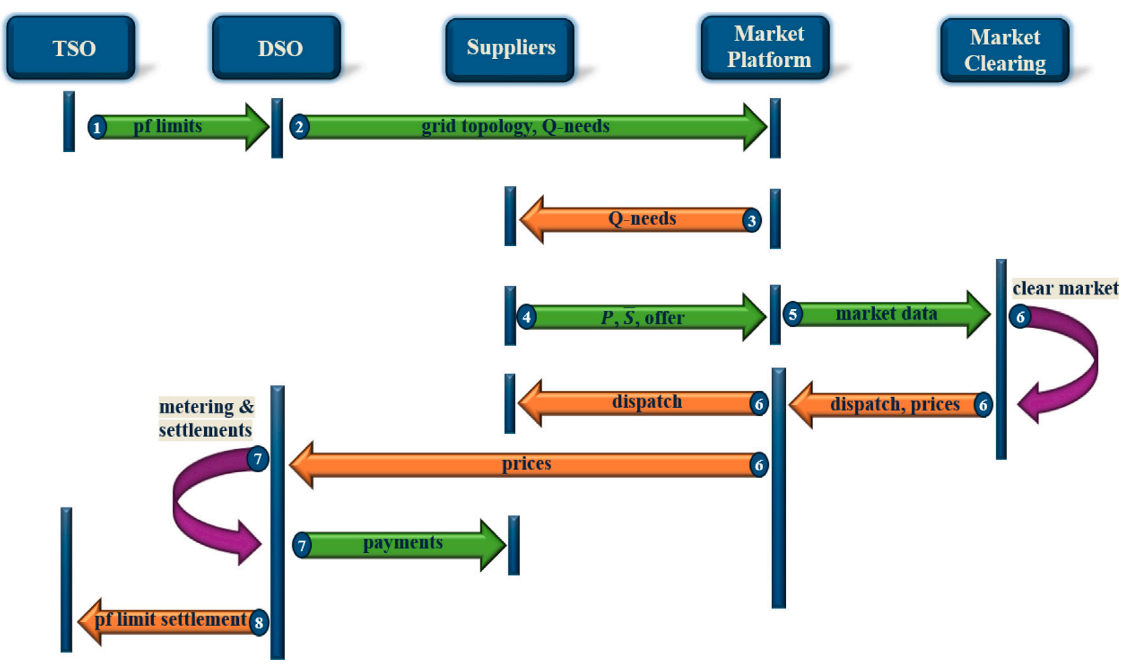

Fig. 7. Operational steps of the market.

6. The market is cleared and the market platform announces each supplier's reactive and real power dispatch, along with the nodal reactive power clearing prices.
7. The DSO verifies the actual real and reactive power generation for the settlement phase and calculates the payments described in Section 3.4.
8. The DSO interacts with the TSO at the end of each month, whether or not the Q/P ratio remains within the specified inductive and capacitive limits.

3.2. Market clearing

The market-clearing price for reactive power can be determined by either marginal pricing or a pay-as-bid settlement scheme (Amjady et al., 2010). Generally, marginal pricing is accepted in the energy markets for various game-theoretic reasons (Oh et al., 2003). However, based on the details of the network model, marginal pricing can be categorized into three spatial arrangements: uniform pricing, zonal pricing, or nodal pricing (Poyrazoglu, 2021). If the network is not considered in the market, the price is referred to as the uniform price (Zhong and Bhattacharya, 2002a). However, when the actual network is considered, a nodal price can be assigned to each node in the network (Cerbantes et al., 2017). Alternatively, the network can be divided into zonal control areas, with a zonal price determined for each zone (Zhong et al., 2004).

In this study, marginal pricing is adopted as the price settlement method since it has greater potential to foster a competitive market

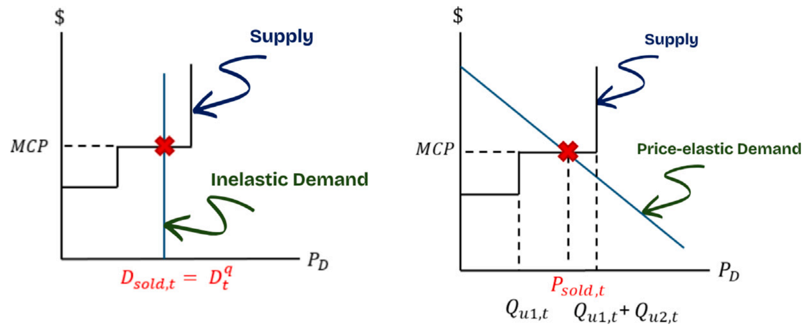

Fig. 8. Supply-demand curves of (a) Price-inelastic demand, (b) Price-elastic demand.

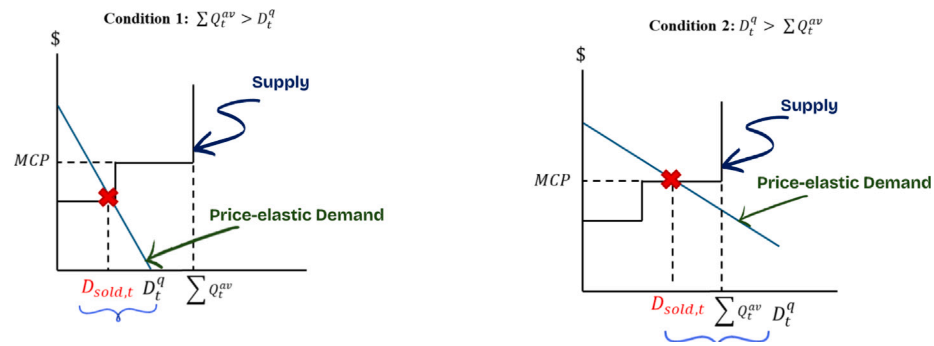

Fig. 9. Supply-Demand equilibrium points for two conditions (a) Low demand & high supply (b) High demand & low supply.

environment than pay-as-bid. Reactive power suppliers, however, are compensated based on nodal pricing through nodal reactive power clearing prices. This approach allows for a fairer representation of radial medium-voltage systems, as the formulation explicitly incorporates congestion, voltage, and loss components.

3.3. Demand elasticity

In designing a local reactive power market, one of the key considerations is the treatment of demand. How demand is represented in the market influences pricing outcomes and the market ability to converge to a fair equilibrium. In the Turkish context, where DSO is penalized for power factor violations but is not explicitly mandated to procure reactive power from PV inverters, determining whether demand should be modeled as price-inelastic or price-elastic becomes crucial.

On the one hand, demand can be considered price-inelastic as illustrated in Fig. 8(a), meaning that the required reactive power demand must be satisfied regardless of price levels. Such a must-satisfy structure can lead to significantly high prices. In contrast, the proposed framework adopts a price-elastic demand representation, in which the required reactive power demand may not be fully satisfied due to the price-responsive demand behavior as seen in Fig. 8(b). Since Turkiye's policy framework seeks to maintain a P/Q balance by the end of each month, price-elastic demand is more appropriate, because it mitigates the potential price surges associated with inelastic demand.

The price-elastic demand structure ensures that the demand ($D_{sold,t}$) consistently remains below the total reactive power demand (D_t^q). Under these circumstances, two key market conditions should be discussed to achieve a fair market equilibrium: (a) Low Demand & High Supply and (b) High Demand & Low Supply.

Suppose the total reactive power demand (D_t^q) is lower than the available reactive supply capacity. In that case, the equilibrium price will likely result in a relatively lower marginal clearing price, as shown in Fig. 9(a). By contrast, when the available supply capacity is insufficient to meet the total demand, an intersection point still occurs, but at a higher marginal clearing price due to the scarcity of supply, as illustrated in Fig. 9(b).

This outcome underscores the importance of increasing market participation to satisfy demand and maintain price stability. Encouraging more participants to enter the market can enhance competition and help reduce prices. The selected price elastic demand structure, combined with greater competition, can make the market more robust and better meet local reactive power requirements while maintaining competitive pricing.

3.4. Payment structure

The reactive power market framework is structured around the Expected Payment Function (EPF), which quantifies the different payment components associated with reactive power provision (Zhong and Bhattacharya, 2002b; Retorta et al., 2025). These components are capacity payment, operation payment, and opportunity payment, each varying depending on the supplier's operational state.

$$\begin{aligned} \text{EPF} =& \text{Capacity Payment} + \text{Operation Payment} \\ &+ \text{Opportunity Payment}. \end{aligned} \tag{7}$$

The capacity payment c_0 is introduced to encourage participant engagement in the market. As shown in Fig. 10, the capacity payment is available across the entire range from 0 to Q_b. However, in order to incentivize actual operation and promote competition, the capacity payment is deliberately kept low, allowing only those committing to provide Q_b to enter the market. The key objective is to ensure that even participants who are not dispatched still receive a minimum compensation of c_0.

In the region between 0 and $+/-Q_A$, suppliers either inject or absorb reactive power, incurring costs associated with the increased system losses. Consequently, compensation is warranted for this service. In this region, the EPF consists of capacity payment and operation payment. The operation payment is calculated as the product of the marginal price and the supplier's reactive power generation, increasing the expected payment linearly in this region.

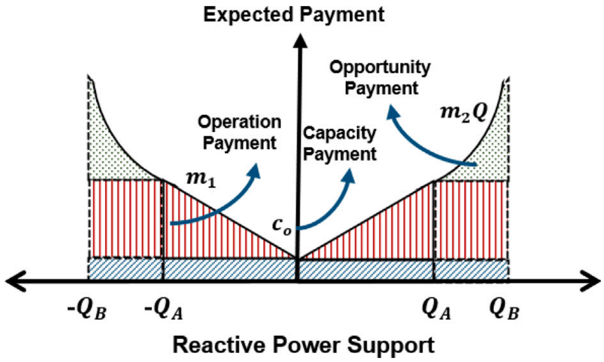

Fig. 10. Structure of the expected payment function of the Q-suppliers.

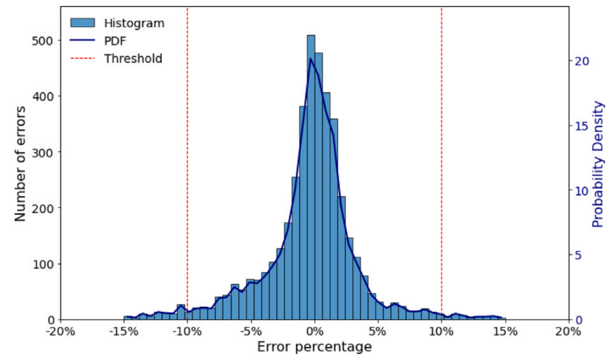

Fig. 11. Hourly SMF Histogram with PDF and ±10% Thresholds.

Between Q_A and Q_B, suppliers are entitled to additional compensation for lost opportunity costs resulting from reduced real power output due to technical requirements, in addition to the capacity and operational payments. When the DSO requests further reactive power output, a trade-off arises between real and reactive power. Although inverters are technically capable of adjusting, this adjustment necessitates a reduction in real power output. The consequent reduction in revenue from the real power sales constitutes the lost opportunity cost. A sustainability threshold is introduced to limit the potential misuse of this necessity for financial gain and to prioritize maintaining renewable energy sources that inherently minimize greenhouse gas (GHG) emissions. Accordingly, the opportunity payment compensates suppliers for possible lost revenue due to real power curtailment required for increased reactive power generation. The reference price for real power may be determined from tariffs or day-ahead market prices. The fundamental principle of the opportunity payment is to compensate the financial loss incurred by generators when real power output is curtailed in favor of reactive power support.

3.4.1. Opportunity payment mechanism based on actual generation with forecast tolerance

The motivation of this subsection lies in the debate of whether opportunity cost should be paid based on forecast capacity or actual generation. This decision has direct implications for the continued participation of market actors. Since real power is inherently more valuable than reactive power, the income generators receive from the real power market typically outweighs the possible compensation from the reactive power market. Therefore, if opportunity payments are based only on forecast values, generators facing curtailments will incur real market losses and may avoid providing services to the reactive power market altogether. To ensure fairness and encourage continuous market participation, it is proposed that opportunity payments be tied to actual generation levels, not forecasted ones.

However, this opens a gap in the market design, potentially causing misuse of the concept. A participant could intentionally announce a low forecast capacity, be dispatched accordingly, and then produce a much higher actual output, hence receiving higher opportunity payments — a behavior resembling free-riding. To prevent such market actions and ensure alignment between forecast and actual generation, a tolerance margin of ±10% is introduced. Suppose the actual generation falls outside this tolerance. In that case, the payment will be calculated not based on actual generation but at the boundary of the ±10% margin — i.e., at the lower bound (−10%) if the actual generation is below, or at the upper bound (+10%) if the actual generation exceeds the forecast significantly. Mathematically, the proposed payment rule can be summarized as:

$$\text{Opportunity Payment} = \min(\text{Actual Generation}, \text{Forecast Capacity} \pm 10\%) * \text{Energy Price} \quad (8)$$

The analysis results conducted to determine an appropriate tolerance threshold for forecast errors are presented in Fig. 11.

The 10% threshold is empirically determined based on annual real-world data collected by Firat DSO, including 24-hour-ahead generation forecasts and actual production values. Specifically, the percentage of Standardized Mismatch Factors (SMF) falling within different error margins is calculated. The results show that 76.98% of the data fall within a ±5% error band, while 91.02% lie within the broader ±10% range. Although a ±5% threshold provides stricter control, it excludes many realistic deviations. In contrast, the ±10% threshold captures most observations, offering a more inclusive and operationally flexible criterion. Therefore, the ±10% range is adopted as the acceptable tolerance level, balancing forecast accuracy with practical system adaptability.

To illustrate the implementation of this payment policy, two scenarios are provided in Fig. 12 and explained below. As shown in Fig. 12(a), a generator offers a forecast capacity of 430 kWh, which the market operator accepts and dispatches accordingly. Since there is no technical mismatch between the forecast and the dispatched capacities, no additional opportunity payment is made for reactive power. However, the actual generation falls short of the dispatched level in real time. This decline is not adverse for the reactive power market, as the power plant can still technically supply the dispatched reactive power.

In the second scenario, as illustrated in Fig. 12(b), the generator offers the same forecast capacity of 430 kWh. However, due to technical constraints in the network (e.g., voltage limits), the DSO decides to use a lower real power dispatch to receive more reactive power from the generator. In this situation, an opportunity cost arises. Moreover, in this scenario, the actual generation exceeds both the dispatch level and the forecast. In line with our proposed policy, since the actual generation falls within the +10% tolerance, the generator receives the opportunity payment based on that amount. If, however, the actual generation exceeds the +10% margin, the opportunity payment would have been limited to the boundary value (i.e., forecast + 10%).

Producing significantly more real power than forecast also leads to reduced reactive power capability, an undesired outcome for the operation. This mechanism is therefore designed not only to mitigate irrational bidding behavior but also to encourage the improvement of forecasting accuracy.

3.5. Mathematical model

The proposed mathematical model is a market structure that minimizes production costs while considering the technical limitations of electricity distribution, including the operational limits of the DSO. The

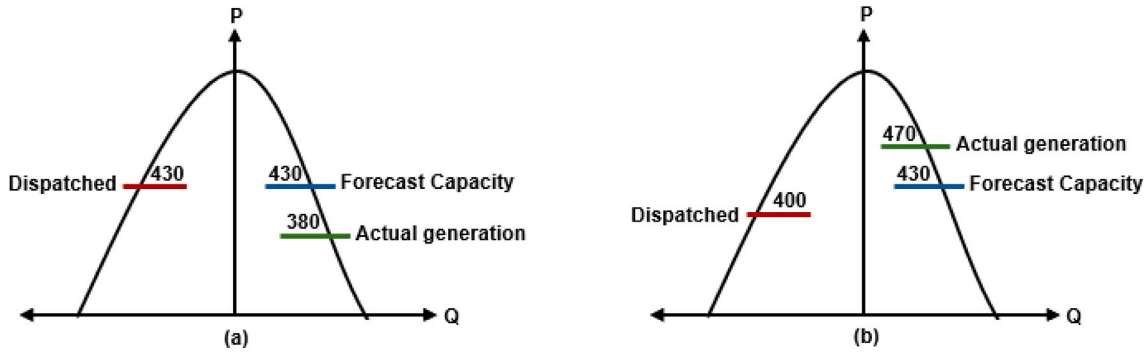

Fig. 12. (a) No technical mismatch and generation shortfall (b) Technical mismatch and generation surplus.

temporal structure is for the next 24 h, similar to the Day-Ahead real power market.

$$\min \sum_{t} \left\{ \sum_{i \in \Omega_G} C_i(Q^G_{i,t}) - B\left(\sum_{i \in \Omega_G} Q^G_{i,t} \right) \right\} \tag{9}$$

subject to:

$$P^G_{i,t} = P^D_{i,t} + \sum_{\substack{j \in \mathcal{B} \\ (i,j) \in \mathcal{E}}} P_{ij,t} - \sum_{\substack{j \in \mathcal{B} \\ (j,i) \in \mathcal{E}}} P_{ji,t} + \sum_{j \in \mathcal{B}} L^P_{ji,t}, \quad \forall i \in \mathcal{B},\ t \in \mathcal{T} \tag{10}$$

$$Q^G_{i,t} = Q^D_{i,t} + \sum_{\substack{j \in \mathcal{B} \\ (i,j) \in \mathcal{E}}} Q_{ij,t} - \sum_{\substack{j \in \mathcal{B} \\ (j,i) \in \mathcal{E}}} Q_{ji,t} + \sum_{j \in \mathcal{B}} L^Q_{ji,t}, \quad \forall i \in \mathcal{B},\ t \in \mathcal{T} \tag{11}$$

$$(V_{j,t})^2 = (V_{i,t})^2 - 2\left(r_{ij} P_{ij,t} + x_{ij} Q_{ij,t}\right) + (r^2_{ij} + x^2_{ij}) \cdot \frac{(P_{ij,t})^2 + (Q_{ij,t})^2}{(V_{i,t})^2}, \forall (i,j) \in \mathcal{E},\ t \in \mathcal{T} \tag{12}$$

$$L^P_{ij,t} = r_{ij} \cdot \frac{(P_{ij,t})^2 + (Q_{ij,t})^2}{(V_{i,t})^2}, \quad \forall (i,j) \in \mathcal{E},\ t \in \mathcal{T} \tag{13}$$

$$L^Q_{ij,t} = x_{ij} \cdot \frac{(P_{ij,t})^2 + (Q_{ij,t})^2}{(V_{i,t})^2}, \quad \forall (i,j) \in \mathcal{E},\ t \in \mathcal{T} \tag{14}$$

$$\underline{V_i} \le V_{i,t} \le \overline{V_i}, \quad \forall i \in \mathcal{B},\ t \in \mathcal{T} \tag{15}$$

$$(P_{i,j,t})^2 + (Q_{i,j,t})^2 \le (\overline{S_{i,j}})^2, \quad \forall i \in \mathcal{B},\ t \in \mathcal{T} \tag{16}$$

$$(P^G_{i,t})^2 + (Q^G_{i,t})^2 \le (\overline{S^G_i})^2, \quad \forall i \in \mathcal{B},\ t \in \mathcal{T} \tag{17}$$

$$\mu \overline{P^G_{i,t}} \le P^G_{i,t} \le \overline{P^G_{i,t}}, \quad \forall i \in \mathcal{B},\ t \in \mathcal{T} \tag{18}$$

Eqs. (10) and (11) ensure the nodal real and reactive power balance, respectively, by matching net injection and ejection at each system node. Then, the voltage at Node i is calculated as a function of the power flow through the line and its line impedance, as defined by (12). It is derived from the DistFlow equations (Baran and Wu, 1989), which provide a nonlinear yet accurate representation of voltage drops across distribution lines, accounting for both resistive and reactive components. Each line's real and reactive power losses are defined in (13) and (14). Eq. (15) ensures the network operates within the predefined voltage range required by DSO, thereby maintaining power quality at each bus. Eq. (16) is the thermal power flow limit of the lines, and Eq. (17) is the apparent power limit of the suppliers. A sustainability threshold (μ) is proposed in (18) to reflect the limitation on real power curtailment, not to penalize clean energy production due to reactive power procurement. This constraint ensures a minimum level of generation commitment from clean energy resources and helps meet policy or regulatory targets related to green energy integration.

The objective function of the market, as defined in (9), aims to maximize social welfare under elastic demand. The maximization is achieved by minimizing the total production cost while maximizing customer surplus. While Function C represents the offers from the suppliers, Function B represents the DSO (buyer) bid to reflect the elastic reactive power demand. Although the formulation of Function B influences reactive power pricing and ultimately affects market outcomes, this paper is not yet focused on how Function B is determined. Future work will include such analysis. The costs that are considered in Function C, on the other hand, can be categorized into three main components (Lamont and Fu, 1999): (i) Degradation costs, which arise from mechanical wear in inverters due to frequent switching operations; (ii) Power loss costs, as the provision of reactive power increases real power losses in inverter electronics; and (iii) Lost opportunity cost, since reactive power generation may lead reduction on the supply of real power; thereby, reducing potential revenue from real power sales.

The real and reactive power dispatch of the suppliers participating in the market is determined when this mathematical model is solved. The payments are made based on the payment mechanism, which will be discussed in the following subsection.

3.6. Limitations of this study

This framework offers a structured perspective on reactive power provision in Turkiye; however, several limitations should be acknowledged when considering its scope. These limitations result from the framework's key assumptions, as well as the methodological and data-related constraints inherent in its construction. The following points summarize the main assumptions and outline potential factors that may limit the framework's applicability.

1. The Q-suppliers, referring to the PV panels in this paper, are considered to have P-Q curves that form a semi-circle. It is assumed that when a setpoint, such as P_g and Q_g is digitally sent to the inverters, which are technically capable of generating the requested value without error.
2. It is recognized that a market platform exists through which small PV panels can submit bids to the DSO.
3. It is assumed that a sufficient number of Q-suppliers are available to ensure the competitiveness required for the continuous operation of this market. This number corresponds to the 'n' value in the proposed model.
4. Since the solar PV data is derived from Turkiye, the +/-10% threshold, obtained from the analysis, may vary for other countries.

4. Discussions

The framework and analyses presented above have been designed to address Turkiye's current regulatory environment and the challenges DSOs face. While the framework has been developed in an applicable form, it should be noted that, as of this writing, a reactive power market does not yet exist in Turkiye. Therefore, to provide guidance for future designs and to contribute to the development of potential market structures, policy, and regulation recommendations derived from the findings of this study are discussed in this section. The proposed policy focuses on increasing price elasticity by enhancing the number of participants through a spatial arrangement. In contrast, the regulatory proposal suggests seasonally adjusted updates to the P/Q limits, reflecting their temporal variability throughout the year, to foster greater market dynamism.

4.1. Proposed policy: Spatial aggregation of power factor limits

The financial penalty to DSO associated with the current regulation, the limits r_l^{ind} and r_l^{cap} at each location are fixed. Therefore, the number of possible market participants is limited; hence, the competition problems may occur (Zhong and Bhattacharya, 2002b; Heilmann et al., 2020). Due to the locality of reactive power and the resulting reduction in competition, there is a need to reassess the existing regulation in Turkiye.

$$r_d^{\text{cap}} \leq \frac{\sum_{l=1}^{L} \sum_{m=1}^{M} Q_{l,m}^{\text{net}}}{\sum_{l=1}^{L} \sum_{m=1}^{M} P_{l,m}^{\text{net}}} \leq r_d^{\text{ind}} \tag{19}$$

where r_d^{cap} is a capacitive unit for the DSO, and r_d^{ind} is an inductive unit.

The proposed approach would assign different limits for each transformer by the TSO. The limits r_l^{ind} and r_l^{cap} suggested in (19) do not have to be at each location l but are instead provided monthly for a zone under the DSO's jurisdiction. Therefore, while the previously required power factor may not be maintained at each substation, it would be kept within the zone. Expanding the Reactive Market zone approach can also avoid the localization problem of Q-suppliers. For the same total reactive power demand (D_l^q), an increase in the number of suppliers leads to a greater number of steps in the supply curve; hence, it contributes to enhanced market efficiency and supports potential price stability.

4.2. Proposed regulation: Dynamic and seasonally-adjusted limits

Another proposed regulation update involves revising the use of fixed r_d^{cap} and r_d^{ind} limits. Maintaining a constant value throughout the month, even with an expanded region and an increased number of participants, can lead to inefficient outcomes such as unnecessary reactive power generation or even real power curtailment. Moreover, the obligation to adhere to fixed limits may result in elevated prices due to the supply constraints they impose. Instead of fixed limits for a year and all locations, seasonality-oriented new temporal limits can be calculated and imposed on locations based on future studies.

Considering the temporal dynamics of PV generation, transitioning from conservative fixed limits applied uniformly over 12 months to seasonal limits could enhance flexibility and efficiency. These seasonal limits could be evaluated monthly instead of maintaining static values for each month, better aligning with the realistic seasonal nature of both supply and demand profiles. Moreover, Turkiye has 21 different distribution system zones, each managed by a separate DSO with unique demand and generation characteristics. Consequently, implementing seasonal and regional limits tailored to each DSO could be a better strategy. This approach would allow the TSO to monitor P/Q balances more accurately and set 21 distinct limits corresponding to each zone's specific needs.

Although this proposal does not represent an existing market design, it can be viewed as a policy-oriented adjustment with potential market implications. Similar seasonality-based mechanisms have been discussed in the literature, such as the introduction of efficient seasonal time-of-use feed-in tariffs for rooftop solar PV in the Australian electricity market (Liu et al., 2018) and the exploration of seasonal forward contracts in the Colombian electricity market (Botero et al., 2007). Such examples highlight the relevance of incorporating temporal variability into market-oriented regulatory frameworks.

4.3. Future work

Several potential avenues for future work can be explored to extend and enhance the current market model. Different types of participants could be introduced to the proposed model along with their specific P-Q capability curves. This introduction would allow for more diversified participation and potentially more efficient market outcomes. Another area of future research involves exploring alternative payment schemes for participants. Lastly, a comparison between investment-based and market solutions could be conducted by realistic simulations to evaluate the financial performance of both models in real-world market operations.

5. Conclusion

The increasing penetration of small-scale PV generation, driven by incentives for renewable energy integration, has altered the dynamics of MV distribution networks. While these DERs contribute to reducing real power drawn from the transmission grid, they do not currently participate in reactive power support due to existing regulatory frameworks. Consequently, the power factor of distribution networks declines from the desired levels, leading to financial penalties imposed on DSOs to maintain acceptable real-to-reactive power ratios.

DSOs typically resort to costly investments in new capacitor banks or reactors to mitigate these penalties and regulate reactive power within predefined monthly limits. To present a real scenario, this paper summarizes the technical impact of Firat DSO's reactive power investment before and after implementation. However, leveraging the inherent capability of PV plants to generate reactive power presents an alternative and possibly an economically viable solution. This approach requires establishing a structured market mechanism that incentivizes suppliers to provide reactive power support while avoiding unnecessary infrastructure investments.

A mathematical model for a local reactive power market is developed and proposed, to evaluate potential payment structures and financial interactions among market participants. The findings highlight the potential of a market-based approach in addressing reactive power deficiencies while creating economic value.

Moreover, the influence of existing financial penalty regulations on market price volatility is discussed. Expanding market participation to increase competition and reevaluating fixed regulatory limits based on near-real-time network conditions are critical factors for stabilizing the market price.

While DERs are incentivized as part of the global transition to renewable energy, unintended financial penalties imposed on DSOs due to reactive power imbalances highlight the need for regulatory evolution. Monetizing the reactive power capabilities of DERs presents a pragmatic and possibly cost-effective solution, transforming a technical challenge into an economic opportunity. This study underscores the necessity of regulatory adaptations to facilitate such a market-driven approach, ensuring the sustainable growth of renewable energy while maintaining grid stability.

CRediT authorship contribution statement

Sinem Kol: Writing – original draft, Visualization, Methodology, Formal analysis. **Gokturk Poyrazoglu:** Writing – review & editing, Supervision, Project administration, Conceptualization. **Hasan Yilmaz:** Writing – original draft, Resources, Data curation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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