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Identifying barriers to large-scale integration of variable renewable electricity into the electricity market: A literature review of market design

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ABSTRACT

For reaching the 2 °C climate target, the robust growth of electricity generation from variable renewable energy sources (VRE) in the power sector is expected to continue. Accommodation of the power system to the variable, uncertain and locational-dependent outputs of VRE causes integration costs. Integrating VRE into a well-functioning electricity market can minimize integration costs and drive investments in VRE and complementary flexible resources. However, the electricity market in the European Union (EU), as currently designed, seems incapable to deliver this end. This paper aims to provide a comprehensive literature review of barriers to the large-scale market integration of VRE in the EU electricity market design. Based on the set-up of the EU electricity market, a framework was developed to incorporate the most pertinent market integration barriers and resulting market inefficiencies.

This paper concludes that an overhaul is needed for the current EU electricity market to address all barriers identified. Firstly, a discrete auction intraday market, a marginal pricing balancing market, a two-price imbalance settlement and a nodal pricing locational marginal pricing mechanism seem more promising in limiting integration costs. Secondly, to support business cases of VRE and complementary flexible resources in the electricity market, a level playing field should be established and the price cap should be lifted up to the value of lost load (VOLL). Meanwhile, to fit VRE's market participation, a higher time resolution of trading products and later gate closure time in different submarkets would be required. Lastly, feed-in support schemes currently widely used for VRE investments might be inconsistent with market integration, as they increase integration costs and lock VRE investments in a subsidy-dependent pathway. To avoid such lock-in, further investigation of alternative capacity-based support schemes is recommended.

1. Introduction

The Paris Agreement aims to limit the increase of the global average surface temperature to 1.5–2 °C above pre-industrial level to avoid the worst impacts of climate change [119]. Keeping the temperature increase well below 2 °C through cost-effective strategies requires the decarbonization of the power sector, which accounted for 38% of global energy-related CO_2 emissions in 2013 [74,80]. Variable renewable electricity (VRE), which is electricity generation from stochastic energy flows (e.g. wind and solar), plays an indispensable role in replacing fossil-fired electricity production that, next to climate change, cause other negative externalities including air pollution and energy insecurity [103,13,81,89]. According to the 2 °C scenario of the International Energy Agency (IEA), the contribution of VRE to global electricity supply has to increase from 4% in 2013 to 25% in 2040 [75]. Similar figures are found for the European Union (EU) that should increase the share of VRE in gross electricity generation from 11% in 2014 [50] to at least 36% by 2050 to contribute to its long-term emission reduction target [36]. VRE, characterized by variability, uncertainty and locational-dependence, however, interacts with the non-VRE part of the power system (hereafter referred to as the residual system). This results in technological, institutional and managerial challenges associated with grid operation, such as the increased need for flexible resources (e.g. flexible plants, storage, demand response, grid infrastructure) and power quality control, better inter-regional coordination and sophisticated method to size reserve. They often cause extra

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operational and investment costs in the residual system to accommodate VRE ([113,61,65,72,5,17]). These costs are often labelled as integration costs,[1] which increase with the rising penetration of VRE. They inevitably become notable when VRE penetration reaches 10%. Various sources [68,118,72,113] indicate that at 10% penetration, integration costs are 9–13 €/MWh for onshore-wind and 26.5–32 €/MWh for solar PV. Integration costs can act as an economic barrier for the continuous growth of VRE [118]. Integration costs reduction becomes increasingly prominent in today's energy policy agenda [107]. Despite an emphasis on "cost-effectiveness" and "cost-efficiency" in the EU's official *Roadmap for Moving to a Competitive Low Carbon Economy* [34] and *Framework Strategy for a Resilient Energy Union with a Forward-looking Climate Change Policy* [38], few efforts have been made yet by policy-makers and regulators for the minimization of integration costs [107,93].

Many parts of the world (including the EU) have established liberalized electricity markets to facilitate the trade of electricity and boost economic efficiency. A well-functioning competitive electricity market can theoretically limit integration costs associated with a given penetration of VRE. This is the case because a theoretical long-run equilibrium exists to deliver the least-cost residual system, which minimizes integration costs. An electricity market functions well, if its price signals support efficient short-term operation and provide sufficient investment incentives for all generation capacity needed [33,69,51,6]. This means that it should be able to provide sufficient remunerations to recover capital costs and support business cases for investments in VRE and complementing low-carbon flexible resources, which are indispensable to adapt to the variable and uncertain outputs of VRE. Otherwise, the least-cost residual system will not be reached. However, in absence of a level playing field due to incomplete internalization of social costs of carbon (SCC) and (explicit and/or implicit) subsidies for fossil fuels, the electricity market cannot effectively promote VRE investments in line with the EU's deep decarbonization goal [35]. This justifies the adoption of various national support schemes, which has driven the rapid and large-scale capacity expansion of VRE in the EU. These schemes aim to financially secure capital-intensive VRE investments against market revenue risks[2] and thus reduce the cost of capital [76,98,101,128]. Their implementation has also contributed to significant costs reduction of VRE technologies, because of economies of scale and technological learning [29,90]. Nevertheless, support schemes, in particular the feed-in tariff, typically create market distortions in operational decisions, due to limited exposure and/or response of VRE generators to market signals [6,10,36,49]. Moreover, such schemes often grant priority dispatch[3] and, sometimes, exemption of balancing responsibilities[4] to VRE generators, regardless of price signals that reflect their negative impacts on system operation [19,30,31,49,85]. These all might contribute to increased residual system costs and thus increased integration costs [99,107,36,62,9,93].

The lack of alignment of VRE development with market price signals have gained increasing concerns, as the penetration of VRE continues to grow [128]. To reduce integration costs and improve economic efficiency,[5] many studies and most EU stakeholders (including the EC) suggest that as an increasingly-mature technology, VRE should be progressively integrated into the electricity market (hereafter referred to as "market integration") [1,18,40,46,49,62,128,6,35,37,39,106,71]. Despite the lack of a standard definition, two dimensions of market integration, with respect to different time horizons, can be drawn from existing literature:

- Firstly, in the short-run, VRE should be exposed and respond to short-time market price signals as much as possible via more market-compatible support schemes, in order to minimize distortions [34,36,41,18,128].

  To fulfill this dimension, the EC's ***Environmental and Energy State Aid Guidelines*** [37] has obliged direct market participation, balancing responsibilities and the removal of subsidies during negative price periods to new VRE installations from 2016 onwards. However, many scholars and stakeholders point out that this also requires the adaption and improvement of electricity market design [104,43,61,76]. As the current market design was historically selected for a power system dominated by dispatchable plants, it may not well suit a power system where VRE plays a growing important role [61]. Furthermore, due to design flaws, certain elements in the existing market design may be incapable of delivering price signals that reflect real market conditions and associated costs [121,20,31,62].

- The second dimension of market integration lies in that support levels should be degressive and eventually be phased out once VRE becomes fully commercially mature [37].

  This means that in the long-run, VRE investments should be mainly driven by market price signals to avoid lock-in into a subsidy-dependent pathway [20,76]. Many authors and stakeholders also stress their concern for a level playing field. They argue that the incomplete internalization of externalities and subsidies for fossil fuels place VRE at a competitive disadvantageous position. Even if VRE becomes fully commercially mature, support schemes may still be necessary in order to compensate for the unleveled playing field [39,5,51,75,128].

Synthesizing all these views, market integration can be defined as a dynamic transition of letting the investment and production of VRE be increasingly driven by market price signals via a well-functioning electricity market in order to minimize integration costs, which must be safeguarded by increased policy efforts to establish a level playing field, improve the electricity market design and adjust support schemes to minimize distortions. Many barriers to market integration still exist to date. Although they can relate to a broader context that covers multiple dimensions (e.g. technological, institutional, political, and societal) (see e.g. 72,73,77,78), barriers related to the market design *per se* are of particular importance. As "the set of arrangements which govern how market actors generate, trade, supply and consume electricity and use the electricity infrastructure" [39], the market design plays a central role in determining market functioning. Market functioning also depends on multiple policy and regulation schemes most relevant to the electrical power sector at EU and MS level, such as carbon pricing under the

[1] Integration costs (C_{int}) can be formally defined as additional costs in the residual system for serving the same amount of residual electricity demand ($E_{resid} = E_{tot}-E_{VRE}$) after VRE introduction, in comparison to a benchmarking conventional system without VRE: $C_{int} = C_{resid}-(C_{tot,conv}/E_{tot})*E_{resid}$. The residual system costs equal total system costs minus VRE generation costs: $C_{resid} = C_{tot}-C_{VRE}$, which include life-cycle (fixed and variable) costs for non-VRE plants, balancing services, grid infrastructure and storage [118]. The concept of integration costs and its decomposition will be further discussed in Chapter 4.

[2] Market revenue risks include price risk due to uncertain electricity price, volume risk due to uncertain sale volume and balancing risk due to penalty for deviations from schedule [128].

[3] Due to very low marginal costs, VRE is normally dispatched in priority based on the merit order. However, priority dispatch here refers to the situation of VRE being dispatched with no or less respect to its marginal costs and price signals. Priority dispatch can be distinguished into two types: explicit physical priority dispatch (i.e. obligations of system operators to dispatch VRE ahead of any other generators) and implicit financial priority dispatch (i.e. subsidies that enable VRE to bid and accept a price below its marginal costs). Both can undermine operational efficiency and exacerbate system stress events, e.g. negative price periods when minimum must-run generation level is reached [6].

[4] Balancing responsibilities for VRE can be fully exempted (e.g. under feed-in tariff schemes in Germany and Croatia) or largely exempted (e.g. a tolerance marginal for imbalances exists for offshore wind in Belgium) [31].

[5] "Efficiency" will appear many times in this paper in different terms, such as operational efficiency, allocative efficiency, efficiency of trading behaviors and price efficiency. It should be noted that they all relate to integration costs, because they reflect different aspects of the electricity market's ability in reducing integration costs.

European Union Emission Trading Scheme (EU ETS) and VRE support schemes. The existence of ill-designed market design elements and policy schemes in the current EU electricity market can give rise to market inefficiencies. They undermine proper market functioning, meaning that they either hinder efficient operation or reduce the feasibility of business cases for investments in VRE and/or complementing flexible resources. Therefore, these design elements and policy schemes directly act as barriers for market integration (hereafter referred to as "market integration barriers"), which also increase integration costs. They are the focus of this paper.

Market integration barriers have been widely reported in literature, but in a fragmented manner. For instance, Scharff and Amelin [112] analyze the negative impacts of market design elements on efficient trading behaviors in the E_{LBAS}[6] continuous trading intraday market. Both Musgens et al. [93] and Hirth and Ziegenhagen [67] report potentially inefficient market designs in the German balancing market, regarding the price settlement rule and the scoring rule. Hiroux and Saguan [62] assessed a limited number of market design options affecting integration costs, regarding the gate closure time of the intraday market, system types of the imbalance settlement and the locational marginal pricing mechanism. Oliveira [99] analytically demonstrated that inefficiencies arising from feed-in VRE support schemes can increase integration costs. To date, however, a framework combining all factors that influence VRE market integration and the general functioning of the electricity market, is still lacking. To fill this gap, this review paper aims to develop a comprehensive framework that incorporates the most pertinent market integration barriers that increase integration costs and resulting inefficiencies. This framework mainly assesses the market integration of large-scale VRE generations, but it is also relevant to small-scale distributed VRE generation. Since distributed VRE generation can participate in the electricity market through smart grid and the role of aggregator, removing market integration barriers is also important to them. The developed framework is supposed to inform policy-makers what market design elements and policy schemes act as market integration barriers. Accordingly, suggestions are given for the redesign of the EU electricity market which aim to improve market functioning and safeguard VRE market integration. This paper provides value-added insights that contribute to facilitate the low-carbon transition of the EU's power sector in a cost-efficient manner. Lessons can also be drawn for countries that plan to decarbonize and liberalize their electric power sector concurrently.

2. Method

Given that the market integration of VRE by definition is to minimize integration costs via a well-functioning electricity market, the framework can be developed through relating different dimensions of the electricity market design and relevant policy schemes to integration costs. To achieve this end, a literature review was performed. Because our aim was to comprehensively include literature from different fields that are related to the electricity market design and VRE market integration, we did not take a specific view to select and assess literature. This means an explorative research approach was taken.

The detailed approach for developing the framework consists of four steps:

Step 1: Characterizing the EU electricity market design per submarket.

In this step, the set-up of the current EU electricity market and the function of each submarket were briefly described. Then key market design elements per submarket were characterized. The characterization focused on five common dimensions, including.

- Trading products
- Price settlement rule
- System type
- Time resolution of trading products
- Gate closure time

Step 2: Integration costs and its allocation per submarket.

In the second step, the concept of integration costs was reviewed, following Ueckerdt et al. [118] and Hirth et al. [65]. This laid the theoretical foundation of this paper. Based on their theoretical framework, integration costs were decomposed and allocated to each submarket of the electricity market. Accordingly, a contour of the framework comprising several blocks was sketched, with each block representing a specific submarket.

Step 3: Identifying potential barriers per submarket.

Following the contour developed in step 2, potential market integration barriers that increase integration costs for each submarket were identified. This step was conducted on the basis of a comprehensive review of literature. The main focus was key design elements per submarket characterized in step 1. Besides, existing policy and regulations schemes at EU and Member State (MS) level that are important to the functioning of electricity market were also looked into, including:

- Carbon pricing under the EU ETS scheme to internalize the climate externality
- Feed-in support schemes for VRE investments
- Price-cap regulation to prevent market power
- Regulation and/or subsidies to retain baseload capacity for security of supply

Step 4: Synthesis, policy recommendations and further research.

In this step the framework was accomplished, highlighting each barrier, their relationship with other barriers, and resulting inefficiencies. Based on the synthesis, recommendations were given regarding how to improve the functioning of the current EU electricity market in order to facilitate successful market integration of VRE. Furthermore, suggestions for further research were also provided for academic researchers.

The outcomes of each method step are presented in Chapter 3–6.

3. Characterizing the EU electricity market design per submarket

Grid stability requires maintaining balance of active power between supply and demand in real-time [115,76]. The electricity market should meet this requirement while respecting multiple constraints in generation capacity, flexibility, transmission, storage and demand elasticity [111,115,126,62]. This determines the set-up of the electricity market, which involves different submarkets with complementing functions to allocate resources and offer different trading opportunities. In the EU, the electricity market typically consists of a day-ahead (DA) spot market, an intraday (ID) market, a balancing (BA) market and an imbalance settlement [111]. In parallel to these submarkets, a locational marginal pricing (LMP) mechanism exists to represent grid constraints [62,76]. Fig. 1 shows an illustrative example of the typical set-up of the EU electricity market. We will now briefly discuss each submarket and their main functions. This serves as the basis for the characterization of market design and later identification of market integration barriers per submarket.

3.1. Day-ahead spot market

The DA spot market is used to trade hourly electricity products in wholesale for the following day. A uniform DA spot price (measured in €/MWh) is set by short-run marginal costs (SRMC)-based bids (i.e. uniform marginal pricing), if the market is able to clear. If the market

[6] E_{LBAS} is the joint intraday market for Nordic countries, Estonia, Lithuania, Latvia, Netherlands, Belgium and Germany [112]

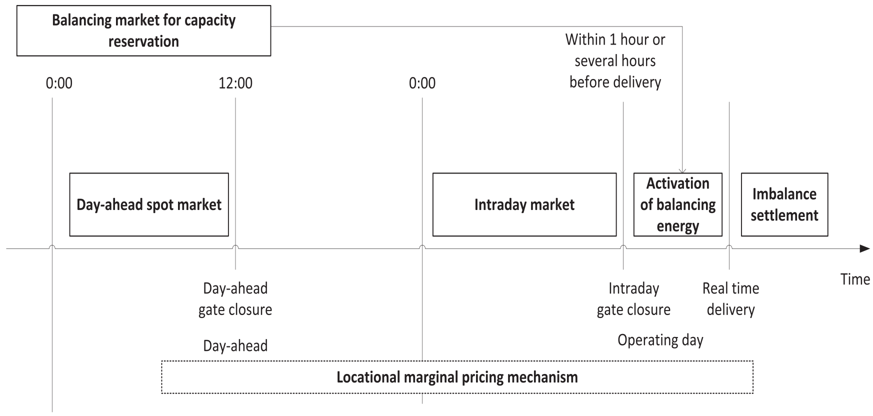

Fig. 1. Illustrative set-up of the EU electricity market.

fails to clear due to insufficient generation capacity to meet demand, the spot price is called scarcity price. Scarcity price in principle should be set at the value of lost load (VOLL), which represents an average consumer's willingness to pay to avoid the involuntary curtailment of electricity consumption [115,76]. It is also approximately equal to the marginal costs of offering one additional unit of electricity (measured in €/MWh). The gate closure of DA trading is typically 12:00 pm day-ahead [111]. Bid-winning participants need to commit themselves to ex-ante operational scheduling for power generation or consumption on an hourly (e.g. Spain) or half-hourly (e.g. France, Ireland, UK) or quarter-hourly (e.g. Belgium, Netherlands, Germany, Austria, Poland) basis [83,111,95,48]. They also need to assign themselves to one balancing responsible party (BRP), which is financially accountable for the real-time net imbalance from DA commitment of the portfolio of generation and/or consumption it manages [67].

3.2. Intraday market

ID market allows BRPs to obtain a better balanced position based on updated information after the gate closure of DA market [111]. It offers flexibility to reduce the need for more expensive resources with high flexibility for real-time balancing [112,126]. ID trading system can be either based on discrete auctions (e.g. Spain, Italy, and Portugal) or continuous trading (e.g. Nordic countries, Netherlands and Belgium). In continuous trading, bids and offers are not matched at the same time but based on “first-come first serve” principle, implying that the price settlement is based on “pay-as-bid” [111]. This also leads to varying prices for the same delivery time [96]. By contrast, discrete auctions aggregate all bids and offers within each trading period in one single auction [111]. The price settlement for each auction is based on uniform marginal pricing, which is similar to the DA trading [111]. Both continuous trading and discrete auctions typically trade hourly electricity products, while quarter-hourly electricity products are also possible to trade in continuous trading [96]. The gate closure times for continuous trading and discrete auctions are currently 5–60 min and 135–690 min before delivery [100,58].

3.3. Balancing market

Due to remaining uncertainties between ID gate closure and real-time delivery and sub-hourly variability, a BA market is established by the transmission system operator (TSO) for the reservation and activation of balancing capacity from balancing service providers (BSPs). BSPs have to commit themselves at a certain generation level in the DA spot market, so that they can ramp up or down in case of being called to provide balancing energy [11]. The TSO determines the size of balancing capacity needed with pre-defined requirements (e.g. contract duration, activation timeframe, ramp rates) and procures them in advance through an auction [67]. The auction consists of a capacity price bid (€/MW•h of capacity product[7]) for capacity reservation and an energy price bid (€/MWh of energy product) for capacity activation [67,93]. Both capacity price and energy price can be determined via pay-as-bid or uniform pricing. Under uniform pricing, the price can be set by either marginal costs or average costs [111]. In the case of the system being short, activated upward reserves receive the energy price being the result of the bid, while in the case of the system being long, activated downward reserves pay the energy price due to saved operating costs [15]. The energy price in the BA market can become negative if downward balancing capacity is in scarcity. The time resolution ranges from yearly to hourly for capacity products, and from hourly to quarter-hourly for energy products [48]. As for gate closure time, it ranges from year-ahead to day-ahead before delivery for capacity products, and from hour-ahead to quarter-hour ahead before delivery for energy products [48].

3.4. Imbalance settlement

IB settlement is used to allocate *ex-post* the costs associated with the reservation and activation of balancing capacity in the BA market to imbalanced BRPs that deviate from their DA commitments. In practice, an IB settlement price mainly consists of the energy price for the activation of balancing capacity in the BA market [22]. Therefore, trading product in the IB settlement is the imbalanced energy between a BRP's real-time delivery and its DA commitment. The time resolution (or settlement period) of the IB settlement and its trading products is consistent with that of the BRP's DA commitment, i.e. ranging from hourly to quarter-hourly [48,52]. Sometimes the settlement price also includes a multiplicative (e.g. Belgium, France) or additive punitive component (e.g. Germany) to strengthen incentives for BRPs to reduce own imbalances [120,121]. Using the DA spot price as a reference, the IB settlement price tends to be higher for upward balancing (in the case of the system being short) and lower for downward balancing (in the case of the system being long). The IB settlement can be either based on a one-price system (e.g. Germany, Spain) or a two-price system (e.g. France, Italy) [105]. Table 1 (adapted from Scharff [111]) shows the economic outcome for BRPs with different positions in respect of system imbalance under a one-price system and a two-price system. In both systems, short BRPs pay while long BRPs get paid. The difference is that in the one-price system the same IB price applies to both BRPs counteracting and aggravating system imbalance. By contrast, two

[7] The capacity product refers to the commitment of reserving a maximum amount of balancing capacity for a specific duration of time. Therefore, it is measured in MW•h. This is different from the energy product measured in MWh. The latter is the total electricity output associated with the actual activation of balancing capacity.

Table 1
IB settlement under a one-price system and a two-price system P_{DA}, P_{up} and P_{down} respectively denote DA spot price, IB price for upward balancing and IB price for downward balancing. E_{short} and E_{long} represent the amount of energies that deviates from DA commitment for BRPs that are short and long, respectively. The green color indicates the IB price is more beneficial for BRPs with respect to the DA spot price, while the red color implies the opposite.
Source: Adapted from Scharff [111]

One-price system	System/BRP position	System short (upward balancing)	System in balance (no balancing)	System long (downward balancing)
	Short BRP	Pay: P_{up}*E_{short} Net loss: (P_{up} −P_{DA}) *E_{short}	Pay: P_{DA}*E_{short} Net: 0	Pay: P_{down}*E_{short} Net gain: (P_{DA} −P_{down}) *E_{short}
	Long BRP	Receive: P_{up}*E_{long} Net gain: (P_{up} −P_{DA}) *E_{long}	Receive: P_{DA}*E_{long} Net: 0	Receive: P_{down}*E_{long} Net loss: (P_{DA} −P_{down}) *E_{long}
Two-price system	System short (Up-regulation)	System short (upward balancing)	System in balance (no regulation)	System long (downward balancing)
	Short BRP	Pay: P_{up}*E_{short} Net loss: (P_{up} −P_{DA}) *E_{short}	Pay: P_{DA}*E_{short} Net: 0	Pay: P_{DA}*E_{short} Net: 0
	Long BRP	Receive: P_{DA}*E_{long} Net: 0	Receive: P_{DA}*E_{long} Net: 0	Receive: P_{down}*E_{long} Net loss: (P_{DA} − P_{down}) * E_{long}

respective price signals (i.e. system imbalance price and DA price) exist in the two-price system for BRPs aggravating and counteracting system imbalance [111,121]. Because of the opportunity costs implied in the spread between the IB price signal and the DA spot price, the two-price system discourages BRPs of any deviations from their DA commitments. However, in the one-price system, BRPs with own imbalance to the opposite direction of system imbalance (i.e. passive balancing) are rewarded.

3.5. Locational marginal pricing mechanism

The LMP mechanism is used in the electricity market to represent grid constraints at different locations on the electricity network, in order to efficiently use the transmission capacity as a scarce good. Electricity prices at two different locations are the same if there is sufficient transmission capacity (i.e. market coupling). However, locational electricity prices differ if grid congestion occurs between the two locations (i.e. market splitting). Depending on the level of details for grid constraint representation, LMP mechanism can be based on a nodal pricing system (e.g. Pennsylvania-New Jersey-Maryland (PJM) interconnection in US) or a zonal pricing system (e.g. most Member States in EU) [94]. Nodal pricing represents the grid transmission capacity at each node of the power system. By contrast, zonal pricing only takes into account the capacity of interconnector between two different price zones, without representing the constraints within each zone.

3.6. Market design characterization

Based on the above descriptions, it is possible to characterize the electricity market design per submarket according to the five key dimensions. The characterization results are shown in Table 2.

4. Integration costs and its allocation per submarket

Integration costs are additional costs in the residual system resulting from the interaction between VRE, featuring variable, uncertain and locational-dependent outputs, and the residual system [65]. For accounting purpose, integration costs can be attributed to the addition of VRE into power system and measured in terms of specific costs (€/MWh_{VRE}) [113]. However, integration costs are often not directly borne by VRE generators, in absence of sufficient market exposure and cost-reflective price signals, e.g. under feed-in tariff scheme. This implies that integration costs will be socialized (e.g. to end-users), if they are incompletely internalized in the electricity market [110,65].

The definition and accounting of integration costs may differ between authors, depending on the system boundary, the techno-economic features of existing power system and the assumptions regarding future scenario (e.g. technology mix and cost, demand elasticity, system adaptation) [5]. Ueckerdt et al., [118] and Hirth et al. [65] establish a wide-cited standard theoretical framework, based on welfare economics, to account and conceptualize integration costs. This paper follows Ueckerdt et al. [118] and Hirth et al. [65].

The constraints of storage, plant flexibility and grid make electricity a heterogeneous commodity with varying economic values across time, delivery lead time and location [66]. This means that VRE cannot directly serve electricity load due to their mismatch across time, delivery lead time and location. Hence, integration costs can either be interpreted as additional costs of accommodating VRE to enable it to serve load, or equivalently, the marginal value reduction of VRE in comparison to a benchmarking power generator perfectly matching load [118,65]. Following the variable, uncertain and locational-dependent nature of VRE, Hirth et al. [65] decomposes integration costs into three components, namely profile costs, balancing costs and grid costs. Profile costs result from the temporal profile mismatch between VRE output and the load. They can be regarded as diminishing cost saving from the substitution of VRE to electricity generation from thermal plants. This is because the use of VRE to serve load involves necessary adjustments of scheduled operation and utilization of thermal plants in the residual system, i.e. increased ramping, cycling, partial-load operations and reduced utilization hours. These adjustments cause additional costs, which decrease the value (i.e. cost saving) that VRE brings to the power system. Therefore, profile costs can also be interpreted as the increase in opportunity costs from the usage of VRE. Balancing costs represent additional expenses for balancing the deviation of VRE outputs from scheduled operation (i.e. forecast errors) because of uncertain VRE outputs. Grid costs refer to cost associated with grid infrastructure investment and management due to locational-dependent siting of VRE resources [65].

The three components of integration costs (profile costs, balancing costs and grid costs) can be allocated to different submarkets, based on the function per submarket. Profile costs can be reflected in the reduced market value (i.e. market revenue) of VRE from a benchmarking power generator with perfect temporal coincidence to the load, which is the difference between load-weighted spot price and VRE output-weighted spot price across time; balancing costs can be reflected in the increased costs associated with balancing services in the ID market and BA market, as well as the price signals to financially settle these costs in the IB settlement; grid costs can be reflected in the price spread between different locations in the LMP mechanism [65]. The three types of system integration costs also give rise to three categories of barriers hampering the progress of market integration: barriers increasing 1) profile costs, 2) balancing costs, and 3) grid costs.

Table 2
Market design characterization for each submarket.

Submarket	Trading products	Price settlement rule		System type		Time resolution of trading products	Gate closure time
DA spot market	Energy	Uniform marginal pricing		N.A.		Hourly	12:00 P.M. DA
ID market	Energy	Uniform marginal pricing	Pay-as-bid	Discrete auctions	Continuous trading	Hourly for discrete auctions; both hourly and quarter-hourly for continuous trading	135–690 min before delivery for discrete auctions; 5–60 min before delivery for continuous trading
BA market	Capacity and energy	Uniform marginal pricing	Pay-as-bid	N.A.		Ranges from yearly, weekly to hour(s)ly for capacity products; ranges from hourly to quarter-hourly for energy products	Ranges from year-ahead, week-ahead to hours-ahead delivery for capacity products; ranges from hourly-ahead to quarter-hourly ahead delivery for energy products
IB settlement	Energy	Marginal pricing	Average pricing	One-price system	Two-price system	Hourly or half-hourly or quarter-hourly	N.A.
		Including/excluding capacity price					
		Including/excluding multiplicative or additive punitive component					
LMP mechanism	N.A.	N.A.		Zonal pricing System	Nodal pricing system	N.A.	N.A.

These barriers can be respectively traced back to certain market design elements per submarket and relevant policy schemes. They either undermine efficient market operation, or reduce the feasibility of business cases for VRE and/or complementing flexible resources. Accordingly, an empty contour of the framework can be drawn, as shown in Fig. 2.

5. Identifying potential barriers per submarket

Via filling the contour set up in chapter 4, the following sections respectively present identified potential barriers increasing profile costs in the DA spot market (5.1), increasing balancing costs in the ID market, BA market and IB settlement (5.2), and increasing grid costs in the LMP mechanism (5.3):

5.1. Potential barriers increasing profile costs in the DA spot market

Profile costs rise with increased penetration of VRE. They are mirrored in market value (i.e. market revenue) reduction of VRE, being equaled to the VRE output-weighted spot prices over time (€/MWh$_{VRE}$) [65,72]. This can be explained by two factors. Firstly, rising VRE penetration reduces the temporary profile correlation between VRE and load, implying that it is less likely for VRE at high penetrations to benefit from high spot prices during scarcity periods[8] [11]. Secondly, because the price settlement is based on ***uniform marginal pricing***, VRE with close-to-zero SRMC is usually dispatched in priority and replaces electricity generated by the marginal thermal plants that set the spot price. This shifts the supply curve to the right and causes a tendency of lower spot prices when VRE generates [24]. Consequently, both the average spot price and the market value of VRE decrease with the increased penetration of VRE, and the market value of VRE decreases faster, *ceteris paribus*. Clearly, the diminished market value of VRE reduces the feasibility of the business case for VRE investments, when the spot price becomes the sole revenue source [78]. Empirical econometric analyses have indicated a correlation between the increased penetration of VRE and the decreased average spot price in many EU Member States, such as Austria [128], Germany [128,26], Italy [25] and Spain [108]. The reduced average spot price, compounded by the increased levelized costs of electricity generation (LCOE) due to reduced utilization hours, also endangers the business case for flexible gas-fired peak load and mid-merit plants. These plants are considered important back-up plants when VRE does not generate. It is reported that in Europe over 20 GW gas-fired plants were mothballed in 2013 and this figure could increase to 110 GW by 2017 [117]. Although a DA market based on uniform marginal pricing is well-known in promoting short-term operational efficiency, a few studies, e.g. De Castro et al. [28]; EC [42]; Agora Energiewende [4], have given concerns over its ability to guarantee long-term market efficiency that foster and remunerate investments in VRE and complementing flexible resources, when VRE with close-to-zero SRMC becomes prevalent and regularly sets the spot price. These concerns seem to be plausible, but often they neglect the fact that the spot price is the result of the supply-demand dynamics and VRE is only one factor that affects such dynamics.

As of today, the current low spot price in Europe is also attributed to a few policy and regulation schemes at EU and MS level:

[8] At very low (≤2%) and low (≤5%) penetration of VRE, a positive correlation may exist between the temporal profile of VRE and peak load, varying from different power systems. For instance, in countries with a hot climate, solar outputs may coincide with the summer peak load at noon due to the use of air conditioning for cooling. A similar case is for wind outputs in countries with a cold climate, where the winter peak load occurs in the windy evening after sunset [5]. These can have an uplifting effect on the market value of VRE. However, as the penetration of VRE further increases, the initial peak load will be inevitably shaved and finally become the valley.

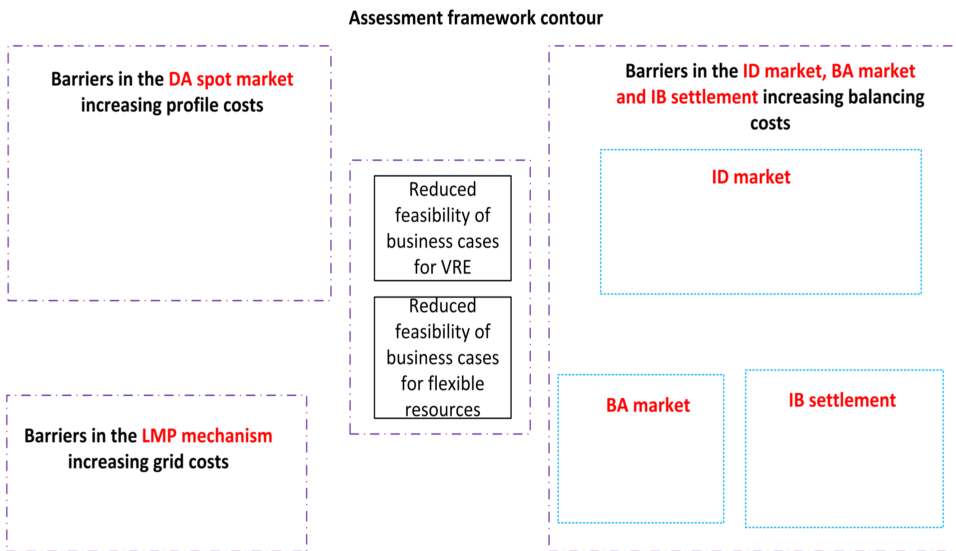

Fig. 2. Contour of the framework development.

- The ***persistent weak carbon price under the EU ETS***, which oscillated between 6.4 and 8.6 €/Tonne CO_2 in 2015 [44], is insufficient to internalize the climate externality and associated SCC [70].
- Due to overly-stringent security of supply or grid reliability standards regardless of its costs, ***regulation and retroactive subsidies (e.g. capacity payment) for retaining inflexible baseload capacity result in overcapacity*** [12,87,109]. Exacerbated by the large addition of VRE capacity driven by support policy schemes, the post-recession flat/declining electricity demand and the neglect of demand response potentials [7,84], overcapacity eliminates the occurrence of scarcity price that are essential to recover capital costs of investments in all types of generation capacity including VRE and flexible resources. For instance, the scarcity price never occurred in Germany in 2014 [30].
- Even if a scarcity situation occurs, price-cap regulation or technical requirement of power exchange can ***limit the scarcity price to a level well-below the VOLL*** [53]. The price cap currently ranges from 150 to 3000 Euro/MWh in Europe [54]. In presence of such a low price cap, the scarcity price is insufficient to remunerate investments in VRE and complementing flexible resources.

These policy and regulation schemes depress the market value of VRE, leading to higher profile costs. In addition, they blur the price formation in the DA spot market, undermining investment incentives included in market price signals.

The reduction of VRE market value (or the increase of profile costs) and the average spot price can be partly, if not fully, mitigated through a few measures that aim to increase the spot price when VRE generates.[9] These measures mainly include flexible resources (i.e. flexible thermal plants, energy storage, demand response), system-friendly VRE technologies and arrangements (i.e. high power density wind turbine, solar panel with unconventional orientation), inter-regional integration of electricity market through market coupling, increasing the carbon price, accelerating the phase-out of the overcapacity of inflexible baseload plants, and increasing the price cap to the VOLL [42,59,63,64,72,78,85,97]. They in general have an uplifting effect on the spot price when VRE generates, either through 1) shift the supply curve left, or 2) increase residual demand,[10] or 3) increase the average height of the supply curve, or 4) smooth the temporal profile of VRE output, or 5) strengthening scarcity price. Therefore, through a synergy of these measures, it seems possible to avoid the situation of spot prices being regularly set by VRE. Even at high penetrations of VRE, spot prices could be restored to a sufficiently high level to stimulate investments in VRE and complementing flexible resources. However, to effectively scale-up the implementation of these measures, many barriers are yet to be overcome. Table 3 summarizes different measures limiting the reduction of VRE market value and the increase of profile costs, their mechanisms and potential barriers hindering their implementation. It may take time to fully overcome these barriers. This implies that alongside the progress of implementing these measures, support policy schemes for VRE investments are still needed, at least in the medium term, since the market revenue alone is insufficient to recoup the high capital costs.

Current, ***Feed-in support schemes*** in the form of either tariffs or premiums that remunerate VRE on the basis of per unit of electricity generation are most commonly used in the majority of EU Member States [79]. Fig. 3 shows different types of feed-in schemes, with each type being briefly described.

In general, these schemes enable VRE generators to largely feed in electricity at very low or negative spot price that is below their close-to-zero SRMC [6,20,86]. Therefore, they lead to reduced market value of VRE and unnecessarily higher profile costs. The extent to which they are market-based differs, as these feed-in schemes expose VRE to the price signal (and thus the market revenue risks) at different levels in the DA spot market. Depending on their market-based level, feed-in schemes also give rise to different levels of market distortions [45,49,10]. As the dominant support policy scheme that steers past VRE investments in the EU, feed-in tariff has been introduced in 17 out of the 28 Member States till 2014 [79]. However, a feed-in tariff fully shields VRE against market price signals, discouraging developers from adopting more system-friendly technologies and arrangements and selecting generation sites that maximize the market value (i.e. market revenue) of VRE. Consequently, the EC has called for more market-based feed-in premiums to progressively replace feed-in tariffs, stating that feed-in premiums can "put pressure on renewable energy generators to become more active market participants, via incentives to optimise investments, plant design and operation according to market signals" [35]. It will prohibit the use of feed-in tariffs to support new VRE installations from 2016 onwards, and as of then it is obliged for all Member States to use feed-in premiums (in combination with tenders and the removal of subsidies during negative price periods) for the sake of better market integration [37]. Among all feed-in premiums, fixed feed-in premiums are deemed as the most market-based and thus have the least distorting impacts on the DA spot market. However, using an analytical model with empirical data, Oliveira

[9] Note that some of these measures (e.g. interconnector, demand response) can also lower the spot price when VRE does not generate or generate less. Therefore, their impact on the average spot price might be limited.

[10] The residual demand is defined as the demand net the output of VRE, which treats VRE as "must-take" generation

Table 3
Measures limiting VRE market value reduction and their barriers.
Source: Buck et al. [16]; de Jong et al. [30]; Papaefthymiou et al. [102]; Zane et al. [128]; Auer [8]; THEMA [116]; Deutsch et al. [32]; Hu et al. [70]; ENTSO-E [47]; He et al. [60]; Hirth and Muller [63].

Measures limiting VRE market value reduction and profile costs increase		**Mechanism**	**Potential barriers**
Flexible resources	Flexible thermal plants (with low minimum load)	Shift the supply curve leftwards	High capital costs; Unsound business cases due to the lack of scarcity price
	Energy storage	Increase the residual demand	High capital costs; Life degradation and fatigue due to cycling (in the case of battery); Unsound business cases due to the lack of scarcity price
	Interconnector	Increase the residual demand	Lack of coordination between the development of grid and VRE; Lack of investment incentive for TSOs; Fragmentation of individual regional TSOs; Public acceptance of overhead lines
	Demand response	Increase the residual demand	Lack of adequate ICT infrastructure; Lack of real-time pricing; Segmentation of consumer groups with different price elasticities of demand within one household; Behavioral changes needed from consumers
System-friendly VRE technologies and arrangements	High power density wind turbine	Smooth the temporal profile of VRE output	High capital cost
	Solar panel with unconventional orientations	Smooth the temporal profile of VRE output	N.A.
Inter-regional integration of electricity market through market coupling		Smooth the temporal profile of VRE output	Lack of interconnector infrastructure; Fragmentation of individual regional TSOs; Political resistance from national governments due to loss of sovereignty
Increase the carbon price		Increase the overall height of the supply curve	Carbon price sufficiently high to steer VRE investments is likely to face political unacceptance in the short and medium run due to concerns over industrial competitiveness and carbon leakage; Incompatible policy designs that have a depressing impact on the carbon price;
Accelerate the phase-out of the overcapacity of inflexible baseload plants		Shift the supply curve leftwards; strengthening scarcity pricing	Retroactive capacity payments for retaining coal-fired baseload plants (e.g. UK, Spain); (Explicit and implicit) subsidies for fossil fuels; Market-exit restrictions; Overly stringent security of supply standard
Lift up price cap to the VOLL		Strengthening scarcity pricing	Lack of risk hedging products for price spikes; Public and political unacceptance

[99] has demonstrated that even in the case of fixed feed-in schemes, perverse incentives that deviate from the objective of market value maximization always exist for firms that own both VRE generators and thermal generators. As for firms that only own VRE generators, these perverse incentives can still exist if the convexity of the supply curve is high [99]. As such, it seems reasonable to conclude that all feed-in schemes can disincentivize VRE generators to maximize their market value and act as a barrier that increases profile costs. Fig. 4 shows that due to the use of feed-in schemes, VRE investments may be locked in a vicious cycle of subsidy-dependent pathway. Feed-in schemes enlarge the gap between the investment costs of VRE and its market value, which in turn increase the subsidy level needed from feed-in schemes to make VRE investments break-even. In other words, feed-in schemes may inefficiently increase their own policy costs. If such policy costs become unaffordable, it can increase the risk of subsidy termination. Therefore, the authors argue that feed-in schemes are inconsistent with the objective of market integration.[11]

The ***gate closure time*** and the ***time resolution of trading products*** of the DA spot market also affect the market efficiency. Although not directly influencing profile costs, these two design elements have cross-market impact on balancing costs that occur in the ID market, BA market and IB settlement via influencing the demand for system balancing services [56].

The current gate closure time for the EU DA spot market is typically 12:00 P.M. day-ahead. It is criticized for being too far from the real-time delivery in the following day [12]. In particular, a delivery lead time as long as 36 h exists for the last hour of the following day. The large forecast errors associated with such long lead time tends to put VRE generators at a more imbalanced position in real time, increasing the overall system demand for balancing resources in the ID market and BA market and the associated balancing costs [85]. Due to large uncertainties and balancing risks, the early gate closure time also creates an unfavorable condition for VRE generators to submit bids in the DA spot market [108]. This can be detrimental to the business case of VRE investments and the process of market integration.

Since hourly electricity products are traded in the DA market, the corresponding DA spot price is also determined on an hourly resolution. However, the spot price with hourly resolution, as an averaged indicator, cannot accurately reflect the physical reality of supply-demand dynamics that is usually scheduled at a sub-hourly resolution [85]. This is particularly the case for VRE supply, whose sub-hourly variability can be significant [88]. Hence, the correlation can be very low between hourly spot prices and sub-hourly IB prices for the same

[11] It should also be stressed that in absence of other more market-compatible support measures and in the context of still existing fossil subsidies and the incomplete internalization of climate externalities, the removal of feed-in schemes is obviously not a good idea.

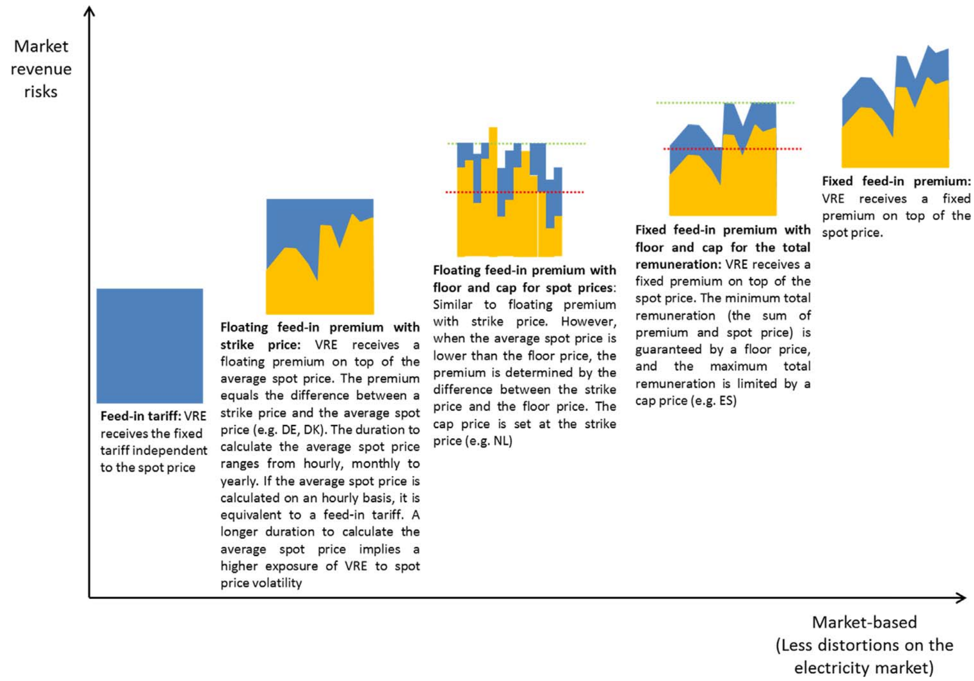

Fig. 3. Different types of feed-in schemes and their brief descriptions. Compiled based on CEER [20]; Noothoot et al. [98]; Huntington et al. [71].

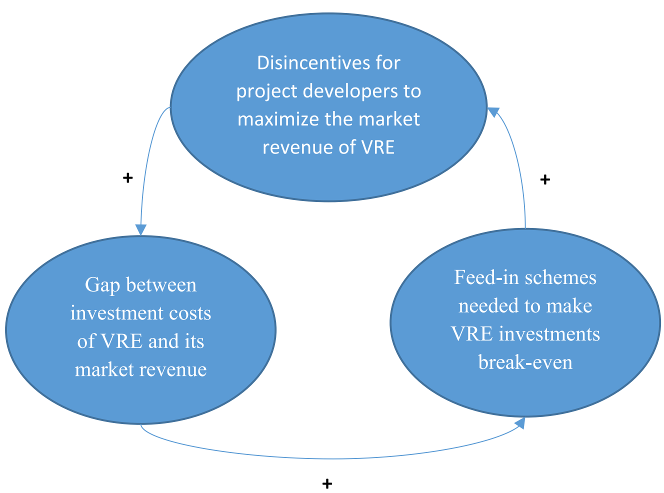

Fig. 4. Subsidy-dependent pathway for VRE investments.

period, which encourages strategic behavior of BRPs to arbitrage between the price differences through deliberately maintaining an imbalanced position [83,95]. This results in higher system needs for balancing services and higher balancing costs. Inefficiencies associated with the low time resolution of trading products in the DA spot market will be further discussed in Section 5.2.3.

5.2. Potential barriers increasing balancing costs in the ID market, BA market and IB settlement

5.2.1. Potential barriers increasing balancing costs in the ID market

To avoid the use of more expensive real-time balancing capacities, the ID market alongside updated information should be used to the largest extent to reduce imbalances and associated balancing costs [126]. However, illiquidity, mirrored by low trading volumes, often characterizes the ID market in Europe, resulting in inefficient performance in terms of resources allocation and limiting balancing costs [112,126,21,23]. Multiple factors contribute to an illiquid ID market:

- Due to ***market concentration***, market participants with large generation portfolios tend to net out own imbalances through internal balancing rather than ID trading [126].
- Clear preference of market participants to trade close to gate closure time of the ID market because of more accurate forecasts [112] suggests that a ***gate closure time insufficient close to real-time (> 60 min before delivery) may undermine liquidity***. This can be relevant for Spain, Italy and Portugal, where ID gate closure times range from 135 to 690 min before delivery.
- ***Limited participation of demand response due to tight access rules*** and difficulty to develop baseline and measure compliance [14,6].
- ***Illiquidity can increase the transaction costs*** of market participants because it is likely that their purchases and/or sales move the market price and reduce the benefits from trading. The fear of such transition costs in turn exacerbates illiquidity [126].

Liquidity also hinges on whether the system type of the ID is based on discrete auctions or ***continuous trading***. Discrete auctions aggregate all bids and offers within each trading period in one auction, and thus show better liquidity performance [112,23]. By contrast, the large price variance from trade-to-trade in continuous trading disincentivizes market participants to trade. In addition, unlike uniform marginal pricing used in discrete auctions, the price settlement rule of continuous trading based on “first come first serve” ***pay-as-bid*** is inefficient by nature, because more expensive bids can be accepted if less expensive bids come later [111,96]. Scharff and Amelin [112] also report that transaction costs in terms of ICT system and trading staff costs are often involved in continuous trading because of the need to monitor the market constantly to identify more lucrative prices. Thus, continuous trading can be deemed as an inefficient design element for limiting balancing costs.

In addition, liquidity of the ID market is affected by interactions and interdependencies with the BA market and IB settlement. Weber [126] argues that since BSPs in the BA market have already earned a capacity price for capacity reservation, they may have incentives to offer energy price bids lower than their true costs for capacity activation. This can lower the energy price for balancing energy, which finally turns into a lower IB price. If the resulting IB price is lower than the ID price, VRE generators and other market participants will have less incentive to reduce their own imbalances through trading in the ID market [126]. This, however, is not an issue, if the price settlement rule for both the capacity price bid for capacity reservation and the energy price bid for capacity activation are based on uniform marginal pricing. Musgens et al. [93] has theoretically demonstrated that, under uniform marginal pricing, rational bidders in competitive markets will disclose their true costs for capacity reservation and capacity activation. To be more specific, the capacity price bid will be equal to the expected opportunity costs from capacity reservation net the expected profits from capacity activation, while the energy price bid will be equal to the SRMC of providing balancing energy [93]. Nevertheless, in many EU countries ***pay-as-bid*** (e.g. Germany, Italy) instead of uniform marginal pricing is currently used as price settlement rule for the BA market, which may contribute to the low liquidity of the ID market. Liquidity of the ID market is also dependent on the system type of the IB settlement, i.e. based on a one-price system or a two-price system [112,126]. As passive balancing is rewarded in a ***one-price system***, BRPs may strategically maintain an imbalanced position. This can reduce the liquidity of the ID market. Scharff and Amelin [112] further illustrates that ***compared with a two-price system, ID trading is less reciprocal for both risk-averse sellers and buyers under a one-price system***. Therefore, it can be suggested that the liquidity performance is better when the ID market is combined with the IB settlement based on a two-price system. However, the better liquidity performance will be undermined if an ***inefficient multiplicative punitive component*** is introduced under a two-price system that asymmetrically penalizes short BRPs more than long BRPs, which is, for example, the case in France and Spain [120,52]. In that case, BRPs including independent VRE generators tend to under-contract or withholding own balancing resources to avoid being short, which may reduce incentives for ID trading.

5.2.2. Potential barriers increasing balancing costs in the BA market

The overall efficiency of the BA market depends largely on the price settlement rule used for capacity reservation (via capacity price bid per MW·h) and activation (via energy price bid per MWh). A general consensus is that ***pay-as-bid*** (e.g. Germany, Italy) is inefficient for limiting balancing costs, compared with uniform marginal pricing [15,67]. As pay-as-bid rewards BSPs best at guessing the clearing price, it does not necessarily accept balancing capacities with least costs [27]. Musgens et al. [93] have demonstrated that both price settlement rules are equivalent under complete information and perfect competition. However, pay-as-bid shows inferiority under imperfect competition and incomplete information in terms of efficiency, transparency and transaction costs.

The ***low time resolution (e.g. yearly, weekly, daily and four-hourly) and very early gate closure time before delivery (e.g. week-ahead) for capacity products*** of balancing services also reduce the efficiency of the BA market, resulting in unnecessarily higher balancing costs. Balancing service provision involves opportunity costs for thermal plants, because these plants have to commit themselves at a certain generation level in the DA spot market in case of being called. The opportunity costs mainly consist of missed income or imposed losses in the DA market [67,93]. For upward balancing, Just [82]; Musgens et al. [92] have qualitatively demonstrated that efficient balancing services should be provided by thermal plants with SRMC close to the DA spot price, which leads to lowest opportunity costs and thus lowest system balancing costs. This means that the capacity mix for providing efficient balancing services changes over time, due to varying spot prices. Therefore, a low time resolution of capacity products can give rise to inefficiencies, because it fixes the same balancing capacity mix for a time period with varying hourly spot prices. Similarly, an early gate closure time for capacity products far away from delivery also leads to inefficiencies due to fixing the balancing capacity mix at a specific time when uncertainty of the spot price is high [82,92]. As for downward balancing services, Hirth and Ziegenhagen [67] have illustrated that they can be efficiently provided by VRE generators, featuring close-to-zero SRMC, at zero opportunities costs. This also reduces the must-run generation level resulting from the use of thermal plants to provide these services. As shown by a few modelling-based studies and pilot projects [55,57,67,124], the technical reliability of balancing services provided by wind farms pooling over a large geographical area is sufficiently high, under hourly time resolution of capacity products and gate closure time one hour-ahead delivery. However, a low time resolution of capacity products and very early gate closure time before delivery create an entry barrier[12] and biased conditions for VRE to participate in the BA market [123,52,67,92]. For instance, in Germany and Belgium, balancing services require a resolution of capacity products ranging from weekly to four-hourly, and the procurement of these services is usually week-ahead or day-ahead [124,67]. Under these conditions, the weather forecasts are too uncertain for VRE to provide reliable balancing services [52,67]. Consequently, these biased contract conditions reduce potential revenue streams for VRE, which is detrimental to the business case of VRE investments.

In addition, Borggrefe and Neuhoff [14] point out the ***lack of joint-optimization between BA market and other submarkets*** also increases balancing costs. The current electricity market design in most EU countries requires power generators exclusively commit themselves either in the DA/ID markets trading energy products or BA market trading capacity products. This eliminates the possibility to contract capacity products for the same hour from power plants that have scheduled to decrease electricity outputs in the DA/ID energy submarkets through partial-load operation, even if upward balancing services provided by these partial-load plants can reduce the overall balancing costs [14].

5.2.3. Potential barriers increasing balancing costs in the IB settlement

IB settlement not only allocates balancing costs to imbalanced BRPs, but signals the price of imbalance from DA commitments. Hence, the price settlement rule affects the overall efficiency of the IB settlement for limiting balancing costs. Depending on whether uniform marginal pricing or pay-as-bid is used in the BA market, IB price can be based on marginal costs or average costs associated with the activation of balancing capacity. Compared to marginal pricing, ***average pricing*** (e.g. Germany, France) depresses price signals of the IB settlement. Therefore, it provides less incentives for BRPs to maintain a balanced position and, in particularly, for VRE generators to improve forecast accuracy [67]. Hence, average pricing is inefficient in limiting balancing costs. Moreover, average pricing is also to the disadvantage of the business case for flexible resources. As average pricing reduces the occurrence of negative and/or extreme high IB prices, it masks the system needs for investment in new flexible resources able to provide upward/downward balancing within short lead time [15]. Similar to the impact of averaging pricing, the ***exclusion of costs associated with capacity reservation of balancing services*** in the IB price also acts as an inefficient design element limiting balancing costs reduction. Vandezande et al. [120]; Hirth and Ziegenhagen [67] suggest that capacity reservation costs, instead of being socialized, should be included in the IB price via an additive component to reflect the full costs of imbalance.

The ***low time resolution*** (e.g. hourly) ***of IB settlement*** may also increase balancing costs. According to Fernande et al. [52] and Vandezande [122], BRPs that are able to maintain a balanced position over a long period of IB settlement can frequently cause imbalances within the period. As a result, the IB settlement may hamper the cost-reflective allocation of balancing costs [52], inefficiently increasing the system demand for balancing services and associated balancing costs. This is the case for Spain. In other MSs, the time resolution of IB settlement is usually sub-hourly [48].

[12] Voet [124] also points out ***feed-in schemes*** can act as a barrier for VRE to provide balancing services in the BA market, because the loss of subsidies cannot be priced in the energy price bid for capacity activation.

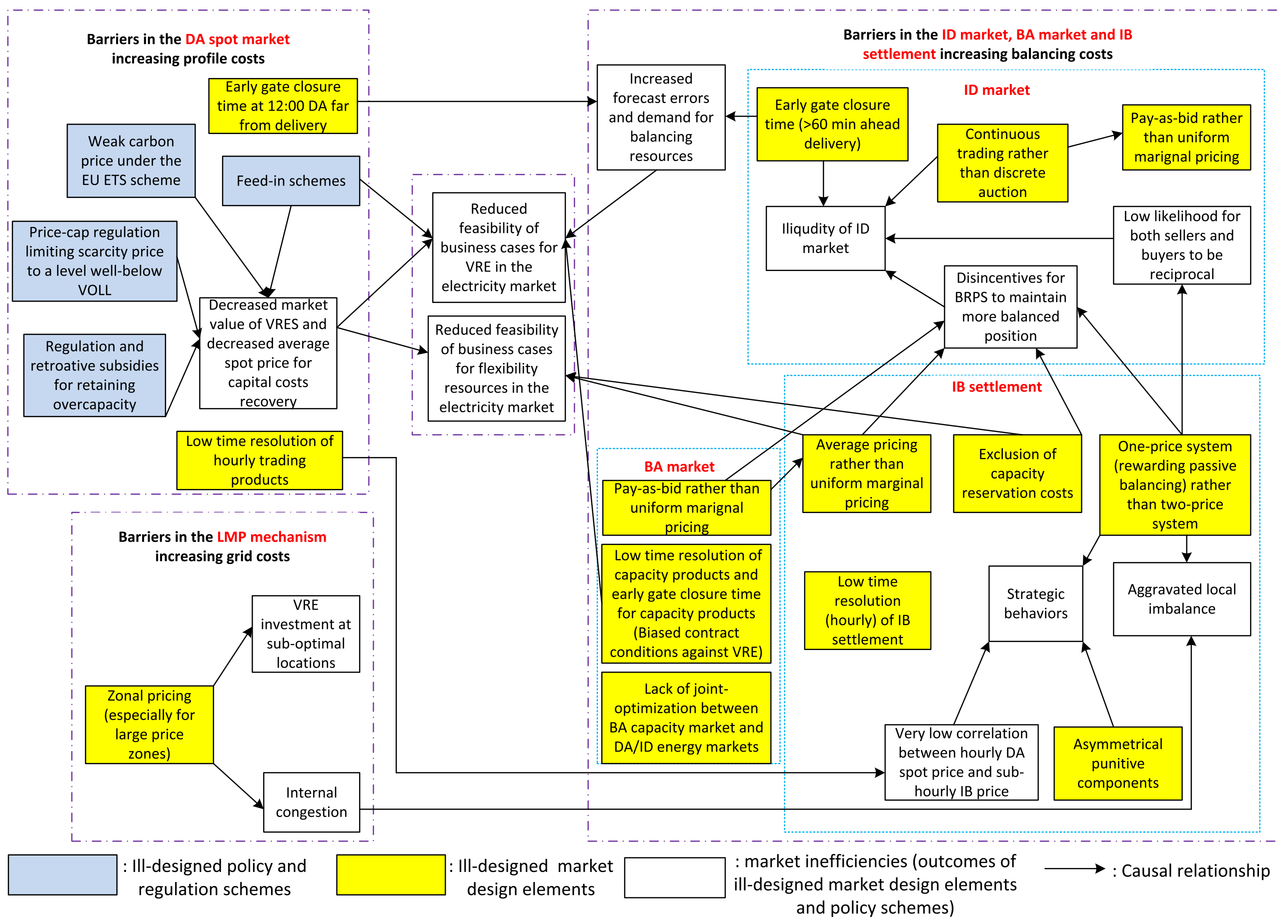

Fig. 5. Framework for market integration barriers.

In addition, Wawer [125] considers the system type, i.e. based on a one-price system or a two-price system, as the most important design element affecting the overall efficiency of the IB settlement. However, views regarding the superiority between both systems in limiting balancing costs differ among authors. Vandezande et al. [120]; Moeller and Fabozzi [91] prefer the one-price system, arguing that passive balancing rewarded under a one-price system could reduce the system needs for holding reserves and the associated balancing costs. However, based on analysis of empirical data in Germany, Just and Weber [83] have observed that passive balancing under a ***one-price system also creates perverse incentives for strategic behaviors arbitraging between the DA spot price and the IB price***. As explained in Section 5.1, the mismatch between hourly spot prices and sub-hourly IB prices for the same time period results in very low correlation between the two price signals. Due to such low correlation, BRPs tend to strategically over-contract and under-contract at high and low DA spot prices, if the system imbalance is expected to be respectively long and short. This strategic behavior could move the system imbalance to the unfavorable direction, resulting in higher demand for balancing capacity and additional balancing costs in an estimated range of € 200–300 million per year [83]. The additional balancing costs associated with strategic behavior are very likely to outweigh the expected costs savings from passive balancing under a one-price system. Following the same case in Germany, Chaves-Avila et al. [22] also reports that a ***one-price system could exacerbate local imbalances in case of grid congestion***, provided that passive balancing gives perverse incentives for local BRPs to intentionally maintain an imbalanced position to the opposite direction of system imbalance. Based on above analyses, a one-price system seems to be less efficient in limiting balancing costs, in comparison to a two-price system designed to prevent BRPs from any imbalance.

5.3. Potential barriers increasing grid costs in the LMP mechanism

The efficiency of LMP mechanism mainly depends on its system type, i.e. zonal pricing or nodal pricing. Because of its limited representation for grid constraints, ***zonal pricing*** (especially for large zones) is inefficient in limiting grid costs, in comparison to nodal pricing. As the uniform price across a single price zone cannot represent internal grid constraints, zonal pricing fails to incentivize VRE investments to efficiently use existing grid infrastructure within the same zone. Consequently, suboptimal decisions could be made to invest in VRE at locations lacking grid capacity, resulting in unnecessarily higher grid costs associated with grid extension and expansion [11,94]. Moreover, exacerbated by increased loop flows associated with the feed-in of VRE into the grid, zonal pricing increases the chance of congestion in meshed networks, because its price signals fail to inform the actual state of power flows [116,61]. Costs associated with grid congestion management are often high due to the need to re-dispatch plants. Recalling that IB settlement based on a one-price system could exacerbate local imbalance in case of grid congestion, zonal pricing that is inefficient in limiting grid costs and a one-price system that is inefficient in limiting balancing costs could further undermine the efficiency of each other.

6. Synthesis and policy recommendations

6.1. Synthesis

Fig. 5 shows that currently many barriers to the market integration of VRE exist in the electricity market in Europe. Many of the barriers lead to the same market inefficiency. Market integration barriers can result in either higher integration costs, or endangered business cases for investments in VRE and complementing flexible resources.

Therefore, they should be addressed to facilitate better market integration.

6.2. Policy recommendations

Based on this framework, we can draw policy recommendations on how to improve the functioning of the electricity market that serves for VRE market integration from two interrelated aspects. They respectively relate to the reduction of integration costs (Section 6.2.1) and the business case for VRE and complementing flexible resources (Section 6.2.2).

6.2.1. Reduction of integration costs

Market design elements within a single submarket have intra-market or cross-market impacts on the market efficiency. They can be improved along five dimensions to reduce integration costs:

- The ***price settlement rule*** should help to disclose and reflect the marginal costs of balancing resources in all submarkets where balancing costs occur. In this sense, in the ID and BA market, pay-as-bid is inefficient and should be replaced to uniform marginal pricing. Similarly, average pricing in the IB settlement that corresponds to pay-as-bid in the BA market should be replaced by marginal pricing. It is also suggested that the capacity reservation costs should be included in the IB settlement price and asymmetrical punitive components should be removed.
- The ***system type*** for each submarket should be selected on the basis that it can better and robustly guarantee market efficiency and liquidity. In this sense, continuous trading in the ID market should be replaced by discrete auctions for better liquidity performance, and zonal pricing in the LMP mechanism is recommended to be replaced by nodal pricing for reducing grid costs. In addition, the one-price system in the IB settlement may better be replaced by a two-price system. This is because not only does a one-price system encourage strategic behavior in the IB settlement, but it decreases the liquidity performance of the ID market. It also aggravates local imbalance, if in combination with zonal pricing.
- The low ***time resolution of trading products*** in different submarkets cannot accurately reflect the physical reality of supply-demand dynamics in a power system with increased VRE. Hourly energy products in the DA market and IB settlement can give rise to increased balancing costs in the IB settlement, due to insufficient reflection of the sub-hourly variability and uncertainty associated with VRE. Therefore, it is recommended to increase the time resolution of energy products in the DA market and IB settlement to quarter-hourly. This implies that the current low time resolution of capacity products in the BA market should also be improved to quarter-hourly, to better match the improved time resolution of DA energy products and thus reduce costs associated with balancing capacity products.
- The early ***gate closure time*** insufficiently close to real-time delivery in different submarkets increase forecast errors of VRE and associated balancing costs. In particular, the 12:00 P.M. DA gate closure time can severely limit the possibility of trading VRE in wholesale without considerable impact on balancing costs. The authors propose to bring the DA gate closure time to 4 h before delivery. Based on Spanish wind farm data [73], such gate closure time can guarantee forecast errors well below 10%. It may also make a compromise with the lead time requirement for thermal plants to schedule their generation in a cost-efficient manner [111]. We suggest further studies to investigate such trade-off. As for the ID and BA market, their gate closure time should be no more than 60 min before delivery to minimize balancing costs.
- The ***lack of joint optimization*** between BA capacity market and DA/ID energy market increases balancing costs. The electricity market design should enable such joint optimization, meaning that commitments to DA/ID energy market and BA capacity market should not be mutually exclusive.

Fig. 6 illustrates how the set-up of EU electricity market might look like once recommended improvements of design elements are made for each submarket. The red color is used to mark the main improvements.

Market inefficiencies may also arise from relevant policy and regulation schemes that distort the electricity market. Their negative impacts mainly concentrate on the DA spot market where profile costs occur. These policy schemes include weak carbon price under the current EU ETS scheme, feed-in schemes, price-cap regulation limiting the scarcity price to a level well-below the VOLL, and regulations and retroactive subsidies for retaining overcapacity. They exacerbate the market value reduction of VRE and thus increase profile costs. Improved policy and regulation schemes can thus lower profile costs and strengthen the business case for VRE and complementing flexible resources because of improved market value. These will be discussed in the next section.

6.2.2. Business case for VRE and complementing flexible resources

Market integration requires the electricity market fits the business case for VRE and complementing flexible resources. Market integration barriers, however, can reduce the feasibility of the business case for investments in VRE and flexible resources in the electricity market, and they should be removed:

- ***Feed-in schemes*** provide disincentives for VRE generators to maximize their market value in the electricity market, increasing the required subsidy level and locking VRE investments in a subsidy-dependent pathway. To avoid potential lock-in and support the business case of VRE investment in the electricity market, the authors argue that a direct capacity-based support scheme on top of the market revenue of VRE investments might be a better alternative to the current feed-in schemes. Not only does it minimize direct distortions on the electricity market, but it can incentivize VRE generators to maximize their market value. As the commercial maturity of VRE improves, the capacity-based support scheme can be degressive. Such capacity-based support scheme has been favored by a few authors, e.g. Andor et al. [3]; Eurelectric [49]; Bunn and Munoz [17]; Huntington et al. [71].
- The weak ***carbon price under the current EU ETS scheme*** is insufficient to internalize the climate externality. It decreases the market value of VRE and creates an unleveled playing field for VRE to compete with fossil-fired generation technologies in the electricity market. Therefore, it reduces the business case for VRE investments. To address this issue, the carbon price should be increased to a level closer to the SCC.[13] It is estimated that a minimum carbon price at 60 €$_{2013}$/Tonne is required to make VRE investments break-even in the electricity market, relying on the market revenue alone [32]. Similarly, explicit and implicit subsidies for fossil fuels also put VRE investments at a competitive disadvantageous position. If these subsidies are not removed, the business cases for VRE investments might remain unsound even in the long run. In that case, the market integration objective seems impossible to achieve.
- The ***scarcity price*** is essential for maintaining the functioning of the electricity market in remunerating investments in VRE and flexible resources. However, the level and frequency of scarcity price are reduced by price-cap regulation and retroactive subsidies for retaining overcapacity. This clearly reduces the feasibility of business cases for VRE and flexible resources, due to insufficient revenue for capital costs recovery. Therefore, the authors suggest policy-makers to lift up the price cap to the VOLL and accelerate the phase-

[13] Based on the Stern Review [114]he SCC is estimated at 123 €$_{2013}$/Tonne CO_{2eq} for the year 2013. The SCC is also expected to increase at a rate of 2–3% per year [2].

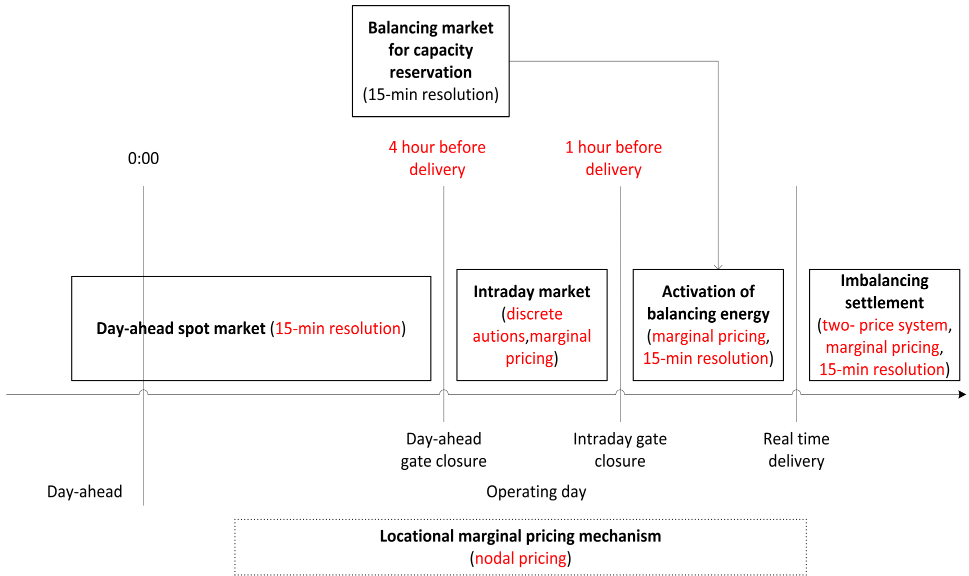

Fig. 6. Illustration of the recommended EU electricity market set-up.

out of excessive inflexible baseload capacity. This can help the electricity market to restore its functioning.

- The electricity market should provide ***a level playing field*** for all market participants. VRE generators capable of providing cost-efficient downward balancing services should be encouraged to participate in the BA market. However, unfavorable market design elements in terms of early gate closure time and low resolution of capacity products limit the possibility for their participation. The exclusion of VRE in the BA market excludes potential revenues from the BA market, which is detrimental to their business case. Hence, to facilitate the business case of VRE, the gate closure of BA market should be moved close to real time (e.g. 1 h before delivery) and the resolution of capacity products should be increased to at least hourly and ideally quarter-hourly.

6.3. Further research

This study has qualitatively assessed barriers to the market integration of VRE through a literature review. To facilitate market integration, recommendations were given regarding how to improve the market design and relevant policy and regulation schemes. The authors propose further researches to quantitatively assess the impact of these improvements. In particular, a cost-benefit analysis is necessary to analyze the pro and cons of the new market set-up (as suggested in Fig. 6) and to what extent it can reduce integration costs. In addition, it is still unclear at what level the proposed capacity-based support scheme can provide sufficient security for VRE investors to de-risk their investments and limit the cost of capital. Model-based studies are required to further investigate this issue.

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