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Melting-pots and Salad Bowls: the Current
Debate on Electricity Market Design for RES
Integration

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CWPE 1354 & EPRG 1329

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We argue that RES integration is first and foremost an issue of economic efficiency, and we review the main debates and frameworks that have emerged in the literature. We first consider to what extent intermittent resources should be treated the same way as dispatchable resources. We then analyse the different tools that have been proposed to ensure the required flexibility will be delivered: finer temporal granularity and new price boundaries, integration of a complex set of balancing markets, and introduction of tailor-made capacity remuneration mechanisms. Finally we introduce the topic of space redistribution, confronting cross-continental markets integration to the emergence of a mosaic of local markets.

Keywords *Electricity market design, large-scale renewables, intermittency*

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Melting-pots and salad bowls: the current debate on electricity market design for RES integration

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This paper discusses a series of issues regarding the economic integration of intermittent renewables into European electricity markets. This debate has gained in importance following the large-scale deployment of wind farms and photovoltaic panels. As intermittent renewables constitute a significant share of the installed generation capacity, they cannot be kept isolated from the electricity markets.

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1. Introduction: RES integration as an economic efficiency challenge

European wholesale electricity markets have not been designed to ensure efficient operation and adequate investment in a power system featuring a large share of intermittent³ Renewable Energy Sources (RES). RES specificities, such as production variability and low-predictability, zero marginal-cost of generation, and strong site-specificity, result in a set of technical and economic challenges. The share of intermittent RES in most European power systems remains relatively low today and their development is framed both by direct support schemes and indirect support schemes such as partial isolation from the market rules (See Batlle et al. (2012) for a review of existing support schemes). However this development is already significant in countries like Denmark (28% of electricity generated from wind in 2011 according to the Danish Energy Agency), Spain, Portugal, and Germany. Such a large-scale development cannot take place in isolation from the market without creating significant challenges for market operations and system operations.

Variability and low-predictability have always been features of power systems, either as a result of demand variation, or due to unexpected power plants outages. Yet, large-scale development of intermittent RES will introduce further variability in power systems. Day-ahead forecast of generation by a single wind-farm typically features 20% errors. Load errors are typically smaller and their evolution easier to predict (Maupas, 2008). There will therefore be a higher need for system flexibility.⁴ Moreover, these higher needs will have to be provided by a smaller number of operating dispatchable units.

There is a wide range of studies concluding that resources flexible enough to ensure smooth operation of power systems exist. A thorough literature review as well as semi-interviews of experts in the United States have been realised by Sovacool (2009). The main conclusion was that there were no technical barriers, but that the main obstacles to large-scale integration of intermittent RES were related to political and practical inertia of the traditional electricity generation system. Some of the technical studies mentioned by Sovacool, such as the one by Gross (2006) do not see any threats to grid stability or the system reliability for large penetration rates (up to 20% electricity generated from intermittent RES). In addition, RES can also provide the required technical flexibility if they receive adequate incentives. In countries with a high share of intermittent RES like Germany or Spain, there are already requirements for fault-ride through capacity, provision of reactive power, frequency and voltage control, and incentives to minimise deviations. The provision of these services is already mandatory in Germany for new power plants, while it is driven by financial incentives in Spain.

The main challenge is thus not a technical but rather an economic one. It is not to find technical solutions, but rather to ensure that stakeholders have the right incentives to develop these technical solutions. As mentioned by Schmalensee (2011), sources of flexibility in operations such as ramping ability need to be more explicitly rewarded.

³ The term “variable” is sometimes considered to describe more accurately the nature of RES behaviour. However, the term “intermittent” is commonly employed and will be used in this paper, referring mainly to wind power and solar power technologies. While these different technologies feature significant differences in terms of ownership, average project size, generation profile, we do not distinguish them in our analysis. Fine-tuning would be necessary when looking at a specific technology but our broad vision should remain pertinent.

⁴ A review of the technical challenges and the corresponding needs are further discussed in the context of the MIT Energy Initiative (2012).

The short-run impact of RES development on prices in European electricity markets is mainly due to the quick transition from an existing set of power plants to a new power system featuring significant excess capacity. This leads to a decrease of old and existing power plants load-factor as described in Sáenz de Miera et al. (2008) and already observed in Spain for instance (Eurelectric, 2011). There are also indirect impacts on prices such as the activation of inflexible take-or-pay gas contracts,⁵ as described by Perez-Arriaga and Batlle (2012).

In this article we follow the approach developed by Cramton and Ockenfels (2011). The strong development of intermittent RES isolated from wholesale market prices will lead to excess capacity, causing stranded costs. However, in our context, compensating existing units is a distributional issue, not an economic efficiency one.⁶ The question is then how to ensure efficiency at every point in time, i.e. an efficient and effective operation and investment in these resources, while achieving the decarbonisation targets at the same time.

While the development of renewables has been fostered in the last decade by support schemes, future renewable investments will occur in a world with little or no subsidies. Hence, we wonder in this article how these investments could take place in a market-driven environment. Yet, another aspect we deal with in our analysis is the implications of a significant development of renewables, both existing supported capacity and future capacity, on programmable units. It is possible to identify two paradigms for integration of intermittent RES. A first solution ('melting-pot') consists in designing an electricity market that could accommodate RES by exposing them to exactly the same rules as dispatchable generators, and remunerating them the same way. However, one can alternatively argue that there are fundamental differences between RES and dispatchable generators and that they should not be treated the same way. A second solution ('salad bowl') would then be to design a market where intermittent RES and dispatchable generators would be coordinated without being exposed to the same rules and with distinct remuneration schemes.

Under both paradigms, an evolution of the electricity market design will be required. The historical choices made when designing the electricity markets were based on supply by large power plants with rather stable and predictable production, following a fluctuating load. Therefore, a change in the physical nature of the power system will necessarily require an evolution of the range of products traded in electricity markets. More fundamental revolutions in the way electricity markets are conceived might also be needed. These evolutions, and potentially revolutions, will be driven by the changes in two dimensions of power systems operations: time-dimension and space-dimension.

A first set of changes will be required to ensure the flexibility needed to manage the variability and low-predictability of RES generation. As generation gets more variable, time-units of electricity products will need to get finer. Moreover, a wider set of reserve products meeting the different flexibility needs will be required. The balancing markets will hence have a more important role to play and their joint operation with forward markets like the day-ahead market will become a key source of efficiency. Finally, energy-only markets might not be sufficient to ensure that flexible back-

⁵ When gas-fired units are exposed to penalties in case they consume less gas than planned initially, the opportunity cost of consuming this gas to generate electricity is reduced, and a lower consumption leads to lower electricity prices.

⁶ It does not mean that the way out of action units get compensated will not have any effect on decisions taken by investors. However, we consider it as a separated issue from the one we focus on in this paper, i.e. ensuring the efficient functioning in the long run of electricity markets featuring a high share of RES.

up units recover their costs and some authors argue that capacity remuneration mechanisms (CRMs) could be needed.

The second set of changes will be needed to cope with the greater variability of locational generation patterns. As for temporal granularity, locational granularity will have to get finer. This could even lead to a drastic shift from a centrally-regulated top-down approach in which the Transmission System Operator (TSO) plays a key-role in ensuring efficient and secure system operations, to a decentralised, bottom-up approach in which an increasing role would be played by local actors such as the Distribution System Operator (DSO) or aggregators.

This article aims to review the different arguments that have been developed recently in key articles dealing with the integration of renewables into power systems and electricity markets. We structure these arguments into relevant blocks of analyses for RES integration. In section 2, we identify two paradigms allowing RES-integration and use these two paradigms as a frame to analyse the main insights developed in previous works by pioneering authors. In section 3, we focus on the evolutions required to ensure that the flexibility needed will be provided efficiently, under both paradigms. The need for a finer set of energy products is analysed in section 3.1. The benefits and challenges of joint operations of a more complex set of reserve products and energy products are reviewed in section 3.2. Finally, the rationale for CRMs is exposed in section 3.3. Section 4 focuses on the evolutions of the market design required to cope with the variability of the locational generation pattern. The benefits of finer space definitions are described in section 4.1 while the drastic shift to a decentralised bottom-up approach is discussed in section 4.2.

2. The two paradigms of RES integration

In liberalised European electricity markets, coordination between participants is driven by price-signals. Yet, under current arrangements, intermittent RES are usually put apart, i.e. kept isolated from signals driving dispatchable production, and treated as inflexible “negative demand”. It is very likely that the signals necessary to ensure efficient operation and investment would then be distorted by a significant development of intermittent RES. In this section, we introduce the two paradigms that build on the literature discussing the challenge of RES integration. In the ‘melting-pot’ paradigm described in section 2.1, intermittent RES and dispatchable generation are integrated under uniform market arrangements. In the ‘salad bowl’ paradigm described in section 2.2, rules are adapted to the specificities of each set of technologies.

2.1. Convergence towards a melting-pot integration

In many European countries, RES are kept out of the market and receive significant revenues from support schemes. The rationale for such schemes is to ensure that decarbonisation targets can be met on time, by allowing a fast deployment of RES until costs are driven low enough to make RES competitive with conventional generation units.

The difficulties currently faced by conventional generators to recover their costs are hence mostly due to the massive introduction of excess generation capacity in an existing power system. What can be observed today is the impact of an unexpected shock on a set of previously existing long-lived assets. The interaction between short-run direct effects and the longer-run indirect effects after adaptation of the generation park is for instance described in analytical studies by Sáenz de Miera et al. (2008), and Keppler and Cometto (2013). On the short-run, reduced electricity prices and residual load (defined as

load minus generation by intermittent RES) predominantly affect technologies with high variable costs such as gas turbines. On the long-run, the evolution of the residual load impacts mostly technologies with high fixed costs such as nuclear power plants.

This might be only a transition phase: once competitiveness of RES will have been achieved, RES could be considered as active units exposed to the same rules as conventional generators. It is the position of the European association of the electric industry (Eurelectric, 2010) to assert that the market will then find a new equilibrium position and the associated prices able to stimulate the needed investments. Some changes might yet have to be made to the present market design. In particular, Eurelectric argues that wind generators should be subject to the same scheduling and balancing obligations as conventional power plants. Similarly, for Perez-Arriaga (2012) the share of wind power is reaching such levels that they cannot be considered as neutral passive units: renewables must operate as other power plants and participate in maintaining power systems stability.

A thorough review of the positive effects of ‘melting-pot’ integration is developed in an analysis of interactions between support schemes and market design realised by Hiroux and Saguan (2010). These benefits include optimal selection of generation sites, improvement of maintenance planning and technology combinations, control of production in extreme cases and higher efficiency of system balancing in general, incentives for innovation, better production forecasts and transparency. As a result, the authors of this study recommended to increase the exposure of intermittent RES to price-signals by adapting support schemes, and to eliminate distorted market signals. Hiroux and Saguan however acknowledged that it might lead to higher risk and higher transaction costs that should be taken into account.

The recent evolution of regulatory frameworks in some countries featuring a significant penetration of intermittent RES already reflects a move towards aligning rules and economic incentives for intermittent RES with the ones for dispatchable generators. RES support schemes have for instance been evolving from feed-in-tariffs to feed-in-premium in Spain (Abbad, 2010), or from FIT and management by TSOs to direct marketing in Germany (Gawel and Purkus, 2013). In both cases the aim was to foster RES integration and to give them a more active role in power systems, through increased participation and exposure to the wholesale electricity markets.

Note that full market integration doesn’t mean that intermittent RES should not receive additional revenues. There might be additional positive externalities justifying such additional remunerations.⁷

2.2. Fundamental differences and salad bowl integration

Even if the costs of generating electricity using intermittent RES get low enough to compete with dispatchable thermal generators, there will still be fundamental differences between non-dispatchable and dispatchable units. On the one hand, intermittent RES have very little incentives not to generate when it is possible, as their marginal cost is zero. A major exception is at times when electricity prices get negative and become low enough to offset any premium received by the RES generator. On the other hand, there is little intermittent RES can do if the resources they are based on are not available. Complementary resources (dispatchable generation units, storage units, or demand reduction) must then provide back-up for RES generation.

⁷ See for instance Borenstein (2011) for a complete discussion of arguments for subsidising RES.

This has led several experts to claim that RES integration should address structural discrepancies between intermittent RES and dispatchable generation and not consider that the issue of RES integration is a transitory one. RES integration should hence follow a ‘salad bowl’ approach, taking into account the specificities of each resource and applying different rules to fundamentally different power units. Three kinds of arguments can be found in the literature: incompatibility between dispatchable units with low variable-costs and energy markets based on marginal pricing, inadequacy of uniform retail pricing to ensure optimal allocation, and inability of RES to react to price signals.

First of all, as put by Finon and Roques (2012), investment in RES, even commercially mature, might not be financially viable if current remuneration mechanisms are removed. They argue that this is a structural fact due to low variable costs leading to lower prices, lower annual load factor, and disappearance of scarcity rents resulting from the high correlation between peak demand and wind power contribution. In addition, this would not only impact the development and revenues of RES but also undermine the case for investments in semi-load technologies. By opposition to the assumptions made by Eurelectric, Finon and Roques conclude that the current market arrangements would not lead to a new equilibrium, in which adequate prices could stimulate the needed investment.

However, this assumption is not really justified on economic grounds: from a theoretical point of view, a new equilibrium could be reached, as for instance concretely described in Sáenz de Miera et al. (2008). Indeed, in the case when, after a transitory phase, intermittent RES become commercially mature (i.e. able to compete with conventional technologies for low load-factors), there will still be a need for back-up flexible units. These resources (for instance generation capacity or demand side management) will be needed at times when intermittent generation is not available to meet load. Prices would then have to be high enough at times of scarcity to cover the fixed costs of these flexible resources, and a new equilibrium would be found between low-carbon intermittent resources and peak or semi-load technologies. We agree that some of the features of this optimal generation mix, such as high uncertainty attached to the low number of running hours, negative prices, or need for high scarcity prices will lead to risks for investors in all kinds of generation technology. However this is not a structural barrier to the long-term coordination of investments by an energy-only market.

A second argument, building on a rigorous economic analysis is provided by Chao (2011) and Ambec and Crampes (2012). Both developed analytical modelling and demonstrated that ex-ante uniform retail pricing does not allow decentralising the energy mix. In the absence of dynamic pricing, in which prices are contingent to the availability of the intermittent source, either cross-subsidies or structural integration within a single company would be required to ensure optimal allocation. Note that if dynamic pricing were to be implemented, a competitive energy-only market would allow market mechanisms to implement the optimal generation mix, while delivering at the same time sufficient revenues to cover the capital costs for the capacity investment. These results seem to contradict the reasoning of Finon and Roques (2012): the main obstacle to a long-term functioning of an energy market would not be the characteristics of intermittent RES but the lack of dynamic pricing.

Finally, some authors employ a third kind of argument and justify salad bowl integration by a reduction of risks and transaction costs, rather than by a fundamental market failure. As pointed out by Klessmann et al. (2008), exposing RES to market signals to which they are not able to react will hinder RES development without bringing any benefits. As wind power producers have high incentives to generate electricity whenever the wind is blowing, it is pointless to expose them to more accurate price-signals. Klessmann et al. distinguished three categories of risks: price risks in forward electricity markets, forecasting and balancing risks, grid connection and system planning risks. In

each case, higher risks will lead to higher capital costs, and more complex schemes will also favour large players.

Battle et al. (2012) also insisted on the fact that there is little efficiency improvement when linking remuneration of RES to wholesale electricity prices, as non-dispatchable generators have no mean to adjust their output. The scope for efficiency gains by planning maintenance at times of low electricity prices will also be quite limited, as availability rates are very high. In their survey about RES integration in Europe, Eclareon (2012) estimated the technical availability factor of wind turbines to 97.5% while it is close to 100% for PV panels.⁸

In addition, Battle et al. explained that exposing RES-E to market prices would create incentives for incumbents owning both conventional and RES generation to abuse their market power. Therefore, they recommend to distinguish non-dispatchable RES from dispatchable RES, and to expose only the latter to price signals.

The nature and the conclusions of these three main arguments are very different. The first point is that a long-term stable market equilibrium could not be found, as a result of the fundamental differences between intermittent RES and dispatchable units. Any kind of melting-pot integration would then be impossible. However, a solid demonstration of this argument, that contradicts more fundamental economic analyses, is missing today. Until then, this argument cannot be included as such in our discussion. The second point emphasizes the need for dynamic retail pricing as a requirement to melting-pot integration, but does not present melting-pot integration as impossible, once such a pricing would be put into place. Similarly the third argument claims that melting-pot integration could be inefficient as it would increase risks for intermittent RES while the prospect for efficiency incentives would remain limited. We can conclude from this section that a rationale for salad-bowl integration instead of melting-pot integration should hence be based on an economic analysis measuring the costs of putting dynamic pricing into place, and of exposing intermittent RES to higher risks. Conversely, such a rationale cannot currently be based on a supposed fundamental inability of energy markets to remunerate generators as the share of intermittent RES increases.

3. Rewarding flexibility under both paradigms

We explained in section 2 that there were two paradigms for RES integration. In the first case, non-dispatchable RES are exposed to the same rules as dispatchable thermal units; in the second case, they are treated differently. Nevertheless, even in case intermittent RES are kept isolated from the electricity markets, the markets will still be impacted by RES.⁹ Hence, independently from the paradigm chosen for intermittent RES integration, the issue of market design remains highly relevant.

European power markets have traditionally been conceived in accordance with the physical properties of conventional units. As intermittent renewables are massively introduced into power systems, current arrangements might not be satisfactory. In this section we follow the footsteps of Green (2008) and Hogan (2010) and wonder whether current market arrangements would still be adapted in

⁸ This impressive figure is due to the fact that there are no moving parts in PV; maintenance mostly consists in cleaning the panels.

⁹ An extreme case is the one in which a large share of RES has full priority of dispatch and receives fixed tariffs. Their production is then considered as inelastic negative demand, but the load factor of thermal units as well as the congestion of transmission lines is still driven by RES production.

a power system with a high share of renewables, as the time perspective of short-term variations gets significantly shorter.

A first issue is whether the definitions (time-units, price boundaries) in place in power markets should be refined to ensure back-up resources operate in a flexible way.

A second issue is whether an evolution of the day-ahead energy market will be sufficient. The rationale for energy-only markets and in particular for a predominant day-ahead energy market must be questioned. Additional components would be needed so that the flexibility required to ensure long-term security of supply can be delivered efficiently. A first option could be to reward flexibility and the ability to produce energy when needed in a complex set of integrated energy and reserve markets. A second (potentially complementary) alternative could be the introduction of Capacity Remuneration Mechanisms, which should be designed to enhance the flexibility of the generation mix.

3.1. Evolution of products exchanged

Exchanges in electricity markets are based on a set of definitions (e.g. temporal and locational definitions). These definitions are based on a trade-off. On the one hand, broader and simpler definitions (e.g. hourly products) enhance liquidity and reduce transaction costs. On the other hand, more accurate definitions (e.g. 5-minute products) allow participants to express better their willingness to pay, as well as their true opportunity cost, for a specific product.

In Europe, simplifications have been introduced with the aim to enhance competition: energy products are for instance typically defined on an hourly basis¹⁰ (See for instance a review of existing definitions in Barquin et al. (2011)). As the share of variable sources of energy in the generation mix increases, the impact of these simplifications gets more significant, and these definitions might need to evolve.

Note that, while this is out of the scope of this article, the need for new definitions could also impact the gas markets, as described by IEA (2012a). Due to the significant role played by gas-fired power plants in renewables integration into the network, the gas market design will have to evolve in parallel to the electricity market design, and new products will have to be defined to meet new flexibility needs (Henriot et al., 2012).

Temporal granularity

As the share of RES increases, variability of electricity generation by intermittent RES becomes the main driver of variations of the net load (defined as load minus generation by non-dispatchable RES). Flexible resources need clear signals to deliver energy when they are needed, and shorter time-unit can deliver these incentives.

A finer temporal granularity of prices is important to provide the appropriate price-signals to investors in flexible resources. Hogan (2010) therefore argued that temporal granularity should match as close as possible real operations. In the lack of market signals accurate enough, such technologies would be either too expensive to operate or would require regulatory support.

¹⁰ 15-minute products have been introduced on the German intraday market in December 2011.

In addition, shorter time-units also contribute to shifting risks from TSOs to Balancing Responsible Parties (Fruent, 2011). Indeed, less differentiated pricing leads to a higher role played by the System Operator and to socialisation of the costs incurred.

However, if the temporal granularity were to be reduced, challenges could arise due to the lack of adequate remuneration for start-up costs in present European energy markets (IEA, 2012b). While such inefficiencies were estimated by Stoft (2002) to be as low as 0.01% of retail electricity costs in conventional electricity markets, these costs might be underestimated when the number of cycling increases (Troy, 2011). This might become an issue for shorter time-frames: if the whole start-up costs have to be internalised in a single energy bid, it is clear that the shorter the time-period, the higher the impact will be on electricity prices. For instance, internalising start-up costs in a 5-minute energy bid would result in a price increase that would be 12 times higher than for a one-hour energy bid.

“Block orders” have been put into place in most electricity markets to deal with non-convexities of power-plant production cost and allow participants to express the complementarities between the different production horizons. However computation time and complexity for participants might become an issue in a system featuring a high number of smaller time-periods with many different complex bids.¹¹ Borggreffe and Neuhoff (2011) also pointed out that block bids can prove quite efficient as long as it is relatively easy to identify block of hours for which demand will be higher. As the pattern of residual load becomes more complex, block bidding will also prove increasingly challenging.

Price boundaries

Electricity markets typically feature price limits introduced by regulators to protect consumers against overcharging, in a context of low demand-elasticity. As the profile of the load served by dispatchable generators evolves, more differentiated price-signals are needed to remunerate the flexible resources necessary to operate the power system safely.

Indeed, as a consequence of an increasing penetration of intermittent renewables, operations by power generation units will become more variable, and some peaking units will be needed to run only a few hours a year. Price-caps should then be high enough to allow these peaking units to recover their fixed costs over these running hours. Note that in theory, price-caps are put into place to compensate for the lack of demand-response and should be set as equal to the value of lost load (VOLL) for consumers. As the VOLL is not affected by renewables, price-caps should in theory remain identical. Yet in practice, the VOLL is difficult to estimate and price caps are very different among power systems with similar consumer preferences.¹² According to Eurelectric (2010), low price-caps constitute artificial limits that limit the scarcity-price signals, and undermine the long-term investment prospects in new generation.

¹¹ In a system featuring 24 one-hour products, the number of possible consecutive block orders within a day is 300, and computation time then remains limited (Meeus et al., 2009). In a system featuring 288 5-minute products, the number of consecutive blocks within a day is a much more significant set of 41616 combinations.

¹² In Spain OMEL has a cap of €180.30/MWh, in Denmark ELSPOT has a cap of €2000/MWh, the German market has a cap of €3000/MWh. A literature survey of estimates for VOLL was conducted by Cramton (2000) who determined that estimates ranged from \$2,000/MWh to \$20,000/MWh.

Negative prices can appear in electricity markets even without intermittent generation, due to non-convexities of power plant generation costs. However, the introduction of a large quantity of intermittent generation capacity with low marginal costs and benefiting from premiums, will naturally lead to a higher occurrence of negative prices. The floor for negative prices is very different in electricity markets like Spain (No negative prices), Denmark (-200€/MWh as in the rest of the Nordpool area), or Germany (-3000 €/MWh as in the rest of the CWE area). The extent to which these limits should be extended is unclear, but some of the current floors seem to be too low, as they are often reached in the markets already featuring a relatively high share of intermittent RES. Zero-prices happened during 300 hours in 2010 in Spain, while a study of the German market by Nicolosi (2010) revealed that even at times of extremely negative prices of -500 €/MWh, the total capacity had an utilisation rate of 46%.

Note that this issue becomes more complex when taking into account cross-border exchanges of electricity. As pointed out by Eurelectric (2010), the lack of common market rules regarding negative prices will lead to distortions when joining offers of energy in zones with different price boundaries.

3.2. The move towards a single platform from day-ahead to real-time

The growing importance of balancing markets

Liberalised electricity markets have been designed to substitute a command-and control system in which the unit-commitment problem and the optimal dispatch problem were centrally solved by vertically integrated entities (Saguan, 2007). In addition to a set of long-term future markets, they typically feature a two-settlement system similar to the one described by Stoft (2002): most of the centralised trades take place in the day-ahead market (when a unit-commitment problem is solved by participants), and deviations from the day-ahead market must be solved in the real-time balancing market (when the problem of optimal dispatch is solved).

However, the key-role played by the day-ahead market in such a market architecture does not match the needs of intermittent RES: forecasts of wind power production indeed improve significantly from day-ahead to real-time (von Roon and Wagner, 2009). Intraday markets that give stakeholders an opportunity to trade after the day-ahead gate-closure, and real-time balancing markets, should therefore gain in importance as the share of intermittent RES increases. Joint provision of energy and balancing services is for instance highlighted in Borggrefe and Neuhoff (2011) as key to handle efficiently wind intermittency.

Cramton and Ockenfels (2011) accordingly argue that well-designed power reserve markets interlinked with each other through arbitrage can ensure recovery of fixed costs for back-up generation and, more generally speaking, long-term efficient exit and entry decisions. Prices in the reserve markets will get higher than prices in the day-ahead market in case of higher scarcity of flexible power plants compared to power plants requiring a day-ahead notification, therefore delivering the right investment signals (Barth et al., 2008).

However the reserves portfolio must then be adapted to the needs of a power system dominated by renewables. In addition to integration of balancing and intraday markets, products such as reserve that is less-flexible but available for longer-time periods¹³ should be put into place. A study by the IEA

¹³ As pointed out by Perez-Arriaga (2012) one of the worst scenarios for the system reliability is a long generation dip associated to one-week anticyclone, occurring at times of high demand.

(2012b) also argues that forward markets for adequate balancing services would help market participants to take investment decisions.

Ensuring inter-temporal consistency

Smeers as well as Borggreffe and Neuhoff criticize the multiple arrangements governing the organisation of day-ahead, intraday and balancing markets. For Smeers (2008), a single trading platform should be put into place, with continuous active trading from day-ahead to real-time.

Components currently missing include intra-day markets for reserve capacities, and the integration of congestion management with the intra-day markets and ancillary services markets. When transmission capacity is priced in the day-ahead market but is free in the intraday market, distortions are created that shatter the inter-temporal consistency between the different trading spaces.

Other distortions can hinder the financial links between the forward markets (i.e. Day-ahead and Intraday markets) and the balancing arrangements. Vandezande et al. (2010) described how the existence of asymmetric penalties in some balancing mechanisms would penalise wind producers and generate incentives to under-nominate injections in the forward electricity markets, leading to higher total system costs. Similarly, De Vos et al. (2011) pointed out that putting a cap on imbalance tariffs would “[violate] the link between the reserve market and the imbalance tariff” and thus endanger the well-functioning of balancing markets. As a consequence, the definitions and boundaries mentioned in section 3.1 should be applied similarly in the full sequence of markets.

Note that all the products aiming to deliver energy at given production time are substitutes. The more products defined, the lower the liquidity might get for these products. Liquidity remains for instance quite low in the intraday markets put into place in Europe, which could be explained by their inadequacy to the real needs of stakeholders, and the complexity for these players to realise arbitrage (Weber, 2010). This is why the IEA (2012b) warned that the definition of too many flexibility products could create issues of market liquidity and market power, and claimed that the number of products defined should remain limited.

The need to clear both simultaneously and sequentially a complex set of related markets could justify joint optimisation by a system operator. Green (2008) for instance advocates integration of energy and ancillary services, as it is often the case in the United States. It is then possible to take into account efficiently the different technical constraints and manage the different substitutes in a single optimisation program, without increasing the complexity for participants. The efficiency gains achieved would get more significant in an electricity system featuring a higher share of intermittent RES, in which a greater role must be played by reserves. Similarly, Borggreffe and Neuhoff (2011) favour pool type trading arrangements to ensure efficient provision of energy and balancing services. This would solve the lack of consistency resulting from a separation between balancing services that are typically acquired by the TSOs, and energy products in day-ahead and intraday markets, that are exchanged either on power exchange or bilaterally. Borggreffe and Neuhoff add that a fully bilateral market would hardly be compatible with a complex set of substitute markets.

RES participation under the melting-pot paradigm

If the melting-pot paradigm is adopted, and if reserve markets play a significant role, RES should be able to participate into the full sequence of markets for the different products, as suggested by the IEA (2012b). It is indeed possible for wind and solar generators to provide ramp down services by curtailing production when needed, but also ramp up services by operating at fixed level below

available output. Note that the melting-pot paradigm does not require the participation of RES into balancing markets, and that it could even prove costly to constrain intermittent RES to manage their production actively (Henriot, 2014). RES can for instance also be exposed to balancing costs without taking part into reserve markets.

3.3. Introduction of Capacity Remuneration Mechanisms

Impact of intermittent RES on the rationale for Capacity remuneration

The large-scale deployment of out-of-market intermittent RES has raised concerns that dispatchable power plants used as a back-up might not recover their investment costs. According to the European association of the electricity industry Eurelectric (2011), there are two main drivers for an increasing “missing-money” problem: lower load-factor for conventional power plants, associated to increasing uncertainty surrounding potentially lower¹⁴ prices.

Some of the arguments traditionally used to justify the need for a capacity remuneration mechanism (CRM) will indeed gain strength as the penetration of intermittent RES gets more significant. In addition to the lack of demand-response, part of the supply-side will also get less responsive as intermittent RES have incentives to generate as much energy as possible. The need for high scarcity prices will increase, and the limits imposed by price-caps will hence have a higher impact. Finally the policy-driven developments currently taking place will add further uncertainty for producers.

As a result, policymakers might have to consider introducing a CRM to ensure generation adequacy. Note that in their study of the rationale for the introduction of CRM, the members of Eurelectric remain however quite circumspect: priorities should be to remove distortions such as price-caps, ensure demand participation, and enhance market integration. CRMs would then be introduced only if long-term security of supply were still threatened despite the previous improvements. Furthermore, these CRMs should be designed as a temporary mechanism to be phased-out once the market would be able to deliver the investment incentives needed.

For Finon and Roques (2012), as mentioned in section 2.2, there is not only a transitory need for a CRM, but also a structural one: even when RES become competitive, a market-wide capacity mechanism would be needed to ensure investment in all reliable capacities.

Note that while there are many reforms considering the introduction of CRMs in Europe, some of the designs taken into consideration have little to do with the ability of resources to generate electricity in a flexible way. Cramton and Ockenfels (2011) caution that CRMs should not be designed to compensate the stranded costs of existing producers, at times of transition to a system with a large-share of renewables. Wrong instruments risk to introduce distortions and to reduce market efficiency. The priority should then be to ensure that proper locational pricing and an appropriate design of reserve power markets are put into place.

Design under both paradigms

The design of a Capacity Remuneration Mechanism has been the subject of an extensive amount of literature (Batlle and Pérez-Arriaga, 2008; Cramton and Ockenfels, 2011; Joskow, 2008), and is not at

¹⁴ As described by Perez-Arriaga & Batlle (2012), the impact on average prices might still be quite modest in some power systems with a rather flat bidding curve.

the core of this article. However, it is interesting to look at how a CRM could be designed following either the ‘melting-pot’ paradigm or the ‘salad-bowl’ paradigm.

Under the melting-pot paradigm, all resources (including intermittent RES) would be allowed to bid for capacity. Finon and Roques explain that a single tool could then be developed to promote both investments in RES and generation adequacy, e.g. a market-wide capacity forward auctioning. There are however serious obstacles to the participation of intermittent RES into a CRM, as these resources are by nature not available all the time. Estimating their capacity factor, or the value of their contribution to the system reliability, is therefore a complex task (Perez-Arriaga, 2012). Moreover, in a system in which the need for back-up would be driven by the availability of intermittent RES, these resources would not be available at times when most needed and would be exposed to severe penalties. In PJM for instance, intermittent RES participation is limited and they only receive less than 1% of the CRM revenues.

Under the salad-bowl paradigm, intermittent RES would be kept out of a CRM designed to provide additional remuneration to back-up dispatchable units. However, the development of RES would not be without having an impact on the design of this mechanism. Capacity has little to do with the ability to produce energy in a flexible way.¹⁵ As the penetration of intermittent renewables increases, the need for flexible resources gets higher. The CRM must then reflect the need for specific resources with adequate operational capabilities. As put by Gottstein and Skillings (2012), it is not only about helping investors to choose whether to invest but also what to build. While generators were previously asked to be available at times of peak demand, they would then be needed at less predictable times of high residual load. They should also be able to cope with more challenging ramping requirements and a range of adequate products might have to be defined.

4. Redefining space: what geographical scale for large-scale integration?

By opposition to larger conventional thermal power plants, RES are often connected at the distribution grid level. Besides, the network flows will get more variable as the generation by power plants (and thus the location where electricity is generated) gets variable. This situation is already quite challenging in Germany, where most of the best wind resources are located in the North while load centres are located in the South. As the congestion patterns get more complex, it will be necessary to refine the locational granularity. In addition, an increasing share of the system operations might have to take place at a distribution level.

4.1. Locational granularity

Most authors seem to agree on the necessity of more accurate locational signals in a context of a large-scale development of intermittent renewables (Green, 2008; Hogan, 2010; Smeers, 2008).

The first reason is that the best locations for wind farms are often far from load centres. As a result there will be a need for further transmission investments. In the Ten-Year Network Development Plan developed by the association of European Electricity TSOs ENTSO-E, 80% of the new projects are needed to solve bottlenecks created by RES (ENTSO-E, 2012). Barth et al. (2008) argue that, as

¹⁵ This is for instance particularly blatant in the case of the CRM put into place in the PJM electricity market, where coal-fired power plants with 48-hour notice requirements receive the same reward as fast-responsive plants (Gottstein & Schwartz, 2010).

finding a compromise between locations with good resources and locations with low connection costs becomes increasingly relevant, efficient signals should be provided to investors. Green (2008) also claimed that the greater need to avoid high-cost locations is a strong argument in favour of locational pricing.

The second fundamental argument in favour of nodal pricing is the impossibility to clearly define zones that would reflect physical realities at all times. As the generation by intermittent resources keeps evolving, the congestion patterns will evolve constantly, and nodal pricing seems to be the only option able to match reality at all times (Borggrefe and Neuhoff, 2011). Note that it is not only an issue of allocating domestic transmission capacity allocation but also of allocating cross-border capacity. Smeers (2008) for instance argued that the simplifications introduced to couple markets in the Central Western Europe area would backfire with the growth of wind power. Borggrefe and Neuhoff also insisted on the necessity to enhance trade between regions. They identified two potential solutions: integration within a single nodal pricing region, or coordination of nodal pricing in adjacent systems.

For consistency purpose, the locational granularity should then be the same for the forward markets (e.g. day-ahead) and the balancing markets. A fully functional market for locational reserves would then be needed (Baldick et al., 2005).

While the shift from zonal pricing to nodal pricing would create winners and losers among the existing network users and might therefore be politically challenging, ways could be found to compensate losers while conserving incentives to respond to locational prices (Green, 2008; Newbery and Neuhoff, 2008).

In the absence of locational energy pricing, locational transmission tariffs or deep connection charges could be used (Barth et al., 2008). However, deep connection charges would only deliver locational incentives at times of investment, and might not be adapted in case of fluctuating congestion patterns. Nevertheless, under a salad bowl paradigm, considering that intermittent RES have little incentives not to produce when available, deep connection charges could be employed to deliver long-term incentives to RES developers, while dispatchable units would be exposed to short-term signals. Note that the calculations of deep connection charges can prove to be quite complicated, and that this complexity would only increase as the generation geographical patterns gets more fluctuating.

4.2. The shift to local markets and active distribution system operators

Two potentially conflicting alternatives are generally considered in the literature in order to cope with variable generation by geographically dispersed RES. On the one hand, some authors advocate the extension of the historical centralistic production paradigm to a continental scale. It requires significant investments in the transmission network and harmonisation of trading rules, in order to build an integrated European market and pool together resources with distinct and uncorrelated generation patterns. On the other hand, it is sometimes argued that massive injection of energy at the distribution grid level requires handling these injections at a local scale. While there are many uncertainties regarding the implementation of the latter option, it is also unclear to what extent the historical paradigm could be extended and applied to very different generation means as such.

Extending the historical centralistic production paradigm

Under this extension of the historical paradigm, that is sometimes referred to as a ‘super grid’, power systems are built around large power units, which could also include renewables such as large off-shore wind farms. Generation is adjusted to meet an inelastic demand. Load centres are connected to generating units through cross-continental transmission lines, and the system is optimised at continental scale as producers take part into integrated European electricity markets. RES integration is made easier as the production of intermittent RES at the system-scale is smoother thanks to the geographical spread of renewables with less correlated output (Holttinen et al., 2009).

Note that this paradigm is compatible with an active participation of intermittent RES in electricity markets. Local distributed generation units can be managed by aggregators that then act as centrally-managed virtual large power plants.

A new paradigm based on local management by real Distribution “System Operators”

The vision of a fully integrated power system might not fit the present evolutions of the generation-side. As fluctuations of the production lead to more variable flows, the costs of maintaining a copperplate will get significant, and TSOs might not be able to cope with them (Henriot, 2013). There will then be challenges related to the increasing complexity of markets and zonal definition that would be required to handle the variations of the generation patterns, as described in the previous section.

In addition, most PV and onshore wind plants are fed at the distribution grid level, and the strongest effects of distributed generation are felt in local grids (KEMA, 2011). Voltage control is for instance mostly a local problem. The equilibrium between injection and withdrawals has traditionally been managed at a transmission grid level, with products defined on a large geographical scale. As congestion will increasingly occur at the distribution grid level, balancing will also have to be ensured on a more local scale.

These considerations lead to a more bottom-up approach, in which an increasing role would be played by DSOs, and partially self-supplying consumers (“prosumers”) optimise their consumption and production. New ancillary services would be provided by distributed intermittent RES at DSO level, through local organised markets or bilateral agreements (Cossent et al., 2011). The transmission grid would become a flexibility resource while most of the efforts to maintain system stability and balance supply and demand would be ensured at a local level by the DSOs. Note that this implies a considerable evolution of the role played by DSOs, including monitoring, control and operation, traditionally done by the TSOs. It would also require a major evolution of the regulatory framework, as detailed in the study by Pérez Arriaga et al. (2013).

5. Conclusion

This study focused on the economic efficiency challenges associated to the penetration of a large share of intermittent RES into present European electricity markets.

We first identified the two main paradigms for RES integration that can be found in the literature. Proponents of a melting-pot integration argue that, after a transition phase, common rules should be applied to intermittent RES and dispatchable generators. Conversely, supporters of salad-bowl integration claim that the differences between these two categories of generators should be taken into account, and special measures put into place to accommodate intermittent RES differently. It comes out from our literature review that the choice of one of these paradigms should be based on a trade-off

between lower transaction costs and higher incentives for generators to operate efficiently. In particular, there is no clear fundamental reason why melting-pot integration could not function as such: it is only a matter of costs associated to a higher complexity.

Under both paradigms, an evolution of the market design will be required to reflect the value of the flexibility required to integrate intermittent RES. There is a consensus in the literature for new definitions: finer temporal granularity and wider price boundaries will be needed to give plants an incentive to operate in a flexible way. However, the consequences of these measures are seldom taken into consideration. For instance, in the lack of an adequate and complex set of block-order products, higher start-up costs will then have to be internalised into energy products with shorter time-periods. Energy prices could then be impacted significantly.

Similarly, joint operation of a wide range of balancing markets and forward markets would help handling efficiently RES intermittency. However, inter-temporal consistency will then be required to avoid distortions, and complex transactions will have to be realised by participants.

Finally, the introduction of CRM to handle wind intermittency is often considered as an unnecessary additional layer of complexity. Delivering the flexibility required while remaining consistent with the finer definitions of energy products could be a highly tortuous process.

The penetration of a large share of geographically scattered and smaller intermittent power units will also require a new approach towards space and locational signals. The value of flexibility must be reflected at a local level. Locational granularity will need to get fine enough to manage efficiently fluctuating congestion patterns at the distribution grid level and there are strong arguments for a switch to nodal pricing.

At last, there are huge discussions around the historical production paradigm based on a transmission grid connecting large generators to load centres. Significant investments are planned in the transmission grid, in order to transfer energy from scattered geographical areas with an uncorrelated energy production by intermittent RES. However there is an increasing number of issues occurring at the local level, and a redistribution of roles between TSOs and DSOs could be needed.

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