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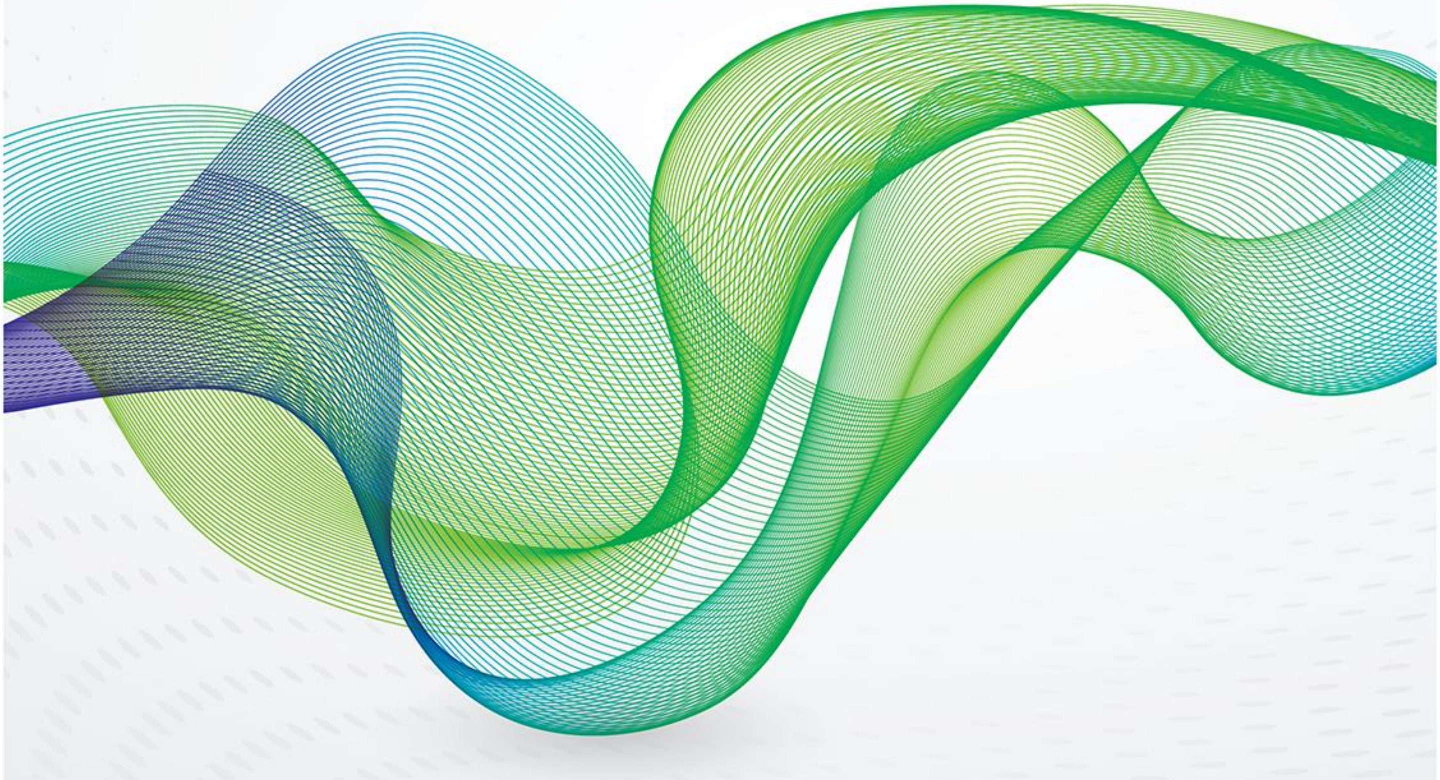

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Electricity market design for a decarbonised future: An integrated approach

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Abstract

In recent years, the debate on electricity market design in the EU has focused on the fitness-for-purpose of the existing dominant design, the appropriateness of energy policy that underpins the existing market design, and on the process through which energy policy is coordinated with market design. In this paper, we contribute to this debate on all three levels. First, we propose a 'module-and-level'-based framework to illustrate our diagnosis of coordination issues present in the EU's power markets. We apply this framework to make a systematic identification of existing misalignments between the components of current market design and physical RES integration/financial RES support schemes. Secondly, we argue that the role of energy policy is not just in managing existing trade-offs between competitiveness, sustainability, and reliability, but also in encouraging innovations that increase the compatibility of energy policy objectives in the future. Finally, we propose a seven-step condition-dependent evolution of power market design, where the government/regulatory authority plays the role of meta-coordinator, matching the adaptation of market-based coordination modules with a hybrid future where distributed energy resources coexist with centralised generation, while decentralised market participants trade with each other and with incumbents.

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1. Introduction

By 2030, power generation from Renewable Energy Sources (RES) is expected to account for up to 50 per cent of the European Union's overall power supply, as the power sector continues to be at the centre of the EU's decarbonisation policies (European Commission, 2015). By 2050, power generation in Europe is expected to be fully decarbonised and electrification is planned to shoulder at least part of the energy demand related to transport and heating/cooling. At that point, the share of RES could range from 64 per cent to 97 per cent of overall power generation (European Commission, 2012), depending on the uptake of some of the more controversial low-carbon technologies such as nuclear energy and carbon capture and storage (CCS). So far, various nationally determined RES support schemes – such as feed-in tariffs and renewable obligations – have been the most important force enabling the rise in RES generation, of which a significant share is embedded at the distribution level. But in the long run, it is expected that investment in new renewable energy capacity will be exclusively market driven, as increasing deployment drives down cost and social barriers.

Already, the growing share of variable RES generation in the power system is introducing strains into the common design of European power markets. The original blueprint, dating from the period of power sector liberalisation and designed for a world of large-scale centralised thermal generating plants, is no longer providing effective signals to an increasingly diverse mix of market participants to enable efficient operation and investment. Internal market integration, the goal that was initially pursued by European power and gas market liberalisation from the 1990s onwards, must now co-exist with other new goals such as security of supply and emission reductions, in European energy policy. Competition must in any case be preserved as much as possible, to reduce the costs of achieving other energy policy goals.

The European Commission, industry representatives, regulators, and observers all recognise the necessity of a new market design, but the debate over which new design to adopt is far from consensual: some focus on decreasing the cost of RES deployment through competition for long-term contracts, some extol the virtues of engaging historically passive demand for system balancing, and some call for a stronger regional approach to market design and policy making. How should we think about such seemingly eclectic proposals? How should we approach the problem of electricity market design given the complexity of electricity markets and their interdependence with other government energy policies? We contend that the answer to these questions is to be found through holistic integrated thinking that seeks to understand and align both *horizontal* relationships among coordination modules of broadly defined market design (from wholesale market, retail market, market coupling, to network regulation), and *vertical* relationships among levels of coordination in the power sector (from macro-level policy making, to the micro-level design of policy instruments and markets).

In this paper, we contribute to the ongoing debate about power market designs and their 'fitness-for-purpose' by proposing an adaptive approach to market design within the context of the European Union and its dynamic energy policy. Unlike proposals that champion revolutionary re-design of the power market, our recommendations, informed by system thinking, are based on evolutionary changes. This type of change is desirable because the operations of the power market need to be maintained while reform is taking place, while incremental adaptation also is more appropriate when designing for complex socio-technical systems (Norman & Stappers, 2015).

In Section 2, we review the prominent positions within this debate. We then devise a holistic framework that allows us to diagnose the many misalignments between the modules and levels of existing electricity market design in Section 3. Combining the partial and non-exclusive solutions (reviewed in Section 2) so that they collectively address the misalignments identified in Section 3, we arrive at an adaptive approach in Section 4 that incrementally aligns the design of multiple market modules. ***We then demonstrate how such a design approach can addresses uncertainties in technology development and consumer preference within the European governance landscape.*** Because the landscape in which electricity market design takes place is always changing, the paper also includes an Appendix in which we scan the horizons for possible future developments of technology and consumer preference that may further challenge or provide opportunities for electricity market design in Europe.

2. Review of state of the debate

The European Union (and several Member States such as Denmark, Germany, Italy, and Spain in particular), is at the forefront of the physical integration of renewable energy into the power system. As the shares of power from RES become important, and technological advances continue to lower the development costs of these facilities, the EU is starting to grapple with the commercial integration of renewable energy sources both at higher voltage levels and in customer premises.

Previous studies have identified four areas as providing the scope for regulatory actions to facilitate power sector decarbonisation (Cochran et al., 2013; Miller & Cox, 2014; Shah et al., 2016; Zinamen et al., 2015). These areas are:

(i) RES support mechanisms,
(ii) Grid infrastructure regulation,
(iii) Long-term resource adequacy,
(iv) Short-term operational security.

In the past, the focus of regulatory action was on de-risking renewables. However, as the share of RES generation in the system grows and these technologies become more competitive, regulatory concern should increasingly expand from a narrow focus on sheltering RES investment from market risks in a system when most of the generation fleet is conventional, to addressing all the consequences of having a generation fleet where most of the generation is RES, with almost zero marginal costs.

In this section, we first provide contextual information on European energy policy and the EU's governance framework for regulation of the power sector. Then, we present a number of perspectives on the inadequacies of many existing power market design features common in EU countries and also, if applicable, of European energy policy and governance.

2.1 The European context

Between the adoption of the EU's first liberalisation directives in 1996 and the adoption of the 3rd Energy Package in 2009, the EU's policy priority for the power sector was focused on incrementally delivering the Internal Energy Market through unbundling and liberalisation (Glachant, 2016). However, by the beginning of the 21st century, new concerns such as sustainability and security of supply entered the European policy agenda; these were triggered both by external circumstances (the 2003 Italy blackout and the 2006–9 Russia–Ukraine gas disputes) and the changing relevance of previously ignored market externalities (such as carbon emissions). The world economic and Eurozone crises have added to the complexity and, in parallel, have increased scrutiny on the implications of energy policy on both affordability to customers and industrial competitiveness (Helm, 2014; Roques, 2014a). The confluence of these policy objectives (addressing climate change, security of supply, and affordability/competitiveness) is commonly referred to as the energy policy trilemma.

Analysis of energy policy in the European Union is further complicated by a multi-level governance of energy. Before 2010, the European Community did not have formal competence in energy, but was able to legislate on matters affecting the energy sector of Member States through linking them to the development of the Single European Market and the environment. But, with the Lisbon Treaty coming into force in 2009, energy became an area in which the EU and Member States have shared competences. According to the Lisbon Treaty: European Institutions shall engage in measures that ensure the functioning of the energy market; ensure security of energy supply in the Union; promote energy efficiency and renewable energy; and promote the interconnection of energy networks. However, Member States maintain the right to determine the conditions for exploiting their energy resources, their choices between different energy sources, and the general structure of their energy supply.

Not only has the relative weighting of the energy trilemma objectives changed over time at the European level, Member States also have diverging views of their relative importance and the most appropriate instruments for achieving the desired outcomes (Szulecki, Fischer, Gullberg, & Sartor, 2016). Nevertheless, new policy concerns embodied by the trilemma culminated in the EU's adoption of the 2009 Climate and Energy Package; this provides a set of binding targets on greenhouse gas emissions, EU energy from renewables, and improvements in energy efficiency for the year 2020. Meanwhile, the continuing march to establish the Internal Energy Market led to the promulgation of the 3rd Energy Package in the same year. Developed relatively independently at this stage, the two streams of policy concerns (trilemma – objective-oriented; market integration – process-oriented) eventually collided.

The 2009 Climate and Energy Package (Directives on Emission Trading, Renewables, and Energy Efficiency) mainly relies on directives, setting binding national RES targets for Member States which are to be achieved through national planning.[1] In 2015, an estimated 16.4 per cent of the EU's gross final energy consumption was supplied by RES. In the power sector, the share of RES is higher at 28.3 per cent (European Commission, 2017). In comparison, the 3rd Energy Package contains directives on unbundling as well as regulations that directly establish conditions for network access. By 2013 a Power Target Model, the blueprint for regional market integration projects, had emerged.[2] But the fitness-for-purpose of this newly minted Target Model has already been called into question, for it neglected development that took place under the 2009 Climate and Energy Package – more specifically, the rapid rise of RES (Keay, 2013). Table 1 shows that the Target Model design is solely concerned with short-term wholesale market coordination over zones, but is silent over other aspects of power market coordination. (By 'long-term', we refer to factors/issues influencing investment decisions, and 'short-term', to those influencing operational decisions.)

Table 1: Key features of the Power Target Model (Based on Glachant, 2016).

Module	Long-term coordination	Short-term coordination
Wholesale	N/A	▪ *Geographic power flow represented as zonal* ▪ *Bids in day-ahead markets are coupled across zones. An optimisation model is used to allocate the available cross-border transmission capacity to minimise the price difference between zones* ▪ *Any balancing or congestion management that remains to be carried out is managed by individual TSOs using resources available to them*
Network	N/A	
Retail	N/A	N/A

[1] The subsidiarity of European policy is codified through two types of legal instruments: directives which stipulate goals and general principles, to be transposed to national laws by Member States, with subsequent monitoring and evaluation by the European Commission; and regulations which are directly applicable to Member States after coming into force.

[2] The 3rd Energy Package establishes two new European bodies – the Agency for the Cooperation of Energy Regulators (ACER) and the European Network for Transmission System Operators for Electricity (ENTSO-E) – both of which play instrumental roles. Network codes jointly produced by ENTSO-E and ACER, once they pass through the comitology process, form the basis of the Power Target Model.

In October 2014, in preparation for the 2015 Paris UNFCCC summit, the European Council agreed on the 2030 climate and energy framework which, in continuation of the 2009 Climate and Energy Package, aims to deliver further decarbonisation while addressing affordability/competitiveness and security of supply concerns. Unlike the 2020 goals (in the 2009 Climate and Energy Package), nationally binding renewable energy targets were not set, allowing Member States greater flexibility to choose policies that are best matched with their preferences.[3] Nevertheless, national policies are required to be compatible with EU-level decarbonisation objectives and competition in a more integrated energy market (European Commission, 2014).[4]

In February 2015, the European Commission published its framework strategy for an energy union with a forward-looking climate change policy. The core focus of the framework is energy security (of gas especially, but also power), to be addressed mainly through improved coordination through the Internal Energy Market, but it also includes proposals to redesign the power market.

Five months later, a set of legislative proposals was published (known as the 'summer package'); this included a communication that outlined the European Commission's vision for a new market design, and also launched a public consultation on the elements presented. The vision set forth in the communication not only advocates for more cross-border integration of electricity markets, but also for more regional coordination in market design/policy making and in the setting of system reliability standards.

In November 2016, the summer package was followed by another set of legislative proposals (known as the 'winter package'), which contained proposals to amend existing energy market and climate change legislation. Overall, the changes proposed embodied increased horizontal integration among Member States (in market transactions and in regulatory/industry cooperation), and increased the vertical integration of wholesale and retail markets (via demand participation and cooperation between TSOs and DSOs) (see Table 2).

Table 2: Market design changes proposed within the winter package

Module	Long-term coordination	Short-term coordination
Wholesale	• *Remove wholesale price cap*	• *Increase flexibility and responsiveness of short-term markets* • *Remove priority dispatch for mature renewable installations* • *Remuneration of demand for flexibility services*
Network	• *Reinvestment of congestion revenue into transmission grid*	• *Regional cooperation of system operation*
Retail	• *Consumer to have access to certified energy comparison tool* • *Switching-related charges are prohibited* • *EU DSO entity to be created to guide cooperation with TSOs*	• *Consumers to be provided with clear electricity bills* • *Consumers entitled to smart meters* • *Dynamic electricity price contracts to be available* • *Consumers able to offer demand directly or through aggregators* • *DSOs to improve efficiency of own operations*

[3] GHG reduction targets in non-ETS sectors are allocated as binding targets to Member States on the basis of relative wealth (GDP per capita), in the Effort Sharing Regulation. The target for energy efficiency remains non-binding.
[4] To achieve coordination between national energy policies and EU-level targets, national plans are prepared according to the guidelines set forth by the Commission, with consultation between neighbouring countries, and reviewed by the Commission to determine their adequacy (followed by revision if deemed insufficient). Further EU action/instruments are put into place only if necessary.

2.2 Perspectives on market design and beyond

Most of the perspectives reviewed for this paper were published between 2013 and 2016 – between the announcement of the Power Target Model and the publication of the winter package. Many of them criticise existing market design (a hybrid of the Power Target Model and RES-supporting national policy instruments) for its inability to accommodate the growing quantity of RES being deployed across Europe. The view of the problem was far from being consensual, as was the corresponding range of proposals. A key contention existed around the necessity of capacity remuneration mechanisms (CRM) and the adequacy of energy-only markets (namely markets without CRM). There is also another stream of commentaries, which extends beyond identifying problems with market designs, and criticises ill-defined energy policy objectives, myopic narrow-scoped policy making process, and the resulting unexpected interactions between policy instruments. Finally, some observers discuss the intersection of policy making and power market design: what policy making approach could better anchor the design of electricity markets?

2.2.1 The existing market design is broken

Keay (2016) argues that the energy-only market dominated designs currently in use fail to trigger investment for conventional generation technologies and cannot be relied upon to trigger mature RES generation technologies, even when they become cost-competitive with conventional generation. He also argues that marginal cost-based price formation in energy-only markets has little relevance for RES generation technologies, given that what distinguishes renewable generating plants from each other is their location and ability to provide flexibility/balancing services, rather than their marginal costs (all close to zero). Additionally, he finds fault with the neglect of demand-side provision of flexibility and the narrow scope of out-of-market RES support and CRM. A wide range of market designs is presented for discussion in his paper. Bracketing the spectrum of designs surveyed are: 1) abandoning market-based coordination and returning to centralised government-based coordination; 2) market transaction-based coordination across energy and capacity, wholesale and retail markets, informed by an underlying market-based carbon price. The other options presented are rather uneven in terms of coordination aspects covered (See Table 3).

Table 3: Summary of market design solutions surveyed in Keay (2016)

Proposal	Module	Long-term coordination	Short-term coordination
Central planning and control	Wholesale	Under control of government/other central authority	Under control of government/other central authority
	Retail	*Not specified*	*Not specified*
Investment market	Wholesale	Competition for long-term contract	Competition for balancing service
	Retail	*Not specified*	*Not specified*
Introduce a capacity element into pricing	Wholesale	Replace production-based RES support with capacity-based subsidies	*Not specified*
	Retail	Introduce a larger capacity-based element into retail tariff	
Remove support for RES energy generation	Wholesale	Remove RES support	*Not specified*
	Retail	*Not specified*	*Not specified*
Refine energy-only markets	Wholesale	Introduce capacity mechanisms	Improve balancing markets
	Retail	*Not specified*	*Not specified*

The two-market solution[5]	Wholesale	Generator decision between 'on demand' or 'as available' (choosing to be balanced or to be balancing) Subsidy to 'as available' if necessary	'As available' generators not responsive 'On demand' generators respond to demand
	Retail	Consumer decision between 'as available' power and 'on demand' power Subsidy to 'as available' group through lowered appliance cost	Consumer in 'as available' market nominates appliances to react to power availability 'On demand' consumers not responsive
Transactive pricing	Wholesale and retail merged	Forward trading of energy and transmission (interpreted as capacity) products Subscription possible	Parallel spot trading of energy and transmission (interpreted as capacity) products Hedging possible

Genoese and Egenhofer (2015) collected the views of a broad range of stakeholders and came to the conclusion that the major failing of existing design was in the triggering of investment. Currently, the low marginal cost and intermittent nature of RES generation leads to reduction and increased uncertainty for the energy market revenues of conventional baseload and peaking generation technologies, disincentivising investment. The stakeholders consulted agreed that continued modifications to the short-term energy market (improving scarcity pricing across day-ahead, intraday, and balancing markets; extending coupling to the intraday and balancing markets; and exposing RES generators to balancing responsibilities) would improve revenue prospects for conventional generation by capturing the value of flexibility, thereby facilitating market-driven investment. No consensus has been reported relative to the need for capacity remuneration mechanisms to trigger investment to the level required for security of supply. This resembles a limited version of the 'refine energy-only market' option in Table 3.

Glachant (2016) takes the view that the day-ahead market, the anchor of the Target Model, is losing its importance as a signal for long-term investment coordination to other mechanisms, while zone-based market coupling and subsequent balancing/congestion management are challenged by the dynamic congestion pattern and flexibility needs that evolve with RES integration. But, he disagrees that add-ons to the Target Model, in other words, refining the energy-only market, are *enough*. Instead, Glachant calls for a giant leap in re-designing the Target Model, where redefinition of zonal boundaries or nodal pricing, access of demand-side flexibility through dynamic retail pricing, and further regionalisation and localisation of network operations are considered. This reflects a position which leans toward 'transactive pricing' in Table 3, with higher involvement of demand-end services and greater use of locational signals compared to the present.

Examining the interface between RES support mechanisms and coordination through energy markets, Newbery (2016b) acknowledges that RES generators need to be exposed to more efficient investment signalling, but disagrees with simply exposing RES investment recovery to short-term energy market

[5] For a more detailed treatment of the two-market solution, refer to (Keay & Robinson, 2017b).

signals, since it will increase the cost of capital considerably, and therefore the cost of decarbonisation. He argues for a stable investment climate in the form of long-term capacity auctions, in addition to exposure to short-term signals, a position that is shared by Fabra et al. (2015) and is aligned with 'investment market' in Table 3. In a later publication, he recognises that an outstanding issue over the determination of capacity to be procured via such long-term contract auctions remains (Newbery, 2016a).

2.2.2 Beyond market design, the existing energy policy is also broken

Helm (2014) argues that the core of many problems besetting current energy markets is the failure to clearly define the objective of energy policies, by ignoring the trade-offs that exists between the goals popularly referred to as the 'trilemma'. Many examples are given of policy measures aimed at achieving one objective having unintended consequences on those targeting another objective (such as the way in which the long-term contract used by national governments to support RES undermines short-term trading at the centre of the Internal Energy Market). Consequently, the way forward, according to Helm, requires the EU to prioritise among sustainability, security, and affordability/competitiveness, and based on that decision, to adopt measures that are aligned with the prioritised goal and accept non-optimal outcomes for objectives deemed less important.

Some authors reviewed maintain, or implicitly assume, that the policy trade-off to be made is clear: decarbonisation is the primary policy goal, whereas affordability/competitiveness is a boundary condition to be managed to retain public support for decarbonisation.[6] The issue of misalignments and self-contradiction that exist in narrowly conceived policy instruments[7] is highlighted in Robinson (2015). Although no specific solution is proposed, Robinson argues that a redefinition of the roles of market-based coordination and government-based coordination in decarbonisation is required. Keay and Robinson (2017a) further explore this issue by comparing UK and Spanish experiences. They criticise isolated and incoherent regulatory responses to an increasingly complex web of issues, calling for a more integrated approach to market design and regulation. Recognising the volatility of short-term political pressure, they recommend setting clear, binding, long-term decarbonisation goals to insulate the Energy Transition from politics. In comparison, instead of isolating the Energy Transition from politics, Fabra et al. (2015) propose better management of the cost of decarbonisation and its distributional effect, to secure broad public acceptance for decarbonisation.

2.2.3 The need for coordinated market design and policy making

Compared to previous streams of discussion that either focus on remediating the inadequacies of market design or that of the policy making process that oversees market design, Verzijlbergh et al. (2016) dive into both streams by discussing the implications of technical challenges that accompany large-scale RES integration for market design and policy making. They observe that RES integration is accompanied by increasing variability and uncertainty, which require adjustment of different modules of the existing coordination mechanism such as: short-term energy markets, network congestion management, and emission trading. Moreover, it also magnifies the interdependencies between these modules, previously designed in relative isolation. Consequently, Verzijlbergh et al. advocate for a more

[6] Energy security does not conflict with domestically sourced RES, therefore energy policy that addresses security has mainly focused on other energy vectors. However, if cross border RES generation is to be relied upon for decarbonisation, the trade-off between decarbonisation and energy security may become activated.
[7] RES generation, subsidised to advance decarbonisation, affects wholesale energy-only market prices and investment decisions based on them, thereby impacting security of supply; subsidies to these RES generation schemes, levied from customer bills and intended to advance decarbonisation of the power sector, prevent further decarbonisation through electrification by making electricity more expensive.

integrated approach to research and policy making, where complex interdependencies in the energy system are captured and reconciled, instead of being neglected.

Similarly, Roques (2014a) distinguishes between two types of problems: *intrinsic* issues with the current design of electricity markets which prevent them from sending the appropriate price signals for investment, and *extrinsic* issues which are related to the lack of internal consistency of Europe's energy policy framework.[8] Thus, on one hand, he recommends a reconciliation of contradictory policy packages through the examination of trade-offs to address extrinsic (energy policy) issues.[9] On the other hand, to address intrinsic market design issues, Roques proposes a phased reform: refining the energy-only market in the short term, followed by a more radical departure from the energy-only market in the mid-to-long term, reflecting change in the underlying cost structure.

Like Verzijlbergh & al., Roques and Finon (2017) adopt a view of multiple interdependencies and interactions between different parts of the coordination mechanism in the European power sector (referred to as 'modules'). They also concur that some of the imperfections existed in the market design prior to RES integration (for example, the issues of 'missing money' and 'missing markets'), but their effects were amplified, at the physical level, by the introduction of intermittent RES generation, and at the institutional level, by the introduction of government-based coordination modules. Instead of advocating for a return to 'pure' regimes, entirely based on either market coordination or government coordination, Roques and Finon argue that a hybrid regime, with elements from both approaches, is unavoidable given that energy policy objectives in decarbonisation and security of supply cannot be entrusted to the market alone. They conclude that future research should be in the identification of best practices within such hybrid regimes, and that periodic adjustments of market design/regulatory framework will be needed.

3. Our diagnostic

Our diagnosis is guided by 'system thinking' – a set of synergistic analytic skills[10] used to improve our capability in identifying and understanding systems, predicting their behaviours, and devising modifications to them, with the goal of producing the desired effects (Arnold & Wade, 2015). We direct those interested in the nature and historical development of system thinking, as well as in the main contemporary system approaches, to Reynolds & Holwell (2010).

Through our literature review, we discover that the existing debate on European power market design suffers from unclear terminology and blurred concepts. For example, authors frequently refer to the electricity 'market design' without further precision, leaving the readers to infer the specific market(s)

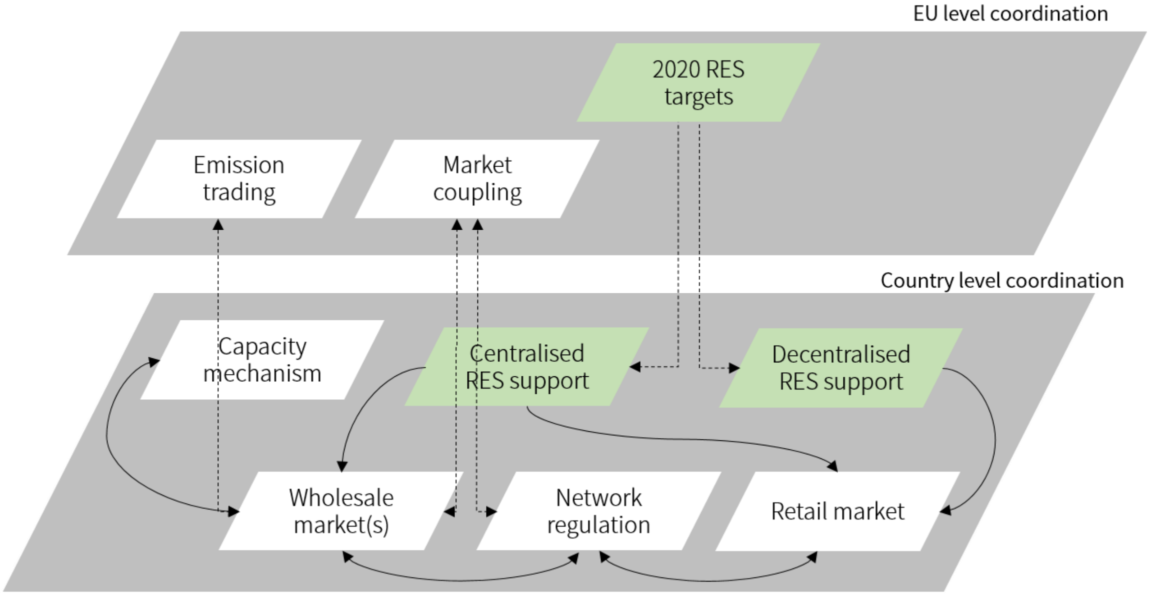
[8] By 'intrinsic issues' the author refers to missing markets (markets able to capture the value of short-term operating flexibility), long-term resource adequacy, and locational injection/uptake of electricity. And, by 'extrinsic issues', the author refers to the incompatibility between market-based coordination (energy-only markets, EU ETS) and government-based mechanisms (RES support).

[9] His position, which is clarified in a follow-up publication, is that liberalisation and the corresponding focus on competition are longer ends in themselves. Instead, they should serve the achievement of security of supply and decarbonisation. Consequently, to decrease regulatory uncertainty for the significant investments that are required to achieve decarbonisation and energy security at relatively lower cost, he recommends aligning short-term policy instruments with long-term policy targets through forward-looking roadmaps, coordinated by consulting stakeholders at the national, regional, and European levels (Roques, 2014b).

[10] This set of skills includes: (1) understanding system structure through recognising interconnections between parts of a system and identifying and understanding feedback (2) understanding the dynamic behaviour of the system through differentiating between stocks, flows, and variables that affect them; and (3) identifying and understanding non-linear relationships. As a result of applying the first two sets of skills, two more skills can be developed (a) selecting more appropriate conceptual representations of a system to reduce its complexity (b) recognising systems at different scales and how they are nested within each other.

being referred to via context (such as: day-ahead, intraday, balancing, and retail). To facilitate discussion among stakeholders, we propose a module-and-level based representation of coordination mechanisms that currently exist in the power sector; we use this to systematically identify those misalignments between coordination modules and levels that plague existing market design. The conceptual representation that we propose is illustrated in Figure 1.

Figure 1: A module-and-level representation of EU power sector coordination mechanisms



In system thinking, it is recognised that there are multiple ways to perceive/represent the same system, and that there is no best unique representation (in other words, all models are wrong, but some are useful). And, the main criterion for judging the usefulness of a given mental representation is whether it leads to fruitful insights. We arrived at our boundary definitions iteratively, refining them so that important interconnections were not overlooked (excluded from the external boundary); these important interconnections are clarified by defining them as relationships between sub-systems that exist within the larger power market design, which we refer to as 'modules'.

In terms of defining an external boundary (deciding what is included as part of the system), we include market-based mechanisms (wholesale markets, for example) and non-market-based coordination mechanisms (for example, RES-support schemes and network regulation are both included as modules of coordination mechanism even though they are not market-based).[11] Also, we include coordination at two levels of jurisdiction: the EU level, which contains climate and energy policies and policies that promote the Internal Energy Market; and the country level, which contains nationally determined policy instruments, network regulation, and wholesale and retail markets.

In terms of internal boundaries (how interconnected elements within the same system are distinguished from each other), we have decided on the modules displayed in Figure 1 because, as shown through Section 03.1 and 03.2, we find that they are the most useful concepts for elucidating the main dynamics underpinning the debate in EU power market design.

[11] Our system boundary for market design is consistent with the recommendations from the series of reports published under the 21st Century Power Partnership; these include RES support mechanisms and grid infrastructure regulation as issues of concern for regulatory action, in addition to coordination mechanisms responsible for long-term resource adequacy and short-term operational security.

Interactions between horizontal modules at the country level occur through common stakeholders (such as: conventional generators, RES generators, consumers who engage in self-generation – also known as ‘prosumers’). In other words, module A may affect the functioning of module B, if there is a stakeholder that participates in both modules. Interactions between policies at the EU level occur less directly: instead of being connected by common participants, policies are connected by inter-linked modules that they affect at the national level.

By ‘misalignment’, we refer to undesirable interaction between two modules (the way in which the implementation of one module negatively affects the functioning of another module to which it is linked through common participants). We demonstrate that misalignments occur between physical RES integration/RES support schemes in a wide range of coordination modules (wholesale market, retail market, and network regulation). Misalignment between country-level physical RES integration/RES support schemes and coordination modules at the EU level, is also observed.

3.1 Misalignment between modules at the country level

In Figure 2, we further break down the country-level coordination modules simplistically presented in Figure 1. More specifically, wholesale market and network regulation both involve sub-components. We lay them out using two dimensions: participants in the coordination mechanism, and the time horizon involved. A long-term time horizon concerns decisions with long temporal ramifications (such as investment decisions), whereas a short-term/real-time horizon concerns decisions with more immediate temporal ramifications (such as operational decisions in real time).

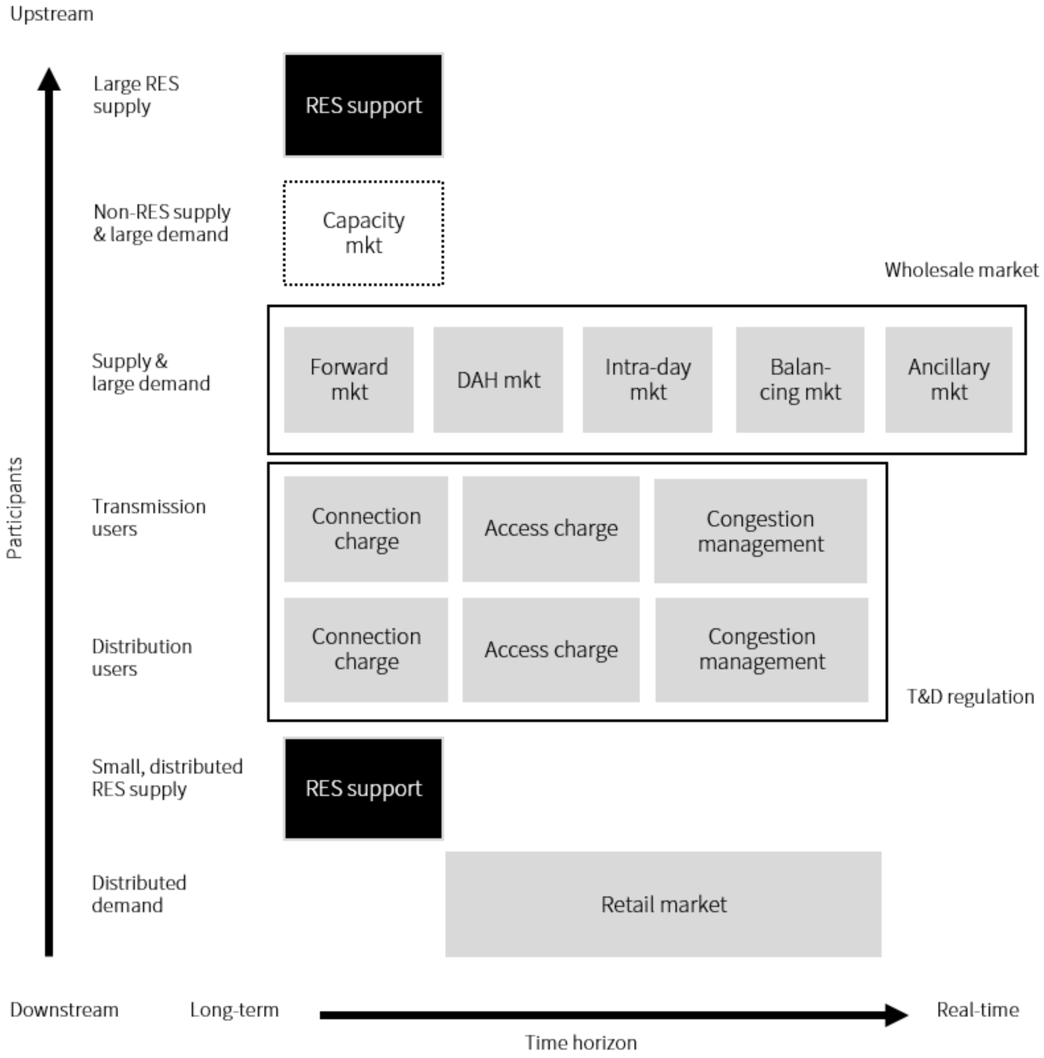
This patchwork of modules has evolved from the unbundling and liberalisation of vertically integrated monopolies. The process of liberalisation transferred the coordination of long-term investment and short-term operations from an integrated monopoly to market-based mechanisms where possible (in wholesale and retail markets), while transmission and distribution networks, given their natural monopoly characteristics, remained under regulation.

In ‘Wholesale market’ (see Figure 2), several coordination modules with different time horizons coexist: from the forward market (on which electricity is traded in contracts whose dates can be anything between a few weeks to a few years ahead of delivery), to the balancing market (where electricity is traded just before physical delivery and the TSO acts the single buyer of balancing services post gate-closure). The market(s) for ancillary services is/are distinguished from other markets by the nature of the services that are procured; provision of ancillary services does not always involve the delivery of energy, but these services are essential to support the operation of the power grid in a reliable manner.

RES-support modules (for large transmission grid-connected RES, and smaller distribution grid-connected RES, highlighted in black in Figure 2) are added to the patchwork of coordination modules. As RES generators grow in number and market share, misalignments between RES integration and the wholesale, retail, and network regulation modules are all observed.

In the following descriptions, we also differentiate between misalignments in long-term coordination (investment decisions) and short-term coordination (operational decisions).

Figure 2: Breakdown of common country-level modules by participants and time horizon[12]



3.1.1 Misalignment between RES integration and wholesale power market

Prior to the large-scale introduction of RES, the abilities of energy-only wholesale markets have been questioned by some due to certain imperfections (Keay, 2016). When generators rely on revenue from energy sales to recover all costs (including that of investment and other fixed charges), peak generators (which generate infrequently but are critical when supply/demand balance is tight) need to recover their fixed costs through above-marginal cost mark up during such periods. Caps on electricity price in the wholesale market, either due to political pressure or legitimate concerns over market power during periods of scarcity, lead to 'missing money', a well-known term referring to the market conditions which prevent generators from recovering their investment. Apart from depressed electricity price levels, the volatility of energy-based revenue for peak generators could also be a concern for investors and their financiers, especially in the absence of a sufficiently liquid forward market in which they can hedge such

[12] We differentiate between intraday and balancing markets through the placement of gate closure: market-based balancing of changes in positions prior to gate closure takes place in the intraday market, whereas post-gate closure, when the SO becomes the single buyer of balancing services, occurs in the balancing market. Some commentators thus include the balancing market within the ancillary market.

risk (Newbery, 2016a). This phenomenon, known as 'missing market', is at least partially attributable to short-term switching of suppliers by consumers in the retail market, encouraged by liberalisation (Helm, 2014).

The integration of RES exacerbates the issues of both missing money and missing market by depressing the energy-based price of electricity – the marginal cost of RES generators is much lower than that of conventional generators, and production-based subsidies may make them willing to bid negative prices in the wholesale market to remain in operation – and making the operating hours of conventional generators more uncertain. The recovery of fixed costs for RES generators, typically more significant than those of conventional generators, is currently achieved through RES support schemes in the form of government-procured long-term contracts.[13]

In countries where long-term resource adequacy is perceived to be low (in low demand growth countries, this is likely to be induced by policy-based phasing out and decommissioning of aging plants, as well as the mothballing of newer conventional generating capacity incurring losses), national governments have implemented, or are considering the implementation of, capacity remuneration mechanisms. Such mechanisms address the missing money/market problem for current or new investment in capacity, especially for non-RES technologies (these are not supported by RES subsidy but make a higher contribution to firm capacity per installed capacity), guaranteeing their fixed cost recovery. Such practice is controversial. Critics argue that the current design of capacity market leads to non cost-effective over-procurement, given the skewed incentives of the System Operator and the government, and that today's consumers should be equipped with the capabilities and rights to make decentralised procurement decisions (Keay, 2016).

In the days before large-scale RES integration, variations in supply–demand balance were relatively predictable and most information required for real-time scheduling was available at the day-ahead time frame. Changes between day-ahead schedule and real-time operation – most likely due to a plant failure, inaccuracy in demand forecast, and re-dispatch due to congestion constraints – were typically handled by the System Operator, through procurement in the balancing market and ancillary service market (Pöyry, 2014). Sometimes, intraday markets also exist for decentralised balancing transactions among market participants, after day-ahead market clearing but before gate closure (Weber, 2010). The design of balancing market, ancillary service market, and intraday market varies greatly from country to country, and is not covered by the existing Power Target Model.

Under the circumstances described, the undervaluing of operational flexibility in illiquid short-term wholesale markets did not pose immediate concerns, because there was relatively little need for flexibility at the post day-ahead time frame, thus revenue streams through those mechanisms accounted for a low share of overall generator revenue. However, the increase in share of intermittent RES generation is reshaping such basic premises. The deviation of RES generation from its forecast requires further adjustment of the day-ahead market-determined schedule relative to real-time operation.[14] Also, given their low marginal cost, RES often displaces conventional generators with a higher level of flexibility in the merit order, thus reducing the amount of online flexibility in the system. In addition, given the depressive effect that low marginal cost RES generation has on day-ahead energy prices, revenue streams from other markets are becoming more important in the overall revenue collected by flexibility providers.

Depending on the country and also on their size, RES generators may, or may not, be responsible for balancing any deviation from their forecasted generation schedule. In the case that they are not

[13] Short-term transaction-based RES support schemes, such as Renewable Obligations, have also been implemented, but they have been shown to be too volatile to incentivise investment in RES generation without unduly increasing the risk premium (Newbery, 2016a).

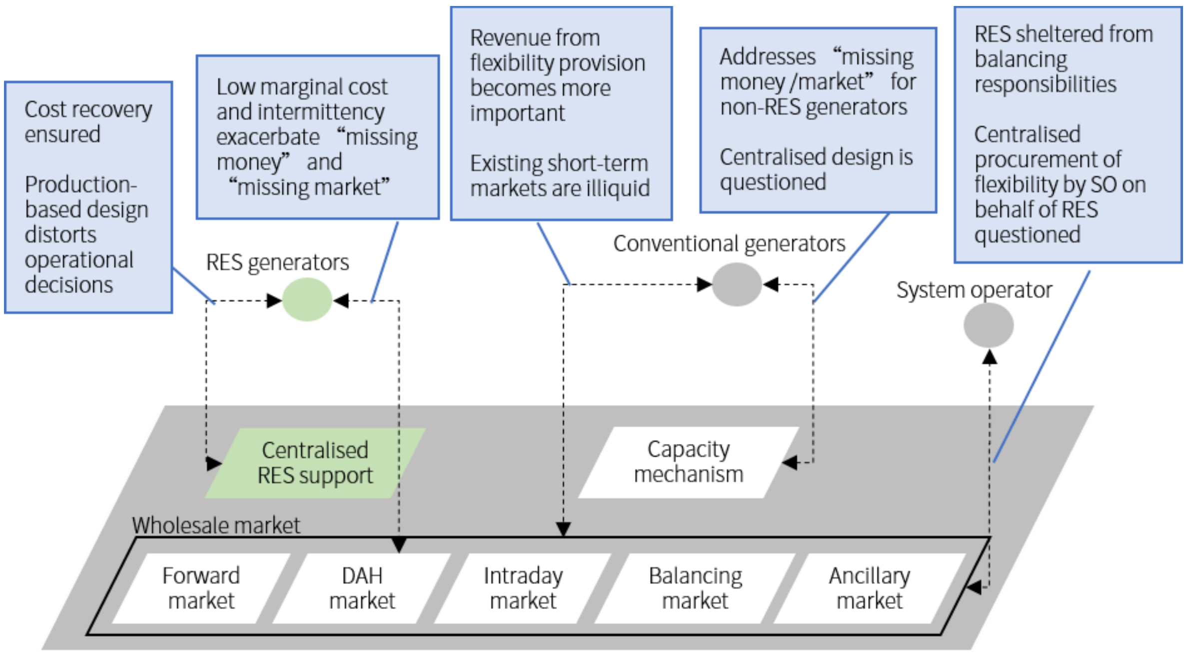
[14] If the relative quality of forecast remains the same, the variance of the wind forecast error increases quadratically with the installed wind power capacity. Therefore, at high installed capacity of wind power, wind forecast error grows to dominate the post-day-ahead-schedule adjustment that is needed (Weber, 2010).

responsible, the adjustment required is made by the System Operator in the balancing market and the cost incurred is socialised among balancing-responsible parties (generators and suppliers who are responsible for balancing the deviation between their scheduled input/output and actual operations). This aspect of RES support is increasingly criticised, for it removes the incentives for RES generators to improve the quality of their forecast. Furthermore, if the System Operator is being relied upon to balance increasingly significant RES forecast errors, it might have the incentive to over procure (when balancing costs are fully socialised), or under procure (when there is regulation to limit balancing costs incurred). Both cases distort the value captured by short-term flexibility providers in the balancing market.

RES generators can provide some operational flexibility, in the form of curtailment, given their fast ramping speeds (when there is no resource constraint). But, in the case that RES support payment is completely sheltered from short-term coordination in the wholesale market (priority dispatch and production-based subsidy independent of market price), RES generators are not incentivised to curtail their production, even when it might be more economical to do so given their lower shut-down costs relative to other sources of flexibility in the system.

The misalignments identified are summarised by Figure 3.

Figure 3: Misalignment between RES integration and wholesale market



3.1.2 Misalignment between RES integration and retail market

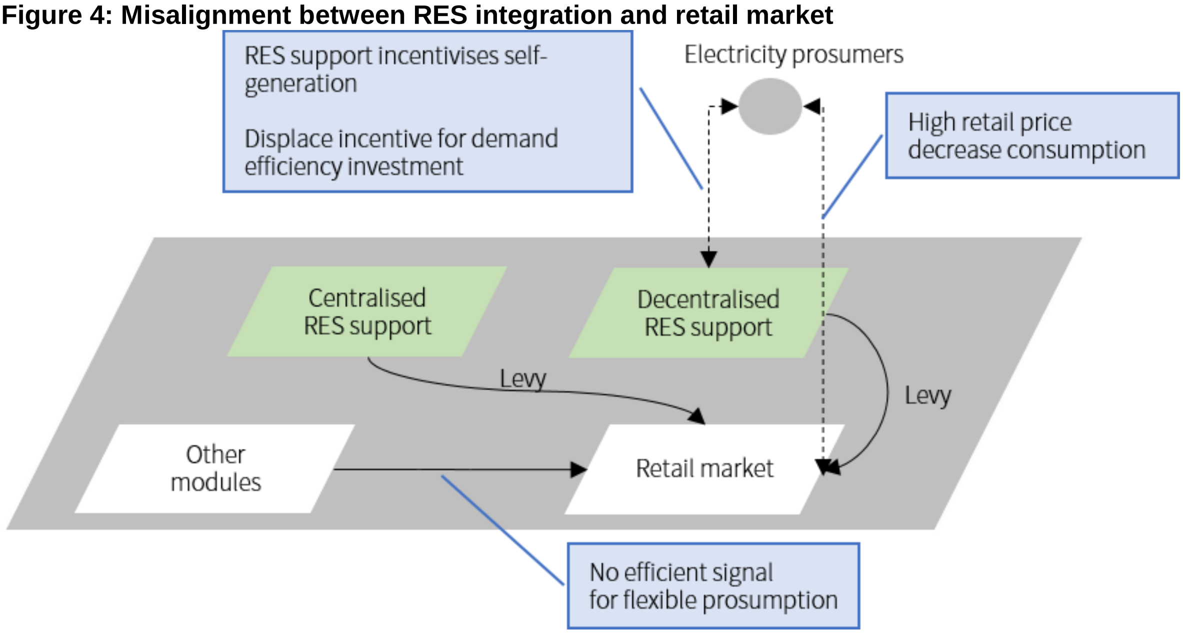
Although the details of RES support schemes vary from country to country, many of them fund such measures through a levy placed on electricity consumption. As RES generation funded by the levy grows, the size of the levy also grows, increasing electricity prices at the retail level, even when RES generation is depressing the wholesale electricity price (Robinson, 2015; Robinson, Keay, & Hammes, 2017). Electricity consumers exposed to such retail over-pricing are also responsible for making investment decisions relating to capital goods that may affect their electricity consumption. These include, for example, electric vehicles and heat pumps which substitute other forms of energy vector by electricity, investment in home improvement (or other purchases) which can improve the efficiency of their electricity consumption, and investment in decentralised RES technologies to self-generate electricity. Increasing the retail price of electricity, and the size of subsidies for RES generation (extended to small decentralised generators), incentivises consumers who have the means to invest in increasingly affordable distributed RES technologies (especially solar PVs), for such investment decreases their energy consumption (thereby decreasing electricity bills) and increases their revenue (through sales of excess generation to the grid) at the same time. The situation is potentially self-reinforcing, as uptake of distributed RES generation by consumers further drives up the retail electricity price via growing the government 'wedge', strengthening the incentive for self-generation. Meanwhile, it undermines the electrification of sectors where decarbonised electricity is relied upon, by current default assumptions, for decarbonisation (transport and heating/cooling).

In addition, in places where the retail tariff is volumetric (the network cost is reflected in the energy component) consumers can avoid the network costs by 'load defection', even though they still rely on the grid for a reliable service. The implication of this is that the network cost needs to be recovered from a smaller pool of end users, and this means that the price must be increased further. In some cases, this has led to 'grid defection' where the customer decides to leave the grid entirely in the face of high retail prices.

Given a historical paradigm of reliance on generation to balance the power grid, today's retail markets, liberalised and competitive to different degrees across countries, do not provide a wide range of signals to their participants, when compared to the wholesale market. Final consumers pay prices that are fixed for several months or years, adjusted periodically by suppliers. Hence self-generators and consumers, who have the potential of providing demand-end flexibility to balance the power system, are not incentivised to invest in new generation or in appliances/equipment that allows for a more flexible use of electricity. Nor do they receive feedback for their non system-optimal consumption/generation behaviour.

The misalignments identified are summarised by Figure 4.

Figure 4: Misalignment between RES integration and retail market



3.1.3 Misalignment between RES integration and network regulation

Historically, the electricity grid, based on one-directional flow of energy through a hierarchical architecture, delivers electricity generated at centralised facilities to decentralised customers' loads, and the network is demarcated into transmission and distribution levels. Although Supervisory Control and Data Acquisition (SCADA) systems provide utilities with active control over the transmission grid, in general the flow of power is not controlled in the distribution network, which is thus often over-engineered to passively withstand peak demand. In the following discussion, a high voltage meshed network over which active operational control is exercised is considered part of the 'transmission network', whereas 'distribution network' refers to the portion of power grid that is radial, low voltage, and currently passively managed through network expansion and reinforcement. We discuss long-term investment recovery and short-term capacity allocation separately.

Conventionally, almost all large generators are connected to the grid at the transmission level. Owners of the regulated transmission network used to recover their fixed and operating costs through a combination of one-off connection charges (charged to users connecting to the transmission grid) and access tariffs (which are regularly charged to all network users). The design of these two elements needed to balance cost recovery for network investors with the need to provide non-discriminatory access to all network users. Subsequently, most transmission network operators adopted a shallow connection charge (connected users pay for infrastructure from installation to the grid) and recovered the remaining costs (reinforcement and extension in the existing network) through an access tariff payable by all connected loads[15] (ENTSO-E, 2016). Currently, most TSOs invoice the access tariff on an 'energy basis' (charge per MWh of energy delivered), but 'capacity basis' is also used by some (charge per MW of network capacity contracted).

Similarly, cost recovery for the regulated distribution network is also achieved through connection charges and access tariffs. Regulated tariff design at the distribution level across Europe is even more varied than at the transmission level, for DSOs by far outnumber TSOs. Nevertheless, the same design choices seem to prevail: shallow connection charge (especially for small connections) and socialised recovery of network costs through an access tariff with a strong energy component (AF-Mercados, REF-E, & Indra, 2015). Overall, locational differentiation in network access charges within the territory served by the same TSO/DSO is weak.

With the rise of RES generation, mainly very large (and sometimes remote) wind and solar farms with high resource availability but little locational flexibility are connected at the transmission level. Offering shallow connection charges to such generators can be argued as being justified, as they do not have control over renewable resource availability and thus should not be asked to bear the full cost of connecting remote RES. However, such an approach increases the network extension cost that is to be socialised and carried by transmission network users, in the form of the transmission network tariff. And, in the case that a remote RES project does not come to fruition, network extension which has already been conducted then risks becoming a stranded asset.

Small, non-remote RES generators tend to be connected to the grid at the distribution level, especially if the transmission network access charge is higher than that at the distribution level.[16] Shallow connection charges at the distribution level do not incentivise distributed RES generators for efficient

[15] As for short-term wholesale market modules, transmission and distribution network regulation differs widely between countries, thus our comments are not exhaustive, but only relate to very common features of network regulation.

[16] In principle, transmission access tariffs should be lower when the connection is made at higher voltages; however, in the event that embedded generation helps to delay transmission investment (by lowering peak demand at a given location), they might receive compensation which, when netted against distribution network charges, makes them lower (for example, the Triad payment in the UK).

placing within the network, for the cost of grid extension and reinforcement is socialised among all distribution network users. Furthermore, if the distribution tariff is invoiced per MWh of electricity that the grid delivers to load, then the share of socialised network cost borne by distributed generators is further reduced, for their own generation decreases their consumption of grid-delivered electricity, thus decreasing the network cost that is recovered from them.

Although all network users are implicitly entitled to access to the transmission grid, network capacity constraints do arise and affect the ability of different generators/suppliers to deliver/uptake electricity. Location-differentiated bidding of energy, in the form of nodal pricing, is a mechanism that internalises such network constraints.[17]

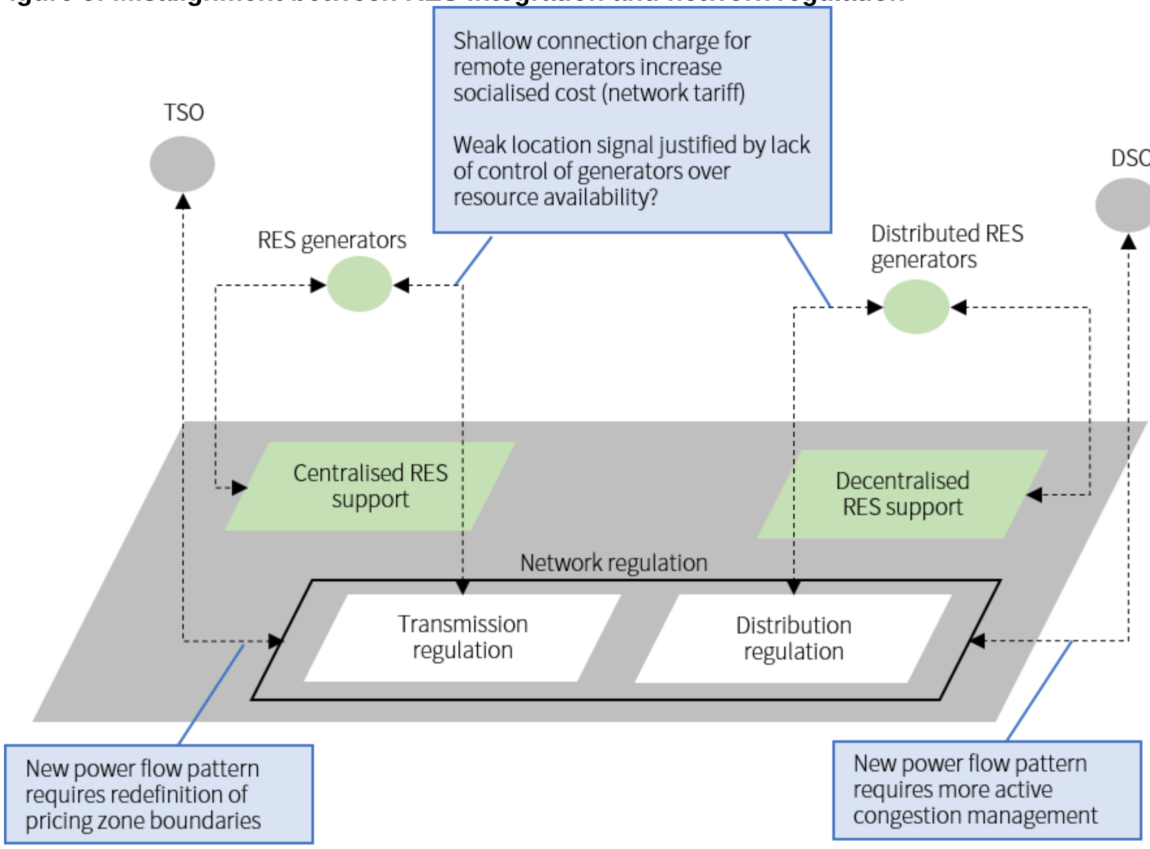
At the transmission level, some EU countries practise 'zonal pricing' (separating their territory into several bidding zones, based on commonly observed congestion constraint patterns) whereas others practise 'single pricing' (ignoring transmission congestion when clearing the day-ahead market). Both methods are simplifications of nodal pricing and rely on post day-ahead re-dispatch decisions made by the TSO to resolve congestion constraints within a price zone. The cost of re-dispatch actions taken, like that of other system services procured by the TSO, is socialised by network users. Increased intermittent generation from RES alters power flow in the network and causes dynamic congestion patterns, affecting the effectiveness of existing zoning boundaries and increasing the cost of re-dispatch within non-differentiated price zones. Thus, the multiplication of RES projects exacerbates pre-existing tensions between efficient locational signalling and price equity (for citizens of the same country/region).

Constraint management in distribution, as mentioned above, primarily relies on passive measures such as over-capacity, rather than active re-dispatch decisions. The rise in distributed RES generation is disrupting this pattern, for distributed generators alter the pattern of power flow throughout the distribution network and require a more active approach to congestion management. Consequently, the boundary between transmission and distribution networks is increasingly blurred.

The misalignments identified are summarised by Figure 5.

[17] Although nodal pricing is effective at guiding short-term operational decisions in the network, short-term congestion rent, arising from the difference between price nodes, is insufficient to recover network fixed costs under realistic market conditions (Marin, Parez-Arriaga, Rubio, Puerta, & Arceluz, 1995; Rubio-Odériz, 2000).

Figure 5: Misalignment between RES integration and network regulation



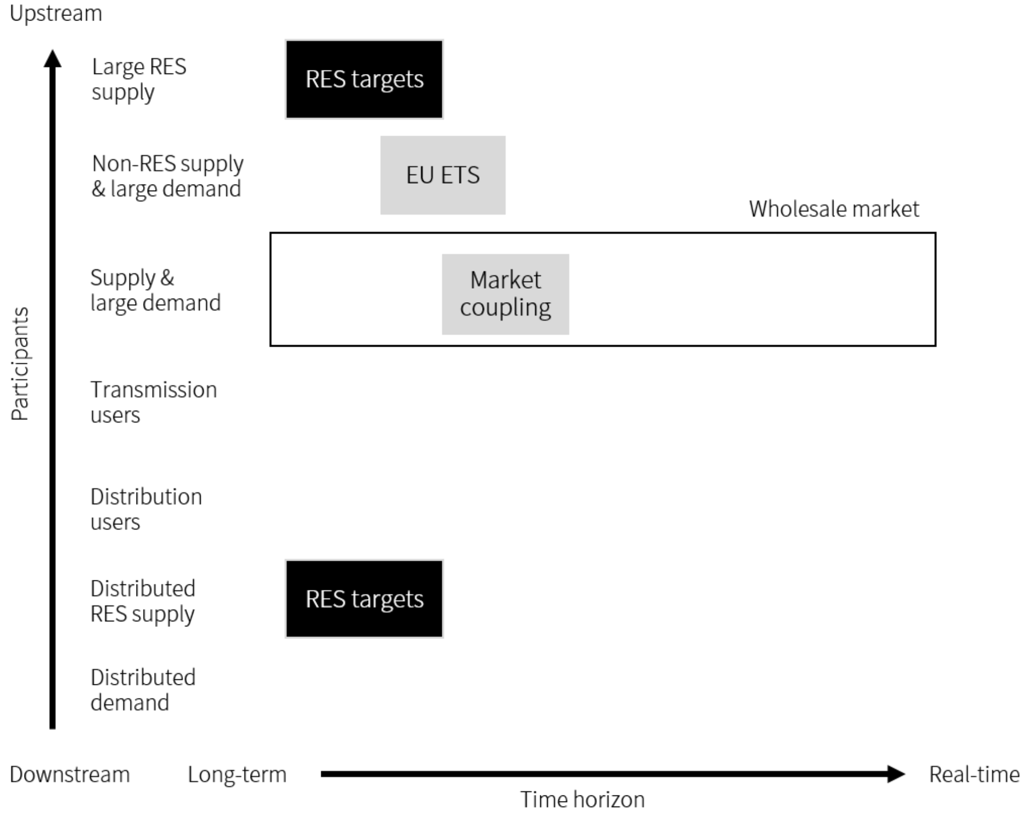
3.2 Misalignment between country and EU-level modules

Beyond misalignments between coordination modules at the country level, we also observe inter-level misalignments, between the modules designed and implemented by Member States (mainly the newly inserted modules to guarantee cost recovery for RES and, subsequently, non-RES capacity) and those designed and implemented by the European Union. As illustrated in Figure 1, three modules are used to coordinate power sector investment and operation decisions at the EU level:

- 2020 RES targets (binding RES national targets for 2020),
- Emission trading (the EU ETS),
- Market coupling (the coupling of zonal day-head markets – where zone boundaries largely coincide with national boundaries).

Laying out these modules by participants and the time frame of coordination as in Figure 2, we find that the EU-level modules mainly target upstream participants and neglect coordination closer to real time (Figure 6). A key cause of inter-level misalignment between the EU and Member States' policies can be traced to misalignments between modules at the EU-level: between RES national targets and the two other modules.

Figure 6: Breakdown of EU level coordination modules by participants and time horizon



3.2.1 Misalignment between RES integration and market coupling

National RES support policies obstruct power market integration within the EU, the core goal of market coupling, in two ways:

1) Market integration implies that power generators throughout Europe should be able to compete on an equal footing, but national RES support policies (and subsequently, capacity remuneration mechanisms) addressed at sector agents within a country's national borders necessarily involve changing the competition environment across countries. So far, the balance between the pursuit of the Single Energy Market and Member States' justified deployment of RES support is being weighed by the EU's state aid investigations.
2) Short-term power system operations in a country with RES generation can sometimes impose negative externalities in physically connected countries with which it trades, making physical interconnections and cross-border trade less desirable and increasing political tension between countries. At other times, they can directly impede trade between countries.

The introduction of RES generation may change the pattern of congestion within a country, leading to increased physical congestion within a bidding zone (see Figure 5). If scheduled power flows neglect such congestion, the physical power flow that results from the scheduled delivery may take the path of least resistance and travel through the network of interconnected zones. Unscheduled physical power flows in bidding zone B resulting from scheduled flows within bidding zone A are known as 'loop flows'.[18]

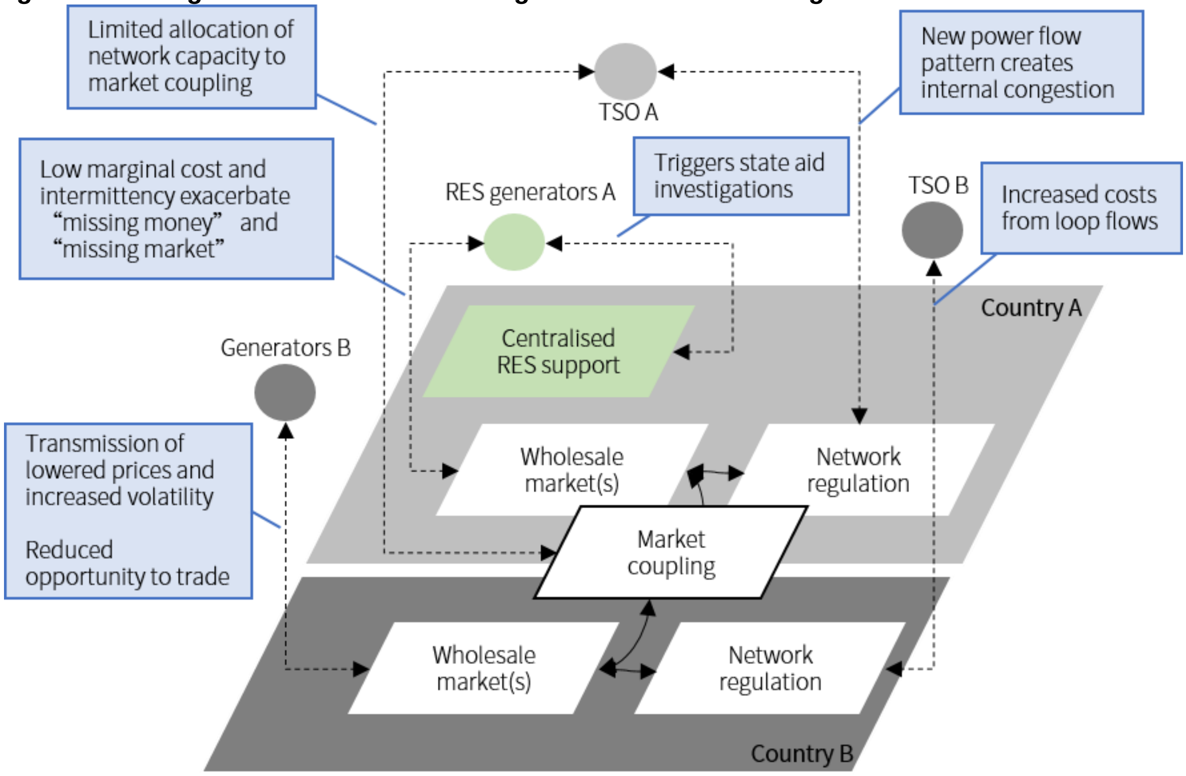
[18] Transit flows are another type of unscheduled physical flows. They take place because of a scheduled flow between two or more control areas, such as between zone A and B (THEMA consulting group, 2013).

In this case, transactions in zone A impose external costs on zone B by decreasing the network capacity that can be used by zone B and increasing the costs of grid management for zone B. Increased internal congestion can also lead the System Operator of zone A to decrease transmission capacity made available to market coupling with zone C, if doing so would avoid or decrease the re-dispatch costs required to accommodate internal congestion. In this case, the decisions of the zone A System Operator deprive market participants in zone C of potential trade with zone A.

The integration of RES generation may decrease energy price levels and increase price volatility in the wholesale market, exacerbating the problem of 'missing money' and 'missing market' in a power system (see Figure 3). In coupled markets, such issues can be transmitted across borders through cross-border trade, leading to lower prices and increased volatility in neighbouring countries. The impact is larger for transmission of price level/volatility from larger, more mature market, to smaller, less mature ones.

The misalignments identified between RES integration and market integration are summarised in Figure 7.

Figure 7: Misalignment between RES integration and market integration

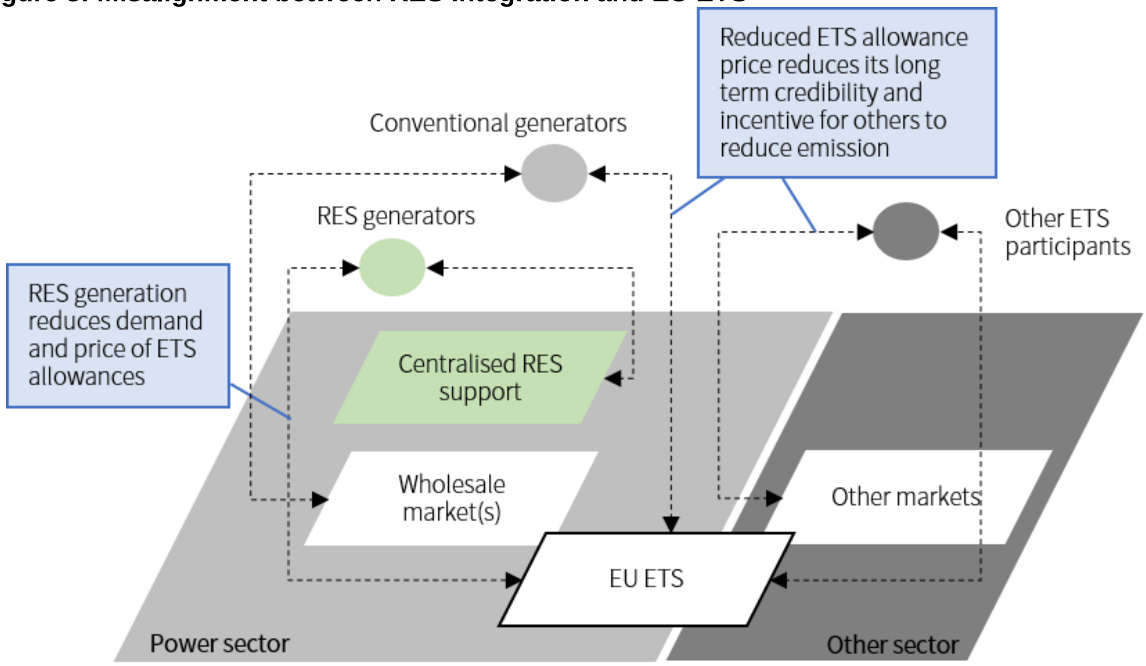


3.2.2 Misalignment between RES integration and EU ETS

The objective of the EU ETS, a pan-EU carbon cap-and-trade scheme, is to allow the EU to meet its emission target in the most cost-effective manner possible. Within the ETS, the price of tradeable emission allowances is determined by the balance between the supply of such permits (set by an administratively determined cap) and the demand for them (determined by the level of carbon emissions resulting from the operations of its participants). All EU-based power plants with capacity higher than 20 MW participate in the scheme, thus policy instruments targeting the power sector and the ETS are linked through common participation.

In the absence of RES support schemes, the price of the ETS allowance is intended to incentivise participants to invest in low-carbon technologies and use other means to lower the carbon intensity of their operations (lower emissions will lead to lower operational costs, once the cost of the allowances is factored in). In the presence of RES support schemes, however, RES generation lowers the need for ETS allowances and, in consequence, lowers the price of the allowances, if the cap is held constant. The depressed allowance price thus loses its significance as a signal for the investment and operational decisions of ETS participants[19]. The primacy of RES support incentives over the ETS carbon price has been criticised for having led to non cost-effective carbon abatement investments, at least in the short term. Therefore, the balance between the ETS and RES support schemes represents a trade-off between static efficiency and dynamic efficiency for emission reduction. Furthermore, by lowering the demand/price of allowances, emission reduction achieved by RES generators in the power sector lowers the cost of emissions for other participants. And, the prolonged period of low prices further undermines the long-term credibility of the EU ETS. The misalignments between EU ETS and RES integration are illustrated in Figure 8.

Figure 8: Misalignment between RES integration and EU ETS



3.3 Incorporating technological evolution and consumer preferences

A truly fit-for-purpose design for power markets needs not only to resolve the misalignments between coordination modules which we have identified in the previous sections, it also needs to be informed by emerging trends in the power sector, be it developments in technical capabilities or changes in consumer and public preference. A lack of forward compatibility will, in time, create new misalignments. In the Appendix of this paper we scan, in detail, the horizon for trends that could have significant influence over the socio-technical landscape through which future electricity market designs will have

[19] In addition to RES generation, the depressed price of allowances has other key causes such as: lower demand due to economic recession or energy efficiency measures, high import of international credits, and industrial lobbying which has led to an oversupply of emission allowances in the market.

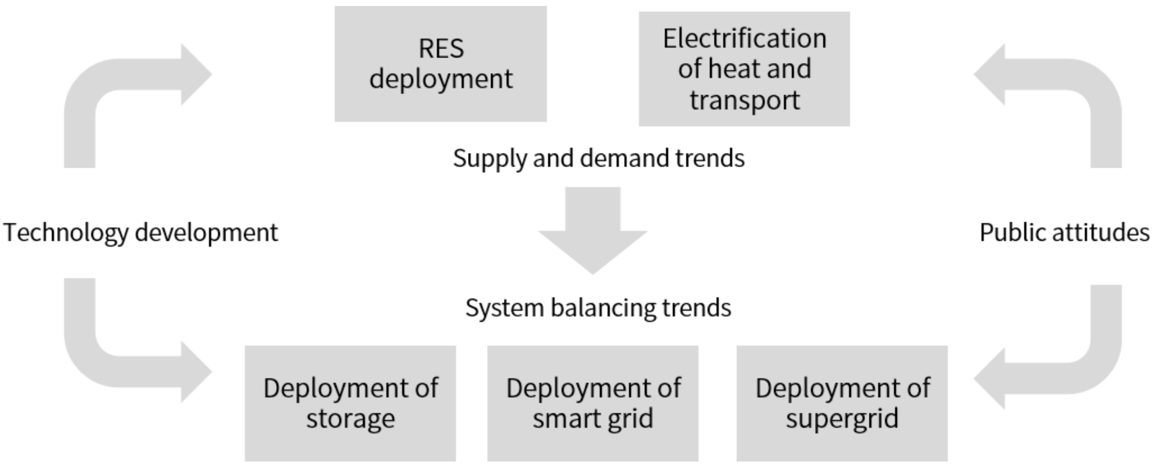
to navigate. A summary of this examination is presented in this section, but for a detailed analysis on technological evolution and consumer preferences in the power sector, we refer the reader to the Appendix.

We have identified five key trends:

- those which will affect the magnitude and profile of future demand and supply:
  - deployment of RES,
  - electrification of other sectors;
- others which will influence the way in which future electricity supply and demand will be balanced:
  - deployment of storage,
  - smart grid,
  - supergrid.

The development of technology, together with the attitudes of power consumers and the wider public, will both influence the evolution of these trends (see Figure 9). After reviewing the social and technical determinants that underpin the five trends, we develop four explorative scenarios, each embodying a plausible combination of these forces, against which we will discuss market design proposals in the next section.

Figure 9: The effect of technology development and public attitudes on power sector trends



These scenarios are: centralised, decentralised, early hybrid and late hybrid, and they represent four combinations of the five trends.

- Centralised scenario: in this scenario, there is a positive public attitude towards further European integration (more interconnectors and cross-border trade). Through the supergrid, regional trade and access to a small number of centralised large-scale storage installations (multi-year hydro reservoirs) are relied upon to provide the flexibility that is required to integrate further RES (most likely to be very large-scale offshore wind farms and desert-based solar farms).

- Decentralised scenario: In this scenario, development of a supergrid is limited, for the public and power consumers place higher value on control and self-reliance. Smart grid-related technologies and infrastructure are spurred by overspill from other rapidly innovating sectors: The 'Internet of Things' delivers associated smart appliances; advanced data analytics delivers associated software. Integrated home energy systems, along with rooftop PV and stationary batteries, become popular with owners of electric vehicles.

- Early hybrid scenario: In regions most endowed with concentrated (and likely remote) RES, electricity supply and demand is balanced at the transmission level via trade with other regions. In regions where small-scale decentralised RES is more prevalent, supply and demand are balanced through a mix of regional trade and demand-end flexibility.

- Late hybrid scenario: In this scenario, the best of centralised and decentralised scenarios are combined. Both remote and distributed RES generation are integrated into the grid, which relies on regional trade and demand-end system services to balance supply with demand, and storage projects of varying sizes are embedded within the power grid at transmission and distribution level. This scenario, of course, is only likely as an extension of the early hybrid scenario.

The four scenarios presented above do not exist in isolation. They are guideposts that mark different points along possible future trajectories: one scenario, given time, may evolve into another. We believe that new forward-compatible market designs will need to incorporate awareness of such underlying uncertainty, remaining flexible to accommodate any upcoming eventuality. It is even more important to recognise that these scenarios, marking different pathways, are not completely driven by exogenous trends. The materialisation of a particular scenario is partially determined by the power sector coordination that is put in place. The future will be co-evolutionary between technology development/public attitude and the endogenous decisions taken on market designs.

3.4 Evaluation of existing proposals for market design

As mentioned in Section 2 many different solutions have already been proposed to address the issue of electricity market design. In this subsection, we re-examine the list of market design changes already proposed, in the light of the horizontal and vertical misalignments diagnosed in the previous subsections. We also reflect on their compatibility with the evolution of technology and consumer preferences in the power sector. To facilitate the analysis, we categorise these proposals into four groups:

1. Absolutist approaches:
   a. Central planning and control,
   b. Removal of support for RES energy generation (purely 'market driven').
2. Wholesale market focused solutions:
   a. Investment market,
   b. Refine energy-only market.
3. Retail market focused solutions:
   a. The two-market solution,
   b. Transactive pricing.
4. Non market-specific solution:
   a. Introduce a capacity-based element into pricing.

As concerns the *Absolutist approaches*, it is very unlikely that a fully centralised investment/operation or a fully market-driven investment/operation can be relied on to meet the current objective of energy policy: achieving long-term decarbonisation while meeting security of supply and affordability/competitiveness conditions. Respectively, these two absolutist approaches lead to non-efficient procurement by centralised actors (government and/or System Operator) and non-correction of market/system failures that privilege incumbent technologies. The negative externality associated with carbon emission is but one of the market and system failures that could restrict the development of low-carbon technologies. Therefore, even in presence of a functioning carbon price, removing RES support schemes without addressing the other underlying failures is unlikely to spur the innovation that is required to bring about decarbonisation. We explain our preference for a hybrid mode of governance, where market-based coordination and government-based coordination both play a role, in detail in Section 4.3.

As for the three other groups of market design proposals:

- The Wholesale market focused solutions offer different propositions of risk-sharing between generators and consumers (represented by suppliers);
- The Retail market focused solutions suggest different forms of direct demand-end participation in the supply-dominated power market;
- Only the non market-specific solution pays attention to the challenges faced by a regulated network.

None of the solutions proposed, however, is cognisant of the full range of misalignments that exist between RES integration and today's dominant power market design, across wholesale market, retail market, network regulation, and beyond (Section 3 summarised in Table 4). We recognise that the following generalisation might not apply to all EU Member States, given that the power market designs of Member States are not identical; however, we believe that it provides a summary, in broad brushstrokes, that highlights the most important tensions in most EU power markets.

Table 4: Misalignments between RES integration and market coordination modules at different levels

	Long-term coordination	Short-term coordination
Wholesale market	Missing money and missing market exacerbated by RES. RES cost recovery guaranteed by long-term contract with central buyer. Current CRM prone to biased procurement by centralised actors.	Undervaluing of operational flexibility in short-term markets. RES generators do not have balancing responsibility; transactions are performed by SO and the imbalance cost is socialised. RES operational flexibility untapped.
Retail market	Increasing government levy in retail price disincentivises consumption of grid-delivered electricity. Prosumers leverage distributed RES generation support to decrease own consumption.	Retail market price signal not sufficiently granular to encourage flexible distributed consumption and generation.
Network regulation	Weak locational signal to RES generators from shallow connection charges, especially at distribution level. Network expansion and reinforcement cost socialised through network tariff.	New power flow pattern blurs boundary of transmission and distribution network. Bidding zone boundaries may require redefinition. More active congestion management required at distribution level.

	Long-term coordination	Short-term coordination
Market coupling	National RES support schemes (and CRM) trigger state aid investigations.	New power flow pattern may impose negative externalities on neighbouring countries: ▪ *Increased grid management costs from loop flows;* ▪ *Transmission of lowered prices and increased volatility;* ▪ *Reduced opportunity to trade.*
EU ETS	RES generation reduces demand and price of ETS allowances. Lowered ETS allowance price reduces incentive for non-RES generators to invest in low-carbon technology.	Lowered ETS allowance price reduces incentive for non-RES generators to reduce carbon emission from operations.

The *investment market approach* (one of the wholesale market focused solutions listed above) advocates the use of long-term contracts for risk sharing between generators and consumers, yet recognises the usefulness of competition for the market – in competitive bidding for the long-term contract, and in the market, in the form of retained short-term wholesale markets to coordinate operational decisions. This approach differs from the *refine energy-only market* approach in the attention paid to short-term markets – the latter includes specific measures to improve the intraday and balancing markets given short-term flexibility needs, while the former assumes that they will be adequate coordination tools – and the technology neutrality of the competition for long-term contracts. Proponents of the investment market approach speak of an (eventually) merged long-term contract competition between RES technologies and conventional generation, while current proposals to refine the energy-only market approach maintain separate auctions for CRM and RES support (Finon & Roques, 2013). Criticism of both approaches is that long-term contracts lead to market foreclosure, decreasing the relevance of short-term market coordination, and that the centralised procurement of long-term contracts does not necessarily represent the preference of electricity consumers. We add that, if these solutions only are implemented, not only does the neglect of retail market misalignments remain, misalignment between RES integration and network regulation, market coupling, and EU-ETS also remains outstanding.

Of the retail market focused proposals, *transactive pricing* completely collapses the boundary between wholesale and retail markets, expecting consumers to participate in trading more actively (either directly or via intermediaries such as aggregators), while the *two-market solution* expects the operational decisions of active consumers to be mediated by intelligent appliances that they have purchased. Two other differences exist between the two solutions:

- Transactive pricing explicitly recognises the role of network capacity, by proposing concurrent trading of transport capacity with electricity (it is unclear if this is to be carried out implicitly via nodal prices or explicitly via parallel auctions), whereas the two-market solution is silent over the impact of network capacity on the functioning of the proposed ‘as available’ market.[20]
- Transactive pricing is silent over the issue of RES support schemes in the wholesale market, and thus does not address concerns related to the RES-exacerbated ‘missing money’ and ‘missing

[20] Two possible solutions can be extrapolated from the description of the two-market solution: automated clearing of supply and demand in the ‘as available’ market (based on spatially differentiated bids and offers to avoid physically infeasible scheduling); or the dispatch of ‘as available’ supply and demand (based on a simplified representation of the networks – the resulting re-dispatch cost required is socialised by the consumers in the ‘on demand’ market as the already socialised overall system costs). Obviously, the second approach raises significant equity concerns.

market issues' for conventional generators.[21] On the other hand, the two-market solution admits that subsidies are likely to be required in the 'as available' market, before RES costs fall to a level competitive with conventional generation technologies (including the costs of carbon externality). Also, capacity and flexibility payments may be required in the 'on demand' market to incentivise long-term investment.[22]

Although the two proposals offer market mechanisms for further engaging consumers in short-term operational and long-term investment decisions in the power sector – via the opening of wholesale trading to retail participants and the offering of long-term fixed contract for demand-end investors in flexible appliances, respectively – both designs still require additional mechanisms to ensure the adequacy of supply-end investment. These could take the form of long-term contracts between consumers and generators for transactive pricing; RES subsidies, capacity and flexibility payments to generators for the two-market solution. Misalignments between such mechanisms and market coupling/EU ETS would thus remain.

Finally, the proposal to *introduce a capacity-based element into pricing* could be applied in the wholesale and retail markets. This is less a proposal for the design of a given coordination module and more of a general design recommendation.

- For the wholesale coordination modules, capacity-based RES support schemes can replace production-based payments to limit the effect of subsidy payments on RES generators' operational decisions, while capacity remuneration schemes can be seen as being aligned with this principle (revenue being based on capacity rather than on energy generated).
- For the retail market, recovering network-related charges and other fixed fees using a capacity element in the tariff can prevent a fall in cost recovery (as energy consumption declines with self-generation by prosumers), if they retain the same level of network access. Alternatively, exposed to the fixed charges, they may decide that it is in their interest to decrease their network access, hence re-establishing the balance between network usage and network cost recovery.

The application of this approach in the wholesale market (especially capacity payments) has been criticised for shifting generators' incentives from optimisation of their generation operations to capital cost minimisation. We argue that, in the case that capacity and other fixed costs are much higher relative to a generator's operational costs, prioritising minimisation of the former over the latter is justified, as long as the assessment of operational costs fully reflects system externalities (the balancing services required). On the other hand, the capacity element in a retail tariff has also been criticised for increasing the average energy cost of a lower consumption household, raising equity concerns.

In terms of compatibility with future scenarios, only the *investment market* and the *two-market solution* approaches recognise that subsequent changes in coordination modules are required with the trend towards increasingly mature RES deployment (this trend is expected in all of our scenarios). The two approaches suggest removing subsidy to RES generators by merging capacity-based RES support schemes with CRMs, or merging generators' revenue with consumer payments in the 'as available' market. Only the two retail market-focused proposals have consumer engagement mechanisms that are compatible with the decentralised scenario. None of the proposals explicitly addresses the market design changes required for further regional integration – the pathway that is associated with the centralised scenario.

Our evaluation of existing market design proposals, relative to their ability to address existing misalignments, and compatibility with future scenarios, shows that most proposed solutions would

[21] Free contracting between supply and demand through long-term contract has been mentioned as a possibility, but not expanded on.

[22] For low-carbon generation suppliers, the difference between the fixed, long-term 'as available' retail tariff and their generation cost needs to be subsidised, although this deficit is expected to fall as RES generators realise cost reductions.

correct only a very limited number of the misalignments that we have identified, and that few of them take an evolutionary view, considering how market design might need to change with future trends. The proposals mainly differ in the misalignment that they focus on (inadequate risk-sharing in wholesale market modules or the lack of consumer engagement in retail market modules). As will be demonstrated in the following section, they are not necessarily exclusive and may be combined.

4. Our approach

In this section, we present our recommendations, which are developed on the basis of our understanding of current market design misalignments, future scenarios, and the strengths/weaknesses of existing solutions. In addition, we also contribute to the debate on the goal of energy policy and its mode of interaction with power market design.

Through the application of system thinking to power market design, we iterated between multiple conceptual representations of the existing dominant market design, seeking a structural representation that satisfactorily explained the dynamics currently being experienced in the power markets across the EU.[23] We arrived at the modules-and-levels framework, which has been described in detail in Section 0. Then, leveraging this conceptual framework and the understanding that it provides, we propose, in this section, modifications to the existing system of power market design to restore its purpose: providing signals for efficient operation and investment in the power sector. Our proposal should be considered a first draft based on conceptual modelling. In order to fully assess its feasibility, quantitative modelling of the interacting component modules and their behaviour under staged market redesign should be pursued.

At the same time, the ongoing transition in the power sector has precipitated an emerging field of research – 'sustainability transitions' – which is concerned with the far reaching changes affecting social, political, institutional, organisational, and technical aspects of socio-technical systems (Markard, Raven, & Truffer, 2012). We have also borrowed significantly from its key analytical frameworks and from theories on 'innovation systems'.

We structured our recommendations with two principles:

1) Given the uncertainty associated with exogenous forces such as technology development and public attitude/consumer preference, we have recommended modifications which are compatible with hybrid scenarios, where decentralised coordination and centralised coordination are both encouraged (see Section 3.3 and the Appendix for the description of these forces). We believe that designs aimed at a purely centralised or purely decentralised future are overly optimistic about the form of coordination that they embrace, with the possible unintended effect of thwarting innovation on the other track, while a design taking into consideration a hybrid future provides more flexibility and resilience.
2) After identifying the relative strengths and weaknesses of existing solutions in Section 3.4, we sought to generate a more comprehensive design by combining elements from existing solutions. We do not think that the existing proposals are mutually exclusive, and we select elements from all proposals to target different misalignments in the dominant design.

[23] System thinking has also been applied in our previous publications. In Peng & Poudineh (2015), we described the Structure–Conduct–Performance–Regulation (SCPR) framework which operationalises the identification of structure and dynamic behaviour for an extended gas-to-power value chain. In Peng & Poudineh (2017), we extended the SCPR framework beyond the regulatory/commercial dimensions, to also describe structure and dynamic behaviour in developing countries' political systems.

4.1 The next steps in market design: our recommendations

In Section 3, we identified the structure of the dominant power market design in the EU and represented it as an interdependent set of coordination modules, not of all which have evolved at the same time. RES support and CRM modules are coordination modules that developed after the other modules, to serve new needs which had been perceived. Altogether, the modules should serve the purpose of providing effective investment and operation decision signals for all participants, albeit misalignment between the incentives that they provide has been preventing this.

Going forward, we take the view that all currently identified misalignments among coordination modules will have to be addressed. However, not all misalignments can necessarily be addressed at the same time. Certain conditions may need to be realised before a measure can be implemented.[24] In addition, the resources and resolve required to adopt a steep step change are not always available. Therefore, we propose a series of changes, sequenced so that earlier reforms may create the conditions required for later reforms (see Table 5). This also allows us some flexibility in the 'ultimate' market design, for adjustments can be made if more information becomes available and alters our diagnosis of the changes required.

With respect to future scenarios, unless smart grid or supergrid development is clearly obstructed by technological challenges and/or public attitudes, forward-compatible designs need to accommodate trends in both centralised and decentralised coordination. In other words, the default design scenario we adopt is the hybrid pathway, where both cross-border and demand-end participation need to be supported, hence maximising the means through which the power system can respond to increased variability with further integration of RES. Finally, our proposal is a synthesis of the proposals reviewed previously (except for 'absolutist approaches'), and demonstrates how these apparently heterogeneous approaches can be combined, gradually, to enable the long-term transition to a low-carbon power system that can be operated in a self-sustainable way.

Measures that open coordination modules to cross-border participation support the development of a centralised supergrid future, whereas measures that open coordination modules to small-scale residential and commercial participants (previously only able to contract from the retail market) support the development of a decentralised smart-grid future. We do not think these market design features are mutually exclusive, therefore we embrace both type of measures in our composite design.

[24] For example, it was found that sequencing mattered in the previous wave of liberalisation-driven power market reform in developing countries. The establishment of an independent regulatory authority before privatisation improved the outcome of the reform (Zhang, Parker, & Kirkpatrick, 2005).

Table 5: Recommended sequential steps for electricity market design reform[25]

Step	Module	Prerequisite	Market design adaptation
1	**RES support scheme and CRM**	None	Competitive bidding for RES support to large generators, awarded in the form of long-term contract based on capacity rather than on production. The capacity market is similarly designed. Distributed RES support may not yet be competitively awarded, but it becomes capacity-based. Both schemes are adjusted for implicit, or are open to explicit, cross-border participation.
2	**Wholesale**	None	Investigation of the benefits of further spatial differentiation for energy markets (nodal or increased number of zones).
3a	**Wholesale**	2	Refining intraday and balancing markets to improve liquidity. Enable cross-border integration of intraday markets; enable demand-end participation in intraday and balancing markets for large consumers and participation of new technologies (such as storage).
3b	**Wholesale**	3a	Place balancing responsibilities on RES generators, so that they are incentivised to improve their forecasts.
4	**RES support schemes and CRM**	1, 2 & 3	Remove subsidies to mature RES technologies, so that they compete with other generation technologies on an equal basis.
5a	**Network regulation**	None	Innovation-oriented distribution network regulation; roll-out of advanced meter infrastructure. Investigation of the benefits of further spatial differentiation at distribution level.
5b	**Retail**	5a	Network tariff and other capacity-based cost recovered using charges based on contribution to peak-coincident capacity; policy levy on consumers also to be charged based on capacity, or passed to government budget.
6	**Wholesale + Retail**	3 & 5	Enable demand-end participation in all wholesale markets (day-ahead, intraday, balancing, and ancillary services market) for distributed consumers via aggregators or smart equipment.
7	**RES support scheme**	4 & 6	Remove distributed RES support scheme.

As a first step, we recommend awarding long-term contracts to large RES generators via competitive auctions. Competition for long-term contracts has already been successful in many countries (from Germany and Mexico to Morocco and the UAE), decreasing procurement costs by enabling price discovery and de-risking investment by providing certainty regarding contracted revenue (IRENA, 2017). It may not be possible to award RES support for the smaller, distributed generators on the basis

[25] Since steps 1, 2, and 5a in Table 5 do not have prerequisite conditions, they can be implemented in parallel, but we describe them sequentially.

of competitive bidding at this stage, because of high transaction costs given the large number of agents involved.

The two main criticisms of such a design are market foreclosure (decreasing the relevance of short-term market coordination) and over/under-procurement by the central authority (the counterparty to such contracts), so that the contracts do not represent the preference of electricity consumers. We argue that by offering RES support on a capacity basis rather than on a production basis, the distortion of such payments on the short-term generation choices of generators is reduced. Payments based on capacity are not expected to influence RES generators' operational decisions in the energy markets, for the revenue from RES support is independent of their generation. Note that capacity-based support will not be the only source of revenue for RES generators.[26] Therefore, RES generators retain the incentive to optimise their performance in the energy markets, for they rely on energy market revenue to supplement the capacity-based support. We also argue that, via subsequent steps of our sequenced recommendation, consumer preference can be better incorporated into the auction of such long-term contracts (see Step 5).

To address the misalignment of national coordination modules with market integration, we recommend that procurement through the centralised RES support scheme and CRM should either consider the contribution of cross-border capacity in its procurement target, or be open to the explicit participation of cross-border capacity. This is more important for a centralised, supergrid-based pathway than for a decentralised, smart grid-based pathway, because non-harmonised and exclusively national schemes lead to sub-optimal investment decisions at the regional level and induce negative operational externalities, a situation which has a greater adverse impact on the centralised scenario.

However, extending participation in RES support/CRM across national borders is politically difficult, because targets for renewable energy and power system reliability remain goals that are anchored at the nation state level. Measures evaluating success and failure in meeting such targets are mostly based on accounting conducted within national boundaries. However, for the regional supergrid approach to develop further, all participants within this extended market, across different countries, need to be exposed to the same competition environment; this includes the various RES support/CRM auction modules in place in different countries. The EU 'winter package', for example, has proposed a revised Renewable Energy Directive, where Member States are required to progressively and partially open their support to projects located in other Member States (European Commission, 2016b). As for CRM, the UK capacity market has decided to account for the contribution of cross-border participation by allowing the participation of interconnectors in capacity auctions (O'Connell, 2015).

The second change we recommend would relate to an investigation of the system benefits of increased spatial differentiation for transactions in the wholesale electricity markets (day-ahead through intraday), either through nodal pricing or an increased number of bidding zones. The potential benefits that might be realised arise from a more accurate representation of the underlying transmission network, reducing the socialised re-dispatch cost that results from infeasible schedules. The arguments against increased spatial differentiation are primarily based on equity: it is often politically unpopular to divide a country into several price zones/nodes. We argue that, to address equity concerns, ex post reconciliation through non-distorting payments (such as direct cash transfers – implemented in many developing countries to phase out energy subsidies) is preferable to deliberately maintaining inefficient ex ante signalling. But, we also recognise that the cost benefit analysis of further spatial differentiation in

[26] RES project developers bid for capacity-based support depending on their expectation of project cost and revenue available from (un-subsidised) energy market operations. Those who have confidence in higher energy market revenues may submit a lower bid in the RES support auction, increasing their chances of securing the long-term capacity-based contracts.

electricity pricing will be different for different jurisdictions, so that not all EU Member States may decide to pursue it.

Once the spatial granularity of energy markets has been reviewed (spatial resolution is either maintained or refined), we recommend making RES generators balancing-responsible parties (Step 3b), with the condition that post day-ahead markets (intraday and balancing) are sufficiently liquid for RES generators to access and supply balancing services (Step 3a). Improving liquidity in short-term markets may require removing the price cap (if applicable), holding auctions rather than continuous trading, and allowing the entrance of more participants: cross-border service providers/large storage service providers need to be included for the development of the centralised pathway, demand-end service providers/small storage operators need to be included for the decentralised pathway. This step is the application of the refining energy-only market proposal, with the goal of removing misalignments in the short-term coordination of the wholesale market.

Once large RES generators were able to compete for the market in centralised RES support schemes, in a format similar to that in the capacity market (Step 1), and bore balancing responsibilities like other generators (Step 3), the phase-out of RES support would have a clear pathway: if the capacity support required for a given type of RES technology decreased to a level that was comparable to payments made in the capacity market, then that technology should transition from competing for RES-specific capacity-based payments to competing for technology-neutral capacity payments (Step 4). Reaching this stage would mean that the misalignment between national RES support schemes and the EU ETS was no longer relevant, for RES support would no longer exist for mature RES technologies[27].

On another track, we encourage the implementation of innovation-oriented distribution network regulation, complementing the roll-out of advanced metering infrastructure (Step 5a), so that further market design measures requiring more advanced sensing and monitoring capability at the distribution level can be unlocked. We also recommend conducting cost–benefit analysis at this stage to assess whether further spatial differentiation for connection charges and network tariffs would improve locational signals to distributed resources (distributed generator, storage, EV charging infrastructure), enabling reduction of distribution grid reinforcement costs. This is especially critical if a decentralised pathway relying on smart grid-based balancing is envisaged.

The direct follow-up measure (Step 5b) would be to recover network-related costs from retail consumers via peak-coincident capacity-based charges rather than energy-based charges. Step 5a is a prerequisite, for better monitoring is required to establish the peak-coincident capacity requirement of network users at the distribution network level. In this way, grid-connected prosumers continue to pay for their use of network capacity, even when their energy consumption has decreased. Correspondingly, the network costs borne by non self-generators do not increase disproportionately.

In a similar vein, the policy costs for RES support and for CRM (which both take the form of long-term capacity contracts) are to be levied via capacity requirement rather than energy consumption. This reduces the distortionary effect of policy levy on electricity consumption (see Section 3.1.2 for the effect of energy-based policy levy on motivation for electrification). Also, this feature partially addresses the criticism that centralised capacity procurement does not reflect consumer preference, because consumers, now exposed to a higher capacity-related cost (as opposed to higher costs for energy consumption), would be incentivised to make more efficient decisions about their capacity requirement.

[27] Support for niche emerging technologies such as wave and tidal might be sustained following full commercialisation of mainstream technologies such as wind and solar, for the sake of supply diversity.

Thus, the capacity that they contract and make use of, if aggregated and used as the basis of CRM procurement, would reflect their preference.

We recognise that recovering investments made in networks and generation capacity (conventional and RES) on the basis of capacity contracted, instead of via energy consumption, will affect the distributive outcome among energy consumers. However, any rebate to low-income households (aimed at correcting the distributive outcome) should be handed out separately, rather than though non cost-reflective retail market prices.[28] We have already elaborated this point, when discussing spatial granularity at transmission level, within Step 2.

Once the refining of short-term energy markets has begun and effective monitoring/controlling capability is in place at the distribution level (Steps 3 and 5), we recommend that distributed generation/demand be allowed in intraday and balancing markets, most likely via the intermediation of aggregators (Step 6). Introducing responsive distributed demand into traditionally supply-dominated wholesale markets allows participating retail consumers to be compensated for flexibility in their consumption and/or generation; it would also allow other participants to benefit from access to those services. This change thus removes the misalignment between short-term coordination in the retail market and further RES integration.

If subsidy-free centralised RES capacity procurement is achieved (Step 4), and distributed prosumers are exposed to (potentially spatially differentiated) capacity-based network charges (Step 5b) and are able to monetise their flexible consumption/demand through their participation in the intraday and balancing markets (Step 6), we suggest removing RES support to distributed RES generators. At this stage, the system cost and benefits of distributed generation would be fully captured by the charges applicable/revenue available to distributed generators. And centralised RES generators already operate without additional subsidy. So, additional investment in distributed generation should only occur if the net benefits (from avoided costs and revenue) offset the investment without subsidy.

The current dominant market design and the hybrid market design is illustrated in Figure 10, and the market design in place once all proposed changes have been adopted is illustrated in Figure 11. The original liberalised market design for conventional fossil fuel generators and passive consumers (Figure 12), and the potential ultimate market design for the hypothetical case in which all generation comes from RES generators and all consumers are active prosumers (Figure 13), are also included.

The full sequence of market design transition would involve morphing from Figure 12, the originally fossil-fuel generators and passive consumer dominated design, through the existing hybrid design (Figure 10), gradual inclusion of forward-looking adaptive measures (Figure 11), eventually to Figure 13, a future where RES generators (including prosumers) dominate. In these figures, the direction of the arrows indicated the flow of payment from one party to another.

The logic driving these adaptive changes is initially the setting up of policy-supported niches that introduce centralised RES generators and distributed prosumers into the power system, via RES support modules. Following that, we plan how to remove obstacles to market-based competition for these new types of participants, and eventually wean these relatively new market participants from subsidies once conditions are mature. Removing all RES-favourable policy instruments in place too soon could prematurely expose RES generation to market conditions designed for the historical fossil fuel-based system, thus endangering the investment in RES required for decarbonisation. However, a failure to recognise the changing circumstances (rising levels of RES generation is now engendering

[28] Examples in the UK, primarily targeting energy used for space heating, include the Winter Fuel Payment, Cold Weather Payments, and the Warm Home Discount Scheme.

sub-optimal dynamics in the dominant power market design) is detrimental to the achievement of long-term energy transition. This is because such inefficiencies increase the cumulative cost of decarbonisation.

The evolution from the market design we recommend (Figure 11) to a more simplified future (Figure 13) occurs if the volume of transactions that occurs in the day-ahead market becomes negligible, as the number of conventional generators and consumers that trade energy at that time horizon dwindles. Once that occurs – this is not expected to be an overnight event – the most important payment stream in the future power sector is expected to be the capacity-based grid access fee, which includes the network tariff and a long-term firm capacity payment. We expect the day-ahead energy market to decline in importance with increasing RES integration, but do not take its full dissolution to be a certainty. Note that our recommendations do not rely on the realisation of the final simplified design embodied in Figure 13. The power market can operate as is in Figure 11 and it will naturally accommodate the decline of some coordination modules, if and when this occurs.

The adaptive multi-market design that we propose integrates concepts from many market proposals reviewed in this paper. Referring again to Table 5: Step 1 culminating in Step 4 relates to the combined application of the investment market and capacity-based pricing in the design of centralised RES support schemes and capacity remuneration mechanisms. Steps 2 and 3 borrow from proposals to refine energy-only markets. A limited form of transactive pricing is achieved with Step 6, when distributed demand is allowed to participate in wholesale energy markets (directly or via an intermediary). Step 5 describes the application of capacity-based pricing in network tariffs and retail markets. And, finally, the overall transition logic is comparable to that behind the two-market solution, where temporary government subsidy is leveraged to transition to a paradigm that is not currently supported by prevailing market forces.

Figure 10: Current dominant power market design

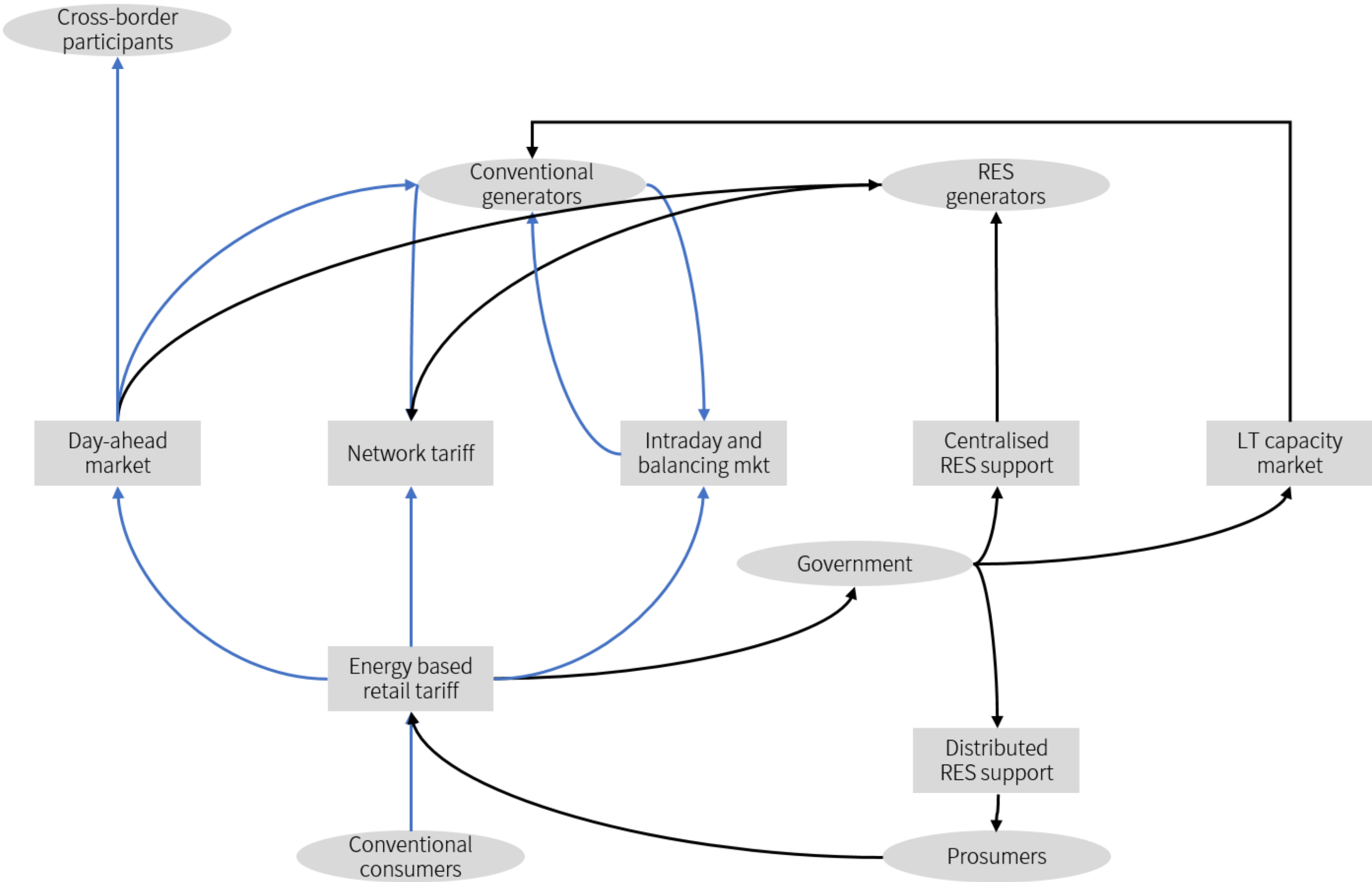


Figure 11: Power market design once all proposed changes have taken place

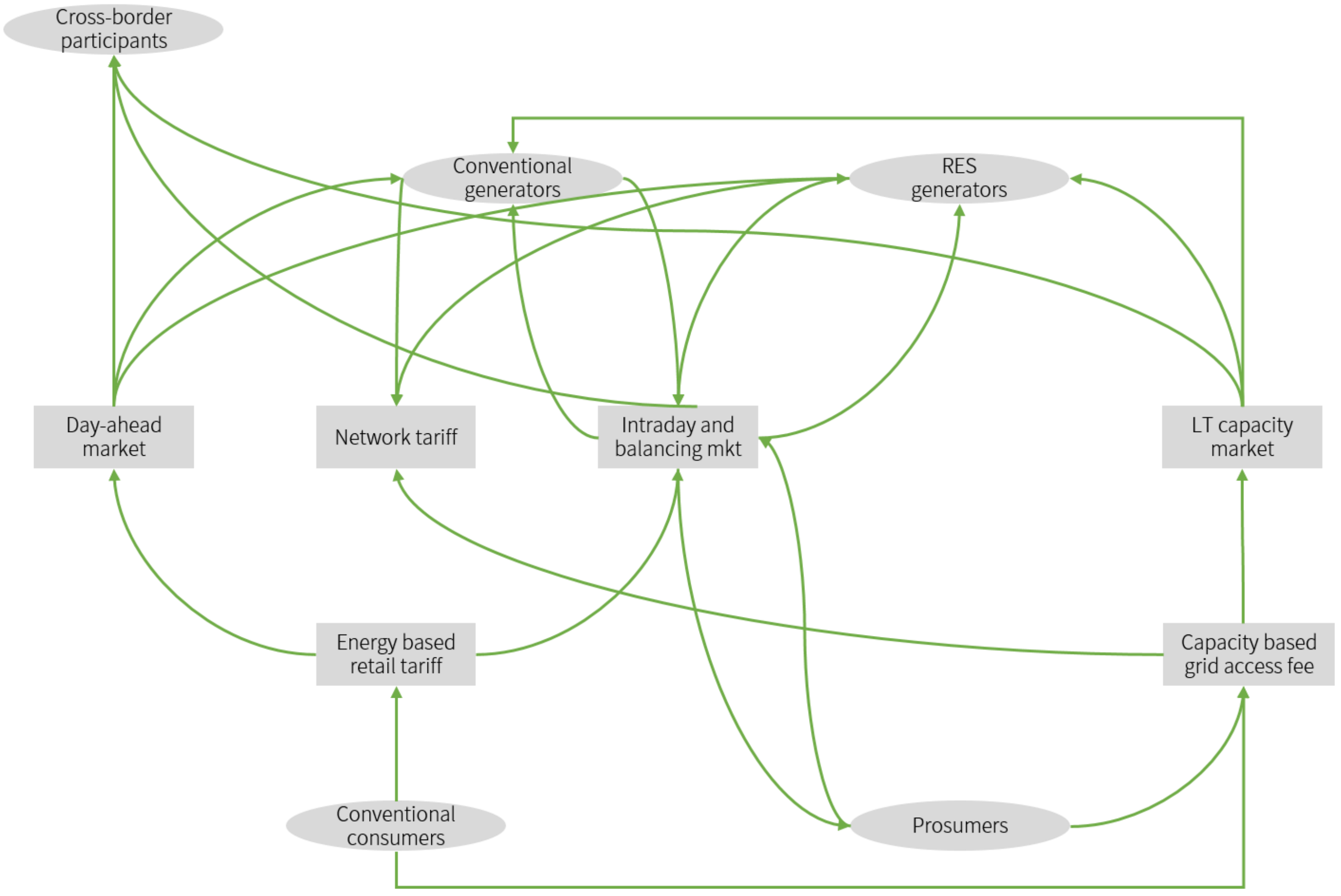


Figure 12: Original liberalised power market design

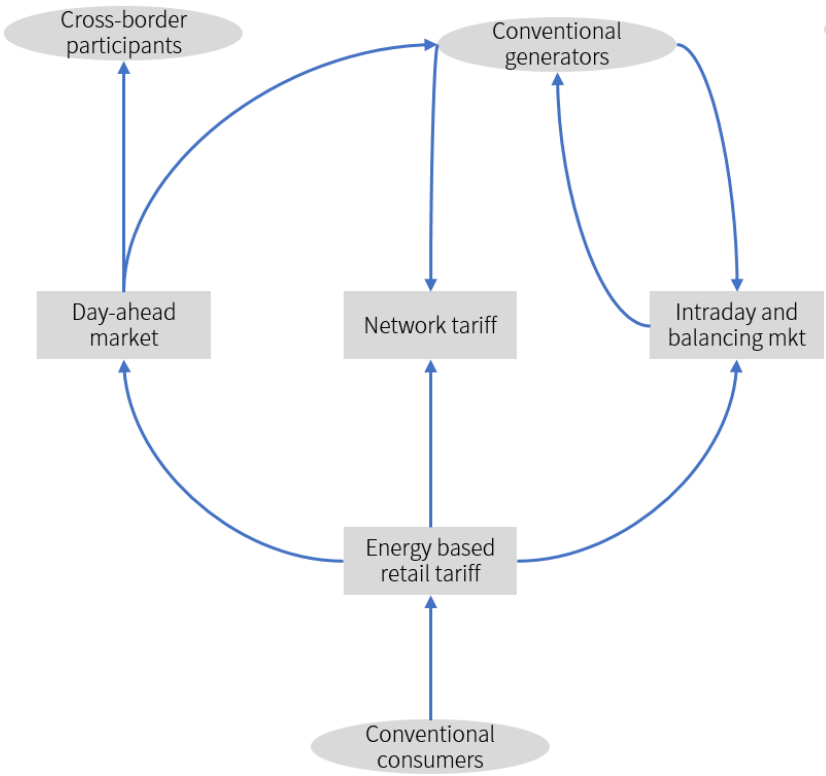
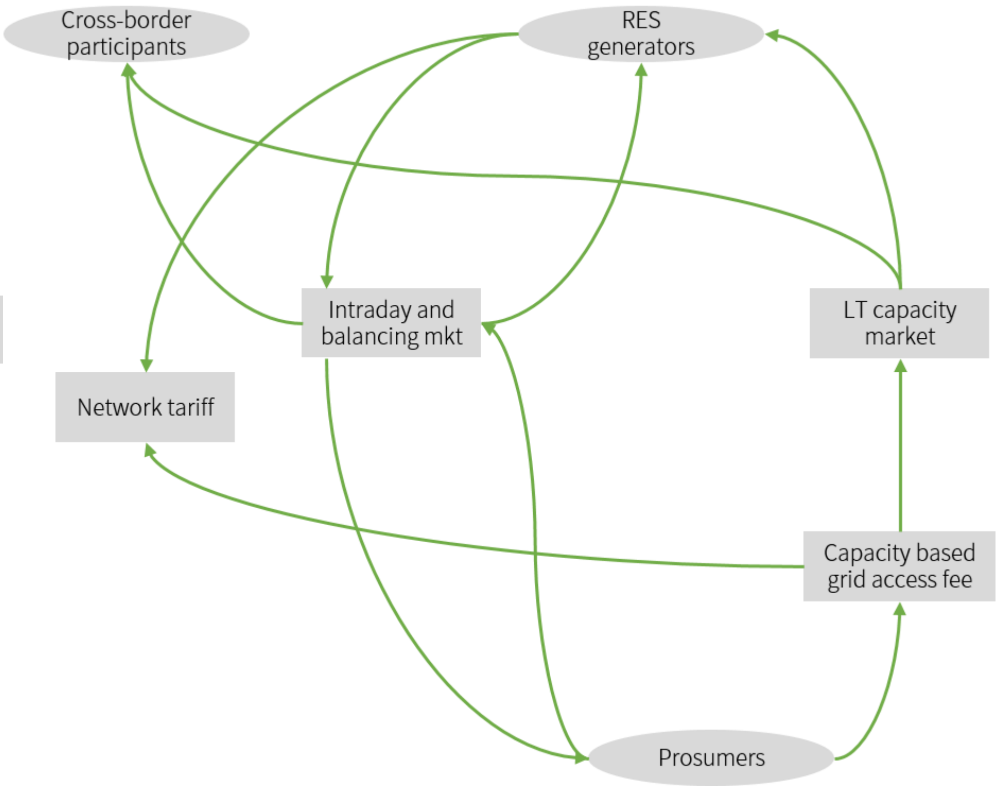


Figure 13: Hypothetical future power market design



4.2 What should be the objectives of power sector policy?

Given the interdependency between power sector policy and electricity market design, it is important to decide on the objective of power sector policy (in other words: what should be the trade-offs between conflicting energy policy objectives?). Among decarbonisation, affordability, and security of supply, we see continued decarbonisation as the primary driver of the transition occurring in the power sector. The interdependence between the objective of decarbonisation with other policy goals should be perceived as being dynamic and open to change.

Currently, the relationship between goals is in conflict, given the lack of complementarity between newly introduced RES generation technologies and the existing socio-technical regime of the power sector, for it is both less costly and easier to maintain reliability standards using conventional technologies.[29] In this case, other policy goals are process boundary conditions, which need to be managed so that the decarbonisation objective is not undermined. For example, the perceived affordability of electricity, which is affected (but not solely determined) by electricity bill levels, is currently linked to government levies that pay for RES support (and in some cases, capacity remuneration mechanisms, or even other non-energy related costs); this needs to be monitored and managed to maintain legitimacy and public support for decarbonisation.

In the future, further developments in technology, contingent upon current policy instruments being implemented, may create a more synergistic relationship between policy objectives. The ongoing reconfiguration of the power sector regime can make the use of RES technologies competitive with conventional technologies in terms of cost and system reliability. First, cost reduction realised through continued deployment is already making RES technologies cost competitive with conventional generation in many parts of the world. Secondly, security of electricity supply – both the long-term availability and short-term reliability of electricity supply – has historically been guaranteed through central procurement by the government and/or the System Operator who have the incentive to over procure. Technology and corresponding market design changes, developed to further the aim of decarbonisation, may enable decentralised procurement of long-term and short-term electricity supply by consumers through a range of different means (such as: self-curtailment, use of storage/self-generation, and purchase from another self-generator/the grid). This approach not only better reflects consumer preference and a reduction in over-procurement, it can also lower the cost of providing security of supply through more efficient use of existing infrastructure.

4.3 Balancing the role of market coordination versus government

The misalignment between market modules also raises questions about what the role of market-based coordination should be, relative to government policy instruments, in meeting policy objectives. Although we have observed many misalignments in existing electricity markets as more government-based modules have been grafted onto the original liberalised market model pursued in Europe, we do not think that this justifies absolutist proposals which seek to annul all government interventions (thereby restoring 'pure' market governance) or to fully revert to centralised planning and operation (thereby restoring 'pure' state governance).[30] Instead, we believe that a hybrid form of governance with better coordination between policy instruments and market competition is required: government-issued policy

[29] We define 'socio-technical regime' as a complex of dominating scientific knowledge/engineering practice, together with the user expectations, institutional structure, and infrastructure with which it is intertwined, co-evolving over many years (Geels & Schot, 2007).

[30] We define 'governance' as the totality of all co-existing forms of collective coordination of societal issues. Currently governance literature commonly divides governance into three ideal types: hierarchical (state bureaucracy), market, and network (horizontal coordination characterised by informal or organic social systems) (Meuleman, 2008).

instruments would assist with coordination across the power value chain, de-risking and thus activating investment in innovative technologies, whereas market competition would be relied upon to increase the efficiency of the adopted innovative technologies. In other words, we do not think that a hybrid form of governance necessarily offers the worst of both worlds (inefficiency from state-based governance and higher risks from market-based governance); instead, if a more reflexive network-based meta-coordination between the two is successful, we might be able to experience the best of both worlds.

Beyond the negative externalities associated with carbon emissions, there are multiple market and system failures which restrict the development and adoption of low-carbon technology, thus legitimising the implementation of policy instruments in addition to the market-based EU ETS (Lehmann & Gawel, 2013). Initially, knowledge spill-over meant that there was a sub-optimal level of investment in innovation. Secondly, it is argued that the external cost of carbon emissions is not completely internalised by the EU ETS emissions cap, given the political nature of the negotiation process. For the same reason, investments based purely on the EU ETS are subject to significant regulatory uncertainty: it is not possible to predict the long-term allowance price beyond the current period given the negotiated nature of the cap, and even within the same period, the allowance price is rather volatile. Finally, the sluggish liberalisation of electricity markets in Europe has meant that dominant firms which do not face sufficient competition may have an even lower incentive to innovate; they may engage in incremental process innovation rather than product innovation and impede the entry of new RES-based competitors. Similarly, policy instruments in the form of capacity remuneration mechanisms are legitimised by imperfections of the existing market (the issues of missing money and missing markets).

If RES support schemes and capacity remuneration mechanisms are removed without addressing the underlying market and system failures that legitimised their implementation in the first place, it is very unlikely that innovation enabling decarbonisation would prevail.[31] However, we also recognise that government interventions are not welfare improving by default: the impact of policy instruments is conditioned by their specific design and, as societies become increasingly complex and interconnected, by unintended interaction between policy instruments and market-based coordination modules (see Section 0 for an extended discussion). A return to centralised planning and operation may seem tempting, as it promises to remove some misalignments by moving all coordination into the centralised public sphere. But, it does not address the issues of policy coordination failure within the public sector: a pure state-based centralised and hierarchical coordination is a structure that cannot adequately deal with fast-paced changes (Espinosa, Harnden, & Walker, 2007).

In the last decades, the role of the government in power sector governance has changed from that of being the sole investor/operator, to that of regulator, responsible for establishing the necessary environment in which decentralised investment and operation can occur. We argue that, to achieve long-term transition (decarbonisation), a further shift in the role of the government is needed, from that of regulator to meta-coordinator. The key difference between these two roles is that a regulator is mainly concerned with monitoring and enforcing market rules, while a meta-coordinator is concerned with facilitating goal-setting and learning among co-dependent stakeholders, supporting them in self-organisation throughout the progress of the transition cycle (Rotmans, Kemp, & van Asselt, 2001).

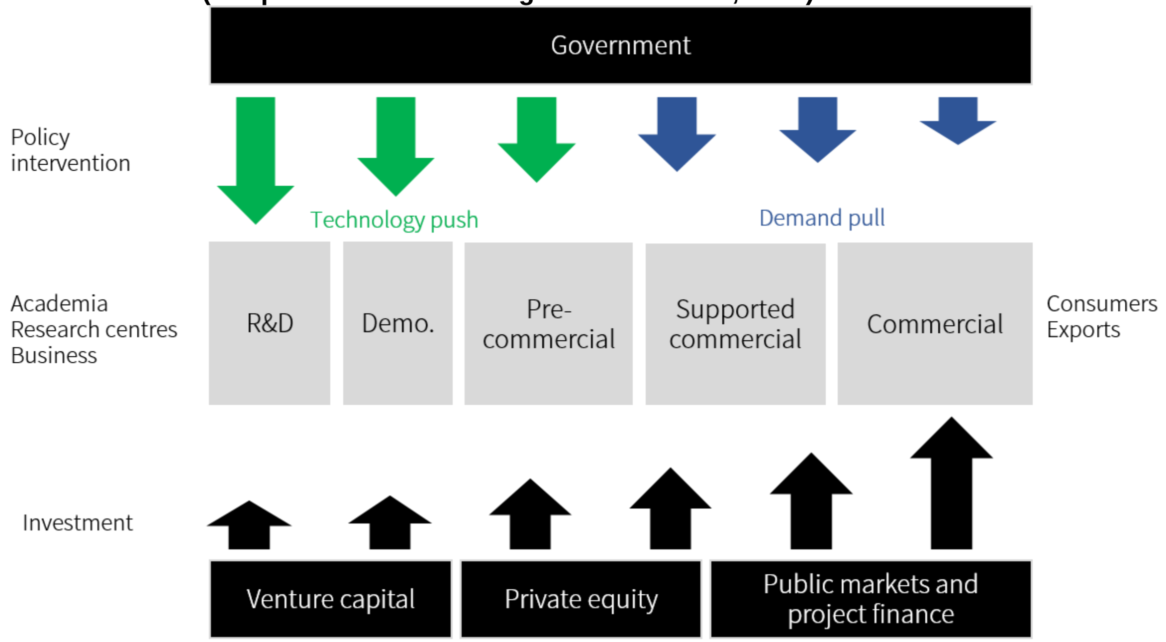
At the beginning of the transition, when uncertainty looms large, the responsibility of the government is to promote variation, catalysing experimentation by creating niche environments that support innovation by sheltering innovating stakeholders from market selection pressure. At this stage, parallel

[31] In terms of sector turnover invested in R&D activities, the energy sector is one of the least innovative sectors in the whole economy, since the big capital investment and long timescales involved naturally increase risk, while energy output cannot command a price premium through product differentiation (Grubb, 2004).

development is admitted for coping with uncertainty. As more information is gained about the various options, the government then needs to provide platforms for interaction where stakeholders (including the government's representatives) can deliberate on the most appropriate policy instruments for the next phase of transition. As a technology matures, the policy instruments supporting it evolve from being R&D-oriented to become more concerned with facilitating commercialisation by removing market entry barriers (see Figure 14). Moreover, because there are likely to be several technologies under consideration for policy support at the same time, policy instrument coordination is required for a mix of technologies at varying maturity levels.

Given that different policy instruments have non-uniform impacts on stakeholders, consensus is not expected, but a reflexive and participatory process, in which stakeholders agree on the protocols for interaction and communication, helps to make such political tensions explicit and legitimise the portfolio of policy instruments selected (Weber & Rohracher, 2012). Once a decision emerges through such an interactive process, the government then needs to mobilise resources to advance it and manage the distributional fallout resulting from the decision (Meadowcroft, 2011).

Figure 14: Coordination between policy instruments and market competition along the innovation chain (Adapted from Wüstenhagen & Menichetti, 2012)[32]



Market competition can contribute towards the selection process among technology alternatives, but we do not believe that it automatically selects the optimal outcome and removes the necessity for political deliberation. This is because the need for deliberation is only pushed to the level of market design, but different market designs can have heterogeneous impacts on technologies at different maturity levels. Hence, in our view, market competition plays a complementary role to two other mechanisms: innovation supported by policy instruments (technology-push policy instruments which evolve to be demand-pull instruments as technology matures) and political deliberation that legitimises

[32] Even pre-commercial technologies still require government support, often in the form of niche markets via public procurement, to bridge the gap between discoveries in the lab and large-scale commercial deployment; this is sometimes referred to as the 'valley of death' (Grubb, 2004). Measures such as carbon tax and cap-and-trade assume technologies are at the end of the innovation chain, only necessitating internalisation of environmental externalities.

the use of evolving policy instruments to drive long-term vision-compatible innovation (illustrated in Figure 15).

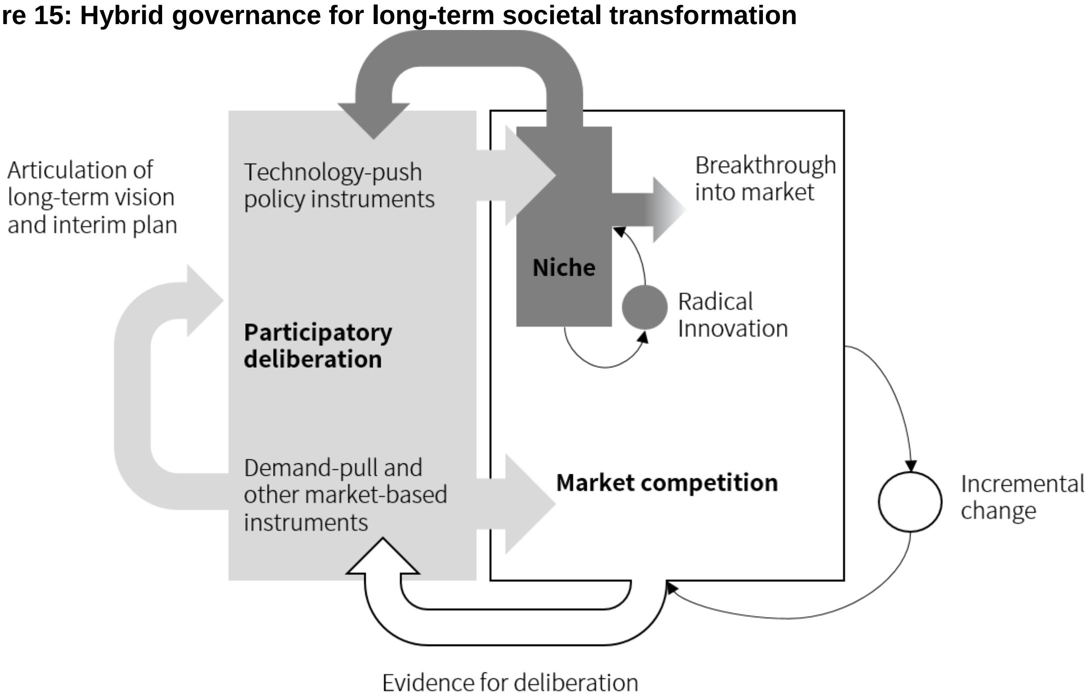
The engine of change, in the hybrid governance model described above, is the deviation between the current state of the system and the long-term vision, articulated interactively. The participatory process which facilitates vision articulation also informs the design and implementation of policy instruments required for the next step, either addressed at niche innovation or through market competition, whose results then feed back into the deliberation process. Therefore, it is very important to build in safeguards against domination and capture by partial interests in the participatory process.[33]

For the hybrid governance approach outlined above to be effective at enabling innovation for long-term transition toward a specific goal, alignment is needed at two levels between governance components:

1) *Macro level: Relatively long-term coordination between the different mechanisms that coexist within hybrid governance: selection and implementation of policy instruments through participatory deliberation, market competition, and innovation in protected niches (Figure 16);*
2) *Micro level: Shorter-term coordination between technology-push policy instruments and innovation processes; between demand-pull policy instruments and market competition (Figure 17).*

For macro-level coordination to achieve its goal (advancing vision-compatible technologies through the innovation chain), micro-level coordination of policy instruments also needs to meet its goal (designing and implementing policy instruments that provide the support that is appropriate for niche-protected innovation and market-driven innovation).

Figure 15: Hybrid governance for long-term societal transformation



[33] Some researchers have proposed to entrust the meta-coordinator role to a new body independent from the government to avoid capture (Keay & Robinson, 2017a).

Figure16: Macro-level coordination in hybrid governance

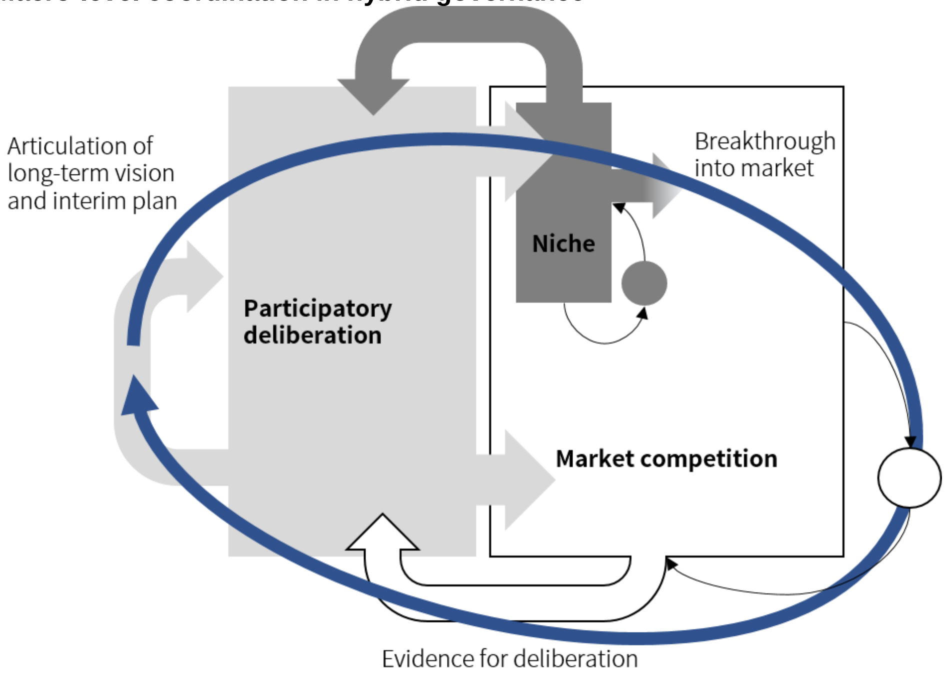
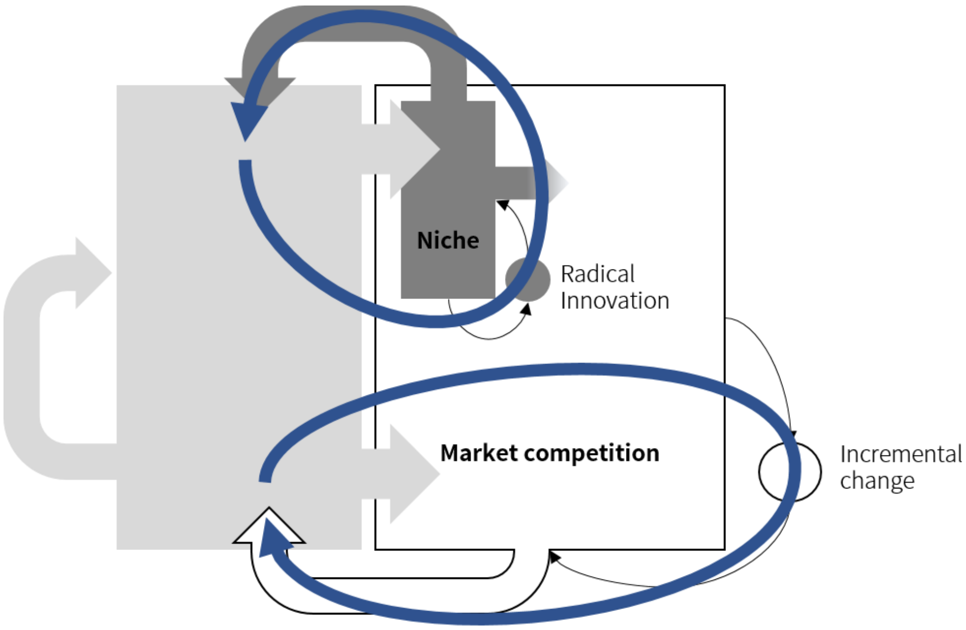


Figure 17: Micro-level coordination in hybrid governance



Other than having outcome objectives focused on the realisation of innovation, both macro and micro-level coordination also have process performance indicators to be managed. The legitimacy of the political deliberative process needs to be maintained to secure the participation of societal stakeholders in the transition process. The credibility of policy instruments that are implemented needs to be maintained to engage stakeholders in innovation and market competition. The outcome of hybrid governance, as it depends on the contribution of decentralised stakeholders, is not within the control of the government/meta-coordinator. However, because the government/meta-coordinator has a major influence over the process of hybrid governance, it can indirectly affect outcomes by affecting the legitimacy or credibility of the macro/micro-level coordination process. The main differences between these two levels of coordination are summarised in Table 6.

Table 6: Comparison of macro and micro-level coordination processes for hybrid governance

	Macro level	Micro level
Objective	Encouraging advances in innovation to achieve long-term vision, while meeting boundary objectives.	Encourage innovation in technology that is appropriate for its level of maturity through targeted policy instruments.
Alternatives	Support certain emerging technologies; Further support of certain developing technologies; Reduce support of certain commercially competitive technologies; Cease support to certain non-promising technologies	Specific technology-push, demand-pull, or systemic policy instruments e.g.: R&D grants, tax incentives, subsidies, public procurement, performance standards, market design, public information campaigns, etc.[34]
Outcome performance	Long-term emission reduction.	Performance of policy instruments in encouraging emission reducing innovation.
Process performance	Consistency, legitimacy, credibility.	Consistency, legitimacy, credibility.
Decision rationale	Select set of mutually compatible policy decisions that allows emission reduction goal to be achieved while meeting process legitimacy concerns.	Select set of mutually compatible policy instruments that supports macro-level objective while maintaining stakeholders' confidence in the existing policy instruments.

4.4 Further discussions

The design of electricity markets within a liberalised context has been separated into a plethora of modules to facilitate coordination between a wide range of participants, following horizontal and vertical unbundling (see Figure 2). We argue that there is a great necessity to evaluate the joint performance of all market design modules, instead of designing and evaluating them separately, to avoid system sub-optimisation. Our literature review has identified the fact that market design proposals are rarely comprehensive: often, design is only specified for some of the modules, leaving the reader to make assumptions about the neglected modules (see Table 3); this makes the comparison of market design proposals on an equal basis very difficult. Therefore, we believe that a shared framework used for identification and evaluation of comprehensive market design proposals is critical. The module-and-level representation of market coordination modules that we have used in Section 3 is an effort to provide such a framework. However, it remains a qualitative representation of interactions between modules, more useful for market design proposal identification than evaluation. Going forward, the development of quantitative yet comprehensive representations of market coordination modules, in the form of modular but connected simulation models, is recommended. Such tools, capable of extensive automated testing, would complement qualitative analysis to detect possible unintended interactions between coordination modules proposed.

[34] See Rogge and Reichardt (2016) for a complete list of policy instrument by type and purpose.

The innovation-driven hybrid governance perspective laid out above also has several implications for the process of power market design. Market design is not a process that exists in isolation, it is embedded within macro-level policies and interacts with the design of other micro-level policy instruments. Market design is an ongoing process. Market rules need to be adapted because of changes in the competition environment due to long-term transition, the need to remove (mostly unexpected) misalignment, and in order to enable the entry of newly emerging technologies or competitors. The process of market design is inherently political, because changes in market rules have differentiated distributional outcomes for market participants. Therefore, participants, who are not necessarily equal in access to power and resources, are incentivised to protect and extend their interests by advocating market design proposals favourable to their position. In consequence, the meta-coordinator (either the government or a newly created independent body) needs to defend the legitimacy of this process, providing democratic participatory platforms where all stakeholders involved can voice their views. This applies to stakeholders within the sector when it comes to market design at the country level, and stakeholders from different countries when it comes to market design at the EU level.

We perceive the market design process to be part of micro-level coordination involving innovation via market competition (lower loop in Figure 17). As such, participants in the market design process need to be aware of developments in the neighbouring niche-protected innovation process (upper loop in Figure 17), so that unjustified barriers (such as exclusion from lists of approved technologies) do not prevent market participation by technologies emerging from niches. The design of demand-pull policy instruments (especially strategic deployment of RES via support schemes), which are meant to work in conjunction with market competition (deployed to drive down the cost of adoption), needs to be considered within the scope of market design, so that they are proposed and evaluated alongside changes to other components of market design, instead of being designed in isolation.

Long-term decarbonisation, at the heart of our perspective for energy policy objectives and governance, entails continuous change as we transform from a fossil fuel-driven society to one that is powered by low-carbon energy. Therefore, market design cannot remain static while the technological fundamentals of our energy system undergo transformation via supported innovation and market competition. Instead, market design needs to be reviewed regularly to evaluate whether adjustments are needed to coordinate market competition with policy instruments being implemented to further the ongoing transition.

Currently, the initiative to draft new regulations in the EU is the responsibility of the European Commission, although general orientation for new policies must come from the European Council. New proposals are usually preceded by white or green papers, public consultation, and/or studies from experts or consultants. Every proposal comes with an Impact Assessment that describes that need for action and the solution proposed. Once the proposal for a new regulation is presented by the European Commission, the legal text is reviewed by both the Council and the Parliament.

Given the high complexity of the task of devising market design for a power system evolving towards full decarbonisation, we believe that peer-based discussion among a network of independent experts is necessary in addition to a hierarchical arrangement, to elucidate the causal relations between the manifold issues.[35] Ideally, the experts involved should be free from conflict of interests regarding the market design outcome. Nevertheless, such informal networks have been criticised for enhancing

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[35] The European Electricity Regulatory Forum, held twice a year in Florence, is an example of such an informal coordination mechanism. Historically, it has been successful in converging stakeholders' perspective on the best practice for transmission network use charges (Eberlein, 2010).

‘group think’ of those embedded within such close-knit policy networks, marginalising and excluding perspectives from citizens, local communities, and social movements (Geels, 2014). Thus, fully public consultations, open to all societal stakeholders, are required in addition to these networks to extend participation. We also recognise that such network-based discussion and negotiation has limited power to resolve distributive conflicts among stakeholders, thus consensus is not necessarily achieved for all components of the market design to be adopted going forward; this leads to gridlock (if common implementation is required, such as the case within a national system), or divergent practice (if independent implementation is allowed, such as the case within the EU). Nevertheless, we argue that such discussion helps to explore divergence in perceptions of the challenges at hand and elicits diverse proposals to the challenges, even if it does not provide consensus on the proposal(s) to be adopted.

4.4.1 General trends for future market design

The other important consideration is the role that the economic and physical attributes of electricity, as a commodity, play in the direction of future electricity markets. Although electricity is physically homogenous (upon delivery, electricity consumers cannot physically distinguish electricity produced by different sources), the economic value of electricity has been perceived to be heterogeneous over time, space, and lead time between contract and delivery (Hirth, Ueckerdt, & Edenhofer, 2016). Three conditions need to converge to create such heterogeneity.

1) Supply and demand conditions for electricity differ in three dimensions: in time (at different moments in a year), in space (between two locations in one country), and in lead time (at different moments before electricity is scheduled to be delivered).
2) There is limited capacity for arbitrage along these dimensions, given limited capacity in storage, transmission, and operational flexibility of suppliers/consumers.[36]
3) Neither supply nor demand is perfectly price elastic.

Currently, active supply-end adjustment is relied upon to meet passive demand, thus wholesale market participants are exposed to price signals that reveal the heterogeneity in electricity’s value, but this does not apply to retail consumers (Table 7). The retail market has very little role in coordinating supply–demand balance. Retail price mainly plays the role of a cost-recovery mechanism for coordination performed in the wholesale market.

[36] A corollary of these conditions required for heterogeneity is that, despite changes in supply and demand conditions over these three dimensions, if there is adequate storage, transmission, and flexible operating capacity, arbitrage can make the value of electricity homogenous over time, space, and lead time, respectively.

Table 7: Exposure of market participants to electricity's heterogeneous value

Module	Lead time to delivery	Time and spatial differentiation
Wholesale market	Long-term	Investment at the supply-end is supposed to be incentivised by expected revenue in (temporally and spatially differentiated) short-term markets. (Increasingly, most new investment is incentivised by long-term contract with the government, where revenue is not linked to temporal and spatial differences in supply–demand balance.)
	Short-term	Generators, suppliers, and large loads participate in a series of time-differentiated markets from a year ahead of delivery to gate closures. Day-ahead market is most prominent. Time resolution of market supply–demand bids of around one hour to 15 minutes; spatial resolution is zonal.
	Real-time	Beyond gate closure, residual supply–demand imbalance within the zone resolved by the System Operator on an instantaneous basis using balancing and ancillary services.
Retail market	Long-term	Investment in electricity consuming devices partially informed by expected cost of electricity based on (typically non time/space-differentiated) contract with retailers.
	Short-term	Consumers sign fixed term contract (one to two years) or one of indefinite duration with suppliers. Limited or no differentiation in time; no differentiation in space in retail contract.
	Real-time	Consumers do not have responsibilities or means to balance own electricity consumption relative to schedule that suppliers bid in the wholesale market on their behalf.
Network regulation	Long-term	Investment in network infrastructure partially borne by generation investors through spatially differentiated shallow/deep connection charges, the remainder is socialised among network users (mostly consumers) through network tariff.
	Short-term	Short-term network capacity allocation implicitly bundled with (temporally and spatially differentiated) short-term markets.
	Real-time	Real-time operation of transmission network controlled by the System Operator. No real-time operation of distribution network.

The heavy reliance on the day-ahead market, dominated by upstream generators, for coordination among all three heterogeneous dimensions is not ‘natural’, not to mention that the price signal from the day-ahead markets is not sufficient by itself to provide the right operational and investment signal to all active market participants. Instead, this reliance has evolved from historical circumstances in the power sector, contingent upon the evolution of sectoral organisational structures and technologies used. We argue that, as these factors evolve, the nature of coordination required will need to change accordingly.[37]

Coordination arrangements between sector stakeholders are regulation/market design decisions that co-evolve with the industry’s physical and commercial structures. The goal of coordination (such as inducing sufficient investment, or encouraging competition) is underpinned by changing policy priorities.

[37] Compared to conventional generation technologies, which benefit from their ability to store and transport fuel, RES technologies are constrained by resource availability both temporally and spatially. Also, they exhibit mixed operational flexibility: fast ramping is possible provided resource constraint does not exist, but resource availability is intermittent.

As an example, during the previous decades, we have observed shifting priorities for generation investment cost recovery mechanism.

Prior to liberalisation, most vertically integrated utilities recovered their investment via cost-plus regulation, which prioritised the sufficiency of cost recovery over efficiency, placing the risk of investment on ratepayers via cost pass-through; this system is believed to lead to over-investment. Subsequently, independent power production was allowed, and new entrants participated in competitive bidding to win power purchase agreements with the incumbent. The power purchase agreement is a long-term contract that divides risk between the independent producer and the incumbent (and by extension, the ratepayers), where the party responsible for absorbing variations in fuel prices, cost of labour and materials, and unexpected plant failures is articulated. Independent producers are allowed to recover their investment cost through annual/monthly capacity charges, which may be linked to the record of plant availability.

Beginning in the 1980s, the approach that is currently dominant – free entry to generation and investment cost recovery (with a return margin) solely based on market revenue – was implemented around the world.[38] It places all investment risks on the investors, which is believed to lead to more economically rational investment decisions. It is observed that the focus on efficiency post-liberalisation (mainly achieved through cost cutting) has incentivised little investment outside of protected pockets. Gas-fired generation in the form of CCGT is an exception, given its low capital intensity and the natural hedge it experiences relative to market price volatility. It was an appropriate strategy for the situation at the time (low demand growth, availability of technologies such as CCGTs, and the existence of a likely inefficient asset base).

The evolution described above reflects changing perceptions of what is the most appropriate way of sharing risk between parties in order to succeed in coordinating long-term investment decisions: over time, risk was shifted from ratepayers to private investors – increasing investment/operational efficiency at the expense of investment sufficiency. The historical context that supported such a shift in policy focus was a loose supply–demand balance, made possible by over-investment under vertically integrated utilities, of which most investment had been paid off. Since then, supply–demand balance in many countries has tightened as a result of asset sweating, decommissioning of aging infrastructure, and policy-induced phase out, while decarbonisation has increased the need to invest in new, riskier low-carbon technologies. Such new developments warrant updating our beliefs about the most appropriate form of risk sharing for long-term investment decisions.

The lead time at which most operational decisions are made is conditioned by characteristics of the leading technologies used. For most power systems, it was determined that one day in advance of real time was the optimal time for vertically integrated utilities to forecast demand consumption and to schedule thermal plant commitments. In contrast, for a few systems where large hydro reservoirs dominate (Brazil especially), commitment decisions are determined on a longer-term basis (MIT Energy Initiative, 2016). As more RES generation becomes integrated into the power system, the information that is required to schedule more generation (resource availability forecast) will become available later than one day ahead of delivery. Most RES generators can also be started up, shut down, or ramped much closer to real time, given the absence of thermal constraints. Consequently, we expect more

[38] Following liberalisation, although fixed remuneration based on capacity no longer existed, capacity payments which complemented revenue from energy bids were available to top up generator revenue, given imperfect market conditions (bids based on audited cost and price caps) and to guarantee long-term security of supply (later known as adequacy). In the existing England and Wales Electricity Pool, the system-wide electricity price paid to all generators was computed with an explicit term representing a scarcity-induced above-marginal price margin for generators, which can be classified as a capacity remuneration mechanism (Batlle, 2013).

transactions to move from the day-ahead market to intraday markets, especially if all RES generators become balancing-responsible.[39]

Overall, we perceive that, as decarbonisation progresses, the centrality of the day-ahead energy market in coordinating short-term operational decisions and long-term investment decisions will decrease.[40] For short-term operational decisions, markets with a post day-ahead lead time, more aligned with the operational constraints of RES generation, will become more important. For long-term investment decisions, risk-sharing mechanisms between investors and consumers, beyond volatile revenues from short-term energy markets, will be required. Furthermore, in additional to domestic generators (the traditional parties ultimately responsible for supply–demand balance in a country), an expanding range of market participants now have the potential for providing such services (foreign generators via interconnectors, industry and consumer demand response, and storage). Therefore, the design of short-term markets and long-term risk-sharing mechanisms should include these new participants.

5. Conclusions

The debate about electricity market designs in the EU is a crowded and complex space, where questions have been raised on the fitness-for-purpose of the existing common design, on the appropriateness of energy policy which underpins existing market design, and on the process through which energy policy is coordinated with market design. We contribute to this debate on all three levels.

1) We clarify the dynamic relationship between energy policy objectives (decarbonisation, security, and affordability/competitiveness). While conflicting in the short term (given the lack of complementarity between low-carbon technologies and the pre-existing socio-technical regime of the power sector), these objectives have the potential to be synergistic if low-carbon technologies and the coordination mechanism in the power sector mutually adapt to each other.
2) We present our understanding of electricity market design – one among a range of other policy instruments – to encourage a long-term vision compatible with innovation. The market design process does not exist in isolation, it is embedded within macro-level policies and interacts with the design of other micro-level policy instruments. Therefore, we argue that participants in the market design process need to be aware of developments in the neighbouring niche-protected innovation processes, so that unjustified barriers do not prevent market participation by technologies emerging from niches. Also, the design of demand-pull policy instruments (like the strategic deployment of RES via support schemes intended to work in conjunction with market competition) needs to be considered within the scope of market design. It is necessary that they are proposed and evaluated alongside changes to other components of market design, instead of being designed in isolation.
3) In order to operationalise the integrated approach to market design that we recommend, we prototype a 'module-and-level' framework to facilitate the discussion of market/non-market coordination modules at both national and EU level. We use this framework to systematically identify misalignments that exist between components of current market design and physical RES integration/financial RES support schemes. In parallel, we have identified five key trends which have implications for the future of coordination in the power sector (deployment of RES, electrification of other sectors, deployment of storage, smart grid, and supergrid) and have

[39] RES balancing costs incurred by the System Operator will be socialised, with services being procured outside the intraday market, post gate closure in the balancing market and through out-of-market ancillary service contracts.
[40] We recognise that there are regions for which the conditions that we have cited (increased intermittent RES generation and high investment need for such riskier technology) are not significant. The Nordic electricity market, for example, benefitting from already abundant and flexible RES generation (hydro power) and well-established regional trade, may see its day-ahead market continue to play an important role in coordinating investment and operation.

developed four explorative scenarios, each embodying a plausible combination of these forces (centralised, decentralised, early hybrid, and late hybrid).

Building on our work on misalignment identification and scenario formulation, we propose a seven-step condition-dependent evolution of power market design. This reflects the gradual relocation of dispatch decisions closer to real time, the increasing use of long-term contracts as a risk-sharing mechanism between investors and consumers, and the provision of electricity services by an increasing range of market participants. The steps are sequenced such that earlier reforms may create the conditions required for later reforms. The adaptive design proposed in this paper is an input to a deliberative market design process and needs to be assessed more vigorously via quantitative simulation of interacting coordination modules.

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Appendix: Evolution of technology and consumer preferences

In this section, we search the horizon, seeking trends that could have significant influence over the socio-technical landscape that electricity market designs of the future will have to navigate. We identify five key trends: two which will affect the magnitude and profile of future demand and supply (deployment of RES and electrification of other sectors) and three which will influence the way in which future electricity supply and demand will be balanced (deployment of storage, smart grid, and supergrid). The development of technology, together with the attitudes of power consumers and the wider public both influence the evolution of these trends. After reviewing the social and technical determinants that underpin the five trends, we develop four explorative scenarios, each embodying a plausible combination of these forces, against which market design proposals can be discussed.

Deployment of RES

Technologically, the potential for cost reduction of the more mature RES technologies, and the potential for breakthroughs in emerging RES technologies, will affect the scale of future RES generation technology deployment – the current workhorse of the decarbonisation process. However, the uptake of these technologies is not just conditional upon technical parameters. It is also mediated by the preferences of stakeholders responsible for making the investment decisions: by utilities and new large-scale project investors at the centralised level, by community cooperatives and self-generators at the decentralised level. Finally, given that in many countries, RES generators receive government subsidies which are typically levied on electricity consumers, the degree to which electricity consumers perceive such cumulative costs as acceptable is a factor that can influence further RES deployment.

RES technology development potential

RES support mechanisms that have been implemented in the last decade rest on the logic that growing deployment of RES technology will lead to cost reduction, eventually making them competitive with fossil fuel-fired power generation. IRENA establishes that between 2010 and 2015, deployment underwritten by support policies had indeed unlocked technological improvements and cost reductions in solar and wind power generation.[41] In the next ten years, there is still very large potential for cost reduction for the currently most deployed technologies: solar PV, parabolic trough collectors concentrating solar power (PTC CSP), solar tower concentrated solar power (ST CSP), onshore and offshore wind generation (see Table A1). These areas represented 80 per cent of overall investment in renewable generation technology between 2004 and 2014 (Mazzucato & Semieniuk, 2016). By the beginning of 2017, the chairman and chief editor of Bloomberg New Energy Finance together announced that, on an LCOE basis, renewable energy has achieved the long-awaited goal of grid competitiveness, undercutting all other sources of new generating capacity in many countries (Liebreich & McCrone, 2017).

[41] Renewable power generation technologies have accounted for more than half of total new power generation added globally in every year since 2011 (IRENA, 2016).

Table A1: Cost reduction potential of renewable power generation technologies up to 2025 (Adapted from IRENA, 2016)

	Cost reduction potential by 2025				
	Core equipment	Balance of system	Installation, O&M	Overall reduction potential	Projected LCOE
Solar PV	Module cost reduction remains, but relatively few gains from convergence given narrow cost spread across markets.	Bulk of cost reduction potential of total installed cost.	Greatly benefit from convergence to best practice.	59%	\$0.03–0.12/kWh[42]
Onshore wind	Improved capacity factor has the potential to decrease overall cost and decrease total installed cost and O&M costs.			26%	\$0.053/kWh[43]
Offshore wind	Optimisation of wind farm design and components.		Construction and installation cost can also be further reduced.	35%	\$0.11/kWh[44]
PTC CSP	Improved solar field components to reduce cost and improve efficiency.	Cost reduction for thermal energy storage system.	Fall in suppliers' margins and EPC contractors.	37%	\$0.09–0.12/kWh[45]
ST CSP	Greater improvement in solar field components given less mature technology relative to PTC.		Fall in suppliers' margins and EPC contractors.	44%	\$0.08–0.11/kWh

Other than these relatively established technologies, an emerging new solar technology, perovskite solar cells, is rapidly gaining traction. This new generation of solar cell, composed of organic metal halide materials which can be made in a less costly way than silicon crystals, increased maximum power conversion efficiency from 3.8 per cent in 2009 to 22.1 in 2016 – this is comparable to single crystalline silicon solar cells at 25 per cent (Correa-Baena et al., 2017). Furthermore, because perovskite materials capture sunlight at slightly different wavelengths than existing silicon cells, it is possible to layer perovskite cells on top of silicon cells to maximise the total efficiency of the assembly. Another promising application of perovskite cells is placement in unconventional areas such as windows, because they can be made transparent (Harvey, 2016).

[42] The LCOE projected accounts for differences from irradiation levels and capital costs, but is limited to utility-scale ground-mount first and second-generation solar projects.
[43] The LCOE projected is for the global weighted average. The range for the 5th and 95th percentiles is from \$0.03/kWh to \$0.09/kWh.
[44] The LCOE projected is the central estimate. Projects in tidal or near-shore locations could see costs fall to \$0.08/kWh, whereas for deeper water projects, the figure is \$0.15/kWh. The majority of cost reduction is WACC reduction, resulting from developers and financing institutions gaining the experience to assess risks more realistically.
[45] The range for LCOE projected only accounts for varying direct normal irradiance (DNI); other assumptions such as WACC have been held constant.

Preference of conventional and unconventional investors

According to classic finance theory, investors rationally weigh the level of risk and return of possible investment opportunities, and select the project with the best risk-adjusted returns. However, a more nuanced view of the factors influencing RES investments also needs to include several other factors: there are different types of investors with different preferences for risk and return, so that similar investment opportunities are valued differently by different investors. Furthermore, given the bounded rationality of investors, the risks and returns that they perceive, based on their prior beliefs, may be different from the actual risks and returns of the opportunities (Wüstenhagen & Menichetti, 2012).

In 2015, global investment in renewable power generation was dominated by two types of investments: large-scale asset finance (on-balance-sheet funding by utilities and specialist developers plus non-recourse project finance), and investment in small distributed capacity by retail investors (typically a small roof top PV eligible for government feed-in tariff). Such investments accounted for 52 per cent and 18 per cent of total investment, respectively (Frankfurt School–UNEP Centre, 2016). A more granulated look at the asset finance between 2004 and 2014 reveals more investor sub-types (Table A2). A comparison of the risk exposure of their investment portfolios suggests that, among private investors, commercial banks and non-financial non-energy firms take on more risky investments, while energy firms and institutional investors are low risk takers (Mazzucato & Semieniuk, 2016).

Table A2: Investor types for renewable energy asset finance (Mazzucato & Semieniuk, 2016)

Category	Type	Share of asset finance provided (%)
Private	Energy firms	11.3%
	Private utilities	17.1%
	Other non-financial firms	10.4%
	Commercial banks	11.7%
	Non-bank financial firms	7.2%
	Charities	0.8%
Public	State banks	15.0%
	State utilities	12.6%
	Other state corporations	4.4%
	Government agencies	2.5%
Unclassified	Unclassified	7.6%

An empirical study on the cognitive and behavioural drivers of investment decisions has found that investors' prior beliefs about the technical adequacy of the RES technology being considered, accumulated from their personal history, education, and previous experience with renewable energy investment, play a more important role in driving investment than the perceived effectiveness of existing policies. Institutional pressure, in the form of prevailing peer behaviour and opinions of external consultants, is also found to be a factor that converges investments on a few specific technologies. Finally, the influence of technical information (specialised press, reports, and briefs) has been found to be insignificant (Masini & Menichetti, 2013).

As for the factors that influence the decisions of retail investors such as homeowners, studies have found that environmental concern is not the only mindset that drives homeowners to adopt residential solar power generation (Schelly, 2014). In fact, the 'green' label sometimes deters more politically conservative individuals who would otherwise behave in an environmentally responsible way. Instead, an interest in technical knowledge and competence is a more commonly shared trait. Narrow economic calculation of return on investment is less important to households than the particular timing of the investment (for example: before retirement, during home renovation, or after inheritance), and it is seen that communities of information (local, person-to-person information channel) such as local renewable energy associations, specific programmes organised by utilities, and neighbours, help make the process of adoption less daunting (Palm, 2016).

Public acceptance of RES deployment costs

In terms of social acceptance, we focus on the public attitude towards the cost of overall national energy policy, instead of opinions relating to specific energy projects such as onshore wind farms. Nevertheless, a comprehensive review of contributory factors is carried out in Lenoir-Improta et al. (2017). A public consultation study in the UK found that although the public considers the cost of energy, discussed in terms of energy bills, very important to them, the cheapest option is not necessarily preferred if it comes with perceived negative traits, such as fossil fuel reliance (Parkhill, Demski, Butler, Spence, & Pidgeon, 2013). Thus, the study warns against a simplistic interpretation of public responses to costs (as only relating to higher or lower energy bills), which is commonly observed in policy and the media. Given that research on the social nature of this exact issue is limited (most studies focus on estimating consumers' willingness to pay for renewable electricity, not on clarifying the mechanism by which this preference is formed), we borrow insights from a different context: support for environmental taxes that correct for externalities is shown to be influenced by the public's trust in how well the government spends the money levied, and the effectiveness of the tax at addressing the environmental externality targeted (Kallbekken & Sælen, 2011).

Electrification of other sectors

It is conventionally accepted that decarbonisation of the power sector is the first step in the overall decarbonisation of the energy system, and that this will be followed by decarbonisation of other sectors, especially transportation and heating. By and large, these other sectors have yet to advance to the forefront of energy policy agenda: in 2015, countries with renewable energy policies targeting the power sector (114) significantly outpaced those with policies targeting the transport and heating/cooling sectors (66 and 21, respectively) (REN21, 2016). The final extent of electrification in transportation and heating is dependent on the affordability of such an option relative to incumbent technologies, but the final users' needs, practice, and preferences, which successful product designers should consider, are also influential.

Cost competitiveness relative to incumbent technology

Currently, the global number of electric vehicles (EV) is above two million, but this figure represents only 0.2 per cent of the total number of passenger light-duty vehicles in the world (IEA, 2017). It is commonly understood that, for EVs to be cost competitive with internal combustion vehicles in terms of manufacturing cost, the cost of battery packs would need to fall below $150/kWh (Nykvist & Nilsson, 2015). Between 2008 and 2015, the average battery cost has fallen from $1000/kWh to $268/kWh. Some EV manufacturers announced that they had already achieved a cost of less than $150/kWh by 2015, and others set goals to reduce costs below $100/kWh by the early 2020s (IEA, 2016). In countries that are members of the Electric Vehicles Initiative (EVI), multiple forms of regulatory measures, financial levers, and waivers of fees and tolls have been implemented to support EV uptake.[46] Publicly accessible charging facilities, often supported by policy, have also grown commensurately with the

[46] EU member states that participate in the EVI are France, Germany, Finland, the Netherlands, Portugal, Sweden, and the United Kingdom.

growth trend of the electric vehicle stock. On average, the current policy goals of EVI-participating countries are to reach 3 per cent EV share in the total 2020 car stock. If the 2015 global growth rate is extrapolated, the existing policy goals will be surpassed.

The electrification of transport, given EVs' high power requirement during charging, is expected to have a significant impact on load profile and load distribution across the electricity network. Depending on the charging modes and patterns (ranging from slow at 3 kW to rapid at up to 50 kW), electric vehicles can become a source of flexibility in the power system, but they can also impose major strains on the system. The design of locational and time-varying signals at distribution level to the siting of charging infrastructure siting and vehicle charging behaviour will become important. The financing and business model for the charging infrastructure will also need to be elucidated (Eurelectric, 2016).

Electrification of heat is one of several means for the decarbonisation of heat. Other candidates being: demand reduction by energy efficiency improvements in buildings, repurposing of natural gas networks to carry lower-carbon forms of gas, and district heating based on waste heat or renewable fuel (Nature Energy, 2016). The extent of future electrification of heat is dependent on the cost of delivering heat using heat pumps, relative to the incumbent technology (different depending on the country). Future capital cost reduction for heat pumps is more likely to come from installation costs than from equipment cost, since most heat pump components are already mass market products (DECC, 2016a, 2016b). In countries with important cooling needs as well as heating needs, the purchase of dual-heating/cooling heat pumps is facilitated, because it reduces the overall capital outlay required for heating and cooling. In the near future, government subsidies applied to heat pumps (and to their competitors, if applicable) will greatly affect the above comparison (Chaudry, Abeysekera, Hosseini, Jenkins, & Wu, 2015).

Compared to EV charging, the pattern of energy consumption for heat is relatively well understood and mostly driven by the weather. Although electricity demand also exhibits seasonal variation, in many countries the seasonal variation in heating demand is much larger, possibly several times higher. Therefore, if electrification of heat occurs without efficiency improvement to reduce heating requirements, the peak demand of electricity will increase significantly, unless large-scale seasonal energy storage, in a form that can bridge heat and electricity, is technologically and economically feasible. Energy efficiency improvement in housing stocks, requiring the overall heating requirement, is another possible development that could lower the strain that electrification of heat places on power sector infrastructure.

Preference of heat consumers and car users

For new technologies such as EVs, where mass adoption has not yet occurred and new consumer behaviour is required relative to conventional vehicles, consumer perceptions play a more important role. Even though many consumers regard the ownership and operating costs of EVs, when compared to those of ICE cars, as a key concern, it has been found that potential adopters may lack the knowledge to make such a comparison (Rezvani, Jansson, & Bodin, 2015). Range anxiety is another well-known adoption obstacle, especially for all-electric BEVs (battery electric vehicles), but limited driving range is argued to be more of a perceived obstacle than a real obstacle, given that potential adopters have been observed to rate EVs more positively after hands-on experience.

Some researchers point out that car use and ownership has hedonic and symbolic value, beyond its instrumental value. They found that the instrumental attributes of EVs (such as speed and range) are important to potential adopters largely because of their contribution to the hedonic and symbolic attributes of EVs (in other words, the pleasure of driving, and the identity derived from owning and using EVs, respectively). Interestingly, consumers who self-identify as pro-environment had more positive evaluations of the multi-dimensional attributes of EVs, whereas those who self-identify as authorities on cars (actively seeking information and advising others on cars) have neither strong positive nor strong negative perceptions of EVs' attributes (Schuitema, Anable, Skippon, & Kinnear, 2013). Also, car attributes become less important in influencing decisions when it is a second car for the household.

The literature on consumer preference for heating systems is less abundant than that for vehicles, but deliberative workshops in the UK have found the public's perception of electric heating systems is affected by their prior experience, and decisions are not always made with full information. For example, most members of the UK public interviewed referred to electric storage heaters (these have been adopted in the country since the 1970s) when comparing electricity-powered and gas-powered heating; they were not familiar with other forms of electric heating such as district heating or ground source heat pumps (Parkhill et al., 2013). The same study also found that the public engages with the idea of heat mainly through bodily comfort levels; improving insulation is thus viewed more positively than curtailing heating requirement, which is perceived as cutting down on comfort. Responsiveness and controllability of the heating system were mentioned as the most important instrumental attributes, while open fires had aesthetic appeals (hedonic and symbolic attributes) which may not be completely given up even if a central heating system is in place.

Deployment of storage

The increased volatility and uncertainty that are being introduced into the power system, along with the integration of ever-increasing levels of RES, have kindled interest in storage technologies. There exists a wide range of storage technologies, vastly different in their power and energy capacities – storing electrical energy by converting it to kinetic, chemical, electrostatic, and other forms of energy. Because of the conversion step, some storage technologies have the potential of bridging the electricity grid with other networks (gas and heat). If deployed at large scale throughout the power system value chain, storage technologies have the potential to fundamentally alter the operating paradigm for the power grid, decoupling the real-time balancing of generation and demand at multiple points in the supply chain.[47] Other than the maturity of such technologies, the deployment of storage is dependent on developers' ability to locate storage systems adequately along the power supply chain to create value for systems users, and to capture value to remunerate storage service provision, if the regulatory environment is one that supports such new business models.

Storage technology development potential

The potential applications of storage technologies in the power sector also call for a range of power and discharge periods (Figure A1). At one end, very large-scale energy storage can be used to store energy for relatively long periods to address seasonal variability in supply and demand (seasonal storage); at the other end, smaller-scale energy storage can be used to adjust supply and demand balance over shorter terms (within the same day, for example, for demand shifting and peak reduction). For decentralised off-grid systems, the size of storage units may even be smaller. Furthermore, high power capacity storage systems (>100 MW) are more suitable for supply-end operations, whereas low power capacity storage systems (<10 kW) are more suitable for distributed demand-end operations. The discharge duration and power rating of commonly inventoried storage technologies is illustrated in Figure A2. Comparing the two figures, pumped hydro energy storage (PHES) seems to be the only technology currently suitable for seasonal storage applications (very large energy storage and power capacity is required for seasonal cycling). Batteries and hydrogen-based storage technologies have the potential to cover a wide range of applications, but they still need to be scaled up to reach their full potentials.

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[47] Currently, the balance of supply and demand is mostly achieved through storage of fossil fuel stock on the supply side.

Of all the technologies shown in Figure A2, only a few are mature or near maturity. High-speed flywheels, Superconducting Magnetic Energy Storage (SMES), supercapacitors, and hydrogen-based storage technologies are all still in the research and development phase. Some batteries (Lithium-based and NaS (Sodium–Sulphur), low speed flywheels, and Compressed Air Energy Storage (CAES) are said to be in the demonstration and deployment phase. However, demand from the transport industry is now spurring large-scale production of batteries, given the interest in transport electrification. As for the level of deployment, by late 2016, of all existing and planned storage projects (about 193 GW in rated power including thermal storage), 95 per cent consisted of pumped hydro storage and only 1.7 per cent consisted of batteries (rechargeable and flow batteries, not counting EV batteries) (Sandia National Laboratories, 2016).

Figure A1: Characteristics of particular storage applications (Based on data from IEA, 2014)

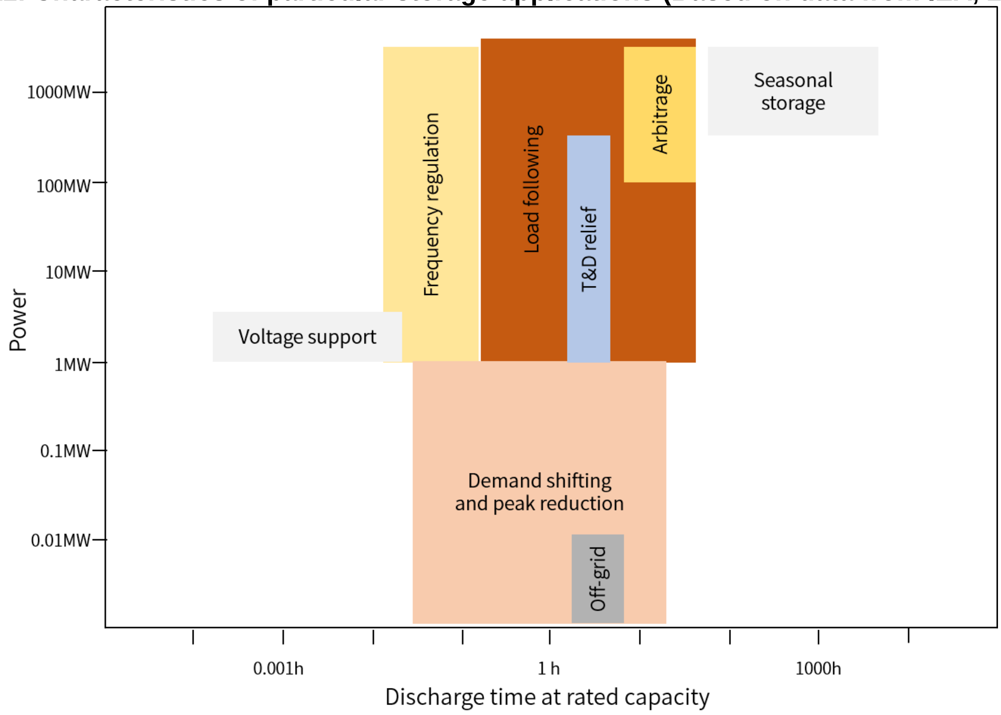
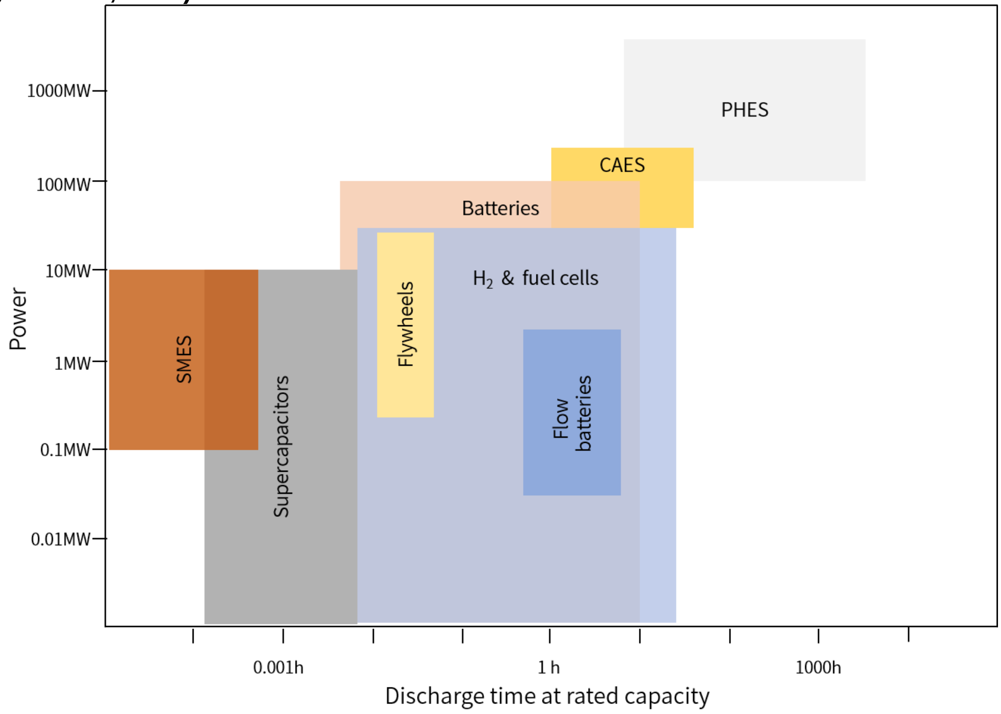


Figure A2: Approximate system parameters for various storage technologies (Based on data from Taylor et al., 2012)[48]



Preference of investors

Theoretically, large-scale generators (especially those with a large share of RES in their portfolio), System Operators, transmission and distribution network operators, distributed consumers and/or generators could all benefit from integrating storage systems into their operations. However, according to European regulation, network operators cannot have any type of control over generation facilities; thus, to the extent that storage is treated within the regulatory framework as generation, network operators cannot invest in them. The revision proposed to the Electricity Directive as part of the winter package specifies that transmission and distribution system operators are not allowed to own, develop, manage, or operate energy storage facilities (European Commission, 2016a). Therefore, the task of investing and operating energy storage facilities falls on independent storage service providers, who have more freedom in aggregating values via contracts with stakeholders from across the system: judiciously located and scaled, a storage system can provide multiple components of the values illustrated in Figure Figure A3. Renewable generation owners may also decide to pair energy storage system with generation capacity to alter the generation profile of RES assets, hence assisting their integration into the power system.

The storage asset of the independent service provider can be centralised or distributed. In the second case, EV owners and/or homeowners may invest in and retain ownership of EV batteries/home energy storage systems, whereas the storage service provider acts as the aggregator. The decentralised version of storage deployment will benefit from advances in electrification of transport and smart grid technologies (two-way monitoring and control for distributed assets).

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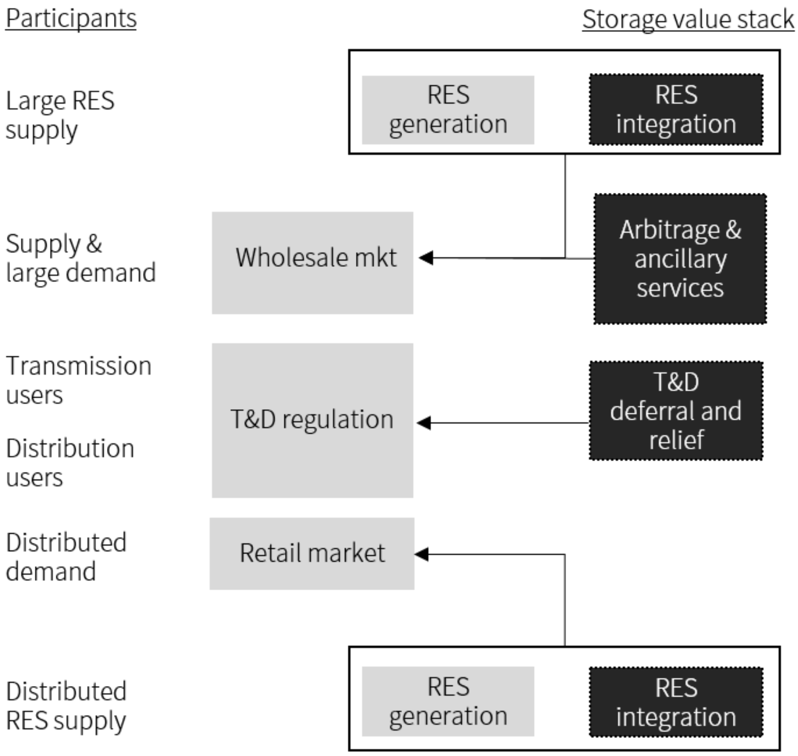
[48] SMES: super magnetic energy storage; CAES: compressed air energy storage; PHES: pumped hydro energy storage.

Significant challenges exist for independent storage operators: developers have little data to demonstrate how their systems will perform over time. Also, existing rules for wholesale power markets were mostly written for traditional equipment that generates and delivers electricity, and the industry is still developing market mechanisms to determine how to value and pay for storage systems that offer different functions. Because the economic costs and benefits of any storage project are dependent on its specifications (power and energy capacity), operating regime (charge/discharge cycles and depth of discharge), and the conditions of the power system in which it is integrated, they are hard to assess for investors and regulators alike (Zakeri & Syri, 2015).

Figure A3: Value stacking for storage systems in the power supply chain



Deployment of smart grid

Improvements in control technology for large, complex socio-technical systems have been demonstrated to provide 'economies of system', increasing productivity by improving the capacity utilisation of infrastructure for systems with comparable scale, scope, and throughput (Nightingale, Brady, Davies, & Hall, 2003). The vision of a modernised power network, where two-way monitoring and control is enabled by the convergence of information and communication technology (ICT) with power system engineering, supporting more flexible business and system operations through efficient exchange of data and energy, is commonly known as 'the smart grid' (Farhangi, 2010). The distribution network, at the root of nearly 90 per cent of all power outages and disturbances, is at the forefront of modernisation. Although utilities and industry observers have heterogeneous definitions and focuses for the smart grid concept, they do agree on the general direction of this transformation.

Development of smart grid infrastructure

The realisation of this vision is expected to take place through the 'plug-and-play' integration of smart microgrids, capable of operating in islanding mode, each containing interconnected distributed generation, loads, and storage elements which can communicate their status and accept commands remotely.[49] The coordination between all these smart elements is mediated by a communication infrastructure that appears to grid users as an energy management application. Given the high costs of a complete overhaul of the existing grid, observers expect that in the near future, the conventional power grid and pockets of smart microgrids will co-exist as transition occurs, with the smart grid eventually emerging once smart microgrids become pervasive (Farhangi, 2010).

A major obstacle for the transition from the current grid configuration to the smart grid is the absence of universally accepted interfaces, protocols, and standards to ensure a common communication vocabulary among system components located within the same network. Another obstacle is the absence of a near real-world environment in which utilities can test and validate newly developed technologies without endangering service reliability. Other than these technical obstacles, a great institutional obstacle exists: within a liberalised power sector, where network segments are unbundled and remain under regulation, distributed network operators, who are assumed in many scenarios to be the lead investors in smart grid infrastructure, have limited incentive to do so, given that they incur the investment risk but do not share the benefits under existing network regulation (Bolton & Foxon, 2010).

Three wider technology trends that are pushing smart grid development are:

- the Internet of Things concept: referring to a worldwide network of interconnected objects which can sense their environment and communicate with each other;
- Big Data: referring to analytics of data with significantly higher volume, velocity, and variety;
- distributed ledgers (such as blockchain): a type of technology that facilitates secure decentralised transactions (potentially with little human interaction).

If these continue to grow, more smart appliances and devices may be developed within the Internet of Things paradigm, more decision-supporting algorithms may be developed within the Big Data paradigm, and more forms of decentralised trading platforms may be developed within the blockchain paradigm; all will facilitate the development of smart grid and its operations, also drawing in a more diverse range of firms to provide smart energy products and services.

The smart grid vision is one which will technically enable a more granular control of distributed generation and demand, one that reacts to real-time system parameters. Market arrangements that previously involved prohibitive transaction costs (such as engagement with distributed loads) can be made feasible once such an infrastructure is in place. Therefore, the speed at which this technical transition occurs delimits the scope for the participation of retail customers/distributed generators in providing system services, directly or represented by aggregators. Ultimately, the speed of smart grid deployment affects the cost of RES integration and electrification of other sectors.

Preference of electricity consumers

Under the smart grid vision, electricity consumers will be interacting more extensively with the power grid via flexible load scheduling, therefore the users' willingness to accept changes in their homes and daily routines, beyond basic economic consideration, significantly impacts the chances of successful smart grid implementation.

Currently, it is perceived that the public in general has low motivation in optimising their energy expenditure (as evidenced by the low percentage of people who switch energy retailers, even when

[49] Smart meters are part of the hardware infrastructure of the smart microgrid, but by themselves do not make the smart grid. Current roll-out of smart meters is part of utilities' move toward advanced metering infrastructure. They reduce metering costs of distribution companies, but must be made compatible with the yet-to-be realised smart grid's topologies, technologies, and user practice to fully unleash their value.

they are uncertain that they have the best deal for their electricity consumption) (ECME Consortium, 2010). Some power sector stakeholders assume that increased levels of electricity demand (coming from electrification of heat and power) will increase householders' interest in managing their electricity bills, and that financial incentives would be enough to incentivise users to act in ways that are aligned with efficient operation of the power system (Verbong, Beemsterboer, & Sengers, 2013). However, it is unclear whether the level of profit realised from individual household optimisation is sufficient to trigger individual behaviour change: although the overall benefit, aggregated over many households, might be large, the benefits realised per household could be too low to offset the time, effort, and worry incurred.

A survey of British power consumers has shown that loss-averse consumers, those caring more about avoiding financial losses than making financial savings (the majority of users), are less willing to switch to a time-differentiated tariff (Nicolson, Huebner, & Shipworth, 2017). This indicates that many are more worried about the possible increase in their bills if they are unable to shift consumption away from peak times, than about savings that could be realised in the opposite case.[50] On the other hand, possession of demand-flexible devices (such as EVs, washing machines and dryers with timers) increases the willingness for tariff switching, suggesting that users who have more control over their demand are more willing to engage in demand response. In a separate study, consumers with major appliances (such as space heating and air conditioners) were also more responsive to time-varying electricity prices than those without such appliances (Gyamfi, Krumdieck, & Urmee, 2013).

Unless control of appliances is granted to third parties or automated algorithms, electricity consumers not only have to be willing to adjust their consumption, they also need to have the practical means to do so. In deliberative workshops, participants broadly stated their willingness to share energy use data under conditions, but preferred some level of control to remote interference (Parkhill et al., 2013). The design of user interfaces for all components of the smart grid system, possibly in the form of an integrated energy management system, then becomes paramount. The complexity of household energy management increases with the deployment of distributed storage (such as EV batteries) and generation. This is because they expand the range of options available to the customer: from rescheduling of activities to selection among multiple energy sources (stored electricity from battery, own generation, or electricity from the grid), effectively turning consumers into micro system operators. Given such differences in consumer preference, and in their ability to take advantage of dynamic pricing, the unintended social redistribution effect of demand response based on dynamic pricing is of major concern.

Deployment of supergrid

An alternative vision to smart grid is the supergrid, which focuses on connecting remote RES to the grid and bridging power systems over a large geographic region through long-distance HVDC cables that overlay the existing grid (Van Hertem, Ghandhari, & Delimar, 2010). The supergrid aims at reducing the variability of RES by aggregating a diverse portfolio and making remote RES available to more electricity users, by expanding and merging existing transmission capacity (Blarke & Jenkins, 2013). By pooling resources over a wider geographic area, the system becomes more resilient as generation forecast errors and variability are reduced. The EU's push for the Internal Energy Market could be perceived as a regional supergrid initiative; proposed projects to connect Europe to large-scale solar resources in MENA are also conceived under the supergrid paradigm. The most ambitious proposal of supergrid, by China's State Grid, spans the entire globe (Liu, 2015).

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[50] In the same vein, consumer protection authorities and consumer associations generally view innovation in tariffs and contracts as detrimental to consumers (ECME Consortium, 2010).

Development of supergrid infrastructure

Given its mandate to connect remote large-scale RES, the supergrid needs to support long-distance transmission at high ratings. Currently, there are already point-to-point HVDC connections in many countries, but the supergrid aspires to develop a multi-terminal meshed grid, where the HVDC lines are connected with each other to improve the reliability of the network. In Europe, because much of the supergrid envisioned is offshore, of the two types of HVDC technology – Voltage Source Converter (VSC) and Current Source Converter (CSC) – the offshore-compatible VSC HVDC is considered to be the key enabler (Cole et al., 2011).

As the HVDC grid is operated in parallel with the conventional AC grid, the dynamic interactions between the DC and AC systems will also need to be handled under both normal circumstances and under disturbed conditions. In existing point-to-point HVDC connections, a DC fault is cleared through AC circuit breakers. The same control strategy cannot be extended to a multi-terminal system, because it would mean the whole DC grid would need to be shut down every time a fault occurred. Therefore, protection of the DC grid, once a fault occurs, requires the development of new protection methods and devices. Standards for HVDC system components and grid codes will also need to be established for a meshed DC grid to be possible. Compared to CSC systems, VSC systems have been limited to lower voltages and power. The highest ratings available are up to 350 kV. In comparison, the first 1100 kV CSC HVDC line (currently under construction in China) will be able to transmit up to 12 GW, half the average power use of Spain (The Economist, 2017). Although immediate technical implementation of supergrid is not yet possible, most of the problems are not fundamental and can be solved given sufficient time (Van Hertem et al., 2010).

Public acceptance of perceived impact

Multiple studies have shown that the economic benefits of renewable energy expansion associated with a unified European approach are greater than those reached through individual national programmes, and others have shown that imports of renewable electricity from non-EU regions such as North Africa could be a lower-cost way of fulfilling Member States' renewables target. However, all EU countries except Italy and Luxemburg have aimed to meet their 2020 renewable targets domestically[51] (Lilliestam, Ellenbeck, Karakosta, & Caldés, 2016). The challenges for the supergrid vision, such as an increase in cross-border regional interconnectors, are neither technical nor strictly financial, instead, they are political and regulatory (Battaglini, Komendantova, Brtnik, & Patt, 2012).

On the political front, public acceptance is necessary at two levels: at the national level, a dominant political coalition needs to support the proposed project, on the basis of their evaluation of its outcomes; at the community level, local residents and the general population also need to support the project on the basis of their evaluation of its outcomes. Evaluation criteria used by actors at different levels in different countries are not uniform (Lilliestam et al., 2016).

Concerns shown to be important for the national-level evaluation of *importing countries* are:

- compatibility with the country's growth and industry policy targets,
- potential security threat of electricity import dependency,
- potential synergy between projects and development cooperation objectives.

For *exporting countries*, key concerns are:

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[51] Article 9 of the EU Renewables Directive (2009/28/EC) allows renewable electricity physically imported from countries outside the EU to count towards the fulfilment of Member States' 2020 renewables target. There are other ways of complying with national objectives, like statistical transfers (art. 6) or Joint projects between Member States (art. 7))

- the ability to meet domestic demand,
- technology transfer induced by projects,
- job creation.

In *transit countries*, where infrastructure construction or reinforcement is required, potential additional income and compensation are perceived to be important.

At the community level, public acceptance is dependent on perceptions of (dis)advantages experienced locally, in economic, political, or environmental terms. The public's perceptions of unfairly distributed overall costs and benefits between countries (such as outsourcing of environmental impacts, fears of neo-colonialism), or between actors (investors and affected public), and perceptions of an unfair process (groups affected have not been duly consulted) can all influence the acceptance of supergrid projects. Finally, collective belief systems, derived and reproduced from shared experiences, values, media attention, and the broadcasted interests of influential groups, are important in shaping public opinion. Historical developments and resulting identities could render some projects (say, RES imports from Russia to the Baltic States or Poland) unimaginable. Large-scale RES imports, a policy option connected to increased globalisation and centralisation, may be opposed by movements which advocate for autarky or decentralisation.

Even when public acceptance at both levels is secured, regulatory challenges remain: investment recovery models need to be determined and regulatory approval secured to access financing for HVDC links; operational decisions of interconnected power systems need to be coordinated either through market-based mechanisms or administrative procedures. These are challenges and opportunities for future market design, especially when the countries connected via the supergrid share neither industry structure nor sector coordination mechanisms.

Future scenarios

Based on our survey of key trends and their socio-technical determinants, we develop four possible scenarios: centralised, decentralised, and two hybrid possibilities, representing four combinations of the five trends (see Table A3). The scenarios do not exist in isolation. They are guideposts that mark different points along possible future trajectories: one scenario, given time, may evolve into another.

Given both the outstanding cost reduction potential for renewables and the attitudes of investors (these have gradually become increasingly favourable), which have co-evolved with increasing deployment in the recent past, we expect RES deployment to increase in all scenarios. This is consistent with the EU's long-term vision as captured by scenarios used in Energy Roadmap 2050, where the share of RES in overall power generation ranges from 64 to 97 per cent by 2050.

Table A3: Future scenarios and their associated trends

	Future Scenario			
Trends	**Centralised**	**Decentralised**	**Early hybrid**	**Late hybrid**
Deployment of RES	Centralised: high Distributed: low	Centralised: low Distributed: high	Centralised: some Distributed: some	High
Electrification of other sectors	Low	Transport: high Heating: some	Transport: some Heating: some	High
Deployment of storage	Centralised: high Distributed: low	Centralised: low Distributed: high	Mixed	High
Deployment of smart grid	Low	High	Fragmented	High
Deployment of supergrid	High	Low	Fragmented	High

In the *centralised scenario*, there is a positive public attitude towards further European integration (more interconnectors and cross-border trade). Through the supergrid, regional trade and access to a small number of centralised large-scale storage installations (multi-year hydro reservoirs) are relied upon to provide the flexibility that is required to integrate further RES (most likely to be very large-scale offshore wind farms and desert-based solar farms). Smart grid and its associated enabling technologies at the distribution level are not developed sufficiently, so they fail to take advantage of the increasing need for flexibility in the power system. Given that increased capacity in the centralised grid does not resolve grid congestion at the distribution level, integration of EVs and heat pumps into the power system remains marginal.

In the *decentralised scenario*, development of supergrid is limited, for the public and power consumers place a higher value on control and self-reliance. Smart grid-related technologies and infrastructure are spurred by overspill from other rapidly innovating sectors: the Internet of Things delivers associated smart appliances; advanced data analytics delivers associated software. Integrated home energy systems, along with rooftop PV and stationary batteries, become popular with owners of electric vehicles. In addition, the design of user-centric energy management systems further integrates the owners of distributed smart appliances into the power system, by lowering the cognitive and behavioural burdens required for them to provide demand-end flexibility services. The ability for distributed prosumers to manage their own electricity consumption and to provide services to the grid lowers the cost of their consumption. It also lowers the cost of integrating such consumption into the power system, by reducing the need for expansion of associated supply-end infrastructure. Increasing efficiency and flexibility at the distribution level, however, cannot fully accommodate the large seasonal difference in heating demand. Therefore, the adoption of heat pumps is limited to regions having access to large-scale seasonal storage.

In both *hybrid scenarios*, smart grid and supergrid infrastructure develops in parallel, neither is blocked by public attitude. But technology development and integration between the two paradigms is more mature in the late hybrid scenario than in the early hybrid scenario.

In the *early hybrid scenario*, in regions best endowed with concentrated (and likely remote) RES, electricity supply and demand is balanced at the transmission level, via trade with other regions. In regions where small-scale decentralised RES is more prevalent, supply and demand is balanced through a mix of regional trade and demand-end flexibility. Because the sophistication of demand-end generation/load devices, in terms of sensing and control, is limited, and distributed storage ownership is not common, the parties providing system services at the distribution level are likely to be DSOs or dedicated energy service companies, rather than power consumers. As a result, the electrification of transport and heat is not geographically uniform. Areas which are served by active distribution grid management, likely to be population centres, can accommodate more EV charging infrastructure, and thus will exhibit higher EV adoption. As in the decentralised scenario, large-scale adoption of heat pumps, due to the large seasonal demand it places on the system, is not possible across the power system.

The *late hybrid scenario* is one in which the best of centralised and decentralised scenarios is combined. Both remote and distributed RES generation are integrated into the grid, which relies on regional trade and demand-end system services to balance supply with demand, and storage projects of varying sizes are embedded within the power grid at both transmission and distribution level. Electrification of heating and transport is high across the power system. This scenario, of course, is only likely as an extension of the early hybrid scenario.

We illustrate the relationship between scenarios in Figure A4. The existing situation is one where the centralised supergrid approach is relatively more developed than the decentralised smart grid approach, given its better compatibility with the historical top-down paradigm of the power sector. In the near-term future, technology development and public attitudes, in addition to the market design reform currently underway, may drive toward the centralised, decentralised, or the early hybrid scenario. If an early hybrid scenario is realised, it will be a flexible interim stage, from which a more centralised or decentralised scenario can develop, if public attitudes shift or technology under-delivers. Alternatively, a more mature hybrid future may emerge, if no such constraints are encountered. In the long-term future, it is theoretically possible that either a pure centralised or a pure decentralised scenario could, at a later point, incorporate some of the other's elements and become a hybrid system; we therefore incorporate these links into Figure A4, but given the extent of catch-up development that would be required, we think those paths are less likely.

Figure A4: Pathways for the evolution of technology and consumer preferences