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Adapting electricity markets to decarbonisation and security of supply objectives: Toward a hybrid regime?

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ABSTRACT

The policy objectives of decarbonisation of the electricity sector whilst maintaining security of supply have led to a new wave of market reforms in many jurisdictions which liberalised their industry. There is a wide range of models under this new hybrid regime which essentially combine the energy market with planning and long-term risk transfer arrangements. This paper takes an institutionalist approach in terms of modularity of the market design, and reviews the issues with the standard historical market model which led to the introduction of additional long term "modules". We then study the interactions between the existing and new "modules" and identify ways in which the initial market modules can be improved to address inconsistencies with the new modules. We conclude by discussing the conditions under which the various changes in market architectures could converge toward a hybrid regime structured around a "two step competition", with a "competition for the market" via the auctioning of long-term contracts to support investment, followed by "competition in the market" for short term system optimisation via the energy market.

1. Introduction

Twenty-five years after the reforms were initiated to liberalise the electricity industry, many electricity markets around the globe are 'hybridised' with various forms of regulatory intervention, with a significant role for the state in planning and auctioning long-term contracts. In this paper, we argue that the revival of public interventions in electricity markets is driving a transformation of the standard historical approach of competitive market design towards a hybrid regime that combines planning and long-term arrangements established with public or regulated entities on one side, and short term "organised markets" on the other side.[1]

This marks a significant shift away from the initial theoretical textbook electricity market design, in which investment decisions are made by market participants based solely on price expectations. In other words the initial reforms were based on the belief that the market is able to assume both the short-term coordination between market players for the economic dispatching and the long-term coordination function between them for investing in generation so that an optimal mix and capacity adequacy can be achieved in a timely way. These new long-term 'out-of-market' building blocks are designed to add a remuneration to the revenues from the energy markets, to guarantee the recovery of fixed costs and to de-risk investment *via* some risk-sharing arrangements between producers and consumers, while some of them make it also possible to subsidise production in the long-run for the new technologies. However, this raises the issue of the consistency of these new elements with the initial wholesale market building blocks, and their subsequent evolution.

These drivers of policy intervention resonate in the OECD countries within a context that is characterised by the resurgence of government interventions aimed at guaranteeing security of supply (SoS) through the introduction of capacity mechanisms, and decarbonising through the support of clean technologies – decentralised renewable energy sources (RES), as well as centralised low-carbon technologies (LCTs) – and the growing challenges of network planning in the context of the development of decentralised and variable RES generation. In the

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[1] We use here the concept of long term arrangements in a restrictive sense to designate bilateral inter-agent coordination, ranging from public-private cooperation to contracting schemes, including public support mechanisms and public-private partnership, but not in the wider sense of the institutionalist theory covering multi-agent organisations, networking and policy arrangements. When an arrangement is in fact a contract, we explicitly use the concept of contract. For instance a feed-in-tariff is a long-term arrangement between private players and the government, to be distinguished from long-term contracts which are auctioned and signed with non-governmental parties, as regulated and private entities.

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emerging economies, the need for investment in capacity is more acute than in the OECD countries, given that the former are experiencing more significant growth in demand, causing them to be the forerunners of market hybridisation with planning and long-term arrangements.

These policy and regulatory interventions, in particular those that are aimed at promoting large scale investment in generation in emerging countries, and deployment of high-upfront-cost and low-variable-cost technologies (RES, LCTs) in advanced economies, can have significant impacts on electricity markets and undermine the ability of energy market prices to provide adequate coordination signals to market participants. This can create fundamental inconsistencies with the current market arrangements, e.g. merit-order effects, limits on system balancing constrained by the rigidity of existing resources, poor market valuation of the flexibility of resources that are increasingly needed, and lack of locational signals to coordinate generation and transmission system development.

These inconsistencies, in turn, can lead to the adaptation of the former set of market rules, such that there is a switch from the initial "market regime" to a new "hybrid regime".[2] We argue that, beyond the various patches of 'out-of-market' mechanisms that have already been added and that are being adopted in these countries, the underlying logic leads to a combination of modules of short-term markets, improved modules of networks access and development, and long-term coordination mechanisms, from the moment that the SoS or/and the decarbonisation objectives are prioritised. The novelty lies in the fact that recent developments have demonstrated the strength of this logic in moving towards a regime that is articulated around two clear principles: short term coordination by markets idealized by the so-called economic dispatching, and long-term coordination by a combination of planning and auctioning of long-term arrangements between producers, investors and regulated entities.

This paper analyses the dynamics of change in the market design and investigates the issues associated with their mutation into a 'hybrid regime' that combines a role for market coordination with strong public governance.[3] Our objectives are:

- To analyse the evolution of market design in the context of the new decarbonisation and security of supply objectives introduced, by using a functional approach that belongs to rational choice institutionalism and that builds on the literature that identifies a number of "modules" in the standard electricity market design;
- To investigate the issues associated with the combination of short-term coordination by the market and long-term coordination by planning and auctioning long-term contracts – referred to as a "hybrid regime" – by drawing from the experience of a number of countries in particular in Europe and Latin America;
- More specifically, to explore two types of inconsistencies: those stemming from these overlapping coordination approaches and those altering the functions of some elements of the initial market architectures.

In Section 2, we present the literature to which our methodological approach belongs, and the related conceptualisation of market design in terms of modules (i.e., blocks of operational and transactional rules), as well as the dynamics of change of this design in functional terms. We identify the drivers of the "reforms of the reforms", namely market failures in current markets in the first stage, and thereafter, the inconsistencies that arise between the initial modules and those introduced subsequently to correct market failures. Section 3 concentrates on the modules that provide the long-term signals that usher in a new hybrid regime, namely the "Long-Term Contracts" module; the "Capacity Mechanism" module; and the "RES-Decarbonisation" module. International experiences in combining these modules with the initial market architecture draw attention to different issues with the articulation of planning and market coordination principles. Section 4 deals with the inconsistencies between these new "long-term" modules and the initial modules, and the remedial measures that are needed to ensure an efficient interplay between the market signals and these "long-term" modules in order to reach a stabilised regime after the hybridisation of the market regime.

2. An institutional framework to analyse the "reforms of the reforms"

Since the initial wave of reforms in the 1980s and 1990s, liberalised electricity markets have continued to evolve around the globe. There are several strands in the literature that focus on explaining the drivers and dynamics of this evolution. These are considered below.

2.1. The institutionalist perspective on reforming industrial organisation and regulation

Three parallel strands of neo-institutionalism have become established in the analysis of regulation or socio-technical regimes (Hall and Taylor, 1996):

(i) the "rational choice" institutionalism which emphasizes economic gains in terms of social efficiency (including the so-called transaction costs in their different meanings) which was initially developed by Williamson (1996) at the level of industrial and services activities and by North (1990) at the broader historical level of the societies, followed by numerous scholars;
(ii) the "historical institutionalism" which focuses on power asymmetries and the general features of the prevailing political and economic system in the concerned sectors and countries; and
(iii) the "sociological or organisational institutionalism" which highlights the importance of culture.

The two last institutionalist streams have coped with the analysis of the initial electricity industry reforms by focusing primarily on explaining the variety of liberalisation reforms. Indeed the implementation of reforms has followed different institutional trajectories and trial and error processes involving experiments with different elements of the market designs (see for instance: Newbery, 2002; Glachant and Finon, 2003; Jamasb, Pollitt, 2005; Joskow, 2008a; Pollitt, 2008; Correljé and De Vries, 2008; Borenstein and Bushnell, 2014). They explain the variety of liberalisation reforms in terms of the differences of institutions and development polices between countries, as well as the steps to establish the initial structures and regulation of the electricity industry. These have served to separate, in a timely way, the natural monopolistic activities and competitive activities, so as to establish a regulatory authority, and thereafter to enable privatisation (Newbery, 2002).

Hollburn and Spiller (2002), Spiller (2009), and Henisz and Zellner (2010) focused on the "reforms of the reforms" that have been implemented in emerging economies that are confronted with the challenge of attracting investment. They have insisted on the importance of the credibility of public governance (referred to as the "public contract") in facing this challenge. They have also shown how the roles of interest groups, the pressure exerted by public opinion, and common beliefs interfere with more objective drivers of market reform. Correljé

[2] In an institutionalist perspective, the general concept of regime in a sector is a set of institutional forms to govern the interactions between players, in particular between private entities, public entities (among which regulators) and government, including market rules, laws, policies and regulations.

[3] In the new regime, there is a hybrid form of markets, with a two steps competition, first the competition "for the market" through the auctioning of long-term contracts; second, the competition "in the market", where existing generators compete in supplying energy to the spot market. Occasionally this is referred to in the paper as a hybrid market, not to be confused with the hybrid regime which combines planning and market principles.

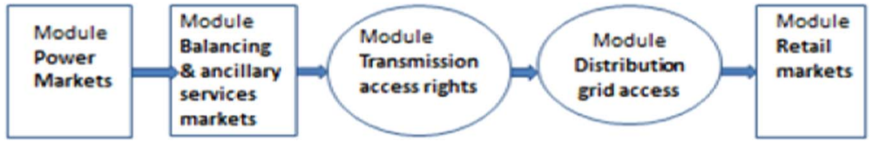

Fig. 1. Chain of modules for the initial industrial organisation of an unbundled electricity sector.

and De Vries (2008) explained the variety of reforms in the OECD and emerging economies in terms of differences in policy goals, political cultures (for example, beliefs in the benefits of markets and competition versus confidence in the efficiency of technocracies), degrees of institutional centralisation, levels of efficiency of former public utilities, as well as some specific issues, such as the legacy of nuclear assets and the availability of primary domestic resources.

Our paper belongs to the "rational choice" strand of the institutionalist literature; however it should be noted that the variety of adaptations of the initial market regime, and differences in the speed of evolutions towards the new hybrid regime related to institutional, legal and political characters would find relevant explanations in the respective historical and sociological strands.

2.2. A "modularity framework" to characterize the key elements of electricity markets

More specifically, our approach builds on the "modularity framework" introduced by Baldwin and Clark (2000), regarding the design of rules in an industrial organisation, as well as the technical definition of modularity as a particular design structure, which distinguishes between the technological constraints within non-separable clusters of tasks on the one hand, and a strong institutional constraint on the design of interfaces that connect task clusters that are technologically separable on the other hand. Perfect modularity allows us to increase the potential for managing a complex chain of operations; it allows the modules to operate in parallel with a certain degree of autonomy, while making it easier to react to uncertainty, provided this uncertainty is confined to a single module. This framework complements the concept of Williamson (1996) on technological separability which distinguishes between the technological constraints within non-separable clusters of tasks and a strong institutional constraint on the design of interfaces connecting clusters of tasks that are technological separable.

That being said, Baldwin and Clark (2000) recognize that "in a complex design, there are often interdependencies between modules and many levels of visible or hidden information (…)(at the level of interfaces linking them)". Baldwin and Clark add: "in a complex design, there are often many levels of visible and hidden information. Perfect modularity is thus not universal". And this is the case of the competitive reforms of power industries in which the hermetic separation of task clusters having different natures is not feasible. Boundaries between modules are porous and some interdependencies between the modules remain.

Glachant and Perez (2009) use this "modularity" framework and the imperfections of the modularity to analyse the complexity and variety of initial power industry reforms which were focused on the introduction of coordination by short-term market price signals, both for operational coordination and decentralised investment decisions. They identify a set of distinct functional and institutional modules along the electricity value chain, each of which have different potentials for the introduction of market and competition factors. The electricity industry indeed comprises different modules of competitive activities, the market module including the set of energy markets (forward, day ahead, intraday), a module of retail supply competition, and a module of real-time (balancing) and ancillary services managed by the system operator, based in particular on a market-balancing mechanism (see Fig. 1). In addition, there are a number of modules associated with regulated monopoly activities, such as the module of transmission rights, which is based on regulatory access rules, and the module of distribution grid access.

Glachant and Perez, (2009, 2012) elaborate around the imperfect modularity inherent to the technological complexity of the power industry, which results in strong interdependencies between modules. These imperfections and interdependencies explain the variety in the design of modules, and of interfaces between modules. The different modules cannot be considered as independent because of their technical and regulatory complexities, in contrast to the pure independency of the modules in the analytical framework of Baldwin and Clark (2000). As this interdependency is one major explanation for the variety of reforms at the different levels of the value chain, this suggests that the same is true for the "reforms of the reforms" that are analysed in this paper, which are characterised by a wide range of variations in design for the different additional modules even if a certain convergence has been observed for some of the modules, as will be discussed in Section 3.

2.3. Applying the "modularity framework" to investigate the recent electricity market reforms

The main issue with the historical approach to electricity market design revolves around the reliance on the market price signals to organise both the short term coordination for the dispatching of different resources and the long term coordination to drive investment in adequate generation capacities to maintain security of supply whilst decarbonising the electricity mix. In theory, the electricity market has two coordination functions. First, in the short-term, it ensures the efficient operation of the total fleet of plants. Second, it signals a scarcity of capacity for different technologies *via* price signals that orient investors' long-term decisions. There is, in theory, complete consistency between short-term and long-term market coordinations when there is pure competition, perfect information, and no risk aversion.[4] The infra-marginal rents generated on the hourly wholesale markets, where prices are aligned according to the variable costs of the clearing marginal plant, plus the scarcity rents during peak periods are supposed to allow recovery of the fixed costs of all the plants and provide a return on invested capital. The optimal technology mix that results from the investment decisions of market players is quasi-identical to the long-term optimum of a benevolent social planner, which minimises the long-term costs, except for some differences linked to the cost of risk management and the inclusion of option values in the decision criteria.

However, in practice, electricity markets are incomplete and suffer from a number of imperfections. This has prompted policy makers and regulators to implement various reforms and additional mechanisms. In particular, electricity markets seem to be capable of driving competition in the short-term, although their ability to deliver investment incentives that lead to a socially optimal generation mix remains uncertain. In addition, policies aimed at supporting the use of renewables by guaranteeing long-term revenues to investors, which which are part of the process of hybridisation of the initial market regime have

[4] A theoretical microeconomic analysis of power systems shows that, under a number of stringent conditions, the short-term price that results from a competitive market provides efficient outcomes, both in the short and long run [see Bohn et al. (1984), Caramanis et al. (1987), Vázquez et al. (2002), Hunt and Shuttleworth (1997)]. In this way, infra-marginal energy revenues provide the necessary income for the recovery of both the operational and investment costs.

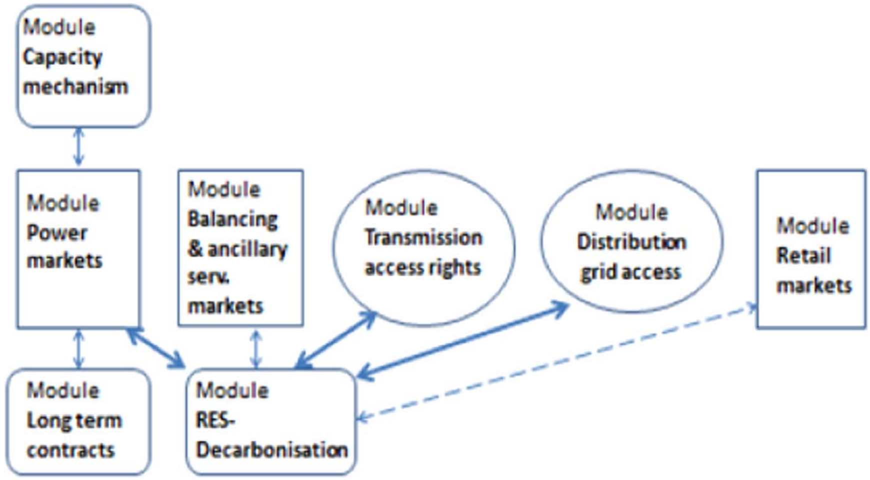

Fig. 2. The initial modules and the three additional long-term modules in hybrid market regimes.

significant effects on electricity markets in Europe, by altering the long-term price signal of the energy market which amplifies the market failures.

In our institutional framework, three different types of new modules are typically implemented to resolve these issues. The Long-Term Contracts module to support risk transfers and facilitate investment in every technology, the Capacity Mechanism module to guarantee security of supply and the RES-Decarbonisation module to drive the decarbonisation of the energy mix as described on Fig. 2.

In general, the mechanisms that are introduced are seen as transitory measures, providing time for the system to evolve sufficiently, particularly in terms of new technologies that enable demand response, and for the technology costs to decrease, before allowing the market to regain its full short-term and long-term coordination functions. However, experience to-date suggests that these mechanisms are here for the long term, creating an irreversible movement towards a hybrid regime combining planning and market.

Given strong interdependencies between different modules, when the new modules and their effects are not consistent with the existing ones and their functioning, the latter need to react and to be adapted. A typical example of the effects of inconsistencies that can arise between old and new modules (as developed later in this paper) is the effect of renewables support in the RES-Decarbonisation module on the other modules. Given the variability of the production profiles of RES generators and their low variable cost, the generation by RES capacity tends to disorganise the economic and technical coordination by the energy markets and the market mechanisms for balancing and reserves.

So the interdependencies of the modules suggest that the introduction of a new module would have a number of unexpected effects on some existing modules that need to be fixed. Moreover, interdependency entails the need to make new modules consistent with the institutional environment, in particular in the rules of competition policy which already frame the competition in the market module.[5] In the following section, we consider successively the three functional aspects of the evolution of the market regime towards a stabilised hybrid regime combining planning, auctioning of long-term arrangements and short-term markets:

- the introduction of new modules, to address market and regulatory failures that affect investment incentives, as well as modules that correspond to the out-of-market mechanisms put in place to support the deployment of clean technologies;
- the adjustment of the new modules through "learning by doing" or through the transposition of foreign "best practices", to make them more efficient, or to conform more closely to their legal environment;
- the correction of inconsistencies that might emerge from the interactions of the new modules with the initial ones.

3. The new low term modules to address market and regulatory failures

In the following sections, we introduce three new modules: the Long-Term Contracts module, the Capacity Mechanism module and the RES-Decarbonisation module. Then we investigate the various combinations of these long-term modules and some issues associated with their implementation.

3.1. The "Long-Term Contracts" module to support investment and facilitate risk transfers

The restructuring of the electricity markets is based on the idea that if electricity generators are not able to carry investment risks, vertical integration can be replaced by bilateral contracts between generators and retailers or large consumers, with the assistance of multilateral markets for spot trading and financial markets for hedging arrangements (Joskow and Schmalensee, 1983). This idea assumes completeness of the markets, including financial hedging products with long maturity periods (see, for instance, IEA, 2007).

However, in practice, electricity market restructuring that is based on unbundling activities and market exchanges has certain market-related imperfections, as compared to the theoretical model. There is no financial market for long-term hedging products (see Green, 2004; Roques et al., 2008b), and there are weak incentives for suppliers/retailers and electricity generators to contract forward and share risks in the long term. The problem arises from the fact that the interests of generators and wholesale buyers (suppliers, large consumers) are not aligned regarding the impact of the duration of contracts on the price and quantity provisions (Neuhoff and De Vries, 2004; Roques et al., 2008a; Chao et al., 2008; Finon, 2011). Electricity producers that prefer such long-term contracts cannot find credible counterparts among suppliers or large consumers (Roques et al., 2008a; Green, 2004, 2006). Indeed retail competition is usually based on provisions allowing retail consumers to switch suppliers on short notice. As a

[5] In his seminal book on comparative institutional analysis, Aoki argues strongly that the effectiveness of a regulatory and organisational model depends upon not only its internal consistency but also on coherence with the institutional environment (Aoki, 2001). The institutional environment includes formal rules, including competition policy rules, and soft laws, alongside "informal" institutions (for instance, market culture or consensus on greening policies in our case).

result, retail companies face inherent uncertainties about their customer base, and will thus not be in a position to sign many contracts for a duration beyond the contract duration with their customers. Retailers are thus hesitant to sign long-term contracts when their customers can simply switch to an alternative provider in the case of reversal of the market price trend.[6] As a result, these market imperfections increase the cost of capital and hurdle rates for investors in power generation technologies. This, in turn, can lead to a suboptimal generation mix, as producers are encouraged to invest in technologies that have the lowest capital intensity and that are 'self-hedged', such as combined cycle gas turbine (CCGT) plants (Roques et al., 2008a; Roques, 2011).

To overcome the obstacles, some countries have already introduced 'out-of-market' mechanisms to establish risk-sharing arrangements and long-term contracts for investing in capital intensive technologies related to their public policy objectives (Finon, 2011; Finon and Roques, 2013). This is often combined with programming and planning procedures led by the ministry or the regulator. This approach in terms of hybrid markets (auctioning of long-term contracts to support investment, together with short-term energy markets) has been used in a number of emerging countries since the 2000's, most notably in Latin America.[7] Combined with centralised planning to coordinate significant investment in new capacities in their fast growing economies, the new hybrid regimes aim also to attract private investment as long term contracts facilitate the use of project financing by guaranteeing the fixed cost recovery, thereby reducing risks for newcomers.

In addition, these policy interventions are supplemented by the nomination of a counterparty for these long-term contracts, either the state, the regulated grid company as in the UK (see Box 1), or else regulated retailers which legally retain a legal supply monopoly licence as in Latin American countries. Indeed the risk-hedging mechanisms in the Long-Term Contracts module generally rely on contracting with regulated entities which have the obligation to enter into long-term contracts to cover the load they supply to themselves, albeit with many variants of long-term contracting for capacity with the grid company as in Colombia (Larsen, 2004; Harbord and Pagnozzi, 2012) and in the UK, for energy with the retailers as in Chile and Peru, or for both as in Brazil (see Table 1). There is also variety in the governance framework: the Brazilian model as well as the British one feature centralised procurement of long-term contracts, while the Chilean model features a decentralised procurement model based on an obligation being placed on retailers to commit to long-term contracts to cover all their future loads.

In the present European context, the role of long-term contracts in supporting risk transfers and investment is undermined by the opening up of retail competition required by EU directives. The difficulty associated with hedging investment risks is a barrier to entry for new investors who develop equipment with high upfront costs. The solution could be the contracting with the regulated grid company as in the UK, or with suppliers with a legal obligation to enter into such long-term contracts if they are able to keep a large core of sticky consumers. Nevertheless, the European experience so far shows that the implementation of such arrangements is challenging. Moreover in the European Union, competition policy rules tend to restrict to specific cases the possibility to establish long-term arrangements.[8] Under current legislation, long-term contracts are subject to case-by-case approval decisions, which can create significant uncertainties (Genoese et al., 2016)..

In contrast, in some countries in Latin America, tenders for long-term contracts that are established with distributors who legally retain their retail monopolies have driven intense "competition for the market", and a number of new entrants have successfully entered the generation market without having a prior established consumer base in the past decade. The hybrid markets have attracted significant interest from investors in a range of technologies, including large hydro projects through the long-term contract auctions. One key benefit is that they support an efficient allocation of risks and enable project financing. They have also allowed the development of renewables projects, initially through technology-specific auctioning and subsequently through technology-neutral tenders.

3.2. The Capacity Mechanism module to ensure security of supply

According to the peak-load pricing theory (Boiteux, 1949; Joskow, 2007), situations of short-term scarcity during peak load periods play a key role in returning investment costs and providing adequate signals for investment. Indeed scarcity prices reflecting accurately the system supply and demand in real time are an important element of an efficient market design. (Roques, 2008; European Commission, 2015).

However, there is growing evidence that the current markets cannot guarantee reliability of supply in every situation in the long-term, for various reasons, apart from the fact that resources for capacity adequacy are quite capital intensive per MWh produced[9]: 1) price caps and barriers to scarcity pricing that result from politically unpalatable high power prices often lead to a chronic shortage of revenue for plant operators (the so-called "missing money" issue, as referred to in the academic literature); 2) aversion to risk associated with investing on the basis of very uncertain revenues from scarcity rents; 3) the incentive for power generators to maintain, through tacit collusion, a situation of relative scarcity; and 4) the difficulty related to hedging or transferring risk on a long-term basis (Cramton and Stoft, 2006; De Vries, 2007; Joskow, 2008b; Roques, 2008; Stoft, 2002; Keppler, 2016). This issue of guaranteeing reliability of supply in the long term is exacerbated by the development of variable RES (VRE), which amplifies price volatility in peak and creates greater uncertainty for annual sales by peaking units (Cramton et al., 2013).

More fundamentally, the origin of the resource adequacy problem lies in two issues: 1) a market imperfection, which entails the absence of price-reactive demand – at least for the time being for a large part of consumers until smart meters are deployed and time varying tariffs become widespread; and 2) the willingness of policymakers to define an administrative SoS criterion that may differ from the socially optimal one. This calls into question the rationale of relying on market forces to determine the level of installed capacity that is adequate to guarantee SoS (Keppler, 2016). There has been much focus in recent years in Europe on the need to reform day ahead, intraday and balancing and reserve markets in order to remove potential barriers to free price formation at times of system stress, and to allow much more scarcity pricing not only for capacity, but also for flexibility services (European Commission, 2015). The focus of such reforms is to address the

[6] Transaction cost theory offers a clear-cut interpretation of this situation in terms of the risk of opportunism on the side of the counterpart in a transaction that concerns the development of a specific asset (see Meade and O'Connor, 2011 about the issue of long-term contracting in the electricity markets).

[7] The first market reforms that started in several Latin American countries in the 1980s failed to stimulate timely investments, in particular in high sunk-cost equipment, such as hydraulic plants. Moreover, as many of these systems include a large share of hydraulic generation, market designs that produce volatile prices have been very vulnerable to episodes of drought in Argentina, Brazil, Chile, Colombia, Peru, etc., with long-lasting price spikes and the imposition of rationing for consumers. This triggered a second wave of electricity market reforms in the early 2000s, which introduced long-term contracts to support and coordinate investment (Battle et al., 2010; Moreno et al., 2010, 2011; Rudnik et al., 2002, 2006).

[8] The legal framework of competition policy and anti-trust measures could limit the development of such policy instruments, as is the case in the EU (Marty, 2015; Hauteclocque, 2012). However, recent reforms in Europe have resulted in the European Commission adopting a pragmatic approach and weighing the pros and cons of long-term contracts with respect to competition (Roques, 2013).

[9] The relative share of the capital cost of a peaking unit in the cost price of the MWh if the unit produces, on average, during 100h per year is around 80% (for a cost of investment of 500€/kW and a variable cost of fuel of 160€/MWh (Data from NEA-OCDE and IEA, 2010)

Box 1.The UK Electricity Market Reform.

After 2010, given the increasing importance placed on climate policy and the poor efficacy of the renewables obligation, the UK government chose to implement a wide-ranging market reform using long-term arrangements to support clean technologies (RES as well LCT) and to maintain SoS. (OFGEM, 2010; DECC, 2011, 2013). The 2013 Energy Act focused on reforms aimed at attracting the investment needed to achieve decarbonisation of the sector while simultaneously ensuring SoS. The Electricity Market Reform (ERM) introduced:

1. Auctioning of long-term contracts for RES and LCT projects in the form of contracts for difference (CfDs) to be established with a regulated entity, the grid company. CfDs are intended to provide support to large-sized RES and LCT plants, in addition to the investment signal generated by the carbon price, and to hedge the market risks between the developers and the public agency. This mechanism is complemented by feed-in tariffs for small-sized RES units in order to reduce the transaction costs and administrative risks of contracts auctioning for these small units.
2. A capacity market that includes long-term capacity contracts for new conventional equipment, together with short-term forward contracts for the existing conventional plants. The capacity market is based around a centralised auction process that is active 4 years ahead of delivery for new and existing capacities (excluding those already benefiting from the CfDs auctioning system). Unlike the US forward capacity markets, new resource investment is secured by long-term capacity contracts (up to 15 years), making the set of the two mechanisms close to the Latin-American mechanisms.

These measures have been complemented by a carbon price floor on the fossil fuel used in the conventional plants to increase the revenue from RES and low-carbon equipment through the market (and reduce subsidies), and by the imposition of an emission standard on new fossil fuel plants to restrict the development of fossil fuel-related equipment.

In parallel to the EMR, the UK is performing several other reforms of the market arrangements. The electricity balancing reform aims to provide better price signals that value scarcity and flexibility. The reform of zonal network charges aims to provide better locational incentives and coordinate network and generation development.

"source" of the various market and regulatory failures, as well as to support the development of intraday and balancing markets with greater liquidity and more granular products in order to enable trading closer to real time.

But in practice in many European countries policy makers and regulators chosen a "belt and braces" approach and introduced in parallel to these reforms a capacity remuneration mechanism (CRM). There is a wide range of options – strategic reserves focused on some existing or specific new units, regulated capacity payment, capacity obligation on suppliers, forward capacity auctioning, reliability options auctioning – with different attributes in terms of effectiveness, market power mitigation, cost efficiency and risk management. The scope of this paper does not allow a comparison of these mechanisms, which are well-covered in the literature,[10] but it is noteworthy that the mechanisms which seem to emerge as the preferred approach are those based on a "quantity instrument": the forward capacity markets implemented in some US regional power markets, the UK, Colombia, and in the near future in Poland; the reliability option (financial contract) mechanisms such as the one adopted in New England, and planned for the future in Italy and Ireland; and the decentralised capacity obligation on suppliers (as in France). These quantity-based capacity mechanisms combine some form of planning through setting of a reserve margin target (or an obligation on suppliers in the French case) with auctioning of forward contracts by the central buyer (the system operator) or decentralised calls for tenders by obligated suppliers.

3.3. The RES-Decarbonisation module

There is a large literature that shows that introducing a carbon price which feeds into power prices is insufficient to be the sole driver of the decarbonisation of the power sector and drive efficient investment in RES and LCTs for a number of reasons (Hepburn, 2006; Jaffe et al., 2005; Grubb et al., 2008; Roques, 2008; Lehamnn and Grawell, 2013). First, some RES technologies are not yet fully mature, and RES plant manufacturers and investors cannot yet reap the benefits derived from cumulative learning; this reduces the incentive to invest in non-mature technologies. Second, the RES and other low carbon technologies are capital intensive and it would be challenging to expose them fully to the market risks for their revenues. Political and regulatory risks inherent to these technologies can further increase the risk hurdle rate associated with investment in these technologies. Third, the carbon price signal stemming from carbon markets such as the European emissions trading scheme lacks the credibility needed to provide a strong enough incentive for investors.

The literature concludes that it is therefore necessary to support investment in RES and other clean technologies with long-term risk transfer mechanisms, in addition to the implementation of a carbon price (Neuhoff et al., 2007, Grubb et al., 2007; Boot and van Bree, 2010; Grubb and Newbery, 2008; Newbery, 2011; Finon, 2011; Finon and Roques, 2009, 2013). These mechanisms therefore can have a double function to both subsidise the deployment of immature technologies, and to support de-risking for the more mature ones. As the RES technologies and other LCTs mature and become competitive, the role of these long-term arrangements changes and concentrates mainly on the de-risking necessary to facilitate financing of capital intensive technologies, and therefore converges with one of the mechanisms of the Long-Term Contracts module.

The three main ways of supporting RES and LCT development implemented across the world are as follows:

1. Feed-in tariffs (or equivalent like the newly floating feed-in premium (FIP) which is presently deployed in some EU members states, France, Germany, etc.) which are defined by reference to the cost-price of each RES technology and guaranteed in the long term by the government.[11] In addition, the support of RES production may be

[10] The respective advantages and drawbacks of the different CRMs are compared in several publications (Cramton and Stoft, 2006; De Vries, 2007; Roques, 2008; Finon and Pignon, 2008; Cramton et al., 2013; The Brattle Group, , 2012, 2014).

[11] The feed-in-premium provides a top-up payment for the energy produced by the RES generators. There are two types of FIP: a fixed FIP which is defined ex ante and remains constant in the long term, and the floating FIP which is calculated ex post each month in a way that gives the RES generator constant revenue to cover their fixed cost (it has, the same function as a FIT, but with a close difference, the producer is exposed to the energy market price and he is responsible for his imbalance. Whatever it would be, we can guess that the first system of fixed FIP introduces more risks for the investors. We must add the existence of a variant to these FIP mechanisms: namely a FIP calculated by MW and paid annually on standard capital cost estimates. The interest of this FIP variant (used in Spain) is to help the recovery of fixed costs while it avoids incentives to produce during episodes of RES overproduction that can entangle market prices to negative levels.

Table 1
Characteristics of long-term modules in different reforms towards a hybrid regime.

Country	Brazil	Chile	United Kingdom	
	Centralized long-term contracting	**Decentralised long-term contracting**	**Capacity Mechanism**	**Auctioning CfDs /decarbonisation**
Degree of centralisation of mechanism	Joint auctions by a central entity before transferring contracts to distributors	Distributors organise and manage their auctions, possibility for joint auctions	Ministry and TSO organise capacity contract auctions and payment by consumers	Ministry and TSO organise auctioning of CfDs and payment by consumers
Autonomy allowed to generators in terms of investment	No freedom of timing Technology-neutral	Freedom of timing Technology- neutral	No freedom of timing	No freedom of timing
Buyers	Regulated users	Regulated users	TSO with some parameters defined by ministry	TSO with some parameters determined by ministry
Sellers (existing and new capacities)	Separate auctions for existing and new capacities	Existing and new capacities in the same auction	Existing and new capacities, demand response and interconnections	Investors for CfDs
Contract structure	Capacity and energy terms/ Energy part as an option contract	Energy contracts	CfDs on capacity Long-term for new contracts (15 years) Mid-term for existing contracts (up to 3 years if refurbishment)	CfDs on energy Exposition to market price 15 years for RES, up to 35 years for nuclear
Degree of technology neutrality	Technology-neutral (occasionally with RES-specific auctions)	All technologies compete together	Generators that receive low-carbon subsidy are not eligible	Technology-neutral for RES technologies

complemented by a priority dispatch rule.

2. Auctioning for the assignment of long-term purchase contracts, either on the total price of the MWh (as if it is a feed-in-payment per MWh or each green part of MWh), or on the total revenue with a symmetrical option contracts of the CfD-type as in the UK,[12]
3. The renewables certificates obligation (RO) imposed on energy suppliers (combined with certificate trading). This mechanism could be complemented by a tax credit on the MWh produced by units from RES and LCT technologies, or on the investment per MW for specific RES technologies (in particular the PV projects), as is the case in the USA at the federal level.

These different approaches to support RES and LCTs have in common that they impose an obligation to purchase RES electricity, or the green part of the MWh, on clearly specified agents – regulated grid companies, historic operators or government in the first two mechanisms, retailers in the third mechanism, but with different forms of arrangements: agreement with the ministry or public agency in the case of FIT or FIP, auctioned private contracts with fixed price or CfDs with regulated entities, and self-developed power purchase agreements (PPAs) with the renewables obligation in the UK before 2016, and the renewables portfolio standards (RPS) mechanism in the US jurisdiction with restructured markets (Wiser et al., 2007; NREL (National Renewable Energy Laboratory), 2014).

In this set of mechanisms, the renewables obligation (RO) was initially supposed to be superior to FITs in terms of consistency with the power market, and because of the greater incentives for more efficiency through the competitive pressure. But conversely, from the point of view of the developers, the RO appears to be the most risky approach as it is difficult to anticipate market and RO revenues (see Table 1), and the greater exposure to risks increases the cost of capital compared to a FIT mechanism or equivalent (floating FIP, CfDs) (Butler and Neuhoff, 2004; Mitchell and Bauknecht, 2006; Mitchell, 2007; Woodman and Mitchell, 2011). Indeed, a major issue with the RO mechanism is the foreseeability of revenues which is questioned from three different sources of uncertainty: the dependency of the revenue value on the timeframe of the mechanism (the horizon of the obligation that defines the time-scale during which a new project could draw a value from its certificates), the regulatory changes linked to the design (adaptation of technology bands, buy-out price, etc.), and the uncertainties of certificate prices and wholesale electricity prices. This led developers and obligated suppliers to enter into long-term contracts to share risks (Mitchell and Baucknecht, 2006; Wiser et al. (2007); NREL (National Renewable Energy Laboratory) (2014)).

The experience with policies that aim to support RES-E in liberalised markets shows an evolution across countries in favour of mechanisms based on long-term arrangements to guarantee revenues, not just in the EU but also in Switzerland, Canadian provinces, Australia, South Africa, etc. In the US, a vibrant private corporate market for long-term Power Purchase Agreements has been the cornerstone of the development of RES driven by Renewable Portfolio Standards (RPS)and long term tax credits.

3.4. Towards a convergence of the new market modules?

The hybrid regime combining short term markets with some form of centralised planning and long term risk transfer arrangements to support RES and LCTs, as well as capacity mechanisms has seen some convergence between these different long term modules in the past

[12] In power markets, a contract for difference (CfD) is a long-term financial contract between two parties, typically described as the "buyer" and "seller", which stipulates that the seller will pay to the buyer the difference between the current value of the energy on the hourly market and its value in the contract (if the difference is negative, then the buyer instead pays to the seller). In effect, CfDs integrate symmetrical option contracts that make it possible to guarantee long-term revenue for the investor.

decade, in particular in Latin America in the early 2000s but also in the UK (see Box 1). second wave of Latin-American electricity market reforms in the early 2000s introduced long-term contracts to support and coordinate investment in answer to investment market failures (Batlle et al., 2010; Moreno et al., 2010, 2011; Rudnik et al., 2002, 2006). The long-term investment decision-making is henceforth largely driven by auctioning of long-term contracts on capacity as in Colombia (Larsen, 2004; Harbord and Pagnozzi, 2012), on energy as in Chile and Peru, or for both as in Brazil.

In OECD countries, the dynamic over the past decades has focussed first on the RES-Decarbonisation module and more recently on the Capacity Mechanism module. The question remains open whether the rapid development of the RES capacity which is based on long term arrangements, now becoming auctioned long-term contracts, can alone lead to the mutation of the market regime into a comprehensive hybrid regime. It is noteworthy that the two types of new market modules (RES Decarbonisation and CRM) implemented in OECD countries increasingly borrow the key features of the Long-Term Contracts module. This is the case of the RES –Decarbonisation module in the European Union countries with the switch from feed-in-tariff systems to auctioned long-term contracts for RES and low carbon projects. That is the case for the CRM module in the UK and France with the implementation of long-term capacity contracts for new plants in the capacity mechanism (up to 15 years contract in the UK, 7 years in France).

Conversely, in some of the Latin American market designs, the auctioning of long-term contracts on energy cover the new RES technology projects in a technology-neutral approach, as in Brazil and Chile. It is therefore possible that eventually the three different new modules will be merged into one single mechanism such as in Brazil, or alternatively into two mechanisms to separate the treatment of RES and LCTs, from conventional fossil technologies such as in the UK (the energy CfD contracts auctioning for RES, and the CRM for the non-RES units with long-term capacity contracts for new units) after the Electricity Market Reform of 2013.

That being said, an important driver of the future evolution of the long-term modules that characterize the new hybrid electricity regime is competition policy rules at the supranational or federal level which might restrict the autonomy of governmental decisions on this matter.[13] For instance, in the EU the State Aid regulations that aim to avoid distortion of competition between member states have recently refined their approach toward both RES and LCTs support and capacity mechanisms. The 2014 Guidelines on energy and environment impose two major changes for RES support policies (DG Comp, 2014). First that FITs and priority dispatch should be abandoned for large installations and be replaced by a system of FIP (or equivalent as the CfD remuneration) in order to expose the RES generators to the energy markets. Second, except for the small-size units, the long-term support arrangements should be systematically allocated by auctioning, with as much as possible a technology-neutral approach for the mature technologies. The principle of getting long-term contracts to help to trigger investment decisions with revenue guarantees is henceforth recognized, provided that long-term competition exists to allocate them. Moreover the principle of regular open tenders for an certain amount of capacity relies implicitly on a planning approach.

Similarly, the European Commission competition directorate published in 2016 the conclusions of its sector inquiry on the capacity mechanisms, with associated guidelines for the design of these mechanisms. In particular, the recent French capacity mechanism (decentralised capacity obligation) assessment by the European Commission is quite revealing of a possible convergence of competition policy concerns and the monitoring of the long term capacity development to maintain security of supply (DG Comp, 2016). Indeed the EU Commission required France to include in its decentralised capacity obligation, the auctioning of long-term 7-year contracts for new equipment, in order to facilitate entry into the French market.

4. Inconsistencies between "old" and "new" market modules: the need for recurrent adjustments

In the hybrid regime that results from the adjunction of some of the three long-term modules in the market design, several issues arise from the interactions between the market and supplementary modules. Where modules are in place to reduce risks for peaking units, for RES and LCTs (as in advanced economies with decarbonisation policy), or for any technology (as in Latin America), there are concerns regarding how these affect the remainder of the initial modules. But in countries where the decarbonisation policies are mainly based on RES development, the problems of intedependencies are amplified because the physical effects on system operation of large-scale variable renewable energy (VRE) production.

Indeed, because of this priority, it is mainly in Europe that the issue of inconsistencies between the additional modules and the initial modules of markets and network access has been raised, particularly when the VRE capacity and production have reached significant shares above a threshold, let us say, of 10–15%. Beyond this threshold, the tensions are revealed by the increasing system costs of the RES production which were not internalised by the VRE producers in the former FIT system, and the very significant total cost of the RES policy (assimilated into the difference between the market prices and the feed-in tariffs). On one side, the system operators must bear the system costs caused by VRE production, without compensation in the regulated transmission tariffs. On the other side, the increasing importance of the levy to finance the RES policy cost in the total price paid by consumers leads governments to envisage control of this cost by reforming the mechanism. A complementary element of this awareness is the effect of RES production on the decrease in average hourly prices and this in the revenues of existing conventional plants, which reflects the important stranded costs for the latter with a strong depreciation of these assets, generally owned by the former utilities.

In this section, we identify the tensions that can occur between the new long-term modules and the existing modules, the self-reinforcing effects on the new modules which can no longer be considered as transitory patches in the market architecture, and ways to limit or remove these tensions by improving the initial modules for markets and grid access. In the following, we implicitly refer to a policy scenario in advanced economies where decarbonisation is not based on dispatchable low carbon technologies (new hydro plants, nuclear, CCS, etc.) but on RES capacities.

4.1. Common tensions between the Long-Term Contracts and RES-Decarbonisation modules and the Power Market module

In countries with market designs that include a Long-Term Contracts module that covers every generation investment, in particular in Latin American countries, or those with a RES-Decarbonisation module, which triggers the majority of investments in mature markets with a prioritised decarbonisation objective, as in EU countries with former FITs, and now auctioned for FIP contracts or CfDs contracts, the power market loses the function of long-term coordination, while the mechanisms of these two long-term modules self-reinforce.[14]

[13] In the EU, the capacity mechanisms adopted by some EU Member States are subject to an EU state-aid review referring to the 2014 State Aid guidelines, as well as to a 2016 Commission Regulation establishing a guideline on forward capacity allocation (European Commission, 2016).

[14] The energy markets have a residual role in dispatching under different forms: (quasi) mandatory pools based on bid prices (in the USA, Ireland, Colombia, etc.), decentralised organised markets based on bid price (in the majority of European countries) and simulated dispatching based on SMRC (as in Brazil, Argentina, Chile,

In the first group of countries, the investment in various technologies that are promoted by the long-term arrangements requires a significant share of low-variable-cost technologies (hydro plants, large-sized RES units, eventually nuclear plants) to achieve the optimal mix, in particular in countries with large hydro and RES resources. These investments tend to lower the annual average price on the hourly energy markets by displacement of the merit order in favour of new lower SRMC plants.[15] Because this effect alters the possibilities of fixed cost recovery, this fact reinforces the existing mechanism based on long-term, risk-sharing arrangements, and consolidates the comprehensive hybrid model adopted in these countries.

In the second group of countries, this interaction between the RES-Decarbonisation module, and the Power Market module is clearer. The production of RES units enters the system *via* out-of-market arrangements (helped also by priority dispatch until 2016 in the EU, which avoids them having to pay for their system costs), to the detriment of existing conventional plant equipment on the day-ahead market. Dispatch distortions exert two important effects on the merit order[16]: a decrease in the wholesale prices and a decrease in the yearly production of existing conventional plants, with each effect being uncertain to occur in any subsequent year. New zero (low)-variable-cost plants based on RES or LCTs displace more expensive thermal plants and reduce the average power prices.[17] Even the recovery of the fixed operational costs of existing equipment is challenged, and the price signal to trigger investment in conventional technologies, which are still necessary to back-up the VRE productions, is definitively distorted. Indeed, the revenues of any new conventional plants are lowered and placed at risk by the uncertain outcomes of the policies in terms of the shares of energy production.

4.1.1. Consequences

This has two important consequences for the general market design. First, the use of long-term arrangements for promoting RES and LCTs is likely self-reinforcing, even with commercially mature technologies, even if they would be made more profitable with a high and credible carbon price. Investment in capital-intensive RES/LCT plants would not be financially viable if these mechanisms were removed. This definitely raises questions as to the transitory role of these arrangements as politically presented. In fact, if decarbonisation is retained as a priority objective, the evolution towards a hybrid regime, including planning and long-term arrangements for RES and LCTs, appears to be irreversible.[18]

Second, it becomes necessary to complement the revenues of the existing conventional plants, as well as those of potential new plants. Existing base-load and peak-load units in conventional technologies tend to be operated with much smaller and uncertain annual load factors and to have lower revenues when they are dictated by the hourly market, which leads to decisions as to early retirements. Indeed a number of existing conventional plants, even recent ones, cannot even cover their operational fixed costs, without mentioning asset depreciation to their owners. Beside these decisions on 'early retirement', this change definitely deters investment in thermal plants in the EU countries, while they are needed as back-up for variable RES production (NEA-OECD, 2012). In other words, the market fails to compensate fully for the stranded costs and depreciation adjustments that result from the RES and low-carbon policies, and fails to signal the new equilibrium of the residual system with an optimal share of flexible conventional plants and other resources (demand response, storage, ,etc), for back-up of the variable production.

A solution to the problems of the decreasing economic value of non-RES plants generated by the energy markets and the barriers to new investment in conventional technologies is the creation of a capacity remuneration mechanism. In order for it to make new conventional plants attractive to investors, the CRM would need to procure them complementary revenues. This could not come solely from new ways to remunerate flexibility products on intraday markets, balancing mechanisms, and ancillary remuneration (which are detailed below), as some have argued (Hogan, 2015). Indeed, efficient remuneration of flexibility products and system services introduces such high volatility in revenue streams that they become barely credible as a long-term price signal for investment in conventional plants or other resources with flexibility qualities.[19]

4.2. Tensions between the RES-Decarbonisation module and the Balancing-Ancillary Services module

Existing electricity systems are generally poorly adapted to offering flexibility services at the level needed in a system in which a very high share of VRE production has been reached. While some demand responses in heavy industry, pumped storage hydro, and merchant interconnections have been accommodated within existing electricity markets, this is a long way short of offering the high degree of flexibility that an electricity system with very high shares of renewable energy would require. The solution to developing flexibility resources mostly lies in market incentives to develop them, in particular in improving the Balancing-Ancillary Services module. The development of VRE reinforces the need to reward operational flexibility, as well as dependability over short time-frames, both for flexible power plants and demand-side response. The value of operating flexibility is typically captured through price variations in day-ahead or intraday markets, balancing mechanisms, and ancillary service contracting. This should be where prices optimise the system in the short run, reveal the value of electricity-related products on an hour-by-hour basis, and thereby orient investments towards flexible resources in the long run (IEA, 2016). This issue is crucial for the European markets, in which existing market designs were less-detailed in terms of products than the US market designs with multi part bids (Saguan et al., 2009; Neuhoff et al., 2016) and were poorly adapted to value flexibility and thereby direct investment towards flexible resources.

4.2.1. Consequences

In many European countries, there are growing concerns that such short-term price signals do not accurately reflect the scarcity value of operating flexibility, leading to calls to revisit the current arrangements for intraday trading, real-time/balancing market mechanisms, and ancillary service procurement, so as to orient investment towards

(*footnote continued*)
Peru, etc.).

[15] This is the case irrespective of the energy market design, whether it is the classic bid-price based form or the cost-based form, as in several Latin American countries where the market operators refer to the SRMC of the different plants that declare their availability (for the market design in Brazil, see Tolmasquim, 2012).

[16] Not to mention negative price episodes due to the rigidity of the equipment fleet (which is discussed later in relation to the problems associated with system balancing)

[17] An example is the increase in the average electricity price reduction from 5 €/MWh in 2010 to around 13 €/MWh in 2015 in Germany, while the RES share of energy production increased from 10% to around 30% during the same period (Institut, 2013; Praktiknjo and Erdmann, 2015).

[18] Certainly one could mention the fact that the MWh of decentralised PV has reached grid parity in countries with high retail prices, suggesting that support mechanisms could be withdrawn some day because costs are falling below end-consumer price. But this objection is unfounded because grid parity has little to do with economic efficiency. Not only does this pseudo-index of competitiveness ignore electricity price heterogeneity across all hours of the day, the week and the season, but also retail electricity prices comprise mainly taxes, levies, and grid fees, especially as wholesale prices are declining. Decentralised solar generation has a poor market value measured with the appropriate electricity prices, and it does not help to save on generation and grid costs, while it has quite important system costs.

[19] The limited scope of this paper does not allow us to develop this issue. Some researchers conclude in the other direction, by arguing that flexibility services remuneration would be sufficient to trigger investment in flexibility resources and by this route, it should be possible to solve the problem of 'missing money' for investment in capacity for improving the reliability of the system in any situation (Hogan, 2015).

flexible resources and to lower the operational costs of the system. This should be accompanied by improvement in transmission pricing to reflect scarcities over space (see below).

As a first consequence, each sequence of these successive markets should be improved to reflect scarcities over time, including the perspective of integrating the intraday and balancing markets between systems. But the situation is changing, regarding the temporal granularity. The traditional hourly bid format has in some countries, like Germany, been disaggregated at intraday stage into intervals of 15 min, thus facilitating a closer match of supply and demand within an hour. But the smaller the interval, the fewer adjustments individual power stations can offer due to technical constraints limiting how quickly they can adjust production (ramping rates). The perceived conflict between the objectives of increasing temporal granularity on the one hand, while at the same time respecting plant capacity in the bidding structure can be resolved with a multi-part bid format. And in this respect the multi-part bids in the US regional markets as well as those which existed in the former British pool show how market participants could submit bids reflecting not only marginal generation costs (or value of load for demand), but also inter-temporal constraints including minimum output levels, feasible ramping rates as well as start-up costs (Neuhoff et al., 2016).

A second consequence is the necessity to drive the evolution of the RES-Decarbonisation module by: 1) making RES producers pay for their system costs, so that they have an incentive to reduce these costs (through better production anticipation on day-by-day and hour-by-hour bases, self-curtailment, offering ancillary services, etc.); and 2) easing the market valuation of flexibility services. Indeed, for developing exchanges of flexibility products, it is important that VRE producers become balancing responsible, in order that these markets become liquid by creating high demands on the intraday and real-time (balancing) markets This is one of the positive aspects of the changes in support mechanisms mandated by the European Commission, with the switch from FIT to FIP and the auctioned CfDs which makes VRE producers balancing responsible (see Table 2). Flexible resources, such as fast ramping plants and storage units, should find higher value on these markets with more demand for flexibility services and more granular products Table 2.

4.3. Tensions between the RES-Decarbonisation module and the Grids Access modules

The VRE units, which are mainly decentralised, are generally connected to the distribution grids, without any price signal to indicate which districts are behind congested transmission lines. The locations of these units could generate new congestions within the transmission system. This raises the issues of optimisation throughout the network and of generation that is made increasingly complex by the growth of this variable generation, as well as the need for flexible resources (demand response services, different types of storage plants etc.). The absence of locational energy price signals (nodal or zonal pricing) or locational transmission charges does not allow for economically optimal development of the network and generation systems.

In this perspective, it is not only important that electricity prices and transmission charges convey locational signals to optimise the operation of transmission, production levels, and loads in different nodes of the network, but also that they provide incentives to optimally locate new production assets and flexible resources and to build new transmission and distribution lines, using price signals that are sufficiently tuned to allow socially efficient location, and grid investment (Li et al., 2009; Glachant et al., 2013; EISPC (Eastern Interconnections State Planning Council), 2013).

However, the problem is not only at the central level. When the VREs are mid-size and small-size plants, they are generally connected to the system at the level of the distribution grid. This means that the reliability of supply problem is first raised by the VREs at the decentralised level. The roles of distribution system operators (DSO) will have to evolve to facilitate balancing at the local level, and the regulation of distribution grids should be improved. When the development of small-scale generation, distributed demand-side response, and electric vehicles are scaled up, which will affect the distribution system operation, these will be powerful incentives to make distribution grids "active".

4.3.1. Consequences

One solution is to move progressively from quite simple transmission access tariffs to zonal tariffs, or even better, to locational tariffs (Neuhoff et al., 2016). A complementary strategy involves activation of the roles of the DSOs to complement the adaptation of the modules Balancing Services and Transmission Access. More efficient regulation will be valuable if it provides the right incentives to DSOs and allows them to optimise between CAPEX and OPEX: for example by using local flexibility – in coordination with TSOs – to facilitate RES integration and possibly limiting or postponing costly T & D grid investments, eventually through VRE production curtailment (see Brandstätt et al., 2011; Florence School of Regulation, 2013).

The distribution grid operators could decide to turn off renewables at times of excess generation, which is currently the case in Ireland, with different forms of compensation (Anaya and Pollittt, 2013). Smart rules for curtailment could be a way to avoid over-investment in transmission and distribution grids (Kemfert et al., 2016). Conversely the VREs and other distributed generators could participate in ancillary services (frequency and voltage regulation) at the local level.

4.4. Tensions between the RES-Decarbonisation module and the Retail Market module: the issue of RES policy cost

While the price signal of the power market becomes more inefficient for triggering investment decisions in conventional technologies, there is an increasing discrepancy between the energy market prices paid by

Table 2
Differences in sources of investment risks between the RES support mechanisms.

Support schemes	Feed-in-tariff per MWh	Green certificate obligation	Contracts for difference / Floating feed-in-premium (MWh)	Fixed feed-in-premium per MWh	Feed-in-Payment per MW
Allocation mechanism	Regulated or through tender	Specific market and long-term bilateral contracts	Through tender (in the UK and EU)	Regulated or through tender	Regulated or through tender
Price risk	No price risk	Risks on electricity price & certificate price	Hedging of most of price risk	MWh market price risk	MWh market price risk
Balancing responsibility	No responsibility	Responsib of real time difference from their contractual position in the day ahead and intraday markets. Short term volume and price risks			

consumers and the total costs of production. This results from the higher cost for MWhs produced by RES that have entered under a specific regime of long-term arrangements, including the system costs that they generate. To fill the gap, the money for the long term subsidies for RES productions needs to come from somewhere, generally from a specific charge paid by the consumers. However, the rules of the cost reimbursement process and its accountability are totally at the discretion of the government, which is far from the ideal textbook model of cost-reflective pricing. Indeed, governments are tempted either to postpone the reimbursement of the cost overruns for the obliged buyers of the RES productions, or to reduce the burden for energy-intensive industries for reasons of competitiveness and to overcharge small and medium consumers. This inequitable burden sharing has two consequences. First, it distorts the price signal of electricity to the large industrial consumers, which are not incentivised to adapt their consumption levels and their equipment to higher electricity costs. Second, it raises an important distribution issue, as underlined in the German case where households paid in 2016 a charge of 62€/MWh while large industrial consumers pay only 0.5 €/MWh, and the energy price paid by every consumer was set at the low level of 30 €/MWh in average over the year (Institut, 2013; CEER, 2016).[20] Regardless of the reason, when the additional RES/LCT costs related to the market prices reach a very high level, governments face pressure to reform the support mechanism, especially if the redistribution issue becomes critical.

4.4.1. Consequences

The main primary solutions rely on cost-containment procedures, through the definition of a cap either on yearly capacity to be installed by technology or on annual expenditures either per technology (as in Spain, Italy, Germany) or for the overall policy (as in the UK). Control of quantity through definition of capacities to be auctioned or by a quantity cap typically relies on a programming approach in a planning process. The procedure in terms of a quantity cap, which is certainly easy to manage, could also be aligned from a social efficiency perspective, which follows the decrease in the economic value of the marginal new VRE capacity (I.e. the sum of revenues on the energy-only market) as and when it is developed and produces. Research studies show that there is an optimal total share of VRE in systems (around 20–30% of the energy), attributable to the effects of the merit order, their system costs, and competition from other low-carbon technologies (Hirth, 2015), which can be identified using complex models that take into account the flexibility resources of the system, and tested with a high and credible carbon price.

5. Conclusion and policy implications

The policy objective of decarbonisation of the electricity sector whilst maintaining security of supply has led to a revival of policy interventionism in electricity markets in many jurisdictions which liberalised their power industry in the 1980s and 1990s. A variety of 'out-of-market' mechanisms have been introduced to support RES and LCTs development, ensure security of supply via capacity mechanisms, and provide some form of long-term risk sharing arrangements to support investment.

In this paper, we apply a functional perspective of institutional dynamics in order to analyse these changes in the light of the modularity framework based on the rational choice institutionalism strand of the literature. This allows us to identify some additional market modules than can be used to address current market imperfections and achieve policy makers' objectives. The introduction of such additional modules affects the pre-existing market modules, and adjustments are therefore required to overcome the resulting inconsistencies and overlaps. In particular, there is a need to improve the market design of some of the existing modules and address some of the existing market imperfections, with regards to balancing, ancillary services, and network charging. It is noteworthy that these market imperfections predate the introduction of variable RES, but their effect has been amplified by the significant growth of RES in recent years in many markets. Some ongoing reform aim at improving scarcity pricing for flexible resources (i.e., fast ramping, storage, demand response) and introduce better locational signals to address congestion in the transmission and distribution grids.

We argue that these policy interventions and market reforms lead to a new hybrid regime that differs significantly from the market regime based on the original textbook approach that guided the first wave of industry restructuring. One can, of course, question the convergence of these different reforms towards a new hybrid regime, given the wide range of experiences and designs across the different countries. Institutional, legal, and political parameters, as well as exogenous factors affect the processes of adaptation, correction, and adjustment of the market framework. But our review of some of the experiences with these additional modules (long-term contracts, RES-decarbonisation, capacity mechanism) suggests a dynamic process of gradual evolution and learning to address some of the issues associated with the interfaces between the modules.

Despite the variety of rules and arrangements adopted in the different countries, one common characteristic of these hybrid regimes can be identified: investment is structured by the combined principles of planning, competitive tenders for long term risk sharing arrangements, and expected revenues in short term markets. This departs significantly from the initial market design template in which investment decisions are driven by short-term energy price signals. In other words, this creates thereby a "two step competition" regime with an initial "competition for the market" via the auctioning of long term contracts on programmed new capacities (either technology-specific or technology-neutral), followed by competition "in the market" via the energy market.

The move towards a hybrid regime appears to be unavoidable as long as governments want to be involved in determining the generation mix and to guarantee SoS at an administrative level. While more research is required to identify the best practices as the different experiments with this hybrid regime grow, the recognition that government involvement is here to stay, given the policy objectives of decarbonisation, would help to cast a new light on existing legislative and regulatory practices. For instance, this recognition would have profound implications for the EU, where market design and policy interventions are scrutinised under the competition policy and state aid rules.

More fundamentally, our institutionalist perspective on the dynamics of electricity market design highlights the importance of a sound governance process that allows for a dynamic approach to market design. Policymakers and regulators need to recognize the need for periodic adjustments in the market and regulatory framework; this requires strong governmental direction and procedures that minimise the regulatory risk and do not have an adverse effect on investment.

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[20] Referring to the German case as being topical on this redistributive issue: when the RES share of energy production reached 21% and the total costs of the policy were €23 billion in 2015, the discriminatory levy (EEG) was 62 €/MWh for households and SMEs, while industrial consumers, in particular the larger ones, paid only 0.5 €/MWh. The large consumers pay only 5% of the cost of the policy while they account for around 30% of the total consumption.

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