# European Electricity Market Reforms: The "Visible Hand" of Public Coordination

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**ABSTRACT**

*The paper investigates how proposed reforms on policies to maintain generation adequacy and to encourage clean technology investments in a number of European countries, modify the role of the market. This is reduced as the government, regulator and system operator take on explicit responsibility through the introduction of capacity mechanisms and long-term support for clean technologies. We highlight the interaction of these mechanisms with the electricity market and we look at how they reallocate risks between generators, government and consumers. The different mechanisms offer varying degrees of autonomy to generators with regards investment decisions. Looking towards the future, the paper also explores how designs of mechanisms might move towards a technology-neutral mechanism in the long-run. This could involve the auctioning of long-term contracts for all types of existing and new capacities, whether it be low carbon or fossil fuelled.*

**Keywords:** Capacity mechanism, Renewables policies, Long-term contracts, Electricity markets

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## 1. INTRODUCTION

Most European countries have long implemented schemes for Renewable Energy Sources (RES). A more recent phenomenon is the introduction of capacity mechanisms, designed to guarantee an adequate level of electricity supply in the long-term. After having been the first to liberalize its power and gas markets at the end of the 1980s, the UK is once again leading the way by launching a major electricity market reform to reach ambitious decarbonisation objectives (DECC, 2011a and 2011b; Newbery, 2011). Other countries, including Belgium, France, Germany, Italy and Spain, are now reconsidering both the design of their electricity market and the support mechanisms for clean technologies (RES and low carbon technology or LCT).[1]

The on-going reforms question the respective roles of public coordination and market coordination. These reforms have two high level features in common. First, they recognize the need to reduce risk for investors by guaranteeing fixed cost recovery. This can be done either through better risk management, by shifting risk onto consumers, or through an output-

1. In the following, RES designates small-sized renewable energy equipment and LCT the large-sized low carbon technologies among which the large sized renewable equipment other than carbon capture and storage, new nuclear, concentrated solar power, large biomass plants, etc.

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based subsidy, the latter of which is to be paid (via a levy) by the consumers when technologies are close to commercial maturity. Second, these reforms give an explicit responsibility to the government, regulator, or system operator to coordinate at different degrees the investment decisions through a wide range of mechanisms, including capacity mechanisms and technology specific support schemes for clean technologies.

There are large and distinct bodies of literatures on both adequacy policies (for instance Stoft, 2002; Cramton and Stoft, 2007; De Vries, 2007, etc.) and low carbon technologies support in the electricity supply industry (see for example Grubb et al., 2008). None to date, however, examine the connection between the two issues of this “Visible Hand”’s intervention within the electricity market. Two relevant dimensions of this connection are examined in this paper—the conceptual and institutional perspectives. Conceptually, the combination of policies interacts in the process to restore some of the virtues of the former utility regime (risks borne by the consumers, possibility of planning in view of being close to the optimal technology mix in an uncertain environment). From an institutional perspective, we could observe the dynamic effects of piling up long-term vertical arrangements for RES and LCTs on the energy markets’ coordination functions.

The paper provides a comparative analysis of the different arrangements proposed with regard to these issues of cost alignment and risk sharing in a dynamic perspective. We investigate the different types of arrangements proposed to maintain generation adequacy—the so-called capacity mechanisms—and to encourage investment in clean technologies. Key issues investigated include the following: the way new arrangements can reallocate risks between generators, government and consumers; the degree of autonomy given to investors; and the influence of these arrangements on the energy market.

We underline two specific dynamic effects resulting from the progressive accumulation of these long-term arrangements in the electricity market architecture. First is the likely restriction of the role of the electricity market to the short-term coordination of market participants’ operational decisions. Second is the effect of RES and LCT deployment on the need for capacity mechanisms to guarantee long-term capacity revenue for fixed costs recovery of both fossil fuel equipment (peaking units, semi-base load/ flexible units) and low carbon equipment.

In the next section we explore the drivers for the current reforms and discuss the market failures that justify the introduction of capacity mechanisms and support mechanisms for RES and LCT. We introduce an analytical framework to also review the objectives of the reforms and to compare the different types of arrangements proposed and their effect on the coordination functions of the market. Section 3 concentrates on capacity mechanisms and section 4 on the different schemes of long-term support mechanisms for RES and low carbon technologies. We then discuss the interaction of the two different types of arrangements and the sequence of reform in section 5.

## 2. DRIVERS AND OBJECTIVES OF REFORMS: IMPROVE RISK ALLOCATION AND INVESTMENT INCENTIVES

### The drivers of reforms: market failures and investment issues in capital intensive technologies

In theory, the electricity market has two coordination functions. First, in the short-term it ensures the efficient operation of competitors’ equipment. Second, it indicates scarcity of capacity in different technologies via price signals that orient investors’ long-term decisions.

There is, in theory, total consistency between short- and long-term market coordination when there is pure competition, perfect information and no risk aversion. 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 would minimize long-term costs.[2]

Decentralized electricity markets seem to have worked well to drive competition in the short-term, but their ability to deliver investment incentives that will lead to a socially optimum generation mix remains uncertain. In particular, there is growing evidence that electricity markets can fail to align revenues with long-term marginal costs of different types of generation technologies. This suggests the market does not allow investors to manage all the risks to which they are exposed. In current markets, the risk management criteria tend to supersede cost minimization and net present value maximization criteria in driving investment choices, to the detriment of investments in technologies that have large upfront costs (Roques et al., 2008).

Several studies have also shown that the price signal alone can fail to fully incentivize investment in RES and LCTs for a number of reasons. First, investors cannot yet reap the benefits derived from cumulative learning about new low carbon technologies. Second, the characteristics of large-sized technologies and the complexity of such systems (e.g. off-shore wind power, new nuclear, CCS, concentrated solar power) magnify the learning costs and associated risks, because the chain of innovations is too long, too complex and diverse. Finally, the large investment risks which are inherent to immature technologies are magnified by the existence of important political and regulatory risks (Grubb et al., 2008; Finon and Roques, 2000; Finon, 2011). In particular, the European carbon price provides an uncertain signal, which undermines investment in clean technologies, as has been argued by Blyth et al. (2007) and IEA (2007).[3]

These market failures and regulatory imperfections have lead a number of countries in Europe to embark on wide ranging market reforms in order to provide better investment incentives for both thermal and low carbon plants, to complement existing renewable support policies. Reformers suggest that new market arrangements should be designed to guarantee the recovery of fixed costs and to de-risk investment through shifting the major share of investment risks onto consumers in first and eventually onto government. For some new technologies, the underlying principle is extended to subsidize production in the long-run.

The challenge in designing these new market arrangements is to combine public and "markets" coordination so that risks and costs are reduced for investment in peaking and low carbon units. Peaking units are a very capital intensive investment, because even if their investment cost is low in comparison to a base load plant, their running hours are random and quite limited (10 to 500 hours per year). The same issues applies to investments in capital intensive low carbon plants built to meet the carbon emission reduction targets while maintaining capacity adequacy. Can policies be designed to preserve all the incentives of the short-term market coordination for market players in generation and system balancing?

2. For a presentation of this theory with an illustration by the geometrical approach by the "screening curves" of the optimal technology mix resulting from that, see Stoft (2002) and Green (2006).

3. The major reason for carbon pricing is to create an incentive to invest in LCTs, in particular in the electricity system which is the largest emitter sector. But in Europe large uncertainties over long-term climate policy and, in particular, with the EU cap-and-trade mechanism create an uncertainty on the future trajectory of the carbon price. To invest in long life-cycle low carbon equipment, investors need to have a long-term visibility on the carbon price. In other words the regulatory imperfection on the carbon price-signal amplifies the effects of the other market failures that create barriers to investment in LCTs.

To align with the principle of social efficiency, such that the different risks are borne by those able or willing to do so at lower cost, new arrangements should be designed to make consumers or/and governments bearing part of the risks. Coming from this perspective, we introduce a number of critical issues that stem out of a comparative analysis of the different arrangements proposed.

## Towards long-term cost-reflective risk-sharing arrangements

In order to reach supply adequacy and lower emissions, the new arrangements aim to replace the revenues which currently accrue through short-term marginal prices by stable revenues aligned to the technologies' long-run marginal costs. There are two intertwined aspects in these new arrangements; first the modes of risk/cost sharing between generators, consumers and government and second, the credibility of these arrangements.

There are three main possible institutional arrangements for risk/cost sharing—centralized regulation, long-term contracts and decentralized regulation. Examples of centralized regulation include feed-in tariffs and regulated asset based pricing. The obligation of purchase may be administered by a neutral agency such as a transmission or independent system operator. Under the second option, long-term fixed price contracts are signed between the producer-investor and a neutral agency, either after an auction, tendering process or negotiation. With decentralized regulation, retailers or suppliers are obliged to respect a capacity credit obligation or an increasing share of clean electricity in their sourcing. This approach aims to align the interests of the investors and the suppliers, subject to a capacity obligation or to a green/clean energy obligation. It consequently creates incentives for vertical arrangements, in particular by signing long-term contracts *ex-ante* to share the risks.

The choice between these different arrangements is subject to issues around information asymmetry, regulatory capture and transparency. It also raises the issue on how the costs and risks are transferred onto consumers (retailers' customers). This may be done either directly (in the case of decentralized obligation by the suppliers' pricing), or indirectly (in the event of auctioning and contracting system with a neutral agency) via a levy or similar method. It is noteworthy that this approach avoids relying on the public budget, but transfers the risk onto different consumers (mass-market ones as well as commercial and industrial ones). As such, the support policies are less exposed to risks of political changes and electoral-cycles.

## The degree of generators' autonomy in investment decisions

The different reforms being considered reflect different opinions on the question as to who should determine the capacity and technology mix targets. In a liberalized market, capacity level and technology mix result from the sum of competitive companies' decisions. This "laisser-faire" paradigm is currently questioned, given the evidence of market failures that deliver insufficient investments in capital intensive, to reach public policy targets under market coordination.

The reforms introduce some degree of centralization for decision-making on generation adequacy, which includes determining the quantity of new capacity to be built to reach an adequate reserve margin in the case of capacity mechanisms. The question is: who should be in charge of determining the total amount of capacity to be reached for each technology and the reserve margin?

The same debate applies to the definition of the targets for RES and the development of RES and/or LCT, the technology-specific development timings and their monitoring. This includes the way that the government, the regulator and the system operator define the objectives and are accountable for risks of overcapacity or over-ambitious targets, given the state of maturity of different low carbon technologies.

### The remaining coordinating roles of the energy market in the short- and long-term market

The new arrangements introduce a difference of treatment between conventional fossil technologies and RES and/or LCT. These reforms call into question the residual role of the market in the short- and long-term and raise a number of issues. First, in the short-term, do some of the new market arrangements to support RES and LCTs isolate these technologies from the energy market and its incentives to operate efficiently?

Second, the promotion of RES and LCT will displace the merit order of conventional technologies on spot markets. This is because RES generators currently benefit in most European countries from priority access. But even without the priority rule and with hourly market risk exposure, most of the RES have low variable costs and their development would alter the hourly merit order in comparison to the counterfactual scenario without any RES support policy. This implies a lower load factor and lower average revenues for new fossil fuel equipment and less predictability of their net revenue, given the variability of the RES generation.

Moreover, the issue is amplified by the uncertainty of the effect of RES and LCT support policies (Baritaud, 2012). Indeed with policies based on price-instruments (feed-in-tariff, feed-in-premium) or output revenues guarantee (as with the contacts for differences), the volumes of RES or LCT deployed in the market are uncertain. The experiences of German and Spanish RES deployment pulled by generous feed-in-tariffs illustrates this risk as these countries are overshooting their RES target trajectory as defined in the 2009 European directive. Combined with the drop in power demand resulting from the economic crisis, this has led to a dramatic reduction in the utilization rates of thermal plants in these markets.

This questions the ability of the market to deliver its long-term coordination role, unless the carbon price sends a sufficiently high and credible signal. In turn, success in promoting RES and LCT technologies is likely to increase the need for support in favor of supplementary fossil fuel technologies' generation capacity which, under sole market coordination without RES and LCT policies, would have naturally developed without assistance. Investors need more predictability of their revenues at a level allowing them to recover their fixed costs. But this predictability is challenged by the exogenous deployment of RES and LCT by specific policies as described previously. This points toward a "vicious circle", whereby policies in support of RES and LCT create the need for policies in support of conventional plant investment.

Third the high fixed costs profile of RES and LCT technologies will increasingly make new projects depending upon long-term risk-sharing arrangements, because they displace the merit order of hourly markets during the majority of yearly hours, and so they decrease their average annual net revenue and all the more in a random way. This suggests the need to explicitly articulate and coordinate the two policies-types in an ideal perspective. This will be discussed in the last section of this paper.

## 3. CAPACITY MECHANISMS FOR GENERATION ADEQUACY: DECENTRALIZED VERSUS CENTRALIZED COORDINATION OF INVESTMENT DECISIONS

Capacity remuneration mechanisms have been implemented by a number of EU countries and are under discussion in others. These are designed to provide better investment incentives in order to guarantee generation adequacy (defined as the ability of the system to deliver reliable energy in every situation in the long-term).

### The rationale for capacity mechanisms

Capacity mechanisms mainly drive investment decisions for any programmable thermal units, by adding an economic value to reliable capacity during scarcity periods. It thus provides a complementary revenue stream, and from an investor's perspective, preferably one that is as stable as possible.[4] This revenue complement is particularly crucial for investing in peaking units. Capacity mechanisms work alongside the energy and reserve markets (day-ahead, infra-day, balancing). Revenue per MW-month given to the generators is conditional on their ability to meet commitments and deliver reliable supply during scarcity periods.

There is an abundant literature exploring the economic rationale for capacity mechanisms and discussing the most efficient design (Oren, 2007; Stoft, 2002; Cramton and Stoft, 2006; Joskow 2007, Pérez-Arriaga et al., 2000; De Vries, 2007; Roques, 2009; Finon et Pignon, 2009). The key dilemma here is the difficulty of attaining long-term efficiency through markets in the absence of price elastic electricity demand and storage. Energy price signals do not work to prompt entry and exit in response, nor reflect customer preferences of supply certainty and protection against price risks. Moreover, too low price caps imposed by regulators in some countries, as well as system operators' premature calling on contractual reserves in scarcity periods act to limit generators' revenues. These create a "missing money" problem, in particular for the peaking units which are capital intensive (in per generated MWh terms) and would need stable annual revenues to recover their fixed costs.

### The different design options for capacity mechanisms

A capacity mechanism can take several forms, ranging from decentralized price or quantity instruments to centralized monitoring through auctioning capacity contracts or options with the system operator. In each case, the regulator anticipates and defines the level of capacity needed to guarantee supply security by a certain date, but with real differences in the ways to meet the target.

**Capacity payments**: All generators, incumbents and entrants are paid for being "available" during every period. Bid prices should be aligned with marginal cost even in scarcity periods with a bid cap. In the most socially efficient design, the level is set administratively, by aligning the sum of energy and capacity revenues with long-run marginal prices of peaking units.[5] Under this efficient outcome, the capacity payment is calculated as the expected value of the

4. Capacity remuneration originates in the theory of peak load pricing (Boiteux, 1953): Peak load users are responsible for capacity requirements for reliability during scarcity periods while off-peak user only consume energy. Hence, efficient pricing must charge for energy during off-peak periods and for energy and capacity during on-peak periods (Oren, 2007).

5. This is one of the main rationales of the adoption of the pool market architecture in Ireland. See IEA (2012) and Lawlor (2012)

loss of load (VoLL) per MWh during the curtailment hours multiplied by the loss of load probability (LoLP) targeted by the regulator. This is added to the short-run marginal price. One drawback of this mechanism is that there is no guarantee that the capacity target will be reached.

**Capacity obligation:** An obligation is established 3–4 years in advance for suppliers to sign contracts with new and existing generators. At the delivery date, the suppliers must submit a required number of capacity certificates equal to the peak load of their customers' portfolio, plus a surplus corresponding to the reserve margin needed for the system reliability. It is defined a number of years in advance by the system operator in order to give time for investors to install new peaking units. As a result, suppliers may comply by developing vertical arrangements, either by building their own capacity units or by long-term contracts with independent producers or entrants. A secondary market is implemented for marginal adjustments by the obliged suppliers and the committed producers to be reliable.

**Capacity forward auction** is a capacity payment where the price is set by a centrally conducted auction in which generators bid for capacity contracts. The auctions are conducted a number of years in advance (four to five years before delivery). Both existing and new capacity providers may participate. Forward contracts might be differentiated between new units (for which capacity revenues could be guaranteed in some way or another for several years), and existing units (for which revenue is only guaranteed for the year of delivery).

**Reliability option auction** is a forward auction like the capacity auction, but the generators who effectively offer a "call option" receive the option premium in exchange of a guarantee that their generation capacity will be available during peak periods. It balances this guarantee against a capping of the revenue by the option strike price when wholesale price exceeds the level of the latter, which is also a way to protect the consumers against the price variability and the price spikes. It is a financial instrument with forward coverage rather than a physical instrument. It aims to guarantee stable revenue strands with energy revenues capped by the strike price and the fixed premium per MW.

**A targeted mechanism for strategic reserves** requires some new reserve units (or demand-side response) to make up for any shortfalls foreseen by the SO.[6] Payments which are contractually guaranteed for a long period are made only to specific generators and technologies. They are called on only as a last resort to prevent distortion of the energy market price signal. However, the targeted mechanism which may be effective in reaching the adequacy objective in the short-run, could deter investment in peaking units through the market, given that market players can anticipate the SO decision to call for tenders if reserve margin decrease too much.

## Comparison of the main traits of the current capacity mechanisms

Each capacity mechanism adds a complement of revenue to energy sales to remunerate their contributions to system reliability in scarcity periods. Table 1 compares the different mechanisms with respect to a number of criteria: the degree of autonomy in investment decisions left to market participants; the relationship between the capacity mechanism and

6. One variant of this mechanism is the so-called "strategic reserve" which consists in TSO's ownership of a number of peaking units, the investment in which is completely under the control of the regulator as well as the rules to activate them for bidding on the balancing and reserves markets. Another variant is the TSO's contracting with non-profitable units their owners are planning to definitively close down.

**TABLE 1**
Comparison of market reforms for generation adequacy

| | Degree of autonomy in investment decisions | Relationship between capacity mechanism and energy market | Public governance by regulators and TSO | Advantages | Limitations |
|---|---|---|---|---|---|
| **Capacity payments** | Additional revenue. Freedom on timing/type of investment | Capacity payment is conceived as a complement because the energy price cap | Determine payment | Simplicity<br>Flexible tool for governance | No guarantee to reach capacity target<br>Exposure to regulatory capture |
| **Capacity obligation** | Additional revenue. Freedom on timing/type of investment | No explicit relation in short-term<br>Risk of double payment<br>Long-term influence on price | Determine adequacy target and obligation on suppliers<br>Control of compliance/ penalty | Low degree of regulatory intervention<br>Simplicity | Volatile price signal if illiquidity<br>Risk of non-compliance<br>Windfall profit on existing equipment |
| **Capacity forward auction** | Central auction determines timing | No explicit relation in short-term<br>Risk of double payment<br>Long-term influence on price | Define target and auction parameters<br>TSO counterpart<br>Regulator's intrusion for limiting double payment | Guarantee to reach adequacy target | Complexity<br>Windfall profits on existing equipment |
| **Reliability option** | Central auction determines timing | No double payment (role of the strike price)<br>Long-term influence on price | Define auction parameters<br>TSO counterpart | Guarantee to reach adequacy target<br>Incentives for efficient operating management | Complexity<br>Windfall profits on existing equipment |
| **Targeted mechanism (strategic reserves)** | TSO determines the timing of reserves investment | Energy price remains unchanged if reserves are dispatched as a last resort | TSO counterpart<br>Dispatch rule (last resort) | Easy to implement<br>Least expensive for consumers (no windfall profits for existing equipm.) | Slippery slope<br>Investors' opportunism and self-entertainment of the mechanism |

the energy market; the public governance by regulators and TSO of the mechanism; and the advantages and limitations of the different designs.

**Degree of autonomy in investment**: Depending on the capacity mechanism, the degree of investors' decision making autonomy varies greatly. In the case of a capacity payment, market participants trigger investment in peaking units freely. With the capacity obligation approach, investment decisions will require signing of a long-term contract with a supplier in search of capacity certificates, because no decision could be triggered by revenue prospects by short-term sales. Under the central auctioning mechanism approach, investment decisions are directly driven by the system operator.

**Public governance**: There is a clear difference between price and quantity instruments, in terms of governance. In the capacity payment approach, the central agency (TSO or the regulator) defines the payment based on availability, technology, VOLL, LOLP to incentivize investments and availability. They do not, however, impose on the market players the means by which to reach the capacity target. In the “quantity approaches”, the central agency specifies requirements for adequacy and planning reserves based on traditional planning tools. These vary considerably, however, across the two existing systems: central auctioning system (PJM, New York, New England, the UK in the future) and the decentralized obligation (France in the future, California). In the latter decentralized approach, the generators and the suppliers retain the decision-making autonomy. They can trade reserves and efficiently reallocate the reserves requirements, although the capacity market and energy market may not be in equilibrium.

Under centralized auctioning systems, of which there are two types, the capacity forward and the reliability options, the TSO is the counter-party of the generators. The two types are distinct in terms of the possibilities of regulatory intervention to limit the double payment by the capacity remuneration and the remaining scarcity rent (the difference between the price cap and the cost of the marginal resource dispatched on the energy market). In the first case there is a strong intrusion to subtract the scarcity rent, but only for the peaking units as in the case in the PJM and the New York system. Instead, in the reliability options mechanism, if the price strike price of the options is fixed at a low level (much lower than the traditional price cap level of 1000 to 3000 €/MWh), double payment could be completely eliminated when options are called during peak load or critical periods, by the system operator. By comparison in decentralized capacity obligation in the EU bilateral energy markets, there is no solution to the double payment problem, because this possibility of regulatory intrusion cannot exist.

**The role of energy markets**: In the five cases, there is a logical long-term effect of the incentives created by the capacity mechanisms on the energy market price. The reduction of the price spikes and the limitation of price volatility can help risk management. However, with regards the energy markets in short-term, capacity mechanisms do not interfere with its coordination unless the targeted mechanism is badly designed. Indeed strategic reserve units should not be called on by the energy and reserve markets before the last marginal units along the rule of last resort call by the TSO. Moreover, the reliability options auctioning can avoid the regulator to set a price cap in the energy market, as stated above.

## 4. PUBLIC COORDINATION AND LONG-TERM CONTRACTS IN SUPPORT OF CLEAN ENERGY TECHNOLOGIES

In the first section, we pointed out a series of regulatory imperfections and market failures which undermine investments in RES and LCT equipment. It follows that the development of RES and low carbon equipment should be efficiently promoted by technology-focused policies combining long-term market arrangements with suitable cost- and risk-sharing mechanisms and overseen by careful public governance after the stage of RD&D. Different policy design options exist and have been implemented by the various European governments and different OECD countries. The former approach aims to stimulate decentralized decisions: either by long-term price incentives or by a quantity instrument based on obligations borne by competing suppliers/retailers specifying their share of clean electricity, who are able then to pass-through specific costs and risks on their customers. The latter approach is logically closer to central planning, with regular auctions of long-term contracts for RES and LCTs.

**TABLE 2**
The characters of market arrangements for clean technologies support

| **Principles** | **Type of arrangement** | **Autonomy left to generators in investment** | **Role of the current market** | **Public governance** |
|---|---|---|---|---|
| **Decentralized coordination:**<br>*Price instrument* | Fixed FIT (with purchase obligation) | Freedom of timing<br>Orientation of choice by technology FITs | No responsibility of RES producers on markets (priority access) | Regulator determines annual payment long-term by technology<br>Tuning of FIT for new contracts |
| **Decentralized coordination:**<br>*Price instrument* | Premium FIT | Freedom of timing<br>Orientation of choices by technology FITs | Responsibility of intermittent producers on balancing and energy market | Regulator determines ex-ante premium over the market price |
| **Decentralized coordination:**<br>*Quantity instrument by obligation* | Renewables obligation/<br>Renewables portfolio standard/<br>Clean energy obligation | Freedom of timing<br>Technology-neutrality[a] | Responsibility of intermittent producers on balancing and energy markets | Regulator definition on 1/target trajectories, 2/ buy-out price, 3/ technology bands |
| **Centralized coordination:**<br>*Auction for LCT contracts with neutral agency* | Fixed price contracts or<br>CfD (equivalent to variable premium FIT) | No technology-neutrality (issue of learning investment) | Responsibility of producers on markets | Regulator definition on: 1/ timing of auction, 2/ target by technologies |
| **Centralized coordination:**<br>*Negotiation of LCT contracts with neutral agency* | Regulated Asset Base pricing | No technology-neutrality | No responsibility of producers on markets | Regulator's definition of RAB<br>Regulator's definition of timing |

[a] In this case there is no technology neutrality but discrimination by there are technology bands.

## The different designs of each option

We present in Table 2 the main characters of the different instruments in terms of the autonomy given to generators to invest in these technologies, the distance of the entries with RES or LCT equipment to the current market coordination of long-term choices, and the role of the public governance. The different support arrangements for renewable and LCTs are intended to replace long-term market coordination based on the hourly markets' marginalist pricing but they are not all equally compatible with short-term coordination of the spot electricity market.

**Fixed feed-in price and regulated asset-based price**: When the regulator aims to give the most secure support to RES and LCTs, the support takes the form of a fixed feed-in tariff (FIT) per MWh, or possibly a regulated price based on a Regulatory Asset Base (RAB) , that is the ex post assessment of actual costs. This is typically used for infant technologies. Used for those with random variability of intermittent production, a fixed FIT approach isolates LCT production from market incentives for operational efficiency, as it does not discriminate between periods of high and low scarcity and price. It does not make these producers economically responsible for their balancing and reserves costs for the system, although arguably this is efficient if these are out of their control anyway before their access to a step close to commercial maturity.

**Fixed FIT premium and variable FIT premium**: The FIT premium is a regulated fixed payment on the top of the wholesale price, or the variable premium is a variable subsidy which emanates from the so-called contracts for differences (CfDs)[7] in a centralized auctioning system. These two mechanisms present better incentives to operational efficiency. Indeed RES or LCT generators sell on the wholesale market and so receive the incentives to operate efficiently. First, every generator has an incentive to carry out maintenance at times when demand and prices are low. Secondly, wind farms selling in energy markets and to balancing mechanisms (under specific rules) are incentivized to improve their forecasts of output in the next few hours before the delivery hour (Usoala et al., 2010). Whether that is desirable will depend on whether it is efficient to decentralise or centralise such forecasts within a more or less large producer to exploit some anti-correlations between local and regional wind productions, and whether this will motivate the supply of better forecasting services to the wind farms.

**Clean energy obligation**: This requires electricity retailers to supply a specific amount of electricity to consumers from clean sources or else pay a penalty for their deficit related to this amount. This system has been implemented for the development of RES in some European countries (e.g. UK, Italy, Sweden, Belgium, Poland) in which renewable energy certificates are exchangeable. In some US jurisdictions, this system with or without exchangeability of certificates is known as a 'Renewable Portfolio Standard' (RPS).In some jurisdictions, it is currently being extended into a clean energy obligation with the inclusion of other LCTs (Paul et al., 2011). In this mechanism, suppliers are supposed to hedge the acquisition of certificates on a long-term basis either by signing long-term contracts at a fixed price with new developers (as in Texas, the UK and Poland) or if vertically integrated, by internally fixing a long-term price between the retail business division and their own RES-E subsidiary or their own low-carbon equipment. Exchanges on the organized market are only aimed to adjust the positions of vertically integrates or for helping small retailers to respect their obligations.

**Auctioning of long-term contracts for RES and LCTs** (concerning mainly the large-sized LCTs): This mechanism is technology specific during the learning process after the demonstration stage, but the ideal design would be technology neutral to let the producers choose the best technology.

### Comparison of these different long-term arrangements

The main function of these long-term arrangements is to stabilize investors' energy revenues over time and to align them to long run marginal costs, either by allocating a fixed output-based payment or by giving additional revenues on top of the energy price, via a regulated or flexible market-priced premium. The contract designs differ in their incentives to bear and manage risks, but they have some similarities. First, because they guarantee a fixed revenue per MWh, the operators only bear investment risk, and consequently they keep incentives to control investment costs and installation delays. Second, operators bear the

7. A contract for difference (or CFD) is a symmetrical financial option contract between two parties, described as "buyer" and "seller", stipulating that the seller will pay to the buyer the difference between a reference price of an asset or a good (here the electricity) and its value at contract time if the difference is positive. If the difference is negative, then the buyer pays instead to the seller.

operational risk and are incentivised to have good operational performances contrary to support schemes which subsidize investment directly.

Market efficiency and operational performances are significantly reduced if, after the step of initial learning, RES and LCT producers are insulated from the risks that they are best placed to manage. Thus fixed FIT and RAB-priced contracts, which isolate private investors from the different market risks (day ahead, intraday, balancing) become inefficient when RES/LCT capacities mature or when their installed capacity reaches a threshold of 20–40% in energy generation, because they suppress short-term incentives for operational efficiency. Besides providing the same ability of any long-term arrangement both to incentivize investment and to make producers bear part of investment risk, therefore, contract designs such as fixed premium contracts or CfDs also keep operators exposed to some part of the market risks.

A second challenge is to combine long-term stable investment incentives for RES and LCT technologies, whilst maintaining incentives for operational efficiency through the short-term market on the other side. In this respect, centralized approaches with strong public governance allow efficient monitoring of LCT capacity development, efficient contracting with effective risk sharing and lower transactions costs for new projects because of contract standardization. It is in particular an advantage displayed by the decentralized clean energy obligation, as shown in a comparison between the Brazilian centralized auctioning mechanisms for capacity and energy contracts and the Chilean mechanism of long-term contracting obligation on distributors (Moreno et al., 2009).

Another issue is the balance between effectiveness and the policy's collective cost. Clean Energy Obligation and Renewables Obligation are supposed to be superior as they are more market driven. However, these instruments have a poor performance record in delivering installed capacity by comparison to the different FIT systems, because of the risks borne by investors, and their preferences to pay the penalty for a part of their obligations, because of costs and administrative barriers. In addition, they are more costly for the consumers than a FIT scheme as the cost of capital includes a higher risk premium (Butler and Neuhoff, 2004; Mitchell and Bauknecht, 2006). Conversely FITs can lead to overinvestment in a technology if they are too generous. However, as the FIT experience for PV shows in the EU, this overshooting could be corrected by FIT reduction for new projects, or by a hybrid approach relying on a combination of annual limitations and decreasing FITs, provided that the correction does not affect existing projects in order to maintain the policy's credibility for investors.

## 5. TOWARDS A CONVERGENCE OF CARBON POLICY AND ADEQUACY POLICY?

In this final section, we investigate how the reforms for low carbon technologies or for capacity mechanisms discussed above should be articulated in a sequential market reform package.

### The induced effects of RES and LCT arrangements on the market's long-term coordination role

The investment coordination role of the market will be progressively eroded through two channels. First an increasing share of RES and LCT generation will fall outside long-term energy market coordination, leaving only fossil fuel generation investment able to respond to the market price signals. Second, even this reduced role of guiding investments in peaking units and mid-merit flexible thermal plants will risk being distorted by the high volumes of

RES-E and LCT generation, mainly because this volume is poorly predictable in the mid- and long-term.

The "artificial" out-of-market deployment of RES and LCTs undermines the case for investing in semi-base load technologies (CCGT). Indeed, investment in thermal generation will become increasingly exposed to fixed cost recovery difficulties and to risks, when they are not securitized by a similar arrangement to those for RES and LCT. Average annual prices will likely decrease because RES and LCT have low variable costs thus displacing fossil fuel plants in the merit order of the hourly markets, with increasing periods where a RES or LCT unit will be the marginal equipment in the merit order with consequently the market clearing with very low prices on the hourly markets.

Moreover, given that the results of RES and LCT policies could be uncertain in terms of installed capacity, this development will introduce uncertainty on the lowering of running hours and consequently on the number of running hours during which infra-marginal rents are extracted to recover fixed costs to be anticipated at the time of investment. Moreover, given the positive correlation between peak demands in winter and wind power contribution as well as peak air-conditioning summer hours and solar PV generation, scarcity rents during peak periods will tend to disappear (Eurelectric, 2011).

As another consequence, the need for out-of-market arrangements for promoting capital intensive RES and LCTs which are all of them capital intensive, by new risk-sharing between investors and consumers will likely be self-reinforcing, because, even commercially mature investment in these capital intensive technologies will not be financially viable if these mechanisms are removed. This is a structural issue which should be underlined, because it challenges every actual policy statement on the transitory character of these arrangements.

### Policy coordination and convergence: combining capacity mechanisms and support for low carbon technologies

It follows that policies aiming to promote clean technologies through new market arrangements should not be designed independently from policies reforming electricity markets to include a capacity mechanism. The discussion should also encompass reforms of ancillary service markets, in particular short-term operating reserve markets (contracting with the TSO, balancing markets) and the infra-day energy markets that allow flexible load and intermittent producers to re-adjust their position.[8] These markets need to adequately remunerate flexibility services, and thus incentivize generation and load to participate in improving the day-by-day system reliability which is made vulnerable by the large-scale deployment of intermittent sources. But this will not solve the problem of increasing reserve margin needs, which will result from the large-scale deployment of intermittent renewable sources. In fact, despite good correlation between wind generation and load during winter peak, capacity adequacy is also questioned in an increasingly way when stochastically occurs low wind generation period during winter peak (Cometto and Keppler, 2013).

Further to the need for coordination of RES support policies and capacity mechanisms and a convergence between the different policy tools can be envisaged in the medium to long-term. As an example, a number of Latin American countries such as Brazil and Colombia already rely on similar policy instruments—a forward capacity auction—to incentivize investment in large hydro plants (as such as a low carbon technology), conventional technologies,

8. Wind in particular can ramp down rapidly or be held at less than full output and ramp up.

as well as RES technologies.[9] In the Brazilian system, the government requires retail companies and very large consumers to purchase a certain percentage of renewable energy contracts for the future three or five years ahead. In another context than Brazil with no large hydro resources, such a market design should be expected to be quite effective to stimulate both renewable and thermal back-up and reserve generation capacity

A number of recent academic papers have explored the advantages of a more comprehensive approach to deal with both objectives of decarbonisation and capacity adequacy through a market-wide capacity forward auctioning (Helm, 2010; Gottstein and Schwarz, 2010; Boot and van Bree, 2010). Each capacity provider in any technology will receive an "availability" payment for capacity through their revenues from forward capacity contracts, while they receive payment for the electricity they produce through the electricity market for their running costs; so the market keeps its role of short-term operational coordination. The difference with the RES and low carbon arrangements presented above is that this approach deals with capacity and energy and not with energy. And the difference with the current capacity market mechanisms (which only addresses long-term generation adequacy) is the long time span of forward capacity contracts to guarantee revenue streams over a long period for all new capacity as it could be the case with a heterogeneous package of measures (such as strong carbon price floor, a stringent $C0_2$ standard (or a ban on unabated fossil fuel plant, from 2025 for instance), and some occasional support for pre-commercial large-sized LCT units).[10]

There are alternative scenarios to the eventual unification of these different long-term policies for RES, LCT and thermal generation into one single mechanism. But a single mechanism, despite its complexity, would provide consistency between the arrangements for promoting the low carbon technologies, those for intermittent RES and those for reaching capacity adequacy and answer to the needs of flexibility and back-up resulting from large intermittency. Such unified mechanism would allow giving a combined value to technologies that both are low carbon emitters and contribute to adequacy. This consistency could help to avoid lobbying and regulatory capture.

## An evolutionary process or a radical and comprehensive reform?

The on-going discussions about market reforms in a number of European countries raise the issue of the sequence and ambition of these market design changes; furthermore, the analysis in this paper has shown that the interdependencies between these seemingly unrelated policies must be taken into account.

In the normative perspective of social efficiency, the best process to reform European power markets would probably be a radical institutional change that would see the implementation of a market wide capacity mechanism at the same time as RES policies support is

9. The benchmark is the Brazilian model implemented in 2002. The TSO auctions tender for long-term contracts for capacity and energy for every new and existing plant, whatever the degree of vertical integration of the retailers. Contracts (which are different for new and existing plant) are attributed to retailers in proportion to their load in power and energy. The energy part of the contracts is a CfD. The advantage of covering not only capacity but also energy is to guarantee revenues not only for capacity but also for energy (Moreno et al., 2009), which makes sense in electricity systems with hydro dominance (around 75%).

10. A number of studies have been conducted on various aspects of this concept. The British regulator evaluated the possibility of differentiating contracts as a function of the characteristics of the technologies in its Project Discovery looking at new market arrangements before the Government's electricity market reform (OFGEM, 2010). Helm (2010) investigated the best-suited auction design to reveal information on the different technologies regarding project costs and lead-time of. Finally Gottstein and Schwarz (2010) looked into the possibility of discriminating between carbon-intensive and low carbon technologies.

being reformed. This would allow an early response to the erosion of the long-term coordination function of the energy market caused by the accumulation of RES-LCT support arrangements. Indeed, even if the current overcapacity in many European markets does not support the need for urgent reforms to introduce capacity mechanisms in most countries, early reforms would have the benefit to facilitate market participants' institutional learning and provide adequate investment incentives for when new capacity will be needed.

However, in practice, the change is likely to be much more gradual and reforms much less radical for two reasons. First, the slowness of the impact of the RES development on the effectiveness of market coordination as the renewables still represent a relatively small share of total generation in most European countries. Second, the remaining strong belief in market virtues and institutional inertia which will likely contribute to postpone any realistic anticipations of long-term effects of the RES and LCT policies.

Institutional economics can provide a useful framework to think about the sequence and ambition of these reforms. Williamson (1996) established that the perceived benefit of a feasible change must be higher than its perceived cost, including negotiation and transaction costs. As a consequence, in the case of RES-LCT arrangements and capacity mechanism, an overall clear-cut policy such as the comprehensive "Electricity Market Reform" package in the UK, will probably remain an exception, because tensions will only appear slowly in other countries, preventing governments and experts from recognizing the problem.

The multiple public policy goals driving RES support policies make reforms more complex: energy independency, employment effects and preservation of climate. These arrangements have been occasionally reformed in various countries when inefficiency or excessive costs are considered as problematic by regulators, and when it becomes possible to refer to more efficient arrangements in other countries. The extension of capacity mechanism to provide long-term guaranteed revenues will likely also be gradual. In order to trigger the process there needs to be a perception of a real tension between RES policy goals and market efficiency. Yet tension will only slowly row over a ten- to twenty-year period, as intermittent RES technologies acquire a major market share, and as the overcapacity resulting from the economic downturn is absorbed.

Finally, the adoption of a consistent set of new arrangements will depend on a range of system specific issues, such as the existing market structure (e.g. the presence of large producers with a diversified portfolio including a large share of hydro or nuclear plants), and the preexistence of flexible generation technologies. The need for market reform will probably be less clear-cut in countries with important embedded flexibility, because this existing flexibility will mask the growing generation adequacy problem raised by an important share of intermittent production in a system (IEA, 2012).

## 6. CONCLUSION

Decarbonizing the European electricity industry while maintaining security of supply, will require significant investment in both clean generation technologies and fossil-fuel peak- and semi-base load equipment. The on-going reforms in Europe recognize the need to reduce risk for investors by guaranteeing fixed cost recovery. This questions the respective roles of government and the market, as these reforms explicitly place responsibility on the government, regulator, or system operator to coordinate the investment decisions through a wide range of mechanisms. These include technology specific support schemes for clean technologies as well as capacity mechanisms.

This paper analysed the drivers for reform and reviewed the different mechanisms proposed. The main contribution of the paper was to bring together the abundant but very distinct literatures on generation adequacy policies and low carbon technology support policies. We studied in particular how the different arrangements proposed can reallocate risks between generators, consumers, and government. Their large-scale deployment will also lead to shifts in the degree of autonomy given to investors, and the influence of these arrangements on the two coordination functions of the energy market in the short and long term.

Our analysis underlined two specific dynamic effects in the interaction between these two sets of policy instruments. First is the probable eventual restriction of the role of the electricity market to the short-term coordination of market participants' operational decisions. Second is the effect of RES and LCT deployment on the need for capacity mechanisms to guarantee long-term capacity revenue for every equipment, both fossil fuel and low carbon. As a consequence, the need for out-of-market arrangements for promoting RES and LCTs will likely be self-reinforcing, because, even commercially mature investment in these capital intensive technologies will not be financially viable if these mechanisms are removed after important capacity development drawn by the present out-of-market arrangements. We stress this structural issue, because of its implications that challenge the current conventional wisdom and policy beliefs that these arrangements are transitory and should be eventually phased out.

The analysis also discussed the best way to pace the reforms. Whilst a radical approach putting in place a comprehensive and well-articulated policy package would be best in theory, the current overcapacity inherited from the recent economic recession and the thus far limited effect of intermittent renewables on power systems will likely justify a more gradual approach to reform.

Nevertheless there is a need for urgent recognition of the necessary evolution towards hybrid "managed markets" by governments and regulators in countries with liberalized electricity sectors, as well as by international organizations. Indeed, this is applicable to any country that simultaneously promotes liberalized market reform while developing strong commitments in climate policies and carbon reduction objectives. The role of public coordination and long-term contracts as part of the European liberalization packages needs to be reassessed. This should lead guidelines of best practices to be developed so that the on-going reforms on a national basis are coordinated and do not hamper progress toward an integrated European electricity market.

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