Market4RES

# D2.1 Opportunities, Challenges and Risks for RES-E Deployment in a fully Integrated European Electricity Market

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## Executive Summary

The work presented in this report (Deliverable D2.1) significantly contributes to the foundation for work carried out in the Market4RES project. Moreover, this report elaborates on the theoretical and regulatory analysis of the European 'energy-only' market model as well as on several relevant policy instruments having being implemented to promote the accelerated market integration of RES-E generation technologies.

The major aim of this report is to understand the historical development of the European electricity market and the background as well as driving forces of the currently existing European 'Target Model' discussion, notably as far as the so-called 'Capacity Remuneration Mechanisms (CRM)' are addressed. Doing so, it is important to understand and study the major shortcomings of electricity market design and market distortions, on the one hand, but also the achieved electricity market benefits in a system with high shares of RES-E generation in an inter-temporal context over the last decade, on the other hand.

The inter-temporal aspects of the analysis in this report is important insofar, as well-designed structures and instruments of an electricity market in the early phase of electricity market liberalisation not necessarily match with the criteria of sustainable electricity market operation and development at a later stage, e.g. at the presence of significant shares of variable RES-E generation having been integration into the market based on financial support instruments.

Based on the knowledge compiled in this report, a better understanding of the challenges ahead in terms of electricity market amendment shall be available. In that sense, the major lessons learned in this report can be mainly summarized as follows:

- In the early phase of European electricity market liberalisation the design of market structures and policy instruments have been perfectly fitting to meet the intended policy objectives and expected market developments.
- Even more, the enormous efforts to promote the accelerated integration of RES-E generation technologies has been a success story, knowing that the financial support (subsidies) is enormous and this support is a market intervention apart from the forces of the electricity market itself.
- In the course of time, however, adverse effects of significant RES-E penetration have been occurring in terms of low average wholesale electricity prices in general and extremely volatile, partly negative prices in particular.
- Subsequently, this has led to the situation that conventional electricity generation technologies have become difficulties to cover their costs while financial support instruments (subsidies) further stimulate investments into wind and PV generation. This has led to increasing profitability risks of many of these conventional generation technologies. Some of them already have been – or are expected to be –mothballed.
- Although the importance to promote Demand Side Management implementation into the electricity market has been discussed for a long time, up to now there do not exist significant and promising best-practise cases qualified to be scaled up.

Against the background of the above mentioned challenges, a couple of years ago already a European discussion emerged on how to further improve the market design contributing to the mitigation of the currently existing "missing money" problem of conventional and RES-E generation, on the one hand, and how to foster European electricity market integration with high shares of RES-E generation in general, on the other hand.

Starting from the explanations of the historical development, this report highlights the driving forces of the currently existing European 'Target Model' discussion, notably as far as the so-called 'Capacity Remuneration Mechanisms (CRM)' is addressed.

It neither elaborates on the diagnosis of the currently existing European energy market discussion in detail, nor provides already some conclusions and/or recommendations to overcome several of the challenges the European electricity market is facing at present. This will be done in subsequent reports of work package 2 (Deliverable D2.2 and D2.3) and also remaining work packages (underpinned with modelling exercises and results) of the Market4RES project.

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## Abbreviations

| | |
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| ACER | Agency for the Cooperation of Energy Regulators |
| BRA | Base Residual Auction |
| CCM | Capacity Credit Market |
| CfD | Contract for Differences |
| CRM | Capacity Remuneration Mechanisms |
| CRR | Congestion Revenue Rights |
| CWE | Central Western Europe |
| DAM | Day-Ahead Market |
| DRUC | Day-ahead Reliability Unit Commitment |
| DSM | Demand Side Management |
| EC | European Commission |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ERCOT | Electric Reliability Council of Texas |
| ERI | Electricity Regional Initiatives |
| ETS | Emission Trading Scheme |
| EUA | EU-Allowance |
| EWEA | European Wind Energy Association |
| FCM | Forward Capacity Market |
| FIP | Feed-in premium |
| FIT | Feed-in tariff |
| FRRA | Fixed Resource Requirement Alternative |
| FTR | Financial Transmission Right |
| GSS | Grid support services |
| IA | Incremental Auctions |
| ISO | Independent System Operator |
| LCOE | Levelized cost of electricity |
| MOE | Merit order effect |
| NC CACM | Network Code on Capacity Allocation & Congestion Management |
| NC EB | Network Code on Electricity Balancing |
| NC FCA | Network Code on Forward Capacity Allocation |
| NC RfG | Network Code on Requirements for Grid Connection Applicable to all Generators |

| | |
|---|---|
| NRA | National Regulatory Authority |
| PCR | Price Coupling of Regions |
| PJM | Pennsylvania Jersey Maryland |
| PTR | Physical Transmission Rights |
| RES-E | Renewable Energy Sources for Electricity |
| PER | Peak Energy Rent |
| PUCT | Public Utility Commission of Texas |
| PPA | Power Purchasing Agreement |
| RA | Reconfiguration Auctions |
| RMR | Reliability must run |
| RPM | Reliability Pricing Model |
| RTM | Real-Time Market |
| SCED | Security Constrained Economic Dispatch |
| SWE | South Western Europe |
| TGC | Tradable Green Certificate |
| TLC | Trilateral Coupling |
| TM | Target Model |
| TYNDP | Ten-Year Network Development Plan |
| UIOSI | Use-it-or-Sell-it |
| UK | United Kingdom |
| U.S. | United States |
| VAR RES | Variable renewable energy sources |
| VRR | Variable Resource Requirement |
| QSEs | Qualified Scheduling Entities |

# 1 Introduction

The work presented in this report (Deliverable D2.1) significantly contributes to the foundation for work carried out in the Market4RES project. Moreover, this report elaborates on the theoretical and regulatory analysis of the European 'energy-only' market model as well as on several relevant policy instruments having being implemented to promote the accelerated market integration of RES-E generation technologies.

The major aim of this report is to understand the historical development of the European electricity market and the background as well as driving forces of the currently existing European 'Target Model' discussion, notably as far as the so-called 'Capacity Remuneration Mechanisms (CRM)' are addressed. Doing so, it is important to understand and study the major shortcomings of electricity market design and market distortions, on the one hand, but also the achieved electricity market benefits in a system with high shares of RES-E generation in an inter-temporal context over the last decade, on the other hand.

The inter-temporal aspects of the analysis in this report is important insofar, as well-designed structures and instruments of an electricity market in the early phase of electricity market liberalisation not necessarily match with the criteria of sustainable electricity market operation and development at a later stage, e.g. at the presence of significant shares of variable RES-E generation having been integration into the market based on financial support instruments.

Based on the knowledge compiled in this report, a better understanding of challenges ahead in terms of electricity market amendment shall be available. Build upon the outcomes of this report, the follow-up analyses in this work package 2 mainly elaborate on the diagnosis of the current policy debate trying to mitigate several challenges ahead and to implement sustainable market rules.

This report (Deliverable D2.1) is organised as follows:

Chapter 2 addresses the "Energy-Only" market problem including the background and economic theory. An overview of sustainable electricity market design options guaranteeing generation and transmission adequacy is also provided. In addition, the historical role and status quo of RES-E support schemes for RES-E market integration is represented. Therefore, a summary of related challenges and discussions outside Europe, mainly U.S., is stated.

In chapter 3 the achieved electricity market benefits in terms of electricity market design and market coupling (enlargement of system boundaries), and benefits of RES-E integration in Europe are addressed.

The prevailing structural market distortions and shortcomings in the European electricity market are discussed in chapter 5. In the first part the fragmentation of electricity markets and the lacks in terms of harmonisation and electricity market coupling are addressed. This is followed by the current market distortions. The last part comprises the lacks of participation of demand side management in different electricity market segments.

Chapter 6 concludes the current discussion of this report.

## 2 The "Energy-Only" Market Problem

### 2.1 Background, Economic Theory

"Energy-only" markets have been established in Europe with the start of the implementation of wholesale electricity markets in 1999 (a few forerunners like UK and Norway have done so already at the beginning of the 1990s). In Europe, the late 1990s were characterised by quite convenient excess electricity generation capacities (on the contrary to some other experiments like California starting in 1998 with rather small supply margins; ending in a collapse in 2001 due to various reasons). Therefore, the implementation of textbook theory on wholesale market places to trade electricity (for different periods in time) based on the short-run marginal cost has been the favourable and most efficient approach. However, now more than one decade later, the structural patterns of the power plant portfolios across Europe – not only, but not least due to continuous and discontinuous structural changes – look quite different and are characterised, among others, by the following developments:

- Decrease of (firm) excess electricity generation capacities
- Significantly increasing share of variable renewable electricity generation (RES-E)
- Significant increase of electricity demand (except 2008/2009 in general and also the following years in some European countries due to the financial crisis)
- Significant increase in electricity trading volumes across national borders
- Gradually visible technologies and potentials enabling demand side management implementation (e.g. Power-to-Heat (P2H) or Power-to-Gas (P2G) technologies)

In this context, one of the most tremendous developments in recent years was the significantly increasing share of variable RES-E penetration in the electricity market. This has also increased, furthermore, the volatility of wholesale electricity prices on the different European power exchanges (due to the so-called 'merit-order effect', see Figure 1), on the one hand, and also decreased – on average – the absolute price level on the wholesale electricity market with partly negative price spikes, see Figure 2.

Figure 1. *The RES-E effect on wholesale market prices [1].*

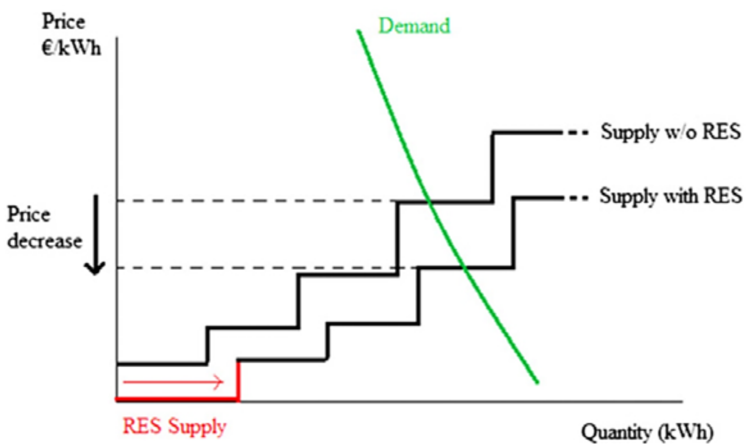


Figure 2. *EPEX Spot Intraday market for DE/AT*


(Source : EPEX-Spot 2014)

The electricity market design in many European countries grants RES-E technologies – among others – priority dispatch. Therefore, whenever (variable) RES-E generation is available, remaining conventional power generation needs to adapt, meaning that conventional power generation needs to reduce load and or shut down in case of sufficient RES-E generation to meet the loads. As a consequence, the annual operation hours of conventional power generation will be reduced and, subsequently, profitably problems may occur. Moreover, it is already and will become a significant problem for rather new conventional power plants (e.g. lignite, coal and/or gas fired plants)[1] due to twofold reasons: (i) reduced operation hours to generate revenues and (ii) low wholesale electricity prices in general due to significant RES-E penetration in the electricity markets.

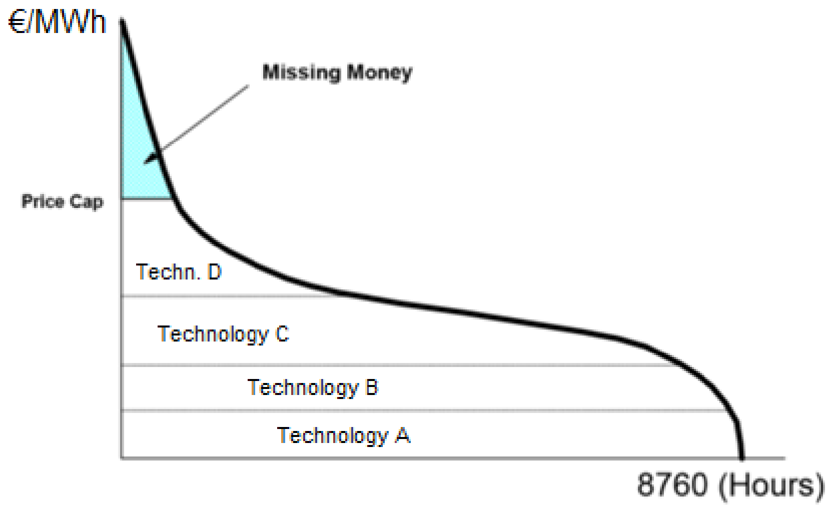
This phenomenon, therefore, leads to sparsely revenues. This revenue problem (also called "missing money problem") is strengthened if there are excess generation capacities in an electricity market.[2] In case of no overcapacities in the electricity market and the implementation of some price caps in the wholesale market – trying to avoid extremely high price spikes in those short periods throughout the year where there is less/no variable RES-E generation available – another dimension of the "missing money problem" occurs. By preventing wholesale electricity prices from reaching high levels during times of relative scarcity, administratively implemented price caps reduce the payments that could be applied towards the fixed operating costs of

[1] If these generation technologies are not entirely depreciated, besides the operation cost also the corresponding investment cost need to be recovered whenever possible throughout a year and over the years.

[2] At present, true in almost all electricity market places across Europe. However, this might change in the years to come in some European regions.

existing conventional generation plants and the investment costs of new plants. The resulting missing money reduces the incentives to maintain plants or build new generation facilities (see Figure 3).

Figure 3. *"Missing Money" problem due to price caps*




In the presence of a significant missing-money problem, alternative means appear necessary to complement the market and provide the payments deemed necessary to support an appropriate level of resource adequacy. At the margin, we refer to the opportunity cost as the cost of meeting an increment of demand by decreasing other load or increasing generation. If contemporaneous spot prices reflect these opportunity costs, these prices would provide market participants with strong incentives during periods of scarcity. During most periods, market prices would be at a relatively low level defined by the variable operating costs of mid-range or base load generating plants. However, in some periods prices would rise above the variable operating costs of peaking units that were running at capacity and would reflect scarcity under constrained capacity with the incremental value of demand defining the system opportunity cost. Aspects like these are further elaborated in the subsequent section 2.2 where an overview of sustainable electricity market design options guaranteeing generation and transmission adequacy is discussed.

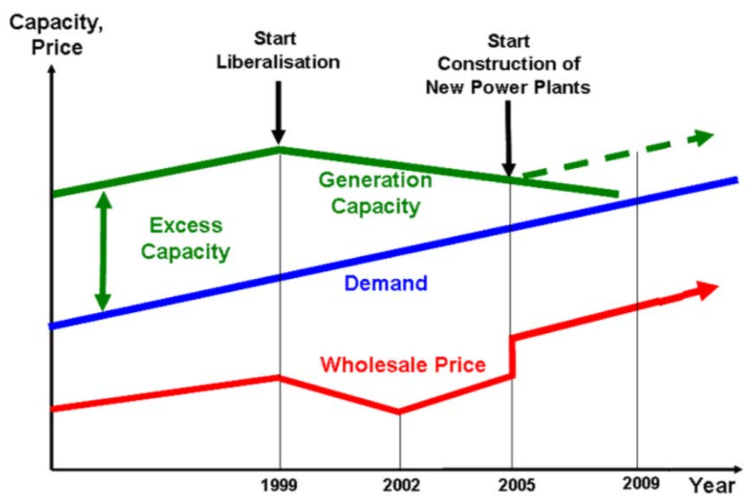
## 2.2 Overview of Sustainable Electricity Market Design Options guaranteeing Generation and Transmission Adequacy

### 2.2.1 Generation Adequacy: Policy Options

Generation adequacy neither has been a serious problem in the European electricity supply industries prior to restructuring in 1999 nor in the first years after the implementation of an electricity market. Moreover, the European electricity system has been in the convenient situation starting electricity market implementation with a significant amount of excess generation capacities (e.g. on contrary to California), see [2].

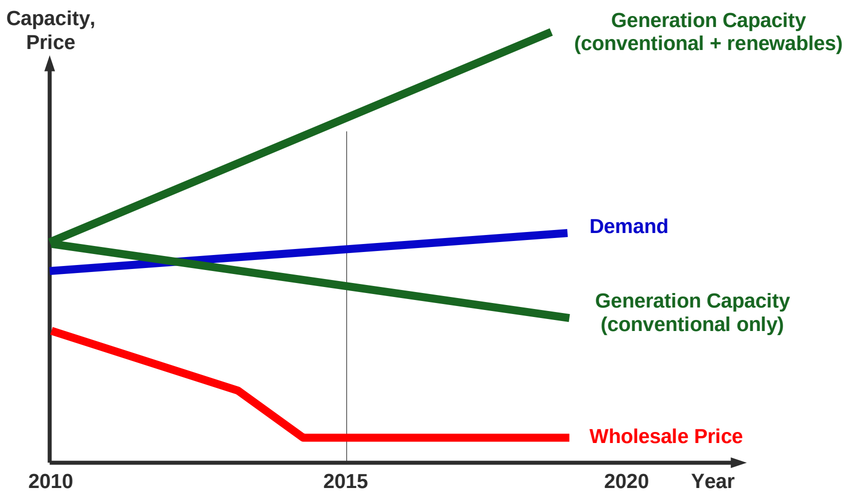
However, not least due to strategic shut downs of excess generation capacities of dominant European generators also the margin between available electricity generation capacities and demand has been decreasing considerable in Europe; especially in Central and Eastern Europe since 2002. As a consequence, the wholesale electricity market price has been increasing continuously (i.e. indication that the electricity market is becoming increasingly short in generation capacities), see Figure 4 below.

Figure 4. *Development of generation capacity, demand and wholesale electricity market price in Central Europe from 1999-2009 [2].*




In addition, in recent years the significant penetration of renewable electricity generation technologies (as a result of favourable financial support instruments) in different European countries has resulted in decreasing wholesale electricity market prices in some of the market places throughout Europe. Moreover, in recent years on some market places there already have been occurring partly negative wholesale electricity market prices as a result of renewable electricity excess generation. Therefore, as a result of these developments in recent years the currently existing European electricity market is confronted with significant generation (and also transmission) adequacy challenges (see Figure 5 below).

Figure 5. *Development and future trend of generation capacity, demand and wholesale electricity market price in Central Europe from 2010 [Source: Extension of Figure 4 by the author of [2]].*




In general, the fundamental question arises which kinds of instruments in a conventional electricity market exist to enable adequate generation capacities in case of market failures in the long run. Economic theory offers at least the following:

- No intervention
- Independent System Operator manages peaking Generators ("Strategic Reserves")
- Regulated Auctions on Investment Contracts ("Auction")
- Capacity Payments
- Mandatory Capacity Obligations to Individual Players
- Reliability Options

Several of them are briefly summarized in the following. For details in this context it is referred to [2].

### No intervention

This simple approach relies on the price signals of an "energy only" wholesale electricity market, minimizing any interference with the market. The critical issue is that it completely ignores the existence of market failures (e.g. risk-aversion of investors as a consequence of different reasons, passivity of consumers) and it may lead to undesirable generation adequacy problems:

- Risk-aversion of generators/investors address the concern that remuneration of the total cost of power plants in an electricity market mainly based on short-run marginal cost pricing is not sufficient.[3] Other open questions in this context are whether the market remuneration mechanism is adequate for generators with the highest variable generation cost (peaking units) or whether it encourages optimal operation strategies (e.g. maintenance schedules, management of pumped-hydro storage plants, etc.) enabling acceptable security of supply levels. These key questions finally determine the investor's decision and, subsequently, electricity generation adequacy in an "energy only" market.
- Similar concerns also exist on the consumer's side. E.g., a risk-averse consumer wants to protect against high electricity prices, i.e. she/he wants to have more generation capacity in the system than a risk neutral one. Long-term contracting solves this problem and reduces the risk of high wholesale electricity prices of a risk-averse consumer, allowing the consumer to pay the capacity he wants. This also diminishes the risk of investors/generators and makes the construction of peaking units more attractive.

The exclusive reliance on market forces in an "energy only" market and learning of dominant market participants in the long-term can, finally, also lead to undesirable developments like in California, where the electricity market totally collapsed in 2001 [4], or to the currently discussed generation adequacy problem we are facing in Europe as a consequence of large-scale renewable electricity integration in the European electricity market.

#### Independent System Operator manages peaking Generators ("Strategic Reserves")

This approach adds an additional element to the market. Moreover, the market is split into two parts: the competitive "energy only" market and the regulated peaking generators operating outside. This regulated peaking generators guarantee prescribed amounts of installed and ready to use peak generation capacity. In practise, the independent system operator purchases and manages a prescribed amount of peak generation capacity in the market under predefined rules:

- Usually, those peaking units are available in this restricted market segment not willing to stay in the market under a "do nothing scheme" any more. So they are prevented from retirement to meet reliability purposes in the future.
- An alternative implementation approach is that the independent system operator buys capacity reserves in advance, providing volumes of electricity available to balance the system during shortages. Although this approach only provides revenues to a few generators also other market participants benefit from wholesale electricity market price stabilisation in this scheme.

[3] According to economic theory generation units recover their investment cost thank to the infra-marginal profits (see e.g. [3]). In "energy only" markets the peaking units recover their investment cost when the electricity prices are (i) either set by the demand or (ii) using their market power during peak-hours.

#### Regulated Auctions on Investment Contracts ("Auction")

Regulated auctions on investment contracts shall guarantee that new electricity generation capacities would be installed if needed. In practice, the approach is based on regulated competitive bidding of new generation capacities if the expected margin is considered too low. Whenever a regulator considers that new investments are needed to meet generation adequacy, an auction is called where long-term contracts are assigned (the auction may or may not include conditions on the desired type of generation technology, etc.).

The biggest problem with this kind of instruments, however, is that investors tend not to invest in new power plants unless they are awarded in an economically more attractive auction. As a consequence, the free investment decision is delayed until the regulator decides to call for an auction. Therefore, the big disadvantage of this instrument is that it significantly interferes with the functioning of the forces of a free market.

#### Capacity Payments

The capacity payment is an extra remuneration to individual generators for guaranteeing security of supply. This could e.g. discourage retirement of old generation capacity if an additional capacity-based payment (global or per unit) exists. Moreover, it simultaneously stabilizes volatile revenues of generators on the wholesale electricity market (reduce risk aversion) and reduces the wholesale electricity market price level due to extra firm capacity available. Although the capacity payment is a long-term payment (on an annual basis) that reduces wholesale electricity market price risk it does not provide proper incentives for short-term operation. On the contrary, short-term dispatch of the power plant portfolio may be distorted and, therefore, detailed rules are important aimed not to interfere into the free allocation among the generators. Besides the significant disadvantage of market interference it is also difficult to establish the absolute level of the capacity payment and, finally, to guarantee that the generation adequacy objectives are ultimately achieved.

#### Mandatory Capacity Obligations to Individual Players

Another planning instrument for regulators and/or independent system operators relies on the guarantee that a regulated adequacy target for the system is determined and commitments of individual generators are defined. The selection of committed generators can take place in an auction. These commitments, however, can be traded within generators also in the short-term. Although market criteria are used to determine the price for capacity, administrative procedures need to be in place to determine firm capacity of generators (problem in case of significant amounts of hydro power plants being characterised by seasonal variability of electricity generation). Furthermore, consumers are not hedged against high and volatile wholesale electricity market prices.

#### Reliability Options

Reliability options are auctions of contracts on behalf of the entire demand. The basic idea of this instrument is that a benevolent market participant (i.e. a regulator and/or independent system operator) acts on behalf of the demand and specifies the desired generation adequacy level. Doing so, the consumers obtain a well-defined commercial reliability product in return for their money (adequate installed capacity; plant availability at the time it is needed; a reasonable price cap whenever shortages occur). For generators, selling a reliability contract means a reduction in its risk and a strong incentive to be available during critical periods.

The big advantage of this instrument is that there is no need to evaluate firm capacity administratively. Reliability payments are determined by the electricity market. Consumers are protected from high spot market prices and benefit from security of supply guarantees. Generators stabilize a fraction of their revenues. The weak points of reliability options are: (i) there exists the potential for market power abuse, (ii) there may not be enough incentives for new entrants, (iii) there exists the potential for volatility of reliability auction results, and (iv) it does not promote demand response activities.

### 2.2.2 Transmission Adequacy: Policy Options

When addressing resource adequacy options in competitive electricity markets the alternative candidate to generation capacities are adequate transmission capacities both nationally and cross-border. However, the most significant difference between the two options finally is that generation capacities are “active” elements in a market whereas transmission capacities are “passive” ones, see [5]. This means in particular, that an extension and/or reinforcement of “passive” transmission capacities can significantly contribute to security of supply and system reliability in the short- to medium-term. In the long-term, however, an “active” capacity element – in fact physical electricity generation capacity – is the ultimate sources of adequacy in an electricity market (“active” not only in comparison to transmission capacities, but ultimately also in comparison to other technologies (e.g. storage (due to efficiency losses in the charging/ discharging cycle) and options (e.g. demand side management (not consumed capacities are passive capacities))).

Nevertheless, in the transition period from previously vertically integrated national electricity supply industries towards competitive international electricity markets cross-border (inter-connection) transmission capacities play a core role at least under the following particularities of electricity markets (see [5] and [6] in detail):

- By linking two neighbouring electricity markets with cross-border transmission capacities, on the one hand, electricity market integration is possible and, on the other hand, security of supply can be enhanced if it allows the linked regions to share their respective reserve capacities in the reserve capacity procurement process (considering a low likelihood of power plant outages in both regions at the same time or limited correlation between demand and generation e.g. from variable hydro-power plants and wind generators).
- Where positive portfolio effects exist (meaning that either an additional transmission or generation capacity is implemented into the system), the incremental cost of investing into cross-border transmission capacities (interconnectors) may be lower than the incremental capacity cost of a power plant. However, due to the “passivity” of cross-border transmission capacities some generation reserve must exist in at least one of the two regions. An interconnector only enables electricity market coupling and adds to security of supply if sufficient generation reserve capacity exists.

The provision of adequate transmission capacities in competitive electricity markets is a difficult task. Empirical evidence so far in almost all electricity markets worldwide has proven that exclusive reliance on market forces can't solve the investment problems of congested transmission lines in the long-term. Therefore, chapter 6 of [2] comprehensively analyses (i) problems of cross-border transmission grid congestion, (ii) correct transmission capacity allocation and also presents (iii) ways forward to trigger investments into adequate transmission grid expansion again.

For a comprehensive consideration of the currently discussed transmission adequacy challenges in Europe, in-depth modelling analyses of the further development of the European transmission grid up to 2050 and corresponding recommendations for policy measures necessary to be implemented it is referred to the ongoing European projects eHighways2050 (www.e-highway2050.eu) and GridTech (www.gridtech.eu).

In addition, ENTSO-E, the European Network of Transmission System Operators (see www.entsoe.eu), the legally mandated body representing 41 electricity transmission system operators (TSOs) from 34 countries across Europe, is in charge of promoting the adequate development of the interconnected European grid and investments for a reliable, efficient and sustainable power system. The work and public stakeholder consultation processes organised by ENTSO-E are most important to guarantee adequate transmission capacities for smooth electricity market integration in Europe in practise. The corresponding document, being updated and extended biannual is the so-called "Ten-Year Network Development Plan (TYNDP)". The latest version is the TYNDP 2014, published on the ENTSO-E website www.entsoe.eu.

## 2.3 Historical Role and Status Quo of RES-E Support Schemes for RES-E Market Integration

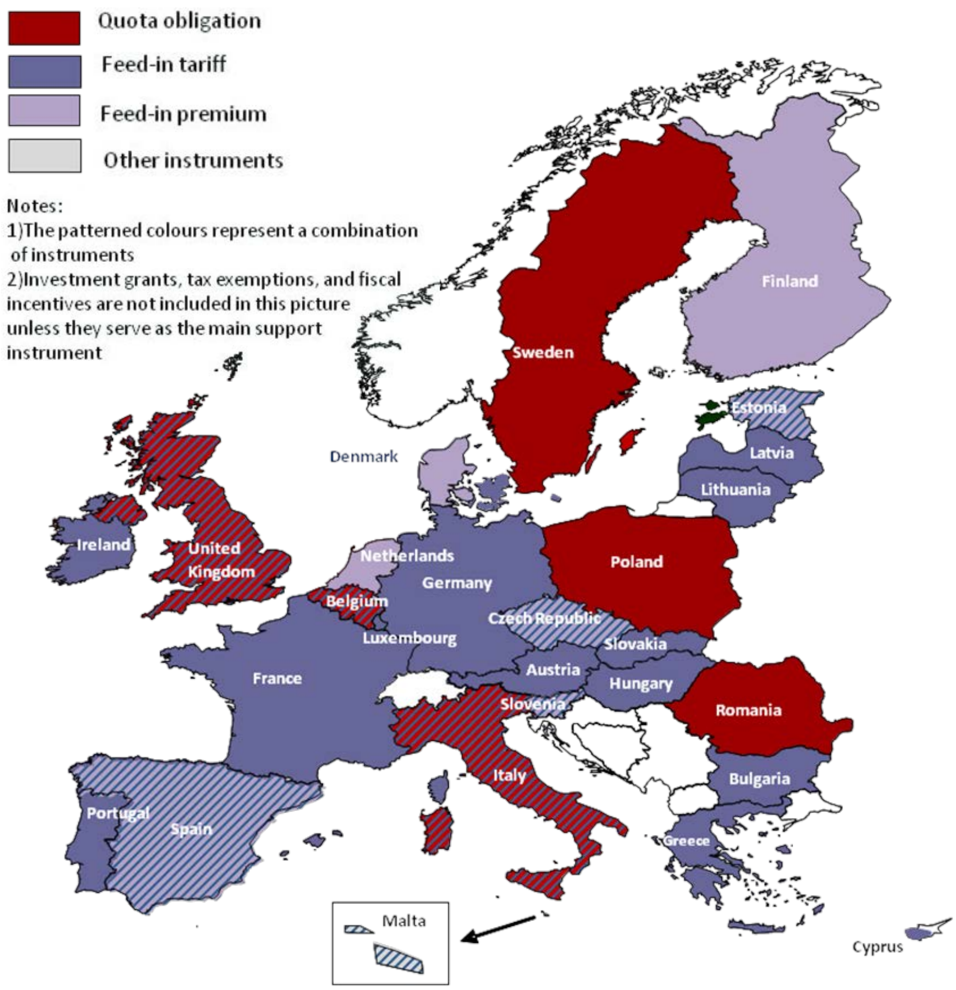
A plethora of different RES-E specific support schemes have been put in place since the start of the energy sector liberalisation efforts in the 1990s as the policy instrument of choice for the roll-out of RES-E. The absence of a common carbon tax, which would internalise all external effects of conventional power generation, disallows the disclosure of the actual cost of these power generation technologies which would ultimately provide for a level-playing field in terms of competitiveness with emission-free power generators. Policy makers opted, instead, to specifically subsidise these new entrants with guaranteed purchase agreements. These support instruments are adapted to differences in levelized cost of electricity (LCOEs) of particular RES-E technologies, but also national specificities, such as differences in grid connection and administrative costs. RES-E specific support mechanisms, most successfully in form of feed-in tariffs (FITs) or feed-in premiums (FIPs), are, therefore, not to be understood as a sheer subsidy for specific technologies, but rather as a compensation for the lack of a level playing field in the energy sector.

Over time, capital-intensive, but very low marginal cost RES-E technologies such as wind and solar PV have proven to have the steepest learning curves and achieve the best results in terms of cost reductions. This is reflected in the dominance of these two RES-E technologies in current RES-E development plans across EU Member States, but also in global installation figures, leaving most other new RES-E power generation technologies behind their expectations in terms of cost reduction pathways. With ever increasing penetration levels of these two main RES-E technologies, various adaptations to support scheme designs and levels have been carried out by Member States over time taking into account cost reduction and market maturity developments.

The overall trend towards a more market-oriented approach with regards to RES-E support schemes has been enshrined in the European Commission Guidelines on State aid for environmental protection and energy 2014-2020 [7]. These Guidelines entered into force on 1 July 2014 and will be the reference used by the European Commission when assessing the compatibility of national support mechanisms with internal market rules. These guidelines notably influence the design of national support mechanisms for renewable energy in the coming years. However, it will be Member States to determine the pace at which national support mechanisms are adjusted to comply with the guidelines as there is no hard stop date for compliance and they also have the possibility to maintain tailor-made support for technologies at different levels of maturity. For most projects, Member States will ultimately need to choose between a feed-in premium (fixed or floating) a tradable green certificate or an investment aid-based model.

Technology neutral tenders will be automatically considered by the European Commission not to result in over-compensation. The Guidelines rule out feed-in tariffs for installations above 3 MW, or 3 units. As a caveat, small RES-E projects are exempted from the obligation to take part in the market and in tenders. While the full impact of these Guidelines on particular RES-E support schemes in Member States remains to be seen, it very clearly depicts the general aspiration by policy makers to converge RES-E support scheme designs across the EU and make it more market oriented. Figure 6 illustrates an overview of the main policy instruments which are used in the renewable electricity sector in the European Union and in Figure 7 is demonstrated the chronological deployment of the different instruments.

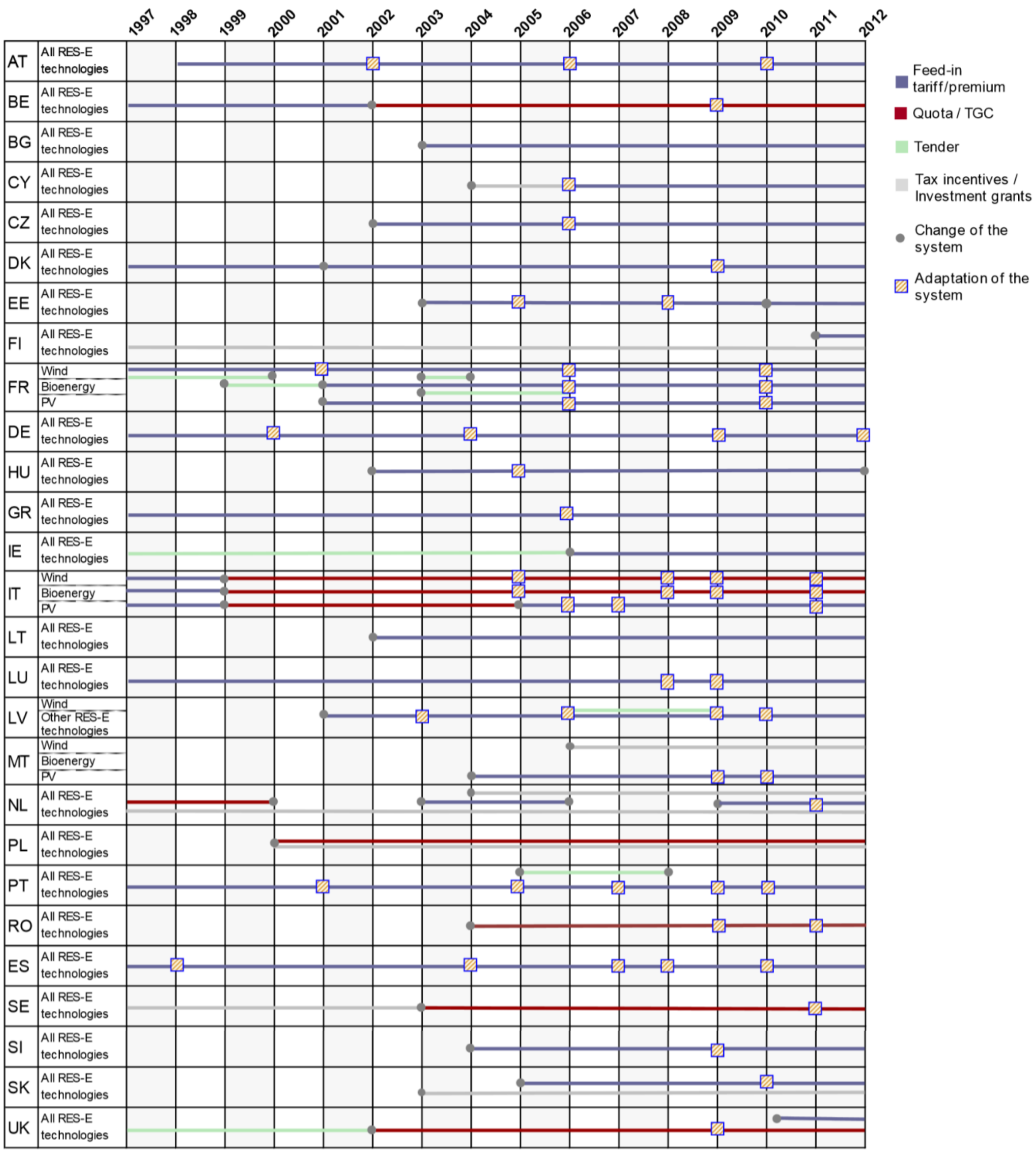
Figure 6. *RES-E support instruments in the EU.*




(Source: RE-Shaping 2012)

There are feed-in tariffs, feed-in premiums, quota obligation systems and combinations of these applied support schemes, especially feed-in tariffs (FIT) and premiums (FIP) are the most commonly used support instruments. However, there can also be observed a trend towards these instruments. Quota systems with tradable green certificates (TGC) are often applied in combination with FIT for small-scale projects or specific technologies, for example in Belgium, United Kingdom and Italy. Belgium offers minimum tariffs for each technology under its quota scheme, as an alternative to the revenues from the TGC-trade and the electricity market price. Italy offers feed-in tariffs for small-scale applications below 1 MW and the United Kingdom introduced feed-in tariffs for small-scale applications in spring 2010.

Figure 7. *Evolution of the main support instruments in EU27 Member States.*




(Source: RE-Shaping 2011)

Tender schemes are no longer used in any Member State of the EU. Only for certain projects/technologies (e.g. wind offshore in Denmark) they are sometimes applied. In Malta tax incentives and investment grants represent the dominating policy measure. Furthermore, they are used in some other countries as a kind of supplementary support which in some cases (e.g. tax incentives in the Netherlands) contributes essentially to the profitability of projects.

## 2.4 Summary of Related Challenges and Discussions in the U.S.

The most advanced regional electricity market in the U.S. is the PJM (Pennsylvannia-NewJersey-Maryland) electricity market on the east coast. Note, in the U.S. there rather exist different regional electricity markets than one single electricity market covering the entire U.S. In addition, there is no or no strong/redundant interconnection between the different regional electricity markets. Therefore, the entire U.S. electricity system can't be compared with the European electricity system. It is rather one regional electricity market in the U.S. only someone can compare with the European counterpart.

In addition, the most obvious difference of the regional electricity markets in the U.S. - compared to the European electricity market - is that in the U.S. electricity markets on each node of the regional transmission system the locational electricity market price signal is visible for the market participants in several market segments (balancing and wholesale intraday/day-ahead market). This is known as the so-called 'nodel-pricing' system. On the contrary, in the European electricity market there exist so-called 'electricity market zones' (each of them covered by the footprint of a single TSO or some neighboring TSOs). Therefore, the European electricity market is characterized by the so-called 'zonal pricing concept'.

This difference is also the main reason why in the U.S. the capacity market discussion is more advanced than in Europe: simply due to the fact that short-term price signals in 'nodal pricing' systems per se do not incorporate signals for long-term capacity investment needs. Therefore, a long-term capacity adequacy market design instrument needs to be complemented to 'nodal pricing' systems in general.

### 2.4.1 Reliability Pricing Model of PJM

PJM Interconnection (U.S.) is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, see [8]. The Reliability Pricing Model (RPM) of PJM has been implemented in 2007 and has replaced the Capacity Credit Market (CCM), which was not able to foster sufficient investments in new power plants, due to too low capacity payments. In detail, the RPM provides:

- Procurement of capacity three years before it is needed through a competitive auction, which is called Base Residual Auction (BRA);
- Locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
- A variable resource requirement to help set the price for capacity;
- A backstop mechanism to ensure that sufficient resources will be available to preserve system reliability.

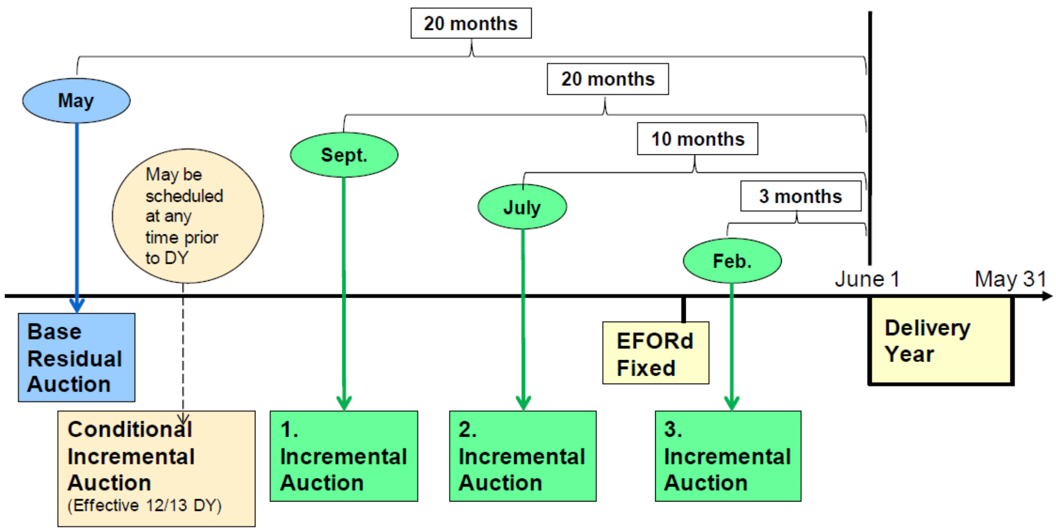
“Demand” in PJM’s RPM auctions is described by the Variable Resource Requirement (VRR) curve, a segmented downward-sloping curve supporting the primary RPM objective of attracting and retaining sufficient capacity to meet resource adequacy objectives. The downward sloping demand curve for capacity should achieve the following objectives:

1. Provide an indication of the incremental reliability and economic value of capacity at different planning reserve levels, in contrast to a vertical demand curve in which the value of capacity is only defined at the installed reserve margin target.
2. Avoid the extreme capacity price volatility that a vertical curve might produce by allowing capacity prices to change gradually with changes to supply and demand, and reflect the idea that capacity beyond the installed reserve margin target has value.
3. Reduce the risk in capacity investment by mitigating price volatility and providing a consistent stream of revenue, encouraging investment when it is needed at a lower cost to the system.
4. Mitigate the potential exercise of market power by moderating the change in price produced by a change in supply.

The “supply” curve is the result of the effectively submitted bids of resource specific providers. The BRA is followed by so-called Incremental Auctions (IA) at regular intervals. These are used to adapt changes that may occur in the production or in requirement. Whereas the conditional Incremental Auction only takes place, if a transmission power line in an area with bottlenecks cannot be accomplished in time. The time course of the different auctions is shown in Figure 8.

The PJM Capacity Market also contains an alternative method of participation, known as the so-called ‘Fixed Resource Requirement Alternative (FRRA)’. The FRRA provides a load serving entity with the option to submit a FRRA Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

Figure 8. *Time course of auctions in the Reliability Pricing Model, see [8].*



The long-term effects of RPM cannot be assessed yet, because it was only introduced 7 years ago. Nevertheless, several statements can be made about the strengths and weaknesses of the model, which are summarized in Table 1.

Table 1. *Strengths and weaknesses of the RPM of PJM, see [9].*

| Strengths | Weaknesses |
|---|---|
| • Obligation to dispose of RU sufficient secured capacity<br>• Allows monetary valuation of security of supply<br>• Local capacity zones<br>• Inclusion of DSM, load management<br>• Promotion of line construction projects<br>• Presence of fines<br>• Price guarantee for new power plants | • Artificial demand curve<br>• Lead time of the auction too short<br>• Price guarantee for new plants too short<br>• High complexity |

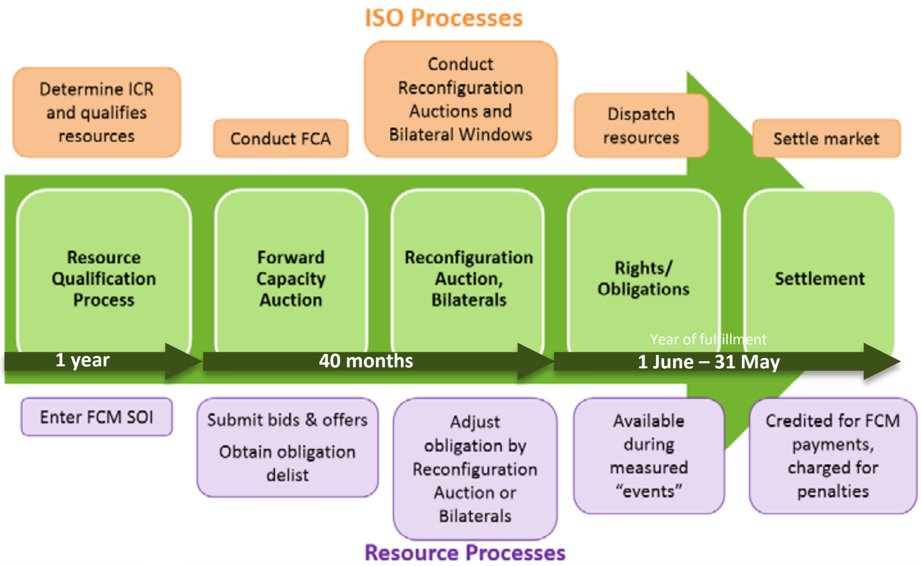
### 2.4.2 Forward Capacity Market of ISO New England

ISO New England (ISO-NE) is an Independent System Operator (ISO) of the North American east coast. The company organises the power plants dispatch as well as the electricity wholesale market and, in addition, they are responsible for the transmission grid in their service area. A capacity market has already been implemented in the area of ISO-NE in the year 1998, which has been a market only for trading installed capacity originally. This first capacity market approach has not been able to reflect the local value of capacity resources and to emit stable price signals. Due to this reasons, ISO-NE decided in 2006 to implement a Forward Capacity Market (FCM), which is an auction based local forward market for secured capacity. The FCM allows separated trading of capacity and should generate additional incomes to compensate the missing revenues of the remaining market places like for example from the day ahead market. The resulting price signals of the FCM should provide enough incentives for new investments in areas with existing bottlenecks.

The demand of required capacity is defined centrally by the ISO-NE like in PJM's Reliability Pricing Model and subsequently procured by an auction. The product of the auction is a capacity option. The capacity resources, which have emitted the options, commit themselves to provide the corresponding amount to the electricity market in the agreed year.

The most important components and processes of the FCM are shown in Figure 9.

Figure 9. *Forward Capacity Market Components, see [10].*




To provide long-term investment signals ISO-NE organizes the so-called Forward Capacity Auction (FCA), which is a descending clock auction, 40 months in advance. In this auction, the projected needs of the service area are procured in secured performance. Initially, ISO-NE calculates requirements for each zone and compares each of them with the installed generation capacity. If there are lacks concerning installed capacity, a separate FCA will be made in the relevant zone. Otherwise, one FCA for the whole area will be performed. The required power can be provided both, of generating units and electricity imports from neighbouring areas, as well as via load shedding by the demand side.

In order to allow responding to possible changes on the supply and demand side, such as load increases or premature plant shutdowns, the so-called Reconfiguration Auctions (RA) are carried out after the FCA. In addition to the RA, capacity can be traded through bilateral contracts as well. If capacity resources do not satisfy the obligation of being available in the year of fulfillment, or during congestion periods, they have to pay a penalty. The amount of penalty is calculated separately for each resource and is based on the capacity payments that are earned by them during the year, as well as a regulatory fixed penalty factor and the availability during the bottleneck hours. In addition, all resources have to pay the Peak Energy Rent (PER), if electricity prices in the energy market are exceeding the exercise price of the options. The PER shall provide incentives to be available during periods of high demand. Moreover, the presence of the PER shall reduce the possibility of abusing market power, since the retention of available resources can indeed lead to an increase in electricity prices, but the additional revenues cannot be generated due to the PER. Furthermore, by the PER it can be avoided, that the fixed costs of a facility are paid twice. The capacity revenues, which are provided by the Forward Capacity Market, therefore, are the result of the sum of the capacity premiums to be determined in the individual auctions, minus the PER and the respective penalties. These revenues are paid by ISO New England and they are passing on these costs of the Forward Capacity Market to consumers in the form of fees.

The first FCA has been in 2008 and the year of fulfilment was 2010/11. Therefore, the long-term impact and the success of the Forward Capacity Markets may not yet be adequately assessed. However, the first four auctions were able to meet the demand.

The strengths and weaknesses of the FCM of ISO NE are summarized in Table 2.

Table 2. *Strengths and weaknesses of the Forward Capacity Market of the ISO New England, see [9].*

| Strengths | Weaknesses |
|---|---|
| • No artificial demand curve<br>• Use of Descending Clock Auction<br>• Presence of Peak-Energy-Rent<br>• Use of Residual Auctions and bilateral agreements<br>• Consideration of congestion areas<br>• Participation of demand through energy efficiency and load reduction<br>• Presence of a price limit | • Complex<br>• Elasticity of demand is zero<br>• Lead time of the auction too short<br>• Price guarantee for new power plants too short |

### 2.4.3 The Electric Reliability Council of Texas (ERCOT) - an energy only market

The Electric Reliability Council of Texas (ERCOT), the state of Texas' independent system operator, runs the only energy-only market in the United States. It is connected to neighboring grids with DC lines and block-load transfer capabilities. It serves a customer base of 23 million covering 85 % of total Texas load and 75 % of land area.

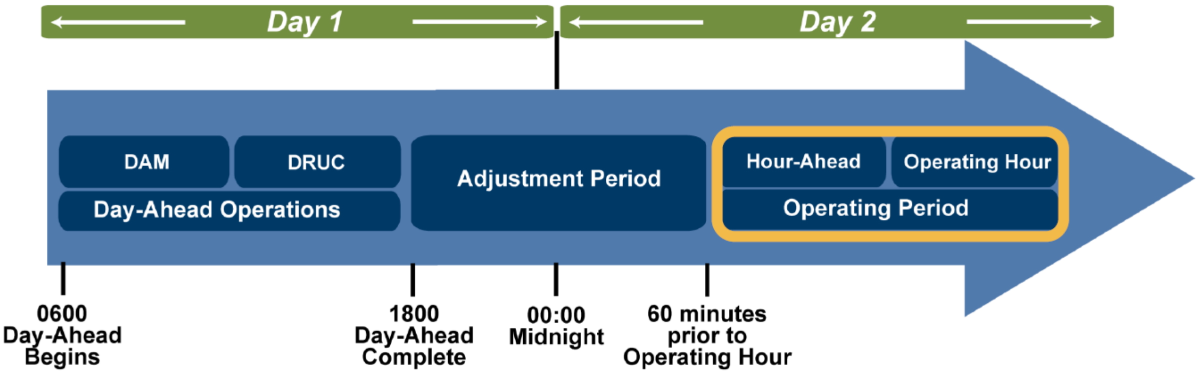
Energy-only markets can avoid the missing money problem if the following conditions are met: Price caps are not set too low, locational differences are reflected in the market price, balancing markets are liquid, demand response is integrated, ancillary services are well designed, and there is very limited out of market dispatch [11]. ERCOT performs well most of these conditions. Its price cap currently stands at 4.500 $/MWh, it uses nodal pricing, its reserve markets are co-optimized with the day-ahead energy market, it has demand side resources in the order of 4 % of peak load and highly efficient ancillary services.

In 2010 ERCOT replaced its previous 4 zone market with a nodal market of over 4.000 nodes (some sources state 8.000). The nodal pricing system coupled with a 5-minute dispatch resolution has allowed ERCOT to successfully integrate 18.5 GW of wind generation (highest in U.S.) out of a total of 80 GW of generating capacity.

ERCOT market Structure

The market is based on congestions management of the grid consisting of 4.000 nodes providing transparency regarding market behavior and congestion cost. It operates a co-optimized Day-Ahead Market (DAM) and ancillary services - Day-ahead Reliability Unit Commitment (DRUC) and Congestion Revenue Rights (CRR) (Figure 10). During the real-time market, ERCOT executes load frequency control and security constrained economic dispatch for 5 minute intervals [12].

Figure 10. *ERCOT Day-ahead and real time market overview, see [12]*




**Congestion Revenue Rights Market** – ERCOT offers different types of CRRs as hedges against congestion costs, which are fully tradable and are measured in tenths of MWs in hour durations. They are defined as source point to sink point rights and flow gate rights. CRRs can be acquired through auctions, direct allocation or by trade. Auctions are run on a monthly and annual basis.

The auction is cleared by running a simultaneous combinatorial feasibility algorithm that uses the nodal network model and maximizes revenue with the constraint that all winners pay the same dollar amount per MW per hour for the same product [12].

**Day-Ahead Market** - The DAM establishes the market value of the CRRs for CRR account holders who have CRRs. Qualified Scheduling Entities (QSEs) can bid to purchase point-to-point obligations in the DAM that settle in the Real-Time Market (RTM). Also during this period, ERCOT runs the Day-Ahead Reliability Unit Commitment (DRUC) study. This process ensures that there is sufficient generation capacity committed in the proper locations to reliably serve the forecasted load and forecasted transmission congestion by committing offline resources, if required [12].

**Real-Time Market (RTM)** - ERCOT controls the RTM by running a Security Constrained Economic Dispatch (SCED) at least every five minutes, using offers by individual resources and actual shift factors by each resource on each transmission element, while considering conditions on the transmission network [12].

**Competitive renewable energy zones: Building transmission and wind capacity**

The Public Utility Commission of Texas (PUCT) was directed to establish the competitive renewable energy zones as a policy to coordinate the expansion of transmission and generation. Twenty five high-resource areas with capacity factors over 35 % were identified in the western part of the state. The PUCT was not required to demonstrate demand through financial commitments by generators in order to establish new lines; transmission developers could pass the cost of the lines to the ratepayers, even if the lines were underused. Meanwhile ERCOT was ordered to identify the optimal transmission developments to serve for four different wind power development scenarios assuming an optimal level of curtailment of 2 %.

The policy reduced investors' initial reluctance to develop the available wind potential in absence of sufficient transmission capacity. Within 4 years 18.5 GW of newly developed wind generation was built together with sufficient transmission capacity [13].

**Investment risk and reserve margins**

To comply with the standard Southwest Power Pool reliability target (1 loss of load event in-10 years) ERCOT should have a reserve margin of 13.75 %. A Brattle Group report [14] stated that investors perceived the energy only market as overall riskier than energy-and-capacity markets. The higher volatility and lack of Power Purchasing Agreements (PPAs) favor bigger investors that can weather a few bad years as long as the long-term revenues are high enough.

The actual reserve margin in 2014 was closer to 9.8 %, which according to the same report is close to the economically optimal reserve margin (the point where the value of load not served equals the cost of additional reserves), which indicates that investments in generation capacity are not insufficient.

As is the experience in European markets wind generation has eroded the revenues of traditional base load, mainly coal and nuclear power plants. The higher price caps that currently stand at 4.500 $/MWh, and are set to increase up to 9.000 $/MWh by June 2015 will provide scarcity prices to finance additional investments. Though reliability targets still won't be met, the predicted 10 % reserve margin should nonetheless keep load shed events to within once a year on a normal year.

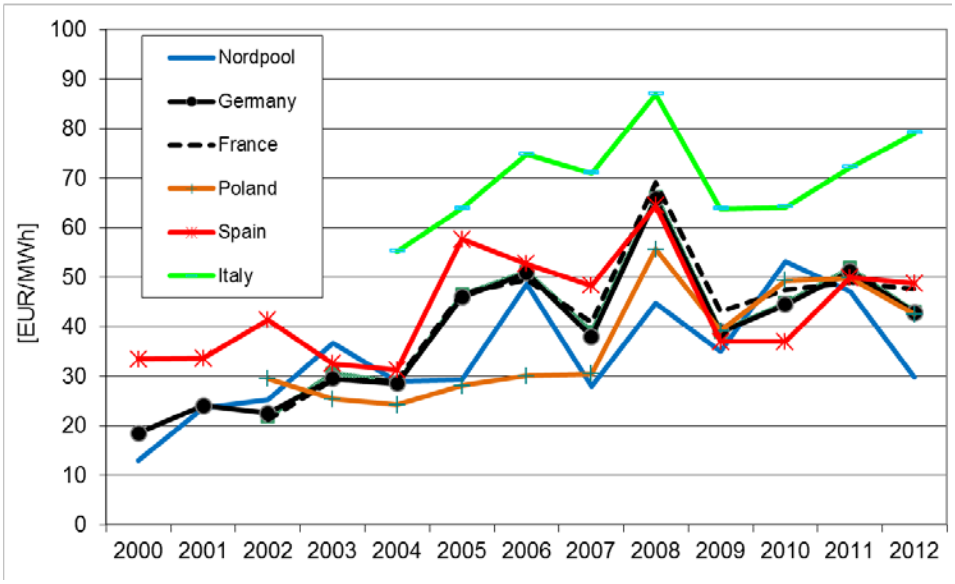
# 3 Achievements in terms of Electricity Market Design

## 3.1 Overview

After the implementation of the EC-Directive EC/96/92, the European Commission has been convinced that the emphasis of the cornerstones finally will result in competitive entry of new players on both markets (wholesale and retail business) and, subsequently, lower electricity prices for consumers. The intention of the European Commission was (and still is) the creation of a common European electricity market. However, currently Europe rather consists of at least seven distinct sub-markets, each of them separated by partly insufficient transmission capacities and different barriers for access to the grid [2].

The most impressive indicator identifying market separation is the wholesale electricity market price development in the different regional electricity markets in Europe. Figure 11 presents the empirical development of the annual average wholesale electricity market price on the most important market places for wholesale trade in Europe from 2000 until 2012.

Figure 11. *Development of spot market prices in different European electricity markets 2000-2012 [2].*

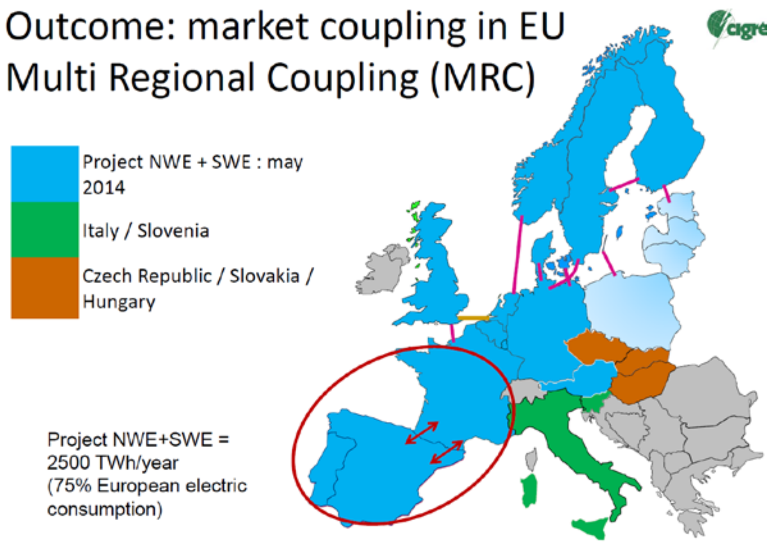



(Source: EEG)

At the beginning there has been a divergence, but in the last years a slight trend to convergence of wholesale prices can be observed, especially for Spain, Poland, France and Germany. On the other side Italy has a high wholesale price level due to insufficient interconnection capacities to neighbouring countries.

On May 2014, the Day-ahead Market Coupling between the Central Western Europe (CWE) and the South Western Europe (SWE) regions was finally accomplished (it is now under analysis the extension to Italy and Switzerland). With market coupling, the daily cross-border transmission capacity between the various areas is not sold separately (explicitly auctioned) among the market parties, but is implicitly made available via energy transactions on power exchanges on either side of the border, which will lead to a more efficient use of the interconnection and, consequently, to the decrease of the Day-ahead market spreads.

Figure 12. *Current Status of the European Day-Ahead Market Coupling*




(Source: ENTSO-E)

At the level of intraday markets, with the exception of the Nordic regional market, integration is less advanced, with cross-border trading platforms mainly developed bilaterally between Member States. The main goal is to achieve a continuous intraday market, where Market participants may access to bids and offers from other market participants in a continuous manner, up to one hour before real time.

## 3.2 Long-Term (Forward/Futures Market)

In the Long Term markets, some regional initiatives have been implemented by the competent National Regulatory Authorities (NRAs) while the Network Code on Forward Capacity Allocation (NC FCA) is still under approval process (it is currently under pre-comitology). This Network code foresees a Single Allocation Platform and there are currently discussions for the merger of two Allocation Offices (CASC.eu and CAO). Nevertheless, given the ongoing discussion carried out on the type of products that should be offered to market participants (Physical and/or Financial), some NRAs have decided to put in place regional platforms with long-term financial transmission rights (FTRs). According to the NC FCA the following products are deemed to be offered to market participants:

- <u>Physical Transmission Rights (PTRs) with Use-it-or-Sell-it (UIOSI) condition</u>: It gives the holder the exclusive right to use a particular interconnection in one direction to transfer a predefined quantity of energy from one market hub to the other. The right can be used for buying and selling energy either on OTC markets, through Power Exchanges or to meet physical positions in the two markets. The UIOSI mechanism gives its owner the right either to nominate energy transfers between two zones, or alternatively, to use it as FTR by reselling it in the day-ahead market.

- Financial Transmission Right (FTRs) options: It gives the holder the right to collect revenue generated by the amount of MW he is holding which, under normal circumstances, is equal to the hourly market price difference, when positive, between market hubs. FTR options are defined in a particular direction, and thus the market price difference represents the price difference between the 'to' market and the 'from' market, which can be positive or zero.
- Financial Transmission Right (FTR) obligations: In contrast to a FTR option, the holder of an obligation is entitled to receive and obliged to pay the hourly market price difference between two areas during a specified time period. The product entails the obligation for owners to pay the respective market price differential if it is negative, i.e. if the price differential is in the opposite direction.
- Contract for Differences (CfDs): It is similar to an FTR obligation, which means that if the system price A is lower than the system price B the holder of a CfD will have to pay the seller of that CfD (equivalent to FTR obligations in case of a negative price difference). However, the CfDs are sold by market players not TSOs.

## 3.3 Day-ahead markets

Market coupling has been identified as the target mechanism for day-ahead interconnection capacity allocation for long. In this chapter, we present how such a mechanism has progressively been implemented in Europe (bottom-up approach), and how it became a regulatory requirement at the European level (top-down approach).

### 3.3.1 Day-ahead interconnection capacity allocation: from bilateral, non-market-based approaches to regional market coupling (bottom-up approach)

**From discriminatory allocation of cross-border capacities to market-based allocation**

Before the liberalization of the EU electricity sector, cross-border interconnection capacities were used for two purposes: emergency support between TSOs and long-term commercial contracts.

In general, interconnection capacities were allocated on a first-come-first-served basis: they were therefore mainly used by incumbents of the electricity sector. The capacity which remained available on top of the part reserved to long-term contracts was in general allocated on a pro-rata basis (non-discriminatory, but still non-market-based mechanism). There was however one significant exception in this non-market-based landscape: the Nordpool market, within which interconnection capacities have been allocated in a market-based way since the 90s ("market splitting" mechanism, see below).

Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity (see [15]) led to a profound reform in the way interconnection capacities were allocated. Its article 6.1 indeed stated: *"Network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals to the market participants and transmission system operators involved. Network congestion problems shall preferentially be solved with non-transaction based methods, i.e. methods that do not involve a selection between the contracts of individual market participants"*. This led to the implementation of auctions for the allocation of cross-border capacities.[4]

In addition, the Judgment C-17/03 of the European Court of Justice (see [16]) set a legal precedent by precluding *"national measures that grant an undertaking preferential capacity for the cross-border transmission of electricity"* at the Dutch borders. This judgment eventually applied to all borders within the EU. Therefore, as from 2006, priority access was no longer granted to long-term contracts: at each border, the whole interconnection capacity was given for auctioning.

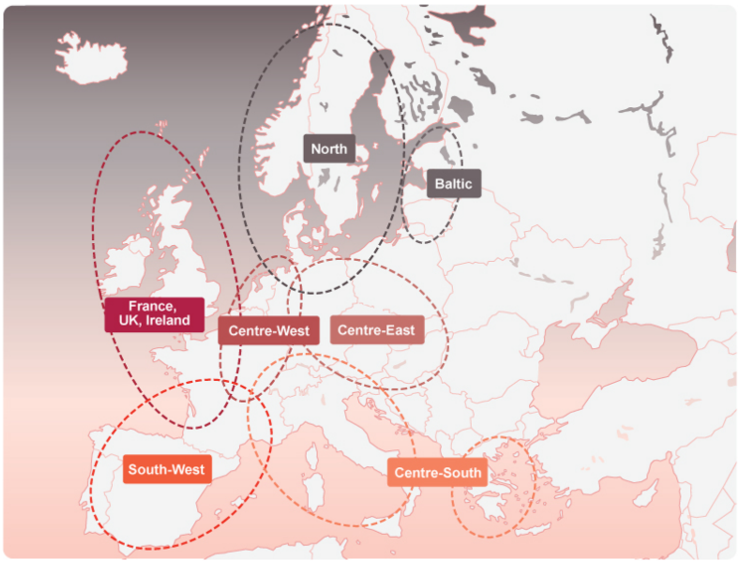
**From a bilateral management of cross-border capacities to regional cooperation**

Initially, electricity interconnection management was performed on a bilateral basis between adjacent countries. There was therefore a patchwork of different interconnection access rules and capacity products.

Regional initiatives were launched in 2006 by ERGEG to speed up the integration of Europe's national energy markets, both for electricity and for gas. Seven Electricity Regional Initiatives (ERI) were therefore created, each covering a specific region of the European Union (see Figure 13).

[4] This Regulation does not address market coupling. This is why it is mentioned in the "bottom-up approach" section rather than in the "top-down approach" section.

Figure 13. *Electricity Regional Initiatives*




(Source: RTE)

Each ERI involved, at different levels, the European Commission, National Regulators, TSOs, Power Exchanges and market players. Regional action plans were adopted to improve the management of interconnection capacities for all segments (capacity calculation; long-term, day-ahead and intraday capacity products allocation; balancing exchanges).

This regional process was initially based on a voluntary participation of the different actors, in particular of the TSOs. It became eventually compulsory when Congestion Management Guidelines (see [17]) were adopted by the EC amending the Annex to EC Regulation 1228/2003. Article 3.2 indeed states: *"A common coordinated congestion management method and procedure for the allocation of capacity to the market at least yearly, monthly and day-ahead shall be applied by not later than 1 January 2007 between countries in the following regions:*

- *(a) Northern Europe (i.e. Denmark, Sweden, Finland, Germany and Poland),*
- *(b) North-West Europe (i.e. Benelux, Germany and France)[5],*
- *(c) Italy (i.e. Italy, France, Germany, Austria, Slovenia and Greece),*
- *(d) Central Eastern Europe (i.e. Germany, Poland, Czech Republic, Slovakia, Hungary, Austria and Slovenia),*
- *(e) South-West Europe (i.e. Spain, Portugal and France),*
- *(f) UK, Ireland and France,*
- *(g) Baltic states (i.e. Estonia, Latvia and Lithuania)."*

[5] This region was initially called "Central-West Europe" (CWE). This initial name is more often used than the official name.

## From explicit to implicit auctions

Since 2005, "explicit auctions" were implemented to comply with the EU regulation and improve the functioning of cross-border trade.[6] At each border, TSOs therefore coordinate to calculate and auction interconnection capacities, independently of the energy markets. In general, capacities are allocated on a yearly, monthly and daily basis. The daily process to use these capacities (the day before the date of delivery) is as follows:

1. Early in D-1 (around 8 am), owners of long-term capacity rights (yearly and monthly capacity products) nominate the capacity they intend to use on day D;
2. Later in the morning (around 9 am), the remaining capacity is calculated by TSOs and auctioned: market participants willing to operate a cross-border trade have to buy interconnection capacity before the day-ahead electricity market closure, meaning they have to bet on the day-ahead price differentials between adjacent markets to value the capacity;
3. At mid-day, the day-ahead electricity markets close;
4. In the afternoon (around 2 pm), owners of day-ahead capacity products have to nominate their capacity to match, as much as possible, the electricity market outputs.

With such a process, day-ahead interconnection capacities are not valued at their real value, which shall be the price differential between the adjacent markets. They are neither used optimally: cross-border flows barely reach the interconnection capacity, even in case of high price differentials; cross-border flows operating in the opposite direction to the economic direction (meaning from the high-price market to the low price market) have been also regularly observed. These inefficiencies have been quantified in various reports published by regulatory authorities. For instance, the loss in social welfare due to the explicit nature of interconnection capacity auctions was estimated for the year 2008 by the CWE regulators (see Table 3 and [18]). More recently, ACER evaluated this loss for the years 2011 and 2012 in all electricity regions (see Figure 14 and [19]).

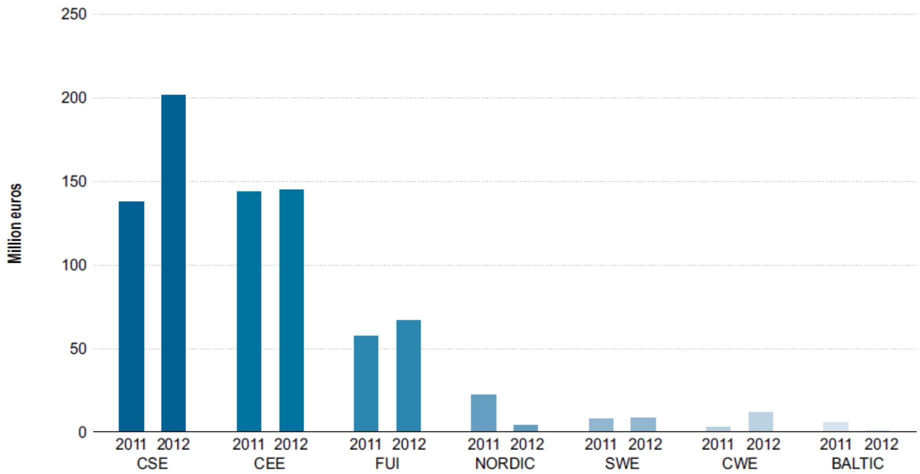
Table 3. *Estimated "loss in social welfare" due to the absence of implicit methods in 2008*

| Border | Loss in social welfare (M€) |
|---|---|
| France-Germany | 96 |
| Germany-Netherlands | 80 |

(Source: CWE ERI - Regional reporting on electricity interconnection management and use in 2008)

[6] Implicit auctions were mentioned as a possible congestion management method in the Congestion Management Guidelines. However, the implementation of explicit auctions for cross-border capacity allocation was sufficient to comply with Regulation 1228, and much easier to implement.

Figure 14. *Estimated 'loss of social welfare' due to the absence of implicit day-ahead methods, per region – 2011 to 2012 (million euros)*




(Source: ACER Market Monitoring Report 2013)

Therefore, based on the experience of the Nordic markets where interconnection capacity was allocated simultaneously with the energy products (market splitting mechanism), and following a joint ETSO and Europex proposal (see [20]), market coupling was identified in 2006 as the target mechanism for the allocation of day-ahead interconnection capacity.

Market coupling and market splitting are the two possible options for implicit auctions. "Market coupling" means that two or several power exchanges, operating on adjacent markets, cooperate with the TSOs operating the corresponding control areas, in order to implicitly allocate the cross-border capacity along with the energy trades negotiated in the respective electricity markets. With market coupling, only the governance structure differs from the so-called market splitting, in which only one power exchange operates within several Member States.

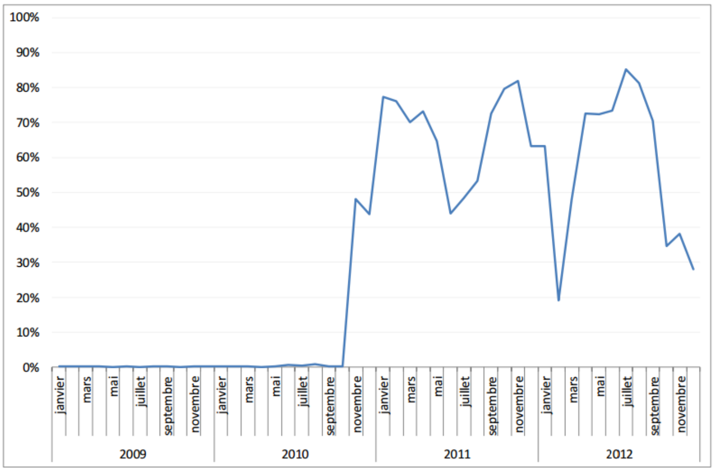
As from 2006, market coupling was identified as the target mechanism for day-ahead allocation of interconnection capacity and was progressively implemented in Europe:

- In November 2006, the Trilateral Coupling (TLC) was launched between France, Belgium and the Netherlands. At this occasion, the Belgian power exchange Belpex was created.
- In November 2010, the TLC was extended to Germany, covering therefore the full CWE region. Simultaneously, an interim mechanism was implemented to couple CWE with the Nordic countries within which market splitting was being operated for several years.
- In June 2012, seven power exchanges decided to cooperate in order to facilitate the further development of market coupling. The Price Coupling of Regions (PCR) initiative was therefore adopted to develop a single price coupling solution to be used to calculate electricity prices across Europe, and allocate cross-border capacity on a day-ahead basis. There was indeed a need for a single algorithm to couple regions in which market coupling or splitting was already running.

- In February 2014, the PCR was implemented for the first time in the North-Western area of Europe (NWE), covering CWE, Great Britain, Nordic and Baltic countries.
- In May 2014, the PCR was extended to cover Spain and Portugal.

The impacts of the CWE market coupling, in terms of price convergence, were assessed by the French regulator CRE in its 2012 report on the use and management of electricity interconnections (see [21]), and are presented in Figure 15.

Figure 15. *Price convergence rate between France, Belgium and Germany*

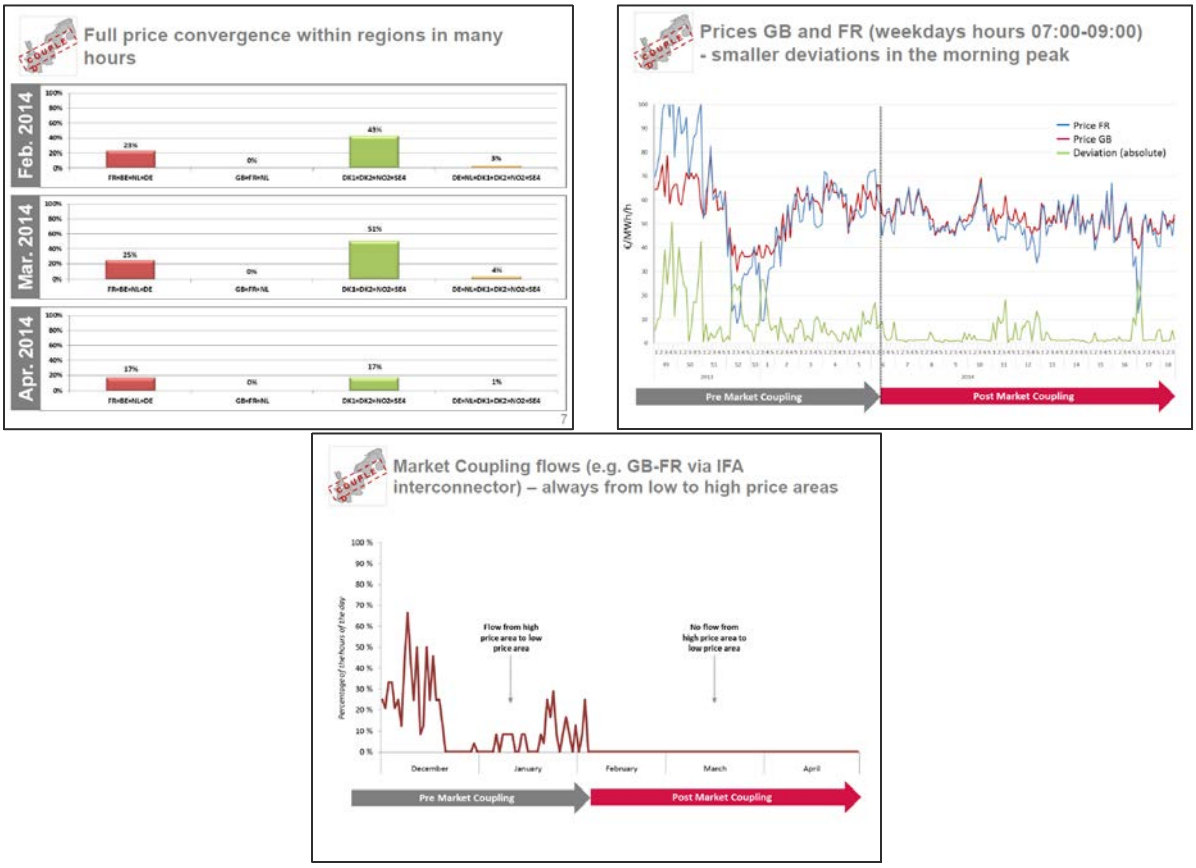



(Source: CRE)

The first results of the NWE market Coupling were presented by ENTSO-E and EUROPEX at the XXVIth Florence Forum (see [22]). Extracts from this presentation are presented in Figure 16. They show:

- The level of price convergence within regions from the start of the NWE coupling;
- The decrease in the price differential between France and Great Britain from the start of the NWE coupling;
- The stop of non-economic flows (from high-price areas to low-price areas) on the interconnection between France and Great Britain from the start of the NWE coupling.

Figure 16. *First results of the North-Western area of Europe (NWE) market coupling*




(Source: ENTSO-E, EUROPEX)

### 3.3.2 Harmonization and further development of market coupling (top-down approach)

In parallel with the Regional Initiative process and the progressive implementation of market coupling, the 3rd Energy Package was adopted and came into force in 2009. Under this new regulatory framework, the cooperation between TSOs as well as the cooperation between National Regulators was given a formal status with the creation of the European Networks of Transmissions System Operators, both for gas (ENTSOG) and electricity (ENTSO-E), and of the Agency for the cooperation of Energy Regulators (ACER).

Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 (see [23]) defines, in its article 6, a process for further harmonizing and improving, in particular, the allocation of cross-border interconnection capacities:

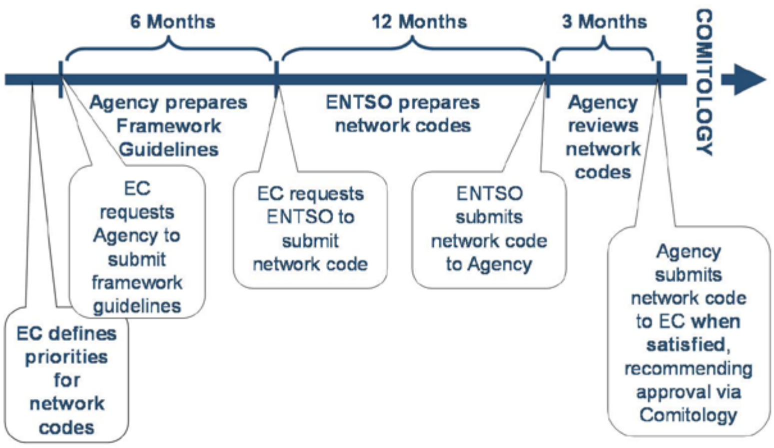
1. The Commission establishes an annual priority list identifying the areas to be included in the development of network codes (NC);
2. The Commission requests ACER to elaborate, and, after having consulted ENTSO-E and other relevant stakeholders, to submit to it within six months a non-binding framework

guideline (FG) setting out clear and objective principles for the development of network codes relating to the areas identified in the priority list;

3. When the Commission is satisfied with the framework guideline, it requests ENTSO-E to submit a network code which is in line with the relevant framework guideline, to the Agency within 12 months;
4. Within 3 months, during which ACER may consult the relevant stakeholders, ACER has to provide a reasoned opinion to ENTSO-E on the network code;
5. When ACER is satisfied that the network code is in line with the relevant framework guideline, ACER shall submit the network code to the Commission and may recommend its adoption within a reasonable time period.

This process is summarized in Figure 17.

Figure 17. *Elaboration process for framework guidelines and network codes*




(Source: ACER)

Interconnection capacity calculation and allocation are addressed in the Framework Guideline on Capacity Allocation and Congestion Management for Electricity (FG CACM), see [24], adopted by ACER in July 2011. In chapter 3 of this FG, day-ahead capacity allocation is addressed and market coupling or splitting is identified as the only authorized mechanism: *"The CACM Network Code(s) shall foresee that TSOs implement capacity allocation in the day-ahead market on the basis of implicit auctions via a single price coupling algorithm which simultaneously determines volumes and prices in all relevant zones, based on the marginal pricing principle. The implementation shall take into account the role of the power exchanges (PXs) and shall require the harmonization of day-ahead bidding deadlines"*.

In March 2013, after several iterations with ENTSO-E, ACER recommended that the European Commission adopts the Network Code on Capacity Allocation & Congestion Management (NC CACM) [7] (see [25] submitted by ENTSO-E in September 2012). In chapter 4 of this NC, the day-ahead market coupling process is described in detail.

In July 2014, the Commission submitted the NC on CACM to the Electricity Committee, shaped as a Regulation proposed for adoption: Regulation establishing a Guideline on Capacity allocation and congestion management (see [26]). If adopted, this Regulation will make the implementation of market coupling legally binding in the EU28.

## 3.4 Very-Short Term Markets (Balancing)

At present, very heterogeneous structures and patterns exist when drawing the different parameter settings characterising national balancing markets in Europe. A comprehensive summary on country level in this respect is presented in [27]. This summary also visualizes the importance for significant harmonization of market structures, market rules, operational procedures and also prequalification criteria for market participants interested in balancing service provision. In the following, the foremost aspect in this context is briefly summarized: the harmonization needs in terms of deviating interfaces between the market sub-segments within the time frame of balancing service provision in Europe.

The different balancing markets within the time frame of balancing service provision are mainly determined by maturity and activation mechanism of balancing capacity. According to the new nomenclature proposed in the Electricity Balancing Network Code (NC EB) – the result of harmonisation of the heterogeneous pattern of the status quo across Europe (see Table 4 in detail) – the following categories are recommended:

- Frequency Containment Reserves (FCR): means the Operational Reserves activated to contain System Frequency after the occurrence of an imbalance. These are operating reserves for constant containment of frequency deviations from nominal value in the whole synchronously interconnected electricity system. Operating reserves have activation time up to 30 seconds and are activated automatically and locally.
- Frequency Restoration Reserves (FRR): means the Active Power Reserves activated to restore System Frequency to the Nominal Frequency and for Synchronous Area consisting of more than one LFC Area power balance to the scheduled value. These are operating reserves to restore frequency to nominal value after electricity system imbalance. Activation up to 15 minutes, typically managed by an automatic controller. However,

[7] For technical reasons, it was decided in May 2014 that the regulation on capacity allocation and congestion management (CACM), would be labelled “binding guideline” instead of “network codes”.

depending on product and country, FRR can also be activated manually (see in Table 4 below).

- Replacement Reserves (RR): means the reserves used to restore/support the required level of FRR to be prepared for additional system imbalances. These are operating reserves used to restore the required level of operating reserves to be prepared for a further electricity system imbalance. This category includes operating reserves with activation time from 15 minutes up to hours. They may be contracted or subject to markets.

In the following Table 4 an overview is presented indicating the allocation of FCR, automatic and manual FRR and RR to the status quo of existing "terms" in the balancing capacity and balancing energy service provision in different European market regions.

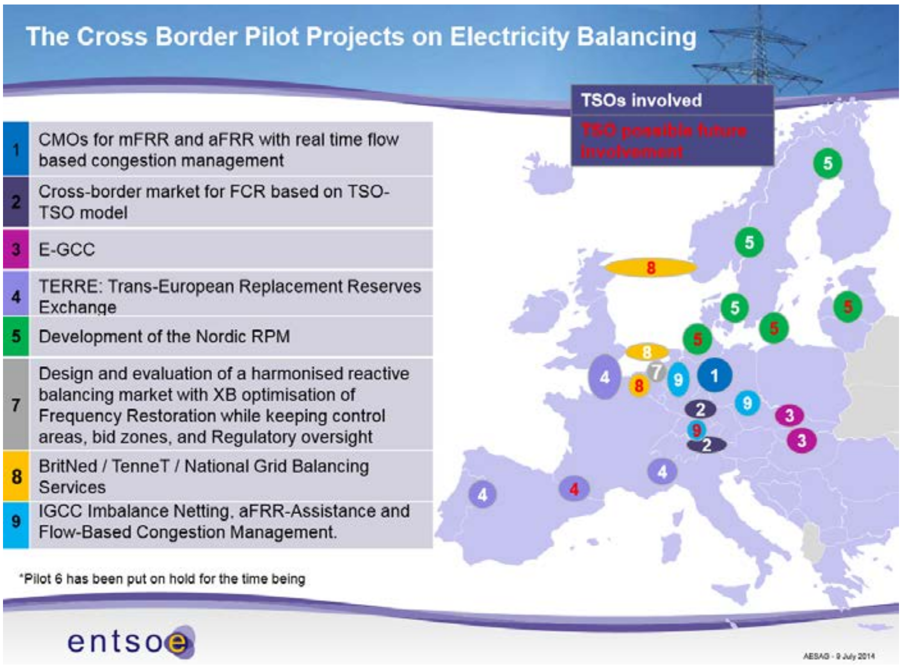
Table 4. *Harmonisation of terms in the different balancing market segments across Europe.*

| Sync. Area | Process | Product | Activation | Local/Central | Dynamic/ Static | Full Activation Time |
|---|---|---|---|---|---|---|
| **BALTIC** | Frequency Containment | Primary Reserve | Auto | Local | D | 30 s |
| **Cyprus** | Frequency Containment | Primary Reserve | Auto | Local | D | 20 s |
| **Iceland** | Frequency Containment | Primary Control Reserve | Auto | Local | D | variable |
| **Ireland** | Frequency Containment | Primary operating reserve | Auto | Local | D/S | 5 s |
| **Ireland** | Frequency Containment | Secondary operating reserve | Auto | Local | D/S | 15 s |
| **NORDIC** | Frequency Containment | FNR (FCR N) | Auto | Local | D | 120 s -180 s |
| **NORDIC** | Frequency Containment | FDR (FCR D) | Auto | Local | D | 30 s |
| **RG CE** | Frequency Containment | Primary Control Reserve | Auto | Local | D | 30 s |
| **UK** | Frequency Containment | Frequency response dynamic | Auto | Local | D | Primary 10 s / Secondary 30 s |
| **UK** | Frequency Containment | Frequency response static | Auto | Local | S | variable |
| **BALTIC** | Frequency Restoration | Secondary emergency reserve | Manual | Central | S | 15 Min |
| **Cyprus** | Frequency Restoration | Secondary Control Reserve | Auto/Manual | Local/Central | D/S | 5 Min |
| **Iceland** | Frequency Restoration | Regulating power | Manual | Central | S | 10 Min |
| **Ireland** | Frequency Restoration | Tertiary operational reserve 1 | Auto/Manual | Local/Central | D/S | 90 s |
| **Ireland** | Frequency Restoration | Tertiary operational reserve 2 | Manual | Central | S | 5 Min |
| **Ireland** | Frequency Restoration | Replacement reserves | Manual | Central | S | 20 Min |
| **NORDIC** | Frequency Restoration | Regulating power | Manual | Central | S | 15 Min |
| **RG CE** | Frequency Restoration | Secondary Control Reserve | Auto | Central | D | ≤ 15 Min |
| **RG CE** | Frequency Restoration | Direct activated Tertiary Control Reserve | Manual | Central | S | ≤ 15 Min |
| **UK** | Frequency Restoration | Various Products | Manual | D/S | N/A | variable |
| **BALTIC** | Replacement | Tertiary (cold) reserve | Manual | Central | S | 12 h |
| **Cyprus** | Replacement | Replacement reserves | Manual | Central | S | 20 min |
| **Iceland** | Replacement | Regulating power | Manual | Central | S | 10 Min |
| **Ireland** | Replacement | Replacement reserves | Manual | Central | S | 20 Min |
| **NORDIC** | Replacement | Regulating power | Manual | Central | S | 15 Min |
| **RG CE** | Replacement | Schedule activated Tertiary Control Reserve | Manual | Central | S | individual |
| **RG CE** | Replacement | Direct activated Tertiary Control Reserve | Manual | Central | S | individual |
| **UK** | Replacement | Various Products but the main one is Short Term Operating Reserve (STOR) | Manual | D/S | N/A | from 20 min to 4 h |

(Source: ENTSO-E 2011)

There are relatively some examples of cross-border balancing markets in Europe today that will act as Pilot Projects after the implementation of the NC EB by the Member States, as it is represented in the following figure:

Figure 18. *Cross Border Pilot Projects on Electricity Balancing.*



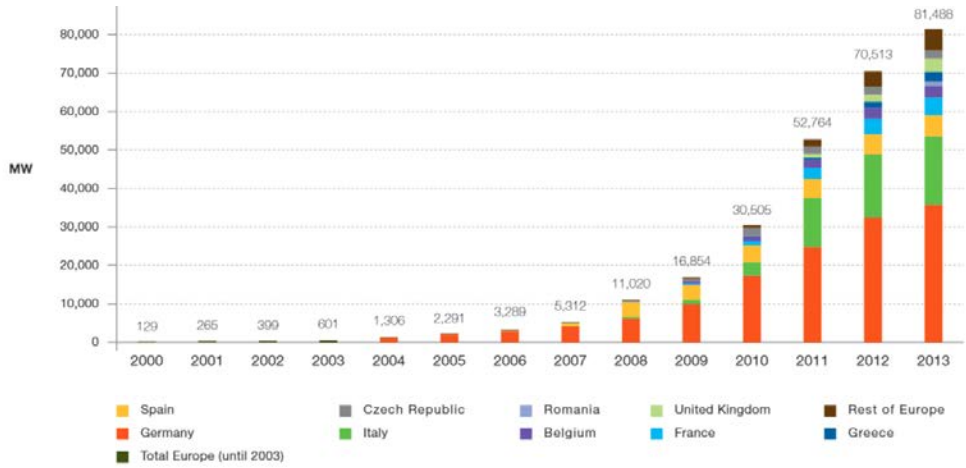

(Source: ENTSO-E)

# 4 Achievements and Benefits of RES-E Integration in Europe

## 4.1 RES-E Grid and Market Integration in General

In Figure 19 the development of the European PV system is demonstrated for the last 13 years. At the beginning of this millennium there were only 129 MW installed capacity of PV. Within 13 years these capacities have increased tremendously. In year 2013 the cumulative installed capacity of PV amounts to 81 GW in the European Union. The majority of the installed capacity as well as the largest growth can be observed in Germany.

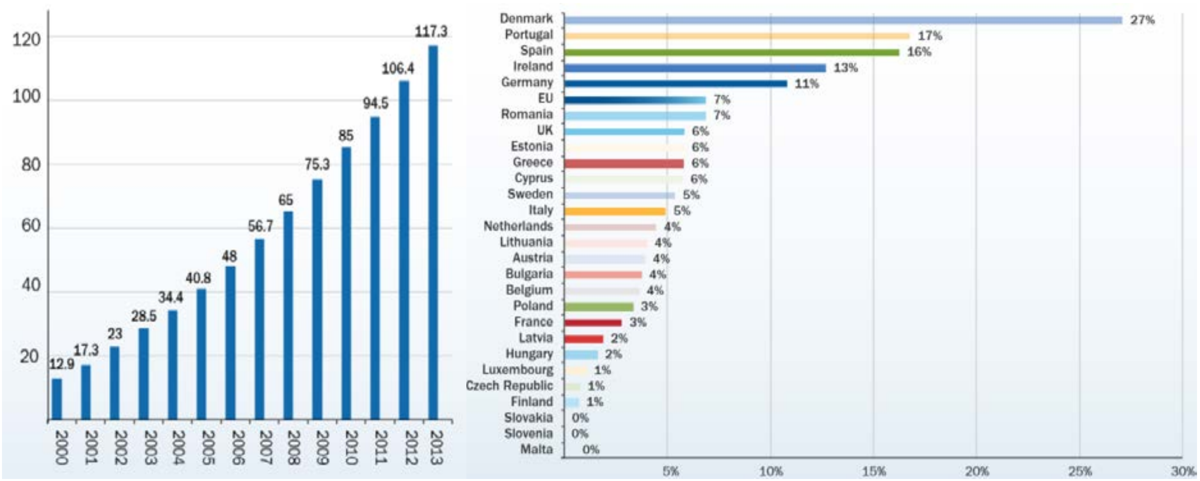
Figure 19. *Evolution of European PV cumulative installed capacity 2000-2013.*




(Source: EPIA)

Additionally, not only the installed capacities of PV increased in the last years but also the wind capacities in the EU, from 12.9 GW in year 2000 to 117.3 GW in 2013.

Figure 20. *Cumulative wind power installations in the EU (GW) and Wind power share of total electricity consumption in EU (7 %) and in Member States*




(Source: EWEA 2013 and 2012)

In order to be able to evaluate the "success of RES-E support instruments, the following two major performance indicators are helpful (and also commonly used in the European RES-E policy debate):

**Effectiveness indicator of renewable energy support schemes:**

Effectiveness addresses the question whether or not the support programs led to a significant increase in deployment of capacities from RES-E in relation to the additional potential. The effectiveness indicator measures the relation of the new generated electricity within a certain time period compared to the corresponding potential of the technologies.

**Economic efficiency indicator of renewable energy support schemes:**

Economic efficiency addresses the question what was the absolute support level compared to the actual generation costs of RES-E generators and what was the trend in support over time? How is the net support level of RES-E generation consistent with the corresponding effectiveness indicator?

The effectiveness indicator can be measured as follows:

$$E_n^i = \frac{G_n^i - G_{n-1}^i}{ADD - POT_{n-1}^i}$$

$E_n^i$ Effectiveness indicator for RES-E technology $i$ for the year $n$
$G_n^i$ Electricity generation potential by RES-E technology $i$ in year $n$
$ADD - POT_n^i$ Additional generation potential of RES-E technology $i$ in year $n$ until 2020

The advantage of the above definition of effectiveness is to receive an unbiased indicator with regard to the available potentials of a specific country for individual technologies.

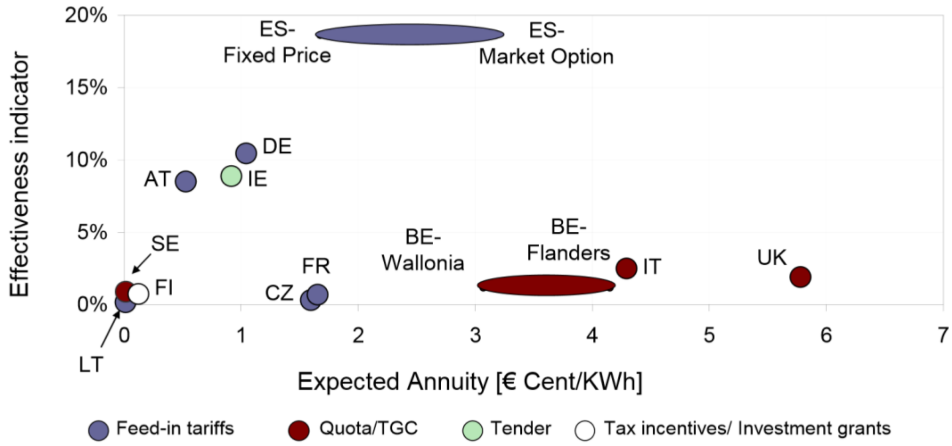
$$A = \frac{i}{1-(1+i)^{-1}} \cdot \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$A$ ... levelised profit, $i$ ... interest rate, $t$ ... year, $n$ ... technical lifetime

The correlation between the levelised profits resulting from investments and the effectiveness of the support instruments for onshore wind is shown in Figure 21. Generally the levelised profit and the effectiveness show a broad spectrum in quantitative terms for the considered countries.

In Figure 21 is shown that Spain achieved the highest growth rates of effectiveness offering an appropriate profit. Compared with other feed-in countries the expected profit for Spain is the highest, not because of a high support level, but rather because of the relatively low electricity generation costs. It is particularly striking that Belgium, Italy and the UK which have recently transformed their markets into quota systems as the main support instrument have high levelised profits, but low growth rates.

Figure 21. *Historically observed efficiency of support for onshore wind: effectiveness indication in relation to the annuity of expected profit for the year 2004*

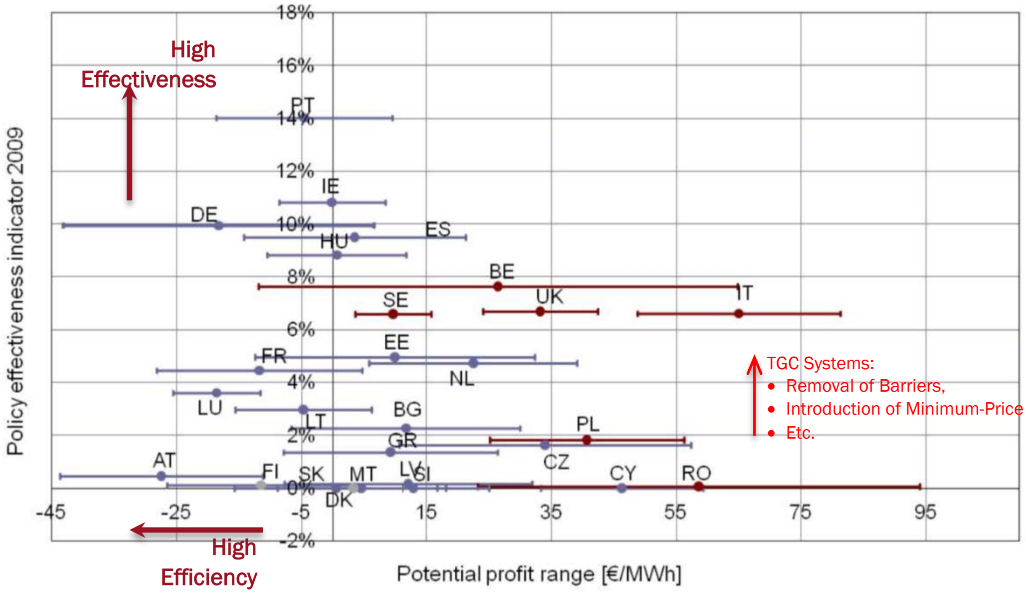



(Source: OPTRES 2007)

The combined illustration of the expected profit from an investment in wind onshore power plants and the Policy Effectiveness Indicator (see Figure 22) shows that in general the countries using feed-in systems such as Portugal, Ireland, Spain, Hungary and Germany have achieved a rather high policy effectiveness at reasonable profits in 2009. The effectiveness of countries supporting wind onshore power plants with a quota obligation including Sweden, Belgium, the United Kingdom and Italy, has improved clearly comparing the year 2009 with previous years and ranges between roughly 6 and 8 %. However, compared to most countries applying feed-in tariffs, it seems that the quota system still enables considerably higher profits for wind onshore electricity, involving higher risk premiums and windfall profits for investors. In the Eastern European countries Poland, Romania, Cyprus, the Czech Republic and Latvia we observe a very low effectiveness despite high potential profit opportunities. The Austrian feed-in tariff apparently is too low to stimulate further investments in wind onshore power plants.

The ongoing uptake of low marginal cost RES-E generators like wind and solar PV generation has a significant effect of average wholesale power price levels through the so-called merit order effect (MOE), as described in section 2.1. Various analyses have looked into what the MOE has brought about both in terms of a "price" and a "volume" effect", see [28]. The price effect refers to the MOE per megawatt hour (MWh). The volume effect refers to the total savings brought about by RES-E power penetration during a particular year through the replacement of conventional power plants and related fuel cost savings. On wind energy alone, the papers specify, dependent on their main assumptions, an MOE range of 3-23 €/MWh. The volume effect, however, is more difficult to assess as the analyses depend heavily on certain assumptions such as the assumed RES-E penetration levels, the power generation mix and the marginal costs of the replaced conventional technology. Consequently, only a few studies indicate so far the total amount of savings made due to RES-E power penetration during a particular year. On the volume effect of increased wind power alone a range of € 0.1–5 billion power system cost savings per year has been identified [28] for Denmark and Germany separately.

Figure 22. *Potential profit ranges (Average to maximum remuneration and minimum to average generation costs) available for investors in 2009 and Policy Effectiveness Indicator for wind onshore in 2009.*




(Source: RE-Shaping 2011)

Although each analysis in each of the specified categories uses different sets of assumptions they essentially draw similar conclusions. The general conclusion in all of them is that there is a downward movement of wholesale/spot price levels, due to increased wind and solar PV power penetration.

## 4.2 Achievements in Terms of Gradual Market-Compatible RES-E Market Integration in Particular (Support Instruments, Fulfilment of Grid Codes, etc.)

All power generators connected to the public grid are bound to fulfil a set of technical rules laid out in grid connection requirements in order to maintain power system stability. With ever increasing penetration levels RES-E technology manufacturers provide for sophisticated products able to deliver a variety of frequency and voltage support capabilities. The European RES-E industry has in this context proven to be highly innovative and constantly adapting to changing requirements and improving cost, yield and reliability. However, the way in which grid codes for RES-E generators in Europe have developed has also resulted in gross inefficiencies and additional costs for consumers, manufacturers and RES-E developers. Currently the European wind industry alone has to contend with a high degree of diversity in technical requirements in more than 30 differing national grid codes from a variety of countries. These requirements are often not sufficiently clear and are not always technically justified nor economically sound from the point of view of the power system. This results in unnecessary extra costs and efforts from the RES-E industry and other system users, including consumers. The lack of harmonised grid code requirements leads to the necessity of maintaining locally adapted products and maintaining staff to interpret grid codes. Overall, such a diverse range of requirements makes RES-E power unnecessarily expensive.

With the growing penetration of inverter-based RES-E power generation, there is an increasing need to develop a harmonised set of grid code requirements to overcome these deficiencies. Between now and 2020 grid codes in the EU will affect the connection of thousands of new wind power projects, not to mention other RES-E. The grid connection of projects is strongly site specific (rated power, local network conditions etc.). The large number of projects requires standardisation as far as possible to reduce the time and costs for preparing connection agreements. In the absence of a thorough standardisation, processes will go slowly, connections will not be cost-effective and system security will not be as desired. Thus, harmonised technical requirements for connecting RES-E power plants will bring benefits for all parties and should be employed wherever possible.

In view of these challenges, the drafting of the ENTSO-E Network Code for the connection of generators (NC RfG) launched within the Third Liberalisation Package [29] is to be seen as an opportunity to deliver such a guiding document with a pan-European approach that ultimately will lead to a harmonised set of grid connection requirements in all Member states. This would serve, in a cost-effective way, the needs of the system and make the best out of capabilities for system support from RES-E power plants. Despite various open issues to clarify, this draft NC RfG is bound to be adopted in Comitology procedure early 2015 and become binding EU regulation with a three year implementation deadline at national level.

**The role of variable RES-E in grid support services markets - Project REserviceS**

Electricity grids must be operated safely and efficiently, and technical services provided to transmission and distribution system operators are an essential part of ensuring this. Such services include controlling the frequency and voltage as well as providing reserves. Generally, these so-called ancillary services are provided by conventional power plants. As the share of renewables in the overall energy system continues to rise – regionally expected to meet up to 50 % of electricity demand by 2020 – a drastic change in strategy for the procurement of such ancillary services is required.

In order to maximise social welfare, grid codes should strike an appropriate balance between the minimum level of compulsory technical requirements (which are not remunerated) and generator performances for delivering system support which would better be solicited through an ancillary or grid support services market. The minimum level of technical requirements should be based on transparent cost-benefit analyses.

REserviceS (Economic grid support from variable renewables) was the first study to investigate wind and solar PV based grid support services (GSS) at EU level[8]. It found proof that these power generation technologies can provide GSS for frequency, voltage and certain functions in system restoration. The REserviceS project confirmed that variable renewable energy sources (VAR-RES) meet most of the capability requirements for delivering such services, as prescribed in grid codes (for details see [30]). Where enhanced capabilities would be required, technical solutions exist, but are not used today because of economic reasons due to additional costs, of which REserviceS has made an assessment. While in some countries financial incentives for VAR-RES with enhanced capabilities exist, this remains the exception rather than the rule in Europe. Appropriate operational and market frameworks are therefore needed for enhanced participation of VAR-RES in GSS, which could be enshrined in EU-wide Network Codes from a regulatory perspective.

The need for VAR-RES' participation in GSS provision, especially at high penetration levels, depends on the power system characteristics (for example its size and resilience) and how VAR-RES are integrated into it (for example its dispersion and technical characteristics). As GSS come with a cost, requirements for generator capabilities and service provision should demand only what is needed by the system to avoid excessive system costs. Importantly, REserviceS analyses found that frequency management can be adequately and economically achieved with only a fraction of all installed VAR-RES generators participating in frequency support.

Therefore, preparing for future electricity systems with large shares of VAR-RES requires detailed studies and simulations to make well-founded estimates of the needs and technical requirements. Moreover, detailed and clear specifications, as well as market designs and products taking into account the characteristics of VAR-RES, are crucial for their participation in GSS provision.

[8] For a full overview of the REserviceS project findings: www.reservices-project.eu.

## 5 Prevailing Structural Market Distortions and Shortcomings in the European Electricity Market

### 5.1 Fragmentation of Electricity Markets, Lacks in Terms of Harmonization and Electricity Market integration

Well-functioning electricity markets are instrumental in improving the integration, competitiveness and affordability of RES-E. As the EU develops its internal energy market and with rising penetration levels of renewables, it is increasingly important that all power producers respond to market signals. However, the EU market integration efforts have to be seen also against the recent backdrop of nationally focused capacity remuneration mechanisms in various Member States, which will have in many cases further distortive effects on the functioning of electricity markets.

Functioning intraday markets are crucial for the efficient and cost effective integration of large amounts of RES-E as well as for system operation. The current ambition of a fully functioning EU electricity market needs to better address the fundamental features of intraday and balancing markets, which are essential for variable RES-E integration. These features include measures to improve market liquidity, harmonising rules across borders and the interactions between these market forms. To this end, beyond providing day-ahead and intraday market integration across borders and improved transmission capacity allocation, a more ambitious vision of cross-border balancing markets should be developed.

The following Table 5 (see next page) provides an overview of the different market arrangements in place in seven countries of the European Union with regard to balancing services (see also section 3.4 in this report). The table illustrates how different approaches have been taken to the design elements of balancing services across Europe and highlights the great diversity of arrangements and lack of harmonization of market designs that currently exists for balancing reserve and balancing energy provision and activation across Europe. Subsequently the main differences are briefly highlighted:

- **Different kinds of balancing services:** Currently there is a great variance of ancillary/balancing service categories in place in Europe with no unified nomenclature and technical requirements, making participations to and/or from outside the country difficult. In course of the ongoing harmonization approach of ENTSO-E in UCTE-Continental Europe primary, secondary and tertiary control are being replaced by Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (FRR) and manual FRR respectively with unified technical requirements.
- **Different balancing market architectures:** In the target countries (and in Europe generally) three different balancing approaches are in place: (i) central dispatch, (ii) self-dispatch – portfolio based and (iii) self-dispatch – unit based. [see Ad (1) below Table 5 for more details].
- **Different parameter settings:** Also when looking on the different parameter settings (e.g. timeframe of the products, gate closure times, minimum bid sizes, etc.) a great

variety can be seen across the target countries. Also this great variety on parameter settings makes participations to and/or from outside the country very difficult.

Table 5. *Overview of the different market arrangements in place in seven European countries with regard to balancing services*

| | | | AT | BG | DE | ES | IR | IT | NL |
|---|---|---|---|---|---|---|---|---|---|
| **Balancing Process in Place**(1) | | | Self - Portf. | Central | Self - Portf. | Self - Unit | Central | Central | Self - Portf. |
| **FRR (Autom.)** | Capacity | Procurement Scheme | Organ. Market | Bilat. Market | Organ. Market | Organ. Market | Mand. Prov. | N/A | Bilat. Market |
| | | Minimum Bid Size | ≤ 5 MW | N/A | ≤ 5 MW | > 10 MW | ≤ 1 MW | N/A | ≤ 5 MW |
| | | Timeframe for Product | Week(s) | N/A | Week(s) | Hour(s) | Year or more | N/A | Year or more |
| | | Timing for Offers for Capacity | Week(s) | N/A | Week(s) | Day(s) | Year or more | N/A | Year or more |
| | | Provider(2) | Generator only | Generator only | Gen. & Load | Generator only | Gen. & Load | Generator only | Generator only |
| | | Settlement Rule | Pay as Bid | Regulated Price | Pay as Bid | Marginal Pricing | Regulated Price | N/A | Pay as Bid |
| | Energy | Procurement Scheme | Market | Mand. Offers | Market | Hybrid | Market | Mand. Offers | Market |
| | | Activation Rule | Merit Order | Pro-Rata(3) | Merit Order | Pro-Rata(3) | Pro-Rata(3) | Merit Order | Merit Order |
| | | Minimum Bid Size | ≤ 5 MW | N/A | ≤ 5 MW | No min. Bid Size | N/A | ≤ 1 MW | ≤ 5 MW |
| | | Timeframe for Product | Hour (or Blocks) | N/A | Hour (or Blocks) | Hour (or Blocks) | 30 Min. | Hour (or Blocks) | 15 Min. |
| | | Gate Closure for Energy | D - 1 | N/A | > D - 1 | N/A | > H - 1 | > H - 1 | ≤ H - 1 |
| | | Settlement Rule | Pay as Bid | Hybrid | Pay as Bid | Marginal Pricing | Hybrid | Pay as Bid | Marginal Pricing |
| | | Cost Recovery Scheme | Grid Users & BRP | Grid Users & BRP | 100% BRP | 100% BRP | 100% Grid Users | 100% Grid Users | 100% BRP |
| **FRR (Manual)** | Capacity | Procurement Scheme | Organ. Market | N/A | Organ. Market | N/A | Mand. Prov. | N/A | Bilat. Market |
| | | Minimum Bid Size | ≤ 10 MW | N/A | ≤ 5 MW | N/A | ≤ 1 MW | N/A | > 10 MW |
| | | Timeframe for Product | Week(s) | N/A | Hour(s) | N/A | Year or more | N/A | Year or more |
| | | Timing for Offers for Capacity | Week(s) | N/A | Day(s) | N/A | Year or more | N/A | Year or more |
| | | Provider(2) | Generator only | Generator only | Gen. & Load | Gen. & Load | Generator only | N/A | Gen. & Load |
| | | Settlement Rule | Pay as Bid | Regulated Price | Pay as Bid | N/A | Regulated Price | N/A | Pay as Bid |
| | Energy | Procurement Scheme | Market | Market | Market | Market | Market | N/A | Market |
| | | Activation Rule | Merit Order | Merit Order | Merit Order | Merit Order | Merit Order | N/A | Merit Order |
| | | Minimum Bid Size | ≤ 10 MW | > 10 MW | ≤ 5 MW | > 10 MW | N/A | N/A | ≤ 5 MW |
| | | Timeframe for Product | Hour (or Blocks) | Hour (or Blocks) | Hour (or Blocks) | 15 Min. | 30 Min. | N/A | 15 Min. |
| | | Gate Closure for Energy | D - 1 | D - 1 | D - 1 | ≤ H - 1 | > H - 1 | N/A | ≤ H - 1 |
| | | Settlement Rule | Pay as Bid | Pay as Bid | Pay as Bid | Marginal Pricing | Hybrid | N/A | Marginal Pricing |
| | | Cost Recovery Scheme | 100% BRP | Grid Users & BRP | 100% BRP | 100% BRP | 100% Grid Users | N/A | 100% BRP |
| **FCR** | Capacity | Procurement Scheme | Organ. Market | Mand. Prov. | Organ. Market | N/A | Mand. Prov. | N/A | Mand. Prov. |
| | | Minimum Bid Size | ≤ 5 MW | N/A | ≤ 1 MW | No min. Bid Size | ≤ 1 MW | N/A | No min. Bid Size |
| | | Timeframe for Product | Week(s) | N/A | Week(s) | Hour(s) | Year or more | N/A | N/A |
| | | Timing for Offers for Capacity | Week(s) | N/A | Week(s) | Year or more | Year or more | N/A | N/A |
| | | Provider(2) | Generator only | Generator only | Gen. & Load | Generator only | Gen. & Load | Generator only | Generator only |
| | | Settlement Rule | Pay as Bid | Regulated Price | Pay as Bid | N/A | Regulated Price | N/A | N/A |

(Source: GridTech 2013)

**Ad (1) - Type of Market Design:** The following different balancing processes are currently in place in the seven above mentioned countries:

- **Central Dispatch:** In a central dispatch arrangement the TSO determines the dispatch values and issues instructions directly to generators (or demand). The TSO determines the dispatch instructions based on prices and technical parameters provided by the participating parties in order to minimize the system production cost while meeting security requirements.

  In a centrally dispatched market the TSO dispatches all plants, based on market commercial offer data, to provide generation and demand balance, external transfers, reserve provision and transmission constraint management. This involves dispatch instructions being issued normally day-ahead of real time to connect off line plant (in particular plant with long start up times) to real time instructions for connected plant. In a central dispatch market there is no inherent balancing link between generators and demand (suppliers). Generators bid into the market and become part of the market schedule if economic; suppliers buy at the resulting market price for their demand. The grid code stipulates the requirements for generators for following dispatch instructions.

Differences between the market schedule and actual generation running as directed by the TSO to balance with reserve and constraint provision become a constraint cost to the end customers [31].

- **Self-Dispatch:** A self-dispatching balancing model is a dispatch arrangement where generators determine a desired dispatch position for themselves based on their own economic criteria to provide commercial independence within a market [31]. In the self-dispatch model, Balance Service Providers (BSPs) – single units or a portfolio of units – follow an aggregated schedule of actions to start/stop/increase output or decrease output in real time, including aggregated incremental instructions by the TSO [32]. The self-dispatching balancing model can be sub-divided in two further market design configurations: (i) portfolio-based balancing, (ii) unit-based balancing. The difference between the two self-dispatch models is that the balancing is scheduled for either a portfolio of generators (i) or for a single unit (ii) [32].

### General Lacks and Barriers

The following general lacks and barriers for the participation of RES-E generators in balancing markets can be observed:

- The **minimum volume** for the participation in the tertiary power reserve (FRR man) is currently an injection/withdrawal of at least ±10 MW in many countries (e.g. Austria, Germany, Italy, etc.). It would be easier for the participation of RES-E in power reserve, if the limits are lower. As an example, in the beginning of 2014 an automated activation of the tertiary control (MOL-Server) has been implemented in Austria and therefore the minimum unit size has been reduced to 5 MW.
- **Pooling** (respectively clustering) is allowed in some countries, however, special rules apply. In Italy, for instance, pooling is allowed just for generators that are connected to a single point of injection – generators that are in different locations or demand/load cannot be pooled. Furthermore, pooling of RES-E is only possible for generators of one power generation plan, with uniform energy sources and the same type. Further on, the limited transmission capacity within Italy reduces the possibility of a bigger possible area for pooling (more generators) and that in a bigger area fluctuating RES-E can more easily smooth each other. As another example, in Austria pooling is allowed for technical units with a size of at least 0.5 MW (minimal prequalified technical unit). However, the prequalification has to be done separately for each technical unit [33]. This can be very time-consuming and costly if done for smaller technical units. In Germany the prequalification can be done for a pool and has not to be completed for the single unit. The prequalification is valid for different periods (e.g. three years in Austria) before the prequalification has to be repeated.
- Generally, **DSM and (variable) RES-E** are not excluded from the secondary and tertiary control, but they are neither particularly included; for instance no special prequalification criteria is defined in Austria. Then again, in the Italian grid code fluctuating RES-E are

explicitly excluded in the prequalification criteria for tertiary power reserve. In the Italian secondary power reserve RES-E are neither excluded nor included either.

- For the RES-E units a **gate-closure** for the procurement of balancing reserves near to real-time is positive since better forecast and more information about the generation are available. Participating only in the day-ahead tertiary balancing market is an option but a less interesting one since no remuneration for the balancing reserve is paid in general.
- The same is also true for **timeframes for the product** – smaller timeframes are positive for the participation of (variable) RES-E units.

**Lacks in terms of harmonization, integration and efficiency of intraday markets**

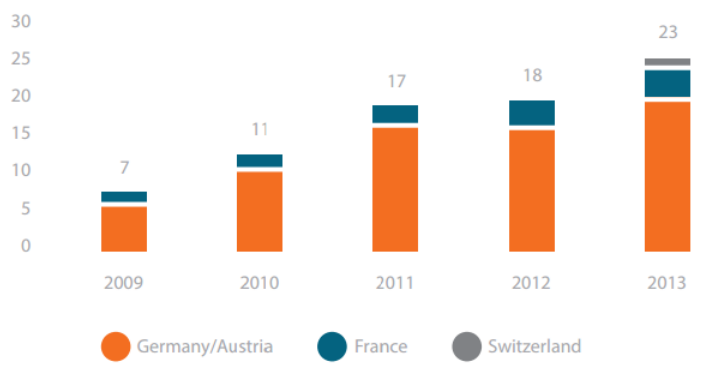
As mentioned in [34], *"the existence of well-functioning intra-day markets is important for two reasons:*

- *Day-ahead markets – organised on an hourly basis – are very simple and do not allow all the technical characteristics of power plants to be taken into account. The day-ahead market clearing might therefore result in infeasible schedules. Intra-day markets partly allow generation to deal with these infeasibilities.*
- *Intraday markets can partly cushion the uncertainty inherent to real time, including power plant outages and changes in wind forecasts or demand."*

With the present and future development of intermittent energy sources, the importance of intraday markets is growing, notably because RES-E generators need to progressively adjust their position according to forecast updates when getting closer to real-time.

Volumes of intraday markets are therefore increasing, as illustrated by Figure 23.

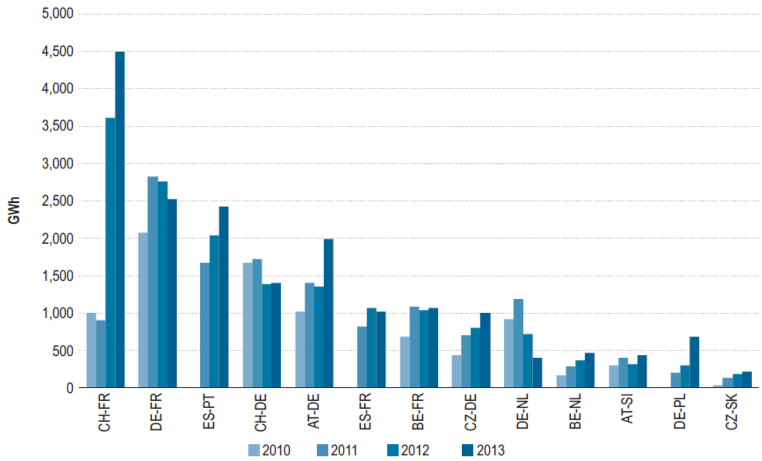
Figure 23. *Evolution of intraday volumes traded on EPEX spot – 2009 to 2013 (TWh)*




(Source: EPEX Spot trading brochure, see [35])

Simultaneously, the utilisation of cross-border capacity at the intraday timeframe follows an upward trend (Figure 24).

Figure 24. *Level of intraday cross-border trade: absolute sum of net intraday nominations for a selection of EU borders – 2010-2013 (%)*

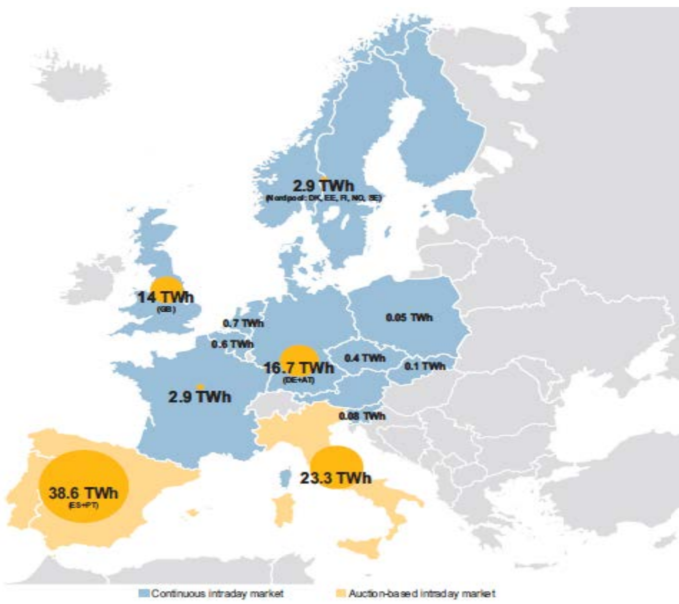



(Source: ACER market monitoring report 2014)

In terms of intraday market design, two different solutions co-exist in Europe (cf. Figure 25):

- **Continuous intraday markets:** under this design, electricity is traded continuously, which provides a high flexibility to market players;
- **Auction-based intraday market:** under this design, less flexibility is provided to market players but price formation is more efficient.

Figure 25. *Intraday liquidity and design in national markets – 2013 (TWh)*



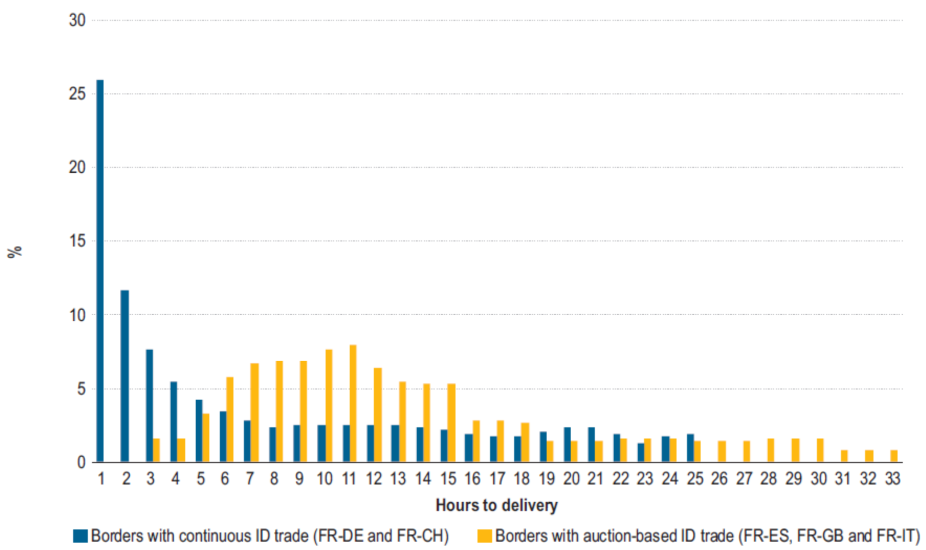

(Source: ACER market monitoring report 2014)

To improve the efficiency and integration of cross-border intraday markets, the "Target Model (TM)" comprehensively addresses also this market segment. In particular, a continuous implicit allocation with capacity pricing reflecting congestion is established: the "Single European Continuous Implicit Mechanism for Cross-border Intraday Trade". In some way, it combines the advantages of the two mechanisms currently coexisting (continuous trading and auctions). It aims at facilitating balancing before the closure of the market and, possibly, short-term arbitrage. This simplification is becoming increasingly important in the context of growing penetration of intermittent generation.

However, so far this model has never been implemented: either continuous implicit allocation with no capacity pricing has been implemented, based on the so-called ELBAS system implemented for long in Scandinavia (France-Switzerland and France-Germany borders, see Figure 26), or explicit auctions have been implemented, providing a price to the intraday capacity, the allocation being neither continuous nor implicit (France-Spain, France-Great Britain and France-Italy borders).

The Intraday Cross-Regional Roadmap [36] envisages a phased approach to implementation, starting with implicit continuous trading which will then evolve to include intraday capacity recalculation, capacity pricing and the ability to trade sophisticated products. As illustrated by Figure 26, continuous allocation offers *"an extra flexibility to market players since almost half of the intraday capacity (45 %) on the analysed borders featuring continuous intraday trading is requested and allocated between one and three hours prior to delivery in 2013. This close-to-real-time capacity demand indicates that intraday markets serve balancing needs for market players associated with RES."*

Figure 26. *Allocation of intraday cross-border capacity according to the time remaining to delivery for a selection of borders – 2013 (%)*




(Source: ACER market monitoring report 2014)

This progressive implementation of the Intraday Target Model has faced obstacles that were summarized by ACER in its Regional Initiatives Status Review Report 2013: Power Exchanges (APX, Belpex, EPEX Spot, OMIE, OTE and NordPool Spot) were unable to reach a consensus on the selection of the cross-border intraday solution and called upon ACER to unlock the situation. But still, PXs could not agree and the EC was called upon by the Florence Forum in November 2013: *"the Forum now asks the EC to intervene and develop an alternative solution…the EC should inter alia explore the possibility of TSOs to take over the early implementation process and take a decision on the way forward by the end of the year"*.

In its Regional Initiatives Status Review Report 2013, ACER concluded: *"The European Commission's involvement underlines the governance issue PXs had reported several times: although being competitors, using different systems and having different interests, PXs are expected to develop a common solution which is unanimously approved. In parallel, TSOs, which are responsible for the allocation of interconnection capacity, may also have diverging interests regarding the implementation of the Target Model, as they have already implemented different systems. This difficulty for reaching a common position at PXs or TSOs level is also influencing the discussion at regulatory level. However, the Agency and NRAs have been in a position to support the process and make decisions when needed. But in such conditions, the voluntary process which requires consensus has repeatedly failed to deliver progress although all parties are still intensively working for reaching a solution."*

## 5.2 Current Market Distortions

### 5.2.1 Market Distortions Caused by RES-E Policy Support Instrument

One of the most prominently discussed market interventions of RES-E support is priority dispatch, which was introduced as a regulatory provision at EU level with the first RES-E Directive in 2001 and was further refined in Article 16(2) c of the 2009 RES-E Directive. Priority dispatch is the obligation on transmission system operators to schedule and dispatch energy from renewable generators ahead of other generators as far as secure operation of the electricity system permits. Member States can either explicitly mention priority dispatch in national legislation or, alternatively, priority dispatch is considered to be implicitly given in support systems which include a purchase obligation, such as feed-in tariffs.

Priority dispatch is not to be understood as a right of a RES-E generator to produce at any time given the uncertainty of its primary energy source. Instead, the rationale for the introduction of this regulatory tool is that given the current market structure and rules, which were not designed with variable energy technologies in mind, the response to price signals from these generators is different, based on availability of its fluctuating source, which they cannot control. If in addition, there is a lack of transparency in operation and curtailment rules, RES-E generators have an additional market risk which they need to be hedged for. In this sense, priority dispatch significantly reduces risks for RES-E generators as new market entrants by:

- ensuring that its energy is sold to the market;
- guaranteeing its in-feed to the grid when it is available;
- hedging wind energy generators from the so-called volume risk[9], that could stem from non-system security-related curtailments.

Wind and solar PV energy in particular, having variable output with very low marginal costs, risk being the first to be curtailed in power systems with low flexibility[10]. As curtailing variable generators would be the easiest solution to solve grid issues in such systems, mostly characterised by a lack of infrastructure, sophisticated operational practices or both, the RES-E Directive puts a requirement on the system operators to reduce curtailment of RES-E generation.

[9] Next to volume risk, investors perceive balancing and price risks as determinant for RES-E generation projects financial viability.

[10] The level of flexibility in power systems is subject of continuous research and debate in the context of integration of large amounts of wind and other RES-E. The IEA defines both, technical and market sources of flexibility that facilitates RES-E integration. Technical sources include flexible generation capacity, interconnection capacity, demand side response and storage. Market sources of flexibility include aggregation of distributed generation, trading electricity close to delivery time, large balancing areas and smart network operation. IEA (2011) Harnessing Variable Renewables.

In mature markets with high penetration levels of RES-E, future regulatory frameworks and power market design can consider increased exposure of wind generators to market risks, including progressively phasing out priority dispatch and/or developing a more market-price responsive mechanism in mature markets with high penetration levels of RES-E. However, this requires a level playing field: a fully transparent, fair and well-functioning power market. According to EWEA (European Wind Energy Association), variable RES-E should benefit from priority dispatch until such a level playing field is achieved which can be tested against the criteria below (see [37]):

- Existence of a fully functioning intraday and balancing market,
- A satisfactory level of market transparency and proper market monitoring
- Priority dispatch for conventional generation and all other forms of non-RES-E power are removed (see also next section),
- The requisite transmission and distribution infrastructure, which can be assessed against the completion of ENTSO-E TYNDP projects in the relevant Member State.
- System operation: Best use of sophisticated forecasts and operational routines.

Overall, priority dispatch has been an important tool to facilitate the integration of RES-E into the power system. The lack of transparency in curtailment rules of new variable RES-E generation in particular, makes priority dispatch in many Member States a policy-driven solution that ensures that its intrinsic characteristics are not a barrier to its exploitation. In this sense, well described and clear rules for curtailing RES-E generation would reduce risks for these generators as new market entrants, specifically by providing compensation rules for non-system security related curtailments.

Ultimately, the objective of the RES-E industry is to be competitive in a liberalised electricity market, and to deliver the benefits of this emission-free energy to consumers. As outlined in the previous sections, regulatory incentives for more mature RES-E power generation technologies such as onshore wind would not be needed with a fully functioning electricity market and full internalisation of external costs.

In the mid-term, incentives in terms of specific financial support schemes for the most mature RES-E generators could be conceived as a top-up to market prices instead of being the sole source of revenue making renewable power producers respond to market signals.

What would be needed in this regard is a methodology for a feed-in premium to be used in all Member States. The level of the premium would vary from one Member State to another to reflect the specific costs for developing a RES-E power plant in the different countries (cost of capital, grid connection costs, administrative costs, availability of resource, etc.). This premium would be capped to avoid any overcompensation and would be zero in the rare occurrences of negative electricity prices, where negative prices are not caused by inflexible generation, inadequate infrastructure, or inadequate system operation.

One of the most crucial factors perceived by investors in the RES-E sector, however, is a stable regulatory framework. The currently deliberated details of the 2030 Climate and Energy framework with binding targets backed by supportive governance guidelines would help accelerate this process, by providing investor confidence and driving economies of scale.

### 5.2.2 Market Distortions Caused by Support of Conventional Technologies

Next to RES-E support schemes, conventional power generation receives in the past and present various forms of financial support as well. An overall lack of data and according studies makes it difficult to make a thorough quantitative assessment of the level of such financial support across the EU. Furthermore, there are doubts that for some provisions, such as socialising all liability costs for nuclear power plants, a quantitative assessment would be ever possible. Another challenge with regards to nuclear energy technology in particular is the lack of robust data on decommissioning and waste storage, both of which are cost elements usually socialised and therefore to be regarded as an indirect financial support measure to this power generation source.

The European Commission published in October 2014 an interim report providing the first full dataset on energy costs and subsidies for EU28 across power generation technologies (see [38]). The results show that in 2012, the total value of public interventions in energy (excluding transport) in the EU28 was between € 120-140 billion. For conventional power generation, coal received the largest amount in current subsidies in 2012 with € 10.1 bn, followed by nuclear (€ 7 bn) and natural gas (about € 5.2 bn). The figures specifying support across technologies do however not reflect the free allocation of emission certificates, which could be regarded as an additional support measure to conventional power technologies. The windfall profits received by industry through free allocation in 2012 amounted to € 14 billion, but this is for the entire industry, not just energy utilities. Nevertheless, all of these free credits amount to additional support for fossil fuel energy, as they allow firms to avoid paying to emit carbon. Up to 2021, MS can allocate up to 70 % of their allowances and after 2021, this figure is reduced to 40 % of their allowances.

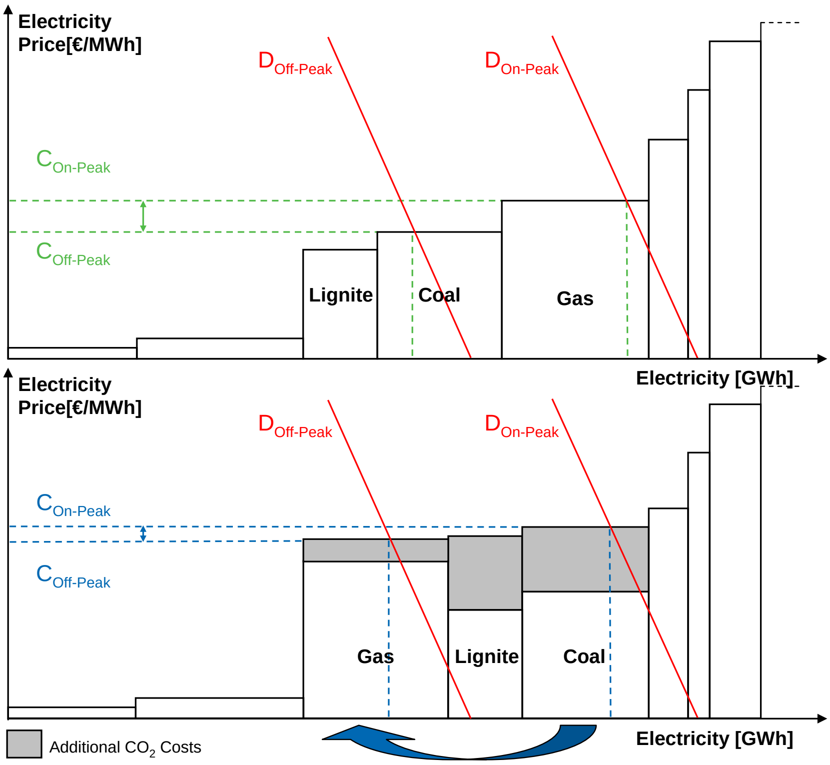
Apart from financial support, conventional power generators also benefit from regulatory support tools, such as priority dispatch under certain circumstances. Often ignored in the public debate, EU legislation provides for priority dispatch for Combined Heat and Power (CHP) plants: the Energy Efficiency Directive formulates in Article 15(5), the same rules of priority dispatch for high-efficiency cogeneration as for RES-E, with the only difference being the obligation to apply a ranking of the different access and dispatch priorities granted in Member States' electricity systems and that these are clearly explained in detail and published. Before this revised Energy Efficiency Directive entered into force, various Member States already were providing for priority dispatch for CHP plants in their national legislation, such as Germany.

Under certain conditions, EU legislation provides for priority dispatch even for conventional power generation. According to Article 15(4) of the electricity directive in the third liberalisation package a Member State may give priority dispatch to power plants using indigenous primary energy fuel sources, such as coal or peat. The extent of the priority dispatch should not exceed, in any calendar year, 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned. Accordingly, various Member States grant priority dispatch to power plants using domestic coal, such as Spain and recently Romania.

Furthermore, regulated prices for both private households and industry, notably in electricity and including electricity-intensive industrial customers, are still abundant. They are a significant obstacle to efficient and fair competition and hinder market entry and infrastructure development [39]. Moreover, energy markets in the EU continue to be characterised by a high degree of concentration with national incumbents exerting significant market power. Overall, these more structural market distortions which still favour large incumbent power generators can be regarded as a historical legacy from a market liberalisation process which commenced only in the 1990s: the majority of the present market structures were conceived for vertically integrated utilities before any significant cross-border trading and any liberalisation efforts took place.

The European emission trading scheme (ETS) came into force in 2005 and obliges the majority of power and heat conversion plants to take part in the new emission trading system. For each tonne of $CO_2$ the plant emits the plant operator has to own a certificate (EU-Allowance, EUA), which can be traded on the market. Those operators that have not enough allowances to cover their emissions have to pay a dissuasive fine for each excess tonne emitted. [40] Therefore, the ETS increases the power generation costs of carbon based power generation technologies, e.g. the variable costs of power generation increase the more $CO_2$ is emitted. This can be seen in Figure 27, where a simple illustrative example of a merit-order of short-run marginal electricity generation is presented.

Figure 27. *Illustrative example of the electricity price spread between on-peak and off-peak in the merit-order of short-run marginal electricity generation with (top) and without additional $CO_2$ costs (bottom)*




(Source: EEG)

The figure shows that the price gap between gas and coal/lignite decreases with the introduction of additional $CO_2$ prices, since lignite and coal have higher specific $CO_2$ emission factors. Given that coal/lignite power plants are generally base load and gas power plants are generally peak load power plants, the decreasing price gap also means that the ETS leads to a more homogeneous merit order and a reduction of the power price spread between base and peak load. In the shown example, gas moreover gets cheaper than coal and lignite and is shifted to the left side of the merit-order curve (Figure 27 bottom).

## 5.3 Lack of Participation of Demand Side Management in Different Electricity Market Segments

Demand Side management (DSM) participation in markets could result in a decrease in system operation costs, an increase in the level of integration renewable generation, thus paving the way for higher RES-E penetration levels, and an increase in the level of competition, thus contributing to a reduction in the level of prices, among other benefits.

However, in order to realize these potential benefits, some barriers, or obstacles, to the deployment of cost-efficient DSM solutions need to be overcome. These have to do with:

1. Technological aspects of service provision, related to the need to have the adequate equipment and communication protocols in place to provide such a service
2. Economic aspects of service provision, related to the need to make DSM profitable for all the parties involved in the implementation of these solutions.
3. Operational aspects related to the deployment of DSM solutions, which are related to the difficulties for carrying out their function in the electricity system that any party may face due to the deployment of the DSM service.

Next, main barriers or difficulties to be overcome in the deployment of DSM are discussed according to the time frame when they are encountered. Those barriers that are common to all market time frames are discussed within the short and long term markets section. This discussion is based on information available in the literature on the subject [[41], [42] and [43]].

### 5.3.1 Long-Term/Short-Term

**Technological barriers**

In the long and short terms, technological barriers to the deployment of DSM are less critical, due to the availability of a larger amount of time for consumers to react to DSM requirements in the form of variations of the load level. In any case, some minimal conditions need to be met in order for this service to be possible:

- Smart meters need to be in place allowing the measurement of the level of demand by each consumer at each time
- Communication equipment will also be needed. The type of it depends on the DSM scheme implemented. In those cases where simple schemes, such as feedback (FB), are deployed, needs are minimum (when FB is used as a DSM measure, the participation of the demand side in markets is not direct, but indirect through the modification of the amount of load needed to be contracted by suppliers). However, if, for instance, direct load control is applied, advanced communication infrastructure is required.
- The standardization of technological solutions applied is also necessary if competition among DSM service providers is to be made possible.

So far, the lack of appropriate meters and the associated communication equipment has limited to a large extent the ability of consumers to participate in markets, either directly, or through some intermediary. However, according to the regulation being implemented now in most European countries, this should not be a large obstacle to DSM in the medium to long term, since according to the estimates of the European Commission, about two-thirds of all countries and 75 % of consumers should have smart meters installed by 2020, see [43].

#### Economic barriers

Economically speaking, one first prerequisite for the deployment of DSM services is that it is efficient from a net social benefit point of view, i.e. that extra revenues, or benefits, resulting from DSM are larger than implementation costs. According to some analyses performed at European level, [[42], [44]], most DSM solutions (estimated to amount to between 0.85 €/active consumer and 6.86 €/active consumer in [42]) cannot be expected to render large enough benefits to justify implementation costs. Making them profitable would require un-tapping the undiscovered potential of DSM through the deployment of highly advanced solutions; implementing very modest solutions whose implementation cost is minimal, or reducing significantly the investment costs of required equipment. Some studies like [45] highlight the large benefits for the European system that the development of DR solutions could potentially bring about if fully developed. These would amount to 202 TWh of annual energy savings, 100 million tons of $CO_2$ emission reductions annually, € 50 bn in avoided investments related to peak generation capacity and transmission and distribution network reinforcements; and € 25 bn annual savings in electricity bills for customers, all of them to be realized by the year 2020.

Apart from this, regulation in place must allow benefits from DSM to be distributed among parties in the system so that all involved relevant parties find it profitable to facilitate the implementation of these solutions. Torriti et al. point out that main reasons for the slow progress of the implementation of DR policies in Europe are related to the economic factors such as the lack of knowledge about the energy saving potential of these measures, the computation of very high estimates of the cost of DR technologies and the associated infrastructures, and the fact that regulation developed with the liberalization of the energy sector has resulted in economic counterincentives for main relevant parties to facilitate the integration of DSM technologies or use them, since this would negatively affect their profits, see [46]. This concerns main groups of stakeholders:

- Consumers: Achieving the involvement of consumers, especially in some systems like Spain [42], may critically depend on the economic benefits they obtain from DSM. Increasing consumer benefits requires the computation of efficient, cost-reflective energy prices in day-ahead wholesale markets and network tariffs (both transmission and distribution ones), which should be updated periodically after long periods of time during which they remain fixed, and which may condition investment decisions by consumers together with generation capacity charges, or charges applied on consumers resulting from the application of capacity remuneration mechanisms. The latter should also be conditioned by DSM because both the amount of generation needed and the allocation of the overall capacity costs among consumers should depend on the level of consumer involvement in the application of DSM already in the long term, maybe in the form of long term contracts, or through the participation of consumers in long term capacity markets.

The lack of cost reflectivity in long and short term charges and prices faced by consumers has traditionally limited the profitability that consumers can obtained from managing their load according to system needs. The subsidization of some consumer groups has traditionally been a big obstacle in this regard.

- Analogously to consumers, aggregators and retailers need cost-reflective energy prices in markets to be able to draw some benefits from the management of the load of their consumers. Normally, energy prices are computed according to the marginal cost principles in wholesale markets, but not in retail ones (retail prices do not include any time differentiation in many counties, for instance). The lack of efficient energy prices may discourage consumers to engage with service providers, or retailers, in DSM schemes for the organization of the electricity supply.
- Network Operators' benefits from DSM depend on the regulation affecting the remuneration they perceive. Thus, remuneration schemes where there is a pass-through of network investment costs do not encourage operators to facilitate the application of DSM measures, while those where reduction in network investments costs result in an increase in operators' revenues, like revenue cap schemes, tend to provide the appropriate incentives to operators. Network operators' operation costs will probably increase with DSM, but this could be taken into account in remuneration schemes. Network operators do not participate in markets, but may condition the installation of flexible demand equipment by consumers in order for the latter to be able to participate.

Besides those economic aspects that are specific to a certain group of agents, or party, there is the general need to avoid limiting more than needed the direct or indirect participation of consumers in markets through minimum-size requirements that are too restrictive; high transaction costs; or other constraints like the need to bid in markets jointly for a block of hours.

Other relevant aspect is the need to have in place the appropriate equipment and regulation to monitor the provision of the DSM service. An adequate mechanism should be put in place to determine the baseline level of load by consumers so as to determine the level of load changes achieved through DSM. This is necessary both to measure the compliance with DSM commitments acquired y consumers or aggregators and for billing purposes and has traditionally not been adequately treated in most systems. This can be considered an obstacle to the participation of demand in all types of markets, long, short, and very short term ones.

One last relevant aspect that needs to be cared about is the design of contracts affecting all parties in the system. Too strict, inflexible contracts, would not allow parties to benefit from the flexibility that active demand could provide them with.

**Operation barriers**

Operation aspects that have traditionally negatively affected the activation of demand concern a multiplicity of factors ranging:

- from the lack of predictability of the level of demand managed by retailers or balance responsible parties, or that managed by TSOs within a control area, which may encourage them not to contract flexibility provided by demands or facilitate demand activation,
- to network congestion and other active technical constraints that may result from changes in the load of consumers in an area;
- going through concerns raised among consumers by the lack of an adequate level of confidentiality in the management of sensitive information about their demand profile; or requirements on access to data by rival entities, and the format of information exchanged among these entities, in order to facilitate competition among them;
- or existing uncertainties on the availability of DSM services when entities like TSOs, DSOs, or BRP need them; lack of knowledge by aggregators and Service providers about the location of their consumers in the grid; uncertainty about the level of the rebound effect, or increase/resp. decrease in the consumption following a decrease/resp. increase prompted by DSM;

These are discussed in [[41], [42]] for each of the different stakeholder groups involved in this process. Barriers of this type may, for example, drive TSOs and DSOs not to facilitate the connection of new active consumers to their grids. In this regard, recent efforts by ENTSO-e to develop a connection code clearly setting the rules for the connection of new consumers may represent a relevant step forward, [47].

### 5.3.2 Very-Short Term

In the following paragraphs, some main barriers faced by stakeholders, or market agents, when contracting balancing services from consumers are discussed. Again, barriers are classified according to their nature into technological, economic and operation ones.

**Technological barriers**

Deploying the appropriate metering and communication equipment is central to deploying DSM solutions for the participation of consumers in very short-term markets, namely balancing and regulation ones. This has to do with the fact that the quickness of the response needed from consumers to changes in system conditions is only possible if this response is fully automated, which, among other things requires the use of bi-directional communication and smart appliances in households and commercial stores.

So far, many have argued that the costs of implementing this technology is larger than potential revenues from it, as [[41], [42]] claim. However, other authors point out to the possibility that estimated of required equipment costs could be inflated [46]. In any case, enforcing the installation of part of this equipment, as some countries in Europe are doing, see [43], may be a reasonable step forward. But, in order for this to take place an effort must be made on the standardization of the functionality of equipment and communication protocols used.

**Economic barriers**

In order for the provision of balancing service by demand to make economic sense, this should be first allowed in the corresponding markets.

One relevant aspect that needs to be considered in balancing markets is the fact that, traditionally, compensating generation imbalances with demand flexibility has not been an option. This would need to be overcome in order to achieve the participation of demand in these markets.

The lack of obligations for energy producers to minimize imbalances between forecasted and actual production may again limit the need for these agents to contract balancing services potentially being provided by demand. This is clearly against the principle that the costs of system operation should be imposed on those agents responsible for the system incurring this cost (cost causality principle already mentioned above).

These are highlighted in [41] and discussed in more depth in [42] by participants in the EU 7FP project ADDRESS.

**Operation barriers**

The existing uncertainty about the dynamics of the activation of demand may play a critical role when contracting regulation reserves (mainly tertiary ones) from consumers or aggregators. This could deter Operators from contracting it from demand. This is again mentioned as main obstacle to overcome by authors in [41].

# 6 Conclusions

The lessons learned in this report (Deliverable D2.1) can be mainly summarized as follows:

- In the early phase of European electricity market liberalisation the design of market structures and policy instruments have been perfectly fitting to meet the intended policy objectives and expected market developments.
- Even more, the enormous efforts to promote the accelerated integration of RES-E generation technologies has been a success story, knowing that the financial support (subsidies) is enormous and this support is a market intervention apart from the forces of the electricity market itself.
- In the course of time, however, adverse effects of significant RES-E penetration have been occurring in terms of low average wholesale electricity prices in general and extremely volatile, partly negative prices in particular.
- Subsequently, this has led to the situation that conventional electricity generation technologies have become difficulties to cover their costs while financial support instruments (subsidies) further stimulate investments into wind and PV generation. This has led to increasing profitability risks of many of these conventional generation technologies. Some of them already have been – or are expected to be –mothballed.
- Although the importance to promote Demand Side Management implementation into the electricity market has been discussed for a long time, up to now there do not exist significant and promising best-practise cases qualified to be scaled up.

Against the background of the above mentioned challenges, a couple of years ago already a European discussion emerged on how to further improve the market design contributing to the mitigation of the currently existing "missing money" problem of conventional and RES-E generation, on the one hand, and how to foster European electricity market integration with high shares of RES-E generation in general, on the other hand.

Starting from the explanations of the historical development, this report highlights the driving forces of the currently existing European 'Target Model' discussion, notably as far as the so-called 'Capacity Remuneration Mechanisms (CRM)' is addressed.

It neither elaborates on the diagnosis of the currently existing European energy market discussion in detail, nor provides already some conclusions and/or recommendations to overcome several of the challenges the European electricity market is facing at present. This will be done in subsequent reports of work package 2 (Deliverable D2.2 and D2.3) and also remaining work packages (underpinned with modelling exercises and results) of the Market4RES project.

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