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RES Integration and Market Design:

are Capacity Remuneration Mechanisms needed to ensure generation adequacy?

RESAP

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RES Integration and Market Design: are Capacity Remuneration Mechanisms needed to ensure generation adequacy?

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Marcel CAILLIAU (BE), Chair;

José ARCELUZ OGANDO (ES); Richard COMBESCURE (FR); Theo DE WAAL (NL); Vittorio D'ECCLESIIS (GB); Hakon EGELAND (NO); Ricardo FERREIRA (PT); Håkan FEUK (SE); Roby GENGLER (LU); Stine GRENAA JENSEN (DK); Kimmo KIVIKKO (FI); Götz LINCKE (CH); Cesar MARTINEZ VILLAR (ES); Sam RIDSDALE (GB); Jan SUNDELL (SE); Giuseppe TRIBUZI (IT); Fernando URQUIZA AMBRINOS (ES); Pekka VILE (FI); Bernhard WALTER (DE); William WEBSTER (DE); Michael ZOGLAUER (AT); Anne-Malorie GERON (EURELECTRIC Staff); Marco FORESTI (EURELECTRIC Staff)

Contact:
Marco FORESTI – mforesti@eurelectric.org

Table of contents

Executive Summary ... 04

1. Introduction ... 07
   - 1.1. Purpose and scope of this paper ... 07
   - 1.2. What is generation adequacy? ... 07
   - 1.3. Current and future EU scenario: important changes in regulatory and market framework leading to the need for back-up services ... 10
   - 1.4. How to ensure generation investments: needs and problems ... 12

2. Market Design and Generation Investments: Theory vs. Reality ... 14
   - 2.1. The theoretical approach ... 14
   - 2.2. The practical reality ... 16
   - 2.3. From a static environment to a dynamic decision world ... 17

3. How to ensure Future Generation Adequacy: Tools and Solutions ... 19
   - 3.1. How can we improve current electricity markets? ... 19
   - 3.2. Will market improvements be enough or implemented in time? ... 21
   - 3.3. Could capacity remuneration mechanisms be a solution? ... 22

4. Capacity Remuneration Mechanisms: Needs, Models, Open Issues ... 24
   - 4.1. In which market conditions should capacity remuneration mechanisms be considered? ... 24
   - 4.2. What are the main types of capacity remuneration mechanisms? ... 27
   - 4.3. Effectiveness of the different CRM models ... 28
   - 4.4. General design and implementation issues ... 31
   - 4.5. Capacity remuneration mechanisms: key open issues ... 33
   - 4.6. How to introduce or phase out CRMs ... 37

5. Policy Recommendations ... 39

Executive Summary

This paper assesses whether current electricity markets are adequately equipped to provide the correct price signals for the necessary amount and type of investments in (existing and future) generation capacity.

EU electricity markets are experiencing fundamental changes as a result of the EU's policy goals, especially the 2020 renewables (RES) targets. The need to generate a large share of electricity from RES reduces the operating hours and profitability of flexible and back-up generation technologies.[1] However, the latter are necessary to cope with RES intermittency and unpredictability. In some EU markets, their lower levels of expected profitability are significant, raising concerns about future investment decisions and thus generation adequacy.

Academic theory argues that "energy-only" markets would function perfectly if prices were free to rise well above the marginal operating costs during scarcity hours, up to a level determined exclusively by consumers' willingness to pay that price. However, in current electricity markets such "scarcity prices" are reached only at some limited moments, and the revenues generated by price spikes have generally not been enough to cover the fixed costs of "peaking" plants.

If this situation persists, the necessary flexible and back-up generation capacity could eventually be closed and not replaced by new investments. To avoid this, **the design and functioning of today's electricity markets must be improved**.

To enhance electricity markets' ability to deliver generation adequacy, governments and regulators must first of all allow energy-only markets to function properly. To this end, **distortions which hinder the balance of demand and supply must be removed**. Such distortions include regulated end-user prices, restrictions on plant operations, price caps, and other regulatory or administrative measures which unnecessarily hinder wholesale market outcomes.

At the same time, **integration of wholesale markets must remain a top priority** for EU and national policymakers. Efforts should thus concentrate on implementing the Target Models of day-ahead market coupling, intra-day and forward markets to fulfil the objective of an EU integrated market by 2014. This process should be accompanied by the strengthening of transmission capacity (both domestic and cross-border) and the establishment of regional balancing markets.

1 Such as CCGT – combined cycle gas turbine plants.

Most importantly, and with a view to enhancing and speeding up the integration of renewables into the EU system, **RES generators must be incentivised to progressively enter into the market** on a level playing field with all other generators. In particular they should be incentivised to sell their own production into the market as well as to meet scheduling, nomination and balancing requirements as other generators do. In addition, there should be harmonisation towards European-wide market-based support mechanisms: this would expose RES generators to market prices that reflect demand and supply variations and would also allow substantial cost reductions.

Enabling market-based demand to participate in wholesale market spot price formation is fundamental for a well-functioning electricity market, although very difficult to achieve.[2] It would considerably decrease not only peak capacity demand, but also the need for "back-up" plants. **Enabling demand response must therefore be a core element of current energy policies**.

In markets where all the above improvements have been made and generation adequacy is nevertheless endangered (through reduced investments and early decommissioning), **policymakers should consider introducing a capacity remuneration mechanism** – ideally at a regional level or at least in coordination with neighbouring markets. In any case, consistency with the process of EU market integration should be ensured.

If introduced, **capacity remuneration mechanisms should be able to be phased out once the market itself delivers the appropriate investment incentives** to ensure the adequacy of the system. In practice, the implemented model, while ensuring sufficient regulatory stability, should produce effects only as long as the underlying problem of generation adequacy requires an additional solution to complement well-functioning wholesale markets.

Finally, while an EU-wide harmonisation of existing or future capacity remuneration mechanisms may be premature and unnecessary at this stage, EURELECTRIC calls on ACER and the European Commission (in cooperation with all relevant EU and national stakeholders) to start working on the development of **a set of minimum EU harmonisation requirements**. This should ensure the well-functioning of regional markets and compatibility with the aim of reaching an Internal Electricity Market by 2014. In addition, developments in national markets – in particular the implementation of the Target Models – should be closely monitored to ensure this political objective is met.

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2 Demand response will also be improved through the large-scale deployment of smart grids and smart meters.

1. Introduction

1.1. Purpose and scope of this paper

This EURELECTRIC paper serves two main purposes:

- To follow up on EURELECTRIC's 2010 report on renewable energy sources (RES) integration, in which we recommended solutions to achieve the 2020 RES targets cost-efficiently, and identified possible open issues for generation investments[3];
- To analyse the implications of RES penetration for the functioning of wholesale markets and for a possible market design review (at this stage confined to capacity remuneration mechanisms), in the context of EURELECTRIC's current work on renewables within its RES Action Plan[4].

Similarly to EURELECTRIC's work, several studies on EU electricity markets have recently recognised that today's legislative and regulatory framework (where rules and support schemes developed to achieve the RES 2020 targets play a major role) is challenging the ability of market dynamics to deliver "generation adequacy" in the short, medium and long term. At the same time, policymakers at EU and national level are also becoming aware of such challenges.

This paper therefore assesses whether current electricity market designs in the EU will be able to ensure "generation adequacy" for the years to come, focusing in particular on the 2020 horizon. It evaluates if existing markets are adequately equipped to provide the correct price signals for the necessary amount and type of investments in (existing and future) generation capacity. Our paper identifies some current shortcomings and proposes possible solutions, highlighting their individual advantages and drawbacks.

1.2. What is generation adequacy?

As defined by ENTSO-E[5], "generation adequacy of a power system is an assessment of the ability of the generation on the power system to match the consumption on the same power system." This general definition implies that such an "ability" of the power system should be ensured at all times. However, any analysis of generation adequacy depends on the timeframe under consideration. More specifically, generation adequacy touches upon three main aspects: short-term reserve, long-term capacity, and back-up capacity.

In order to explain the scope of our paper, it is therefore important to first give the reader a picture that summarises three main different perspectives from which generation adequacy should be analysed.

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3 EURELECTRIC: "Integrating Intermittent Renewable Sources into the EU Electricity System by 2020: Challenges and Solutions", May 2010. Available at www.eurelectric.org.

4 Launched in 2010, EURELECTRIC's RES Action Plan aims at developing a comprehensive EURELECTRIC vision and strategy on the role of RES for 2020 and beyond. It includes 13 different projects across EURELECTRIC committees and working groups whose results will be presented at a conference in November 2011.

5 ENTSO-E Report, "System Adequacy Forecast 2010 - 2025", 2010.

As long as the share of intermittent RES in the market is low (i.e. a single-digit percentage of total installed capacity) generation adequacy is characterised by two time dimensions: the short term and the long term. **For the short term**, it can be in principle ensured through an appropriate quantity of reserves (primary, secondary, tertiary) to cover stochastic demand fluctuations and the **loss of the largest generation unit. For the long term**, generation adequacy is guaranteed when investments (taking into account commissioning and decommissioning compared to the expected off-take growth and demand response) and power import possibilities secure enough **capacity to cover peak demand**. For this purpose, the regulatory framework should ensure the current and future availability of sufficient peak units (which normally have lower investment cost but a higher variable cost).

These two fundamental requirements do not change when a high share of intermittent RES (which generally has a very low marginal cost) is integrated into the generation mix. Reserves remain necessary, as it is impossible to exactly forecast either demand or outages. However, due to the intermittent nature of the main RES sources (i.e. wind and solar), an increased share of RES means that more reliable generation assets need to be constantly available (i.e. in "stand-by mode") to generate the required amount of energy when renewable sources are not available due to weather conditions. In this scenario, the short-term adequacy requirement thus not only covers daily demand changes and the outage of the largest plant, but also **"back-up" capacity for intermittent plants**, thereby creating a third dimension of generation adequacy.

Both conventional and renewable generators have a natural interest in being available at any time. For conventional power plant owners in particular, the incentive to be in the market is very strong: whenever their plants are not available, they risk missing their profit opportunities which derive solely from wholesale market prices. Moreover, in order to hedge their market risk (price and quantity), conventional generators take longer term commitments (up to several years ahead), both in procuring their fuel and in selling their output, leaving only part of their position open for the short-term market. In an electricity market with only conventional (i.e. thermal and hydro) generation, these long-term commitments, together with the incentive to be available in the market at any time, normally lead to an equilibrium that minimises the need for short-term reserves.

With relatively low volumes of (intermittent) RES in the market, "back-up" needs and costs are generally small because the existing flexibility of the conventional installed capacity can guarantee both the necessary short-term reserves and the back-up service for the whole generation portfolio. With growing intermittent production, however, this is no longer true. Moreover, conventional generators in such markets face other consequences: with their plants increasingly running in "back-up" mode (considerably reducing the number of operating hours compared to the situation in a "non-RES" electricity market), they often experience revenue losses. In markets where these cases are frequent, generators would rather mothball their plants, unless the market provides a fair remuneration for this back-up service through a combination of the day-ahead, intraday, balancing and reserve markets.

Many analyses mix the three dimensions of generation adequacy (short-term reserve, long-term adequacy and intermittency back-up). This is understandable because the dimensions are interrelated: with enough dispatchable capacity in the system, there shouldn't be any problem for either short-term reserves or for the RES back-up service. The issue, however, is to find an appropriate market design that guarantees a fair remuneration for all three dimensions of generation adequacy.

In summary:

- **Short-term reserve** is necessary at any given moment to cover potential incidents that decrease power supply to the system. Short-term reserve enables TSOs to secure the system, as the market lacks the oversight and overall system control to react quickly enough by itself.
- **Long-term capacity** is necessary at peak demand moments. The market should have sufficient information and a favourable investment climate to react properly to decreasing long-term security. The TSOs' role lies in monitoring investments, decommissioning and demand evolution, and providing additional information to the market and to the regulators (e.g. through system adequacy reports).
- **Back-up capacity for intermittent RES** is necessary when the "wind is not blowing or the sun is not shining." In principle the market should be able to cope with the lack of RES supply in the short term (especially via day-ahead and intraday trading). In real time, TSOs also have to take actions for the residual dispatch (with balancing power).

The following figure summarises these three complementary dimensions of generation adequacy, which require different power plant features and usage.

Needs	Reserves (R1-R2-R3) = Short-Term (continuous) adequacy	Long-Term Capacity = Mainly peak capacity adequacy	RES Back-up Capacity = Stand-by/flex capacity adequacy
Load Factor	• Primary Reserve ≈ 0 • Secondary/Tertiary ≈ small	Around 100 hours/year	Around 1000 hours/year (but less than 3000h)
Plant Usage	• Specific Technical Features • Capacity Procurement, Energy = Balancing	• Low Efficiency (OCGT/Oil) • Only start/stop	• High Efficiency (low CO_2) • Flexibility/Regulation

Figure 1: The three dimensions of generation adequacy

1.3. Current and future EU scenario: important changes in regulatory and market framework leading to the need for back-up services

EU electricity markets are experiencing fundamental changes as a result of the EU's **policy goals**, especially the 2020 targets. As outlined in our previous paper[6] the need to generate a large share of electricity by RES (along with the intermittent and concentrated nature of the main RES sources) poses important challenges on grids and markets. The ambitious targets of the RES Directive and the priority of dispatch for renewables further reduce the scope for other generation technologies that are still necessary to cope with intermittency and unpredictability.

The policy framework also affects wholesale **market prices**, which in turn directly affect the profitability of plants and generators' expected return on investment (ROI). Moreover, the low variable cost of some RES technologies and the guarantees for RES (via different support schemes, but also via priority dispatch) result in less operating hours for conventional plants, thus influencing the business investment case. In markets with an already important share of wind generation, combined cycle gas turbine (CCGT) plants are experiencing a constant reduction of their load factors. In Spain, for instance, CCGTs were dispatched for only half as many hours in 2010 compared to 2004 (*see Figure 2*).

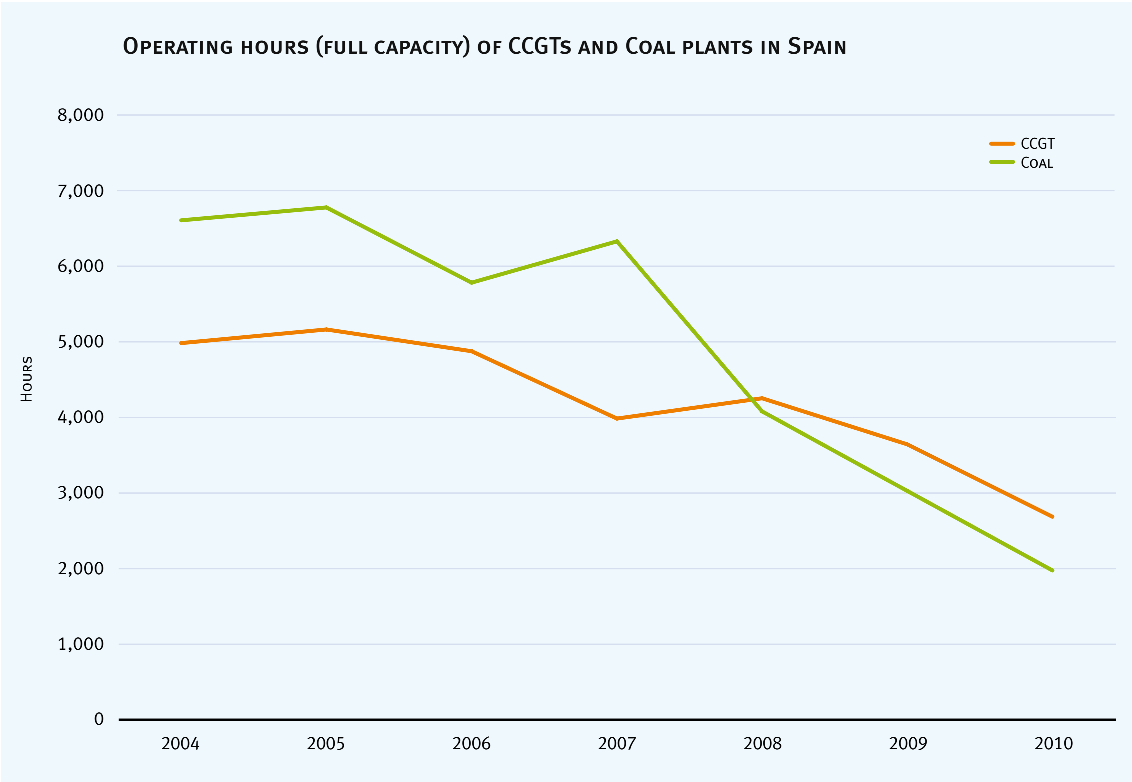

Figure 2: Reduction of operating hours of CCGT in Spain (Source: Red Electrica Espana)

This trend, even if probably less severe in countries with less installed wind capacity, is forecast to continue in most EU markets until at least 2015 (*see Figure 3*).

6 See footnote 3.

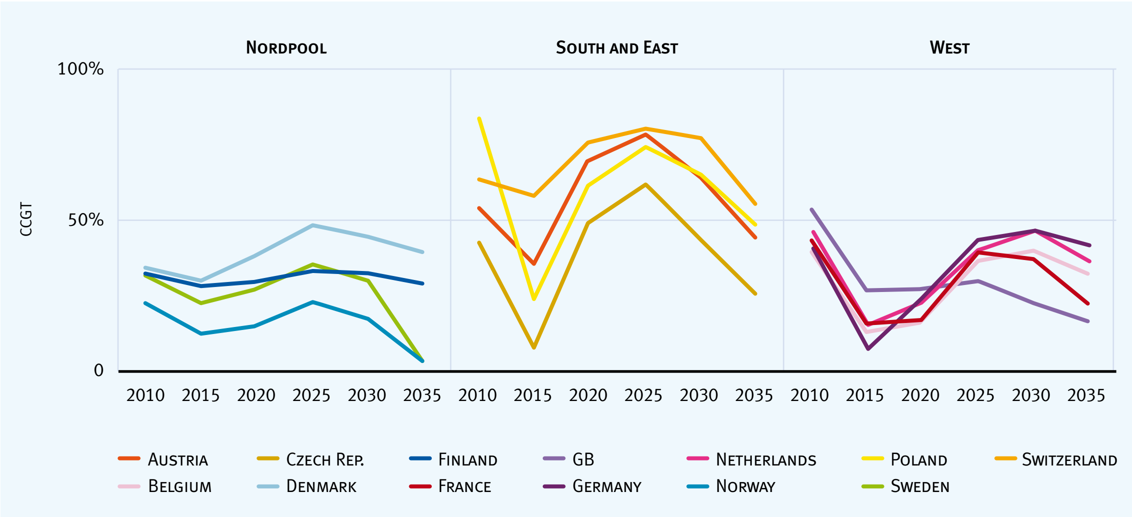

Figure 3: Reduction of operating hours of CCGT in some EU countries (Source: Pöyry Management Consulting from the report "The challenges of intermittency in North West European power markets" – March 2011)

If there are no offsetting wholesale price increases when conventional plants are running, such significantly reduced operating hours lead to decreased revenues and endanger the profitability of generation investment. In some EU markets, the lower levels of expected ROI for these types of plants are significant, raising concerns about future investment decisions and thus generation adequacy.

In addition to the EU's renewables targets, **further legislative and regulatory changes** also affect investment choices, regarding both existing and future plants. These include:

- the Large Combustion Plant Directive, adopted in 2001, which will lead to decommissioning of older plants with higher polluting emissions by end-2015;
- the Industrial Emissions Directive, which will impose more restrictive levels of SO_2, NO_x and dust emissions from 2016 onwards leading to additional decommissioning of non-compliant plants;
- nuclear phase-outs or restrictions in building new nuclear plants;
- stricter standards for authorisation procedures to build new plants;
- CO_2 emission allowance costs with no free allocation to power generation from 2013 onwards in most countries.

While there are some common situations across the EU, the above-mentioned effects will obviously vary across different national markets depending on their distinctive features. Forecasts[7] for several EU markets indicate substantially reduced reserve margins[8] over the next five years as a result of expected plant closures related to legislative/regulatory compliance. Nevertheless, the adequate level of reserve differs across markets: what is acceptable in one market may be problematic in another.

The differences between markets can depend on various factors: level of intermittent RES penetration, overall generation mix, availability of demand response resources, interconnection levels, degree of market integration, market rules, stability and predictability of the regulatory framework, etc. We will come back to these particular features, and to their effects, in Chapter 4.

7 See for instance CERA (Roundtable European Power London - 2010) and ENTSO-E (*Scenario outlook and system adequacy forecast 2011-2025* – 2010).

8 The reserve margin of a system is generally defined as the percentage of installed capacity in excess of peak demand.

1.4. How to ensure generation investments: needs and problems

Having described the goal (generation adequacy) and the current scenario (EU legislative framework), what are the **needs** for future years?

Will the current market designs ensure the availability of sufficient generation units for flexible and back-up capacity? To a large extent, the answer depends on the expected ROI of those plants.

In our 2010 report, we demonstrated how integrating RES in the market will create additional needs for generation plants that are able to deliver flexible output and operate in stand-by mode. Insufficient grid capacity to cope with the changing flow pattern due to high shares of wind generation capacity will result in additional congestion; therefore more redispatch will be needed as well. We also explained how large-scale RES introduction combined with priority of dispatch reduce the load factor of existing conventional power plants, generally weakening their ability to recover their fixed costs and possibly leading to earlier decommissioning. Similarly, prospective investors in new conventional generation capacity will face increasing uncertainty, weakening their appetite for investments in these technologies. While less efficient and more polluting power plants should indeed be replaced to meet EU environmental targets, the reduction of operating hours also affects those conventional plants with highest efficiency and lowest CO_2 emissions.

Deviations between the short-term forecast (i.e. day ahead) and the real-time RES production output still occur, with differences of up to more than 5%. To nevertheless ensure generation adequacy, important investments will be required either to make such conventional plants even more flexible (e.g. steeper ramping rates, lower minimum stable load, etc.) or to develop new plants suitable to frequent variation of their output.

In addition, it is widely recognised that the level of firmness (the so-called "capacity credit") of intermittent energy sources is quite limited (5-10% maximum) which means that they can be considered as energy resources but not as capacity suppliers. They are therefore broadly unsuitable to ensure an adequate reserve margin to cover the peak demand. Instead the system must rely mostly on conventional capacity with sufficient levels of firmness and a well functioning balancing/reserve market.

As an example, a system with a peak demand of 40,000 MW, and without any intermittent RES capacity, would require 44,000 MW of installed conventional capacity with a high level of firmness to guarantee a 10% reserve margin over peak demand. If the same system included 20,000 MW of wind with a capacity credit of 2,000 MW (10%), then there would still be a need for 42,000 MW of conventional firm capacity to guarantee the 10% reserve margin – i.e. hardly less conventional capacity than in the previous system without wind generation.

However, in this latter RES scenario, technical requirements for the conventional 42,000 MW (or at least for a considerable share of them) are much higher, as conventional plants now need to supply the residual demand (i.e. demand minus the low variable cost generation, which includes RES) which has a high variability due to RES. In fact, they must be able to be dispatched with a high degree of flexibility, reliability and more challenging ramping rates. Indeed, the "quality" requirements imposed on the original 44,000 MW conventional fleet supplying the total demand of the RES-free system were actually lower than for the 42,000 MW conventional fleet supplying the residual demand in the new system with 20,000 MW of wind.

The simplified situation in the example above can be illustrated with a recent example from Spain (*see Figure 4*) that occurred on 3 March 2010. In this case, the difference between the minimum and the maximum capacity that flexible conventional generation needed to ensure within one day reached 20,000 MW, representing a near fourfold (3.71) increase from the night-time minimum to the day-time maximum generation.

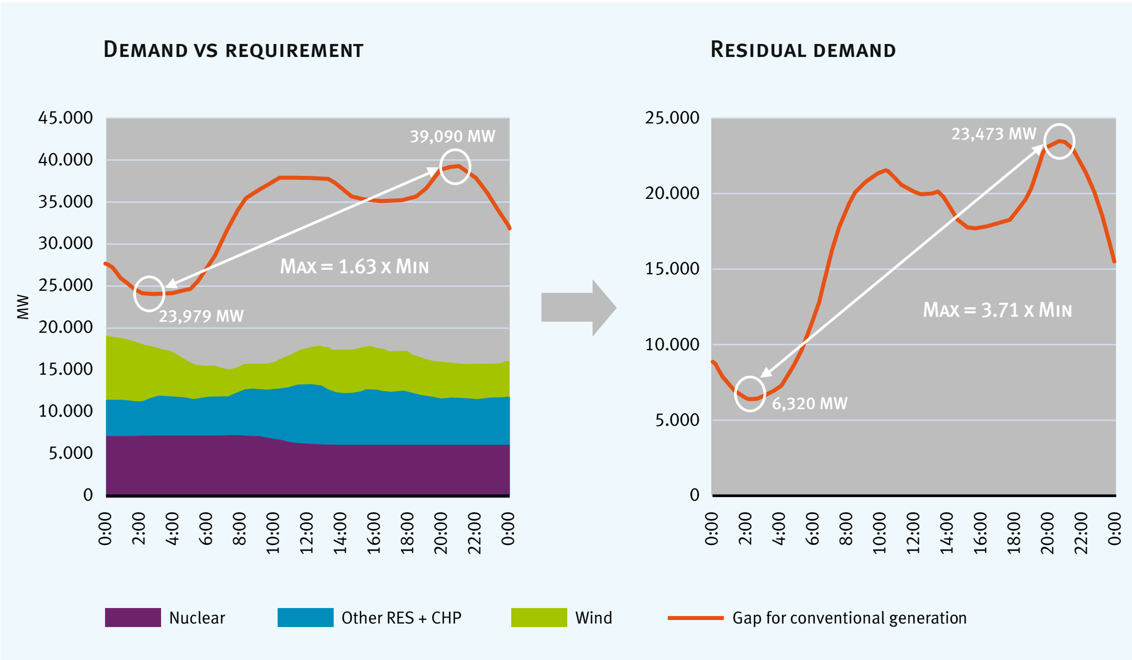

Figure 4: Variation of residual demand within 1 day (Source: Red Electrica Espana)

If insufficient investment in new flexible generation and in other measures (grid investments, demand response) occurs as a result of insufficient price signals, or if existing flexible plants like CCGT face a deterioration of profits, leading to a temporary or permanent withdrawal from the market, the generation adequacy of a system might be jeopardised as well. This would then require investment in more peak capacity to re-establish the adequate level of (peak) generation adequacy.

Having highlighted the potential critical interactions between RES and conventional generation, the following chapter undertakes a more detailed analysis of today's electricity market designs, both in theory and in practice.

2. Market Design and Generation Investments: Theory vs. Reality

2.1. The theoretical approach

To better understand the issues touched upon in section 1.4, this section provides a short theoretical introduction to electricity market design and its main functioning mechanisms.

Although a number of academics have written on this subject, the most acknowledged work on market design and its economic aspects is probably the one by Joskow[9]. The paper uses a simplified load duration curve, together with the assumption that the market reaches a "Least Cost Generation Capacity Mix" based on three (simplified) types of technologies: baseload, intermediate load and peaking plants. The example initially assumes a vertical demand curve and marginal system pricing, where the wholesale price reflects the marginal cost of the "last" dispatched unit in the merit order. In this simplified model, all three technologies fall short of covering their fixed costs, by an amount equivalent to the fixed costs of the peaking plants.

Now let us consider what happens if demand becomes price-responsive, i.e. if the demand curve is no longer vertical, but decreases when prices increase. In this case, when demand is close to the maximum available capacity, wholesale prices may be much higher ("scarcity prices") than the marginal costs of the last dispatched unit. These scarcity prices provide the whole generation system with an additional rent ("scarcity rent"), allowing it to completely cover its fixed costs.

All three technologies therefore receive their fixed cost remuneration from the scarcity rent. This model is commonly called the "energy-only" market because investments are fully paid back via the energy prices remuneration.

The simplified model thus illustrates two crucial elements for the proper functioning of the energy-only model (in common with any other market):

- the **presence of an adequate market-based demand response**, allowing supply-demand curves to cross in an equilibrium point (price) that exactly expresses the maximum price that demand-responsive consumers are willing to pay;
- the **possibility for prices to rise well above the marginal operating costs**, during the scarcity hours, up to a level determined exclusively by consumers' willingness to pay that price[10].

9 Center for Energy and Environmental Policy Research: "Competitive Electricity Markets and Investment in New Generation Capacity", April 2006.

10 Either directly or indirectly via their supplier.

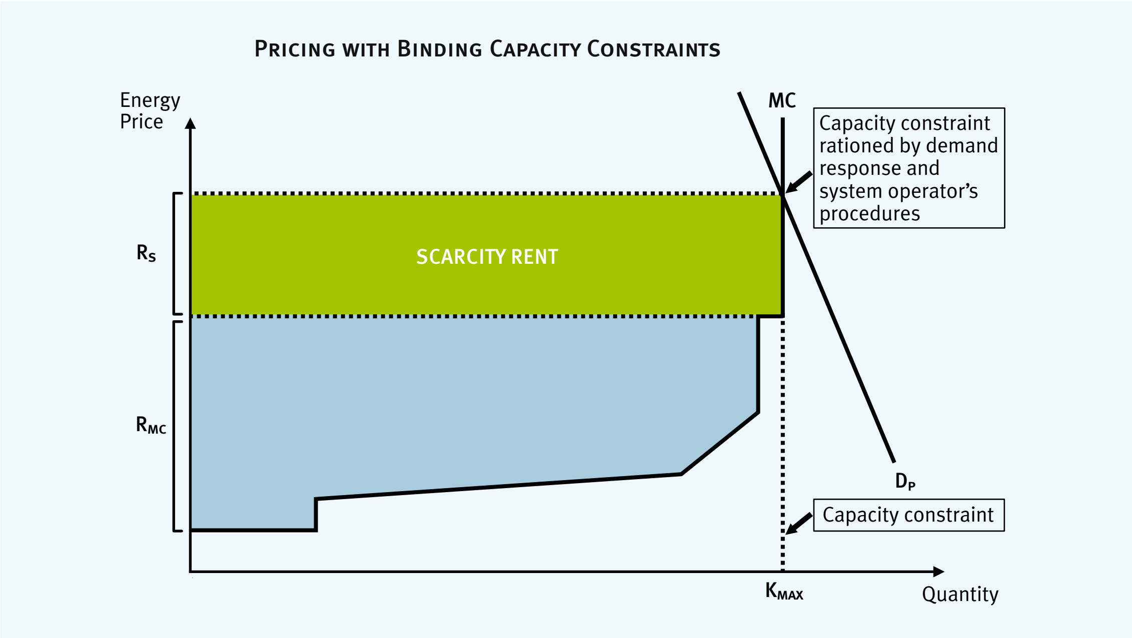

Figure 5: Pricing with capacity constraints[11] (Source: Joskow)

11 The area labelled Rmc represents the quasi-rents that would be earned by infra-marginal generators if the wholesale price is equal to the marginal generating cost of the least efficient generator on the system required to clear the market. The area labelled Rs reflects the additional scarcity rents from allowing prices to rise high enough to ration scarce capacity on the demand side to balance supply and demand.

2.2. The practical reality

As usual, reality differs from simplified theoretical examples. Joskow lists some of the reasons why wholesale markets do not produce adequate revenues to incentivise investments. For instance, he states that "supply and demand conditions which should lead to high spot market prices in a well functioning competitive wholesale market (i.e. when there is true competitive scarcity) are also the conditions when market power problems are likely to be most severe"[12]. For this reason, and even more often to have a sort of "political" control over the level of prices, governments and regulators have introduced "price caps" in some markets.

The obvious side-effect of such measures lies in reduced scarcity revenues and consequent potential "missing money" problems.[13] In other words, market design imperfections can jeopardise necessary generation investments.[14]

Energy-only markets would theoretically function perfectly if both supply and demand participate in the market based on the marginal costs of generation and the marginal market values of the electricity used. However, in current electricity markets supply and (especially) demand curves do not follow these dynamics.

While hourly supply-demand balance is normally reached in the spot market, the scarcity threshold is reached only at some limited moments, resulting in short-term price spikes. Some studies[15] show that, to date, the revenues generated by most price spikes have generally not been enough to cover the fixed costs of new "peaking" plants. If this situation persists, these plants – that are also needed to ensure the necessary flexible and back-up generation capacity for the system – will not be replaced by new ones because the expected ROI will not be sufficient. Even more critically, if wholesale prices do not sufficiently cover variable costs, existing plants could be closed or mothballed, potentially endangering generation adequacy.

In conclusion, and based on Joskow's theory, all types of generation investments, be they peak-load (like OCGT), mid-merit load (like CCGT) or baseload, can suffer from "missing money" (*see Figure 6*).

Yet two recent ENTSO-E reports (the 2010-2025 Adequacy Report, and the Scenario Outlook and System Adequacy Forecast 2011-25) both conclude that generation adequacy criteria seem to be fulfilled. So is the ENTSO-E analysis missing something in forecasting medium and long-term investment decisions?

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12 Joskow, p.37.

13 For the sake of completeness, Joskow also states that price caps are not the only reason for missing money: even with a capacity remuneration mechanism in place, recovering all (peaking) investment cannot be guaranteed.

14 For additional views on this risk see Cramton and Stoft: "The Convergence of Market Designs for Adequate Generation Capacity", April 2006.

15 See for instance §4.2 (1) of the EURELECTRIC report under footnote 3.

2.3. From a static environment to a dynamic decision world

Investment decisions, as well as mothballing and closure decisions, are not only driven by short-term price signals (wholesale forward prices only cover the first 2-3 years), but also by the long-term marginal costs and by the expectations of the market environment for a period covering the next 15 years or even up to 60 years (depending on the technology and investment type). Such expectations take into account all parameters that might influence the return on the investment: the expected evolution of the generation mix (own generation portfolio, as well as what is expected to exist in the market) and of fuel and CO_2 prices, expected residual demand, expected transmission capacity and further market integration, etc. Obviously no investor will approve an investment that will not deliver the right return for the whole duration of the plant life.

As a result of new investments, but also changing consumption and demand patterns, regulatory interventions, fuel and CO_2 prices, etc., the "missing money" situation is constantly evolving. Investors monitor these changes closely and continuously adapt their generation park to reach an optimal portfolio mix. In a "boost and bust cycle" situation there will be periods of tightness that will create price spikes and therefore scarcity rents, attracting new investments, while other, almost depreciated plants may be adapted to a "second life" as peak plant[16].

The necessity for EU Member States to achieve the ambitious RES targets for 2020 is putting huge pressure on most investment decisions. Indeed, the quite "swift" change from electricity markets with a low share of renewables to up to more than 35% (on average) within only one decade represents a real challenge. Adapting the generation mix to the new requirements towards the "Least Cost Generation Capacity Mix" (as described in paragraph 2.1.) will be much more complex than in the previous century. While the past system was relatively static, we currently live in a fast-changing environment with a more variable and less predictable generation mix. Existing conventional plants (mainly mid-merit and baseload plants) are pushed out of the merit order and run far less hours than initially foreseen. Moreover, they face lower, more volatile and more uncertain market prices, resulting in a lower margin. The "missing money" problem increases significantly, leading to more decommissioning decisions and less new investment.

16 This usage will not be possible anymore after 2015 for some units having opted out from the LCP Directive. From 2016 onwards, some other units might use the flexibility options under the Industrial Emissions Directive (or they might fit a de-NOX and have a "third life").

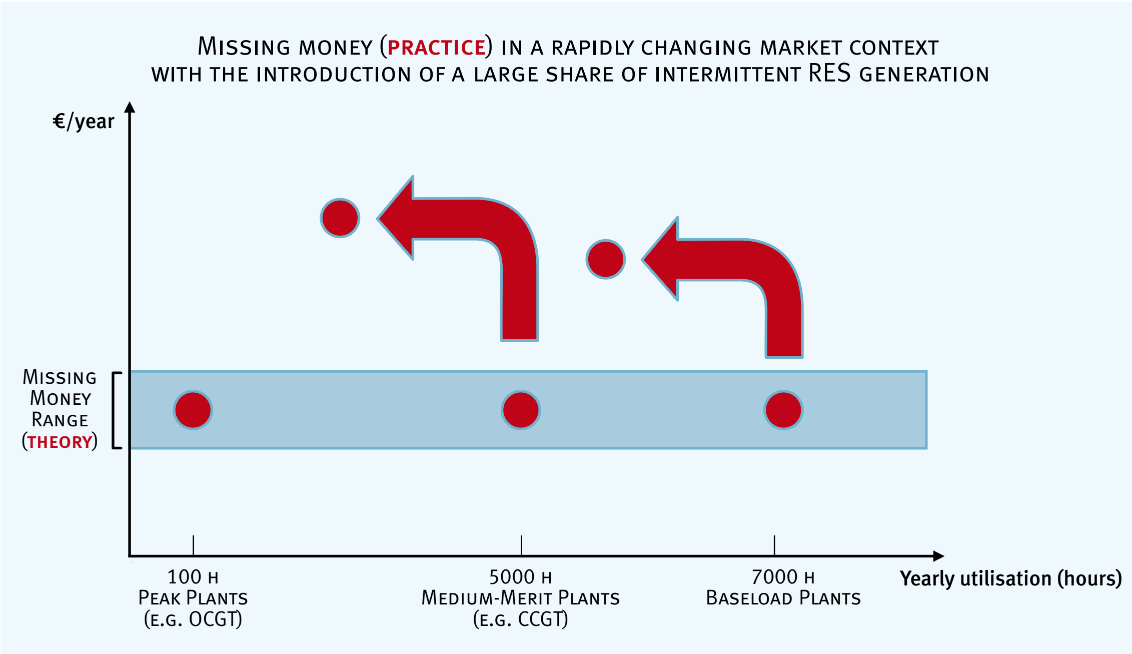

Figure 6: Missing money in theory and in practice

Investors are of course willing to adapt their generation portfolio to the new situation, but the speed of change is high and the "end game" is not yet in sight. In fact, the 2020 targets are only an intermediate step towards a carbon-neutral generation mix which various "roadmaps" and modelling exercises have tried to forecast – with very different results and therefore different ways of getting there.

This leads to a number of conflicting incentives. For instance, some generators would wish to withdraw plants from markets where they cannot even cover their operation and maintenance costs. However, as most new capacity is provided by intermittent RES generators with a lower level of firmness for the system, TSOs/regulators in some countries might prevent such earlier decommissioning by denying (conventional) generators the necessary closure authorisation.

Of course, it is not only environmental policy goals that can create strong uncertainty in the market: other phenomena (regulatory or legislative decisions, market reforms, impact of financial crisis, shift in public acceptance of certain technologies and infrastructure, etc.) can raise investment costs and generate uncertainty in terms of costs and income. While the investment climate for the electricity sector becomes ever more complex and challenging, our sector must also decisively contribute to win the battle against global warming. EURELECTRIC believes that we are entering a decisive, rapidly evolving transition period in which policy and regulatory decisions will have a huge impact on this battle's probability of success and on the costs that we will have to bear. Policymakers should therefore take decisions on wholesale markets design with great care and carefully consider their possible consequences: risks to security of supply and severe market inefficiencies and distortions should be avoided.

In the meantime, how can the current situation be improved?

3. How to ensure Future Generation Adequacy: Tools and Solutions

3.1. How can we improve current electricity markets?

Before discussing more radical solutions for generation adequacy, we believe that a number of measures should in any case be pursued in all EU markets without delay. In our view, the most important measures to improve electricity markets should be:

- Enhancing market-based demand participation in the spot market. This should also be underpinned by deploying smart grids and smart meters and by introducing more dynamic pricing models for customers. The presence of a fully price-responsive demand is the most important, and perhaps the most difficult, condition for a well functioning energy-only market. It would reduce both peak plant and back-up needs: in the event of low RES generation, rising spot prices would lead demand-responsive customers to reduce consumption, while in the event of high RES generation, consumption would be increased.
- Removing regulated electricity prices (except “social tariffs” for vulnerable customers), thus allowing customer prices to truly reflect the supply-demand balance[17].
- Avoiding regulatory or administrative measures which unduly distort wholesale market outcomes.
- Strengthening the transmission capacity both within the domestic market area (to avoid internal congestion) and with neighbouring market areas, enabling additional imports and exports in situations of generation deficit or surplus. Interconnection capacity should be increased by investment in grids and by optimising grid-usage through efficient and harmonised allocation methods. This will allow existing flexibility resources to be available in several markets and thus reduce the need for keeping “mid-merit” or “baseload” plants operational in case they are losing too much money.
- Abolishing price caps or setting them high enough in order not to constrain the demand response potential and all short-term generation flexibility options.
- Establishing and integrating intraday markets, enabling portfolio optimisation after the day-ahead phase. In particular, gate-closure of the intraday markets should be moved as close as possible to the real time (e.g. up to H-1). This will give market players optimal chances to compete with one another with all their flexibility resources (on both the demand and supply side). Moreover, all market actors should be encouraged to participate in the balancing market on a voluntary basis.

17 Retailers will also have to reflect the preferences of their customers within their purchasing and hedging strategies.

- Optimising the use of flexible supply and demand capacity for balancing reasons through integrated regional balancing systems: flexible capacities or power reserves should not be confined to single nations as they would be inefficiently used in a limited market area. The balancing market design as such should also be improved in many countries: a marginal pricing system with two prices for upward and downward regulation is essential to create the right price signals when the market is tight.[18]
- Incentivising RES generators to progressively participate in the market on a level playing field with all other generators. RES generators should eventually: be responsible for selling their own production in the market (i.e. not via the TSO); be required to schedule, nominate and balance their portfolio; offer positive/negative bids and offers into balancing and reserve markets rather than being pure "must run" capacity. In addition, there should be harmonisation towards European market-based support mechanisms[19]. This would "expose" RES generators to market prices reflecting demand and supply variations, therefore decreasing inefficiencies such as frequently occurring negative prices, and allowing substantial cost reductions[20].
- Removing any restrictions on plant operations, including free withdrawal from the market (or mothballing) of unprofitable plants. While this might temporarily lead to tighter markets and probably higher price volatility, it would also trigger a higher need for demand participation and new investment in the market, thus incentivising demand and supply to find a new equilibrium point (if the market design allows).
- Widening wholesale markets area by implementing European-wide market coupling by 2014 as targeted by the European Commission.
- Promoting more flexibility in gas markets and rules, as regards the balancing regime (including access to flexibility tools such as storage and linepack), nomination and re-nomination lead times, secondary markets for both capacity and commodity, procurement contracts, etc. A gas target model should be developed to avoid price spreads between neighbouring gas markets when cross-border capacities are not physically congested[21].
- Implementing and harmonising market transparency throughout Europe, e.g. on grid and generation outages, in order to give market participants a clear and accurate view of market tightness.

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18 See EURELECTRIC's position paper from July 2008 on this subject: "EURELECTRIC Position Paper Towards Market Integration of Reserves & Balancing Markets", www.eurelectric.org.

19 Non market-based support mechanisms, such as feed-in tariffs, can be helpful in "kick-starting" renewables development but are unlikely to be economically sustainable when RES reach higher market shares.

20 Up to 10 billion € per year, according to the EC Communication "Renewable Energy: Progressing towards the 2020 target" COM (2011) 31, January 2011.

21 This leads to competition distortion in coupled electricity markets, and thus to more congestions than necessary, in turn reducing electricity cross-border capacities in the intraday phase.

3.2. Will market improvements be enough or implemented in time?

All above-mentioned improvements will undoubtedly be necessary in all EU markets to minimise the system costs of ensuring generation adequacy. They should therefore be pursued by policymakers in parallel with the increased penetration of RES generation. Yet the key question remains: will they be sufficient in every EU region? The answer is probably yes, if they are all implemented in time. But what does “in time” actually mean? In general terms, this means before changes in power plant investment plans (expected closures and new builds) can jeopardise the future level of generation adequacy. Obviously this moment varies from market to market, depending on current conditions and future scenarios.

However, in some EU markets it appears unlikely that all market improvements will indeed be implemented in time. The cost-benefit ratio of each improvement and the required implementation time play an important role in this respect. For instance, market coupling has basically “no cost” and can be implemented quickly, but will have only a limited impact in some markets (even if the optimal allocation of interconnection capacity will somewhat reduce the need for new generation capacity). By contrast, increasing interconnection and developing effective demand-side response are very lengthy processes, and the latter’s effectiveness may vary from country to country. So what are the problems associated with the measures highlighted above?

- Increasing transmission capacity: Licensing issues, difficult terrain, funding issues, coordination of systems, etc., mean that increasing interconnection capacity on some borders can takes decades. Preventing or removing “internal” national network congestions is also often both long and costly.
- Demand side participation: The potential of demand participation varies across countries: per capita consumption levels may differ according to climate and to the industrial structure; the presence of significant interruptible load depends on the share of energy-intensive customers, electric or gas heating and cooling, etc[22].

  Moreover, any large-scale development will be complex (involving standard definitions and hardware implementation for smart grids and smart meters, funding issues, setting up dynamic pricing models, educating consumers, etc.) and will therefore take time.

  Many applications that aim for demand side participation actually shift energy demand from one moment in time (when supply is scarce) to another (when supply is large enough). Such applications require adapted steering signals and other updates. For instance, heat and cooling systems will need larger buffers to store heat/cold longer. Storage will become more important in this context and should of course be developed. Yet the potential for heat is limited and a large-scale roll-out of batteries and electric vehicles will take a long time.
- Price caps: Some governments still exercise price control over wholesale and retail energy prices, and the prospect that they will let go of this prerogative depends mainly on political orientations.
- Develop other sources of flexibility on the supply side: Gas market flexibility is still rather low in most countries[23] and must therefore be accelerated over the next few years. The same applies to the lengthy process of integrating EU gas markets and to significantly increasing energy storage in general (hydro, pumped storage, compressed air, etc.).

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22 Demand side participation can also be developed to utilise cheap RES surplus power, for instance to produce heat production with heat pumps and electric boilers replacing fossil fuels. Another option would be to produce hydrogen through electrolysis, which however requires further technological development of hydrogen storage.

23 However, some Member States are currently reviewing their market design (in particular the balancing regime) and developing additional storage facilities.

3.3. Could capacity remuneration mechanisms be a solution?

As the improvements outlined above may not all be implemented in due time – at least not in all EU markets –, a new solution in terms of market design could be appropriate and necessary for some markets. Capacity remuneration mechanisms (CRMs) are one instrument that has raised thorough reflection in the USA and Europe, from politicians to academics and sector professionals alike.

In some countries, including some of those where the market was initially conceived as an "energy-only" market, various CRM elements have been introduced in order to allow some or all generators to recover the share of their costs not remunerated by the energy-only market.

The main feature of these mechanisms is that they provide investors with a minimum but fairly guaranteed stream of revenues for their investments. In most CRM models, price volatility (price spikes) is reduced because the capacity remuneration guarantees that enough capacity is available in the system. Thus scarcity periods and the associated price spikes occur less often. CRMs have a number of advantages and disadvantages. Many of the benefits are related to the pursued objective of fostering investments to preserve generation adequacy. However, being a regulatory intervention, they also have several drawbacks. These need to be evaluated with a cost-benefit analysis when considering this option.

The main advantages and drawbacks are summarised below in a simplified and non-exhaustive list. Depending on the specific CRM model, its design and its market context, any of the listed advantages or disadvantages may be more or less pronounced (chapter 4 analyses the specific features of different models in greater depth).

Pros:

- Less uncertainty in revenues, resulting in stronger incentives to invest in (new or existing) generation capacity;
- Higher generation adequacy and security of supply for the system;
- Less price volatility (price spikes) benefiting some types of consumers that will have a stable, more predictable electricity bill;
- Lower financing costs for generation investments thanks to lower uncertainty.

Cons:

- Regulated choice on the amount and/or quality of reserve margin needed, which might "arbitrarily" impact the supply-demand balance and thus market prices (although a certain degree of regulatory measures to determine reserve margins is necessary in any case)[24];
- Potential disincentive for demand side participation in the energy-only part of the market and for investments in interconnections and storage, due to less price volatility;
- Possible negative impact on market integration and investment distortions with neighbouring countries;
- As some experiences show, design and implementation can be complex. Moreover, existing models have been mainly developed to guarantee peak capacity, while new models would have to mainly target the RES "back-up" dimension of generation adequacy.

24 The basic principle that the wholesale markets, through hourly marginal pricing, deliver the most efficient solution would, at least partly, be distorted.

4. Capacity Remuneration Mechanisms: Needs, Models, Open Issues

4.1. In which market conditions should capacity remuneration mechanisms be considered?

Capacity remuneration mechanisms (CRMs) are generally introduced to overcome one or more shortcomings of electricity markets, as a means of nevertheless ensuring generation capacity availability. As the name suggests, CRMs foster generation adequacy by remunerating plants not only on the basis of their output (MWh) but partly also on the basis of their capacity availability (MW). In the particular case of high intermittent RES penetration, the proposed mechanism should also adequately remunerate flexible generation capacity necessary to cope with a large share of intermittent RES. Existing models implemented so far in the US or in some EU countries were not initially designed with this additional goal in mind.

When considering the introduction of a CRM in a particular national market, some key factors should be taken into account, namely:

- Negligible impact of demand participation in wholesale price setting
- Lack of sufficient transmission capacity (especially cross-border)
- Presence of significant regulatory/operational distortions such as:
  - Existence of price regulation at wholesale or retail level
  - Regulatory decisions directly affecting the generation mix (e.g. limiting generators' decisions to withdraw non-profitable plants).

The following subsections further elaborate these three factors.

4.1.1. Negligible impact of demand participation in wholesale price setting

The role of demand in setting prices is probably the most critical issue to consider when analysing the ability of a certain electricity market to deliver generation adequacy. In theory all components of the demand should actively participate in the market, adapting their consumption to price signals and thus decisively influencing price setting[25]. In practice it is enough if a "relevant" part of the demand is price responsive and participates in the market, either directly or through an aggregator[26]. For some countries, this is already the case today, mostly through the participation of energy-intensive industries in wholesale spot markets and even in reserve and balancing markets. If their contribution is effective in setting the price, this level of demand participation is probably enough to avoid the need for CRMs. The development of smart metering and smart grids will be a further big step towards enabling demand participation also for smaller customers, but will take several years to reach a significant scale at EU level.

On the other hand, in markets where demand does not participate at all in setting wholesale market prices – or where its impact is not significant – the introduction of a CRM should be considered.

25 An alternative could be paying suppliers to hedge price volatility by contracting providers of peaking plants.

26 Provided that the aggregator can intervene on single end-users.

In this context, it should be kept in mind that any intervention deterring active demand participation negatively affects the ability of electricity markets to work properly and deliver generation adequacy. In particular, regulated wholesale prices or end-user tariffs are a type of market price distortion that, since they prevent (scarcity) market prices from being passed on to customers, impedes demand from having any incentive to react to spot prices.

4.1.2. Lack of sufficient transmission capacity

A system's generation adequacy also depends on the availability of internal transmission capacity and the physical interconnections with neighbouring systems. In the case of a complementary energy mix on each side of the border (taking also into account that intermittent generation will not have the same production pattern in each country[27]) strong interconnections can allow countries to access reserve capacity resources beyond their borders when needed to cover peak demand and back-up or flexibility needs for intermittent and unforeseen variations of generation supply. Integrated markets with enough cross-border capacity will allow systems to assess and address their capacity needs in a coordinated manner, especially where cross-border intraday and balancing markets function effectively. The larger the area for potential reserves and back-up generation, the less need for introducing CRMs in that area.

The principle is also valid for domestic transmission capacity: bottlenecks in national grids can limit a system's ability to provide the necessary amount of generation capacity at all times. This is especially true if the generation portfolio is geographically strongly diversified within the country, for instance with wind production in one particular area and CCGT plants in another.

By contrast, if a system has limited internal transmission capacity and interconnections with its neighbours, its isolated market can rely only on its own "local" resources for generation adequacy. If sufficient additional interconnection capacity is not developed in time, and if other market or technical constraints jeopardise generation adequacy, it is sensible to consider introducing a CRM.

One simple indicator of a market's degree of isolation is the amount of cross-border capacity as a percentage of the peak demand. However, we regard this partial picture as too narrow and would suggest considering a number of additional factors, including the presence of internal bottlenecks, the utilisation of interconnection (and internal) capacity, the system's generation portfolio (e.g. share of intermittent vs. flexible sources) as well as that of the neighbouring markets. If two markets have high interconnection capacity but a very similar and/or inflexible generation portfolio (and wind generation locations with highly correlated wind speed patterns) this would contribute less to generation adequacy than if the same amount of interconnection capacity were to exist between two markets with different and/or flexible generation portfolios. For instance, markets with a large share of hydro generation can potentially offer significant benefits in terms of generation adequacy to their neighbouring countries, if sufficient interconnection capacity is developed.

27 In fact, a broader integration of national electricity systems can also enable a "portfolio balancing effect" for intermittent RES, therefore smoothening their injection profile in the grid.

Some studies[28] have tried to assess the "criticality" of generation adequacy due to the introduction of RES across the EU as a function of interconnection capacity, share of intermittent RES and peak (or minimum) demand. While this analysis can provide a generic idea of where CRMs may be most needed, we believe several other factors (namely those mentioned in this paragraph, as well as under 4.1.1 and 4.1.3) should be duly considered by policymakers.

4.1.3. Regulatory distortions

A number of regulatory interventions can distort the normal functioning of the market and therefore prevent the correct price signals for generation investments. Among these, we consider as most relevant: price caps and regulated tariffs as well as regulatory decisions directly affecting the generation mix.

a) Price boundaries:

Generation assets can be fairly remunerated only when the wholesale market price reflects the cost of scarcity. If regulatory authorities set a cap to wholesale market prices, so that scarcity costs are no longer reflected in the prices, the previously described "missing money" problem will arise.

Some governments and national regulators believe the price should not be freely set by market participants, preferring instead to keep some control by introducing price caps. While many EU wholesale markets[29] have price boundaries in place, their assessment depends on the level of such a price cap. In some cases, the cap is set close to what is perceived as a fair scarcity price – the price is intended to replicate the price of scarcity. In these cases, the distortion to the market can be considered as low or negligible. On the other hand, there are cases where the price boundary bears no relation to scarcity costs and the level of the cap is arbitrarily set at a level considered "politically acceptable" (by either the government or public opinion).

It should also be noted that some regulators might be tempted to tighten the price boundaries when a CRM is in place. However, we believe this measure would be counterproductive: it would make demand participation in the market even less attractive.

b) Regulatory decisions directly affecting the generation mix:

A number of regulatory interventions can impact the generation mix, some of which result in critical distortions:

a. Impeding (through a "veto" of TSOs or regulators) generators' decisions to close or mothball non-profitable plants. As system operators are responsible for assessing and ensuring system reliability, they would like to keep control over plant closure decisions, rather than leaving this decision to market drivers only. This is especially true for those plants which – even if they are currently not (or scarcely) running – are forecast as "necessary" for the system to cope with lower firmness of intermittent RES. In some countries, TSOs or regulators have denied an authorisation for these plants to shut down or even to close temporarily.
b. Priority dispatch for some non-RES sources – as for example the prioritising of indigenous coal in Spain – is another type of intervention which distorts the market equilibrium by bringing certain plants out of the merit order, increasing the amount of "missing" money.

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28 Pöyry Management Consulting, "The challenges of intermittency in North West European power markets" – March 2011.
29 We refer here to power exchanges, not to "over the counter" (OTC) markets.

In these situations some plants will not be fairly remunerated and could incur losses. As these regulatory measures determine a high "regulatory risk" which investors will duly factor in when making their investment decisions, the result may be a deterioration of the investment climate leading to insufficient new builds and compromised generation adequacy. In these circumstances, the regulatory distortions (which should in any case be removed) would justify the introduction of a capacity remuneration mechanism.

4.2. What are the main types of capacity remuneration mechanisms?

It is difficult to categorise the numerous different types of CRMs: many features and design options can vary between one model and the next. However, to simplify our analysis, the main types of CRMs can be divided into five categories[30]:

- **Capacity payment (CP):** pays a fixed amount for available capacity to all generators. The level of payment is set by a central body, rather than through a competitive process. The payment could be given also when the plant does not run, but certain availability criteria have to be met.
- **Tender for targeted resource (TTR):** capacity payments are only given to resource needed to make up for any shortfall in the market. The level of payment is set through a competitive tendering process. Conditions on how the resource operates limit the market distortion, as they in principle only operate in extreme peak conditions[31] (as in the Swedish model where they enter in the market at a premium to the market price only when the market coupling result would lead to a curtailment).
- **Capacity obligation/ticket (CO):** an obligation on suppliers to contract with generators for a certain level of capacity (determined by TSO/regulator and related to their average off-take or off-take profile) or pay a buy-out price/fine if not enough capacity is contracted. The price for capacity is determined in a decentralised way, through the contracts; this model could also include a market of exchangeable obligations.
- **Capacity auction (CA):** the capacity volume is set centrally (normally by the TSO or regulator) a number of years (e.g. three years) in advance. The price is determined by auction and paid to all resources (existing and new) clearing the auction. The total auction value is charged to final customers through suppliers/distributors based on their off-take (or off-take profile). This mechanism is currently used in the PJM and ISO-NE markets in the USA.
- **Reliability option (RO):** this model is also based on a forward auction, but as a financial market instrument (a "call option") rather than a physical instrument; generators must be available to the system operator for dispatch above a defined strike price. This model has been proposed by several academics, but has been implemented only in Colombia.

30 Classification based on UK consultation document: "Electricity Market Reform", December 2010. However sometimes other names/classifications are used, see also the Brattle Group: "A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs", September 2009.

31 One could imagine their use out of extreme peak load situations (i.e. an economic dispatch), however this would then distort (lower) the market prices and thus lower the rent of other capacities, which might lead to a decommissioning of these plants, leading to a vicious circle where more plants should be contracted and in the end the whole market would fall under this remuneration.

4.3. Effectiveness of the different CRM models

Capacity remuneration mechanisms should be evaluated by way of several criteria, among them the type of problem they solve, non-discrimination between actors, stability of the long-term investment signal, consistency with the European internal energy market and its integration process, technical and economical feasibility, fairness for both customers and investors, avoidance of gaming by participants, successful implementation examples, etc.

A detailed analysis of the different models would however go beyond the scope of this paper – the five categories of models would have to be described in much more detail to allow for a comprehensive comparison. In addition, theoretically effective models may prove rather more ineffective in a specific, real-life market context – and vice versa. Designing an effective mechanism for a specific case will also need to take compatibility constraints into consideration, which need to be assessed on a case-by-case basis.

This paper therefore provides only a general and non-exhaustive comparison of the different models classified in 4.2, highlighting their main pros and cons. In practice, additional design features might enhance or mitigate the advantages and disadvantages outlined below.

CRM Model	Advantages	Disadvantages
CAPACITY PAYMENTS	• Simple and flexible tool for policymakers to retain and attract necessary generation capacity • All firm generation capacity becomes less costly through the stable and direct payment • The payment automatically reduces to zero when the required reserve margin is reached	• Often, neither price nor volume are determined via market based tools o Higher risk that payments will be changed ad-hoc or in a non-transparent manner adding regulatory risk • Risk that payments become the main driver for investment • Cost normally recovered from customers through charges based on consumption rather than peak load (but could be addressed through design)

CRM Model	Advantages	Disadvantages
TENDER FOR TARGETED RESOURCE	• Easy to implement • Retains only the necessary peak load reserve plants at limited system costs • No disturbance of the (spot) wholesale price formation mechanism => energy prices remain the main driver to attract new investments at the location where needed • Potentially less expensive than other models (since only a limited part of the capacity is remunerated)	• Existing models mainly targeted at existing peaking plants (that would otherwise close): o No direct incentive/support for new investment (especially in mid-merit flexible plants) o Not ideal to remunerate "stand-by" service for intermittent RES plants as TTR resources may be called too often • Lower demand response in the spot market (especially if demand is allowed to participate in the TTR) • If supply/demand is in balance but there is a high price, some available TTR resources may not be used because the price boundary to activate them is not reached
CAPACITY OBLIGATIONS	• Decentralised mechanism reduces degree of regulatory intervention • Straightforward tool for regulators: simple obligation placed on suppliers equal to the desired reserve margin • Cost of capacity adequacy assigned to suppliers whose customers are causing more peak load demand (gives suppliers more incentives to flatten their off-take profiles)	• Lack of forward requirements limits long-term price signals for investments • Potential barriers for new entrants who have to purchase tickets before knowing their customer portfolio, especially if many customers switch • Issuers of capacity obligations (i.e. generators) do not have a direct incentive to be available at the peak (or when necessary) • If markets of exchangeable obligations are not liquid and transparent enough, (new entrant) suppliers may face high risks • In a market with many suppliers, verifying their "voluntary" compliance is a complex process

CRM Model	Advantages	Disadvantages
CAPACITY AUCTIONS	• Stabilisation of investment through (multi)year forward commitments • If “scarcity pricing” is adopted: incentives for production & consumption; avoidance of double payment of peak energy rents • Successful implementation in US (e.g. PJM) • Centralised capacity markets provide liquid and transparent price formation (as for all models where capacity is paid via a tender or auctioning process)	• Volatility of capacity prices and therefore of price signals for investments observed in US • Transferability of US models to EU markets questionable (mandatory vs. voluntary exchanges, different balancing arrangements, participation of imports, zonal vs. nodal) • Requires complex design and constant implementation adjustments (e.g. modelling demand curve: volume and price-setting determined by “Cost of New Entrant” parameter) • Risks becoming the main driver for investment (as spot price volatility is reduced)

RELIABILITY OPTIONS	• Strike price ensures stable payments to producers => risk reduction for both producers and consumers
	• Good incentives for generators to invest and to maximise their output/ availability during shortages
		• Original design more suitable for mandatory pool systems
		• Absence of sufficient number of practical experiences
		• Determination of the strike price level is key to make the model successful:
		  ○ If too high: generators stay in an energy-only model;
		  ○ If too low: risk of interfering with other price drivers (e.g. increasing fuel costs alone should not lead to reaching the strike price!).

Overall, considering that most of these models were designed to ensure capacity availability during peak load situations[32], rather than for RES back-up, policymakers should enhance the effectiveness of any model under consideration by adapting the general design to the specific needs of RES integration. The next section outlines a number of general recommendations and issues to be taken into account when designing and implementing CRMs.

32 The TTR model, for instance, will not ensure an efficient back-up capacity for intermittent generation as it will run only in extreme market conditions when there is a risk of shortage. Indirectly, it can however improve possibilities for commercial back-up generation when some of the existing plants are reserved only for the TTR use and thus do not operate in the commercial market. Contracting existing capacity as tertiary reserve by the TSOs will have the same effect. The remaining commercial back-up capacity can then get adequate revenues from the sales in the day-ahead, intraday and balancing energy markets since an element of existing capacity is then prevented from offering in normal markets, leading to higher scarcity rents.

4.4. General design and implementation issues

With a view to completing the EU internal energy market, EURELECTRIC believes that any CRM should take a European perspective as far as possible in order not to hinder market integration or distort competition. Even if models and design features may be implemented differently according to the specific needs of a certain national market, a minimum set of harmonised principles should be agreed at regional and EU level to avoid endangering the benefits of market integration already achieved.

In this section we identify some general design and implementation features which in our view should be common to all models:

- *Should the capacity remuneration differentiate between technologies and between existing and new plants?*

  No. In order to avoid competitive distortions and to guarantee maximum liquidity within the CRMs, discrimination between different forms of capacity, including load shedding provided by the demand side, should be avoided. If the scheme is properly designed, the market will provide the most cost-efficient solutions.

  The amount of rights/payments attributed to a plant should depend on the guaranteed service it will offer to the electrical system, which depends in turn on several criteria regarding, for instance, total installed power capacity, plant availability, ability to generate when needed (reliability), technical specification like ramping rates, start-up times, etc. As implemented in several existing models, a complementary mechanism of bonuses and penalties could ensure that those plants (or customers via load shedding) that received the remuneration upfront are actually available when and as long as needed by the system. The basic principle is to verify ex-post the real availability of such capacities and reward or penalise those which were available for longer or shorter periods than needed. By doing so, plants with a higher level of firmness and reliability would be adequately remunerated because of their higher service to the system.

- *How should demand participation be treated by the capacity remuneration mechanism?*

  Demand should generally be incentivised to contribute to security of supply through load shedding. The contribution of load shedding and generation should be treated equally in economic terms.

  Load shed availability should be closely tracked. Verifying customers' availability for load shedding is in fact more difficult than verifying the availability of conventional power plants to increase their output or to start up. Likewise, it is more difficult to determine the marginal price of customers (i.e. the energy market price for which they are willing to interrupt their consumption) than the marginal price of generators (although difficult to estimate for hydro generation).

  Incentivising demand participation through CRMs might however not always be the most appropriate solution. In the TTR or CA model, for instance, end users could participate in the tender for the capacity premium, but could also be present in the daily spot markets, where they would be able to benefit from spikes (below the curtailment level) by offering to reduce their off-take. In these cases it would therefore be more appropriate to incentivise customers to participate directly in the supply curve of the spot market, without taking part in the CRM at all.

- *How should the issue of potential double payments be addressed?*

  The issue of "double payments" occurs when the party that benefits from capacity remuneration receives additional income via spiking energy prices at moments of market tightness. The presence of the CRM, in fact, will reduce the frequency of (scarcity) price spikes but will not eliminate them completely.

  As pointed out in 4.1, price boundaries should generally be avoided or set at sufficiently high levels[33]. Even with a CRM in place, this will still create incentives for the demand side to participate in the spot market and reduce the need for additional generation capacity. Additionally, policymakers should be careful when introducing far-reaching measures to prevent "double payments" as such measures could remove any prospect of capacity being constructed and/or maintained on the basis of the energy price. In some existing models, particular measures have been taken (e.g. the capacity auction schemes in the US): when spikes occur, there is an off-set of the capacity remuneration compared to a predetermined limit market price. This however complicates both the implementation and the administrative monitoring[34].

- *Who pays? And how? Are customers all equal (peakload vs. baseload customers)?*

  When developing CRMs, customers with a baseload profile, who cause less costs to the system, should in principle contribute less (per MWh) than customers with a profile that includes more peak load demand. Models such as the capacity obligation model would reflect this quite directly: a baseload profile of 1 MW would be able to spread the capacity obligation cost over 8,760 hours, while an off-take with 1 MW during peak hours and 0 MW during off-peak hours would have the same capacity obligation, but be able to spread the costs over only about 4,000 hours.

  Our proposed solution would therefore be to make customers pay on a MW-basis, ideally measured at times when the system reaches peak levels (or residual peak net of RES generation levels). In most network contracts the customers pay a MW-based price, which in this case would not go to the grid operator but to their supplier. To further improve the implementation of CRMs, full deployment of smart meters is necessary. This will enable customers to be metered with an increased frequency of interval data.

  It could also be questioned whether a customer with a baseload profile should be required to contract the same amount of capacity per MWh as one with a peak load profile. Differentiating between them would further stimulate suppliers to find customer portfolios that approach as closely as possible a baseload off-take, and incentivise these suppliers proposing contractual arrangements to their customers to offer them load shed facilities.

  As a rule of thumb, any model should result in a fair symmetry between funding and payments. This looks more likely to be achieved in centralised models (like CP, CA, RO and TTR) than in decentralised models. In centralised models, the costs will first be borne by the TSOs, who will then pass on these costs to the grid users. In decentralised models like the capacity obligation model, it is more difficult to see how suppliers will balance costs and revenues. On the other hand, being a market-based model, more customers might change supplier if they see that their charge for capacity is comparatively high. Customers in such a model will only become sensitive to the capacity fee when clearly marked on their invoice, and if a transparent framework guides the entire capacity remuneration process.

33 Like, for instance, the technical maximum price in the CWE market set at 3000€/MWh.

34 In markets where this issue could raise concerns, we believe that a reliability option (RO) mechanism could be an adequate solution, as the strike price will cap prices and avoid double payments at the desired level.

4.5. Capacity remuneration mechanisms: key open issues

4.5.1. How to treat cross-border capacity for the purpose of capacity remuneration systems?

EURELECTRIC believes that markets with a CRM in place should not discriminate between capacity provided domestically or from across the border. The liberalisation process has opened competition between foreign and domestic market players for the supply of energy, and this should extend to the supply of "capacity products".

However, it is also clear that, in comparison to energy supply, "delivering" capacity products across borders is challenging. Unlike energy, "availability of capacity" can only "cross" the border if sufficient firm cross-border transmission capacity is available. While energy actually enters into the area of demand via physical flow, capacity availability "remains" in the area of the generation asset (or of the load shed potential). Delivering such capacity to a non-domestic market with a CRM in place would thus require that the capacity can be made available for that market whenever needed. To this end, a cross-border capacity "channel", as well as domestic transport capacity up to the interconnection, would need to be firmly available.

Without considering the internal network, reserving part of the cross-border capacity for CRM purposes would make this capacity no longer available for the liquidity of the cross-border energy market on the various timeframes: long-term, short-term (day-ahead coupling), intraday or even balancing. Establishing such a dedicated channel would therefore jeopardise the general principle – advocated by EURELECTRIC – that cross-border capacity should be offered to the energy market as much as possible in order to maximise competition across borders. Rather, any ex-ante reservation of capacity would in fact reduce competition in the energy markets, in particular in the day-ahead and intraday market timeframes where market outcomes determine the physical energy flows in the system. The Target Models[35] adopted by the Florence Forum ensure optimisation of energy flows at any moment by directing them to those market locations where the energy is valued the most, subject to the available cross-border capacities. As a general principle, any cross-border capacity reservation may therefore hinder such optimisation.

These arguments demonstrate that cross-border participation in CRMs would become fairly complex, and would actually require full integration of market (bidding) areas in order to bring competing capacities on equal footing in the CRM. As market integration leads to larger price areas (and generation capacity is assessed on wider areas), this demonstrates that the more markets are integrated (moving towards a "copper plate" world), the more transmission and generation capacity can be commonly used and the easier it becomes to select the more efficient assets. Since market integration will be an important tool to reduce the need for CRMs, policymakers in favour of a CRM should ensure that its design and implementation are as harmonised as possible on a regional level.

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35 The target models for the integration of the EU electricity markets cover forward, day-ahead, intraday and balancing markets as well as capacity calculation and governance issues. Their detailed features are now outlined in the "Final ERGEG Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity" (February 2011), available at www.energy-regulators.eu. The 15th Florence Forum, held on 24-25 November 2008, invited ERGEG to establish a Project Coordination Group (PCG) of experts, with participants from the EC, Regulators, ETSO, Europex, EURELECTRIC and EFET, involving Member States' representatives as appropriate, with the tasks of developing a practical and achievable model to harmonise interregional and then EU-wide coordinated congestion management, and of proposing a roadmap with concrete measures and a detailed timeframe, taking into account progress achieved in the ERGEG ERI. This PCG was chaired by the European Energy Regulators and met regularly to develop an EU-wide target model for the integration of the regional electricity markets.

4.5.2. How do CRMs interact with market coupling?

To assess the interaction between CRMs and market coupling, let us imagine a simplified European map like the one below, where different types of CRM have been implemented in different markets, and where one market has no capacity model (NC) in place.

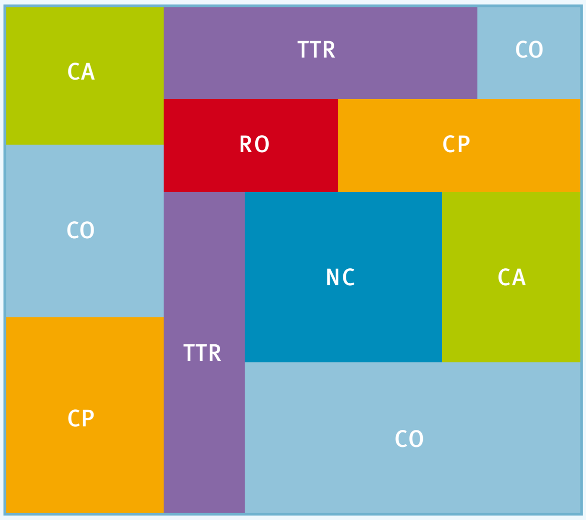

Figure 7: Possible "geographical patchwork" of different CRMs in the EU

Let us first analyse three short term situations:

Market A	Market B
CRM - X	CRM - X
NO CRM	CRM - X
CRM - X	CRM - Y

1) Technically, market coupling should work perfectly in neighbouring markets with the same CRM: in this case the results obtained through the market coupling are consistent and the most efficient power plants/capacity are/is selected. Indeed, market participants on the supply side will still be incentivised to offer their energy at marginal prices.

2) In cases where one market has no CRM and the neighbouring market has a CRM in place, market coupling results would also be unaffected, as all market participants would still be incentivised to offer their energy at marginal prices[36]. The same comment is also valid for RO models.

3) The same applies to market coupling between markets with two different CRMs in place (for instance CX and CY): as long as there are no price caps in either market, market coupling outcomes would still not be affected – irrespective of the available cross-border capacity.

36 Provided, of course, that players are not obliged by other regulatory measures to follow a certain bidding behaviour or to compulsory bid in exchanges at certain given times.

4.5.3. How do CRMs affect generation investments in neighbouring countries?

In the previous section we concluded that the introduction of a CRM does not hinder market coupling outcomes in the short term. However, if coupling between two markets results in price convergence, the differences in design between the two CRMs – especially if the mechanisms are not well calibrated – may cause generation investments to be more attractive in one of the two markets.

For two markets with sufficient interconnection, a lack of level playing field would, in the long term, create a lack of investment on one side and a higher investment level on the other, eventually resulting in differing generation adequacy and probably also in differing marginal cost structures. The ensuing decline in price convergence would thus paradoxically jeopardise the original benefits of market coupling: an initially non-congested border would then become congested[37].

On the other hand, if cross-border capacity is lacking and markets are partially isolated, different CRMs would attract more investments to the market with the best incentives. If the model is not well designed, the low price area risks attracting more investments, leading to less price convergence, and thus deteriorating the market coupling outcomes.

For these reasons EURELECTRIC would like to encourage policymakers, if CRMs are introduced, to coordinate their work and progressively establish a minimum set of harmonised principles in Europe. As a minimum, all the countries involved in the same market coupling project/region should coordinate their respective policies. This will guarantee the correct functioning of the market coupling in the long term and will avoid distortions that affect investment decisions and competition among generators. A positive example in this context is the cooperation between Spain and Portugal, where on top of a market splitting, countries share a very similar model of capacity payments scheme.

As a conclusion, the interactions between different CRM models in neighbouring markets could be summarised as follows:

Market A	Market B	Short term	Long term
CRM - X	CRM - X	OK	OK
NO CRM	CRM - X	OK	Not Ideal
CRM - X	CRM - Y	OK	Not Ideal

37 This trend would continue until a market with a CRM reaches the desired level of capacity reserve so that capacity remuneration for new investments would normally decrease to zero.

4.5.4. Relationship between capacity remuneration mechanisms and reserve market for ancillary services

TSOs are obliged to permanently secure the balance of power supply and demand during the operational hour through the balancing market with adequate reserves (in addition to the automatic primary and secondary reserves for frequency control). Two main market design alternatives for this are:

- capacity remuneration for all capacity, thus guaranteeing adequate volume of reserves (but not necessarily adequate reserve quality, i.e. start-up time);
- tertiary reserve contracts for capacity available within 15 minutes.

In most European markets, TSOs ensure the availability of tertiary reserves through long-term (quarterly, annual or multi-annual) or short-term (daily) contracts. Tertiary reserves are needed in order to:

- cope with major or systematic imbalances in the control area;
- offset a significant frequency variation;
- in certain markets, also to resolve major congestion problems.[38]

With growing intermittent RES generation, the system imbalances and thus the need for tertiary reserves will increase in spite of more liquid intra-day trading possibilities. In order to attract adequate reserve volumes, the tertiary reserves should be procured from both generation and the demand-side through competitive procedures.

With adequate reserve compensation (taking into account the balancing energy income as well), the tertiary reserve contracts will provide incentives to invest in new flexible reserve capacity and to maintain the existing capacity. Cross-border procurement of tertiary reserves could also be possible when no grid congestions exist.

When using CRMs, tertiary reserve contracts might be additionally needed to guarantee the reserve quality. In that case, both the general capacity remuneration and the tertiary reserve payments have to be considered in generation investment decisions.

38 See Elia, Product Sheet Tertiary Production Reserve, at: http://www.elia.be/repository/ProductsSheets/S3%20E%20TERTIARY%20RES.pdf.

4.6. How to introduce or phase out CRMs

It could be argued that EU Member States should have the freedom to address their security of supply by implementing any type of CRM that attracts new investment in generation or prevents existing plant from being decommissioned. This is however not the case as EU legislation already sets some important principles that Member States have to respect when additional measures to foster availability of generation capacity are introduced. For instance, Member States are required to maintain demand/supply balance by establishing wholesale electricity markets that provide "suitable price signals for generation and consumption"[39]. Additional measures should generally be restricted to situations where normal market mechanisms do not suffice to ensure the required generation capacity and/or demand response[40].

In addition to respecting existing EU provisions, national policymakers should duly take into account all the possible interactions between security of supply measures and the completion of the Internal Energy Market. As we move towards integrated day-ahead and intraday wholesale markets (agreed by all EU stakeholders for 2014), it is important to ensure that EU market designs find the appropriate balance between subsidiarity and harmonisation and that possible national CRMs are consistent and not in conflict with the EU Electricity Target Models.

Already today the attractiveness of investing in electricity generation varies across countries. This can be related to the national permitting procedures, land prices, the availability and cost of cooling water, gas and electricity infrastructure, tax structure, human resources knowledge and costs, etc. Introducing a CRM could enhance or mitigate these differences. But unlike geographical differences which are likely to persist, regulatory interventions such as CRMs should be able to be phased out as quickly as they are introduced – ideally automatically – as soon as generation adequacy can be permanently ensured by balancing supply and demand through energy-only pricing. Phasing out could be achieved either by dropping the mechanism as such, or by lowering the remuneration close to zero in the light of more favourable market conditions. This will mean investors will take into account a CRM only for a limited time horizon, so the effect will be limited. On the other hand if the mechanism is not automatic but generally aims at preventing the decommissioning of capacity, these effects will be felt for the duration of the CRM[41].

The effects of CRMs on market coupling discussed in section 4.5.2 are in fact effects on price formation. In the context of regional (and soon European) coupled markets, we believe that countries should unilaterally implement a CRM only if there is no effect on price formation and therefore on market coupling. If there is evidence of a continuous and relevant effect on price formation, CRMs should only be introduced on a wider, regional scale or not at all.

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39 Article 5 of the Directive 2005/89 on Electricity Security of Supply and Infrastructure states that *"Member States shall take appropriate measures to maintain a balance between the demand for electricity and the availability of generation capacity. In particular, Member States shall:*

a) without prejudice to the particular requirements of small isolated systems, encourage the establishment of a wholesale market framework that provides suitable price signals for generation and consumption.

b) require transmission system operators to ensure that an appropriate level of generation reserve capacity is available for balancing purposes and/or to adopt equivalent market based measures."

40 For instance, article 8 of the Electricity Directive 2009/72 states that tendering procedures may *"be launched only where, on the basis of the authorisation procedure, the generating capacity to be built or the energy efficiency/demand-side management measures to be taken are insufficient to ensure security of supply."*

41 The TTR model foresees contracts for existing capacity only for one year at a time and can thus be quickly phased out when no longer needed.

Before introducing a CRM model, policymakers should take into account the following principles:

- The first step should be to **estimate the required generation adequacy level** of a certain system, taking into account the penetration of intermittent RES, the interconnection capacity, the demand participation, etc. Based on the estimated value, a thorough analysis should be carried out to determine whether the current market design (without regulatory distortions) could ensure such a level of generation adequacy.
- A CRM should only be introduced if it is proven to **increase the social economic welfare** of the whole system, to be measured with a cost-benefit analysis on the increased level of security of supply. This means that the introduction of a CRM has to be accompanied by an assessment from the regulator or designated body of its effects for end-users.
- The **necessity** for a CRM should ideally be **assessed at a regional level**: having enough capacity to meet demand is also a regional issue that depends not least on the available cross-border transmission capacity.
- CRMs should be able to be **phased out once the market itself delivers** the appropriate investment incentives to ensure the adequacy of the system. In practice, we believe that, as is currently the case in some CRMs, the remuneration should follow a downward sloping curve which decreases to zero if the existing and future reserve margins are considered sufficient[42]. We believe that this approach provides a stable underlying model that at the same time delivers temporary effects when the problem of generation adequacy demands an additional solution.

42 At a level normally predefined by the regulator.

5. Policy Recommendations

Significant progress has been made over the last few years in the pace of integrating wholesale markets: the definition of appropriate target models for every timeframe of electricity trade, the monitoring of bottom-up projects' compliance with these models through a stakeholders platform and lately the clear objective set by the 19th Florence Forum[43] of establishing day-ahead price coupled markets and a single continuous intra-day platform in the NWE[44] region have given new impetus and a clear direction to the process of integrating wholesale electricity markets.

EURELECTRIC has drawn up this report as a contribution to this process and believes the analysis and recommendations elaborated before and hereafter are an integrated part of the implementation of the Target Models. To facilitate the development of a core market (the NWE region) which will act as a stepping stone to the establishment of a pan-European market by 2014, it is imperative that the introduction of CRMs, where they are necessary (see sections 4.1 and 4.6) is done in an adequate and appropriate fashion with full regard to their implications for the overall objective of completing the single electricity market. Based on the analysis and findings of the previous chapters, EURELECTRIC therefore proposes the following policy recommendations:

- As a first fundamental step, **energy-only markets must be allowed to function** properly by removing distortions which hinder the demand and supply balance. Such distortions include regulated end-user prices, restrictions on plant operations (including free withdrawal for unprofitable plants from the market whose costs cannot be recovered from market prices), price caps (or they should be at least sufficiently high to avoid constraining demand and supply), and other regulatory or administrative measures which unnecessarily hinder wholesale market outcomes.
- At the same time, **integration of wholesale markets must remain a top priority** for EU and national policymakers. Efforts should thus concentrate on implementing the Target Models of day-ahead market coupling, intra-day and long-term markets to fulfill the objective of an EU integrated market by 2014. This process should be accompanied by the strengthening of transmission capacity (both domestic and cross-border) and the establishment of regional balancing markets.
- Most importantly, and with a view to enhancing and speeding up the integration of renewables into the EU system, **RES generators must be incentivised to progressively enter into the market** on a level playing field with all other generators. In particular they should be incentivised to sell their own production into the market as well as to meet scheduling, nomination and balancing requirements on their portfolio as other generators do. In addition, there should be harmonisation towards European-wide market-based support mechanisms: this would expose RES generators to market prices reflecting demand and supply variations while allowing substantial cost reductions[45].

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43 http://ec.europa.eu/energy/gas_electricity/doc/forum_florence_electricity/meeting_019_conclusions.pdf

44 The Northern Western European (NWE) region is composed of Norway, Sweden, Finland, Denmark, Germany, France, Belgium, the Netherlands and the UK.

45 Up to 10 billion € per year, see footnote 20.

- Enabling **market-based demand to participate in wholesale market spot price formation** (also through large-scale[46] deployment of smart grids and smart meters) is fundamental for a well functioning electricity market, although very difficult to achieve. As demand response would considerably decrease not only the peak capacity demand but also the need for "back-up" plants, this must be a core element of current energy policies.
- In markets where all the above improvements have been made and generation adequacy is nevertheless endangered (by reduced investments and early decommissioning), policymakers should consider the **need** of introducing a **capacity remuneration mechanism ideally at a regional level**[47] or at least in coordination with neighbouring markets. In any case, consistency with the process of EU market integration should be ensured.
- If introduced, capacity remuneration mechanisms should be **able to be phased out once the market itself delivers** the appropriate investment incentives to ensure the adequacy of the system. In practice, the implemented model, while ensuring sufficient regulatory stability, should produce effects only as long as the underlying problem of generation adequacy requires an additional solution to complement well-functioning wholesale markets.
- Finally, while an EU-wide harmonisation of existing or future capacity remuneration mechanisms may be premature and unnecessary at this stage, we call on ACER and the European Commission (in cooperation with all relevant EU and national stakeholders) to start working on the development of a set of **minimum EU harmonisation requirements**. This should ensure the well-functioning of regional markets and compatibility with the aim of reaching an Internal Electricity Market by 2014. In addition, developments in national markets should be closely monitored – in particular the implementation of the Target Models – to ensure this political objective is met.

46 Where economically feasible.

47 This is in line with the requirements of the Third Energy Package on regional coordination.

Union of the Electricity Industry - EURELECTRIC

Boulevard de l'Impératrice, 66 boîte 2
1000 Brussels
Belgium

tel: + 32 (0)2 515 10 00 - fax: + 32 (0)2 515 10 10
VAT: BE 0462 679 112
website: www.eurelectric.org