Capacity Markets and European Market Coupling – Can they Co-Exist?[1]

RAP Discussion Draft, March 13, 2013

I. Introduction and Summary

The European Union (EU) is committed to creating broad, integrated regional markets for electricity by implementing what is referred to as the EU target model of *market coupling*. In effect, market coupling requires that regional --and no longer exclusively national—supply and demand for electricity will establish energy market clearing prices. This pan-European vision of market trading builds upon current European energy-only markets, which consist of power exchange-based short-term energy markets, longer-term bilateral trades between individual buyers and sellers, and real-time balancing services administered by the system operator.

By design, the target model optimises cross-border flows to reflect energy-only price differentials between the coupled markets. It implicitly allocates interconnector capacity in the day-ahead and intra-day timescales until a uniform market clearing price is achieved or the available capacity is fully utilised. The Annex to this paper presents a more detailed explanation of the EU target model and how it, in effect, combines the demand and supply curves for electricity (kWhs) of coupled markets to arrive at market clearing prices, with and without cross-border transmission constraints.

Europe is committed to achieving market integration through market coupling by 2014. At the same time, the rapid growth of variable renewable[2] production in pursuit of Europe's decarbonisation goals has intensified concerns over the ability of energy-only markets to deliver sufficient investment in conventional plant to ensure system reliability going forward. Consequently, a number of Member States have introduced or are considering arrangements to reward firm capacity explicitly, in the belief that this is required for progress towards

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[1] Co-authors: Phil Baker, University of Exeter and Meg Gottstein, Regulatory Assistance Project (RAP). Invaluable review and input also provided by Mike Hogan, senior policy advisor (RAP).

[2] "Variable" as used in this paper refers to any source of electricity production where the availability to produce electricity is largely beyond the control of operators. It can be simply variable—changing production independently of changes in demand—or variable and uncertain—variable, and in relevant timeframes, unpredictable. Another term for this latter category of services is "intermittent."

decarbonisation to continue without jeopardizing traditional levels of system reliability. "Firm capacity" refers to the volume of megawatts (MWs) guaranteed to be available to provide energy to the power system at any moment in time, most importantly when total demand is at its highest (peak) level.

The debate in Europe over the need for "traditional" quantity-based capacity market designs to provide investment is now—appropriately-- evolving into discussions over how to reward capacity with sufficient *flexibility* to reliably operate power systems with rapidly growing shares of variable renewables. The debate is also beginning to evolve away from an exclusive focus on supply-side resources and toward the inclusion of qualifying demand-side resources. As described in several RAP papers and presentations, the new resource paradigm in Europe and elsewhere requires this evolution of thought and market design in order to secure reliability at least cost. [3] But whether one is considering more traditional, quantity-based capacity markets, or mechanisms designed to address the future need for resources with enhanced flexibility or "capability", there remains the question: ***Can these arrangements co-exist with the EU target model, and if so, how?***

We address this question by exploring two key concerns raised in the European debate over Member State capacity market developments. First, there is concern that introducing firm capacity payments on a national rather than regional or even European basis could irreparably compromise the formation of consistent and uniform energy prices that is the basis for cross-border trading under the target model. Second, there is concern that differences in the market arrangements to remunerate firm capacity could create inefficient "virtual" (or even physical) migration of firm capacity, with generation seeking access to more stable capacity payments in adjacent markets.

In considering these issues, we commence with a short discussion of the perceived need for investment incentives for firm capacity, and their likely impact on both energy prices and the generation supply curve. We then consider the possibility of "double payments" for generation in receipt of capacity payments when markets with explicit capacity payments are coupled with markets that rely on energy prices alone to sustain investment in firm capacity. We suggest arrangements whereby these double payments could be avoided, namely by incorporating "claw back" provisions directly into the capacity payment design. The consequences, however, are that a Member State cannot create a firm capacity payment mechanism based exclusively on its *national* resource adequacy projections without potentially creating higher costs for its consumers and double payments to those generators receiving firm capacity payments. To

[3] See RAP straw man proposal "What Lies Be yond Capacity Markets? Delivering Least-Cost Reliability Under the New Resource Paradigm", at http://www.raponline.org/document/download/id/6041 and "Experience with Capacity Markets-Lessons for Germany and Europe", a presentation to the European Energy Design Conference in Berlin 21 August 2012 at http://www.raponline.org/document/download/id/6054

avoid this outcome, it must take into account how coupled energy prices reflect the combined bidding queue and total demand *across national borders*, and adjust (reduce) capacity payments accordingly.

The consequences of generation in an energy-only market seeking to access firm capacity payments by participating in an adjacent capacity market are also considered in this paper. We conclude that the target model's coupled energy prices are not expected to change with such occurrences. Nonetheless capacity could migrate "virtually" and, ultimately physically, towards the Member State with a capacity market and away from one without, in some cases resulting in an overall inefficient outcome. This resulting migration is likely to create competitive tensions between Member States over firm capacity commitments and associated investment. It could also it result in a reduction in total capacity across the two coupled markets. The net result of this reduction may in fact be the most economic outcome leading to significant cost savings for both Member States; however these mutual benefits cannot be effectively tapped without market design collaboration.

The potential consequences described above—double payments for firm capacity and virtual (and ultimately physical) capacity migration--could both be addressed with a more coordinated approach to resource adequacy assessment. Initial steps in this direction could, for example, include those set out in a recent study for the WWF Germany environmental foundation[4] and, over time, the creation, with appropriate regard to the availability of interconnector capacity, of regionally-based auctions with firm generation capacity "trading" arrangements. Essentially, this would extend the concept of "market coupling" to include resource adequacy and the procurement of capacity, as well as energy.

In sum, the answer to the question posed above is a qualified "yes". While differences in national capacity market design have the potential to create double payments for firm capacity and could lead to inefficient virtual (or physical) capacity migration between Member States, mitigating measures are available. Most notably, we observe that the process of market coupling, which has the distinct implementation advantage of not demanding total harmonisation from the outset, is likely to lead to the harmonisation over time of national policies aimed at ensuring resource adequacy. That is, as market coupling unfolds in practice, resource adequacy will increasingly be recognized as a regional issue, rather than an issue that can or should be exclusively dealt with on a national basis. This is not to imply that national resource adequacy issues become irrelevant - indeed it implies an expanded suite of options

[4] See *Focused Capacity Markets, A New Market Design for the Transition to a New Energy System,* prepared for WWF Germany by Őko-Institut and LBD-Beratunsgesellschaft available on line (at this time in German only) at http://www.wwf.de/fileadmin/fm-wwf/Publikationen-PDF/Fokussierte-Kapazitaetsmaerkte.pdf; Page 81 of the study sets out one example of a step-wise approach to harmonisation involving the delimiting of cross-border deliveries, joint assessment of security of supply and the harmonisation of central capacity mechanism functions.

available for achieving national resource adequacy - but rather that the interactive effects with market coupling will emerge in any case, and therefore it behooves Member States to explicitly consider and discuss them. We hope that our paper contributes to this outcome.

We also briefly explore the deliberate use of enhanced forward services markets as an “alternative way forward” to addressing future reliability challenges, rather than establishing separate payments for firm capacity alongside an energy market. We conclude that such services markets, employed for the purpose of acting as an alternative (or adjunct) to capacity payment mechanisms, would by their nature entail the possibility of the same interaction with energy prices as we describe in this paper, with similar remedies. However, we also discuss the ability—and potential advantage-- of an enhanced forward services market to readily adjust to improvements in the operation of energy markets with respect to scarcity pricing, producing instead a neutral impact on energy prices and market coupling. In this respect, the “alternative way forward” may be more compatible with the objectives of the European internal energy market.

II. Member State Interest in Explicit Capacity Payments

The rising deployment of variable renewable technologies (e.g., solar and wind) in pursuit of both national and European decarbonisation goals will naturally lead to some amount of disinvestment as existing capacity is replaced. However, there is understandable concern over how security of supply will be maintained through the transition. The firm capacity value of variable renewable generation is low[5] and a portfolio of non-renewable resources (including demand-side, storage and flexible conventional generation) will need to be retained and to evolve over time to ensure that demand can continue to be met reliably and at least cost. Moreover, the power system will be required to reliably serve a “residual” demand profile that is net of variable, (virtually) zero-marginal cost renewable output. The possibility of more uncertain and volatile energy prices, together with the need for more mid-merit and peaking plant and less inflexible base-load plant, will complicate the evaluation of investments in conventional plant. Consequently, there is increasing interest by Member States in the deployment of mechanisms that reward firm capacity explicitly, in order to ensure that decarbonisation can proceed without threatening traditional levels of supply reliability.[6]

[5] Due to the nature of the primary resource, the ability of technologies such as wind or solar to contribute to meeting demand at a particular point in time is reduced. For example, the assumed contribution of wind generation to meeting winter peak demand in Great Britain is around 5-10% of rated capacity. In some of the US capacity markets the imputed firm capacity value for renewables is on the order of 10%.

[6] See, for example,

1) Overview map presented in Figure 14 (Capacity mechanisms in Europe, 2012) in Focused Capacity Markets, A New Market Design for the Transition to a New Energy System*,* prepared for WWF Germany

The capacity payment mechanisms currently operated or being considered by some Member States can be considered as being "traditional" in nature, in that they focus solely on the provision of sufficient quantity (MWs) of firm capacity to meet periods of peak demand in a secure fashion, i.e. they deal with the issue of "*resource adequacy.*"[7] Moreover, they are also "traditional" in the sense that they focus almost exclusively on securing sufficient investment in generation resources to meet resource adequacy needs, providing relatively little consideration (or none at all) to the firm capacity value of demand-side resources, including end-use energy storage (such as thermal energy).

However the continuing growth of variable renewable resources such as wind and solar raises issues of resource flexibility as well as resource adequacy. Dispatchable resources on the system will need to follow a demand profile *net* of variable, zero-marginal cost renewable output (and of other non-dispatchable resources such as combined heat-and-power). This profile will be far more volatile and unpredictable than that which conventional generation has traditionally been required to follow, imposing additional requirements on generation in terms of ramping capability, minimum on and off times etc. [8] The power system of the future will also need to tap the cost-effective potential of flexible demand-side resources and storage technologies to manage the residual (or "net") demand profile, and not just focus on conventional generation and supply-side storage resources to fulfill that role. It will therefore be necessary, where Member States contemplate investment-based market interventions, to consider not only a sufficient quantity of firm capacity, but also whether system resources possess the necessary flexibility characteristics or "capabilities" to allow power systems to be operated in an efficient and economic fashion.[9]

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by Őko-Institut and LBD-Beratunsgesellschaft at http://www.wwf.de/fileadmin/fm-wwf/Publikationen-PDF/Fokussierte-Kapazitaetsmaerkte.pdf;

2) Quantitative assessment for a European capacity market (slide 3), presentation by Johan Linnarsson at http://srv128.bluerange.se/Documents/Market%20Design/seminars/CapacityMarkets/4_Fortum.pdf
3) "Capacity Markets: relevant for Europe & appropriate for Germany" (Cervigni & Niedrig, 2011) at www.formaet.org/GetFile.aspx?file=6444.
4) "Energy Policy of Poland until 2030" published by the Council of Ministers, at http://www.mg.gov.pl/files/upload/8134/Polityka%20energetyczna%20ost_en.pdf ;
5) On the status of France's capacity market design: http://www.icis.com/heren/articles/2012/11/22/9617162/power/edem/french-government-to-reveal-electricity-capacity-scheme-soon---source.html;
6) Capacity market design in Great Britain: http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/7104-emr-annex-c-capacity-market-design-and-implementat.pdf

[7] While focusing principally on resource adequacy, some capacity payment mechanisms do specify flexibility requirements as a condition of qualification. For example, the all-Ireland Single Electricity Market capacity mechanism requires participating generation to be able to ramp to full load within 20 minutes.

[8] See, for example, figures 1-3 at http://www.raponline.org/document/download/id/4854.

[9] As the impact of variable resources grows, a key benefit of recognizing the value of (and paying for) flexible capabilities is that doing so also recognizes that inflexibility imposes higher lifecycle costs for variable renewables

There is an increasing appreciation of the need for future power systems to exhibit flexible capabilities that are consistent with the requirements of a low-carbon electricity system. For example, in addition to calling for a coordinated approach to resource adequacy assessment and capacity market design, a recent EU Commission Internal Energy Market communication[10] points to poorly designed mechanisms that lock in inflexible generation capacity and fail to deliver the flexible and demand-side resources that will be increasingly required going forward. Similarly, in their scrutiny of the UK Government's draft Energy Bill, the House of Commons Energy and Climate Change Committee expressed concern over the compatibility of the proposed Great Britain capacity mechanism with European market integration, its failure to address the issue of flexibility and the absence of measures to value an appropriate demand-side contribution or support innovative technologies such as storage.[11] Recent contributions by organizations such as ENTSO-E[12], Eurelectric[13], European Wind Energy Association (EWEA)[14] and the Florence Forum[15], reinforce these themes. They stress the need for capacity mechanisms to

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due to higher levels of curtailment, and/or increases system investment and operating costs due to a greater need for, and more frequent deployment of back-up peaking resources. While there are instances in which curtailment of renewables may be the most economic choice for the system, current practices do not adequately consider these cost tradeoffs and thereby can lean on curtailment of renewables far too heavily to balance the system. For more discussion about the nature of future system flexibility needs, with specific visuals and examples in US and Europe, see "What Lies Beyond Capacity Markets? Delivering Least-Cost Reliability Under the New Resource Paradigm" at http://www.raponline.org/document/download/id/6041, and accompanying presentation at http://www.raponline.org/document/download/id/6046. Also see "Meeting Renewable Energy Targets in the West at Least Cost", Report by the Western Governors Association at http://www.westgov.org/component/joomdoc/doc_download/1602-meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration-challege

[10] Making the Internal Market Work; Communication from the Commission to the European Parliament, the Council and the Committee of the Regions: IEM Communication COM (2012) 663 final. See http://ec.europa.eu/energy/gas_electricity/doc/20121115_iem_0663_en.pdf.

[11] See http://www.publications.parliament.uk/pa/cm201213/cmselect/cmenergy/275/27502.htm http://www.publications.parliament.uk/pa/cm201213/cmselect/cmenergy/275/27502.htm

[12] See ENTSO-E communication paper on Capacity Remuneration Mechanisms. at https://www.entsoe.eu/fileadmin/user_upload/_library/position_papers/120510_MC_TOP_11_CRM_memorandum_external.pdf

[13] See Eurelectric publication "RES Integration and Market Design: "Are Capacity Remuneration Mechanisms necessary to Ensure Generation Adequacy?", at http://www.google.co.uk/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&cad=rja&ved=0CCcQFjAA&url=http%3A%2F%2Fwww.eurelectric.org%2Fmedia%2F26300%2Fres_integration_lr-2011-030-0464-01-e.pdf&ei=vxaJUM_2AcPH0QXLtYGwBA&usg=AFQjCNHTwkYMBYXs4yrSjTmeyrzy-yr1_w&sig2=YcMhFb3ctE-O9f7gNayvyg

[14] See "Creating the Internal Energy Market in Europe", a report by the European Wind Energy association at http://www.google.co.uk/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=6&cad=rja&ved=0CFIQFjAF&url=http%3A%2F%2Fwww.ewea.org%2Ffileadmin%2Ffiles%2Flibrary%2Fpublications%2Freports%2FInternal_energy_market.pdf&ei=cBqJUMyHH46o0AW_9YGQAQ&usg=AFQjCNEePZXCPK6JFnES_TTBI_VSa0YWkQ&sig2=qrzlqAQ7585IYdyJelk44w

[15] See "A Future-proof Energy Market", a Florence School of Regulation workshop, 12 October 2012, at http://www.florence-school.eu/portal/page/portal/FSR_HOME/ENERGY/Policy_Events/Workshops/2012/Future-proof%20Energy%20Market.

have a European dimension and to reflect "system" requirements in terms of flexibility, rather than simply addressing the issue of financing conventional generation or remediating the "missing money" problem.

Irrespective of whether one is compensating system resources under traditional capacity payment mechanisms or designing variations to recognize the flexible capabilities required of system resources in the future, such non-energy based payment mechanisms have implications for energy prices. In fact, a properly designed capacity payment mechanism should interact with energy prices in the manner we describe below.

III. Market Design and Implications for Energy Prices

In attempting to answer the question posed by this paper, i.e. can capacity markets and the European target model co-exist, it is useful to review briefly how capacity markets provide investment incentives for firm generation capacity, together with the implications for energy prices. While there are a variety of capacity payment approaches that Member States have taken or are contemplating, we focus our discussion and illustrations on those that provide capacity payments via a market-wide auction process, since these are the clearest to illustrate in terms of the impact on scarcity pricing in energy-only markets and have the most direct impact on them. However, all capacity payment mechanisms designed to replace "missing money" in energy-only markets will have an impact on energy prices, to varying degrees.

A. Energy-Only Markets

Energy-only markets[16] mostly rely on energy prices alone to reward capacity through infra-marginal rents, as illustrated by the price-duration curve depicted in Figure 1. With marginal prices set by the most expensive plant clearing the energy auction, the difference between marginal energy price and the variable costs of generation is assumed to be sufficient to cover the investment and other fixed costs of that plant and so ensure economic viability. However, for flexible plant and most new plant investment to be economically viable in such a market, it has to be assumed that the most expensive-to-run peaking plant is able to exercise a degree of market power in scarcity situations and bid above its marginal cost. In such situations, marginal

[16] We use the term "energy-only" markets in this paper to distinguish from those energy markets that are accompanied by a separate market/mechanism to pay for firm capacity. In energy-only markets throughout Europe and elsewhere, essential *non*-energy services (e.g., primary, secondary and tertiary reserves) to maintain continuous balance of demand and supply are also regularly procured by the system operator. In Europe, these services are typically acquired via short-term services markets that are run as day-ahead or week-ahead administrative auctions. For simplicity, the illustrations and accompanying discussion in this paper refer to energy-only markets as those in which energy (kWhs) is traded without a separate payment mechanism (market) for firm capacity. However, it is important to keep in mind that there is no such thing as a stand-alone energy trading market--they all are accompanied by services markets of one form or another, which may contribute to meeting the fixed costs of capacity.

prices could justifiably rise to high levels as the most expensive peaking plant would need to recover its fixed costs over a very limited and uncertain number of operating hours. Ultimately, scarcity prices would be limited only by the unwillingness of customers to pay, a situation that may not reveal itself in practice because of significant demand-side "flaws". [17] Moreover, allowing energy prices to increase to their full scarcity value may not be acceptable either in regulatory or political terms, an issue that, in many applications, has led to the introduction of price caps or other features which undermine incentives to invest. Restoring this "missing money" that energy-only markets should provide via short-term scarcity pricing as an incentive for long-term investment, is one of the primary purposes of capacity payment mechanisms.

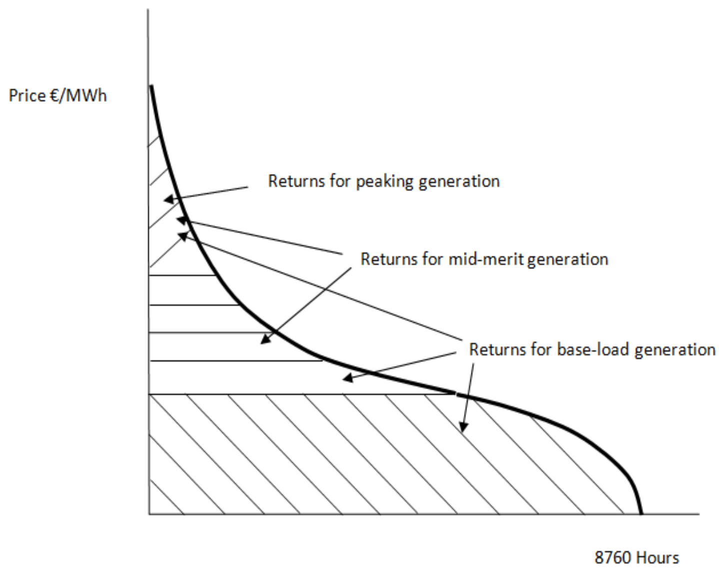

Figure 1. The reward of capacity via infra-marginal rents in an energy-only market, including scarcity prices during hours of highest total demand

B. Capacity Markets

"Capacity markets" refer in this paper to the form of capacity payment that emulates most closely the function of an energy-only market in terms of how generators compete for energy payments, including scarcity value, in a competitive wholesale market. That is, a capacity market sets up a competitive auction that pays any generator on the system (new, existing,

[17] See "generation Investment and Capacity Adequacy in Electricity Markets": Botterud & Dorman, at www.iaee.org/documents/newsletterarticles/208Botterud.pdf or "Competitive Electricity Markets and Investment in New Generating Capacity": Joskow, at http://www.google.co.uk/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=5&cad=rja&ved=0CEcQFjAE&url=http%3A%2F%2Feconomics.mit.edu%2Ffiles%2F1190&ei=qxiQUNfnNsG-0QW54oDIBg&usg=AFQjCNGHbJ8EDtRSYDvAgDJuJOSRzJYtUA&sig2=HWRi1Be_Q6uOmwpHRvS66g

retrofitted)[18] that clears the auction (bids competitively) a payment for the firm capacity they agree to make available to the system, most notably during the hours of highest (peak) demand.

Capacity markets are designed to at least partially replace scarcity pricing in competitive energy-only markets and restore any "missing money" in that market by creating a separate bidding platform that just pays winning bidders the marginal clearing price for firm capacity. This bidding platform is designed to provide market participants with an opportunity to compete for a known revenue stream to be paid out regularly for a pre-determined period of time. These revenues are designed to be both more certain and more stable than the energy market revenues they are intended to replace.

Accordingly, the capacity markets hold periodic "forward" auctions, that is, establish the quantity of firm capacity required to meet peak demand (plus a margin designed to satisfy an explicit or implicit security standard) in a future year. Typically the forward period is 1 to 3 years, which means that the winning bidders know today what price (e.g., in Euros per MW-day) they will be paid for firm capacity when they make it available in one to three years later to the system operator. Some of the capacity markets currently in place allow the winning bidders to fix these annual payments for multiple years so they can hedge against the risk of fluctuating capacity prices (at their option). Capacity auctions of this type are designed to reconfigure scarcity value (no more, no less) that would otherwise be available in well-functioning, competitive energy-only markets into revenue streams whose timescales more closely align with investment considerations.[19]

In these capacity markets, all generation clearing the capacity auction receives payments for MWs of capacity committed to be available to the system operator (subject to penalties) if and when needed to meet peak demand in the forward year. This payment is made in addition to the revenues the generator may earn in the energy market, but as illustrated below, those prices are correspondingly lower due to the removal of scarcity value from the energy market (and payment of that value via the capacity auction).

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[18] In the US, forward capacity markets are designed such that both supply-side and demand-side resources (e.g., demand response, energy efficiency, distributed generation) are eligible to bid in the auction, with very successful results in terms of participation levels, (especially demand response), cost savings to consumers, and the reliable performance of these resources when actually called upon by the system operator to meet system reliability needs.. However, for this paper, in order to explain the dynamics of capacity market payments on energy-only market prices we refer only to those *generation* resources participating in the capacity auction.

[19] See "The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects" at http://www.raponline.org/document/download/id/91

Here's why: With appropriate levels of capacity payments, the generation supply curve in a competitive energy market should now more closely reflect marginal costs – even when capacity is scarce. This is in contrast to the operation of energy-only markets, i.e. in the absence of a capacity market, where energy prices can be expected to rise substantially above marginal prices in scarcity situations. As illustrated in figure 2, the generation supply curve in a market that rewards all required generation capacity separately should therefore fall below that of an energy-only market in situations when capacity is scarce. This assumes perfect competition and, in practice, mechanisms may be required to claw back capacity payments where energy prices are seen to unjustifiably exceed marginal costs due to market power as, for example, applied by ISO NE.[20]

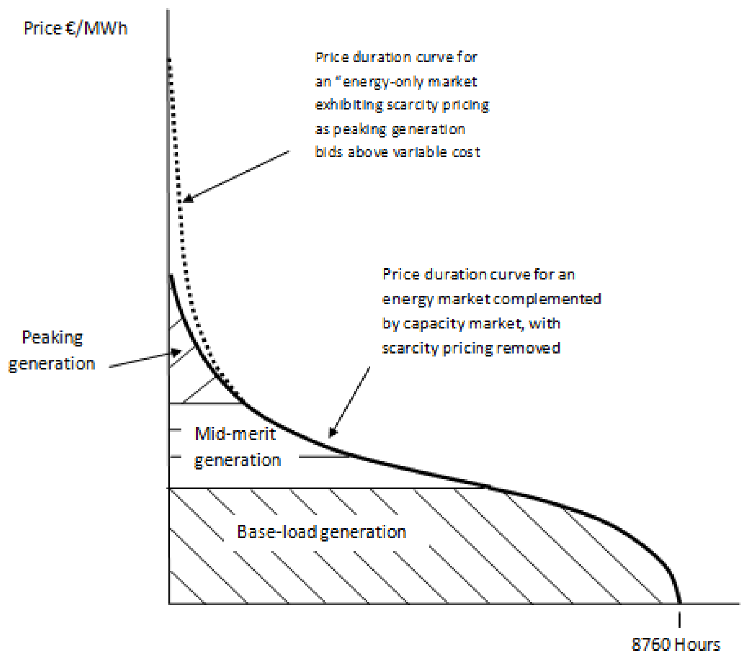


Figure 2. The elimination of scarcity pricing through capacity payments

Figure 2 also illustrates that capacity markets are intended to address scarcity pricing "missing money," the magnitude of which will vary from one market situation to the next. Capacity markets are not necessarily designed to cover all of the fixed costs of generation. The degree of fixed cost coverage depends upon the corresponding design of the energy market.

[20] The ISO NE electricity market relates capacity payments to energy prices via a "Peak Energy Rent (PER)" adjustment. The PER adjustment is triggered when energy market prices exceed a strike price, reducing capacity payments to reflect revenues earned in the energy market above that strike price. The reduction is then applied to the capacity payments of all generators, regardless of whether or not the generator actually operated during the period when prices were high. See http://www.iso-ne.com/support/training/courses/fcm/fcm_day_four.pdf

IV. Impact of Capacity Markets in the Context of Market Coupling

The Annex provides a description, with accompanying illustrations, of how market coupling works in practice. Briefly, market coupling creates a single merit order of generation price bids and a combined demand curve "as if" there were only a single, regional energy trading market, rather than individual national power exchanges. The result is a single energy clearing price for the coupled markets, unless there is interconnection congestion, in which case prices will diverge. Market coupling creates corresponding "trades" (exports and imports) between the coupled national markets to achieve this outcome, which occur "automatically," i.e., independent from bilateral agreements between Member States or their TSOs.

In this context, we consider the potential consequences when a capacity market is introduced in one of the coupled markets, along with potential ways to remedy or mitigate those consequences. First, we look at the possibility of double payments for generation in receipt of capacity payments when markets with capacity payment mechanisms are coupled with markets that rely on energy prices to remunerate capacity. More generally, we examine how the allocation of market revenues and costs across the coupled markets and market participants can be affected. Second, we consider the consequences on coupled energy prices and resource adequacy when generation in an energy-only market seeks to access capacity payments by participating in an adjacent capacity market.

We base our discussion and illustrations in this section on the implementation of a "traditional" capacity market in one of the coupled markets, that is, one designed to pay exclusively for a firm quantity of MWs irrespective of the flexible capabilities of that capacity. Nonetheless, we believe that our general observations would similarly apply to a more differentiated form of firm capacity auction, such as the "apportioned forward capacity market" we describe in a recent RAP paper.[21] As we discuss in Section IV, when enhanced forward services markets are deployed deliberately as an alternative to a capacity payment mechanism—an option we propose in that same paper—we expect that they will exhibit similar consequences in coupled markets, with similar remedies.

A. Potential for Double Payments and Resulting "Winners and Losers"

As indicated above, access to adequate levels of capacity payment in a fully competitive market should result in energy prices remaining close to marginal cost - even during periods of plant scarcity. With energy-only markets however, energy prices will need to rise significantly above

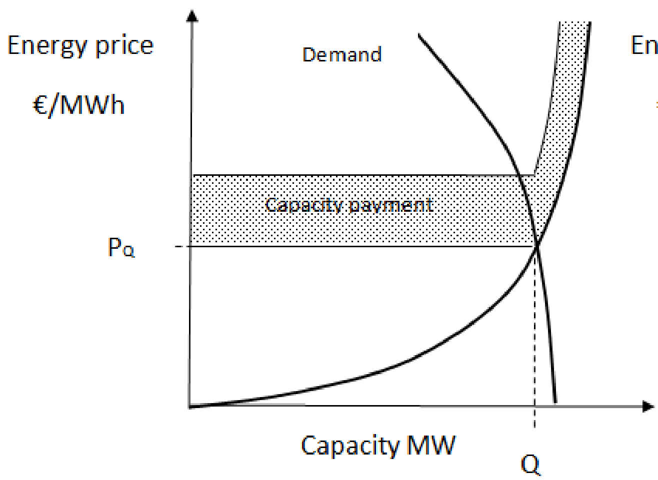
[21] "Apportioned Forward Capacity Market" represents a capacity payment mechanism where total resource adequacy requirements are apportioned to sequential auction tranches, each tranche based on specific resource flexibility attributes. See RAP straw man proposal "What Lies Be yond Capacity Markets? Delivering Least-Cost Reliability Under the New Resource Paradigm", at http://www.raponline.org/document/download/id/6041

marginal cost when capacity is scarce. Thus, the generic concern when markets with capacity markets are coupled with those that have energy-only markets is what happens during periods of scarcity, where the divergence in national energy prices is based on the manner in which firm capacity is remunerated and not on actual resource cost differentials. More specifically, what is the potential impact on the coupled energy market clearing price and--in turn--the allocation of market revenues and costs among market participants?

Here's what we can expect to happen: Energy prices would rise in the coupled markets driven by low-utilisation generators not in receipt of capacity payments attempting to recover their fixed costs. In effect, scarcity value would "reappear" in the coupled market clearing price because generators operating in the market without a capacity payment put in higher energy-only bids to meet total demand. Generation in receipt of capacity payments would benefit from the higher single-clearing prices in the coupled energy market, which would effectively result in that generation being "paid twice" for the capacity provided. As stated earlier, this problem should only occur occasionally in competitive markets, since energy prices should remain close to marginal costs for the majority of time. However, the frequency of such scarcity pricing instances could increase with the continued rapid deployment of variable renewable generation, with the effects becoming more pronounced as displaced conventional plant is increasingly forced to rely on price spikes during periods of low renewables output in order to cover its fixed costs.

If this impact is not mitigated, electricity consumers in the Member State with a capacity market will pay more than they should for the reliability benefits they are receiving from the generators to whom they are also paying firm capacity payments. This of course also increases the overall cost of electricity in that Member State's economy. Correspondingly, the electricity consumers in the Member State with an energy-only market will benefit from the lower energy clearing prices resulting from a bid stack that includes the lower bids of generators "across the interconnector" being paid separately for firm capacity by another Member State's consumers. As a result, there will be a distortion in the efficient allocation of market revenues and costs that market coupling is designed to produce, since these impacts result solely from differences in how firm capacity is remunerated and not because of underlying cost differentials. *Simply put, all other things being equal (and with no mitigation measures put in place), the consumers of the Member State with a capacity market will be the "losers" of this unilateral change in market design, the generators that obtain capacity payments from that Member State's auction become the "winners" as do the consumers in the coupled energy-only market.*

There are ways to mitigate this impact drawing directly from practices currently in place in US capacity markets. Design of each capacity auction "demand curve" for example, can reduce the potential for these double payments over time if it is adjusted to reflect what a generator earns in the *coupled* energy market (as well as the services markets). [22]. However, for a Member State contemplating the introduction of a capacity market (or has one in place) who may require a more immediate relation between capacity payments and energy prices, a "claw back" approach could be introduced to mitigate the double payments within the same year. For example a "contract for differences" approach could be adopted with capacity payments reduced to take account of the higher cleared energy price for the coupled markets. This approach, which is illustrated below, would reduce the possibility that generators in receipt of capacity payments are being rewarded twice.



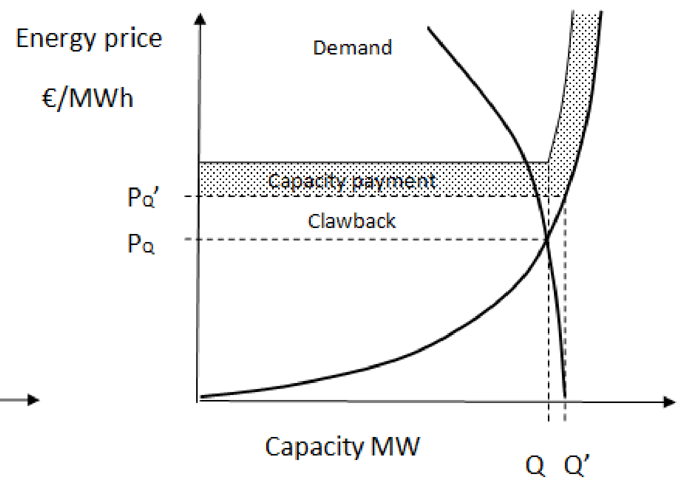


Figure 3a **Figure 3b**

Potential Double Payments for Firm Capacity in Coupled Markets and "Claw Back" Mitigation

In Figure 3a, the shaded area represents the additional income in terms of €/MWh accessed through capacity payments made to all plant declared available in a market with a market-wide capacity mechanism. All capacity that clears the energy market also receives the marginal energy price €PQ/MWh. In Figure3b, the market is coupled with an energy-only market, and exports Q-Q' MW, resulting in an increased marginal price PQ'. If the capacity payment were to

[22] PJM's Energy and Ancillary Services (E&AS) Adjustment provides an indication of how such an adjustment may work in practice: When constructing the demand curve for the Base Residual Auction (capacity auction), PJM determines a specific amount of capacity to be purchased at the Cost of New Entry (CONE). To adjust for revenues from the E&AS markets, the demand curve is shifted down to achieve the quantity of capacity that corresponds to the new cost of Net CONE. The difference between CONE and Net CONE is roughly the E&AS Adjustment, which is calculated as a rolling average of revenues earned in the E&AS markets over the last three years. Through this mechanism, PJM adjusts future capacity payments to take account of historic revenues earned in the E&AS markets in order to avoid over-payment. See http://www.pjm.com/training/~/media/training/core-curriculum/ip-rpm/rpm-training-appendix-b-rpm-vrr-curve.ashx

remain unchanged, then the difficulty of double payments arises as described above. In order to avoid this, generation that cleared the uncoupled energy market should have its capacity payments reduced by a €/MW amount equivalent to difference in marginal price PQ'-PQ as shown. For generation that cleared the coupled energy market only, capacity payments should be reduced by the difference between PQ' and bid price. Generation that did not clear in either energy market would continue to receive the full capacity payment.[23]

This "claw back" approach mirrors mechanisms already in place within some US capacity markets to reduce capacity payments when (uncoupled) energy prices rise to unjustified levels.[24] It can be applied to "traditional" capacity markets or those that differentiate among capacity capabilities, based on the difference between the coupled and uncoupled energy price. In either case, the claw back mechanism would require individual market prices in the absence of market coupling to be calculated in addition to the coupled clearing price. This should be feasible given the intended application of market coupling, with individual power exchanges inputting national bid and offer data to some overarching entity. (See Annex.)

What is most interesting to note, however, is that the impact of market coupling on a capacity market corrected for double payments is effectively to "hybridise" the capacity payments in any case, i.e., producing a situation where capacity is increasingly rewarded via infra-marginal rent

[23] These provisions are designed to ensure that the income accrued in the coupled market by resource receiving capacity payments does not exceed those that would have been accrued in the uncoupled market. If C is the €/MWh equivalent of the capacity payment, and the infra-marginal rent earned by resources in the energy market is energy clearing price (PQ or PQ') – bid price, then the proposal would work as follows for the three possible outcomes:

1) The total income of resource that clears the original energy market is C + (PQ – bid price) in that market and C -(PQ' – PQ) + (PQ' – bid price) in the coupled market, i.e. the same outcome in both instances.

2) Resource that does not clear the original energy market but does clear in the coupled market receives C in the original market and C – (PQ' – bid price) + (PQ' – bid price) in the coupled market, so the same outcome again.

3) Resource that does not clear either energy market just gets C in both cases, , which is illustrated in the diagrams by the shaded area along the supply curve that appears beyond the quantities (Q/Q1) clearing in the energy market.

If the coupled market energy price PQ' increases to the point where it exceeded PQ + C, then the income accrued by resource would exceed that available in the original market. However, in this situation, all capacity payments would have been recovered.

[24] For example, this claw back mechanism essentially extends the "Peak Energy Rent" principles currently employed by ISO NE internally, to a coupled market situation. (See footnote 20 above.) There are however differences in the approach, e.g., ISO NE applies the adjustment to all generators, regardless of whether or not the generator actually operated during the period when prices were high, See http://www.iso-ne.com/support/training/courses/fcm/fcm_day_four.pdf

in the coupled energy market and less by capacity payments. In other words, under the EU target model a Member State cannot think only "nationally" in trying to reconfigure scarcity value pricing into a different payment stream, because in coupled markets scarcity value will "reappear" again in the coupled market clearing price, leading to "winners and losers" emerging from distortions in the allocation of market revenues and costs.

As we discuss further below, these impacts illustrate how market coupling by definition will make it more and more difficult to sustain purely national instruments to pay for firm capacity, as they are by definition based on a construct of national supply "merit order" bid curves and national peak demand levels that are no longer what is setting energy-only prices (including scarcity value) in coupled markets. We suspect that those Member States highly engrossed in national debates about capacity markets have not yet fully recognized these far-reaching implications of the target model. When they do, we anticipate that market design discussions will become much more bilateral and even multilateral in nature, given the reality of the how energy market clearing prices are being established under EU-adopted market coupling requirements.

B. "Virtual" Migration of Capacity and Impact on Resource Adequacy

The prospect of a more certain contribution towards fixed costs may result in generation operating in an energy-only market seeking to participate in the capacity auction operated by an adjacent market. In fact, the participation of "external" generation in an adjacent capacity market is well established in the US, albeit with certain obligations placed on those external generators. [25] Where this occurs, generation capacity participating in and clearing a capacity auction in an adjacent market would "virtually" migrate to become part of that "recipient" market.

However, if the two markets are coupled, we would expect that such migration of capacity would have *no impact on the level of the resulting energy market clearing prices*. [26] Once the markets are coupled, the "stack" of generation dispatched to meet demand, together with the coupled marginal energy price, is indifferent to which market the generation is operating either "physically" or "virtually". This is because the marginal energy bid for the coupled supply curve is not expected to change even when some capacity successfully "migrates," assuming (as we do throughout this paper) competitive bidding behavior. Even when the interconnector

[25] See for example "Capacity in the PJM Market" by Monitoring Analytics", August 2012 at: http://pjm.com/~/media/documents/reports/20120820-imm-and-pjm-capacity-whitepapers.ashx

[26] There would still be the potential for double payments for firm capacity described above, but no more or less when an external generator successfully participates in the adjacent capacity market than would be the case if only "internal" generators cleared the auction. The difference is only in which generators would get double payments across the coupled markets—in this case, the external generator clearing the capacity auction has the potential to receive the double payment because it now bids a lower energy price into the coupled energy market.

capacity between the two markets is insufficient to allow energy prices to converge fully, those prices remain the same as if no capacity migration had taken place. (See Annex.)

While not expected to alter the level of coupled energy prices, the virtual capacity migration described above would be expected to impact the "recipient" market (with a capacity market) and the "donor" market (without a capacity market) in differing ways. When productive capacity located within its borders successfully clears another Member State's capacity market, the donor market will now have less generation capacity available to meet its own targets for firm capacity and associated reserve margins. As long as resource adequacy is viewed as a strictly national issue, the Member State concerned may view this capacity migration as a distinct disadvantage. However, as discussed throughout this paper (and illustrated in the Annex), market coupling creates a regional market for electricity that defies national borders. In doing so, market coupling can create an opportunity for significant capacity cost savings for both the "donor" and "recipient" market (see below), subject to any locational constraints.

The recipient market, on the other hand, would see an advantage as the external generation displaces more expensive incumbent generation in the capacity auction, reducing the clearing price and overall cost of capacity payments. In order to participate in an adjacent capacity auction, the external generation would, however, be required to demonstrate firm capacity to the market boundary, an issue which may in practice limit the extent to which external generation can take part in adjacent capacity markets.

Furthermore, the loss of income experienced by incumbent generation in the recipient market displaced from the capacity auction might result in generation closures and, although firm capacity levels would be maintained by the capacity payments to participating external generation, there could be a net loss of capacity across the two markets. Overall, the reduction in total capacity requirements due to pooling effects and the sharing of risk may in fact be the most economic outcome leading to significant cost savings for both Member States. However, these benefits cannot be tapped without a more regional approach to resource adequacy and market design collaboration. Without such collaboration, Member States may be inclined instead to push for excluding external generation from participating in national capacity markets, and thereby forego potential positive synergies. However, this may not be a sustainable approach to ensuring power system reliability as EU market integration also moves towards harmonising and expanding Europe's balancing market areas.[27]

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[27] The draft Framework Guidelines are available at: http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Stakeholder_involvement/Public_consultatations/Open_Public_Consultations/DFGEB-2012-E-004. RAP's Advisory Note on the draft is available at: www.raponline.org/document/download/id/5045. We note that even with expanded balancing areas or the development of resource adequacy targets across coupled markets, it is reasonable to expect that some form of national—or at least locational-

The situations described above were presented in the context of market-wide capacity payments in one of the coupled market(s), and an energy-only market in the other(s). We would expect similar consequences in instances where these types of capacity markets are coupled with market designs that take a more targeted approach to paying for firm capacity. That is, double payments can also occur in these situations and capacity could be expected to migrate towards the market with the broader reaching capacity payments. However, these consequences could similarly be addressed by a more coordinated approach to resource adequacy assessment and market design, possibly involving a step-wise approach to extending the concept of “market coupling” to include resource adequacy and the procurement of capacity, as well as energy.

V. Enhanced Services Markets and Market Coupling

The discussion so far has focused on the interaction between market coupling and “traditional” capacity payment mechanisms designed to deliver firm capacity - i.e., mechanisms that exclusively address the issue of having enough MWs of capacity available to meet peak demand on the system. However, the continuing growth of variable renewable resources raises issues of flexibility as well as resource adequacy. Generation will, in the future, be required to exhibit increased ramping capability, minimum on and off times and other flexibility services. The cost-effective potential of flexible demand-side resources and storage technologies (including heat) will also need to be fully exploited. Electricity market designs introduced by Member States will therefore need to be capable not only of delivering a sufficient MW quantity of firm resources, but also of ensuring that the resource portfolio possesses the necessary flexibility characteristics or “capabilities” to operate the power system reliably and cost-effectively around the availability of energy from variable renewables.

The evolution of “traditional” capacity markets into ones that deliver investment in generation and other resources with the necessary flexibility is an option that we describe at some length in our “What lies Beyond Capacity Markets” straw man proposal. [28] However, we also outline an alternative approach called the “enhanced forward services market.” As the name suggests, this option builds on existing arrangements for the procurement of “ancillary” services, such as primary, secondary and tertiary reserves--arrangements that are generally procured via short-term services auctions. An enhanced forward services market would broaden the range of flexibility services to be procured in order to fully address future power system flexibility needs,

-assessments will still play a role: For example, in the event of a capacity scarcity (or of operating reserves) across the coupled markets, it will be necessary to understand whether a particular market or location was in deficit in order to assign cost responsibility or remedial action.

[28] See http://www.raponline.org/featured-work/beyond-capacity-markets-delivering-capability-resources-to-europes-decarbonised-power

while at the same time encouraging demand-side contribution and the participation of storage capabilities (including storage of thermal and other forms of end-use energy).

Critically, the enhanced services market would also extend the procurement of flexibility services into investment timescales, providing a more certain stream of revenue at the design stage and encouraging the development of generation or other resources with appropriate capabilities. In essence, it would “enhance” the current short-term services auctions run by system operators in two ways: First, by introducing non-energy products/services that reflect the flexibility needs of a system with an increasing share of variable renewables, and second, with a more “forward” investment timeframe for bidding an option price into the services auction. For example, running a competitive auction *today* to establish the fixed option payment paid *1-3 years from* now for a commitment of capacity with X/minute minimum ramping capability or comparable demand-side services. A representative example of non-energy services that such longer-term, “forward” services auctions might be designed to procure are: 1) 15-minute synchronised restoration reserves, 2) 15-minute non-synchronised restoration reserves, 3) 30 minute replacement reserves, 4) non-reserve ramping capability, 5) frequent short-cycling capability and (6) a minutes-to-hours storage-like service.

We’ve suggested that an enhanced forward services market could serve as an alternative to a capacity mechanism as a way of replacing missing money in the energy market, in addition to compensating resource owners for investing in the types of flexibility services described above. By definition, this approach incurs the possibility that the market for such services may compensate investors for more than the incremental cost of adding flexibility capabilities—that is, it may compensate them for some portion of the fixed costs of the underlying capacity as well. This is likely to occur over time as the system approaches the limits of the flexibility service or services that can be provided by existing resources, from both the supply- and demand-side.

For example, the system may need more sheer quantity (MWs) of firm productive capacity capable of non-reserve ramping services than is currently available from the existing resource mix. An enhanced forward services market is designed to provide this investment incentive to the extent that energy-only prices do not (due to missing money) in order to procure a sufficient level of flexible services to reliably operate the system. It does so by permitting the market price of the enhanced services to increase (within certain bounds, and subject to competition) until sufficient capacity with the requisite flexible service(s) is procured for the future delivery year. The difference between the resulting market price and the incremental cost (capital and variable) of providing the flexibility service represents a contribution to the fixed costs of capacity. Or put another way, it represents the level of restored “missing money” that is necessary to attract sufficient investment in capacity.

Under these circumstances, the enhanced forward services market can be expected to impact scarcity pricing in energy markets much in the same way as a capacity market does by design, as described in Section III.B. Therefore, we can also expect that the potential for double payments described above would emerge under this alternative as well–with similar remedies and implications in the context of market coupling.

However, one advantage of this approach with respect to the EU target model is that, by design, an enhanced forward services market will pay for the underlying cost of capacity in procuring flexibility services only in those energy markets where scarcity pricing is limited. As discussed in Section III.A, energy market scarcity pricing may be limited by one or more different factors. If such limitations can be effectively removed (along with corresponding concerns over their removal addressed), then the resulting prices in a well-designed enhanced services market should only cover the incremental cost of providing enhanced flexibility—and not the underlying cost of capacity. Under these circumstances there should be none of the consequences we describe above in terms of energy prices, scarcity pricing or market coupling.[29] In this way, the enhanced forward services market offers a market design alternative that adjusts readily to improvements in the operation of energy-only markets, which is a key objective for the European internal energy market.

VI. Conclusions

The question posed at the outset was whether a capacity market unilaterally implemented by one or more Member States could "co-exist" with market coupling, the vehicle adopted for the integration of Europe's electricity markets. The paper concludes that they can, with certain qualifications. In particular, we point out the need to take steps to eliminate the potential "double payments" for firm capacity that emerge under market coupling arrangements, which could be substantial even in a highly competitive bidding environment. Otherwise, Member States who elect to unilaterally establish a capacity market run the risk of creating considerable windfalls for the generators receiving the capacity payments, and correspondingly higher electricity costs for their consumers and national economy. The remedies discussed in this paper, drawing from existing "claw back" arrangements in some US capacity markets, illustrate how it will therefore become increasingly difficult to sustain purely national instruments to pay for firm capacity with market coupling.

We also examine the potential impacts of "virtual" capacity migration, where generation operating in an energy-only ("donor") market is a successful bidder in the capacity auction

[29] Effective competition in services markets will be key to achieving this outcome, which speaks to the need for full participation of qualifying demand-side and storage services, as well as generation. Expanding balancing market areas with correspondingly more harmonised non-energy products/services (as contemplated by the proposed EU Framework Guidelines) would also serve to ensure this outcome.

operated by an adjacent ("recipient") market. While not expected to alter the level of coupled energy prices, virtual capacity migration is expected to impact the achievement of national resource adequacy targets in the donor market, and possibly also result in a net loss of capacity across the coupled markets. Overall, the reduction in total capacity requirements due to pooling effects and the sharing of risk may in fact be the most economic outcome leading to significant cost savings for both Member States. However, these benefits cannot be tapped without market design collaboration, which underscores another overall conclusion of this paper: Market coupling will impact the allocation of market revenues and costs under purely national approaches to resource adequacy in ways that reveal the advantages of taking a more regional approach to this issue, including capacity market design.

In many ways, market coupling serves as an inescapable "magnifying mirror" that clearly exposes who will be the "winners" and "losers" from these market design differences, and we expect that Member States who perceive they are disadvantaged will initiate mitigating actions. This, in fact, speaks to a general strength of the target model and market coupling process: It is sufficiently flexible and pragmatic to be able to accommodate differences in market design that are perceived to be necessary to advance individual Member State priorities, thereby easing implementation. But these differences can, as described in this paper, lead to market revenue and cost allocation impacts that do not arise from underlying resource cost differentials. Awareness of and exposure to these impacts will incentivise disadvantaged Member States to take appropriate measures, and therefore serves to harmonise market arrangements over time.

Finally, we briefly explore an alternative market design option to address future system reliability challenges, namely, an "enhanced forward services market" that builds upon the current short-term services markets being operated by European system operators today. By design, the forward procurement of flexibility services under this option serves as an alternative to a capacity market in replacing missing money in the energy market. As such, it has the potential to create similar impacts to those we describe in this paper for capacity markets, with similar remedies and implications for market coupling. However, one advantage of this approach with respect to the EU target model is that, by design, an enhanced forward services market can adjust relatively easily to improvements in the operation of energy-only markets, which is a key objective for the European internal energy market.

More specifically, if limits to scarcity pricing can be successfully removed over time in energy-only markets (and concerns over their removal effectively addressed), enhanced services markets will produce prices that increasingly reflect only the incremental cost of providing enhanced flexibility—and not the underlying cost of capacity. Under these circumstances there should be none of the consequences we describe above in terms of energy prices, scarcity pricing or market coupling.[30] Moreover, an enhanced services market approach to addressing system reliability on a regionally coordinated basis seems well-suited to developments underway to expand European balancing areas with more fully harmonised non-energy products, as contemplated by the draft EU Framework Guidelines on balancing markets.

As indicated in the introduction, this paper is intended to contribute to the discussion about capacity markets and related market design in the context of the European internal energy market and market coupling. In distributing a discussion draft of our observations on this topic, we seek to encourage further dialogue and feedback. Please feel free to contact Phil Baker (philip.baker2000@yahoo.co.uk) or Meg Gottstein (mgottstein@raponline.org) with your comments or questions.

[30] Effective competition in services markets will be key to achieving this outcome, which speaks to the need for full participation of qualifying demand-side and storage services, as well as generation. Expanding balancing market areas with correspondingly more harmonised non-energy products/services (as contemplated by the proposed EU Framework Guidelines) would also serve to ensure this outcome.

Annex: The EU Target Model of *Market Coupling*

The "target model" (*market coupling*) adopted as the means of integrating EU national electricity markets reflects the predominately energy- only nature of those markets. Although not demanding complete harmonisation of market design (presumably this was a major factor in adopting market coupling), the model does require participating markets to have a functioning power exchange-based, day-ahead market and intraday market with continuous trading, with a real time balancing market run by the TSO as the sole counter party. At the day ahead and intraday stages, interconnector capacity is traded "implicitly", i.e. as an integral part of the energy trading process, while explicit auctions of interconnector capacity takes place in advance of the day-ahead stage in order to facilitate forwards energy trading between price zones, very much as now. The implicit trading of interconnector capacity via the energy trading process at the day-ahead and intra-day stages is referred to as "market coupling."

Figure 1 below presents a simplified depiction of implicit auctioning of interconnector capacity between two coupled markets A and B under circumstances where there is no interconnector congestion (Figure 1a), and when there is congestion (Figure 1b). Implicit auctioning of interconnector capacity via market coupling requires each national power exchange to submit energy purchase and sales information to a central coupling algorithm, which will calculate flows between, and prices in, the individual coupled markets. Energy will flow from the market with the lowest energy price to the market with the higher energy price until either a single energy price is achieved (Figure 1a), or the interconnection capacity between markets is fully utilised (Figure 1b).

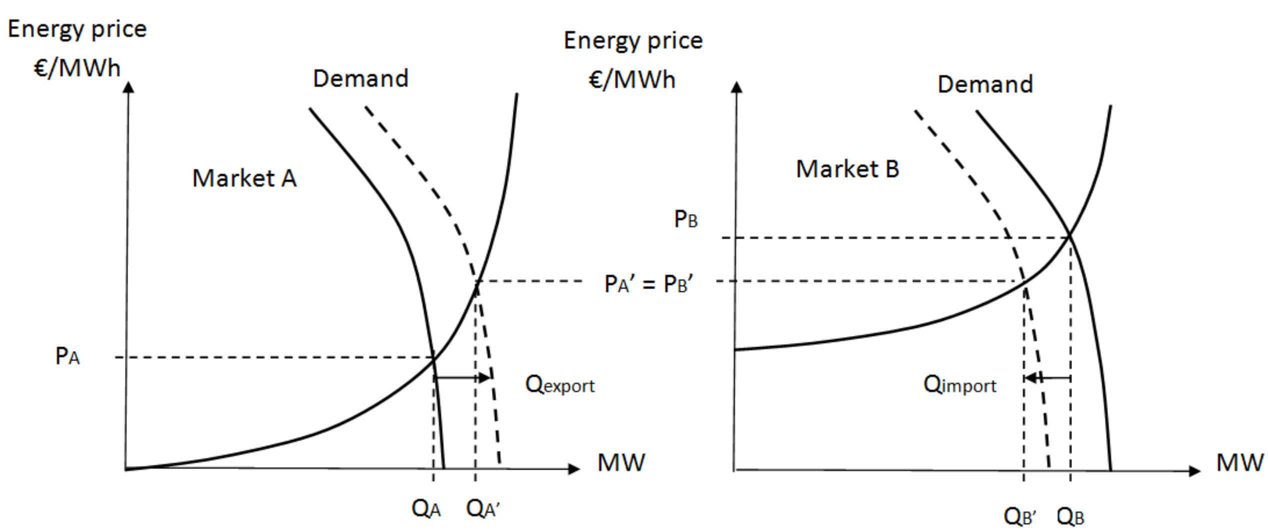

Figure 1a, Interconnection not congested

In either case, the price PA for the exporting market A will be higher in the coupled market than if market A were isolated (e.g., in Figure 1a the price increases from PA without a coupled market to PA'/PB'; in Figure 1b the price increases from PA to PA'). The converse holds true for the importing Market B (the price decreases).

In the absence of congestion, use of interconnection capacity is essentially "free" and the energy prices in both markets converge. However, when the optimal flow across the interconnection exceeds available capacity, a congestion rent arises equal to the product of the flow across the interconnector and the price differential. As indicated in Figure 1b, energy is produced in market A at a price PA'', but flows across the interconnector and is sold in market B at the higher energy price PB''. This creates a congestion rent equal to the product of the interconnector flow and the price differential (PB''- PA'').

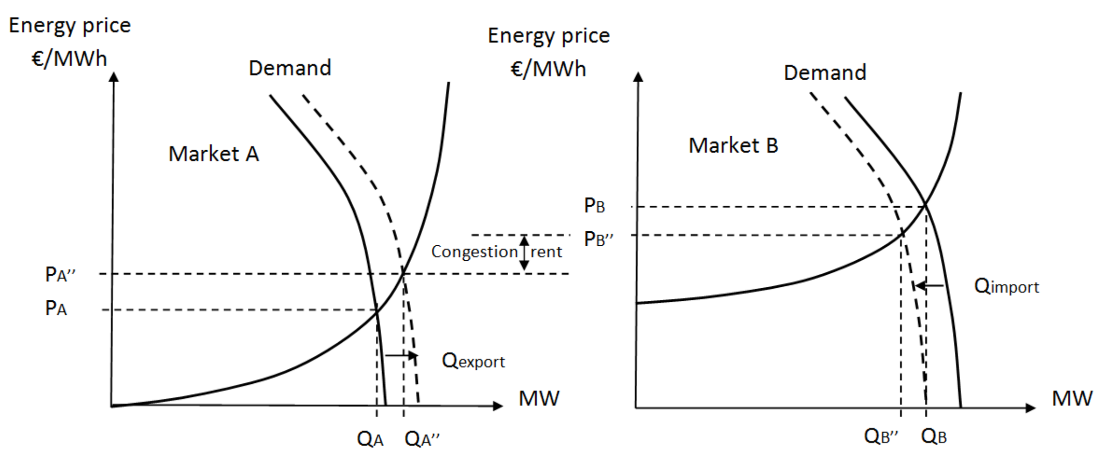

Figure 1b Interconnection Congested

Allocation of Congestion Revenues

As described above, congestion revenues arise due to the implicit allocation of constrained interconnector capacity through the market-coupling process. In effect, when there are transmission constraints the markets will "split" as depicted in Figure 1b. Suppliers in Market A receive the split market clearing price PA" based on the quantity supplied to meet domestic demand plus the amount exported through market coupling that can be delivered across the constrained transmission path (totalling QA"). The suppliers in Market A do not know what portion of their production flows to meet demand in Market B versus that which is supplied to meet domestic demand. They just receive the price PA" for all of QA." Similarly, on the other side of the interconnector (Market B), the split market price PB" arising from the market-coupling process reflects the supply quantity QB", that is, the combination of domestic supply and imports from Market A that can be delivered over the constrained transmission path.[31] Price PB" is paid for all deliveries to Market B, irrespective of whether the supply originates from Market A or Market B. Therefore, while suppliers in the lower price Market A "sell" their supply of kWhs at Price PA", purchasers in Market B are actually paying for the portion that is exported over the constrained interconnector and sold through the exchange at the higher price PB".[32]

These price differentials provide a locational signal to market participants, as do the explicit interconnector capacity auctions prior to the day-ahead stage (described above.) In particular, generation is encouraged to migrate to the area of higher prices (Market B). That is, the only way for generators to access the higher price PB" is either to physically locate in Market B or to purchase transmission rights in the explicit capacity auctions. Thus, absent private market arrangements to secure transmission capacity and sell in the higher-price market, the revenue accruing to generation located in Market A will be lower than the revenue to generators located in Market B because of transmission congestion.[33]

Moreover, the revenue paid by purchasers in Market B for power delivered from Market A will exceed the revenue received by Market A generators for the exported power. The resulting revenue differential under market coupling is referred to as "congestion rents," calculated as the quantity of cross-border flow (QA" minus QA, or QB minus QB") times the difference between the split market prices (PB" minus PA"). These congestion rents accrue to the market operator, e.g., the entity that serves as the overarching power exchange for coupled markets—such as the EPEX Spot covering France, Germany, Austria and Switzerland. The market operator then passes the congestion rents on to the owners of the interconnector assets, i.e., the boundary TSOs or in more limited instances (e.g., Great Britain), the merchant owners of those assets.[34] In addition, boundary TSOs receive the revenues arising from the explicit auctioning of interconnector capacity in advance of the day-ahead stage.[35] The manner in which TSOs can use these sources of congestion-related revenues is set out in Article 16 of the 3rd package Regulation EC 714/2009. The Regulation requires that priority be given to maintaining or

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[31] The equilibration of PA' and PB' depicted in Figure 1a therefore does not occur and in fact, the now "split" market price in Market A (PA") will be lower than that level, whereas the market price in Market B (PB") will be higher.

[32] While they are paying congestion rents, purchasers in Market B are also benefitting from lower clearing prices generally.

[33] For a discussion about the impact of locational pricing signals on the deployment of intermittent renewables, within the context of Europe's policy objectives for power sector decarbonisation and renewables, see pages 17-18 of *Advancing Both European Market Integration and Power Sector Decarbonisation: Key Issues to Consider* (May 2011). This briefing paper was also prepared by RAP, and is available at www.raponline.org/document/download/id/879.

[34] The arrangements for the collection and distribution of congestion revenues will be defined by Articles 67 & 68 of the Forward Capacity Allocation Network Code, Articles which have yet to be written. This description is therefore based on current and recent practice.

[35] However, the revenues arising from interconnector capacity rights purchased via explicit auctions but given up to the market at the day-ahead stage are returned to the holders of those capacity rights.

increasing interconnector capacity and, only where this is not possible, can revenues be used to reduce national transmission tariffs.[36]

In addition to providing locational signals to market participants, congestion revenues also signal the need for additional interconnector capacity. However the law of diminishing returns applies in that additional capacity is likely to reduce these revenues. A merchant investment in capacity that is entirely funded via congestion revenues is likely to be sized so as to maximise those revenues. Conversely, a regulated TSO investment that is funded entirely by regulated national transmission tariffs is likely to be sized to maximise social welfare, which would correspond to a larger investment in interconnector capacity.[37] In practice, however, there are a number of other factors that may limit TSO investments in such capacity, including regulatory concerns and inertia stemming from "winners & loser" issues, partly-unbundled TSOs concerns about the impact on their generation assets and difficulties in getting the necessary permissions and permits. In fact, only a small proportion of total congestion revenues are used to maintain or increase interconnection capacity in Europe. For example, one study estimates that only 17% of congestion revenues collected in 2007 were used for these purposes, the remainder being used to reduce national transmission tariffs.

How to increase interconnector capacity in Europe up to the optimal level, including careful considering all cost-effective alternatives[38], is clearly beyond the scope of this paper. However, this Annex serves to illustrate the way in which market coupling creates a new source of market revenues ("congestion rents") through the implicit trading of interconnector capacity (market coupling) that can be put to this purpose.[39]

Alternative View of Market Coupling

Another way of visualizing market coupling and the manner in which the coupling algorithm works is to think of two national supply and demand curves being combined into a single bid stack supply curve to meet the combined demand of the two coupled markets.

[36] *See "Interconnector Investment for a Well-functioning Internal Market",* Bruges European Economic Research Papers by Kapff L & Pelkmans J at; http://www.coleurope.eu/sites/default/files/research-paper/beer18.pdf

[37] In terms of energy prices, and leaving aside the possible advantages of increased security and market liquidity etc., social welfare will be maximised when the interconnector capacity is just sufficient to allow prices to converge. However, construction costs need to be taken into account and the point at which the annuitized incremental cost of capacity is equal to the corresponding reduction in annual congestion cost is often taken as the capacity at which overall social welfare is maximised.

[38] In the example above, it would be possible to reduce the price differential between Market A and Market B, and to reduce congestion by investing in distributed generation, energy efficiency and/or demand-management programs in Market area B. Investing in these so-called "non-transmission alternatives" can be part of a coherent plan, along with transmission upgrades, to reduce congestion and promote broader market coupling.

[39] For a broader discussion of key considerations for the evolving European approach to infrastructure planning and investments, see RAP's Policy Brief, *Securing Grids for a Sustainable Future,* available at http://www.raponline.org/document/download/id/4694

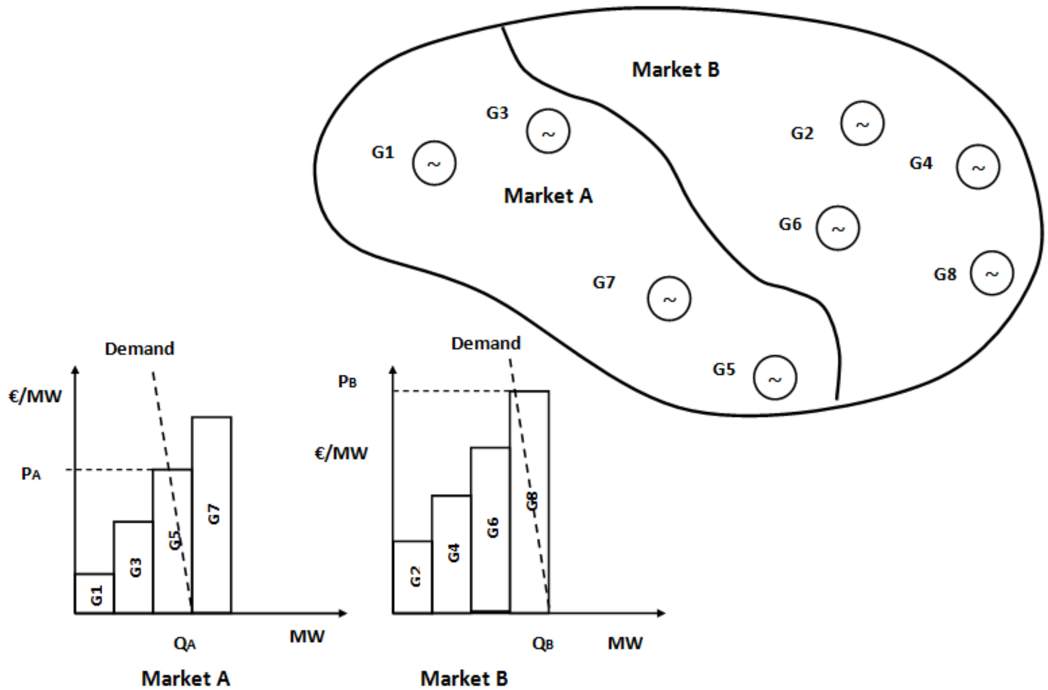

Figure 2a, Two Markets A and B operating independently

In Figure 2a, the two markets A and B are illustrated as operating independently, with clearing prices PA and PB respectively serving their internal demands. When the two markets are coupled, as illustrated in Figure 2b, a combined supply and demand curve is created that utilizes the lowest cost resource across the coupled markets to serve the combined demand, resulting in a new coupled clearing price PA'/PB' - assuming adequate interconnection capacity and no congestion.

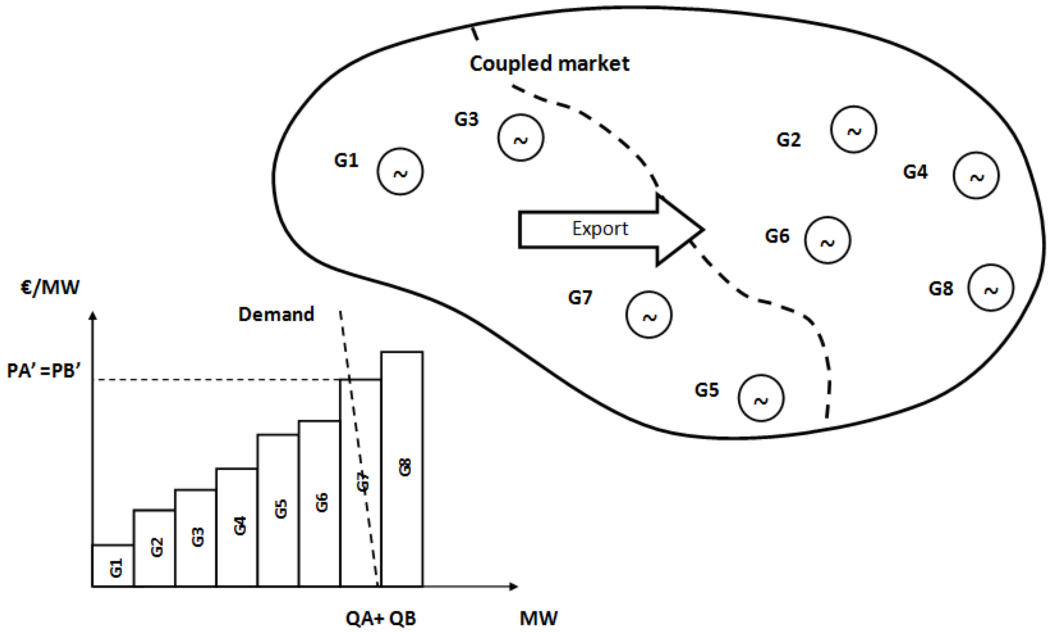

Figure 2b, Market coupling with supply and demand curves combined

Market coupling requires cooperation between TSO and market operators. TSOs will be required to calculate and supply interconnector capability data to an overarching power exchange, such as EPEX Spot[40], who will also receive national supply and demand bid data from the relevant national power exchanges. Congestion rents will be returned to the TSOs involved, either to fund additional interconnection capacity or offset national use-of- system charges.

Harmonising the characteristics of coupled markets will facilitate cross border trading. However, as distinct from market splitting where a single power exchange is created and markets split only in the presence of congestion, market coupling allows the continued operation of separate national power exchanges and avoids the need for complete harmonisation.

Forwards energy trading between coupled markets will be facilitated by the explicit auctioning of interconnector capacity, very much as now. At the day ahead stage, "use it or sell it" rules requires that parties having acquired capacity must either nominate a flow across the interconnector or "sell" that capacity to the day-ahead auction at a price determined by the price differential (PB' – PA'). Capacity unused at the intraday stage will be allocated via the continuous implicit auction without compensation, i.e. a "use it or lose it" rule applies.

[40] EPEX Spot covers France, Germany, Austria and Switzerland and was formed from the amalgamation of the French Powernext and German EEX AG power exchanges.