# Regulatory Design of Capacity Remuneration Mechanisms in Regional and Low-Carbon Electric Power Markets

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Doctoral Thesis

Madrid, Spain 2016

# Regulatory Design of Capacity Remuneration Mechanisms

## in Regional and Low-Carbon Electric Power Markets

PAOLO MASTROPIETRO

# Regulatory Design of Capacity Remuneration Mechanisms

## in Regional and Low-Carbon Electric Power Markets

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# Regulatory Design of Capacity Remuneration Mechanisms

## in Regional and Low-Carbon Electric Power Markets

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The EACEA is not to be held responsible for contents of the Thesis.

*A Rosa*

# SUMMARY

Capacity remuneration mechanisms (CRMs) are "climbing" regulatory agendas in all liberalised power sectors, especially in the European Union. CRMs are introduced to improve system reliability and to minimise power shortages to an economically efficient extent. These schemes will have a central role in future power systems. This PhD thesis provides an in-depth review of CRM design elements and recommendations to increase their efficiency and effectiveness, particularly in view of the challenges that these mechanisms have to confront in the current power sector environment, characterised by the pursuit of decarbonisation. The attention is focused here on the interaction with regional market integration, the need for properly-designed performance incentives, and the interaction with renewable technologies.

The research is based on empirical evidence collected from international experiences, which is complemented, where applicable, by a model-based analysis to examine specific design elements. The outcomes of this PhD thesis can be summarised as follows.

- The participation of cross-border resources in national CRMs must be guaranteed in order to fully seize the benefits of regional market integration. However, this participation requires a strong commitment from power systems (and governments) in the regional market and the implementation of network codes and market rules that deter system operators from blocking exports when the latter are the outcome of an efficient market clearing. Where short-term markets are coordinated through market coupling, the algorithm must include a conditional nomination rule that ensures that, during regional scarcity conditions, available resources are assigned to those consumers that paid for them in the CRM market.
- CRMs must rely on robust performance incentives that foster the actual delivery of the committed capacity. High penalty rates may increase the cost of the capacity market, but the overall cost of electricity supply may decrease.
- Renewable technologies should be allowed to participate in CRMs and should be exposed to the market signals provided by these mechanisms. If renewable and conventional technologies must compete in the same markets, they should do it subject to the same rules. Obviously this participation must be coordinated with renewable support schemes, discounting CRM revenues.

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# RESUMEN

Los mecanismos de capacidad (CRMs en su acrónimo inglés) ocupan el centro de la discusión regulatoria en todos los sectores eléctricos liberalizados, especialmente en la Unión Europea. Dichos mecanismos se introducen para mejorar la fiabilidad del sistema y para minimizar la escasez de energía de manera económicamente eficiente. Los CRMs tendrán un papel central en los sistemas eléctricos del futuro. Esta tesis doctoral ofrece una revisión detallada de los elementos de diseño de los mecanismos de capacidad y presenta recomendaciones para mejorar su eficiencia y su eficacia, sobre todo en vista de los nuevos desafíos que estos mecanismos tendrán que enfrentar en el actual contexto de descarbonización del sector energético. Los temas que se tratan en esta tesis son la interacción con la integración regional de los mercados eléctricos, la necesidad de incentivos para el cumplimiento de los contratos de capacidad y la interacción con las tecnologías de aprovechamiento de las energías renovables.

La investigación se basa en evidencias empíricas recogidas de las experiencias internacionales más destacadas con los mecanismos de capacidad, complementadas, cuando sea posible, a través de análisis basados en modelos computacionales. Se resumen abajo las principales aportaciones de esta investigación.

- La participación de los recursos transfronterizos en los mecanismos de capacidad nacionales ha de garantizarse para aprovechar plenamente los beneficios de la integración regional. Esta participación requiere un firme compromiso hacia el mercado regional. Además, cuando los mercados de corto plazo están acoplados, es necesario introducir una nominación condicional de la capacidad de interconexión.

- Los CRMs deben contar con fuertes incentivos para el cumplimiento de los contratos de capacidad. Unas penalizaciones elevadas en caso de incumplimiento pueden aumentar el coste del mercado de capacidad, pero el coste total del suministro eléctrico puede disminuir.

- Las tecnologías basadas en energías renovables deberían participar en los mecanismos de capacidad y estar expuestas a las correspondientes señales de mercado. Si las tecnologías renovables y convencionales tienen que competir para la asignación de contratos de capacidad, las reglas tienen que ser las mismas y la remuneración relativa al mercado de capacidad debería ser descontada de los incentivos a la renovable.

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# SAMENVATTING

De capaciteitsvergoedingsmechanismen (CRM's) staan centraal in de regelgevende discussie in alle geliberaliseerde elektriciteitssectoren, met name binnen de Europese Unie. Die mechanismen worden ingevoerd om de betrouwbaarheid van het systeem te verbeteren en de energieschaarste op economisch efficiënte wijze te minimaliseren. De CRM's zullen een cruciale rol spelen in de elekticiteitssystemen van de toekomst. Dit proefschrift biedt een gedetailleerde evaluatie van de ontwerpelementen van de capaciteitsmechanismen en reikt aanbevelingen aan om de efficiëntie en doeltreffendheid ervan te verbeteren, vooral met het oog op de nieuwe uitdagingen waarvoor deze mechanismen staan binnen de huidige context van het koolstofvrij maken van de elektriciteitssector. De onderwerpen die in dit proefschrift aan bod komen zijn de interactie met de regionale integratie van de elektriciteitsmarkten, de noodzaak van incentives voor het naleven van de capaciteitscontracten en de wisselwerking met de technologieën van benutting van duurzame energiebronnen.

Het onderzoek steunt op empirisch bewijsmateriaal verzameld uit de belangrijkste internationale ervaringen met de capaciteitsmechanismen, waar mogelijk aangevuld aan de hand van analyses op basis van computermodellen. Hieronder worden de voornaamste bijdragen van dit onderzoek samengevat.

- De deelname van de grensoverschrijdende hulpbronnen aan de nationale capaciteitsmechanismen moet worden gegarandeerd om de voordelen van regionale integratie ten volle te benutten. Deze deelname vereist een sterke verbintenis ten overstaan van de regionale markt. Wanneer de markten van korte termijn gekoppeld zijn, moet bovendien een conditionele nominatie van de koppelingscapaciteit worden ingevoerd.
- De CRM's moeten sterke incentives hebben voor de naleving van de capaciteitscontracten. Aanzienlijke sancties in geval van niet-naleving kunnen de kostprijs van de capaciteitsmarkt verhogen, maar de totale kost van de elektriciteitsvoorziening daalt.
- De technologieën op basis van duurzame energiebronnen moeten deelnemen aan de capaciteitsmechanismen en blootgesteld zijn aan de overeenkomstige marktsignalen. Indien de duurzame en conventionele technologieën moeten concurreren voor het toewijzen van capaciteitscontracten, moeten de regels dezelfde zijn en de vergoeding met betrekking tot de capaciteitsmarkt moet worden afgetrokken van de incentives voor duurzame energie.

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# SAMMANFATTNING

Kapacitetsmekanismerna (CRM i engelsk akronym) står i den regulatoriska diskussionens centrum i alla de elsektorer som liberaliserats, särskilt inom Europeiska unionen. Sådana mekanismer införs för att förbättra systemets tillförlitlighet samt för att minimera energibrister på ett sätt som är ekonomiskt effektivt. CRM kommer att spela en central roll i framtidens elsystem. Denna doktorsavhandling erbjuder en detaljerad genomgång av kapacitetsmekanismernas designelement och lägger fram rekommendationer för att förbättra deras effektivitet, speciellt givet de nya utmaningar som dessa mekanismer står inför i det nuvarande sammanhanget av dekarbonisering i energisektorn. De ämnen som behandlas i avhandlingen är interaktionen med elmarknadernas regionala integration, behovet av incitament för uppfyllelse av kapacitetsavtal samt interaktionen med förnybar teknologi.

Forskningen grundas på empiriska underlag hämtade från de mest framträdande internationella erfarenheterna med kapacitetsmekanismer. Dessa komplementeras när det är möjligt med analyser baserade på beräkningsmodeller. Nedanför sammanfattas avhandlingens huvudsakliga bidrag.

- De gränsöverskridande resursernas deltagande i nationella kapacitetsmekanismer måste garanteras för att till fullo utnyttja den regionala integrationens fördelar. Ett sådant deltagande kräver ett starkt engagemang för den regionala marknaden samt implementeringen av nätverkskoder och marknadsregler som hindrar systemoperatörer från att blockera export som resulterar från en effektiv marknadsclearing. När de kortsiktiga marknaderna är sammankopplade är det dessutom nödvändigt att införa en villkorlig nomineringsregel som i tider av regional brist försäkrar att de tillgängliga resurserna tilldelas till de konsumenter som betalade för dem på CRM-marknaden.
- Kapacitetsmekanismerna måste vila på starka incitament för uppfyllelse av kapacitetsavtalen. Höga böter i fall av bristande avtalsuppfyllelse kan medföra en ökad kostnad av kapacitetsmarknaden, men den totala kostnaden för elförsörjning minskar.
- Teknologier baserade på förnybar energi borde delta i kapacitetsmekanismerna samt utsättas för de gällande marknadssignalerna. Om förnybara och konventionella teknologier skall konkurrera om tilldelningen av kapacitetskontrakter bör reglerna vara likvärdiga för båda. Ersättning som är knuten till kapacitetsmarknaden bör dessutom diskonteras från ekonomiska incitament till förnybar energi.

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## List of Abbreviations

| | |
|---|---|
| ACER | Agency for the Cooperation of Energy Regulators (European Union) |
| AEEG | *Autorità per l'Energia Elettrica e il Gas* (Italy) |
| APX | Amsterdam Power Exchange (Belgium, Netherlands, United Kingdom) |
| BMWi | *Bundesministerium für Wirtschaft und Energie* (Germany) |
| CCGT | Combined Cycle Gas Turbine |
| CEER | Council of European Energy Regulators (European Union) |
| CSMEM | *Comité de Seguimiento del Mercado Mayorista de Energía Eléctrica* (Colombia) |
| CREG | *Comisión de Regulación de Energía y Gas* (Colombia) |
| CRM | Capacity Remuneration Mechanism |
| DECC | Department of Energy & Climate Change (United Kingdom) |
| DSR | Demand-Side Response |
| EEAG | Environmental and Energy State Aid Guidelines (European Union) |
| EFOR | Equivalent Forced Outage Rate |
| EIA | Energy Information Administration (United States) |
| ENFICC | *Energía Firme para el Cargo por Confiabilidad* |
| ENTSO-E | European Network of Transmission System Operator for Electricity |
| EU | European Union |
| EUPHEMIA | EU Pan-European Hybrid Electricity Market Integration Algorithm |
| FCM | Forward Capacity Market |
| FEC | Firm Energy Certificates |
| FERC | Federal Energy Regulatory Commission (United States) |
| FTR | Financial Transmission Right |
| IEM | Internal Energy Market (European Union) |
| ISO | Independent System Operator |
| LDC | Local Distribution Company |
| MIT | Massachusetts Institute of Technology |
| MTBF | Mean Time Between Failures |
| MTR | Mean Time to Recovery |

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| NWE | North West Europe |
| OLADE | *Organización Latinoamericana de Energía* |
| ORTP | Offer Review Trigger Prices |
| PCR | Price Coupling of Regions |
| PHPA | Peak-Hour Period Availability |
| PJM | Pennsylvania New Jersey Maryland Interconnection |
| PTR | Physical Transmission Right |
| RES-E | Renewable Energy Sources for Electricity |
| RPM | Reliability Pricing Model |
| RTE | *Réseau de Transport d'Électricité* (France) |
| SCED | Security Constrained Economic Dispatch |
| TSO | Transmission System Operator |
| UC | Unit Commitment |
| UIOSI | Use It Or Sell It |

# PREMISE

*'Adam Smith's invisible hand - the idea that free markets lead to efficiency as if guided by unseen forces - is invisible, at least in part, because it is not there'.*

Joseph Stiglitz, 2002

According to the widespread interpretation of Adam Smith's Invisible Hand provided by Milton Friedman and other representatives of the Chicago School of Economics[1], in a free market environment, individuals (and corporations) intended only to pursue their own interest are led by an Invisible Hand to promote the public welfare, which was not part of their intention. A consequence of this line of thinking is that, since the maximisation of the social welfare is already guaranteed by the Invisible Hand of the market, the role of the state in the economic life of a country should be minimised. This argument provided a central justification for the *laissez-faire* economic theory that has dictated the political agenda in the last three decades.

Nonetheless, while the Invisible Hand (as per this widely accepted interpretation) works perfectly in ideal markets, as well as in mathematical models formulated to represent them, its effects in real markets have been often lower than expected. Self-interested individuals have been pursuing their own interests for a long time, but the maximisation of social welfare has remained on paper. Actually, in the real world, the Invisible Hand has been hiding so well that one may wonder, as Joseph Stiglitz in the opening quote, whether it exists at all.

The Invisible Hand exists indeed, this meaning that the market, in most of the cases, is indeed the best way to allocate scarce resources among consumers. However, in real markets, the Invisible Hand is buried beneath such a thick layer of market failures that it can hardly move and it does not manage to work its "magic". Some of these market failures can be corrected and minimised, but some others are there to stay. Information asymmetry, market incompleteness, and externalities might not be fully avoided, and if no measure is

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[1] It must be reminded that this explanation is actually misleading. Many academicians (Persky, 1989; Meeropol, 2004; Chomsky, 2011) highlighted the discrepancy between Adam Smith's use of the expression in his masterpiece *The Wealth of Nations* and the modern interpretation of the Invisible Hand.

taken to counteract their impact, it cannot be claimed that the outcome of the "free" market is optimal.

A sector in which the effects of the Invisible Hand have been particularly hard to be observed is the power sector. A wave of liberalisations, started in Chile in 1982 and having its worldwide peak in the late 1990s, replaced monopolies with electricity markets, but results in terms of economic efficiency have been ambiguous. Two main reasons can be identified to partially explain this situation. Firstly, in modern societies, electricity is perceived as an essential good by the vast majority of its consumers, and the state (and the government) is considered somehow responsible for its provision, and even for its price. Implicitly or explicitly accepting this responsibility, states issue regulations that, in many cases, "cuff" the Invisible Hand, trying to avoid undesirable outcomes of its actions. Obviously, this dramatically reduces its range and constrains its movements at the moment of pushing and pulling agents towards the economic optimum. Secondly, electricity has some characteristics that differentiate it from other products or services, as non-storability, capital intensity, lumpiness of investments, or large environmental impact. These features make the power sector more prone to market failures, which, as already mentioned, hinder the Invisible Hand and result in a suboptimal outcome.

If this discussion affects to a greater or lesser extent many aspects of the power sector, in the security of supply, and more specifically in the system adequacy dimension, it gave rise to a dilemma. Is the short-term market price an economic signal strong enough to drive an efficient system expansion or further signals are required in order to attract investments and ensure a reliable electricity supply? In theory, the Invisible Hand is supposed to be endowed also with a very long sight, thus its actions should maximise the social welfare also in the longer term and no further intervention is required. This point of view resulted in the implementation of the so-called energy-only markets. Nevertheless, as it will be presented in this thesis, many countries decided, from the very beginning of the liberalisation process, to complement the short-term market price with further signals to investors, through what are now usually referred to as Capacity Remuneration Mechanisms (CRMs). Also those countries, especially in Europe, which had originally opted for more or less "pure" energy-only markets, are now in the process of introducing CRMs.

This thesis focuses on capacity remuneration mechanisms, and on the interaction of these schemes with other elements of power sector regulation (mainly, regional market integration and renewable energy support). These mechanisms represent interventions that must be introduced keeping in mind the basic tenet of economic regulation, i.e., the possible regulatory failure must not be larger than the market failure to be corrected, and which must be carefully designed, for the cure not to be worse than the disease. Following the simile underlying this premise, CRMs represent a Visible Hand[2] acting on electricity

[2] This expression is not used here with the meaning assigned to it by The Economist (2012) in its famous report titled "The Visible Hand", which associated it with state capitalism, underlying the

markets, whose movements must be certain, transparent, and predictable by all the agents in the sector. In this context, the objective of the research presented herein is to provide a small contribution to the design of this Visible Hand and to the identification of limits to its intervention.

In the last chapter of the book *Regulation of the Power Sector*, edited by Ignacio J. Pérez-Arriaga, the editor himself identifies the future challenges in power sector regulation. In the part of this foresighted analysis discussing the limitations of energy markets, the following statements can be found.

> '*It seems necessary to bestow the market with some kind of long-term vision, so that, while minimizing the interference with the efficiency of the allocation mechanisms of markets, market agents receive additional signals to steer them in the right direction*'.

And he concludes.

> '*Tensions and ambiguities will always exist regarding the fuzzy borderline between markets and governments. But in the energy sector, they must be seen not as opposite but complementary forces*'.
>
> Ignacio J. Pérez-Arriaga, 2013a

The path to social welfare maximisation is uphill and bristling with pitfalls. The state and the market, the Visible and the Invisible Hand need to learn how to better work together if they want to be ready for the tremendous challenges that the next decades seem to have in store for the energy sector.

importance of this economic model especially in the energy sector. It does not coincide either with the definition of the Helping Hand as outlined by Shleifer and Vishny (2002), which considers an entrepreneurial role for the state. The Visible Hand mentioned in this premise only foresees for the state the role of issuer of robust regulation. Finally, the term as it is intended here is obviously not related with the Visible Hand described by Chandler (1993), who referred to managerial capitalism in modern multiunit enterprises.

# 1. INTRODUCTION

*This first chapter provides the reader with the context of the thesis. It introduces the topics that are analysed in the following chapters, presents the research questions and the objectives of the thesis, and outlines the structure of the document*[3].

## 1.1. Context

The main reason behind liberalising the power generation activity was to promote economic efficiency at all levels, in the short term (at an operational level), but especially in the long term (at capacity expansion level), where the largest efficiency gains were supposed to be achieved. This belief was based on fundamental economic theory, which asserts that the short-term market marginal price is all that is needed to remunerate generators in order to lead the system expansion towards an optimally adapted generation mix. However, from the outset, ever since Chile restructured its power sector with its pioneering reform in 1982, the ability of short-term marginal prices to provide sufficient investment incentives was called into question in a number of countries in which liberalisation was implemented. This was especially the case in the American continent: most Latin American countries (with the exception of Brazil) and most power systems in the United States (e.g., PJM) introduced in their original market designs some sort of capacity mechanism (a capacity market or payment, or sometimes both), aimed to complement short-term marginal prices with a remuneration for available capacity. On the other hand, the majority of European countries

[3] Part of this chapter draws on Batlle, C., Mastropietro, P., Rodilla, P., Pérez-Arriaga, I. J., 2015, *The System Adequacy Problem: Lessons Learned from the American Continent.* Chapter 7 of the book *Capacity Mechanisms in the EU Energy Markets: Law, Policy, and Economics*, 2015, Oxford University Press. ISBN 978-0-19-874925-7.

(once again with some exceptions, namely Spain and Ireland) followed the so-called energy-only market approach, refusing to implement any explicit capacity mechanism[4].

In the years following the implementation of the first market-oriented reforms, it has become evident that the theoretical premises, through which the market alone would provide the optimal investment signal, are unfortunately absent in practice in the vast majority of cases. As a result, capacity mechanisms are currently being implemented or under discussion in almost all of the countries that initially opted for an energy-only market design. Today, this issue is at the core of the regulatory debate in Europe, where many states are designing or implementing capacity remuneration mechanisms. The United Kingdom has recently held the second auction of its capacity market (National Grid, 2015), Italy is accelerating on its reliability options mechanism (AEEG, 2011), France will soon launch a CRM based on decentralised capacity obligations (RTE, 2014), while Germany is currently discussing about the possibility of encompassing a market-based capacity mechanism in the Energy Transition reform (BMWi, 2014).

On the other hand, over the past decade, the countries that originally introduced a capacity mechanism have realised the need to "fine-tune" their schemes. In North America, PJM fixed flaws in its original capacity market design during the implementation of the new Reliability Pricing Model in 2008, and a new capacity mechanism based on auctions, the so-called Forward Capacity Market, was implemented in New England. In South America, several countries suffered serious power shortages at the beginning of the twentieth century, which evidenced the ineffectiveness of the initial capacity mechanisms. These circumstances resulted in the implementation of a second wave of reforms, based on long-term auctioning, which significantly modified the old schemes (Batlle et al., 2010).

Despite the already vast and still-growing international experience with capacity mechanisms, these regulatory instruments are now to face new challenges as the power sector context evolves in terms of available technologies, regulatory framework, and political scenarios. This thesis focuses on three of these challenges, which are summarised in the list below.

- Regional market integration processes need capacity mechanisms open to cross-border participation, and this requires specific provisions and new institutional arrangements.
- Enhanced performance incentives must be designed in order to maximise the coupling between the remuneration obtained from the capacity mechanism and the actual performance of the resource during scarcity conditions, thus ensuring system reliability.

[4] However, the majority of them employed implicit and subtle regulatory safeguards regarding security of supply. As argued in Batlle and Rodilla (2010), examples of regulatory safeguards are represented, for instance, by the presence in the market of large state-owned companies, or by the long-term procurement of reserves to be used during scarcity conditions, either from the generation side or from the demand side (through auctions for interruptible demand).

- The role of renewable energy technologies in CRMs must be clarified. If RES-E support mechanisms and capacity mechanisms have to converge towards a single investment mechanism, renewable and conventional technologies should compete on the same level.

These macro-topics, only sketched in this initial list, are better outlined in the following sections of this introductory chapter, to be then fully examined in the body of this thesis. The overall objective of this research project is to collect and review in detail empirical results from international experiences (focusing on South America, North America, and Europe) and to present proposals to enhance the design of capacity mechanisms, for these instruments not to clash with the new conditions that will take place in power sectors during the next decades. This analysis aims at providing a valuable tool to those regulators, in Europe and elsewhere, who are presently implementing or planning to introduce a CRM in their systems.

## 1.2. The need for CRMs

Many power sector liberalisations were theoretically founded on the pioneering work from a research group from MIT (Massachusetts Institute of Technology), who applied microeconomic marginal theory to electricity systems (among other publications, Caramanis, 1982; Caramanis et al., 1982; Joskow and Schmalensee, 1988; Schweppe et al., 1988). These authors demonstrated how, under a number of ideal conditions, the short-term price resulting from a competitive generation market provides efficient signals both in the short and in the long term, fostering the investments necessary to guarantee the system adequacy[5]. Nonetheless, these ideal conditions could not be found in real power systems. Based on empirical evidence from the first experiences with power sector liberalisations, many authors identified a number of market failures, which detract from the efficiency of the price signal and deviate the long-term development of the generation segment from the optimal one (among other publications, Pérez-Arriaga, 2001; Stoft, 2002; Neuhoff and De Vries, 2004; Joskow, 2008; Cramton et al., 2013; Rodilla and Batlle, 2013; Henriot and Glachant, 2014).

Listing all these market imperfections exceeds the scope of this chapter and it is a topic already extensively covered by academic literature. Nevertheless, it is important to mention at least the element which has historically affected power sector investment to a larger extent, i.e., market incompleteness, and its impact on risk allocation. The electricity industry is a cornerstone of national economies and it has always been subject to certain degree of political control. On the one hand, this increases uncertainties for investors beyond those that are typical of all markets (price volatility, uncertainty about competitors' strategies,

[5] The set of measures to be taken in order to guarantee the security of electricity supply is known as the security-of-supply problem, whose long-term dimension is the system adequacy; for a definition of the different dimensions of the security-of-supply problem, see Batlle and Rodilla (2010).

etc.), since agents have to face also the risk of possible regulatory changes, an element commonly referred to as regulatory risk. On the other hand, demand has been to date somehow "unconcerned" about the risk of power shortages, because it is commonly assumed that the government is in charge to take actions to avoid these conditions (and, of course, to prevent the very high prices that would result from them). This gap in risk perception results in a lack of demand in the long- to very long-term segment of the market, a problem which is usually referred to as market incompleteness[6]. Generators, unable to properly hedge their risk through long-term contracting, tend to under-invest, with the consequent threat to security of supply.

In order to correct this and other market failures, several countries introduced, or are in the process of introducing, CRMs. Capacity mechanisms are regulatory instruments designed to reinforce the economic signal provided by short-term electricity markets with additional remuneration to attract investment and ensure system adequacy in liberalised power sectors. When properly implemented, this additional remuneration should also be protected from political interferences, thus minimising the regulatory risk. The final goal of a CRM is to guarantee the security of supply in the system where it is introduced. This can be achieved by attracting investment to cover the expected demand growth, or by avoiding decommissioning in those contexts where loads are not increasing, but where plants are losing profitability in the energy market.

This thesis does not aim at contributing to the discussion about the necessity of capacity mechanisms. The fact that most of the liberalised power sectors which had not introduced a CRM during the initial restructuring are now implementing some design of capacity mechanism is a powerful proof of the need for these instruments in real markets. The objective of this thesis is to shed a light on how capacity mechanisms should be enhanced to be able to cope with the new challenges awaiting them, which are analysed in the following sections, after presenting the CRM classification that underlies this research.

## 1.3. A CRM taxonomy based on design elements

Capacity remuneration mechanisms share the same main objective, i.e., guaranteeing the security of electricity supply, but they can have different designs to achieve it. The most widespread classification of capacity mechanisms applied so far (see for example ACER, 2013a) considers a first distinction between price-based and quantity-based schemes and a further subdivision between targeted and market-wide instruments. The majority of the CRMs recently implemented are quantity-based mechanisms, often following a market-wide

[6] Long-term markets are defined to be incomplete when perfect inter-agent risk transfer cannot take place (Rodilla et al., 2015).

approach[7]. However, this broad taxonomy has several limitations at the moment of embracing all possible CRM designs and also some theoretical flaw. Its main defect is probably the confusion it makes between the procurement process (direct selection, centralised auction, decentralised bilateral contracting, etc.) and the reliability product (obligation to offer in a certain market, obligation to deliver, option contract, etc.). Because of this inconsistency, the boundaries between the CRM designs proposed by this commonly-used classification are much more blurred than it seems. As an example, the reliability option mechanism is usually based on a centralised auction, but the term reliability option only refers to the kind of product to be traded in the CRM and it tells nothing about the procurement process. Reliability option contracts can be procured in a centralised capacity auction or bilaterally traded in a decentralised scheme.

For this reason, some authors start expressing a preference for classifications based on the design elements that compound a capacity remuneration mechanism (Batlle and Pérez-Arriaga, 2008; FERC, 2013a). Design elements represent regulatory decisions that the policy maker has to take when designing the CRM. In the second chapter of this thesis, a taxonomy based on design elements is provided and applied to different national CRM designs. Concepts and nomenclature expressed in chapter two are then used in the rest of the document.

## 1.4. The interaction with regional markets

The integration of national electricity markets into broader regional markets creates a new cross-border dimension of capacity mechanisms. Historically CRMs have been used to guarantee the security of domestic supply by attracting investment in generation facilities located on the national territory. However, benefits from the implementation of regional markets (optimal exploitation of energy resources) can be fully seized only through a coordinated long-term development of the regional power sector and this requires opening capacity mechanisms to agents located outside of national borders. As discussed in the third chapter of this thesis, the alternative approach brings the regional market back to national autarkies, which install on their territory all the capacity needed to supply their demand plus a reserve margin, and trade in the regional market only electricity "leftovers" in the short term.

Nonetheless, the participation of cross-border capacity in national CRMs presents some complications. Specific provisions must be considered, particularly as concerns the definition of the so-called reliability product, and must consider the mechanism used to trade electricity through interconnections. This topic is analysed in depth in the third chapter, for

[7] For example, in Europe, the United Kingdom has already introduced capacity auctions, France is completing the design of its capacity obligations, while Italy opted for a scheme based on reliability options.

the context in which advanced regional market integration coincides in time with the introduction of new capacity mechanisms, i.e., the European Union. Furthermore, stronger institutional commitments and new risk-allocation strategies are needed, as well as a coordinated management of regional scarcity conditions. This subject is discussed in chapter four.

## 1.5. The need for performance incentives

As mentioned in the previous sections, capacity mechanisms aim at attracting new investments for the power system to achieve a level of security of supply that the regulator considers adequate. However, the objective of CRM is not merely to contract new "nameplate" capacity, but rather to encourage the installation of reliable generation technologies that actually enhance the security of electricity supply during real-time operation. In exchange for the additional remuneration provided by the CRM, which allows them to hedge part of their risk, resources must commit to be available when the system needs them the most, i.e., during scarcity conditions.

After two decades of experience with the implementation of CRMs, the need of strictly correlating capacity mechanism remuneration to each resource's actual contribution to security of supply appears evident. This can be obtained through specific incentives that directly couple the remuneration with the performance during scarcity conditions. The design of these performance incentives in the first capacity mechanisms was often flawed, when they were not directly absent. Especially in the American continent, this provoked stress events during which many resources were not able to fulfil their commitment, thus receiving a fixed remuneration for a contribution they were not providing to the system. In order to correct these flaws, at this writing, some power systems in the United States are in the process of reforming their capacity mechanisms according to the "pay-for-performance" principle.

The fifth chapter of this thesis analyses international experiences with CRM performance incentives, including recent developments and the conditions that have caused them. Empirical evidence is collected from those systems particularly prominent in this regard, as Colombia, ISO New England, and PJM. The analysis is then extended to see how this experience is being reflected in the capacity mechanisms currently under design in Europe, focusing on the United Kingdom and France.

After this theoretical analysis, the sixth chapter stresses again the importance of performance incentives and penalty schemes in capacity mechanisms, but this time through an analytical modelling approach. A simulation model is used to assess and highlight the effect of penalty schemes on the merit order of a centralised CRM auction. The outcomes of the model are used to demonstrate how an explicit penalty for underperformance provides existing plants with incentives to improve their availability during scarcity conditions and eventually results in the entrance of new and more reliable power resources.

## 1.6. The interaction with renewable energy technologies

The interaction between renewable energy resources and capacity mechanisms is twofold. On the one hand, the high penetration of RES-E technologies, mainly investments in wind and solar photovoltaic facilities prompted by some sort of support mechanism, is stressing the necessity and the importance of CRMs in liberalised power sectors. In fact, these intermittent and non-dispatchable technologies need the backup of conventional power plants to cover any deviation from their schedule due to forecasting errors, but at the same time they increase uncertainties in the market and might discouraging investments.

On the other hand, it not clear yet whether renewable technologies, once they reach economic maturity and become competitive with conventional power plants, are or will be allowed to participate in capacity mechanisms and, if positive, under which conditions. The contribution of renewable technologies to the security of supply depends on the typology of scarcity conditions and varies greatly between energy-constrained and capacity-constrained systems. The typology of stress events is reflected in the design of the reliability product to be traded in the CRM, which determines the possibility of renewable participation in the mechanism. As a general recommendation, for RES-E support to become more market-compatible in the future, renewable technologies should be exposed to market signals as much as possible, including those stemming from the capacity segment (obviously this source of remuneration should be coordinated with the economic incentive provided to these technologies). Nonetheless, this theoretical discussion has been difficult to apply in practice and the participation of RES-E power plants in CRMs has been very limited until now both in Europe and in the United States.

A region where some sort of "convergence" between RES-E support schemes and capacity mechanisms is already taking place is South America. The most prominent example is Brazil, where renewable technologies have already participated and been selected in conventional long-term electricity auctions, in which they somehow compete with thermal and hydropower plants. However, a detailed analysis of the regulation permits to observe how renewable and conventional technology rarely compete on the same level, subject to the same rules and contract provisions. The seventh chapter of this thesis goes into this topic. First, it deepens the theoretical discussion only outlined here, and then it presents the South American experience, identifying those features which differentiate renewable and conventional technologies when taking part to a capacity mechanism.

## 1.7. Research questions

After having outlined the background of this research work, it is possible to formulate the research questions that are addressed in this thesis. As already mentioned, the overall objective is to provide analyses and, consequently, recommendations to improve CRM design in view of the forthcoming challenges resulting from the fast-paced evolution of power systems. Specific questions can be expressed as follows.

- Can capacity mechanisms be open to cross-border resources in a regional market context? If positive, under which assumptions? How is this subject related with the short-term market harmonisation through market coupling? Which institutional arrangements are required to improve the firmness of these cross-border trades?
- Can performance incentives improve the efficiency and effectiveness of capacity mechanisms? How should performance incentives be designed in order to guarantee that the resources involved in the CRM fulfil their commitment during scarcity conditions?
- Can RES-E support schemes merge with capacity mechanisms? Can renewable energy technologies compete with conventional technologies in providing reliability? In those systems in which this competition is already occurring, are renewable and conventional technologies competing on the same level, subject to the same rules?

The answers to these questions are pursued through a combination of empirical analysis (based on international experiences with CRMs) and modelling approach.

## 1.8. Document structure

Apart from the summary and the premise that precede this introductory section, the document is structured around six central chapters (from chapter two to seven) plus a final chapter that summarises the main findings of the research work, identifies the main policy recommendations that can be drawn from it and outlines potential future works. The organisation of this document is also represented graphically in Figure 1.1.

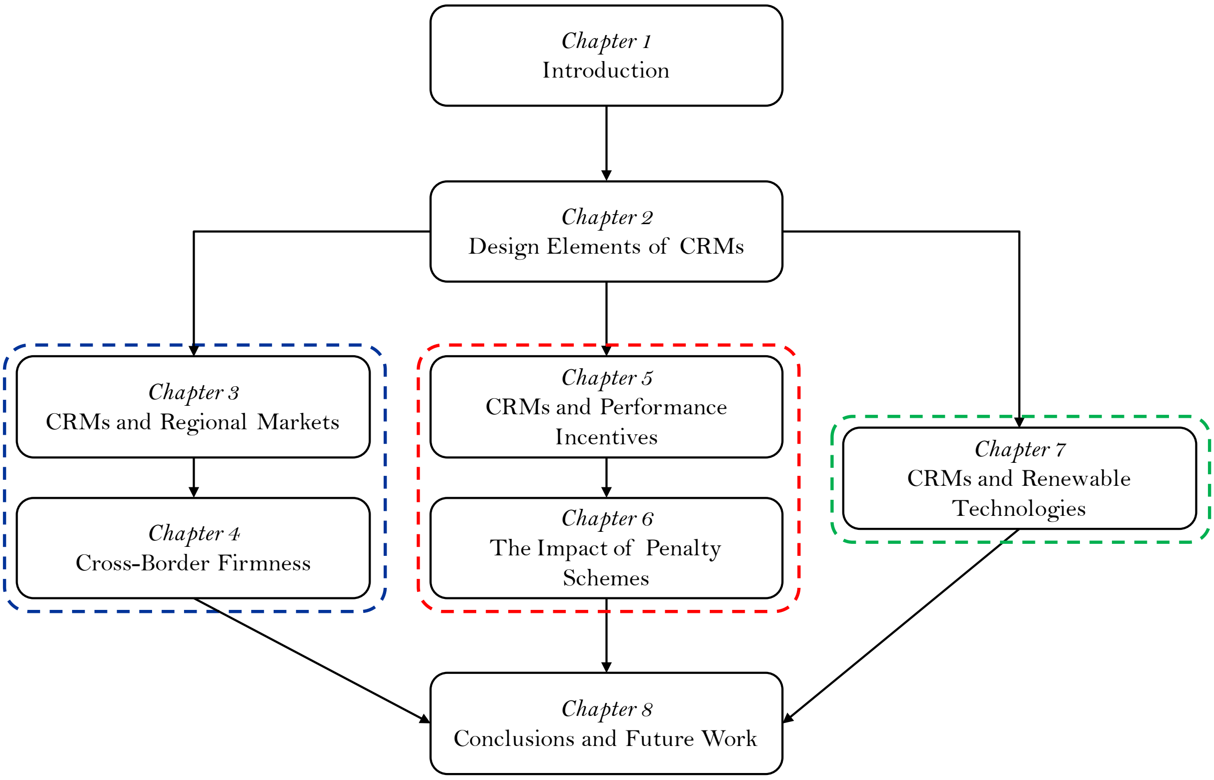


Figure 1.1. Structure of the document

As anticipated throughout this introduction, the thesis is organised around three pillars, reflected with different colours in Figure 1.1. Chapter three is focused on the design of capacity mechanisms in an integrated regional market context. Based on the European experience, recommendations are provided to allow the participation of cross-border capacity in CRMs. After this, chapter four proposes new institutional arrangements to enhance the firmness of these cross-border CRM trades. Chapter five and chapter six are both centred on performance incentives in capacity mechanisms, and they stress, through empirical evidence and a model-based analysis, the importance of coupling CRM remuneration with each resource's performance during scarcity conditions. Finally, chapter seven shifts the attention to the interaction between capacity mechanisms and renewable energy technologies, focusing on the competition between the latter and conventional technologies. Prior to the analysis of the three main topics, the next chapter, chapter two, presents a taxonomy of capacity mechanisms based on the design elements that compound them, using examples of CRMs implemented on both sides of the Atlantic.

# 2. DESIGN ELEMENTS OF CRMS

*Capacity mechanisms can be accurately analysed by dissecting and assessing their various design elements. This chapter presents a CRM taxonomy based on these elements, and provides some guidelines for their selection*[8].

## 2.1. Introduction

Several classifications of capacity mechanisms are available in the academic literature (De Vries, 2004; Finon and Pignon, 2008; ACER, 2013a). All these taxonomies span from the energy-only market solution, to capacity payments, up to more complex market-wide designs (capacity markets and capacity obligations). Nonetheless, it is not always obvious how to assign real CRMs implemented in national power systems to one single cell of these grids, since many times they share features with more than one design. Furthermore, as mentioned in the introductory chapter, this kind of classifications may result in confusion between the procurement process and the reliability product to be actually procured. Recently, some experts started preferring taxonomies centred on the design elements on which CRMs are based (Batlle and Pérez-Arriaga, 2008; FERC, 2013a). This chapter extends the list of these design elements (target market, lag period, contract duration, reliability product and performance incentives, and indexation and warranties), provides a definition for each one of them, identifies potential solutions for their selection, and presents examples from capacity mechanisms implemented in real markets. These examples are based on the experiences with CRMs from South America (Argentina, Brazil, Chile, Colombia, Panama and Peru), from the United States (ISO New England and PJM), and from some of the designs proposed or under implementation in the European Union (France, Italy, and the United Kingdom). Such geographical scope does not try to embrace all the capacity

[8] A condensed version of this chapter was published in Batlle, C., Mastropietro, P., Rodilla, P., Pérez-Arriaga, I. J., 2015, *The System Adequacy Problem: Lessons Learned from the American Continent.* Chapter 7 of the book *Capacity Mechanisms in the EU Energy Markets: Law, Policy, and Economics*, 2015, Oxford University Press. ISBN 978-0-19-874925-7.

mechanisms currently being used around the world, but it is broad enough to encompass the majority of possible designs.

CRM design elements are not independent and their design should not be decided in isolation. Rather, they should be seen as pieces of a puzzle, to be modelled in a way that allows them to fit together, in order to form a robust regulatory instrument that is as effective and efficient as possible. Furthermore, this puzzle has to fit together with other "external dowels", since CRMs are strictly correlated with other regulatory issues, as the design of short-term markets and RES-E support mechanisms, the regional integration process, or the calculation of tariffs. This is schematised in Figure 2.1.

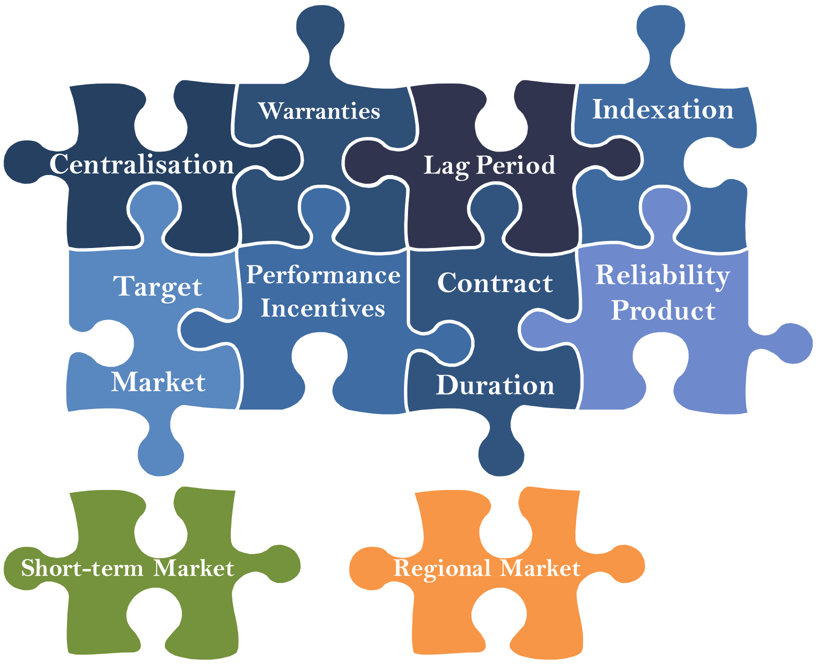


Figure 2.1. Design elements of CRMs as a puzzle with external dowels

In the following sections, from 2.1 to 2.6, the design elements will be studied one by one, characterising the potential impact that each of the available choices might have on the CRM performance and providing guidelines for their determination. Nonetheless, since capacity mechanisms must be tailored first to the peculiarities of each power system and ultimately to the regulatory and policy objectives pursued through them, it will not be possible to provide general guidelines which may be valid for every condition.

## 2.2. Target market

### 2.2.1. The buying side

When designing a capacity mechanism based on auctions, the first element which must be specified is the type of demand that will be involved in the transaction, i.e., defining who the buyer is, or on whose behalf the regulator is buying. The main options are the following. First, buyers can be regulated customers supplied by distributors or more generally regulated retailers (captive demand). Secondly, buyers can be free customers, usually large users, who are eligible to procure electricity independently (free demand). Lastly, the entire system demand can be covered. An additional alternative, in this last case, is to allow all of the demand to participate in the auction, while permitting consumers to opt out, depending on the clearing price, by offering DSR (Demand-Side Response) products. When implementing this option, it is important to allow demand response bids only from those agents for whom it is possible to guarantee that the demand reduction is effective (Chao, 2011). Penalties for underperformance similar to those applied to generating units should also be applied. This approach, not considered for example in South American long-term auctions, has been implemented in the Forward Capacity Market of ISO New England, where DSR can bid in centralised auctions (ISO-NE, 2014), and in the PJM Reliability Pricing Model, where DSR is also accepted as capacity services provider (PJM, 2014d). In these cases, capacity auctions have proven to be capable of involving demand response resources, even if this did not result in full exploitation of their potential.

This design element is significantly affected by the regulatory objectives of the auction. For example, capacity mechanisms based on long-term electricity auctions, originally introduced in order to solve problems related to system adequacy and system expansion, are utilised in the South American context to achieve a secondary objective: hedging the end-user default tariff price[9]. This is the reason why in Brazil, Chile, and Peru auctions cover only the captive demand, although in the Brazilian case free demand is also required to cover 100% of its requirements through long-term contracts to be backed by firm energy certificates. In these countries, distribution companies (acting as regulated retailers) are mandated to take part in the long-term auctions, so that they can also set stable default tariffs for their customers for a significant period of time via these mechanisms.

Considering now only the original objective of a capacity mechanism (that is, solving system adequacy problems), the decision about who has to buy leads us to the following question: who benefits from system adequacy? Today, long-term security of supply is still a "good" that benefits all the consumers of the power sector, thus it seems that the only correct answer to this question would be to encompass the entire demand of the system. Any other arrangement would create an evident situation of free-riding, because some users would be taking advantage of the system adequacy without paying the associated costs. In this context it is important to bear in mind that the South American long-term auctions we discuss here mainly aim at providing investors with a hedge to cover their regulatory and

[9] It must be reminded that many CRMs implemented in South American energy-constrained systems are based on energy contracts. See section 2.5.1 for details.

market risk, so the part of the system demand which actually buys in these auctions bears the related risk[10].

Since the charge associated to the CRM is one of the costs that comprise the total cost of electricity supply, if it is paid only by a part of the demand, this can be seen as a cross-subsidy from the customers who must take part in the capacity mechanism to those who do not have to participate[11]. From this point of view, the choice made in the Colombian, North American, British and Italian auctions, in which the regulator procures some sort of reliability product on behalf of the whole spectrum of consumers, seems to be the most adequate.

The most recent Argentinean regulation addresses the same problem in a clearly different way. Following the economic crisis of the early 2000s and the ensuing electricity scarcity, the government decided that regulated consumers had full priority on electricity supply and that non-regulated users had to cover their own expected capacity requirements through auctions. To some extent, it can be stated that also this approach results in a free-riding issue, but in this case in the opposite direction, since free demand bears the cost of attracting new investments, and captive consumers benefit from it.

#### 2.2.1.1. Level of centralisation

The level of centralisation of a CRM auction can refer both to the procurement process and to the demand forecasting activity. In the former case, the regulator can either organise a centralised auction or assign this task to other agents involved in the auction (free demand or distributors on behalf of their regulated demand). In the latter case, the regulator either calculates the amount of capacity to be procured based on demand growth estimations, or leaves this task to the agents previously mentioned.

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[10] In the South American context, an argument commonly used to justify the decision to lay the obligation to buy in the auctions only on regulated consumers, is that a contract with a distribution company (in their role of regulated retailers) as counterparty reduces investors' perception of credit and regulatory risk, which would be higher if the counterparty were just the whole system (in the form of a regulatory commitment instead of a contract) or free consumers.

[11] This approach would give a justification for the regulator to shed the load of free customers in case of a future scarcity event, therefore eliminating the concern of free-riding. However, the problem is that it is not always technically feasible to discriminate between categories of consumers when cutting the supply during scarcity conditions, so a certain level of free-riding will always be present. It is worth noting that the whole discussion may change in the future. New concepts such as smart metering principally allow that security of supply can be turned into a private product (where those not paying for security of supply may be offered a lower level of service). Whether regulators and politicians would allow those consumers who did not pay to be switched off in instances of generation capacity shortfall would be a key question in such context. If politicians would not allow this, then we are back to the free-riding problem (even if technically we could discriminate consumers in their security levels).

In the American context, different approaches have been applied. Colombia opted for a completely centralised approach, both in terms of the overall auction process as well as demand forecasting, while the Chilean and Peruvian schemes are fully decentralised[12]. Brazil has centrally-managed auctions, but the quantity that needs to be procured is calculated by distribution companies. In Panama, the original design considered decentralised auctions, but it was modified in 2009, when a centralised procurement process was introduced (Maurer and Barroso, 2011). The ISO-NE and PJM capacity mechanisms can be considered as completely centralised auctions, as also the CRMs implemented or proposed in the United Kingdom and Italy.

There are several advantages to a centralised CRM auction approach (Batlle and Rodilla, 2010). The most important feature of a centralised auction is that it allows for the full benefit of exploiting economies of scale in electricity generation. If all the agents involved in the mechanism organised independent auctions, the amount of capacity/energy to be procured by each one of them would be too small to justify the construction of a new plant, especially if large hydropower projects are considered.

In South America, other advantages of centralised, public, and therefore transparent auctions derive from the specific structure of power systems in the region. Only a few countries have unbundled distribution from retailing and the most common sector organisation is to have local distribution monopolies in charge of purchasing electricity for the regulated customers connected to their grids, i.e., acting as regulated retailers. Where this configuration is in place, the main concern is that the unbundling of generators and these distributors/ regulated retailers is insufficient at the very least, and often non-existent. Within this structure, vertically-integrated distribution companies, acting as regulated retailers, not only have no incentive to design a mechanism that results in the minimisation of prices for end-consumers, but they could even arrange the auction process in order to procure their entire future supply needs from the generation part of the same company, at a non-transparent price. In this context, a centralised auction minimises the risk of competition infringements by vertically-integrated companies. Moreover, in the South American context, this design also ensures that all the regulated demand faces the same energy price, and fulfils the equity principle of ratemaking. In fact, in those systems where auctions are decentralised, smaller distribution companies are commonly exposed to higher prices (or complex equalisation strategies must be applied).

[12] Actually, Peru has implemented two different auction schemes. The first to be introduced (auctions under the framework of Law 28.832) only targets distribution companies supplying captive demand and follows a fully decentralised approach. However, a secondary mechanism (managed by the *Proinversión* Agency) was implemented to contract large power projects, mainly aiming at the untapped hydropower potential present in the country, which is completely managed by the Peruvian state.

Concerns regarding vertical integration and entry barriers can be found not only in South America but also, to some extent, in North America and Europe. As it has already been observed in the United Kingdom (Ofgem, 2011), vertical integration between generation and retailing reduces the liquidity in the market and acts as an entry barrier to new competitors. In fact, incumbents plan their capacity expansion in order to supply their consolidated portfolio, and this reduces the potential market share for new entrants in this context. A capacity mechanism in the form of a decentralised auction allows vertically-integrated incumbents to favour their subsidiaries. In order to avoid this scenario and reduce entry barriers for new entrants, a transparent and centralised auction should be launched for the coverage of the entire reliability demand, in which the perfect match between the vertically-integrated generator's supply and retailer's demand is not possible. This is the case in the United Kingdom, where a CRM based on centralised auctions has recently been implemented (DECC, 2014). However, the capacity mechanism currently under design in France, another market characterised by vertical integration between generation and retailing, will be a decentralised one. The guidelines released by the French System Operator (RTE, 2014) impose capacity obligations on retailers, who need to procure capacity certificates via bilateral contracts in order to meet these obligations. Apparently, no auction scheme is foreseen, not even a decentralised one, and exchanges may take place through direct negotiations. This design highlights the previously mentioned concerns regarding vertical integration and permits incumbents to create entry barriers for new entrants.

Regarding the allocation of responsibility in estimating future demand, some authors (Moreno et al., 2010) have expressed their preference for a decentralised approach, suggesting that distribution companies should be in charge of forecasting future demand, with an appropriate scheme of penalties for over/under estimating. This methodology is based on the assumption that distributors have a clearer vision of the extent of the demand and could better estimate its growth. While this argument cannot be disproved, it should be remarked that the ultimate responsibility for security of supply is always with the regulator (or the system operator often acting on its behalf). Moreover, it is important to remember that one of the key reasons for the implementation of capacity mechanisms is the inability or unwillingness of the demand side to properly hedge in the very long term (all demand to some extent, but most relevantly residential consumers). If the design of efficient CRM penalties imposed on generating units for non-compliance is a complex and controversial issue, setting the right incentives and credible penalties for retailers to properly estimate their long-term demand is an even more troublesome task. Accordingly, demand forecasting should be made by the regulator with the advice of the system operator, trying to provide an estimate as accurate as possible and avoiding over-forecasting.

As regards this complex calculation, the most delicate part is probably related not to the estimation of the future demand itself, but rather to the selection of the capacity elements to subtract from it. In fact, in order to avoid over-procurement in the CRM auction, the contribution of those resources which do not take part in the auction but will be available during the delivery of the CRM should be deducted from the demand to be procured. This is the case of renewable projects that are already receiving an incentive and may be not eligible to participate in the capacity mechanism. Another central issue in this regard is the consideration of interconnectors. Cross-border capacity contributes to the security of supply of all countries. If the explicit participation of cross-border resources in the CRM is not allowed (see chapter three for details), their expected contribution should be deducted too, considering statistical flows during scarcity conditions. Newbery and Grubb (2014) analysed the methodology used to determine the amount of capacity to be procured in the first UK capacity auction and showed how much the final outcome of the CRM is sensitive to this discussion.

### 2.2.2. The selling side

The regulator, or the agent running the CRM auction, has to decide who is allowed to present bids. Two major decisions have to be made: first, whether both existing and new investments should be allowed to participate; and second, if technological priorities should be explicitly applied.

#### 2.2.2.1. The role of existing plants

The regulatory decision to implement an auction mechanism in order to bring in new generation could be perceived as a market intervention that negatively affects existing plants, as this new generation depresses prices in the spot market. Therefore, from a rigorous economic theory perspective, it can be argued that existing power plants should also be allowed to compete on equal terms in order to receive the same price. The equal treatment of existing and new power plants would guarantee, in the long term, an efficient signal to drive generation expansion. In fact, this approach is common in most markets[13].

However, the above-mentioned reasoning is often refuted with two objections. First, political interests often lead to the simple conclusion that, since their fixed costs are sunk, there is no need to allow existing generation units to participate in the auction or to receive the resulting price. Excluding these units from the auction certainly minimises supply costs for consumers in the short term, but, as stated, it is far from being clear that this decision will not result in higher supply costs in the long run, since investors might conclude that they will not be able to capture the long-term marginal price when their plants will be considered as existing. Secondly, the majority of existing generating units were installed under the former traditional cost-of-service scheme, which guaranteed the recovery of the capital costs. This, and the fact that they may be publicly owned or controlled, provides some justification for the regulator's decision to discriminate between existing and new

[13] For example, in the real estate market, it is unquestioned that old and new houses compete at the same level.

generation units, especially in the South American context. However, even if this regulatory solution is chosen, it would be important that existing plants, which have fully recovered investment costs, would also be given an economic signal encouraging them to manage their units in order to enhance their availability under scarcity conditions. This is the underlying motivation behind the proposal from Batlle et al. (2008) to define two different reliability-oriented payments: i) an adequacy-oriented payment available only for new entrants and ii) a firmness-oriented payment, targeting all the generation units in the system (both new and existing)[14].

Therefore, the most common distinction for this design element is between mechanisms where different auctions are organised for new and existing plants, and schemes that mix the two categories in the same auction. Brazil has implemented separate auctions from the beginning, while in US-ISOs, Chile, Colombia, and Peru existing and new plants participate in the same tenders. However, a further discrimination is then applied in Colombia and ISO New England, based on the duration of the contract, which is one year for existing plants and up to twenty years (Colombia) or five years (ISO-NE) for new projects. Another approach is to allow existing generation units to take part in the auction only as price-takers (i.e., only allowing them to bid at zero or under a predetermined threshold), while leaving the task of setting the auction price to the new power projects (which act as price-makers). This is the current design in ISO New England's Forward Capacity Market and in the UK Capacity Market, while in Colombia a system of different price caps to be applied in specific auction conditions is used to further discriminate between existing and new generation units.

#### 2.2.2.2. Technological neutrality or not?

The second issue related to this design element is the introduction of technology-specific auctions, which have been launched by the regulators of several Latin American countries. This was done either to promote RES-E projects[15], or to foster the exploitation of the continent's large untapped hydropower resources[16]. From a theoretical point of view, in liberalised power systems, decisions about capacity expansion, particularly the choice of technologies to be installed, are left to market agents, who are expected to bear the related risk of a poor assessment of the system's future needs. This approach forms the basis of the

[14] Nonetheless, it must be remarked that nowadays the scenario has already changed and the recently-implemented performance incentives (see chapter five for details) go in the opposite direction, i.e., they merge the adequacy and the firmness incentive.

[15] For example, the case of the RER (Renewable Energy Resources) auctions in Peru or the Brazilian auctions to add biomass or wind generation. See chapter seven for details.

[16] For instance, the *Proinversión* auctions in Peru or the project-specific hydropower auctions in Brazil.

original decision to liberalise electricity markets, and it is thought to allow the most economically efficient combination of technologies to enter the system.

The intervention that technology-specific auctions represent is usually accepted if it aims at the very long-term strategic objectives of the country, which would not otherwise be achieved because they are not considered by market agents when making their decisions. In this case, these long-term objectives should be specified at the moment of launching the technology-specific auction, and subsequent regulation should be consistent with them.

However, it is important to bear in mind, that when there is a broad range of potential technologies, certain auction details (e.g., contract provisions) often might lead to *de facto* discrimination between different generation sources. For example, defining a lag period (i.e., the maximum time available for building a power plant) of three years makes it almost impossible for large hydro plants to compete against conventional thermal generation. This is discussed in more detail in the following sections.

Apart from the issues analysed in this section, there are other relevant decisions that must be taken when the CRM selling side is identified, which, however, cannot be studied in detail in this chapter for the sake of conciseness, or because they are analysed elsewhere in the document. Is a portfolio approach allowed or each generating unit has to participate as a single agent? Only generation bids or also demand-response bids are accepted in the selling side of the mechanism? Is the participation in the CRM limited to domestic resources? If cross-border participation is permitted, which approach is to be used? Is the explicit participation of foreign resources preferable to the implicit participation through the interconnector-led approach? The last three questions are addressed in chapter three and four of this thesis.

## 2.3. Lag period (or lead time)

The lag period is the time between the contract signature and the date when the contract comes into force. This definition applies also to contracts signed in the framework of a capacity mechanism. Unless they are involved in previous contractual commitments, existing plants need no lag period, because from a technical point of view they can start producing electricity immediately. However, for administrative reasons, contracts with existing plants usually consider a lag period between a few months and one year. On the other hand, for new generation projects the lag period represents the maximum time available for construction. Obviously this parameter heavily conditions the competitiveness of the different plants and technologies in the auction. A critical look at the length of the lag periods in South American CRMs clearly illustrates this point.

In Brazil, three different kinds of auctions are implemented with the main difference between them being precisely the lag period. The so-called A1 auction (one-year lag period) is meant for existing generating units, while the A3 auction (three years) clearly aims at adding thermal generation and the A5 (five years) is intended for large hydro projects.

In Peru, the first design defined a three-year lag period, clearly in line with the governmental desire to exploit the *Camisea* gas pipeline constructed in the late nineties through the installation of gas-fired power plants (three years is also the lag period used in Panamanian auctions, which also target gas-driven units). A few years later, the government considered the need for new large hydro investments, and questioned the auction design. This concern led to an out-of-the-electricity-regulation call for tenders aimed specifically at attracting this generation technology (managed by the *Proinversión* Agency).

The Colombian reliability charge mechanism aims to attract both thermal and hydro plants. Colombia introduced two related but separated auctions: i) a Firm Energy Obligation (OEF, *Obligaciones de Energía Firme*) auction with a lag period of four and a half years, more suitable for and implicitly targeting thermal plants, and ii) an auction with a lag period of seven years, focusing on new hydropower projects[17].

It can be deduced that the only way to design an auction in which different technologies could equally compete would be to allow for different lag periods. Therefore, if no strategic objective results in a preference towards certain technologies, the only approach to avoid a *de facto* technology discrimination would be to allow all kind of plants to bid in the auction with the assurance that they have enough lead time for installation. However, this leads to another relevant problem, as it is very difficult to define proper criteria to transparently compare bids with different lag periods. For instance, it would be difficult to compare a plant bidding for a short lag period and a higher price with a plant bidding for a longer lag period and a lower price.

Therefore, the regulator faces a trade-off in defining whether single or multiple lag periods are to be considered. In the United States, the most common approach has been that of considering one single lag period, usually of three years (PJM and ISO-NE). In the British Capacity Market a similar lag period is used, equal to four years. However, it is worth noting that these mechanisms principally target thermal plants (mainly CCGTs, which have short construction times), which do not need long lag periods.

## 2.4. Contract duration

The duration of the contracts traded in the framework of the CRM is one of the most relevant design elements of a capacity mechanism. As mentioned in the introduction and throughout this chapter, the main objective of capacity mechanisms is to hedge part of the

[17] The so-called GPPS auction is organised in Colombia after the OEF auction and it is designed for those plants with construction times exceeding the OEF lag period. The reserve price in the GPPS auction is the price cleared in the OEF auction.

generators' risk against the high volatility of spot market prices and more importantly, against regulatory risk, in order to facilitate their access to financing and to improve the overall attractiveness of the investment. Keeping this in mind, the contract duration should be long enough to provide investors in new generation projects with a stable and predictable cash flow.

The long-term incentive to attract new investments is enclosed in this parameter and its determination has a dramatic impact on the results of the CRM. As in the case of the lag period, the contract duration may vary within a tender, and it is also possible to differentiate between plants (new or existing) and technologies (e.g., hydro or thermal) in the same auction.

The Brazilian experience clearly illustrates how tenders can be "guided" through their design elements. The A1 contracts, since they are aimed only at hedging the market price volatility due to the *El Niño* Southern oscillation[18], have a duration of five to eight years. Conversely, the length of the contracts offered in the A5 auctions ranges from fifteen to thirty years, confirming the previous statement that these auctions are clearly designed to attract large hydropower projects. Similar conclusions can be put forward when reviewing Peruvian auctions, where, in the *Proinversión* tenders, contract durations can extend beyond ten years.

Regarding new plants, the contract duration should reflect the capital intensity of the technology. Obviously, thermal plants need shorter terms to mitigate their risk than hydropower plants. In any case, at the point of determining the contract duration, consideration must be given to how the project is financed and the discount rate involved. In fact, due to the effect of the discount rate, the more distant future income is from the present, the lesser is its impact on the net present value. Cash flows perceived thirty years from now are almost irrelevant in the decision making when high discount rates are considered. Therefore, contract durations above this value are seldom justified with the high discount rates (higher investment risk) used in the generation sector in South America. On the other hand, in North America, common contract durations are significantly lower. In the ISO-NE Forward Capacity Market, existing plants are entitled to only a one-year contract, while new plants can choose contract durations from one to five years. This is probably due, once again, to the different technological targets (thermal plants, in this case), but also to the lower country risk.

As regards European capacity mechanisms, the Capacity Market of the United Kingdom considers contract durations equal to one year for existing plants and fifteen years for new projects. On the other hand, the capacity mechanism currently discussed in Italy is based on

[18] *El Niño* Southern Oscillation, or ENSO, is a naturally occurring phenomenon that involves fluctuating ocean temperatures in the equatorial Pacific. They can be anomalously warm or cold for long periods of time causing variations in regional climate patterns, especially in terms of rainfall.

reliability option contracts to be procured in a centralised auction with no discrimination between new and existing plants. These contracts, as proposed by the Italian Regulator (AEEG, 2011), have a lag period of at least four years, thus clearly targeting new generation projects. Nevertheless, the contract durations foreseen are equal to three years, which could even be reduced to one year in some cases. While these contract durations could be acceptable for existing generation, they are clearly not sufficient to hedge investors' risk and, therefore, they are not suitable for attracting new plants. This type of design could hamper the effectiveness of the mechanism in guaranteeing system adequacy.

## 2.5. Defining the reliability product

There are many types of capacity or energy products that the regulator can purchase on behalf of demand to solve the security-of-supply problem (also known as reliability products). Among others, these are capacity credits/obligations, firm energy contracts, reliability contracts/options, strategic reserves, etc. Today, the use of these terms is still vague and can be misleading, as it is not clear which actual characteristics and commitments they are supposed to define. In general, the reliability product can be more properly defined and classified based on the following questions: i) Is the product energy-based or capacity-based? ii) Does the contract imply a physical commitment, financial or both? iii) When are agents holding a CRM contract required to fulfil their commitment? iv) How are they penalised in case of underperformance (or compensated in case of overperformance)? v) Is there any regulatory limitation on the quantity of reliability product that each resource can sell via the capacity mechanism? Dealing with these questions, in this section, permits the identification of different kinds of reliability product.

### 2.5.1. Reliability in capacity- and energy-constrained systems

There is a relationship between the security-of-supply problem that is to be addressed and the product the regulator should define. This first step is to properly identify the kind of scarcity conditions that can be expected in the system. The main classification that can be applied divides systems into those that are capacity-constrained and those that are energy-constrained.

In capacity-constrained systems, scarcity problems arise because there is not enough installed capacity available (MW) to satisfy demand at a given moment due to, for instance, the forced outage of thermal plants and/or minimum wind output. Aggregating all the hours, the system could certainly have enough energy available to satisfy demand on a given day (more than enough production capacity in off-peak hours), but it lacks installed capacity to satisfy peak demand. This type of potential scarcity conditions are usually found in the European and North American systems, which has prompted operators of these grids, and the market participants, to be primarily concerned with modelling the very short term in great detail. Note that in these systems a high penetration of non-dispatchable wind and solar generation ensures that enough energy is there through the year, but capacity is not necessarily available at the time it is needed the most.

The situation is quite the opposite in energy-constrained systems, which could certainly satisfy peak demand, but would not be able to supply the loads during the remaining hours of the day/week. Thus, rationing takes place due to a lack of available energy (MWh), not capacity. A large proportion of Latin American systems traditionally fall into this category due to the large share of hydropower in their generation mixes. The availability of reservoirs with a large storage capacity has historically reduced the necessity of considering the short-term operation in any detail. However, in these systems it has been of critical importance to suitably represent uncertainty and to determine the optimal management strategies for hydro resources and their medium-, long- and very long-term interaction with thermal facilities.

This distinction must obviously be reflected in the design of the reliability product. On the one hand, a capacity-constrained system has to remunerate resources for their ability to provide instantaneous power to cover peak demand. On the other hand, an energy-constrained system should reward the capability of agents to manage their resources in order to guarantee their availability in those long-lasting periods when energy scarcity occurs, for example, during a dry year. This consideration is confirmed by the diversity of capacity mechanisms introduced in different systems. In the United Kingdom, a system with a very large share of conventional thermal plants, the CRM product is completely focused on the capacity that agents can inject into the network. By contrast, the energy-constrained Brazilian system ensures the security of supply through long-term auctions, in which generators offer full-energy contracts, with monthly (or even yearly) settlements. An intermediate solution between these two extremes can be found in the Colombian energy-constrained system. The capacity mechanism implemented in this country (firm energy obligations scheme) requires resources to deliver the energy committed in the auction during those days when the spot price exceeds the strike price at least during one hour.

### 2.5.2. Critical period indicator

Certain types of capacity mechanisms define a critical period (also called scarcity conditions, shortage events, or near-rationing conditions), during which each agent with a CRM commitment must deliver its reliability product. In case performance incentives are established, the critical period indicator also identifies the conditions during which the performance must be assessed (see chapter five for details). For the countries analysed in this chapter, this does not always apply. In Brazil, Chile, and Peru, where standard future supply contracts are auctioned, the generators selected by the tender mechanism have to deliver electricity according to the contracts they sign. No critical period is defined, and even if the system has some method to identify near-rationing conditions, this does not affect the contract provisions. The Colombian firm energy obligation (OEF) mechanism is, in contrast, based on a definition of scarcity conditions. The spot market price is used as a critical period indicator and the scarcity conditions are defined as the period of time during which the spot market price exceeds a predetermined strike price. The Colombian mechanism is based on option contracts whereby the seller, in exchange for a fee, commits to provide the buyer with electricity not at the actual spot price, but at the strike price. Therefore, the strike price has two functions: on the one hand, it identifies the critical period, on the other hand, it acts as a soft price cap (only for the generation awarded with a reliability commitment in the auction).

A number of general recommendations on the selection of the critical period indicator were already provided by Batlle and Pérez-Arriaga (2008), who identified the short-term market price as the best "thermometer" of scarcity conditions in a market environment. This consideration should become increasingly valid in the future, with greater elasticity of demand. In fact, as long as the share of completely inelastic demand in the market (i.e., the demand that bids at the price cap) decreases, it will become increasingly difficult to define the demand which must be served and, consequently, to identify near-rationing conditions based only on the comparison of peak demand and available generation. This critical period indicator obviously assumes the presence of a liquid short-term market in the system (reference market). The selection of the reference market also affects the type of scarcity conditions that are covered, and those that the regulator wants to be covered, by the capacity mechanism. On the one hand, day-ahead markets are only capable of capturing emergency situations related to the combination of high loads (as peak winter demand) and reduced supply (due to fuel constraints or a dry year that limits hydro production), that is, pure system-adequacy issues. A capacity mechanism using a day-ahead market as a reference would thus address this type of scarcity.

On the other hand, intraday and balancing markets are also subject to price fluctuations due to more or less sudden events, such as the outage of a nuclear plant or, in those systems with high renewable penetration, the unexpected loss of intermittent generation due to bad forecasting. These are events which provoke temporary generation scarcity even if the load is far from its peak, and have a time horizon longer than the one covered by ancillary services, i.e., flexibility issues. Therefore, by adding intraday and/or balancing markets as reference markets (there can be more than one reference market), a capacity mechanism may address not only adequacy but also flexibility issues. However, the selection of the relevant market also has to take into account the signal that the capacity mechanism is providing to the generation mix. While all units are more or less technically capable of producing if notified one day ahead, certain technologies (base-load technologies, such as coal power plants) would not be able to take part in the balancing market, because they cannot respond in such a short time frame, due to ramp constraints. Therefore, a capacity mechanism using the balancing market as reference market provides agents with a signal that discourages the installation of new base-load units, and this may not be the regulator's objective.

Where the short-term market price is selected as a critical period indicator, and a strike price has to be determined in order to signal scarcity conditions, two aspects must be taken into consideration (Vázquez et al., 2002). First, the strike price must be predetermined by the regulator based on a formula available to all interested agents and must be unique for all resources taking part in the auction. Allowing agents to bid on both the strike price and the option fee associated with it would add a significant level of complexity to the auction mechanism. Since bids would not be simple price-quantity pairs, their comparison would be possible only through a model simulating the market behaviour[19]. This would reduce transparency and add a degree of arbitrariness to the process. Secondly, the strike price must be determined in such a way that it does not interfere with the normal functioning of the short-term market. This can be achieved by fixing it well above the short-term marginal cost of generation production (and demand response measures).

In any case, the selection of the critical period indicator should take into account the long to very-long time frame of CRM contracts. A critical period indicator that may appear appropriate in the present could become unsuitable in the future because of changes in the generation mix or fuel prices. The capacity mechanism under design in France (RTE, 2014) apparently identifies expected scarcity conditions using the temperature as the critical period indicator. However, a critical period indicator based on temperature does not take long-term contracts into account as the correlation between scarcity conditions and temperature may change in the future (e.g., due to a large penetration of RES-E generation), and there is a risk that long-term contracts are no longer providing the expected reliability.

Critical period indicators based on the identification of stress events by the system operator through the monitoring of some network parameters, as those used in the United Kingdom, ISO-NE, and PJM, are also not aligned with the recommendations presented here. In the British Capacity Market, for example, scarcity conditions are replaced by the concept of "system stress", defined as "any settlement periods in which either voltage control or controlled load shedding are experienced at any point on the system for 15 minutes or longer" and communicated to agents with a reliability commitment at least four hours in advance through a "capacity market warning". As a result, the scarcity conditions are no longer linked to the reserve margin and they could also occur when the demand is, for example, 70% of peak demand. In this case, each reliability provider "will only be required to be generating electricity or reducing demand up to 70% of their full capacity obligation" (DECC, 2014). This is usually known as a load-following obligation. This approach has two clear drawbacks. First, the determination of system stress is somehow arbitrary and completely unpredictable. This uncertainty will be considered by resources when assessing the impact that taking part in the capacity mechanism can have on their revenues, and it will be reflected in their bids. Secondly, it hampers DSR participation in the capacity mechanism, as most demand-response resources are only available to provide a certain demand reduction during peak demand conditions.

[19] This is what happens in Brazil, where thermal plants compete for option contracts with different strike prices. See Bezerra et al. (2011) for details.

A detailed analysis of the correlation between the critical period indicator and the design element presented in the following subsection, i.e., performance incentives, would be useful to understand how to jointly select these parameters. However, this discussion is examined in chapter five, which is completely dedicated to performance incentives, and it is not anticipated here.

### 2.5.3. Performance incentives

The unfulfilment of contract commitments must be penalised by the regulator. The penalty should be high enough to dissuade committed resources from failing to accomplish their obligations. At the same time, the penalty should not be excessive in case of prolonged technical unavailability. This could be achieved through an hourly penalty associated with a correction factor diminishing with the duration of the unavailability, or through the use of cumulative penalty caps. On the other hand, overperformance with respect to contract commitment can be compensated with a credit in order to reinforce the incentive for resources to be available during scarcity conditions.

Two entire chapters of this thesis, chapters five and six, are fully focused on performance incentives, a design element that revealed to be pivotal for the overall efficiency of the capacity mechanism, and a very detailed discussion on this topic can be found there. Therefore, only a review of penalties considered in the CRMs analysed in this chapter is presented here. In South American mechanisms, the only penalty usually applied is the implicit one, which consists in requiring agents to procure in the short-term market the energy they are not able to provide through their assets during scarcity conditions. Conversely, in the North American context and in Europe, explicit penalty schemes are now being considered. Actually, in the United States, these regulatory instruments are at the centre of a reform process that is affecting several CRMs, based on the pay-for-performance principle. Also these reforms will be analysed in detail in chapter five.

### 2.5.4. Constraints on tradable quantities

Constraints on tradable quantities limit the amount of reliability product that a resource can trade in the framework of a capacity mechanism. Theoretically, there should be no need to set these constraints, provided that i) the explicit penalties to be paid in case of underperformance are properly designed, and ii) collaterals are high enough, providing the system with a financial warranty in case agents' estimations prove to be wrong. Nevertheless, most regulators and system operators in power sectors with a CRM in place have developed a methodology for setting an upper and a lower limit on the quantities tradable by each resource. The introduction of constraints on tradable quantities is based on the following reasoning.

Without an upper limit, the number of cases where resources overestimate the quantity of reliability product they are capable of producing during scarcity conditions might compromise the financial stability of the entire power sector, with potential repercussions for security of supply. In order to avoid this, very large and costly warranties should be introduced. However, this could dramatically reduce participation in the capacity mechanism.

Without a lower limit, some resources could be tempted to behave strategically, withholding part of their capacity from the auction, with the objective of increasing the clearing price. Therefore, setting a minimum amount that resources are required to trade would help manage market power issues.

Constraints on tradable quantities resulted in the development of the concepts of firm energy and firm capacity[20] and the establishment of some sort of prequalification phase, during which these parameters are calculated for all resources willing to participate in the CRM. In South American auctions, most of the regulators have introduced such methodologies, Chile being the main exception[21]. A detailed description of these calculation methods exceeds the scope of this chapter (they are further analysed in chapter five), but by way of example, the methodology used in the Colombian case for South America and in ISO New England for North America is presented.

In Colombia, generators willing to take part in the OEF auction must be backed by firm energy certificates (also called ENFICC), whose calculation methodology has been developed by the Colombian Regulator (CREG, 2006). The ENFICC of hydropower plants is calculated using a computational model (HIDENFICC), which determines the maximum production that can be obtained monthly from a hydro unit during dry periods. The lower ENFICC limit that a generator or investor can trade is termed "ENFICC Base" and corresponds to the minimum energy obtained by the maximisation model. The upper ENFICC limit corresponds to the energy that a generator can produce with a probability of 95%, called "ENFICC 95%". If a generator or investor is willing to trade an ENFICC higher than the ENFICC Base in the auction, without exceeding the ENFICC 95%, it should back this difference with a financial warranty. On the contrary, the ENFICC of a thermal plant is calculated based on the plant's generation capacity, fuel availability, the number of generating hours per year, and an index that incorporates the historical restrictions imposed upon the plant, which limits its maximum energy generation. As regards renewable energy, CREG has recently outlined the methodology for calculating the ENFICC Base and the ENFICC 95% for wind farms (CREG, 2011).

[20] Depending on the specific design of the reliability product auctioned.

[21] Theoretically, the contracts signed in Chilean auctions are not required to be covered by any firm energy certificate and distribution companies have to assess the bidders' credibility on their own. However, generators have to specify to the Regulator, on a yearly basis, which plants will be used to cover the contracted supply.

The Forward Capacity Market of ISO-NE follows a different approach, based on historical availability. Existing plants have recognised summer and winter qualified capacities, calculated as the median of the claimed capability ratings for the five most recent summer and winter seasons. For hydro plants with daily cycles, the qualified capacities are based on the seasonal average, calculated using the 50th percentile flow rate. As regards new plants, project sponsors must submit an expression of interest to the System Operator which contains the requested summer and winter qualified capacities. Based on the financial reliability of the project, the construction schedule, and the requested qualified capacities, the expression of interest can be accepted or rejected. The qualified capacities are then adjusted during the following auctions based on real data from the plant.

Finally, it must be underlined that firm energy and firm capacity are the basis on which plants and projects are remunerated in the capacity mechanism. Therefore, a revision procedure that punishes underperformance by administratively reducing the firm energy or capacity of a plant can constitute a very effective penalty scheme (see chapter five for details).

## 2.6. Indexation and warranties

There are several other design elements that, although often considered as secondary, can have a significant impact on the outcome of a capacity mechanism. In this section two of them are singled out for review: indexation formulas and warranties.

### 2.6.1. Indexation formulas

Indexation formulas define the methodology to update the CRM remuneration throughout the duration of the contract. In the South American experience, in line with what has been the traditional method of remunerating utilities and independent power producers in the previous regime, all the economic parameters set by the contract are usually subject to indexation formulas that determine their future evolution. Commonly, these formulas, besides being linked to the retail price index (as in the United States) or the exchange rate of the US dollar with the local currency (in South America), use the international price of fuels as a reference, with a view to determining how this parameter will affect the operating costs of power plants. However, economic theory recommends assigning risks to the agents who can best manage them. Indexing the CRM remuneration to fuel prices implies allocating this risk to electricity consumers who have no ability whatsoever to properly manage it. Thus, it would be better to avoid fuel indexation in the contracts, since, in principle, generators should be able to hedge this risk more efficiently by signing contracts on the international markets for commodities. Unfortunately, it is also true that these markets present a low liquidity in the long to very long term (i.e., longer than five years). Therefore, the optimal solution would be to design an incremental "indexation weight", i.e., the percentage dependence of the contract prices with respect to international fuel prices.

Another question, concerning indexation, is whether to use a single formula to index all the contracts or to allow agents to include the required indexation within their bid. The latter approach, used for example in Chile[22], Brazil and Panama, creates a challenge when comparing different bids, because their competitiveness in the long term varies broadly according to this parameter. A general recommendation is to define a unique indexation formula for all the resources involved in the CRM in order to increase transparency and keep the format as simple as possible.

### 2.6.2. Financial warranties

With respect to warranties, as in other markets, resources holding a CRM contract should provide a monetary endorsement to cover at least part of the potential penalties for underperformance. In order not to introduce large warranties that could limit participation in the capacity mechanism, this endorsement could be achieved by retaining part of the first contract payments until a targeted figure is reached. However, it must be stressed that the determination of these warranties is strictly related to the selection of the reliability product and, in particular, to the performance incentives and the constraints on the tradable quantities. In fact, the higher the penalties for underperformance and the higher the warranties required, the lower the need to be strict on defining the maximum value each unit can trade at or the level at which it can be remunerated (Batlle and Pérez-Arriaga, 2008).

## 2.7. Conclusions and recommendations

Capacity mechanisms, commonly based on auctions, have been selected by many regulators in the American continent as the most effective instrument to guarantee the adequacy of the system. Some European regulators are following this path (United Kingdom, France, and Italy). CRMs reduce the risk associated with the long-term volatility of spot market prices and the potential regulatory interventions by guaranteeing and fixing ex-ante part of resources' future income. This economic signal facilitates project financing and fosters the installation of new generation capacity. However, these instruments must be designed carefully. In this chapter, the key design elements of CRMs have been identified, reviewed, and discussed, extracting guidelines from the South and North American experiences and

[22] As mentioned by Maurer and Barroso (2011) in Chile, the indexation formulas are determined and published by the Regulator in the form of a multivariable linear function of fuel and inflation indices, in which each multiplying factor is ultimately adjusted by each bidder, thus creating different indexation requirements. However, indexation formulas are not taken into account by the auctioneer during the allocation process, thus affecting the overall economic efficiency of the process, since the set of winners could dramatically change if indexation formulas were incorporated into the clearing mechanism.

from the recently introduced European designs. The main lessons learned can be briefly summarised as follows.

On the buying side, the best option seems to be to involve all the system demand in the CRM, since the entire system demand benefits from the increased system reliability, thus avoiding free-riding issues. The demand which is not willing to be covered by the reliability mechanism, can then trade demand-response or energy-efficiency products in the CRM market. However, this option should only be open to loads that can actually be disconnected during scarcity events, and after a careful determination of the customer baseline.

As regards the centralisation level, the most efficient solution appears to be a centralised auction that covers the whole system demand. A centralised auction has a threefold benefit. First, it allows the exploitation of economies of scale in generation. Secondly, it mitigates the impact of vertical integration of electricity companies, which is still an issue in several power sectors, and gives an opportunity to new entrants. Last but not least, it enhances transparency and guarantees an equal "system-adequacy" price for all consumers.

On the selling side, existing and new generators can compete in the same CRM, as long as specific measures are taken in order to differentiate between the two categories, such as, for instance, defining existing generators as price-takers in the auction or setting different price caps. As regards technology-specific tenders and the determination of such parameters like, for example, the lag period for new power plants, which can implicitly include or exclude certain technologies, it must be understood that a certain degree of discrimination will always be present. A capacity mechanism which accurately defines the reliability product and the associated parameters, will always favour a certain technology. However, the alternative approach, i.e., letting bidders specify the parameters of the reliability product (lag period, contract duration, strike price, etc), leads to the undesirable result of having to "compare apples and oranges" in order to assign CRM contracts.

Regarding the critical period indicator, the best choice is the short-term price of the reference market in the system, which is the most suitable measure of scarcity conditions in a market environment. Having the short-term price as the critical period indicator obviously assumes the presence of a liquid power exchange in the system, but this, in fact, is now considered as an essential feature of any efficient wholesale market. Therefore, in those systems where such a reference market is not yet in place, the implementation of a capacity mechanism of this sort could be an opportunity to foster the development of a liquid short-term market (day-ahead or balancing).

Finally, as regards performance incentives, it is essential to define a robust explicit penalty scheme which adds an extra fee on top of the implicit penalty of having to purchase, in the market, the electricity necessary to fulfil the CRM commitment if the agent is not able to deliver it with its own assets. An explicit penalty discourages those resources that are not backed by reliable generation capacity and encourages those selected in the CRM to manage their units in such a way as to improve their availability in scarcity conditions, thus enhancing the firmness of the generation mix. A detailed analysis of the design of performance incentives in capacity mechanisms is provided in the fifth and sixth chapter of this thesis. Prior to this, the following chapters three and four focus on the first central topic of this thesis, i.e., the role of CRMs in regional markets.

# 3. CRMs AND REGIONAL MARKETS

*This chapter is focused on the regional dimension of capacity mechanisms. The regulatory basis for the effective participation of foreign agents in national CRMs is discussed here. The regional context used to analyse this topic is the Internal Energy Market of the European Union, where the problem of cross-border trading of "reliability products" is more pressing. The author supports that two conditions must be fulfilled: i) stronger coordination among TSOs during scarcity conditions (this topic is further analysed in chapter four) and ii) the introduction a particular type of firm cross-border nominations associated to the CRM commitments*[23].

## 3.1. Caveat

The ultimate objective of regional integration of energy markets is to achieve a coordinated planning of generation and transportation infrastructures that allows to exploit as efficiently as possible the regional resources. Among other necessary pre-conditions, this implies that countries in a regional energy market accept to rely on neighbours at the moment of supplying their national demand. In order to establish confidence in the regional market, countries must commit to face potential system stress events through a coordinated regional approach, fulfilling also during energy scarcity conditions contracts and agreements previously signed, without trying to protect exclusively the rights of their national demand. Following this vision, the European Commission, when designing its Internal Energy Market, issued several pieces of regulation which claim for the respect of cross-border contracts also during emergency situations.

Despite of this, the vast majority of people working in the power sector still consider the security of supply as a strictly national issue, assuming that no Member State would allow exports of electricity during scarcity conditions, unless their national demand is fully covered. According to these experts, it is naive to believe that a stress event can be solved

[23] This chapter draws on Mastropietro, P., Rodilla, P., Batlle, C., 2015a, *National Capacity Mechanisms in the European Internal Energy Market: Opening the Doors to Neighbours.* Energy Policy, Volume 82, Pages 38-47.

through a coordinated regional approach. Contrary to this widespread point of view, the chapter that follows is based on the requirements of the European legislation and on the principles that lie behind the Internal Energy Market. The author believes that this autarkic vision of the long-term security of supply is totally contrary to the current effort towards the short-term market integration, and that this conflict will limit the scope of the Internal Energy Market to a short-term market for "leftovers".

## 3.2. Introduction

As mentioned in the first chapter of this thesis, in Europe, after several years of firm opposition to the implementation of capacity mechanisms (with some exceptions, e.g. Spain, Ireland or Italy), a general rethink is swiftly taking place. The United Kingdom, France, and Italy, just to mention the most relevant, have introduced or are proposing the introduction of a CRM in their system. The importance of capacity mechanisms in the European regulatory discussion is demonstrated also by the frenetic activity of European institutions on this topic. Examples of this activity are the consultation paper on generation adequacy and capacity mechanisms that the European Commission launched in 2012 (EC, 2012) and the more recent sector inquiry on capacity mechanisms and state aid (EC, 2015).

This wave of regulatory reforms overlaps in time with another cardinal change of paradigm for the power systems in the region: the shift towards the European Internal Energy Market (EU-IEM), which, after a long process, is finally taking place. Until now, the efforts of the European Commission, ACER, CEER and ENTSO-E have focused on the security and the economic efficiency of the shorter-term time horizon, concerning day-ahead and operation markets. Recent outcomes of this effort are the Framework Guidelines and Network Codes that will result in an EU-wide Target Model for the wholesale electricity market. Coordination will be accomplished for EU-wide congestion management, with a day-ahead market that will encompass the entire region with harmonised bidding and pricing rules[24]. Further harmonisation is also being sought for more complex short-term issues, such as the coordination of the balancing markets of the different Member States, a very demanding task that requires a great deal of engineering and organization skills.

While these efforts are already resulting in the integration of the short-term wholesale markets, in the (long-term) system-adequacy dimension, an EU-wide approach on capacity mechanisms is far from being achieved. Actually, it is not completely unrealistic to state that the most recent legislation from national governments is moving exactly in the opposite direction. CRMs implemented or still under design in Europe seem to rely almost exclusively on the domestic generation (i.e., directly connected to the network managed by

[24] In this framework, the Price Coupling of Regions (PCR) initiative will allow different power exchanges to use a common clearing algorithm (called EUPHEMIA) for the day-ahead market (ACER, 2013b). Further details regarding the PCR project are provided throughout the chapter.

the national system operator) and clearly aim at increasing the self-sufficiency of the national power system. Foreign resources are not allowed to actively participate in these capacity mechanisms and they are excluded from the resulting remuneration. This is the approach that, according to the most recent reform proposals, is being followed in the design and implementation of CRMs in the United Kingdom (DECC, 2014), France (RTE, 2014), and Italy (AEEG, 2011)[25].

So far, European institutions have not yet adopted any direct measure regarding the convenience of harmonising the efforts in the system-adequacy dimension[26]. Nevertheless, limiting the integration efforts to the short-term dimension would be short-sighted and harmful for the future development of the European internal market.

Concerns on this issue have been expressed in several documents recently released by key EU institutions in power sector regulation. Just to mention some of the most relevant:

- In EC (2012) it is stated that "if capacity mechanisms are introduced prematurely or without proper coordination at EU level, they risk being counterproductive" and that "poorly designed capacity mechanisms will tend to distort investment signals".
- EC (2015) claims that "as these capacity mechanisms are mostly being planned or introduced in an uncoordinated manner they risk being inefficient and materially distorting cross-border trade and competition between the various capacity providers".
- In ACER (2013a) it is observed that the "lack of coordination (on generation adequacy measures) has resulted in a patchwork of CRMs in the EU, which may be at the detriment of the market integration process".
- In ENTSO-E (2013) it is said that although "there are significant difficulties in standardizing generation adequacy analyses methodologies (…), there would be a clear

[25] The first auction of the Capacity Market recently introduced in the United Kingdom, held in 2014, considered a "zero net contribution" from interconnectors (Newbery and Grubb, 2014), as proposed by the System Operator (National Grid, 2014). The second auction, held in 2015, allowed the participation of interconnectors (DECC, 2015), but the explicit participation of foreign resources is not considered yet. The capacity obligations mechanism under design in France will implicitly consider cross-border capacity, by somehow reducing the obligation of each supplier (RTE, 2014), but the explicit participation of foreign agents, with the consequent access to the capacity remuneration, is only foreseen as a hypothesis for the future. The Italian CRM will consider cross-border imports conservatively and no active participation of foreign agents is foreseen at the moment (AEEG, 2011). On the general EU context, ACER (2013a) well resumes the situation when it states that "the experience with cross-border participation (in national CRMs) is virtually non-existing".

[26] Actually, it should be underlined that, at the moment, no EU Agency has the power to issue restrictive legislation regarding national capacity mechanisms. The elaboration of guidelines has apparently not been sufficient to influence decisions from Member States. The only tool that the European Commission has is probably the regulation on state aid, which may be applied in the future in order to guarantee the compatibility between CRMs and the IEM Target Model (EC, 2015).

benefit in reporting in a systematic harmonised fashion the key security metrics across the internal market".

- EURELECTRIC (2013) outlines as a key message that "CRM should be open to cross-border participation, underpinned by close coordination between Member States and respective system operators (TSOs)".
- Finally, EFET (2013) underlines that CRMs have to be "non-discriminatory, by taking into account the contribution of non-national generation through interconnection which may decrease local needs".

However, the strongest position assumed so far can be found in the EC (2013) working document on generation adequacy in the Internal Electricity Market. In this communication, it is specifically stated that "given the increasing integration of electricity markets and systems across borders it is now increasingly difficult to address the issue of generation adequacy on a purely national basis".

### 3.2.1. Levels of CRMs harmonisation in the regional market

As regards capacity mechanisms in a regional market framework, different degrees of harmonisation are possible. The highest level would be represented by the implementation of an EU-wide capacity mechanism, covering the entire regional demand. Nonetheless, this scenario is not only extremely unlikely for the moment, but also unnecessary from the theoretical and practical point of view. In fact, the final goal of these mechanisms is to guarantee a certain level of reliability of electricity supply. Regulators in different Member States can and should be allowed to require different levels of reliability, depending on the expected impact of a potential electricity curtailment in their system.

The implementation of different national CRMs to achieve a range of diverse reliability targets is therefore the most likely scenario. In this context, most of the benefits of market integration can still be exploited. The only basic requirement is that, using the words of EC (2013), "mechanisms to ensure generation adequacy should be open to all capacity which can effectively contribute to meeting the required generation adequacy standard, including from other Member States". To this end, a minimum requirement in a regional market should be that all resources are allowed to participate in whatever capacity mechanism is established by any local authority, being the commercial capacity of the interconnections the only limit to this participation. How to ensure the proper conditions to comply with this minimum integration requirement is the focus of the discussion presented here.

The chapter is organised as follows. Section 3.3 analyses the current barriers to the cross-border participation in national CRMs in the EU context, and presents an approach to remove these barriers. Section 3.4 outlines the theoretical framework which is then used in section 3.5 to test the proposed approach with a capacity mechanism based on reliability option contracts, studying different combinations of short-term market conditions in two neighbouring systems. Finally, section 3.6 summarises the main conclusions of this chapter.

## 3.3. Problem diagnosis and regulatory proposals

### 3.3.1. Current barriers to cross-border participation in CRMs

The overall objective of a capacity remuneration mechanism is (or should be) to ensure that the system has enough generation (or demand-response) resources during scarcity conditions. In order to include generation from a neighbouring system in a capacity mechanism, the TSO of the country launching the CRM (hereafter CRM-system) must be sure that, during scarcity conditions on its national grid, foreign resources are able to fulfil their supply obligations linked to the capacity mechanism. Unfortunately this is not currently the case, basically because of two reasons.

The first reason is related to the mistrust of the fulfilment of article 4.3 in the Security of Supply Directive (2005/89/EC), when it states that "Member States shall not discriminate between cross-border contracts and national contracts". This mistrust is based on the existence in most electricity laws and national network codes in force in the Member States of clauses that maintain that exports to other countries will be interrupted in case of a domestic emergency of supply. Therefore, in case of concurrent scarcity conditions, the TSO of the foreign country will surely limit the flow through the interconnection, thus impeding foreign resources to fulfil their commitment with the CRM-system[27].

The Iberian MIBEL is a clear example of this contradiction. In the MIBEL, the market splitting assigns all the transmission capacity through an implicit auction. Bilateral contracts are considered through balanced bids at the two sides of the interconnection (also known as mirror bids, as in Batlle et al., 2014, i.e., the combination of a selling bid at the injection node and a purchasing bid at the withdrawal node) and are not backed by physical transmission rights. In the proceedings of the common Market Operator OMIE (SEE, 2013), the rule 30.2.4 foresees that in case of scarcity conditions, the missing energy will be spread among all the demand, regardless of its location. However, the actual operation of the system is managed separately by the two System Operators. In the operation procedures of the Spanish System Operator REE (SEE, 2002), one of the measures to be taken in case of scarcity is the interruption of export programmes in those hours when they represent a

[27] Some authors seem to support this right of Member States to give its domestic consumptions higher priority during scarcity conditions (e.g., Finon, 2012) and claim in favour of the exemption of capacity rights exchanges from the above mentioned Security of Supply Directive and from the trade provisions of the Treaty of Functioning of the European Union. The usual alternative proposed by these authors is to consider the contribution that foreign generators can provide to the adequacy of a system in a statistical way when designing the capacity mechanism, calculating the expected import through the interconnections during scarcity conditions. This approach, besides the difficulties involved in the definition of this statistical measure, has the evident flaw of not considering concurrent scarcity conditions.

threat to the domestic security of supply. This seems to violate the article 4.3 of the Security of Supply Directive and to be in opposition to the Market Operator Proceeding[28].

The second reason is linked to the future consideration of long-term cross-border contracts in the market coupling mechanism. A strict application of the Target Model would result in the automatic allocation of the entire transmission capacity through the short-term market clearing algorithm, being the flows through the interconnections determined by the equilibrium between generation and demand in the different zones. This approach would impede the fulfilment of CRM contracts by foreign resources during system stress events. This fear is clearly expressed in DECC (2013), where it is stated that "the Target Model being introduced across Europe to promote efficient operation of the Internal Energy Market means that interconnector flows will be determined largely by energy price differentials between interconnected markets" and that this arrangement could impede a foreign reliability provider to export towards Great Britain when scarcity conditions arise in this system. A similar concern is expressed in RTE (2014), where it is asked "what should happen to capacity contracted through a capacity mechanism and the energy it generates (when there is a shortage in two countries simultaneously)? The market coupling algorithm might not be able to clear in those situations". If these concerns are well-funded, it is even possible that, during these scarcity conditions in the entire regional system, domestic generation with a CRM commitment in its system could "slip out" through the interconnection driven by price differentials with neighbouring countries. Paradoxically, this would mean that the presence of cross-border interconnection could increase the amount of capacity to be procured and could result in overinvestment in the country implementing the capacity mechanism.

### 3.3.2. An approach to remove the existing barriers

#### 3.3.2.1. Removing the first barrier

The first of the two aforementioned barriers can only be tackled by means of a stronger coordination and commitment between TSOs regarding the requirement established in the Security of Supply Directive. In particular, this requirement should be accomplished through the modification of the national (and regional) network codes and operation procedures applied by several system operators in the region and through an actual responsibility

[28] Also the regional Network Codes being drafted by ENTSO-E do not seem to properly address this issue. In a letter to the European Commission, EURELECTRIC clearly claims for amendments to article 69.1 of ENTSO-E draft guidelines on Capacity Allocation and Congestion Management, which states "in the event of *force majeure* or an emergency situation (…), where the TSO shall act in an expeditious manner and re-dispatching or countertrading is not possible, each TSO shall have the right to curtail cross-zonal allocated capacity". EURELECTRIC argues that, with such approach, "capacity contracts for adequacy purposes with foreign generators would not be as reliable as in-land generation and cross-border participation in CRM would be more difficult".

transfer on security of supply issues from the system operator to the market operator. This is based on the basic principle that the outcome of a properly designed market, considering both the short and the long term, should not be modified by the system operator, unless because of the occurrence of technical issues. Chapter four goes into this issue and puts forward proposals to improve the firmness of cross-border trades.

#### 3.3.2.2. Removing the second barrier

The second barrier, i.e., the way long-term contracts are expected to be considered in the PCR context, is the one that seems to be more challenging for a number of reasons. It must be reminded again that the final objective should be to allow the TSO of the CRM-system to be sure that, during scarcity conditions, all generation contracted through the CRM, either national or cross-border, is able to fulfil its physical capacity commitment.

**Traditional approach**

Such a simple but crucial condition could be achieved through the existence of Physical Transmission Rights (PTRs). This has been traditionally considered as the only mean to ensure an effective physical cross-border trading. However, it is worth noting that allowing PTRs is not in line with the guidelines expressed by ACER for the future development of the regional market[29]. Apparently, the explicit auctioning of PTRs is supposed to be eventually removed and the entire interconnection capacity will be assigned through the PCR algorithm. Only Financial Transmission Rights (FTRs) will be made available, but these tools do not ensure physical delivery. In this context, other solutions must be considered.

**Proposed approach: conditional nominations**

The alternative approach proposed in this chapter is a soft version of physical cross-border commitments. In fact, it would be sufficient that the PCR permits to declare a sort of "conditional nomination" associated to CRM contracts. This conditional nomination would allow resources to physically contribute to the supply of electricity to the CRM-system during scarcity conditions. However, the "physical" supply from the reliability providers holding a CRM contract (both national and cross-border) should be claimed by the CRM-system only in specific combinations of scarcity conditions and flows through the cross-border interconnection. In order to justify this statement, Figure 3.1 presents four possible scenarios, resulting from the combinations of having or not declared scarcity conditions in the CRM-system (non-scarcity, "NS", and scarcity, "S") and having imports from, "I", or exports to, "E", the neighbouring country flowing through the interconnection. For the sake of simplicity, it will be assumed in this preliminary example that imports and exports

[29] The major drawback of PTRs (even if they are of the use-it-or-lose-it type) is that if they are not properly managed, due to for example (among other potential reasons) information asymmetries, they could affect the short-term efficiency of cross-border trading (Batlle et al., 2014).

involve the use of the full cross-border capacity. Reliability providers have been contracted, in the framework of the capacity mechanism, on both sides of the interconnection.

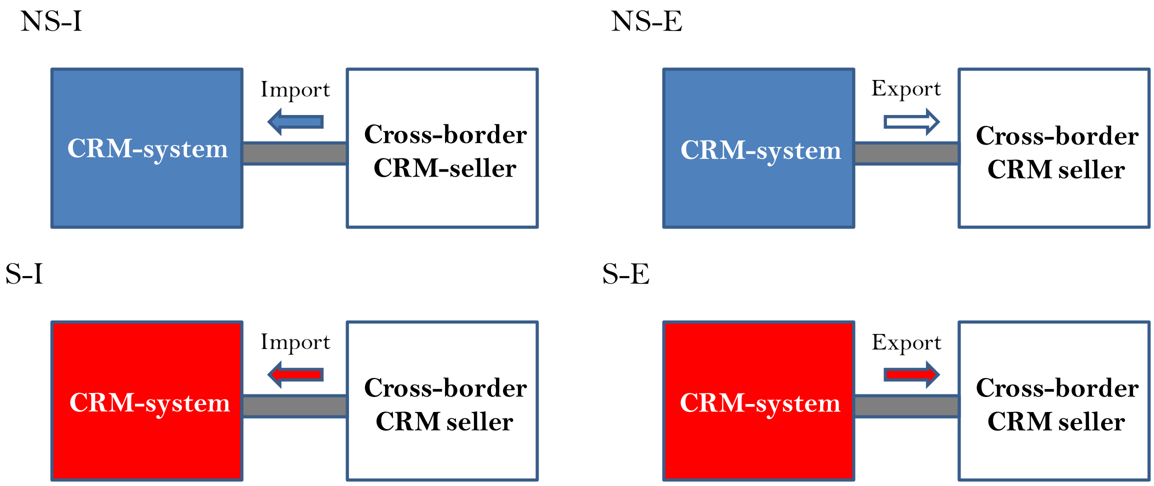



Figure 3.1. Four relevant cases for a CRM in a regional context

Obviously, in the upper cases in Figure 3.1 (NS-I and NS-E) there is neither the need nor the right of claiming for the CRM contracted capacity and the flow through the interconnection will be determined by commercial considerations. On the other hand, in the lower cases, when scarcity conditions are declared in the CRM-system, the TSO of the latter has to guarantee the delivery of the contracted CRM capacity. In case S-I, scarcity conditions in the CRM-system are concurrent with the congestion of the interconnection in the importing direction (towards the CRM-system). In this situation, no further benefit could be achieved from ensuring that cross-border reliability providers are supplying the CRM-system, because the maximum capacity is already flowing through the interconnection. Therefore, as explained in detail in the detailed discussion in section 3.5, there is no need to include in the design of the CRM a cross-border delivery checking in this case.

In case S-E, even if scarcity conditions have been declared in the CRM-system, the interconnection is congested in the exporting direction, i.e., leaving the CRM-system. In this case, the TSO of the latter has to check if all CRM resources are delivering the contracted capacity and if this delivery is actually contributing to relieve the scarcity condition in the CRM-system. In order to ensure both the delivery and the contribution to the CRM-system adequacy, both national and cross-border reliability providers must be allowed to express a conditional nomination that assigns their delivery to the CRM-system. In the case of cross-border resources, this nomination will apply only as long as the interconnection is not congested in the direction towards the CRM-system. Therefore the conditional nomination will have a slightly different scope for the two different groups:

- For national reliability providers, the “conditional nomination” rule allows to nominate energy within the CRM-system frontiers whenever the latter declares scarcity conditions.

- For cross-border reliability providers, the "conditional nomination" allows resources in the regional market to "nominate" cross-border contracts to be exercised whenever the following two conditions are simultaneously met:
  - The CRM-system declares a scarcity situation (as it is the case with the national providers).
  - There is free capacity in the interconnection (as determined by the PCR) in the direction towards the CRM-system. As it will be further discussed in the following sections, if there is no cross-border interconnection capacity available, the CRM-system is already receiving all possible support to its reliability from the neighbouring system. This second condition is the key to avoid ex-ante capacity reservation, and leaves much more space to the PCR for it to efficiently assign transmission capacity in the regional market during normal operation.

These features ensure the physical delivery from reliability providers when such delivery actually contributes to relieving the scarcity condition in the CRM-system. After having presented the proposed approach, in the following sections it will be demonstrated, by means of several representative and comprehensive examples, that if this type of "conditional nomination" is considered in the regional market design, i) there is no hurdle to the effective participation of foreign resources in the capacity mechanism of a system in the same regional market and ii) the short-term market efficiency is not distorted.

## 3.4. Reference framework

In order to assess the effectiveness of the proposed approach, a theoretical framework is defined hereunder in terms of CRM design, consideration of bilateral contracts, and short-term market integration, which is used for a case-by-case analysis in the next section.

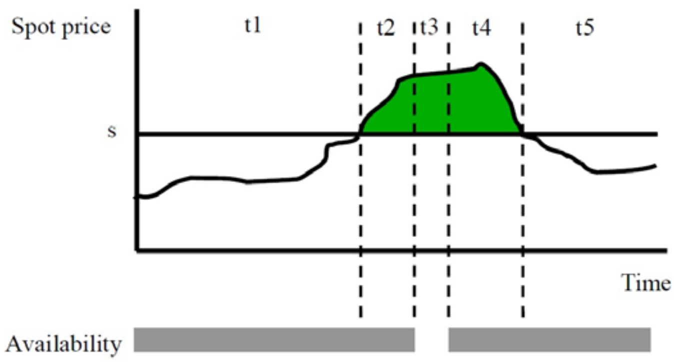
### 3.4.1. Reliability option contracts in a regional context

#### 3.4.1.1. The basic product

There is a broad variety of possible CRM designs (Rodilla and Batlle, 2013). In this chapter, in order to provide a realistic background to the discussion, a specific capacity mechanism will be considered for examples in the dissertation, namely, the reliability option contracts. This design, originally proposed and presented in Vázquez et al. (2002), is briefly summarised right below, together with the terminology used in the discussion (this part can be skipped by the reader acquainted with this kind of CRM).

The reliability option contract consists of a combination of a financial call option with a high strike price to be backed by physical resources and an explicit penalty for underdelivery. It entitles the buyer of the option to receive from the seller any positive difference between the short-term market price $p$ and the contract strike price $s$ for each MW purchased under the contract. In exchange for that, the seller receives a premium fee $F$. From the generator point of view, selling an option means that it will receive an amount of money $F$ in exchange for limiting to $s$ the price it will obtain from selling its energy, therefore renouncing to the opportunity of selling at short-term prices higher than $s$. The generator is exchanging an uncertain income, associated to the part of the spot price above the strike price $s$, for the fixed payment $F$. The option stabilises a fraction of the generator's income, therefore reducing its risk.

The mechanism also clearly identifies the scarcity conditions of the system as the periods of time when the short-term market price $p$ exceeds the strike price $s$. In order to strengthen the incentive for the generator to be available at this time, an explicit obligation associated to the physical delivery of the committed capacity is encompassed in the mechanism. Whenever $p$ is higher than $s$ and the unit is unable to honour its obligation to produce, the generator has to pay, apart from the implicit penalty $(p-s)$ representing the basic fulfilment of a plain-vanilla financial call option, an additional penalty, denoted as $pen$. This explicit penalty is meant to discourage those bids that are not backed by reliable generation capacity. The overall functioning of the reliability option contracts mechanism was represented in Vázquez et al. (2002) through Figure 3.2, which analyses the contract payoff for all possible combinations of spot price, strike price and generator's availability.




| Time period | | *t1* | *t2* | *t3* | *t4* | *t5* |
|---|---|---|---|---|---|---|
| Demand pays ($/kWh) | | *p* | *p*-(*p*-*s*) = *s* | *s* | *s* | *p* |
| Generator receives ($/kWh) | without option | *p* | *p* | - | *p* | *p* |
| | with option | *p* | *p*-(*p*-*s*) = *s* | -(*p*-*s*)-*pen* | *s* | *p* |

Figure 3.2. Payoff of the reliability option contract, Vázquez et al. (2002)

This chapter is based on the reliability options mechanism because it is considered to be the most efficient in terms of reduction of investors' risk, low interference with the short-term market, and overall transparency of the process. However its main advantage concerns the market-based identification of scarcity conditions. This way to identify power scarcities obviously assumes the presence of a liquid reference short-term market in the system, which should be a requisite of all liberalised power sectors, as already mentioned in chapter two.

It must be highlighted that, even if the remainder of this chapter will focus on the reliability option contracts mechanism, part of the discussion outlined until now is valid also for other CRM designs. Nevertheless, it is true that the explicit participation of cross-border resources in a national capacity mechanism may be complicated by designs that do not consider a critical period indicator based on a reference market price. If scarcity conditions, during which CRM resources are called to deliver their contribution, are identified through network parameters or emergency actions taken by the system operator, it may be difficult to find arrangements that do not affect the efficiency of the market coupling, forcing to distort its outcomes to fulfil CRM commitments. A detailed analysis on how to allow explicit cross-border participation in these contexts exceeds the scope of this chapter. However, it is a very relevant topic for a future work, as mentioned in the conclusions of this thesis.

#### 3.4.1.2. Refining the commitment in the regional context

As mentioned above, the reliability option consists of a financial option plus a physical delivery commitment. The financial option commitment is the same for national and foreign resources. Foreign resources will need to enter into FTRs if they want to reduce base risk exposure (as discussed in this chapter).

However, the physical commitment is the contract provision that must be carefully defined in the regional context. As it will be analysed in section 3.5, the product has to be slightly modified for national and cross-border reliability providers.

- National reliability providers: for the reliability providers situated in the CRM-system, the commitment to deliver physical capacity within national frontiers will be checked any time scarcity is declared in the CRM-system. If those having committed capacity are not producing for the CRM-system when such a situation in the CRM-system materialises, a penalty will apply. In order to ensure this, it will be checked that national reliability providers have presented a conditional nomination in their own system and that they are actually delivering.
- Cross-border reliability providers: in order to comply and be coherent with the conditions established in section 3.2, the commitment for cross-border capacity has to be carefully defined. In particular, the compliance of capacity delivery coming from cross-border resources will only be checked when i) a scarcity is declared in the CRM-system and ii) the interconnection with the neighbouring system is not congested in the direction towards the CRM-system. When this is the case, the CRM-system will check that the cross-border reliability provider has declared the conditional nomination to the PCR and it is actually delivering.

#### 3.4.1.3. Zonal capacity auction

Due to the presence of an interconnection with limited capacity (and due to the small difference in the products sold by national and foreign resources), the reliability option mechanism should be organised around a zonal auction, which could result in different prices for national and cross-border reliability providers.

### 3.4.2. Bilateral contracts in the PCR

As previously pointed out, the consideration of long-term bilateral contracts in the European short-term market coupling is not fully clear yet. Apparently, in the pilot phase of the project, bilateral contracts will need to be backed by physical transmission rights, to be nominated in a use-it-or-sell-it approach (PTRs + UIOSI). In this case, part of the interconnection capacity would be auctioned in the form of PTRs and only the part remaining from this process would be assigned through the price coupling algorithm. However, this approach can be modified in a second phase, leaving the entire transmission capacity allocation to the PCR and complementing it through the auctioning of financial transmission rights[30].

In the following discussion, it will be assumed that only two types of long-term contracts are allowed:

- Financial Transmission Rights.
- Conditional nominations linked to the CRM.

### 3.4.3. Day-ahead market coupling

The day-ahead price coupling mechanism allows a coordinated congestion management in the region[31]. In broad terms, once the commercial capacities of the interconnections have been calculated (considering also bottlenecks within single national systems), a shared algorithm clears the regional market, efficiently allocating all the limited transmission capacity and calculating different zonal prices whenever the maximum capacity of an interconnection is reached. Additionally, in line with the requirements presented above for the cross-border CRM participation, it will also be supposed that the short-term mechanism takes cross-border conditional nominations into account.

[30] The decision between these two different approaches will depend, among other issues, on the consideration that FTRs will finally have in the second Directive on Markets in Financial Instruments (MiFID II). See Batlle et al. (2014) for details.

[31] According to ACER (2013b), the North West Europe/PCR pilot project went live on 4 February 2014 (including the Iberian MIBEL) and roadmaps have been set for cross-regional intraday trading, harmonised allocation rules for transmission rights, and cross-border capacity allocation methods.

### 3.4.4. Terminology and notation

Herewith the discussion will be based on two countries, country $A$ (CRM-system) and country $B$, and their power systems, which are interconnected through a transmission line of maximum capacity $I_{AB}$. Resources in $B$ are allowed to take part in the reliability auction of country $A$, but their bids will be obviously accepted up to the maximum capacity of the interconnection. This can be carried out through a zonal auction. It is also possible that some resources in $A$ do not participate or are not selected in the auction of their own system and therefore have no obligation under the framework of the capacity mechanism. Thus, for the sake of simplicity, resources can be divided into reliability providers in $A$ (resources in system $A$ whose bid is accepted in the reliability auction), non-reliability providers in $A$ (resources in system $A$ whose bid is not accepted or which do not take part in the reliability auction), reliability providers in $B$ (resources in system $B$ whose bid is accepted in the reliability auction of system $A$), and non-reliability providers in $B$ (resources in system $B$ whose bid is not accepted or which do not take part in the reliability auction of system $A$). This nomenclature will be used in the dissertation and is represented graphically in Figure 3.3.

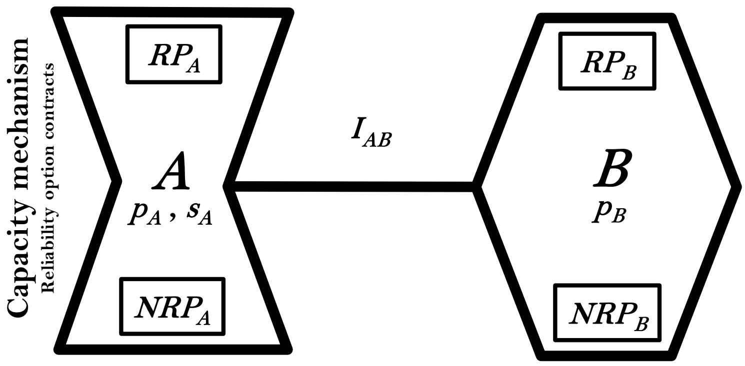



Figure 3.3. Graphical representation of the problem under study

The possible existence of a capacity mechanism in country $B$ is not relevant for the purposes of the dissertation, subject to the fulfilment of avoiding double-commitment of capacity. This means that if a resource, located either in system $A$ or in system $B$, commits part of its capacity in the reliability auction of system $A$, then it cannot commit that same part of its capacity in any other capacity mechanism whatsoever to which it has access. In a regional market, this can be accomplished by a coordinated accounting of CRM contracts between TSOs, without the need of a single regional mechanism.

However, it must be remarked that the definition of double commitment may be controversial, depending on the kind of scarcity conditions expected in each system. If two neighbouring countries have both winter peak demands, expected to take place during the same weeks, than a reliability provider should clearly be allowed to sell its capacity only in one system. However, if the two countries commonly face peak loads at different times of the year (e.g., one during winter, the other during summer), the same reliability provider could contribute to solve both scarcity conditions. The reasoning becomes even more complex when the two neighbouring countries rely on different generation mixes and, for example, one is energy-constrained and the other capacity-constrained. Only a simulation model could provide, in this case, an estimate of the capability of one single resource to contribute to the reliability of both systems. Theoretically, in all those cases in which it is foreseeable that the same resource could provide reliability to more than one country, a certain degree of double commitment could be allowed and this approach would avoid unnecessary over-procurements. Nonetheless, the most likely scenario is that system operators would limit such double commitment in the qualification phase of the CRM, applying very conservative estimates in their simulation models.

## 3.5. Detailed discussion

Assuming the above mentioned context and hypotheses, all the possible relevant cases that can occur as combinations of short-term price in $A$ ($p_A$), strike price in $A$ ($s_A$), and short-term price in $B$ ($p_B$), are analysed, focusing on their impact on the fulfilment of reliability contracts. The goal is to demonstrate that an effective participation of cross-border capacity in a national capacity mechanism is possible and economically efficient.

### 3.5.1. Case I: $p_A < s_A$

In this first case, the short-term price in system $A$ does not exceed the strike price of reliability option contracts. Therefore there is no scarcity condition in $A$ and consequently there is no obligation to deliver, neither for the reliability providers in $A$ nor for the reliability providers in $B$. The market is cleared through the price coupling and the flow through the interconnection depends on the equilibrium of generation and demand bids in the two systems.

As a result, when the CRM-system operates under normal conditions (no scarcity), short-term prices in the two systems and flows through the interconnection are fully determined by the short-term price coupling mechanism.

### 3.5.2. Case II.1: $p_A > s_A, p_A > p_B$

In the second case, the short-term price in system $A$ exceeds the strike price of reliability option contracts. Furthermore, the short-term price in system $A$ is higher than the one in system $B$ ($p_A > p_B$), this meaning that there is a net flow of electricity through the interconnection that results in the congestion of the line, i.e., an electric power equal to the maximum transmission capacity $I_{AB}$ is flowing from system $B$ to system $A$.

In this case, as explained above, only the physical commitment of reliability providers in $A$ will be checked. If this commitment is not fulfilled, these resources are subject to a penalisation. On the other hand, since $I_{AB}$, the maximum capacity of the interconnection, is also the maximum contribution expected from the reliability providers in system $B$, it is not necessary to verify whether these resources are actually producing for $A$ or not (Figure 3.4). In fact, in this case, it is not important to check whether the flow coming from the neighbouring country correspond to the reliability providers in system $B$ (left chart in the Figure) or to other resources in the same system (right chart in the Figure), as long as the interconnection is providing the capacity contracted with foreign resources.

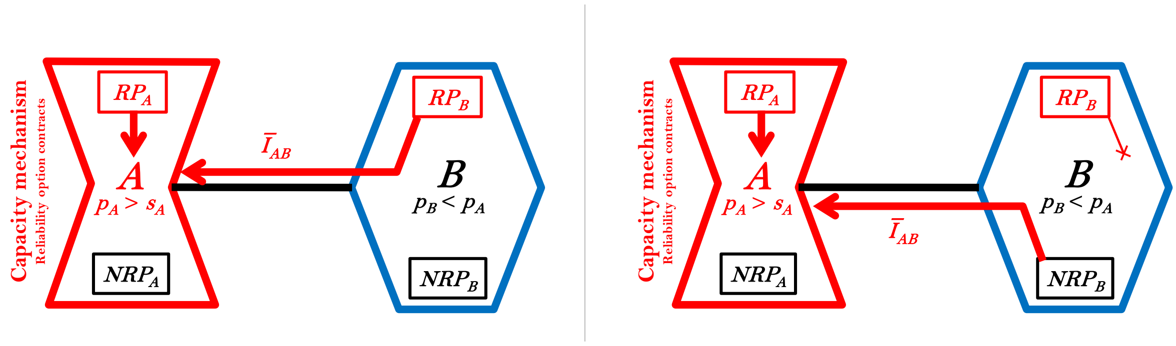



Figure 3.4. Graphical representation of two cases when $p_A > s_A, p_A > p_B$

Therefore, under these conditions, the cross-border conditional nominations do not need to activate and they are discarded by the PCR algorithm, because the market coupling is already assigning to system $A$ the contracted capacity from system $B$.

Summing up, when the CRM-system suffers scarcity conditions and the neighbouring system does not, short-term prices in the two systems and flows through the interconnection are again fully determined by the short-term price coupling mechanism. The short-term market naturally results in the congestion of the interconnection and in the delivery to the CRM-system of the CRM contracted capacity.

### 3.5.3. Case II.2: $p_A > s_A, p_A < p_B$

It will be assumed in this case that, always under scarcity conditions in system $A$ ($p_A > s_A$), the short-term market price in system $A$ is lower than the one in system $B$ ($p_A < p_B$). This means that the interconnection between system $A$ and system $B$ is congested, but this time by a net flow, as determined by the PCR, which is going from $A$ to $B$. Note that this situation is likely to represent scarcity conditions both in system $A$ and in system $B$.

This is probably the most interesting scenario, since in this case the market coupling algorithm is assigning the available cross-border capacity in a way that may go "against" CRM commitments. It must be underlined how this affects not only reliability providers in the neighbouring system but also national reliability providers, since the algorithm could result in the export of electricity, either from reliability or from non-reliability providers in system $A$ (Figure 3.5). From a purely economic point of view, this would be the short-term optimal solution. However, when scarcity or near scarcity conditions are reached, there is a lot to discuss on the efficiency of electricity prices as short-term signals.

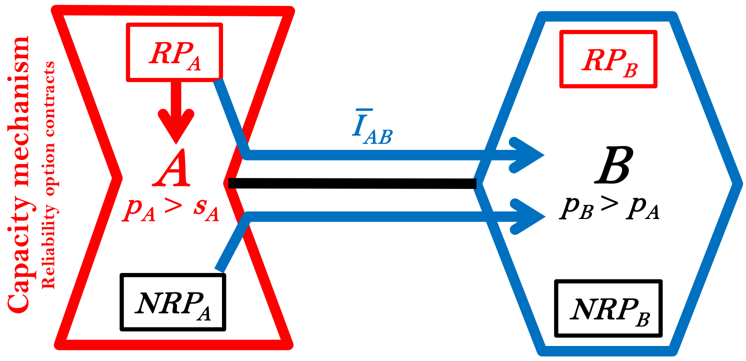



Figure 3.5. Graphical representation of the national resources "slipping out" as a consequence of the PCR

In this situation, the conditional nomination plays a key role. The CRM-system has to verify that both reliability providers in $A$ and in $B$ have declared a conditional nomination in the PCR, and that they are also delivering. This is coherent with the approach presented above in Section 3, where it was said that physical delivery would only be checked when the flow from the interconnection with the neighbouring system does not reach the expected contribution.

If the condition above is fulfilled, and all reliability providers are delivering as committed in the auction, the situation analysed in this subsection is only possible if there are so many non-reliability providers in system $A$ cleared in the short-term market in order to economically "export" to system $B$ that they cause a flow through the interconnection not only capable of balancing the flow deriving from reliability providers in system $B$ that are economically exporting to system $A$, but also to result in the interconnector congestion in the other direction, i.e., from $A$ to $B$ (Figure 3.6)

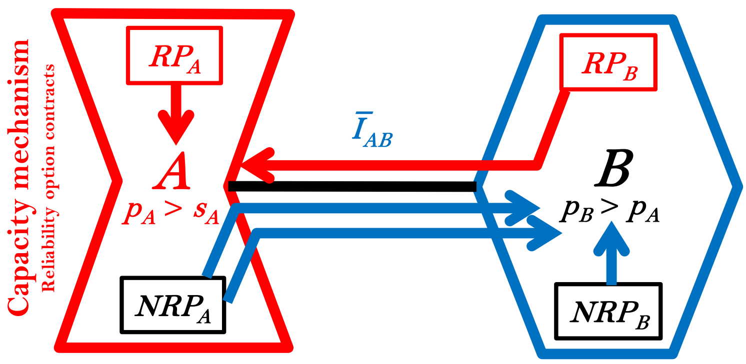



Figure 3.6. Graphical representation of case II.3: $p_A > s_A, p_A < p_B$

**Is the short-term efficiency affected by the conditional nominations?**

In this case, questions related to the economic efficiency of the operation could be raised. Besides other issues, price caps[32] are a key factor affecting this efficiency[33]. Reliability providers in $B$ are economically exporting electricity to a market where the short-term market price is lower. However, when short-term market prices are defined through the activation of price caps, as it is likely to be the case when scarcity conditions arise, it is arduous to make any reasoning regarding the utility of the demand. Commonly the determination of price caps is more the outcome of a regulatory agreement than the result of a process aiming at calculating the real value that demand assigns to electricity. Actually, the price cap could only be a rough approximation of an average value of the demand utility, because different consumers assign electricity a different utility at different times. Since price caps cannot be regarded as accurately reflective of the demand utility, the economic export of electricity from a system with a higher to a system with a lower price, if the latter are the result of price caps activation, does not represent an economic inefficiency.

Indeed, short-term market efficiency is already distorted because of the existence and activation of price caps, since price caps do not allow to fully express the willingness to pay for electricity in the short term. Conditional nominations proposed in this chapter can act as an effective safety valve to this imperfection. These nominations actually do not worsen the market efficiency, but, on the contrary, they improve it. When market agents pay to hold the physical right under these extreme circumstances, they are reflecting precisely their utility.

On the other hand, if prices are correctly representing the actual value of the energy in each system, then theoretically the demand in system $A$ (or the regulator on its behalf), which is covered by the reliability option contract and is the actual owner of the electricity produced by reliability providers in $B$, with this price combination, should sell this electricity in system $B$. In fact, its utility is represented by the short-term price and, if the price in system $B$ is higher than in system $A$, the demand should prefer to sell the electricity in system $B$ and retain the revenues from the sale, since the latter are higher than the utility value it is assigning to the electricity supply.

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[32] Price caps (or offer caps) are in place in the vast majority of short-term power markets. They are used to set the price when the generation is not sufficient to cover the load, because in these conditions the inability of a large part of the demand to properly reflect their utility value in their bid does not allow to clear the market. Their application is often justified by regulators as necessary to tackle market power issues, but they are commonly used to simply avoid electricity prices that regulators and governments consider unacceptable to be passed through to consumers. Even if economic theory demonstrates that price caps negatively affect market efficiency, these instruments are so widely used that a realistic analysis has to take them into account.

[33] Short-term to very short-term regional markets can fail to allocate efficiently electricity due to other reasons, as for example a lack of well-functioning coordinated regional markets after the spot market or directly because of an out-of-the-market intervention of TSOs (and or regulators).

This scenario could be feasible, thus the mechanism does not avoid reaching the ideal optimal outcome if scarcity prices were representing the actual utility of the demand in the two systems. However, it is obvious that this efficient scenario is not realistic, due to the activation of price caps. The discussion above does not mean that the demand which is actually able to react to price changes through short-term decisions could not be allowed to follow different strategies. However, the correct approach would be to leave to consumers the possibility of opting out from the auction for reliability option contracts, either requiring the regulator not to consider their demand in the auction, or by selling in the auction itself demand-response products.

Thus, when the CRM-system suffers scarcity conditions and the price, as determined by the PCR, is higher in the neighbouring system than in the CRM-system, the fulfilment of CRM contracts may not be naturally met by the market coupling algorithm, as it is defined now. This is the scenario in which physical CRM commitments have to prevail over PCR results and this is proposed to be obtained through the application of conditional nominations. Although it can be claimed that a flow from a system with a higher to a system with a lower price is inefficient, it must be underlined that, during scarcity conditions, short-term prices are far from being efficient signals, at least as long as price caps are activated.

### 3.5.4. Case II.3: $p_A > s_A, p_A = p_B$

It will be assumed in this case that, always under scarcity conditions in system $A$ ($p_A > s_A$), the short-term market price in system $A$ and in system $B$ is the same ($p_A = p_B$). This implicitly means that the interconnection between system $A$ and system $B$ is not congested.

This case can be formulated and solved following exactly the same reasoning as the one followed for case II.2. Again, if the market coupling algorithm is assigning the entire cross-border capacity and only FTRs are available, it is not possible to ensure that CRM contracts are fulfilled. Therefore, also in this situation it is essential to apply conditional nominations as presented above. Also in this case the regulator of system $A$ has to check that both reliability provider in system $A$ and $B$ have presented the conditional nomination in the PCR, and that they are delivering. Note that in this particular case there is not any type of arguable inefficiency in the short-term dispatch, since the conditional allocation would only be solving a tie situation in which prices in both countries are identical.

This price combination is of particular interest, since it could be also the result of concurrent scarcity conditions in system $A$ and system $B$, potentially related to the occurrence of non-served energy, that provoke the activation of price caps in the two short-term markets. In fact, under the framework of the PCR project, and in particular of the NWE/PCR (North West Europe PCR) pilot project, consensus is being gathered around the necessity of harmonising the price caps of the short-term markets coupled by this mechanism[34]. If this design were implemented, a situation where both harmonised price caps are activated would belong to this case ( $p_A > s_A, p_A = p_B$ ), because the short-term capped price at the two sides of the interconnection would be the same.

So, finally, when the CRM-system suffers scarcity conditions and the price as determined by the PCR is equal in the two systems, the fulfilment of CRM contracts may not be naturally met. In this scenario, physical CRM commitments have to prevail over PCR results and this is proposed to be obtained through the application of conditional nominations. In this case, conditional nominations only solve a tie situation and do not hamper the short-term market efficiency.

### 3.5.5. Consideration on FTRs and locational signals

It may be argued that resources in system $A$ and resources in system $B$ do not compete on the same basis in a reliability auction launched by system $A$, through its system operator. In fact, a reliability provider in system $A$ and the buyer of the reliability option (in system $A$) are natural risk counterparties, while this is not true for a reliability provider in system $B$[35].

In the framework of market coupling, a likely scenario is that, when scarcity conditions arise in system $A$, the short-term price in $A$ will be higher than the one in $B$ ( $p_A > p_B$ ). In this case, the remuneration of the reliability provider in $B$, i.e., $p_B - p_A + s_A$ (in fact the agent in $B$ receives the short-term price of system $B$, but has to settle the reliability option contract, by returning $p_A - s_A$), can be significantly lower than the one of the reliability provider in $A$, i.e., $s_A$, or even negative. In order to hedge this risk, the reliability provider in $B$ can strategically buy financial transmission rights, which assign it the congestion rent of the line, thus providing also the cross-border reliability provider with the status of natural counterparty with respect to the buyer of the reliability option. Nonetheless, it has to pay for these FTRs and the expense, in theory, will be exactly the expected short-term price deviation between system $A$ and system $B$. The result is that the reliability provider in system $B$ will have to internalise this expense in its bid in the reliability auction and

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[34] ACER (2013b), regarding the harmonisation of floor and ceiling prices in the framework of the PCR project, states that "a consensus emerged around the values + 3000 € and - 500 € (per MWh) and this range is to be implemented with the NWE market coupling go-live".

[35] See Rivier et al. (2013) for a detailed explanation on transmission rights and on the "natural counterparties" concept.

therefore it will have a disadvantage with respect to a reliability provider using the same technology, but located in system $A$ [36].

However, this is not an undesirable effect. In fact, it represents an efficient locational signal for agents willing to invest. A similar situation occurs when a large demand is concentrated in a first node which is linked to a second node, where several generators are connected, and the line between them is usually congested. Obviously, generators in the "load node" have a commercial advantage in comparison with generators in the "supply node", but this happens because the former are better located than the latter. The same occurs with a capacity mechanism: reliability providers in a node with a high demand for reliability will always have, in a reliability market, an advantage on reliability providers located in a node with no reliability demand and connected to the first node through a line subject to congestion. This disadvantage affecting cross-border resources (together with the fact that they are likely to receive a lower clearing price as a result of the zonal auction) is partially balanced by the different commitment they are required, as explained in section 3.5.2.

## 3.6. Conclusions and recommendations

Several European countries, albeit committed in a harmonisation process of their national short-term markets, are independently and separately designing and introducing long-term capacity mechanisms. While the implementation of different CRMs is acceptable from a regulatory point of view, this should not be translated in the creation of national energy autarkies.

This chapter, by means of examples based on the reliability option contracts mechanism and on the price coupling market coordination approach, demonstrates that it is feasible to eliminate the current regulatory barriers to the participation of foreign resources in the CRM of a system in the same regional market, while not affecting the short-term market efficiency. The assumptions under which this can be achieved can be resumed as follows.

- Capacity mechanisms must be based on contracts to be exercised during scarcity conditions in the system. The spot price is the best critical period indicator and this is likely to turn to be more valid in the future, in a scenario of increased elasticity of the demand. In CRM designs that identify scarcity conditions through network parameters or emergency actions by the system operator, it may be more difficult to guarantee the explicit participation of cross-border resources.
- Countries in the regional market must always fulfil article 4.3 of the Security of Supply Directive, which states that "Member States shall not discriminate between cross-border

[36] This being said, there are other relevant reasons that can make cross-border capacity more competitive than domestic one, among others the fact that capacity can be cheaper in neighboring systems (competitive advantage to strategic resources) or, for instance, that existing foreign capacity can compete against new investments in the domestic system.

contracts and national contracts", also during scarcity conditions. This requirement should be accomplished through the modification of the operation procedures of several system operators.

- If a resource in the regional market commits part of its capacity in the CRM of one system, then it cannot commit that same part of its capacity in any other capacity mechanism whatsoever to which it has access. This can be accomplished by a centralised and coordinated accounting of CRM contracts.
- If a system implements a capacity mechanism open to all the resources in the relevant regional market, it will procure reliable capacity from abroad only up to the maximum transmission capacity of the interconnection, by means of a zonal auction[37].
- The performance assessment of cross-border reliability providers has to be carried out only when the interconnection is not saturated in the importing direction (towards the system implementing the CRM).
- If the entire transmission capacity is assigned through the market coupling, a conditional nomination rule must be included in the clearing algorithm, which ensures the fulfilment of reliability contracts during concurrent scarcity conditions on both sides of the interconnection. Such conditional nomination enhances the firmness of cross-border reliability contracts. At the moment it is not contained in the current procedures of the PCR project, but its inclusion is essential to increase the confidence in foreign reliability providers in the framework of CRMs. It does not represent an actual transmission capacity reservation, but rather a rule to make this reservation superfluous. The non-necessity of cross-border capacity reservation has been demonstrated in this chapter for the different price combinations. The conditional nomination rule is only needed to ensure the fulfilment of reliability contracts during scarcity conditions when, due to the activation of price caps, short-term prices do not allow the proper consideration of bilateral contracts.

[37] Actually, zonal capacity auctions are already in place in some power system in the United States (PJM), where the transmission constraints within the system do not allow a single-node auction.

# 4. Cross-Border Firmness of CRM Contracts

*In this short chapter, the discussion presented in chapter three regarding the participation of foreign resources in national capacity mechanisms is complemented through proposals to reinforce the firmness of cross-border CRM contracts*[38].

## 4.1. Introduction

In the previous chapter, it was stated that two main barriers are hampering the participation of cross-border resources in national capacity mechanisms implemented in the European Union, namely i) the mistrust of the fulfilment of cross-border contracts during regional scarcity conditions, because of potential interruptions of export programmes; and ii) the uncertainty regarding the consideration of long-term cross-border contracts in the short-term market coupling algorithm. Chapter three focused on the second barrier, proposing the introduction of conditional nominations in the market coupling scheme. Nevertheless, if system operators block exports through interconnections during regional scarcity conditions in order to protect their domestic demand, no conditional nomination can guarantee the fulfilment of cross-border contracts. As mentioned in the third chapter, this mistrust is supported by the existence of clauses in national and regional network codes that allow (and, in some cases, compel) system operators to act on interconnections in case of a domestic emergency of electricity supply. This chapter focuses on this barrier and puts forward proposals to reinforce the commitment of system operators towards cross-border contracts.

In order to properly understand the current design of network codes, it must be reminded that, from the very beginning, power sector regulation always had a great emphasis on the

[38] A condensed version of this chapter was published in Mastropietro, P., Rodilla, P., Batlle, C., 2015b, *The Unfolding of Regional Electricity Markets: Measures to Improve the Firmness of Cross-Border Trading*. Working paper IIT-14-160A, submitted for publication.

security of electricity supply and that this issue was mainly addressed on a national basis. Institutional arrangements also reflect this point of view (Baritaud and Volk, 2014). System operators are usually in charge of guaranteeing, whenever possible, the supply of the demand connected to the grid they manage by taking a wide range of measures. Evidence (and also network codes) has demonstrated that one of these measures consists in reducing to zero the flows through cross-border interconnections in case the system operator expects this flow to be directed out of the system, in the export direction. This obviously does not permit the execution of cross-border contracts that serve a demand located on the other side of the interconnection and the objective is to retain the generation committed in the contract in order to cover the largest possible share of domestic demand.

This potential intervention by the system operator (commonly also prompted by the regulator) represents a sword of Damocles hung above cross-border trades. In fact, in theory, the risk associated with the fulfilment of a contractual commitment should be completely manageable by the counterparties entering into the agreement. Nonetheless, if a regulatory intervention by the system operator can impede the execution of the cross-border contract, potentially triggering a compensation for non-compliance to be paid by the generator, then one of the agents is exposed to a risk on which it has no control, and it is subject to a penalisation for an unfulfilment which it is not responsible for. Paradoxically, the compensation for non-compliance, a clause which should aim at increasing the firmness of the contract, becomes, in this situation, a significant disincentive to the stipulation of the contract itself.

If this line of reasoning is valid for all kind of cross-border trades, the threat of export interruption is even more severe in case of cross-border contracts signed in the framework of a capacity mechanism. In fact, these contracts consider penalties for unfulfilment that may be very high (see the discussion on the evolution of CRM performance incentives in chapter five). In order to analyse the impact of export curtailments, a case study entailing two systems connected through a cross-border line with limited capacity is considered. The same reference framework and terminology presented in the previous chapter (see section 3.4.4) is used.

## 4.2. Risk-allocation strategies

### 4.2.1. Two-system case study

A resource located in system $B$ holds a reliability option contract signed in the framework of the capacity mechanism of system $A$, therefore being a reliability provider to system $A$. Furthermore, the resource is also in possession of a transmission right that hedges its position against price differentials. Both systems have price caps that can be activated in their short-term markets and these caps can be different. The remuneration of the reliability provider in system $B$ depends, apart from its operational costs, on the spot market price in system $A$ and the spot market price in system $B$ (for the settlement of the reliability option contract), and on the explicit penalty considered by the reliability option mechanism.

Now, it will be assumed that concurrent scarcity conditions occur in the two systems. The system operator of system $B$ considers that the export programme to system $A$ endangers the supply of domestic demand, thus it interrupts exports through the interconnection. In this situation, prices in the two systems will no longer be coupled and a price differential is likely to appear. However, this differential does not originate any congestion rent, because no electricity is flowing through the interconnection, benefitting from the trading price gap. Since transmission rights are correlated with congestion rents (see Rivier et al., 2013; Batlle et al., 2014), an indefinite situation takes place, and the most likely scenario is that no financial compensation is provided to the holders of transmission rights.

In addition, the interruption of export programmes also impede the reliability provider in system $B$ from fulfilling its contract with system $A$. As mentioned, this results in the application of the explicit penalty considered by the reliability option mechanism, which could have very high rates. Therefore, the reliability provider in system $B$ could be required to pay the settlement of the reliability contract $p_B - p_A + s_A$ (see section 3.5.5), without being hedged against the price differential $p_B - p_A$, plus the explicit penalty $pen$, thus suffering a significant financial loss.

The risk encompassed in this situation is absolutely unmanageable by resources in system $B$ and it represents a huge disincentive to the stipulation of cross-border CRM agreements.

### 4.2.2. Proper allocation of the risk of cross-border interruption

Since a financial loss associated with a situation in which the resource has no responsibility is so detrimental, it may be thought that one possible solution is to include in the cross-border CRM contract clauses that limit the application of the explicit penalty only to non-compliances related with the availability of the generation facility. Therefore, a non-compliance due to regulatory interventions (as the interruption of export programmes) would not be subject to penalties, eliminating this risk (or part of it, since the risk related with the price differentials would remain). However, such provisions are incompatible with the design of the CRM itself, which is based on the reliance on committed resources during scarcity conditions. In this context, this approach would further reduce the firmness of the cross-border commitment, transferring the unmanageable risk from the generation to the demand, and it would once again impede the participation of foreign resources in national capacity mechanisms.

If the objective is to foster the unfolding of cross-border CRM contracts and to create a regional market in which the demand in one system relies on the generation in a neighbouring system when planning in the long term, only "real" *force-majeure* conditions (e.g., a natural disaster) should exempt resource committed in a capacity mechanism from paying the explicit penalty when the physical delivery is not guaranteed.

Since the risk associated to the penalty is not removable, it should be properly assigned. Actually, the most reasonable solution would be to transfer this risk to the party that is responsible for the contract non-compliance, i.e., the system operator deciding to interrupt exports through the cross-border interconnection. This implies that, whenever the fulfilment of the CRM contract is not possible because of an intervention from the system operator, the latter should be required to assume the consequences of its actions, by paying both the explicit penalty and the financial settlement related to price differentials. The system operator (once again, representing the regulator and, eventually, the government) should be also required to deposit warranties for the coverage of such payments.

The main drawback of this approach is represented by the possibly exaggerated warranties that should be deposited to cover potential compensations to be paid by the system cutting the exports, which could make this mechanism practically infeasible. In Mastropietro et al. (2015b), the factors affecting these warranties in a context of regional electricity trade (not related, in principle, with CRMs) were studied. Transposing that analysis to the case of CRM contracts in a regional electricity market, several reflections can be withdrawn.

Warranties to be deposited in order to cover the consequences of an interruption of electricity exports basically depend on two terms: the value of the compensation to be paid for each hour of non-compliance of the CRM contract, composed by the explicit penalty and the financial settlement covering price differentials between the two zones, and the expected duration of scarcity conditions[39], which prompt the occurrence of the situation requiring the payment of the compensation.

Therefore, the warranty should be proportional to the probability of occurrence of scarcity conditions. However, this is not much related to isolated scarcity conditions taking place only in one system. In fact, going back to the case study, if a shortage occurs only in system $A$, exports from system $B$ to $A$ are not interrupted and no compensation is required. On the other hand, if the scarcity only affects system $B$, the CRM in system $A$ is not even triggered and no commitment is to be fulfilled. Therefore, the warranty should increase according to the probability of concurrent scarcity conditions in the two systems. If the complementarity of generation mixes in the two systems results in an extremely low likelihood of concurrent shortages, the warranty could assume very low values.

[39] As regards the duration, it must be highlighted that, depending on the regional market under study, scarcity conditions may not be sporadic events taking place with a very low frequency. Electricity shortages may sometimes be the result of isolated and temporary unavailabilities of generation plants or transmission facilities in the system. Nevertheless, many times, scarcity conditions are related with planning mistakes in the medium and long term, which generate structural deficiencies that need months, or even years, in order to be solved.

Another factor affecting the warranty is obviously the penalty rate considered by the CRM contract. The higher the penalty, the higher the compensation to be paid in case of exports interruption, thus the higher the warranty to be deposited. Furthermore, the warranty is influenced also by the expected price differential between the two systems, since this should be settled also when exports are interrupted and no congestion rent can be exploited. In case of concurrent scarcity conditions in two neighbouring systems, it is likely that both markets have their price caps activated. Therefore, the expected price differential is the difference between the two price caps. If, in the context of the regional market, these price caps are harmonised in a single value, this element can be neglected and the warranty can be lower.

Finally, a reflection must be made regarding the economic source of such warranties. They cannot be part of the regulated remuneration paid for the system operation service, because in this case their "cost" would be passed through to consumers. Since the choice of prioritising domestic demand is usually a political decision, such warranties should come from the state budget. Governments would then have an incentive to require the system operator to respect market outcomes. An alternative source could be represented by loans from any sort of development bank willing to promote the regional market integration. Another remark is that this approach works only if warranties apply to all the countries in the regional market. If this is not the case, generators located in a system that has not deposited any warranty would be discouraged to sign CRM cross-border contracts and such countries would be free-riders in the regional reliability market.

### 4.2.3. Bilateral or trilateral contracts? Transmission right compensations

In the previous subsections, it has been assumed that the system operator blocking exports, thus impeding the fulfilment of the CRM cross-border contract, should be required to pay, on the top of the financial settlement related to price differentials, the explicit penalty considered by the capacity mechanism. Such penalty is commonly included in the CRM contract stipulated between the reliability provider and the institution in charge of managing the capacity mechanism. Nonetheless, it is not obvious how to transfer such compensating responsibility to the system operator of the country where the reliability provider is located. Any clause of an agreement reached between two parties cannot be automatically transferred to the system operator, who had no role at all in the elaboration and in the signature of the contract and cannot be required to pay the compensation expressed in the CRM contract.

A possible solution is to include a clause in the contract governing the transmission right (to be procured by the resource willing to take part in the foreign CRM), in which the system operator commits to pay the price differential also in the absence of any congestion rent (due to the block of exports) plus a generic compensation, valid for all the contracts that involve a delivery commitment, including CRM contracts, regardless of the value of the specific compensation considered by these agreements. The generic compensation (and the potentially associated warranty) should be calculated according to the reflections expressed in the previous subsection. The gap between the generic compensation of transmission rights and the explicit penalty of CRM contracts may still expose the reliability provider to a significant risk. It is, therefore, of paramount importance to set the transmission right compensation high enough, in order not to hamper the signature of cross-border contracts[40].

Another option would be to let agents include the compensation they would require in case of non-compliance in the bids they present in the auction for transmission rights. However, this solution has the main disadvantage of resulting in an auction with two-parameter bids, which could be difficult (when not impossible) to clear.

### 4.2.4. Binding agreements and enhanced institutional arrangements

The attention so far has been focused on the compensation to be paid in case cross-border CRM contracts cannot be fulfilled due to the interruption of exports. However, the payment of a penalisation is only a second best. The first-best solution entails the actual fulfilment of the contract, with the system operator of the exporting country taking no measure that impedes the delivery of electricity to the system that secured it through its capacity mechanism. Even if a regulatory framework capable of achieving this first best is still far from being in place, gradual changes to the institutional arrangements governing regional markets could approach this ambitious goal.

In order to increase the confidence in the fulfilment of cross-border contracts, especially in the framework of capacity mechanisms, binding agreements must be signed by all the countries in the regional market, who should commit to permit the execution of cross-border CRM contracts, guaranteeing for them the same treatment as national contracts, regardless of the supply conditions in their system. However, the experience from the European Union demonstrated how the existence of these binding agreements is a necessary but not a sufficient condition for the fulfilment of cross-border contracts. Network codes in force in each country must be modified accordingly. This shift represents a dramatic change of paradigm in the way national countries manage their security of supply, but it should be introduced pursuing the huge efficiency gain that a regional market entails.

On the same line of reasoning, the unfolding of cross-border CRM contracts, and the consequent development of regional markets, also requires a redefinition of the role of the system operator. Even after power sector liberalisations, the system operator has often kept being considered as responsible for the security of supply, implying somehow the obligation to serve all electricity demand in the system. However, in a regional market context, the

[40] In this context, the identification of the subject in charge of fixing the compensation assumes a particular relevance. System operators, especially where they combine this role with the one of market operator, have access to the best information to carry out this calculation, but they clearly have a conflict of interests. A possible solution is that national regulatory authorities contract an independent consultant, who estimates the compensation in a transparent and reproducible way.

national system operator should be only in charge of maintaining network parameters (frequency and voltage) within predefined limits, managing the grid in a way that allows, whenever possible, the execution of commercial agreements signed in the wholesale electricity market. If national system operators are not relieved by the institutional obligation of serving the load connected to their network, they will always be forced to take measures that favour their domestic demand, thus jeopardising the effectiveness of the regional market.

## 4.3. Conclusions and recommendations

Chapters three and four focused on how to enhance cross-border participation to national capacity mechanisms in a regional market context. While chapter three analysed in detailed the consideration of CRM contracts in the short-term regional market coupling, chapter four proposes new institutional arrangements that improve the firmness of cross-border CRM contracts. Many of the outcomes of this chapter can be generalised to cross-border trades in general and do not depend on the characteristics of the systems involved.

A major barrier to the unfolding of cross-border trade of reliability products is the potential intervention of system operators that can interrupt exports in case their domestic demand is endangered. In fact, in this situation, a reliability provider with a delivery commitment in a neighbouring system would be subject to significant financial losses for a contract non-compliance on which it has neither responsibility nor control. This risk cannot be managed by the reliability provider and should be transferred to the party that is responsible for the non-compliance, i.e., the system operator blocking exports, which should be required to pay the penalty considered in the CRM contract. This obligation can be included in the transmission right to be procured by resources willing to participate in foreign CRMs.

In order to ensure the coverage of such payments, system operators (representing regulators and, eventually, governments) should deposit specific warranties. As explained in this chapter, such warranties must be proportional to the probability of occurrence of concurrent scarcity conditions in the neighbouring countries and to their expected duration, and to the penalty rate considered by the capacity mechanism.

The presence of such a designed compensation/warranties scheme is supposed to improve the commitment to the fulfilment of cross-border CRM contracts by system operators, reducing the probability of exports interruption, which is the actual first-best solution (indeed the only good one) pursued by this measure. Furthermore, it should also represent an incentive to manage regional scarcity conditions in a more coordinated way.

As mentioned in this chapter, the penalties considered by CRM contracts are pivotal in the estimation of warranties. Chapter five and chapter six dig deeper into performance incentives, in order to understand their role in modern capacity mechanisms and to assess the impact of the penalty rate on the outcomes of a CRM.

# 5. CRMs and Performance Incentives

*The existence of significant financial penalties for failure to comply fully with commitments to a capacity mechanism creates an incentive for resources to invest in measures to enhance their performance under scarcity conditions. This chapter compiles empirical evidence from international regulation and provides guidelines for implementing more effective capacity mechanisms*[41].

## 5.1. Introduction

As mentioned in the first chapter of this thesis, capacity mechanisms are necessary in the electricity market to offset market failure, which detracts from the efficiency of the price signal (Neuhoff and De Vries, 2004; Joskow, 2008; Cramton et al., 2013). Market failure is generally identified with factors such as market incompleteness, lumpiness of investment in generation facilities and the inelasticity of electricity demand. In particular, demand inelasticity is believed to impede proper market clearing when the reserve margin is tight, and that, in conjunction with other more politically-oriented reasons, leads regulators to set price caps[42]. The absence of the efficient signals that would be emitted by prices higher than such official thresholds also removes the natural incentive for generators to be available at times of system stress, when the reserve margin is narrow and the risk of demand curtailment consequently high. These "missing performance incentives" pose a threat to system reliability (ISO-NE, 2012).

In (imperfect) markets where price signals are distorted, the missing performance incentives problem can be minimised by precisely defining the capacity mechanism product to be purchased, especially as regards performance assessment. The importance of linking capacity

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[41] A condensed version of this chapter was published in Mastropietro, P., Rodilla, P., Batlle, C., 2015c, *The Need for Non-Performance Penalties in Capacity Mechanisms: Conceptual Considerations and Empirical Evidence*. Working paper IIT-15-088A, submitted for publication to Economics of Energy & Environmental Policy.

[42] See footnote 32 for details.

mechanism remuneration to each resource's actual contribution to security of supply has been highlighted by authors working on capacity mechanism design (Vázquez et al., 2002; Bidwell, 2005; Finon and Pignon, 2008). A need has been identified for strong penalties for underperformance in scarcity conditions, firstly to discourage bids from non-firm generation, and secondly to enhance agents' incentive to manage and operate their resources in ways that raise their availability in such events.

These factors were given insufficient consideration in early capacity mechanism design. In Latin America, where initial capacity payments remunerated generation facility availability (with no further definition of what that meant), actual performance played almost no role in revenue flows. Long-term auctioning mechanisms introduced subsequently corrected some of the flaws in these early schemes (see Batlle et al., 2010, for details), but placed little emphasis on penalising underperformance. The pioneering reliability options mechanism implemented in Colombia, for instance, included no explicit penalty scheme, even though that element was the cornerstone of Vázquez et al.'s (2002) original proposal.

A slightly higher remuneration-performance correlation was gradually introduced in the capacity mechanisms implemented in the United States. ISO New England explicitly included a penalty for non-compliance in its capacity market. However, as explained in ISO-NE (2012), "at times of greatest need, many resources are delivering far below the performance ability represented in their supply offers" (quantified at up to 40% of the additional power required by the System Operator during contingencies). This situation resulted in a wave of reforms based on a "pay-for-performance" approach, which are being introduced at this writing[43].

A capacity mechanism that in addition to providing a long-term investment hedge for market agents also ensures security of supply calls firstly and foremostly for due definition of the reliability product to be acquired. The design elements for this product have been identified in the second chapter of this thesis. This chapter focuses on the two major (non-conflicting) approaches to coping with scarcity conditions through capacity mechanisms, namely constraints on tradable quantities and eligibility criteria (analysed in section 5.2), and performance incentives (studied in section 5.3). The latter are analysed in some detail, identifying the major features of penalty schemes (critical period indicator, penalty rate, overperformance credits, exemptions, and penalty caps). The analysis covers the experience of several countries particularly prominent in this regard (Colombia, ISO New England,

[43] The arguments put forward in these two paragraphs should be set against the backdrop of "real-life" regulation. The introduction of a capacity mechanism always entails negotiations among all the agents involved, whose conflicting interests must be integrated. In this context, the absence of a robust penalty scheme in a capacity mechanism is never the result of regulator "oversight", but rather the outcome of this "bargaining" between the CRM designer and the reliability providers, who normally oppose heavy penalties for underperformance.

PJM, United Kingdom, and France) and includes very recent developments. Section 5.4 summarises the main findings.

## 5.2. Constraints and eligibility criteria

As pointed out in chapter two, market agents are theoretically better able than anyone else to estimate the expected contribution from their facilities during scarcity conditions. If a sound explicit penalty scheme is in place (including a demand for warranties to provide the system with a financial guarantee in case of curtailments), then, there should be no need for the regulator to impose limits on the amounts of reliability product that each resource can trade in a capacity mechanism or to establish criteria that must be met to earn capacity remuneration. Nevertheless, most capacity mechanisms implemented to date include such features, reflecting regulators' mistrust of market agents' estimates and fear of the concomitant power shortages.

As explained in chapter two, constraints on tradable quantities and additional eligibility criteria (requiring any manner of guarantees) consist in quantity caps assigned by the regulator to each agent willing to participate in the capacity mechanism. Such caps should reflect its firm energy or capacity, i.e., the energy and capacity that the resource can provide in scarcity conditions. Constraints, normally applied in a qualification or verification phase, are based on each resource's historical or statistical performance. Strategies differ depending on the technology and include, for example, de-rating of thermal plant capacity on the grounds of the equivalent forced outage rate, or using a stochastic optimisation medium-term planning modelling tool to calculate the maximum energy that a hydropower plant can produce in a dry year (methodologies actually used in Colombia and ISO New England have been presented in section 2.5.4). An example of the eligibility requirements that could be coupled to these constraints would be for gas-fired plants to be in possession of a long-term contract for the firm supply of natural gas.

If properly implemented, limiting the amount of reliability product that can be traded by each resource to the contribution expected by the regulator from that resource in scarcity conditions reduces the likelihood of hidden under-procurement and improves security of supply. Constraints on tradable quantities are particularly important where demand-response products are concerned, in which a baseline must be clearly defined to measure the actual contribution. Nonetheless, such ex-ante qualifications may also induce inefficiencies if the limits or warranties required by the regulator are overly demanding.

In Latin America, due to the high share of hydropower in the generation mix, the use of complex optimisation models to calculate the expected contributions is advisable. The region's systems have consequently always featured constraints on tradable quantities. A paradigmatic example of this approach can be found in Colombia, which is addressed in the subsection below. That analysis is followed by a discussion of experience in North America, specifically in ISO New England and PJM.

### 5.2.1. Constraints on tradable quantities and guarantees: Colombia

Colombia's hydro-dominated power system is particularly vulnerable in dry years such as induced in the region by *El Niño/La Niña* fluctuations, when low hydropower contributions must be offset by raising thermal plant output. Initially, this objective was pursued by introducing a capacity payment to remunerate generators based on their availability during the dry season. Batlle and Pérez-Arriaga (2008) showed that this design led to inefficient reservoir management by hydro-power resources. In an attempt to correct this and other flaws detected in the system, in 2006 the Regulator introduced the already-mentioned reliability charge mechanism (see chapter two), in which market agents sell firm energy obligations (OEF) in a centralised auction in exchange for a fixed annual payment.

To be eligible to sell OEFs, resources participating on the Colombian market must be backed by ENFICC certificates (Spanish initials for *energía firme para el cargo por confiabilidad*, i.e., firm energy for the reliability charge), which establish constraints on tradable quantities. ENFICC certificates are assigned using methodologies that vary depending on the technology (see chapter two for details). For hydropower plants, the expected contribution is calculated with an optimisation modelling tool that assumes inflows where the likelihood of being exceeded is high. For thermal plants, certificates are assigned on the grounds of installed capacity, track record of forced outages and fuel availability. As an additional guarantee, these plants are required to ensure the fuel supply (and, if necessary, the fuel transportation capacity) necessary to back the ENFICC assigned to them through advance contracts.

The first testing ground for the reliability charge mechanism was the dry year that affected the country in 2009/2010. The Regulator deemed that hydro generators' approach to resource management (generating at the beginning of the dry year to honour their bilateral contracts, as reported in CSMEM, 2011) would have resulted in very low reservoir levels at the beginning of the actual dry season. As a result, the Regulator decided to intervene, incentivising thermal generation with a change in dispatching rules and consequently constraining hydropower plants. At the same time, exports of both electricity and natural gas were blocked to guarantee the use of national resources to supply domestic demand.

While these measures ensured water storage in the reservoirs, they also revealed the limitations of the natural gas transportation network. Despite the firm contracts with gas suppliers (to meet the aforementioned OEF eligibility requirements), only thermal plants on the coast received the natural gas committed to under contract. All other units received a lower supply, due primarily to structural insufficiencies in some pipelines (these units consequently contended that their lack of availability and the high market prices were not attributable to them). Since many inland facilities were able to operate as dual-fuel plants, liquid fuels were used to meet obligations. The infrastructure for transporting liquid fuels had not been tested either, however, and severe problems were detected in some cases. Finally, of the 93 GWh per day of firm energy obligations (backed by ENFICC certificates) contracted with thermal plants, only 80 GWh per day were actually delivered (CSMEM, 2011), due mostly to constraints in the supply chain of natural gas and liquid fuels. Despite these setbacks, the Colombian electricity system managed to operate with no demand curtailment in the dry year.

OEF mechanism performance during the 2009/2010 *el Niño* prompted criticism in several respects. The lower contribution from natural gas- and liquid fuel-fired plants revealed flaws in the ENFICC calculation methodology. The Colombian Market Monitoring Committee (CSMEM, 2010) contended that the firm energy expected from thermal plants proved to be overestimated, with fuel supply the factor primarily conditioning their actual contribution. ENFICC calculation methodology proved to be unable to reflect the shortcomings in the gas transportation network (and the associated risk) when assigning firm energy certificates to thermal plants. Hydro generators, in turn, argued that the Regulator's intervention prevented them from demonstrating that they would have been able to perform better than the ENFICC limit they had been assigned. This raises the question of whether regulators have the fullest information and the necessary expertise to calculate each resource's expected contribution in scarcity conditions or whether this task should be left to market agents, contingent upon the existence of properly designed penalty schemes[44].

The Colombian experience, which provides for no explicit penalties for underperformance, affords the opportunity to reflect on performance incentives. As noted, contrary to the Regulator's expectations, during the 2009/2010 *el Niño*, hydropower plants continued to operate early in the dry year to meet their bilateral energy commitments, progressively emptying reservoirs. The Colombian Market Monitoring Committee (CSMEM, 2010) concluded that this was an indication that hydropower companies preferred the risk of future underperformance of their firm energy obligations over the immediate economic loss they would have incurred had they interrupted production and purchased power on the market to honour their bilateral contracts.

A strong explicit penalty might have harshened the consequences of future non-compliance with OEF contracts, prompting hydropower companies to store water to avoid potential charges[45]. Such an incentive might have also mitigated the fuel shortage-induced

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[44] As a clarification, in Colombia market agents calculate their own ENFICC, but through a model or a methodology established by the Regulator, who is also in charge of verifying and approving the results of the calculation.

[45] The Regulator does not appear to be inclined to implement such measures, inasmuch as the CREG (2014) "institutionalised" the interventionist approach applied in 2010: Resolution no. 26 introduces indicators to identify periods at risk of shortage, during which additional dispatching rules are applied, allegedly to guarantee the reliability of supply.

underperformance of thermal plants. The risk of a very high penalty might have encouraged thermal generators to sign “fully” firm (primary or alternative) fuel supply contracts, making provision for the potential charge in the agreement, thereby motivating gas suppliers to reinforce the transportation grid.

The country underwent another dry year in 2014. Although no regulatory intervention was required on this occasion, the behaviours reported resembled the 2009/2010 reactions (CSMEM, 2014b). Nonetheless, hydropower plants were observed to increase their bids prior to the dry season, paving the way for earlier thermal plant dispatching (CSMEM, 2014a).

### 5.2.2. ISO New England and PJM and eligibility criteria

Thermal generation prevails in the ISO New England and PJM power systems. In ISO New England, 44% of electric power consumption is presently met by natural gas-driven plants (ISO-NE, 2015a). With the rising availability of low-cost shale gas, the role of this fuel is expected to grow in the near future. Generation project proposals in the pipeline consist almost exclusively of natural gas thermal plants (57%) and wind turbines (42%).

Peak demand in PJM is nearly six times larger than in ISO New England. According to Monitoring Analytics (2014), at 40.5% of installed capacity, coal-fired power plants continue to be predominant in the PJM generation mix, followed by natural gas with 30.1% and nuclear power with 17.8%. That same report notes that from 2011 to 2019, nearly 20.5 GW of coal-fired capacity will be decommissioned and replaced with around 40 GW of gas-fired plants that will come on stream in the interim. This pattern mirrors the shale gas revolution and is expected to significantly increase PJM’s dependence on natural gas, which will eclipse coal as the prevalent fuel by 2015/2016 (PJM, 2014c).

These data imply a challenging transition for these systems, partially explaining the reforms presently being introduced in their capacity mechanisms. The growing share of intermittent renewable energy will need to be backed by a thermal fleet that is also changing dramatically, with old (nuclear and coal) plants being replaced by new natural gas units. The major threat for ISO New England and PJM, as well as for many other power systems in the United States, is probably related to the actual reliability of the supply of this natural gas. Shale gas is revolutionising the country’s energy consumption, with a significant proportion of demand shifting to natural gas to benefit from low prices. This shift renders the current infrastructure inadequate and calls for fast-paced reinforcement of the gas transportation network.

Moreover, this growing demand also intensifies competition for the supply of natural gas, particularly as regards the use of networks. MITEI (2013) notes that prior to the shale gas revolution, power generators did not secure firm gas supplies because interruptible contracts were less expensive and supply was almost never suspended. According to the same report, at this time "power plants in many parts of the country are unable to recover the higher cost of long-term firm contracts through their electricity market bids, and therefore rely on interruptible contracts for gas supply". This lack of firmness obviously constitutes a threat to the reliability of power sectors so heavily reliant on natural gas. The fact that plants burning natural gas purchase fuel on a day-to-day basis from LDCs (local distribution companies) increases the risk that generators may not be able to obtain the gas supply needed to run their plants when most needed. That problem is intensified by the current regulation on gas pipeline network expansion. As explained by MITEI (2013), "gas pipelines (are) built if and only if LDCs signed sufficient contracts for firm gas supplies". Therefore, even if the right incentives were in place, a generating unit could find it impossible to conclude a firm gas supply contract unless a coalition of plants requested the installation of a new pipeline (and even then, guaranteed firm supply could be delayed).

Such concerns obviously affected deliberations on ISO New England's and PJM's capacity markets (the forward capacity market or FCM and the reliability pricing model or RPM, respectively). Both systems feature constraints on tradable quantities assigned during a qualification phase. Proposals were put forward to supplement these constraints with an eligibility criterion, which would allow gas-fired units to sell their power on the capacity market only where backed by a firm contract for natural gas supply. At this writing, however, the focus is apparently shifting from eligibility criteria to performance incentives (analysed in section 5.3). This choice is openly mentioned in PJM (2014b), which states that "based on stakeholder input, PJM also has eliminated many of the stated eligibility requirements and instead depends on stringent performance standards to allow resources to manage their own participation approaches". Although the interaction between the gas and power industries transcends this discussion, be it said that a number of amendments to the regulatory scheme will be necessary to ensure optimal exploitation of their synergies.

## 5.3. Performance incentives

Performance incentives aim to ensure that agents assuming CRM commitments manage their resources in ways enabling them to meet their obligations when the system is tight or pay the consequences of underperformance. A critical period indicator must first be selected to identify scarcity conditions, during which the contribution must be delivered and each resource's performance is assessed. Penalties or incentives are applied based on recorded performance during critical periods. Performance incentives and constraints on tradable quantities are not incompatible and are usually applied in parallel.

The discussion of the importance of performance incentives and of the difference between implicit and explicit penalty schemes in the subsections below is followed by a classification of performance incentives by their design elements, based on recent experience on both sides of the Atlantic (ISO New England, PJM, United Kingdom, and France).

### 5.3.1. The importance of performance incentives

As noted in the introduction to this chapter, the central role of performance incentives in the design of effective capacity mechanisms was identified, among others, by Vázquez et al. (2002), who contended that the implementation of explicit penalties is the only way to guarantee the installation of a sufficient level of firm capacity and its delivery in scarcity conditions. The consequences of the lack of an explicit penalty scheme or of the existence of a scheme with a limited impact on resources were felt by some of the systems that reformed their capacity mechanisms in the first decade of the century (Colombia, ISO New England, and PJM). The inefficiencies resulting from the lack of an explicit penalty for underperformance in the Colombian mechanism were described in the preceding section.

Contrary to that experience, the design of the more recent capacity mechanisms implemented in the ISO New England and PJM systems did include explicit performance incentives. ISO New England's FCM established so-called availability penalties, based on the calculation of shortage event availability scores. PJM's RPM, in turn, applies a peak-hour period availability (PHPA) charge based on actual performances during 500 peak hours. Nevertheless, these performance mechanisms, which provided for many exemptions from penalties, did not yield the expected results and their limitations have become increasingly visible in recent years.

During recent scarcity events, many resources in the ISO New England system failed to deliver the full capacity specified in their forward capacity market supply offer, with average underperformance quantified as 40% of the additional power required by the System Operator during contingencies (ISO-NE, 2012). That obviously placed system reliability at risk. The System Operator attributed such significant underperformance to the fact that "capacity resources rarely face financial consequences for failing to perform, and therefore have little incentive to make investments to ensure that they can reliably provide what the region needs: energy and reserves when supply is scarce" (FERC, 2014b).

The road test for PJM's reliability pricing model came with the "polar vortex" event in January 2014. Extremely low temperatures not only prompted high electricity demand, but affected the generation capability of some plants rather directly. During the record-breaking winter peak (141 846 MW), PJM experienced an equivalent forced outage rate (EFOR) of 22%, far in excess of the 7% historical average. The capacity shortfall relative to obligations (PJM, 2014c) amounted to 40 200 MW, 47% of which was accounted for by gas and 34% by coal-fired plants. In much the same vein as ISO New England, PJM concluded that "a capacity resource committed in RPM currently faces only limited and attenuated adverse consequences for failing to provide energy and reserves when needed" (FERC, 2014a).

With a view to correcting such flaws, both ISO New England and PJM are in the process of introducing new performance incentives, which tie each resource's capacity mechanism remuneration more tightly to its performance in scarcity conditions. In May 2014, the Regulator partially approved ISO New England's pay-for-performance mechanism (FERC, 2014b). In December 2014, PJM presented its proposal for a capacity performance product, under study at this writing[46]. These schemes are analysed in greater detail in the breakdown of performance incentive design elements.

The importance of explicit penalties and performance incentives in the framework of capacity mechanisms is apparently being acknowledged in Europe (EEAG, 2015), where regulators are introducing a new wave of market-based capacity mechanisms. Performance schemes proposed by or implemented in the United Kingdom (DECC, 2014) and France (RTE, 2014) are also addressed in the design element analysis below.

Before proceeding with the analysis, however, it should be noted that the design of capacity mechanisms, including any penalty schemes, is the outcome of negotiations between the regulator (and/or the team of experts selected by the regulator) and power industry agents. Some of the latter object to the introduction of heavy penalties, which could mean significant financial loss for underperformance. The implementation of a "soft" penalisation scheme or none whatsoever in CRM design is, then, never the result of regulator "oversight", but rather the outcome of this "bargaining" between opposing interests.

### 5.3.2. Implicit and explicit penalties

In the context of capacity mechanisms, care must be taken to clearly distinguish between implicit and explicit penalties. As explained in chapter two, an implicit penalty requires an underperforming agent to resort to the electricity market to acquire the reliability product it is unable to provide with its own means to honour its entire expected contribution. Explicit penalties, which adopt the form of an extra charge for underperformance, are applied in addition to implicit penalties. Here, underperforming resources are explicitly "fined" for failing to comply. Some documents written on this topic do not properly recognise the difference between implicit and explicit penalty (e.g., EEAG, 2015), but this is of paramount importance for the effectiveness of the capacity mechanism. Implicit penalties, in any event, are not performance incentives, for agents assuming an obligation subject to an implicit penalty have exactly the same incentive to produce as agents with no such obligation.

The following example may make this clearer. Imagine a system with reliability option contracts in place (see section 3.4.1.1 for a description of the mechanism) in which the strike price for reliability contracts is 100 $/MWh and the current spot price is 500 $/MWh. An agent with a reliability option and delivering its contribution obtains 500 $/MWh from the market but has to return 500 – 100 = 400 $/MWh to the system operator, for a net profit of 100 $/MWh (excluding variable costs). If the same agent is unable to meet its commitment,

[46] At this writing, it is difficult to say what the new performance mechanism will look like. PJM's proposal as reflected in the FERC filing has changed substantially relative to the drafts posted by PJM. The amendments required by the Regulator are also difficult to predict. The design discussed in this chapter is based on FERC (2014a).

it will be required to pay the implicit penalty of 400 $/MWh, for a net loss of 400 $/MWh. The difference between delivering and not delivering is a net loss of 500 $/MWh. Agents with no reliability option contract, in turn, earn 500 $/MWh if they produce and 0 $/MWh if they do not. The difference between delivering and not delivering is also a net loss of 500 $/MWh. Clearly, the implicit penalty affords no incentive[47]. This example shows how only a properly defined explicit penalty scheme can encourage agents to honour their obligations and ensure system reliability. Each design element of such explicit penalties is analysed in the subsections that follow.

### 5.3.3. Design elements of performance incentives

The remainder of this chapter focuses on the design elements of performance incentive schemes in CRMs. A thorough review of the past and present experience identified the relevant design elements to be the critical period indicator (to define scarcity conditions during which the capacity obligation must be met and resource performance is assessed), the penalty applied for underperformance, overperformance payments[48], exemptions and penalty caps.

#### 5.3.3.1. Critical period indicator

In chapter two the advantages of using the market price as the critical period indicator were discussed. In the systems analysed here, however, scarcity conditions are defined by the short-term market price under the Colombian firm energy obligations arrangement only[49]. In contrast, in many CRM designs scarcity conditions are identified via technical grid parameters or emergency actions taken by system operators. In some cases, this is related with the lack of a reference market price capable of reflecting power shortages in real time. Under such an approach, establishing a criterion that denotes the existence of actual scarcity conditions is of paramount importance, for otherwise committed resources would never, or very rarely, be required to perform their contract obligations.

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[47] Actually, the problem is even more complex. In the cash accounting of power companies, the two net losses presented in the example are perceived in a very different way, since not earning a certain revenue is not the same as having to pay out the same amount. Therefore, also an implicit penalty could, in some cases, provide a weak performance incentive. However this effect is not comparable with the strong signal provided by a proper explicit penalty, thus it is not analysed further.

[48] By way of clarification, here and throughout the rest of this chapter, “overperformance” should be construed positively, i.e., to mean an extra contribution to power system resources that improves reliability.

[49] The contracts signed in ISO New England’s FCM are also financial options (when the real-time locational marginal price exceeds a certain strike price, obligation holders must return the difference between the former and the latter), but the physical obligation is linked to shortage events identified by the System Operator.

In ISO New England, for instance, shortage events were initially defined as periods when the system exhibited shortfalls in 10-minute reserves for over 30 minutes. According to FERC (2013b), such a strict criterion had not induced a single shortage event at any time since the advent of the capacity market. This flaw was corrected by amending the definition of "capacity deficiency", which is now deemed to exist where 30-minute, i.e., operating, reserves are short.

In the new design for the PJM's reliability pricing model, outstanding approval at this writing, resources assuming capacity performance obligations commit to being available to supply energy and reserves whenever PJM determines that an emergency condition exists. Such conditions are "locational or system-wide capacity shortages that cause pre-emergency mandatory load management reductions or a more severe action" (FERC, 2014a).

A resource committed in the UK capacity market, in turn, is required to deliver during stress events, defined as "any settlement periods in which either voltage control or controlled load shedding are experienced at any point on the system for 15 minutes or longer" (DECC, 2014). Stress events are announced four hours in advance via capacity market warnings.

In France, a decentralised capacity market based on bilateral transactions is being implemented. The new mechanism seeks primarily to ensure that growing peak winter loads resulting from indoor heating systems can be met. According to the most recent detailed proposal (RTE, 2014), the days constituting peak periods are announced by the System Operator one day in advance. Electric power suppliers' actual demand and capacity providers' real performance are assessed on such days.

Lastly, depending on the critical period indicator, obligations may be fixed or load-following. When fixed obligations enter into effect, resources must deliver the entire contribution committed. Under load-following arrangements, the enforceable contribution is calculated by applying to the total commitment the ratio of the demand at issue to the peak demand covered by the mechanism. In other words, if a shortage event occurs when the demand is 60% of peak demand, the units committed must deliver at least 60% of their capacity obligation or pay the penalty. Of the mechanisms analysed in this chapter, Colombia and France have fixed obligations, whereas ISO New England, PJM, and the United Kingdom have opted for a load-following design. The potential for overperformance is higher when load-following arrangements are in place. In off-peak shortage events in which obligation holders are required to deliver 60% (for instance) of their committed capacity, they may try to overperform (supplying up to 100% of their capacity obligation) to earn extra revenue, if provided for in the mechanism. Conversely, load-following arrangements may hamper demand response, for such resources may find it difficult to contribute in off-peak times, and cross-border participation, as discussed in chapter three.

### 5.3.3.2. Penalty rate

The penalty rate established for non-compliance must be high enough to encourage investment in performance improvements, the ultimate aim of capacity mechanisms. Such improvements may consist in shorter start-up times, continuous staffing, more reliable fuel supply arrangements or dual-fuel capability. The lower the initial firmness of a resource, the greater the investment necessary to avoid very high penalties. The rate applied constitutes a signal for attracting firm capacity and, in the case of centralised CRMs, impacts the merit order of the capacity auction heavily. It can be calculated either on the grounds of the capacity price cleared in the auction (which would link it to capacity remuneration) or of the net cost of new entry (net CONE)[50]. Another data item often used in this calculation is the expected number of scarcity hours during the year at issue.

In ISO New England, the System Operator established a high performance payment rate (based on the net cost of new entry) subject to a phase-in period. The rate will be increased from 2 000 $/MWh (2018/2021) to 3 500 $/MWh (2021/2024) and subsequently to 5 455 $/MWh (from 2024 onwards), as reported in FERC (2014b).

The penalty rate in PJM's proposed capacity performance product is also based on the net CONE. A comment to the Independent Market Monitor's proposal (FERC, 2015) estimated the underperformance charge rate to amount to 3 625 $/MWh.

In France, negative imbalances are settled at a so-called unit price (representing the penalty rate), which assumes different values depending on the security-of-supply status of the system. When security of supply is at risk, the unit price rises to an administratively-set price based on the net cost of new entry (RTE, 2014), for which no estimate has yet been provided.

In the United Kingdom's Capacity Market, in contrast, penalties are linked to the capacity remuneration. The penalty rate is 1/24th of the respective auction clearing price, adjusted for inflation (DECC, 2014). However, it must be remarked that this was a result of the consultation process and of the already-mentioned negotiation with stakeholders. In fact, the penalty rate initially proposed by the Regulator was much stronger than the final charge, being equal to 16 000 £/MWh (NERA, 2015).

[50] Methodologies to calculate the penalty rate based on net cost of new entry may vary. As an example, both FERC (2014c) and ISO-NE (2013) propose calculating the "performance payment rate" as the yearly net CONE (based on CCGT technology) divided by the expected number of hours with scarcity conditions and the expected performance during scarcity conditions: e.g., 106 394 $/MW-year / (21.2 hours/year x 0.92) = 5 455 $/MWh.

#### 5.3.3.3. Overperformance payments

Overperformance payments may be envisaged to supplement underperformance charges. Depending on the design, performance payments may constitute significant revenues over and above the base capacity auction payment. This clearly strengthens the performance signal. However, as mentioned above, this approach is more effective in CRMs based on load-following obligations, in which the potential for overperforming is higher. If in an off-peak shortage event a resource is required to provide 60% of its committed capacity, for example, and delivers 100% of its obligation, its overperformance payment would amount to 40% of the total contribution. Further potential for overperforming lies in constraints on tradable quantities. If a resource were allowed to trade only 80% of its installed capacity on the capacity market due to de-rating, it could generate electricity at full load and receive overperformance payments for 20% of its installed capacity.

The payment rate can be set to equal the penalty rate to establish completely symmetrical performance incentives. It might otherwise be calculated for each separate shortage event by providing that charges collected from underperforming resources are to be distributed among overperforming resources. The second approach is preferred by some regulators (such as PJM and the United Kingdom) because it guarantees that payments never exceed charges (self-balancing mechanism). However, as shown in ISO-NE (2012), designs based on symmetrical charge and payment rates can achieve the same result if implemented properly. Examples of this latter approach are ISO New England's pay-for-performance scheme and France's capacity imbalance settlements.

The matter of who is entitled to overperformance payments is another factor that must be determined. In ISO New England, United Kingdom, and France, only resources participating in the capacity mechanism are eligible for performance credits. In PJM, in contrast, both RPM resources that exceed their load-following obligations and resources that did not sign on to the capacity market qualify for such payments. In the latter case, the entire contribution is regarded as overperformance.

#### 5.3.3.4. Exemptions and penalty caps

Incentive arrangements may also envisage exemptions from performance and hence from penalties. Specific pre-established circumstances may partially or entirely exempt some resources from their obligations. Exemptions should be minimised, however, so as not to significantly attenuate the performance incentive signal. Some authors have called for the application of a strict no-exemption policy (Peter Cramton in FERC, 2014c). The principle that informs this approach is that performance incentives in a CRM should mimic the incentives in an ideal energy-only market. If a generator fails to deliver electricity to the grid during a price spike occurring in a perfect energy-only market, it forfeits that revenue regardless of the reason for its unavailability and of where the responsibility for such unavailability lies. This raises the question of which risks should be assumed by the resources taking part in the capacity market. Holding agents financially responsible for risks far beyond their control could be extremely counterproductive. For example, penalising resources is questionable when their underperformance is due to a transmission facility outage that disconnects the unit; or, where new plants are concerned, when the commitment cannot be fulfilled because of connection delays attributable to bureaucratic issues or to a delay in the construction of a planned transmission line. Nonetheless, these exemptions should be valid for the explicit penalty, while the implicit penalty, which is more related to the market cash flow, can consider fewer or no concessions.

Penalty caps may be applied to reduce the risk exposure of resources committed to a capacity mechanism scheme (particularly when scant or, better still, no exemptions are considered). Here also, exposure to the risk of large penalties is what prompts resources to make the investments necessary to improve their performance. Consequently, penalty caps must be designed to have a minimum impact on this efficient signal. Some schemes limit the duration of punishable underperformance events, beyond which no charge is applied. More frequently, designs envisage monthly or yearly caps. Such ceilings may be linked to capacity remuneration (so as to avoid penalties exceeding the initial revenue from the mechanism) or other parameters. Defining the penalty cap in terms of time (monthly, seasonal, yearly) has been shown to have a heavy impact on the strength of the efficient signal. Inasmuch as scarcity conditions are usually concentrated in a very few months, setting a monthly cap and setting it too low (e.g., one-twelfth of the yearly cap) all but eliminates the performance incentive. These parameters usually lie at the core of the aforementioned negotiations between regulator and power sector agents.

ISO New England's pay-for-performance scheme provides for barely any exemptions. Whether a resource underperforms due to an outage or scheduled maintenance, it is not eligible for an exemption in the calculation of its performance score. If the agent believes that this creates significant financial risk, it should include the risk in its FCM bid. According to Peter Cramton (FERC, 2014c) "a policy of no exemptions creates a level playing field. Responsibilities are clear and settlement is straightforward. Suppliers do bear greater performance risk, but it is precisely this risk that motivates performance-improving investments".

The pay-for-performance approach does, however, provide for a stop-loss mechanism that caps underperformance charges. According to FERC (2014b), the monthly stop-loss limit is the resource capacity obligation times the starting price of the capacity auction (which could be considerably higher than the clearing price), while the annual stop-loss limit is three times the resource's maximum potential net loss per month.

For participants in the PJM capacity market, the only exceptions to the delivery obligation (and the consequent penalty) are planned and approved maintenance outages or System Operator decisions that prevent commitment of the resource. As in ISO New England, PJM has a stop-loss provision that sets monthly (0.5 times the yearly net CONE) and yearly (1.5 times the yearly net CONE) caps on underperformance penalties (FERC, 2014a).

In the United Kingdom, delivery exceptions are limited to *force-majeure* situations. According to DECC (2014), resource delivery obligations are suspended and no penalties are applied only in the event of National Grid-imposed transmission constraints, suspension of the electricity market or similarly severe or emergency situations. Contrary to the approaches adopted by the US systems, however, in the United Kingdom, penalty caps are linked to capacity market revenues (through the capacity auction clearing price). Penalty caps apply on a monthly (200% of the monthly capacity market revenue) and yearly (100% of the yearly capacity market revenue) basis.

Lastly, a word is in order about the interaction between overperformance payments and penalty caps. The primary drawback to penalty caps is that, once the ceiling is reached, the resource committed lacks any incentive to continue to meet its obligations. The incentive is restored, however, if provision is made for overperformance payments.

## 5.4. Conclusions and recommendations

The developments described in this chapter highlight the central role played by performance incentives in enhancing the effectiveness of capacity mechanisms and ensuring power system reliability, in combination with other approaches, as the application of constraints on tradable quantities or specific eligibility criteria. Without properly designed penalty/credit schemes, resources committed in a CRM are not subject to any significant financial consequences for underperformance. Therefore, they have insufficient incentives to invest in measures able to improve their performance during scarcity conditions, when their contribution is much needed. In this context, explicit penalties and overperformance payments are of paramount importance for solving what has been defined in this chapter as the “missing performance incentives” problem.

The experience of electricity markets in the United States, where severe underperformance was observed despite the existence of explicit penalty schemes built into capacity mechanisms from the outset, stands as proof of the utmost importance of performance incentive details and their implementation. Only careful refinement of the design elements discussed in this chapter can guarantee the expected performance of resources participating in a CRM. This constitutes a lesson worth learning for European regulators, especially in the present context of widespread institution of capacity mechanisms.

# 6. The Impact of Penalty Schemes

*This chapter complements the qualitative study presented in chapter five with a model-based analysis of the impact of penalty schemes on the outcomes of a capacity mechanism, in terms of resulting generation mix, system reliability, and supply costs*[51].

## 6.1. Introduction

In the previous chapter of this thesis, empirical evidence from international experiences was gathered in order to stress the importance of properly-designed performance incentives in effective capacity mechanisms. The state of the art was presented, in order to show the centrality of this topic in the current regulatory debate, the main design elements of performance incentives were outlined, and guidelines for their selection were drawn. This qualitative analysis is complemented in this chapter by a model-based analysis, which demonstrates how the introduction of explicit penalty schemes for underdelivery can positively impact CRM outcomes, providing resources with sound incentives to maximise their reliability, discriminating against non-firm generation units, and therefore increasing the effectiveness of the mechanism in achieving its objectives.

As mentioned in the previous chapter, CRMs foster new investments by providing resources with an additional and more predictable remuneration with respect to the energy market. The goal of capacity mechanisms, however, is not merely to attract investments in new "nameplate" capacity, but to foster the installation of firm generation technologies that allow to actually enhance the security of electricity supply during real-time operation and to achieve the level of reliability established by the regulator. In exchange for an additional and predictable remuneration, resources taking part in the CRM are required to deliver the contracted contribution when the system most needs it, i.e., during shortages. A design element aimed at providing market agents with incentives to be available during scarcity

[51] This chapter draws on Mastropietro, P., Herrero, I., Rodilla, P., Batlle, C., 2016, *A Model-Based Analysis on the Impact of Explicit Penalty Schemes in Capacity Mechanisms*. Working paper IIT-14-159A, submitted for publication to Applied Energy.

conditions is an explicit penalty for underdelivery (see section 5.3.2 for a definition of implicit and explicit penalties), to be applied to those generators not fulfilling the CRM commitment. As mentioned in the previous chapter, penalty schemes were proposed by several authors working on the design of capacity mechanisms (Vázquez et al., 2002; Bidwell, 2005; Finon and Pignon, 2008). Nonetheless almost no CRM design did include effective and explicit penalties for underdelivery from the beginning.

However, the situation is swiftly changing. At this writing, penalties and, more generally, performance incentives in CRMs are at the core of the regulatory debate. As already mentioned, ISO New England (FERC, 2014b) and PJM (FERC, 2014a) are reforming their capacity mechanisms following the so-called "pay-for-performance" principle. On the other side of the Atlantic, a specific working group established by the European Commission is focusing on the design of appropriate obligations and penalties (EEAG, 2015), and CRMs implemented or under design in Member States already consider stringent penalty schemes. Nevertheless, many questions about performance incentives still need to be answered. How do they affect the generation mix installed in the system? Which is their impact on reliability, measured in terms of non-served energy? How do performance incentives, such as explicit penalties, affect the total cost of electricity supply? Is the higher cost in the capacity market offset (and outbalanced) by a reduction in the expenses related to non-served energy and energy market?

Despite the growing number of reports on this subject issued by relevant institutions working on the implementation of CRMs, no formal analysis of the problem is available in academic literature. The objective of this chapter is to fill this gap and to stress the ability of the explicit penalty in discriminating against non-firm energy units, providing existing plants with stronger incentives to improve their reliability and eventually leading to the entrance of new and more reliable generation plants. The research is developed on the basis of a simulation model that analyses and highlights the effect of the penalty scheme on the merit order of a CRM auction. This discussion benefits from and extends the seminal work of Vázquez et al. (2002), who provided the theoretical basis of the reliability option contracts, a mechanism already presented in this thesis. Vázquez et al. (2002) also proposed a theoretical framework for the bid calculation to be expected from market agents in the auction. This chapter draws on such framework to provide a detailed discussion on the role of the explicit penalty through: i) a theoretical analysis of the problem, focusing on the bids building methodology, and ii) a two-stage model that simulates the auction itself and allows analysing case studies to confirm the outcomes of the theoretical analysis.

The chapter is organised as follows. Section 6.2 describes the methodology used to face the problem. In the first subsection, the bid calculation methodology originally proposed is reminded. In the second subsection, the model used to simulate the auction mechanism is introduced and the theoretical analysis of the problem is developed. After that, section 6.3 presents the outcomes of the simulation and provides an interpretation of the results. Finally, section 6.4 draws conclusions and identifies potential policy implications.

## 6.2. Methodology

Prior to delving into the description of the methodology, it is worth starting with a caveat: the whole discussion is based on a centralised capacity auction for reliability option contracts. However, most of the results of the analysis presented in this chapter are valid also for other quantity-based CRM designs, procuring different reliability products or using alternative critical period indicators.

### 6.2.1. Reliability option contracts

A detailed description of the reliability option mechanism was provided in section 3.4.1.1 of this thesis and it is not repeated here. The design considered in this chapter is the one originally defined by Vázquez et al. (2002).

### 6.2.2. Bid calculation in theory

As described in section 3.4.1.1, the bid in the auction reflects the required premium fee of the option contract. Since the option caps the future hourly remuneration of the generating unit selling the contract to the strike price $s$ (this obviously does not mean that the spot price cannot exceed this value, since not all available resources have necessarily been committed in the auction), the bid will be defined with the objective of at least recovering, through the fee, this loss of income, plus the expected charge to be paid in case of underperformance. Each agent is expected to calculate the offer according to its forecasts on the short-term market price and on its expected availability during scarcity conditions. As discussed right next, the approach depends on whether the plant is an existing generation facility (whose investment costs are considered as sunk) or a new investment.

#### 6.2.2.1. Bid calculation for existing facilities

As just mentioned, for existing generation facilities, investment costs do not play any role in the offer, so in this case the bid calculation can be represented by the following formula (Vázquez et al., 2002):

$$F_i = \int_{p>s} (1-\lambda_i)\cdot(p-s)\,dt + \int_{p>s} \lambda_i \cdot (p-s+pen)\,dt \qquad (1)$$

In this equation, $\lambda_i$ represents the probability of generator $i$ not being able to produce the capacity committed in the option contract during scarcity conditions. In order to clarify and gain insights on the previous expression, it will be considered that each time the spot price exceeds the strike price, it reaches the price cap. The expression can then be formulated as:

$$F_i = \left(p_{cap} - s\right)\int_{p>s} dt + pen\int_{p>s} \lambda_i dt \qquad (2)$$

According to this last formulation, the bid from risk-neutral agents can be divided into two terms. The first term represents the expected option value for a risk neutral agent, i.e., the remuneration that the generator is losing from the spot market because of signing the option contract, while the second term represents the expected penalty. With this formulation, it is also possible to observe how the option value depends on the expected number of hours with scarcity conditions $(p > s)$, while the penalty depends on the integral of $\lambda_i$. This factor is of special interest for the analysis outlined in this chapter. It represents the expected number of hours in which the scarcity conditions are concurrent with the unavailability of the generation facilities of the agent, due for example to the forced outage of a generating unit or to fuel supply constraints. Furthermore, it must be underlined that the expected option value is the same for all the agents, whereas the expected penalty is different for each agent (the same penalty value is applied to different unavailability factors).

#### 6.2.2.2. Bid calculation for new investments

In the case of a potential new generating unit, which can still decide whether to invest or not, an additional term must be included in the bid calculation, besides the expected option value and penalty. For the investment to be attractive, the agent needs to recover the total fixed and variable costs. If the spot price is not sufficient to recover the investment, the agent will be eager to seize this required income in the reliability market, i.e., in the auction. Such additional term can therefore be expressed as any positive difference between the required annual income and the expected short-term market remuneration.

### 6.2.3. Model structure

Vázquez et al. (2002) developed a stylised case example in order to simulate possible auction results. The approach followed was based on some simplified heuristic assumptions (for example, generators, at the moment of calculating their bid based on the expected future dispatch, perceive the number of hours of scarcity as proportional to their own availability). Although some relevant insights could be obtained with such modelling approach, many relevant correlations were lost.

The objective of this study is to refine the modelling approach by "allowing" the agents to forecast more realistically the parameters required for properly calculating the bid in the long-term auction. The problem is represented through a two-stage model that replicates the tender itself based on the results of a simulated future short-term market. The latter is represented by means of a deterministic Unit Commitment (UC, used to reproduce a day-ahead market with perfect competition), including explicit consideration of hourly availability through Monte Carlo simulation[52]. In this chapter a direct-search approach is

[52] For other modelling approaches on capacity mechanisms or, more in general, investment strategies, the reader can refer to Hasani and Hosseini (2011) and Schwenen (2014) among others.

applied. First, all potentially feasible generation mixes are identified and the short-term market is simulated for each one of them. Then, bids are calculated based on the result of the short-term market and long-term auctions are cleared. Finally, the mix resulting from the auction is compared to the initial mix used to simulate the short-term market for validation. Once all feasible solutions are determined, the model selects the one that minimises the price in the auction. This methodology, only outlined here and graphically represented in Figure 6.1, is carefully described in the sections that follow.

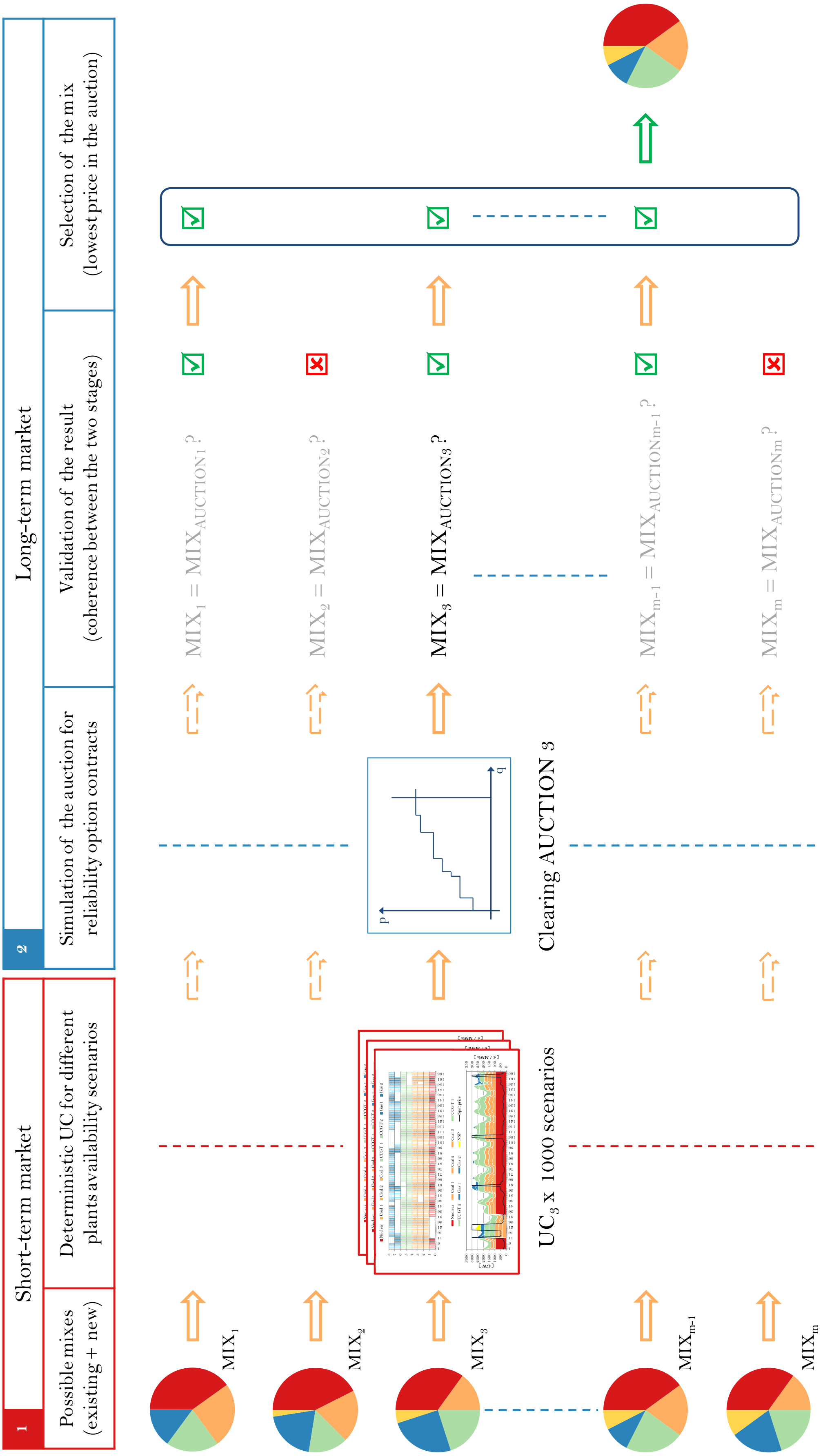


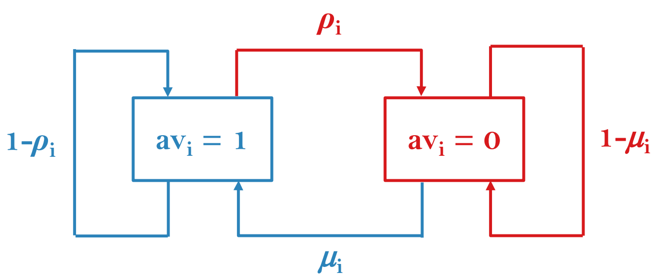

Figure 6.1. Schematic representation of the two-stage model used to simulate the auction process

#### 6.2.3.1. First stage: the short-term market considering unavailabilities

The model is based on a reference generation mix composed of 80 existing thermal generation units (20 nuclear units, 30 coal units, 25 CCGT units, and 5 fuel oil units), to whom 15 potential new CCGTs are added. Different combination of existing and new plants are explored and, depending on the number of new units considered to be installed, different initial mixes are created.

For each one of these potential generation mixes, a deterministic unit commitment is run for a time period of one year. The UC is used to reproduce a day-ahead market with perfect competition, whose spot price is calculated as the marginal cost of the system, as in the Security Constrained Economic Dispatch (SCED) models used in many power systems in the United States (Helman et al. 2008). Besides the spot price, non-linear side payments with daily settlements are considered for those units which do not recover their start-up, no-load, or shut-down costs. Furthermore, a 3 000-€/MWh price cap is applied, as in the EUPHEMIA algorithm used to clear the European regional day-ahead market, see (APX, 2014). For the detailed model formulation, as well as for data used, see the Appendix to this chapter.

On the other hand, a proper representation of generation availability is of utmost importance for the purposes of this study. The hourly representation of plants availability allows to analyse the contribution of each generator to the reliability of the system during scarcity conditions. This is achieved through a random availability matrix, which defines for each plant $i$ and for each period $t$, i.e., each hour for which the unit commitment problem is solved, whether the unit is available or not (i.e., $av_{i,t}$ can be either 0 or 1). This random availability matrix is created through a two-state Markov chain, which simulates the transition from the availability to the unavailability state and vice versa through predefined probabilities. The schematisation of the process is presented in Figure 6.2, in which $\rho_i$ represents the probability of failure of unit $i$, while $\mu_i$ represents the probability of recovery from failure of unit $i$.




$$\rho_i = 1/\mathrm{MTBF}_i \qquad \mu_i = 1/\mathrm{MTR}_i$$

$$EFOR_i = \mathrm{MTR}_i/(\mathrm{MTBF}_i + \mathrm{MTR}_i)$$

Figure 6.2. Two-state Markov chain used for the creation of the availability matrix

The two probabilities involved in the process are calculated from the combination of three parameters: the Equivalent Forced Outage Rate (EFOR) of thermal units, which represents the percentage of hours of unit failure and can be used as a proxy of the probability of the unit not being able to produce; the Mean Time Between Failures (MTBF), which represents the expected elapsed time between successive failures of a thermal unit; and the Mean Time to Recovery (MTR), which represents the expected time required to repair the thermal unit. For the sake of simplicity, the MTR has been considered to be the same for all the units. Therefore, it is the EFOR, and consequently the MTBF, the parameter which is used to reflect the diverse reliability level of each generation plant. In the case study (presented in the following section), new CCGT units are considered to have lower EFOR rates than existing plants, reflecting the higher expected reliability of new facilities.

Once $\rho_i$ and $\mu_i$ probabilities have been calculated for each plant, the availability matrix can be created, through a random number generator. In order to get comparable results for different case studies and input parameters, the random numbers are maintained constant through the use of the same random seed. Furthermore, the utilisation of Monte Carlo techniques requires to solve the UC problem for several scenarios, applying different availability matrixes, so as to have a statistically relevant sample. In this model, 1 000 scenarios, 1-year long, have been used for each generation mix.

In order to illustrate the impact of generation availability on the solution of the unit commitment, a sample week has been selected and the UC problem was solved for a simplified system with only eight generation units (for graphical purposes). The results are presented in Figure 6.3 and Figure 6.4. As it can be observed in the charts, the consideration of unavailability through the matrix causes plants to “fall” in the resulting unit commitment, causing the start-up of more expensive plants and, in the cases in which the available generation is not sufficient to cover the demand, the occurrence of non-served energy and the consequent activation of the price cap (as described in the appendix, demand is assumed to be inelastic). As it can be seen in the availability matrix, units’ failures have different durations (but the average duration is equal to the Mean Time to Recovery).

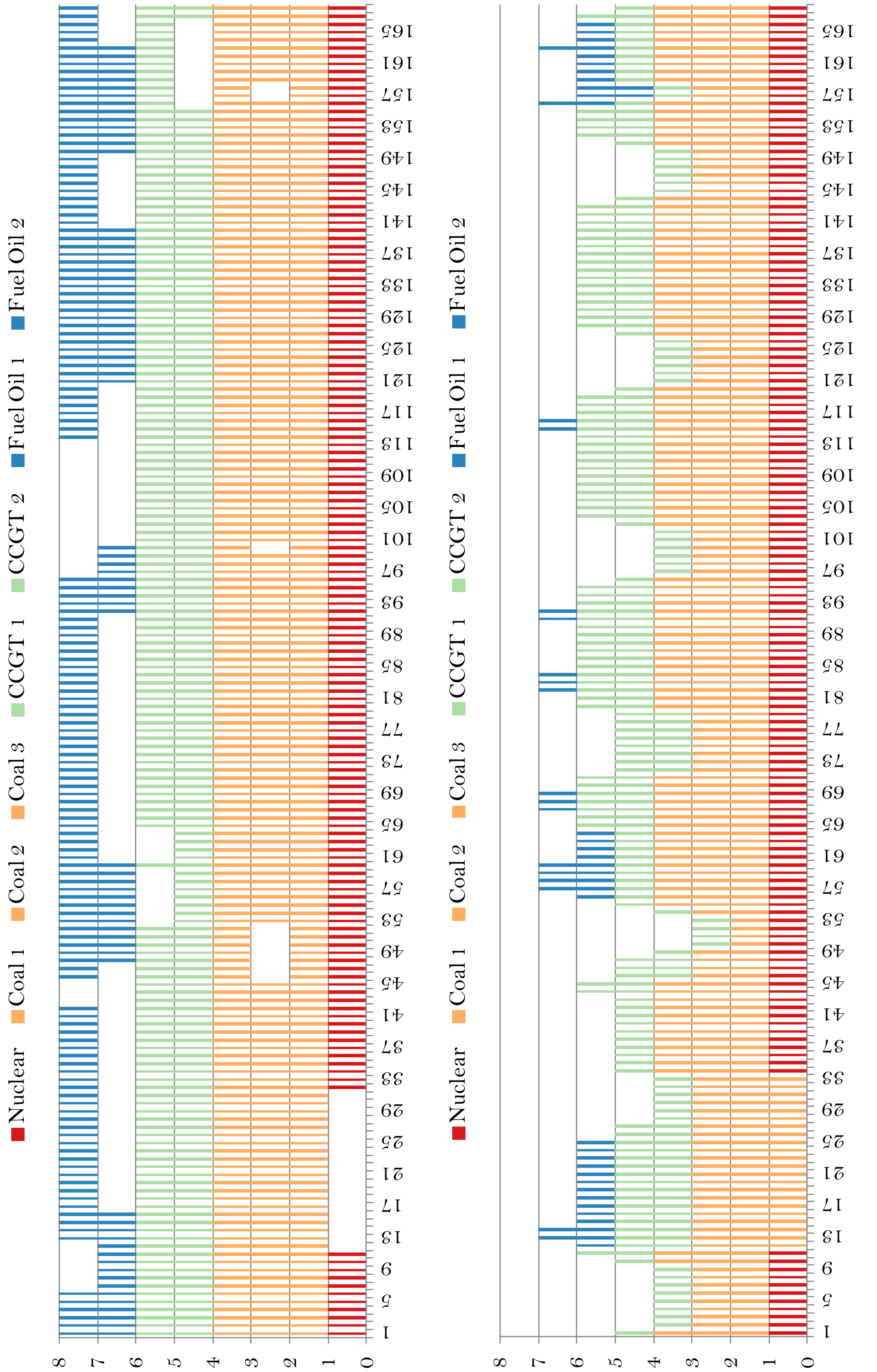



Figure 6.3. Availability matrix (above) and resulting commitment variables (below) for one week and one scenario

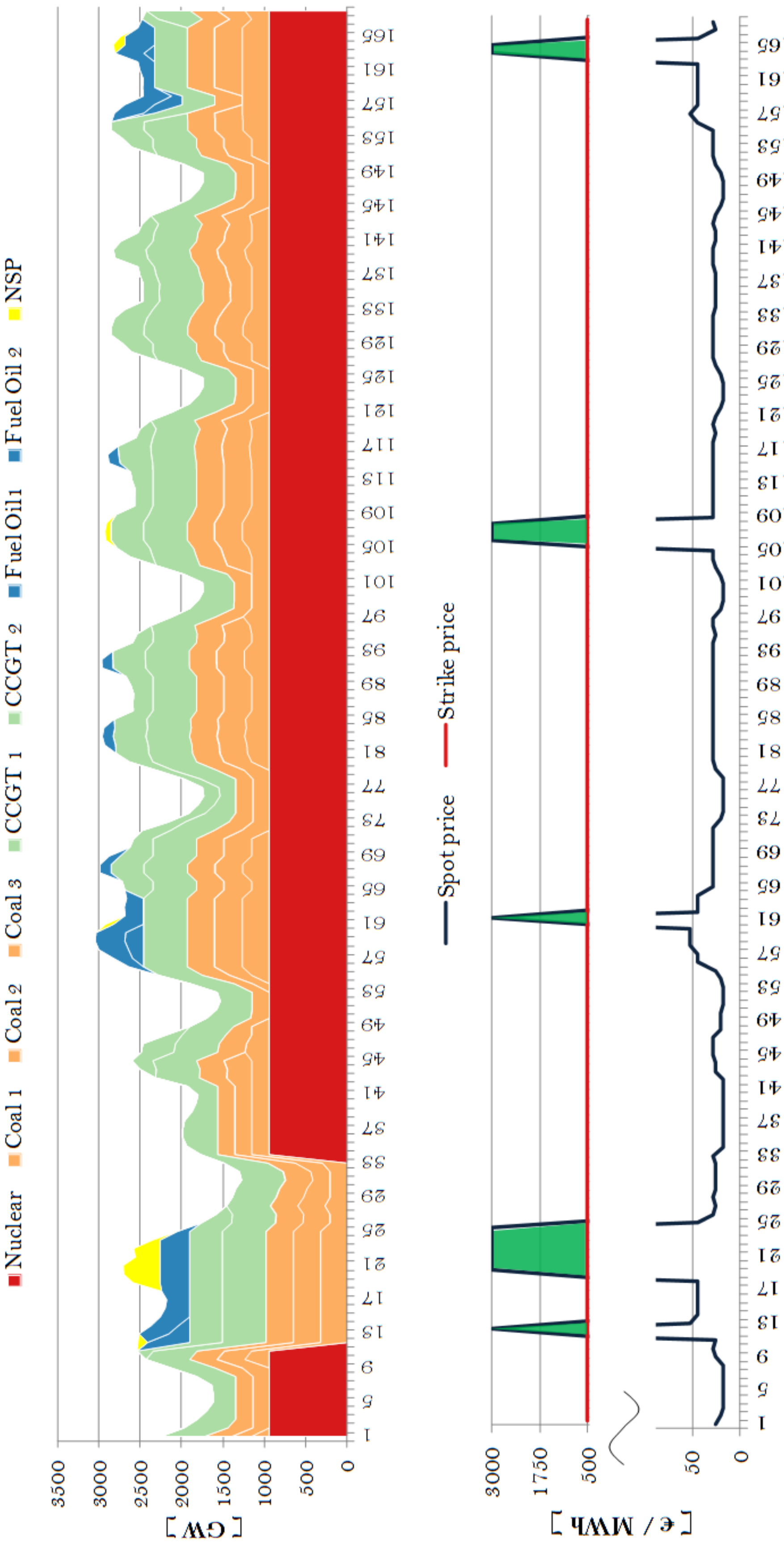



Figure 6.4. Production variables for the UC problem (above) and comparison between the resulting spot and the strike price (below)

In Figure 6.4, the spot price resulting from the unavailability consideration is compared to the strike price[53] of the option contracts. This exercise allows to identify the scarcity conditions of the system. It is easy to observe the equivalence between Figure 6.4, obtained from the modified unit commitment, and Figure 3.2, which was shown when presenting the payoff of the reliability option mechanism. The results from the model allow not only to identify scarcity conditions, but also to assess the performance of each generation unit in those conditions. This provides all the information required for the calculation of the expected bids in the auction.

#### 6.2.3.2. Second stage: the long-term market

The outcomes of the first stage are used to feed the auction simulation. The economic performance of each generator is analysed for each scenario and the bid is calculated considering the economic impact of signing a reliability option contract (the bid calculation methodology used in the model is explained in detail in the next subsection 6.2.4). An average bid is then calculated for each unit by averaging the results of the 1 000 scenarios, and the auction is cleared for a predefined demand value. These operations are carried out for each one of the generation mixes initially considered.

Once the simulated auction is cleared, it is possible to check how many new power plants are selected and installed based on the auction result and, therefore, to define the resulting generation mix. In fact, in this model new entrants will invest only if they are cleared in the auction and have access to the CRM remuneration. However, this creates the need for a validation of the result. If the generation mix resulting from the auction is different from the mix used to simulate the short-term market through the unit commitment, then the two stages of the model are not coherent and that solution must be rejected. Otherwise, the two stages are coherent and the solution is maintained (green checks in Figure 6.1). This operation results in several feasible solutions, representing all possible generation mixes.

The final solution, which represents the generation mix resulting from the auction for a certain set of input parameters, is selected as the feasible solution that has the lowest clearing price in the tender.

[53] In order to avoid the interference of the capacity mechanism with the short-term market, in Vázquez et al. (2002) the strike price was suggested to be set at least 25% above the variable costs of the most expensive generator expected to produce in the market. The strike price for the model has been selected complying with this rule and it has been set to 500 €/MWh. This implies that when the strike price is exceeded, the spot price automatically reaches the price cap active in the short-term market.

### 6.2.4. Bid calculation in the model

#### 6.2.4.1. Bid calculation for existing generators

The premium fee required by each unit, i.e., the bid it would present with perfect information, can be obtained by processing the results of the short-term market simulation. This requires the introduction of new parameters, which are presented hereunder.

- $cuna_i$ is the counter of unavailability of generator $i$ and represents the number of hours during the year in which the unit has been unavailable.
- $csca$ is the counter of scarcity conditions in the system and represents the number of hours during the year in which the spot price exceeds the strike price and reaches the price cap.
- $cund_i$ is the counter of underdelivery of generator $i$ and represents the number of hours during the year in which the unavailability of the unit is concurrent with the occurrence of scarcity conditions in the system.
- $lrem_i$ is the lost remuneration of generator $i$ and represents the summation along the year of the income that the agent is returning to the buyer of the option contract when it is producing electricity during scarcity conditions, because in those hours its remuneration is capped to the strike price $s$.
- $ipen_i$ is the implicit penalty of generator $i$ and represents the summation along the year of the difference $p-s$ that the agent has to return to the buyer of the option for each MW considered in the contract when scarcity conditions occur and the unit is not producing.
- $epen_i$ is the explicit penalty of generator $i$ and represents the summation along the year of the explicit penalty that the agent has to pay to the buyer of the option because of underdelivery during scarcity conditions.
- $capa_i$ is the maximum capacity that generator $i$ can bid in the auction and is equal to its nameplate capacity (no constraints on tradable quantities are considered).
- $bid_i$ is the bid of generator $i$ in the auction and represents the premium fee that the agent requires in order to enter into the option contract.

For the sake of simplicity, it will be considered that all the units are willing to take part in the auction with their entire capacity, for which they will present one single price bid. With these assumptions, the parameter $bid_i$ can be calculated as the sum of the loss of income $(lrem_i)$ plus the implicit $(ipen_i)$ and explicit $(epen_i)$ penalty that the generator incurs because of signing the reliability option contract, divided by the capacity that it can bid in the auction $(capa_i)$. Note that these new parameters represent yearly values, this is why the integral does not appear in the following equations. The expression can be written as:

$$bid_i = \frac{lrem_i + ipen_i}{capa_i} + \frac{epen_i}{capa_i} \tag{3}$$

With this formulation, it is possible to observe once again two terms, one representing the option value and the other representing the penalty. The bid calculation formula can be expressed as:

$$bid_i = \frac{capa_i \cdot \left(p_{cap} - s\right) \cdot \left(csca - cund_i\right) + capa_i \cdot \left(p_{cap} - s\right) \cdot cund_i}{capa_i} + \frac{capa_i \cdot pen \cdot cund_i}{capa_i} \tag{4}$$

$$bid_i = \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_i \tag{5}$$

The second equation, obtained by simplifying the first one, is exactly equivalent to equation (2), resulting from the theoretical analysis. Again, the option value is the same for all the agents, while the penalty varies according to the parameter $cund_i$, which is different for each generator (and which is equivalent to the integral of the $\lambda_i$ term in the original equation).

### 6.2.4.2. Bid calculation for new entrants

In the case of new entrants, the same considerations expressed in the previous section apply. Since the new entrant can still decide whether to invest or not, an additional term must be included in the bid calculation, representing any positive difference between the required annual income and the expected short-term market remuneration. With the formulation proposed in this section, this can be obtained through the introduction of further parameters.

- $icos_n$ is the annualised investment cost of generator *n* and represents the required annual income.
- $ocos_n$ is the operation cost of generator *n* along the year simulated.
- $mrev_n$ is the short-term market revenue of generator *n* and represents the summation along the year of the incomes from the spot market.
- $bid_n$ is the bid of generator *n* in the auction and represents the premium fee that the new entrant requires in order to invest and to enter into the option contract.

The $bid_n$ parameter can therefore be calculated as for existing generators, with the addition of the new parameters.

$$bid_n = Max\left(0; \frac{icos_n + ocos_n - mrev_n}{capa_n}\right) + \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_n \tag{6}$$

Therefore, the formulation for new entrants has three terms. Besides the option value (the same for all existing generators and new entrants) and the penalty (different for each generator, depending on the $cund_n$), the first term is related to the annualised investment costs and it depends on the technology considered and on its incomes in the market.

#### 6.2.4.3. Theoretical discussion on the dependence of the bid on the penalty

The next section presents the impact of the explicit penalty on the merit order of the auction and on electricity supply costs, according to the outcomes of the simulation model. In order to understand such impact, this subsection clarifies the dependence of bids on the explicit penalty. In the previous subsections, the formula for the calculation of the bid from existing unit was expressed as follows.

$$bid_i = \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_i \tag{7}$$

In order to highlight the dependence of the $bid_i$ on the $pen$ value, the previous expression can be rewritten as:

$$bid_i = A + pen \cdot B_i \tag{8}$$

Therefore, the bid from existing units is composed of a term that does not depend on the explicit penalty (the option value), which can be considered as a constant for all the existing plants ($A$), and a term where the $pen$ value is multiplied by the $cund_i$ factor ($B_i$), which is different for each resource. As mentioned in the previous subsection, the $cund_i$ factor measures the expected unavailability of each unit during scarcity conditions and it depends basically on the EFOR.

However, this is no longer true in the case of new entrants bidding in the auction. In fact, their bids consider an additional term, as introduced in the methodology and repeated here.

$$bid_n = Max\left(0; \frac{icos_n + ocos_n - mrev_n}{capa_n}\right) + \left(p_{cap} - s\right) \cdot csca + pen \cdot cund_n \tag{9}$$

Once again, the previous expression can be rewritten as:

$$bid_n = C_n + pen \cdot D_n \tag{10}$$

The same two terms as in the case of existing generators can be identified. However, in the case of new entrants, also the constant term that does not depend on the explicit penalty is different for each new entrant. It can be assumed that the $C_n$ factors are greater than $A$, because of the investment term to be added to the option value in the bids from new entrants, and that the $D_n$ factors are usually lower than the $B_i$ factors, because new facilities are commonly more reliable than existing ones.

Offers from existing generators and new entrants are represented in a *bid-pen* chart in Figure 6.5 for a simplified example with three generators. The evolution of the unitary bids

(€/MW) from existing generators as the penalty increases is represented by a family of straight lines leaving from the same intercept (the option value) and having different slopes. Bids from new entrants leave from a higher intercept, due to the internalisation of their investment costs, but have lower slopes, reflecting their higher reliability. Lines representing the evolution of unitary (€/MW) bids from existing units never cross among them, but they do cross the bid from the new entrant. This means that a change in the explicit penalty does affect the merit order causing the displacement of existing units by new entrants. This can be observed in the right part of Figure 6.5.

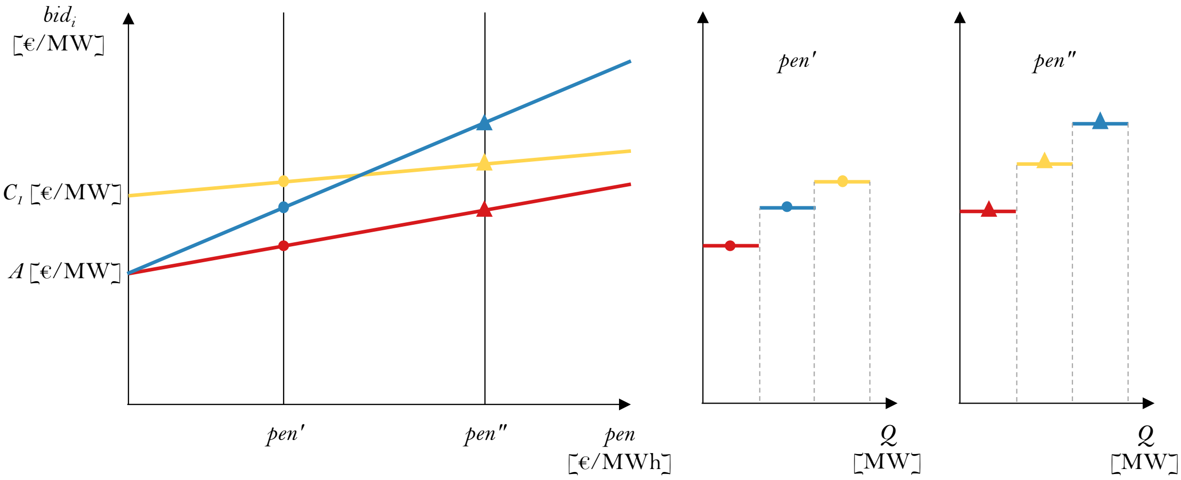



Figure 6.5. *bid-pen* chart with two exiting generators and a new entrant and the impact on the merit order

## 6.3. Results and discussion

After the detailed explanation of the functioning of the model, this section presents the outcomes of the case study. Results are divided in two subsections. In the first one, the impact of the explicit penalty on the merit order of the auction is analysed. In the second one, the attention is focused on how the explicit penalty affects the total cost of electricity supply for final consumers.

### 6.3.1. The impact on the auction merit order

As mentioned in the methodology, the model allows to find the generation mix (thus, the number of new entrants joining the system) that results in the lower auction clearing price for a certain set of input parameters. However, instead of providing results in terms of single sets of inputs, in this section the attention is focused directly on the parameter under study in this chapter, i.e., the explicit penalty. For different values of the explicit penalty, the model selects a different generation mix (even if the impact of investment lumpiness is observed) due to the dependence that this parameter has on auction bids, as showed in the previous section. The first result that can be obtained is a reproduction of Figure 6.5 with real data produced by the model for the case study. Figure 6.6 shows the results of a simulation with a generation mix composed by 80 existing units plus nine new CCGT plants.

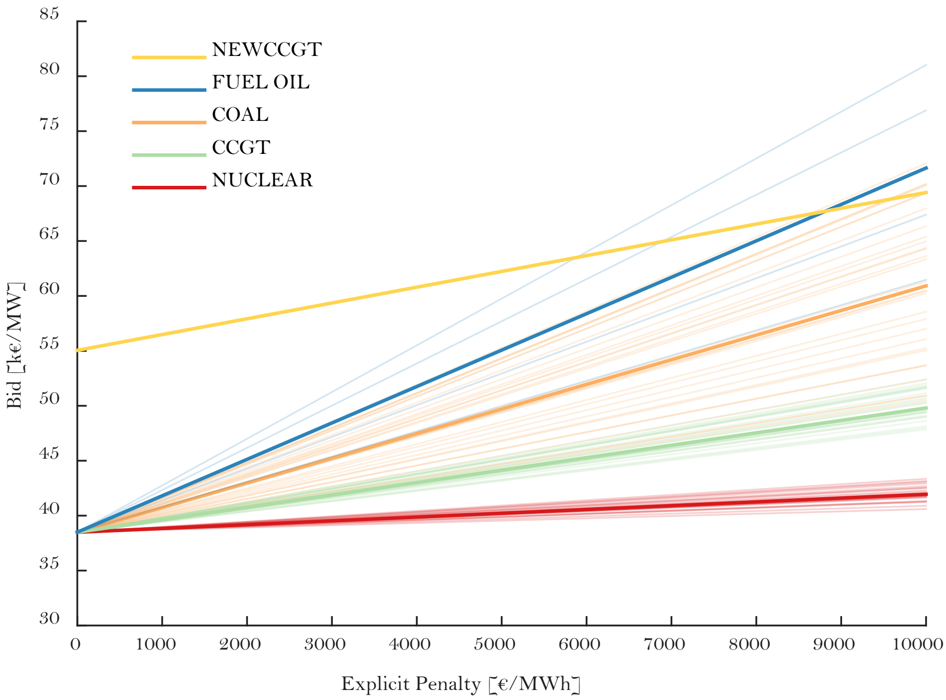



Figure 6.6. *bid-pen* chart for a system with 80 existing units and nine new CCGT plants

As mentioned in the theoretical discussion, bids from existing units are represented by a family of straight lines leaving from the same intercept (the option value) and having different slopes (the counter of underdelivery, $B_i$ in the picture). Each technology is represented with a different colour. Since each plant may have a different EFOR within a range defined for each technology, dark lines represent the unit with the median EFOR for the specific technology and light lines the rest of the units. If only existing plants are considered, an increase in the explicit penalty can widen or narrow the gap between different bids, but it cannot affect the merit order, because the straight lines do not cross. The merit order is completely defined by the slope of the lines, i.e., by the counter of underdelivery.

On the other hand, bids from new entrants are represented as a single line (since they are all the same technology, i.e., CCGT, the same investment costs and the same EFORs are considered), leaving from a higher intercept, but having a lower slope, which crosses the family of straight lines representing existing units. Since the lines cross, in this case a change in the explicit penalty does affect the merit order, causing the displacement of existing units by new entrants.

The chart in Figure 6.6 represents a specific initial generation mix (in this case, the one considering 9 new units), which is used to run the unit commitment. Similar charts can be drawn for different initial mixes, considering a different number of new CCGT plants. By applying the coherency checks described in section 6.2 (Figure 6.1), it is possible to aggregate all this information to obtain the chart in Figure 6.7, which represents the generation mix cleared in the auction for increasing values of the explicit penalty for underperformance.

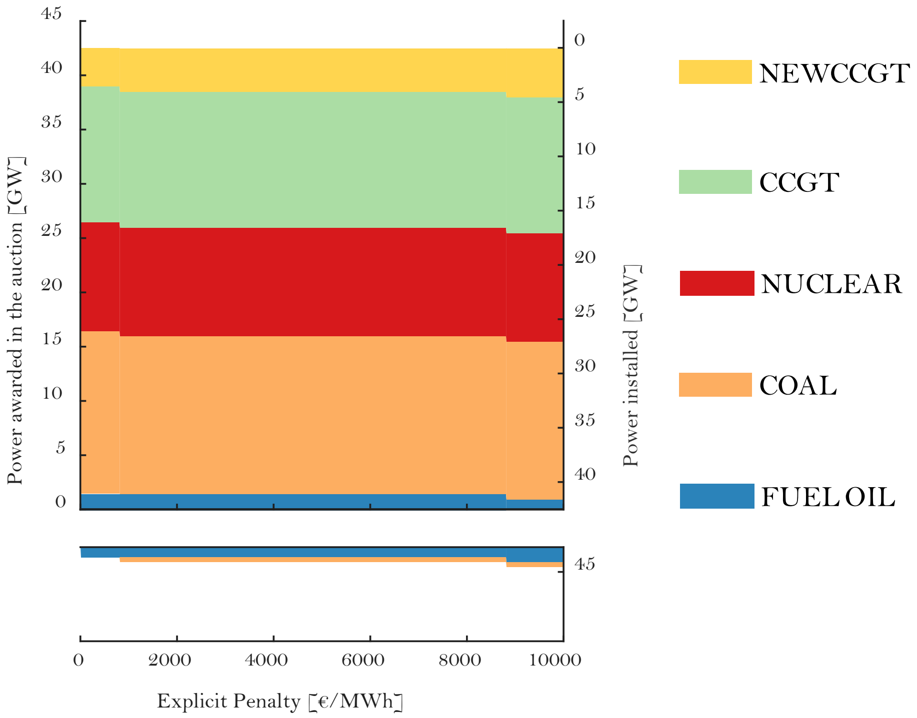



Figure 6.7. Evolution of the auction merit order and resulting mix for different values of explicit penalty

The positive y-axis shows the merit order of the auction and which plants are cleared in. The negative y-axis shows existing plants which have been displaced by new entrants with lower bids. Those plants are not cleared in the auction, but they are considered to keep on being part of the system. Thus, on the right side of the y-axis, the total installed capacity, including both new and existing units, is shown.

The effect of the explicit penalty can be clearly observed. Without an explicit penalty, only those new plants needed to cover the demand in the auction (which represents the expected growth in electricity demand with respect to the current one) are cleared in and all existing units are granted reliability contracts. However, as the explicit penalty is increased, new units start displacing existing plants in the merit order. The higher the penalty, the higher the number of new and more reliable units that enter the system and the higher the number of non-firm existing generation plants that are displaced. This is due to the fact that, as shown in Figure 6.6, the economic impact on the bid caused by higher penalties is more severe for those less-reliable units with higher EFOR rates.

### 6.3.2. The impact on the total supply costs

The previous subsection showed the effect of the explicit penalty on the merit order of the auction and how it fosters the entrance of new and more reliable units. However, this intervention can affect in different ways the market income of the existing generation mix, the cost that end consumers have to pay for their electricity supply and, in general, the net social welfare. This subsection analyses the variation in capacity-market and energy-market costs (as well as the evolution of non-served energy) for different values of explicit penalty. The objective is to assess the impact of the explicit penalty on the cash flows of power sector agents and on the overall cost of electricity supply.

First of all, the application of higher penalties decreases non-served energy. The entry of new units, obtained through the introduction of the explicit penalty, results in a higher reliability of the system, which can be measured through the number of hours with scarcity conditions (Figure 6.8). In this chart, the effect of the lumpiness of investments is evident. Each time a new CCGT plant is cleared in the auction (when the penalty value becomes high enough to allow it to displace an existing unit) the number of scarcity hours is significantly reduced. This is due to the combined effect of having a more reliable plant in the system, and of an increased reserve margin (the displaced existing unit is considered to remain in the system, as explained in the methodology).

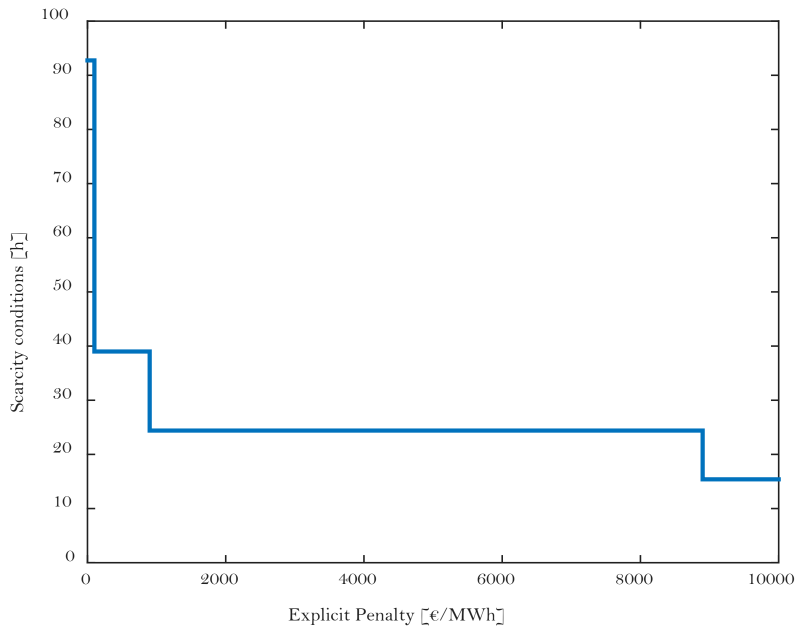



Figure 6.8. Evolution of the number of hours with scarcity conditions for different values of explicit penalty

Beyond this straightforward "physical" impact on the system reliability, the level of the explicit penalty also alters the economic flows among market agents. Figure 6.9 provides a graphical comparison of the capacity-market and the energy-market costs (including the value of non-served energy) as the explicit penalty increases. Two different penalty values are considered, a low-penalty (1 000 €/MWh) and a high-penalty scenario (10 000 €/MWh).

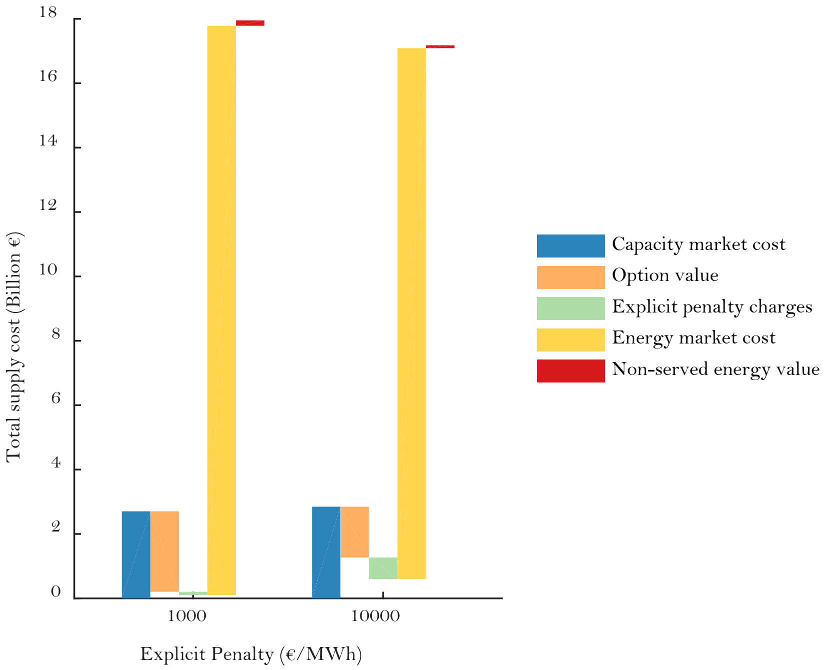



Figure 6.9. Overall cost of electricity supply for two different values of the explicit penalty

The introduction of higher penalties increases the clearing price in the auction (as shown in Figure 6.6) and, therefore, the overall cost of the capacity mechanism (which is eventually paid by end-users), as a higher clearing price is received also by those exiting units selected in the auction. This has been identified by some stakeholders as a windfall profit (APPA, 2013). This effect can be observed in Figure 6.9, where the cost of the capacity market increases as the penalty value grows from 1 000 to 10 000 €/MWh. However, in order to understand this increase, the reader must remember the functioning of reliability option contracts. Part of the premium paid to generation resources is recovered during scarcity conditions, when reliability providers have to return the difference between the spot and the strike price, i.e., the option value. It can be observed that the option value declines when the penalty is increased. This is due to the entry of new plants that improve the reliability, decrease the number of scarcity events, and therefore decrease the total rent to be returned by resources during shortages.

Another part of the premium paid in the auction is also finally compensated to the system through the explicit penalty charges paid by underperforming resources. This part obviously increases for higher penalties. In fact, even if fewer scarcity conditions occur due to the improved reliability, the growth of the penalty value counterweights and overcomes this effect.

Subtracting from the capacity-market cost both the option value and the explicit penalty charges, it is possible to obtain the "net" cost of introducing the capacity mechanism, which represents the remuneration distributed among power resources taking part in the CRM. When the penalty value is increased, new units are cleared in the auction, through bids that internalise part of the investment cost of these facilities, thus resulting in a higher net cost of the capacity mechanism. In this case, it is true that a very reliable existing unit is receiving a higher remuneration from the capacity market in the high-penalty scenario by selling the same product as in the low-penalty scenario.

Nevertheless, the analysis must encompass also an assessment of the energy market cost. The latter as well is affected by an increase in the penalty value. In fact, when new and more reliable plants enter the system because of higher penalties in the capacity market, these units displace old and more expensive generation plants also in the energy market. This reduces the short-term market price, decreasing the energy-market remuneration for all agents, existing and new, resulting in a lower energy-market cost. This effect is reflected in Figure 6.9. Obviously also the non-served energy value diminishes with higher penalties, due to the enhanced reliability of the system. Summing up all these components, it can be observed how the overall cost of electricity supply can decrease when the explicit penalty increases. This demonstrates that the supposed windfall profits obtained in the capacity market can be overcome by the lower remuneration in the energy market[54].

These outcomes, even if by means of rough numbers, provide regulators with an important recommendation. The introduction of a capacity mechanism always represents an intervention in the electricity market. Some agents benefit from this intervention, while some others are impaired by it and this is unavoidable. However, positive results are still achievable if the intervention could eventually result in an increment of the social welfare.

As a final remark, the x-axis in all the charts presented in this section considers penalty values from 0 to 10 000 €/MWh and the effect of the penalty is more evident for higher values, in the order of thousands of €/MWh. These "fines" could be perceived as quite high if compared with prices commonly recorded in most electricity markets. However, they are in the same order of magnitude of the explicit penalties which are planned to be introduced in some capacity mechanisms in United States, which are leading the discussion on this topic. ISO New England is introducing a penalty rate which will grow up to 5 455 $/MWh (FERC, 2014b), while PJM proposed to apply a charge which has been estimated to be around 3 625 $/MWh (FERC, 2015). Much higher than these values, the penalty originally proposed in the United Kingdom was equal to 16 000 £/MWh (NERA, 2015), which was

[54] It must be remarked that this result may depend on specific assumptions of the model and could not be fully generalisable to different scenarios. One of the hypotheses is that existing units that are not cleared in the capacity auction are not decommissioned and keep on being available, thus increasing the reserve margin and depressing prices in the energy market. This scenario is not unrealistic, but it may not be always fulfilled. Another element that may influence the results shown in Figure 6.9 is that the model does not consider risk aversion. Risk-averse agents may internalise high penalties in their bids in a very different way and the economic balance between capacity- and energy-market costs may diverge from the one presented here. Furthermore, very high penalties may complicate the access to finance for new projects, and this may not be a desirable result. Penalties should be set at a level that does not disrupt the economic stability of power companies in case of prolonged scarcity conditions, as also mentioned in chapter five.

finally reduced to a charge coupled to the remuneration obtained from the capacity market (see chapter five for details).

## 6.4. Conclusions and recommendations

The international experience presented in chapter five stresses the relevance of performance incentives for the effectiveness of a CRM. This chapter has complemented that assessment through a model-based analysis on the impact of penalty schemes on the outcomes of a capacity mechanism. Since less reliable units are more likely to fail in providing their contribution during scarcity conditions, they are more exposed to an explicit penalty and this is reflected in their bid. The explicit penalty, in case existing generators and new entrants compete in the same auction, can alter the merit order of the tender, causing the exit of non-firm energy blocks and the entrance of new and more reliable generation plants.

This chapter presented a model that studies the impact of the explicit penalty on the generation mix resulting from the implementation of a capacity mechanism. As explained in section 6.2, the two-stage model is based on the simulation of an auction for reliability option contracts, in which bids are calculated according to the results of a short-term market, represented through a unit commitment considering the unavailability of generation units. Results from the model, presented in section 6.3, confirm the expected effect of the explicit penalty and allow to draw some relevant conclusions, summarised hereunder.

- New entrants include in their bid an estimation of the part of the required annual income that they do not manage to recover in the short-term market. Therefore, without an explicit penalty, new units will present higher bids than existing plants and they will be cleared only to cover the expected demand growth.
- However, new units are expected to be more reliable than existing ones and to provide a higher contribution to the reliability of the system if they are cleared in the auction. Therefore they represent a better asset for the regulator to achieve the reliability target it sets. The explicit penalty can be used to amplify this signal. Less-firm generation plants are more exposed to higher penalties and this is reflected in their bids. This results in the displacement of non-firm energy blocks by new and more reliable generation units.
- Improvements in reliability can be observed through the number of hours with scarcity conditions in the system. When a new unit is cleared in the auction because the penalty value is high enough to allow it to displace an existing plant, the number of hours with scarcity conditions is reduced.
- Higher penalty values result in an increase of the net cost of the capacity market (obtained by subtracting the option value and the penalty charges from the capacity-market cost). However, this increase can be counterweighted by a decrease in the energy-market cost (new units reduce short-term market prices) and in the non-served energy value.

- The penalty value for which the above-mentioned effects are more evident is quite high if compared with electricity market prices normally observed, but it is in line with the penalties being proposed and implemented in capacity mechanisms in the United States.

These findings have been obtained by considering a centralised auction for reliability option contracts. They are likely to be valid for CRM designs based on centralised auctions, even when the reliability product to be procured in the latter is different. However, these outcomes may not be generalised to decentralised mechanisms. The main recommendation that can be extracted from this chapter is that capacity mechanisms must consider a penalisation scheme if they aim at attracting investment in new and more reliable resources. This represents a lesson worth learning for European regulators, especially in the current framework of widespread introduction of capacity remuneration mechanisms. Nonetheless, penalty schemes also have a dramatic impact on the capability of renewable technologies to take part in CRMs, as analysed in the next chapter.

## Appendix: Detailed model formulation

This appendix includes the detailed formulation of the unit commitment model used to simulate the outcome of the short-term market. For the scope of this analysis, the UC problem has been simplified and some constraints, not relevant for the product considered in the auction, have been removed. Moreover, the demand is supposed to be totally inelastic.

In order to accurately model the functioning of a "real-size" system with 80 generation units during a whole year while, at the same time, keeping the computational time within acceptable levels, the UC problem is based on a clustered formulation proposed, for example, in Gollmer et al. (2000).

As regards the representation of units' availability, prior to the execution of each scenario, a different availability matrix is generated using a string of random numbers and the probabilities $\rho$ and $\mu$, as described in Section 6.2.3.

**Unit commitment formulation**

*Indexes and sets*

| | |
|---|---|
| $g \in G$ | Generating technologies |
| $t \in T$ | Hourly periods |

*Parameters*

| | |
|---|---|
| $C_g^{LV}$ | Linear variable cost of a unit of technology $g$ [\$/MWh] |
| $C_g^{NL}$ | No-load cost of a unit of technology $g$ [\$/h] |
| $C^{NSE}$ | Non-served energy price [\$/MWh] |

$C_g^{SD}$ Shut-down cost of technology $g$ [$]

$C_g^{SU}$ Start-up cost of a unit of technology $g$ [$]

$D_t$ Load demand in hour $t$ [MWh]

$\overline{P}_g$ Maximum power output of a unit of technology $g$ [MW]

$\underline{P}_g$ Minimum power output of a unit of technology $g$ [MW]

$N_g$ Number of units installed of technology $g$

$AV_{g,t}$ Number of units of technology g available in hour $t$

*Variables*

$nse_t$ Non-served energy in hour $t$ [MWh]

$p_{g,t}$ Power output at hour $t$ of technology $g$ units above minimum output $\underline{P}_g$ [MW]

$u_{g,t}$ Number of units of technology $g$ committed at hour $t$

$v_{g,t}$ Number of units of technology $g$ starting-up at hour $t$

$w_{g,t}$ Number of units of technology $g$ shutting-down at hour $t$

*Formulation*

$$\min \sum_{t \in T} \left[ \sum_{g \in G} \left[ C_g^{NL} u_{g,t} + C_g^{LV} \left( \underline{P}_g u_{g,t} + p_{g,t} \right) + C_g^{SU} v_{g,t} + C_g^{SD} w_{g,t} \right] + C^{NSE} nse_t \right] \tag{A.1}$$

$$s.t. \quad \sum_{g \in G} \left[ \underline{P}_g u_{g,t} + p_{g,t} \right] = D_t - nse_t \qquad \forall t \in T \tag{A.2}$$

$$u_{g,t} - u_{g,t-1} = v_{g,t} - w_{g,t} \qquad \forall g \in G, \forall t \in T \tag{A.3}$$

$$p_{g,t} \le \left( \overline{P}_g - \underline{P}_g \right) u_{g,t} \qquad \forall g \in G, \forall t \in T \tag{A.4}$$

$$u_{g,t} \le AV_{g,t} \qquad \forall g \in G, \forall t \in T \tag{A.5}$$

$$0 \le u_{g,t}, v_{g,t}, w_{g,t} \le N_g, \quad u_{g,t}, v_{g,t}, w_{g,t} \in \mathbb{Z} \qquad \forall g \in G, \forall t \in T \tag{A.6}$$

$$p_{g,t}, nse_t \ge 0, \quad p_{g,t}, nse_t \in \mathbb{R} \qquad \forall g \in G, \forall t \in T \tag{A.7}$$

**Input data**

This subsection provides the data used for the case study presented in section 6.3, in terms of cost items and technical parameters of each technology (other data, as the price cap or the strike price, are already specified in the body of this chapter). The objective of this research is not to predict actual results for a specific system, but rather to show the impact of a parameter, the explicit penalty for underperformance, on the outcomes of a capacity mechanism. Some data have been approximated (as the installed capacity of generation units), but they keep on reflecting realistic values. Table 6.1 provides the data used for the case study, with the acronyms presented in the formulation.

Table 6.1. Input data for the case study

| | Nuclear | Coal | CCGT | Fuel oil | New CCGT |
|---|---|---|---|---|---|
| No. of units | 20 | 30 | 25 | 5 | 15 |
| $\overline{P}_g$ [MW] | 500 | 500 | 500 | 500 | 500 |
| $\underline{P}_g$ [MW] | 500 | 300 | 200 | 200 | 200 |
| $C_g^{LV}$ [$/MWh] | 6.50 | 37.25 | 60.75 | 189.50 | 59.00 |
| $C_g^{NL}$ [$/MWh] | - | 525 | 3 150 | 6 750 | 3 150 |
| $C_g^{SD}$ [$] | - | 4.5 | 7.0 | 1.5 | 7.0 |
| $C_g^{SU}$ [$] | - | 45 | 70 | 15 | 70 |
| $\overline{EFOR}_{tech}$ [p.u.] | 0.01 | 0.05 | 0.04 | 0.10 | 0.02 |
| $\underline{EFOR}_{tech}$ [p.u.] | 0.02 | 0.15 | 0.06 | 0.20 | 0.02 |
| $AIC_{tech}$ [k$/MW] | - | - | - | - | 120 |

# 7. CRMs and Renewable Technologies

*Renewable energy technologies have been so far a driver for the implementation of capacity remuneration mechanisms, but in the near future they could become a relevant resource to guarantee the adequacy of the power system. RES-E support schemes may sooner or later "flow into" CRMs and renewable and conventional technologies will compete equally in the same mechanism. Nonetheless, for the time being, this convergence is taking place without the necessary harmonisation of the requirements for these different technologies. This chapter first analyses the impact of renewable technologies on system adequacy and then focuses on the regional context in which the overlap between CRMs and RES-E support is already taking place, i.e., South America, to see which factors need to be harmonised*[55]*.*

## 7.1. Introduction

The penetration of renewable energy technologies in power systems have often been mentioned as one of the reasons that prompt the implementation of a capacity mechanism. This is especially true in Europe, where this penetration has already reached significant shares. RES-E, whose installation has been commonly driven, so far, by some sort of regulatory support, are claimed to depress prices in the electricity market (Moreno et al., 2012; Reuter et al., 2012). This reduces profitability for conventional thermal technologies, which, on the other side, are most needed to back up the intermittent RES-E generation pattern. In this context, CRMs provide conventional technologies with an additional remuneration that incentives the installation (or at least avoids the decommissioning) of dispatchable power plants.

[55] Part of this chapter was published in Mastropietro, P., Batlle, C., Barroso, L. A., Rodilla, P., 2014, *Electricity Auctions in South America: Towards Convergence of System Adequacy and RES-E Support.* Renewable and Sustainable Energy Reviews, Volume 40, Pages 375-385.

Nevertheless, renewable technologies also represent a valuable resource for the security of supply (Gouveia et al., 2014). Regional markets can help manage fluctuations in RES-E electricity production, by increasing the geographical scope and thus reducing the probability of concurrent lack of renewable energy. Developments in storage technologies can reduce these fluctuations on a smaller scale, for each unit or plant. Renewable sources may offer a complementary availability with respect to the main energy resource and their construction time may be significantly shorter than that of other technologies. In addition, the cost of RES-E units, especially that of on-shore wind and solar photovoltaic, is swiftly decreasing and these technologies will soon be able to compete with conventional technologies in electricity markets without any additional support. Depending on the type of technology and on the particular design of the mechanism, renewable technologies could also be able to participate in CRMs, thus competing with conventional technologies also in the capacity market. Nonetheless, the ability of renewable technologies to contribute to the security of supply and to help relieve scarcity conditions is not always guaranteed and depends on the specific conditions of the power system where they are located and on the typology of scarcity conditions, as it will be analysed in the following sections of this chapter.

In capacity mechanisms implemented around the world, renewable energy technologies have so far had a very limited role, or at least this was the situation until few years ago. In many cases, RES-E resources were not eligible, because they were already receiving some other kind of incentive (grant, feed-in tariff, etc.). In some other cases, the detailed design of the capacity mechanism, even if without applying any explicit technology discrimination, did *de facto* not allow RES-E participation. Despite this, in the last few years, renewable technologies started being selected in CRMs. In PJM's reliability pricing model, 803-MW wind power plants and 116-MW solar resources were cleared in the 2017/2018 RPM base residual auction (PJM, 2014e).

However, the region of the world where renewable and conventional technologies did start competing in the same market is South America. Power sectors in this continent, which pioneered power sector liberalisations back in the 1980s and 1990s, are commonly organised around electricity auctions, which are used to guarantee that the fast-paced demand growth is always covered by long-term contracts, thus ensuring the adequacy of the system. Besides these conventional auctions, specific tender for renewable energies have been used during the last decade to prompt the installation of RES-E technologies. These schemes have until now been run in parallel, but the steep learning curve of RES-E technologies is apparently opening the door to the implementation of new tendering procedures open to all kinds of generation technologies. Convergence of system-adequacy and RES-E support auctions has already been observed.

This chapter focuses on the complex interaction between capacity remuneration mechanisms and renewable energy. First, it assesses the impact that RES-E technologies have on system adequacy and flexibility issues, differentiating between energy-constrained and capacity-constrained power systems (section 7.2). Then, section 7.3 focuses on the potential participation of renewable technologies in CRMs and the coordination with RES-E support mechanisms. Finally, the main part of this chapter is dedicated to the review of auction mechanisms for new generation implemented in South America, with the objective of analysing regulatory challenges that stem from the competition of conventional and renewable technologies in the same tender process. The main finding is that, although the first impression might lead to the conclusion that conventional and RES-E technologies are in some cases close to compete or even ostensibly competing in the same auctions, full convergence is still far to happen, as rules and products applied to the different technologies differ significantly. The analysis is based on the experience of three countries (namely Brazil, Colombia, and Peru) in which this convergence is more evident, presented and assessed in section 7.5. Prior to this country-by-country study, section 7.4 provides a full description of the South American context, indispensable to understand the design of the auctioning mechanisms. Finally, section 7.6 summarises the main conclusions of this chapter.

## 7.2. Intermittent generation in energy- and capacity-constrained systems

In energy-constrained systems[56], e.g., in hydro-dominated countries, the coverage of the instantaneous peak load is not an issue and scarcity conditions are more related with dry seasons that could last for months. In this context, the short-term intermittency of renewable technologies does not impede them to contribute to the reliability of the system. If they are able to deliver, on average, their expected contribution in the medium term, they permit to save water in the reservoirs, regardless of the daily or hourly schedule of their production. Their participation in a "capacity mechanism"[57] can be therefore beneficial.

Brazil is a typical example of energy-constrained system and it will be studied in detail in section 7.5. Its market is organised around different kinds of long-term electricity auctions, which determine the majority of the economic flows, leaving to the short-term market only minor settlements. These tenders also represent the generation-adequacy mechanism used in this country. The outstanding participation of wind turbines in the Brazilian auctions has been celebrated worldwide for the low prices offered by these RES-E units. These prices are

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[56] For the definition of energy- and capacity-constrained systems, see section 2.5.1.

[57] In an energy-constrained system, the reliability product procured in a capacity mechanism is not capacity. For example, in South America, where many systems are hydro-dominated, CRMs take the form of long-term electricity auctions in which the reliability product is energy, or a call option on future energy. In some cases, these auctions "substitute" somehow the energy market (as, e.g., in Brazil or Peru), in some others, they let agents trade electricity in the short-term market (Colombia). See Maurer and Barroso (2011) for details. In these contexts, it would be more correct to use the expression generation-adequacy mechanisms.

related with the very high capacity factors considered in the project planning, which range from 30% to 60%. This high capacity factor sets the amount of energy that each unit can sell in the long-term auction, but it represents also its expected contribution to generation adequacy. In fact, in the scarcity conditions foreseen in Brazil, the intermittency of wind power does not impede these plants to contribute to the reliability of the system.

In capacity-constrained systems, scarcity conditions arise because there is not enough installed capacity available to cover load at a given moment. In CRMs implemented in these systems, the reliability provider is usually required to deliver its contribution during stress events identified by the system operator with short notice (or no notice at all). In this context, the intermittency of renewable production is an issue, because if the RES-E resource is not available at the very moment when the system stress occurs (e.g., due to the lack of wind or solar radiation), it cannot contribute to reduce or solve the shortage. Since it cannot deliver the kind of reliability needed in the system, its involvement in capacity mechanisms could be difficult to realise in practice. Statistical analyses can be used to calculate the likely production from the RES-E resource during expected scarcity periods. This information can be used to define a de-rating factor that constraints the amount of capacity that the resource can trade in a capacity mechanism, thus limiting also the remuneration it can receive from it. Nonetheless, its capability to deliver electricity during scarcity conditions cannot be guaranteed in advance. In CRM designs that consider high penalties for underperformance, renewable technologies could therefore be exposed to significant financial losses.

PJM can be used as an example of capacity-constrained power sector. The capacity mechanism implemented in PJM (the reliability pricing model, or RPM) was presented in chapter five. As mentioned above, 803-MW wind power plants and 116-MW solar resources were cleared in the 2017/2018 RPM base residual auction (PJM, 2014e). On average, wind and solar units were assigned respectively a 13% and 38% capacity factor during the qualification phase prior to the auction. These factors, quite lower than those mentioned for the Brazilian case, represent the expected contribution of these units during scarcity conditions in PJM. Since the latter are related with short-term shortages, the likelihood of RES-E resources being available at the specific time when scarcity occurs is estimated to be low.

### 7.2.1. Flexibility concerns

According to several experts (EURELECTRIC, 2011; RAP, 2012), the penetration of intermittent RES-E technologies does not actually affect the adequacy dimension of the security-of-supply problem, but it rather just increases the need for flexible resources. According to Pérez-Arriaga (2013b), flexibility can be defined as the capability of a power system to adapt electricity production or consumption in response to variability, expected or otherwise, rapid and/or large, whatever the cause. This same author claims that flexibility does not represent an additional dimension of the security-of-supply problem, since it is not a new requirement but a characteristic that power systems have always had to have in order to follow the variability of the load. Nonetheless, it is undeniable that the intermittency of renewable technologies adds a further variability, which exacerbates flexibility issues.

Obviously also this impact differs depending on the system. Energy-constrained systems have a huge availability of flexible resources that can be used to compensate for the variability of RES-E technologies. On the other hand, flexibility concerns are particularly relevant in capacity-constrained power sectors, which usually rely on thermal plants that are not always capable of changing their output rapidly. Some market designs do not allow a proper pricing of flexibility products, especially in terms of long-term economic signals, which are supposed to drive the expansion of the system. In the absence of these signals, the penetration of variable power sources may not be offset by the entrance of flexible resources and this may endanger the security of electricity supply. Different opinions have emerged on how to solve this flaw. Some authors (RAP, 2012, among many others) claim for the enhancement of electricity markets in those segments encompassing flexibility issues, e.g., through the creation of a long-term market for ancillary services. Some other experts (Pérez-Arriaga, 2013b; EURELECTRIC, 2011) advocate for the introduction of capacity mechanisms with a design capable of attracting flexible resources. In many capacity mechanisms, the reliability product has been designed with the objective of partially respond to the flexibility concerns of the regulator. Regardless of the approach finally chosen, future markets are likely to rely on several short-term and long-term signals, guiding market agents towards different regulatory objectives (an economic efficient dispatch, an adequate installed capacity, sufficient amount of flexible resources, a target level of renewable technologies, etc.).

A paradigmatic example of the increasing relevance of flexibility issues in the design of capacity mechanisms can be found in the Italian regulation. The introduction of a CRM in Italy was partially triggered by the 2003-blackout that affected most of the country and left consumers without electricity for several hours. The Government issued the Legislative Decree 379/2003, which required the Regulator (AEEG) to design a mechanism for the remuneration of generation capacity. In 2003, the Italian power system was mainly composed of conventional dispatchable units and the main concern was the adequacy of the system. With the significant penetration of intermittent and non-dispatchable renewable technologies that took place in the last decade, however, the focus moved on flexibility concerns and on guaranteeing the capability of the system of adjusting the dispatch according to the production of RES-E units.

This evolution affected the design process of the Italian CRM. While the capacity mechanism proposed by the Regulator (AEEG, 2011) was under approval, Law 147 of 2013 acknowledged the new flexibility concerns and required the Regulator to reflect them in the design of the capacity mechanism. AEEG Resolution no. 320/2014 mandated the System Operator to include a new segment in the capacity market for the procurement of flexibility products. It is still uncertain which the final design of the CRM will be, but the current proposal considers a specific segment for flexible resources, in the framework of a mechanism based on reliability option contracts. The price cleared in the auction for flexibility products will always be higher than the one cleared in the auction for simple adequacy products (the former auction is the final step of the latter). In exchange for this higher remuneration, flexible resources will sign a reliability option contract with two reference markets, the day-ahead market and a shorter-term market. This arrangement will require them to deliver also during scarcity conditions detected in the very short term, i.e., more related to flexibility issues than adequacy ones.

## 7.3. CRMs and RES-E support schemes

As already mentioned, the decreasing cost of generating electricity from renewable energy sources could soon allow certain RES-E technologies to compete with conventional technologies in the wholesale market. If capacity market rules permit it, this competition will encompass also the generation-adequacy mechanism. Nevertheless, as previously discussed, in capacity-constrained systems, renewable energy technologies have so far had a very limited participation in capacity mechanisms. In many countries, regulators decided that RES-E resources which are already receiving some other kind of incentive (grants, feed-in tariffs, etc.) are not eligible for the CRM remuneration. This was the case, for example, in the United Kingdom's Capacity Market (DECC, 2014), and the same approach has been proposed in Ireland (I-SEM, 2015). The idea behind this kind of provisions is that the capacity mechanism remuneration represents an investment incentive. Renewable technologies, for which investment is already being incentivised by some sort of RES-E support mechanism, should be therefore not eligible, since they do not need further investment support.

While this argument makes sense, it does not mean that RES-E technologies do not need to be sensitive to market signals. They should be integrated in the wholesale market as much as possible. Capacity remuneration mechanisms do not only promote new investments; they are also supposed to provide market agents with incentives to foster the availability of committed resources during scarcity conditions, with the objective of avoiding electricity rationing. This aspect of the mechanism is the one that now is being reinforced through the implementation of performance incentives, as mentioned in chapter five. If the capacity mechanism design is robust and the reliability product is technology-neutral, RES-E participation in the resource-adequacy mechanism allows to consider the contribution from these power plants to system reliability (avoiding over-procurement) and to expose them to an economic signal that prompts them to be available when the system most needs them. The requirement, as analysed next, is that renewable power plants are not favoured either in terms of penalties or in terms of firm energy/capacity recognition. If RES-E units have to compete with conventional technologies, they should be subject to the same rules. RES-E support mechanisms are not incompatible with this approach. The ideal RES-E support scheme should be able to deduct the revenues obtained by the renewable plant in all the markets, including energy and capacity market, from their total costs, in order to calculate the incentive required to make the investment attractive and to make it available to the project developer.

Nonetheless, in real markets, several factors can complicate this simple theoretical discussion. Capacity markets are being introduced to guarantee the profitability of conventional power plants that provide an essential back-up to intermittent generation. These plants have seen their profitability shrink because RES-E technologies have depressed prices in the energy market. According to some stakeholders, if "subsidised" renewable technologies are allowed to take part in the capacity market, it may be difficult to guarantee that they do not depress prices also in capacity auctions.

This point of view can be found, for example, in ISO New England's regulation. Renewable penetration in this power system has been very limited until the moment, but it may grow significantly in the next few years (wind turbines represent 42% of generation project proposals in the queue). According to ISO New England (2015b), state subsidies for renewable resources will put downward pressure on energy-market prices, but the capacity market will help balance the revenue needs for conventional resources. In order to "protect" the capacity market from excessive renewable participation, which could depress capacity prices, the Regulator introduced specific Offer Review Trigger Prices (ORTPs) for renewable technologies, which apply to all renewable bids exceeding 200 MW in each auction. ORTPs are intended to prevent uneconomic or subsidised new entry from distorting market prices, by setting a price floor below which new entrants must demonstrate their costs or be withdrawn from the capacity auction.

After this more theoretical analysis, the remainder of the chapter is dedicated to the analysis of the South American experience with renewable participation in generation-adequacy mechanisms.

## 7.4. The South American context

South America has shown high economic growth rates during the last decades, which have started decreasing only recently. Energy consumption, and particularly electricity demand, has followed this economic development. Summing up the annual electricity demand of Argentina, Brazil, Chile, Colombia and Peru, the largest electricity markets in the region, it is possible to observe an almost constant increase from 307.6 TWh in 1990 to 483.2 TWh in 2000 (with an average annual rise of 4.63%), to 695.7 TWh in 2010 (with an average growth equal to 3.75% per year)[58]. Looking at these figures, it appears evident that the main challenge for power sectors in the region is to guarantee a capacity expansion capable of covering this fast-paced demand growth.

[58] Statistic elaboration based on EIA, 2014.

### 7.4.1. The diversity in generation mix and potential

The electric power systems in the region are very diverse, in terms of prevailing generation technologies, availability of fossil fuels, and hydropower potential. For instance hydropower dominates the generation mix of the Brazilian system but accounts for less than 40% of Chile's power system. Figure 7.1 presents a comparison of the technology share in the generation mixes of five South American systems.

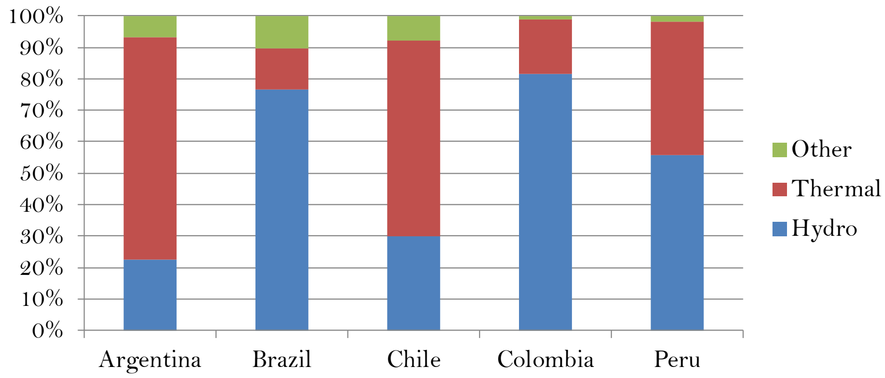


Figure 7.1. Comparison of electricity generation mixes in representative South American power systems. Data from EIA (2014) for 2012

Even more interesting than the current composition of generation mixes is their potential evolution. Power sectors in the region have a very large spectrum of possible options, in terms of both technological solutions and resources available. The hydropower potential is far from being exhausted; the average rate of exploited/physically-potential hydropower is below 15% (statistic elaboration based on OLADE, 2012). Very large reserves of natural gas have been recently discovered, opening the field to the installation of combined cycle gas turbines. Also coal is widely available and it is not subject for the moment to environmental restrictions related to carbon emissions. The nuclear energy option, although rather rare until now (only present in Brazil and Argentina), has not been ruled out. Furthermore, South America is endowed with one of the largest non-conventional renewable energy potentials in the world: strong and persistent wind flows, suitable conditions for small-hydro exploitation, significant solar power resources, and availability of biomass, especially from agricultural waste. Figure 7.2 shows a graphical representation of this huge "green" potential in the region, as regards solar and wind energy.

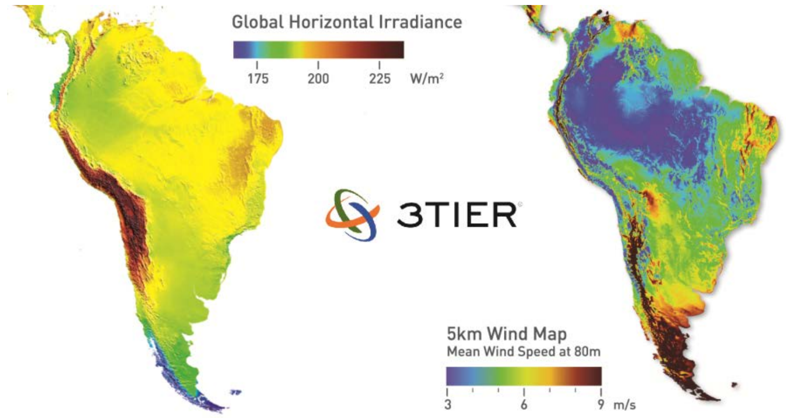


Figure 7.2. Solar and wind energy potential in Latin America. Maps from 3TIER

This broad range of alternatives is obviously an advantage for these countries, but, paradoxically, it "complicates" the planning and expansion of power systems and, as a consequence, the design of long-term electricity auctions, because of the several different directions that the systems may take.

In the last decades, South American countries have focused their efforts towards the achievement of an important "social" target, i.e., the provision of electricity access to the largest possible share of their population. This, combined with the lack of pressure to fulfil any international commitment on emissions reduction, sidelined the promotion of the still-emerging RES-E technologies. Nonetheless, this situation is changing swiftly and several initiatives resulted in the implementation of renewable energy projects throughout the region.

The reasons behind this new push in favour of RES-E, besides the observed steep learning curve of some of them, are diverse (Barroso and Batlle, 2011):

- RES-E technologies represent the opportunity to diversify the current generation mix, in many cases heavily based on hydropower. Furthermore, some of them, as wind and biomass, present seasonalities which are complementary to hydro periodicity (Chade Ricosti and Sauer, 2013).
- The comparatively short construction times of RES-E units turn them into a valuable alternative to avoid under- or over-procurement, especially taking into account the demand growth rates in the region and the long lead times demanded by hydro plants.
- RES-E technologies are often the most efficient solution to improve the access to electricity for a large number of people living in the numerous isolated areas in the region.

On top of this, the high proportion of large-reservoir hydro plants in these systems, as already mentioned, provides an abundant storage and fast ramping capability that mitigates the impact of intermittency and non-dispatchability of most of RES-E technologies.

However, while conventional large hydropower plants already play a major role in the power sectors of the region, non-conventional RES-E sources are almost still untapped and, until very recently, they have represented quite a negligible share of the generation mix.

### 7.4.2. The regulatory pursue of new investments in generation

South America has been the cradle of the power sector market reforms. In 1982 Chile issued its Electricity Act, which considered the unbundling of vertical-integrated utilities and the introduction of market competition in those sectors not identified as natural monopolies, a scheme which would then be implemented all over the world in the following decades. This pioneering reform became a model for several South American countries such as Argentina (1992), Peru (1992), Colombia (1993) and Brazil (1994), which restructured their power sectors following to a greater or lesser extent the guidelines of the Chilean liberalisation. The conceptual background of these reforms lied in the marginal pricing theory, according to which the market marginal price is the only economic signal required to drive investments towards the optimal generation mix. However, several regulators complemented from the very beginning short-term market prices with some sort of capacity mechanism (capacity payments, capacity markets, or both), in order to provide investors with a further incentive to investment.

Despite all these measures, in the last decade of the twentieth century the original designs started showing their limitations in guaranteeing the adequacy of the system. Short-term market prices, especially in those countries with hydro-dominated mixes, were considered too volatile to be an effective driver for new investments and the strong governmental influence on the sector was perceived as a threat by foreign capitals. For a number of reasons (ill design and regulatory interference), original capacity mechanisms did not work as expected and the expansion of the electricity supply was not able to follow the fast-paced growth in demand. This resulted in the narrowing of reserve margins, high prices and, in some cases, serious shortage situations (see Batlle et al., 2010). Regulators in the region started looking for new reforms to tackle the matter. In most of the cases, the backbone of these reforms was the implementation of long-term electricity auctions.

#### 7.4.2.1. Long-term auctions to guarantee system adequacy

A new mechanism, able to guarantee an economic-efficient expansion of the electricity supply, was to be designed in order to deal with the lack of investment. In 1999, an innovative proposal, based on the already mentioned reliability options mechanism, subsequently described in full in Vázquez et al. (2002), was proposed in the Colombian context. Although this design was finally not implemented until 2006, the discussion was already taking place all over the region. In 2004 Brazil finally launched a new scheme, based on electricity auctions. Similar long-term auction mechanisms, with minor or more important variations, were implemented in other countries, such as Chile in 2005 and Peru in 2006. The conceptual background of this second wave of reforms lied in the long-term contracting: fixing in advance and through a competitive mechanism part of the generators' remuneration hedges risks related to the volatility of short-term market prices and to potential regulatory interventions. Figure 7.3 represents graphically these two regulatory waves: the first one, from vertical-integrated monopoly to liberalisation and market competition, originated by the pioneering Chilean reform; the second one, from capacity mechanisms to long-term electricity auctions, inspired by the Colombian and the Brazilian experiences[59].

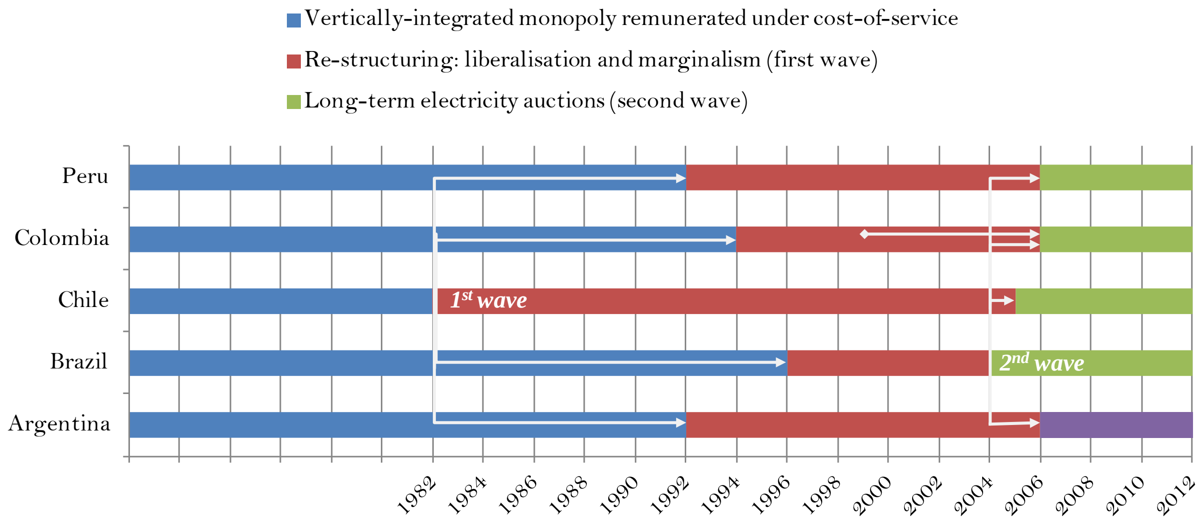


Figure 7.3. First and second wave of regulatory reforms in South America

Long-term electricity auctions are now the driving force for the expansion of power sectors in South America and they have already been described in literature (Maurer and Barroso, 2011; Moreno et al., 2010). Also in the context of RES-E support mechanisms, after some initial and isolated subsidisation programmes, the current trend is to carry out renewable energy auctions.

### 7.4.2.2. RES-E technologies: from traditional support mechanisms to auctions

At the beginning of this century, only few South American countries introduced national RES-E support programmes. Examples of these programmes were the priced-based mechanisms implemented in Argentina and Brazil[60]. Although they were responsible for bringing in the first RES-E capacity to these countries, their results were criticised on the grounds of their low economic efficiency (administrative definition of a feed-in tariff) and implementation process (most projects delayed years to start operation with respect to the planned commercial operation date).

[59] The development of power sector regulation in Argentina after the 2001-economic crisis must be considered exceptional and did not resemble reforms implemented in the other countries.

[60] For a detailed classification of RES-E support mechanisms, see Batlle et al., 2012.

Therefore, while long-term electricity auctions were acquiring a central role in the regulation at the security-of-supply level, also the RES-E support frameworks started to move towards renewable energy auctions (quantity-based mechanisms). In the auction-based approach, the winning bidders are usually offered a long-term contract for the production of renewable electricity, thus reducing the uncertainty for RES-E generators. Renewable auctions have been implemented in several countries in the region (Argentina, Brazil, Peru and Uruguay) and in some cases they have resulted in very low electricity prices if contrasted with similar experiences in comparatively more mature markets.

#### 7.4.2.3. Towards a common level playing field

This chapter analyses long-term electricity auctions, both for system adequacy and RES-E support, implemented in Brazil, Colombia, and Peru. In some cases, there are significant signs that a certain convergence is taking place. For instance, in Brazil and in Colombia wind turbines can compete with conventional generation technologies in system-adequacy auctions. The review is built around the classification of CRM design elements presented in the second chapter of this thesis. As it will be observed, the most relevant design elements that can influence the participation of RES-E technologies in CRMs are constraints on tradable quantities, i.e., the calculation of the firm energy or capacity expected by the renewable unit, and performance incentives, especially in terms of penalties for underdelivery. The differences that should be harmonised to achieve a proper convergence are discussed next.

## 7.5. Long-term auctions review

### 7.5.1. Brazil

Brazil is the largest power system in the region. Its generation mix is dominated by a complex hydropower system with plants spread over a vast area and with large reservoirs with multi-year storage capacity. Being such an important part of the demand covered by hydropower plants, hydrology has a large impact on the electricity market. When reservoirs are full, prices can be very low for a long period of time. On the other hand, during scarcity conditions, prices can reach very high levels, tempting the Government to interfere in the spot price, and introducing a large volatility that makes the risk of investing in new capacity very high.

#### 7.5.1.1. The 2004 reform

In order to solve this structural problem and to correct the initial market reform, which had not been able to guarantee the necessary expansion rates, a new regulatory framework was introduced in 2004, which has long-term electricity auctions as its backbone. This mechanism is based on two main pillars:

- All the demand (captive and free, regulated and unregulated) must be 100% covered through long-term electricity contracts and all contracts must be backed up by a physical coverage capability from the seller (firm energy). The compliance with this rule is verified by the Market Operator. Any positive difference between consumed and contracted energy is penalised at the average spot price during the year, or at the cost of new entry, if the latter is higher than the former.
- In order to pursue competition and transparency in the captive market, distribution companies (acting as regulated retailers) can only procure contracts through centralised electricity auctions organised by the Regulator. Free customers are not allowed to procure their electricity through these tenders and, since they must also be 100% covered by long-term contracts, they should procure energy through bilateral negotiations or decentralised auctions.

All contracts are financial instruments and do not affect the dispatch, which is centrally managed by the System Operator. Separate auctions are organised for new and existing power plants. The so-called A1 auctions are designed to set the default tariff price, they have a very short lag period (one year), and thus they just target existing power plants. Tenders with longer lag periods are described hereunder.

#### 7.5.1.2. Long-term auctions for system adequacy and for reserve energy

Brazil conducts two types of long-term auctions: regular tenders for system adequacy and auctions for reserve energy. The first type of auctions is used to procure energy to supply distribution companies' expected demand. These auctions are organised by the Market Operator, who carries out a joint procurement process, and all captive consumers pay the same energy cost. On the other hand, in reserve energy auctions, the Regulator defines the demand to be contracted and purchases supplementary capacity on the top of the one acquired in the regular auctions for system adequacy, in order to enhance the reserve margin. The cost of these contracts is born by all consumers (regulated and free).

In both auction types, the final goal is to foster new investments by reducing the associated long-term risk. Contracts for electricity to be produced by new power plants should have large durations and in Brazil this is obtained by conducting two different auctions for system adequacy every year (with a three- and a five-year lag period, namely A3 and A5 auctions). In the case of reserve energy auctions, the lag period is usually of three years.

There is a long list of technical pre-requisites to register a candidate project to these auctions, including a prior environmental license, a grid access statement, financial qualifications, and technology-dependent documents (such as certified wind production or firm fuel supply agreement). Winning projects have to deposit several guarantees, including a bid bond of 1% of the project estimated investment cost and a completion bond of 5% of the project estimated investment cost. Several penalties are applicable in case of delays: during the period in which the plant is delayed, the contract price is reduced, replacement firm energy contracts may be required depending on the auction type, and the Regulator has the right to ask for contract termination if a delay higher than one year in any of the project milestones is observed.

One relevant feature of system-adequacy tenders is that each generator selected through the centralised auction signs a bilateral contract with each distributor taking part to the auction, in proportion to their share of the total contracted energy.

#### 7.5.1.3. Renewable auctions

In both auction types (regular or reserve), the Government can interfere in the candidate projects with policy decisions. The Government has used this option to organise tenders for the construction of a specific large hydropower projects or to foster RES-E technologies by means of exclusive auctions, which is the origin of the so-called renewable auctions. In 2007, there was one regular auction where the candidate supply was restricted to bioelectricity and small hydro projects.

On the other hand, the reserve energy auction model has been strongly oriented towards non-conventional RES-E development since the very beginning: it was first implemented in 2008, with a specific auction for bioelectricity projects, and from 2009 it has been used to contract wind power projects. A product catered to the peculiarities of wind power generation was designed. This product has specific accounting mechanisms that allow wind farms to compensate in the long run for seasonal and inter-annual wind fluctuations, without affecting the project yearly cash flow, and this design was fundamental to allocate production risk.

#### 7.5.1.4. The price convergence

Table 7.1 shows the results of the most recent auctions held since 2010, illustrating how non-conventional RES-E are currently competing against conventional generation apparently in similar terms.

Table 7.1. Results of recent auctions in Brazil, data from ANEEL, expressed in US$

| | LFA [a] Aug 2010 | | LER [b] Aug 2010 | | Belo Monte [c] 2010 | | A-5 Jul 2010 | |
|---|---|---|---|---|---|---|---|---|
| | MW | $/MWh | MW | $/MWh | MW | $/MWh | MW | $/MWh |
| **Thermal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Hydro** | 0 | 0 | 0 | 0 | 11 233 | 47 | 730 | 55 |
| **Small hydro** | 101 | 88 | 31 | 78 | 0 | 0 | 79 | 92 |
| **Biomass** | 65 | 82 | 648 | 87 | 0 | 0 | 0 | 0 |
| **Wind** | 1 520 | 80 | 528 | 73 | 0 | 0 | 0 | 0 |
| **Total** | 1 686 | 81 | 1 207 | 79 | 11 233 | 47 | 809 | 59 |
| | **A-5 Dec 2010** | | **LER Aug 2011** | | **A-3 Aug 2011** | | **A-5 Dec 2011** | |
| | MW | $/MWh | MW | $/MWh | MW | $/MWh | MW | $/MWh |
| **Thermal** | 0 | 0 | 0 | 0 | 1 029 | 58 | 0 | 0 |
| **Hydro** | 2 120 | 39 | 0 | 0 | 450 | 57 | 135 | 50 |
| **Small hydro** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Biomass** | 0 | 0 | 377 | 56 | 198 | 57 | 100 | 56 |
| **Wind** | 0 | 0 | 861 | 55 | 1 068 | 55 | 977 | 57 |
| **Total** | 2 120 | 39 | 1 238 | 55 | 2 745 | 57 | 1 212 | 56 |
| | **A-5 Dec 2012** | | **LER Aug 2013** | | **A-5 Aug 2013** | | **Summary 2010/2013** | |
| | MW | $/MWh | MW | $/MWh | MW | $/MWh | MW | $/MWh |
| **Thermal** | 0 | 0 | 0 | 0 | 0 | 0 | 1 029 | 58 |
| **Hydro** | 292 | 48 | 0 | 0 | 445 | 55 | 15 405 | 54 |
| **Small hydro** | 0 | 0 | 0 | 0 | 154 | 64 | 364 | 78 |
| **Biomass** | 0 | 0 | 0 | 0 | 647 | 68 | 2 035 | 70 |
| **Wind** | 282 | 45 | 1 505 | 55 | 0 | 0 | 6 740 | 62 |
| **Total** | 574 | 47 | 1 505 | 55 | 1 246 | 63 | 25 574 | 58 |

Small hydro: hydro plants with capacity < 50 MW and reservoir area < 3 $km^2$. Exchange rate: 2 BRL/USD.
[a] A-3 auction restricted only to RES; [b] LER = Leilão de energia de reserva ("reserve energy auction")
[c] Mega hydro plant auctioned in a separate process

First of all, it is noteworthy that Brazil has acquired from 2010-2013 some 25 500 MW at an average (all-in) energy price of 58 US$/MWh. From 2011, both wind and biomass generating units have taken part in the A3 and A5 and from these outcomes one could get the rushed impression that, from the price perspective, conventional and non-conventional generation technologies have already converged. However, this would be a rather hurried conclusion, since, in the case of A3 and A5 auctions, a number of design elements treat differently the diverse generation technologies and there is a difference in the product auctioned for hydro, thermal and wind resources. The main factors that differentiate conventional and renewable technologies are discussed next.

### 7.5.1.5. Firm energy certificates

As mentioned above, in Brazil, all contracts need to be covered by firm energy certificates (FEC), calculated by the Ministry of Mines and Energy, which are assigned to each plant depending on its expected contribution during scarcity conditions. The computation of the number of FEC for new generation projects is a rather complex process, but can be summarised as follows.

- Before the auction, every hydropower or thermal candidate project submits its technical data (variable costs, installed capacity, expected unavailability rates, historical record of inflows, etc.) to a planning company.
- This planning company computes the expected contribution to the security of electricity supply from each plant for a given supply reliability level. The same stochastic hydrothermal scheduling tool used by the System Operator to run the system is employed to simulate the joint operation of all assets in the system, for a set of synthetic inflow scenarios produced by a Monte Carlo simulation process, and to assess the FEC of each project.
- The FEC is a "paper" figure rated in MWh/year. For example, a 1-GW gas-fired plant with a 90% availability factor has a typical FEC of 1 GW (capacity) x 90% (availability) x 95% (FEC "factor") x 8.76 = 7 489.8 GWh/year. A 1-GW hydro plant with a 98% availability factor would have a typical FEC of 1 GW (capacity) x 98% (availability) x 55% (FEC "factor") x 8.76 = 4 721.6 GWh/year. The "FEC factor" translates the different installed capacities into comparable energy contributions to the system security of supply (for a given reliability level).
- In the case of hydro plants, the FEC represents their expected production in dry years. In the case of thermal plants, the FEC depends on its variable operating costs: the lower the unit variable operating cost, the larger the FEC. Under this scheme, a thermal plant that is always available to produce, but whose costs are extremely high would receive a close-to-zero firm energy because of its low expected energy contribution even in dry periods.
- The FEC calculation of wind and biomass plants, however, is carried out based on the energy delivery commitment declaration signed by the agent in the power plant registration act. In the case of wind plants, it corresponds to the production certified at the 50$^{th}$ percentile ("P50") and in 2013 it was revised to P90. In other words, for these RES-E technologies the FEC is not the outcome of an integrated simulation of the unit's operation within the hydropower system, but it is assigned as a declaration by the agent.

**FEC revision procedure**

FECs do not constitute a formal physical delivery obligation for hydro and thermal plants. In fact, the dispatch of the system is centrally managed by the System Operator and production patterns depend on the supply and demand balance and on the water resource availability. Nevertheless, this value is expected to naturally converge to the one observed in the FEC calculation procedure during critical supply periods, as the System Operator uses the same scheduling models employed to calculate the FEC.

During operation, the actual unavailability of resources is measured. In the case of thermal plants, if the measured average unavailability is larger than the one declared for the FEC calculation, then the latter is reduced in the following year. The unavailability indexes are verified and updated in August every year based on the values gathered during the last 60 months (moving average). In case of hydropower plants, FECs can be reviewed every five years. In each revision, it cannot be changed by more than 5% and the limit for its total alteration throughout the project's concession is 10% of the value originally conceded. This rule is valid regardless of whether the project has sold electricity in regulated auctions or to free consumers.

In the case of wind installations, rules differ depending on which market the project has sold energy. Wind projects with sales in the regulated auctions have their FEC adjusted every four years to its average production observed in the four preceding years. Rules for wind projects with sales in the free market have not been defined yet.

As mentioned in chapter two, revisions of the amount of reliability product that each resource can trade in the CRM represents a penalty. The FEC revision penalises generation units for not fulfilling their contracts, and, as it has been presented, in Brazil it is carried out differently for the different technologies. Besides, additional penalties are also implemented.

#### 7.5.1.6. Penalties

In case a project has a reduction in its FEC, penalties apply. Hydropower and thermal projects must buy replacement FECs in the market to make up for any deviation from their contracted FECs. If replacement FECs are not procured, the penalty is as explained above: the largest between the cost of new entry and the average spot price during the past twelve months.

In the case of wind plants, however, different penalty rules apply for sales in the regulated market or through reserve auctions: in the latter case, the four-year settlement has some fixed-price penalties for non-compliance, related to the project price. As it can be observed, different technologies clearly face different penalties.

### 7.5.2. Colombia

Although to a slightly lesser extent, the Colombian power sector is characterised by hydropower predominance and similar price volatility issues than Brazil. Initially, the regulatory instrument implemented to attract new investments was a payment remunerating the available capacity of generation plants. However, especially in the case of hydropower plants, the determination of the value of such capacity payment revealed to be a challenging task for the Regulator and the scheme did not succeed in ensuring availability during scarcity conditions.

Therefore, in 2006 an innovative approach was implemented, whose conceptual basis was to "auction" the capacity payment, leaving this challenging task to the market. The basic principles of the firm energy obligation mechanism have already been presented in previous chapters and they will not be repeated here. OEF auctions are fully focused to guarantee system adequacy. Contrary to the Brazilian case, the Regulator procures firm energy obligations on behalf of the whole system demand in a centralised auction. The demand is not considered as completely inelastic. When launching the auction, the Regulator sets a demand curve, based on the cost of new entry.

Similarly to what happens with the Brazilian auctions, the factor that differentiates between conventional generation and RES-E technologies is the procedure to calculate the firm energy to be assigned to each plant, as well as the penalties established for non-compliance.

#### 7.5.2.1. ENFICC: The Colombian firm energy certificates

In order to participate in the auction, generators must be backed by physical resources to be certified as capable of producing electricity during scarcity conditions. The Regulator has established methodologies for the calculation of these firm energy certificates (also called ENFICC), which differ for each technology. The methodologies applied to thermal and hydropower plants have already been presented in chapter two (section 2.5.4) and in chapter five. Methodologies for RES-E technologies are discussed hereunder.

#### 7.5.2.2. RES-E technologies in the reliability charge mechanism

In 2010, through Resolution no. 180919, the Ministry of Mines and Energy of Colombia adopted an indicative action plan for the unfolding of renewable energy and energy efficiency, defining specific targets of penetration of renewable energy in the power sector (3.5% in 2015 and 6.5% in 2020). However, no explicit RES-E support mechanism was considered by the action plan.

In any case, at least from the regulatory perspective, the full integration of RES-E in the auction mechanism has already begun to take place. After some debate in literature[61], since 2011, although not a single project was among the winners, wind installations could fully take part in the firm energy obligation auctions. CREG (2011) determines the methodology to calculate both the ENFICC Base and the ENFICC 95% (the maximum ENFICC that can be offered in the Reliability Charge auctions) for the case of wind installations, differentiating it for wind farms with and without 10-year wind speed studies. For those projects without 10-year wind speed studies, CREG (2011) sets an ENFICC Base for wind

[61] See for example Vergara et al. (2010) and Botero et al. (2010).

farms that considers a contribution to the firm energy equal to 6% of their nominal power, which is well below the average capacity factors of this technology.

#### 7.5.2.3. Penalties

The firm energy obligation is a daily obligation, this meaning that if the strike price is exceeded only in one hour, committed resources must provide their firm energy during the entire day. The strike price automatically becomes a cap price in the short-term market for those generators selected through the auction. If a generator is not able to fulfil its commitment during scarcity conditions, it must cover its obligation by acquiring electricity in the spot market, at the uncapped spot price. As mentioned in chapter five, this approach represents only an implicit penalty.

### 7.5.3. Peru

After the 1992-liberalisation, the Peruvian electricity market was based on bilateral contracts between distributors and generators that were capped by the so-called busbar energy tariffs. These tariffs were calculated by the Regulator based on the expected average marginal price in each node. The determination of the busbar tariffs had always been a controversial issue and generators criticised its decoupling from the real marginal price. The situation became unsustainable in 2004, when the marginal price increased strongly without this being reflected in the energy tariff of regulated customers. As a consequence, generators decided not to renew existing contracts with distribution companies (Maurer and Barroso, 2011). This finally resulted in 2006 in a new scheme introduced through Law 28832. Long-term electricity auctions were implemented to achieve a double goal, i.e., to define the energy tariff in a competitive way and, at the same time, to enhance the entry of new and more reliable generation in the system.

The reform introduced the obligation for distribution companies to contract the expected demand of their captive consumers three years in advance (i.e., the lag period), signing contracts (with either existing or new plants) that must have durations larger than five years for 75% of the demand. Even if the scheme is completely decentralised, a strong regulatory control on the tenders is applied. The auction format and indexation formulas must be approved by the Regulator, who also sets a price cap for each auction.

In 2011 the Government, through the Agency for the Promotion of the Private Investment (*Proinversión*) decided to launch a second type of auctions. These tenders target the construction of new hydropower plants (15-year contract durations) and dual-fuel (gas and diesel) turbines (20-year duration contracts); they are project-specific and the lag period is also tailored to the project.

#### 7.5.3.1. Renewable auctions

In 2008, Peru decided to implement a support scheme for RES-E development in the country. Decree 1002/2008 introduced a mechanism of incentives for those projects exploiting non-conventional RES-E (the so-called RER technologies, i.e., wind, biomass, small hydro, and solar). The mechanism considers a premium on the top of the market price in order to guarantee a 12% rate of return, which must be assigned through competitive bidding and it is settled once a year.

Despite the complex technicalities of the scheme, also the Peruvian mechanism can be considered as based on a renewable auction that fixes in advance the remuneration for generators. Selected bidders sign 20-year contracts directly with the Ministry of Energy and Mines and the premia are collected from end-customers through a surcharge included in the access tariff.

This remuneration scheme is based on an ex-ante calculation carried out by the Regulator, who forecasts short-term prices during the following year and computes the premia necessary to reach the 12% rate of return. Premia are provided in the form of monthly payments to renewable generators. Unbalances between the expected and the real spot market price or between the contracted and the actual electricity injections of the generators are settled once a year and included in the following-year remuneration. However, if the energy produced exceeds the contracted one, the difference is settled at the market price and not at the contracted remuneration. Table 7.2 presents the results of recent auctions, for both conventional and renewable technologies.

Table 7.2. Results of recent auctions in Peru, data from CAF (2012), expressed in US$

| | **Law 28832** | | **Proinversión 2011** | | **RER Jan. 2010** | | **RER Aug. 2011** | |
|---|---|---|---|---|---|---|---|---|
| | MW | $/MWh | MW | $/MWh | MW | $/MWh | MW | $/MWh |
| **Large hydro** | 202 | 36.7 | 544 | 48.25 | | | | |
| **Thermal** | 154 | 40.7 | 854 | 90.63* | | | | |
| **Wind** | | | | | 142 | 81 | 90 | 69 |
| **Biomass** | | | | | 27 | 60.6 | 2 | 99.9 |
| **Small hydro** | | | | | 181 | 60.5 | 104 | 53.2 |
| **Solar** | | | | | 80 | 221.4 | 16 | 119.9 |

* $/kW-year

#### 7.5.3.2. Penalties

Contracts signed under the framework of Law-28832 auctions consider both power and energy. Firm power and firm energy are assigned to each plant according to methodologies established by the Regulator. The difference between the energy actually produced by a generator and the contracted one is settled at the short-term market price. For the power, the reference price is calculated by the Regulator based on the cost of new entry. As in the Colombian case, the only penalty considered by these contracts is an implicit one. This is also the case for plants selected through the *Proinversión* auctions.

In the case of RES-E plants selected through Decree-1002 auctions, the mechanism includes an explicit penalty scheme that is applied whenever the energy injected in a year is less than the contracted one. The penalty factor used is equal to the percentage of the missing energy over the contracted one and it is multiplied by the total remuneration received for that year. This explicit penalty is collected in the following year settlement. However, being the settlement of this penalty carried out on a yearly basis, what is penalised is not the non-dispatchability and the intermittency of RES-E technologies (which occurs in the short term), but rather the underperformance due to an overestimation of the load factor of the plant by project promoters (that is related to the long term and can be checked on a yearly basis).

When comparing RES-E and conventional technologies, another difference that must be taken into account lies in the fiscal incentive provided to renewable generators. Decree 1058/2008 introduced a scheme of accelerated depreciation equal to 20% per year (this means a 5-year tax postponement) for all the investments on machines, equipment and constructions of RES-E projects.

### 7.5.4. Comparison

The discussion provided above regarding the interaction between system-adequacy and renewable energy auctions is summarised in Table 7.3 for the three countries analysed in this section (Brazil, Colombia, and Peru). Brazil is the country where this interaction is more evident, with RES-E technologies entering the system not only through renewable-specific auctions, but also through standard system-adequacy auctions. However, as highlighted in the table, this entrance is favoured by the different contract provisions, in terms of firm energy calculation and penalties for underperformance, which discriminate in favour of RES-E technologies. On the other hand, in Colombia, where no renewable-specific auction has been implemented yet, the only entry point for RES-E technology is the system-adequacy auction. However, due to the daily settlement of the firm energy obligation contract, the competitive position of non-dispatchable generation technologies is weakened, and no penetration of RES-E in these auctions has been observed. Finally, in Peru no RES-E participation in system-adequacy auctions has taken place and renewables are entering the system exclusively through RES-E specific auctions, characterised by a comprehensive explicit penalty scheme.

Table 7.3. Comparison of auction schemes implemented in Brazil, Colombia, and Peru

| | **Brazil** | **Colombia** | **Peru** |
|---|---|---|---|
| **System-adequacy auctions** | | | |
| Buying side | Captive demand | All-system demand | Captive demand |
| Auction process | Centralised | Centralised | Decentralised |
| Firm energy/capacity | FEC | ENFICC | Firm power + firm energy |
| Penalty | FEC reduction in case of underperformance + contracts not backed by FECs penalised at the maximum between the cost of new entrant and the average spot price | Implicit penalty (energy not delivered must be replaced and procured at the spot price) | Implicit penalty (power and energy not delivered must be replaced and procured at the short-term price) |
| Potential RES-E participation | Yes | Yes | Yes |
| Actual RES-E participation | Yes (wind power) | No | No |
| Conventional/RES-E discrimination | Different provisions (FEC based on a declaration of the project promoter; different settlements in case of underperformance) | Same provisions | Same provisions |
| **Renewable energy auctions** | | | |
| Remuneration | Long-term contract at fixed price from the auction | No specific renewable energy auction in place | Premium on the top of the short-term market price for achieving 12% rate of return |
| Firm energy | Calculated and declared by the project promoter | | Calculated and declared by the project promoter |
| Specific penalty | No (same penalties as in the case of system-adequacy auctions) | | Yes (complex penalisation scheme with explicit penalty in case of underperformance) |

## 7.6. Conclusions and recommendations

The participation of renewable technologies in capacity mechanisms is a highly controversial issue. The actual ability of RES-E technologies to contribute to the security of supply of a power system depends on several factors. The deployment of intermittent generation has different impacts in energy-constrained and capacity-constrained power systems. In the former, RES-E technologies do not have a negative impact on the security of supply and they can actually contribute to generation adequacy. In capacity-constrained systems, the penetration of non-dispatchable power plants stresses the need for flexible resources and the participation of RES-E technologies in CRMs may be more difficult, even if not impossible.

RES-E technologies, as any other technology, should be exposed as much as possible to market signals. If they are not, they will not be responsive to the system's needs that these signals express and their impact on the operation could be hard to assimilate. Therefore, RES-E technologies should be allowed to participate also in generation-adequacy mechanisms, to the extent RES-E agents consider feasible and acceptable in terms of risk. Obviously, the participation of RES-E technologies in capacity mechanisms, as in any other market segment, should be coherent with the support being received by these technologies out of the market. In this sense, RES-E support schemes must become more market-compatible in the future, fostering investments in renewable technologies, while minimising market distortions.

Despite economic theory seems to endorse RES-E participation in CRMs, in the United States and in Europe the involvement of renewable power plants in capacity mechanisms has been very limited until now. This chapter focused therefore on South America, a region where renewable and conventional technologies are already competing in the same tenders.

Long-term electricity auctions are nowadays the main driver for capacity expansion of electricity systems in South America, where they have acquired during the last decade a central role in the regulation of several power sectors. Initially, auctioning schemes worked as a system-adequacy mechanism, which fosters the investment in new generation plants by competitively assigning long-term contracts that fix part of the generators' remuneration, thus hedging their risks. Nonetheless, following this regulatory trend, recently these mechanisms have started being used also for the promotion of non-conventional renewable energy technologies.

At the beginning, these two contexts were considered as separated. Conventional technologies (large hydro, fossil-fuels thermal plants) competed in system-adequacy auctions and non-conventional renewable energy technologies in RES-E-specific auctions. The former were supposed to involve large quantities of energy (or firm energy) at market price, while the latter should cover lower quantities at relatively higher prices. However, as detailed in this chapter, the most recent renewable auctions carried out in Brazil and Peru contracted renewable energy supply at very competitive prices, difficult to be imagined just a few years ago.

These until-now separated schemes, system-adequacy auctions and RES-E-specific auctions, seem now to be close to convergence, and this idea can be reinforced by the participation of wind energy projects in recent Brazilian conventional A3 and A5 auctions and by the issue of CREG (2011), which allows wind farms to take part in the Colombian reliability charge mechanism.

Nevertheless, as discussed and evidenced throughout this chapter, in all those countries and regulations where these mechanisms seem to be merging together, it is possible to observe how conventional and renewable technologies are still far from competing under parity of conditions. The main differential factor is the way the contribution to the security of supply of these technologies is assessed and settled (constraints on tradable quantities, firm energy and firm capacity, performance incentives) and the implication that this issue has on the design of the reliability product. This and other factors impede, for the time being, to have a level playing field where conventional and renewable technologies compete for the supply of electricity demand.

# 8. CONCLUSIONS AND FUTURE WORK

*This final chapter of the thesis summarises the main findings of the research developed here and draws some main recommendations on the design of capacity remuneration mechanisms. The research questions defined in the introduction have been answered throughout the document and the responses are resumed in these conclusions. Finally, further work that could enrich the analysis presented in this thesis is identified.*

## 8.1. Summing-up

An increasing number of power systems rely on capacity remuneration mechanisms (CRMs) to foster an efficient expansion of the resource mix and to guarantee the reliability of electricity supply. Some countries included explicit mechanisms targeting system adequacy from the very beginning of the liberalisation process. Some others initially opted for energy-only market designs, but had to introduce capacity mechanisms at a later stage. CRMs are currently on the top of the regulatory agenda in many power systems, especially in Europe.

Capacity remuneration mechanisms "shape" the power sector where they are introduced. While in force, the design of the CRM will affect the mix of technologies in the generation segment, the penetration of renewables, and the development of demand response and storage. In order to perform efficiently this central role, capacity mechanisms must rely on a very careful and accurate design, tailored to the objectives pursued through them and coherent with other aspects of the power sector regulation in place. The experience with these regulatory instruments demonstrated that their effectiveness is determined by design details that may look as secondary at a first glance. Furthermore, capacity remuneration mechanisms are currently facing new challenges, resulting from the fast-paced evolution of power sectors in terms of new technologies, new actors, and new business models.

This thesis took advantage of the experience developed so far with CRMs in those countries that already introduced them in order to draw guidelines for an efficient design of these instruments. It first provided a classification of CRMs based on their design elements and then it focused on three main challenges that capacity remuneration mechanisms have to confront, namely the interaction with regional markets, the need for well-designed performance incentives, and the interaction with renewable technologies. This final chapter summarises the main findings of the research presented in this document and identifies some future work that could enrich it.

## 8.2. Main contributions and policy recommendations

### 8.2.1. Design elements of CRMs

The second chapter of this thesis presented a CRM taxonomy based on the design elements that compound these mechanisms. These elements represent decisions that the policy maker has to take when designing the regulatory intervention. This kind of classification has the advantage of embracing all possible capacity remuneration approaches and it avoids confusion between, for example, the procurement process and the reliability product. The design-based analysis was extended in chapter five to performance incentives, a central feature in modern CRMs. All the design elements examined in this thesis are summarised in Table 8.1, together with possible options for their selection.

Table 8.1. Design elements of capacity remuneration mechanisms

<table>
<tr><td colspan="13">Procurement mechanism</td></tr>
<tr><td>Level of centralisation</td><td colspan="6">Centralised</td><td colspan="6">Decentralised</td></tr>
<tr><td>Demand estimation</td><td colspan="6">Centralised</td><td colspan="6">Decentralised</td></tr>
<tr><td>Buying side</td><td colspan="4">Captive demand</td><td colspan="4">Whole-system demand</td><td colspan="4">Free demand</td></tr>
<tr><td rowspan="5">Selling side</td><td colspan="6">Existing plants</td><td colspan="6">New plants</td></tr>
<tr><td colspan="6">Technology-specific</td><td colspan="6">Technology-neutral</td></tr>
<tr><td colspan="6" rowspan="2">Domestic resources</td><td colspan="6">Cross-border resources</td></tr>
<tr><td colspan="6">Interconnectors</td></tr>
<tr><td colspan="6">Generation resources</td><td colspan="6">Demand resources</td></tr>
<tr><td colspan="13">Contract provisions</td></tr>
<tr><td>Lag period</td><td colspan="12">From few months (existing plants) to several years (new plants with long construction time)</td></tr>
<tr><td>Contract duration</td><td colspan="12">From one year to many years (risk hedging)</td></tr>
<tr><td>Indexation formulas</td><td colspan="12">Indexed to fuel prices, currency exchange rates, etc.</td></tr>
<tr><td>Financial warranties</td><td colspan="12">From low to very high warranties</td></tr>
<tr><td colspan="13">Reliability product</td></tr>
<tr><td rowspan="2">Product</td><td colspan="6">Capacity</td><td colspan="6">Energy</td></tr>
<tr><td colspan="3">Installed capacity</td><td colspan="3">Availability</td><td colspan="3">Financial contract</td><td colspan="3">Physical delivery</td></tr>
<tr><td>Critical period indicator</td><td colspan="6">Reference market price</td><td colspan="6">Grid parameters or emergency actions by TSO</td></tr>
<tr><td>Obligation (in case of delivery)</td><td colspan="6">Fixed</td><td colspan="6">Load-following</td></tr>
<tr><td>Constraints on tradable quantities</td><td colspan="12">Upper and lower limits, based on the expected capability of providing the reliability product</td></tr>
<tr><td colspan="13">Performance incentives</td></tr>
<tr><td>Penalty rate</td><td colspan="6">Based on contract price</td><td colspan="6">Based on cost of new entry</td></tr>
<tr><td>Performance credits</td><td colspan="6">None</td><td colspan="6">Overperformance payments</td></tr>
<tr><td>Exemptions</td><td colspan="6">No exemption</td><td colspan="6">List of exemptions</td></tr>
<tr><td>Penalty caps</td><td colspan="6">Based on contract price</td><td colspan="6">Based on cost of new entry</td></tr>
<tr><td>Time frame of the cap</td><td colspan="4">One month</td><td colspan="4">One dry season</td><td colspan="4">One year</td></tr>
</table>

As mentioned in chapter two, no generic recommendation can be drawn regarding the selection of each single element, because CRMs must be tailored to the power system in which they are introduced and to the specific objectives pursued by the regulator.

Nonetheless, it is important to stress the strong correlation among all design elements, which cannot be selected in isolation from each other.

In terms of procurement process, the main decision probably concerns the centralisation level. As observed for example in South American countries, a decentralised system-adequacy mechanism, organised around bilateral contracting, may not be the most efficient solution in markets characterised by a certain degree of vertical integration between generators and retailers (this is a problem not only in South America, as analysed in chapter two). In such a context, a centralised auction seems to be the best approach in terms of transparency and competition. Furthermore, a centralised procurement covering the whole system demand allows to better exploit the economies of scale at the generation level.

As regards contract provisions, it has been underlined how the selection of lag period and contract duration may implicitly discriminate among technologies. Very capital-intense power projects, as hydropower reservoirs or nuclear plants, need long lag periods to cover the construction time and large contract durations to hedge the investment risk. Therefore, a biased definition of these parameters may result in poor performances in terms of attracting new investments.

As highlighted in more than one chapter of this thesis, the most relevant design elements of a CRM are those that define the reliability product. The latter must be accurately tailored to the specific needs of the system and to the typology of stress events that are likely to affect it. If the regulator fails in designing the reliability product, the demand will procure and pay for a service that does not help relieve scarcity conditions in the system and improve reliability. Another central decision concerns the possibility of administratively setting upper and lower limits to the amount of reliability product that resources can trade in the capacity mechanism.

Finally, both chapter two and chapter five stressed the importance of performance incentives in order to have a capacity mechanism that, beyond fostering investments, also achieves its main objective, i.e., to guarantee the security of electricity supply. The penalty rate must be high enough to incentivise committed resources to invest in measures that improve their reliability. Exemptions and penalty caps, if any, must be defined with the objective of not distorting the efficient signal conveyed by the penalty.

### 8.2.2. CRMs and regional markets

Regional electricity markets provide large efficiency gains and potentially huge economic savings for all the countries involved. This is true in the short term (lower system operation costs), but also, and more relevantly, in the long term (optimal resources exploitation and coordinated capacity expansion). If the harmonisation of the electricity market is limited to the short term (day-ahead to real-time trades) and the long-term market represented by capacity remuneration mechanisms is not coordinated at all, the largest part of the efficiency gain gets lost. Different countries can implement diverse capacity mechanisms (reflecting different regulatory objectives and pursuing different reliability levels), but these markets, and the remuneration they provide, must be opened to cross-border resources located in the regional trading environment.

However, opening CRMs to resources located abroad requires a very strong commitment from the countries involved in the regional market. This implies the need for a robust institutional framework, which is not easy to build. A paradigmatic example of these complexities can be found in the European Union, which can rely on one of the most advanced models of energy market integration. Several countries are in the process of introducing a CRM, but for the time being, the explicit participation of cross-border resources has been excluded.

Chapter three and chapter four focused on the two main barriers that are hampering cross-border participation in European capacity mechanisms, namely the uncertainty about the consideration of long-term contracts in the short-term market coupling, and the mistrust of the fulfilment of cross-border contracts during regional scarcity conditions.

The first barrier stems from the fact that, in the regional short-term market, flows through the interconnections will be fully determined by the coupling algorithm, which only considers the equilibrium of supply and demand in the different market zones. The algorithm does not take long-term contracts into account, because they could distort the economic efficiency and cause flows from zones with higher prices to zones with lower prices. In this context, it may not be possible to guarantee the fulfilment of CRM contracts when two or more neighbouring countries are suffering concurrent scarcity conditions. In chapter three, it was argued that, if capacity mechanisms are designed properly, using a reference market price as critical period indicator, this uncertainty could be solved through the introduction of a conditional nomination rule in the coupling algorithm. The conditional nomination does not interfere with market functioning during normal operation, but it allows to solve a tie situation when market prices, due to the activation of price caps, are not representative anymore of consumers' utilities. This does not affect economic efficiency and permits to make supply available to those consumers that paid for it in the "reliability market" represented by CRMs.

The second barrier derives from the existence in many network codes of clauses that maintain that exports to other systems will be interrupted in case of domestic emergencies. This generates a lack of confidence in the firmness of the supply to be received from another system. If the system operator of a neighbouring country can curtail the flow through the interconnection, no matter of CRM contracts signed to properly assign the supply during regional scarcity conditions, then the only option is to pursue some sort of electricity autarky. However, this solution is highly inefficient and it must be avoided, as recognised also by the European Commission in the Security of Supply Directive (in its article 4.3). As mentioned in chapter four, in order to enforce the Directive, national and regional network codes must be modified accordingly, restricting *force-majeure* conditions and preventing system operators from blocking exports when they are the result of an efficient market clearing.

### 8.2.3. CRMs and performance incentives

Most of the initial capacity mechanisms (starting from capacity payments implemented in Chile in 1982 up to some of the most recent designs) failed in strictly coupling the capacity remuneration provided to each resource with its performances during stress events. In some cases, this was due directly to the lack of an explicit penalty scheme that incentives resources to perform according to their commitment. In other cases, the problem was related with the definition of the critical period indicator, which never or very rarely triggered scarcity conditions during which performances could be assessed. The empirical evidence from the American continent shows that the lack (or flawed design) of performance incentives results in a costly CRM that fails in achieving its main objective, i.e., improving the reliability of electricity supply. This situation was defined by Peter Cramton as the "money for nothing" problem.

Chapter five analysed international experiences (ISO New England, PJM, and Colombia) to stress the need for performance incentives and to identify the design elements of these penalty schemes. Very recent reforms carried out in the United States, inspired by the pay-for-performance principle, were examined in detail. Such empirical assessment allowed to draw some recommendations for the design of effective performance incentives, which were already summarised in section 8.2.2.

Chapter six complemented the empirical analysis through a model-based assessment of the impact of penalty schemes on the outcomes of a capacity remuneration mechanism. The results of the simulation model suggest that explicit penalties can modify the merit order of a CRM auction, causing the exit of non-firm units and the entrance of new and more reliable generation plants. This obviously results in the occurrence of fewer scarcity conditions and in the improvement of the security of supply. The model undertakes also an economic analysis, which suggests that higher penalties result in an increase of the overall cost of the capacity market, but that this higher cost may be offset and surpassed by the reduction in the overall cost of the energy market (including economic losses related to non-served energy).

### 8.2.4. CRMs and renewable technologies

The penetration of renewable energy technologies in the power sector is modifying the security-of-supply problem and this is obviously reflected in the design of capacity remuneration mechanisms. The intermittency of RES-E units and the impossibility of forecasting their output beyond a short advance diversely affect the operation of power systems. As explained in chapter seven, energy-constrained systems, as hydro-dominated power sectors, can rely on a very large amount of flexible capacity, which can cover the intermittency of renewable energy sources and increases the amount of RES-E generation that the system can assimilate. On the other hand, in capacity-constrained systems, the large variability of renewable technologies may constitute a problem. Intermittent generation must be backed by flexible thermal units with fast-ramping capabilities that permit them to cover a sudden change in the renewable output. The fast penetration of RES-E technologies is actually causing a shift in security-of-supply concerns from pure adequacy to flexibility issues (the evolution of the Italian CRM design is paradigmatic in this context).

The installation of renewable power plants has been fostered so far by RES-E support schemes, which usually provide a remuneration on the top of market incomes. These schemes can be considered as technology-specific capacity mechanisms. As the cost of producing electricity from renewable energy sources is swiftly decreasing, RES-E power projects may soon be able to compete with conventional technologies in standard capacity mechanisms, if rules allow their participation. Chapter seven studied from a theoretical point of view whether this participation is beneficial and advisable or not, whether CRMs and RES-E support schemes will merge in one single mechanism in the future, and which rules must be harmonised to create a level playing field for the competition of renewable and conventional technologies.

Renewable technologies must be integrated in the wholesale market, for their penetration to be sustainable. This implies that RES-E resources must be exposed as much as possible to market signals, including those conveyed by the capacity mechanism (through its performance incentives). Renewable generation should be allowed to participate in CRMs and it should be exposed to market signals that prompt it to maximise its availability during periods in which power shortages are more likely to occur. This will not always imply the disappearance of RES-E support mechanisms. These schemes may still be needed to complement the net revenues obtained by renewable resources in the different segments of the wholesale market. However, the incentive made available to these plants must obviously consider the remuneration provided by the CRM.

This being said, if renewable and conventional technologies have to compete in the same markets, they must be subject to the same rules. A detailed analysis of the South American experience, where RES-E technologies have already been cleared in long-term electricity auctions that had usually targeted conventional generation, demonstrated that this is not always the case and that some rules still need to be harmonised. Especially in terms of firm energy/capacity calculation (used to define constraints on tradable quantities) and settlement of performance penalties, many differences can still be observed in the treatment received by renewable and conventional plants. Without a proper equalisation of these rules, the participation of RES-E may distort the outcome of the CRM and result in economic inefficiencies.

## 8.3. Future work

This thesis encompassed a variety of subjects that, according to the researcher, will have a strong impact on the design of future capacity remuneration mechanisms. Due to the vastness of the topic, the research presented in this document had to leave some “grey areas” in which the analysis could not be deepened as desired. Such grey areas represent opportunities for future research lines and they are briefly outlined in this section.

In terms of cross-border participation in national capacity mechanisms, an essential contribution of this thesis was the proposal of introducing a conditional nomination rule in the market-coupling algorithm. Such conditional nomination should set the dispatch when regional scarcity conditions are in place and the activation of price caps does not permit to efficiently assign the available capacity. This simple concept (allowing market agents to specify in which zone their power injection has to be withdrawn when certain conditions are met) must be translated in a set of restrictions whose definition is not obvious and depends on the design of the algorithm. A future research line could study in detail the current market-coupling algorithm used in the European Union (EUPHEMIA) and propose possible restrictions to be included in the code in order to allow the introduction of the conditional nomination.

Another grey area, which was not analysed in the document, is how to allow cross-border participation in a CRM when the critical period indicator used by the mechanism is not a pre-defined reference market price. In chapter three, the subject was examined through a case study based on a capacity auction for the procurement of reliability option contracts. This approach results from the belief that the market price is the best thermometer of scarcity conditions and that it should be used, whenever it is possible, as critical period indicator. However, many systems are introducing CRMs in which the obligation to deliver the committed capacity is triggered by some emergency actions taken by the system operator. In this case, it could be difficult to guarantee the fulfilment of cross-border CRM contracts without affecting the economic efficiency of electricity trades. Further research could be conducted on this topic in order to understand whether explicit participation of cross-border resources is still possible or only a statistical approach is feasible in these contexts.

An alternative could be the so-called interconnector-led approach, which considers the direct participation of interconnections as reliability providers in the capacity market, usually subject to the same rules applying to domestic resources. This solution has already been applied in the second capacity auction run in the United Kingdom (DECC, 2015) and it has been proposed for the French capacity market (RTE, 2015). However, if the interconnector-led approach could make sense in the presence of merchant lines, allowing interconnectors to participate in CRMs in regional markets where most of the interconnections are owned by partnerships of TSOs (as in the European context), is an unfortunate solution. First, it gives rise to a significant conflict of interest between the TSO in its role of delivering body of the CRM (that undertakes the procurement process and manages shortage events and penalties) and the TSO in its role of resource participating in the CRM. Second, the participation in the capacity market implies the exposure to the market risk deriving from the capacity obligation and this is incompatible with the regulated nature of the transmission activity. All these aspects should be further investigated.

As regards the simulation model used in chapter six to study the impact of the explicit penalty on CRM outcomes, many research “veins” had to be left unexplored due to the lack of time. The model assessed how an increase in the penalty rate affects differently existing and new resources. This approach could be extended to refurbishment projects, which, as observed in the British Capacity Market, are subject to an intermediate treatment. Nonetheless, the most promising further research that could be undertaken through the model is probably an analysis on the impact of the reference market selection. The model considers reliability option contracts in which the obligation to deliver is triggered by the day-ahead market price, when it exceeds a pre-established strike price. The choice of the day-ahead market as reference market allows committed resources to take actions in order to be dispatched and deliver during scarcity conditions, thus fulfilling their obligation. If a shorter-term market was selected as reference market, only flexible resources would be able to modify their output rapidly enough to fulfil the obligation. Slow-ramping units would incur more frequently in penalties for underperformance and this would be reflected in their bids in the reliability-option market. In a power sector environment in which flexibility is a growing regulatory concern, this research could provide very relevant information to policy makers.

As concerns the participation of intermittent RES-E technologies in capacity mechanisms, the theoretical analysis presented in chapter seven could be extended to understand which CRM design elements are more likely to affect renewable participation. Some reliability products are more suitable than others to be provided by an intermittent generation technology. Another interesting research is to study international experiences with methodologies to calculate the firm energy/capacity that an intermittent resource should be assigned and to draw recommendations on this issue. At a first sight, very different approaches are being followed for the de-rating of RES-E technologies. However, a transparent and straightforward methodology for this calculation is pivotal if the participation of renewable projects in capacity mechanisms is to be fostered.

# List of Publications

## Journal articles

Mastropietro, P., Herrero, I., Rodilla, P., Batlle, C., 2016. A Model-Based Analysis on the Impact of Explicit Penalty Schemes in Capacity Mechanisms. Applied Energy, Volume 168, Pages 406-417. **JCR impact factor 5.613** (2014)

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# CURRICULUM VITAE

Paolo Mastropietro is an environmental engineer specialised in energy and sustainability. He was born in Rome, Italy, on 24 December 1984. He obtained his pre-university diploma from the "Edoardo Amaldi" sciences' secondary school in 2003 and he received his Bachelor's (2007) and Master's Degree (2009) from the University of *Roma Tor Vergata.* After two years of work experience in the private sector, between Spain (*NTDA Energía*) and Italy (PNO Consultants), Paolo was selected in 2011 for the UNV (United Nations Volunteers) Programme and he served for one year as Project Officer at the Addis Ababa UNEP (United Nations Environmental Programme) Liaison Office. In Ethiopia he also worked as a consultant at Project Gaia, an American-based NGO working in the bio-energy sector.

In 2012, Paolo joined the Institute for Research in Technology of Comillas University in Madrid to serve as Assistant Researcher in the framework of the SETS (Sustainable Energy Technologies and Strategies) Erasmus Mundus Joint Doctorate. Besides developing his thesis, he carried out consultancy activities in the field of power system regulation (commissioned, among other, by *Fondazione Centro Studi Enel*, the Inter-American Development Bank, and IRENA). In the last years, he contributed to the publication of several scientific papers and project deliverables.

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